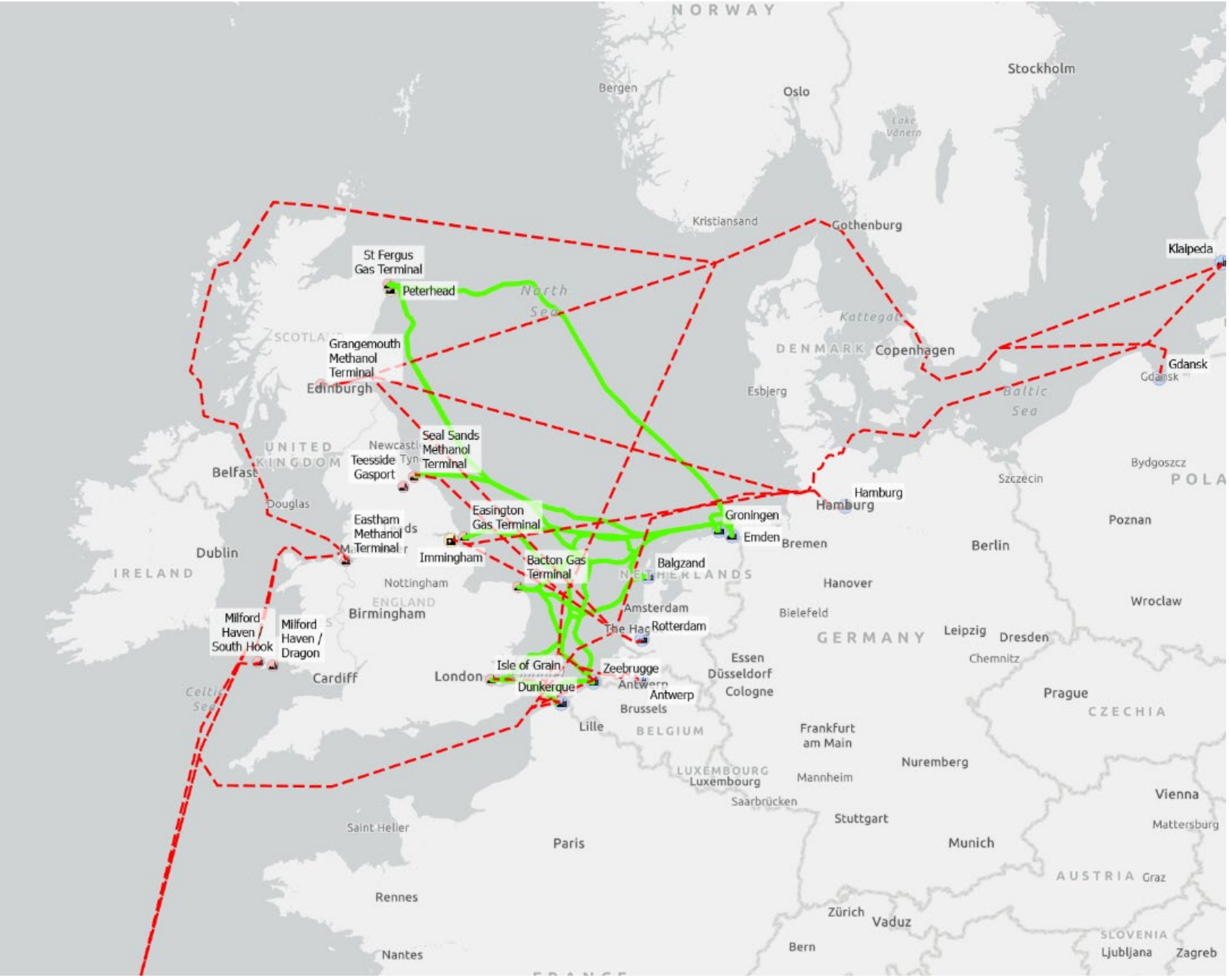
UK Department for Energy Security and Net Zero

The potential for exporting hydrogen from the UK to continental Europe

Hydrogen Technical Advisor WP45

V1 | 10 May 2024



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Introduction

The UK Department for Energy Security and Net Zero (DESNZ) commissioned Arup to deliver a study considering the strategic, technical, and economic factors of hydrogen export from the UK to continental Europe.

The study aimed to build the evidence base on hydrogen export and inform decision making on further support for hydrogen export from the UK to continental Europe and was split into three main sections:

1. Setting out the UK Opportunity with regards to hydrogen export.
2. A pre-feasibility assessment of potential export routes for hydrogen from the UK, considering pipeline and non-pipeline transportation methods. The assessment identified potential export locations and import locations for the two transportation methods.
3. A UK-specific levelised cost of transport (LCOT) model

This study also provides an overview of the potential export routes available for the UK to export hydrogen to Europe and outline the UK-specific advantages and disadvantages for that export.

UK Opportunity

The UK is a leader in the development of low carbon hydrogen production infrastructure. The main objective of stimulating production in the UK has been to encourage industry users in the UK to switch to low carbon hydrogen for feedstock and fuel, and hence drive UK decarbonisation. Projected demand for low carbon hydrogen in the UK under the net zero 2050 emissions scenarios is significant. A strong pipeline of low carbon hydrogen projects has been established to meet this demand, with projects continuing to be developed and progressed towards final investment decision (FID). This has encouraged policy makers and industry to consider the potential of connecting UK hydrogen infrastructure with continental Europe, in the same way as the natural gas networks are interconnected today, once a thriving hydrogen economy in the UK has been established. An analysis of Europe's hydrogen ambitions at the European Union level, and country level was completed to determine whether demand for hydrogen imports in Europe is likely to be sufficient to warrant further work on an export route(s) from the UK.

To begin with, the infrastructure connecting UK supply with UK demand must be developed. Project Union and other local hydrogen locations have made significant strides towards the development of a UK hydrogen transportation network. The UK Government has agreed, in principle, with the potential benefits of a core UK hydrogen network as set out by the National Infrastructure Council (NIC) in their second National Infrastructure Assessment. The NIC recommendation suggested connecting production locations from the south coast to the northeast of Scotland and extending east and west to Norfolk and northwest England.

The appetite for hydrogen imports in Europe is high, the EU set out a target to import 10 million tonnes (approximately 395 TWh higher heating value) of low carbon hydrogen per year by 2030. Three strategic import corridors were identified and prioritised in the EU hydrogen strategy: a North Sea corridor, a Mediterranean corridor and a Ukrainian corridor as shown in Figure 1. Due to the war in Ukraine the North Sea and Mediterranean will be the first to be developed. The UK is positioned well to form part of the North Sea corridor.

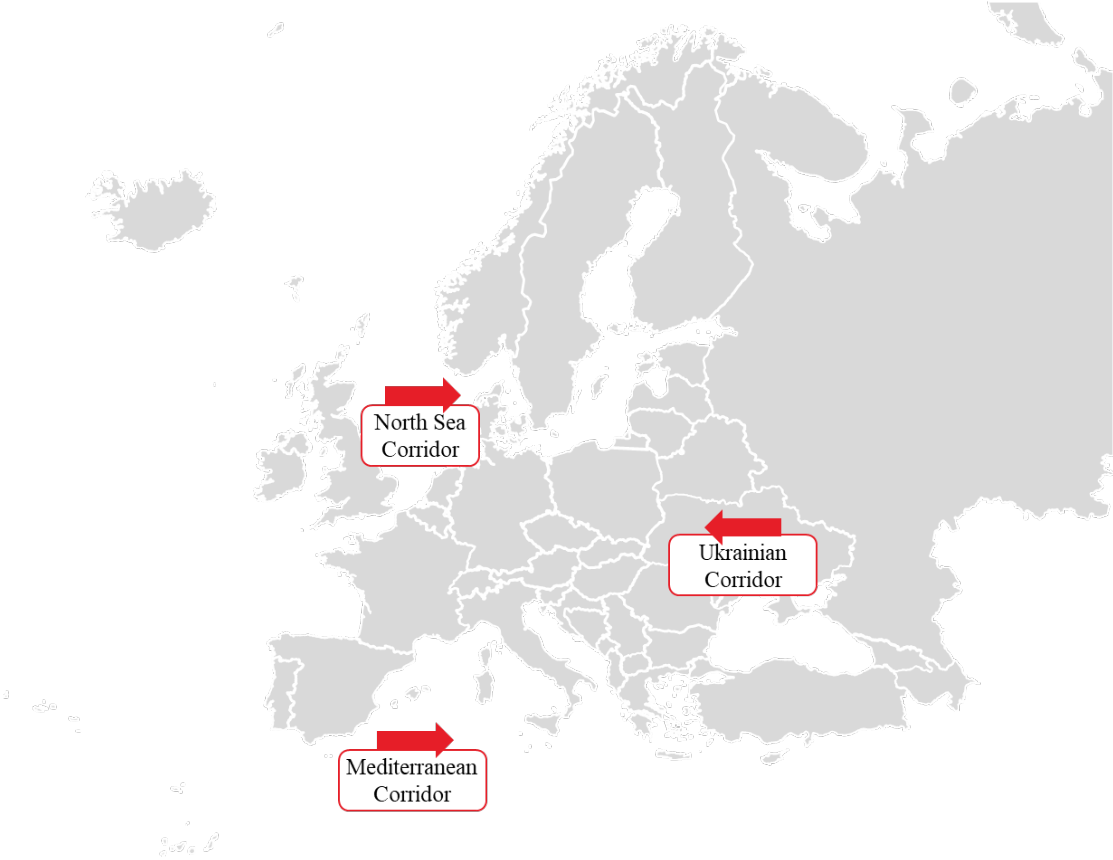

Figure 1: Hydrogen import corridors identified in the EU hydrogen strategy.

Countries in northwest Europe, particularly Belgium, the Netherlands, and Germany are leading the development of low carbon hydrogen development in mainland Europe and have already committed public spending to the development of a hydrogen network, with a focus on imports. Development of hydrogen production, import, transportation, and storage infrastructure in Europe to date has centred around large demand areas in the industrial regions of northwest Germany and the Netherlands, so the UK is well positioned geographically to facilitate a pipeline connection to these import locations.

Currently, national hydrogen strategies of EU members have production targets which may broadly align with the EU domestic production target in 2030. In addition to domestic production, the EU has an import target of 10 Mtpa (395 TWh/ yr) of hydrogen by 2030, with trade between EU nations counting towards this import target. The current level of ambition for imports to the EU outstrips all projections on the quantity of low carbon hydrogen that will actually be available for import in the timeframes set out, so it is unlikely that nations with low carbon hydrogen available for export will face significant competition on price. This means that the UK could be in a strong position to export hydrogen to Europe even if production costs are higher than other regions if it can achieve first mover or fast follower status.

Even if price is considered, analysis completed by the International Energy Agency and International Renewable Energy Agency has shown that hydrogen production costs in the UK, especially in areas with high renewable potential, could be some of the lowest in Europe (International Renewable Energy Agency, 2022). Moreover, given the UK's geographic position, the cost of transporting the hydrogen to Europe will be lower compared to importing from North America, Latin America, or Australia, increasing the competitiveness of UK hydrogen on a delivered cost basis, particularly if hydrogen is exported via pipeline. Facilitating export solutions also has the potential to improve energy security for both the UK and EU.

The results of this study indicate that hydrogen export from the UK to continental Europe presents a significant opportunity for the UK hydrogen economy and possibly the only export route where UK hydrogen production could be cost competitive with hydrogen produced in regions with better renewable resources. However, the export concept requires significant development if the opportunity is to be realised, particularly around production certification, and the integration of production and export strategy. Moreover, exporting any hydrogen produced in the UK producing emissions associated with the production, but not benefitting from reductions as a result of using the hydrogen. Accordingly, the carbon intensity of hydrogen production, whether CCUS or electrolytic enabled hydrogen, also would need to be considered if exported.

Assessing Hydrogen Export Options

Export Routes

To develop potential export routes, export locations were selected considering geographic position, existing infrastructure and facilities, planned UK hydrogen production and transport infrastructure and availability. Likewise, based on planned European infrastructure, import locations were identified. Export routes connecting each of the export locations with import locations were developed to a pre-feasibility level to enable a cost comparison to be developed using a levelised cost of transport model. The export and import locations identified are shown in Figure 2.Figure 2The recommended locations offered the best balance of proximity to planned infrastructure, least complex routes, existing export and product handling capabilities, and proximity to European import locations.

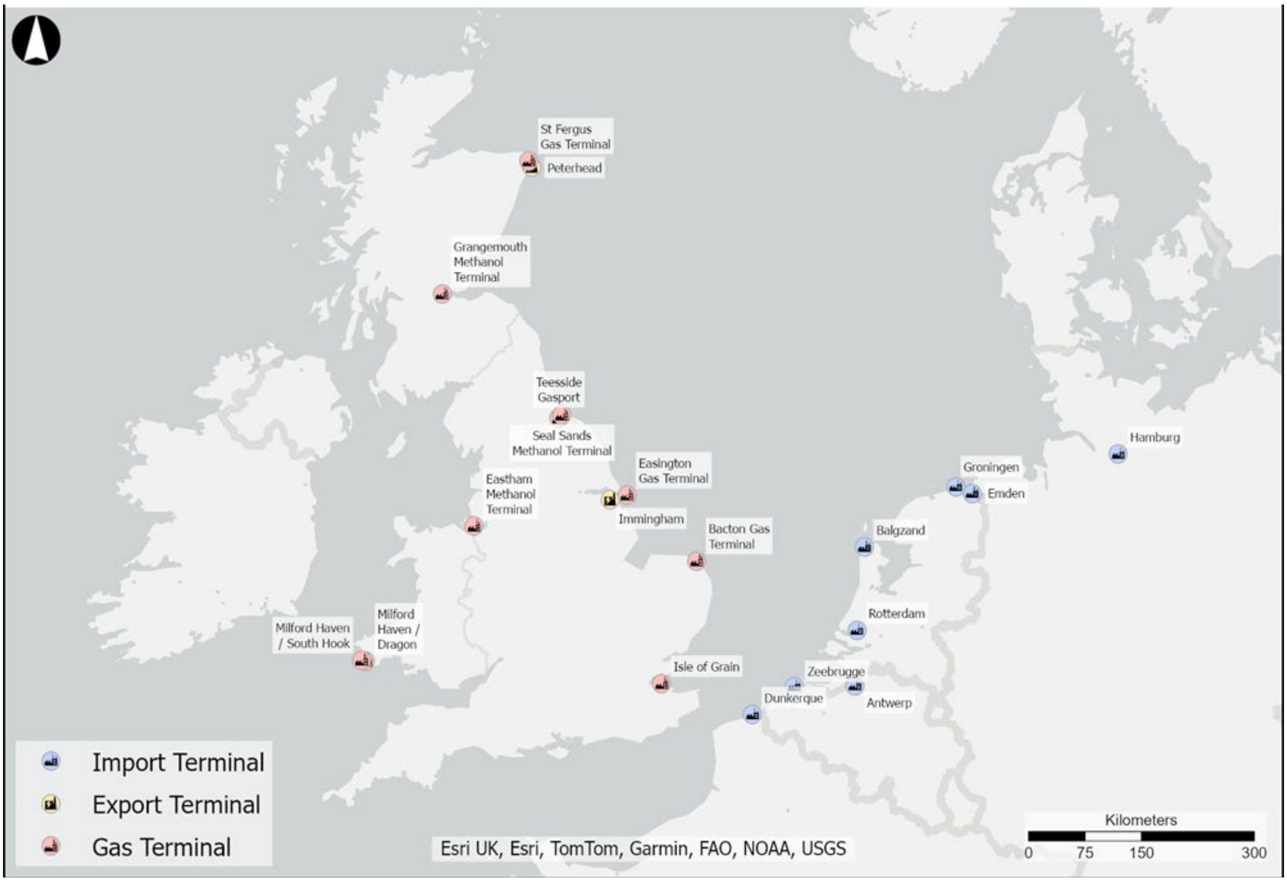

Figure 2: Export and import locations recommended.

Hydrogen Transportation Type

The analysis carried out in this report indicated that large scale export of hydrogen from the UK is likely to only be potentially viable in two main categories, pipeline transport and shipping.

Three main existing gas pipeline connections between the UK and Mainland Europe are available:

- The Interconnector (Bacton to Zeebrugge, Belgium),
- BBL connection (Bacton to Balgzand, Netherlands), and
- Langeled pipeline (Nyhamha, Norway to Easington via the Sleipner offshore platform).

None of these options are deemed to be practical for the basis of this study due to the existing commitments and future business case associated with each pipeline.

For new build pipelines, the UK has significant expertise and capability in building and operating gas pipelines and terminals for the international transport of gas. Alongside the existing interconnector gas terminals, there are several other terminals which may be capable of repurposing to support the export of hydrogen. It is expected that the Bacton and Easington terminals could potentially serve as hydrogen export terminals while still operating as natural gas import/export terminals if new pipelines were constructed from these terminals. This study analysed new pipeline routes from Bacton, Isle of Grain (Medway), Easington, Teesside and St Fergus.

For shipping purposes, port facilities which cater for liquefied natural gas (LNG), liquid petroleum gas (LPG) and methanol have been considered as potential strategic areas of development in the supply chain to cater for hydrogen shipping in the future. The list of potential export locations considered for export via shipping include: Isle of Grain (Medway), Milford Haven, Teesside, Grangemouth and Immingham.

The size and type of the required transport fleet depends on the packaging mode. These means of transport are at different stages of technological readiness. For example, liquid organic hydrogen carriers (LOHC) can be transported in conventional oil tankers, and ammonia can be transported in refrigerated chemical tankers. By contrast, liquefied hydrogen will need to be transported in large carriers with a similar design to LNG carriers, and compressed hydrogen will be delivered in tanker ships analogous to those transporting compressed natural gas.

Pipeline export appears to offer an advantage over non-pipeline export for the export of hydrogen from the UK to Europe. When considering pipeline export, the UK has significant existing infrastructure and expertise which could be leveraged to facilitate an export connection. Export locations in the south of the UK offer the shortest, and hence cheapest pipeline export routes but also face complexity in routeing due to interactions with existing infrastructure in the Southern North Sea. Ultimately, all potential export locations could feasibly facilitate the export of hydrogen from the UK to Europe and the overall selection of a preferred location is dependent on strategic, commercial, and political objectives.

The UK's access to renewable resources and short transport distances to these regions mean that UK hydrogen may be cost competitive with hydrogen imports from other worldwide regions due to the lower cost of transport, even if production costs are higher in the UK.

Selecting a Transport Mechanism

Each shipping transport vector is made up of several different process steps, from conversion and storage on the UK side, then transport, and storage and re-conversion in the European side. For each vector, at least one element of the transportation chain is still to be demonstrated at scale. Given the constraints and study basis assumptions, new pipelines are preferred for nearly all options of distances and flowrates considered in this study for all timescales. Although some small-scale export via shipping would be possible in a shorter timeframe than pipeline export, the feasibility of shipping hydrogen is dependent on the availability of hydrogen transportation infrastructure (e.g. hydrogenation, hydrogen compression, hydrogen liquefaction facilities) on both the UK and European side. For small volumes, the LCOT would be significantly greater and therefore uncompetitive as a long-term, large scale, export option. The distance ranges for proposed European destinations from the recommended UK export locations are shown in Figure 3 below.

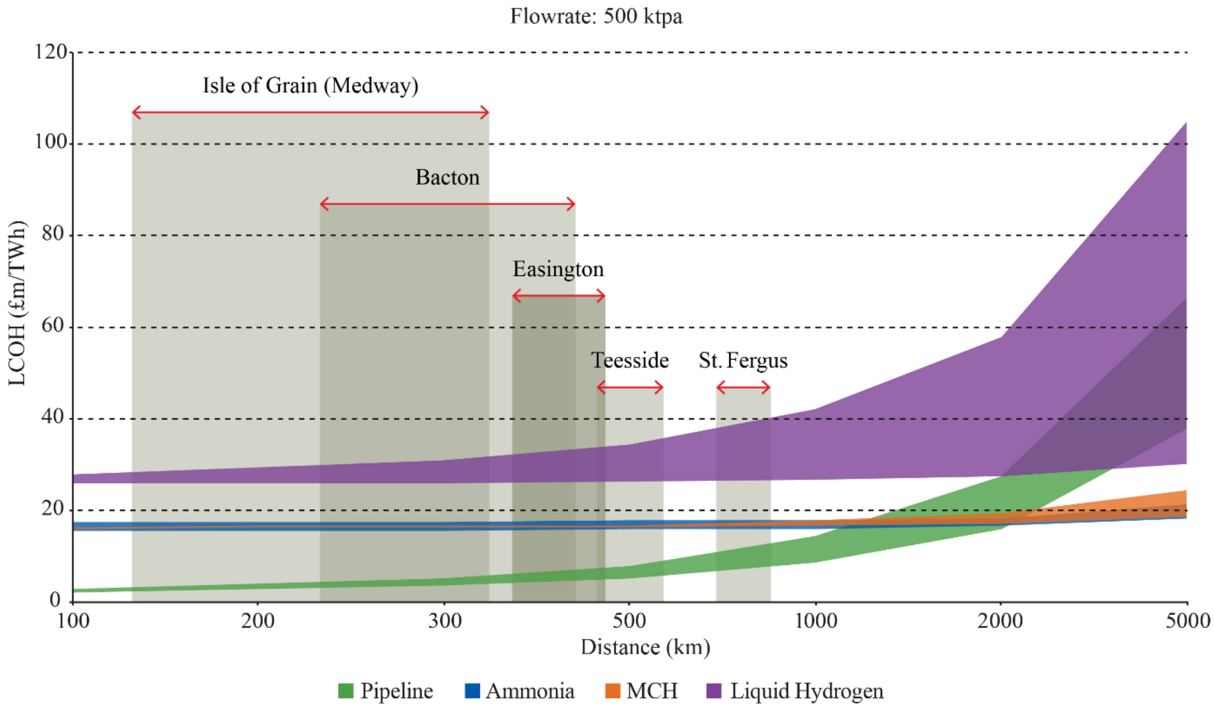

Figure 3: Levelised Cost of Transport representation with distances from export locations shown

Research has indicated that UK hydrogen production has the potential to be cheaper than hydrogen produced elsewhere in northwest Europe in certain circumstances. Some countries with significant renewable resource potential, such as the USA, Canada, Chile, Brazil, Saudia Arabia, Morocco, and Australia, may have the potential to produce hydrogen at a lower cost than in the UK. However, the UK's geographic proximity to the major hydrogen demand centres in northwest Europe mean that transport costs will be significantly lower from the UK than the countries mentioned, who will have to ship hydrogen in derivative form to facilitate export to Europe. The UK could pipeline or ship hydrogen to mainland Europe, with a pipeline solution offering a significantly lower LCOT than shipping for all export locations considered in this study. The study also showed that shipping costs remain relatively flat over distance therefore, there is less incentive for the UK to ship ammonia or LCOH short distances to mainland Europe as it would be less cost competitive compared to other nations also exporting derivatives.

Selecting UK Export Location

The UK is well positioned to export hydrogen to Europe via pipeline and provides one of the shortest connection routes from any country outside the EU. There is also the potential to export hydrogen to Europe via ship in derivative form. Global hydrogen trade is in its infancy and the UK is in a strong position to potentially become a key exporter to northwest Europe, which is expected to be one of the largest demand centres for low carbon hydrogen in the world out to 2050.

A key next step of developing an export route is the selection of a suitable export location(s) in the UK. The location selection process will depend on the sequencing of developing a domestic and international network, if a hydrogen export route is progressed. Three scenarios are set out below, which aim to demonstrate how the three factors identified above would be considered differently in the location selection process, dependent on the build out strategy selected.

Scenario 1 – An export route from the UK to continental Europe is established before a core UK domestic hydrogen network is fully developed.

Scenario 2 – An export route to continental Europe is not considered until the UK's core hydrogen network is fully developed.

Scenario 3 – Export routes to continental Europe are considered as part of strategic planning for, and the development of, the UK's core network.

Scenario 1 could see an export route developed sooner than either of the other two scenarios, giving the UK hydrogen sector an advantage as first-mover status. This scenario would likely connect electrolytic hydrogen production in the UK directly to demand in continental Europe, due to the renewable fuel from non-biological origin (RFNBO) requirements under the EU Renewable Energy Directive (RED), where a certain percentage of low carbon hydrogen used in industry must qualify as a RFNBO. Accordingly, the selection process would be heavily influenced by the location of electrolytic hydrogen production. However, this could result in higher costs of transporting the hydrogen, as developing export routes from these locations may be more costly than other, shorter routes.

In Scenario 2, as the UK would have a fully connected hydrogen network, the preferred UK export location would be selected based on cost of transport. However, the delayed build-out would risk the UK losing first mover status if export routes are considered only after a core domestic hydrogen network is fully established. This may impact the UK's competitive advantage over other countries aiming to export hydrogen to Europe, if export routes from other regions are brought into service before a connection from the UK. Since the development timeline of export infrastructure is significant, if a decision on hydrogen export is delayed until surplus hydrogen production is available, the UK's competitive position in export may also be further affected.

Therefore, it is recommended that the development of a potential export route to Europe is considered as part of the strategic planning for domestic core network (Scenario 3) to mitigate against:

1. The potential cost impacts of establishing an export route solely based on the location of electrolytic hydrogen production as outlined in Scenario 1.
2. The potential schedule impacts of delaying a decision on export routeing until a UK core hydrogen network is established outlined in Scenario 2.

Continuing the development of a potential export route through further studies and engagement with potential importers in Europe would provide the opportunity to gather further evidence and mitigate against the above risks.

UK Competitiveness Summary

Considering Levelised Cost of Hydrogen (LCOH) projections and the Levelised Cost of Transport (LCOT) developed in this report, the UK can be competitive for the export of hydrogen to Europe but likely only via pipeline export. The current level of ambition for imports to the EU outstrips all projections on the quantity of low carbon hydrogen that will actually be available for import in the timeframes set out, so it is unlikely that nations with low carbon hydrogen available for export will face significant competition on price. This means that the UK could be in a strong position to export hydrogen to Europe even if production costs are higher than other regions if it can achieve first mover or fast follower status, the UK's potential competitiveness for hydrogen export based on the results of this study is shown in Table 1.

Table 1: Summary of the UK's potential for export

Scope Area	Potential	Conclusion
UK position for export	Strong	The UK is very well positioned to export low carbon hydrogen to continental Europe. The UK's geographic position means that it can feasibly seek to export hydrogen via pipeline to Europe. A particularly competitive advantage is seen in the shorter pipeline routes, as these minimise the LCOT, however all pipeline routes have a lower LCOT than shipping. Energy security could also be improved by having a hydrogen pipeline connection to and from Europe. There could also be a strategic benefit from becoming an incumbent import route to the EU for hydrogen. Existing gas interconnectors between the UK and Europe have been in operation for many years and expertise from these services is highly applicable to hydrogen export via pipeline. The UK's best competitive position for export to Europe is via pipeline.
Cost competitiveness of UK exports	Promising	The LCOT of pipeline transport is significantly lower than non-pipeline transport at distances up to 2,000 km. Based on publicly available estimates for potential levelised cost of hydrogen production

Scope Area	Potential	Conclusion
		around the world, and the LCOT calculated in this report, the delivered cost of hydrogen landed in Europe from the UK would be competitive with imports of derivatives from regions with lower production costs, when the required product is hydrogen.
Political alignment with European importers	Good	The UK is aligned well in terms of hydrogen policy with Belgium, the Netherlands, and Germany who are the primary export targets. A working relationship on gas import / export is already in place with Belgium and the Netherlands. Overall, the UK is better aligned with the EU than other potential major exporters, such as Saudia Arabia, Australia, Chile, Brazil, North African nations and the USA. The UK and the EU have the opportunity to offer improved energy security with a direct pipeline connection to Northwest Europe where other major exporters such as North and Latin America, and Australia will only be able to export via ship.

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Abbreviations and Acronyms

Abbreviation	:	Definition
ACCE	:	Aspen Capital Cost Estimator
AiP	:	Agreement in Principle
ALARP	:	As Low As Reasonably Practicable
ANSI	:	American National Standards Institute
CAPEX	:	Capital Expenditure
CGH2	:	Compressed Gaseous Hydrogen
CNG	:	Compressed Natural Gas
COMAH	:	Control of Major Accident Hazards Regulations
DCO	:	Development Consent Order
DESNZ	:	Department for Energy Security and Net Zero
EC	:	European Commission
EHB	:	European Hydrogen Backbone
EIA	:	Environmental Impact Assessment
EU	:	European Union
FEED	:	Front End Engineering Design
FID	:	Final Investment Decision
GDP	:	Gross Domestic Product
GH2	:	Gaseous Hydrogen
GW	:	Giga Watts
H2TC	:	Transatlantic Clean Hydrogen Trade Coalition
HBL	:	Hydrogen Backbone Link
HBTT	:	HES Botlek Tank Terminal
HEO	:	Harbour Empowerment Order
HHV	:	Higher Heating Value
HRO	:	Harbour Revision Order
HSE	:	Health and Safety Executive
IGEM	:	Institute of Gas Engineers and Managers
IMO	:	International Maritime Organization
IRA	:	Inflation Reduction Act
kg	:	Kilogram

Abbreviation	:	Definition
KHI	:	Kawasaki Heavy Industries
kt	:	Kilotonnes
kW	:	Kilowatt
kWh	:	Kilowatt-hour
LCOH	:	Levelised cost of Hydrogen
LCOT	:	Levelised Cost of Transport
LH2	:	Liquid Hydrogen
LHV	:	Lower Heating Value
LNG	:	Liquid Natural Gas
LOHC	:	Liquid Organic Hydrogen Carriers
LPG	:	Liquid Petroleum Gas
m	:	Metres
MAOP	:	Maximum Allowable Operating Pressure
MAPP	:	Major Accident Prevention Policy
MCH	:	Methyl Cyclo-Hexane
MJ	:	Megajoule
MMO	:	Marine Management Organisation
Mtpa	:	Megatonnes per annum
MW	:	Megawatt
MWh	:	Megawatt-Hour
NH3	:	Ammonia
NTS	:	National Transmission System
NZTC	:	Net Zero Technology Centre
OPEX	:	Operating Expenditure
PMI	:	Projects of Mutual Interest
RAG	:	Red, Amber, Green
RED	:	Renewable Energy Directive
RFNBO	:	Renewable Fuel of Non-Biological Origin
SHA	:	Statutory Harbour Authority
SMYS	:	Specified Minimum Yield Strength
TCPA	:	Town & Country Planning Act
TEN-E	:	Trans-European Networks for Energy Regulation

Abbreviation	:	Definition
TWh	:	Tera Watt Hours
UAE	:	United Arab Emirates
UK	:	United Kingdom
USA	:	United States of America
USD	:	United States Dollar

1. Introduction

1.1 Purpose of Study

This study was undertaken to develop an evidence base for the export of hydrogen from the UK to Europe. Through a literature review, publicly available information on the infrastructure requirements, cost, timeline to operation, policy, and demand for hydrogen imports in Europe was gathered, reviewed, and used to outline the UK-specific advantages and disadvantages of hydrogen export. A UK-specific levelised cost of transport (LCOT) was also developed to directly compare export cases using different transport methods. Considering the analysis completed in the study, recommendations are proposed to DESNZ on the technical feasibility of hydrogen export from the UK, potential export locations in the UK and export corridors which appear the most viable, and specific countries to consider for bi-lateral engagement on hydrogen export.

1.2 Study Objectives

Overall, the study aimed to provide an overview of the potential export routes available for the UK to export hydrogen to Europe. Through a detailed literature review and consultation with subject matter experts, the study also aimed to build the evidence base for a case for exporting hydrogen from the UK or otherwise. To achieve the overarching objectives, three primary activities with the following objectives were carried out:

- To assess the UK's skills and competencies in relation to the production, handling, and transportation of hydrogen and derivatives to assess which transport vector may provide the most cost-effective pathway to export.
- To provide a levelised cost comparison of the pipeline and non-pipeline transportation methods for a series of selected distances considering the costs associated with processing the hydrogen from a common entry specification to the transportation state, transportation, and processing required to reach a hydrogen exit specification.
- To recommend favourable export corridors considering technical feasibility, policy landscape, and projected demand to provide a direct levelised cost comparison of the transport methods for the recommended corridors.

1.3 This Report

This report was developed to support the development of the UK Government's evidence base on the UK's potential to export hydrogen in the future. A methodology for assessing the LCOT including conversion from hydrogen to the transport vector, processing, transportation, and re-conversion to hydrogen at the import location was developed considering the export routes and conditions specific to the UK. While the LCOT methodology has considered the studies available in the literature, the analysis presented in this report is specific to the UK and therefore not directly comparable with other LCOT estimates, as many of the metrics used in the cost model are specific to the UK market. The UK's existing capabilities and infrastructure available to support the transport methods identified was considered to provide a robust overview of the potential feasibility and timeline to implementation for each method.

Based on the LCOT and capability analysis, several specific export corridors were identified, with transport methods for the corridors assessed on a case-by-case basis. This analysis sought to provide a more tangible insight into the feasibility of establishing hydrogen export corridors from the UK to Europe and the potential costs associated with specific routes. Overall, the report provides:

3. A review of the demand for hydrogen imports in Europe, a qualitative and, in some cases, a semi-quantitative comparison of the technical viability of different transport methods, leading to a recommendation of regions to target for export.
4. Recommendations for potential export locations considering the location of low carbon hydrogen production centres and planned hydrogen infrastructure in the UK. These are not intended to be considered as the only potential options, merely as potential locations with favourable characteristics to provide a basis for this study.

5. A levelised cost comparison and demand review to outline the potential benefits of hydrogen export to the UK and recommend where the UK may be able to establish a competitive position in the export market.

1.4 Scope

The overall scope of the project was split into four main workstreams; context and hydrogen import demand in Europe, existing pipelines, new pipelines, and non-pipeline transport. Each workstream had individual requirements to deliver the study objectives as outlined above, which are summarised in Sections 1.4.2, 1.4.3, and 1.4.4.

1.4.1 Context and Hydrogen Import Demand in Europe

To provide a basis for the report and the potential benefits to the UK of considering a hydrogen export route to Europe, a desktop review of hydrogen policy, projects, initiatives, and import demand was scoped. The review was to include an overview of the various hydrogen strategies in Europe and their respective hydrogen demand and import targets, along with a review of actual projects developing hydrogen production and transport and storage infrastructure. A desktop review of the state of development of hydrogen production projects in the UK and their location, along with transport infrastructure in the UK and Europe was also considered in scope despite not being included in the LCOT assessment as it provides evidence for the export locations assessment.

The data gathered in the review was used to frame the discussion of hydrogen export in terms of demand from Europe and how it could support the development of the hydrogen sector in the UK. Additionally, the hydrogen demand from Europe was classified by country of origin and region, where possible, to support the selection of strategic export locations from the UK and import locations in Europe. Location selection was to consider the state of development of hydrogen infrastructure in the UK and Europe and how this could support potential export corridors.

1.4.2 Existing Pipelines

The existing pipelines scope specifically includes the review of existing pipelines connecting the UK to mainland Europe. While other existing oil and gas pipelines which connect to offshore infrastructure may also be suitable for conversion to hydrogen service, they were excluded from the scope of this assessment as they are primarily not direct routes from the UK to Europe and there is significant uncertainty in their availability and suitability for hydrogen service which would not have been feasible to assess adequately in this report. The review of existing pipelines suitability as potential hydrogen export routes was to include the following:

- Technical:
  - Location
  - Design conditions: pressure rating, material of construction, capacity, length, diameter, flow direction, year of construction, operating requirements, entry / exit specifications and additional infrastructure requirements (compression, valves, metering specifically) for conversion to hydrogen service.
  - Desktop review of the current state of regulation in the UK and international design codes and standards to review the requirements for conversion.
- Commercial
  - Review of existing pipelines owners and operators.
  - Provide an estimate of the timeframes required for existing pipelines to become available for conversion to hydrogen service based on current service life expectancy.
  - Provide a location agnostic levelised cost estimate for the transportation of hydrogen using existing pipelines prior to reviewing and selecting the most advantageous start and end points for comparison.

- Approximate costs for conversion of existing pipeline based on selected options, considering publicly available information and internal databases for cost assumptions.

- Environmental
  - Desktop research to identify high level environmental risks associated with converting existing natural gas pipelines to hydrogen.

1.4.3 New Pipelines

The scope of the new pipelines workstream included the topics necessary to achieve a pre-feasibility level of technical design supporting the development of a generalised LCOT for new pipelines of various distances, as set out in the objectives. Following the generalised assessment, preliminary pipeline routeing for the respective corridors identified in the hydrogen demand review was determined to provide a more detailed LCOT to reach specific locations and provide a basis for like for like comparison to non-pipeline transport options. The analysis included the following activities:

- Technical:
  - Evaluation and pre-feasibility design of new pipelines for gaseous hydrogen, including pipe diameter, length, wall thickness, construction material and compression requirements.
  - A high-level program considering the construction, installation, testing, and planning and consenting timeframes for new pipelines.
  - A review of pipeline installation vessel availability and qualitative commentary on the potential availability moving forward and its impact on the timelines identified for construction.
  - A comparison of the effect of pipeline size and operating conditions on capacity, resulting in the selection of a preferred pipeline diameter and construction material for the specific corridor options identified.
  - Determine a suitable pipeline size to enable the required hydrogen volume to be transported 500 km before recompression is required to provide a consistent basis for the cost model.
  - Infrastructure requirements at each end of the pipeline with a pre-feasibility level design developed to determine costs to be included in the LCOT model.
  - Review of potential locations for new pipeline start / end points.
- Commercial:
  - Provide costs for design, constructing and installing new pipelines to feed into the LCOT model.
- Environmental:
  - High level impact assessment of conversion to hydrogen.
  - Regulatory review of codes and standards for approval.

1.4.4 Non-Pipeline Transport

A desktop review of the potential non-pipeline options for transporting hydrogen was completed to provide high level capital and operating costs for the methods as inputs to the LCOT model. The options considered in scope were liquid hydrogen, compressed gaseous hydrogen, ammonia, and liquid organic hydrogen compounds (methyl cyclo-hexane, toluene). A qualitative review of the infrastructure requirements at ports was also included in scope to assess the feasibility of exporting each transport option considered under non-pipeline transport from port locations in the UK. To achieve the scope, various activities were defined:

- Technical:
  - Hydrogen and hydrogen-derivative compatibility (existing bulk handling facility capabilities)
  - Port infrastructure availability and suitability, including:

  - Port Capacities (size and number of berths, existing landside infrastructure and land availability for new equipment required, technical potential for material throughput).
  - Port Logistics Infrastructure.
  - Storage Capacity and Capability / Compatibility.
  - Jetty Capacity / Limitations.
  - Potential lead times required to make port facilities available for hydrogen and hydrogen-derivative components.
  - Analyse location advantages / disadvantages.
- Provide an outlook of shipping vessel availability.
- Consider the entry and exit specification requirements for port handling and shipping operations.

- Commercial:
  - Review of existing port owners and operators.
  - Provide approximate costs of hydrogen handling conversions and those of hydrogen derivative storage and export.
  - Consideration of ownership model (port, shipping).
- Environmental:
  - Regulatory review of codes and standards for international transport.
- Other:
  - Provide high level review of alternative non-pipeline transport including rail, tube trailer / ferry, and air.

1.5 Methods of Hydrogen Transport

1.5.1 Pipelines

Repurposing of existing and construction of new pipelines were both considered in this study. The LCOT, construction time frames, capacity, potential locations, and challenges to development were reviewed on a qualitative basis. Facilities required to enter and exit the proposed pipelines are included in the analysis, as shown in Figure 4. Storage is not included in the analysis as it the pipeline connection allows for continuous and variable flow and provides inherent storage in the form of line pack. Storage is also expected to be covered by the respective local or national networks on either side of the input / output location.

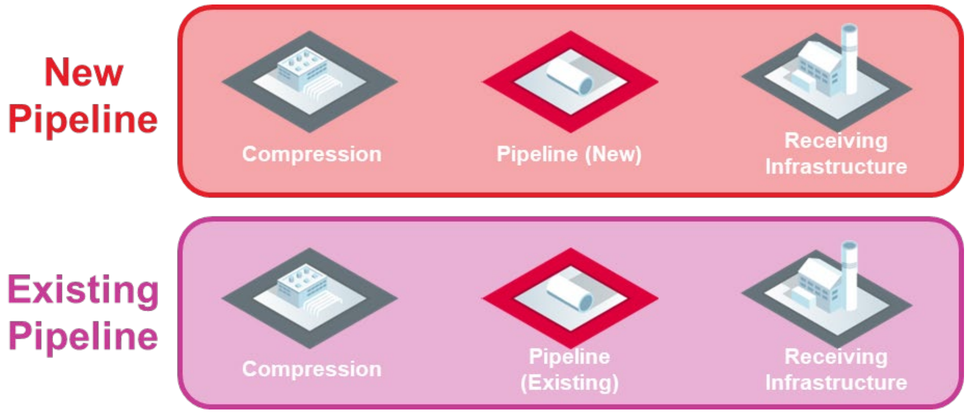


Figure 4: Pipeline transportation options considered in the study.

Over time, existing interconnectors could be transitioned to support hydrogen trade between continental Europe and the UK, which is explored further in Section 6.2. However, the requirement for natural gas in

Europe is not expected to decline in years to come, with demand increasing in 2023 over 2022 (International Energy Agency, 2023). Additionally, as a result of the 2022 energy crisis, many industrial users in the EU have fuel-switched from gas to oil. This is a trend which does not align with the decarbonisation aims of the bloc and can largely be attributed to the high gas prices seen since the EU shifted away from Russian gas imports. Therefore, assuming this demand would switch back to gas or an alternative fuel when prices are right is not beyond the realms of possibility. The interconnectors have tariffs for natural gas transportation set out until 2038, meaning they are unlikely to be available for hydrogen transport until at least 2039, unless the business case changes dramatically.

New pipelines, like the existing natural gas interconnectors, could be constructed to provide a route to export via pipeline before the existing interconnectors became available for repurposing. This could be beneficial in establishing a market for the international trade of hydrogen and provide a demand source for hydrogen production projects designed to make the most of renewable resources which may otherwise be curtailed or underutilised. A new pipeline option would be more expensive than repurposing existing pipelines but provides greater control over the timeline and enables the selection of specific locations for export and import based on hydrogen supply and demand, rather than having to supply to where the existing interconnectors are located.

1.5.2 Non-Pipeline Transport

Hydrogen can be transported via ship in a variety of forms. In this report, the vectors shown in Figure 5 were considered as the most technologically mature options for large scale hydrogen transport.

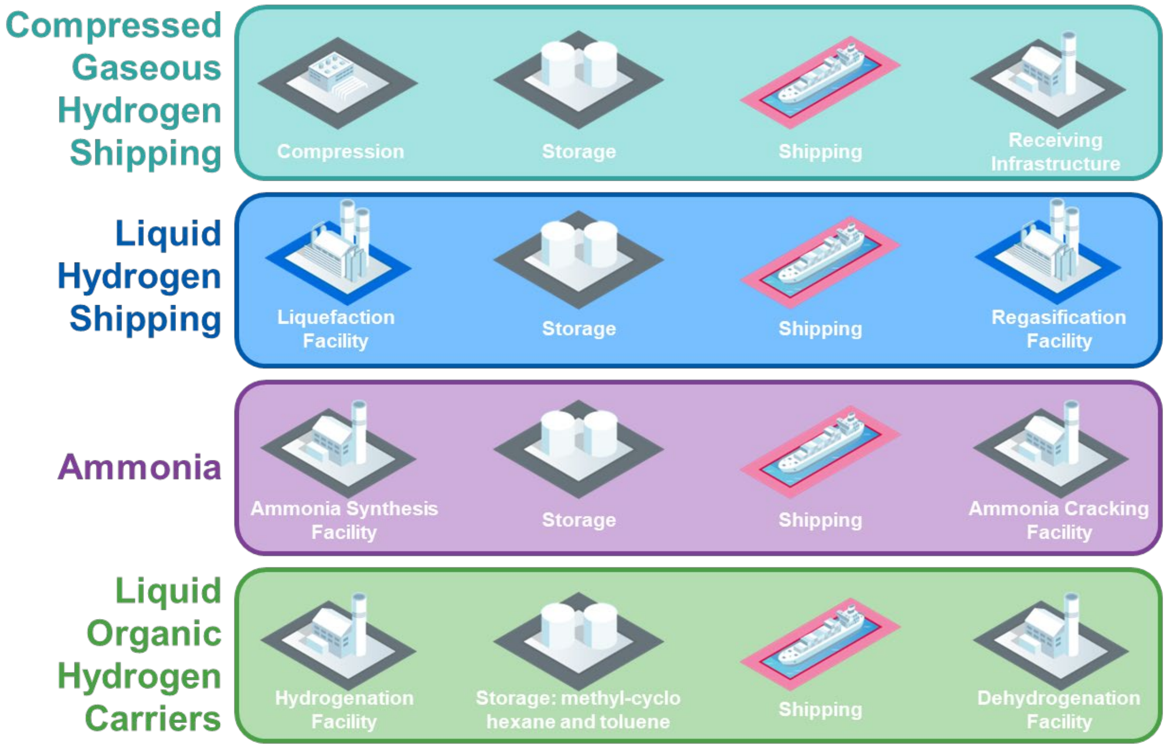


Figure 5: Non-pipeline hydrogen transport vectors considered in this report.

The list is not exhaustive of all potential transport vectors for non-pipeline transport. Alternative non-pipeline transport vectors may be suitable to transport smaller volumes of hydrogen than the volumes considered in this study in a shorter timeframe than the methods discussed in this report. Since this study focuses on strategic level national export of very large volumes of hydrogen only methods which have a feasible pathway to enable large scale export were considered. The selected options shown in Figure 5 are the most advanced non-pipeline transport vectors in terms of large-scale hydrogen transport at the time of writing. A brief overview of the vectors considered is provided below:

- Compressed gaseous hydrogen (CGH_2) – hydrogen is compressed to very high pressures to increase its density and stored in specially designed pressure vessels on board the ship. Existing compressed gas storage vessels are likely to be fit for repurposing to hydrogen service, although further research is required to determine the economic viability of repurposing. New landside infrastructure to support the loading and unloading of the compressed hydrogen would be required, potentially including compressors, new loading arms, and new control systems. Hydrogen storage and / or pressure reduction systems will also be required depending on the end use of the hydrogen.

- Liquid hydrogen (LH_2) – liquid hydrogen follows the same principle of LNG in that by cooling hydrogen to below its boiling point, it can be stored and transported as a liquid, with a higher density than its gaseous form. This means more hydrogen can be transported in the same volume of container. LH_2 is still significantly less dense than LNG and therefore the quantity of energy transported per m3 of capacity will be less than LNG. Hydrogen also must be cooled to below -253°C to be liquefied compared to -161.5°C for natural gas, which requires significantly more energy input and means it is harder to keep the hydrogen liquefied during transport. This transport method will require liquefaction and storage facilities at the export side and storage and regasification facilities on the import side of the export corridor. Additionally, new loading arms and control systems will also be required. It is assumed there is potential for LNG infrastructure to be repurposed to LH_2 service however the validity of this assumption is not yet widely verified, therefore it was considered a requirement to include the cost of new liquefaction and storage infrastructure on both sides of the export corridor as part of the LCOT assessment.

- Ammonia (NH_3) – ammonia is already produced in large quantities throughout the world for use in the fertiliser industry. Ammonia is synthesised using the Haber-Bosch process, which is well understood, with many experienced technology licensors offering flow sheets for the process. To transport hydrogen as ammonia, the hydrogen will be combined with nitrogen in the Haber-Bosch process before being stored as a liquid and loaded on to ships. At the import location, the ammonia will be unloaded and can then be cracked into its constituent parts to provide gaseous hydrogen or used directly as ammonia. The synthesis and cracking of ammonia was included in the LCOT modelling during this project to provide a like for like comparison with the other vectors, however sensitivities considering the direct use of ammonia were also reviewed.

- Liquid Organic Hydrogen Carriers (LOHC) – hydrogen can be "loaded" into LOHCs using exothermic hydrogenation, i.e. the reaction generates heat. At the other end, the LOHC is dehydrogenated to free the hydrogen molecules from the LOHC for use. This reaction is endothermic and requires heat input from an external source. The LOHC can then be "reloaded" and used to transport hydrogen again. LOHCs with properties similar to existing fuels like diesel and petrol are typically used as it allows for the existing bulk liquid shipping practices to be used. LOHCs are much easier to handle than hydrogen in its native form as they are less reactive, a liquid at ambient conditions and carry approximately 50 kg of usable hydrogen per m3 of LOHC, providing a relatively high hydrogen density compared to other transportation methods while offering a much lower risk profile and less stringent handling / technology requirements due to their physical properties.

As outlined above, there are many challenges presented by hydrogen's physical properties which must be considered when developing a design for hydrogen export via ship, which are considered in more detail in the LCOT analysis and qualitative evaluation of the transport methods. Each of the methods identified can transport a different mass of hydrogen per unit volume of cargo space, which affects the LCOT of each option. A summary of the volumetric efficiency of the selected transport vectors is shown in Table 2, with the greatest mass per m^3 representing the best volumetric efficiency.

Table 2: Usable mass of hydrogen transported per unit volume of the non-pipeline transport methods selected.

Transport Vector	CGH_2	LH_2	Ammonia	LOHC
Usable hydrogen mass per m^3 of vector transported	23.8 kg (at 350 barg) 38.8 kg (at 700 barg)	70.9 kg	107.3 kg	50 kg

2. Study Basis

The study has considered the export of hydrogen from the UK to Europe via pipeline and non-pipeline transportation methods. For pipelines, the repurposing of existing and construction of new build pipelines was considered. For non-pipeline transport, road, rail, shipping, and air transportation were considered to a high level.

2.1 System Boundaries

To provide a level playing field for the analysis and ensure the cost comparison was completed on a like-for-like basis, the system boundaries were established as shown in Figure 6.

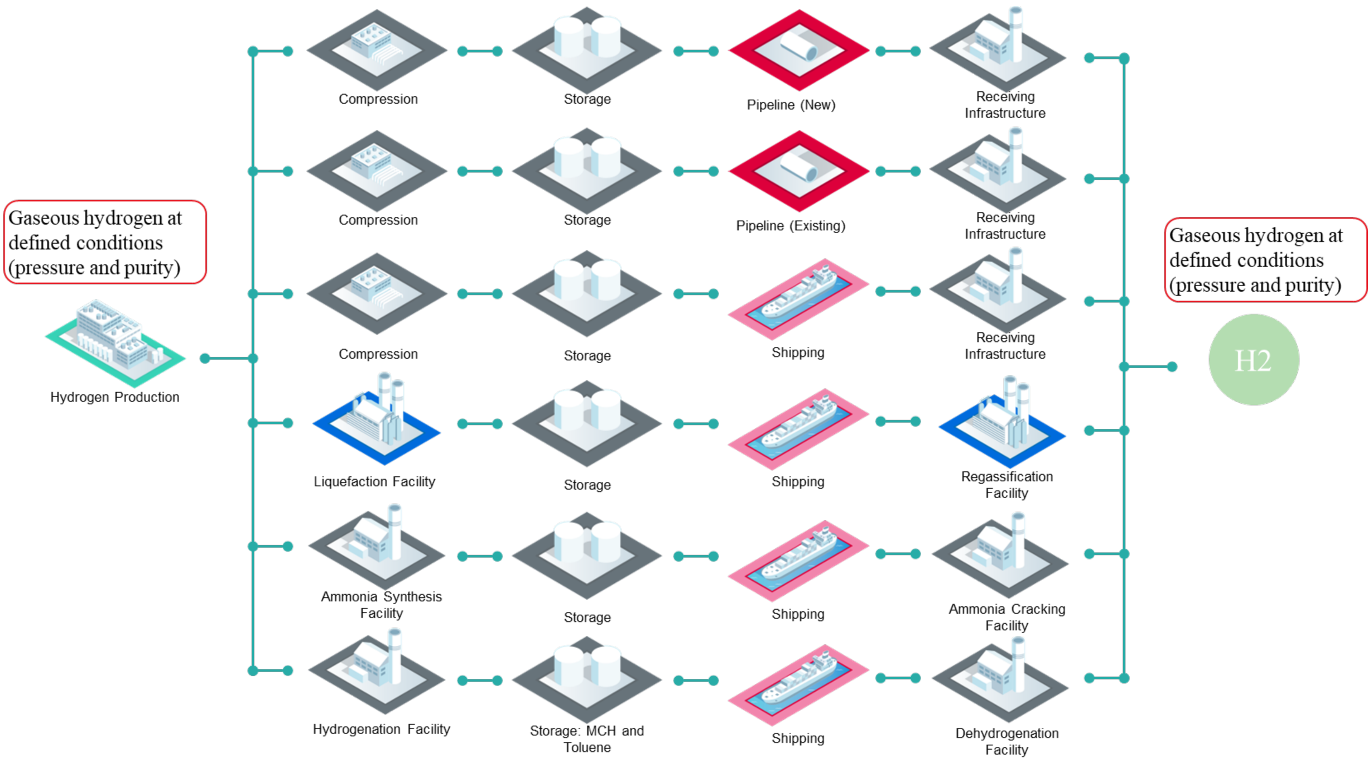


Figure 6: System boundaries for the study

The boundaries in Figure 6 include all ancillary equipment required to process the hydrogen from the input specification to be transported, any loading/unloading equipment required, the transportation vector itself and the ancillary equipment required to process the hydrogen to the required output specification.

2.2 Hydrogen Input and Output Conditions

As shown in Figure 6, the input to the system is equal to the output of the system. The input and output specification is hydrogen at the conditions as shown in Table 3. This provided a levelised basis of analysis to be applied for all transport vectors considered.

Table 3: Input and output hydrogen conditions applied at the input and output points shown in Figure 6.

Property	Unit	Value	Comment
State	-	Gaseous	Most production in the UK is currently expected to be gaseous. Transport networks connecting supply locations with demand and export locations are also expected to transport hydrogen as a gas in pipelines as it is the most effective way to transport hydrogen in bulk.
Minimum purity	mol%	98	98% purity aligns with the IGEM/H/1 Reference Standard for low pressure hydrogen utilisation (Institute for Gas Engineers and

Property	Unit	Value	Comment
			Managers, 2023) and is expected to be a reasonable compromise between hydrogen cost and impacts on equipment.
Temperature	°C	5	Related to standard operating temperature of the natural gas national transmission system
Lower Heating Value	MJ/kg	120.21	Lower heating value used to standardise the energy content of the various production, demand, and import targets. Lower heating value in MJ/kg taken from (Hydrogen Analysis Resource Centre, 2008), value in kWh/kg converted from MJ/kg data using SI units definitions.
	kWh/kg	33.4	
Higher Heating Value	MJ/kg	142.18	Higher heating value used to standardise the energy content of the various production, demand, and import targets. Higher heating value in MJ/kg taken from (Hydrogen Analysis Resource Centre, 2008), value in kWh/kg converted from MJ/kg using SI units definitions.
	kWh/kg	39.5	

2.3 Pipeline Transport

Two distinct scenarios were considered for pipeline transport: repurposing existing infrastructure and new build.

2.3.1 Repurposing Existing Infrastructure

Existing natural gas interconnectors between the UK and Europe and existing offshore oil and gas pipeline infrastructure were considered for repurposing to form part of a hydrogen interconnector to Europe. Based on publicly available information, the suitability of the infrastructure was assessed and considered only for use as a connection between the current start and end points of the interconnectors.

2.3.2 New Pipeline Infrastructure

Construction materials were selected from American National Standards Institute (ANSI) standard datasheets for steel line pipe sections. Pipelines were considered to use standard pipeline sizes according to the nominal bores and standard line pipe thicknesses available in ANSI standard datasheets. The construction of a new high pressure, fully welded steel pipeline between selected export points in the UK and import locations in mainland Europe.

2.4 Non-Pipeline Transport

Port locations with bulk liquid handling capabilities for substances such as methanol were considered for use as potential LOHC export locations and ammonia potential hydrogen-derivative export locations in the UK based on existing facilities to support other cargo services, e.g. methanol and LPG terminals.

Based on analysis of the current fleet of LNG, LPG, crude oil, and chemical tankers, it has been assumed that existing tankers could be retrofitted to be utilised as hydrogen-derivative carriers in the future, hence the potential volumetric capacity of derivative carriers has largely been based on the existing fleet.

The graph on Tanker capacity in 2013 shows that the highest number of tankers range in capacity between 20,000 m^3 and 60,000 m^3. Following on from this figure, LNG carriers in 2020 have the highest number of vessels in the 120,000-180,000 m^3 range. LPG carriers are typically smaller than LNG carriers with capacities ranging up to 100,000 m^3 with approximately 50% under 5,000 m^3 capacity (PIANC, 2022). Considering these tanker sizes as a basis of assumptions for our hydrogen derivatives, namely, liquefied hydrogen, and compressed hydrogen, ammonia, and LOHCs. The list of vessel sizes shown in Table 4 was derived and used as a basis for the assessment.

Table 4: Typical carrier size and capacity for the transport of methanol, ammonia, LOHC, LH_2, and CGH_2

Carrier Type	Current Capacity ('000 m^3)	Future Capacity ('000 m^3)	LOA (m)	Draught (m)
Methanol/MCH	45-160	60-160	147-241	8.7-12.2
Ammonia	22.5-35	22.5-80	160-225	9.0-13.0
LH2	1.25	1.25-160	116-346	4.5-12.5
Compressed Hydrogen	-	26-120	-	-

3. UK Opportunity

UK Opportunity Summary

There is significant demand for hydrogen imports in continental Europe. A major source of demand in continental Europe is likely to centre around industrial areas in Belgium, the Netherlands, and Germany, all of which are in relative proximity to the UK. Currently, national hydrogen strategies of EU member have production targets which may broadly align with the EU domestic production target in 2030. In addition to domestic production, the EU has an import target of 10 Mtpa (395 TWh/yr) of hydrogen by 2030, with trade between EU nations counting towards this import target. Given, that the domestic production targets of EU member states may struggle to reach EU domestic production targets by 2030, significant hydrogen import from outside the bloc will be required to work towards the 395 TWh/yr import target, with the UK well positioned geographically to export hydrogen to the EU.

3.1 Context

Hydrogen has been identified as a key vehicle for helping to deliver the world's emissions reduction ambitions. While electrification will be an effective decarbonisation tool for many sectors in the UK, low carbon hydrogen is a leading option to decarbonise industrial processes that are harder or more expensive to electrify, and can provide cleaner, homegrown energy for power, transport, and potentially heating. Low carbon hydrogen is also expected to offer a significant decarbonisation impact through new applications across the shipping (includes hydrogen derivatives), aviation, transport, iron and steel, and chemicals sectors, where electrification alone will not be feasible to reach net zero emissions.

