# UK-Germany Joint Feasibility Study on the Trade of Hydrogen

Produced on behalf of the Bundesministerium für Wirtschaft und Klimaschutz and the UK Department for Energy Security and Net Zero

Study Report | F01

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# Contents

# Executive Summary

As the hydrogen markets develop in the UK and Germany, there is an opportunity to realise pipeline-based hydrogen trade between the two countries. This could either be through a pipeline directly between British and German landfall, connected into an offshore hydrogen network or via connections to the Netherlands or Belgium. To facilitate the international market, several activities require action, particularly those supporting the development of respective domestic markets in the UK and Germany.

These activities include the development of onshore networks, the alignment of technical requirements for the trading of the hydrogen molecule, and supporting the convening of the market to secure agreements between producers and offtakers.

To this end, this study recommends a series of delivery enablers, as set out below, with a preliminary focus in the following areas:

1. – Developing a delivery plan for the minimum regulatory alignment needed to enable an interconnector.
2. – Determining the best mechanism to support the convening of the market.
3. – Performing a high-level techno-economic deliverability assessment of routing options.
4. – Carrying out stakeholder engagement across the hydrogen value chain.

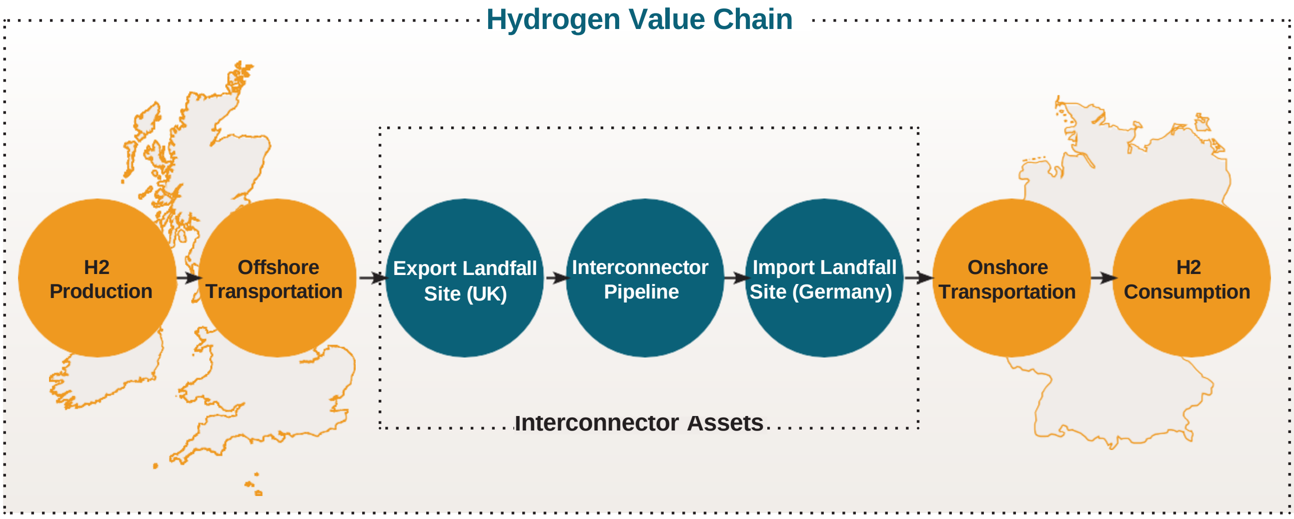



Figure 1
Boundary conditions of the study scope.

## Study scope

This study, conducted under the 'UK-Germany Hydrogen Partnership', outlines the steps required to enable potential pipeline-based hydrogen trade between the UK and Germany in the future.

The study aims to support the development of both countries' hydrogen economies, aiding their net zero ambitions, fostering collaboration, supporting hydrogen trade and transport infrastructure development, and promoting an international hydrogen market.

The specific outputs included: determining the high-level infrastructure requirements; identifying the regulatory, business model and commercial requirements to enable a market to trade hydrogen between the UK and Germany; developing a roadmap outlining the next steps to realise hydrogen trade including associated delivery enabler decisions; and providing a list of proposed actions for the respective Governments.

In this context, the scope of the study has looked at six workstreams; industry engagement, infrastructure assessment, business models analysis, regulatory analysis, commercial arrangements assessment, roadmap development and focus areas.

The analysis of business models, regulations, and the assessment of commercial arrangements considered the whole hydrogen value chain, whilst the high-level infrastructure assessment focused solely on assets related to the interconnector, as defined for this study in Figure 1.

The infrastructure assessment has considered four route options:

– Connection to Germany offshore (Base Case): a subsea pipeline from a UK east coast landfall to an offshore tie-in point on the AquaDuctus offshore pipeline system.
– Connection to Germany onshore: a direct subsea pipeline from a UK east coast landfall to a German coast landfall.
– Connection to the Netherlands onshore: a direct subsea pipeline from a UK east coast landfall to a Netherlands coast landfall.
– Connection to Belgium onshore: a direct subsea pipeline from a UK east coast landfall to a Belgian coast landfall.

**The UK has set interim targets of a**

**68%**

**reduction by**

**2030**

## Opportunity Landscape

The UK and Germany have set ambitious decarbonisation goals, aiming for net zero greenhouse gas (GHG) emissions by 2050 and 2045 respectively when compared to a 1990 baseline.

Within these goals, both countries consider hydrogen playing a key role in their pathway to GHG neutrality.

The UK has also set interim targets of a 68% reduction by 2030 and an 81% reduction by 2035. Low-carbon hydrogen plays a crucial role in this strategy, particularly for sectors that are complex or expensive to electrify.

The latest Hydrogen Strategy Update to the Market, published in December 2024, highlights hydrogen's critical role in the UK's future energy system, by providing a source of cleaner, homegrown energy and significant economic opportunities across the UK.

This update also emphasises the opportunities of leveraging the country's abundant renewable energy resources, by positioning the UK as a future exporter of hydrogen.

The UK Government is currently prioritising the development of domestic low-carbon hydrogen to meet future demand by establishing funding initiatives aimed at enhancing hydrogen infrastructure. Key initiatives include the Net Zero Hydrogen Fund (NZHF) specifically the Hydrogen Allocation Rounds (HAR), and the Carbon Capture Utilisation and Storage Cluster Sequencing Process.

These initiatives, combined with one of the world's largest offshore wind sectors, have enabled the UK to secure a competitive advantage in various low-carbon hydrogen production technologies.

This creates significant opportunities for industry, with over 250 projects currently under development in the UK, presenting a potential pipeline with a production capacity of 25.1 GW by 2030. While current rules restrict funding eligibility to projects for non-domestic offtakers, this potential project pipeline offers the UK an opportunity to emerge as a hydrogen exporter to international markets.

**Following the publication of 'The potential for exporting hydrogen from the UK to continental Europe a study', this study also highlights the potentially competitive price of hydrogen for offtakers in continental Europe.**

Germany has set interim targets of reducing emissions by 65% from 1990 levels by 2030 and 88% by 2040, with low-carbon hydrogen set to play a key role, particularly for sectors that cannot be fully electrified.

Germany's current hydrogen demand is 55 TWh, and the German Government expects it to rise to 95-130 TWh by 2030; this includes the anticipated demand for hydrogen derivatives such as ammonia, methanol, and synthetic fuels.

By 2045, hydrogen demand is projected to be between 360-500 TWh with an additional 200 TWh for hydrogen derivatives. To meet its growing hydrogen demand, Germany aims to achieve a domestic electrolyser capacity of at least 10 GW by 2030 and become one of the largest hydrogen importers globally.

The German Government's 2024 Import Strategy for hydrogen indicates their expectation to import 50-70% of its hydrogen needs by 2030.

The primary infrastructure for importing hydrogen and its derivatives includes pipelines for molecular hydrogen and shipping for hydrogen derivates.

The domestic distribution will be secured through a 9,040 km hydrogen core network, consisting of repurposed natural gas pipelines and new hydrogen pipelines, to be completed by 2032.

By 2030, plans are in place for Germany's hydrogen network to connect with neighbouring EU countries through the European Hydrogen Backbone (EHB), with significant infrastructure developments planned, including import terminals and hydrogen-ready LNG terminals.

**To contribute to Germany's import needs there is the potential to connect UK production to German demand via a hydrogen interconnector.**

Two extremes were identified for how an interconnector project could be structured; 'Project to Network', where one production project is solely for export with limited to no onshore network needs, and 'Network to Network', where multiple hydrogen production projects are connected via a Great Britain (GB) onshore network to an export terminal.

The 'Network to Network' approach depends on the development timeline of the onshore network, while the 'Project to Network' approach, though not onshore network timeline-bound, may face commercial viability issues and limit the ability to scale hydrogen trade from the UK in the long-term.

The latter is less aligned with the UK Hydrogen Strategy to develop a strategic domestic hydrogen transportation network and is therefore considered less favourable from a UK perspective.

Engagement undertaken with potential offtakers has confirmed the support for the opportunity, however, this also has identified the challenges of ramping up the hydrogen market in Germany, this includes regulatory clarity on hydrogen storage, expanding and flexing funding mechanisms like the Carbon Contracts for Difference (CCfD) scheme, and clarifying the EU and Germany's certification approach. Swift implementation of these measures is crucial.

The market is still in its early stages and significant future stakeholder engagement will be required across the hydrogen value chain, particularly with offtakers, producers, and transport and storage operators in the early stages of the initiation of an interconnector project to understand the needs case and feasibility for trading hydrogen between the UK and Germany.

**Germany has set interim targets reducing emissions by**

**65%**

**from 1990 levels by**

**2030**

## Infrastructure Assessment

This study has found that pipeline route options from UK to AquaDuctus or mainland Europe with onward connection to Germany are technically feasible, at a high level, but require further assessment and more certainty on how the two countries' domestic networks will materialise in the next decade.

The routing options assessed are displayed in Figure 2. Existing interconnectors and pipelines in the North Sea are unlikely, in the short to medium term, to be available for conversion to hydrogen use due to their existing contract requirements to supply natural gas and security of supply considerations.

Significant work would be required to determine the viability of repurposing existing oil and gas pipelines in the UK North Sea for hydrogen transport in an effort to create a network linking the UK with continental Europe, including; evaluating the condition, purpose, and lifespan of these pipelines and addressing technical challenges such as pressure rating, material compatibility, and the need for additional infrastructure such as compression stations.

The conversion process would require coordination among multiple stakeholders and compliance with environmental regulations. Continuous monitoring and maintenance would be essential, and supply chain disruptions associated with the additional infrastructure requirements could affect the project timeline and cost.

The availability of these pipelines for conversion depends on their current use for natural gas supply and the expiration of existing contracts, which could impact the feasibility of repurposing them for hydrogen in the future.

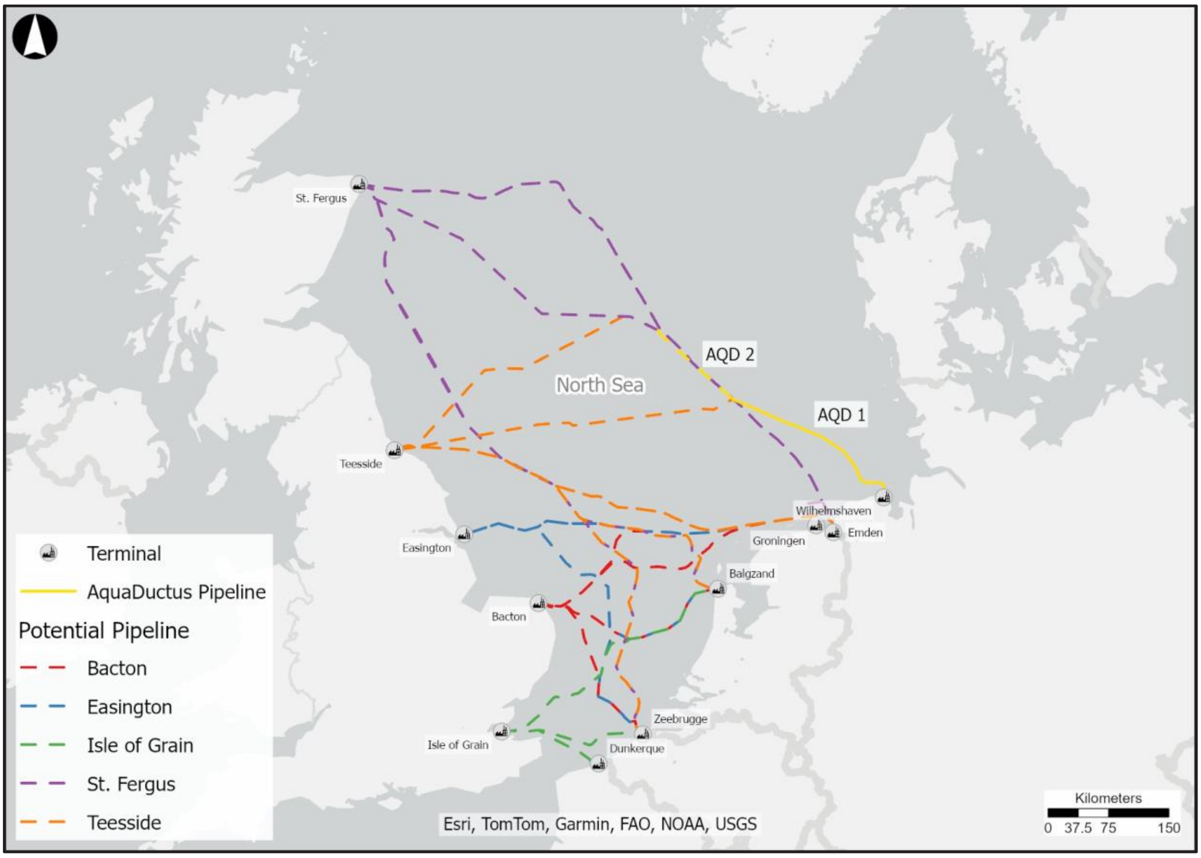



Figure 2

Potential interconnector pipelines from a number of UK east coast landfall sites.

## Delivery Enablers

To enable the development of a hydrogen interconnector, five key enablers have been identified, spanning across the business model, commercial arrangements, and regulations needed.

These enablers are intended to unlock the largest barriers to developing an interconnector between the UK and Germany. The enablers look beyond the interconnector itself given the nascent status of the UK and German domestic hydrogen economies and the dependency of the interconnector with the onshore markets. This includes supporting the development of market arrangements between producers and offtakers and the development of the onshore networks.

The enablers identified will need to be delivered in two distinct phases, as displayed in Figure 3

This study recommends Phase 1 delivery of the enablers should commence following the publication of this study and will focus on convening the market to bring together offtakers and producers to establish commercially viable hydrogen offtake agreements. Additionally, it will involve developing the technical requirements necessary for trading the hydrogen molecule.

Phase 2 will see the continuation of the development of the regulatory framework and convening of the market but will also see an expansion to consider the development of an interconnector business model and the alignment of the wider hydrogen value chain.

In parallel to the delivery enablers implementation, there are a wider range of actions that will need to be delivered to support the development of the respective domestic hydrogen markets.

Whilst these actions will be delivered by a range of parties, at the end of each phase depicted, as in Figure 3, there are government led project gates to review the status of the needs case of the interconnector before progressing to the next phase of delivery.

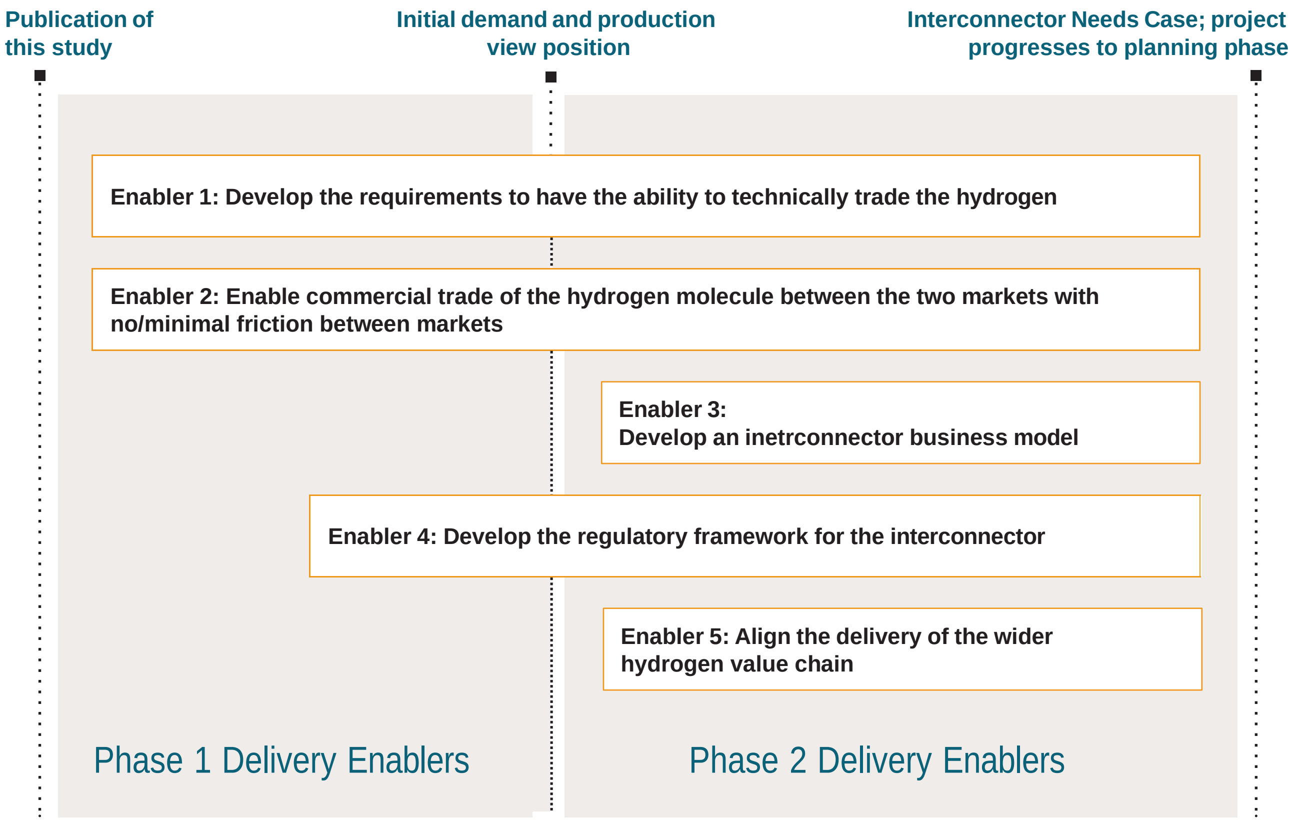



Figure 3
Delivery Enabler sequencing.


1
2
3
4
5

The minimum required actions under each enabler, which are proposed by this study, are detailed in Table 1 below.

| Enabler | Proposed Actions |
|---|---|
| **1**<br>**Develop the requirements to have the ability to technically trade the hydrogen molecule** | 1.1 The UK and German Governments to work together to align hydrogen emissions standards and respective hydrogen certification schemes where appropriate, working with the relevant authorities, including the European Commission, that hold responsibility for the establishment and implementation of the standards and certification schemes.<br>1.2 The UK and German Governments, or respective technical authorities, to work together to develop the technical operational requirements (including, for example, inlet pressures) associated with the flow of hydrogen between the two future networks. |
| **2**<br>**Enable commercial trade of the hydrogen molecule between the two markets with no/minimal friction between markets** | 2.1 The UK and German Governments to explore how to facilitate market arrangements between UK and German hydrogen markets and engage with potential project developers.<br>2.2 The UK Governments to undertake an assessment of the potential production export capability, specifically capacity, location, quality, and timing, in the UK market.<br>2.3 In parallel to action 2.2, the German Government to undertake an assessment of the potential offtaker requirements in terms of load requirements, timing, location, price sensitivity, and quality in Germany.<br>2.4 The UK and German Governments, separately or together, to consider whether financial support mechanisms may be required to ensure the commercial viability of future hydrogen trade, specifically concerning production or offtake, in compliance with WTO rules. |
| **3**<br>**Develop an interconnector business model** | 3.1 Undertake an assessment of the business model risks and potential guarantees that may be required to manage revenue uncertainty for an interconnector and potential high charges for users in the initial scale-up operational period. Based on this assessment, the UK and German Governments should determine the needs case for interconnector business model support.<br>3.2 The UK and German Governments, and respective regulators (or future regulators), to determine the potential process for interconnector business model allocation.<br>3.3. During the allocation of business model support, the respective regulators, within their responsibilities, to review evidence provided by project developer(s) on the pipeline sizing to determine whether the sizing is optimal from a technical and economic perspective. |
| **4**<br>**Develop the regulatory framework for the interconnector** | 4.1 The UK Government to review the gas licencing framework to determine whether potential revisions may be required for the development and operation of hydrogen interconnectors.<br>4.2 The UK and German Governments to work together to develop, coordinate, and ensure the compatibility of the commercial operational requirements for the interconnector (including access, charging, balancing, and trading) as part of the regulatory framework.<br>4.3 The UK and German Governments and/or relevant regulatory authorities to examine whether there is any misalignment between national technical regulatory requirements (covering safety, planning, consenting and permitting, environmental assessment, operations, and future decommissioning liabilities) and develop a plan to ensure that any differences are understood and managed to allow the development of the technical regulatory framework for a hydrogen interconnector. |
| **5**<br>**Align the delivery of the wider hydrogen value chain** | 5.2 GB's NESO to consider the potential need for links between a domestic hydrogen transport and storage network and new international hydrogen trade infrastructure as part of its anticipated role in strategic planning.<br>5.3 The German Government to assess how a potential interconnector is considered in the further planning of the hydrogen core network and that coordination between the onshore network operators and the operator(s) of the interconnector is enabled.<br>5.4 The German Government to coordinate the timeline with the expansion of AquaDuctus Stage 1 and 2 and the completion of the core network and thus the connection of potential offtakers. |

Table 1
Delivery Enablers and the Associated Proposed Actions.

## Focus Areas

As this study finds, the nascent nature of the international hydrogen market poses significant complexity when seeking to develop a pipeline-based trade between the UK and Germany.

As such, within the delivery enablers, four key focus areas have been identified to initiate, and support the delivery of, the enablers following the publication of this study:

- Develop a delivery plan for the minimum regulatory alignment needed to enable an interconnector.
- Determine the best mechanism to support the convening of the market.
- Perform a high-level techno-economic deliverability assessment of routing options.
- Carry out stakeholder engagement.

### Focus 1: Develop a delivery plan for the minimum regulatory alignment needed to enable an interconnector.

As identified within enabler 1, alignment is required between the regulatory frameworks, specifically the hydrogen emissions standards and hydrogen certification schemes, so that the hydrogen can technically flow between the countries.

As this alignment will be critical to support the convening of the hydrogen market, and the typically long lead times associated with the development of regulations, following the publication of this study it will be necessary to identify a plan for the delivery of the alignment hydrogen emissions standards, the countries respective hydrogen certification schemes, and the technical operational requirements associated with the flow of hydrogen between the future UK and German networks.

This study therefore recommends that the UK and German Governments collaborate to develop a delivery plan for the minimum regulatory alignment needed to enable an interconnector.

### Focus 2: Determine the best mechanism to support the convening of the market.

The business case for the interconnector is underpinned by aligning market supply and demand. Given the current nascent nature of the hydrogen market, this will be a complex process, as outlined in enabler 2, Section 3.5.

Therefore, this study recommends that following the publication of this study the UK and German Governments collaborate on determining a mechanism that they can utilise to manage the complexity of the stakeholder engagement required across the hydrogen value chain.

### Focus 3: Perform a high-level techno-economic deliverability assessment of routing options.

Understanding the commercial viability of the interconnector will be critical to engage the market and support the development of producer and offtaker arrangements.

Therefore, this study recommends that the UK and German Governments, or an independent party perform a high-level techno-economic deliverability assessment of the route options, focusing on assessing the CAPEX and OPEX costs of the interconnector assets, as defined in Figure 1, potential route options to understand the high-level range of potential interconnector costs.

This will inform the producer and offtaker arrangements and determine the commercial viability of the offtaker agreements. It is important to note that this will be a very early-stage assessment and further, significantly more detailed routing and techno-economic assessments will be required. It is important to note that this will be a very early-stage assessment and further, significantly more detailed routing and techno-economic assessments will be required.

**Four topics have been identified as priority focus areas following the publication of the study.**

Focus 4: Carry out stakeholder engagement.

Given the nascent nature of the hydrogen market, it will be important to engage with stakeholders across the hydrogen value chain to understand market challenges and stakeholder requirements to feed into the interconnector needs case.

This stakeholder engagement will be necessary across both phases of the delivery enablers.

In phase 1 engagement with offtakers and producers will be particularly important to understand the potential demand and production capacity positions. In phase 2 broader engagement across the value chain will be important to support the development of the interconnector needs case.

This study therefore recommends that, following the publication of this study, a stakeholder engagement strategy is developed, building on the outputs of the limited engagement carried out in this study, to ensure critical stakeholder requirements are considered ahead of the initiation of a project.

It is important to recognise that this engagement will need to be undertaken in the context of the wider market development.

The stakeholders to be considered would include but not be limited to:

– Producers: to understand the landscape of development including capacity, availability and associated timelines to commercial operation dates.
– Onshore Network Developers: to understand development plans, geographical rollout, and the associated timelines.
– Interconnector Operators: to further understand the operational requirements of an interconnector and identify potential future operators.
– Offtakers: to understand offtaker specific requirements including; timelines, quantum of demand, quality and specification requirements, and initial and future demand profiles.
– Regulatory Authorities: to understand existing regulations and development plans for hydrogen across the value chain.
– Storage Operators: to understand the landscape of development in both countries and future availability to provide security of supply for offtakers.
– Supply Chain Providers: focusing on providers of critical products upstream and downstream (such as electrolysers, compressors, special materials and alloys, seals and filters, etc.) and key contractors (EPC contractors, offshore pipe lay barge operators, etc.) to better understand future supply chain capability and capacity.

Various parties will need to carry out stakeholder engagement across the two phases of delivery enablers, including, the UK and German Governments, any parties involved in supporting the convening of the market, and potential independent stakeholders to contribute to the development of the interconnector needs case.

**Engagement is required across the hydrogen value chain to understand market challenges to feed into the interconnector needs case.**

# 1

# Introduction

**This study aims to support the development of the UK and German hydrogen economies, aiding the countries' respective net zero ambitions, fostering closer relationships for collaboration, supporting hydrogen trade and transport infrastructure development, and promoting the development of a regional hydrogen market.**

## 1.1 Study Context

This study was conducted in support of the five pillars of collaboration under the 'UK-Germany Hydrogen Partnership', signed on 26th September 2023, between the UK Department for Energy Security and Net Zero (DESNZ) and the German Bundesministerium für Wirtschaft und Klimaschutz (BMWK).

Through a comprehensive literature review and analysis of publicly available information, the study outlines the steps required to enable future hydrogen trade, including a detailed examination of the regulatory landscape, assessment of potential pipeline infrastructure requirements, and the steps required to enable future hydrogen trade from regulatory, technical, and commercial perspectives.

This study aims to support the development of the UK and German hydrogen economies, aiding the countries' respective net zero ambitions, fostering closer relationships for collaboration, supporting hydrogen trade and transport infrastructure development, and promoting the development of a regional hydrogen market.

## 1.2 Study Objectives and Outputs

The objective of this study was to provide the basis for the UK and German Governments to consider the potential for a hydrogen pipeline in the future to facilitate trade of hydrogen between the two countries, considering the components of the interconnector only and not the production or storage of hydrogen.

The study outputs were defined to include:

- Determine the high-level infrastructure requirements.
- Identify the Regulatory, Business Model and Commercial requirements to enable a market to trade hydrogen between UK and Germany.
- Develop a roadmap outlining the next steps to realise hydrogen trade via an interconnector including and associated delivery enabler decisions.
- Provide a list of proposed actions for the two Governments.

## 1.3 Study Scope

The overall scope of this report was split into six workstreams; industry engagement, infrastructure assessment, business models analysis, regulatory analysis, commercial arrangements assessment, and roadmap development.

Each workstream had individual requirements to deliver the study objectives as outlined above, which are summarised in Sections 1.3.1 to 1.3.6.

**This study outlines the steps required to enable hydrogen trade, looking across regulatory, technical and commercial perspectives.**

### 1.3.1 Industry Engagement

To provide a basis of understanding of the development of various areas of the hydrogen value chain that would be required to realise hydrogen trade between the UK and Germany, a high-level desktop stakeholder mapping exercise and engagement with potential UK hydrogen producers, UK and German environmental and regulatory authorities, and German hydrogen consumers was scoped.

For UK engagement, the focus was on identifying and engaging with a select number of stakeholders interested in potential interconnector projects and discussing their development status and plans for export of hydrogen to Germany.

For Germany, the engagement included identifying potential hydrogen customers and discussing their supply requirements, as well as identifying relevant German environmental and regulatory authorities interested in the pipeline systems construction and operation.

### 1.3.2 Infrastructure Assessment

The infrastructure assessment scope included the high-level assessment of four interconnector route cases and was defined to go into a level of detail sufficient to provide the inputs necessary to assess the delivery enablers, namely the business models, regulatory models and commercial arrangement considerations. For the infrastructure assessment, the elements of the hydrogen value chain defining the 'interconnector' are illustrated in Figure 4 below.

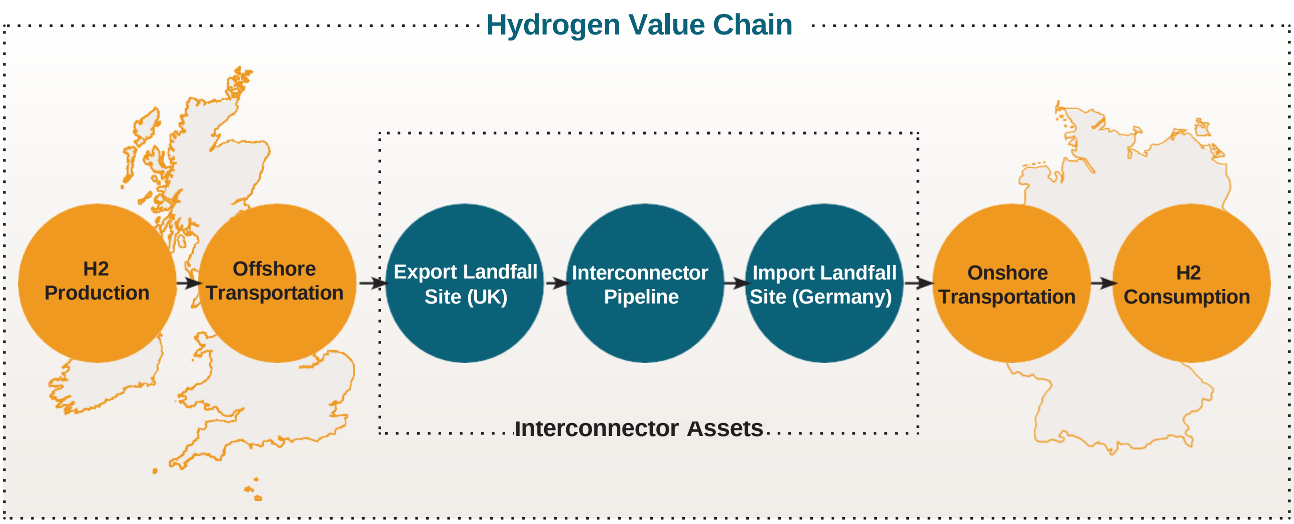



Figure 4

Elements of the hydrogen value chain comprising an interconnector.

Four interconnector route cases were scoped for assessment within this study as presented in Table 2.

| | 1. Germany Base Case | 2. Germany Direct | 3. Netherlands | 4. Belgium |
|---|---|---|---|---|
| **Connection** | Subsea pipeline from a UK east coast landfall to an offshore tie-in point on the AquaDuctus offshore pipeline system. | Direct subsea pipeline from a UK east coast landfall to a German coast landfall. | Direct subsea pipeline from a UK east coast landfall to a Netherlands coast landfall. | Direct subsea pipeline from a UK east coast landfall to a Belgian coast landfall. |
| **Transmission** | Transmission of hydrogen to Germany, and potentially to the Netherlands and Belgium via the German hydrogen core network. | Transmission of hydrogen directly to Germany. | Onward transmission of hydrogen to Germany via an onshore link from the Netherlands. | Onward transmission of hydrogen to Germany via an onshore link from Belgium. |
| **Assessment level** | Two UK start points (England and Scotland) will be evaluated for input to the Delivery Enablers assessment. Different start points may result in different tie-in locations on the AquaDuctus offshore pipeline system. | High-level route assessment only, considering two UK start points (England and Scotland). | High-level route assessment only, considering a UK start point in England.<br>A Scotland to Netherlands option is excluded due to excessive length, cost, and additional compression facilities required. | High-level route assessment only, considering a UK start point in England.<br>A Scotland to Belgium option is excluded for similar reasons as the Netherlands option. |

**Table 2**
Routing Options.

The assessment activities included

### Landfall Infrastructure
A high-level indication of the technical considerations around the landfall at export and import locations.

### Pipeline Routing
A review of potential routing pipelines from the UK to the AquaDuctus Offshore Pipeline System (Base Case) with alternatives provided for direct connection to Germany, Belgium and Netherlands.

### Repurposing
Review the existing natural gas interconnectors from the UK for potential repurposing to hydrogen export.

### Sizing
A pipeline sizing assessment of the Germany Base Case determining the appropriate, approximate pipeline dimensions to handle varying capacities while maintaining typical acceptable pressure drop and velocity constraints.

### 1.3.3 Business Models Analysis

The business models analysis was scoped to identify the potential business models options for the interconnector, including the UK and German onshore assets and the interconnector itself taking into consideration models for the transition and enduring phases.

Additionally, the analysis reviewed the regulatory and commercial requirements associated with each model.

The scope of this study included exploring the need to put in place a viable business model for the interconnector only, specifically the import/export terminals and the associated pipeline(s) connecting the UK and Germany.

The scope did not include business models associated with the production, respective onshore networks and the offtakers.

The business models for these elements are in development in both countries and were to be considered as key interfaces for a potential interconnector business model given the development status of the hydrogen market, as displayed in Figure 5.

Several factors are outside the scope of the study.

These included the likely revenue support that might require a revenue guarantee in the early stages of development, the manner in which this support would be provided and the associated potential sharing of the guarantee between the respective Governments.

However, these factors will need to be considered in the further development of the model as they will influence the principles of the business model and the associated impact assessments.

### 1.3.4 Regulatory Analysis

The regulatory models analysis included reviewing the existing technical and economic gas regulatory frameworks, as well as the proposed hydrogen regulatory frameworks where they exist and identifying the regulatory gaps, enablers and actions for import and export of hydrogen between the UK and Germany.

This was scoped to cover both the economic and technical regulations across the UK, Netherlands, Germany and the European Union (EU). As the hydrogen sector is relatively nascent, regulations in some areas are in development and in others will need to be developed in upcoming years to support the development and operations of the interconnector.

**Analysis has been undertaken to identify the potential business models for an interconnector.**

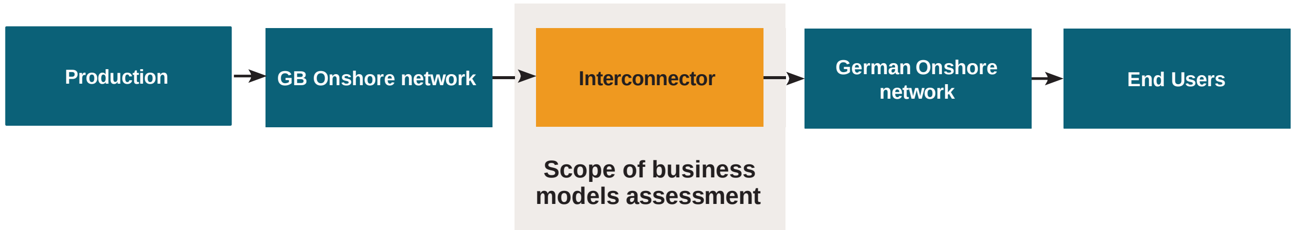



**Figure 5**

Hydrogen value and chain and business model boundary.


The regulatory analysis was split into economic analysis and technical analysis and was to include:

- Review of the current hydrogen regulations and identification of the regulatory gaps in the UK and Germany.
- Assessment of the suitability of UK and German natural gas regulations for the interconnector and onshore network.
- Assessment of the alignment of the onshore and interconnector regulatory requirements.
- Identification of the key decisions the UK and German Governments will need to make regarding ownership, regulation, licensing and operability.

### 1.3.5 Commercial Arrangements Assessment

The assessment of the commercial arrangements was scoped to include the identification and assessment of the potential charging regimes for an interconnector. To achieve the scope various activities were defined as:

- Review of the role of network charging.
- Assessment of current natural gas interconnector approach.
- The charging options to enable the interconnector owner to recover the costs.
- Assessment of the interaction of commercial arrangements with the design of the business model.

### 1.3.6 Roadmap

The roadmap was scoped to showcase the requirements for delivery of the Germany Base Case and identify the next steps to achieve it. The development of this roadmap and identification of the next steps was defined to include the assessment of the required delivery enablers, identifying long lead items to inform development timelines associated with the business models regulatory and commercial requirements.

## 1.4 Low-Carbon Hydrogen Definition

Low-carbon hydrogen is defined differently in the UK and the EU, whose hydrogen standards are applicable to Germany as a member state.

### UK:

The UK defines ‘low-carbon hydrogen’ as hydrogen that has a final emission intensity of less than or equal to the GHG Emission Intensity Threshold of 20 grams of carbon dioxide equivalent per megajoule of Hydrogen Product, using Lower Heating Values (20.0g$CO_2$e/MJLHV Hydrogen Product)[1].

### Germany/EU:

As Germany is embedded within the EU’s regulatory framework, the EU’s standards on hydrogen are applicable to Germany.

The EU distinguishes between low-carbon hydrogen and renewable hydrogen. Low-carbon hydrogen is characterised by its ability to reduce GHG emissions by at least 70% compared to traditional fossil-based hydrogen.

It is produced from non-renewable energy sources, such as natural gas with carbon capture and storage (CCS) or through electrolysis powered by nuclear electricity.
The focus here is on the reduction of emissions, regardless of the energy source used. Renewable hydrogen, commonly referred to as green or clean hydrogen, is defined by its production through electrolysis using electricity derived from renewable sources, or through the reforming of biogas and the biochemical transformation of biomass.

According to EU legislation, hydrogen and its derivatives that are produced without the use of biomass are considered as renewable fuels of non-biological origin (RFNBO)[2].

**Low-carbon hydrogen is defined differently in the UK and the EU, whose hydrogen standards are applicable to Germany as a member state.**

For the purposes of this report the use of the term ‘low-carbon hydrogen’ can be taken to encompass both renewable and other forms of hydrogen which comply with both the UK and German standards for low-carbon hydrogen, these standards are discussed in further detail in Appendix C.

There are several eligible production pathways which can be used to produce hydrogen which complies with the UK and EU standards for low-carbon hydrogen.
In this report, when referring to a specific form of hydrogen produced via specific technology pathways, the relevant terminology is used.

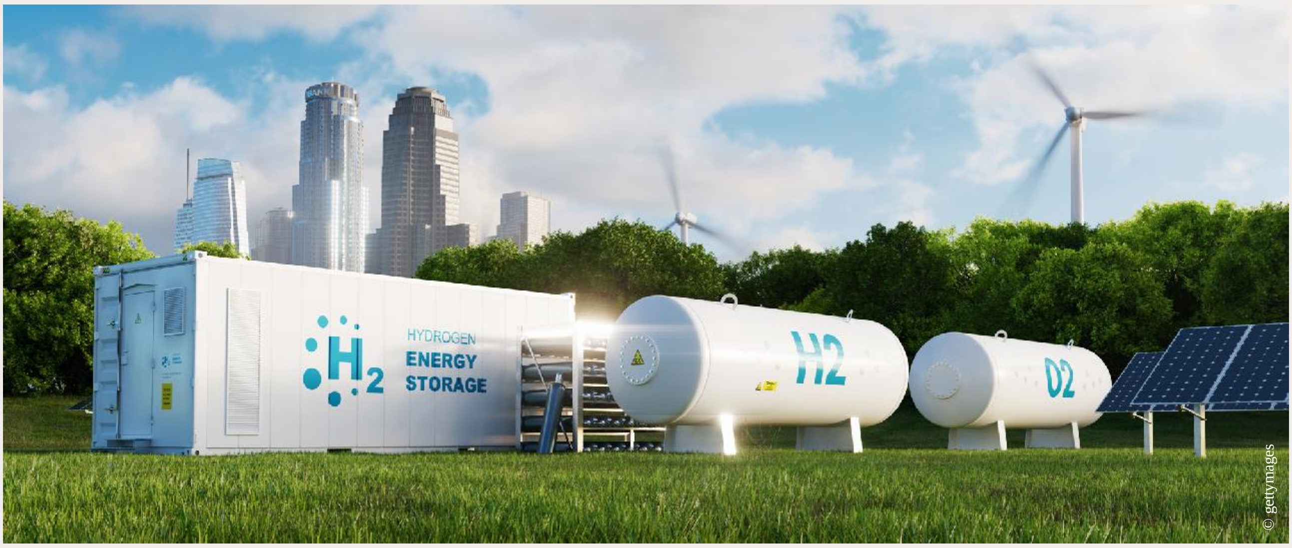
# 2

# Landscape

**Germany has set ambitious import targets and this presents a significant opportunity for the UK to export in the future, given a strong pipeline of potential projects. There are two extremes of how an interconnector project could be structured:**

**1) Project to interconnector – this option is unlikely to be commercially viable and limits opportunity for future hydrogen trade.**

**2) Network to interconnector – this will be affected by the GB onshore network development timelines. Stakeholder engagement is required, particularly with offtakers, producers, and transport operators to understand the needs case for trading hydrogen between the UK and Germany.**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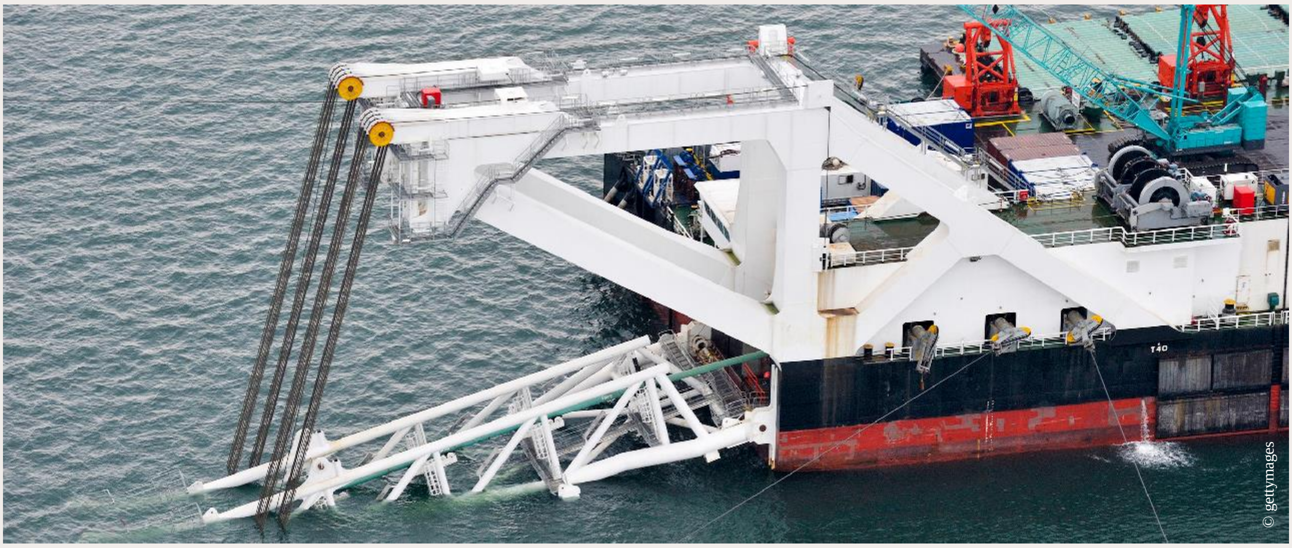
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GREEN HYDROGEN
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## 2.1 UK Context

The UK has made a legally binding commitment to reduce all GHG emissions to net zero, against a 1990 baseline, by 2050. This is commonly known as the 'net zero' target. Through its legal framework, the Climate Change Act 2008, the UK has set five-yearly legally binding carbon budgets. This includes an equivalent of a 77% reduction in emissions over the sixth carbon budget covering 2033-37, with the seventh carbon budget due to be agreed by 2026, which will cover 2038-2042. In parallel, as part of its Nationally Determined Contribution to the Paris Agreement, the UK has set a 68% emissions reduction target by 2030 and 81% by 2035 (excluding international aviation and shipping).

The UK Government believes low-carbon hydrogen will play a key role to achieve its net zero ambitions, its mission to deliver clean power by 2030, and its mission to secure the highest sustained growth in the G7. In its latest Hydrogen Strategy Update to the Market[3], hydrogen is identified as a crucial enabler of a low-carbon and renewables-based energy system, that will help to deliver new clean energy industries which can support jobs in the country's industrial heartlands and coastal communities.

To advance its growth and clean energy missions, the UK Government has identified hydrogen as a unique solution in transitioning crucial UK industries away from fossil fuels and towards a clean, homegrown source of fuel. Hydrogen can decarbonise hard-to-abate sectors like chemicals and heavy transport, complementing wider electrification efforts and accelerating progress to net zero[3].

The UK has an ambitious range of policies in place to incentivise and support industry to invest in low-carbon hydrogen, as it reaches the delivery phase of its Hydrogen Strategy, supporting 11 renewable hydrogen projects from the first Hydrogen Allocation Round (HAR1), which comprised £90 million in capital grant support through the Net Zero Hydrogen Fund (NZHF) and c. £2.3bn revenue support through the Hydrogen Production Business Model (HPBM). Moreover, the UK Government's recent announcement of up to £21.7bn of funding for the carbon capture industry includes support for Carbon Capture, Utilisation, and Storage (CCUS) enabled hydrogen and paves the way for the UK's first large-scale hydrogen projects.

Leveraging its abundant renewable energy resources, the UK Government recognises its potential to become an exporter of low-carbon hydrogen in the future. By enhancing its export capabilities, the UK would strengthen its supply chains, stimulate clean growth, and increase its strategic importance as a supplier of low-carbon energy to Europe.

**UK government's recent announcement of up**

**£21.7**

**billion of funding for the carbon capture industry**

### 2.1.1 Production and demand

The UK is strategically positioned to gain a competitive advantage in various low-carbon hydrogen production technologies, particularly electrolytic hydrogen and carbon capture, utilisation and storage-enabled hydrogen. With one of the world's largest offshore wind sectors, natural assets, and expertise in CCUS, UK companies are leading the way in hydrogen technology development.

The GB National Energy System Operator (NESO) published their updated Future Energy Scenarios (FES) document in 2024[4].

This includes four energy scenarios:

1. Holistic Transition: Net zero met through a mix of electrification and hydrogen, with hydrogen mainly around industrial clusters.
2. Electric Engagement: Net zero met through mainly electrified demand.
3. Hydrogen Evolution: Net zero met through fast progress for hydrogen in industry and heat.
4. Counterfactual: Net zero missed, though some progress is made for decarbonisation compared to today.

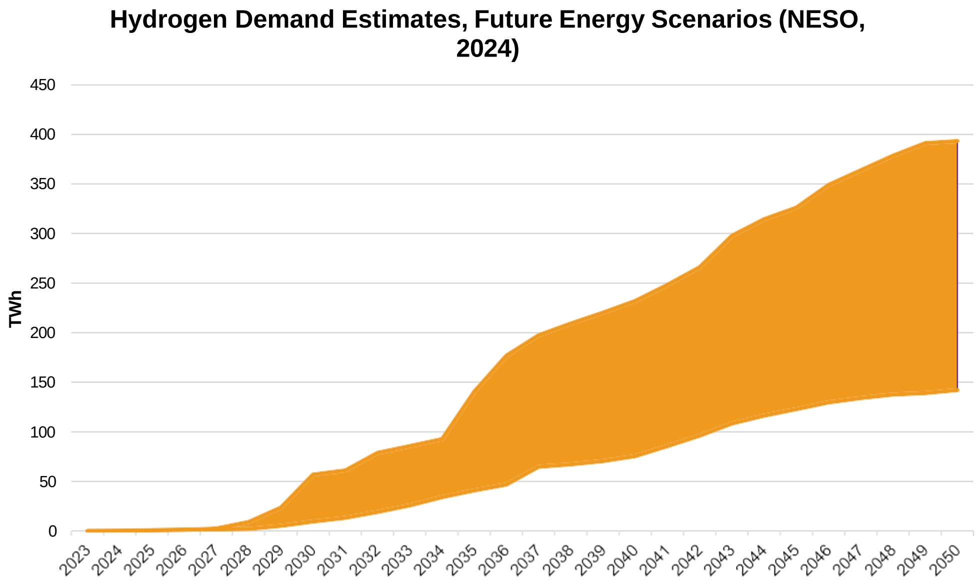



**Figure 6**

Hydrogen Demand Estimate Ranges in the Future Energy Scenarios, not including the 'Counterfactual' scenario. (NESO, FES Data Workbook 2024).