Projected demand for low carbon hydrogen in the UK under the net zero 2050 emissions scenarios is significant. A strong pipeline of low carbon hydrogen projects has been established to meet this demand, with projects continuing to be developed and progressed towards final investment decision (FID). A production capacity target of 5 GW by 2030, first set out in the UK Hydrogen Strategy in 2021, was subsequently doubled to up to 10 GW of low carbon hydrogen, with at least 5 GW from electrolytic production by 2030 (UK Government, 2022). Revised figures in the Hydrogen Production Delivery Roadmap published in December 2023 indicate that 6 GW of production capacity in 2030 is expected to be electrolytic, with only 4 GW of CCS-enabled production (Department for Energy Security and Net Zero, 2023). Subsequently, a strong pipeline of low carbon hydrogen projects has been established, with projects continuing to be developed and progressed towards FID, with the electrolytic projects directly supported by Government are expected to unlock over £413 million of private capital between 2024-2026 and create 760 direct jobs during construction and operation (UK Government Department for Energy Security and Net Zero, 2023).

The European Commission (EC) also published a hydrogen strategy for the European Union (EU) in 2020 (European Commission, 2020). In the strategy, a target of 6 GW (LHV) installed electrolyser production capacity on an output basis io displace existing grey hydrogen production by 2024 was set, ramping up to 40 GW by 2030. It is highly unlikely that the 2024 target will be met as, in December 2023, the total installed electrolyser capacity globally was approximately 0.44 GW (LHV) on a hydrogen output basis (International Energy Agency, 2023). Almost all member states have developed plans for hydrogen as part of their National Energy and Climate Plans and 26 Member States have signed up to the "Hydrogen Initiative" (European Commission, 2020), which seeks to develop a common low carbon hydrogen economy in Europe.

A key area of the hydrogen economy which requires further development is the infrastructure connecting supply with demand. Traditionally, hydrogen has been produced locally to where it is required, typically on oil refineries or chemical plants, therefore there has been no need to transport hydrogen over long distances. This means that there is little to no interconnected transportation and storage infrastructure for hydrogen across most countries in Europe. Therefore, to enable hydrogen production growth, the establishment and connection of transportation and storage networks is required to connect supply and demand. Methods for transporting hydrogen are well known. Hydrogen can be transported in large quantities via pipeline like how natural gas is transported today, as well as in compressed gas pressure vessels on heavy goods vehicles, trains, or ships for smaller volumes. Liquified hydrogen (LH2) could also play a part in the future although it is not yet available at scale and faces significant technical challenges for development. Hydrogen can also be chemically combined into other substances such as ammonia or liquid organic hydrogen carriers (LCOH) for more efficient bulk shipping transport and converted back to gaseous hydrogen after transport where required. However, there has been a lack of development in hydrogen transportation infrastructure which has led to uncertainty for investors in hydrogen production projects and end users alike. This uncertainty has been hampering hydrogen project development and means that most nations are not on track to meet the production targets set out in their respective hydrogen strategies (International Energy Agency, 2023).

The UK is now developing transport and storage business models to facilitate the hydrogen infrastructure required to connect hydrogen producers with demand. This is expected to encourage the development of hydrogen transport and storage networks in the UK, which are already under development through projects such as HyNet (Cadent, 2021), National Gas's "Project Union" (National Gas, 2022), and Northern Gas Networks and Cadent's "East Coast Hydrogen" (Northern Gas Networks, Cadent, National Gas, 2022). Similar projects and initiatives have been set up to try and establish a hydrogen network to facilitate hydrogen transport and enable the commodification of hydrogen as a product for trade across Europe. These initiatives primarily focus on connecting hydrogen supply and demand within Europe via pipelines, with projects such as the European Hydrogen Backbone (EHB) considering the conversion of existing natural gas pipelines coupled with the construction of new hydrogen pipelines to establish a hydrogen network which replicates the natural gas networks of today (European Hydrogen Backbone, 2022).

While the first generation of low carbon hydrogen projects in the UK and Europe are expected to be formed around relatively local industrial clusters / regions, as demand ramps up, the scale of opportunity for interconnection between the UK and Europe should not be overlooked. Given the UK's geographic position and access to offshore wind resources, there is an opportunity to export home grown energy in the form of low carbon hydrogen to Europe and improve energy security through interconnection as the UK simultaneously drive down emissions domestically. As such, the UK Government is seeking to position the UK as a future exporter of low carbon hydrogen as part of implementing its hydrogen strategy (UK Government, 2022). A natural export location would be continental Europe, where, despite ambitious hydrogen production targets, the EU has also recognised that hydrogen imports will be required to meet demand. The EU is aiming to import 10 million tonnes per year of low carbon hydrogen (European Commission, 2020), which equates to approximately 395 TWh/yr (HHV).

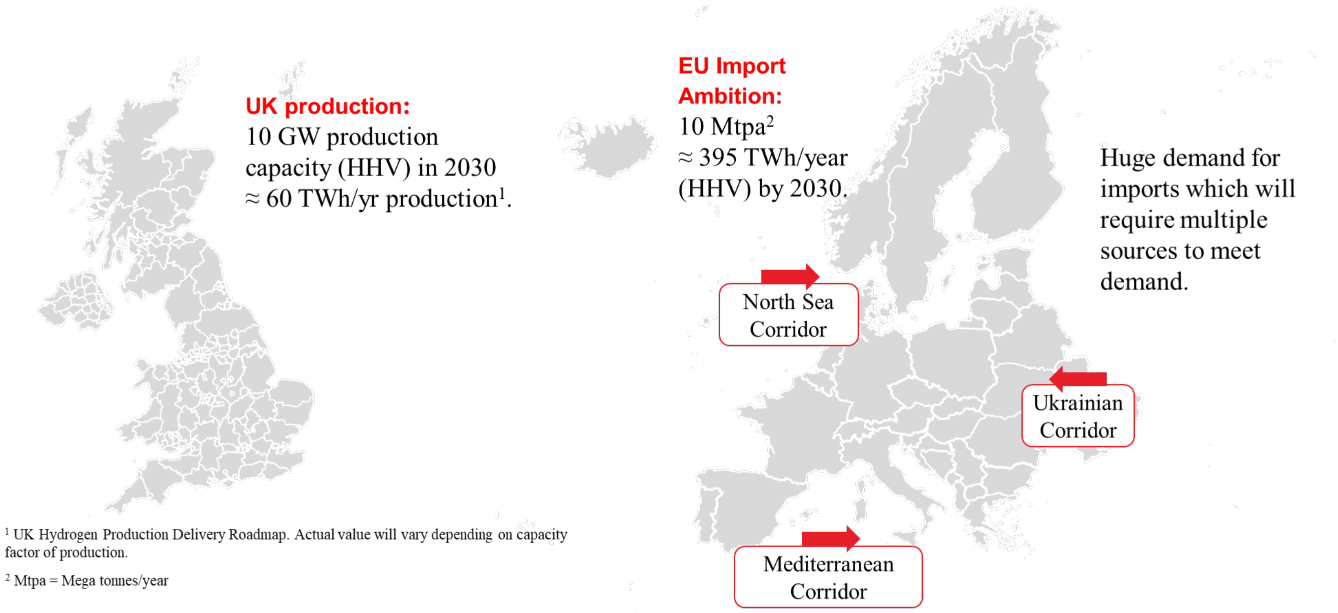


Figure 7: Indicative view of UK production ambitions compared to EU import ambitions. Sources: (UK Government, 2022), (Department for Energy Security and Net Zero, 2023) (European Commission, 2020), (Hydrogen UK, 2021).

To facilitate this import strategy, the EU has committed to "support three major hydrogen import corridors via the Mediterranean, the North Sea and, as soon as conditions allow, Ukraine." (The European Commission, 2022), as shown in Figure 7. This commitment, coupled with the fact the EU has identified the UK as one of 70 countries it is targeting to supply its hydrogen imports (Alsulaiman, 2023) and the UK's proximity to demand centres in northwest Europe, create a strong case to explore the opportunity to export hydrogen to Europe.

If the UK is to export hydrogen, Europe is a natural partner not only in terms of geography, but also as the region with the most significant hydrogen import target of any announced to date (Alsulaiman, 2023). Export to Europe could stimulate further hydrogen production projects in the UK, adding to the private investment and job creation already expected through the first round of production projects. Ultimately, to unlock this opportunity, rapid development of hydrogen infrastructure is required to connect production and end users to reduce uncertainty for project developers, end users, and investors. To enable rapid development in infrastructure, a clear understanding of the potential benefits, limitations, and costs associated with its development is required. Exploiting this opportunity will require careful consideration of the technical, cost and environmental factors associated with hydrogen transportation onshore and offshore via pipelines and non-pipeline transport methods.

3.2 European Hydrogen Development

Development of hydrogen production, import, transportation, and storage infrastructure in Europe to date has centred around large demand areas in the industrial regions in Belgium, northwest Germany and the Netherlands (Oxford Institute for Energy Studies, 2022). The EU has a target of importing 10 Mtpa (395 TWh/yr) of low carbon hydrogen by 2030. Of the EU states with dedicated hydrogen strategies, 14 have set distinct targets for hydrogen production, with policy and public funding schemes set up to support development. These countries are Denmark, France, Netherlands, Spain, Portugal, Sweden, Germany, Poland, Austria, Italy, Greece, Norway, Belgium, and Finland. The policy landscape for hydrogen production and the progress made towards meeting these targets was reviewed. The analysis was used to help frame the potential demand for imports in Europe, considering the overall EU strategy and any explicit import targets set in the national strategies.

3.2.1 Hydrogen Ambitions in the EU – National Strategies, Policies, Regulations, and Support Mechanisms

The strategies of the 14 countries identified in Section 3.2 were reviewed. Key data for production targets and public funding support available for hydrogen production projects is shown for the EU countries that appear in the list, namely Denmark, the Netherlands, France, Spain, Portugal, Sweden, Germany, Poland, Austria, Italy, and Greece. A summary of the data is presented in Figure 8.

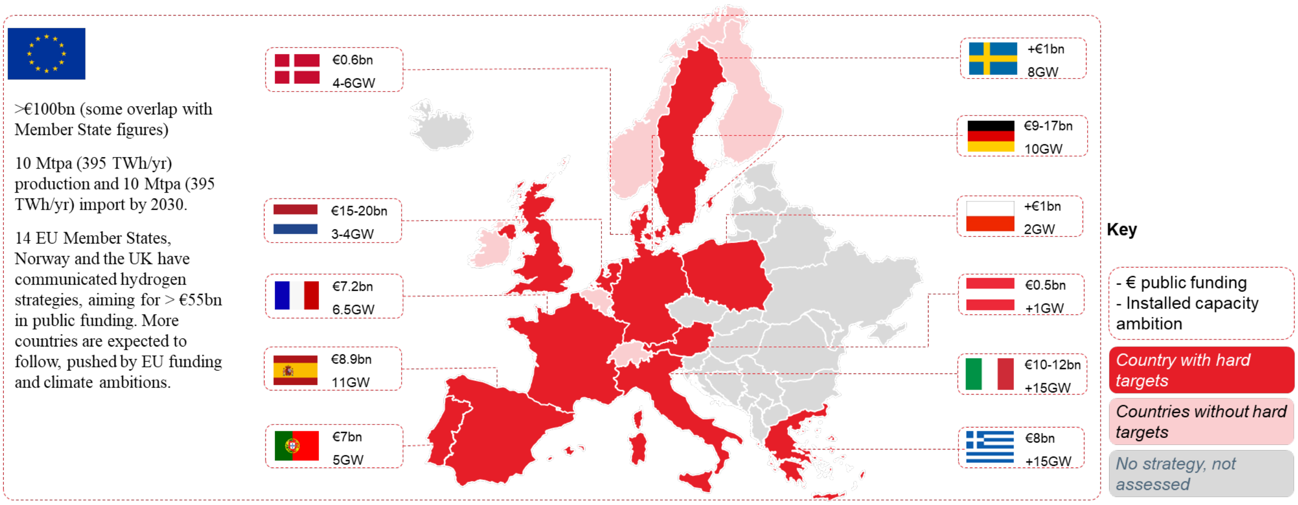


Figure 8: Summary of the hydrogen production targets and public funding support available in countries in the EU leading hydrogen strategy and policy.

The EU has set various targets for hydrogen consumption in industry, transport, and the energy system which have been communicated in the Renewable Energy Directive (RED), RePowerEU and ReFuelEU plans and Fuel EU regulations (Ricardo, 2023). The RePowerEU plan echoed many targets set out in the European Hydrogen Strategy and stated an ambition of 10 Mtpa of installed electrolyser capacity in the EU and 10 Mtpa of renewable hydrogen imports by 2030. These targets are ambitious, and are not legally binding, therefore the deliverability of these targets could be questioned.

To the contrary, the RED notably sets legally binding targets for the use of energy in renewable forms, which includes hydrogen as a RFNBO. The most recent iteration, RED III, set legally binding targets for the use of RFNBOs in Europe for the transport and industry sectors in terms of minimum consumption of RFNBOs in

2030. In addition to the legally binding targets set out in RED III, the following targets have been established to develop the hydrogen infrastructure:

- Align the sub-targets for RFNBOs under the RED for industry and transport with the REPowerEU ambitions, including:
  - Double the number of hydrogen valleys through Hydrogen Joint Undertaking.
  - Proposal of two Delegated Acts on (i) the definition of renewable hydrogen production; and (ii) defining a methodology for calculating greenhouse gas emissions of different production methods. A third delegated act defining "low carbon hydrogen" is expected to be published by the end of 2024.
  - Mapping hydrogen infrastructure needs by March 2023; ultimately published in November 2023 (Gregoire de Jerphanion, 2023).
  - Scale-up of electrolyser manufacturing, as per the 'Electrolyser Declaration'. The declaration which was signed between the commissioner for internal markets and 20 industry CEO's is a commitment from industry to a tenfold increase of its electrolyser manufacturing capacities by 2025.

To facilitate this development, several EU-wide funding mechanisms have been established and are available for projects in the bloc. A summary of these mechanisms is shown in Table 5.

Table 5: Hydrogen funding mechanisms in the EU.

Country	Scheme Name	Funding Available	Scheme type	Eligibility
EU	Important Projects of Common European Interest (IPCEI)	~€26.7bn state aid approved funding (2018 – 2023), €10.6bn for hydrogen	Grants (focusing on CAPEX)	Prove innovative nature and European relevance
EU	Innovation Fund	€38bn current, with € 3bn for 3rd round in 2023	Grants	Beneficiaries include players across the whole H2 value chain
EU	InvestEU	€26.2bn to mobilise € 372bn, share for H2	Grants and loans	Clean hydrogen infrastructure investments, 2021-2027
EU	EIB Hydrogen Bank	€3bn for closing gap between fossil and green H2 and early production support	Auctions for EU production (€ 800m in 2023) and fixed premiums for imports	Renewable (RFNBO) hydrogen producers
EU	Just Transition Fund and Recovery & Resilience Facility	>€25bn for hydrogen, via IPCEI of other state funded programmes	Government support funds from the EU under specific programmes	Member states to support own resilient, green economies. Specific focus is, inter alia, on renewable hydrogen
Global	H2Global	€4 billion	Hydrogen purchase and sale agreements through central body	Imports of ammonia, methanol and electricity based SAF

3.2.2 Country Analysis

A more detailed analysis of each country's position on production and imports in terms of policy position and progress towards their objectives was completed as part of the study. The results are presented in a qualitative red, amber, green (RAG) assessment of each country in terms of hydrogen policy and progress. Table 6 shows the key for the RAG assessment.

Table 6: Country hydrogen policy and progress RAG assessment key.

Policy RAG Key		Progress RAG Key	
Does not have a detailed domestic hydrogen policy or set targets for their hydrogen ambitions.		Has yet to release any funding or make significant developments in their hydrogen strategy.	
Has a domestic hydrogen policy and clear and comprehensive targets but has no clear ambitions for hydrogen imports or exports.		Has started to issue funding and deliver on their projects but are yet to make significant progress towards their 2030 targets.	
Has a domestic hydrogen policy with clear and comprehensive strategy and targets and has clear ambitions and targets specifically for importing hydrogen.		Has made significant progress in the progression of their hydrogen strategy with multiple projects under way and are on track to achieve their 2030 targets.	

The analysis included a review of each country's individual hydrogen policies and strategies, as well as the public funding mechanisms in place. A high-level review of existing projects and the progress being made against the targets set out in the hydrogen strategies was also completed. Based on the qualitative analysis, a red, amber, or green rating was applied to each country based on the key shown in Table 6. An overview of the results of the assessment are shown in Table 7 with commentary.

Table 7: RAG assessment of European countries policy support for hydrogen production and imports and progress being made to meet objectives stated in policy.

Country	Policy	Progress	Import Ambitions	Narrative
Belgium				**RAG rating as a potential destination for UK H_2 export: Green** Belgium published their National Hydrogen Strategy in 2021 with updates in 2022. They have no specific commitments on electrolyser capacity but have stated their ambitions for 20TWh of hydrogen demand by 2030 and 200 TWh of hydrogen demand by 2050. Their hydrogen strategy focuses on their hard-to abate sectors more specifically their steel industry and transportation sectors. Their ambitions are heavily geared towards the import of hydrogen, and positioning themselves as a hydrogen import location is the first pillar of their strategy. They do not have an established fund for hydrogen development but have already begun initiating projects.
Denmark				**RAG rating as a potential destination for UK H_2 export: Red** Denmark announced the power-to-X (PtX) strategy in December 2021 through which they plan to build upwards of 4-6 GW of electrolysis capacity by 2030. To accompany the policy, they have proposed investing €170 million (DKK 1.25 billion) through PtX tenders for the operational support of the production of hydrogen. The tender was open from April 2023 to September 2023, and 6 projects with a combined capacity of 280 MW were selected. The subsidy is granted over 10 years paid per produced amount of green hydrogen. Focus markets include aviation, shipping and high temperature industry.
Finland				**RAG rating as a potential destination for UK H_2 export: Red** The Finnish government has set a target to produce 10% of the EU's hydrogen by 2030. Outside of this target they have not set a comprehensive framework or established a funding mechanism for their hydrogen ambitions. They adopted a resolution on hydrogen in

Country	Policy	Progress	Import Ambitions	Narrative
				2023 which includes the country's broad ambitions. Finland benefits from multiple competitive advantages in the creation of renewable energy and are thus unlikely to be importers of renewable green hydrogen.
France				**RAG rating as a potential destination for UK H_2 export: Amber** France set out its national strategy in 2020 with the objective to build 6.5 GW of low carbon electrolytic hydrogen by 2030, rising to 10 GW in 2035. The policy is backed by public funding worth €9 billion. The first 10 projects have been launched in France and approved by the European Commission involving public and private investment of €2.1 billion and €3.2 billion respectively. Significant progress in deploying hydrogen technologies. Several projects have been initiated, such as the ZEV project in Auvergne-Rhône-Alpes and the H2 Corridor in Occitanie.
Germany				**RAG rating as a potential destination for UK H_2 export: Green** German National Hydrogen Strategy was published in 2020. They have set a target for electrolyser capacity of 10 GW by 2030. Their strategy is heavily reliant on imports with 50% to 70% of domestic hydrogen demand to be met by imports. Public funding is ranging between €9 billion to €17 billion. They have made significant progress thus far and are on track to overachieve on their hydrogen ambitions.
Greece				**RAG rating as a potential destination for UK H_2 export: Red** Their National Energy and Climate Change Strategy (2021) sets a target of 1.7 GW of electrolyser capacity by 2030 and 30.6 GW of electrolyser capacity by 2050. Aside from these targets, they have no clear and comprehensive framework for the deployment and use of hydrogen, including the potential for hydrogen imports, and no clear funding mechanisms. They have made no significant progress towards their targets.
Italy				**RAG rating as a potential destination for UK H_2 export: Red** National Hydrogen Strategy launched in 2020 with a hydrogen ambition of 5 GW by 2030. The Ministry of Economic Development Is targeting an investment in the sector of €10 billion, €5billion from European public funds, and €5 from private investments. Funding will be divided between hydron production, distribution and consumption facilities, research and development and infrastructure to integrate production with end uses. Hydrogen is anticipated to account for 2% of Italy's final energy demand increasing to 20% by 2050. Italy has some projects in development to help achieve their 2030 goals, however, relative to other European nations their progress to policy is slow.
Netherlands				**RAG rating as a potential destination for UK H_2 export: Green** Hydrogen ambitions are set out in the Dutch Climate agreement (2019) followed by the National Hydrogen strategy (2020) with an ambition to increase electrolyser capacity to 3-4 GW by 2030 and 8 GW by 2032. Their key areas of focus are storage, trade and infrastructure. The Netherlands have allocated €7 billion for the development of renewable hydrogen, €300 million of which is specifically allocated to facilitating the import of renewable hydrogen. They have made significant progress to policy and are on track to overachieve their 2030 targets. In addition, they have displayed an optimistic outlook on hydrogen imports through their strategy. The Netherlands have set ambitions for the import of hydrogen and have allocated €300 million to facilitate the import of renewable hydrogen.

Country	Policy	Progress	Import Ambitions	Narrative
Norway				**RAG rating as a potential destination for UK H_2 export: Red** Norway has a broad mandate surrounding the deployment and use of hydrogen domestically and has no clear capacity targets. They have stated their ambitions to develop domestic hydrogen locations and are exploring the potential to export hydrogen to other European countries in need of fulfilling their hydrogen demand. There is no clear funding mechanism. They have begun to develop hydrogen projects, however with no clear policy their progress cannot be concluded.
Poland				**RAG rating as a potential destination for UK H_2 export: Amber** Their National Hydrogen Strategy was introduced in 2021. The strategy includes 6 main objectives, including the use of hydrogen technologies in energy and heating, and as an alternative fuel in transportation. Public funding for the development of the hydrogen economy is valued at €1 billion. Poland has a pragmatic approach to imports, and the government have stated their interest in regional energy cooperation, which could mean the development of cross-border hydrogen pipelines. However, they have not developed a specific policy or strategy for hydrogen imports. Poland is a slow starter with regards to making progress on their hydrogen ambitions, but they have announced numerous projects, and the development of their hydrogen valleys is set to make significant contribution to achieving their hydrogen ambitions. As one of the world largest hydrogen producers, decarbonising their existing hydrogen production facilities will contribute significantly to hydrogen ambitions and reducing emissions
Portugal				**RAG rating as a potential destination for UK H_2 export: Red** National Hydrogen Study published in 2020 with an ambition of 2.5 GW of installed capacity in electrolysers. More recently, in July 2023, the Portuguese Government presented a proposal to the European Commission to revise the National Energy and Climate Plan 2030, calling for an increase in the installed capacity of electrolysers in 2030 to 5.5 GW. Their focus areas are transport and gas. Approx €7 billion in funding has been allocated to the deployment of hydrogen and they have numerous projects already in place.
Spain				**RAG rating as a potential destination for UK H_2 export: Red** Spain's National Hydrogen Roadmap: A commitment to renewable hydrogen (2020) defines 60 specific measures in 4 key areas for the development of their hydrogen economy. They set an initial target of 4 GW of electrolyser capacity by 2030 which has now been revised to 11 GW. €1.5 billion of public funding has been allocated to hydrogen schemes. As of 2022 they were overachieving on the electrolyser capacity targets.
Sweden				**RAG rating as a potential destination for UK H_2 export: Red** Proposal for a National Fossil Free hydrogen strategy published in November 2021 setting capacity targets for both 2030 of 5 GW and 15 GW by 2045. Key sector of focus are the steel and transportation industries. €5 billion in funding has been allocated towards hydrogen schemes. Hydrogen schemes in Sweden also benefit from a significant amount of private investment. They are making steady progress towards the hydrogen targets with the announcement of several projects.

The full description of each country's position is available in Appendix A. Key takeaways from the analysis that informed the direction of this report were:

- The only countries that have clear policy on the import of hydrogen are Belgium, The Netherlands and Germany. It should be noted that these countries have begun establishing partnerships to facilitate their hydrogen imports.
- Of the countries with import targets, Germany has been progressing import routes with several other nations. In November 2023, the Norwegian and German governments published a feasibility study for a Norway-Germany hydrogen pipeline carried out by the gas company Gassco and the German Energy Agency (Deutsche Energie-Agentur GmbH (dena) and Gassco AS, 2023), which indicated that a pipeline could feasibly be in operation by 2030 (Deutsche Energie-Agentur GmbH (dena) and Gassco AS, 2023). Energinet and Gasunie, the gas transmission network operators in Denmark and Germany respectively, have signed a cooperation agreement to develop a hydrogen pipeline from Denmark to Germany, with the aim of completing the project between 2028-2030 (Gasunie, 2023). The Netherlands and Germany have also agreed to work towards hydrogen interconnection through the Delta-Rhine corridor (Government of the Netherlands, 2023) and the AquaDuctus project, recognised as an Important Project of Common European Interest (IPCEI), aims to connect Germany with offshore hydrogen production in the North Sea before forming a wider offshore network connecting Germany to the Netherlands, Belgium and other North Sea nations (AquaDuctus, n.d.). On top of the projects with European neighbours, Germany has signed joint declarations of intent to develop production and import infrastructure in Denmark, Algeria, and Australia.
- Despite clear policy support and appetite for production projects in Europe, the combined hydrogen production targets of all 14 countries considered in the detailed analysis would not meet the internal production target set out in the EU's Hydrogen Strategy, which means it is also unlikely that producers within the EU will be able to provide a meaningful proportion of the import target of 10 Mtpa, as shown in Figure 9 (in the strategy, it was originally assumed that trade between EU member states would make up a large contribution of this hydrogen import).

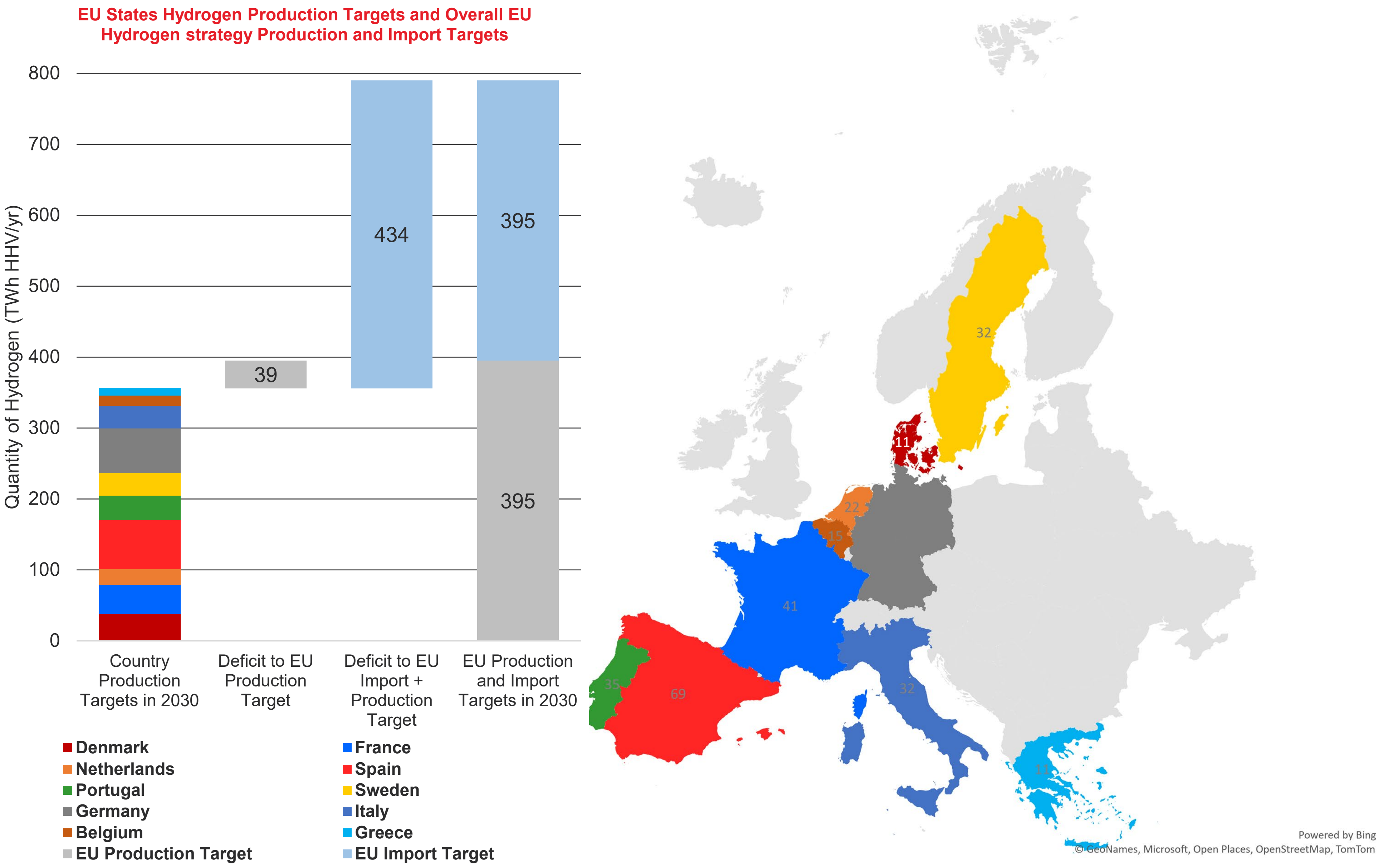


Figure 9: Build-up of European production ambitions against EU production target.

Considering policy targets, there is a clear case for the UK to explore the potential of exporting hydrogen to continental Europe. Domestic production in the EU is unlikely to meet the target set out in the EC Hydrogen Strategy, so even if demand does not ramp up as quickly as envisioned in the strategy, there is likely to still be significant demand for imports to meet the legally binding emissions reduction targets set out in RED III. Based on the production and import targets set out in the EU hydrogen strategy and the current domestic hydrogen production targets set out above, the EU could have to import up to 434 TWh/yr of hydrogen to meet its 2030 target. This figure is unlikely to be achievable, however it does show that there will be a significant requirement for imports to the EU.

3.3 European Hydrogen Imports

Considering the findings of Sections 3.1 and 3.2, to understand the UK's position to contribute to Europe's hydrogen import targets, a review of the countries and regions aiming to export hydrogen to Europe was carried out.

3.3.1 Import Sources

Of the 70 countries identified as a potential exporter by the EU, particular interest has been paid to countries with their own hydrogen strategy or those which are deemed to have the best export potential based on renewable generation potential, cost of hydrogen production, transportation locations, cost of transportation and security of supply. Considering the factors outlined, those countries are Canada, the USA, Norway, Australia, Oman, Saudi Arabia, the United Arab Emirates (UAE), Egypt, Morocco, Algeria, Tunisia, Australia, Brazil, Chile, Namibia, and eastern Europe/central Asia (Stifftung Wissenschaft und Politik (German Institute for International and Security Affairs), 2023).

The USA, Canada, Norway are the EU's closest allies with well-established commodity and oil and gas export infrastructure (Stifftung Wissenschaft und Politik (German Institute for International and Security Affairs), 2023), which makes them the ideal sources for export to the EU. Other countries and regions prioritising hydrogen export which are most likely to be able to supply a considerable quantity of hydrogen to mainland Europe include Australia, Saudia Arabia, Chile, Brazil, and North Africa. Spain, while within continental Europe, is also positioning itself as a net exporter of hydrogen to wider Europe and has been included in the analysis. Overviews of the export potential of each of the countries and regions identified are provided in Appendix A.

3.3.2 UK Potential

Considering the strategies and production targets outlined in Appendix A, even in a best-case scenario, all the regions combined would not be able to provide a reliable hydrogen supply equivalent to the entirety of the EU's 10 Mtpa import target by 2030, even if stated production targets are met in full (International Energy Agency, 2023) (Stifftung Wissenschaft und Politik (German Institute for International and Security Affairs), 2023). Moreover, imports from regions other than Norway and potentially North Africa would only be economic via shipping. Pipeline connections from Norway and North Africa could be developed, however the length of the pipelines from North Africa may make them uneconomic compared to shipping from other regions, or at least push development timeframes. This leaves the UK and Norway as potential exporters to the EU via pipeline through the North Sea corridor. Shipping from Norway has been targeted as an interim measure to develop hydrogen export trade before pipelines can be made available and a similar pathway may be possible from the UK. Additionally, the pipelines from the UK to Europe have the potential to be significantly shorter and hence less expensive than pipelines from Norway to Europe.

Canada, the USA, Australia and Saudi Arabia are leading the way when it comes to developing low carbon hydrogen production for export to Europe. These countries have all had some engagement with European states and organisations on the export of hydrogen to Europe and have invested heavily in the development of the hydrogen economy in their respective nations. Furthermore, other regions are also developing capability and infrastructure. Of the nations best positioned to export to the EU by 2030, only Norway offers a viable potentially cost competitive pipeline import option via the North Sea corridor for northwest Europe outside of the UK. Despite this, it is highly unlikely that the EU will be able to meet its 2030 hydrogen import target, even when aggregating exports from the nations leading hydrogen development and other regions.

Overall, hydrogen production projects targeted specifically at export are increasing in number year on year, with 16 Mt (632 TWh/yr) worth of announced hydrogen production projects for 2030 attributed to hydrogen trade projects (International Energy Agency, 2023), representing an increase of 25% year on year. On the other hand, only three projects aimed at hydrogen trade have reached FID: NEOM in Saudi Arabia, the Green Hydrogen and Chemicals SPC Project in Oman and CF Industries' plant in Donaldsonville in the USA, with the combined capacity of these projects only representing 0.3 Mtpa (11.9 TWh/yr) of hydrogen trade by 2030 (International Energy Agency, 2023). Thus, to achieve anywhere close to the EU import target, significant ramp up in development of hydrogen production for trade will be required, so there is an opportunity for the UK to develop capability in this space. This will require support from Governments to make projects bankable, which could be done through the development of shared export infrastructure.

Global hydrogen trade is still in its infancy, but development is accelerating rapidly as emissions reductions targets in Europe approach. Projects spread across developed and developing countries in North America, Latin America, Europe, north and southern Africa and Australasia are being developed and while most are still at an early stage, development is accelerating with support from Governments and private organisations demonstrating a willingness to support the growth of the projects and a belief in their viability. Most of the projects identified in these regions are specifically aiming to export at least some of the hydrogen produced to the demand centres in Europe, meaning that UK projects are behind in this space. However, given the nascency of the market, the wind resources available in the UK, its strong commitment to developing hydrogen production value chains, and geographic position, the UK is in a strong position to become a key hydrogen trade partner with Europe, if renewable generation, hydrogen production, national infrastructure, and national strategy can be developed to support the growth of the hydrogen economy in the UK.

3.4 UK Export Routes to Europe

UK Export Routes Summary

The UK is well positioned to export hydrogen to Europe via pipeline and provides one of the shortest connection routes from any country outside the EU. There is also the potential to export hydrogen to Europe via ship in derivative form. Global hydrogen trade is in its infancy and the UK is in a strong position to potentially become a key exporter to northwest Europe, which is expected to be one of the largest demand centres for low carbon hydrogen in the world out to 2050.

To export hydrogen to continental Europe, the UK has several potential transport options. These can broadly be split into two main categories, pipeline transport and non-pipeline transport, as outlined in Section 1.5. The UK currently operates three subsea natural gas pipeline interconnectors with continental Europe (Bacton to Balgzand, Bacton to Zeebrugge, and Nyhamna to Easington), one domestic subsea pipeline connection between Scotland and Northern Ireland, and a further two gas interconnectors from Scotland to the Republic of Ireland. Operating gas pipeline infrastructure between the UK and continental Europe is therefore an established sector with good experience in not only the physical operation of the systems but also the commercial, and regulatory frameworks which facilitate the international trade of gas.

3.4.1 Existing Gas Connections

The existing connections between the UK and Europe of interest to this study are the connections between the UK and continental Europe. Currently, there are three direct gas pipeline connections to continental Europe in operation: The Interconnector (Bacton to Zeebrugge, Belgium), the BBL connection (Bacton to Balgzand, Netherlands) and the Langeled pipeline (Easington to Nyhamna, Norway via the Sleipner offshore platform). Of the three connections, The Interconnector and the BBL connection are bi-directional, i.e. gas can be both exported and imported depending on requirements. The Langeled pipeline is uni-directional, with gas only flowing from Norway to the UK. The alignments of the existing interconnectors are shown in Figure 10.

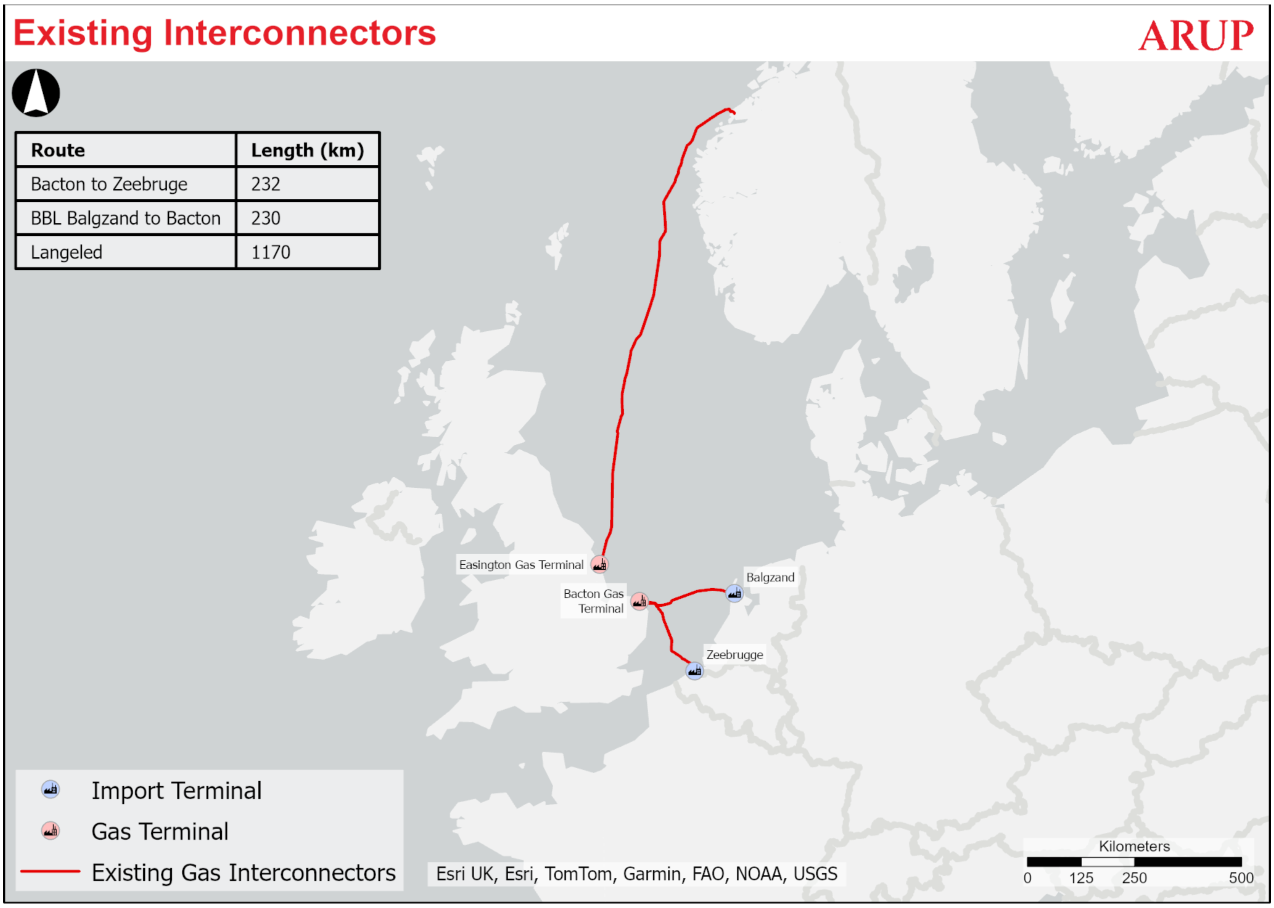


Figure 10: Existing natural gas interconnectors between the UK and continental Europe.

The North Sea corridor identified in Figure 10 above will be a critical import pathway for Germany and northwest Europe, which will be a significant demand area.

3.4.2 Shipping

LNG has become increasingly important in recent years, particularly to support energy security in Europe following Russia's invasion of Ukraine in 2022. Additionally, the shipping of bulk liquids, such as methyl-cyclol hexane (MCH, an LOHC), and products like ammonia is well established globally In the UK, the top four ports for LNG are Milford Haven, Medway, Forth and at Teesport. Medway and Teesport are located on the East Coast of the UK, while the two facilities in Milford Haven are situated on the West Coast. Grangemouth also has the capacity to handle bulk liquids however not at the scale of the other facilities mentioned. Shipping is a technically viable route for hydrogen export from the UK to Europe, considering the existing expertise and established trading corridors between the UK and European nations.

4. Export Considerations

To realise the opportunity set out in Section 2, the UK needs to establish how it could facilitate the export of low carbon hydrogen. This is a multi-pronged question, with several conflicting objectives. The UK Government will prioritise domestic demand first, which will influence the export location through the development of domestic production, transportation, and storage infrastructure. Following this, the key driver for export will be the quantity and quality of demand, with the location of demand also playing a key role in the selection of export locations. A high-level hierarchy of decision making for export location is shown in Figure 11.

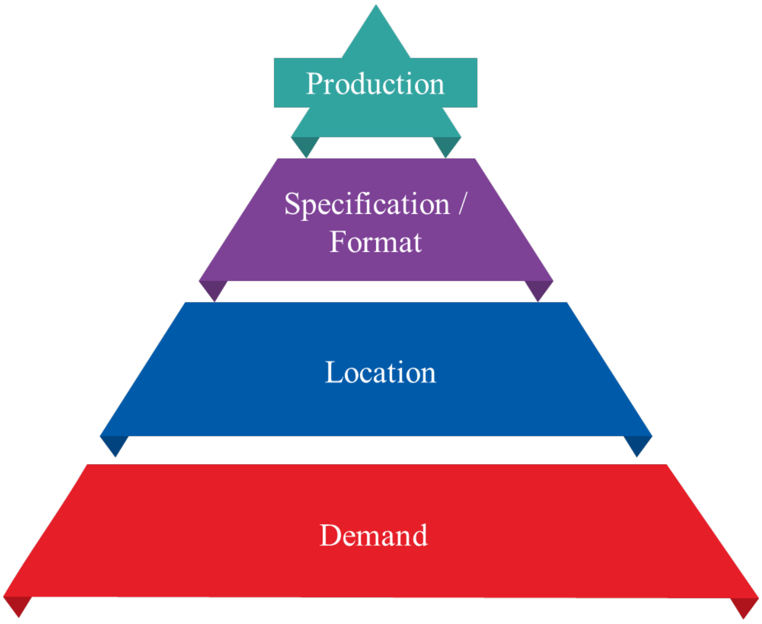


Figure 11: Hierarchy of the selection criteria for export location.

Figure 11 attempts to demonstrate what have been considered as the key building blocks to selecting potential hydrogen export corridors. The core driver is hydrogen demand. Hydrogen strategies in Europe suggest strong demand, however the actual development of demand should be monitored closely as projects mature. Demand will likely depend on the pace of the transition to hydrogen in industrial regions. Following the establishment of a demand source, the location of it must be factored into the selection of export locations. This is key as it will influence the economics of each export option. Following location, the specification of hydrogen or derivative required by the demand side should be considered as this may also affect which transport option would be the most efficient. Production methods and volumes must also be considered in the export route selection process.

The case for demand has been set out in Section 3.2, the location of that demand is explored further in Section 4.1, before the location of planned hydrogen production and transportation infrastructure in the UK is considered in Sections 4.2 and 4.3 and existing export infrastructure is described in Section 4.4. The information provided in the following sections was used to inform the selection of potential export locations as a basis for the LCOT analysis completed in the report.

4.1 European Import Infrastructure

European Hydrogen Infrastructure Summary

Hydrogen infrastructure projects in Northwest Europe are the most advanced in Europe and have received significant support from Governments and the European Commission. Distribution network developments in Belgium, the Netherlands, and Germany have received public funding to accelerate their development, with construction having started on the first sections of the Dutch and Belgian hydrogen networks. Each of the three nations' transmission networks have included the option for hydrogen import in their strategies, so these nations were deemed to be the most suitable to target for hydrogen export as a basis for this study.

Several large-scale hydrogen infrastructure initiatives have been set up in Europe, aiming to facilitate the transition to hydrogen in line with the EU hydrogen strategy and national policies. Gas networks across the bloc have begun developing plans for the repurposing of natural gas networks, and the construction of new hydrogen networks to facilitate the inter-state transport of hydrogen within the EU. An export corridor from the UK to Europe should aim to tie-in with the development of hydrogen infrastructure in Europe to ensure synergies between projects, organisations, and nations are maximised to avoid duplication of work, resources, or costs associated with hydrogen trade.

Development of large-scale hydrogen networks in northwest Europe is gathering momentum, with the Netherlands, Belgium, and Germany all committing public spending to the development of hydrogen networks, with a focus on imports. The possibility of an interconnected North Sea region is also gaining traction, with projects like AquaDuctus (see Section 4.1.2) and the GASCADE proposed European Offshore Hydrogen Backbone (DNV, 2023) all aiming towards connecting up Europe's hydrogen producers and users through an integrated offshore system. A system of this nature could spread the cost and ensure greater security of supply for continental Europe which could accelerate development. The following sections consider the demand locations in Europe in more detail, highlighting the planned infrastructure with the aim of selecting potential export corridors for the UK to reach continental Europe. Additionally, other feasibility studies exploring hydrogen export from the UK to Europe via the North Sea have been completed, like the Scottish Government "Hydrogen Backbone Link" (Net Zero Technology Centre, 2023).

4.1.1 European Hydrogen Backbone Initiative

A principal initiative is the European Hydrogen Backbone (EHB), which aims to develop an interconnected hydrogen network across Europe. The EHB is split into three distinct phases, starting out by connecting the regional demand clusters with local production and import locations, before expanding connections across Europe to create a fully interconnected continental hydrogen transmission system. If the EHB were to develop the entire network as per its ambitions, it would result in the establishment of 28,000 km of dedicated hydrogen pipelines by 2030, expanding to 53,000 km across 28 European countries in 2040 (S&P Global, 2023) This can be seen in the contrast between the 2030 systems and 2040 systems as shown in Figure 12 and Figure 13.

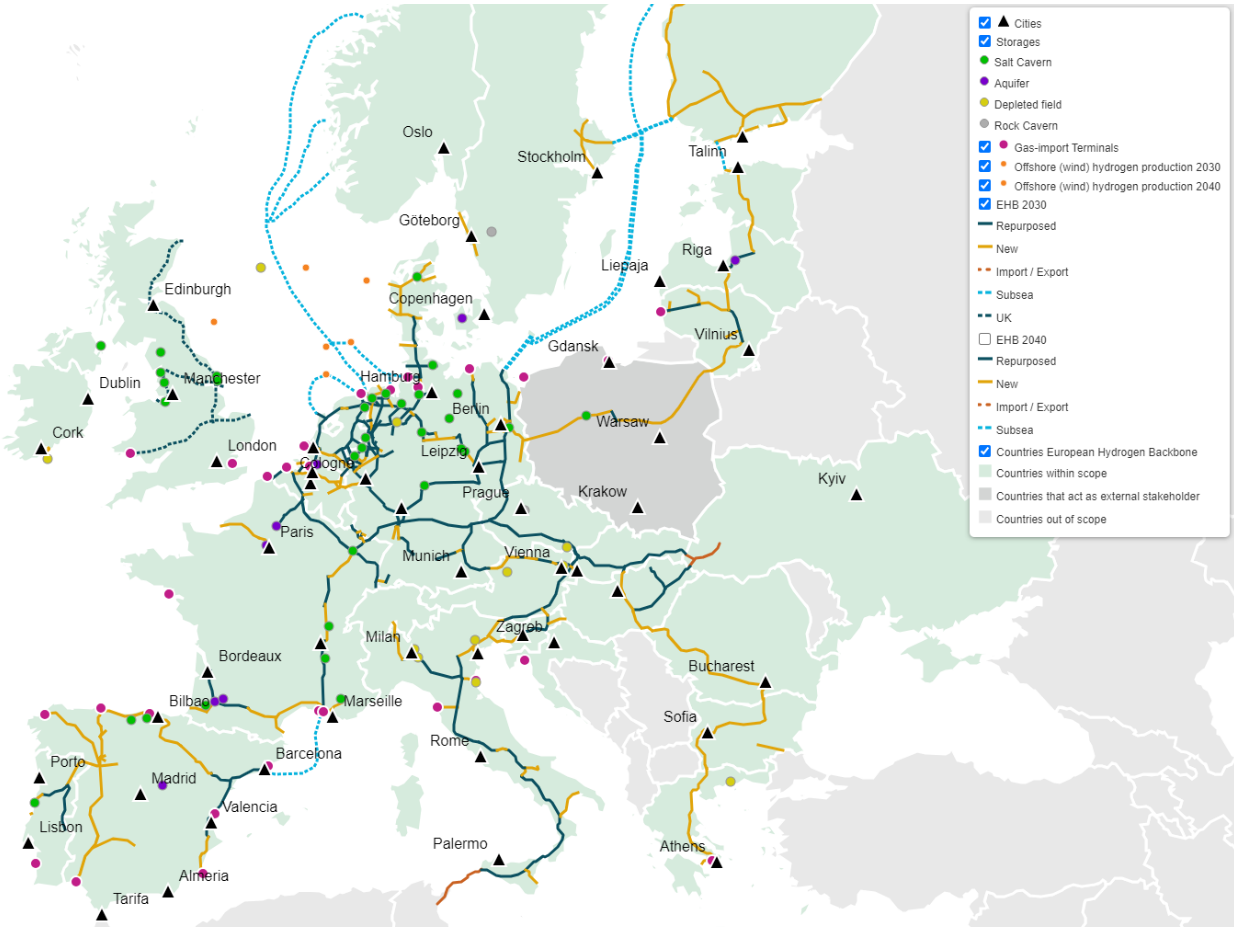


Figure 12: Map of the EHB system showing the provisional routes of the core network proposed to be developed by 2030. Source: (European Hydrogen Backbone, 2024).

As shown in Figure 12, the proposed initial build out of the network is centred around the industrial regions in northwestern Europe. This coincides with the European locations with the shortest transport distance from the UK. As the network develops towards 2040, regions become more interconnected across countries and the continent, working towards the ultimate vision of the network as per Figure 13 below.

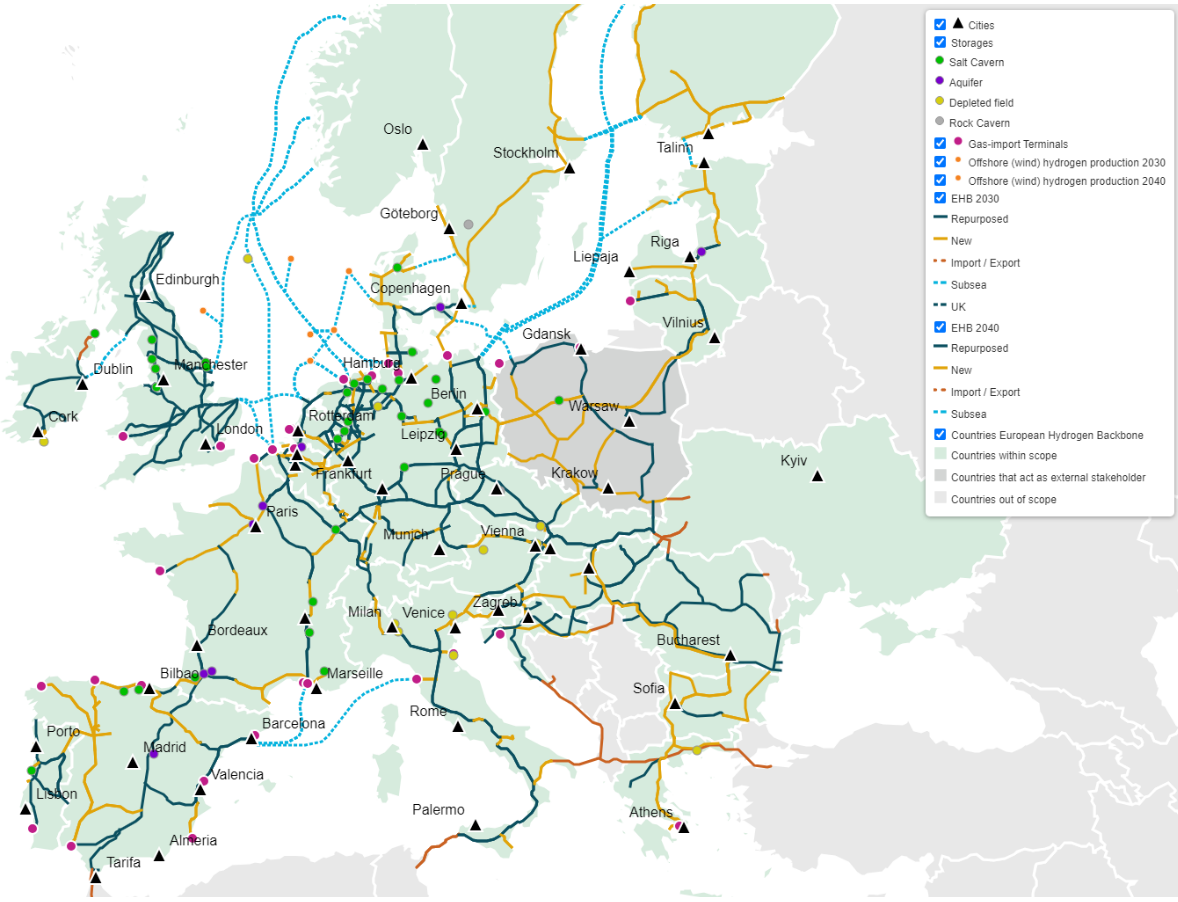


Figure 13: Map of the EHB system showing the provisional routes of the core network at full build out in 2040. Source: (European Hydrogen Backbone, 2024).

It should be noted that the EHB is an aspirational initiative consisting of 33 energy infrastructure operators as partners, there has been no firm commitment to developing the initiative and the development of the network in each country will be at the behest of the national gas transmission operator and government. There is no firm commitment from the EU to develop an overall network, although aspirations for such a system are set out in its hydrogen strategy. While there is no firm commitment, the EHB initiative presents a signal of intent from national gas transmission system operators to develop an interconnected network which would provide access to large demand sources and greater certainty of offtake to hydrogen producers.

The EHB network includes several coastal nodes which align with existing gas import terminals. These nodes, particularly in northwest Europe, would be favourable for connection from the UK for hydrogen imports. These nodes are Dunkirk, France; Zeebrugge, Belgium; Rotterdam, Antwerp, Balgzand, and Groningen, Netherlands; Emden, and Wilhelmshaven, Germany. An extract of the EHB map showing the nodes listed is shown in Figure 14.

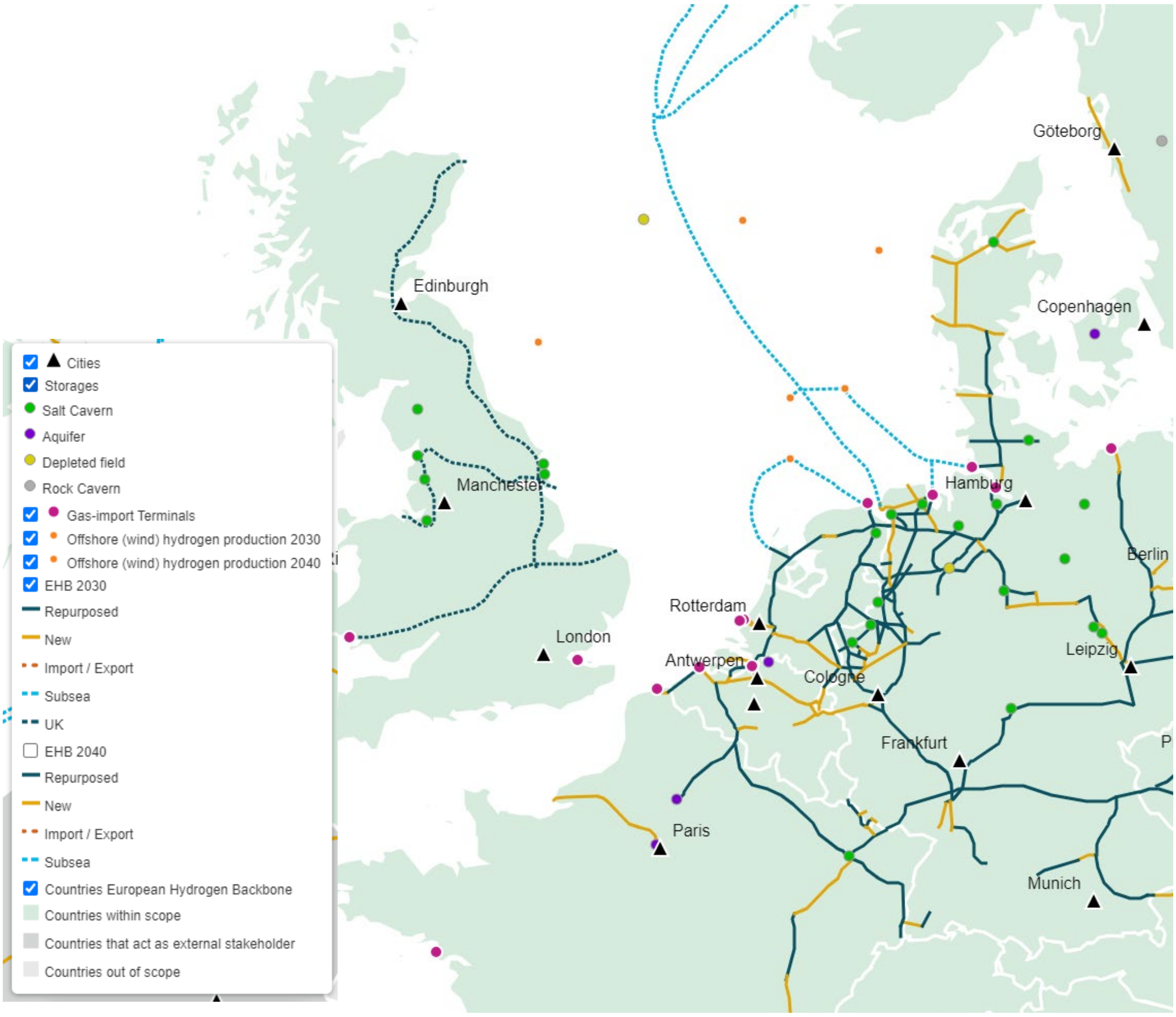


Figure 14: Import nodes in northwestern Europe identified by the EHB initiative in the 2030 build out.