Figure 6 shows a plot of the range of demand for low-carbon hydrogen estimated by NESO in the FES 2024, including only scenarios where net zero is met, which excludes the 'Counterfactual' scenario. NESO estimate that demand for low-carbon hydrogen could range from 9-57 TWh in 2030; 41-140 TWh in 2035; and 142-393 TWh in 2050.

Figure 7 shows the location of projects that to date have been offered or have received UK Government funding for commercial scale low-carbon hydrogen production.

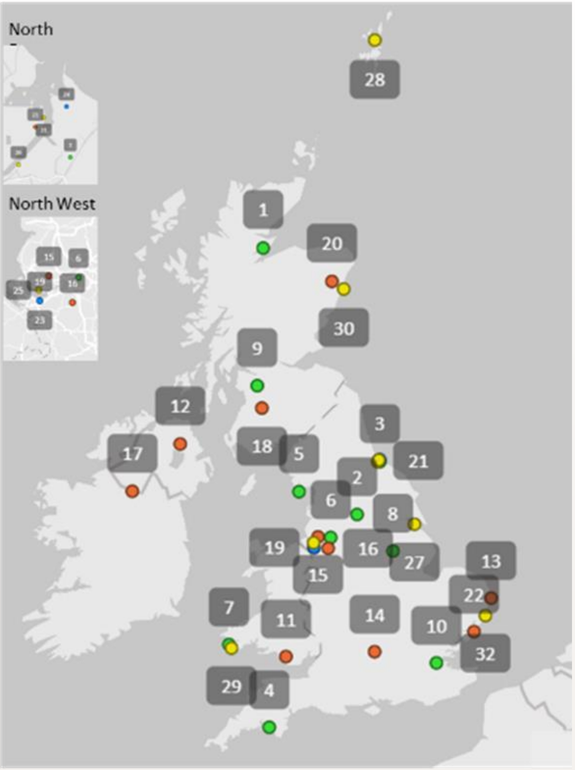
The geographical location of a significant proportion of UK production funding has, to date, been allocated to projects co-located with demand sites, since UK funding requires projects to have domestic offtakers.

## HAR1

| Project Name | Developer | No. |
|---|---|---|
| **Cromarty** | Storegga | 1 |
| **Bradford Hydrogen** | Hygen | 2 |
| **Tees Green** | EDF | 3 |
| **Langage Green Hydrogen** | Carlton Power | 4 |
| **Barrow Green Hydrogen** | Carlton Power | 5 |
| **Trafford Green Hydrogen** | Carlton Power | 6 |
| **West Wales Hydrogen** | H2 Energy & Trafigura | 7 |
| **HyMarnham** | JG Pears | 8 |
| **Whitelee Green Hydrogen** | Scottish Power | 9 |
| **Green Hydrogen 3** | HYRO | 10 |
| **HyBont** | Marubeni | 11 |

## NZHF Window 2

| Project Name | Developer | No. |
|---|---|---|
| **Grenian Hydrogen Speke** | Grenian Hydrogen | 25 |
| **Tees Green Methanol** | EDF | 26 |
| **Humber Hydrogen Hub 3 (H3)** | Air products | 27 |
| **Sullom Voe Terminal Green Hydrogen Project** | Enquest Hydrogen | 28 |
| **Pembroke 200 MW Green Hydrogen Electrolyser Phase 11** | RWE Generation | 29 |
| **Aberdeen Hydrogen Hub** | Bp Aberdeen Hydrogen Energy Limited | 30 |
| **Tees Valley Hydrogen Vehicle Ecosystem (HYVE)** | Exolum International UK | 31 |
| **Suffolk Hydrogen** | Hyrab Power | 32 |




**Projects offered support through windows 1 and 2 of the NZHF and HAR 1, and the CCUS enabled hydrogen projects in the Track-1 cluster sequencing process**

## NZHF Window 2

| Project Name | Developer | No. |
|---|---|---|
| **Ballymena Hydrogen** | Ballymena Hydrogen | 12 |
| **Conrad Energy Hydrogen Lowestoft** | Conrad Energy | 13 |
| **Didcot Green Hydrogen Electrolyser** | RWE | 14 |
| **Green Hydrogen St Helens** | Progressive Energy | 15 |
| **Green Hydrogen Winnington and Middlewich** | Progressive Energy | 16 |
| **Mannok Green Hydrogen Valley** | Monnock | 17 |
| **Knockshinnoch Green Hydrogen Hub Project** | Renantis | 18 |
| **Hynet HPP2** | Vertex | 19 |
| **Kintore Hydrogen** | Statera | 20 |
| **H2 NorthEast** | Kellas | 21 |
| **Felixstowe Port Green Hydrogen** | Scottish Power | 22 |

## CCUS Sequencing

| Project Name | Developer | No. |
|---|---|---|
| **Hynet HPP1** | Essar Energy Transition Hydrogen | 23 |
| **bpH2 Teesside** | bp | 24 |

**Figure 7**

Announced Hydrogen Production Projects: Net Zero Hydrogen Fund (NZHF) and Hydrogen Allocation Round 1 (HAR1). Data correct as of 2024.

A plot of power and industrial emitters in the UK, as detailed in Figure 8.

As detailed in the Hydrogen Strategy Update to the Market, in December 2024, the UK sees hydrogen playing a key role in transitioning crucial industries to clean alternatives to oil and gas.

As outlined in the UK's Clean Power 2030 Action Plan[6], there is a 2-7 GW range of installed low-carbon dispatchable power possible by 2030.

Hydrogen to power, which is the conversion of low-carbon hydrogen to produce low-carbon electricity is intended to form a part of this.

Across industry, hydrogen is poised to be a key solution for decarbonising industrial processes that are complex or more expensive to electrify.

This includes its application as a fuel in high-temperature, energy-intensive equipment, as well as a feedstock for specific industrial processes.

In addition to projects the projects identified in Figure 7, there is a known pipeline of over 250 UK projects under development, presenting a potential production capacity of 25.1 GW by 2030, as displayed in Figure 9[7].

Although it is unlikely that the entirety of this pipeline will be realised, this suggests there is significant industry ambition to further develop UK hydrogen production.

Depending on market conditions and UK policy, exports of hydrogen could help bring some of this potential pipeline of projects forward in the future.

**As outlined in the UK's Clean Power 2030 Action Plan there is**

**2.7 GW**

**range of installed low carbon dispatchable power possible by**

**2030**

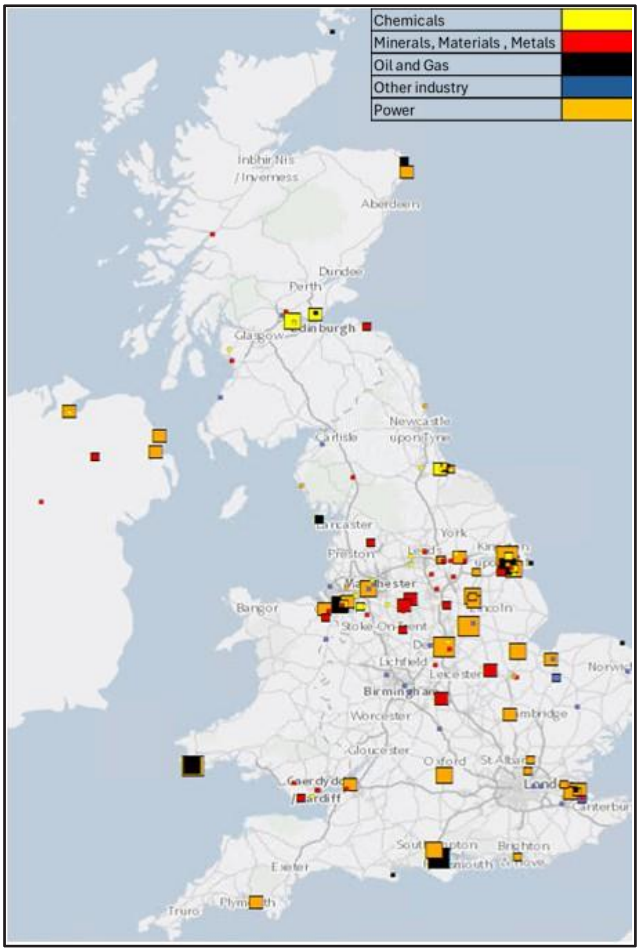



**Figure 8**

Industry emitters plotted from the National Atmospheric Emissions Inventory (NAEI) dataset (DESNZ).

To evaluate the feasibility of this pipeline for exports or domestic demand, further analysis is required to determine the renewable electricity requirements and other resource requirements, such as water for electrolysis, to facilitate project implementation.

Additionally, ongoing monitoring of these projects will be essential to assess how the UK's production capacity can meet future demand requirements.

### 2.1.2 Low Carbon Hydrogen Standard and Certification Scheme

The UK Low Carbon Hydrogen Standard sets a maximum threshold for GHG emissions for hydrogen to be considered 'low-carbon'. This is to ensure that low-carbon hydrogen production contributes to the UK's decarbonisation efforts. The UK defines low-carbon hydrogen as hydrogen produced with GHG emissions from well-to-production gate of no more than 20 gCO2e/MJLHV of hydrogen produced[8].

The Low Carbon Hydrogen Certification Scheme is currently under development. It will verify the emissions intensity of hydrogen, determined using the Low Carbon Hydrogen Standard methodology. This will enable low-carbon hydrogen producers and users to prove the low-carbon credentials of hydrogen and will be a key enabler for trade.

Version 3 of the Low Carbon Hydrogen Standard was published in 2023[8]. Version 4 of the Low Carbon Hydrogen Standard is under development, to ensure that the Standard remains fit for purpose and keeps pace with growing understanding of how new technologies work in practice. Future versions of the Standard will also refine the requirements in preparation for the launch of the certification scheme.

The UK Low Carbon Hydrogen Standard and Certification Scheme are discussed further in Appendix C.

**Hydrogen is poised to be a key solution for decarbonising industrial processes that are complex or more expensive to electrify.**

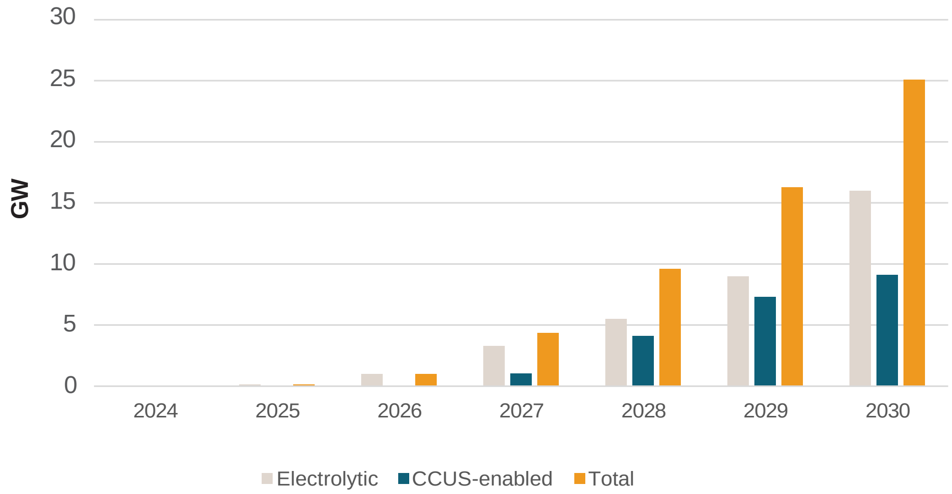



**Figure 9**

Cumulative Potential UK Total GW Low-Carbon Hydrogen Production Capacity[7].

## 2.2 UK Funding

### 2.2.1 Net Zero Hydrogen Fund

The Net Zero Hydrogen Fund (NZHF), announced in 2021[9], will allocate up to £240 million to support the development and construction of new low-carbon hydrogen production plants.

The Fund has been open to various production technologies, including CCUS-enabled and electrolytic hydrogen, and targets projects that are able to commence production during the 2020s.

The grant allocation of the NZHF is divided into four strands:

**Strand 1:**

**provides development expenditure for front end engineering design studies and post-front end engineering design costs.**

**Strand 2:**

**provides capital expenditure for projects that do not require revenue support through the Hydrogen Production Business Model.**

**Strand 3:**

**provides capital expenditure for projects that require revenue support through the Hydrogen Production Business Model and are part of the first Hydrogen Allocation Round.**

**Strand 4:**

**provides capital expenditure for carbon capture, utilisation and storage-enabled hydrogen projects that require revenue support through the Hydrogen Production Business Model and are part of the Phase 2 cluster sequencing process.**

In February 2024, DESNZ announced seven successful applicants for Round 2 of the NZHF Strands 1 and 2[10], allocating up to £21 million for hydrogen production projects across England, Scotland, and Wales, pending contract signings. This follows Round 1, which allocated £37.9 million to 15 projects.

Additionally, over £90 million from NZHF Strand 3 will support construction costs for projects selected in the HAR1.

NZHF Strand 4 will provide capital support for CCUS-enabled low-carbon hydrogen production plants selected through the Track-1 cluster sequencing programme, also subject to contract signings.

### 2.2.2 Hydrogen Production Business Model

The Hydrogen Production Business Model (HPBM)[11] provides revenue support to incentivise investment in new low-carbon hydrogen production and encourage users to switch to low-carbon hydrogen by making it a price competitive decarbonisation option.

The HPBM will stimulate demand for low-carbon hydrogen as the subsidy paid to hydrogen producers will enable them to sell hydrogen at a price that users can afford to pay. The subsidy to hydrogen producers directly addresses barriers to investment in production, which will help achieve the UK's Clean Energy Superpower and Growth Missions at pace.

The model is delivered through the Low Carbon Hydrogen Agreement, which is a private law contract signed between a hydrogen producer and a government counterparty, the Low Carbon Contracts Company.

**DESNZ announced seven successful applicants for Round 2 allocating up to**

**£21m**

**for hydrogen production projects across England, Scotland, and Wales.**

### 2.2.3 Hydrogen Allocation Rounds

The HARs allocate revenue support through the HPBM to non-carbon capture, utilisation and storage-enabled hydrogen production facilities across the UK.

Following the announcement of 11 successful projects to be offered contracts under the first HAR, totalling 125 MW capacity, the Low Carbon Contracts Company has signed the first Low Carbon Hydrogen Agreements with the first three HAR1 projects.

Signing contracts has enabled these projects to be among the first commercial scale hydrogen projects in the world to take final investment decisions (FID) and move into construction. The first project is expected to be operational in 2025[11].

HAR2 was launched in December 2023 and was oversubscribed. This includes a spread of applications across the delivery years between 2026 and March 2029. DESNZ aim to publish a shortlist of HAR2 projects to be invited to the next stage of the process in due course.

The UK Government is currently developing the approach to HAR3, to ensure it delivers on the Government's priorities.

In 2025, the UK Government will also review the design of future allocation rounds. This could include moving to an independent allocation body and a price-based competitive allocation model.

When conducting this review, the UK Government will take the relevant market conditions and experience of earlier rounds into consideration.

### 2.2.4 Carbon Capture, Utilisation and Storage Cluster Sequencing Process

As part of the Carbon Capture, Utilisation and Storage Cluster Sequencing Process, revenue support to CCUS-enabled new hydrogen production facilities is to be allocated through the HPBM.

In October 2024, commercial agreement was reached with the private sector to announce up to £21.7 billion of funding available over 25 years to launch the UK's new CCUS industry[12].

This announcement should help pave the way for the UK's first large-scale hydrogen production plant, decarbonising vital industrial sectors, subject to negotiations and final agreements that represent value for money.

Following an announcement in October 2024 of funding for the initial Track 1 cluster, further decisions for continued CCUS deployment, including for Track 2 clusters, will be taken in due course.

## 2.3 Hydrogen networks and storage

The infrastructure for hydrogen transport and storage (T&S) will be essential for linking hydrogen producers with consumers and addressing supply and demand imbalances.

This T&S infrastructure is crucial for fully realising the UK's hydrogen goals and achieving the Clean Energy Superpower[13] and Growth Missions[14] by establishing a leading hydrogen network across the UK.

New business models for hydrogen transport and storage infrastructure are being developed, to remove market barriers and unlock private sector investment.

The Energy Act 2023[15] provides the legislative framework that will underpin the delivery of the Hydrogen Transport Business Model and the Hydrogen Storage Business Model.

Strategic planning is also being utilised to provide greater certainty on future transport and storage network requirements and development, for both domestic needs and to align with the UK's trade ambitions.

The UK Government is continuing to assess growing evidence of emerging hydrogen transport and storage network requirements to determine what infrastructure is needed, where and when.

### 2.3.1 Strategic planning and funding for hydrogen transport and storage infrastructure

DESNZ is the interim strategic planner for the build out of hydrogen transport and storage infrastructure and will continue to work closely with Ofgem and industry to provide early strategic direction.

This was previously outlined in the Hydrogen Transport and Storage Networks Pathway published by DESNZ in December 2023[16].

The NESO was launched in October 2024. DESNZ intends for NESO to take on responsibilities for the strategic planning of hydrogen transport and storage infrastructure from 2026[7].

In early 2025, DESNZ is planning to take forward work on National Energy System Operator's (NESO) scope of activities for strategic planning of hydrogen transport and storage infrastructure, including through consultation and engagement with industry where appropriate.

The government is designing business models to incentivise investment in hydrogen transport and storage infrastructure. These business models are the:

#### Hydrogen Transport Business Model (HTBM):

This model is intended to support the development of hydrogen transport infrastructure to connect producers with end-users and stores.

The first Hydrogen Transport Business Model round will contribute towards an ambition of incentivising the development of regional pipeline infrastructure to be in operation or construction by 2030.

In August 2023, the UK government published its "minded-to" positions on the high-level design of the HTBM and intends to publish an update in due course.

#### Hydrogen Storage Business Model (HSBM):

This model supports the development of storage facilities, with a focus on geological storage in early rounds. UK government intend to design the first Hydrogen Storage Business Model round to contribute towards an ambition to support up to two storage projects at scale to be in operation or construction by 2030. UK government published its "minded-to" position in August 2023 to outline initial high-level thinking of the HSBM design. In November 2024, government advised the market that it has started early strategic planning to procure rights to store hydrogen in geological storage facilities, and support in remarketing/reselling those rights to end users.

In addition to these strategic plans, the UK industry is actively working on several key projects to establish a comprehensive hydrogen network. Initiatives, presented in Figure 10 could prove pivotal in developing the necessary infrastructure. The different networks are shown indicatively in different colours representing the connectivity between locations and are not representative of route alignments

These projects focus on creating interconnected pipelines that provide access to potential large-scale hydrogen storage facilities that mirror, in part, the existing natural gas networks and aim to support a seamless transition to hydrogen.

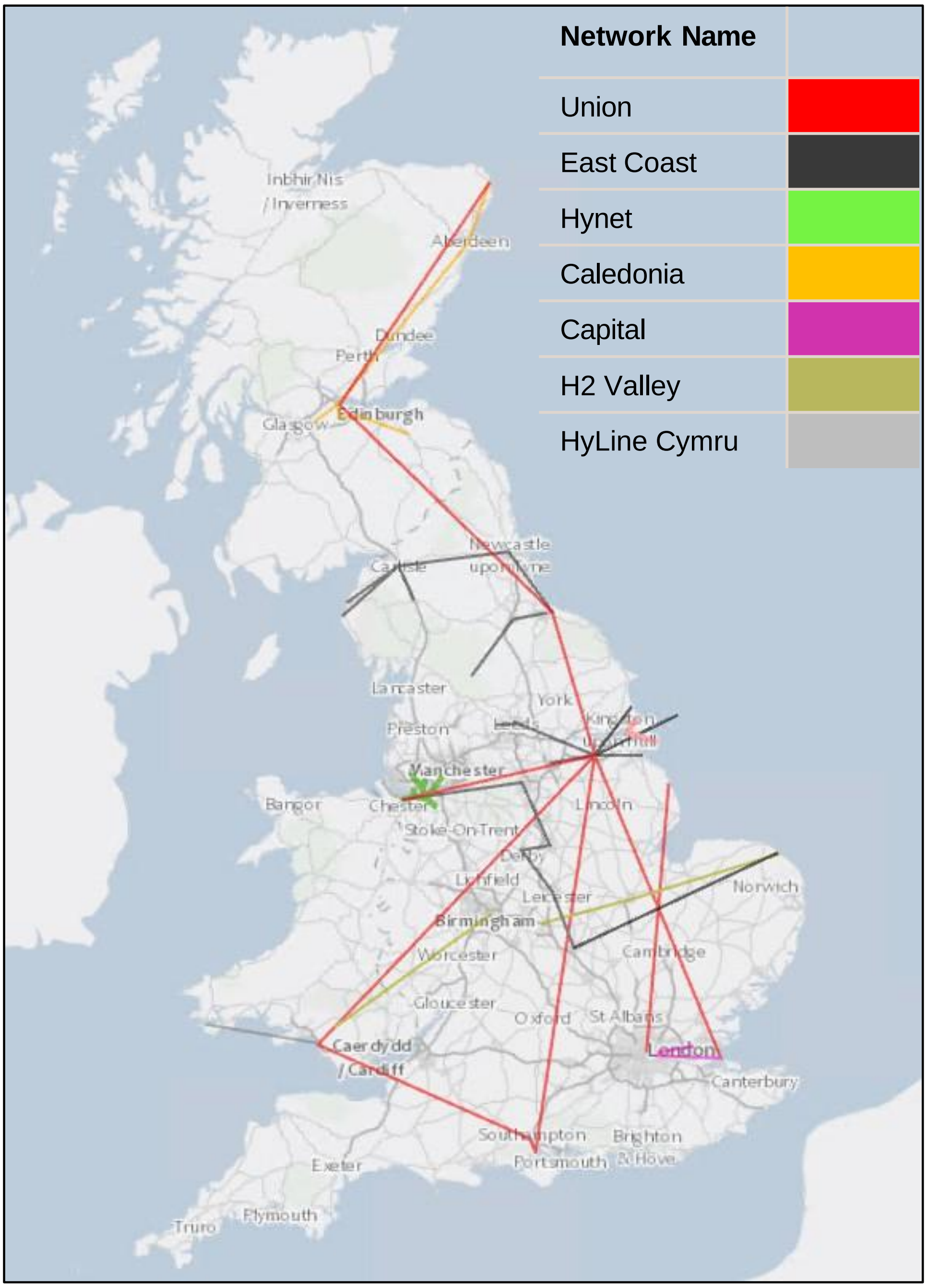



**Figure 10**

UK Potential H2 Transportation Projects (Source: DESNZ).

## 2.4 UK Export Opportunity

The UK has a significant opportunity to become a major exporter of low-carbon hydrogen in the future, driven by ambitious production targets and strong European demand.

The UK's strategic geographic position and access to offshore wind resources further enhance its potential as a key future hydrogen supplier to Europe.

The EU's goal to import 10 million tonnes[18] of hydrogen annually by 2030 presents a lucrative market for UK exports. When looking at Germany specifically, Germany's Import Strategy for hydrogen and hydrogen derivatives indicates that the country will rely on imports for 50-70% of its hydrogen needs by 2030.

As outlined above, the UK is also developing essential T&S infrastructure to connect hydrogen producers, which will be a key dependency to potentially connect the two networks in the future, as discussed in Section 2.3.

This opportunity is further bolstered by the estimated competitive nature of the UK's Levelized Cost of Hydrogen (LCOH), as reported by Bloomberg New Energy Finance (BNEF)[19] Table 6, indicating that UK hydrogen production could be economically viable against other emerging hydrogen markets globally.

Furthermore, the UK's geographical proximity to Europe enhances the cost-effectiveness of hydrogen transportation via pipeline, making its Levelised Cost of Transport (LCOT) competitive with that of other international markets, including those in the Americas, China, and Australia[20].

In May 2024, Arup published a report commissioned by DESNZ[20] which confirmed the UK could be in a strong position to trade low-carbon hydrogen to continental Europe in the future.

# Ireland Future Export Opportunity

Ireland's National Hydrogen Strategy, published in July 2023[21], outlines the country's vision for integrating hydrogen into its energy system as a key component of a zero-carbon economy. Ireland will prioritise the scale up and production of renewable (electrolytic) hydrogen, leveraging the country's significant wind resources.

Ireland has a 2 GW target of offshore wind, for the production of renewable hydrogen and other non-grid limited uses, to be in development by 2030.

The strategy also outlines Ireland's aims to develop export markets or renewable hydrogen and related technologies.

Tri-partite discussions between the UK, German, and Irish Governments indicate the future potential of connecting Irish low-carbon hydrogen production to a UK transportation network, enabling onwards connection of additional production capacity to Germany.

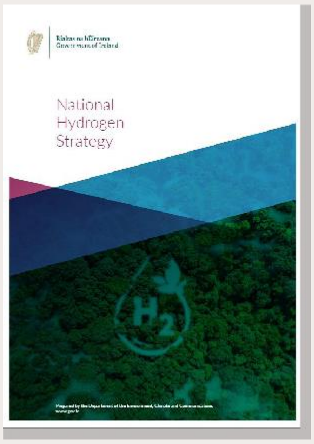



**Table 3**

Future Potential Export Capacity via Connection to Irish Production.

The study, which considered both pipelines and shipping to transport hydrogen, demonstrated that transport by pipelines would allow the UK to compete with ship exports from regions with lower hydrogen production costs.

### 2.4.1 Hydrogen Interconnector Projects under development

Two extremes have been identified when considering how an interconnector project could be structured:

1. Project to Interconnector: A production project that is only for export and has no/limited onshore network need as the project would be directly linked to the interconnector.
2. Network to Interconnector: Two or more hydrogen production projects located in different locations are connected by a Great Britain (GB) onshore network to the GB export terminal of the interconnector.

There are several ways to structure a project within the defined extremes.

The 'Network to Interconnector' extreme will be influenced by the timelines related to the development of a GB onshore network.

Conversely, the 'Project to Interconnector' extreme, while not bound by this timeline, may face challenges regarding commercial viability and could restrict future opportunities for scaling up hydrogen trade, given that in the network scenario, additional UK capacity will be connected as the market ramps up providing greater diversity of supply.

Moreover, the 'Project to Interconnector' approach is not well aligned with the UK hydrogen strategy to develop a wider hydrogen transport and storage network, as discussed in Section 2.3, and is therefore considered less favourable within a UK context.

**The EU's goal to import**

**10m**

**tonnes of hydrogen annually by 2030 presents a lucrative market for UK exports.**

A number of stakeholders were identified who are considering hydrogen interconnector projects for the export of hydrogen from the UK to Europe.

Those who have consented to the sharing of information have been included in Table 4 below.

| Project | Description |
|---|---|
| National Gas and Fluxys | National Gas and Fluxys Belgium have signed a MoU [22] with the aim of stepping up their cooperation on decarbonisation infrastructure and supporting CCUS. As a result of the MoU, National Gas and Fluxys have agreed to explore the potential development of a hydrogen interconnector between the UK and Belgium. This initiative aims to leverage North Sea energy resources, such as offshore wind and hydrogen production, to enhance energy security and to support large-scale decarbonisation efforts.<br><br>This collaboration builds on the 25-year history of operating the natural gas interconnector between Bacton (UK) and Zeebrugge (BE). The key goals of their plan are focused around;<br>– Hydrogen Transport Corridors: Developing infrastructure to transport hydrogen between the UK and Belgium, enabling the trade of hydrogen between the UK and mainland Europe;<br>– Carbon Capture and Storage: Exploring the potential for CCUS to further reduce carbon emissions;<br>– Energy Security: Enhancing energy resilience and security for both countries.<br>National Gas estimates a COD between 2033 and 2035, contingent upon the development of the respective onshore transportation networks in both countries.<br>In this regard, National Gas is developing plans for a domestic hydrogen transmission network in GB, referred to as Project Union. This initiative aims to establish a national hydrogen transmission network, connecting various industrial clusters, which will serve as crucial prerequisite infrastructure for the development of a hydrogen interconnector between Bacton and Zeebrugge. National Gas has recently submitted a funding request for Front and Engineering Design (FEED) studies that will look to develop the detailed engineering design of the proposed onshore hydrogen transmission network. |

**Table 4**

Summaries of UK to Europe Hydrogen interconnector projects in development.

| Project | Description |
| --- | --- |
| Confidential Project | This project is a combined new build hydrogen production and transportation project, utilising electrolytic hydrogen production in northern Scotland and subsea pipeline transport to Germany, either directly or via the AquaDuctus offshore pipeline system.<br>The project has the ambition to supply up to 5% of the EU's hydrogen import needs or around 30% of Germany's by 2030. This goal is based on producing 500-600 kilotonnes per annum (ktpa) of hydrogen via a 4 GW electrolyser plant, linked to a roughly 900 km, 40-inch diameter pipeline to Germany. However, this is contingent on reaching a timely FID.<br>It is estimated to cost approximately £15 billion.<br>Given the production is based on renewable hydrogen, this will be favourable for use in Germany as it is recognised as a RFNBO in the transport, industry, and building sectors under the latest revision of the EU Renewable Energy Directive, RED III.<br>Most importantly, the viability of the project hinges on favourable decisions regarding zonal pricing and the establishment of a North of Scotland bidding zone under the UK Government's Review of Electricity Market Arrangements (REMA), which has the potential to make the hydrogen produced by the project cost-competitive with other German import options. Without zonal pricing under REMA, this would not be feasible. |
| Net Zero Technology Centre (NZTC) | The NZTC is leading an international consortium to deliver the 'Hydrogen Backbone Link Project', assessing an export pipeline connection from Scotland to Europe. The project looks at establishing a route utilising a purpose-built single large bore pipeline, which would start from various potential production hubs in northern Scotland, connecting to the proposed European Hydrogen Backbone onshore infrastructure.<br>In Phase 1 the project focussed on a route through the North Sea, avoiding existing Central North Sea infrastructure and routing through Norwegian and Danish waters before landing in Germany. This route closely followed most of the ScotWind leasing sites to the north of St Fergus, as well as the German offshore windfarms namely BorWin, DolWin, HelWin, and SylWin, allowing for potential future connections to wind-powered offshore hydrogen electrolysers.<br>In the ongoing second phase of the project, the NZTC-led consortium is considering alternative routings to the Phase 1 case – including the option to remain predominantly within UK waters. Routing now includes additional connections from the West Coast of Scotland, England and connectivity with Ireland. It also considers alternative European landing points such as a direct connection to the AquaDuctus project. |

**Table 4**
Summaries of UK to Europe Hydrogen interconnector projects in development.

## 2.5 Germany Context

Germany has set itself the ambitious goal of becoming carbon neutral by 2045[23]. To achieve this, all sectors will have to adjust their current modes of operation.

While significant emission reductions can be achieved through energy efficiency improvements and electrification (especially if this is based on the build-out of renewable energy), some processes, particularly in the industry sector, have reached the technological limit in terms of efficiency improvements and cannot be electrified[24].

This is where hydrogen comes in as an additional solution. With its broad and flexible applicability as a fuel, energy carrier, and storage medium, hydrogen is versatile and, when produced via electrolysis based on renewables (renewable hydrogen) or via fossil gas reforming / methane pyrolysis with CCS or waste gasification, low in emissions.

**To position itself in the emerging global hydrogen market, the German Government published its original National Hydrogen Strategy (NHS) in June 2020 and released an updated version in July 2023.**

The overarching aim of the NHS is to secure and strengthen Germany's position as a leading provider of hydrogen technologies along the entire value chain.

Additionally, the updated strategy formulates four goals, each of which is underpinned by short, medium and long-term action steps:

- Securing sufficient availability of hydrogen: Establishing a reliable supply, both through installing 10 GW of electrolyser capacity domestically by 2030 and by ensuring the availability of imports;
- Expanding the hydrogen infrastructure: Developing the hydrogen core network and connecting to the EHB
- Establishing hydrogen applications across sectors: Promoting the use of hydrogen in various sectors, particularly those that are hard to decarbonise, such as industry, heavy-duty transport including shipping and aviation, and energy;
- Creating suitable framework conditions: Developing regulatory and policy frameworks, at the national, EU, and international level, to achieve a coordinated approach that allows for a global hydrogen market to emerge.

Together, these goals are intended to promote the use of hydrogen to achieve the sectoral decarbonisation targets and at the same time create the conditions for meeting the emerging demand[26].

In the strategy, the German Government places particular emphasis on the use of low-carbon hydrogen in the energy-intensive industrial sector, where few or no alternatives to the usage of low-carbon hydrogen exist to achieve the necessary emission reductions.

**In 2023, Germany had a hydrogen demand of**

**55 TWh**

Specifically, the German Government envisages low-carbon hydrogen, preferably renewable hydrogen, to replace fossil raw materials in applications. Moreover, low-carbon hydrogen is to be used energetically, especially for high-temperature process heat (steel and chemicals industry).

Other usage areas are the transport, power, and heating sectors. However, in all three of these sectors, the German Government is very selective regarding the sub-sectors, where the application of hydrogen makes sense.

The key criterion for this selection is always the availability of alternative solutions, such as electrification. Accordingly, the German Government is concentrating on the application of hydrogen in heavy-duty vehicles and the maritime and aviation sectors, long-term energy storage, and as a transport medium.

In the heating sector, hydrogen is only to be used after 2030, with immediate and long-term preference given to alternatives such as heat pumps[26].

### 2.5.1 Low-Carbon Hydrogen Demand

In 2023, Germany had a hydrogen demand of 55 TWh. The German Government expects that this will increase by 40-75 TWh by 2030, resulting in an overall demand for hydrogen and hydrogen derivatives of 95-130 TWh in 2030, as shown in Figure 11[26].

This aligns with predictions by the National Hydrogen Council[27]. However, different studies predicting the demand for 2030 show a wide range of possible demand. This reflects a high degree of uncertainty regarding the actual offtake of hydrogen[28].

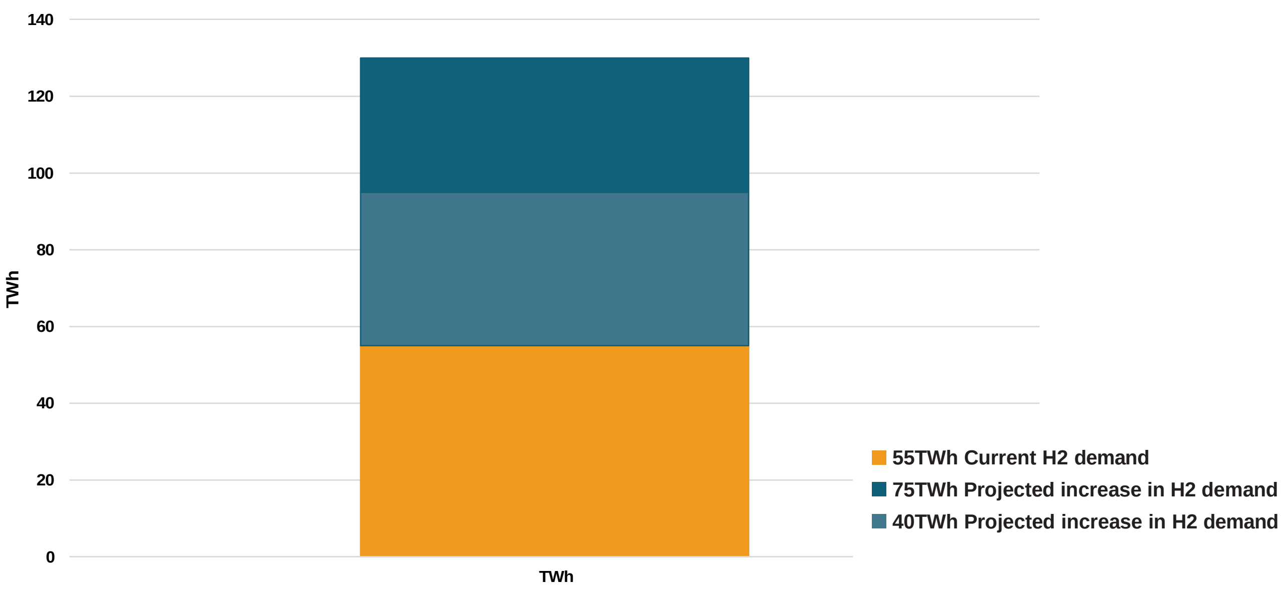



**Figure 11**

Hydrogen Demand in 2023 and Projected Demand for Hydrogen and Hydrogen Derivatives in Germany by 2030 According to the German Government.

In 2045, the German Government anticipates a hydrogen demand of 360-500 TWh, with an additional 200 TWh for hydrogen derivatives [26].

The National Hydrogen Council, on the other hand, expects a significantly higher demand, ranging from 620-1288 TWh for both hydrogen and hydrogen derivatives[27] (see Figure 12).

Up to 2030, it is anticipated that the steel industry, basic chemicals and petrochemicals, mobility, logistics, and the power sectors will be the primary consumers of low-carbon hydrogen and its derivatives.

According to the latest calculations by the National Hydrogen Council, the industry sector will have a demand of 56- 82 TWh in 2030, making it the largest source of demand.

This is followed by the transport sector with a predicted demand of 33 TWh, 22 TWh of which are expected to come from heavy-duty applications.

The heating sector is expected to demand 5-10 TWh (see Figure 13)[27], although this is a highly contested area of application of hydrogen, with the German Government emphasising the availability of alternative approaches, as displayed.

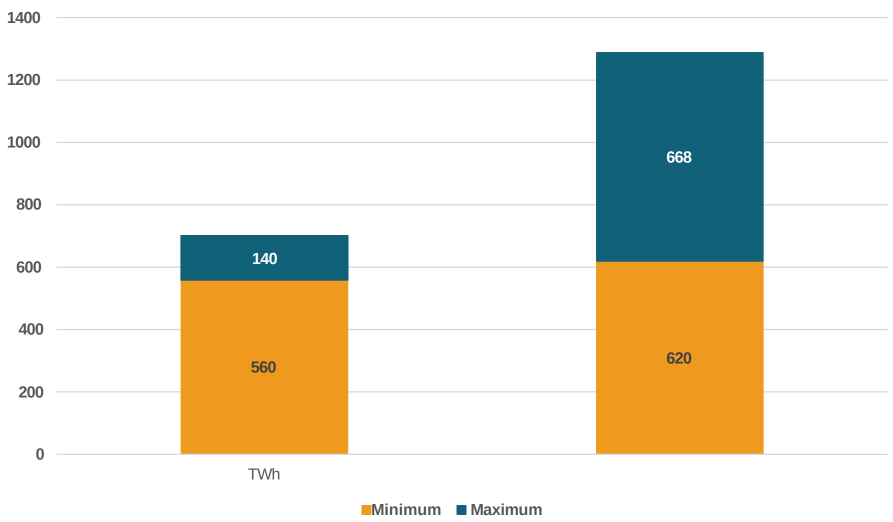



**Figure 12**
Projected Demand for Hydrogen and Hydrogen Derivatives in Germany by 2045.

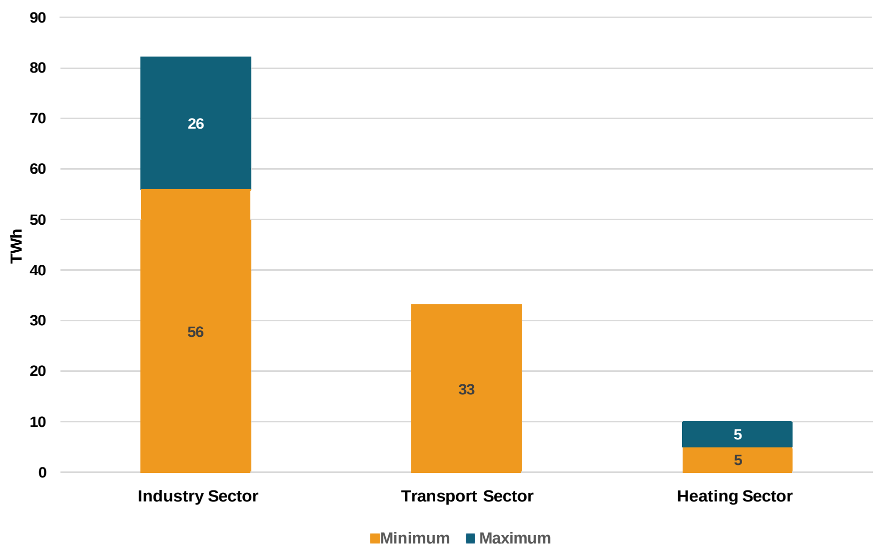



**Figure 13**
Projected Demand for Hydrogen and Hydrogen Derivatives in Germany by Sector for 2030 According to the National Hydrogen Council.

Hence, demand predictions for the heating sector must be regarded with some caution.

In 2045, long-term scenarios from the BMWK estimate industrial hydrogen demand to be between 290- 440 TWh, while the annual hydrogen demand in the conversion sector (electricity and heating networks) is projected to grow from 0 TWh in 2023 to around 80-100 TWh by 2045[26].

The National Hydrogen Council anticipates industrial demand to be between 254-402 TWh in 2045, which is closely aligned with BMWK's prediction.

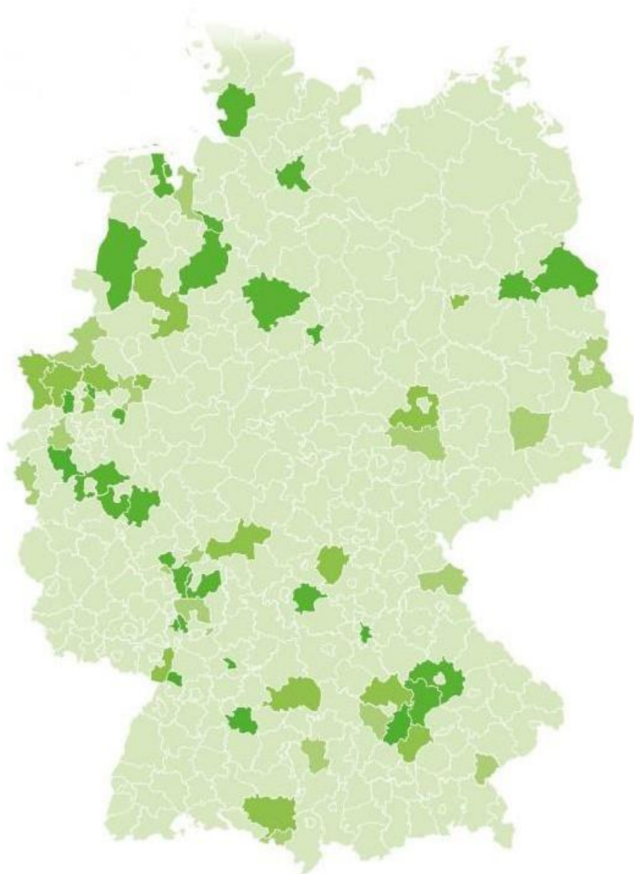
However, in the power sector, the National Hydrogen Council expects a demand of 80-200 TWh and in the heating sector a demand of 125-500 TWh.

For the transport sector they expect demand numbers of 161-186 TWh, a significant share of which is predicted to come from the heavy-duty (88 TWh) as well as aviation sectors (60-85 TWh)[27].

As Figure 14 shows, hydrogen demand is spread across Germany, but industrial clusters exist.

**Industrial demand in 2045**

**290 -440 TWh**



**Hydrogen Withdrawals at District Level in 2032**

Absolute volumes at district level in TWh

- less than 0.1 TWh
- from 0.1 to under 0.5 TWh
- from 0.5 to under 1 TWh
- from 1 to under 5TWh
- more than 5 TWH

Source: Transmission system operators

**Figure 14**

Regional Distribution of Hydrogen Withdrawals at District Level for the Year 2032[29].

**The German Government aims to achieve a domestic electrolyser capacity of at least**

**10 GW**

**by 2030**

## 2.5.2 Low-Carbon Hydrogen Production and Import

To address this demand, the German Government aims to achieve a domestic electrolyser capacity of at least 10 GW by 2030[26].

It also expects to become one of the largest hydrogen importers globally and in the EU (alongside Belgium and the Netherlands).

According to its Import Strategy for hydrogen and hydrogen derivatives, which was released in July 2024 as a key supplement to the hydrogen strategy, Germany will rely on imports for 50-70% (45-90 TWh) of its hydrogen needs in 2030.

The primary infrastructure for importing hydrogen and its derivatives includes pipelines and ships.


**Figure 15**

Hydrogen Core Network (FNB Gas, 2024).

Pipelines are specifically used for transporting the hydrogen molecule, while ships are intended for carrying hydrogen derivatives. Furthermore, the transportation of hydrogen derivatives may also involve rail and road systems.

This implies that Germany will rely on a diverse set of countries as hydrogen suppliers with its trade relationships intended to be global.

Additionally, the strategy reiterates the German approach of favouring renewable hydrogen in the long-term but first allowing the import of other low-carbon forms of hydrogen, including hydrogen produced via fossil gas reforming with CCS, methane pyrolysis with CCS, and waste gasification, to ensure sufficient quantities are available in the short-term[30].

Initially, the domestic distribution of hydrogen will be secured through the hydrogen core network (see Figure 15). This network will span 9,040 km and is to be built from 2025 and completion is planned by 2032. The financing framework through the amortisation account secures any delays in the development of the core network until 2037.

It will consist of 60% repurposed natural gas pipelines and 40% newly built hydrogen pipelines. It will also be connected to hydrogen storage facilities. The network will be financed primarily through grid fees, with initial financing gaps being addressed by an amortisation account.

This amortisation account is to be balanced through user fees by 2055.

If the amortization account is not balanced by 2055, for reasons that cannot be foreseen today, a subsidiary state guarantee will take effect.

**By 2030, Germany's hydrogen network will link with neighbouring EU countries through the EHB.**

The German Government will then make up the remaining shortfall and the operators of the hydrogen core network will contribute a deductible of up to 24%.

In addition, the state will bear the liability risk if one of the transmission system operators becomes insolvent[31].

Parts of the hydrogen core network will be funded through the EU's Important Projects of Common European Interest (IPCEI) hydrogen programme (for more information on this funding instrument, please refer to the following subsection)[30].

The final network development plan was approved by the Federal Network Agency in October 2024.

The next step is now the preparation of an integrated network development plan for gas and hydrogen (NEP Gas and Hydrogen), which is to be published in 2025.


**Figure 16**

Potential German Hydrogen Import Corridors (dotted lines indicate potential expansions) [30].

Currently, the Federal Network Agency (BNetzA) is developing regulations regarding hydrogen network charges, hydrogen transport capacity products, and hydrogen network balancing.

These provisions are aligned with the requirements in the EU Hydrogen and Decarbonised Gas Market package and are now subject to several consultation phases (BNetzA, 06.06.2024; BNetzA 03.07.2024).

By 2030, Germany's hydrogen network will link with neighbouring EU countries through the EHB. This is planned to encompass 32,616 km of pipelines by 2030, with 4,500 km set to come online in the initial phase comprising 1,500 km of new construction and 3,000 km of repurposed pipelines.

The coordination of the EU's hydrogen network will be managed by the Agency for the Cooperation of Energy Regulators (ACER). Germany is developing at least five major pipeline-based import corridors (see Figure 16):

The North Sea Region, the Baltic Sea Region, South-East Europe, South-West Europe, and Southern Europe.

Fifteen interconnectors will be critical to the hydrogen core network and import terminals are to be constructed on German coasts by 2030 to facilitate imports of hydrogen and most likely its derivatives by ship.

Additionally, new onshore Liquefied Natural Gas (LNG) terminals are required to be hydrogen-ready to be able to handle hydrogen derivatives once they are no longer used for the import of LNG[30].