4.1.2 European Offshore Hydrogen Backbone

GASCADE and Fluxys commissioned DNV to complete a feasibility study to develop a specification for a European Offshore Hydrogen Backbone. The report provides a generic overview of a potential system to connect offshore wind farms in the North Sea with the potential for electrolytic hydrogen production to North Sea countries with hydrogen demand. The network is primarily focused on transporting the production from wind farms in the first instance but has a strong consideration for connecting to a wider North Sea import/export hydrogen pipeline network in the future (DNV, 2023). The report considers the potential use cases and location of demand for hydrogen, with the delivery location set as Germany due to its existing hydrogen demand and appetite for hydrogen use in industry (DNV, 2023). The report also cites that the long transport distances required to import hydrogen to Europe from other continents significantly increases the delivered LCOH (DNV, 2023), which would suggest support for import from more local sources would be advantageous to supplement domestic production.

4.1.3 AquaDuctus Project

The AquaDuctus project is a joint venture between Fluxys and GASCADE which aims to develop a common offshore hydrogen network in the German Economic Exclusive Zone (EEZ) of the North Sea to interconnect offshore hydrogen production at offshore wind farms in the Dutch, Belgian, Danish, British and Norwegian sectors of the North Sea with mainland Europe, starting with Germany (AquaDuctus, n.d.). The project is receiving EU funding from the EU to support its development (AquaDuctus, n.d.). Thus far, a feasibility study has been completed, which formed the basis for its application as a project of common interest. The project has also been recognised as part of the core German network, which was announced in 2023 (see Section 4.1.4 for more detail) (AquaDuctus, n.d.). The project plans to build out an extensive offshore network, targeting 400 km of offshore pipelines in operation by 2035. The initial build out of the network is planned to connect the SEN-1 wind farm site to Germany as shown in Figure 15.

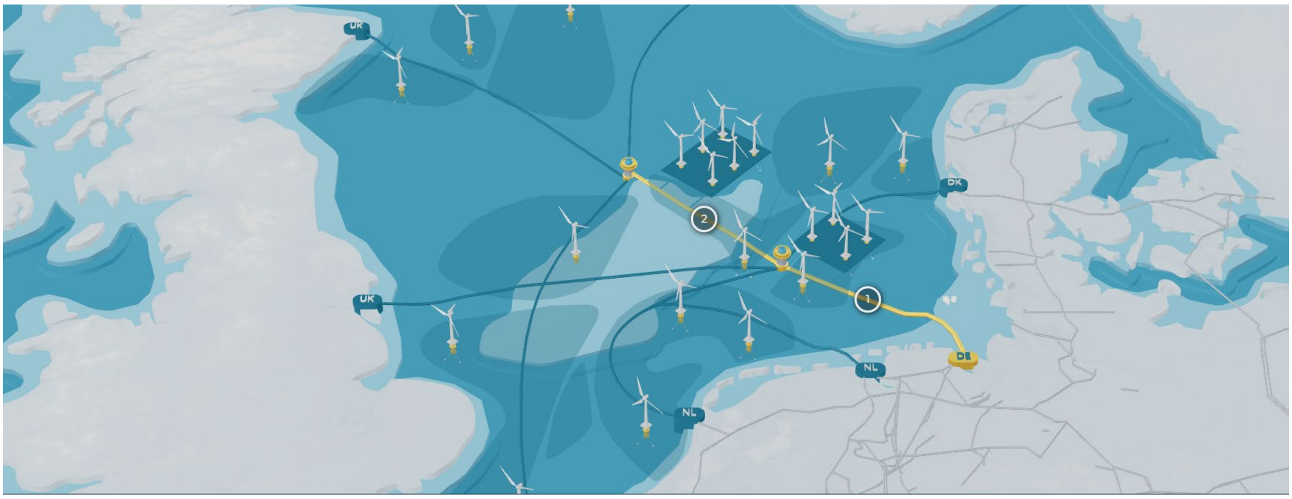


Figure 15: Graphical representation of the planned AquaDuctus network showing the termination point in Phase 1, marked by the pin at the end of the section denoted "1" and the aspirational termination point of Phase 2 marked by the westerly pin at the end of the section denoted "2". Source: (AquaDuctus, n.d.).

Figure 15 shows the ambitions of AquaDuctus for interconnection, with illustrative connections from St. Fergus and Easington in the UK shown, as well as connections to the Netherlands, Belgium, Norway and Denmark.

4.1.4 German Hydrogen Network

The German Government has set out ambitions for a dedicated "hydrogen core network" to begin transporting hydrogen by 2025, scaling up to 9,700 km of hydrogen pipelines by 2032 (Collins, German hydrogen pipeline network will begin transporting H2 in 2025, with 9,700km in place by 2032, says government, 2023). The network is expected to cost approximately €20 billion and will be focused on connecting ports, industry, power, and storage facilities. The proposed routeing of the core network is shown in Figure 16.

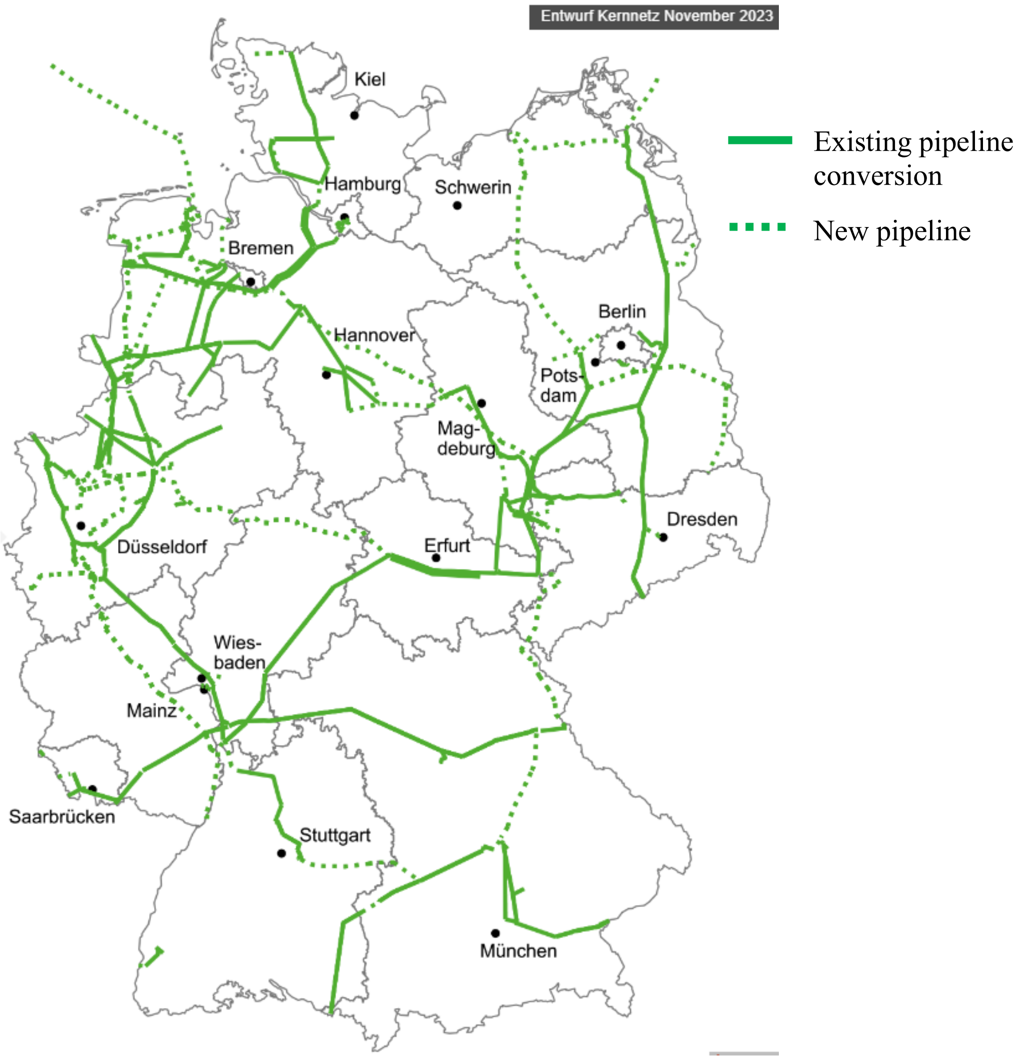


Figure 16: Proposed German hydrogen core network at full build out in 2032. Source: (FNB Gas e.V., 2023)

The network plan has been accepted by the German government, with a commitment to support its development (Collins, German hydrogen pipeline network will begin transporting H2 in 2025, with 9,700km in place by 2032, says government, 2023). Included in the network is the AquaDuctus project, as mentioned in Section 4.1.2, with the AquaDuctus project offering a potential direct route for hydrogen imports from North Sea countries as well as delivering hydrogen from offshore wind farms in the German EEZ of the North Sea. The AquaDuctus system could serve as a connection point for pipelines from the UK to integrate into a wider hydrogen transportation network interconnecting the likes of Norway, the UK, Belgium, the Netherlands, and Germany. With strong policy support for the German hydrogen network and the AquaDuctus project, it is likely that Germany will be one of the first major importers of low carbon hydrogen in the world and the infrastructure under development provides a significant opportunity for the UK to become an exporter.

4.1.5 HyNetwork, Netherlands

The Netherlands has begun developing its domestic hydrogen transmission network, HyNetwork. The network aims to connect the production and import locations centred around the port of Rotterdam and Groningen to domestic demand locations and eventually out to Belgium and Germany, tying into the wider EHB ambitions. Ultimately, the network will extend over 1,200 km if it reaches the ambitions set out in the Dutch hydrogen strategy as shown in Figure 17.

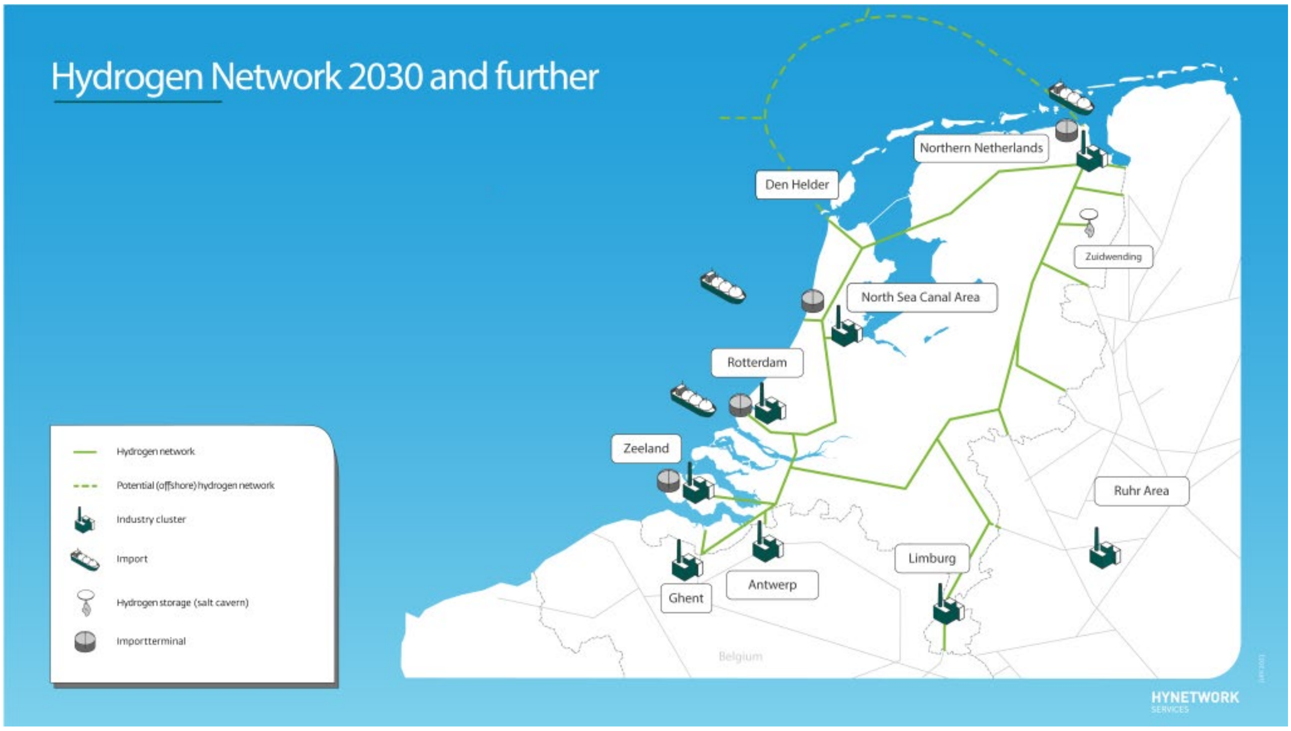


Figure 17: Graphical representation of the proposed Dutch HyNetwork. Source: (Gasunie, n.d.)

The first phase of the network, which will form a 30 km connection between Rotterdam ports to refineries in the area, is already under construction with commercial operations targeted to commence in 2025 (S&P Global, 2023). The project is owned by Gasunie, who have committed €100 million in funding for the first phase of the network which will be carried out by HyNetwork Services, a Gasunie subsidiary. The project is primarily based on repurposing existing gas pipelines with few new pipelines included, hence the overall network cost is comparatively low at approximately €1.5 billion (S&P Global, 2023).

4.1.6 Belgian Hydrogen Network

Belgium is among the leaders in the development of hydrogen infrastructure and policy in Europe. In 2023, The Belgian Government announced €250 million of public funding was to be made available for the development of the country's hydrogen network (Martin, Belgium approves €250m of public funding for hydrogen pipelines throughout country and into Germany, 2023). A schematic of the proposed network taken from the Belgian national hydrogen strategy is shown in Figure 18.

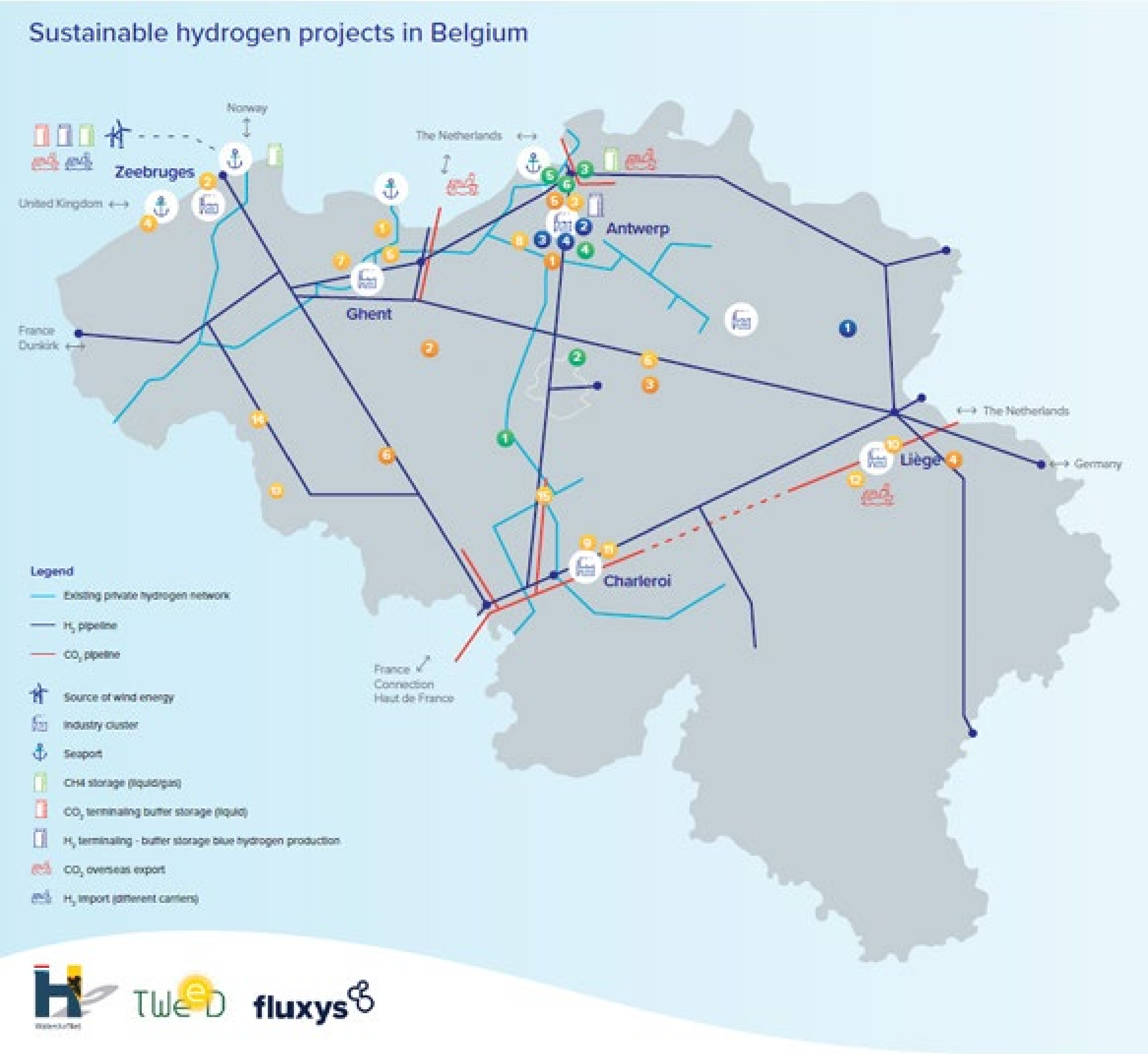


Figure 18: Sustainable hydrogen projects in Belgium, including hydrogen pipelines, set out in the Belgian National Hydrogen Strategy in 2021. Source: (Federal Government of Belgium, 2022).

Fluxys are already constructing a section of this network between Zeebrugge (current natural gas import terminal where "The Interconnector" from the UK lands) and industrial locations in Ghent and on to Brussels, named the "H2 Highway" (Fluxys, 2024). The pipeline is being developed in two stages, stage 1 from Ghent to Brussels and Stage 2 from Ghent to Zeebrugge, as shown in Figure 19. Eventually, H2Highway may connect into the wider network linking Belgium, the Netherlands and Germany.

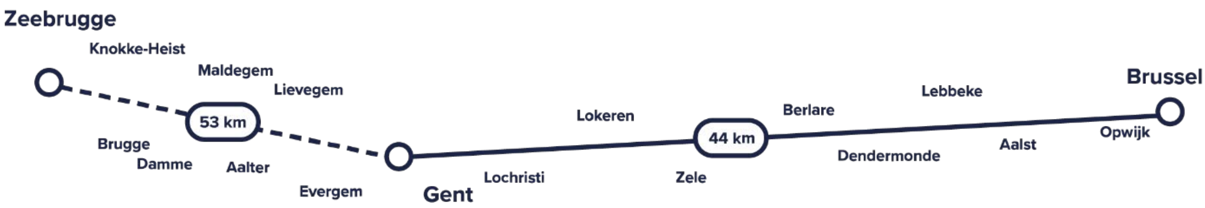


Figure 19: Fluxys H2Highway pipeline schematic. Source: (Fluxys, 2024).

The first section of H2Highway (Ghent to Brussels) is due to complete commissioning in 2024, with the second section (Ghent to Zeebrugge) due to be commissioned by the end of 2026. Belgium has indicated a clear support of hydrogen imports for distribution to its own industry but also wider Europe through connection with the Netherlands and Germany.

4.1.7 Plans in France, Spain, Portugal, Italy, and North Africa

France currently has no set strategy for hydrogen transmission. Spain and Portugal are positioning themselves for hydrogen export, given their renewable resources.

Other countries in southern Europe, such as Italy, and the Balkan states are behind on hydrogen development compared to states in northern Europe. Additionally, due to their relative proximity to North Africa and Spain (see Figure 20) when compared to the distance to the UK, it is unlikely that the UK would have a competitive position for hydrogen export to these countries, even if hydrogen policy develops quickly in the region.

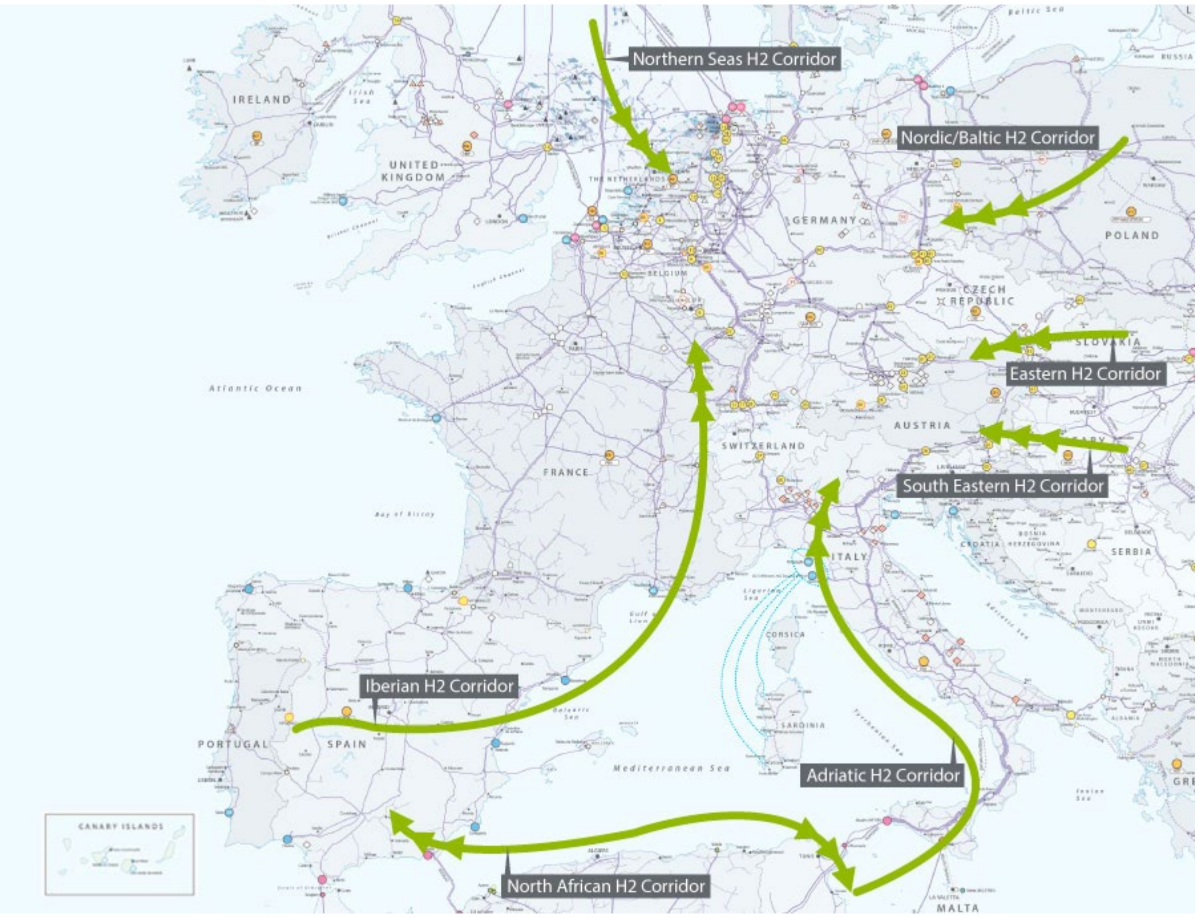


Figure 20: Proposed hydrogen import corridors under the REPowerEU plan. Source: (Enagas, 2024).

Alternative locations in southern Europe and the Mediterranean are also attractive from a demand perspective, but less accessible from the UK. Options in these regions were also considered in the analysis to assess the potential for UK hydrogen export to these regions, considering the fact there will be competition from southern Europe and North Africa with comparable or superior renewable resource to the UK, meaning that the advantage seen for countries in northwest Europe is unlikely to be carried over to southern European locations.

4.2 UK Low Carbon Hydrogen Production

Planned UK Infrastructure Summary

Research was completed on existing gas import / export infrastructure, the location of planned UK hydrogen production, transportation and storage infrastructure and port facilities. Data was consolidated into an ArcGIS database to enable spatial representation of the data to be used to support the selection of potential export locations. Information on the potential cost of hydrogen production across the UK taken from the IEA was also reviewed to help inform the selection of potential export locations. The information gathered heavily influenced the selection of potential export locations as good access to hydrogen infrastructure is required to facilitate export.

4.2.1 Announced Hydrogen Production Projects

The location of planned low carbon hydrogen production projects in the UK are considered in the analysis. Projects' level of development and production targets were taken from the IEA Hydrogen Project Database 2023 (International Energy Agency, 2023), while locations were gathered from publicly available sources. Reducing the distance between the production locations and export locations ultimately reduces domestic transportation costs prior to export. Production location is outside the scope of this report but should bias the lowest levelised cost of production, as this will be a greater contributor to the competitiveness of UK hydrogen against other exporters than domestic transportation costs. Only projects that are at a feasibility stage of development were selected and included in the analysis. Even considering projects at feasibility is likely to be an optimistic view of the quantity of production projects which will actually become operational, however it gives a broad view of where production locations are likely to be located. A visualisation of announced production projects is shown in Figure 21.

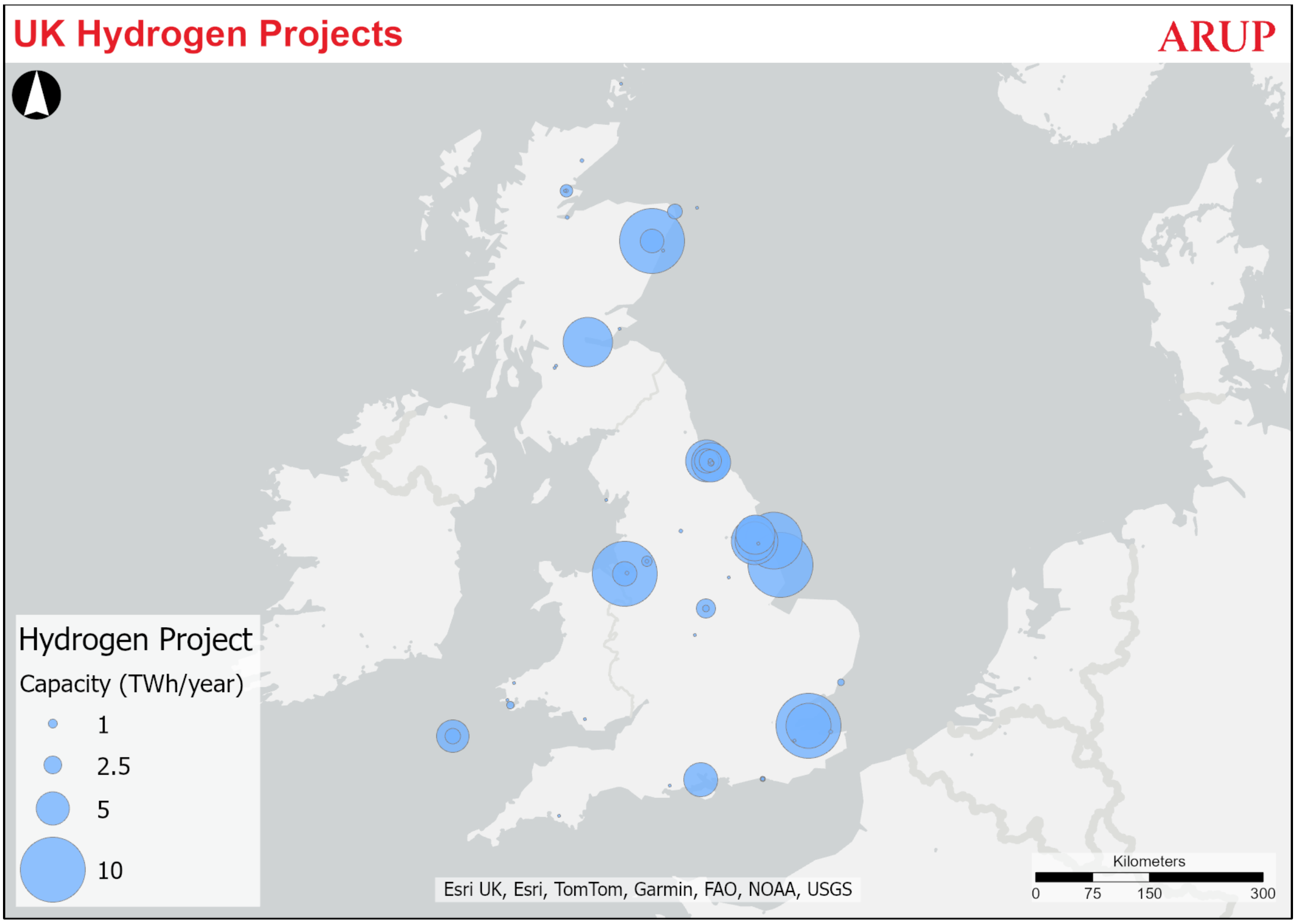


Figure 21: Visualisation of announced UK hydrogen production projects with capacity shown as maximum theoretical output. Source: Arup analysis and IEA Hydrogen Project Database 2023 (International Energy Agency, 2023).

The East Coast of the UK has high potential for hydrogen production. This correlates well with export to mainland Europe and hence it is recommended that export locations be primarily focused on east coast locations.

4.2.2 Renewable Generation Potential

Future production of low carbon hydrogen, particularly electrolytic hydrogen, could be distributed and not necessarily tied into the existing industrial clusters. The extent of project distribution will depend on the development of a domestic T&S network to connect supply with major demand sources. To optimise the LCOH of production, access to sufficient renewable electricity at low costs is required. To reduce the cost of electricity a “behind the meter” connection is often preferred as it means that the hydrogen producer may avoid the additional cost for transmission covered by the Transmission Network Use of System, Balancing Services Use of System, and Connection charges for users of the national grid. This means that electricity can be sourced at closer to the actual levelised cost of electricity, hence reducing the price. Analysis completed by the IEA has shown that the UK, particularly areas with high renewable potential, has the opportunity to be some of the lowest cost hydrogen production in Europe, and competitive with all but the most renewable resource rich countries in the world, as shown in Figure 22.

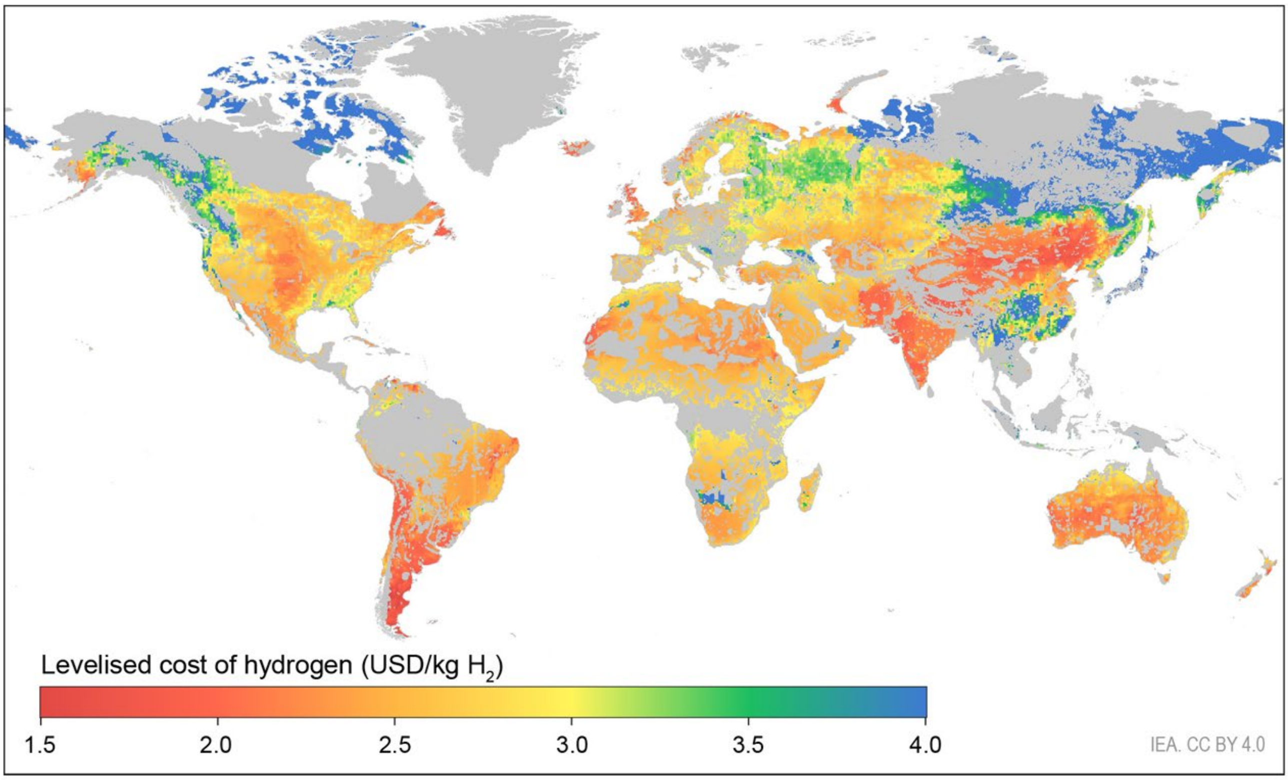


Figure 22: Global LCOH in 2030 projection published in the IEA Global Hydrogen Review 2023. Source: (International Energy Agency, 2023) (Bloomberg, 2024).

In the UK, the strongest renewable generation potential leading to the lowest LCOH for hydrogen production is around the West and North coasts of the UK, as shown in Figure 23.

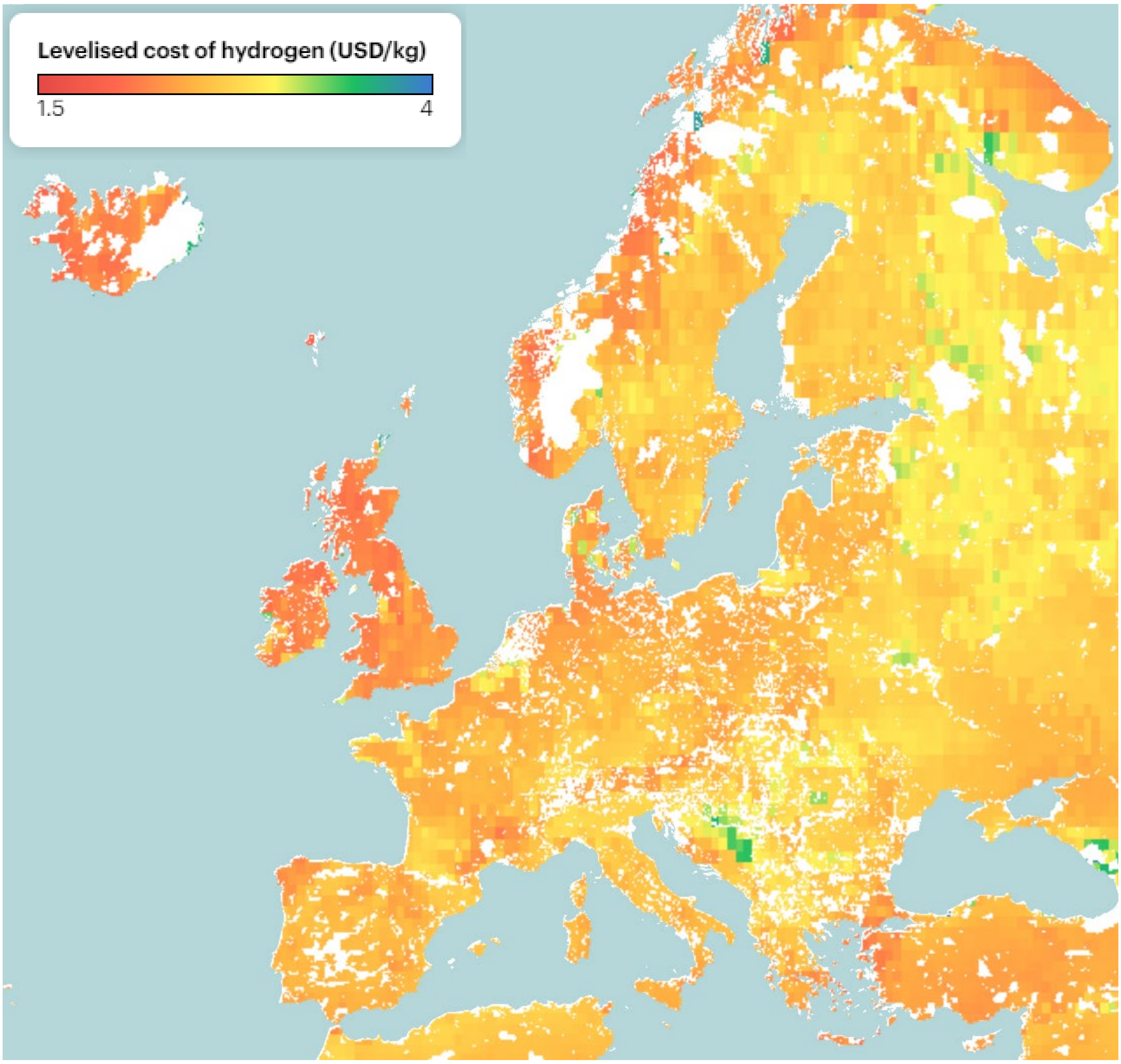


Figure 23: LCOH of hydrogen production across Europe considering the IEA's base assumptions for solar PV, onshore wind and electrolyser costs. Conversion to GBP/MWh taken using GBP to USD spot pricing on 27/03/24 Source: (Bloomberg, 2024) (IEA, 2023).

Potential production in the renewable rich areas on the UK's west, north, and northeast coasts should be considered when selecting potential export corridors.

Development of a UK domestic hydrogen network is already underway and a domestic hydrogen transportation network in the UK is already planned to connect the initial production locations and facilitate UK-wide distribution of low carbon hydrogen. Priority use for UK produced low carbon hydrogen will be the UK market, therefore, the development of a consolidated export route prioritising the lowest LCOT for export which leverages the UK domestic network is likely to offer the largest number of producers access to the export market.

The primary risk of waiting to establish an export route until all domestic networks are fully established is the loss of first mover and incumbent status. The UK will face significant competition on pipelined hydrogen exports to northwest Europe firstly from Norway and Denmark in the early 2030s, and potentially wider afield by the late 2030s and 2040s if the European Hydrogen Backbone is realised. First mover or fast follower status on infrastructure projects such as interconnectors, which are highly capital and time intensive is often vital to establish competitive position. Therefore, development of export options for the UK should be continued in parallel with the rollout of the domestic network.

4.2.3 Low Carbon Hydrogen Certification

The UK Government is developing a low carbon hydrogen certification scheme to give industry a way to provide reliable, verified emissions intensity of hydrogen, using the Low Carbon Hydrogen Standard as its basis. The certification scheme will be a key enabler for both domestic and international trade of hydrogen via mixed transport systems and will use a mass balance chain of custody.

A mass balance system requires that certificates are sold with the hydrogen and cannot be sold separately, meaning the certification scheme will enable users to link the hydrogen they use to the source they paid for. A mass balance system also allows for the mixing of products (e.g. mixing of certified and uncertified hydrogen, or hydrogen from different production pathways), therefore the implementation of a low carbon hydrogen certification scheme will mean that a segregated supply chain between specific producers and users will not be required to prove the low carbon credentials of the hydrogen.

To comply with a mass balance system, scheme users will need to provide evidence to track the hydrogen through the supply chain, which is then verified and audited (Iseal Alliance, 2016). For movement of hydrogen via pipeline, evidence regarding the amount of certified gas injected into a system and withdrawn would be needed, and proof of a reasonable physical connection between the point of production and the point of end use is required. This is to ensure that there is a balance of certified hydrogen entering and exiting the system. To apply this to a possible export scenario via a hydrogen pipeline, in order for an end user to claim they are using a certain amount of electrolytic hydrogen, the electrolytic producer they have bought from must give evidence that they are injecting any equal amount of hydrogen into the system the end user is connected to and has withdrawn from, and therefore the system maintains an even mass balance (Iseal Alliance, 2016)Similar certification schemes are used in Guarantees of Origin/Renewable Energy Guarantees of Origin and the EU and UK Emissions Trading Schemes (CMS, 2023).

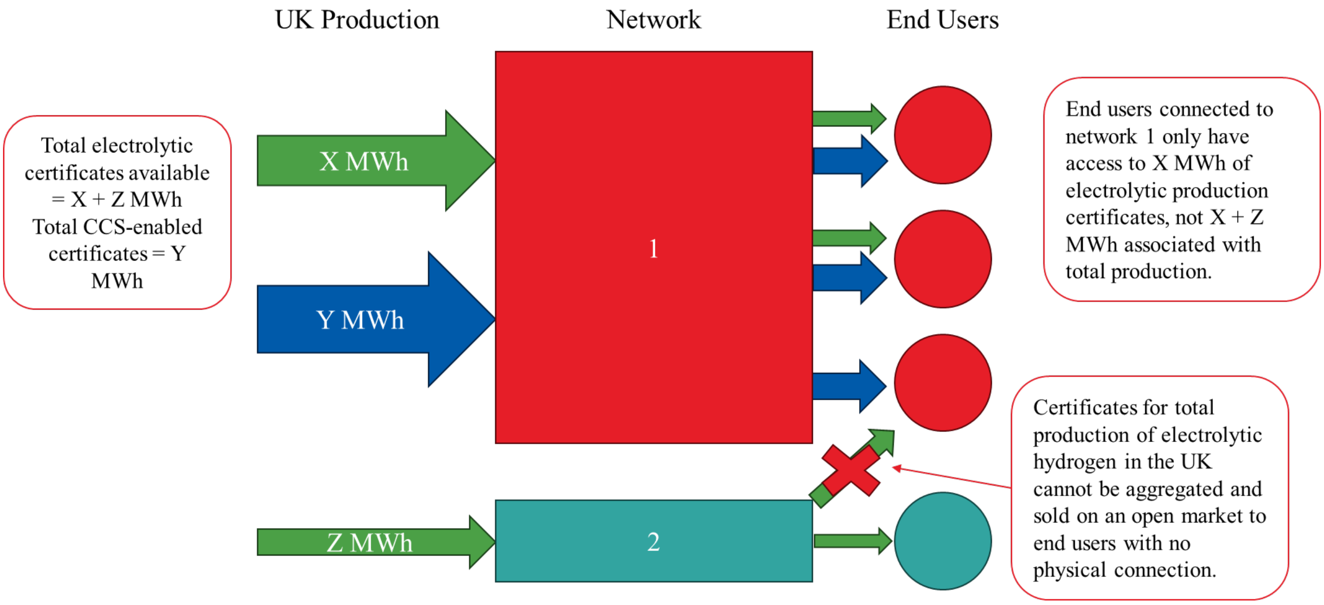


Figure 24: Diagrammatic representation of the proposed certification scheme highlighting which certificates would be accessible to specific end users.

Domestic low carbon hydrogen production in the UK will be used to meet domestic demand in the UK in the first instance, however, when it comes to international trade of hydrogen, the UK is aiming to prioritise the export of electrolytic hydrogen as it is likely to be more desirable in Europe due to the requirements of RED III. RED III sets out requirements for emissions reduction that RFNBOs must have over the counterfactual fuel used today (European Commission, 2024) which any hydrogen exported to the EU would be required to meet. A robust certification scheme monitoring production with a mass balance chain of custody which is recognised by the EC will be required to facilitate international trade at large scale. In addition, the location of export in the UK must be connected to a sufficient supply of electrolytic hydrogen production via domestic networks linked to domestic electrolytic production to be able to transfer certificates via export and provide hydrogen that meets EC requirements. The EU defines low carbon hydrogen as "hydrogen derived from non-renewable sources that meet a criterion of 70% less lifecycle GHG emissions than fossil fuels.", and stated that the methodology for calculating the GHG savings from low-carbon fuels will be specified in a new delegated act by 31st December 2024 (Gregor Erbach, 2023). the export of CCS-enabled hydrogen may also be acceptable which may influence the selection of export location; however, the UK will still aim to prioritise the export of electrolytic hydrogen if export is pursued.

4.3 UK Hydrogen Transport Infrastructure

Several initiatives and projects are in the process of planning potential infrastructure for hydrogen transportation and storage in the UK which should be considered when selecting potential export locations. Connection of UK production and demand is essential to support the development of hydrogen use in the UK and hence most infrastructure projects focus on this. The UK Government released its minded to position on the high level design of the Hydrogen Transport Business Model in August 2023, which stated that a Regulated Asset Base (RAB) will form the basis of the business model. The minded to position also stated that an external subsidy mechanism will be created alongside thew RAB to ensure that charges to pipeline or network users are not prohibitive while allowing hydrogen transport providers to make a reasonable return on investment. However, many of the initiatives and projects also consider connections to potential international trade locations following the connection of domestic production and demand. While there is little certainty on the exact infrastructure routes or whether organisations will commit to building them, export locations considered for connection as part of the domestic networks may be favourable to prioritise as export locations when developing an export strategy.

4.3.1 Project Union

Project Union is a project being led by National Gas aiming to develop a 100% hydrogen gas network connecting the major production regions with demand in a similar way to the natural gas National Transmission System (NTS). Project Union would form a “GB Hydrogen Backbone” of high pressure, high-capacity hydrogen pipelines which would transport large quantities of hydrogen over long distances between production and local transmission and distribution systems. The project primarily targets reuse of the existing NTS pipelines, with 25% of the UK’s existing natural gas transmission pipes targeted for repurposing as part of the project (National Gas, 2022).

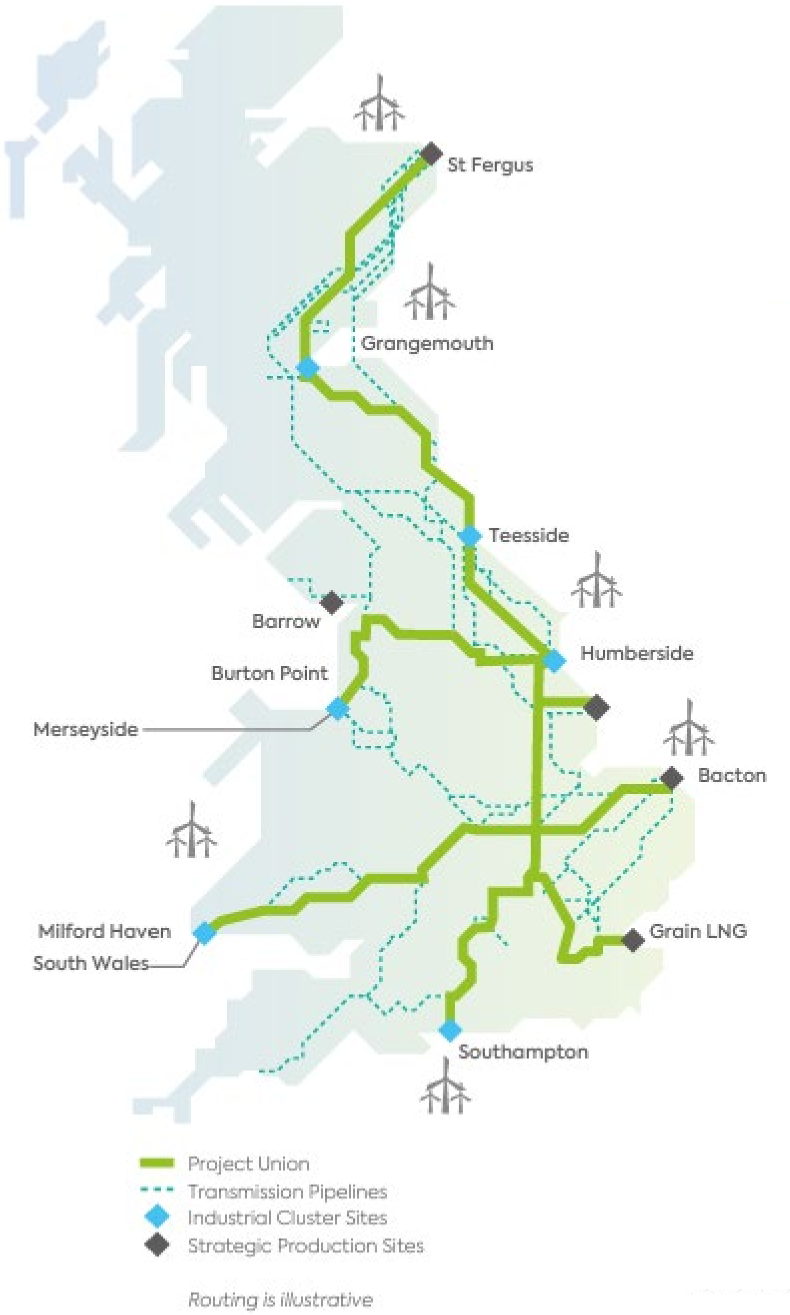


Figure 25: Schematic of the proposed Project Union System. Source: (National Gas, 2023).

Project Union is expected to be built out in stages, centring around areas with high hydrogen production and demand, such as the industrial clusters around Teesside, Humberside, and the Northwest, before expanding to further clusters in South Wales, the South Coast and in Scotland. The phasing proposed in Project Union's latest commercial plan is shown in Figure 26.

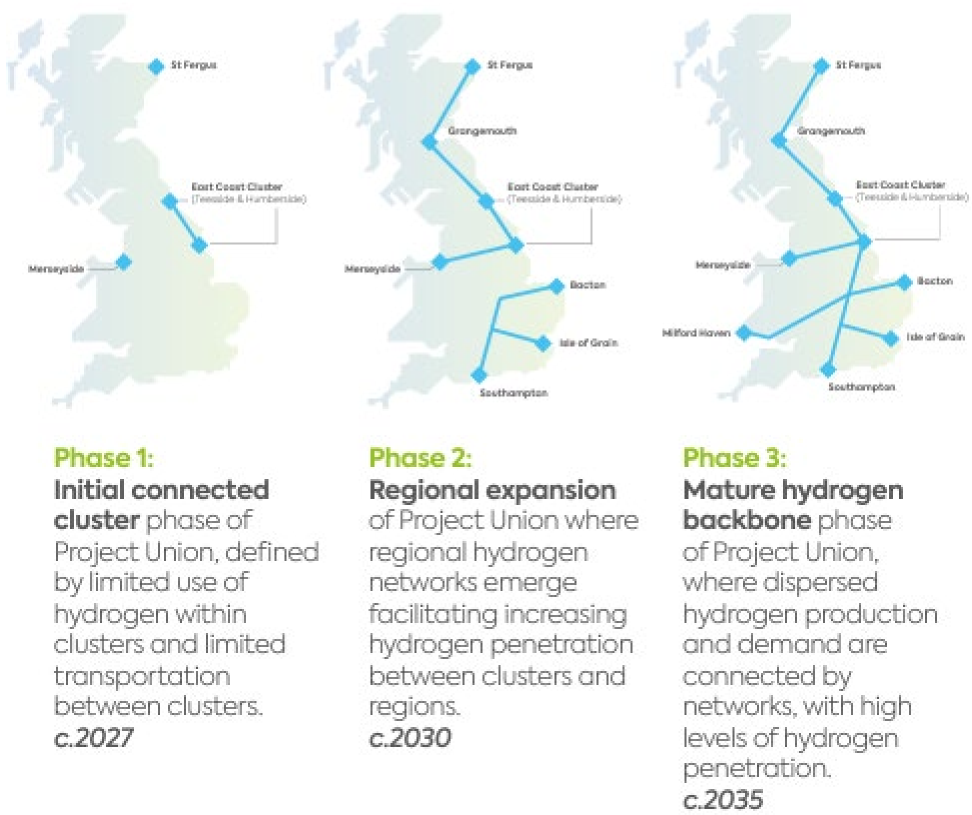


Figure 26: Proposed phasing of Project Union published in October 2023. Source: (National Gas, 2023).

If the project progresses as planned, then National Gas expect to have a system connecting major potential hydrogen production and demand locations around St Fergus, Grangemouth, Teesside, Humberside and the Northwest, and a separate network connection the south coast, Medway and Bacton. A fully developed network is expected by 2035 in Phase 3, where the two networks created in Phase 2 would be connected and expanded to include South Wales.

Project Union will connect the industrial clusters which in turn are developing their own local networks. These local networks are explored in the subsequent subsections.

4.3.2 HyNet

HyNet is the hydrogen production and distribution project covering the Northwest industrial cluster. The project consists of CCS-enabled and electrolytic production, as well as hydrogen transport and storage infrastructure. The project has received government support through being selected as a Track 1 cluster as part of the CCS Cluster Sequencing process, which has encouraged the development of an initial production location and distribution network to connect to local offtakers. The proposed network in Phase 1 of HyNet is shown in Figure 27.

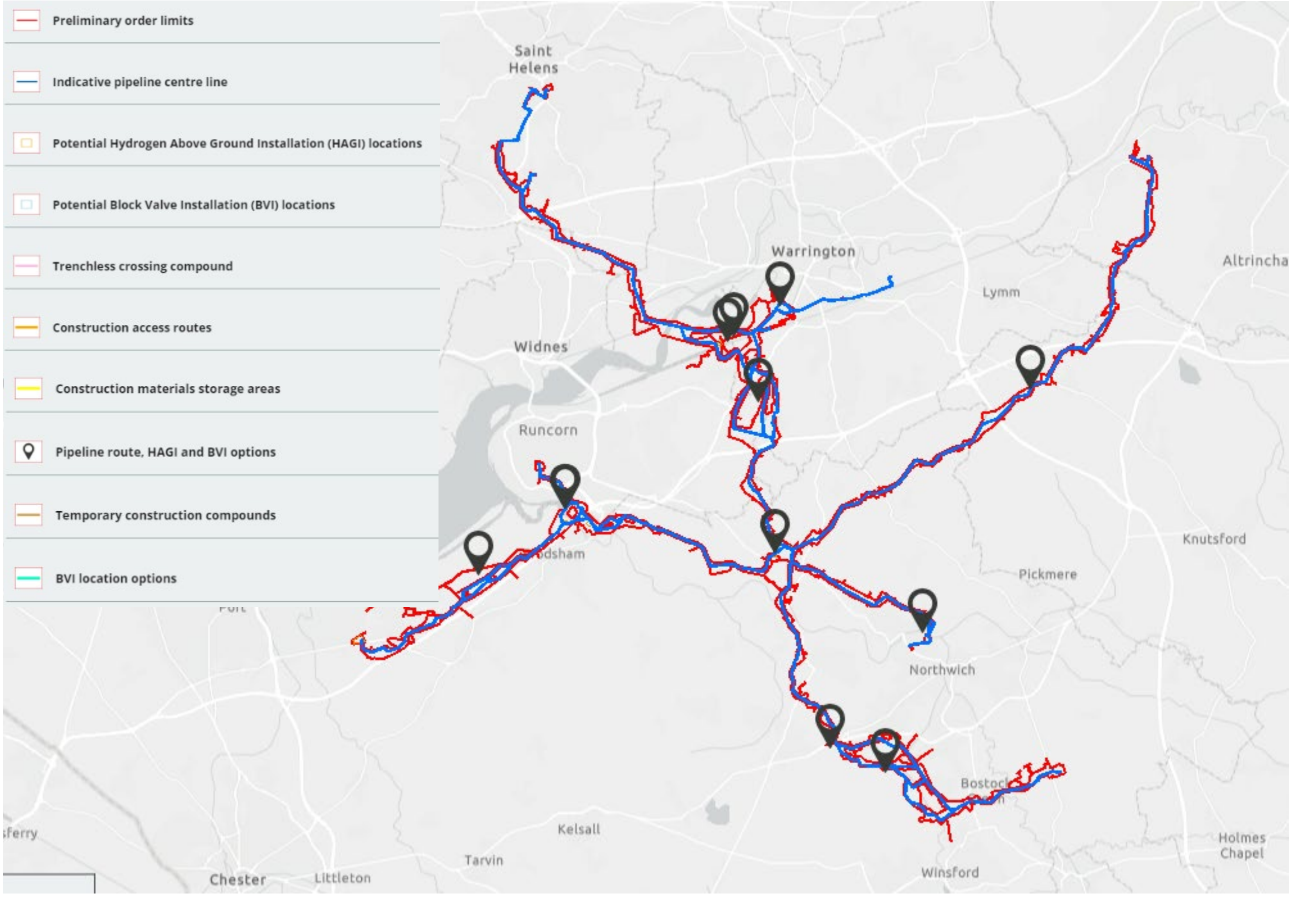


Figure 27: Proposed HyNet network in Phase 1 of the project. Source: (Cadent).

As mentioned in Section 4.3.1, the smaller regional networks aim to connect local production and demand and wider scale interconnection will be facilitated by Project Union.

4.3.3 East Coast Hydrogen

On the opposite side of the country, East Coast Hydrogen is aiming to connect the East Coast Cluster and Viking clusters on Teesside and Humberside, respectively. Hydrogen production in these regions is expected to be significant as shown in Figure 28, so the interconnection of these locations is an important step in domestic hydrogen distribution. The proposed network for East Coast Hydrogen is shown in Figure 28.

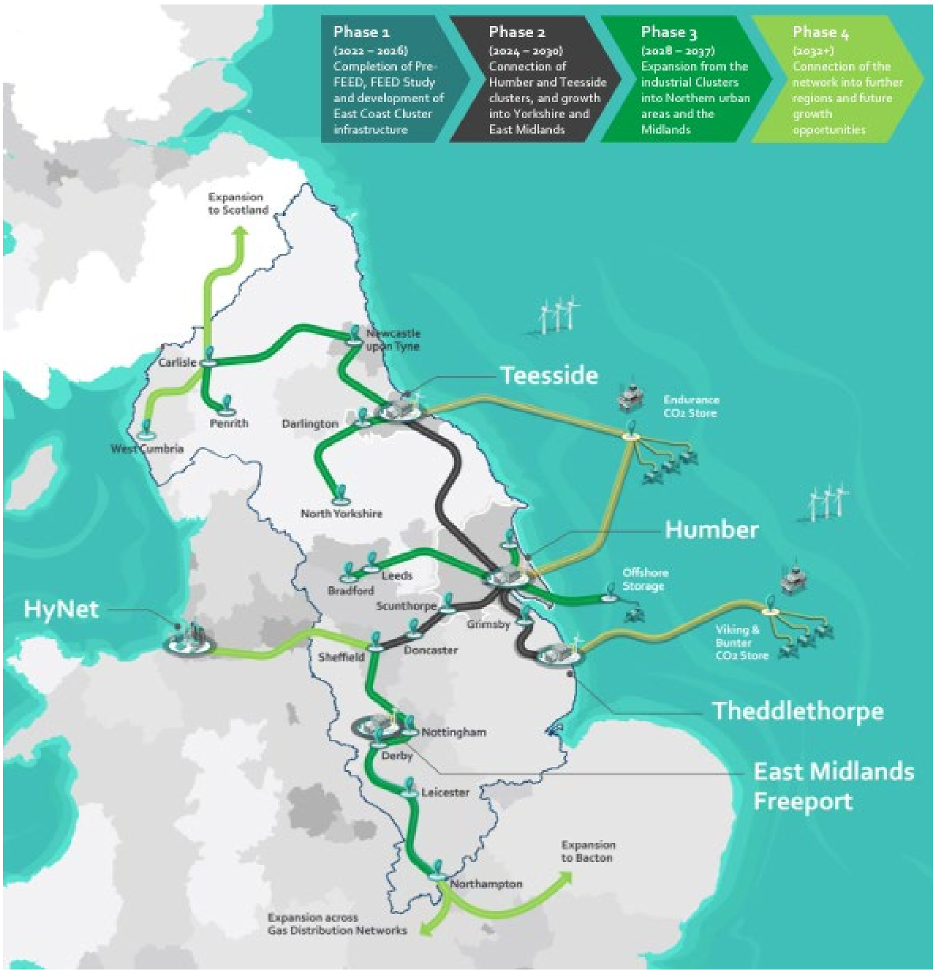


Figure 28: East Coast Hydrogen proposed build out. Source: (NGN, Cadent, National Grid, 2023).