**Through the Federal Fund for Industry and Climate Action, the German Government will issue**

**€3.3 bn**

**to companies in the industry sector which achieve emission reductions of**

**40%**

**by either electrifying processes or by replacing fossil fuels with low-carbon hydrogen.**

### 2.5.3 Government Funding and Financial Incentives for Low-Carbon Hydrogen Projects

The German Government solely provides direct financial support for the production of renewable hydrogen.

Until sufficient renewable hydrogen is available, the German Government will provide limited support to other types, including hydrogen produced via fossil gas reforming with CCS, waste gasification, and methane pyrolysis with CCS, with strict GHG emission limits applying to the entire value chain[26].

The Federal Government has a variety of funding instruments (see Figure 17) to support and promote the rapid market ramp-up of hydrogen. At the national level, financial incentives have been put in place to support the development of renewable hydrogen production.

To this end, the Government has amended the Energy Industry Act to exempt renewable hydrogen production plants from electricity grid fees for 20 years.

To be eligible, the electrolyser must have been newly built after 31st December 2008 and have been commissioned within 18 years from 4th October 2011. This measure is to be terminated by 2029.

Additionally, renewable hydrogen production plants are exempted from some additional levies, including the so called StromNEV levy (issued to enable the reduction of grid fees for energy-intensive companies); combined heat and power as well as offshore levies (issued to support the build-out of both technologies); and the electricity tax.

These measures aim at increasing the economic competitiveness of renewable hydrogen compared to other forms of hydrogen and thus support its market ramp-up[32].

In an amendment to the Federal Immission Control Act, the German Government has also introduced measures to simplify and thus speed up the planning approval process for electrolysers[33].

In addition to these financial incentives, numerous funding programmes are available, which cannot be outlined in this report for reasons of conciseness.

Therefore, only the most prominent will be mentioned. For a complete list, please refer to the website on funding programmes by the German Government[34].

Two major funding programmes, the CCfD scheme and the Federal Fund for Industry and Climate Action, are aimed at encouraging the production and uptake of low-carbon hydrogen by the industry sector.

Through the Federal Fund for Industry and Climate Action, the German Government will issue €3.3 billion to companies in the industry sector, which achieve emission reductions of 40% by either electrifying processes or by replacing fossil fuels with low-carbon hydrogen.

The production of hydrogen can receive funding if the produced hydrogen is renewable and plays a dominant role in the company's main operational processes.

The funding starts at €500,000 for small and medium-sized enterprises (SMEs) and at €1 million for large companies. The maximum funding per company is €200 million.

The program was initiated in August 2024 and module 1, which is relevant to financing projects involving low-carbon hydrogen (module 2 applies to CCS projects), is set to run until the end of 2030 with yearly funding rounds[35 36 37 38].

The CCfD scheme aims to support heavy industry in reducing 350 $MtCO_2$ emissions (i.e. 20 Mt per year) until 2045.

The scheme is organised in the form of auctions, where those companies that can achieve the highest relative emission reductions within the first five years of receiving funding at the lowest cost per tonne of $CO_2$-emissions reduced will receive a 15-year contract.

Companies who participated in the preparatory process in the summer of 2023 were able to apply for overall €4 billion of funding over the summer of 2024.

In October 2024, 15 recipients, comprising heavy industry and SMEs particularly from the glass, ceramic, paper, pulp, and chemical sectors were announced. Another bidding round was initiated in July 2024 and companies were able to hand in their applications until the end of September 2024 [39 40 41].


**Figure 17**

Overview of Relevant Regulation and Support Mechanisms in Germany[30].

**Technological innovation, production, and the application of hydrogen in different sectors is further encouraged through the Important Projects of Common European Interest (IPCEIs).**

The use of renewable hydrogen in the transport sector (either through direct use in vehicles or in the refinery process) is incentivised by the 37th BImSchV through multiple accounting, i.e. RFNBOs count with a factor of three towards the respective company's GHG quota and GHG quota certificates are issued accordingly.

Since these GHGquota certificates are tradable, this multiple accounting is likely to increase demand for renewable hydrogen by the transport sector, thus incentivising the production of the required renewable hydrogen.

While state aid/funding is not used directly here, the regulation guarantees the availability of indirect aid, which can be influenced by the state (for example by adjusting the crediting factor or introducing minimum quotas for the use of hydrogen to achieve the GHG savings targets).

Technological innovation, production, and the application of hydrogen in different sectors is further encouraged through the Important Projects of Common European Interest (IPCEIs). IPCEIs are embedded within the EU's state aid law and allow member states to provide state aid to projects that support economic growth, the creation of jobs, the green and digital transition, and competitiveness in the EU without violating EU competition policy[42].

So far, the European Commission has approved four IPCEIs encompassing 90 companies from 16 member states including Norway. The total state aid provided in the context of these projects amounts to €18.9 billion.

The German Government provides state aid under the following IPCEIs:

- Hy2Tech which encompasses 41 projects receiving €5.4 billion from 15 member states. Four German companies are involved in this and receive state aid support.
- Hy2Infra which encompasses 33 projects receiving €4.6 billion from seven member states. 23 German companies are involved and receive state aid support.
- Hy2Move which encompasses 13 projects receiving €1.4 billion from seven member states. Three German companies are involved and receive state aid support[43 44].

As Germany is highly reliant on international hydrogen imports, the German Government has also developed a number of funding programmes to support international hydrogen production.

The best known of these programmes is H2Global, a two-sided auction mechanism with an intermediary [45] that facilitates contracts between sellers and buyers by buying hydrogen products at higher prices and selling them at lower prices to stimulate demand.

The price difference is covered by public funds or potentially by climate funds or private capital[30].

The pilot auction was divided into three categories: renewable ammonia (Lot 1), renewable methanol (Lot 2), and electro-sustainable aviation fuel (e-SAF) (Lot 3).

In July 2024, the first contract for renewable ammonia (Lot 1) was awarded after attracting interest from over 65 countries. Out of 22 bidders in the qualification phase, five advanced to negotiations.

The producer must adhere to sustainability requirements, including EU standards for hydrogen.

Fertiglobe, the largest nitrogen fertiliser producer in the Middle East and North Africa (MENA) region, emerged as the successful bidder with a contract price of €1,000 per tonne, broken down as follows: 81% product price, 9% transport charges, 7% logistics, and 3% import duties.

The net product price is €811 per tonne of renewable ammonia. Fertiglobe will commence production of renewable ammonia in Egypt for European ports in 2027.

The renewable ammonia will be transported to storage tanks at the nearest Egyptian port using an existing 7 km pipeline.

From there, it will be shipped to the Port of Rotterdam. With this contract, Europe has secured a significant renewable ammonia supply, starting at 19,500 tonnes in 2027, with potential growth to 397,000 tonnes by 2033. The subsidy amount to be paid will depend on the upcoming sale auctions.

The auction for e-SAF (Lot 3) concluded without awarding a contract. Although three companies qualified in the qualification phase, only one submitted an indicative bid.

The other two refrained due to complexities in the regulatory framework for GHG accounting in e-SAF production as well as the contract's small value and duration, which did not align with the investment and development time for a new e-SAF plant.

Consequently, the third bidder did not submit a final offer. The results of the auction for renewable methanol (Lot 2) are expected in 2025[45].

To enhance the ramp-up of the global hydrogen market, the German Government welcomes the involvement of other countries in H2Global[30] and is committed to joint auctions.

In November 2023, plans were unveiled by the German and Dutch Governments to conduct a joint auction for importing renewable hydrogen or its derivatives[46]. However, no updates have been released since.

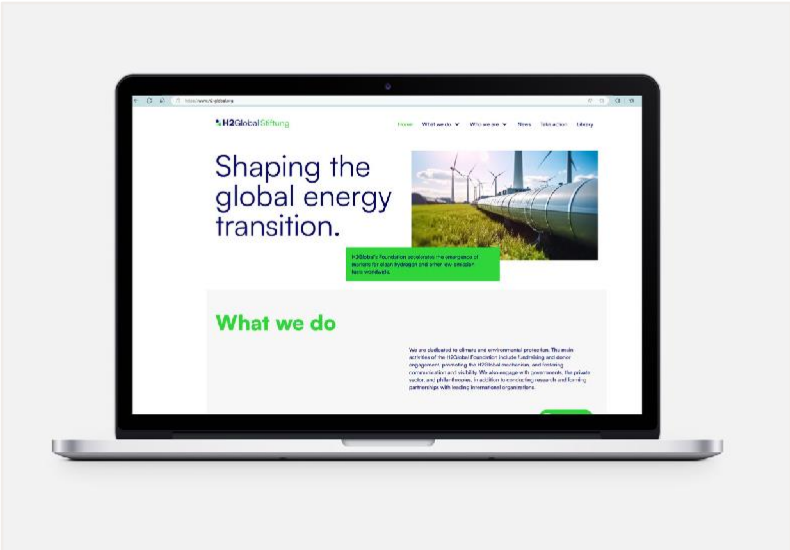
In March 2024, a bilateral auction window between Germany and Canada was agreed upon[47].

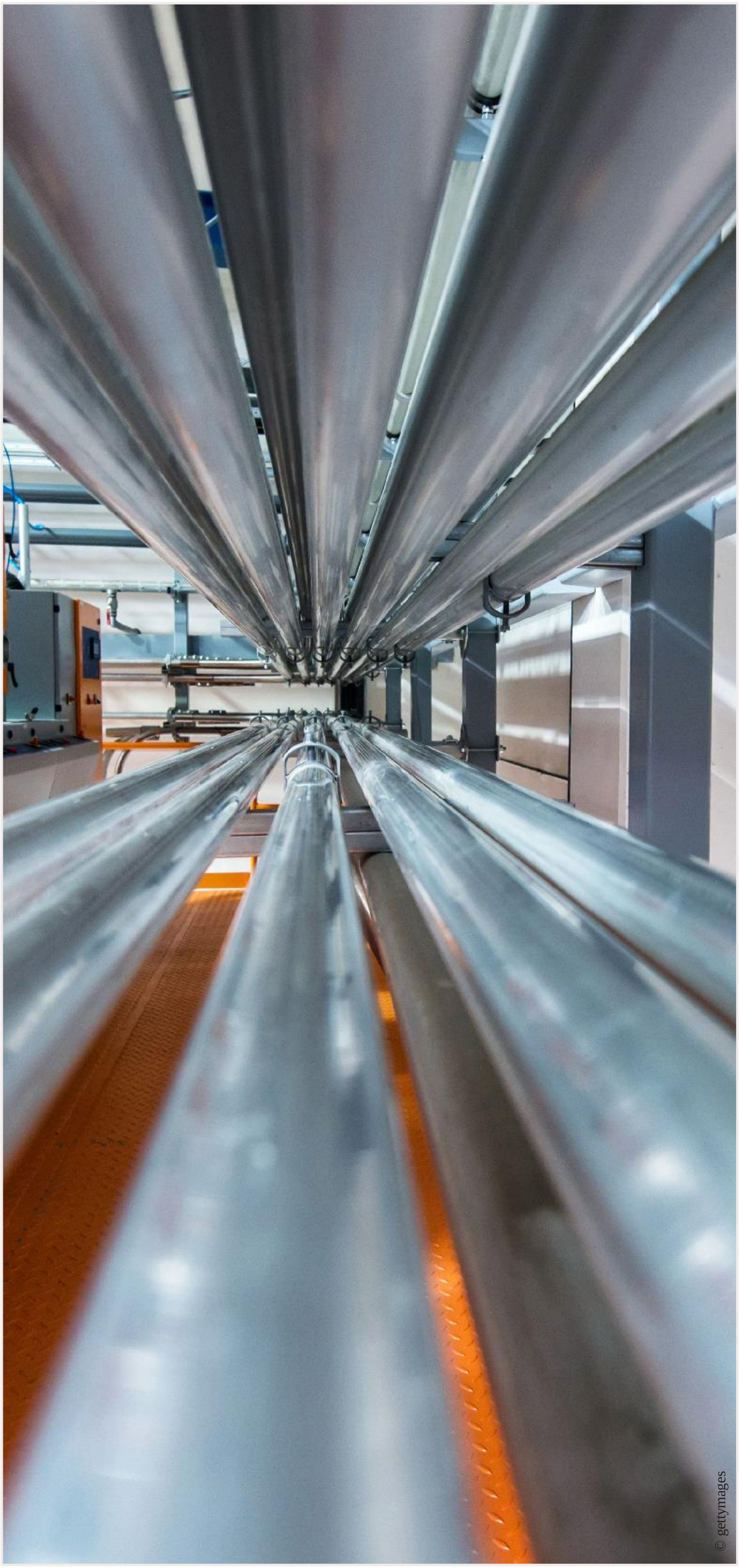
Consultations between National Resources Canada and the BMWK have been finalised. Now, a notification process with the EU Commission is in progress to ensure that the auction window is in line with EU state aid rules.

Auctions are expected to commence in 2025. In September 2024, Germany and Australia also signed a joint declaration of intent to negotiate a bilateral H2Global auction window, aiming to connect European buyers with Australian producers of renewable hydrogen and its derivatives[48]. Negotiations on this are ongoing.

Other funding programmes to support international production include the PtX Development Fund (available for projects in developing and emerging countries)[30].

**To enhance the ramp-up of the global hydrogen market, the German Government welcomes the involvement of other countries in H2Global and is committed to joint auctions.**






### 2.5.4 Initiatives and Regulations under Development

To further stimulate the hydrogen market, the BMWK is working on several measures, including the publication of a hydrogen storage strategy and the development of common or internationally recognised certifications with minimum standards for hydrogen imports[30].

The German approach will be based on the requirements for low-carbon hydrogen production defined by the EU.

For renewable hydrogen, these can be found in the EU Renewable Energy Directive (RED) II and the associated delegated acts (additionality, temporal and geographical correlation).

For low-carbon hydrogen (excluding renewable hydrogen in the EU context), these can be found in the EU Hydrogen and Decarbonised Gas Market package. Since the delegated act for the gas market package is still under development, details on the certification of low-carbon hydrogen are still pending (for more details see Appendix C.1.3.6).

Environmental and sustainability criteria such as the avoidance of water scarcity, competition for use, pollution, and competition for land as well as the protection of human rights in the supply chains are also crucial for Germany.

Additionally, the German Cabinet is working on the adoption of a new law, the Hydrogen Acceleration Act ("Wasserstoffbeschleunigungsgesetz"), intended to streamline, digitalise, and thus accelerate planning approval processes for renewable hydrogen projects[30].

## 2.6 German Industry Engagement

To gain a deeper understanding of the realities of the ramp-up of the hydrogen market as well as existing hurdles and the resulting need for action by the Government in Germany, 14 interviews were conducted between August and October 2024 with various mid-streamers and offtakers from the transport, chemical, steel, and paper sectors.

### 2.6.1 National policy landscape

Considering the developments at the national level, the interviewees largely regarded the hydrogen demand projections by the National Hydrogen Council for 2030 (94-125 TWh) and 2035 (233-284 TWh) as realistic.

However, it was stressed that this will be highly dependent on the swift implementation of relevant regulation at both the EU and national levels as well as on the necessary production capacities and import infrastructure being developed.

The question of whether the demand forecasts will actually materialise was therefore considered to depend more on sufficient supply than on possible lower demand.

Overall, companies were careful in passing their judgement but only a few regarded the projected demand numbers as unrealistic.

In this case, the numbers were regarded as too optimistic, only one interviewee regarded the numbers as being too conservative.

However, several companies cautioned that the numbers can only be seen as guidelines and that the possibility of distortions must be taken into account.

For instance, offtakers may declare maximum needs to secure sufficient supplies.

No judgements could be passed on the numbers for 2040 and beyond, as the uncertainties attached to these were considered as being too high.

There was considerable disagreement as to which sector can be expected to become the first major offtaker of low-carbon hydrogen in Germany.

The steel sector was usually identified as being among the first movers (either first or second) due to its high share of hard-to-abate emissions, where there is no alternative to the use of low-carbon hydrogen to reach the required decarbonisation goals, and the comparatively high level of financial support provided by the German Government for that reason.

The transport sector was also named as an early or first offtaker, especially due to the GHG quota (see Section 2.5.3). Within the transport sector, heavy-duty and aviation were named as the main expected offtakers.

With regards to the application in the maritime sector, the interviewees were less certain.

In the heavy-duty transport sub-sector, interviewees explained that a smaller price gap between conventional fuels and hydrogen results in a higher willingness to pay and therefore earlier uptake.

However, the availability of hydrogen trucks and buses may constitute a bottleneck.

Additionally, refineries were identified as earlier offtakers, yet several interviewees did not mention refineries  at all.

This may however also be due to refineries using hydrogen today already, so that they were not considered anymore as future offtakers.

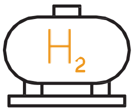
The RED III provisions were identified as driving uptake by refineries. Several interviewees agreed that hydrogen would only play a subordinate role in the heating sector.

The first offtake of low-carbon hydrogen was generally expected to be between 2027 and 2028. Earlier offtake was assumed to be unlikely due to the need to construct the necessary infrastructure and projects.

Moreover, the commencement of first projects falls within this timeframe. Yet, several challenges and, accordingly, several required action steps by the German Government were identified as crucial for enabling uptake by 2027.

Three issues emerged as particularly important: storage, prices, and certification.

## Hydrogen storage




### 2.6.2 Hydrogen storage

According to the interviewees, hydrogen storage has not yet received the necessary attention in the German debate and policymaking. Although a storage strategy is currently in development, many interviewees emphasised the importance of accelerating the process. This is because on the one hand regulatory certainty is required and, on the other hand, storage site development takes several years while the availability of storage facilities will be crucial to the flexibility of the emerging hydrogen market.

## Funding mechanisms

### 2.6.3 Funding mechanisms

A second often repeated challenge is that prices for low-carbon hydrogen remain high and, importantly, much higher than expected a few years ago.

Therefore, the interviewed companies called for more funding and subsidies to be issued by the German Government as well as a shift towards a more realistic discussion on the prices that can be expected in the short-term.

In terms of funding, several interview partners criticised the CCfD scheme as ‘too complicated’.

Specifically, it was noted that the funding instrument is very complex and therefore difficult to understand, the calculation formula very strict with no funding allowed under the contracts if companies start repaying earlier (either due to calculation errors or a change in production processes), and the funding period too short as companies do not believe they will be competitive after the available 15 years without funding.

Furthermore, interview partners suggested adapting the CCfD scheme by making it sector-specific and opening it up to all parts of the hydrogen supply chain, including to mid-streamers, as well as to ‘blue’ hydrogen (produced via fossil gas reforming with CCS) instead of only to renewable hydrogen.

In general, a more sector-specific approach to funding was propagated, also with regard to H2Global auctions. For instance, representatives from the logistics sector criticised that the discussion of and (lack of) funding for the transport sector ignored the differentiated needs and technological possibilities within the transport sector. Some vehicles in the logistics sector need to operate around the clock and cannot be electrified.

However, as electrification is the preferred choice for the transport sector more broadly, this special need has not received the required attention or funding thus far.

Moreover, interviewees stressed the need for funding and the respective application procedures to be simplified, especially to ensure that it is accessible to SMEs with fewer resources. Lastly, it was requested that CAPEX funding be supplemented by OPEX funding.

## Hydrogen certification

### 2.6.4 Hydrogen certification

Establishing a clear and transparent approach to certification emerged as a third issue of central importance. While some companies criticised the EU approach outlined in RED II as too stringent, especially in the ramp-up phase, the overarching narrative was that certainty regarding standards and certification procedures, including who will do the certification, is the most important next step, irrespective of the exact requirements.

Beyond these three key issues, two further challenges and corresponding action items were identified.

First, the interviewees criticised the lack of long-term certainty and explained that there was too little regulation beyond 2030.

Moreover, they added that both the EU and Germany developed regulation too slowly and that Germany needed to accelerate the transposition of EU regulation into German law, especially RED III and the EU Hydrogen and Decarbonised Gas Market package.

To further increase certainty at the national level, instruments such as a green gas quota were suggested as well as provisions to ensure that the ramp-up remains unaffected by a change in Government.

However, it was also recognised that Germany has made significant progress in the past year with the passing of the regulation on the hydrogen core network.

With this, Germany was regarded as being ahead of other EU countries and the planning was praised for its speed, especially considering that the network is unprecedented in scale and complexity.

Companies also acknowledged that the BNetzA is now in the process of addressing balancing and capacity allocation within the network.

While the planning of the hydrogen core network was generally recognised as a great success, there was also a consensus that other infrastructure projects must now be given greater attention.

This includes distribution networks, ammonia infrastructure, import terminals, and rail transport.

The latter is especially relevant to offtakers who need pure hydrogen, which cannot be transported via pipeline (without post-transportation treatment, which would increase costs).

### 2.6.6 Company-level considerations

Moving away from national level discussions, the interviews also provided insights into plans and considerations at the company level.

Here, no statements could be made regarding the anticipated quantities of low-carbon hydrogen that would either be distributed by mid-streamers or purchased by offtakers.

This will be highly dependent on the regulation being implemented swiftly, the price of low-carbon hydrogen, the willingness to pay, and the availability of funding as well as the infrastructure being developed and the network connection including for distribution system operators being ensured.

Both renewable and 'blue' hydrogen (produced via fossil gas reforming with CCS) are expected to be purchased, with mid-streamers answering requests by offtakers.

However, most companies expressed a preference for renewable hydrogen, also for environmental reasons but especially to comply with regulatory requirements (GHG quota in the transport sector, quota in the aviation sector, funding requirements, etc.).

Interestingly, several companies did not regard 'blue' hydrogen as a bridging technology but rather as an additional source of supply expected to be taken up after renewable hydrogen has seen some offtake.

This is because the companies interviewed did not expect 'blue' hydrogen to be (significantly) cheaper than renewable hydrogen while being less useful for fulfilling regulatory requirements.

In the end, companies stressed that the price will be decisive as well as the need to comply with existing regulations.

A similar narrative emerged regarding hydrogen and its derivatives. Both are expected to play a role in the German hydrogen market, with mid-streamers again providing according to the needs and requests by the offtakers.

Derivatives were regarded as especially interesting in terms of transport. Here ammonia was seen as the most promising transport vector, as there is an existing infrastructure (e.g. containers for ship transport) and extensive experience in handling it.

Moreover, it was mentioned that focusing on ammonia, as several producers are already indicating to do, would create greater flexibility regarding the target market.

This is because ammonia enters the liquid state at -33°C already (as opposed to hydrogen, which enters the liquid state at -230°C) and thus can be transported in liquid form via all modes of transport (ship, train, truck, and pipeline) across diverse distances and geographical conditions.

This acts as a risk mitigation strategy for producers, which may make up for potential additional costs associated with ammonia cracking if the desired product is hydrogen instead of ammonia.

However, even though ammonia infrastructure is already in place, it will need to be expanded significantly if ammonia indeed emerges as the main transport vector, and public discourse interventions may be necessary, as ammonia is seen critically due to its toxicity.

Both mid-streamers and offtakers were open to imports, with the price being named as the decisive criterium.


Some consideration is given to the reliability of the production country more broadly and the producer specifically (risk assessment) as well as to social and environmental issues, including human rights and water availability, but this is secondary if relevant at all.

In terms of EU versus non-EU imports, both were regarded as possible, with imports from non-EU countries potentially being more complex to set up initially. Importantly, the alignment of certification schemes was seen as the decisive step, which is expected to reduce if not eliminate the difference in complexity between EU and non-EU countries.

In terms of contracts, mid-streamers seek to create a diversified portfolio encompassing both short and long-term contracts with offtakers. However, in the ramp-up phase, short-term contracts will dominate.

Current contract lengths under discussion range from one to five years. Contracts with suppliers, on the other hand, will be long-term, ranging between ten to twenty years, with the majority being at the higher end of the spectrum, as most projects still need to be constructed.

The successful bidder in the H2Global pilot auction on ammonia, Fertiglobe, was able to offer a supply contract of seven years, which interview respondents explained with the already existing ammonia plant and export terminal.

Importantly, mid-streamers agreed that they would only enter into purchase agreements if there was secured offtake, at least during the ramp-up phase.

Later, an open market is expected to emerge, which is also one of the reasons storage was identified as an important issue to be tackled in a timely manner.

### 2.6.7 Conclusion

Overall, it became apparent that predictions regarding demand quantities and sectors are difficult to make.