By 2030, East Coast Hydrogen plans to have an operational pipeline connection between Teesside, Humberside, Theddlethorpe, and Sheffield before progressing connections to wider regions in subsequent phases of the project. This core network would connect into Project Union via the connection shown on the diagram "Expansion to Scotland", "Expansion to Bacton" etc. This could be a key piece of infrastructure development for the export of hydrogen, given that this region is expected to provide a significant proportion of the UK's low carbon hydrogen production and is well placed to potentially facilitate a subsea connection to mainland Europe.

4.3.4 HyLine Cymru

HyLine Cymru is a similar scheme to HyNet and East Coast Hydrogen, however it is not as advanced since HyNet and East Coast Hydrogen are focusing on development of the Track 1 clusters under the Cluster Sequencing process and South Wales was not selected as a Track 1 cluster. A schematic of the network is shown in Figure 29.

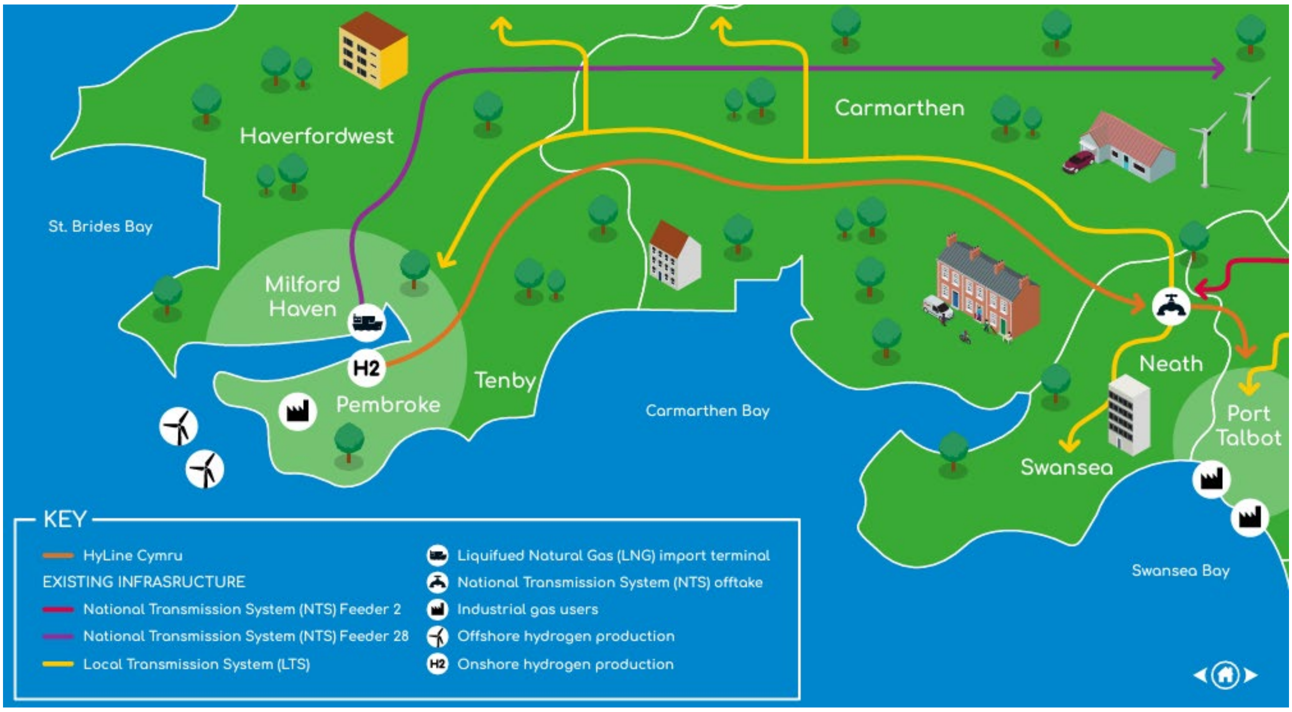


Figure 29: Diagram of the proposed HyLine Cymru hydrogen transportation network. Source: (HyLine Cymru).

HyLine Cymru would from part of the wider Project Union in its later phases, however it is not proposed to be connected until Phase 3 of Project Union. Furthermore, the area is not well situated to facilitate export to mainland Europe via pipeline given its geography and shipping routes would not necessarily rely on a pipeline supply of hydrogen to the port area as local production could facilitate export via ship. Therefore, HyLine Cymru is expected to be less of a differentiator when considering potential export locations when compared to particularly the East Coast Cluster and Project Union.

4.3.5 Scottish Hydrogen Backbone Link

The Scottish Hydrogen Backbone Link differs from the other distribution systems mentioned above as it is specifically targeting the export of hydrogen from Scotland to Europe. To support the Scottish Government's position prioritising the export of low carbon hydrogen from Scotland to neighbours (including the rest of the UK), the Scottish Hydrogen Backbone Link (HBL) report has been developed by the Net Zero Technology Centre with joint funding from the Scottish Government and private investment. HBL suggest to build a new subsea pipeline from St Fergus to Emden, Germany, as shown in Figure 30.

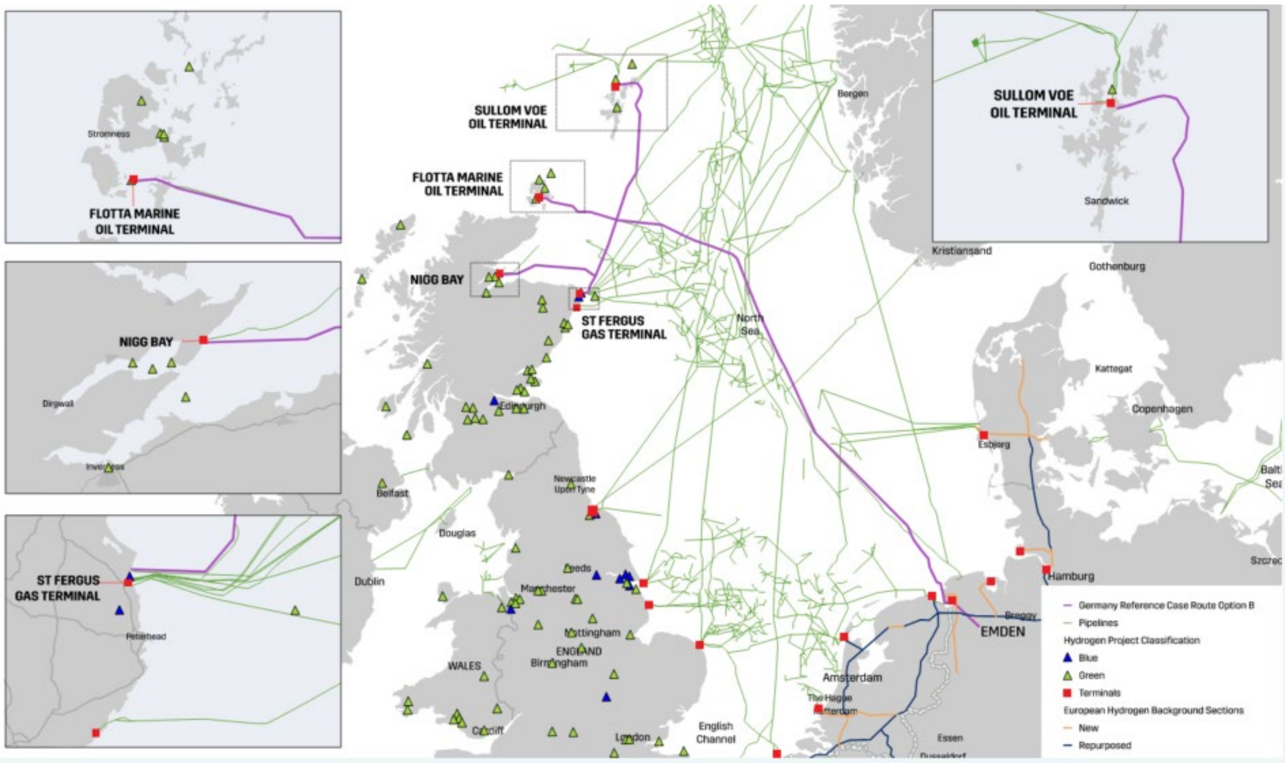


Figure 30: Scottish Hydrogen Backbone Link proposed routeing. Source: (Net Zero Technology Centre, 2023).

This connection could be a potential export route to Europe for hydrogen produced in the wider UK as well as that produced in Scotland if it could be connected with the wider UK network.. The routeing and study findings for the HBL have been considered in the analysis of export locations for this study.

4.4 Existing Export Infrastructure

Existing Export Infrastructure Summary

The UK has significant existing export infrastructure and expertise relating to the import and export of natural gas via pipeline. Much of this infrastructure is likely to have the potential to support the development of a new hydrogen pipeline connection to Europe of required. This could help to reduce the cost, time to construct and environmental impact of constructing a new pipeline connection to Europe, hence these locations have been prioritised for consideration as export locations.

The UK already stores, imports, and exports ammonia at port facilities spread across the country and imports and stores LNG at three facilities. Similarly, the UK has extensive infrastructure and expertise relating to the handling, import, and export of bulk liquids such as methanol, which are analogous to the transportation of LOHCs. On the European side, there are several terminals across Europe which have the infrastructure to support the import of LNG, ammonia, and methanol. Each of these European locations has been considered as a potential import location for hydrogen vectors and categorised into the respective derivatives they could handle ammonia, LOHC, CGH_2, or LH_2.

Exporting hydrogen from the UK to Europe will require export locations to facilitate the transfer of hydrogen from the domestic transportation system or production location to the export vector. Likewise, at the other end of the export corridor, a terminal location will be required to unload the hydrogen from the transport vector. Export and import terminals are major pieces of infrastructure and therefore the strategic selection of their location is key as it will likely serve as the location for the exports for decades to come.

4.4.1 Pipeline Export Facilities

For pipeline transportation, the terminals will need to include metering, compression, pressure control systems, emergency shut down valves and flow control systems to govern the flow in the pipeline and ensure that the hydrogen exported or imported is accounted for correctly. These systems are well established for natural gas export infrastructure and the principles are likely to remain very similar, however, the actual equipment used will have to be updated to be suitable for hydrogen service and to satisfy modern regulations. Metering, source of origin monitoring, and leak detection and emissions monitoring could be of particular importance from a commercial and regulatory perspective since certain regulations require the hydrogen to be from electrolytic sources only.

The UK has significant expertise and capability in building and operating gas pipelines and terminals for the international transport of gas. A summary of the operational facilities is provided in Table 8.

Table 8: Operational gas import/export systems connecting the UK and continental Europe.

Interconnector	Origination	Terminal	Description
The Interconnector	Bacton, UK	Zeebrugge, Belgium	Interconnector (UK) Limited (IUK) (https://www.fluxys.com/en/about-us/interconnector-uk) own and operate the bi-directional gas pipeline between the UK and Belgium which connects the transmission system operated by National Gas at Bacton to the transmission system operated by Fluxys Belgium at Zeebrugge. The company is part of the Fluxys Group and SNAM, who own an equity interest of 76.32% and 23.68% respectively. IUK started operations in October 1998. The gas flows between terminals at Bacton in the UK (Interconnector Bacton Terminal – IBT), and Zeebrugge in Belgium (Interconnector Zeebrugge Terminal – IZT) via a 235km subsea pipeline (Figure 10). The IUK system provides 20 bcm/yr of UK export capacity and 25.5 bcm/year of UK import capacity. GWh/d values are based on an assumed GCV of 11.5 kWh/Nm^3 for IBT entry/exit and IZT entry/exit.
Balgzand to Bacton Line (BBL)	Bacton, UK	Balgzand, Netherlands	The offshore pipeline comprises 230 km of the pipeline's overall 235 km length. Installation of the pipeline across the North Sea took place in 2006, with construction by pipe lay barge progressing ad at a maximum rate of 4.9 km a day. The pipeline crosses several sand banks and other typical seabed features and a large number of shipping lanes. Temporary cofferdams were built at either end of the offshore pipeline to enable safe connection of the pipeline to the onshore section. The onshore section is a 4 km length of pipeline that begins at the Anna Paulowna compressor station in the Netherlands and ends at the dune crossing location in Julianadorp. The BBL Company pipeline is connected to the Dutch national grid, which is owned by Gasunie Transport Services, at Grasweg near Anna Paulowna and is linked to the Anna Paulowna compressor station, formally called compressor station Noord-Holland (Figure 10).
Langeled	Nyhamna, Norway	Easington, UK	The Langeled pipeline (originally known as Britpipe) transports Norwegian natural gas from the Ormen Lange gas process terminal to the UK. The pipeline is owned by Gassled, operated by Gassco with technical service provider Equinor. The subsea pipeline runs 1,150 km through the North Sea from the Nyhamna Processing Plant in Norway via the Sleipner Riser platform to the Easington Gas Terminal in the UK and is one of the longest subsea pipelines in the world. The pipeline was opened in two stages. The southern section (Sleipner Riser Platform to Easington) began piping gas on 1 October 2006, the northern section (Nyhamna to Sleipner Riser Platform) opened in October 2007. The Easington Receiving Terminal on England's east coast receives the gas. Pressure and temperature are adjusted before the gas is injected into the UK gas system.

Further information on the existing pipeline connections is available in Appendix B.

Alongside the existing interconnector gas terminals, there are other existing gas terminals which may be capable of repurposing to support the export of hydrogen, which are listed in Table 9.

Table 9: Alternative UK gas terminals considered as potential export locations.

Terminal	Location	Description
St Fergus Gas Terminal	St Fergus, Scotland	Large gas processing terminal in the northeast of Scotland. St Fergus is the terminal point of several oil and gas pipelines, including the Forties, SAGE, Cromarty, and Britannia pipelines. The facility is designated as a piece of critical national infrastructure and operates under an upper tier COMAH licence. The St Fergus plant is split into three main processing plants, owned and operated by National Gas, Shell and Esso, respectively.
Teesside	Teesside, England	An export location on Teesside was considered although a specific export location was not selected. There are several existing gas processing terminals located at Teesside, including the Central Area Transmission System (CATS) terminal and the Teesside Gas Processing Plant. It is proposed that one of the existing facilities could be considered for repurposing in due time or a new facility be developed in the area.

Existing pipeline connections to mainland Europe are all located on the east coast of the UK, which aligns to the recommendation for exporting hydrogen. It is expected that the Bacton and Easington terminals could potentially serve as hydrogen export terminals while still operating as natural gas import/export terminals if new pipelines were constructed from these terminals.

Grangemouth was excluded as it does not offer a material advantage in terms of distance to import location over St Fergus and is located further from renewable generation sites announced under recent funding rounds, such as ScotWind and INTOG.

4.4.2 Port Facilities

A technical review of a sample of existing ports in the UK and mainland Europe was undertaken to understand current port capabilities handling similar materials and potential compatibility for the import and export of hydrogen. In the context of shipping, port facilities which cater for LNG, LPG and methanol have been considered as potential strategic areas of development in the supply chain to cater for hydrogen shipping in the future. A long list of UK ports with the potential to support export was developed for further consideration of the infrastructure availability and their suitability for the export of hydrogen or derivatives. Considering the existing infrastructure in the UK, the ports listed in Table 10 were selected as potential export locations for export via shipping. Further information on existing ports and infrastructure in the UK is available in Appendix C.

Immingham, in the UK, has two main terminals capable of handling methanol tankers, the Immingham Oil Terminal, and the Inter Terminals (East and West Terminals). The Oil Terminal has three berths and four piers currently being used to handle crude oil and aviation fuel but can potentially be repurposed to handle methanol with berth lengths ranging from 180-330 m and depths of 7.2-19 m. The Inter Terminals consist of the East Terminals with berth lengths ranging from 110-220 m and a depth of 9.8 m and the West Terminals with berth lengths ranging from 85-100 m and depths ranging from 6.6-10.8 m.

In the UK, existing LNG terminals vary in quay length and dredge depth, reflecting their differing capacities and operational capabilities. For instance, the South Hook LNG terminal in Wales has a quay length of 800 m and dredge depth of 14.5 m, facilitating large-scale vessel berthing and accommodating deep-draft Q-Max sized ships. Similarly, the Dragon LNG terminal in Milford Haven features infrastructure to handle large LNG carriers, with a dredge depth of 12 m and quay length of 270 m ensuring accessibility for vessels requiring deeper water. In contrast, smaller terminals like the Medway LNG terminal may have comparatively shorter quay lengths (main jetty of 550 m and a small jetty of 280 m) and shallower dredge depths of 12.8 m, suitable for smaller LNG carriers and tailored to specific market needs. These variations in infrastructure reflect the diversity of LNG importation facilities across the UK, catering to different vessel sizes and operational requirements within the LNG industry, which could be replicated to meet the requirements of different hydrogen carriers.

Table 10: Existing UK ports with capacity to handle bulk liquids in the future.

Location	Type
Medway	LOHC/Ammonia
Milford Haven	LOHC/Ammonia
Teesside	LOHC
Grangemouth	LOHC/Ammonia
Immingham	LOHC

A summary of the UK LNG facilities and their capabilities is provided in Table 11.

Table 11: LNG infrastructure in the UK.

Particulars	Milford Haven – South Hook LNG	Milford Haven – Dragon LNG	Medway
Number of Jetties	2	2	2
Minimum depth at berth (m)	17.1	15.6	13.0
Maximum vessel size (m)	QMax (345m LOA, 53.8m beam, 12m Draught)	QFlex (315m LOA, 50m beam, 11m Draught)	QMax (345m LOA, 53.8m beam, 12m Draught)
Number of tanks	5	2	8
Maximum storage capacity (m^3)	775,000 LNG	320,000 LNG	1,000,000 LNG
Tonnage & volume	South Hook LNG Terminal has a total processing capacity of 15.6 million tonnes per annum, which is equivalent to around 20% of the current UK natural gas demand.	The terminal includes two jetties for LNG carriers, two 160,000 cubic metre storage tanks, regasification equipment, and export facilities.	Total Import capacity is 14.3 million tonnes per annum and expansion pipeline for 2025 import capacity of 3.8 million tonnes per annum. By 2025, total storage will increase to 1.2 million m3 and total regasification capacity will reach 18.8 Mtpa.

Similar facilities were identified in in Europe as potential import locations. The ports identified are shown in Table 12 further detail on the port infrastructure is available in Appendix C.

Methanol terminals are more prevalent in mainland Europe with terminals in Rotterdam, Grangemouth, Venice, Hamburg, and Zeebrugge that are equipped with facilities to accommodate ships for loading and unloading methanol, making them accessible points for maritime transportation of methanol. Each of these terminals have different scales of infrastructure, including the number and size of storage tanks, berth lengths and depths for vessels, and varying handling equipment sizes. Rotterdam, being Europe's largest port and bunker location, has various berths with the largest the HES Botlek Tank Terminal (HBTT) with a berth length of 420 m and depth of 10.6 m.

Table 12: Import ports identified for hydrogen derivatives.

Potential Import Locations		
Location	**Country**	**Type**
Antwerp	Belgium	Methanol/MCH/Ammonia
Zeebrugge	Belgium	Ammonia
Dunkirk	France	Ammonia/ LOHC
La Nouvelle	France	Methanol/LOHC/Ammonia
Hamburg	Germany	Methanol/LOHC
Willemshaven	Germany	Methanol/LOHC
Rotterdam	Netherlands	Methanol/LOHC/Ammonia
Thessaloniki	Greece	Ammonia/Methanol/LOHC
Aspropyrgos	Greece	Ammonia/Methanol/LOHC
Revithoussa	Greece	LNG
Venice	Italy	Methanol/LOHC
Sines	Portugal	LNG/Methanol/LOHC
Barcelona	Spain	LNG
Gdansk	Poland	Methanol/LOHC
Klaipeda	Lithuania	Methanol/LOHC

5. Export Corridors

Export Corridors Summary

Export corridors between the UK and mainland Europe were identified considering the technical feasibility of the potential corridors. Routes between the potential export locations and potential import locations identified were used to inform the cost analysis and present an overview of the technical and cost considerations for exporting from different locations in the UK. Potential export locations were biased towards the east coast of the UK as the East Coast locations have substantial existing infrastructure, good access to planned hydrogen production and transport infrastructure, and access to the shortest crossing routes to infrastructure on the European side.

Based on the demand and policy analysis presented in Section 3, priority potential import locations in Northwest Europe which have good access to high potential demand sources were selected to be considered in this study:

- Emden,
- Hamburg,
- Groningen,
- Balgzand,
- Rotterdam,
- Antwerp,
- Zeebrugge,
- Dunkirk.

Similarly, considering existing infrastructure, UK and European planned hydrogen infrastructure, and routeing constraints, potential export locations with the most favourable technical conditions considering the basis of this study were selected:

- St Fergus,
- Grangemouth,
- Teesside Gasport,
- Seal Sands Methanol Terminal,
- Easington Gas Terminal,
- Immingham Port,
- Bacton Gas Terminal,
- Isle of Grain (Medway) LNG Terminal,
- Milford Haven LNG Terminal,
- Eastham Methanol Terminal.

The UK's access to renewable resources and short transport distances to these regions mean that UK hydrogen may be cost competitive with hydrogen imports from regions identified in Section 3.3 due to the lower cost of transport, even if production costs are higher in the UK. In particular, the locations selected have been aimed at providing strategic export corridors locations between production and demand.

5.1 Potential Import Locations

Based on the analysis presented above, primary focus on terminals in northwest Europe, specifically the Netherlands, Belgium, and Germany is recommended. Therefore, large scale import terminals in these countries make a natural target for export. Locations were selected based on the national policies set out in Section 3 and the presence of existing infrastructure and expertise and are shown in Figure 31.

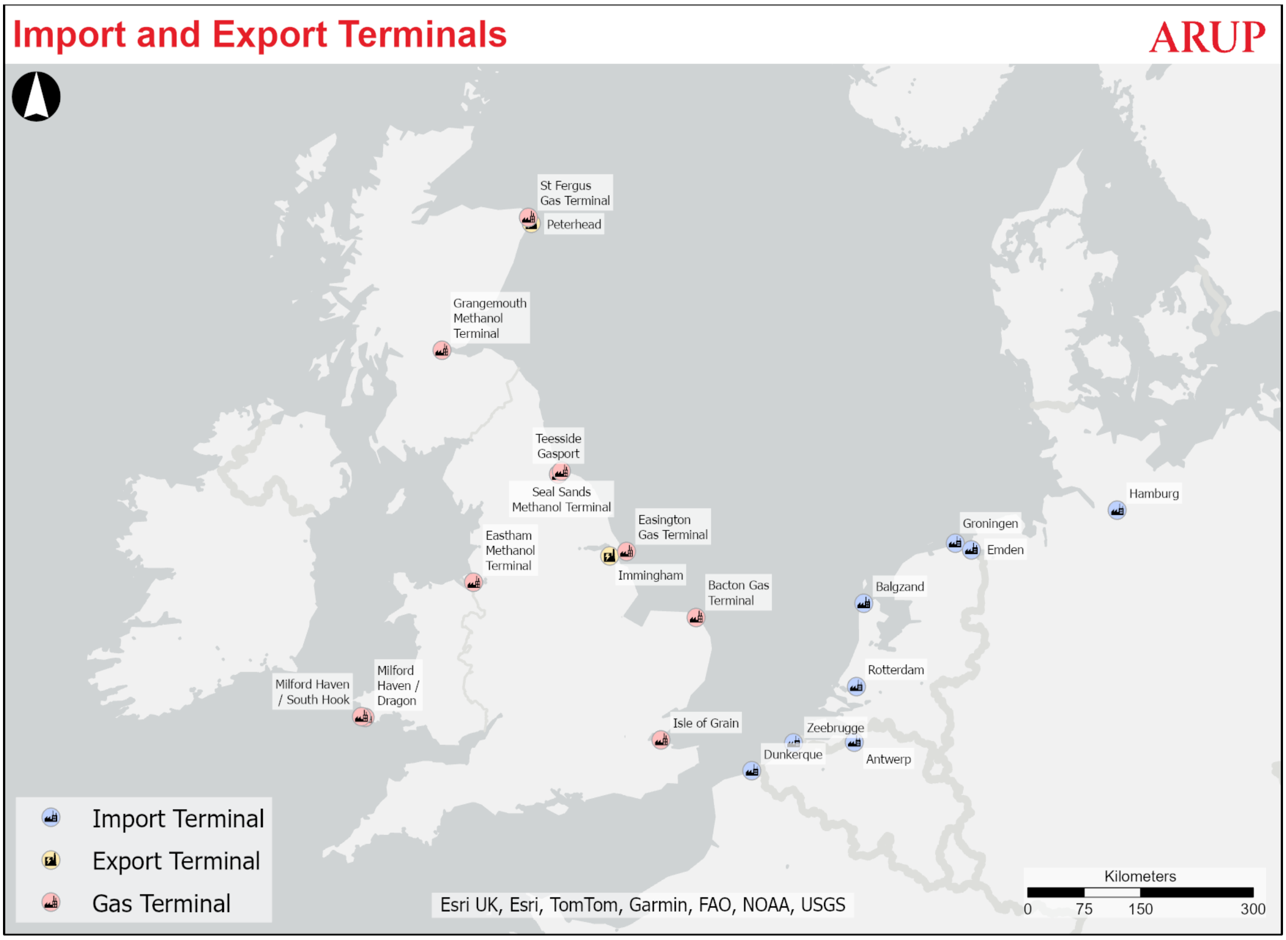


Figure 31: Recommended European import locations with export locations also shown.

Shipping routes to southern Europe were also considered as part of the analysis. The locations selected were ports which have existing facilities for the handling of ammonia, bulk liquids, and/or LNG as these are likely to be convertible to hydrogen derivative handling. Shipping to the northwest European ports was also considered to form a direct comparison to pipeline export.

5.2 Selected Potential Export Locations

Considering the UK's position, the development of hydrogen networks and demand in Europe, and the information presented in Sections 3 and 4, UK Export Locations were selected. ArcGIS Pro software was used to amalgamate and visualise data to inform the selection process. Data from the IEA Global Hydrogen Project Database 2023 was collated and imported to ArcGIS to provide a visual representation of production locations of CCS-enabled and electrolytic hydrogen projects in the UK. Additionally, data from the European Hydrogen Backbone, domestic hydrogen transportation infrastructure projects and publicly available data on global port facilities, existing oil and gas terminals, pipelines, and subsea cables was all imported to the model.

To select export terminals, datasets were overlaid in GIS to visualise which facilities offered the most promising combination of existing infrastructure, proximity to planned hydrogen production and infrastructure, and proximity to the target export locations. Example figures showing CCS-enabled, electrolytic, and type-agnostic production projects overlaid with existing interconnectors, oil and gas infrastructure and terminals are shown in Figure 32 overleaf.

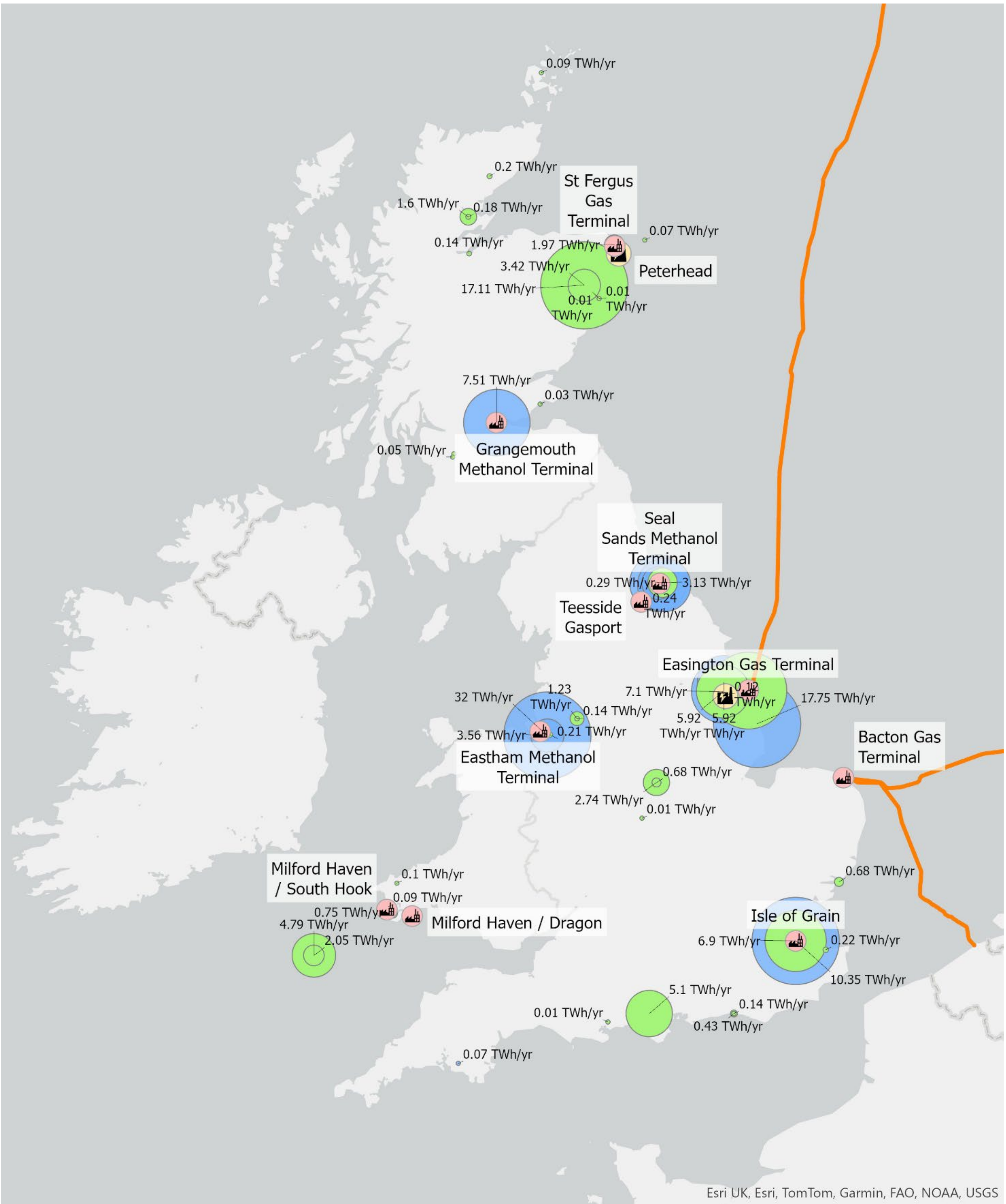


Figure 32: Map of the UK with electrolytic (green) and CCS-enabled (blue) planned hydrogen projects, bulk liquid and LNG shipping terminals, natural gas and LNG terminals, and existing interconnectors overlaid.

Using the approach set out above to attempt to maximise the UK advantage and synergies between production, transportation and export, the export locations shown in Figure 33 were selected to attempt to minimise the LCOT of the export corridors.

Figure 33: Potential UK export locations identified.

5.3 Pipeline Routes

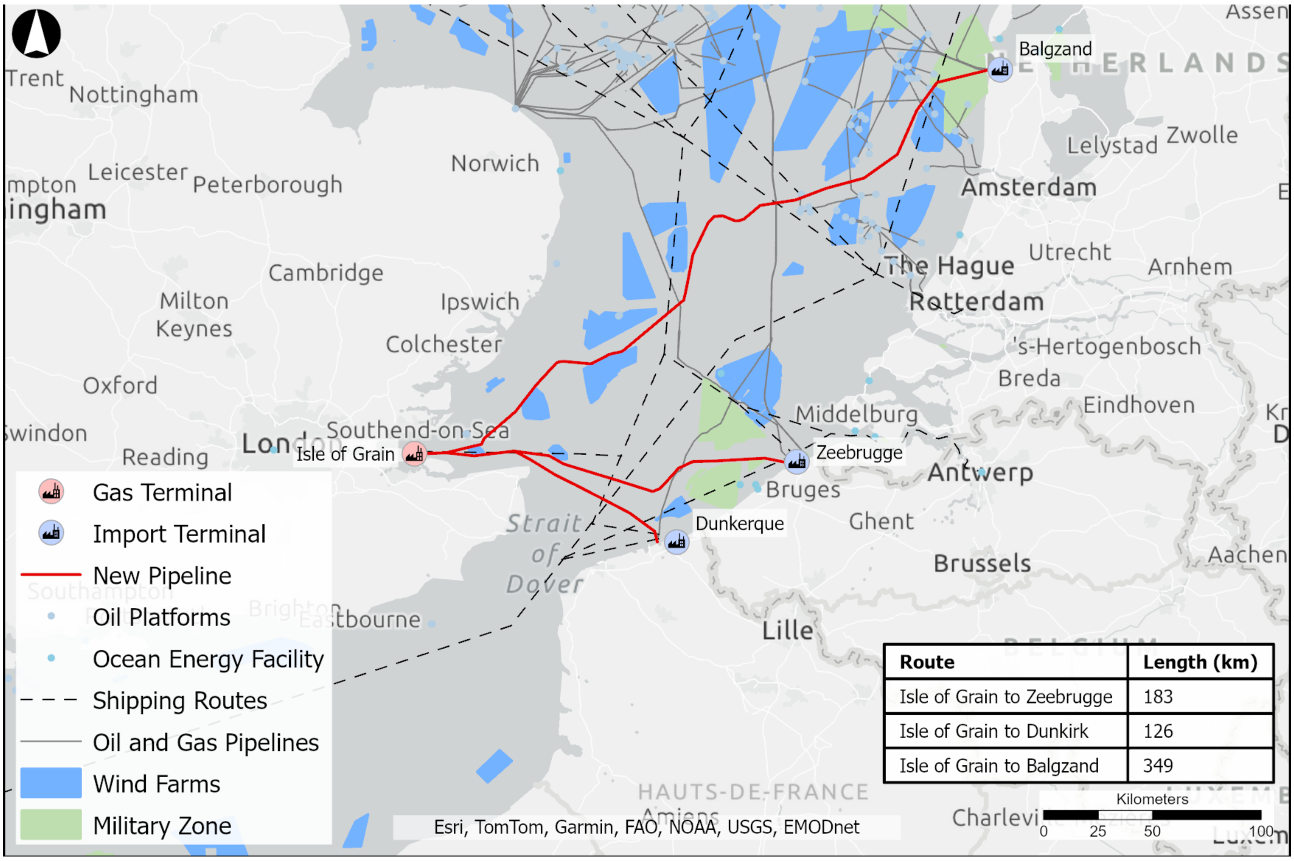
Constraints for pipeline routeing were identified from publicly available data sources and Arup's experience on other projects. Constraints considered:

- Wind farm developments
- Existing oil and gas infrastructure, including:
  - Platforms
  - Pipelines
  - Cables
- Military Areas
- Dredging areas
- Shipwrecks
- Environmental designations
- Bathymetry

The data was imported into a common GIS database for visualisation purposes and was used to select appropriate, feasible routes for new pipeline connections between the export locations and import locations identified. These are shown in the sections below.

5.3.1 Isle of Grain (Medway)

Pipelines from the Isle of Grain (Medway) were only considered to reach Zeebrugge, Dunkirk and Balgzand. Routes from the Medway are shown in Figure 34 and are the shortest to the southernmost locations (Zeebrugge and Dunkirk), although it is not expected to be a primary export location due to the nature of the terminal. Medway is an LNG import facility, with proposed CCS-enabled hydrogen production in the form of Project Cavendish. However, given it is the end of the network, and unlikely to be connected to other sources of production or demand in the first phases of the network, and given the narrow channel which houses busy shipping lanes and is likely to contain unforeseen obstacles to routeing like unexploded ordnance, the routes from Medway are provided more as an indication of the shortest possible export routes from a UK terminal to a European Terminal.



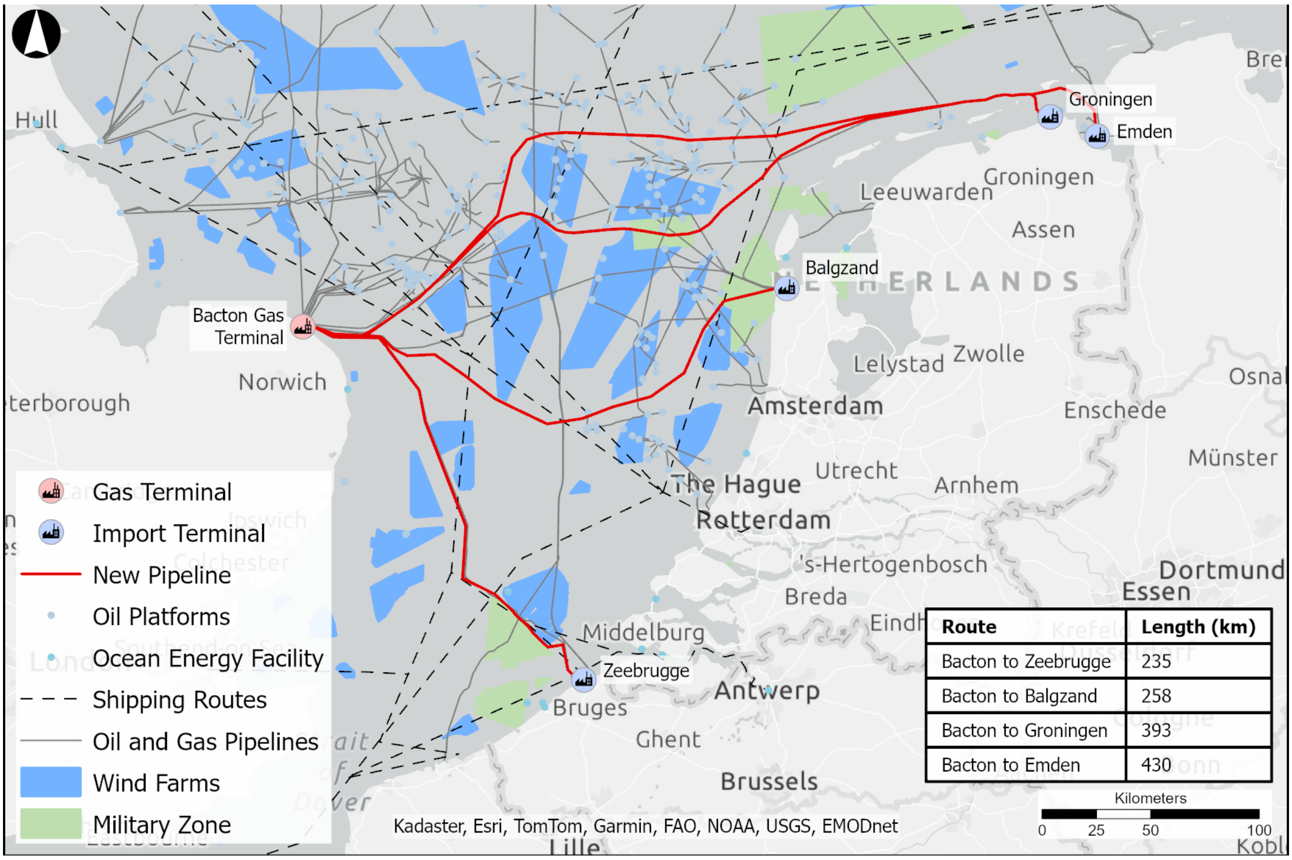
Route	Length (km)
Isle of Grain to Zeebrugge	183
Isle of Grain to Dunkirk	126
Isle of Grain to Balgzand	349

Figure 34: Potential new pipeline routes from the Isle of Grain (Medway) Terminal.

5.3.2 Bacton

Bacton is one of the most promising export locations of those identified. With extensive existing gas pipeline export infrastructure, short crossing distances to Belgium, the Netherlands and Germany, and its inclusion as part of Project Union and the wider domestic network, there is strong potential for Bacton to deliver one of the lowest cost export routes of all the export locations. The routes identified linking Bacton to the chosen import locations are shown in Figure 35. Two alternative routes to Groningen and Emden were identified. The preferred route (Groningen route) crosses through a military zone so an alternative route (Emden route) was identified in case this crossing is infeasible.

The routeing of pipelines to Balgzand and Zeebrugge attempted to follow the existing interconnectors as far as possible, however additional constraints like the new wind farm developments have been developed since the existing interconnectors were constructed. Therefore, the routeing has been adjusted to avoid the current constraints while maintaining the shortest possible routes. Overall, Bacton provides good access and short connections to all four import locations identified, with the shortest routes to Balgzand, Groningen, and Emden of any of the export locations. All routes from Bacton are short enough to avoid the need for recompression offshore.



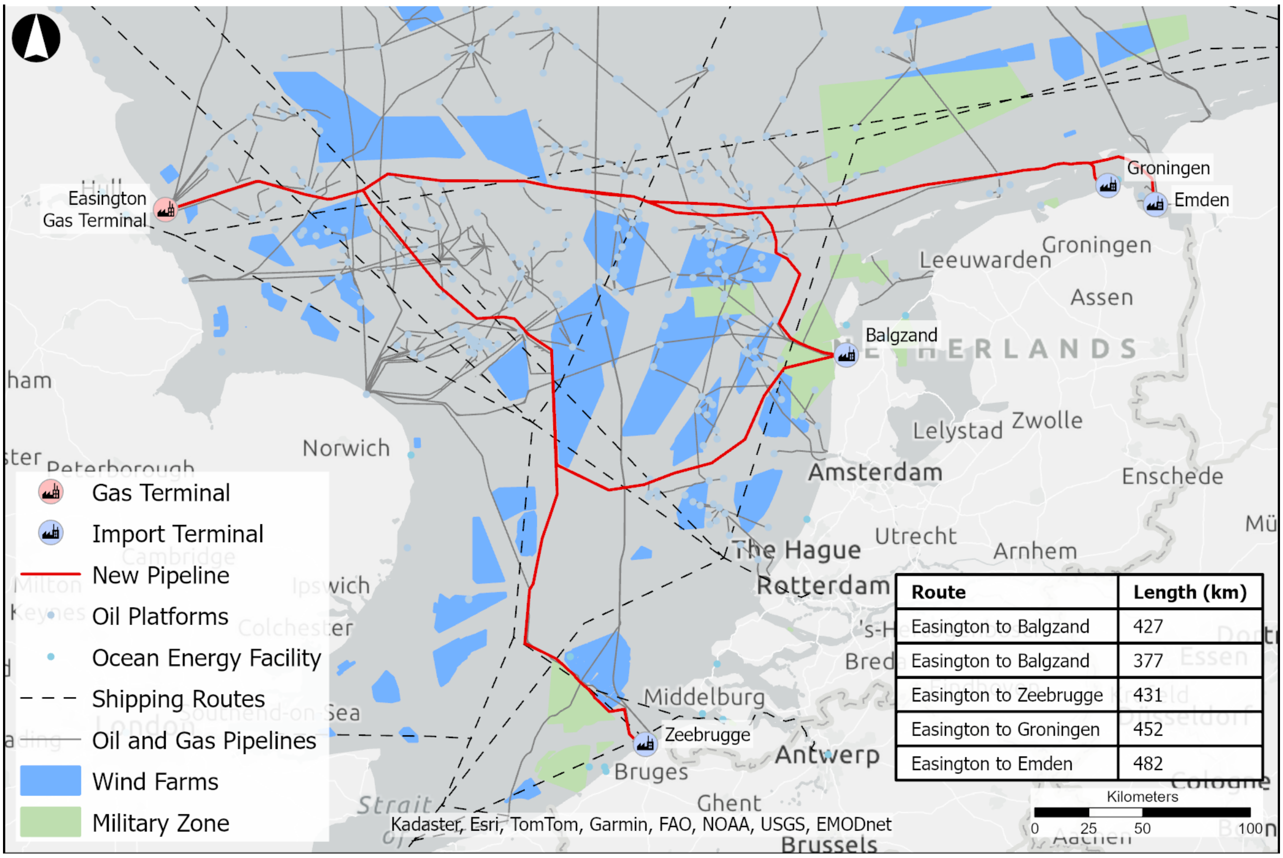
Route	Length (km)
Bacton to Zeebrugge	235
Bacton to Balgzand	258
Bacton to Groningen	393
Bacton to Emden	430

Figure 35: Potential new pipeline routes from Bacton.

5.3.3 Easington

Easington is another export location which benefits from existing operations as an international gas trade location, facilitating the import of gas from Norway via the Langeled pipeline. The terminal itself is well equipped and has been identified by potential hydrogen producers as a desirable location for production both to feed the local industry and because of the potential for export in the future. Pipeline routeing from Easington is less complex for the Dutch and German import locations as interactions with the majority of gas infrastructure in the Southern North Sea can be avoided by routeing the pipeline directly east from Easington. Additionally, the route to Groningen and Emden avoids crossing as many major shipping routes compared to the same pipelines from Bacton. Routeing from Easington to Balgzand and Zeebrugge is significantly longer than the pipelines from Bacton to the same locations and does not significantly reduce the complexity or routeing and interactions with existing services compared to the Bacton routes.

An export route from Easington also offers a promising solution with pipelines lengths that are short enough to avoid the need for a recompression station, which greatly reduces capital costs and design complexity. Additionally, given its vicinity to local production on Humberside and the East Coast Hydrogen proposal to connect the terminal to a wider hydrogen network connecting major production locations in Teesside and Humberside, means the port may have a large potential supply of hydrogen as domestic networks develop.



Route	Length (km)
Easington to Balgzand	427
Easington to Balgzand	377
Easington to Zeebrugge	431
Easington to Groningen	452
Easington to Emden	482

Figure 36: Potential new pipeline routes from Easington.

5.3.4 Teesside

Teesside offers similar advantages to Easington as an export route in that it avoids the complexity of the Southern North Sea and is planned to be connected to significant production capacity. However, given that it is further north, pipeline routes from Teesside are longer and hence more expensive than the export locations located further south. All pipeline routes from Teesside, except potentially the route to Balgzand, would likely require offshore recompression which adds significant CAPEX and complexity to the design. Moreover, unlike Bacton and Easington, Teesside currently does not facilitate international gas import/export operations, however there is extensive large scale gas operation experience in the area as it is a major landing location for natural gas produced in the UK continental shelf. The pipeline routes identified from Teesside are shown in Figure 37.

Overall, Teesside will have good access to hydrogen production and offers a viable export route, however pipeline export from Bacton and Easington may be more advantageous from a cost perspective when considering export exclusively.

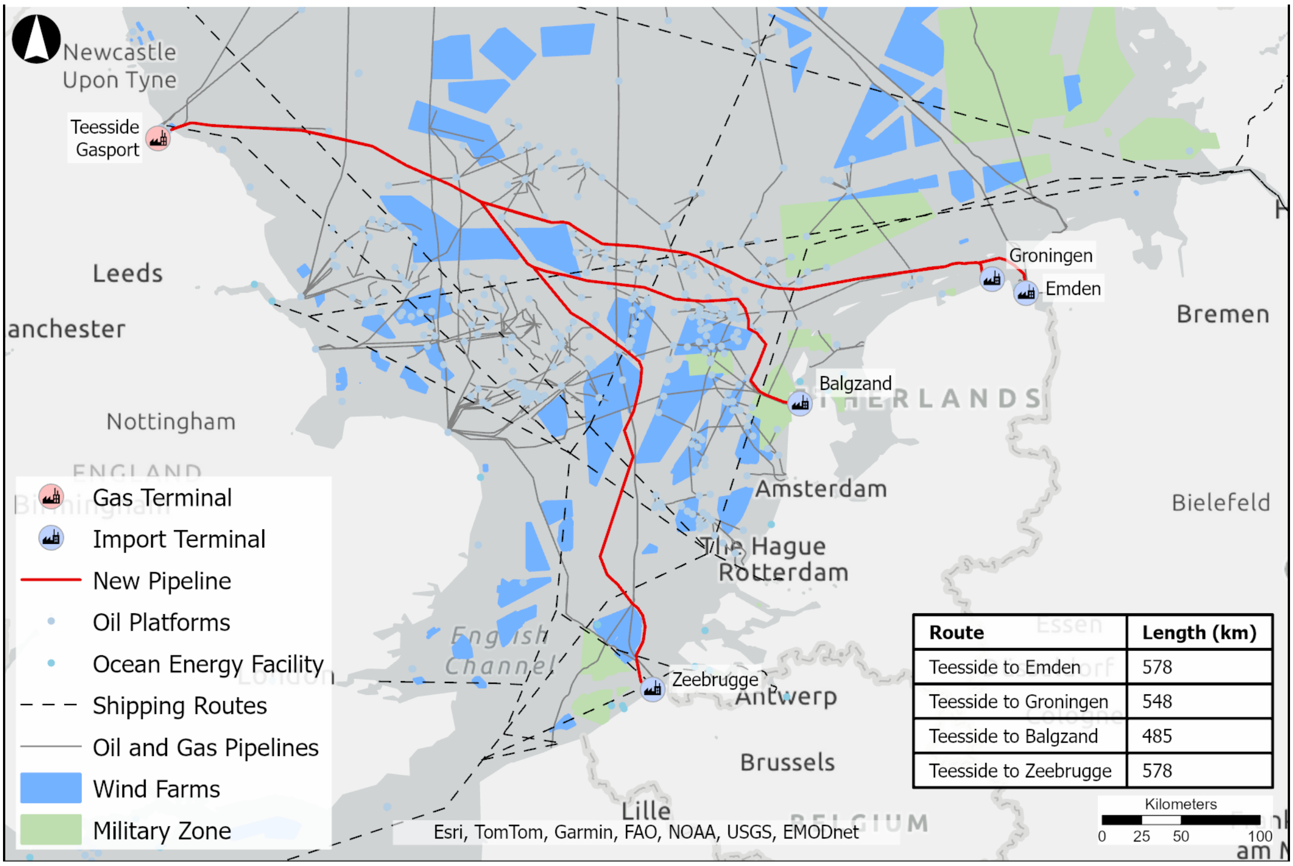


Figure 37: Potential new pipeline routes from Teesside.

5.3.5 St Fergus

St Fergus could offer a good export route for electrolytic hydrogen production in Scotland. By locating the export route close to production, domestic distribution costs could be reduced, however the development of domestic distribution networks is to be prioritised in the UK, hence it is assumed any export routes would only be in place following the establishment of a domestic network. On this basis, export routes from St Fergus are still technically and economically feasible upon initial review, however they are the longest and most expensive routes of all the export locations considered in the study. Offshore recompression would be required for all routes from St Fergus and routeing is more complex than from Teesside and Easington given the dense existing infrastructure in the Northern North Sea. However, if existing pipeline corridors could be followed, planning and consenting could be simpler than from Teesside and Easington.

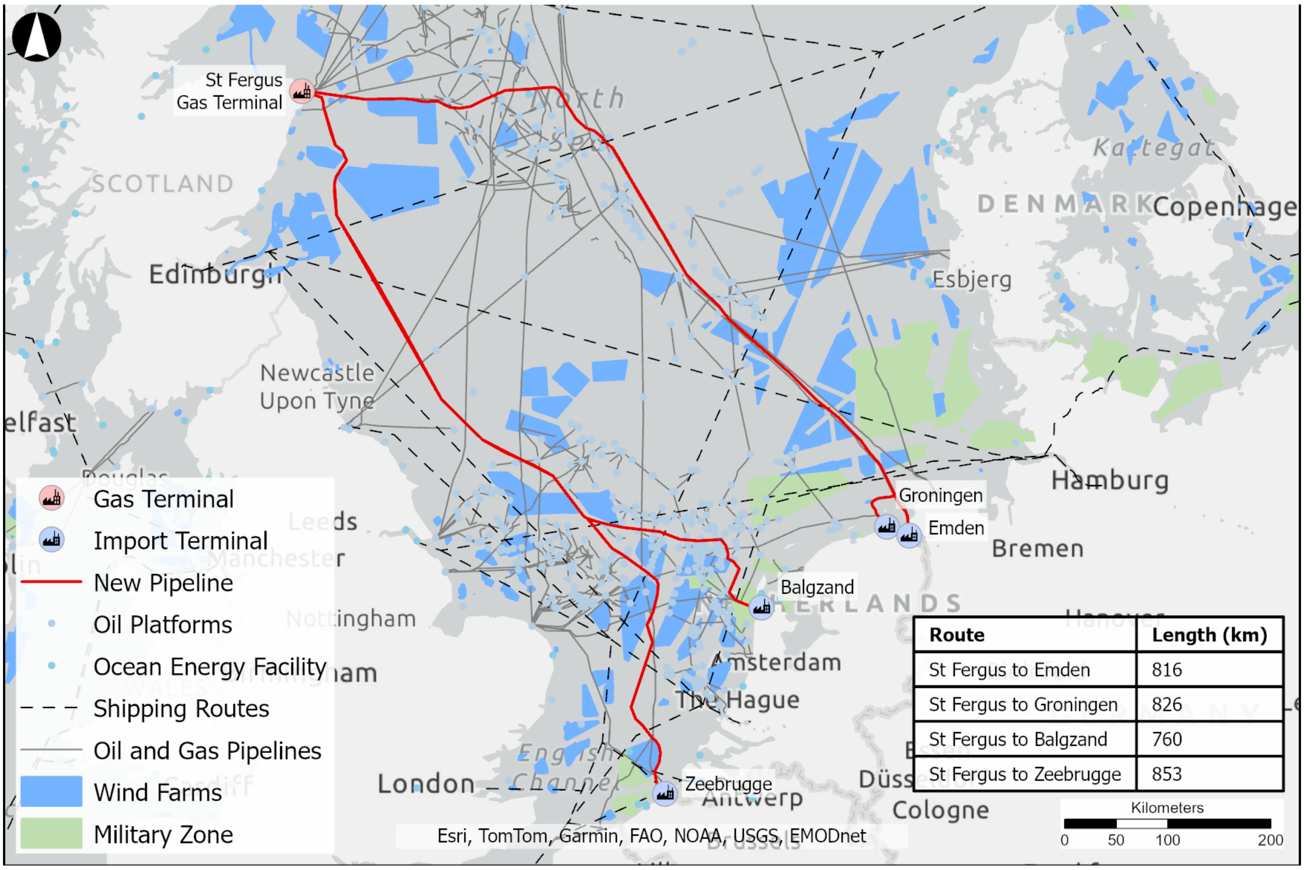


Figure 38: Potential new pipeline routes from St Fergus.

5.3.6 New Pipeline Routes Summary

When considering wider political, production and strategic objectives, all export locations identified could provide viable routes for the export of hydrogen from the UK. All export locations have technically feasible routes based on the initial review completed in this report and none of the route options were found to be economically infeasible. However, the routeing study undertaken indicates that new build export pipelines from Bacton and Easington may be the most advantageous when considering the technical design and cost of the export system exclusively, as they offer the most direct routes and are proposed to be connected to most UK networks. A summary of pipeline export routes identified in the study is shown in Table 13.

Table 13: Lengths of new pipeline routes from the UK to Europe.

Route Number	Start Point	End Point	Length (km)
1	Bacton	Zeebrugge	235
2		Balgzand	258
3		Groningen	393
4		Emden	430
5	Medway	Zeebrugge	183
6		Dunkirk	126
7		Balgzand	349
8	Easington	Balgzand – option 1	427
9		Balgzand – option 2	377
10		Zeebrugge	431

Route Number	Start Point	End Point	Length (km)
11		Groningen	452
12		Emden	482
13	Teesside	Emden	578
14		Groningen	548
15		Balgzand	485
16		Zeebrugge	578
17	St Fergus	Emden	816
18		Groningen	826
19		Balgzand	760
20		Zeebrugge	853

5.4 Non-Pipeline Transport Routes

In addition to the pipeline export routes, shipping export routes were also identified. Shipping routes considered the shortest practical route from UK export locations to European import locations and established industry tools were used to determine the overall length of shipping routes. The shipping routes identified are shown in Figure 39.

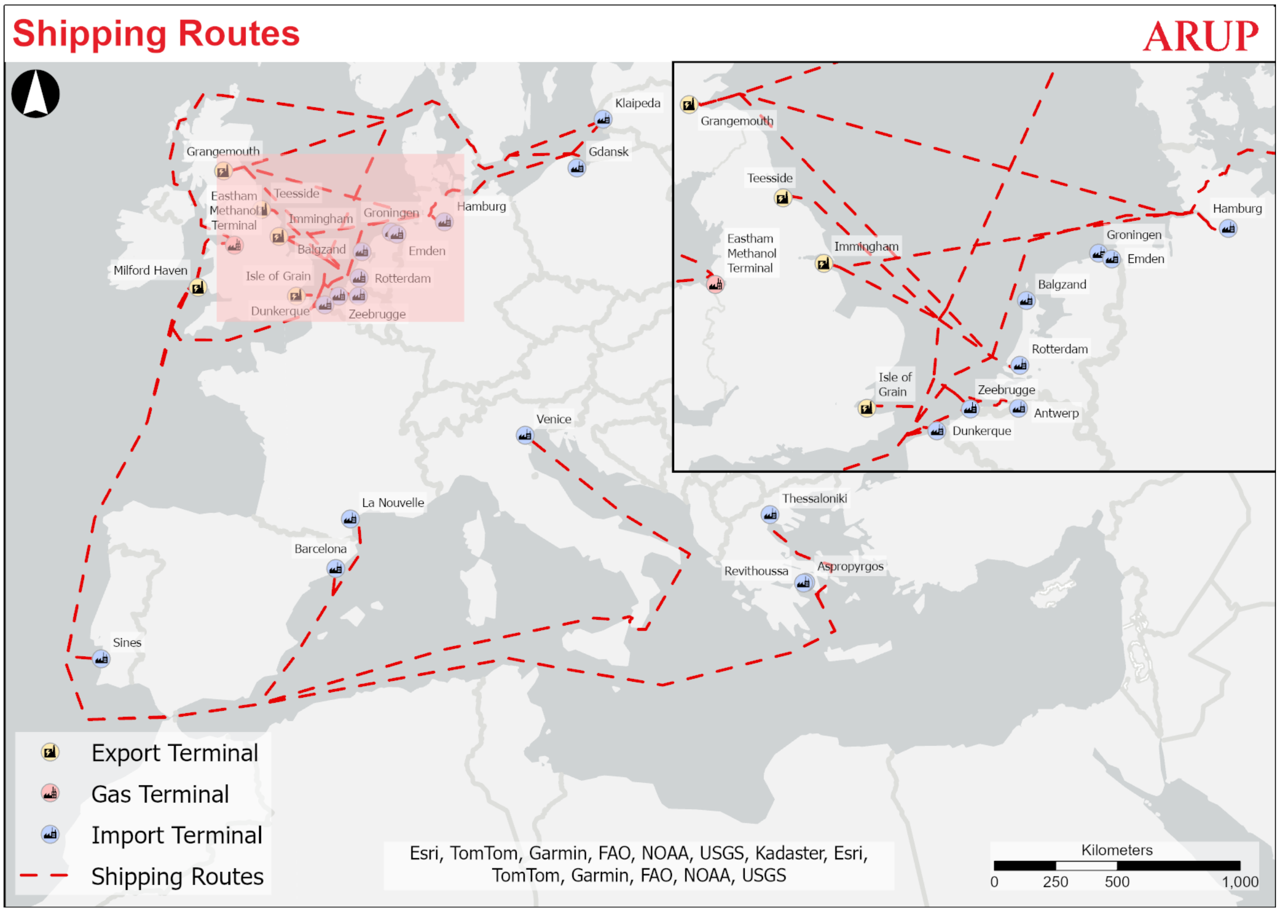


Figure 39: Shipping routes from export locations to European import locations determined in the study.

Shipping routes were selected based on the utilisation of established shipping lanes as far as possible while minimising the shipping distance between the potential export and import locations. The routes from port to port were selected to give as direct a comparison against pipeline export for North West Europe as possible, since these corridors are the only ones where pipelines are economically viable export solutions. Routes to southern Europe aimed to follow existing shipping lanes and minimise the transport distance to reduce the LCOT to provide a basis to evaluate the potential competitiveness of UK hydrogen exports to Southern Europe. Selection of shipping corridors between ports aimed to ensure that the infrastructure at both the export and import side was suitable to accommodate the same vessel class and derivative shipped to maximise efficiencies. The aim of the route identification was primarily to provide a reference point to the LCOT estimates outlined in Section 9 for where the potential cost of exporting hydrogen and derivatives from the UK to certain locations in continental Europe.

6. Pipeline Export

Pipeline Export Summary

Repurposing of the existing interconnectors from Bacton to Zeebrugge and Balgzand, respectively, is technically feasible, however it is unclear when the systems would be available to transition from natural gas to hydrogen. Repurposing the existing interconnectors has the potential to offer a low LCOT to export hydrogen to continental Europe.

New pipelines also offer a viable export solution. The design of new pipelines can be tailored to suit hydrogen operation at specific capacity and pressure specifications which provides improved control over the technical, operational, and health and safety implications of operating high pressure hydrogen pipelines compared to repurposing existing pipelines. New pipelines also enable specific start and end points to be selected based on domestic and European hydrogen infrastructure development, rather than constraining the start and end points to the existing natural gas interconnection points. Construction methods for subsea pipelines are well understood, although there is uncertainty around the timing of the availability of lay barges which introduces a schedule and cost risk.

In summary, new pipelines are considered as the most appropriate from of pipeline transport to be considered in this report as they offer improved certainty on cost and schedule, while increasing start and end point flexibility.

To facilitate hydrogen export via pipeline, several technical considerations must be made. This section briefly summarises the technical factors impacting the repurposing of existing pipeline infrastructure, as well as an overview of the design considerations to be taken into account when designing new hydrogen pipeline connections. The technical factors considered will impact on the overall cost of the export route and were considered during the development of the cost model. Further detail on the technical considerations is available in Appendix B.

6.1 General

For both repurposing of existing pipelines and new build pipelines key systems will be required to facilitate the export of hydrogen. These include:

- UK Terminal infrastructure which connects the domestic system to the offshore pipeline inlet. This will likely include isolation valving, metering, quality monitoring to confirm the product specification and associated telemetry and control systems to operate the pipeline system.
- Compression facilities in the UK to boost the pressure from the production facility or the domestic transmission system to the inlet pressure of the offshore pipeline. This is likely to be combined into the UK Terminal.
- European Terminal infrastructure which connects the offshore pipeline to the European transmission and distribution system. This will likely include isolation valving, metering, pressure reduction to control the inlet pressure to the European pipeline system, quality monitoring to re-confirm the product specification for entry into the European system and associated telemetry and control systems.
- There may be a requirement for compression facilities at the European Terminal to allow bi-directional flow back into the UK in an import scenario.

6.2 Repurposing Existing Pipelines

To repurpose existing pipelines for hydrogen service, there are several design, safety, and operational factors which must be considered and accounted for. There are several established standards and design codes which aim to provide guidance on the design, construction, and safe operation of hydrogen pipeline systems, and some of these codes include reference to repurposing existing pipelines to hydrogen service. A list of these codes is shown in Table 14.

Table 14: Regulatory, Codes & Standards requirements for conversion.

Standard		Hydrogen Service within Scope	Hydrogen Embrittlement Considered
ASME B31.12	Hydrogen Pipelines and Piping	Y	Y
IGEM/TD/1 Edition 6 Supplement 2	Steel Pipelines for High Pressure Gas Transmission	Y	Y
BS PD 8010	Pipeline systems	Y	N (revision in development to account for IGEM hydrogen supplement)
EN 14161	Petroleum and natural gas industries - Pipeline transportation systems (ISO 13623:2009 modified)	Y	N
ISO 13623	Pipeline Transportation Systems	In development	N

In the standards, there are design factors included for reducing the operating pressure of existing pipeline systems to account for the effects of hydrogen in the pipelines. Standards are typically used in the design of gas pipelines and are referred to by permitting authorities. Standards set out a series of design methods which have been proven to provide designs which can achieve acceptable risk profiles. Each development is different however, and just because a standard has been followed, it is not guaranteed that the regulator (for the UK, the HSE) will accept the design presented without further justification of its suitability. In the case of repurposing pipelines for hydrogen service, examples of conversion of major high pressure natural gas pipelines to hydrogen is limited and therefore the standards for these purposes are still developing. As conversion projects progress, there will be new methodologies presented and included in standards. The burden of proof for early conversion projects will be very high and likely costly, which can then feed into the development of future projects and therefore the most up to date revisions at the time of design should be used.

6.2.1 Export Pressure

To convert existing pipelines to hydrogen service, typically the design factor must be reduced, meaning that a lower maximum operating pressure is used. This reduces the maximum potential flowrate of the pipeline compared to natural gas service. The operating pressure must be reduced to limit the effects of mechanisms like hydrogen embrittlement, as hydrogen is more likely to diffuse into higher strength steels at higher pressures and temperatures. Therefore, operating at a lower pressure reduces the risk of hydrogen diffusing into the pipe material. Higher strength steels are more susceptible to hydrogen embrittlement. As most subsea pipelines operate at high pressures (typically around 130-160 barg), they are mostly constructed of high strength steels, also known as high grade steels. The design factors for high grade steels are more stringent than for lower grade steels due to the increased impact of embrittlement in these materials. An overview of the design factors in IGEM/TD/1 Edition 6 Supplement 2 is shown in Table 15.

Table 15: Design factor key limit on allowable pressure

	Material Grade		SMYS (N/mm^2)	Design factor, f
</=	L360	X52	360	0.5
=	L415	X60	415	0.433
=	L450	X65	450	0.4
=	L485	X70	485	0.371

The existing interconnectors between Bacton and Balgzand and Bacton and Zeebrugge are both constructed of Grade X65 steel. Their maximum operating pressures while transporting natural gas are 137 bar in Bacton to Balgzand Pipeline and 147 bar in the Bacton to Zeebrugge Pipeline. In hydrogen service the existing interconnectors must be limited to the design pressures shown in Table 16.

Table 16: Design conditions for repurposing the existing interconnectors to hydrogen service.

Parameter	Symbol	Unit	The Interconnector (Bacton-Zeebrugge)	BBL Pipeline (Bacton-Balzgand)
Wall thickness	t	mm	21.76	20.9
Outer Diameter	D	mm	1016	914.4
Material grade	N/A	[-]	X65	X65
Specified Minimum Yield Strength (SMYS)	s	N/mm^2	450	450
Design Factor	f	[-]	0.4	0.4
Maximum Allowable Operating Pressure (MAOP)	P	barg	77	82

As shown in Table 16, repurposing existing high strength steel natural gas pipelines under current design standards will require a significant reduction in maximum allowable operating pressure and hence transport capacity. However, despite the reduction in MAOP, both interconnectors would have the capacity to transport the volumes considered in this study. Therefore, if the interconnectors were to be made available for hydrogen transport, they would be viable options to export hydrogen to either Zeebrugge or Balgzand, dependent on the compatibility of the weld materials, condition of the assets when available and with the required replacement / modification of compression equipment, valves, meters, and other fittings.

6.3 New Build Pipelines

The construction of a new build pipeline allows much greater flexibility to size the pipeline to provide the required throughput capacity to meet the design demand targets. There are a number of both technical and commercial considerations which will have a bearing on the design of the pipeline system and the ability to install the pipeline to the required schedule. Specialist pipeline lay barges are sophisticated marine vessels which are low in number and high in demand. The lead times for procuring the lay barges can be lengthy, in some cases they need to be booked years in advance, and the availability of different types of lay barge may dictate the design of the pipeline as much as the operational and integrity aspects of the design.

The diameter of the pipeline will be calculated to ensure the capacity needed for the length of the connection taking into account the entry pressure in the UK, required delivery pressure at the European landfall and the subsequent pressure losses along the pipeline.

Once the pipeline diameter is defined the required structural design to provide the required level of integrity during all phases of the lifecycle of the system from installation, testing and commissioning and final operation can be completed considering the physical loads imposed during installation and the operational loads from the pressurised hydrogen. The wall thickness to contain the pressure can be defined based on a certain material grade. Due to the differences between natural gas and hydrogen, specific design considerations need to be included to ensure long term integrity. These are discussed below.

6.3.1 Design Considerations

Material Selection and Hydrogen Embrittlement

Transmission pipelines (high-pressure, long-distance pipelines) are most frequently constructed from carbon steel or stainless steel, with pipe diameters ranging from 4 to 48 inches. In natural gas pipelines, high strength steels (> 100 KSI) are often used, however, high strength steels are more susceptible to hydrogen embrittlement (Wang, et al., 2022). Hydrogen embrittlement occurs due to small size of hydrogen molecules (which are approximately 1/100th the size of methane, the key component of natural gas). Hydrogen embrittlement results in reduced ductility and tensile strength of the steel, due to the absorption and diffusion of hydrogen atoms or molecules. This can result in cracking and rupture of the pipeline and will therefore be a significant factor in the safe design of hydrogen pipelines. Optimal design and checking of weld joints will also be of paramount importance, as these are the most prone to hydrogen embrittlement.

Data suggests that lower strength/grade steels (X52 or below) are less susceptible to hydrogen embrittlement. However, the use of lower grade steel means lower operating pressures are possible or that the wall thickness will need to be increased to accommodate the high operating pressures of transmission pipelines.

Temperature

The IGEM/TD/1 Edition 6 Supplement 2 standard states that in the majority of buried transmission systems, the normal operating temperature will be constant and recommends that the minimum design temperature should be 0°C. For the purposes of this study, an operating temperature of 5°C has been chosen. The operating temperature affects the density and viscosity of hydrogen, however, given the pipeline will be on or below the seabed, assuming that the gas will largely be close to the ambient temperature of water at the seabed along the length of the pipeline is a reasonable assumption for connections that do not require recompressions stations.

6.3.2 Pipe wall thickness

The minimum pipe wall thickness should be equal to or greater than the design thickness. This is determined from a consideration of all the load conditions the pipeline will be exposed to during its lifecycle. Pipe wall thickness will take into account the loads applied during installation and operation. The temporary stresses induced into the pipeline during the process of installation can be significant and impacted by the water depth and the type of lay barge installation methodology utilised. The combined bending and longitudinal stresses must be resisted by the pipeline to prevent bucking and over stressing prior to installation.

In addition, the pipeline must have sufficient wall thickness to resist the internal pressure of the hydrogen at the maximum operating conditions and take into account the external pressure resulting from the depth of water the pipeline is installed in. The design codes make allowance for the temporary overstressing experienced during hydrotesting within the design factors.

6.3.3 Energy Density (Pressure vs Capacity)

An important consideration in pipeline transportation of hydrogen vs natural gas is energy density. The energy density of hydrogen is lower than natural gas: at the same pressure one cubic metre of hydrogen contains around 1/3 of the energy of one cubic metre of natural gas. Therefore, to ensure sufficient energy content in the pipeline, the volumetric flow rate of hydrogen must be higher than for natural gas. Increasing the pipe pressure and/or pipe diameter enables more hydrogen to be transported.

This relationship between pipeline pressure, diameter and hydrogen capacity must be optimised for cost. As described in the 2020 European Hydrogen Backbone report (Enagas; Energinent; Fluxys Belgium; Gasunie; GRTgas; NET4GAS; OGE; ONTRAS; Snam; Swedegas; Terega, 2020), analysis by gas TSOs has shown that operating hydrogen pipelines below their maximum capacity can result in lower costs per MWh of hydrogen transported, as high-capacity compressor stations (and therefore high electricity consumption) can be avoided. This is, however, highly dependent on several factors, including the pipeline length (i.e. the route distance).

As hydrogen travels along the pipeline, it experiences a pressure drop due to friction between the gas and the wall of the pipeline. To achieve a certain output pressure, it may be necessary to either operate the pipeline at a higher initial pressure or recompress at points along the pipeline alignment.

For longer lengths of pipeline connection where the distance is such that the required UK inlet pressure to achieve the desired outlet pressure in Europe would be too high to be practical or present safety and operational challenges for the inlet compressor station, intermediate compression facilities will be required. These could take the form of new build compression platforms where the pipeline is routed via risers onto a topsides compression facility which recompresses the gas for onwards transmission. The alignment of the pipeline may offer the opportunity to utilise existing offshore infrastructure to support the new compression facilities avoiding the need for a new facility. Alternatively subsea compression facilities could be considered but these have challenges in terms of operation and maintenance. If additional compression is required this should be positioned at equidistant spacings such that the facility could be utilised in a scenario where the flow direction could be reversed to provide an import route for hydrogen into the UK, if needed in the future.

6.3.4 Codes and Standards

There is currently no offshore pipeline code specifically for the transport of hydrogen. In 2019, a new revision of the ASME B31.12 Hydrogen Piping and Pipelines design code was released. However, it still does not cover offshore specific design considerations.

The existing DNV standard for submarine pipeline systems standard (DNV-ST-F101) is widely used in industry and is recognised as the one of the most used standards for offshore pipeline design, construction and operation. Whilst this standard does include hydrogen, there are further considerations which must be made to ensure target safety requirements are met. It is also crucial that the standard can provide reliable design and material requirements, so that the pipeline safety is not compromised. DNV have therefore started a joint industry project to develop a guideline for safe and reliable offshore hydrogen gas transportation. The JIP is currently in Phase 2, with an estimated completion date of 2025.

With the potential future deployment of large-scale hydrogen transmission pipelines, there will be a need to determine the balance between pipeline safety and cost-effectiveness, in order to achieve optimal design.

7. Non-Pipeline Transport

Non-Pipeline Transport Summary

Shipping is the only viable non-pipeline transport method for large scale (>100 ktpa or 3.9 TWh/yr). To facilitate the export of hydrogen and derivatives via shipping, appropriate landside infrastructure is required. Existing landside infrastructure for bulk liquid handling, loading, and export (e.g. methanol) would be suitable for the storage, loading and transportation of LOHCs. Likewise, ammonia is a product which is already traded today, and existing infrastructure would be suitable to export ammonia produced using low carbon hydrogen. While LNG terminals may have potential to be repurposed to liquid hydrogen service, there is significant uncertainty in the technical and economic viability of doing so. Additionally, the LNG terminals have become a key consideration for energy security and hence are unlikely to be available for transition until at least 2040.

Existing carrier vessels for ammonia and bulk liquids can be directly used for the transport of ammonia and LOHCs, respectively. For compressed and liquid hydrogen transport, the potential capacity of vessels is more uncertain. Based on the research completed in this study, potential capacities for these vessels were assumed based on projections in the literature and comparison existing LNG and compressed natural gas carriers, which have similar design conditions to what will be required in new hydrogen carriers.

To repurpose the existing infrastructure for all non-pipeline transport options, new conversion systems to convert hydrogen to the chosen vector for transport and back to hydrogen at the other end would be required to facilitate export. The conversion systems add significant complexity and cost to shipping export routes. This also means that the timeline for exporting via shipping is dependent on the roll out of conversion infrastructure, which introduces significant uncertainty to the potential timeframe to export.

Overall, the development of a shipping export route is technically feasible. Landside infrastructure requirements for the storage and loading of ammonia and LOHCs are already deployed today and the requirements for compressed gas storage and handling are analogous to other processes deployed today. Liquid hydrogen is more of an unknown and requires significant technical development in liquefaction processes, and vessel design to enable large scale export. Timelines to develop shipping export infrastructure are more uncertain than for pipeline export.

7.1 Shipping

7.1.1 Hydrogen Derivatives

The delivery of hydrogen is dependent on the mode in which it is transported. This could be either as compressed hydrogen or, liquefied in its pure form or in a chemical derivative form. The main chemical hydrogen carriers are ammonia (NH3), and Liquid Organic Hydrogen Carriers (LOHC) including MCH and toluene. In the context of shipping, port facilities which cater for Liquified Natural Gas (LNG), Liquefied Petroleum Gas (LPG) and methanol have been considered as potential strategic areas of development in the supply chain to cater for hydrogen shipping in the future. Table 17 provides a summary of the main hydrogen derivatives considered for export.

Table 17: Summary of the main hydrogen derivatives considered in the study.

Compressed Hydrogen	LH_2	NH_3	LOHC
Hydrogen is compressed and contained in ambient conditions at a maximum allowable operating pressure of 250 bar. (Offshore Energy , n.d.)	Cooling hydrogen below its boiling point of -253°C and transported in double-hulled tanks. Pros: Higher volumetric storage density, established at small-scale, high purity	Reacting hydrogen and nitrogen to synthesize liquified ammonia, which can be transported in refrigerated tanks. Pros: Process is well established and ammonia is a	Hydrogenation by chemically binding hydrogen to a liquid compound, e.g. toluene. (Roland Berger, n.d.) Pros: Toluene is safe to transport and has good viscosity characteristics under

Compressed Hydrogen	LH_2	NH_3	LOHC
Pros: No additional energy required for dehydrogenation or desorption to provide hydrogen at the destination at the outlet specification set out in Section 2.2. Cons: Early stages of development, smaller volumes of hydrogen can be transported.	hydrogen, no complex reconversion. Cons: Liquefaction process requires a high amount of energy, complex handling and transportation to maintain liquefaction temperature, boil-off losses can be high.	global commodity in fertilizers. Ammonia liquefaction is comparatively less energy-intensive than hydrogen liquefaction (25°C and 10 bar or -33°C at atmospheric pressure) and ammonia storage can utilise well-developed existing infrastructure. Liquified ammonia has a high volumetric H2 density (107-120 kg/m^3) Cons: Ammonia synthesis requires nitrogen provided by air separation which is an energy intensive process. Large heat input is required during the catalytic cracking process (the reaction temperature is between 850°C-950°C) which is required to provide hydrogen as per the outlet specification set out in Section 2.2. Toxic fluid – additional safety precautions required against toxicity and explosion risks.	ambient pressure and temperatures. Cons: Dehydrogenation requires very high temperatures, large volumes of LOHC liquid are required for transport and require a treatment process before re-use. LOHCs have a low gravimetric hydrogen density (6.19% weight and 7.29% weight), which can restrict their use in weight-limited activities.

7.1.2 Vessel types

Vessel types have been assessed based on the current fleet distribution for established cargo, including LNG, methanol, and chemical carriers. In addition, current vessels catering for compressed and liquefied hydrogen have been included within the range. It is currently understood that vessels carrying specific cargo could be re-configured to cater for hydrogen, e.g. ammonia could be transported in conventional chemical carriers, liquefied hydrogen transported with similar size vessels in the LNG market and LOHC via conventional oil tankers. New carriers are under development, but they are expected to largely follow similar design principles to the existing fleet to maximise continuity and reuse of port infrastructure.

Ammonia

Ammonia can be transported via different ship types, depending on how it is stored and today ammonia is typically transported in gas carriers designed for liquefied petroleum (LP). (ClimateXChange, 2022). According to the IEA, ammonia carrier are in the range of 20,000 – 35,000 m^3 capacity, with about 200 gas carriers across the world capable of transporting ammonia. There is a possibility that carriers will increase in capacities to over 80,000 m^3, as shown by recent new-build orders in the Middle East (Snyder, 2023). Transporting ammonia in liquid form can result in a reduction in volume as the temperature difference between the ammonia storage tanker and the ambient air temperature results in boil-off gas. The total daily energetic boil-off gas for ammonia is c.0.1%, which is less than other liquified energy carriers such as LNG, given ammonia has a comparatively higher boiling point. (ClimateXChange, 2022) Boil off mitigation is a key component of transportation systems, with additional compressors and energy required in Boil Off Gas (BOG) systems.

In terms of intercontinental transmission, the most developed means of transporting hydrogen by a carrier would be as ammonia. This would rely on chemical and refrigerated and pressurized tanks on vessels similar to LPG carriers for transport.

Methylcyclohexane (MCH)

Hydrogen as liquid methylcyclohexane (MCH), which is produced from toluene and hydrogen, can be safely and economically stored, and transported. Both toluene and MCH are maintained in a liquid state at ambient temperatures and pressures. MCH is commonly used as a solvent, for example in whiteout correction tape, and has a low degree of risk as a chemical substance. Liquid MCH efficiently transports hydrogen because it contains 500 times more hydrogen per volume than hydrogen gas. Gaseous hydrogen is catalytically extracted from MCH through the dehydrogenation process at the site hydrogen is supplied to hydrogen users. Toluene, a by-product of the hydrogen extraction process, is repeatedly recycled as a raw material for producing MCH. (Chiyoda, n.d.).

Chiyoda has successfully developed the proprietary dehydrogenation catalyst for MCH and has conducted technological demonstrations to make the catalyst for practical use. Chiyoda has registered MCH including hydrogen for storage and transportation as the trade name SPERA Hydrogen. Chiyoda are now expanding the system towards semi-commercialisation by the mid-2020s, reducing costs through economies of scale in line with increased hydrogen demand (Chiyoda, n.d.) (Green Car Congress, n.d.).

The transportation of liquid MCH can be facilitated in traditional oil tankers as MCH and toluene are both classified into the same category as petroleum (e.g. under the Fire Service Act in Japan), where this demonstration took place. It was determined to be feasible to repurpose existing petroleum transportation and distribution infrastructure for SPERA Hydrogen, thereby lowering the capital investment in its transportation and distribution. (Chiyoda, n.d.) This study also assumes that for transportation of MCH and toluene between the UK and Europe existing oil tankers can be repurposed (Chiyoda, n.d.).

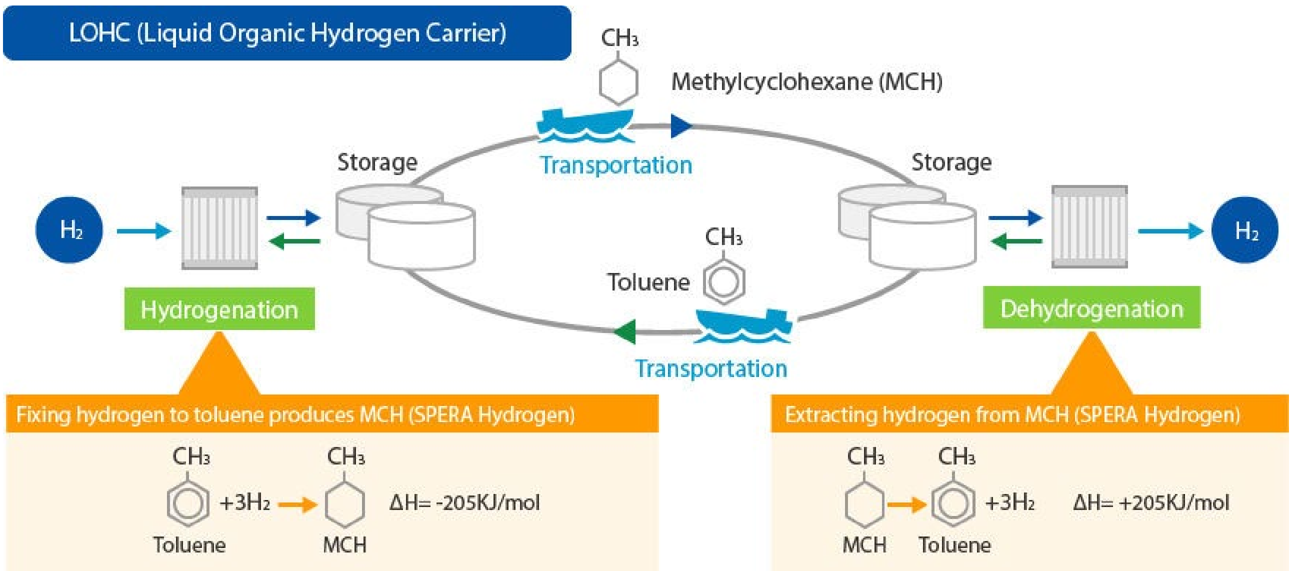


Figure 40: Chiyoda's business plan for storing and transporting hydrogen utilizes the liquid organic hydrogen carrier (LOHC) method (Chiyoda, n.d.).

Liquefied Hydrogen

An alternative method to storing hydrogen, aside from compression, is through liquefaction. However, converting hydrogen from gas to liquid form demands extra energy and ongoing cooling. This process involves cooling hydrogen gas to cryogenic temperatures, typically below -252.8°C. It is estimated that around 30-40% of the hydrogen's energy content is consumed during liquefaction, compared to 15% for compressed gas storage. Moreover, the exceptionally low temperatures required for storing and transporting liquefied hydrogen (LH_2) require that all associated mechanical components, such as valves and tanks, are resistant to hydrogen embrittlement.

Ships designed for transporting liquefied hydrogen face challenges such as significant levels of evaporation due to the cold and lightweight nature of the fluid. To mitigate this, would require either enhanced insulation of the cargo or investment in complex cryogenic systems. Currently the only liquefied hydrogen carrier to exist is the Suiso Frontier with an LOA of 116m and a draught of 4.5m launched in 2021 by Kawasaki Heavy Industries (KHI) to transport liquefied hydrogen from the Port of Hastings, Victoria, Australia to Kobe, Japan. The vessel has two tanks, capable of storing a total capacity of 1250 m^3 of LH_2 at -253℃. The only other LH_2 carrier with Agreement in Principle (AiP) is a Kawasaki LH_2 carrier with dimensions similar to a Q-Max LNG carrier vessel capable of carrying a capacity of 160,000 m^3 of LH_2 in four tanks with an LOA of 346 m and a draught of 9.5 m. The company expects to trial this vessel by the mid 2020's.

Methanol

Methanol carriers are typically in the range of 45,000 - 120,000 m^3 currently and expect to increase to between 60,000 – 160,000 m^3 in the future. Similarly, Grangemouth, has Tanker Terminals capable of handling methanol carriers with berth lengths ranging from 100 - 200m at a depth of 13.5 m.

LNG

There are currently no vessels that can transport pure hydrogen on a large scale; however, such vessels could possibly be comparable to a modified LNG carrier and would require the hydrogen to be liquefied prior to transport. Another aspect that would have to be considered is that hydrogen boils off during the journey (around 0.2% of the cargo would be consumed per day, similar to LNG carriers) [49].

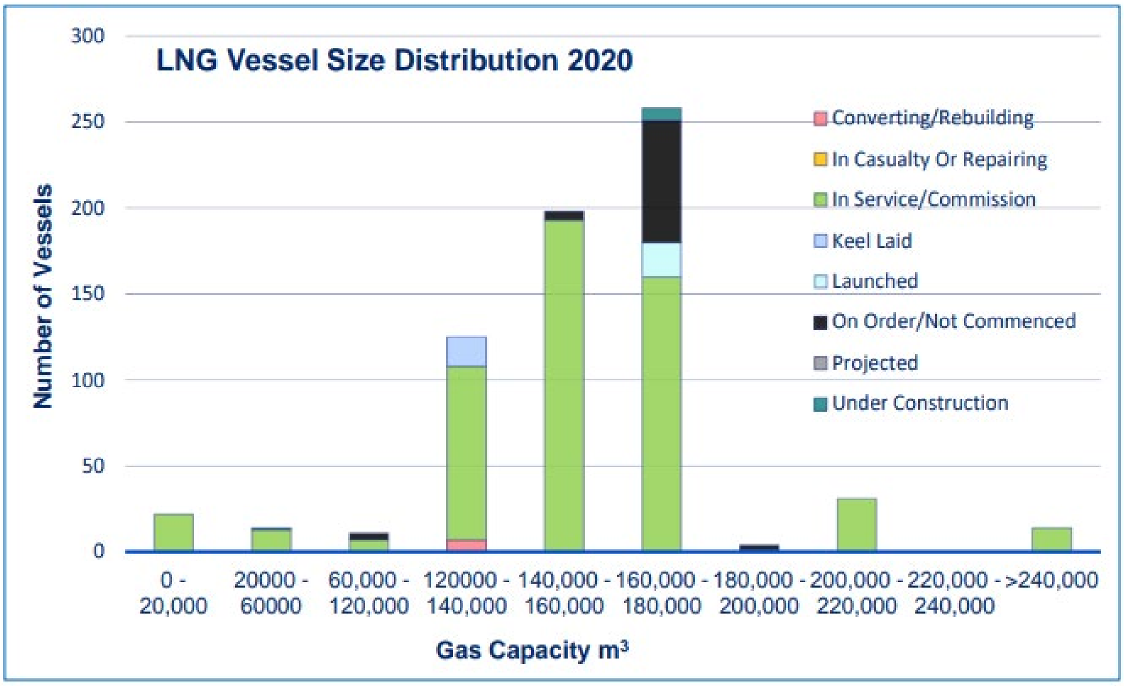


Figure 41: LNG Tanker Size Distribution (2020) (PIANC, 2022).

Compressed Hydrogen

Compressed hydrogen carriers are designed to accommodate high pressures, suitable for storing hydrogen gas in its compressed state. Hydrogen is typically compressed between 350 to 700 bar (5,000 to 10,000 psi), to maximize storage density, enabling a larger quantity of hydrogen to be contained within a specific volume. However, even at the high pressure of 700 bar, compressed hydrogen possesses only 15% of the energy density of gasoline. Consequently, storing an equivalent energy amount would demand nearly seven times the space.

Currently, the global supply chain is in its early stages of development for transporting compressed hydrogen. Nonetheless, there are ongoing developments in creating smaller-scale vessels, anticipated to be operational as early as 2026, with larger-scale vessels projected to follow suit by 2030 (Provaris, 2022). While compressed hydrogen shipping is in its early stages, it is considered a viable option, particularly for shorter export distances, e.g. from the UK to Europe, due to its economic potential. Specialised vessels will be employed for transporting compressed hydrogen. Provaris, an Australian technology provider, aims to introduce vessels with a carrying capacity of 26,000 m^3 by 2026 and 120,000 m^3 by 2030. Through an extension of prototype tank design, Provaris has developed initial concepts that will have relevance to a range of hydrogen applications. The tank structure will be based on the use of multi-layered carbon-steel which has a design pressure of 250 bar (Provaris, 2022).

Summary

To determine the envelope of vessels with the potential to support hydrogen and hydrogen derivatives, vessel carriers have been classified into liquid hydrogen carriers, compressed hydrogen carriers, ammonia, methanol, LNG, and LPG carriers. The expected vessel range can subsequently be used to assess the compatibility of current UK and EU ports with the potential to export and import hydrogen in its various forms. The dimensions and storage capacity of each type of carrier are summarised in Table 18.

Table 18: Capacity range of vessels for each hydrogen

Carrier Type	Current Capacity (m^3)	Potential Future Capacity (m^3)	LOA (m)	Draught (m)
Methanol/MCH	45.000 – 120,000	120,000	147 - 241	8.7 - 12.2
Ammonia	34,500-88,000	88,000	174 - 225	9.0 - 13.0
LH_2	1,250	160,000	116 - 346	4.5 – 12.5

The size and type of the required transport fleet depends on the packaging mode. These means of transport are at different stages of technological readiness. For example, LOHC can be transported in conventional oil tankers, and ammonia can be transported in refrigerated chemical tankers. By contrast, liquefied hydrogen will need to be transported in large carriers with a similar design to liquefied natural gas (LNG) carriers, and compressed hydrogen will be delivered in tanker ships analogous to those transporting compressed natural gas (CNG) (European Union, n.d.). LH_2 carriers require significant technical development to reach a comparable transport capacity to ammonia or LOHC. It is unclear what the timeframe for development may be as there are still several uncertainties surrounding the economic viability of liquid hydrogen trade or its suitability compared to ammonia or LOHC transport.

7.1.3 Development of new Infrastructure

Total cost for a new jetty and berth (including owner's cost, technical studies, prelims, and the construction of the approach jetty, loading platform, dolphins, and walkways) could be in the range of £50 - 200 million depending on size, site location, and geological conditions.

- Planning Permissions, permitting: 1-4 years
- Front End Engineering Design: 1 year
- Environmental / Social / Health Impact Assessments – 1-2 years
- Procurement: 1 year
- Construction: 2-3 years
- Commissioning: 0.5-1 year

Some of these activities can occur concurrently, notably design work (front end and detailed engineering) and planning and consenting processes (environmental / social / health impact assessments) and – to some degree – procurement and construction, which are all time intensive processes. This means that the overall transition should be credible in a 5-year timeframe, unless port already moves the product.

The general international ownership models for ports are summarised below, the categories are not mutually exclusive and are presented to provide a high level overview of the potential ownership models and how they may affect development:

- Full Public: Where all Construction and Operations are financed and undertaken by public sector. No private sector involvement which becomes difficult to finance, maintain efficient operations, or attract volumes.
- Full Private: Where the private sector owns and operates the port in full. The port is a strategic asset therefore it may be in the state's interest to have influential powers, to enable the port to be used as a stimulus for economic development.
- Tool Port: Where all is financed and provided by public sector. Only stevedoring is provided by the private sector under service contract.
- Landlord Port: Where expensive waterside infrastructure provided by public sector (dredging, reclamation, quay, breakwater). Private sector invest in topside infrastructure (pavement, buildings etc,) and equipment in relatively short/ medium exclusive operations concession.
- Landlord BoT: Where Public sector finance dredging, breakwater, reclamation. Private sector finance equipment, quays, topside, operations under a longer-term concession.

In the UK, there are three main types of ownership models for ports or Statutory Harbour Authority (SHA): private, municipal and trust ports:

- Private ports have equity owners or shareholders.
- Municipal ports are owned by the local authorities.
- Trust ports operate under a unique governance structure and largely private, although publicly accountable to their stakeholders. Trust ports are required to reinvest their profits back into the port infrastructure and operations to support their long-term sustainability and development. (Association, 2024)

Quayside development would also require an MMO license in addition to planning permission in the UK.

7.1.4 Safety Considerations

Handling procedures for each hydrogen derivative requires special considerations which are related to the individual characteristics of each chemical compound.

Additional risk assessments are required to identify hazards associated with each bunkering operation and adequate controls are required to mitigate them. Typically, these controls include establishment of safety and security zones, defined as follows:

- Safety zone: area around the methanol station where personnel access, activities and ignition sources are controlled.
- Security zone: where ship or vehicle movements are monitored or controlled, including external movements that may become a hazard.

The size of these zones is established based on the extent to which a flammable cloud will reach following an accidental release under defined scenarios. These zones can have an impact on other port operations and are therefore important to consider when selecting a preferred approach to bunkering. For example, the extents of safety and security zones considered in the Port of Gothenburg methanol bunkering regulations (Port of Gothenberg, 2022) require a minimum safety zone of 25m around the receiving vessel bunkering station and a minimum-security zone of 25m in all directions from the vessel.

Specific hazards associated with each hydrogen derivative are described below.

Liquid Hydrogen

The hazards related to liquefied hydrogen are low ignition energy, a wide range of flammability limits, low visibility of flames in case of fire, high flame velocity which may lead to the detonation with shockwave, low temperature and liquefaction/solidification of inert gas and constituents of air which may result in an oxygen-enriched atmosphere, high permeability, low viscosity, and hydrogen embrittlement including weld metals. Where vacuum insulation is adopted, due consideration should be given to the possibility of untimely deterioration of insulation properties at the envisaged carriage temperatures of liquid hydrogen.

The majority of special requirements for liquefied hydrogen carriers are provided based on ISO/TR 15916. This standard refers to liquefied hydrogen tank storage facilities on shore, tank trucks and so on, and includes basic viewpoints when discussing the properties of liquefied hydrogen. (IMO, 2016)

Ammonia

Hazards related to ammonia are due to its flammability and toxicity which are well understood within industry due to the large number of operating ammonia plants globally. In this regard, ammonia will burn and can explode if ignited in a confined space. The toxicity of ammonia can produce lethal effects, however, is considered manageable as evidenced by the large number of ammonia plants in operation.

A consideration with the ammonia cycle proposed in this project is the high pressures of the synthesis process which could result in significant leak sizes and consequence (flammable and toxic) distances.

The low storage temperature required in the ammonia shipping model could potentially cause issues if spilled or handled incorrectly e.g. cracking of marine structural steel.

MCH and Toluene

The hazards related to MCH and toluene can be considered as conventional liquid hydrocarbons, with both chemicals having moderate toxicity (lower than ammonia) however, both MCH and toluene are carcinogenic and dedicated handling procedures are required.

The MCH transportation model contains the lowest operating pressures and releases are likely to be limited to localised pool fires.

7.2 Alternative Non-Pipeline Transport Options

Transportation of bulk materials through options which are not pipeline or shipping are unlikely to be competitive at the volumes considered in this study. Options including road transport or rail are available but are orders of magnitude lower in terms of scale and volume.

When looking at road transport of hydrogen and its derivatives, constraints on capacity, safety, and conversions losses need to be considered. Road transport has a limited capacity making it less efficient for large-scale or long-range transportation. Handling either compressed or liquefied hydrogen, ammonia, and methanol on roads requires safety precautions that will have to be met considering factors like toxicity of some of these substances and well as the energy losses during compressions and decompressions.

While there are no fixed road links between UK and EU, road transporters could be transported by rail through the Channel Tunnel or on ferry links. There is only a single rail option between the UK and EU through the Channel Tunnel connecting Folkstone with Coquelles. The link currently provides commuter rail travel and would raise security concerns if the tunnel had to be used to move hazardous substances like ammonia and methanol. This constrains the capability of transporting large-scale derivatives of hydrogen. While freight aviation links exist between UK and EU, there is limited scope for bulk materials such as hydrogen and associated vectored products. Aviation also remains the most expensive freight transport alternative.

8. Planning, Consenting, Environmental, and Schedule

Planning, Consenting, Environmental, and Schedule Summary

Planning and consenting are on the critical path for both pipeline and non-pipeline transport options. Planning and consenting timeframes will have a significant impact on the schedule of any export corridor development. The cross-border nature of a pipeline interconnector system introduces additional complexity, however there is significant precedent for the development of these systems in the North Sea to follow.

Environmental issues are prevalent for both pipeline and non-pipeline transport. During design, environmental best practice guidelines from UK and European authorities should be followed to reduce any adverse impact on the environment. Following the design, environmental impact assessments for the new infrastructure required would be completed as part of the planning and consenting processes.

The planning, consenting, and environmental issues have a heavy influencing factor in the development timeframe estimates for the pipeline and non-pipeline export options and introduce uncertainty into schedule estimates.

8.1 New Pipelines

The development of a new build pipeline option will require a number of consents and permits to be put in place on both sides of the crossing to comply with national and local legislation. These are numerous and have potentially long consultation and determination periods which must be taken into account in the overall development programme.

In addition to the international and national consents and permits required to comply with local legislative requirements, crossing and proximity agreements will be required for every existing service that is crossed. These will be determined in parallel with the other permits and will involve consultation and negation with the relevant service operator to put in place separate agreements for every crossing. An allowance should be included in the development programme to secure these agreements in advance of construction.

Figure 42 shows the extent of the UK Marine Works Controls which will apply to the new build pipeline within UK jurisdiction.

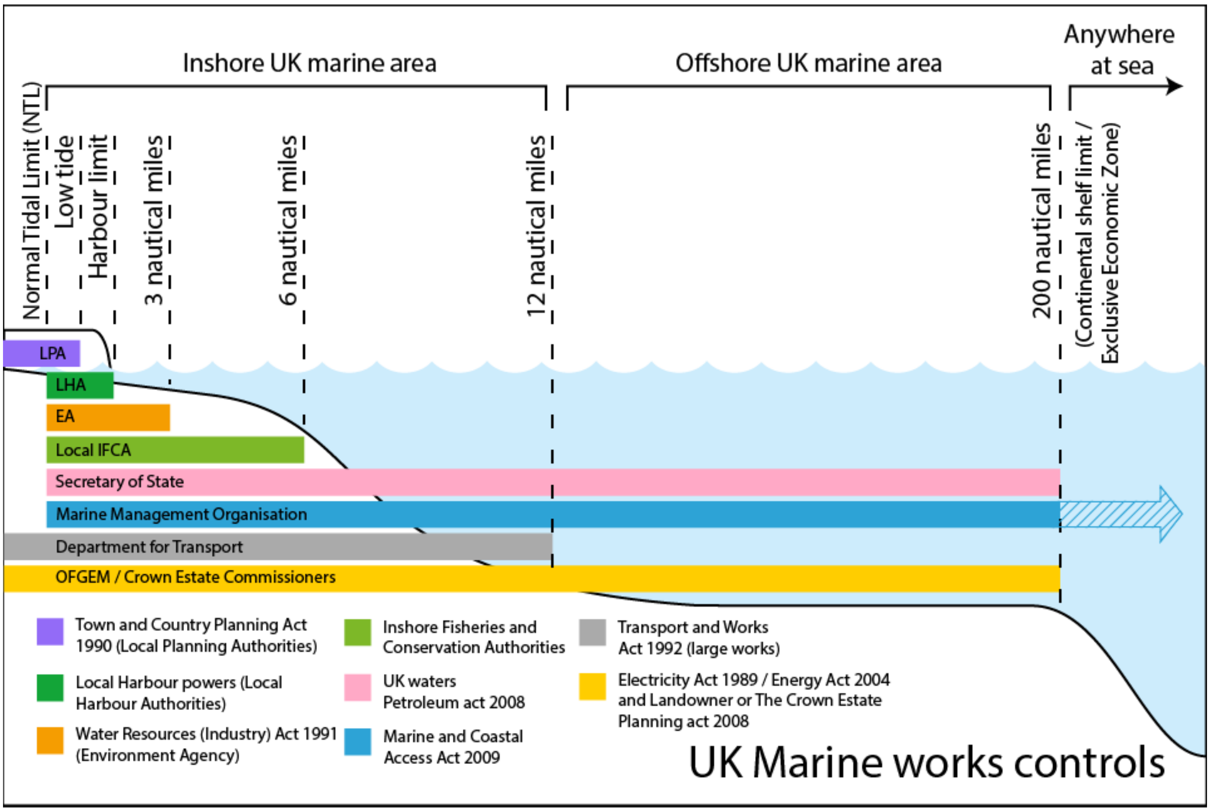


Figure 42: UK Marine Works Controls (© UK Government).

On the UK side, the following describes the range of consents which may need to be put in place to allow the works to proceed. A detailed assessment of the consents and permitting requirements and a strategy for engagement with the various permitting authorities and other statutory bodies and interested stakeholders will need to be developed at the start of the project.

- **Planning Consent** will be required from the relevant Local Planning Authority for the onshore compression facilities and for any works partly on land up to the lowest local tide limit. This could be sought under the Town & Country Planning Act 1990 (TCPA) but given the strategic nature of the development it would likely be consented under a Development Consent Order (DCO).

- **Section 278 Agreement** under the Highways Act 1980 may be required for the UK Terminal facilities if permanent alterations or improvement to a public highway are required as part of the planning approval.

- **Fisheries Disruption Agreement** may need to be set up and negotiated if the route of the pipeline impacts on established fishing grounds and construction could result in disruption to fishing operations.

- **Consent under the Petroleum Act 1998 will be required from the North Sea Transition Authority (NSTA) for pipeline works up to 200 nautical miles offshore**. The construction and use of offshore pipelines set out in Part 3 of the Petroleum Act 1998 now includes conveyance of hydrogen using pipelines, meaning that an authorisation from the NSTA is required to construct or use a hydrogen pipeline in the UK territorial sea or UK continental shelf. This follows a legislative change made in September 2023. This change in turn means that the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) will be responsible for environmental assessment (EIA and Habitats Regulations requirements) of a hydrogen pipeline in these areas.

- **Environmental Permit / Water Abstraction Licence** from the Environment Agency (EA) may be required if there is a discharge of some kind or abstractions of water in the zone up to 3 nautical miles offshore in English waters.. Separate requirements will exist in other UK waters, for those considered in this study, the Scottish Environment Protection Agency protections on the water environment up to 3 nm from the coast of Scotland requires consideration.

- **Harbour Authority Permits and Orders** may be required from the Local Harbour Authority under the Harbours Act 1964 for any works which may impact the area up to the extent of the local harbour limit.

- **Department of Transport Licence** may be required under the Transport and Works Act 1992 (Large Works) for works up to 12 nautical miles offshore.

- **OFGEM Licence** under the Energy Act 2004 may be required for the works up to 200 nautical miles offshore and for the operation of the interconnector pipeline.

- **Seabed Licence** for seabed surveys or coastal surveys will be required from The Crown Estate for survey activities that physically interact with the foreshore (including estuarine) or seabed under ownership of The Crown Estate under the Landowner or The Crown Estate Planning Act 2008 up to 200 nautical miles offshore. Other projects, such as habitat restoration, will also require a licence from The Crown Estate if it impacts upon the foreshore or seabed that they manage. Surveys and habitats assessment will be covered via the Petroleum Act 1998 consenting regime (administered by NSTA) and OPRED's Habitats regulations.

- **Wildlife Licence** may be required if the proposed activity could impact a protected species or habitat. This can include disturbance, injury, killing, collection, damage or destruction of place or structure that is used for shelter or protection and preventing access to such a place or structure. The MMO is responsible for wildlife licensing of activity in English waters (up to 12 nm from the coast). OPRED is the relevant administration to grant wildlife licences in offshore waters 12 – 200nm, in relation to hydrogen pipelines.

- **Sites of Special Scientific Interest (SSSI) Consent** from Natural England may be required for activities taking place within SSSI's.

The time taken to obtain the required licences will be influenced by the complexity of the application and the supporting information required. A project of this magnitude and potential impact will require an Environmental Impact Assessment (EIA) and potentially an assessment under the Habitat Regulations. These will require substantial survey information, which could include sampling and sediment analysis. Many of these surveys will be seasonal in nature and therefore a substantial period of survey coverage will be required to support the application.

A similar range of permits, requiring a similar timeframe, will be required at the European end of the pipeline to comply with the landfall countries legislative requirements. For example, the MMO equivalent in Germany is BSH (*Das Bundesamt für Seeschifffahrt und Hydrographie* – The Federal Maritime and Hydrographic Agency) who will determine the offshore permit.

Given the UK-EU cross border nature of the project there are likely to be advantages in making an application for the project to be considered a Projects of Mutual Interest (PMI). PMIs are key cross-border energy infrastructure projects between the EU and non-EU countries, which contribute to the energy and climate policy objectives of the Union. This is a new category of projects that can be supported following the revision of the Trans-European Networks for Energy Regulation (TEN-E) in 2022. TEN-E covers cross border permitting to align the consenting regimes in different countries.

The hydrogen and electrolyser projects are an important component as they are part of the EU's efforts to establish a hydrogen market in Europe and globally. These projects will enable the export or transit flows of renewable hydrogen to neighbouring Member States. This will allow major EU industries to decarbonise while at the same time remain competitive and thus stay in Europe.

The PMI Application must be made by a project promoter in an EU Member State. The PMI application process takes around 6 months although they are subject to application windows.

Projects recognised by the EU as PMIs benefit from several advantages including:

- Priority status and streamlined permit granting procedures (a binding three-and-a-half year time limit).

- Improved, faster and better streamlined environmental assessment.

- A single national competent authority (one-stop-shop) coordinating all permit granting procedures and specific points of contact for offshore projects.

8.2 Non-Pipeline Transport

As the non-pipeline transport options have prioritised reuse of existing infrastructure, the planning burden of non-pipeline transport will be less impactful than that of constructing a new pipeline. However, the nature of the substances being stored, handled, and shipped as hydrogen derivatives means that compliance with health and safety regulations such as the Control of Major Accident Hazards Regulations (COMAH) 2015 will be required to operate the export facilities in the UK. For European ports, compliance with Seveso III, the European equivalent of the COMAH regulations, will be required for terminals to operate. Like the UK ports, import ports identified for this study are ports which already handle hazardous substances and will therefore already be Seveso compliant where required.

The Control of Major Accident Hazards Regulations (COMAH) 2015 set out the general duties of operators of facilities which fall under either the lower or upper tier limits dictated in the regulation. For the proposed bunkering options, the production and storage only pathways will likely fall under COMAH regulations. The COMAH regulations state lower and upper tiers in terms of quantity of dangerous substances, or category of dangerous substances are kept at the facility. Both hydrogen and methanol are included as dangerous substances and therefore must be aggregated to determine the facility's COMAH tier. The COMAH tier thresholds for hydrogen and methanol are shown in Table 19.

Table 19: Lower and upper tier COMAH thresholds for hydrogen and methanol

Substance	Lower Tier Threshold (tonnes)	Upper Tier Threshold (tonnes)
Hydrogen	5	50
Anhydrous Ammonia	50	200
Methanol	500	5,000

Based on the values shown in Table 19, if more than 5 tonnes of hydrogen is stored on site (including inventory within the process units and site piping), then a lower tier COMAH license will be required to operate. The current design basis is that 5.1 tonnes of hydrogen storage will be required on site, therefore the site would require a lower tier COMAH licence.

The lower tier threshold for methanol inventory is 500 tonnes, and the upper threshold 5,000 tonnes. Aggregation of the two substances will be required to ensure the site does not exceed upper tier COMAH, however, given the quantities it appears lower tier COMAH is more likely to be applicable.

Complying with lower tier COMAH would, at a minimum, require (Health and Safety Executive, 2015):

- Submission of a notification to the Health and Safety Executive (HSE) of the development, typically 3-6 months before construction starts.
- Development of major accident prevention policy (MAPP) agreed with the HSE within 3 months of the site becoming subject to COMAH.
- Demonstrate to the HSE that health and safety risks at the facility have been reduced to as low an as reasonably practicable (ALARP) level.

Alongside the COMAH requirements, the facility would need to apply for a hazardous substances consent from the Hazardous Substances Authority.

The regulations for the transportation of liquefied gases by ships are covered by the International Maritime Organization (IMO) Resolution MSC.370(93), which amends the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code). Additionally, the IMO adopted Resolution MSC.420(97) on November 25, 2016, which provides interim recommendations for the carriage of liquefied hydrogen in bulk.

For Ports in the UK that will need repurposing to handle new low carbon fuels, will require a Harbour Revision Order (HRO) which are used to change the existing legislation governing the management of a harbour or harbours controlled by the same statutory harbour authority (including the provision of new powers and duties). For Ports that will require the new construction of a jetty, land side infrastructure, loading arms, etc. a Harbour Empowerment Order (HEO) may be required if the need is to create entirely new harbour authorities responsible for improving, maintaining, and managing them.

The application processes involved for a works Order and a marine licence fall under different respective legislation, so the role of the MMO is slightly different in each application type and will have different timescales. If the development is deemed to require both a marine licence and a Harbour Order, as is quite common, the MMO expects the applications to be submitted together (GOV.UK, n.d.).

More detailed consideration of the planning, consenting, and permitting of new port infrastructure should be considered if new ports are required.

8.3 Development Schedule Estimates

High level estimates for the duration of pipeline and non-pipeline projects is shown in Figure 43, with a key shown in for illustrative purposes. For both routes, the assumptions used in this study and the Levelised Cost model demonstrate that it could take approximately 10 years from FEED commencing until the first start-up and hydrogen is being exported.

Table 20: Indicative schedule key.

Symbol	Meaning
◆	Project start
●	Optimistic activity end date
●	Pessimistic activity end date
●	Earliest activity start date
◆	Optimistic project end date
◆	Pessimistic project end date

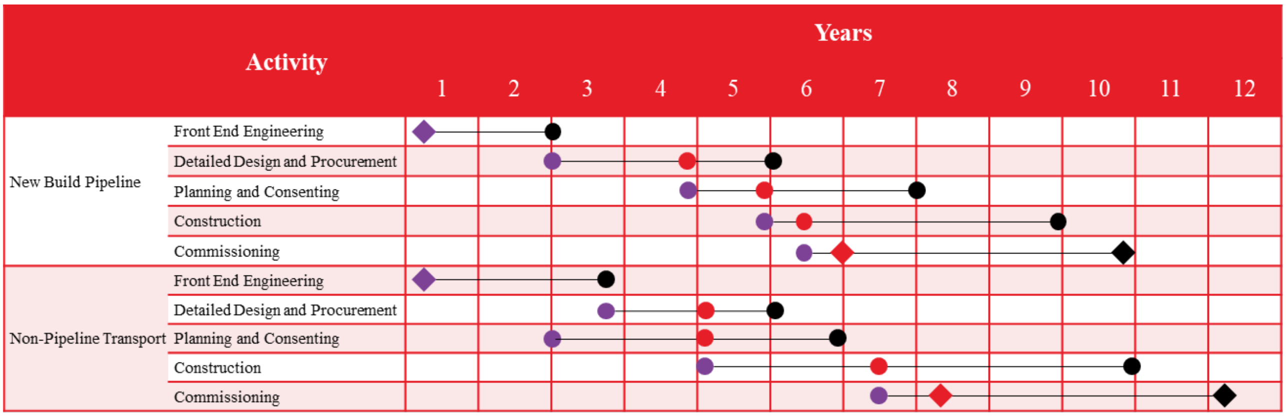


Figure 43 - High Level Project Schedules

9. Levelised Cost of Transport

A cost model has been developed for this study using a mixture of finternal and external data points and project-specific assumptions to allow a comparison to be made between the following hydrogen trade options.

- New Pipeline; and
- Shipping.

The costs of re-purposing the existing pipeline interconnectors to Europe have not been costed in this study as the business case for their use is not thought to be a viable alternative. For comparison, published studies have indicated that the levelised costs of re-purposing pipelines can be approximately 30% of an equivalent new build pipeline however, there will be additional project-specific increases.

The total levelised cost of any option is made up of the following cost elements: production, distribution, transportation and delivery / landed costs. This study only considers the transportation costs, as shown in Figure 44, and would have to be included with all the remaining elements to generate an overall levelised cost.

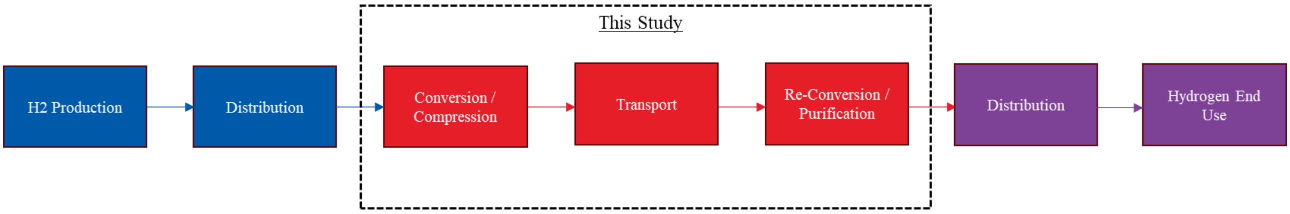


Figure 44: Levelised Cost Sections of a Hydrogen Value Chain

9.1 Transport Cost Modelling Assumptions

This section should be read in conjunction with the Study Basis (Section 2). All costs are presented in 2024 prices.

A levelised cost model has been developed for this study with the overall key assumptions shown in Table 21. Specific assumptions used in the development of individual options are described in their corresponding sections.

Table 21: Key overall assumptions used in the levelised cost model

Parameter	Value	Unit
Discount Rate	8%	
Power costs	35	£/MWh
Years of operation	25	Years
Operating Hours per Year	8,760	hrs/yr
Hydrogen Higher Heating Value	142	MJ/kg

An excel based model has been developed utilising in-house cost metrics, Aspen Capital Cost Estimator (ACCE) software, and published studies / data.

This study focusses on a key range of hydrogen flowrates (shown in Table 22) and transportation distances:

1. 100 km
2. 200 km

3. 300 km
4. 500 km
5. 1,000 km
6. 2,000 km
7. 5,000 km

Table 22: Hydrogen transportation flowrates used in this study

Mass Flow (ktpa)	Energy (GW (LHV))	Energy (GW (HHV))
100	0.4	0.4
200	0.8	0.9
500	1.9	2.2
1,000	3.8	4.5
1,500	5.7	6.7

These values are used as key inputs in the model with the sizing and costing metrics defined to calculate based on these input values.

9.2 Pipeline Transport

The pipeline transportation model is depicted in Figure 45.