However, it also became clear that a great willingness and desire exists to kick-start and ramp-up the hydrogen market in Germany.

Companies value the steps the German Government has taken so far, particularly regarding the planning of the onshore hydrogen core network and would now like to see greater flexibility in existing measures as well as an expansion of funding and regulation to provide greater clarity along the hydrogen value chain.

Key issues for meeting the offtake targets in 2030 will be regulatory clarity on hydrogen storage (here the planned storage strategy will be a crucial step forward), an expansion and increased flexibility of existing funding mechanisms such as the CCfD scheme as well as new funding opportunities, and the clarification of the EU's and Germany's approach to certification.

With 2030 approaching quickly, an emphasis was put on the need for the swift implementation of these matters.

Additional future stakeholder engagement will be required, particularly with offtakers, producers, and transport operators in the early stages leading into the initiation of an interconnector project to understand the needs case for trading low-carbon hydrogen between the UK and Germany.

# 3

# Delivery Enablers

**Five enablers have been identified as fundamental requirements to enable the trade of hydrogen between the two markets.**

**These span across the themes of regulation, business models and commercial arrangements to support the delivery of a hydrogen interconnector project.**

**The breadth of these actions reflect that, unlike existing electricity and natural gas interconnectors, a hydrogen interconnector project would require connecting two markets that are still in early development.**

## 3.1 The hydrogen value chain

The hydrogen value chain spans from production to the offtakers, with onshore and offshore networks critical to enable the future flow of hydrogen between the UK and Germany.

For the purposes of this study, the boundary of the interconnector asset only includes the interconnector pipeline and the associated onshore terminals, including compression facilities, if required.

The utilisation of the interconnector is dependent on the wider value chain incorporating hydrogen production, onshore networks in the respective countries and securing offtaker(s) for the duration of the asset's life in Figure 18.

This section makes an underlying assumption that the initial flow of hydrogen through the interconnector will be in one direction (UK to Germany) and that the interconnector is built directly between the GB onshore network and the German hydrogen core network (including AquaDuctus 1 or 2).

These enablers will not preclude the future bi-directional flow of hydrogen through the interconnector.

Further, the enablers would be extended if the interconnector was built between the GB onshore system and another part of continental Europe, e.g., the Netherlands or Belgium, to reflect the additional actions and action owners required.

Given the nascent state of the hydrogen market, each element of the value chain is likely to be developed in in stages and, subject to how the market develops, are likely to grow in scale over the 2030/2040s.

As discussed in Section 2, the development of the UK hydrogen production landscape, driven by the renewable potential and development of the electricity network, is encouraging a breadth of projects to be developed across GB.

Almost all the projects receiving, or shortlisted for, government funding have the offtaker and production co-located with either short pipelines or tube trailers for the hydrogen transportation solution.

In parallel, government policy is currently under development to determine the potential size and coverage of a GB onshore hydrogen network to connect these production projects with wider domestic demand.

This is expected to be captured as part of the wider strategic energy planning to be undertaken by the GB National Energy System Operator (NESO). Given the potential breadth of projects, the onshore network will be critical to connect production with the interconnector.

Similarly, in Germany the core network will be critical for transporting the hydrogen to several offtakers as the main offtakers will be spread across several regions in Germany (see Section 2.5.1).

**The interconnector will be reliant on the delivery of the wider hydrogen value chain, including the onshore networks.**

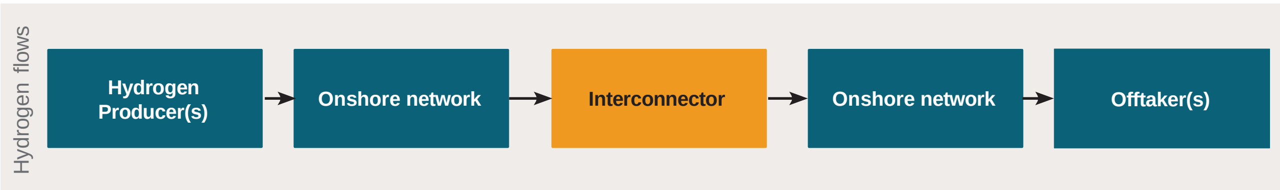



**Figure 18**
Hydrogen value chain.

It is assumed that the domestic production of hydrogen will take place primarily in northern Germany, meaning that the hydrogen will have to be transported over long distances to the customer centres in western and southern Germany.

Similarly, the hydrogen storage potential in salt caverns is mainly located in northern Germany.

Taking into consideration the whole hydrogen value chain, this study has considered the delivery enablers across business models, commercial arrangements and regulation that would be required to support the development of a hydrogen interconnector between the UK and Germany and has identified the following five key enablers:

The following section provides an overview of the enablers and further details are provided in Appendix A: Business Models, Appendix B: Commercial Arrangements, and Appendix C: Regulatory Analysis.

**Enabler 1:**
– Develop the requirements to have the ability to technically trade the hydrogen molecule

**Enabler 2:**
– Enable commercial trade of the hydrogen molecule between the two markets with no/minimal friction between markets

**Enabler 3:**
– Develop an interconnector business model

**Enabler 4:**
– Develop the regulatory framework for the interconnector

**Enabler 5:**
– Align the delivery of the wider hydrogen value chain

# Delivering historic interconnections

There are several interconnectors between the UK and continental Europe/Germany. Of the natural gas interconnectors, Interconnector UK, connecting UK to Belgium was commissioned in 1998 and Balgzand Bacton Line (BBL) connecting the UK to the Netherlands was commissioned in 2006.

The first electricity interconnector between the UK and continental Europe was commissioned in 1986 (Interconnexion France-Angleterre (IFA) between Sellindge (GB) and Les Mandarins (France)) and the first electricity interconnectors between the UK and Germany are expected to be operational by 2028 (NeuConnect) and followed by Tarchon in late 2030; these interconnectors are presented in the Figure 19 below.

All of these interconnectors have been developed in the context of the mature natural gas and electricity markets with understood market prices, the operation of multiple generators/producers and offtakers, expansive onshore networks and well-developed policy and regulatory frameworks.

As a result, the interconnector developer was then simply able to focus on ensuring that their project is developed in line with the existing technical and economic regulatory frameworks; for the most recent electricity interconnectors this has included working with the respective regulators to secure business model funding for the interconnector infrastructure.

Conversely, with respect to the potential UK-Germany hydrogen interconnector explored in this study, the hydrogen market in the respective countries is immature, the domestic policy and regulatory frameworks in both countries are still under development, there are no cross-border hydrogen market arrangements and the onshore networks at both ends are currently localised and driven by project need rather than expansive networks.

Therefore, in comparison to previously developed interconnectors, a wider breadth of actions is required to support a first of a kind hydrogen interconnector in a nascent market reflecting that the frameworks for the hydrogen markets need to be developed in parallel to the interconnector itself.

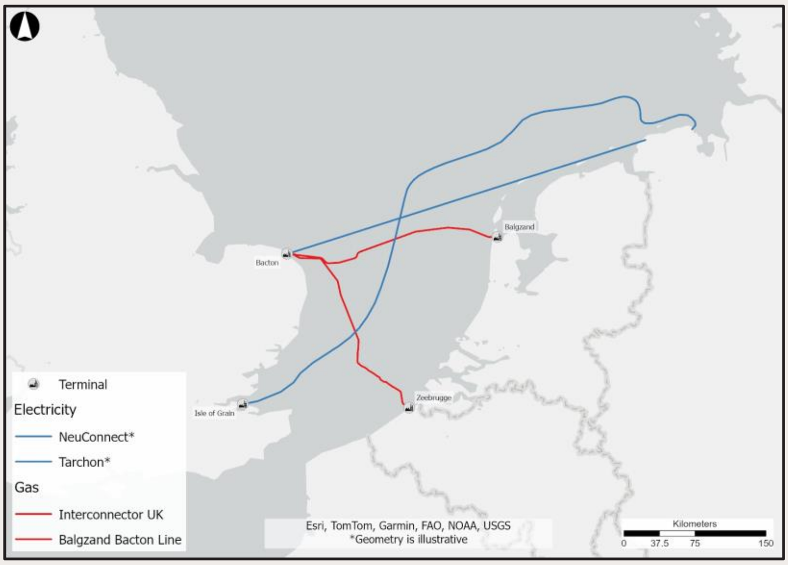



**Figure 19**

Current UK & Europe natural gas interconnectors and in development UK & Germany electricity interconnectors.

**Table 5**

Role of enablers in delivering historic interconnectors.

## 3.2 Delivering the enablers

Given that the hydrogen markets are in their infancy in the UK and Germany and the range of actions that need to be delivered to support the development of a hydrogen interconnector, the identified delivery enablers are to be implemented in two phases.

This recognises the market uncertainty and where project developers will need sufficient clarity to confidently engage within the process.

Whilst these actions will be delivered by a range of parties, at the end of each phase, there are government led project gates to review the needs case of the interconnector before progressing to the next phase of delivery. Further, phase 1 delivery of the enablers should commence following the publication of this study.

Outside of the identified delivery enablers will be a wider range of actions that will need to be delivered to support the development of the respective domestic hydrogen markets in the UK and Germany, for example allocation of production business model funding and development of onshore networks.

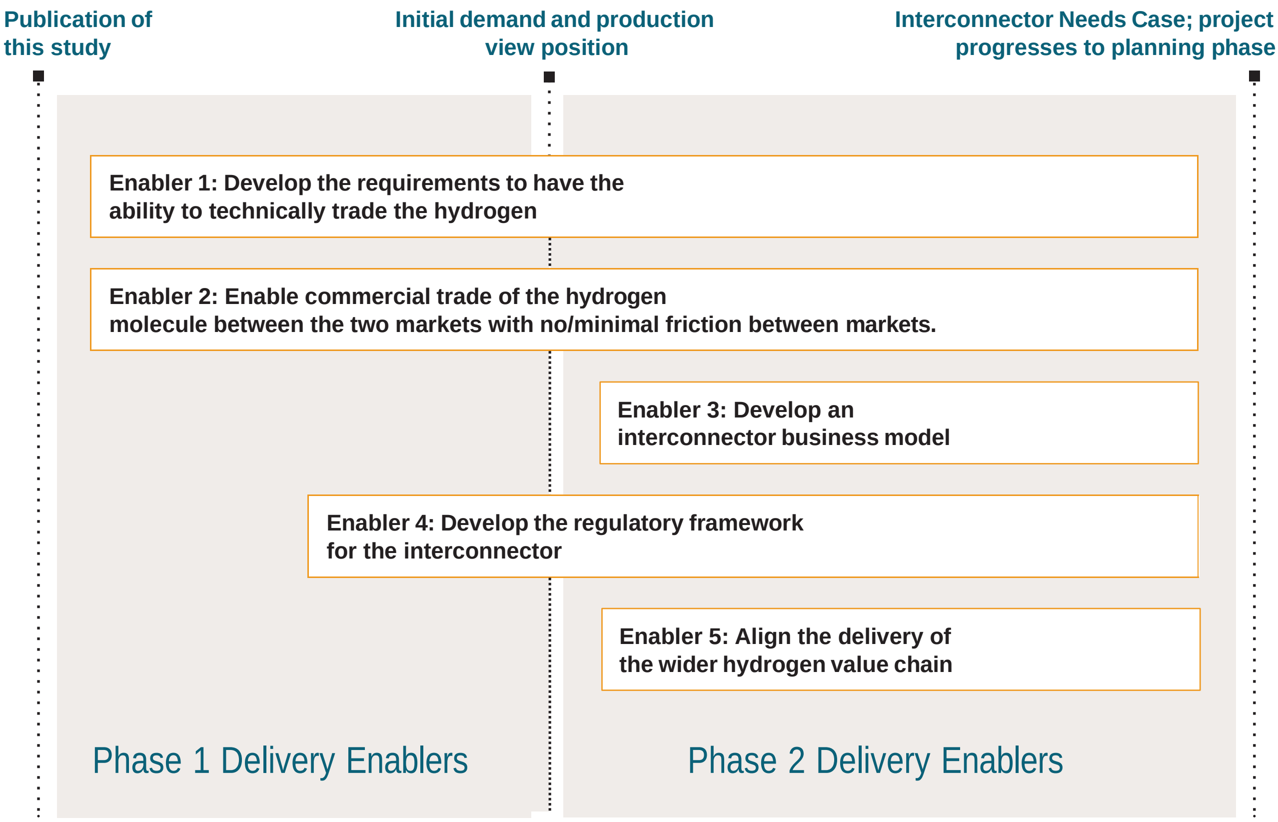



**Figure 20**

Delivery enablers sequencing.

The first area of focus for the delivery enablers, alongside developing the UK and Germany's respective domestic hydrogen markets including onshore networks, is convening the market to bring together offtakers and producers to establish commercially viable hydrogen offtake agreements, as this will fundamentally underpin the business case of the interconnector.

For offtakers and producers to proactively engage in the process, they will need to have confidence in the ability to trade and therefore in parallel there will be a need to develop the technical regulations to have the ability to trade the hydrogen molecule.

This effectively means ensuring that the hydrogen molecule produced in the UK is technically acceptable in Germany and vice versa.

This is achieved through understanding the alignment of low carbon hydrogen standards and respective certification schemes.

By the end of phase 1, there should be an initial view on the viable demand and production positions and whether this is sufficient to explore the needs case of an interconnector further.

Phase 2 will see the continuation of the development of the regulatory framework and convening of the market but will also see an expansion to consider the development of an interconnector business model and the alignment of the wider hydrogen value chain.

By having an initial view at the end of phase 1 on the viable demand and production positions, the technical feasibility for the pipeline can be progressed to identify proposed routing, sizing, and associated costs.

This will allow for an assessment of the barriers and risks to the interconnector development to inform whether a business model is required and how this is to be structured, funded and implemented.

Similarly, as identified within Figure 18, the interconnector is one element of the required network infrastructure and therefore parallel delivery of the respective onshore networks will be required.

This means there will be a need in the second phase to align the delivery of the respective networks to ensure that the hydrogen can be transported from the producer to the offtaker in line with the timelines agreed in the offtaker agreements.

The end of phase 2, effectively acts as a project delivery gate such that if there is sufficient evidence to underpin the needs case, the interconnector development would progress into the planning phase, undertaking pre-FEED and FEED.

## 3.3 UK-Germany Hydrogen Partnership

In September 2023, Germany and the UK launched the UK-Germany Hydrogen Partnership to deepen their collaboration in the hydrogen sector between the countries.

The partnership's goals are to accelerate the growth of the hydrogen economy, foster regional and global hydrogen markets, and enhance research, innovation, and investment opportunities in both countries.

To this end, the partnership has already hosted numerous policy and knowledge exchanges covering topics such as national hydrogen strategies, hydrogen production and transportation, and standards and certification.

**The UK-Germany Hydrogen Partnership' goals are to accelerate the growth of the hydrogen economy, foster regional and global hydrogen markets, and enhance research, innovation, and investment opportunities in both countries.**

In May 2024, Arup published a study commissioned by DESNZ, 'The potential for exporting hydrogen from the UK to continental Europe a study'[20].

This study explored the strategic, technical, and economic factors of different transportation methods for hydrogen export from the UK to continental Europe.

The study aimed to build the evidence base on hydrogen export to continental Europe to inform decision making and was split into three main areas:

– Setting out the UK opportunity with regards to hydrogen export.
– A pre-feasibility assessment of potential export routes for hydrogen from the UK, considering pipeline and non-pipeline transportation methods.
– A UK-specific levelised cost of transport (LCOT) model.

The study found that pipeline transportation provides a more cost competitive solution, when compared to other transportation methods, at the lowest throughput (100 ktpa) up to ~400km and is significantly more cost effective for distances less than 2,000km at the largest throughput flowrates of 1,500ktpa.

This led to a key recommended next step to carry out engagement with a number of European counterparts, including Germany, to collaborate on a potential hydrogen export/import infrastructure project.

This study laid the basis of understanding for DESNZ and BMWK to commission this joint feasibility study under the UK-Germany Hydrogen Partnership.

This report recommends that the UK-Germany Hydrogen Partnership should have overarching governance for the delivery enablers, including considering how these actions should be delivered and by whom, and then track progress during delivery.

**A 2024 study exploring the potential for exporting hydrogen from the UK to continental Europe found that pipeline transportation provides a more cost competitive solution, when compared to other transportation methods.**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# 3.4 Enabler 1:


## Develop the requirements to have the ability to technically trade the hydrogen molecule.

**Proposed actions under this enabler:**

1.1 The UK and German Governments to work together to align hydrogen emissions standards and respective hydrogen certification schemes where appropriate, working with the relevant authorities, including the European Commission, that hold responsibility for the establishment and implementation of the standards and certification schemes.

1.2 The UK and German Governments, or respective technical authorities, to work together to develop the technical operational requirements (including, for example, inlet pressures) associated with the flow of hydrogen between the two future networks.

### 3.4.1 Near term alignment of standards

To support the development of the hydrogen market and meet net zero requirements, both the UK and Germany (via the European Union) are developing technical standards associated with how to measure the carbon emissions of the produced hydrogen and the accompanying certification of hydrogen.

How these regulations are currently developing is detailed within Appendix C.

To enable the physical trade of the hydrogen molecule between the UK and Germany, the hydrogen produced in the UK, which is required to meet the UK's technical requirements, needs to be considered as acceptable for consumption by an offtaker in Germany, as defined by German and EU regulations.

Misalignment of the standards could create additional regulatory burden on producers and offtakers or act as a barrier to trade as the costs associated with reducing the carbon content and/or increasing the quality of the hydrogen to meet requirements could make the hydrogen uncompetitive compared to alternatives.

Whilst the UK Low Carbon Hydrogen Standard and the EU Commission GHG assessment methodology for renewable hydrogen are already in place, the EU Commission GHG assessment methodology for CCS-enabled hydrogen is expected to be finalised in August 2025.

Once this methodology has been finalised, this study recommends that the UK and German Governments work together to align the standards for carbon content level and the methodology for determining the carbon content where appropriate, working with the institutions, including the European Commission, to remove friction in the trading of hydrogen between the UK and Germany.

This alignment could be through either having the same standards or recognising the standards accepted by the other country as compliant with their own regulations.

### 3.4.2 Operational alignment of the interconnector requirements

For hydrogen to flow through the interconnector, technical standards will be required to ensure that this is undertaken in a safe manner.

This requires technical alignment across the UK onshore network, the subsea interconnector pipeline and German onshore network components of the interconnector system.

This study assumes that hydrogen will be transported through the interconnector system from a UK east coast landfall location via an offshore pipeline (in the base case via the AquaDuctus offshore pipeline system) to a German coast landfall location for onwards transmission to the German core network.

To ensure that the hydrogen can physically flow through the interconnector system, the operational parameters need to be compatible, specifically the pressures and flow rates across all parts of the interconnector system.

For this to be possible, an inlet specification will need to be agreed with all interested parties for all operational conditions to ensure that flow is possible under the anticipated range of operational scenarios across the wider system.

This may require additional conditioning, either compression or pressure control systems, to ensure compatibility can be maintained under variable operational conditions.

Ongoing liaison between the parties responsible for each component of the interconnector system during the design phases will be essential to ensure the operational requirements and constraints are understood and the required control systems and safeguards are designed to ensure the operability, safety and integrity of the whole system.

Therefore, this study recommends that the UK and German Governments, or the mechanism identified under Enabler 4, determine the requirement for any alignment between the national regulatory authorities and coordinate with the respective system component design teams for the selected routing to develop and agree the technical operational requirements to ensure all parties are working to a common basis.

The requirements of all interested parties will need to be understood and managed to reach a common set of operating parameters that all parties will adhere to.

This will ensure technical compatibility between the two future networks in the UK and Germany to allow hydrogen to flow.

# 3.5 Enabler 2:


## Enable commercial trade of the hydrogen molecule between the two markets with no/minimal friction between markets.

**Proposed actions under this enabler:**

2.1 The UK and German Government to explore how to facilitate market arrangements between the UK and German hydrogen markets and engage with potential project developers.

2.2 The UK Government to undertake an assessment of the potential production export capability, specifically capacity, location, quality, and timing, in the UK market.

2.3 In parallel to action 2.2, the German Government to undertake an assessment of the potential offtaker requirements in terms of load requirements, timing, location, price sensitivity, and quality in Germany.

2.4 The UK and German Governments, separately or together, to consider whether financial support mechanisms may be required to ensure the commercial viability of future hydrogen trade, specifically production or offtakers, in compliance with WTO rules.

As discussed in Section 2, the UK and Germany are developing their own domestic hydrogen markets.

Currently, the low carbon hydrogen market has limited liquidity and trading when compared to the existing natural gas market. T

o date projects have generally been developed either on a local or regional scale between specific producers and offtakers with project-only transportation solutions (i.e. tube trailer or short pipelines); similarly, some smaller hydrogen production projects have been co-located with their research activities.

This has meant that first of a kind producers have typically developed their production capacity based on the needs of their confirmed offtaker and, whilst in some cases, projects have expansion plans, they have not overbuilt their production capacity in anticipation of future offtaker demand.

Further, in the UK, to date, all of these projects have been supported by the NZHF providing business model support; the first rounds of projects (HAR1) having received funding confirmation in Autumn 2024 are expected to make financial investment decisions shortly.

The business case of the interconnector will need to be underpinned by sufficient offtake agreements between producers and offtakers so that the interconnector is sufficiently utilised to recover the interconnector developer's investment.

As a result, a key requirement to progress the development of an interconnector is an assessment of the potential production export capability, specifically capacity, location, hydrogen quality and timing, in the UK market.

From the German perspective, it will be necessary to understand the potential offtaker requirements in terms of load requirements, timing, location and quality in Germany.

For the assessment to provide a level of certainty of the potential interconnector flows, both producers and offtakers will need to understand the range of the potential hydrogen prices, volumes, supply durations and quantity of hydrogen that could be agreed within the offtake agreements.

As reflected in Figure 21, there are factors that will influence costs and volumes across production and infrastructure assets as well as the offtakers willingness to accept the hydrogen price.

**The business case of the interconnector will need to be underpinned by sufficient offtaker agreements between producers and offtakers.**

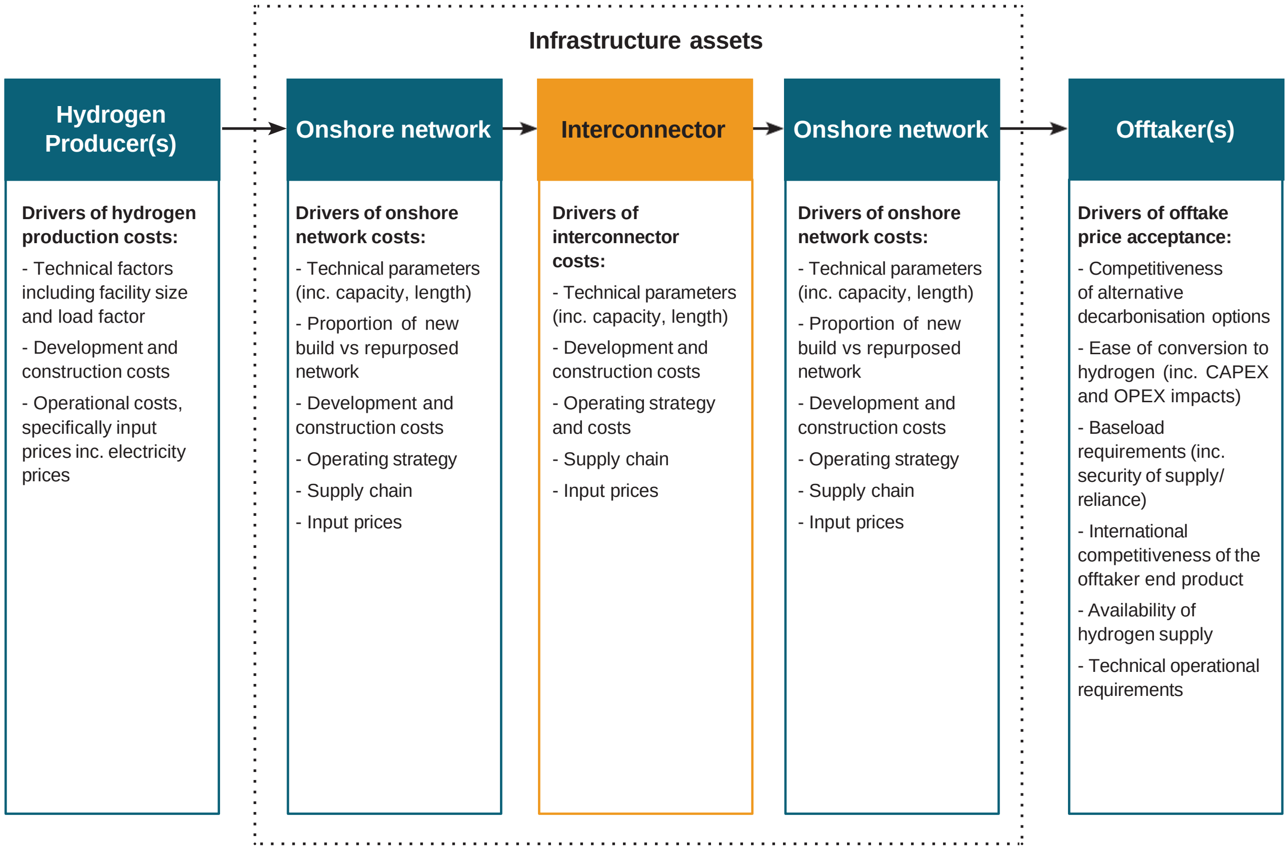



**Figure 21**

Factors influencing the hydrogen value chain costs and prices (excluding taxes and policy support).