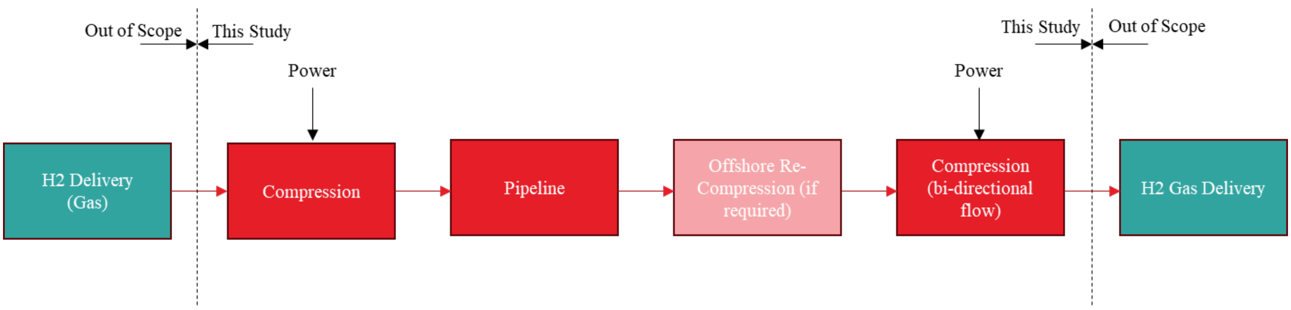


Figure 45: Pipeline transportation model

The pipeline transportation levelised costs are developed using the following assumptions:

- Construction period of 4 years from Final Investment Decision (FID).
- Pipeline asset life of 50 years.
- Large-scale storage not required for pipeline transportation as it is assumed that the supply of hydrogen to the boundary points of this project are constant and reliable.
- The inlet pressure to the pipeline used in the model is 150 barg which corresponds to the maximum pressure allowed for standard steel material strength which is hydrogen-compatible.
- A constant / fixed CAPEX is used for compressor costs which is assumed to be 2x units compressing from UK hydrogen distribution pressure up to 150 barg and the associated utilities.
- The arrival pressure at the landing site is assumed to be a minimum of 20 barg so that there is some flexibility in the downstream users' ability to further transport or handle the hydrogen product.

The pipeline inlet pressure and arrival pressure assumptions above result in a balance between pipe size, pressure drop and fluid velocity when designing pipelines. For the purposes of this study, standardised methodology has been developed such that if the pressure drops below a minimum value of 20 barg at 500 km then a re-compression system is required. This re-compression system is assumed to be an un-manned offshore platform that supports only compressors (and associated utilities) at a fixed CAPEX.

Another key parameter used in this study is the material cost of steel for the pipeline. The steel price has varied significantly over the last 10 years, so caution should be used when viewing cost estimates for projects which won't be scheduled to start for a number of years.

The cost variance in offshore pipelines varies significantly and is difficult to generalise in a cost curve methodology as it depends significantly on water depth, availability of a lay vessel, installation method etc. Therefore, a low and a high 'offshore cost scaling factor' of 1.3 - 2.3 times the price of an onshore pipeline has been used in the generation of pipeline costs, aligning with the Hydrogen Council (Hydrogen Council, 2021).

The results of the pipeline cost assessment using the assumptions listed above and the low and high offshore scaling factor for an example of one of the data points assessed, are shown in Figure 46for a fixed flowrate of 500 ktpa. This example shows how the variance in cost is greatly exaggerated at longer pipeline distances.

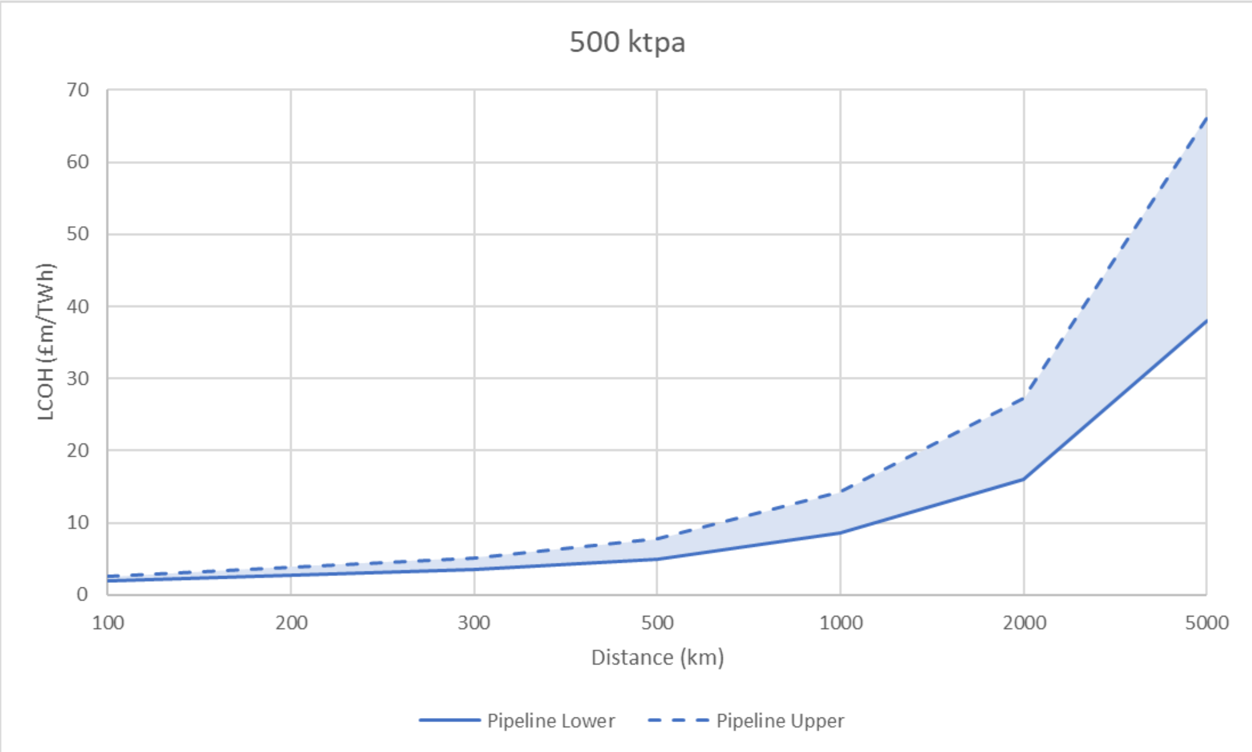


Figure 46: Pipeline LCOH results for a fixed flowrate of 500 ktpa

When considering the installation of offshore pipelines, a key consideration is the availability of suitable lay barges and early determination of this would be a key project driver. Lay barge costs typically involve a day rate for the vessel, mobilisation / demobilisation costs, and costs associated with surveying the route. A carbon steel pipe can typically be installed in a range of 2 – 5 km/day (up to 36" diameter). However, for the longer pipeline distances used in this study, this introduces another degree of variance and should be considered in more detail.

9.2.1 Bi-Directional Flow

In order to make the pipeline bi-directional and allow hydrogen to be exported from mainland Europe to the UK, additional compression systems will be required at the European end of the pipeline. The CAPEX and OPEX increase with the inclusion of these systems is relatively minor from a levelised cost perspective e.g. at 2,000 km and 1,500 ktpa, the increase in LCOH rises from 15.8 to 15.9 £million/TWh.

9.3 Shipping Hydrogen Carriers

The choice of specific hydrogen carrier for shipping is a complex one and involves considering the future trends of both production technologies and shipping capacity / capability.

For the purposes of this study, a comparison between shipping of Liquid Hydrogen, Ammonia and Methyl Cyclo-Hexane has been carried out. Methanol and other hydrogen carriers which require an additional CO_2 source have not been considered due to the further complexity in introducing another market which is not yet developed. Compressed hydrogen shipping has also been excluded from the cost modelling exercise.

The same excel-based model has been used to develop the levelised costs of the different shipping options at the flowrates and distances described in Section 9.1.

A key consideration with the levelised cost model for shipping is that the hydrogen delivered to the mainland Europe destination is fixed at the flowrates described in Table 22. If additional hydrogen is required at the downstream side of the process (e.g. for conversion of carrier back to hydrogen) then the additional volume is fed into the front end of the model.

9.3.1 Liquid Hydrogen

The Liquid Hydrogen (LH2) transportation model used in this model is shown diagrammatically in Figure 47.

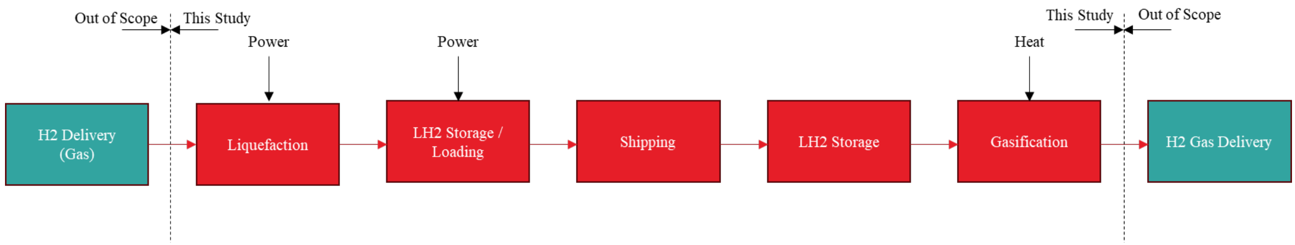


Figure 47: LH2 transportation model

The LH2 transportation levelised costs are developed using the following assumptions:

- Construction period of 3 years from Final Investment Decision (FID)
- OPEX is fixed at a rate of CAPEX.
- The onshore storage component is 1.5x the capacity of ship.
- Major maintenance overhaul of the liquefier is assumed for every 30 years (i.e. not included during this project lifetime), however major overhaul of the storage facility is included.
- Port side manifold upgrades are included.

The levelised cost outputs for the LH2 shipping transportation model is dominated by:

- The shipping capacity of existing LH2 vessels which is three orders of magnitude less than the other carriers considered in this study (described in Section 7.1.2). For this cost model, a sensitivity was carried out using the capacity of the proposed Kawasaki LH2 carrier with dimensions equivalent to a Q-Max LNG carrier vessel.
- The significant energy requirements to liquefy gaseous hydrogen and produce a LH2 product that is suitable for long distance transport and maintaining it in a cryogenic state.

A key advantage of the LH2 transportation model is the comparatively simple regassification process which is the least capital intensive of the shipping options and lowest energy requirements in the final step prior to export from the model. This could be advantageous when considering the import locations used in this study which may not be able to support the infrastructure requirements of the other shipping options.

9.3.2 Ammonia

The ammonia transportation model used in this model is shown diagrammatically in Figure 48.

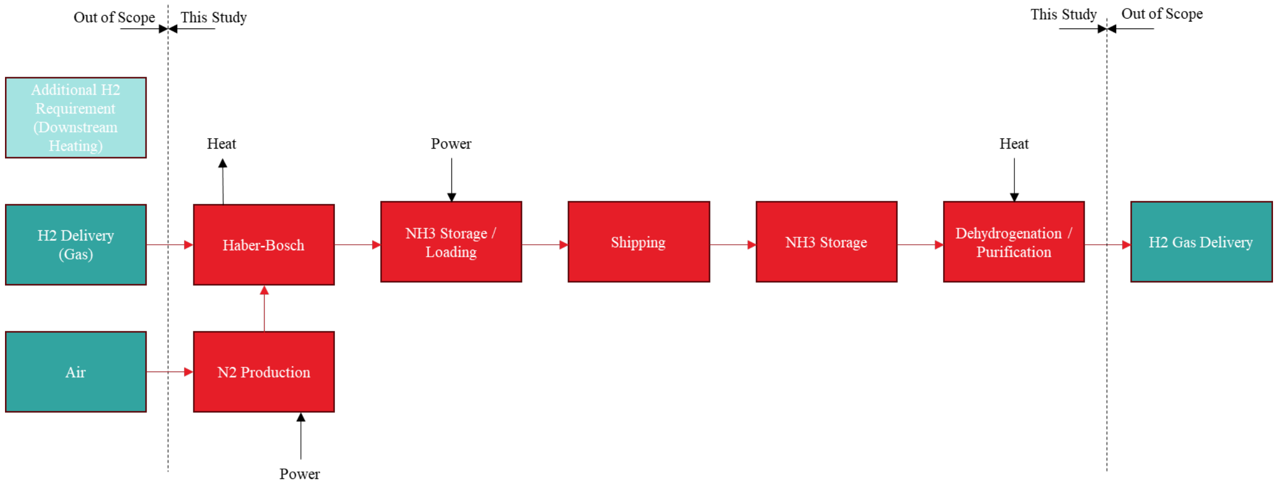


Figure 48: Ammonia transportation model

The Ammonia transportation levelised costs are developed using the following assumptions:

- Construction period of 3 years from Final Investment Decision (FID).
- OPEX is fixed at a rate of CAPEX.
- The onshore storage component is 1.5x the capacity of ship.
- An allowance has been made for the storage power requirements which is average power demand as storage is built / drawn down.
- The ammonia plant is sized based on the air separation unit energy consumption and the synthesis energy consumption requirements.
- Boil off rates are included in the storage facility and losses throughout the shipping cycle.
- Port side manifold upgrades are not included as existing capability at ports for ammonia handling is assumed.
- For ammonia cracking, a heating duty as a percentage of the feed is assumed for releasing hydrogen as a product.

The ammonia transportation model requires a significant amount of energy at the front end of the process to generate the required Nitrogen feedstock. The Haber-Bosch process generates excess heat net of cross exchange (i.e. exothermic reaction). However, this hasn't been explored further here to determine if there are suitable upstream processes that could utilise this and achieve a cost benefit.

The dehydrogenation step requires temperatures >500°C which will not necessarily be readily available at every location as waste heat from nearby processes and electrical-induced heaters could not provide the required temperatures.

The ammonia cracking duty for the flowrates considered in this study range from 2 to 31 GWh/y. The requirements for high temperature and significant heat duty mean that fired heat is the most appropriate solution. Two main options exist for this study which will either be using natural gas fired heat with additional carbon capture and storage (CCS) on the flue gas stream or using a hydrogen-based mixture in a Fired Heater.

The use of CCS is a further unknown in this study and therefore a Base Case of hydrogen-fired heat is used. A key assumption of additional ammonia being shipped and utilised to generate the feedstock for the fired heaters in the downstream infrastructure is used such that additional hydrogen can be used as the heating medium.

9.3.3 Methyl Cyclo-Hexane

The Methyl Cyclo-Hexane (MCH) transportation model used in this cost model is shown diagrammatically in Figure 49.

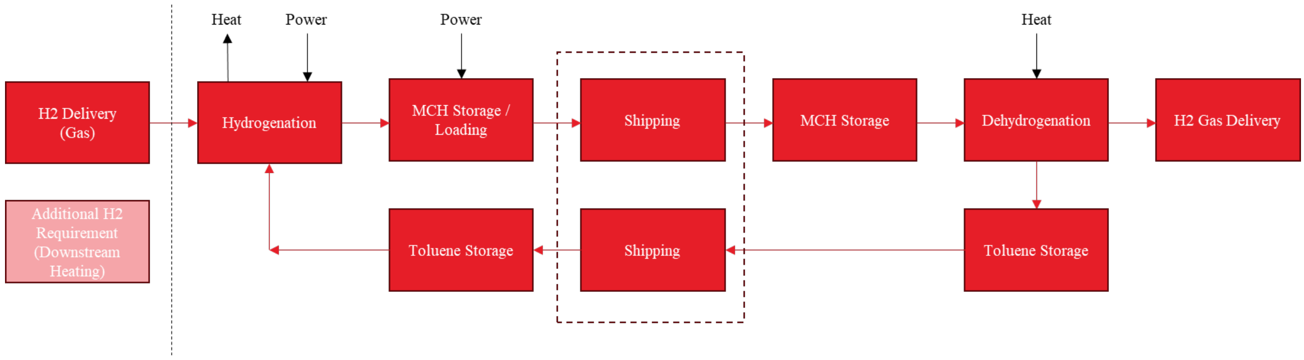


Figure 49: MCH transportation model

The MCH transportation levelised costs are developed using the following assumptions:

- Construction period of 3 years from Final Investment Decision (FID).
- OPEX is fixed at a rate of CAPEX.
- The onshore storage component is 1.5x the capacity of ship.
- The MCH hydrogenation plant is sized based on the synthesis energy consumption.
- Boil off is not included for the MCH cycle.
- Port side manifold upgrades are not included as existing capability at ports for ammonia handling is assumed.
- For the dehydrogenation plant, an iterative heating calculation is used assuming hydrogen is burned in Fired Heater at 90% efficiency to provide the required heating load.

A key parameter in the MCH value chain is heat integration. In the hydrogenation the process generates excess heat net of cross exchange (exothermic reaction). A potential use case for this heat would be upstream or nearby processes however, this hasn't been explored further in this study.

The dehydrogenation process requires a significant amount of heat at temperatures >200°C which can either be provided from waste heat sources nearby, electrical heat or via transporting additional hydrogen to use as the fuel source of a fired heater.

The lower energy density of the MCH carrier solution means that additional ships are required to transport the equivalent amount of hydrogen (when compared to ammonia) therefore, the shipping cost is larger for MCH.

Another unique point of this transportation model are the inventory costs as toluene is needed as a source material to be transported in addition to the product.

9.3.4 Shipping Conclusions

The difference between the three shipping options can be categorised into differences in: conversion, shipping, re-conversion.

For conversion, the LH2 option has the largest energy requirements and thus the largest CAPEX and OPEX in this step and significantly larger than the other two carriers. Ammonia and MCH have costs in a similar scale, but ammonia is more expensive than MCH.

The number of ships required to deliver the same amount of hydrogen at the export of the model is a key consideration, particularly at the larger flowrates used in this study. This number is related to energy density, size of existing carrier ship and the additional hydrogen to be transported for heating purposes.

This is illustrated in the following example: At 1,000 km distance and 1,500 ktpa (largest flowrate for this study), the number of ships required varies as follows (lower and upper bound):

- Ammonia: 1 to 2 ships
- MCH: 2 to 4 ships
- LH2: 1 to 53 ships

The re-conversion step of the hydrogen carrier into the gaseous hydrogen product varies significantly between the options. Regasification in the LH2 option is significantly less expensive than the energy requirements for dehydrogenation of ammonia or MCH which both require high temperature heat for their respective reactions. The significant uncertainty in the required quantity of LH2 carriers demonstrates the uncertainty in LH2 carrier development, projections indicate vessel capacities could be similar to LNG carriers of today in 2050 but so far only very small carriers have been demonstrated with carrying levels of success, therefore, a broad range of LH2 carrier capacities was considered in this study to cover the uncertainty range.

9.4 Pipeline and Shipping Comparison

Shipping options have considerable costs attributed to the conversion of hydrogen to its corresponding carrier (ammonia, MCH or LH2), storage and import regassification / dehydrogenation steps. However, these are consistent (when comparing a target hydrogen production rate) regardless of distance, with only the frequency of the ships (and therefore day rates and fuel costs) changing.

A comparison of the different levelised cost of transport for pipeline and shipping options is shown in Figure 50 and Figure 51 with varying flowrates but a fixed distance to travel (500 and 5,000 km). As shown, pipelines transporting gaseous hydrogen demonstrate the biggest decrease in levelised cost with increased flowrate however with very long distances, the amount of volume to be transported would need to be significant.

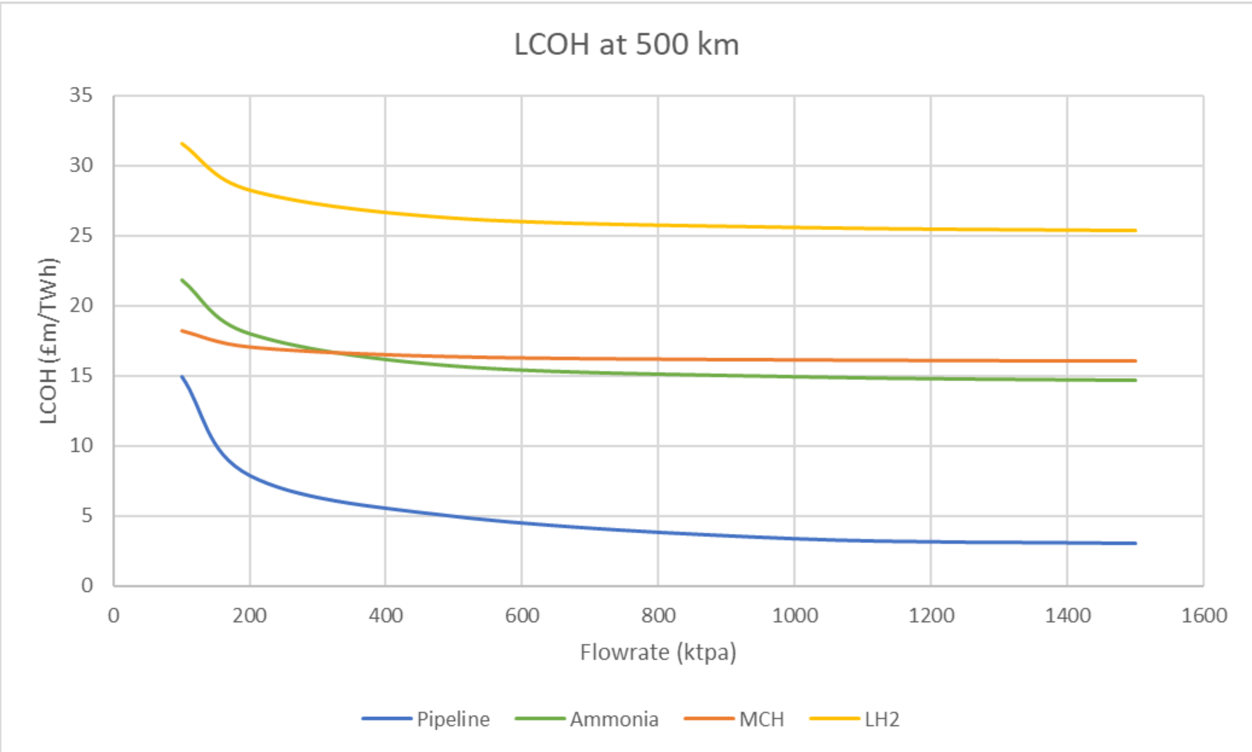


Figure 50: Levelised Cost at a Fixed Distance at 500 km

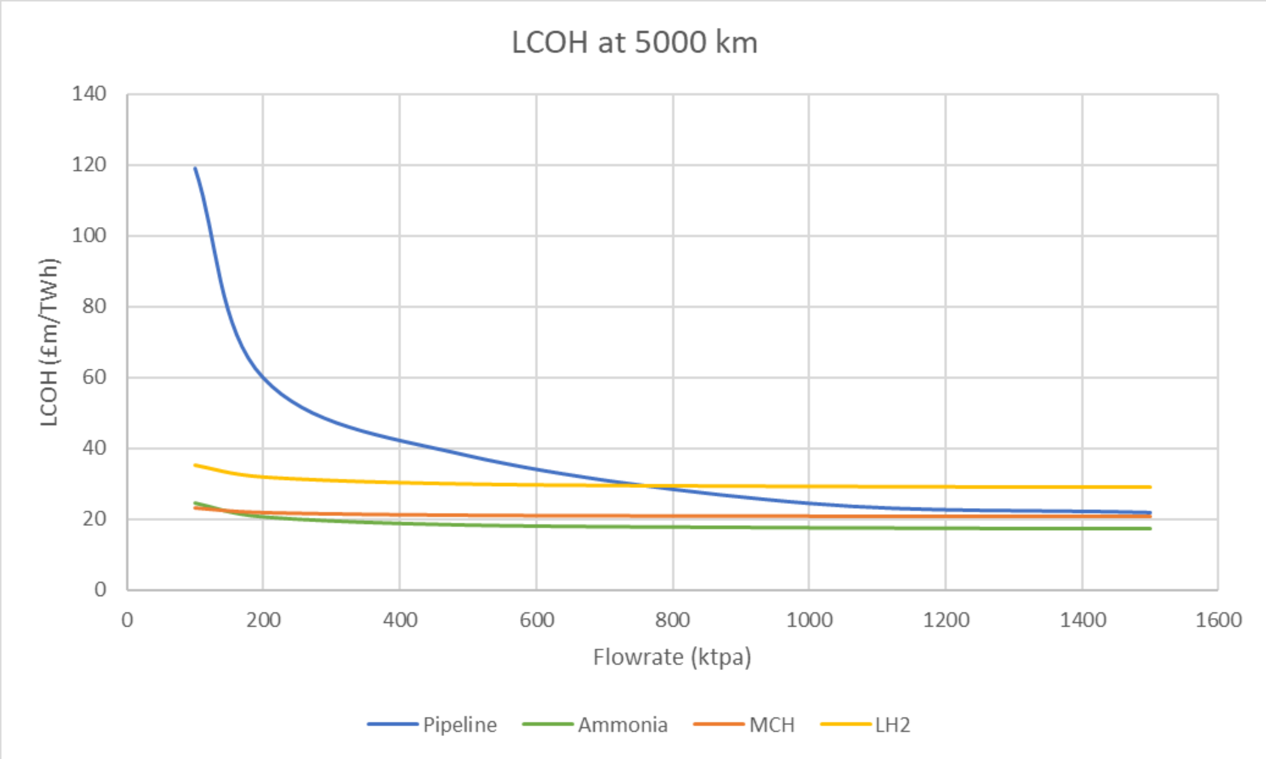


Figure 51: Levelised Cost at a Fixed Distance of 5,000 km

Pipelines provide a more cost competitive solution at the smallest throughput (100 ktpa) up to a distance of ~400 km (Figure 52) and are significantly more cost effective for distances less than 2,000 km at the largest throughput flowrates of 1,500 ktpa (Figure 53).

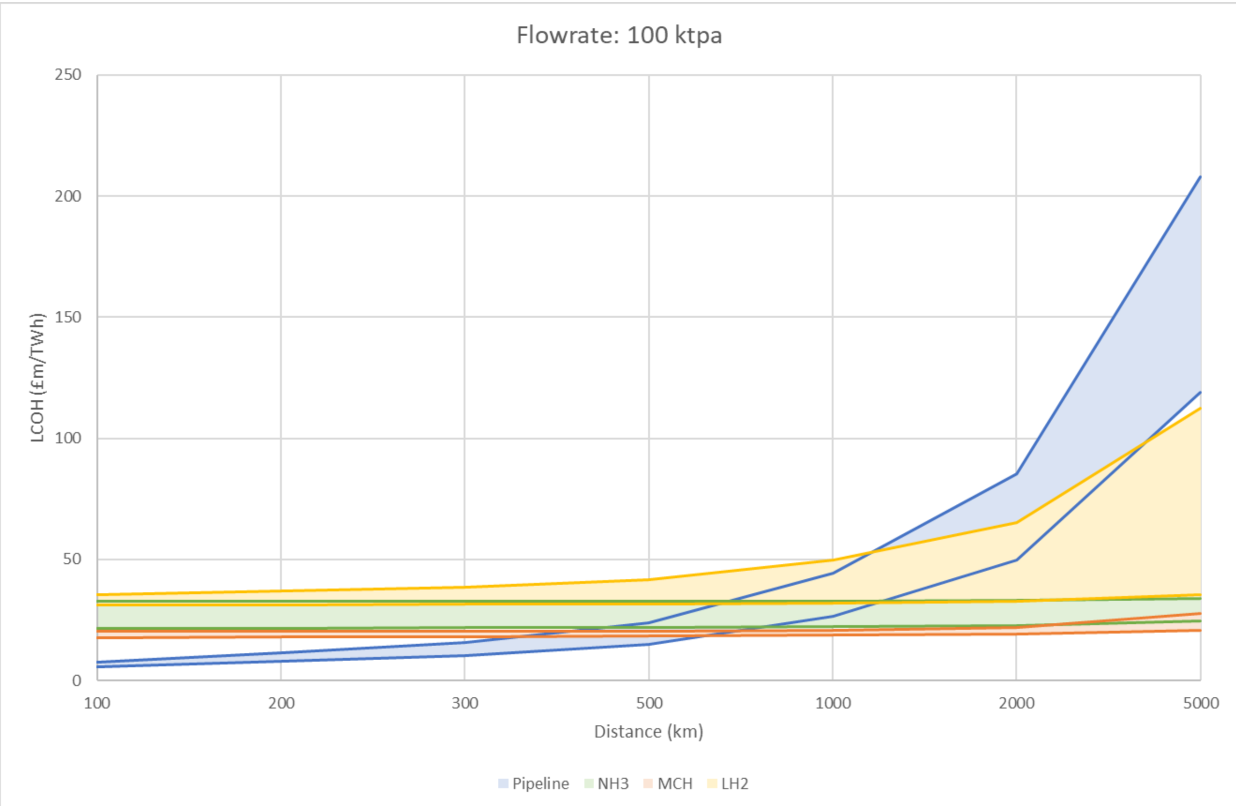


Figure 52: Levelised Cost of Transport at a fixed flowrate of 100 ktpa

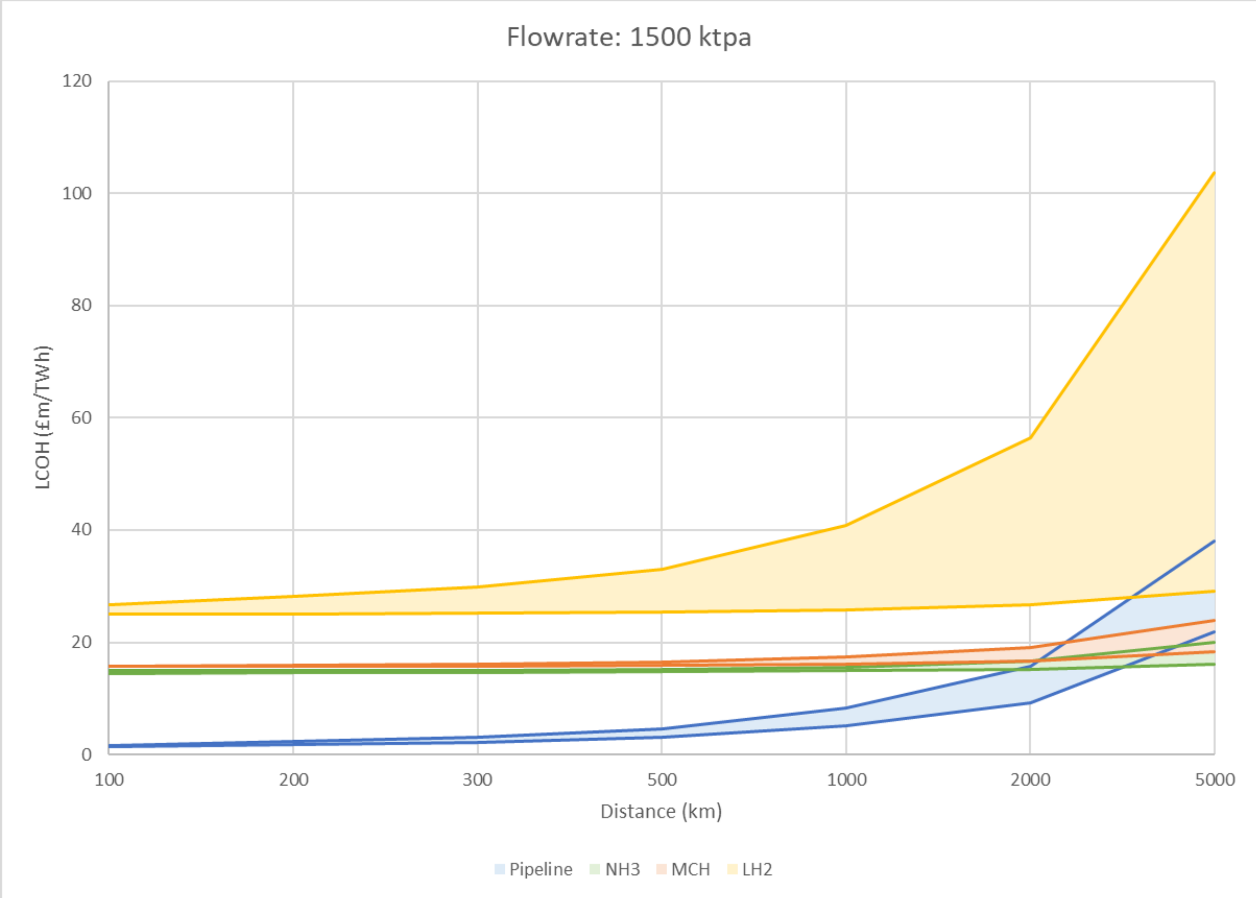


Figure 53: Levelised Cost of Transport at a fixed flowrate of 1,500 ktpa

Table 23: Comparison of different transportation options

Transportation Method	Advantages	Disadvantages
Pipeline	Transportation of large volumes is well understood and proven at scale No conversion of hydrogen into another form is required Lowest levelised transportation cost at the distances and flowrates assumed in this study	Material selection for pipelines is a key issue and impacts the compression requirements which need to be further understood for this range of options The availability of offshore lay barge vessels in the North Sea may be a longer term risk to development
Ammonia	Currently produced worldwide at scale and traded as a commodity in its original form High energy density and hydrogen content	Significant energy consumption required in production of ammonia and cracking facilities Ammonia is a toxic substance and requires more careful handling Ammonia cracking is less provided at significant scale

Transportation Method	Advantages	Disadvantages
MCH	Can be treated as a bulk chemical and handled and stored relatively easily (compared to other cryogenic carriers) Existing shipping capability at scale	Significant energy consumption for hydrogenation and dehydrogenation steps Low hydrogen content of the transported fluid resulting in increased volumetric shipping requirement Significant heating duty of dehydrogenation step requires most additional hydrogen to be transported and used in Fired Heater Storage and transportation of two chemicals is required Scale up from currently installed facilities would be required
LH2	Benefits are most visible in the import / downstream facilities as regasification facility is comparatively simple and lowest energy requirement	Significant energy consumption in liquefaction step Smallest shipping vessels available currently on the market with scale up for shipping providers unproven Largest energy losses in transportation life cycle due to lowest operating temperature

10. Selected Costs

To demonstrate the decision to select a pipeline option, the minimum and maximum distances from each of the selected UK export locations to each of the potential European destinations has been plotted onto the levelised cost of hydrogen transport figure for a fixed flowrate of 500 ktpa (equivalent to ~2.2 GW (HHV)).

As can be seen in Figure 54, distance from export location makes the most significant difference in levelised cost and pipelines are the preferred transportation mechanism.

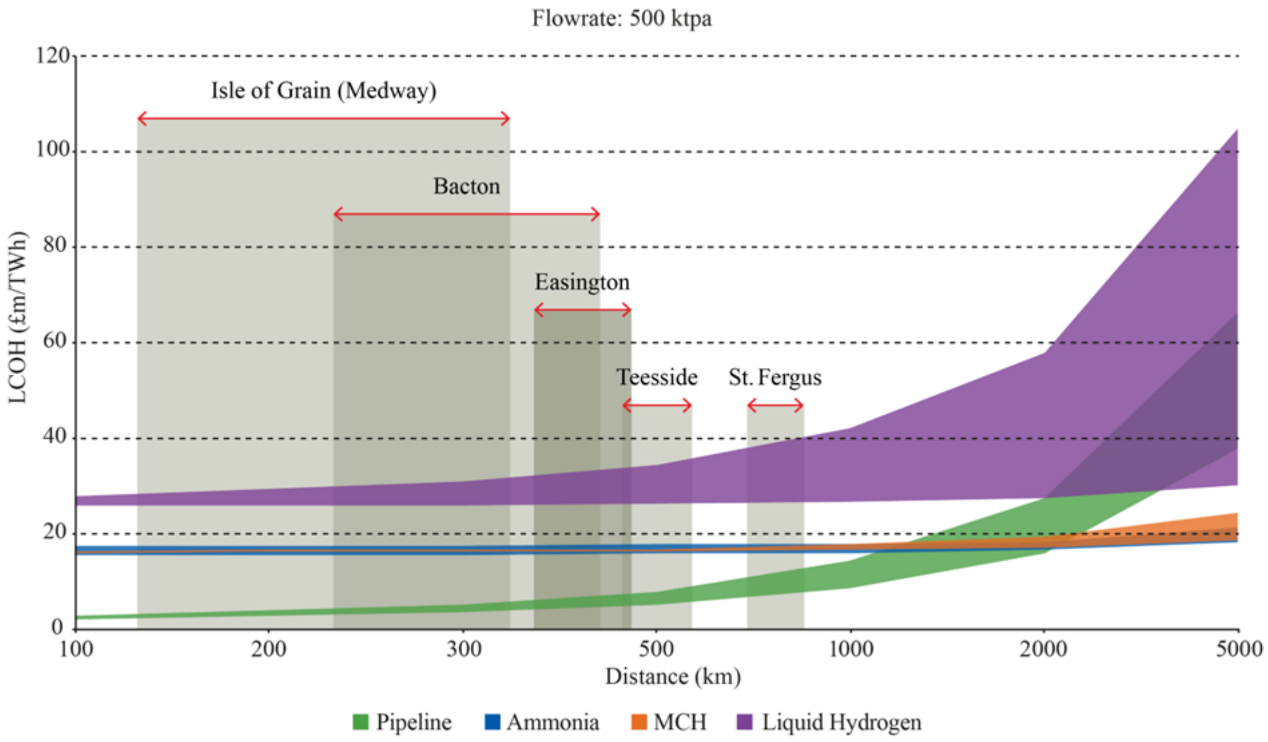


Figure 54: Levelised Cost representation with distances from export locations shown

11. Production Costs (Outside of Project Scope)

IRENA report that optimistic LCOH estimates for UK production in 2050 are in the region \$1-1.25/kgH_2, with pessimistic estimates between \$1.25-1.5/kgH_2. Compared to the cheapest production areas in their report (China, Chile, North African nations, Saudia Arabia etc) have optimistic estimate of around \$0.75/kgH_2. However, the pessimistic estimates are significantly more impactful on this cost than seen for the UK, rising to approx. \$1.75/kgH_2 for Saudi Arabia, \$1.50/kgH_2 in the USA. Chile, Australia, China, Morocco, Colombia, and Australia have the lowest optimistic and pessimistic production cost estimates (International Renewable Energy Agency, 2022).

Compared to other European countries, the UK's production cost is favourable, with its optimistic and pessimistic cost projections coming in lower than in Germany. The optimistic case is comparable with France however the pessimistic production cost estimate for French hydrogen is greater than that of the UK's. Spanish hydrogen production is likely to be lower than UK production in an optimistic case, but again a pessimistic estimate is greater than that of the UK. This implies that UK hydrogen production costs in the UK are more certain over the long term compared to other European production which may be a competitive advantage when financing projects.

The optimistic cost estimates presented also represent LCOH in 2050, therefore, in 2030 production costs will likely be more than the pessimistic estimate for 2050 across all regions. From these estimates, it appears that the UK will be a more expensive place to produce hydrogen compared to the optimum renewable resource locations but could be competitive on price as the market develops if transportation costs are lower to export hydrogen from new projects with access to low-cost power for production. The UK is also more advanced in terms of hydrogen production development than many of the countries mentioned and a closer partner to the EU, both politically and physically. Therefore, there is a strong case to investigate the potential for hydrogen export to Europe.

This is in agreement with various other studies which have considered pipelined imports of "North Sea hydrogen" to Europe against imports from further afield requiring shipping. Reports from DNV and the Net Zero Technology Centre have both independently found that imports of hydrogen from countries with access to North Sea wind resource in northwest Europe is likely to be competitive in the long term with imports from other countries where the cost of production is lower, but the cost of transportation is higher. This conclusion considers that hydrogen is required in its molecular form, and not in a derivative format such as ammonia, at the end user. If ammonia is the required product, then the economics or production have more of an influence and may result in North Sea ammonia being more expensive on a delivered basis than imported ammonia from other regions.

12. Recommendations and Future Work

The key recommendations from this study are described below:

- DESNZ should further consider the options for an optimal hydrogen export route via pipeline from the UK to continental Europe, considering the UK's national hydrogen production, demand, and transportation and storage strategy.
- DESNZ should engage with counterparts in Germany, the Netherlands and Belgium to progress the development of potential export corridors. Engagement with other European countries should also be considered, but priority should be given to Germany, the Netherlands and Belgium considering their proximity to the UK, existing gas trade and the ramp up of hydrogen demand and infrastructure development in these countries.
- Development of a low carbon hydrogen certification scheme accepted under the European RED and common specification for hydrogen quality should be developed as a matter of priority with input from industry.
- DESNZ should start considering a pipeline for the export of hydrogen to continental Europe in its strategic planning for UK hydrogen infrastructure to enable further development of estimated tariff rates and to support a potential business case for an export pipeline. Strategies for identifying hydrogen production to be exported should be developed in conjunction with the existing hydrogen production, transportation, and storage strategies, domestic industrial decarbonisation targets, carbon budgets, and economic targets to support the development of tariff estimates for an export route, providing a basis for a business case and potentially improve the bankability of the project.
- Consider stronger messaging on UK support for hydrogen exports to encourage potential production projects to begin development.
- Develop an investment risk reduction program to begin to progress potential export systems towards bankability.
- Shipping is a less competitive option for the export of UK hydrogen to the most developed European hydrogen demand centres (north west Europe) compared to pipeline export and should therefore be considered a secondary option for the export of hydrogen to Europe.
- Where shipping to Europe is concerned, Southern Europe may have high import demand and shipping is the only economically viable option for export, therefore the development of the import market in countries such as Italy and Greece should be monitored. Since the LCOT for shipping of ammonia and LOHCs remains almost constant regardless of the distance transported, the import demand in other regions should also be monitored.
- It is recommended that shipping is considered as a project specific route to market, rather than a strategic UK export route for large volumes of hydrogen.

The following further work activities are recommended to be reviewed as part of the next phase of this project:

- External engagement with counterparts in Belgium, the Netherlands and Germany to collaborate on a potential hydrogen export / import infrastructure project.
- Further development of the technical solution for export to minimise the LCOT of a potential pipeline system and narrow down potential export corridor options, considering:
  - Further design of the compression systems required for pipeline export, considering synergies with existing infrastructure, to minimise the LCOT of a pipeline export option. Consider whether any existing platforms can be utilised. Further design of the offshore compression facilities in terms of water depth and location in national waters. Further design of the offshore compression facilities in terms of water depth and location in national waters.

  - Further work to determine the most appropriate pipeline diameter with respect to the existing flowrate considerations but also future throughput aspirations. The cost of the pipeline does not scale linearly with pipeline diameter therefore, it is usually more appropriate to oversize a pipeline (subject to meeting minimum velocity and pressure drop considerations).
  - Further work considering the technological advancements of each derivative production technology (i.e. advancements in green ammonia, hydrogen liquefaction, or LOHC conversion processes) option. There is potentially some cost reduction either through competitiveness in the market or economies of scale which are not shown in this study.
  - Further development of route corridors to minimise the length of pipeline connections considering the technical, environmental, and regulatory constraints present.
  - Evaluation of the technical requirements for connecting into a wider offshore international North Sea hydrogen pipeline network.
  - Further consideration of production and transport and storage infrastructure in the UK and its phasing to narrow down potential export location locations based on different hydrogen infrastructure development scenarios in the UK.
- Development of an economic case for a potential pipeline export system, considering the cost of investment, potential tariffs to deliver certain rates of return based on the technical design constraints of the pipeline.
- A study considering the effect of exporting low carbon hydrogen on the UK Carbon Budget is also recommended to evaluate the potential decarbonisation benefits of hydrogen export.
- More information should be sought to consider ammonia as a landed product itself and the relative benefits / drawbacks of creating a green-ammonia transportation cycle.

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Appendix A

European Position on Hydrogen Analysis

A.1 Hydrogen Ambitions and Policy in the EU

There has been significant progress in Europe in the development of their hydrogen strategies, and the EU have developed a comprehensive framework to support the uptake of renewable and low-carbon hydrogen. The European Commission have set a target for the EU to produce 10 million tonnes of hydrogen and import 10 million tonnes of hydrogen by 2030. The EU strategy on hydrogen was adopted in 2020 and suggested key policy action points for the development of the EU hydrogen economy. Following this, the Fit-for-55 package (2021) put forward legislative proposals converting strategy to policy. The REPowerEU (2022) plan builds on the implementation of the Fit-for-55 package to accelerate the clean energy transition with a combination of short, mid-term and long-term targets (including the EU hydrogen production and import target). measures have been set covering the following three pillars: (i) demand reduction, (ii) diversification of suppliers for conventional (fossil) fuel imports whilst future–proofing the corresponding infrastructure, and (iii) acceleration of the transition to renewable energy sources. In addition, the following targets have been established to develop the hydrogen infrastructure:

- Align the sub-targets for renewable fuels of non-biological origin (RFNBOs) under the RED for industry and transport with the REPowerEU ambition (75% for industry and 5% for transport);
- Double the number of hydrogen valleys through Hydrogen Joint Undertaking.
- Proposal of two Delegated Acts on (i) the definition of renewable hydrogen production; and (ii) defining a methodology for calculating greenhouse gas emissions of different production methods.
- Mapping hydrogen infrastructure needs by March 2023 (status not confirmed);
- Scale-up of electrolyser manufacturing, as per the 'Electrolyser Declaration'. The declaration which was signed between the commissioner for internal markets and 20 industry CEO's is a commitment from industry to a tenfold increase of its electrolyser manufacturing capacities by 2025.

The table below highlights the various funding mechanisms that are available in the EU.

Country	Scheme Name	Funding Available	Scheme type	Eligibility
EU / Germany	H2Global	€4 billion	Hydrogen purchase and sale agreements through central body	Imports of ammonia, methanol and electricity based SAF
EU	Important Projects of Common European Interest (IPCEI)	~€26.7bn state aid approved funding (2018 – 2023), €10.6bn for hydrogen	Grants (focusing on CAPEX)	Prove innovative nature and European relevance
EU	Innovation Fund	€38bn current, with €3bn for 3rd round in 2023	Grants	Beneficiaries include players across the whole H_2 value chain
EU	InvestEU	€26.2bn to mobilise €372bn, share for H_2	Grants and loans	Clean hydrogen infrastructure investments, 2021-2027
EU	EIB Hydrogen Bank	€3bn for closing gap between fossil and green H_2 and early production support	Auctions for EU production (€800m in 2023) and fixed premiums for imports	Renewable (RFNBO) hydrogen producers

Country	Scheme Name	Funding Available	Scheme type	Eligibility
EU	Just Transition Fund and Recovery & Resilience Facility	>€25bn for hydrogen, via IPCEI of other state funded programmes	Government support funds from the EU under specific programmes	Member states to support own resilient, green economies. Specific focus is, inter alia, on renewable hydrogen

Public funding mechanisms in Europe

Source: EU, Public sources of information

A.2 Country Analysis

A.2.1 Denmark

Policy	Progress
Strategy and policy	Denmark has a national plan Power-to-X (PtX), also known as green hydrogen, plan for domestic hydrogen production. The Danish government is targeting 4-6 GW of electrolyser capacity by 2030. For example, the majority of European Sustainable aviation fuel (SAF) production pathways are located either in Germany or Denmark.
	General applications for green hydrogen have been stated with key focus areas being the direct use for local transportation and green fuel in the form of ammonia for large energy consumption.
Funding	In March 2022, Denmark has announced a €161 million investment package towards the development of Power-to-X and hydrogen value chain projects to accompany their hydrogen strategy. The subsidy is granted over 10 years paid per produced amount of green hydrogen. The Tender was open from April 2023 to September 2023; the six allocated projects are discussed in the progress to policy section. An additional €7.5 million in 2022-2026 has been earmarked for a hydrogen task force responsible for providing guidance to project developers and authorities. The Danish government has also funded Danish value chain projects for hydrogen (IPCEI) with €115 million, allocated roughly €54 million to the development of Power-to-X via the EUDP and Danish Energy Agency's energy storage funding pool.
Progress to policy	Based on a snapshot of installed capacity of announced projects as of 2030, Denmark has a capacity target completion rate of 73%[1] in achieving their 6 GW capacity target for 2030. There are several projects underway in Denmark that are progressing their hydrogen ambitions. Esbjerg has been highlighted as a hydrogen location as part of the European Hydrogen Backbone. As of January 2024, 1 GW green hydrogen production facility to be based in Esbjerg, has received environmental approval, bringing it one step closer to FID. The project is expected to be operational in 2028. Some other key projects/ developments have been highlighted below: • 6 projects with a total capacity of 280 MW have been awarded funding as part of the Danish government investment package for hydrogen. The largest of the six is the European Energy/Padborg PtX ApS project (150 MW), and the Plug Power Idomlund Denmark project (100 MW). • Green Fuels for Denmark, led by energy developer Ørsted in partnership with Maersk and DFDS, aims to accelerate the production of sustainable fuels. The

[1] Deloitte, The European Hydrogen Economy- taking stock and looking ahead, 2022

	Project has brought forward 100 MW from the second phase to produce sustainable fuel (mainly e-methanol) for the shipping industry by 2025. • Denmark and Germany have agreed to build a hydrogen pipeline between the two countries which is expected to be operational in 2028, enabling Denmark to export its excess hydrogen production to countries like Belgium, Germany and the Netherlands.

A.2.2 France

Policy	Progress
Strategy and policy	France set out their national strategy in 2020 with the objective to build 6.5GW of low carbon electrolytic hydrogen by 2030, rising to 10 GW in 2035. Key priorities for the national strategy are: decarbonising industry, developing the use of decarbonised hydrogen for heavy-duty mobility and supporting research, innovation, and skills development to promote the uses of tomorrow.
	As part of the strategy, France acknowledges the need for alternative sources of hydrogen; this includes substantial amounts of ammonia, methanol, and Sustainable Aviation Fuel (SAF) to meet the requirements of the FuelEU Maritime and ReFuelEU Aviation regulations. France has not explicitly stated any ambitions for the import of hydrogen.
Funding	France's strategy is backed by public funding worth €9 billion. The first 10 projects have been launched in France and approved by the European Commission involving public and private investment of €2.1 billion and €3.2 billion respectively. These 10 projects are part of the first phase of the IPCEI projects which have been selected, and will enable the construction of gigafactories for electrolysers, fuel cells, and hydrogen tanks in France. As part of the €9 billion fund, the government will spend €4 billion on subsidies (in the form of contracts for difference style auction) to support the deployment of 1 GW of electrolyser hydrogen production over the next 3 years. The first tender would be for 150 MW (with the possibility of extending this to 180 MW), with a second 250 MW tender in 2025 and a final 600 MW tender in 2026.
Progress to policy	Hydrogen demand is anticipated to develop within seven major hydrogen clusters including the main ports, the valleys as well as the transborder areas with Spain and with Germany. These are namely, The north, The Seine Valley, Greater West, Moselle Rhin, Rhone-Alps, The Southwest and The Mediterranean. There are 55 hydrogen projects that have been announced in France[2]. Although the number of projects is expected to increase in coming years, especially in France's 7 geographical clusters named above. Based on a snapshot of installed capacity of announced projects as of 2030, France has a capacity target completion rate of 16%[3] in achieving their 6.5 GW capacity target for 2030. • France has made significant progress in deploying hydrogen technologies. Several projects have been initiated, such as the ZEV project in Auvergne-Rhône-Alpes and the H2 Corridor in Occitanie. • Air Liquide Normand 'Hy Hydrogen electrolysis Project is Frances largest hydrogen project to date and is set to be operational in 2026. The project aims to build an electrolyser capacity of at least 200 MW.

[2] BloombergNEF Clean Hydrogen Database, September 2023

[3] Deloitte, The European Hydrogen Economy- taking stock and looking ahead, 2022

A.2.3 Netherlands

Policy	Progress
Strategy and policy	The Dutch government set out its hydrogen ambitions in the Dutch Climate Agreement in (2019), followed by the National Hydrogen Strategy (2020). They have stated in their strategy that their primary areas of focus will be: (1) developing hydrogen infrastructure, (2) unlocking supply channels, (3) cross-sector cooperation and (4) facilitating green hydrogen projects, and have set a target of 4 GW of electrolyser capacity by 2030. This will increase to 8 GW by 2032. Blue hydrogen and blending have not been stated as part of their ambitions and they will consider the full hydrogen value chain, including storage, trade, and infrastructure.
	The National Strategy to 2030 is split into three major phases and is based on 4 areas (legislation and regulation, cost reduction, sustainability of final consumption, and supporting and flanking policy). The phases are as follows: • **2019-2021**: Roll out programme for current green hydrogen projects. • **2022-2025**: Develop the demand for green hydrogen and regional infrastructure. Scaling up installed electrolyser capacity to 500 MW by 2025 • **2026-2030**: Massive scaling up of electrolyser capacity to 4 GW by 2030, and expansion of storage and infrastructure. • **After 2030:** renewable offshore hydrogen and large-scale import network, hydrogen use in steel and chemicals industries, refineries, electricity generation and transport. In addition, they have displayed an optimistic outlook on hydrogen imports through their strategy. The Netherlands have set ambitions for the import of hydrogen and have allocated €300 million to facilitate the import of renewable hydrogen.
Funding	The government will allocate a total of around €7.5bn for the development of renewable hydrogen in the country, of which the bulk of the funding is dedicated to supporting hydrogen production capacity for domestic production. A proportion of funding has been granted via the H2Global programme, that secures 10-year contracts for the purchase of hydrogen internationally, for resale in the domestic market.
Progress to policy	As a result of its geographical location at the North Sea, offshore wind potential and existing oil and gas infrastructure, The Netherlands is a European energy location. Internationally the Netherlands aims to position itself as the low-carbon hydrogen location of Northwest Europe, connecting international exporters and Dutch domestic production at the North Sea with industrial demand centres in Northwest Europe. Hydrogen demand locations have been identified in Den Helder- Amsterdam, Eemshaven- Groningen) and Rotterdam- Zuid Holland. Alongside Belgium, The Netherlands is forecast to collectively provide 62% of the EU import target. There have been 60 projects announced and or planned in the Netherlands since 2017[4]. Based on a snapshot of installed capacity of announced projects as of 2030, the Netherlands has a capacity target completion rate of 229%[5] and are on track to significantly overachieve their 4 GW capacity target for 2030. They have a strong pipeline of projects. Some key projects and are highlighted below:

[4] BloombergNEF Clean Hydrogen Database, September 2023

[5] Deloitte, The European Hydrogen Economy- taking stock and looking ahead, 2022

	• Gasunie building a €1.5 billion Hydrogen network connected to Germany and Belgium. Construction of the network has already begun, and the first part of the national network to be available in 2025. • Imports from Portugal (Sines) through the H2Sines.RDAM project to be operational in 2028 and has recently been greenlit for EU financial support. Hydrogen will be produced in Sines and transported, in liquid form, to the Netherlands. • The NorthH2 project developed by RWE, Shell and Equinor aims to supply industry with 2 to 4 GW of green hydrogen by 2030 and 10 GW by 2040. The pipeline is proposed to run from Eemshaven on the north shore of the Netherlands supplying industrial customers in Netherlands / North-West Europe. There are numerous hydrogen projects underway in Den Helder, Eemshaven and Rotterdam. **Den Helder:** (1) H2Gateway blue hydrogen production facility, min 0.2 Mt/a capacity to supply industrial clusters via H2Backbone (construction starts in 2027). (2) Zephyros maritime hydrogen location including solar park, electrolyser, public refuelling installation, hydrogen-electric vessels (2028). (3) LH2 Bunker station: bunker station with 200 m³ of liquid hydrogen storage capacity (2028) **Rotterdam:** 11 production facilities underway (at varying stages of development), including Uniper (100 MW by 2025), Shell (200 MW capacity, electrolysers on order). Several large-scale wind farms on North Sea (7.4 GW) expected to be connected to the port by 2030. **Eemshaven:** Eemshydrogen project (RWE) with 50 MW electrolysis capacity and potential for upscaling (FID expected in 2023).

A.2.4 Spain

Policy		**Progress**	
Strategy and policy	Spain published their National Hydrogen Roadmap: A commitment to renewable hydrogen in 2020. The roadmap set targets across the value chain: production, storage/transport and usage, and defines 60 specific measures which are divided into 4 key areas. These are namely regulatory, sectoral, cross cutting and promotion of R&D. Spain has an initial target of 4 GW of green hydrogen by 2030, they have recently updated their targets, almost tripling their green hydrogen goal to 11GW. Regarding hydrogen imports and exports, both Spain and Portugal want to export hydrogen through the H2Med pipeline project that would connect northern Spain to southern France.		
Funding	Spain is allocating €1.5bn in EU funds to boost renewable hydrogen as part of the national roadmap. Out of the €7 billion announced towards renewables including green hydrogen and energy storage, €1.5 billion has been set out by the State for green hydrogen under its Strategic Project for Economic Recovery and Transformation plan (PERTE).		
Progress to policy	Overall, Spain is making significant progress to achieving their hydrogen targets Based on a snapshot of installed capacity of announced projects as of 2030, Spain has a capacity target completion rate of 79%[6] in achieving their initial 4 GW capacity target for 2030. There have been 126 planned and or announced hydrogen projects in Spain from 2020[7]. Below we have highlighted a few of the key hydrogen projects/ developments:		

[6] Deloitte, The European Hydrogen Economy- taking stock and looking ahead, 2022

[7] BloombergNEF Clean Hydrogen Database, September 2023

	• Power to green H2 Mallorca is part of the Green Hydrogen Route Map approved by the Spanish government. It will serve as a model to be replicated across five other territories across Europe, including another one in Tenerife, Spain. The project became operational in 2021 and produces appx. 300 tonnes of hydrogen a year. • Sun2Hy project based in Puertollano, Spain will develop a new technology that allows for the production of green hydrogen from solar energy through a direct process. The projects planned date of entry into operation is 31 March 2025 and has a hydrogen production capacity of 200 tonnes per year. • The Andalusian green hydrogen valley- involves a €3bn investment for the creation of two new green hydrogen generation plants which will have a combined total electrolyser capacity of 2 GW. The plants are set to come become operational in 2026 and 2027 respectively and produce up to 300,000 tonnes of hydrogen per year. • Hydeal Espana an independent hydrogen project to supply competitively priced green hydrogen. Operations are set to begin in 2028 and total installed electrolyser capacity is anticipated to reach 3.3 GW (. • Project Catalina is being delivered by a consortium of companies including Engas and Copenhagen infrastructure partners, to developing a pioneering green hydrogen and green ammonia project. The projects aim to develop 5 GW of combined wind and solar and produce green hydrogen through a 2GW electrolyser. The project is set to be operational in 2027. Once fully implemented it will produce enough green hydrogen to supply 30% of Spain's current demand. • The Green Hyland project aims to deploy a fully functioning Hydrogen (H2) ecosystem in Mallorca, making it the first H2 location in Southern Europe. The project won the hydrogen valley of the year prize in 2023. It is supported with €10 million in funding by the clean hydrogen partnership. Anticipated end uses include, transport, industry and energy sectors, including gas grid injection for green heat and power local end-use. Once fully operational it will produce at least 300 tonnes of renewable hydrogen per year.

A.2.5 Portugal

Policy	**Progress**
Strategy and policy	Their National Hydrogen Study, published in 2020 set a target of 2.5 GW of installed capacity in electrolysers by 2030. More recently, in July 2023, the Portuguese Government presented a proposal to the European Commission to revise the National Energy and Climate Plan 2030, calling for an increase in the installed capacity of electrolysers in 2030 to 5.5 GW. Focus areas for the deployment of green hydrogen in Portugal include green hydrogen for transport (in particular the heavy road, maritime, rail and even air) and as a replacement of natural gas in the industrial sector. The strategy identifies five key elements of the hydrogen value chains in Portugal in which the strategy has set further ambitions for 2030: • Power to Gas (P2G): Direct injection into natural gas network of which 10% to 15% of the network is to be injected with green hydrogen. • Power to Mobility (P2M): The development of 50 to 100 hydrogen supply filling stations, 1% to 5% of roadway transport being powered by green hydrogen; 3% to 5% of domestic maritime transport consuming energy from green hydrogen;

	• Power to Industry (P2I): replace natural gas with green hydrogen in industries (steel, chemical, refining etc.); • Power to SynFuel (P2S): Replace fossil fuels with green synthetic fuel • Power to Power (P2P): Excess electricity from renewable sources to be converted into hydrogen, stored, and then converted back to electricity via fuel cells. Portugal has stated an ambition to be an exporter of hydrogen utilising excess renewables.
Funding	The national strategy estimates an investment for €7 billion by 2030 in hydrogen production projects. These will be awarded through tenders for 10-year contracts to developers in the production of green hydrogen.
Progress to policy	Based on a snapshot of installed capacity of announced projects as of 2030, Portugal has a capacity target completion rate of 40%[8] in achieving their initial target of 4.5 GW capacity target for 2030. Key projects and developments are highlighted below: • H2Évora: Portugal's first successfully commissioned solar-to-hydrogen project, which has been operating continuously since late 2021 and is now connected to the Portuguese electric grid. • They have begun developing their industrial clusters for hydrogen production with the Hydrogen valley in sines with the GreenH2Atalnatic. The 100 MW project began construction in 2023 and operations are set to begin in 2025. • H2Sines.RDAM- A consortium of companies has agreed to develop a green hydrogen logistic maritime corridor connecting the ports of Sines in Portugal and Rotterdam in the Netherlands. Set to be operational in 2028, green hydrogen will be produced in Sines and liquefied hydrogen will be exported to Rotterdam. • The Madoquapower2X is the first large scale commercial production facility in Europe, located in the Sines Industrial and Logistics Zone, and will supply both industrial and pan- European cutsomers. It is a combination of the Madoqua H2, and the Madoqua NH3 projects. Phase 1 of the Madoqua H2 has a total investment of €800 million and will install a 500 MW electrolyser capacity at Sines. The project is set to produce 70,000 tons of hydrogen per annum. Phase 1 of the Madoqua NH3 project, expects an investment of €500 million, and 500ktpa ammonia production. Once all phases are complete, the project will use 1 GW of electrolyser capacity to produce 150,000 tons of green hydrogen, and 300,000 tons of green ammonia. Full commission for the MadoquaPower2X is expected by 2030.

A.2.6 Sweden

Policy	**Progress**
Strategy and policy	Proposal for a National Fossil Free hydrogen strategy published in November 2021 setting capacity targets for both 2030 (5 GW) and 2045 (15 GW). The Fossil Free Sweden Hydrogen Strategy developed in collaboration with industry and transport sectors, has developed 22 roadmaps for fossil free competitiveness due to be implemented. The strategy has identified a number of measures to promote hydrogen development, including putting in place instruments to reduce the cost gap between fossil-free and fossil hydrogen and to establish a platform for dialogue between government actors, companies and industry organisations. Sweden has no explicit policy on the import of hydrogen. As represented by their project development, key sectors for Sweden are industry, specifically steel and transportation, specifically aviation.

[8] Deloitte, The European Hydrogen Economy- taking stock and looking ahead, 2022

Funding	Total public funding for the deployment and use of hydrogen is valued at €1.5 billion. The mechanisms for how this funding are allocated is not clearly outlined. Private investment has played a major role in the development of the Swedish hydrogen economy. As part of the €1.5 billion in public funding, the Swedish Energy Agency is awarding funding for hydrogen projects that can lead to fossil-free aviation. Two projects have been awarded funding thus far, namely, GKN Aerospace for developing engine subsystems in the national H2JET project, and RISE SICOMP AB to develop ultralight liquid hydrogen fuel tanks for aircrafts.
Progress to policy	According to the Bloomberg NEF clean hydrogen database, Sweden 16 hydrogen production projects, all using electrolysis as a production method, and for use in either industry or transportation, confirming the focus of their policy[9]. Key projects/ developments are listed below: • Swedish steel firm Ovako has inaugurated a 20MW electrolysis system, the largest to start operations in the country yet. • H2 Green Steel is building a production plant for emissions-free steel. By 2026, the plant is to produce 2.5 million tons of hydrogen-powered steel annually, and 5 million tons from 2030. The plant will have an 800MW electrolyser. • With a grant of €143 million from the HYBRIT Demonstration (Vattenfall, SSAB and LKAB), the HYBRIT Green Steel project will see the world's first customer delivery of "green steel". The project is set to produce 1.2 million tonnes of hydrogen-reduced iron annually using approximately 500 MW electrolyser capacity powered by fossil-free electricity with full commercial production of green steel by 2026. In addition, HYBRIT have reached the halfway point in the construction of a rock cavern storage facility in a coastal city in northern Sweden. The 100-cubic-meter facility is being constructed 30 metres below ground and will begin storing green hydrogen next year. • Hydrogen for aviation GKN Aerospace for developing engine subsystems in the national H2JET project, which is investigating hydrogen combustion-powered turboprop and the other, RISE SICOMP AB, which is focused on the development of ultralight liquid hydrogen fuel tanks for aircraft awarded funding form the Swedish Energy Agency

A.2.7 Germany

Policy		Progress	
Strategy and policy	Germany has set a target of 10 GW of green hydrogen by 2030. Germany's priority use for their hydrogen is industry. They plan to replace all current grey hydrogen used in chemical, refineries and fertiliser plants with green hydrogen, and switch their steel production to Direct Reduced Iron (DRI) with hydrogen, in addition to the other popular uses of hydrogen i.e., heavy duty transportation, and heating.		
	The German National Hydrogen Strategy (2020) aims to position Germany as a global frontrunner in green hydrogen and sets measures for the comprehensive use of hydrogen from 2030. In July 2023 the German government coalition presented an update of its national hydrogen strategy in which they aim to further scale up the hydrogen market in the country to achieve climate neutrality by 2045. Hydrogen Demand is expected to reach 95-130 TWh by 2030. Their strategy is heavily reliant on imported fuels with around 50-70% of the hydrogen will need to be imported from abroad through pipelines and shipping, mainly from Norway and Denmark.		

[9] BloombergNEF Clean Hydrogen Database, September 2023

Funding	Government subsidies on the production side are limited to renewable hydrogen but there is support for applications using low-carbon hydrogen including blue hydrogen. €7bn of public funding has been allocated to 62 projects in production, infrastructure and usage. The German government has pledged a total of €4.5 billion to the H2 global initiative. The initiative is focused on fostering the production, distribution and utilisation of green hydrogen as well as fostering green hydrogen purchasing scheme for international partnerships and import infrastructure. Funds for launching a hydrogen network with more than 1,800 km of pipelines in Germany are expected to be operational by 2027/2028 through IPCEI financing scheme with the goal of connecting all major generation, import storage centres to customers by 2030.
Progress to policy	Based on a snapshot of installed capacity of announced projects as of 2030, Germany has a capacity target completion rate of 94% and are on track to significantly overachieve their capacity targets for 2030. Some key projects/ developments are highlighted below: • Germany has signed several hydrogen cooperation agreements with countries such as Canada, Norway, UAE and Australia. • They have allocated €300 million to facilitate the import of renewable hydrogen with demand expected to significantly supersede supply. • Emden: EWE has announced plans to build a 320-MW electrolysis plant in Port of Emden to produce 1 TWh green hydrogen annually. The area is advantaged by a well-developed gas network, port proximity, large storage caverns and vicinity to key TenneT (TSO) power lines. • 50 MW capacity electrolysers at Emden site of Statkraft and Energiepark Emden sites to supply local transport sector from 2024. Part of H2NORD which intends to construct green hydrogen filling stations. • Tree Energy Solutions aims to deploy a purpose-built terminal for the import of LNG and green hydrogen based electric natural gas (e-NG) by 2027; • Lhyfe project is currently in the development phase, scheduled do go operational in 2029 with an electrolysis capacity of 800 MW and a production capacity of up to 330 tons of green hydrogen per day. • Energy Location (aims to become a key location for import of hydrogen derivatives with scale up potential to meet ~50% of Germany's estimated hydrogen demand by 2030);

A.2.8 Poland

Policy		**Progress**	
Strategy and policy	National Hydrogen Strategy introduced in 2021 with a target electrolyser capacity of 2 GW by 2030. The strategy includes 6 main objectives: • Implementation of hydrogen technologies in the energy and heating sectors. • The use of hydrogen as an alternative fuel in transport. • Support for the decarbonisation of industry. • Hydrogen production in new installations. • Efficient and safe transmission, distribution and storage of hydrogen. • Creating a stable regulatory environment. The Strategy sets out the main objectives and over 40 actions for the development of a low carbon hydrogen economy in Poland with an emphasis on the use of hydrogen in the energy, transport and industry sectors. It covers each part of the value chain of the		

	hydrogen economy: production, distribution, conversion, storage and use of hydrogen, as well as necessary changes of law and financing. The basis of Poland's Hydrogen Strategy is the development of the Hydrogen Valley Innovation Ecosystem, where each valley is to be a cluster of as many elements of the hydrogen economy value chain as possible in a specific location. As part of their strategy they want to introduce multiple hydrogen valleys, have 1,000 hydrogen buses in operation, more than 32 hydrogen refuelling stations, and establish a hydrogen technology centre by 2030.
	Poland has a pragmatic approach to imports, and the government have stated an interest in regional energy cooperation, also to improve energy security which could mean the development of cross-border hydrogen pipelines. However they have not developed a specific policy or strategy for hydrogen imports
Funding	Public funding for the deployment and use of hydrogen for Poland is valued at €1 billion. To guarantee the development of the Polish hydrogen economy, the Strategy provides for ensuring adequate financing programmes available to entrepreneurs, as well as establishing research units and public entities. The Strategy mentions several programmes and funding methods, both on a European and national level, including IPCEI (Important Projects of Common European Interest).
Progress to policy	Based on a snapshot of installed capacity of announced projects as of 2030, Poland has a capacity target completion rate of 3%[10] to achieving their 2 GW target, placing it amongst the lowest in Europe. Poland is currently developing 8 different hydrogen valleys aiming to create regional markets across the full hydrogen value chain. These are namely, The Lower Silesia Hydrogen Valley, The West Pomeranian Hydrogen Valley, The Silesia and lesser Hydrogen Valley, The Pomeranian Hydrogen Valley, The Masovian hydrogen valley, The Subcarpathian Hydrogen Valley, The Greater Poland Hydrogen Valley and The Swietokrzyskie Hydrogen Valley. The first of these was announced by government in 2021 as part of The National Hydrogen Strategy. Poland is set to produce 30.18TWh of hydrogen by 2030, of which 4.58TWh is green hydrogen, against demand expectations in the country of 30.24TWh/year[11]. Currently, with production of around 1.3 million tons, Poland is the world's third-largest manufacturer of hydrogen Orlen, within the framework of Hydrogen Eagle project, plans to build nine new hydrogen locations, including five in Poland. However, it is not low carbon hydrogen since it is mostly produced by refineries and chemical plants and does not use the process of water electrolysis. The aid, which will take the form of a direct grant of €158 million, will support the installation of an electrolyser with a capacity of 100 MW, as well as the construction of 50 MW photovoltaic power plant and 20 MWh battery storage. The electrolyser is expected to start operating as of 2027 and to gradually increase its production up to 13,600 tonnes of renewable hydrogen per year. Once completed, the project is expected to avoid the release of a total of 2.5 million tonnes of carbon dioxide over the project lifetime. In addition, to maximise the reduction of greenhouse gas emissions, hydrogen will be produced solely with electricity generated from renewable sources.

A.2.9 Italy

Policy		**Progress**	

[10] Deloitte, The European Hydrogen Economy- taking stock and looking ahead, 2022

[11] ICIS Hydrogen Analytics

Strategy and policy	Italy's National Hydrogen strategy launched in 2020 set a hydrogen ambition of 5 GW by 2030. Hydrogen is anticipated to account for 2% of Italy's final energy demand increasing to 20% by 2050.
	The main areas of focus for the national hydrogen strategy are in transportation, heavy industry and natural gaseous pipelines.
Funding	The Ministry of Economic Development is targeting an investment in the sector of €10 billion; €5billion will come from European public funds, and €5 from private investments. The above amount includes investments are structured as follows: 1. Hydrogen production – €5-7bn. 2. Hydrogen distribution and consumption facilities (hydrogen-powered trains and trucks, refuelling stations, etc.) – €2-3bn. 3. Research and Development – €1bn; and 4. Infrastructure (such as gas networks) to properly integrate hydrogen production with end uses. In addition, The European commission has approved a total of €450m to support renewable hydrogen production in Italy. The funds will be issued by the Italian government in the form of direct grants with a maximum of €20 million in aid per project.
Progress to policy	Based on a snapshot of installed capacity of announced projects as of 2030, Italy has a capacity target completion rate of 6% [12]in achieving their 6.5 GW capacity target for 2030 at present. As of September 2023, Italy had 21 projects that were either planned/ announced[13]. Key projects/ developments are listed below: • Italy's Hydrogen Valley, The Valle Peligna, has an electrolyser capacity of 30 MW, and will produce 4,200 tonnes of hydrogen annually. The facility will provide green electricity to the local grid by the second half of 2025. Its development also includes a hydrogen refuelling station. • Four European energy companies (Snam, Hera, Engie and Societa Gasdotti) have announced two green hydrogen energy projects in Italy. The hydrogen produced will go to public transport groups and has received €9.5 million of funding through the EU's post pandemic recovery fund. The project will produce 300 tonnes of green fuel a year once operational. • Smart energy has developed a 200 MWe green hydrogen plant in Sardinia, Italy. The project began in 2021, with estimated delivery dates between 2026 and 2030, as it will be developed in 3 phases.

A.2.10 Belgium

Policy		Progress	
Strategy and policy	Belgium has not set specific electrolyser capacity targets for their 2030 and 2050 hydrogen ambitions; however, they have stated that they anticipate 20 TWh of hydrogen will be needed by 2030 to cover their domestic demand. This will increase to 200 TWh by 2050. The Belgian strategy for hydrogen is focused on positioning themselves as an import transit location for hydrogen. This is the first pillar in their hydrogen strategy. The government has also acknowledged that the majority of their domestic hydrogen demand will be supplied by hydrogen imports. Belgium's renewable energy potential is		

[12] Deloitte, The European Hydrogen Economy- taking stock and looking ahead, 2022

[13] BloombergNEF Clean Hydrogen Database, September 2023

	limited and importing hydrogen has been established to be more cost efficient than local production. Furthermore, they have stated that their preference on the type of hydrogen is governed by availability and process of acquisition, but they anticipate 30% to 60% of local demand to be for H2 molecules and 40% to 70% for H2 derivates such as ammonia, e-methane, e-methanol, e-kerosene. For example, the steel industry, which is one of Belgium's focus industries, will mainly need hydrogen in its gaseous form however, ammonia, methane, and methanol will be needed for the shipping industry.
	Within their strategy, they have identified three major import routes in their strategy. The North-sea (pipeline), The southern route (pipeline) -piped imports from southern Europe and North Africa, and The Shipping route which consists of importing H2 derivatives via ship. Belgium intends to collaborate with key partners across each of these routes.
Funding	The Belgian Federal Government has committed to providing up to €395 million to complement private investments. Belgium already has well established hydrogen transport infrastructure and is pursuing development of its open-access pipelines, commissioning and investing €95 million in at least 100–160 km of pipelines for H2 transport by 2026.
Progress to policy	Belgium has been developing projects in the hydrogen sector and have shown signs of progress being made towards their targets thus far. Key projects/ developments are as follows: • The H2 Delta network (2021-2025) which is the development of aH2 infrastructure in the North Sea port. Currently, there are at least six electrolyzer projects in advanced stages of planning and development with an aggregated capacity of over 2 GW, as well as major blue hydrogen- and CCU projects. • Green Octopus (2019-2030) which is a combination of dedicated roll-out projects and hydrogen transportation trajectories. The project is aiming to contribute to the formation of an integrated hydrogen market between Belgium, Germany and the Netherlands. • H2 Highway Zeebrugge aims to transform 97km natural gas pipeline and transport network to carry hydrogen and CO2 between Zeebrugge and Brussels. First section completion expected in late 2023, second phase by winter 2025-6. • Hyoffwind hydrogen project aimed at developing power-to-gas facility that can convert 25 MW renewable electricity into green hydrogen (potential scale up to 100 MW). Submitted for IPCEI funding. • Port of Antwerp-Bruges has received Hydrogen Valley status and announced commitment to import large volumes of sustainable hydrogen carriers and expanding infrastructure to convert into pure hydrogen as a raw material or fuel. • Cluster Hydrogen for Mobility and Industry in Antwerp (CHYMIA) exploring 100MW green hydrogen production plant in the Port of Antwerp.

A.2.11 Greece

Policy		Progress	
Strategy and policy	Greece published their National Energy and Climate Change Plan in 2021. The plan sets a target of 1.7 GW of electrolyser capacity by 2030, and 30.6 GW of electrolyser capacity by 2050. Greece has also set a target for blending hydrogen into the gas system with a target of 5.6% of natural gas in the system to be mixed with green hydrogen by 2030, and 15.4% by 2050.		
Funding	As there is no comprehensive framework to accompany the hydrogen strategy there is no clear and conducive funding mechanisms for hydrogen projects.		

Progress to policy	The move to net-zero emissions and the role of hydrogen in Greece is not clear and they lack a comprehensive framework for the deployment and use of hydrogen. The market for green hydrogen in Greece is still in its infancy, falling behind its European counterparts. However, total consumption of green hydrogen in Greece is expected to reach 63.6 TWh a year by 2050 with 70% of the fuel used in transportation. As part of the European backbone demand locations for hydrogen have been identified in Kartso, Mongstad and Nvhanna Greece has made little progress to their targets to date, but despite the gaps in national strategy, certain hydrogen initiatives have begun development. Five Greek hydrogen projects were included in the first wave of important projects of common European interest (IPCEI), Hy2tech: White Dragon: Involving the deployment of large-scale renewable electricity to produce green hydrogen by electrolysis by 2029. Will produce 250,000 tons of hydrogen per year once fully operational, which will go almost entirely to pipelines. Green HIPo: One of 41 IPCEI Hy2Tech projects. It involves the construction of a plant to produce innovative electrolytes and fuel cells in Western Macedonia. The project is aiming to produce electrolysers of total 1.5 GW over 6 years. Blue Med: This project dedicated to production of blue and green hydrogen. The project will have an installed electrolyser of up to 100 MW In Greece's coal region, with the electrolyser scheduled to be commissioned by 2027. H2CEM – TITAN: the production, storage and use of green hydrogen for combustion to produce energy to decarbonize the cement plants of the Greek firm TITAN. Green hydrogen production units with a total power of 3.5 MW will be installed and operated at Titan cement plants in Greece.

A.2.12 Norway

Policy		**Progress**	
Strategy and policy	There is currently a broad mandate surrounding domestic hydrogen deployment and use. Hydrogen has been identified as a potential energy carrier to reduce emissions, in particular for the transportation sector. Norway have placed an increased focus on hydrogen-related research and technology development. With the broad mandate, there is a lack of clarity with capacity targets, but Norway has developed a hydrogen roadmap. Between 2025-2030 the roadmap aims to have an established demand-based hydrogen locations for the supply of vessels and vehicles. The plan states that five hydrogen locations will be created for maritime transport and up to two industrial projects will be established by 2025. These hydrogen locations dot the coastline, and are based in Agder, Glomfjord, Rovik, Hitra and Floro. In addition, around five to ten pilot projects are also established to support the development of cost-effective hydrogen solutions and technologies, including plans to develop a research centre by 2025 for both hydrogen and ammonia.		
Funding	There are no specific funding mechanisms for hydrogen projects. CfD's and carbon taxation and tax exemptions will be used to bolster hydrogen demand.		
Progress to policy	Norway is exploring their domestic export potential and the cost efficiency exporting natural gas vs hydrogen, to European countries, and they note Germany as a potential export destination. Blue hydrogen is more likely to be used in Norwegian industry due to the large and predictable demand patterns from industrial regions, while green is earmarked for use in transport and to support the development of locations. There are several projects that are being developed in Norway.		

	• Norwegian Hydrogen has been working on the development of a large-scale production plant for green hydrogen at Ørskog in Ålesund municipality and have announced plans for what will become one of the largest production facilities for green hydrogen in the entire Nordic region. The factory will have a capacity of 270 MW when it is fully developed. A capacity of 20MW has been granted, and an application for a further 250MW capacity has been submitted and is being processed. • North Ammonia Arenda (2021-2027) develop, build, own and operate green ammonia production, storage and distribution facility. • Several other projects in the research and development phase such as, HYline, a key project in the European Hydrogen Backbone Initiative, is looking to convert the existing Norwegian pipeline infrastructure of the Norwegian subsea network to a hydrogen network and create a new hydrogen network along with it. The project envisions a 6,800 km hydrogen network by 2030 and a 22,900 km network by 2040. • For shipping, Norway also has the Green Shipping Programme, a public-private partnership that supports low- and zero-carbon emissions projects. Several fuels have arisen from this as potential alternative for the maritime industry, including hydrogen and ammonia Alongside this, there are competitions for hydrogen-powered bulk carriers to be established by 2023, and two hydrogen-power vessels by 2024.

A.2.13 Finland

Policy		**Progress**	
Strategy and policy	The Finish Government adopted a resolution on hydrogen in 2023, outlining their hydrogen objectives. Their goals are the production of clean hydrogen and electrical fuels for domestic demand, transport and the energy system, the renewal of industry and the growth of export business with high processing value, as well as securing investments. They have set a target to produce 1.4 million tons of green hydrogen by 2030. Their potential areas of focus are: (1) The expansion of domestic clean hydrogen production (2) to accelerate the ramp-up of domestic clean industries (3) to grow exports of hydrogen-related technologies and services		
Funding	No clear and conducive funding mechanisms for hydrogen projects.		
Progress to policy	Finland has multiple competitive advantages with regards to hydrogen production, such as a clean electricity system, cost-competitive renewable generation potential and abundant natural resources in forestry. For example, Finland's electricity system has one of the lowest grid carbon intensities in the EU due to the availability of hydro, nuclear, wind, and bioenergy resources. Finland is therefore unlikely to be an importer of renewable green hydrogen. Finland has 14 hydrogen production projects, 2 of which have secured financing and are under construction. These two projects have an estimated hydrogen output of 3,500 tons per year, and 2,000 tons per year respectively. Although this showcases progress towards the development of a hydrogen economy, there is little activity in comparison to other European nations. Neste, Finland's largest oil company, is developing a 120 MW green hydrogen facility at it Porvoo refinery. The project has attracted €35.4 million in funding from the ministry of economic affairs and employment. The goal is to build a 120 MW electrolyser that will produce green hydrogen for the refineries existing processes.		

	Plug power aims to build three plants in Finland, for the production of green hydrogen and ammonia for the European market, valued at $6million. Final decision is planned for 2025. The Flexens Kokkola project is set to have a hydrogen production capacity of 300 to 350 MW. The project will produce mainly green hydrogen and some green ammonia. Date of operation is set at the end of 2027.

Appendix B

Pipeline Transport Technical Considerations

B.1 Existing Pipeline Conversion

B.1.1 Introduction

There are several existing pipeline connections from the UK to mainland Europe and the Republic of Ireland. These are either dedicated interconnectors forming a point-to-point connection between terminals for the principal reason of transporting gas between countries or they are part of a wider offshore pipeline system. Some of the pipelines which come ashore in the UK from oil & gas fields in the North Sea have connections via interconnecting offshore pipelines and field connections which could enable gas to be transported from the UK to another country.

The 4 dedicated gas interconnectors are:

- BBL Balgzand to Bacton
- Bacton to Zeebrugge
- UK to Ireland Interconnector 1
- UK to Ireland Interconnector 2

This study has only considered connections from the UK to mainland Europe. UK to Republic of Ireland Interconnectors 1 and 2 are discounted at this stage due to the limited market potential and the need to include an additional transport vector, such as shipping, to link to the larger mainland European market.

The ability to repurpose existing pipelines is influenced by a number of technical factors but the availability of the pipeline to change from natural gas or oil to hydrogen service will be influenced by the demand from customers and other users. The ability to secure the multiple components of an integrated offshore pipeline system to form a continuous connection from the UK to Europe is likely to be extremely difficult to achieve given the multiple linkages. The simplest connection utilising existing oil & gas infrastructure is the Langeled pipeline system from Nyhamna, Norway to Easington, which is discussed below. Other more complex interconnections have not been considered at this stage. The following sections describe the details of the existing UK to mainland Europe interconnectors and the Langeled pipeline system.

B.1.2 BBL Balgzand to Bacton Interconnector

BBL Company (https://www.bblcompany.com/) was established in 2004 as a partnership between Gasunie BBL B.V. (60%), Uniper Ruhrgas BBL B.V. (20%) and Fluxys BBL B.V. (20%), subsidiaries of Gasunie, E.On and Fluxys respectively.

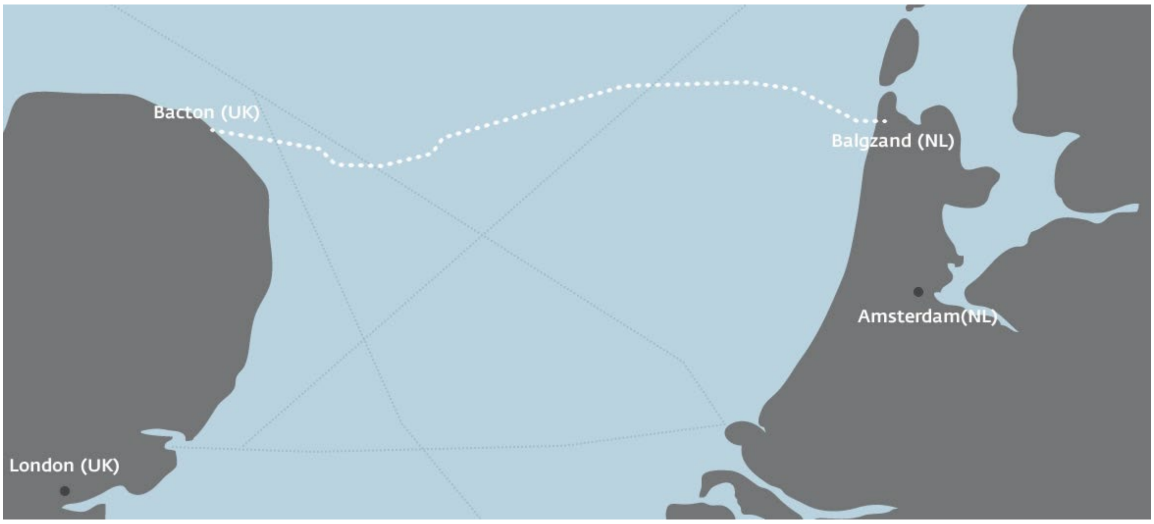


Figure 55: BBL Balgzand to Bacton Interconnector Pipeline Alignment (© BBL Company)

The BBL (Bacton-Balgzand Line) asset comprises a compressor station at Anna Paulowna at Balgzand in the Netherlands and a 235-kilometre gas pipeline (Figure 55) between Balgzand and Bacton. The pipeline is a

36” OD (914mm) carbon steel pipeline (Grade X65) with 20.9mm wall thickness and a design pressure of 137.4 barg.

Table 24 defines the pipeline capacity in forward flow (Balgzand to Bacton) and reverse flow (Bacton to Balgzand) mode.

Table 24: BBL Pipeline Capacities

	Forward Flow	Reverse Flow
Daily Capacity (GWh)	494	168
Hourly Capacity (kWh/h)	20,600,000	7,000,000

The Anna Paulowna Compressor Station comprises 4 x 23 MW compressors which includes one full spare giving N+1 redundancy. Laying the pipeline between the compressor station at the Balgzand Gas Plant and Bacton Gas Terminal started on 14 July 2006. The pipeline became operational on 1 December 2006. The initial capacity was 16 billion cubic metres (bcm) per year, which was increased to 19.2 bcm at the end of 2010 by installing a fourth compressor at the compressor station at Anna Paulowna. The key components of the system are described in further detail below.

B.1.2.1 Bacton Gas Terminal

The Bacton Gas Terminal (Figure 57) is located on the Norfolk coast in the East of England. It is part of a large site that accommodates Shell, Perenco, ENI, Interconnector and National Grid. On the Shell site itself there are three distinct systems operating separately. One of them, the BBL plant, lands gas from the compressor station in Anna Paulowna in the Netherlands. The reception plant is owned by BBL Company, and the plant is being operated by Shell.

Figure 56: Bacton Gas Terminal (© BBL Company)

Gas lands at Bacton at approximately seabed temperature and a landing pressure which varies depending on the amount of line pack at the time. Bacton’s role is to reduce the pressure for entry to the National Gas National Transmission System (NTS). As such, significant Joule-Thomson cooling may occur prior to gas injection into the NTS. Therefore, four identical parallel streams are installed at Bacton, each equipped with a direct-fired water bath heater on a slipstream and designed to operate as three duty and one standby at maximum flow conditions, in order to control the delivery temperature and pressure of the gas.

Besides the gas temperature and pressure conditions required by National Gas, the gas flow rate will vary depending on demand within a daily period and on shippers' requirements. An End-of-Day system assures that the correct amount of gas is delivered.

B.1.2.2 Pipeline

The offshore pipeline comprises 230 km of the pipeline's overall 235 km length. Installation of the pipeline across the North Sea took place in 2006, with construction by pipe lay barge progressing ad at a maximum rate of 4.9 km a day. The pipeline crosses several sand banks and other typical seabed features and several shipping lanes. Temporary cofferdams were built at either end of the offshore pipeline to enable safe connection of the pipeline to the onshore section.

The onshore section is a 4 km length of pipeline that begins at the Anna Paulowna compressor station in the Netherlands and ends at the dune crossing location in Julianadorp.

B.1.2.3 Anna Paulowna Compressor Station

The BBL Company pipeline is connected to the Dutch national grid, which is owned by Gasunie Transport Services, at Grasweg near Anna Paulowna and is linked to the Anna Paulowna compressor station, formally called compressor station Noord-Holland (Figure 57).

Figure 57: Anna Paulowna Compressor Station (© BBL Company)

The compressor station pumps gas from the Dutch national grid via the 235 km long pipeline across the North Sea to the BBL Company Bacton reception facilities. The station's 4 x 23MW compressors, (three plus one full spare) are electrically driven and able to pump 1.9 million m^3/hr to the UK. On the BBL premises there is also a blending station and metering runs which are owned by Gasunie Transport Services.

The facilities at Anna Paulowna are maintained and operated by N.V. Nederlandse Gasunie.

B.1.2.4 Bacton to Zeebrugge

Interconnector (UK) Limited (IUK) (https://www.fluxys.com/en/about-us/interconnector-uk) own and operate the bi-directional gas pipeline between the UK and Belgium which connects the transmission system operated by National Gas at Bacton to the transmission system operated by Fluxys Belgium at Zeebrugge.

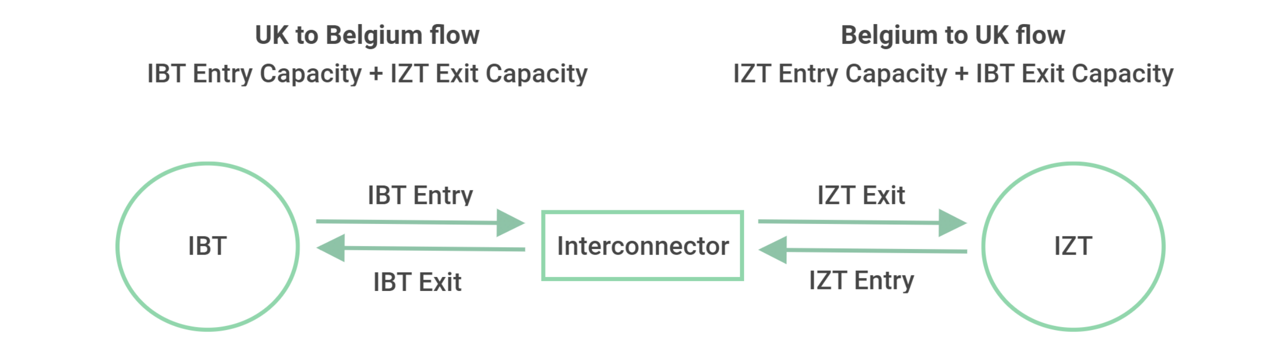
The company is part of the Fluxys Group and SNAM, who own an equity interest of 76.32% and 23.68% respectively. IUK started operations in October 1998.

The gas flows between terminals at Bacton in the UK (Interconnector Bacton Terminal – IBT), and Zeebrugge in Belgium (Interconnector Zeebrugge Terminal – IZT) via a 235km subsea pipeline (Figure 58).

Figure 58: Interconnector UK Pipeline Alignment

The IUK system provides 20 bcm/yr of UK export capacity and 25.5 bcm/year of UK import capacity. The technical capacity of the system in either direction is shown in Table 25. GWh/d values are based on an assumed GCV of 11.5 kWh/Nm^3 for IBT entry/exit and IZT entry/exit.

Table 25: IUK Pipeline Capacities

Technical Capacities	kWh/h	GWh/d
		
IBT Entry	27,153,206	651.7
IBT Exit	33,476,006	803.4
IZT Entry	33,476,006	803.4
IZT Exit	27,153,206	651.7

IUK have published the following details on the technical capacity of the system when operating in either direction.

B.1.2.5 IBT Entry / IZT Exit Capacity

The technical capacity of the entry point at Bacton into the pipeline from the UK system is determined by the capacity of the compression facilities at IBT.

The technical capacity of the IBT compression facilities is a function of the following principal variables:

- Required pressure lift or compression ratio, i.e. the ratio of the inlet pressure to the pipeline pressure on the discharge of the compressors.
- Available power from the compressors.
- Gas inlet pressure from the UK system.
- Inlet gas temperature at the UK system.
- Ambient temperature.
- Gas inlet composition.

The main constraints to capacity at IBT are the station inlet pressure and gas temperature from UK system together with the ambient temperature.

The current maximum theoretical technical firm capacity at IBT for entry to the pipeline has been assessed at 27,153,206 kWh/hour based on the following assumptions:

- Station inlet pressure of 55 barg. The contractual minimum inlet pressure from National Gas is 45 barg, and there is an agreement in place for the inlet pressure to be increased by National Gas.
- Maximum ambient temperature of 17°C at which the design flow-rate can be achieved at minimum arrival pressure.
- Maximum gas inlet temperature of 10°C.
- 3 compressors operating in parallel mode.

The technical capacity of the exit point at Zeebrugge from the pipeline into the Fluxys system is determined by the following variables:

- Gas pressure in the pipeline for exit into the Fluxys system.
- Gas temperature for exit into the Fluxys system.
- Minimum entry pressure to the Fluxys system of 80 barg.
- Availability of the heater trains.

The current maximum theoretical technical firm capacity at IZT for exit from the pipeline has been assessed at 27,153,206 kWh/hour.

B.1.2.6 IZT Entry / IBT Exit Capacity

The technical capacity of the entry point at Zeebrugge into the pipeline from the Fluxys system is determined by the capacity of the compression facilities at IZT.

The technical capacity of the compression facilities is a function of the following principal variables:

- Required pressure lift or compression ratio, i.e. the ratio of the inlet pressure to the pipeline pressure on the discharge of the compressors.
- Available power from the compressors.
- Gas inlet pressure from the Fluxys system.
- Inlet gas temperature at the Fluxys system.
- Ambient temperature.

- Gas inlet composition.

The main constraints of capacity at IZT are the station inlet pressure and gas temperature from the Fluxys system together with the ambient temperature.

The current maximum theoretical technical firm capacity at IZT for entry to the pipeline has been assessed at 33,476,006 kWh/hour based on the following assumptions:

- Station inlet pressure of 55 barg.
- Maximum ambient temperature of 25°C at which the design flow-rate can be achieved at minimum arrival pressure.
- 3 compressors operating in parallel mode.

The technical capacity of exit point at Bacton from the pipeline into the UK system is determined by the following variables:

- Gas pressure in the pipeline for exit into the UK system.
- Gas temperature for exit into the UK system.
- Minimum entry pressure to the UK system of 45 barg.
- Availability of sufficient heater trains.

The current maximum theoretical technical firm capacity at IBT for exit from the pipeline has been assessed at 33,476,006 kWh/hour.

B.1.2.7 Terminals

The Interconnector system was originally designed for the export of gas from the UK. Compression facilities were installed at the Bacton terminal to raise the pressure of gas taken from the UK grid for transportation via the sub-sea line to Zeebrugge.

The Bacton Terminal consists of four 27 MW gas turbines, which provide the power for the compressors at Bacton to pump up to 58 million cubic metres of gas per day at pressures of up to 140 bar.

The Zeebrugge Terminal consists of four compressors driven by electric motors. These have the capability to pump 74 million cubic metres of gas per day at pressures of up to 147 bar. Zeebrugge is operated remotely from the Bacton terminal, although if needed, it can be run locally.

B.1.2.8 Pipeline

The 235km, 40” OD (1,016mm) interconnector pipeline runs beneath the southern North Sea and operates at pressures up to 147 bar.

The pipe is made of carbon steel with an epoxy internal coating to smooth the walls and enhance pipeline efficiency. A coating of asphalt enamel protects the external surface with additional cathodic protection provided by aluminium "bracelet" anodes. A concrete coating provides extra weight to keep the pipeline stable on the seabed.

The IUK Operations team works alongside Lloyd's Register and others to carry out regular inspections and maintenance to optimise the pipeline's efficiency and availability.

B.1.3 Langeled Pipeline System

The Langeled pipeline (originally known as Britpipe) transports Norwegian natural gas from the Ormen Lange gas process terminal to the UK. The pipeline is owned by Gassled, operated by Gassco with technical service provider Equinor.

The subsea pipeline (Figure 59) runs 1,150 km through the North Sea from the Nyhamna Processing Plant in Norway via the Sleipner Riser platform to the Easington Gas Terminal in the UK.

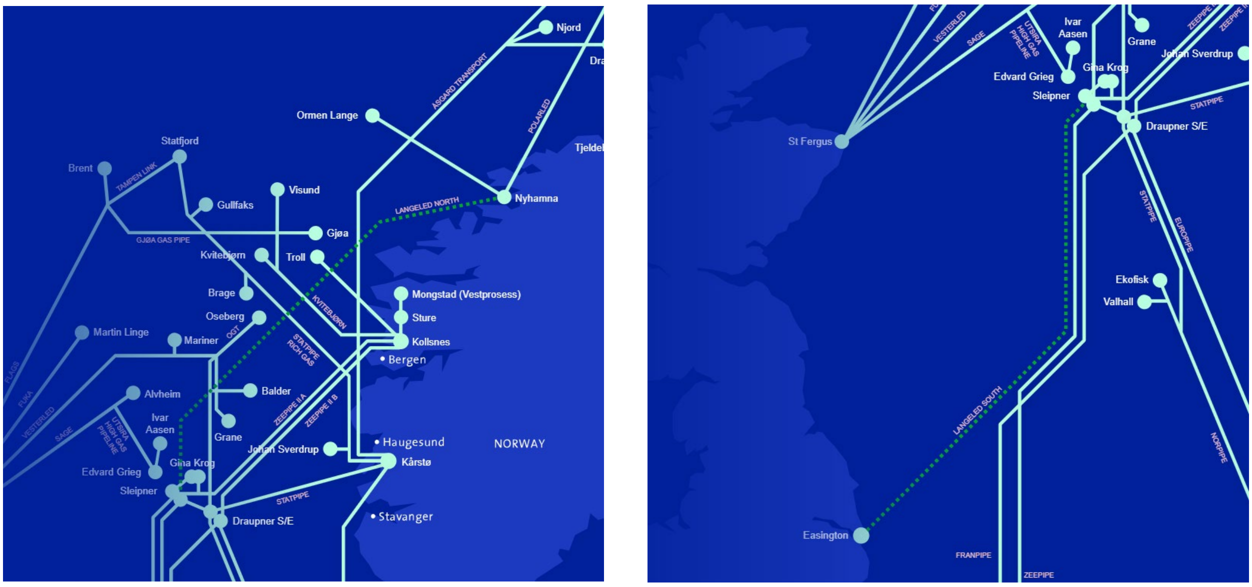


Figure 59: Langeled Gas Pipeline System (© Gassco)

B.1.3.1 Terminals

The Nyhamna Processing Plant (Figure 60) near Kristiansund in Norway dewaters gas arriving from the Ormen Lange and Aasta Hansteen fields in the Norwegian Sea before it is sent through the Langeled pipeline system. Condensate is also treated at Nyhamna.

Figure 60: Nyhamna Process Plant (© Gassco)

The Easington Receiving Terminal (Figure 61) on England's east coast receives the gas. Pressure and temperature are adjusted before the gas is injected into the UK gas system.

Figure 61: Easington Receiving Terminal (© Gassco)

B.1.3.2 Pipeline

The 1,150km long pipeline from the Nyhamna Processing Plant via the Sleipner Riser platform to the Easington Gas Terminal is one of the longest subsea pipelines in the world. The pipeline was opened in two stages. The southern section (Sleipner Riser Platform to Easington) began piping gas on 1 October 2006, the northern section (Nyhamna to Sleipner Riser Platform) opened in October 2007.

Langeled North, from the Nyhamna Terminal to the Sleipner Riser Platform, is 627 km long with a diameter of 42” OD (1,067 mm) and can operate at a pressure of 250 bar with a capacity of 74.7 million cubic metres of gas per day. Langeled South, from the Sleipner Riser Platform to Easington, is 523 km long with a diameter of 44” OD (1,118mm) and operates at a pressure of 155 bar with a capacity of 73.8 million cubic metres of gas per day. The system typically delivers around 70 million cubic metres of gas per day to the UK.The pipeline is designated to bring natural gas to the UK, but through the interconnection at the Sleipner Riser Platform it can send gas through Gassco's existing network to continental Europe.

B.1.4 Summary

The key details of the two existing interconnectors running from the east coast of the UK to mainland Europe are summarised in Table 26.

Table 26: Existing Interconnectors Summary

Component	The Interconnector (Bacton-Zeebrugge)	BBL Pipeline (Bacton-Balzgand)
Description	Bidirectional Flow	Bidirectional Flow
Asset Age	2006	1998
Inner Diameter (inch)	38.3	34.4
Outer Diameter (inch)	40	36
Wall thickness (mm)	21.76	20.9
Offshore Length (km)	230	235

Component	The Interconnector (Bacton-Zeebrugge)	BBL Pipeline (Bacton-Balzgand)
MAOP (bar) - NG	147	137
NG Mass flow rate (mcm/hr)	2.42	1.9
Metallurgy / Material Suitability	X65 (Assumed to be same as BBL) Carbon steel with epoxy lining Asphalt enamel and aluminium anodes for cathodic protection Concrete coating to provide additional weight for pipeline seabed stability	X65
Compression	Bacton: 4 x 27 MW compressors (gas turbine driven) up to 140 barg Zeebrugge: 4 x electric compressors up to 147 barg	Compression stations in Anna Paulowna (4x 23MW compressor trains, N+1 redundancy)

B.1.5 Technical Issues

Repurposing existing pipelines for hydrogen service requires consideration of key technical issues which can affect the operability and safety of the pipelines. A RAG analysis of the key risks related to repurposing existing pipelines rating was completed according to the criteria set out in Table 27.

Table 27: RAG Assessment Criteria

RAG Rating	Risk Classification
(Green)	Low technical risks that could either be of no or marginal consequence and/or unlikely to materially affect the project's feasibility provided the necessary study and remediation work is completed effectively.
(Amber)	Either of: Medium technical risks that could either be of some consequence to the project's feasibility by way of extending schedules or increasing costs. Items with limited information and/or limited evidence, in which case further information and consequential review is required to finalise the conclusion.
(Red)	Either of: High technical risk items that could either be of significant consequence to the project's feasibility by way of conversion not being possible. Items with no or very little bona fide information and/or evidence, in which case further information and consequential review is required to finalise the conclusion.

These ratings have been applied to indicate where mitigation measures are well progressed or otherwise. A summary of the key risks, considerations, and mitigation measures is presented in Table 28.

Table 28: General technical risks associated with converting existing pipelines to hydrogen service.

Risk Area	Description	Key Mitigations / Recommendations	RAG
Metallurgy / Material Suitability	Repurposing of high strength NG pipelines for hydrogen service requires careful consideration of the metallurgy of the pipeline and, particularly, weld materials. Most offshore and onshore high pressure NTS gas pipelines are constructed from API 5L X65 grade steel or equivalent in the UK and Europe.	Further analysis of the pipeline and weld materials will be required as the design progresses. Lab testing of samples from the pipeline will likely be required to confirm the materials susceptibility to hydrogen embrittlement and other adverse effects. Study work to prove the suitability of the pipelines is time and cost intensive for any pipeline, which is amplified for the subsea portions of the system. Gathering this data while the pipeline is currently in use as a major import of natural gas for	(Amber)

Risk Area	Description	Key Mitigations / Recommendations	RAG
	High grade steels (>API 5L X52) are more susceptible to hydrogen embrittlement and hence require the downrating of design pressure according to IGEM/TD/1 Supplement 2 and ASME B31.12.	the Irish gas grid is likely to be challenging in order to facilitate a transition to hydrogen service by 2030. Reduction in operating pressure and more regular inspections and monitoring are proven methods to enable safe usage of existing high strength pipelines for hydrogen use. Other potential solutions such as pipe linings are being explored in academia. These solutions are still at a research level of development and have not been deployed on commercial projects to date. Therefore, it is expected that it will be unlikely that pipelines will be completely unsuitable for hydrogen service, dependent on their age and condition, rather they will be operable with certain mitigations in place. The amber RAG rating is associated with the timeline required for repurposing which poses a risk to this project.	
Age of existing assets	Approximately 50% of the total length of the UK NTS was installed between the 1960s and 1970s, and therefore may be reaching the end of its design life and may require additional remediation work to ensure it is suitable for hydrogen service. It is possible that in-line inspections of pipeline sections may detect cracks which result in the pipeline section being unsuitable for hydrogen service.	More detailed research, integrity testing and destructive laboratory testing is required to assess the fatigue damage of the relevant pipeline sections. This should be used to assess the feasibility of repurposing the pipeline sections for hydrogen service and may indicate that sections should be replaced with new-build pipeline sections.	
Metering	Regulations and guidance for hydrogen metering systems are still in development. The differing fluid mechanical properties of hydrogen may result in the recalibration or replacement of metering systems.	Regulations and guidance for hydrogen metering systems should be monitored to understand further whether existing metering systems should be replaced or recalibrated.	
Control Systems	Flow analysers must be recalibrated or replaced for hydrogen service. The control system must also be re-certified for hydrogen service.	In-depth analysis will be required for re-certification of the natural gas control system for hydrogen service.	
Valves and Fittings	Existing valves and fittings are expected to have a greater leak propensity in hydrogen service and will likely need to be replaced. Additionally, materials used in valve construction are of particular interest as hydrogen induced stress and hydrogen embrittlement could cause operational challenges with valve systems.	More information on existing valves and fittings within the existing gas infrastructure is required to understand the scale of replacement of valves and fittings required. Several projects are currently considering this, such as Project Union and the European Hydrogen Backbone. Valves suitable for use in hydrogen systems are available in the market already so it is expected that if the valves currently installed on NG systems are not suitable then they will be replaceable within the proposed timeframe of this project. If new valves are required, it will likely increase the cost of repurposing, therefore this is deemed as an amber risk to the proposed network on cost grounds.	
Pressure Reduction Systems	The metallurgy, age and integrity of existing pressure reduction systems is largely unknown. There is no indication that significant changes to technology behind pressure reduction systems is required, however it is likely that valves and fittings will	More information on the metallurgy, age and integrity of relevant pressure reduction systems should be gathered. In-depth dynamic analysis and physical testing of the pressure reduction system may be required for recertification of the natural gas pressure reduction systems for hydrogen service. When pressure is reduced, hydrogen behaves differently to natural gas and therefore new purpose-built systems may be required to deliver the required reduction in pressure. This is	

Risk Area	Description	Key Mitigations / Recommendations	RAG
	be replaced. The system must also be recertified for hydrogen service.	dependent on the overall operating philosophy of the system and is not expected to pose a material risk to the repurposing of NG pipeline systems for hydrogen service, but it will likely add cost to the repurposing process.	
Leak Protection / Prevention	Repurposing NG pipelines for hydrogen is likely to increase the propensity of crack growth in steel through hydrogen diffusion and embrittlement as a result of cyclic loads.	This effect is well understood and can be mitigated against by avoiding cyclic loads, using lower-grade strength steels, increasing pipe wall thickness, reducing internal pressures or a combination of these activities. Repurposing existing NG pipelines for hydrogen service therefore often requires a capacity reduction compared to NG service, however the size of this capacity reduction will vary system to system, and it may be feasible to repurpose some existing systems with little to no capacity reduction in energy transfer terms depending on the condition and nature of the asset. Therefore, this risk is not seen as a major risk to the proposed system, considering the capacity requirements and well understood nature of the risk.	

Based on the key risks identified in Table 27, issues with the existing interconnectors are most likely to be related to the weld material, pipeline construction material and compression.

There are two primary methods of hydrogen compression: positive displacement (the method applied by reciprocating compressors) and dynamic (the method applied by centrifugal compressors). A comparison of the two compression methods is summarised in Table 29 and illustrated in Figure 62 below.

Table 29: Comparison of Reciprocating and Centrifugal Compressors for Hydrogen Service

	Reciprocating Compressors	Centrifugal Compressors (a.k.a. Turbocompressors)
Method of compression	Hydrogen is drawn into the cylinder through suction. As the piston moves, the volume that the hydrogen is contained in reduces, increasing the pressure. When hydrogen reaches discharge pressure the discharge valves open.	Fluid passes through high-speed impellers. Changes in the angular momentum of the fluid increases the kinetic energy of the fluid. The kinetic energy is converted to a pressure increase through a stationary diffuser.
Pressure ratio	Limited by discharge temperature only, therefore high-pressure ratios can be achieved.	Limited by several factors, including impeller tip speed. Centrifugal compressors are less efficient with gases of low molecular weight. To compensate, the number of stages or impeller blade tip speed can be increased. Increasing the tip speed will impart higher design stresses, therefore particular hydrogen-compatible materials must be selected. The pressure ratio achieved by centrifugal compressors operating on hydrogen is therefore limited.
Maximum flow rate	Capacity is limited by the cylinder size, and therefore there is a trade-off between maximum flow rate and footprint.	Capacity is limited by the choke point (the point at which the flow through the compressor reaches a velocity of Mach 1). Hydrogen has a high sonic velocity, and therefore high flow rates can be achieved.
Footprint	Directly related to flow rate, number of stages, driver speed.	Although more stages of compression are likely to be required, the nature of the design is such that large volumes can be handled in machines with a smaller footprint than reciprocating compressors.
Reliability, Maintenance	Large number of parts, increasing the maintenance requirements.	As per API 617, a centrifugal compressor must be designed for five years of uninterrupted service.

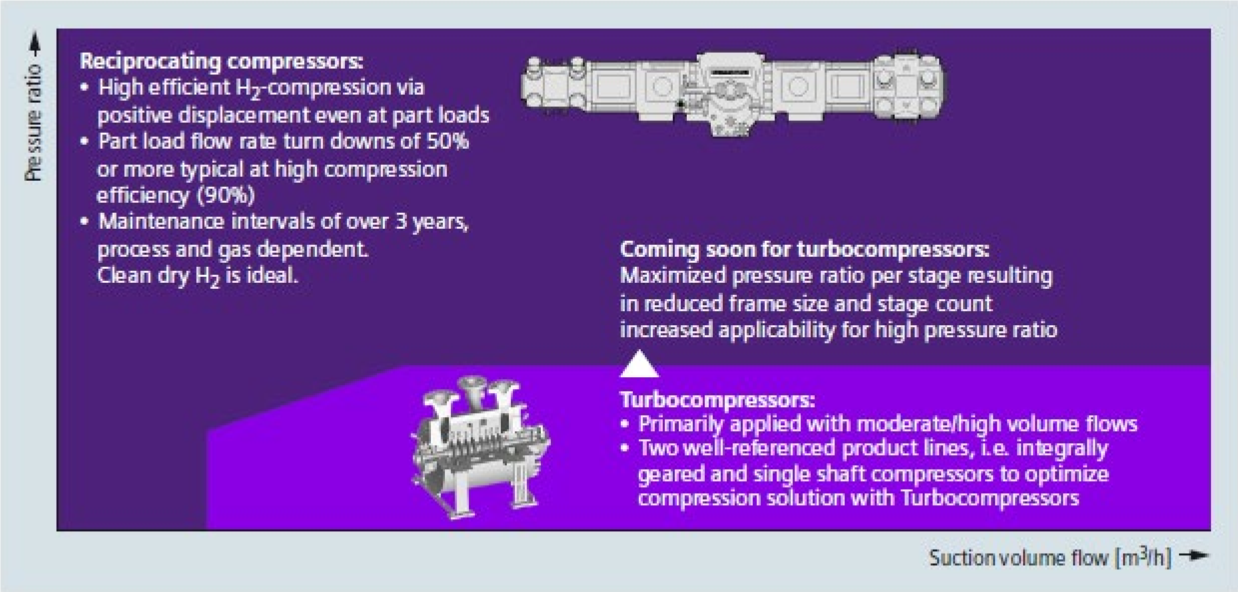


Figure 62: Hydrogen Compressor Comparison

National Grid have commissioned HyNTS Compression to investigate repurposing existing NTS assets to compress hydrogen and hydrogen blends. The project focuses on compressors driven by gas turbines, as these make up the majority of compressors on the NTS.

The project concluded for a 100% hydrogen stream, the increase in pressure was <1bar, and therefore the existing centrifugal compressors were not suitable. An additional three stages of compression would be required to match the pressure ratios for natural gas, which increases the footprint of the train. Existing compressors have the potential to be repurposed for 20% and 50% hydrogen blends.

The use of hydrogen as a fuel to power the gas turbine was also investigated, which considers the additional power required to compress hydrogen and hydrogen blends. The gas turbine fuelled on 100% H_2 was shown to provide the power required to compress 20% and 50% hydrogen blends.

To summarise:

- Current NTS centrifugal compressors cannot deliver adequate pressure ratios required under 100% hydrogen operation, however, may be re-purposed for 20% and 50% blends.
- Most centrifugal compressors on the NTS are powered by gas turbines. These may be re-purposed by fuelling with 100% hydrogen to compress a hydrogen blend; however, as the power requirement of the 100% hydrogen compressor (with additional stages) is unknown, it is uncertain if a gas turbine fuelled with 100% hydrogen can compress a 100% hydrogen stream.

The general consensus is that existing compressors used for compression of NG cannot be repurposed. Significant development is still required if centrifugal compressors are to be used at all, otherwise multiple reciprocating compressors (which has a much lower volume flow rate) will be required in parallel.

B.2 New Pipelines

B.2.1 Construction Methodology

The development of a new subsea interconnector pipeline involves a number of distinct phases from design and consenting to construction and commissioning, which overall can take many years. The pipeline system comprises a number of components, the onshore section, inter tidal section and offshore section. Each of the different sections have different challenges and requirements but will go through similar development phases.

Once the terminal locations have been established pipeline route planning can commence. The alignment of the pipeline will take into account a number of key factors. The route will need to consider compliance with regulatory authorities and design codes, water depth and seafloor topography and conditions, environmental constraints and considerations, marine activities and installation method, including vessel availability, and interfaces with existing subsea structures and other pipelines and cable services.

A desk study will typically be performed using available data such as existing bathymetry, environmental constraints mapping and publicly available information. From this constraints maps will be developed to allow the pipeline to be routed as far as possible from known areas of potential issues for the successful implementation of the project.

Once the preliminary alignment has been determined, the proposed route needs to be surveyed to gather route specific information and confirm the selected route. Specialist survey companies would be contracted to obtain data including bathymetry, seabed characteristics, soil properties, stratigraphy, geohazards and environmental data. A range of survey techniques will be employed including hydrographic sonar surveys using echo sounders to provide the seabed profile over the pipeline route which will allow 3D mapping to be generated. The resolution accuracy and level of definition achievable from the survey will allow obstacles, hazards and service crossings to be identified and their locations confirmed against previous information.

Other surveys will include data on the tidal and steady current profiles across the water column depth and details of the metocean conditions in terms of wave data and associated water column velocities. Pipelines are subject to drag, lift and inertia forces as a result of the hydrodynamic loads from wave and current action. This data will allow checks on the on bottom stability of the pipeline to be undertaken to determine the need for burial for lateral stability. To keep the pipeline stable, the soil resistance should be greater than the hydrodynamic force induced on the pipeline.

Geophysical surveys will be undertaken to determine the seabed and near surface geology for long term stability design. This data together with any public domain geotechnical investigation data and project specific site investigation data (boreholes, CPT testing, grab samples, etc.) will be used to identify any unfavourable ground conditions and to determine any areas of mobile seabed surface and the need for additional stability measures to prevent pipeline lateral movement and the development of free spans and ensure lateral stability.

Once the data gathering phase has been completed, pipeline design will be undertaken. The pipeline will be sized (diameter) based on the required throughput to be transported. The operating pressure will determine the required wall thickness of the pipeline, based on a selected strength of material for the steel pipe, to ensure the pipeline will have sufficient integrity to contain the gas. The loads on the pipeline during installation and operation will be determined and any changes in wall thickness to accommodate these loads will be determined.

A key design parameter for pipeline stability is the net submerged weight of the pipeline calculated as the difference between the weight of the pipeline and any applied coatings and the uplift buoyancy loads on the pipeline during installation and operation. In general, the larger the submerged weight the higher the frictional resistance. This can be enhanced by the application of concrete weight coating or increasing the depth of embedment of the pipeline (partial or full burial as opposed to just laying the pipeline on the seabed). Additional resistance is provided by the soil which could reduce the required submerged weigh of the pipeline.