From the perspective of the producer, hydrogen costs will be determined by a range of factors including technical factors such as the production facility size and its operating load factor, which will in turn be driven by the offtaker requirements as well as input fuel load factor.

The technical factors will then determine the DEVEX, CAPEX, and OPEX of the production facility, a key driver of their hydrogen cost. The cost of electricity is the biggest driver in determining the LCOH.

The most significant driver of the electrolyser cost is the electrolyser stack. OPEX will include a range of costs, of which the input fuel (electricity) is likely to be the most material, with stack replacement and maintenance also a considerable cost driver.

The BNEF Hydrogen Levelised Cost Outlook 2025[19] estimates that the LCOH breakdown for the UK figures are Electrolyser (39%), Power Cost (53%), and Tax (7%) as shown in Figure 22.

**Electrolyser**

**39%**

**Power Cost**

**53%**

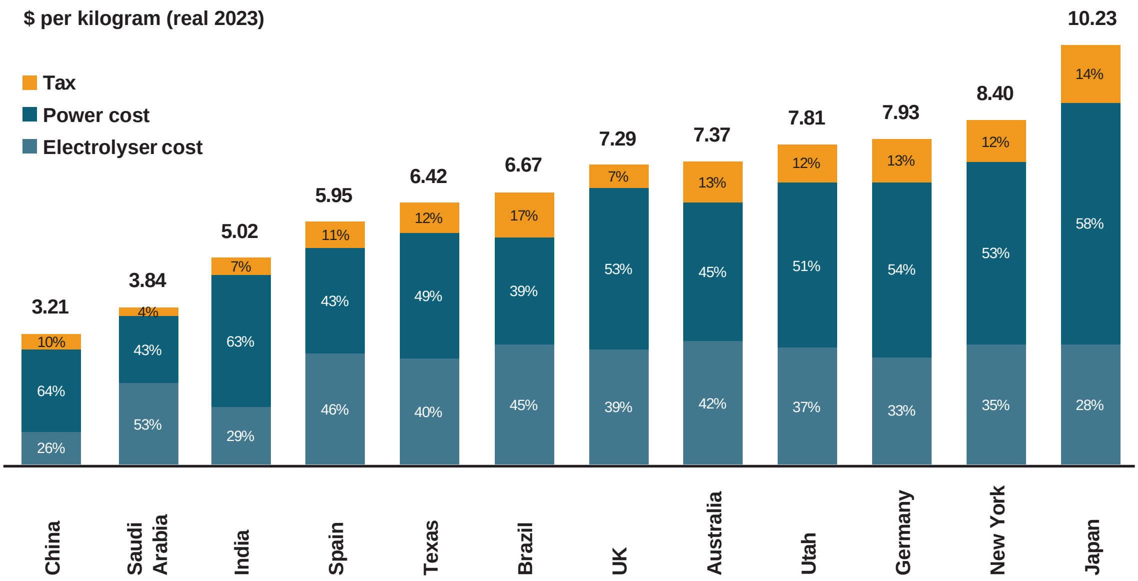



**Figure 22**

LCOH breakdown by power and electricity cost, 2025 ($/kg real 2023).

Source: BNEF. Note: Electrolyser costs consist of electrolyser CAPEX and OPEX costs, power costs consist of renewable generation CAPEX and OPEX. Both costs include tax and financing.

To date in the UK, production projects have been able to progress through support from the HBPM.

This provides revenue support to manage the price for the offtaker, allowing for a hydrogen producer to sell to offtakers at a price below cost with the UK Government paying the difference through a contract for difference mechanism.

Under the current rules of the HPBM, and powers under the Energy Act 2023, only domestic offtakers are allowed, with hydrogen export not considered a qualifying offtaker for revenue support.

The production developer can expand the facility to a greater capacity than submitted into the NZHF, for example to meet export needs, however, they will only receive the business model support for hydrogen that meets the qualifying offtaker requirements.

The World Trade Organisation (WTO) rules prohibit subsidies specifically contingent upon export performance.

The WTO defines a subsidy as ‘a financial contribution by government or a public body to an individual or business’ and includes grants, loans, loan guarantees, and tax breaks[49]. So far, all UK hydrogen projects that are currently in development have received financial support and have thus allocated their production capacity for domestic usage only.

It is therefore uncertain whether an offtaker would be willing to sign a long-term contract to purchase hydrogen at cost, without any financial support.

This study recommends undertaking an assessment of whether hydrogen production is commercially viable without financial support, in order to determine the potential capacity available for export.

This evaluation should consider whether the volumes, price, and durations within export offtake agreements alone are a sufficient incentive for UK hydrogen producers to operate.

It is also recommended that alternative forms of support are reviewed by the UK Government’s Subsidy Control Unit to confirm compliance with WTO rules.

This could include alternative forms of support such as low-cost credit to hydrogen producers and investment in research and development.

# UK Levelised Cost of Hydrogen Review

The Levelised Cost of Hydrogen (LCOH) is a metric used to evaluate the total costs in producing hydrogen over the entire production facility lifecycle. This includes both CAPEX and OPEX.

Essentially, it represents the average cost per unit of hydrogen produced, considering all production costs from the initial investment to ongoing operational costs.

This does not take into account any costs associated with transporting the hydrogen to the offtaker or storage. The LCOH metric is a valuable tool for comparing the cost-effectiveness of hydrogen production against other energy sources and determining its market competitiveness.

The following provides a summary of recent LCOH analysis comparing potential UK production costs to European and international producers.

Figure 23 provides an indication of the LCOH for different countries, including the UK, with a forecast of how the cost will fall in the coming years. It should be noted that the revised LCOH forecasts for all countries are increasing significantly according to BNEF.

The LCOH for UK electrolytic hydrogen production in 2025 with an electrolyser utilisation of 90% is modelled to range from \$7.29-\$8.62 per kilogram of hydrogen (kgH2), with forecasts estimating a reduction to <\$6/kgH2 by 2030, and further to <\$4/kgH2 by 2050, as illustrated in Figure 23 and Figure 24.

The anticipated decline in costs from 2023 to 2030 can be attributed to economies of scale of electrolysers (and therefore lower cost), financing and renewable energy costs, and better electrolyser efficiency.

Figure 24 indicates that the UK production costs in 2025 will be competitive with those of several European nations. Estimates for the UK are closely aligned with those of Germany. BNEF highlights a comparable

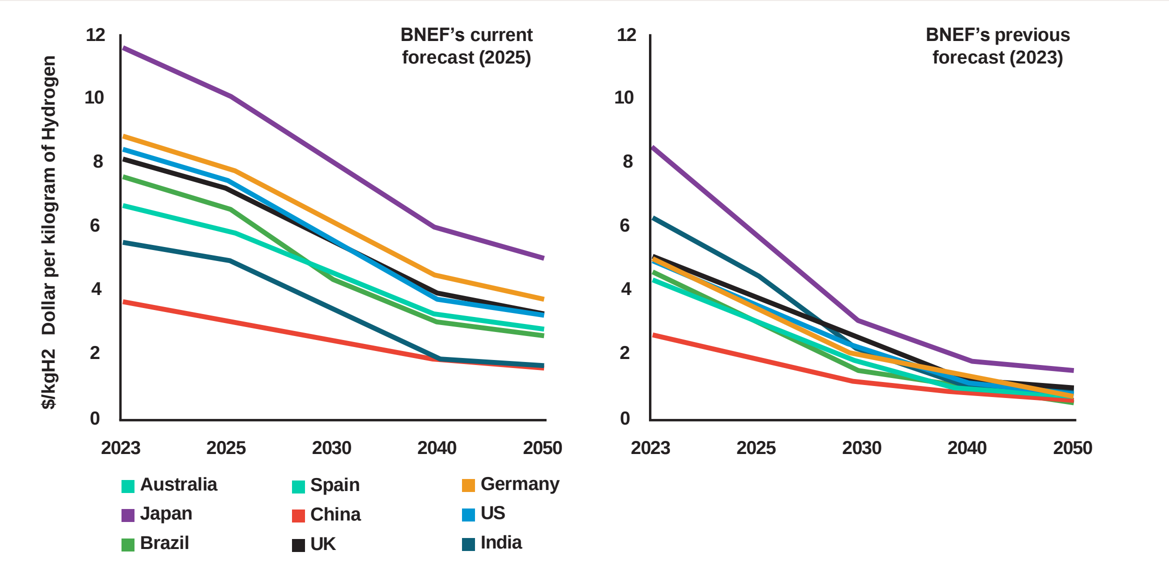



**Figure 23**
LCOH forecast between 2023-2050 for different countries (\$ real 2023), Source: Hydrogen Levelized Cost Outlook 2025, BloombergNEF.

**Table 6**
UK LCOH Review

LCOH estimate for Australia in 2025 when compared to the UK. Both Australia and Canada have agreed to jointly commit to H2Global auctions with Germany[50 51].

The two bilateral tender agreements have been committed to by Germany between Canada and Australia to a value of €588 million[52]. It is anticipated that the UK will remain competitive with Canada and Australia once the Levelised Cost of Transport is factored in.

Several other reports, including the International Renewable Energy Agency's (IRENA) report in 2022[53], which were published earlier than the BNEF information above, document have much lower anticipated LCOH values. It is assumed that if these reports were updated in 2025, they would contain a similar increase in LCOH to the BNEF figures above.

It is assumed, as part of this study, that imports of hydrogen from countries with access to North Sea wind resources in Northwestern Europe are likely to be competitive in the long-term with imports from other countries, despite lower production costs there.

This conclusion is based on the requirement for hydrogen to be in its molecular form rather than in a derivative form such as ammonia at the end-use point, where energy intensive post-processing infrastructure would be required to crack the ammonia to attain the hydrogen.

Should ammonia be the desired product, the economics of production will be more influential, potentially resulting in North Sea-produced ammonia being priced higher on a delivered basis than imported ammonia from other regions.

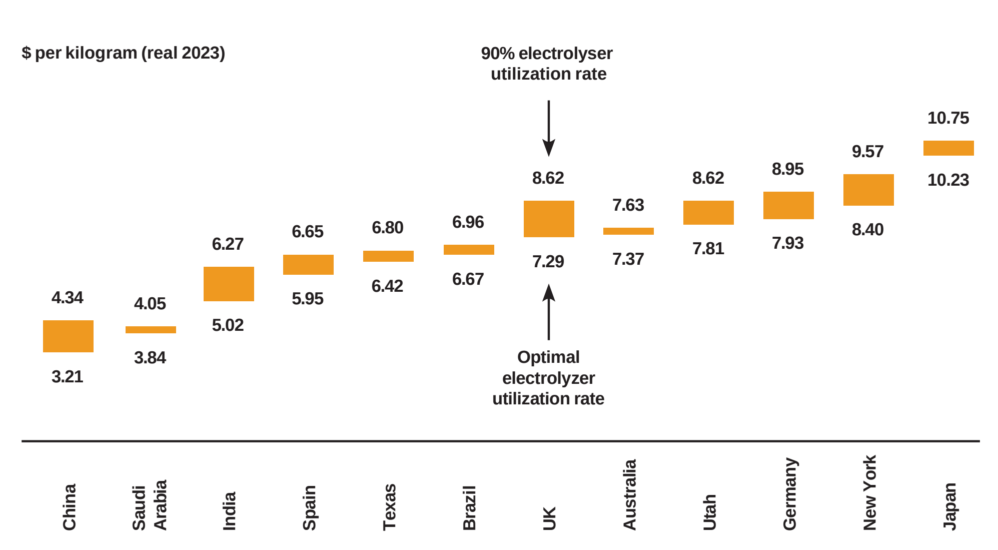



**Figure 24**

LCOH range from optimal to 90% electrolyser utilisation in 2025[19].

Source: BloombergNEF. Note '90% electrolyzer utilization rate' is the electrolyzer utilization rate in the baseline scenario. 'Optimal electrolyzer utilization rate' is the electrolyzer utilization rate that produces the lowest levelized cost of hydrogen. The optimal utilization rate for each market can be found in the attached data sheet.

For the offtaker, based on the stakeholder engagement undertaken and detailed in Table 7, there are several factors that will influence their willingness to accept the hydrogen price from a producer, these include:

- How competitive the hydrogen price is when compared to other hydrogen options and other decarbonisation solutions such as CCS and electrification.
- The scale and cost implications for the business model of the modifications required to the offtaker's existing assets to convert to hydrogen.
- How the hydrogen supply would meet the baseload operating requirements of the offtaker, including any security of supply requirements that may require storage.
- How domestically and internationally competitive their product's price would be after hydrogen conversion.
- The quality of hydrogen required for their technical processes.

As discussed within Section 2.5, from the domestic perspective, reflecting that the hydrogen market is currently at an early stage of development, funding mechanisms have been provided to manage the high hydrogen prices for offtakers.

In addition to the willingness to accept the hydrogen price, the offtaker would also need to consider the costs associated with the hydrogen transportation solutions capturing the onshore networks in the respective countries and the interconnector charges.

As reflected in Figure 21, there are several factors that will influence the transportation costs for the offtaker, namely whether the network is new build or repurposed, the distance of the offtaker from the producer and the operating strategy of the infrastructure.

Compression costs could be a significant driver of operational costs given the potential length of required network infrastructure and the energy density differences between natural gas and hydrogen means that, on a like-for-like energy basis, approximately three times the volume of hydrogen to natural gas would need be transported.

# Offtaker stakeholder engagement summary

As part of this study, stakeholders from the transport/logistics, chemical, and steel sectors were interviewed. For the majority of the German offtakers interviewed, low-carbon hydrogen presented a viable or the most viable option for decarbonisation. In arriving at this position, offtakers considered regulatory requirements, such as the sectoral quotas laid out in the EU RED III, as well as alternative options, especially electrification. Another consideration was practicality, i.e. whether the necessary infrastructure (pipeline and/or import terminal connection, road and train transport options, storage facilities, etc.) and the regulatory framework at the EU and national level were already in place or could be expected to be so in the near future, as well as whether the required purity of hydrogen was available.

In those cases, where low-carbon hydrogen was identified as the most viable decarbonisation option, German offtakers agreed on price being the decisive criterion when considering supply contracts. Whilst the reliability of trading partners and compliance with environmental and social standards in the country of production were also mentioned as decision criteria by some, these were clearly secondary. Importantly, high prices for low-carbon hydrogen were identified to be one of the key bottlenecks for initiating offtake before 2030. A key issue here was that prices have generally turned out to be higher than expected and predicted a few years ago[54].

Accordingly, an extension and increased flexibility of financial support by the German Government emerged as a key requirement for facilitating the market ramp-up in Germany and meeting the offtake targets. The German Government is providing extensive financial support to encourage offtake already, specifically in the form of the Federal Fund for Climate and Industry as well as the CCfD scheme targeted at the industrial sector. However, particularly the CCfD scheme was criticised for its complexity, complicating the application process especially for SMEs, and its narrow focus on renewable hydrogen and the industrial sector. Additionally, the provision of OPEX funding was identified as an important addition to existing funding approaches.

**Table 7**

German Offtaker Stakeholder Engagement Summary.

In summary, there are several factors that are likely to influence the agreement of offtake contracts between producers and offtakers, which creates uncertainty for the interconnector business case.

Of these factors, many are interdependent with certainty required from both the producer and the offtaker in parallel to understand the commercial and technical feasibility of offtake agreements for the respective parties.

To manage this market uncertainty, this study recommends that the UK and German Governments explore how to facilitate market arrangements between the UK and Germany and engage with potential project developers to understand the delivery requirements.

In facilitating arrangements, this study recommends that the following activities are undertaken to support the trading of hydrogen between the UK and Germany.

As set out in Figure 25, these activities will be critical during the initiation phase of an interconnector development by firstly exploring the hydrogen market (phase 1) and secondly aligning the market appetite to underpin the interconnector needs case (phase 2).

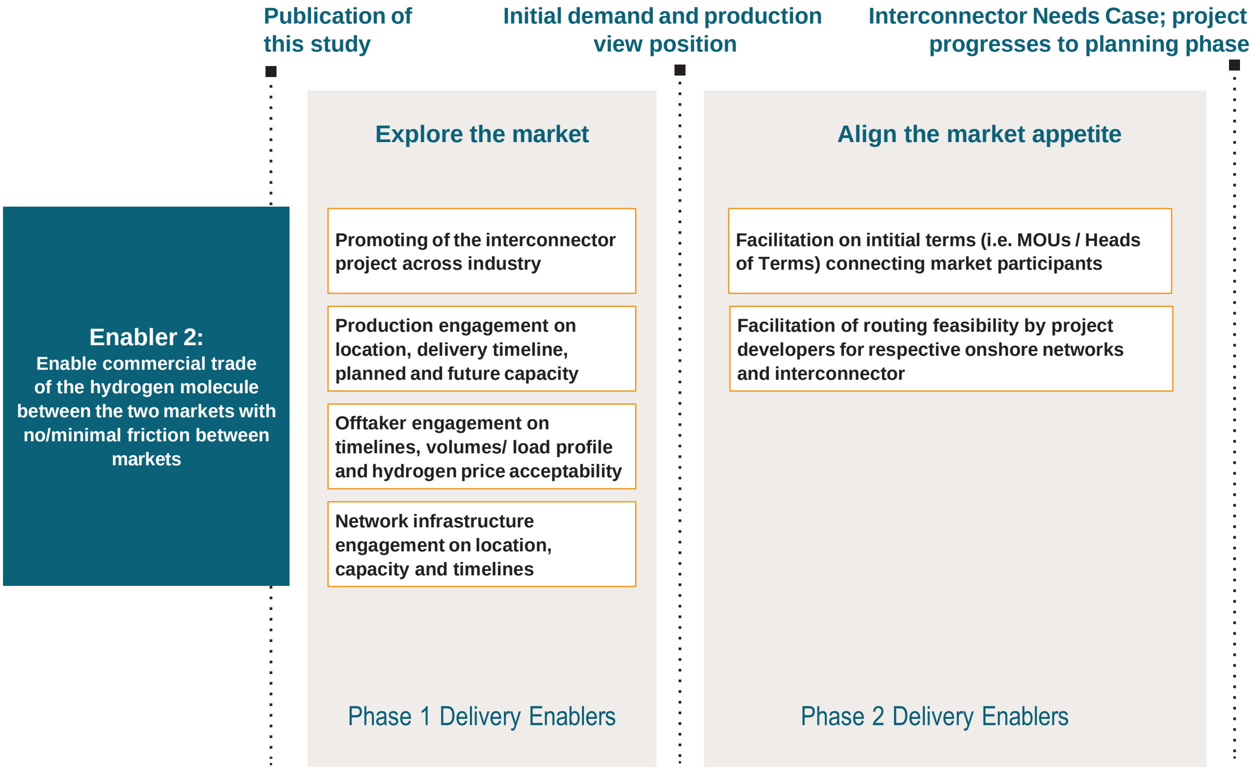



Figure 25
Enabler 2 actions.

### Phase 1: explore the market

The first phase would focus on the following action steps:

- At an overarching level, promoting the interconnector project objective in line with and UK and German Government policy objectives and inviting stakeholders to engage in its development.
- Engagement with a wide range of individual hydrogen production project developers on a project-by-project basis to understand their positions against the following: location, delivery timeline, planned and future capacity, hydrogen available for export as well as any barriers to project delivery. Engagement would also focus on their project's cost structure and associated hydrogen price. The output of the engagement should be an initial long list of potential projects that have export potential.
- Engagement with German offtakers on their timelines for conversion/new build, required hydrogen volume and associated load profile and hydrogen price acceptability covering both production and transportation. The output of the engagement should be an initial long list of offtakers and their associated willingness for hydrogen in terms of volume and timings.
- Engagement with interconnector project developers and gas network operators on planned and future hydrogen network development, including potential routing of production projects and offtakers to export/import locations. The output of this engagement should be a view on development timelines and pipeline capacity as well as potential infrastructure costs associated with transporting the hydrogen from producer to offtaker.

The output of this phase would be an initial view of production and offtaker demand positions, which is then assessed against a technical and commercial framework to determine the production/offtaker projects that should progress to the next step for further exploration; this would effectively rule out the projects that are not considered to be viable/credible.

Based on the list, provisional export/import location options would be identified to be explored by the interconnector project developer.

### Phase 2: align the market appetite

Following the development of the initial view of production and offtaker demand positions, the second phase will narrow to:

- Facilitation of detailed engagement between shortlisted production projects and demand offtakers on price and volumes to support the agreement/signing of hydrogen contracts.
- Engagement with the interconnector developer and respective onshore network infrastructure developers on the routing during the delivery of interconnector/onshore networks feasibility studies.

The output of this phase would be MoU/ HoTs for offtaker agreements and selected export/import locations, which underpin the Interconnector Business Case and support the progression of the project into the planning phase as indicated in the roadmap in Section 5.2.

This phase could include the facilitation of either bilateral contracts or, if there is sufficient liquidity, undertaking auctions to achieve offtake agreements between parties.

It is also likely, as seen domestically in the UK and Germany, that offtakers would need funding support at least in the near term to manage the potentially higher hydrogen prices whilst the market is nascent.

Therefore, in summary, this study recommends that the UK and German Governments explore how to facilitate market arrangements between the UK and Germany, as well as whether the existing mechanisms for offtaker and production support are sufficient in providing funding mechanisms to support cross-border trade between the UK and Germany.

# 3.6 Enabler 3:

## Develop an interconnector business model


**Proposed actions under this enabler:**

3.1 Undertake an assessment of the business model risks and potential guarantees that may be required to manage revenue uncertainty for an interconnector and potential high charges for users in the initial scale-up operational period. Based on this assessment, the UK and German Governments to determine the needs case for interconnector business model support.

3.2 The UK and German Governments, and respective regulators (or future regulators), to determine the potential process for interconnector business model allocation.

3.3. During the allocation of business model support, the respective regulators, within their responsibilities, to review evidence provided by project developer(s) on the pipeline sizing to determine whether the sizing is optimal from a technical and economic perspective.

**As the conduit between production and offtakers, the interconnector is exposed to the uncertainty of a developing market.**

### 3.6.1 Interconnector business model and charging arrangements

Where there are market barriers that prevent investors from developing needed infrastructure that will deliver value for consumers, governments can provide support through a business model to unlock necessary investment.

In this context, through the allocation of a business model, governments and/or regulators undertake an assessment of the infrastructure costs to ensure that they are, firstly, in the interests of consumers and, secondly, are economic and efficient.

As the conduit between production and offtakers, the interconnector is exposed to the uncertainty of a developing market.

This creates revenue uncertainty for the interconnector asset owner, which in turn creates a barrier for private investors with regards to the level of risk that they would be exposed to in developing and operating a hydrogen interconnector.

Compared to the barriers associated with an onshore hydrogen transmission network, this is further compounded by the cost and demand/supply uncertainty associated with cross-border markets in a developing hydrogen economy.

The ultimate impact of these risks if they materialise is that the utilisation of the interconnector could be lower than anticipated creating revenue uncertainty, which either results in a significant market barrier or a guarantee requirement from the respective countries to underwrite the investment.