Other design loads to be checked include the lateral drag and inertia forces due to the water particle velocities and accelerations, and lift forces acting vertically which will tend to reduce the submerged weight of the pipeline.

The pipeline will usually be carbon steel. Material selection may need to be modified to ensure the optimum material grade based on a balance between cost, weight, weldability. Lower grade steel is potentially cheaper but will require greater thickness to contain the required pressure which in turn will make welding more complex and installation more difficult and costly. These trade-offs will be determined, and the final design confirmed.

The requirements for long term corrosion protection will be determine. The internal surface of the pipeline is not typically coated for clean dry gas. But if erosion due to high flow velocities and the risk of particulates being carried in the pipeline is high, then a fusion bonded epoxy (FBE) or similar coating system will be applied. External coating will typically take the form of a FBE, 3-layer polypropylene (3LPP) or 3-layer polyethylene (3LPE) coating. Concrete weight coating will be applied over the corrosion protection if required.

Some pipelines may need to be heated to maintain the temperature of the fluid being transported. This can either be by active means (electrical trace heating or circulating hot water in a pipe-in-pipe annulus, etc.) or passive means (insulation, burial, covers, etc.). It is unlikely that hydrogen pipelines will require heating.

Once the design is finalised the line pipe can be ordered for fabrication and coating. The line pipe will then be shipped to an onshore storage location. Installation of a subsea pipeline can be achieved by several different methods including Towing, S-Lay, J-Lay and Reel-Lay. The selected method will depend on a number of factors including pipeline size, wall thickness, length and water depth and the management of installation bending and longitudinal stresses and strains within the pipeline.

Towing

There are 4 types of towing installation method – Surface, Mid-Depth, Off-Bottom and Bottom (Figure 63). This requires the prefabrication of pipe strings comprising multiple lengths of pipe which are welded together onshore at a beach construction facility. The limit on string length will be impacted by the size of the fabrication site and the towing capacity of the installation vessels. This method requires several marine vessels, but these will be less expensive than specialist offshore lay barges.

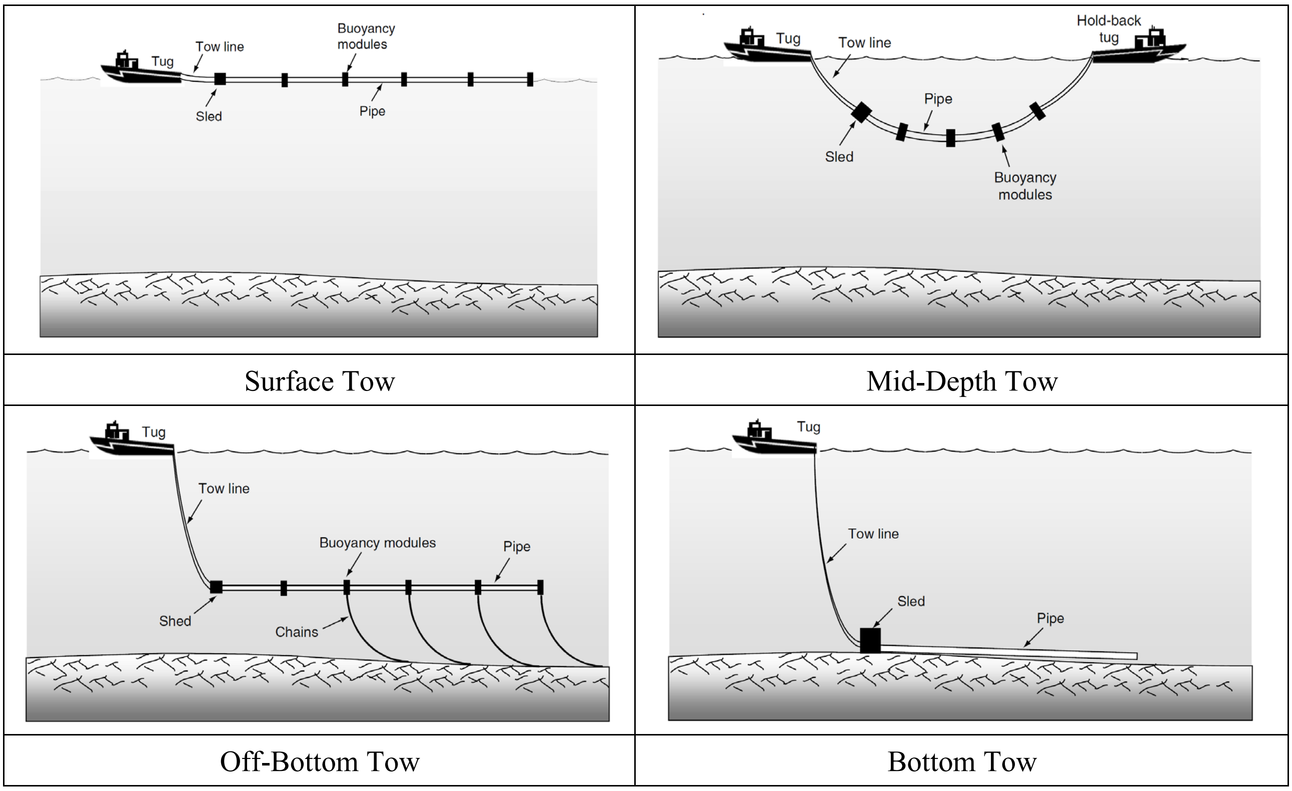


Figure 63: Towing Pipeline Installation Methods

For the surface tow approach, buoyancy modules are added to the pipeline so that it floats at the surface. Once the pipeline has reached the site the buoyance modules are removed or flooded to allow the pipeline to settle to the seabed. The mid-depth tow method is a variation on this with less buoyancy modules so that the pipeline will drop to the seabed when the forward motion of the tow vessels ceases. The off-bottom approach involves buoyancy module and chains to add weight to control the depth of the tow. Removal of the buoyancy allows the pipeline to settle onto the seabed. The bottom tow approach allows the pipeline to sink to the bottom and it is then towed along the sea floor. This is only appropriate for soft and flat sea floors in shallow water.

S-Lay

The S-Lay method (Figure 64) is the most common of the offshore pipeline installation methods and involves the use of a specialist pipeline lay barge (Figure 65) to progressively and continuously fabricate and lower the pipeline onto the seabed. The pipeline is fabricated on board the lay barge in a continuous process which involves welding the pipe sections together in a controlled environment at a number of welding stations, undertaking the Non Destructive Testing (NDT) to check the welds. Common NDT methods include radiographic testing (RT), ultrasonic testing (UT), and magnetic particle inspection (MPI). The final step is for the pipeline to pass through the field jointing station to infill the corrosion protection coating across the joints. The S-lay method requires substantial deck space on the lay vessel for pipe storage, handling, and assembly. This constraint can limit the pipe laying capacity and necessitate the use of additional pipe transportation and storage barges to improve logistics.

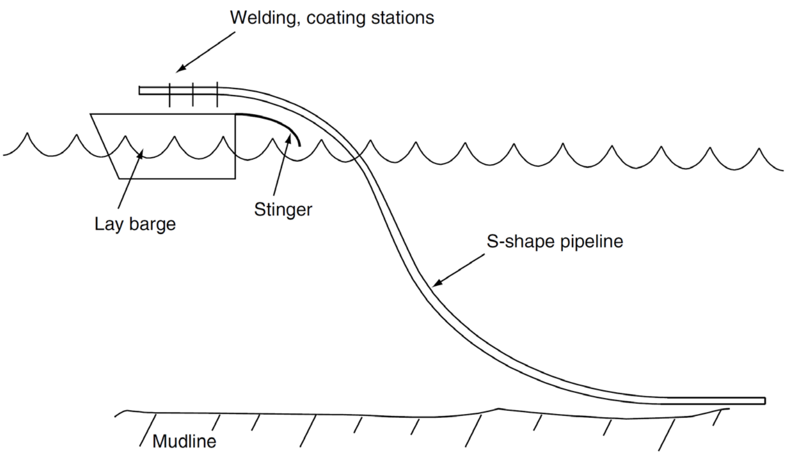


Figure 64: S-Lay Pipeline Installation Method

As the barge moves forward, the pipe is then fed horizontally off the stern of the lay barge over a support structure known as a stinger, which can be up to 100m long, either as a single structure or in 2-3 articulated sections. This reduces the bending stresses in the pipe. The pipe curves down through the water until it touches the seabed. As more pipe is fed out the pipe resembles an S-shape profile. To avoid buckling the pipe a tensioning roller and controlled forward thrust is used to maintain the pipeline in tension. Tensioners on the vessel / barge pull on the pipeline, keeping the whole section to the seabed in tension. The reaction of this pull is taken up by anchors installed ahead of the barge or, in the case of a dynamically positioned (DP) vessel, by thrusters.

S-Lay is used for pipeline installations in a range of water depths. Deeper water requires longer stingers and higher tension which increases the risk. Typical lay rates are around 3-4km per day and the larger lay barges can accommodate up to 60” diameter pipelines.

Figure 65: Typical S-Lay Vessel – Allseas Solitaire (© Allseas)

J-Lay

The J-Lay method (Figure 66) is similar to S-Lay but the pipe is fed close to vertical off the rear of the lay barge which reduces the tension force required to prevent pipe buckling and removes the need to use a stinger or tensioners and forward thrust to control the stresses in the pipeline.

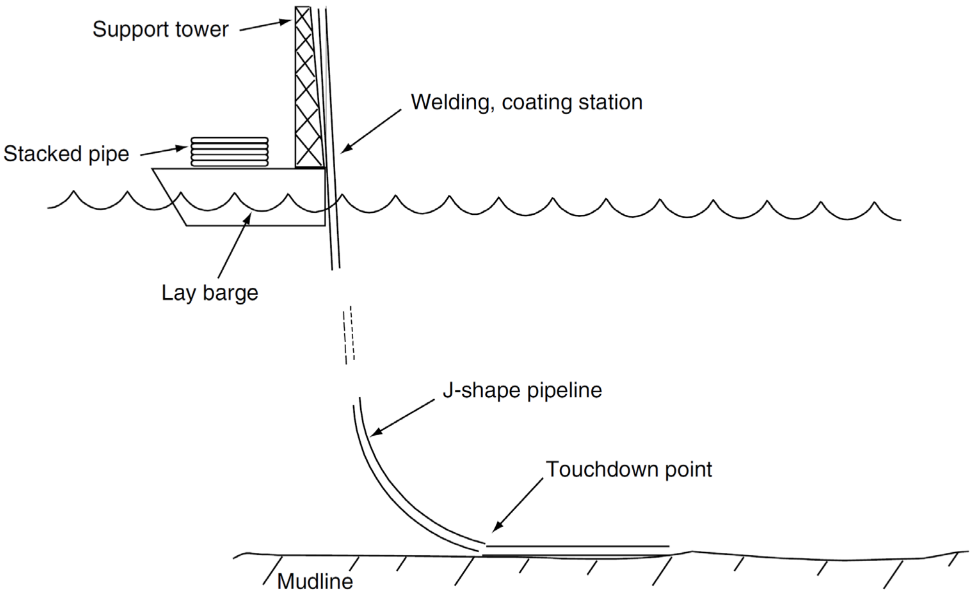


Figure 66: J-Lay Pipeline Installation Method

J-Lay barges have a tall tower on the stern (Figure 67) where the pipe sections are lifted and welded before being lowered to the seabed where the forward progress of the barge pulls the pipeline into a J-shape. This simpler shape allows pipelines to be laid in greater water depths.

Welding is only performed at a single welding station so lay rates are slower. Typical lay rates are therefore only 1-1.5km per day and the maximum pipe size is around 32" diameter.

Figure 67: Typical J-Lay Vessel – Saipem 7000 (© Saipem)

B.2.1.1 Reel Lay

Small-diameter pipelines can be installed with reel barges (Figure 68) where the pipe is welded and coated in a controlled environment onshore and spooled onto reels in a continuous length to reduce costs. Horizontal reels lay pipe with an S-lay configuration. Vertical reels most commonly do J-lay but can also S-lay.

Much lower tension is required which gives more control when S-Laying. There are limitations on the diameter of the pipeline and coating types as no concrete weight coating or stiff insulation coating can be accommodated. The reel capacity will be limited by volume of weight, but the typical lay rate is much higher, at around 12-15km per day.

Figure 68: Typical Reel Lay Vessel – Subsea 7 Seven Navica (© Subsea 7)

Once the most suitable method of installation for the project conditions and design requirements has been established the specialist installation vessel must be procured. There are limited numbers of these types of vessels operating in the world and lead times for availability can be very long. The vessel needs to be booked well in advance to ensure its availability in the required installation period. Pipeline installation vessels have envelopes for operating conditions which will restrict the times of the year when pipes can be laid, and this will need to be considered in the installation programming.

Landfalls mark the critical transition point between subsea pipelines and onshore facilities. Various techniques are used to achieve a secure connection while minimising environmental impact and ensuring pipeline integrity. These include:

- Pull ashore into cofferdam: A cofferdam, a temporary watertight structure, is constructed around the landfall area. The pipeline is pulled ashore from the lay barge through a trench and into the cofferdam, where it is connected to the onshore facilities. Once the connection is complete, the cofferdam is removed, and the trench is backfilled.
- Pull offshore from onshore construction site: In this method, the pipeline is assembled onshore and pulled into the water using winches or other pulling equipment on the lay barge. This technique is typically used for smaller pipelines or when environmental constraints limit access to the landfall area.
- Directionally drilled landfalls: Directional drilling technology allows for a more precise and controlled installation of pipelines under sensitive coastal areas, minimising environmental impact. The pipeline is pulled through a pre-drilled hole, connecting the subsea and onshore sections.
- Offshore pipeline installation will then commence at one end of the pipeline route. Typically, the pipe lay barge would manoeuvre as close as possible, given water depth constraints, to the landfall site and commence fabrication of the pipe away from the shore connection point.

Once the connection is made the lay barge will start to lay the pipe and progress away from the shore by a series of steps if tethered by anchors or utilising the vessel's DP system. Line pipe will be continuously supplied by barge to the lay barge to ensure the installation proceeds without interruption. Pre lay surveys will be undertaken in advance of the pipe installation barge to ensure any seabed obstructions or crossing locations are identified and mitigated as required. Post lay surveys will also be undertaken to confirm the placement of the pipeline and any stabilisation measures required.

If conditions, such as bad weather, require it, the fabrication process can be stopped, and the pipeline dropped to the seabed (after welding on an end cap to prevent water from entering the pipeline) and then retrieved when construction is able to restart.

The design process will determine the requirements for pipeline stabilisation and protection. This will be dependent on the seabed conditions and the potential for damage to the pipeline during operation. In areas where the seabed current forces are small and the seabed is stable or areas away from the risk of damage, the pipeline could be laid directly onto the seabed. Over time the pipeline may self-bury or be covered by sediments. Pipelines laid on the surface can be covered with rocks or concrete mattresses. This method is good for a pipeline laid on a hard rock sea bottom which is difficult to be buried.

- If more protection is required, the pipeline may need to be lowered below the seabed level in a trench.
- Offshore pipelines are trenched for such conditions and requirements as:
- Physical protection from anchor dropping or trawl dragging.
- On-bottom stability.
- Approval authorities' requirements.
- Trenching equipment should be selected based on seabed soil conditions. Different methods and equipment are available depending on the soil type:
- Ploughing – all types of soil (Figure 69)
- Jetting – sand and soft clay
- Mechanical excavation & cutting – stiff clay and rock (Figure 69)

- Dredging – all types of soil

Trenching Plough © Delta Subsea Deepocean

Seabed Pipeline Trencher © Seatools B.V.

Figure 69: Typical Trenching Equipment

The open trench could be covered by natural sedimentation depending on soil conditions and currents near sea bottom. However, backfilling after the trenching or burial may be required for additional protection and thermal insulation purposes. Burial in the open trench could be achieved by creating backfill soil by cutting the top of each side of the open trench using the same equipment used for trenching and allowing it to fall on the pipeline. Alternatively imported material could be placed onto the pipeline utilising a fall pipe vessel to accurately place the material from the surface.

Following installation and stabilisation the pipeline will be pre-commissioned to confirm its integrity prior to the introduction of hydrogen. This verification process generally involves flooding the line with treated fluids and sending a cleaning pig down the line to clear out any accumulated debris followed by a gauging pig to prove it is of full bore over the entire length. The pipeline would then be hydrostatically tested to confirm the overall system integrity and check for leaks. The system will be pressurised beyond the design pressure to confirm the pipeline design. After successful hydrotesting and leak testing and before introducing hydrogen, the pipelines will need to be dewatered, dried, and purged.

B.2.2 Routeing

Preliminary pipeline routeing was completed manually using ArcGIS software. The routeing considered the constraints of constructing as new crossing, such as existing and planned energy infrastructure including oil and gas platforms and pipelines, subsea cables and offshore wind farms, bathymetry, shipping lanes, environmentally designated areas, military areas, dredging areas, shipwrecks, The datasets used to inform the routeing of new pipeline connections are shown in Figure 70. The datasets were taken from publicly available sources.

AMZ_EMOD_AggregateArea_Pl
AMZ_EMOD_DischargePoints_Pt
AMZ_EMOD_DredgeSpoilDump_Pl
AMZ_EMOD_DredgingZone_Pt
AMZ_EMOD_MilitaryAreas_Pl
AMZ_EMOD_MunitionsZone_Pl
AMZ_GFW_Anchorages_Pt
ENG_ARUP_ExportTerminals_Pt
ENG_ARUP_GasTerminals_Pt
ENG_ARUP_ImportTerminals_Pt
ENG_EMAP_Nodes_Pt
ENG_EMAP_PipeSegments_Ln
ENG_EMAP_Production_Pt
ENG_EMAP_Storage_Pt
ENG_EMOD_OceanEnergyFacilities_Pt
ENG_EMOD_OceanEnergyTestFacilities_Pt
ENG_EMOD_WindFarms_Pl
HIS_EMOD_ShipWrecks_Pt
IND_EMOD_OilPlatforms_Pt
INF_ARUP_UKHydrogenProjects_Pt
PRO_EMOD_NationallyDesignatedAreas_Pl
PRO_EMOD_WorldDatabaseProtectedArea_Pl
TPT_ARUP_GlobalPorts_Pt
UTI_EMOD_BSHContisCables_Ln
UTI_EMOD_CICACables_Ln
UTI_EMOD_MaltaCables_Ln
UTI_EMOD_OilGasPipelines_Ln
UTI_EMOD_PowerCablesNVE_Ln
UTI_EMOD_PowerCablesRijks_Ln
UTI_EMOD_PowerCablesSHOM_Ln
UTI_EMOD_RijksCables_Ln
UTI_EMOD_SHOMCables_Ln
UTI_EMOD_SigCables_Ln
UTI_EMOD_UKFibreCables_Ln

Figure 70: Datasets used in the pipeline routeing process.

The data was visualised and preliminary route alignments were plotted for each route with the objective of minimising the length of the route and minimising interaction with existing constraints identified. Where possible, constraints were avoided entirely however the crossing of some services and impingement into designated areas is unavoidable for long international crossings such as these. An extract of the GIS model showing the constraints map used to plot the pipeline alignments is shown in Figure 71.

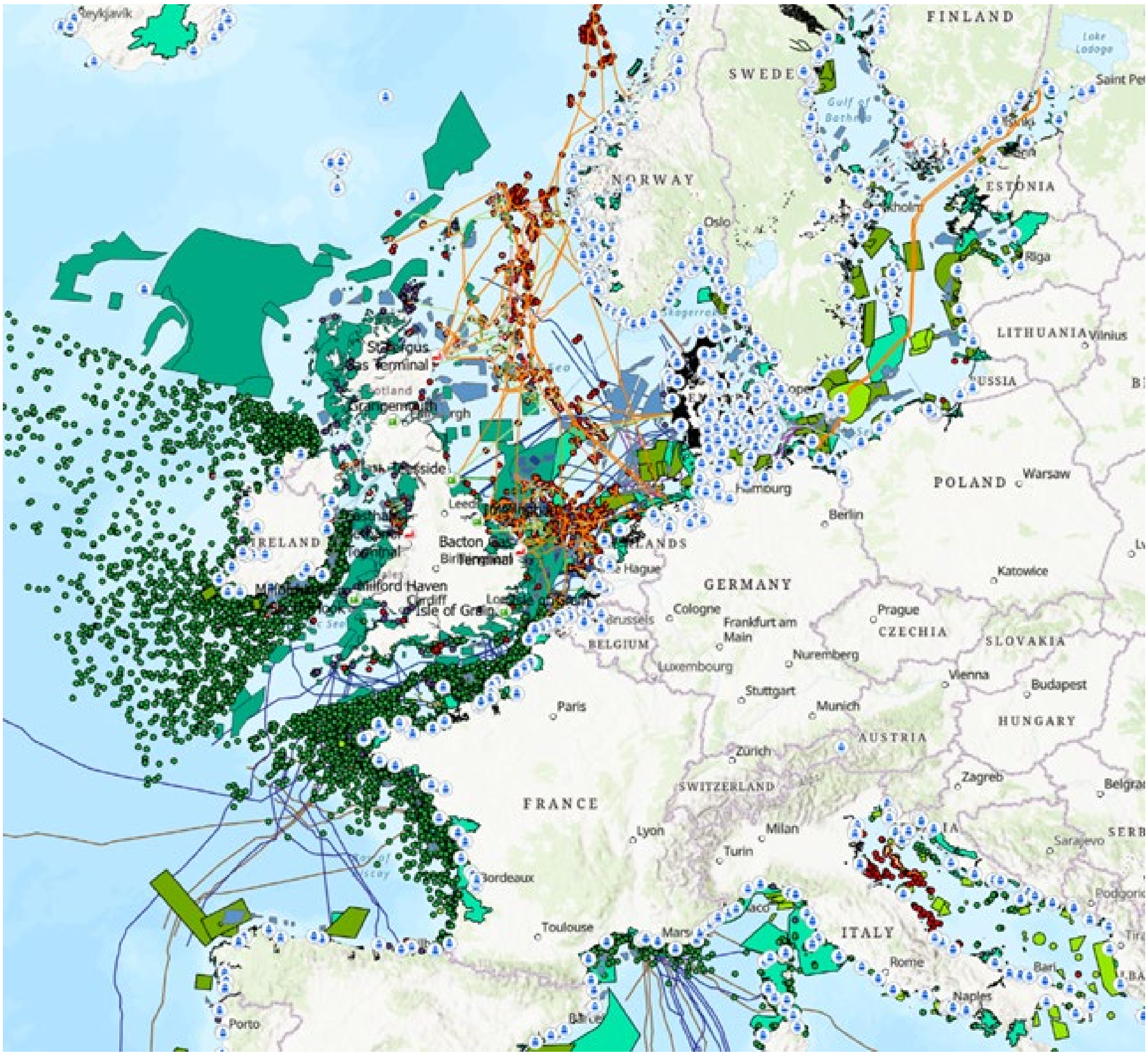


Figure 71: Extract of ArcGIS model shwoing the constraints considered during pipeline routeing.

Free span areas were avoided as far as possible and route selection aimed to maintain a bathymetry profile which would not cause undue difficulty during construction, although this will require further development as the designs progress.

Appendix C

Non-Pipeline Transport Technical Considerations

C.1 Non-Pipeline Transport

C.1.1 UK

In the UK, the main port facilities handling bulk liquids are in the Isle of Grain, Milford Haven, Grangemouth, Immingham, Peterhead, Grangemouth and Teesside. The Isle of Grain, Teesside, and Immingham are located on the East Coast of the UK, while the two facilities in Milford Haven are situated on the West Coast. Grangemouth lies in the Forth Valley, on the banks of the Firth of Forth, and Peterhead is located in Aberdeenshire in Scotland.

C.1.1.1 Milford Haven

At Milford Haven, there are two operational LNG facilities: South Hook LNG Terminal and Dragon LNG. The approach channel is dredged to allow vessels of up to 16.5 m draft to berth on every tide, which varies from 6.3m at Mean Springs to 2.7m at Mean Neaps. South Hook LNG Terminal comprises two jetties, with the ability to unload LNG tanker sizes between 125,000m^3 and 267,000m^3 (South Hook LNG Terminal Company LTD, n.d.). The largest vessel that the facility can accommodate is Q Max, which has an approximate overall length (LOA) of 345m. The facility has 5 storage tanks with a working capacity of 155,000m^3 each (775,000 m^3 total storage capacity).

Figure 72: South Hook LNG Terminal (South Hook LNG Terminal Company LTD, n.d.).

Dragon LNG terminal has two jetties with the capability to accommodate Q-Flex vessels, which have a length, beam, and draught of 315m, 50m and 12.4m respectively. The maximum cargo capacity is 217,500m^3. The facility has a maximum unloading rate of 12,000m^3/h via 3 unloading arms. Dragon LNG has two storage tanks with a capacity of 160,000m^3 each (Dragon LNG, n.d.).

Figure 73: Dragon LNG Storage Terminal (Dragon LNG, n.d.)

C.1.1.2 Isle of Grain

The Isle of Grain has two jetties, a main and a small jetty. The main jetty with a quay length of 550 m is capable of accommodating Q-Max vessels, which has an approximate overall length (LOA) of 345 m. The small jetty is capable of accommodating Q-Flex vessels, which have a length, beam and draught of 315 m, 50 m, and 12.4 m respectively. It also has an LNG storage capacity of 1,000,000 m^3 in eight storage tanks with plans to have an additional 200,000 m^3 by 2025. The approach channel is dredged to allow vessels of up to 13 m draught to berth at the jetties (Gas Infrasturcture Europe, n.d.).

C.1.1.3 Teesside

Teesside Gasport was the first floating facility of its kind in the world. It was located near Middlesbrough in the UK. It could handle up to 600 million cubic feet of natural gas per day at its busiest times. It had a special jetty where floating storage and regasification units could dock, with a capacity of up to 150,900 m^3. The project was decommissioned in 2015 after the facility came to the end of its commercially viable life (Excelerate Energy, n.d.). There is a possibility that an FSRU can be redesigned to store methanol/MCH, however, this might involve several technical challenges including those to containment systems to protect against aggressive sea conditions. Methanol has different properties than LNG, so assessing compatibility with existing materials and coatings is important to consider. On this basis, the study is not looking at the repurposing of FSRUs in further detail.

The movement of liquid bulk cargo is a significant part of Teesport's operations. Nearby facilities contribute to 58% of the UK's chemical sector and export goods worth £12 billion each year. Teesport is utilized by top petrochemical companies for various activities like importing, refining, storing, and exporting products.

On both sides of the River Tees, there are major petrochemical complexes that play vital roles in the supply and distribution chain. ConocoPhillips is one of the well-known companies here, operating the Teesside Oil Terminal at Seal Sands. It processes and exports North Sea crude oil and gas (PD Ports, n.d.). Other significant contributors to the chemical sector in the Tees Valley include SABIC, INEOS Nitriles, Navigator

Terminals, Huntsman, Lotte Chemicals, CF Fertilisers, and Inter Terminals. They all shape the region's industrial landscape and economic activity.

The Seal Sands Methanol Terminal, located on the north bank of the River Tees, is crucial to the UK's chemical cluster. It has various types of storage tanks and can be accessed by pipeline, truck, and vessel. There are three berths available for vessels, and the terminal is well-connected to local industries through its pipeline system.

The sector and its associated movements of liquid bulk cargo constitute a substantial portion of Teesport's overall volumes, with nearby facilities contributing to 58% of the UK's chemical sector and facilitating the export of £12 billion worth of cargo annually. Teesport has attracted some of the world's leading players in the petrochemical industry, who utilise its facilities for various activities such as importing, refining, storing, converting, blending, manufacturing, adding value, and exporting their products. (PD Ports, n.d.)

Both the north and south banks of the River Tees host several major petrochemical complexes, each playing a crucial role in the extensive supply and distribution chain of this significant cluster. Among the globally renowned companies operating in and around the River Tees is ConocoPhillips, whose Teesside Oil Terminal at Seal Sands serves as a reception point for North Sea crude oil and gas via the Ekofisk pipeline, followed by processing and exportation (PD Ports, n.d.).

Other notable contributors to the chemical sector in the Tees Valley include SABIC, INEOS Nitriles at Seal Sands, Navigator Terminals, Huntsman, Lotte Chemicals, CF Fertilisers, and Inter Terminals, all of which play pivotal roles in shaping the region's industrial landscape and economic activity. (PD Ports, n.d.) The Seal Sands Methanol Terminal, situated on the north bank of the River Tees, is an essential part of the UK's largest chemical cluster. The terminal has a storage capacity of 283,467m^3 (Navigator, n.d.). It features tanks made of stainless steel, coated steel, mild steel, spheres, and temperature-controlled tanks with sizes ranging from 65 to 8,500m^3. The terminal can be accessed via pipeline, truck, and vessel. For vessels, there are three berths available. The ConocoPhillips No 1 Jetty, No 2 Jetty, and No 8 Jetty have a maximum permissible draught of 11.5m, 11m, and 7.5m respectively, with a berth size of 8.3m for ConocoPhillips No 1 and No 2 jetties. Furthermore, the terminal is fully integrated into the pipeline system, making it well-connected to local industries (PD Ports, n.d.).

C.1.1.4 Grangemouth

The Grangemouth terminal has a dedicated liquid bulk terminal for oil and gas and is situated within close proximity, approximately 5km, of several major industrial complexes, including Petroineos Manufacturing and INEOS Chemical sites. Additionally, it is conveniently located near Forth Ports, which has the potential to utilise hydrogen for bunkering fuel and within its port equipment. (Forth Ports, n.d.)

Situated within Grange Dock on Scotland's east coast, ED&F Man's Grangemouth terminal offers convenient access to the markets of Glasgow, Edinburgh, and the Central Industrial belt of Scotland. It caters to third-party bulk liquid natural product and low hazard chemical markets in Scotland. The terminal's strategic location on the East Coast ensures efficient connections to all core European Ports. The terminal capacity is 18,953m^3, handling oils and fertilizers in 43 tanks that can be served by vessels, barges, and trucks. With the facilities already housing heated and stainless-steel tanks, the terminal allows vessels with an LOA of 180m and a draught of 9.9m. (ED&F MAN, n.d.)

The Grangemouth site is undergoing significant development, with plans for the establishment of hydrogen production facilities. (INEOS, n.d.) Situated along the shoreline of the Firth of Forth, it occupies an area designated as a Site of Special Scientific Interest (SSSI), a Special Protected Area (SPA), and a Ramsar site. This designation is due to its crucial role as a habitat for numerous wintering waders and wildfowl, many of which exist in nationally and internationally significant numbers.

C.1.1.5 Immingham

The Immingham Oil and Tanker Terminals are currently capable of receiving LPG tankers of LOA 280m, 11m draught, and 87,000m^3 capacity at four berths (IHS Maritime and Trade Ports and Terminals Guide, 2017 IHS Global).

ABP is bringing forward proposals to construct, operate and maintain the Immingham Green Energy Terminal (IGET) – a new multi-user liquid bulk green energy terminal located on the eastern side of the Port of Immingham. This facility will include a new jetty for the handling of bulk liquids, including loading arms and pipelines. On the land side, infrastructure will include a jetty access road and related infrastructure, two operational sites supporting hydrogen production facilities (an East Site and a West Site). This will include pipework, pipelines, and utilities, to support green hydrogen production and distribution.

A refrigerated ammonia storage tank (on the East Site) will be installed for the production of hydrogen units that convert ammonia to produce the green hydrogen (on both East and West Sites). Finally, hydrogen liquefiers to liquify the hydrogen for temporary storage on the West Site will be constructed and loading bays to fill road tankers with liquified hydrogen which would then be distributed to hydrogen filling stations throughout the UK (on the West Site). The facility will also include a hydrogen refuelling station and bulk hydrogen trailer filling station. The image below shows an illustrative map of the proposed new layout (ABP and AIR Products, n.d.).

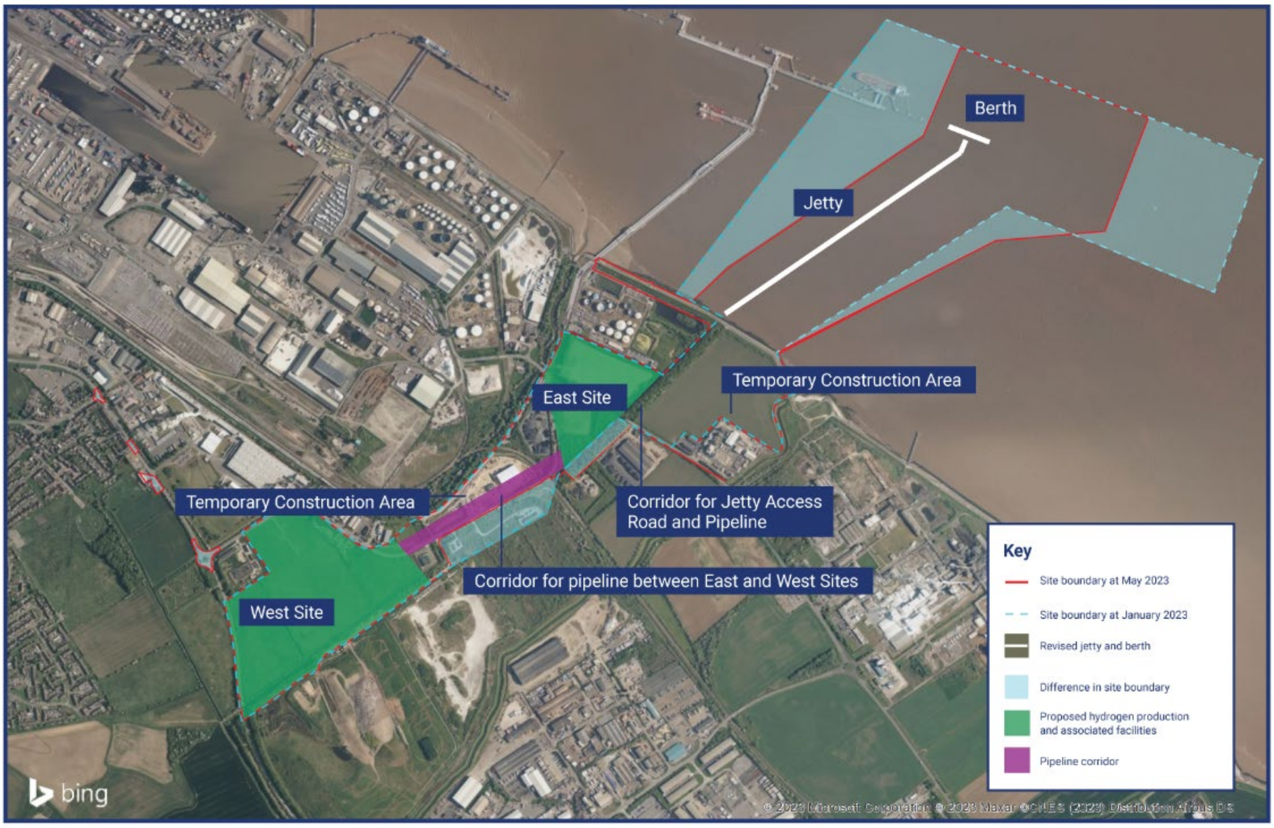


Figure 74: Illustrative map showing proposed site layout at Immingham (ABP and AIR Products, n.d.)

C.1.1.6 Peterhead

The Peterhead Port in the United Kingdom is a versatile harbour that caters to various industries, including oil and gas, renewables, fishing, and leisure. The port can accommodate vessels with depths up to 14 m. It has the capability to accommodate small-scale methanol/MCH facilities, however, the site is in close proximity to the town, and it has constrained port entrance access for larger vessels, and the jetty is likely able to accommodate small-mid range carriers. Due to the technical constraints highlighted and limited expansion options within the harbour, plans to accommodate larger methanol/MCH facilities with the ability to berth accompanying vessel sizes within the harbour are challenging. A new facility would require new berthing infrastructure, including modifications to the outer harbour and come with additional legislation challenges, e.g. an amendment to the Harbour Revision Order (HRO), new marine licenses, etc.

C.1.2 Europe

C.1.2.1 North Sea Ports

C.1.2.1.1 Antwerp

With more than 6 million tonnes of fuel bunkered in 2022, The Port of Antwerp-Bruges is the fifth largest bunkering port in the world. The port is transitioning towards a multi-fuel port where, in addition to conventional fuels, more sustainable alternatives can be bunkered. LNG is already bunkered on a regular basis. By 2025, the port aims to become a fully-fledged multi-fuel port, in which seagoing and inland vessels will be able to bunker low-carbon fuels such as methanol, ammonia, hydrogen, or electricity. (Logistics Insider, n.d.)

The Antwerp Terminal & Processing Company has 90 mild steel / 900,000m^3 storage tanks and 5 gas tanks/ 35,000m^3 storage tanks of LPG and Chemical Gas storage.

The Belgian energy infrastructure company Fluxys, in collaboration with local firms Advario Stolthaven Antwerp and Advario Gas Terminal, is conducting a feasibility study for the development of an open-access green ammonia import terminal at the Port of Antwerp-Bruges. The collaboration among the three companies involves leveraging their respective strengths in logistics, storage, and pipeline transmissions to determine the most effective ammonia storage solution for northwest Europe. This initiative responds to the increasing demand for importing and storing green energy amidst Europe's push for decarbonisation. Situated at Belgium's Port of Antwerp-Bruges, the forthcoming terminal aims to commence operations in 2027. It will offer storage facilities and multimodal logistics services for ammonia, accommodating transportation via train, truck, barge, and potentially through ammonia pipelines linked to nearby industrial sites (Offshore Energy, n.d.).

Figure 75: Stolthaven Terminals. Source: (Offshore Energy, n.d.).

By 2026 an open-access hydrogen backbone will be in operation in the Antwerp platform, connecting Antwerp to Zeebrugge and the German hinterland between 2028 and 2030. The existing terminal infrastructure for ammonia, methanol and LNG will be adapted in the coming years for the rising hydrogen import flows and connected to splitting or cracking installations for reconversion to hydrogen gas.

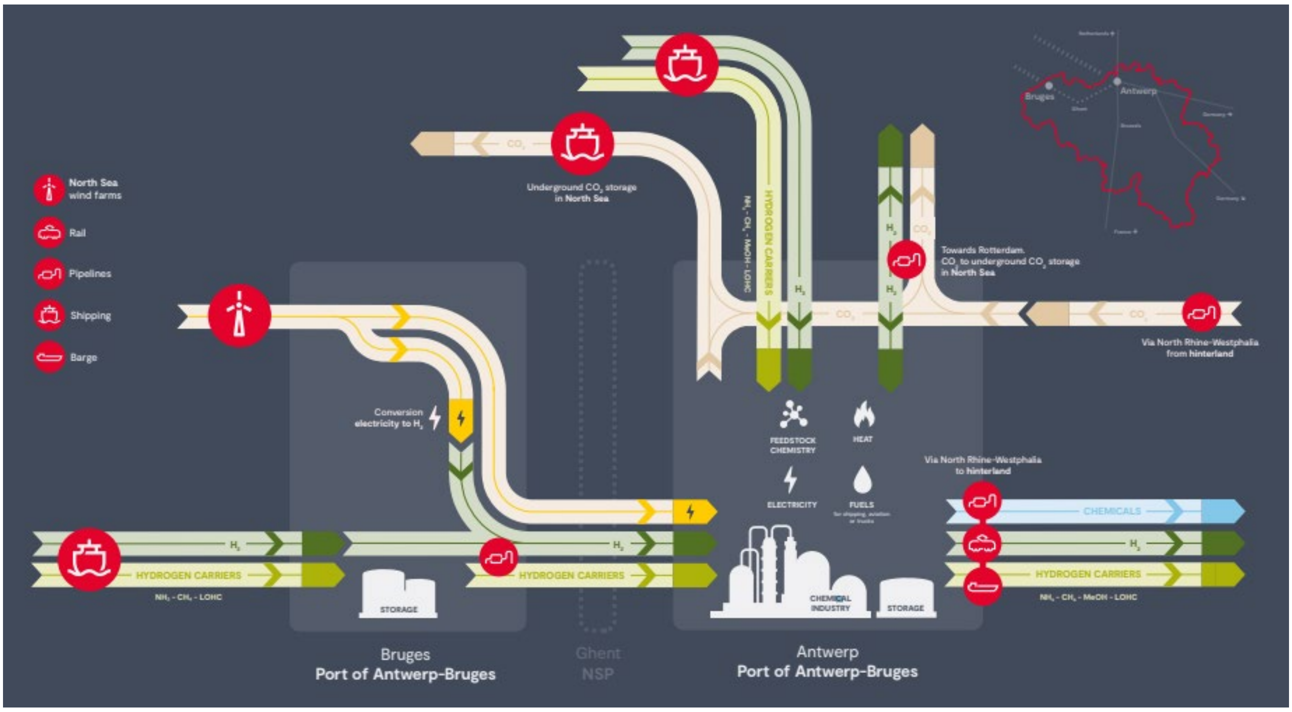


Figure 76: Future Green Gateway Plan for Port of Antwerp. Source: (GreenPort, n.d.).

C.1.2.1.2 Zeebrugge

The port of Zeebrugge, situated on the Belgian coast of the North Sea, is the second-largest port in Belgium and closely associated with the city of Bruges. It is located 12 nautical miles west of the mouth of the Scheldt estuary and 5.4 nautical miles west of the Dutch/Belgian border. The port handles containers, Ro-Ro and bulk traffic and is a transshipment location for coastal and river traffic. Principal commodities handled include vehicles, LNG, and forestry products. A new dredging programme aims to accommodate vessels with a 16.7 m draught.

The Zeebrugge LNG Terminal, owned by the Belgian energy infrastructure group Fluxys, has a maximum berth length of 385 m, with vessels of a maximum size of LOA 350 m, draught of 12m, and gas capacity of 135,000 m^3. Fluxys LNG has initiated a call for market interest aimed at expanding and reconfiguring the terminal in Zeebrugge to facilitate the importation of hydrogen and its derivatives. Interested parties, as stated by the company, are invited to indicate their interest in various offerings, including services for carbon-neutral bio-LNG or synthetic LNG, hydrogen, hydrogen derivatives, compressed natural gas (CNG), and conventional LNG (Offshore Energy, n.d.).

The EuroServices Terminal with a maximum berth length of 350 m handles LPG bunkers with a maximum LOA of 230 m and draught of 9 m. This facility could be repurposed to handle ammonia in the future.

C.1.2.1.3 Dunkirk

The LNG terminal at Dunkirk will have 1.5 billion m^3 in 2026 and up to 3.5 billion m^3 of regasification capacity as of 2027, adequate to fulfil around 20% of France and Belgium's yearly gas consumption. Ranking as the second-largest terminal on the European continent, it stands out as the sole facility directly linked to both the French and Belgian markets through two distinct pipelines (Fluxys, n.d.).

Spanning a 56-hectare area adjacent to Dunkirk's Western Harbour, the Dunkerque LNG terminal features a jetty ready to receive vessels ranging from 5,000 m^3 to the largest Q-max LNG carriers, with a capacity of 265,000 m^3. These vessels can unload at a peak rate of 14,000 m^3 per hour and reload at 8,800 m^3/h. The terminal comprises three storage tanks, each capable of holding 200,000 m^3 of LNG at a frigid temperature of -162°C. Additionally, it houses 10 Open Rack Vaporizers (ORVs) to elevate the LNG's temperature, transforming it back into natural gas suitable for distribution. Moreover, a 5km tunnel connects the discharge canal of the Gravelines nuclear power plant to the terminal, facilitating the transfer of heated cooling water from the plant to aid in reheating the LNG in the ORVs (Fluxys, n.d.).

The Rubis Terminal in Dunkirk is an efficient storage and distribution termina for liquid bulk products including ethanol and biofuels with a storage capacity of 475,000 m^3 in 125 tanks with sizes ranging from 260 to 23,000 m^3. Ther terminal has four jetties and a draught of 10 to 13.3 m. These terminals showcase the port of Dunkirk's capability of handling various fuels, with the capacity to repurpose existing infrastructure to handle hydrogen, methanol, MCH, and ammonia (Fluxys, n.d.).

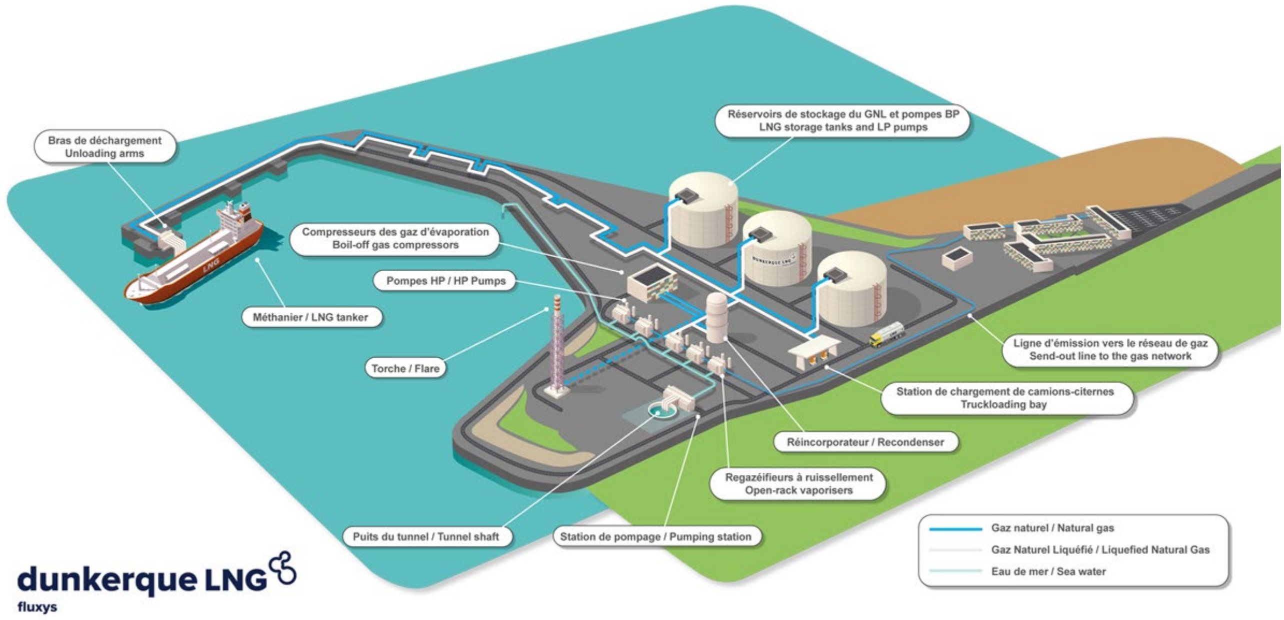


Figure 77: Dunkirk LNG Infrastructure. Source: (Fluxys, n.d.).

C.1.2.1.4 Hamburg

The Port of Hamburg is Germany's largest and most important port, with over 320 berths, handling a wide variety of cargoes and especially prominent in container and petroleum movements. The Vopak Dupeg Terminal handles liquefied gas and biofuels and has a maximum berth length of 130 m which can berth vessels of LOA 25 m, draught of 13 m and 85,000 DWT. (IHS Maritime and Trade Ports and Terminals Guide, 2017 IHS Global)

With a storage capacity of approx. 670,000 m^3, which is primarily used for the storage of petroleum products, the Evos Hamburg GmbH terminal is located directly in the port of Hamburg and has five jetties for seagoing vessels and barges. In addition to the existing storage facilities, the terminal also offers specialised transhipment facilities and access to the road and rail network. The terminal offers the storage and transhipment of liquid mineral oils, biofuels, base oils and vegetable oils (Port of Hamburg, n.d.).

Figure 78: Evos Hamburg GmbH terminal, Port of Hamburg. Source: (Port of Hamburg, n.d.).

C.1.2.1.5 Rotterdam

Rotterdam is situated on the mouth of the River Maas and is the premier port of the North European hinterland. The port's large industrial centre and its position at the gateway of the European inland waterway network enable it to produce a large throughput of cargo. Rotterdam is well equipped for handling this throughput having facilities for bulk and general cargoes, coal and ores, crude oil, LNG, biofuels, agricultural products, chemicals, containers, cars, fruit and refrigerated cargoes. The Gate Terminal, a joint venture of Gasunie and Vopakin, is a dedicated LNG terminal consisting of three storage tanks, each with a storage capacity of 180,000 m^3. The maximum berth length of the terminal is 362 m with an LOA of 350 m, draught of 12.5 m, and capacity of 267,000 m^3. The Tanker terminals that receive LPG have a maximum berth length of 285 m and can receive vessels of LOA 220 m, draught of 12 m, and 40,000 DWT. The port is at the forefront of the energy transition and with successful hydrogen and methanol bunkering already taking place. Hydrogen is already being bunkered at the port on a small scale. One example is the hydrogen-powered water taxi, which emits only water. A small-scale hydrogen bunkering station is under construction. Inland shipping is also preparing to run on hydrogen. The port of Rotterdam is the largest methanol location in north-western Europe. Ship-to-ship bunkering has taken place at the port successfully several times. The largest traders and producers of methanol operate in the port, including Methanex, OCI and Proman. Methanol can be stored at various tank storage terminals at EVOS, Vopak, ETT and Koole (Port of Rotterdam, n.d.).

Figure 79: Rotterdam liquid bulk storage. Source: (Port of Rotterdam, n.d.).

C.1.3 Mediterranean Sea Ports

C.1.3.1 La Nouvelle

Port-La Nouvelle, situated in the Mediterranean, is undergoing a significant transformation into a pivotal location for the energy transition in France. Presently, its liquid bulk facilities encompass a berth (D2) tailored for tanker vessels with a length overall (LOA) of up to 145 m and a summer draught of 8 m. Looking ahead, the port is poised to introduce a new berth, P1, managed by EUROPORTS-CLTM, which will accommodate ocean-going vessels with a draft of up to 14.5 m (ranging from 60,000 to 80,000 DWT). P1 will incorporate a framework supporting pipelines facilitating the delivery to onshore terminals and liquid bulk storage areas. Additionally, plans include the potential construction and operation of three similar berths adjacent to the North breakwater.

FOSELEV, an independent private operator, occupies 10 hectares within the liquid bulk terminal. It holds the distinction of being classified as a Green SEVESO High-Level terminal due to its focus on handling non-polluting products. FOSELEV's facilities comprise six truck loading/unloading stations, a weighbridge, and two railcar loading stations integrated into a sizable private rail yard. The terminal has 39 storage tanks with a total capacity of 82,000 m^3: 6 tanks of 1,000 m^3 in 316 L stainless steel, 24 tanks in 304 L stainless steel (7 x 2,350 m^3, 15 x 1,300 m^3 and 2 x 500 m^3) and 9 tanks in carbon steel (4 x 5,000m^3 and 5 x 2,350m^3) (Port La Nouvelle, n.d.).

Figure 80: FOSELEV terminal. Source: (Port La Nouvelle, n.d.).

The Hyd'occ plant, with an estimated completion date by the end of 2024, will generate renewable hydrogen on a large scale to fulfil local demands in heavy mobility, industrial applications, and power generation. Commencing operations in 2025, the plant will initially produce 3,000 tonnes per year, with projections to increase output to 6,000 tonnes per year (equivalent to 50 MW) by 2030 (Port La Nouvelle, n.d.).

C.1.3.1.1 Thessaloniki

Thessaloniki, in Greece, is a Mediterranean port that serves as a gateway to the Balkans. The Tanker Terminals currently receive LPG bunkers of a maximum LOA of 240 m and 12.8 m draught. It's strategic location between the Balkans and Europe could serve as a location for importing and exporting hydrogen and its derivatives, such as ammonia, methanol, and MCH (IHS Maritime and Trade Ports and Terminals Guide, 2017 IHS Global).

C.1.3.1.2 Aspropyrgos

The Aspropyrgos Port, located in Greece, is strategically positioned to play a significant role in the energy transition. The port can facilitate the import, export, and distribution of clean hydrogen and its derivatives including ammonia, methanol, and MCH. The Bunkering Tanker berths which currently handle LPG bunkers can be repurposed to handle hydrogen derivative carriers with a maximum berth length of 295 m and draught of 11.7 m (IHS Maritime and Trade Ports and Terminals Guide, 2017 IHS Global).

C.1.3.1.3 Revithoussa

The Revithoussa LNG Terminal in Greece serves as a critical facility for LNG operations. It is Greece's only LNG terminal that receives, temporarily stores, regasifies LNG, and supplies the National Natural Gas Transmission System. The terminal has a storage capacity of 225,000 m^3 LNG and a regasification capacity of 1,400m^3/h (DESFA, n.d.). While Revithoussa primarily deals with LNG, its infrastructure and expertise can be leveraged for hydrogen derivatives including methanol and MCH.

Figure 81: Revithoussa LNG terminal. Source: (DESFA, n.d.).

C.1.3.1.4 Venice

Situated in the North Adriatic Sea, the Port of Venice connects Europe to the Mediterranean. The Tanker Terminals in the port can handle bunkers of a maximum LOA 220m and draught of 10.4 m at the 440 m long berth. Current imports and exports include crude oil, oil products, liquid fuels, liquefied gases, chemical products, and fertilisers making it an ideal location for the potential storage and shipping of ammonia, methanol, and MCH in the future (IHS Maritime and Trade Ports and Terminals Guide, 2017 IHS Global).

C.1.3.1.5 Sines

Since 1981, the Port of Sines has been home to a specialised terminal for handling petrochemical products known as the TPQ – Petrochemical Terminal. This terminal facilitates the efficient movement of goods through a dedicated pipeline connecting vessels to the petrochemical complex situated in the Sines Industrial and Logistics Area or Zona Industrial e Logística de Sines (ZILS). Repsol Polímeros operates this terminal under a private use concession regime (Port de Sines, n.d.).

The TPQ features two jetties equipped with berths at a depth of 12m, enabling the reception of vessels with cargo capacities of up to 20,000m3. These vessels transport a range of products including Propylene, Ethylene, Butadiene, ETBE, Ethanol, MTBE, Aromatic Compounds, and Methanol. Complementing the terminal infrastructure is a storage park, housing essential facilities such as two cryogenic storage tanks for ethylene (25,000 m^3) and propylene (22,000m^3), two butadiene spheres with capacities of 4,500m3 each, an ETBE tank holding 10,000m^3, and an ethanol tank with a capacity of 6,000m^3 (Port de Sines, n.d.). This terminal has a fuel bunkering facility managed by Petrogal which allows the supplying of ships at the TGL through a fixed installation and throughout the port by barge (Port de Sines, n.d.).

Figure 82: Port of Sines Petrochemical Terminal. Source: (Port de Sines, n.d.).

C.1.3.1.6 Barcelona

The Port of Barcelona has a handling capacity of 4 million m^3 for products including chemical, oil, and biofuel products at the Muelle de la Energia. This terminal is strategically equipped with direct rail, road, and oil pipeline connections to both the Spanish hinterland and the wider European rail networks. Within the port area, ten dedicated terminals cater to liquid bulk, encompassing petroleum products to chemicals. The combined storage is spread over 18 berths capable of accommodating vessels with draughts of up to 15.1 m. These berths are specifically designed to accommodate new generation ships of up to 275 m LOA and 150,000 DWT. Furthermore, the port features an LNG dock equipped to handle gas carriers up to Q-Max size, alongside state-of-the-art regasification facilities and storage tanks with a capacity exceeding 840,000 m^3 of LNG (Port de Barcelona, n.d.).

These terminals are meticulously prepared to meet the diverse needs and demands of various liquid bulk products prevalent in the market, including chemicals, oil derivatives, and biofuels. With its ample storage capacity and extensive direct connections, the Muelle de la Energia has the capability to facilitate the storage and transportation of hydrogen, methanol, and MCH in the future (Port de Barcelona, n.d.).

Figure 83: Port of Barcelona LNG dock. Source: (Port de Barcelona, n.d.).

C.1.3.2 Baltic Ports

C.1.3.2.1 Gdansk

Gdansk is situated at the mouth of Wisla River, in the North of Poland, on the southern Baltic coast. Port Gdansk consists of two parts which differ in terms of natural operation parameters, the inner port, and the outer port, called Northern Port. The inner port, extends along Martwa Wisla and Port Channel, providing mainly general cargo, handling, and storage services on both sides of the fairway. The outer port features piers, quays and cargo handling stations located directly in the water basins of Gulf of Gdansk. There are modern handling and storage facilities for containers and bulk cargoes of crude oil, heating oils and fuels, coal, and LPG, together forming an area for servicing the energy sector. The LPG Tanker Terminal and Berth has a length of 220 m and currently handles LPG bunkers of LOA 190 m and draught 9.5 m with a maximum capacity of 37,500 m^3. The existing storage facilities can be repurposed to store methanol and MCH (IHS Maritime and Trade Ports and Terminals Guide, 2017 IHS Global).

C.1.3.2.2 Klaipeda

The Klaipėda Liquid Energy Products Terminal, a versatile facility specialising in the dependable and effective management of oil products, is located in Klaipėda, the most northerly Baltic Sea port. The terminal's primary objective is to facilitate the handling, utilising various methods, of oil products sourced from or destined for oil refineries, as well as to provide storage for such products within its tank park. Additionally, the terminal facilitates the importation of liquid products via the KN Liquid Terminal, offering services for the transfer of oil products from tankers to clients' facilities (KN Energies, n.d.).

The terminal operates two berths the location of which is close to the Klaipėda Seaport entrance (berths No 1 and No 2), both with a length of 274 m and a depth of 14 m. Panamax, Aframax and (in exceptional cases) Suezmax type oil tankers are accepted at the berths. The terminal also consists of more than 50 tanks with a capacity of 1,400 m^3 to 31,500 m^3 for oil and other liquid products. The total capacity of the storage tanks is 600,000 m^3. The Klaipėda LNG terminal operates in the southern part of Klaipėda State Seaport, in the Curonian Lagoon at the Kiaulės Nugara Island. It currently consists of an FSRU connecting the gas pipeline and gas metering system and is permanently moored to a berth in the Klaipėda State Seaport (KN Energies, n.d.).

The Port of Klaipėda is poised to transform into an energy location, with plans including methanol-related initiatives. A Memorandum of Understanding (MoU) with Proman, a leading methanol producer, outlines collaboration on methanol bunkering and potential methanol-to-power projects. The agreement includes sharing information on methanol-related aspects, sustainable port development, and joint participation in projects and events. Proman also pledges support for dialogues and partnerships with methanol experts, clusters, associations, and shipping lines (PORT OF KLAIPĖDA, n.d.).

Figure 84: Port of Klaipėda. Source: (PORT OF KLAIPĖDA, n.d.).

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