Therefore, a business model is likely to be necessary to provide investors with sufficient certainty given the uncertainty across the wider hydrogen value chain, specifically the uncertainty associated with the offtaker demand and production capacity as well as the subsequent connecting onshore networks.

This study has explored several options for the design of possible business models, for example the Regulated Asset Base (RAB) model, Cap and Floor model, as well as a government backer as a capacity guarantee model and public ownership models. These models have been evaluated against an assessment framework, which includes factors such as investability, value for money, and promoting market development. The models, the assessment framework, and the assessment itself are detailed in Appendix A.

The business model will need to reduce the exposure of the other risks potentially through a level of guarantee in the event that the actual utilisation is lower than necessary to provide an investment return.

This is likely to be particularly pressing in the near term when the hydrogen market remains in a nascent state.

**This study has explored options for possible business models**

# Potential risks

## that could materialise and may need to be managed through a business model

This study has identified that there are several potential market failures that may need to be managed through an interconnector business model, these risks are further detailed within Appendix A.

- The respective countries have their own domestic demand decarbonisation targets as well as production capacity targets, which are likely to influence the supporting policy for their hydrogen markets. This creates a trade-off in the signals that could be provided to the market which could result in two outcomes;
  1. UK produced hydrogen being used non-domestically when there is UK domestic demand, thus preventing the UK from achieving its carbon emissions reduction ambitions or domestic demand required to utilise other decarbonisation approaches at potentially greater cost, or
  2. A decision to use the hydrogen in the near term in the UK could mean that it is not needed in Germany in the longer term as offtakers secure long-term alternative solutions.
- Hydrogen produced in the UK is not as competitive as that from other countries and therefore is not sufficiently attractive to offtakers.
- Demand does not materalise as expected as offtakers are unwilling/unable to commit to long-term offtake agreements or the GB and/or Germany onshore network has not developed in line with required timelines.
- In the event that either production or demand does not materialise as expected, the pipeline will still need to be pressurised and filled up to the normal operating level in order for the hydrogen to flow. The funding approach for the "first fill" hydrogen (which could be a significant volume) would need to be considered in the business model design.

**Table 8**

Potential Risks to be managed through a business model.

# Business models explored in this study

This study has explored the following business model options:

- UK/German public ownership: the asset would be 100% owned by one or both Governments such that the Government(s) would provide the funding for the development and construction of the asset.
- Co-investment by Government(s): the asset would be co-owned by one or both Governments and private investment based on an agreed ownership split, with the ability for the Government(s) to reduce its share later when there is sufficient market confidence.
- Regulated Asset Base (RAB): the asset would be privately owned, and the owner and operator of the infrastructure would earn a regulated return on asset costs.
- Cap and Floor: the asset would be privately owned, and the owner and operator of the interconnector receives a revenue cap and floor set for a specified period.
- Contracts for Difference (CfD): the investor receives revenue certainty through an agreed strike price for an agreed capacity, which is a set price that, if the market price falls below it, an external funding provider will pay the difference to the asset owner between the strike price and the market price.
- OFTO Model: the owner and operator of the interconnector receives an agreed revenue stream (covering the cost of the asset and financing) by an organisation for a specified period.
- Government as a capacity booker: the Government(s) would reserve an agreed amount of capacity on the interconnector, which provides a baseline revenue.

These business models were reviewed to determine the extent to which they can cover various risks.

This study has found that after an initial assessment of the business model options, several of the identified risks are expected to remain after the business model is applied and therefore continue to pose challenges to an interconnector's development.

This includes risks that offtakers are not willing to lock into long-term contracts whilst the hydrogen market remains in its infancy and that UK production is not competitive compared to alternatives.

In designing the business model, the following will need to be considered:

- The potential delivery risks and whether there are any barriers that will prevent private investment from being forthcoming.
- The scale of potential guarantee support that may be required to manage the revenue uncertainty risk during the development and enduring stages.
- Whether the business model is designed as one joint model between the connecting countries or whether models are developed by the individual connecting countries with agreed funding responsibilities between the respective Governments.
- The trade-off between operational and commercial requirements of the interconnector, particularly whether the interconnector is sized for confirmed demand at the point of FID or future expected demand.

**Table 9**

Business models explored in this study.

Similarly, the charging and access arrangements are fundamental to recovering the business model allowed revenue from relevant customers.

Within Appendix B, Commercial Arrangements, several potential options for determining charges are detailed including bilateral contracts, auctions and fixed tariffs as well as detail on the European charging arrangements that are being developed through the EU Hydrogen and Decarbonised Gas Market Package.

Given the current development status of the hydrogen market, the number of users in the initial operational period of the interconnector is likely to be lower than in the longer term, when there is expected to be a more mature hydrogen market.

A key consideration in the design of the charging arrangements for the interconnector, as with the onshore networks, is to ensure that initial charges do not act as a barrier to early users if they were exposed to tariffs that reflected the full asset costs.

Current onshore policy development in both the UK and Germany is considering how to manage this risk.

The UK's current minded to position is that charges may be subsidised and in Germany an amortisation account is utilised to evenly distribute charges over a longer duration.

These approaches are further detailed in Appendix B. There is potential that a similar intervention is likely to be needed to reduce the early users' exposure to the interconnector costs.

At this stage, it is too early to select a business model and the charging arrangements. Further clarity is needed on the routing and associated technical parameters, particularly pipe size and length, as well as the potential offtake agreements and therefore expected utilisation of the pipeline, as discussed under Enabler 2.

Once there is further clarity on these factors, this study recommends that an assessment is undertaken to understand the detailed risks that need to be managed through a business model and how the potential utilisation impacts the revenue certainty for the potential interconnector owner, and therefore the potential guarantee required.

This assessment should explore the approach that will be adopted for allocating ownership and relevant business model funding.

**The process for how potential business model support is provided will inherently be linked to how and when the interconnector project is initiated.**

### 3.6.2 Allocating business model support

The process for how potential business model support is provided will inherently be linked to how and when the interconnector project is initiated.

The project could be developed through a private investment driven concept engaging directly with offtakers, producers, onshore networks, and the respective Governments.

As outlined in Section 2.4.1, there are currently several projects that are in the early stages of development, which would need to develop an evidenced project needs case to enable development from project concept to an FID.

As discussed under Enabler 2, this will need significant engagement and commercial alignment by the project developer across the full value chain to understand potential demand and producer volumes, prices, durations, and quality requirements to then inform the offshore routing and connection to the onshore networks.

Alternatively, the project concept could be steered through providing a signal for an interconnector to be developed to incentivise the mobilisation of investment.

This signal could be achieved through several routes, for example:

- Communicating the need for the project through hydrogen network planning processes to allow investors to develop the project. This would identify the potential export locations in the respective countries and then allow a private investment driven concept to determine the specific routing and technical requirements, working with producers and offtakers.
- Progression of the project to a sufficient level of technical information to launch an early competition for the ownership rights of the project. This option allows for the opportunity to recover a level of development fees that may be vested in the project by the Governments.
- late competition process whereby the project is progressed to the commercial operation date (COD) and then tendered in a similar manner to the current regulatory arrangements under the UK's Offshore Transmission Owner (OFTO) regime.

To support the allocation of potential business model funding for an interconnector, the mechanism determined by the UK and German Governments to facilitate market arrangements could play a role in determining when there is sufficient confidence in the level of offtaker and production commitments to commence the allocation of potential interconnector business model support.

This will be fundamental as the interconnector development will need certainty over any business model support ahead of an FID.

The level of confidence in the offtaker agreements can then inform the Governments' assessment of the extent to which interconnector business model support is required and how the benefit of such support is shared between the countries.

Therefore, this study recommends that the UK and German Governments, with the respective regulators, consider the process and timelines for potential interconnector business model allocation and whether the mechanism determined to facilitate the market arrangements could also have a role in the allocation.

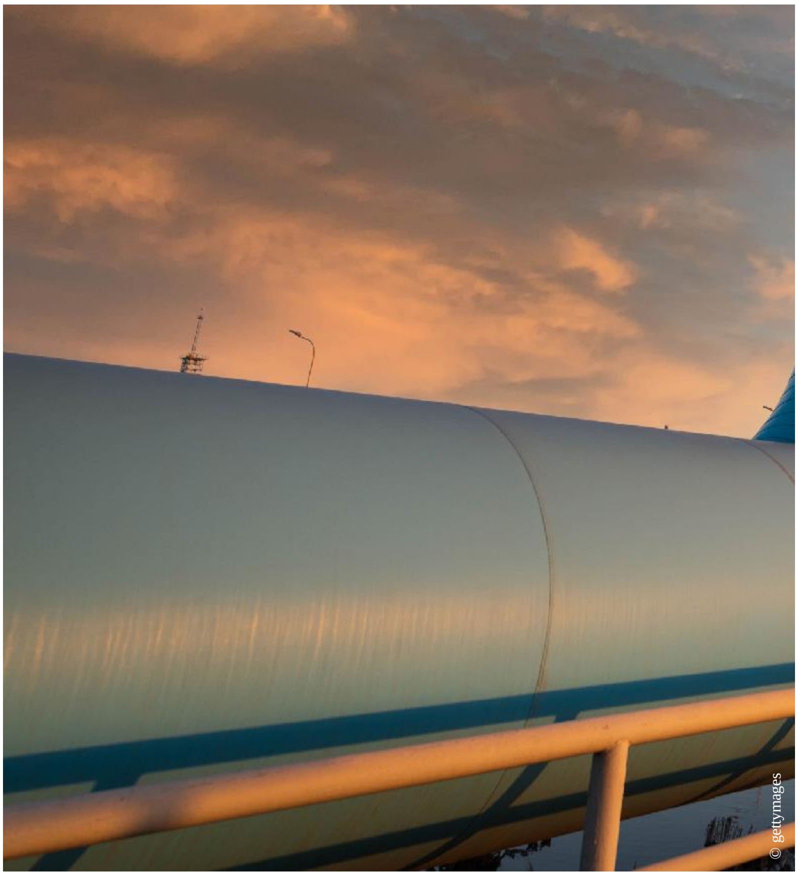
As discussed within Chapter 4, the pipeline will need to meet minimum operational requirements for confirmed demand whilst providing sufficient flexibility for increased future demand and taking into consideration deliverability, planning, and consenting.

Therefore, there is a trade-off in the sizing of the pipeline considering the confirmed demand compared against the potential future demand.

A pipeline that is designed to be significantly greater than the expected near-term demand in anticipation of higher long-term demand will result in larger costs and carries a greater utilisation risk; this could result in a potentially stranded asset and from a UK perspective the regulator is required to manage the impact of this risk on behalf of current and future consumers.

Therefore, as part of the business model process, interconnector developers will need to provide evidence for their pipeline sizing decisions and the associated underlying assumptions.

This study recommends that during the business model funding process, the justification for the pipeline sizing is assessed by the regulators, within their responsibilities, to determine whether the sizing of the proposed pipeline is optimal in terms of both technical requirements and consumer value based on the known and future demand.



# 3.7 Enabler 4:

## Develop the regulatory framework for the interconnector


**Proposed actions under this enabler:**

4.1 The UK Government to review the gas licencing framework to determine whether potential revisions may be required for the development and operation of hydrogen interconnectors.

4.2 The UK and German Governments to work together to develop, coordinate and ensure the compatibility of the commercial operational requirements for the interconnector (including access, charging, balancing and trading) as part of the regulatory framework.

4.3 The UK and German Governments and/or relevant Regulatory Authorities to examine whether there is any misalignment between national technical regulatory requirements (covering safety, planning, consenting and permitting, environmental assessment, operations and future decommissioning liabilities, etc.) and develop a plan to ensure that any differences are understood and managed to allow the development of the technical regulatory framework for a hydrogen interconnector.

### 3.7.1 Licencing of the interconnector

In the UK, the licencing of electricity and gas infrastructure is underpinned by The Electricity Act 1989 and The Gas Act 1986.

This legislation sets out the fundamentals associated with ownership rules, including where cross-sector ownership is prohibited, and the activities that they are obliged to undertake as well as the requirements, including industry codes, that they must comply with.

Currently within the gas market, the following activities are licenced: transporter, interconnector, shipper, supplier and gas system planner, and the licencing is managed primarily by Ofgem.

Under a risk-based approach, prior to granting licences, Ofgem assesses the suitability of the organisation to hold a licence for the applied activity and ensure that when granting licences, it is in interests of current and future consumers as well as supporting the delivery of net zero. Organisations are required to submit a range of information including company information, licence/application history, suitability to hold a licence, proposed arrangements to start licensable activity and whether they have met the licence requirements. The legislation does provide the ability to provide exemptions, however, these are generally determined on a project-by-project basis based on thresholds or for a particular asset type. Also, it is on the organisation to determine the case for an exemption from a licenced entity.

**In the UK, licencing of gas infrastructure is underpinned by The Gas Act 1986.**

# How the UK and Germany Regulate

The UK and Germany regulate their gas markets and associated infrastructure through slightly different approaches.

In the GB, there is an economic regulator known as the Office for Gas and Electricity Markets (Ofgem) who oversees the licencing of organisations within the gas market as well as overseeing the development, modification and implementation of gas market codes, which provide the rules for market participation.

Ofgem provides this oversight for natural gas and will act as the regulator for hydrogen as the market develops. From a technical perspective Ofgem is the technical regulatory authority responsible for enforcing overarching legislation enacted by the Gas Act 1986 and the Energy Act 2023 onshore, both of which have both been amended to cover hydrogen.

Ofgem administers industry codes and standards, such as the Independent Gas Transporters Uniform Network Code (IGT UNC). Offshore, the technical regulator is the North Sea Transition Authority (NSTA) who is responsible for regulating and influencing the oil, gas, offshore hydrogen and carbon storage industries.

The NSTA is the technical regulator for offshore hydrogen storage and hydrogen pipelines (including interconnectors). The NSTA issues Hydrogen Storage Licenses under the Energy Act 2008. The NSTA issues Pipeline Work Authorisations (under the Petroleum Act 1998) which govern the construction and use of pipelines/ interconnectors (as well as any subsequent changes thereto). Its remit regarding interconnectors extends from the UK low water mark to an offshore median line with the counterpart state (e.g. Belgium, Germany, or the Netherlands).

Every pipeline authorised under a PWA will also have approved PWA Holders and Users, Owners, and Operators associated with it (any changes to these are similarly subject to approval by the NSTA).

In Germany, EU membership adds another legislative level, as energy regulation is an area of shared competence. This means that both the EU and the member states can pass legislation on energy matters. However, member states may only do so if the EU does not or chooses not to pass legislation on a particular energy-related issue. EU regulations take effect in all member states at the moment of passing while EU directives set common goals but leave more room for manoeuvre and need to be transposed into national law by member states within a time frame of usually 2 years. This task is performed by the German Government.

The German BNetzA is subsequently responsible for the operationalisation of the legislation passed at the federal level including rules for market participation, the development of the network and the setting of network charges. The BNetzA further acts as the oversight authority for the gas, electricity and future hydrogen network. At the technical level, the Energy Industry Act (EnWG) stipulates that natural gas pipelines (and thus also hydrogen pipeline systems) must comply with the ‘generally recognised rules of technology’. Section 49(2) of the EnWG specifies the German Technical and Scientific Association for Gas and Water (DVGW), the industry association of the German gas and water industry, as the institution that determines and develops these rules.

Further detail on the status of the hydrogen regulations in the UK and Germany are included with Appendix C.

Hydrogen is included within the gas definition included within the Gas Act 1986 and therefore a hydrogen interconnector would be covered by the existing interconnector licence.

As this licence was designed with natural gas market arrangements in mind, it is recommended that a review is undertaken to determine the suitability of the existing interconnector licence for hydrogen; this may include either developing a new hydrogen interconnector licence or making modifications to the existing licence to recognise any differences between the developed natural gas market and the evolving hydrogen market.

Further, the current unbundling rules mean that an interconnector licence cannot also be held by a transporter, shipper or supplier; it is recommended that a review is undertaken to determine whether this remains appropriate for an emerging hydrogen market.

Comparing to recent and currently in development electricity interconnectors, which have the cap and floor business model, a project is required to be licenced before it is granted provisional or confirmed business model support.

This is because the requirements for the business model allocation, including the application process and information requirements, are defined within the licences that they must secure ahead of their business model application.

Once business model support is provisionally or fully confirmed, this is also incorporated into the licence as are the arrangements associated with charging and access rules; this ensures that the licenced entity complies with the conditions of the business model funding.

Therefore, any modifications to the existing licencing framework for a hydrogen interconnector (or the establishment of a new licence) will need to be in place ahead of the allocation of any interconnector business model support.

This will require the appointment of a regulator and stakeholder engagement on the design of the licences.

It is important to recognise that historically licencing frameworks have evolved over time as policy is further developed or project/cross-sector challenges are identified.

As a result, the licencing framework at the point of business model allocation will need to provide the interconnector owner with sufficient confidence to take a FID.

In Germany, the licencing process for the planning and construction of an offshore pipeline is carried out by the mining authority responsible in the respective federal state and the Federal Maritime and Hydrographic Agency (BSH) (Section 133 (4) in conjunction with Section 133 (1) No. 1 BBergG).

The special feature of the authorisation procedure under the Mining Law is that two permissions are required: a mining and an operating licence.

The mining licence is issued by the competent state authority. The operating licence requires authorisation from the BSH.

The BSH examines whether the project is compatible with the normal utilisation and use of the waters above the continental shelf and the airspace above these waters (Section 133 para. 2a BBergG).

In Germany there is no general need of licencing of pipeline operation but if required, unbundling rules need to be fulfilled and approved by the national regulatory agency BNetzA.

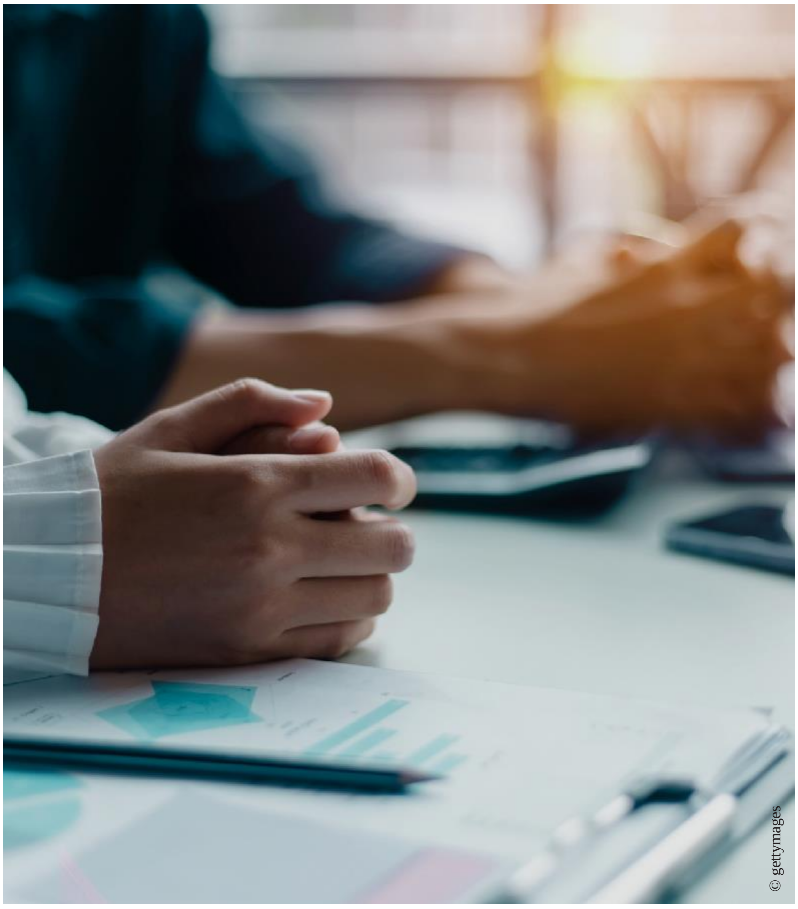
### 3.7.2 Economic regulatory framework for the operation of the interconnector

Commercial operational standards and codes will be required so that hydrogen flows through the pipeline in a transparent, economic and efficient manner in line with wider energy policy objectives of the two countries.

These operational regulations include, but are not limited to, the following areas: access, charging, balancing requirements and trading. The arrangements would need to be designed so that they do not preclude the interconnector operating bidirectionally in the future.

Currently, for the UK and Germany the focus is on developing the codes and standards for the respective domestic networks.

In the UK, the Gas Act 1986 provides the legislative framework including the codes and market rules and provides the definition of gas which includes both natural gas and hydrogen and therefore provides the existing requirements for hydrogen; although it is recommended that these arrangements are reviewed to ensure that they remain appropriate for a developing hydrogen market.



Germany is progressing the development of onshore policy through the EU Hydrogen and Decarbonised Gas Market Package, which is expected to be transposed into German law by 2026, and ongoing regulations processes by the BNetzA for the hydrogen core network.

For the interconnector operator, understanding the potential operating requirements, and how these interact with the onshore networks, will be a critical element to the interconnector business case as it provides clarity of the operating parameters of the asset and the associated CAPEX and OPEX.

The existing natural gas regulatory framework is likely to provide a reasonable starting point for the development of hydrogen regulations. This is detailed in Appendix C Regulation.

To support the progression of the interconnector, this study recommends that the Governments work together to ensure there is sufficient understanding of the alignment of the technical and commercial operational requirements associated with the cross-border flow of hydrogen, as well as with the respective onshore hydrogen networks.

### 3.7.3 Technical regulatory framework for the operation of the interconnector

Similarly, to the economic framework, the construction and operation of a hydrogen interconnector will require compliance with the necessary technical regulations covering safety, planning, consenting and permitting, environmental assessment, operations and future decommissioning liabilities to ensure the safe flow of hydrogen.

Currently the UK and Germany are establishing the technical regulatory requirements for the onshore transport of hydrogen under their respective legislative regimes.

The establishment of a technical regulatory framework for an interconnector must take into account each countries' requirements to develop a common framework under which the interconnector will operate.

To support the development of a regulatory framework for the interconnector, this study recommends that the UK and German Governments determine the best mechanism to identify whether there is any misalignment between the applicable national technical regulatory requirements and establish the approach to be taken to manage any differences to allow the development of the technical regulatory framework for the interconnector.

Development of the technical regulations for the interconnector will need to cover safety, planning, consenting and permitting, environmental assessment, operations and future decommissioning liabilities.

These would need to be developed in conjunction with the existing UK and German Technical Regulatory Authorities, such as the UK Health & Safety Executive, Ofgem, NSTA and other relevant UK authorities.

In Germany it will be important to consult with the Landesämter für Bergbau (State Office for Mining) and the BSH, to prepare a set of Technical Regulations for the construction and operation of a hydrogen interconnector.

**Development of the technical regulations for the interconnector will need to cover safety, planning, consenting and permitting, environmental assessment, operations and future decommissioning liabilities.**

In Germany, the process of the hydrogen technology standardisation (“Normungsroadmap Wasserstofftechnologien”)[55] to determine which technical gas regulations need to be adapted to hydrogen and how, has yet to be finalised.

The hydrogen technology standardisation roadmap is the nationally coordinated strategic roadmap for the technical regulation of hydrogen technologies and defines guidelines for establishing and further developing the technical regulations in this area.

The roadmap, which was drawn up on behalf of the BMWK, contributes to the demand for uniform standards for the development of hydrogen infrastructure.

Around 180 recommendations for action were developed in the roadmap.

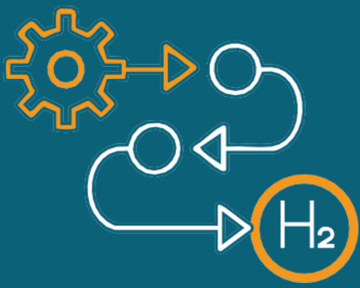
## Historic Technical Regulation Interconnector Working Groups

There is some precedence with the establishment of working groups at the start of the development of an interconnector project between two countries to understand any differences in regulations on either side of the interconnector. The first electricity interconnector (IFA) was commissioned in 1986 between GB and France. At that time, the legislative and energy policy landscape was distinctly different, the Central Electricity Generating Board, predecessor to what are now National Grid Electricity Transmission (NGET) and National Energy System Operator (NESO), operated as a nationalised entity and functioned as a combined Transmission System Operator. Collaboratively, they partnered with Réseau de Transport d’Électricité (RTE), their French counterpart, to develop the interconnector, ensuring alignment between the offshore direct current (DC) system and the onshore alternating current (AC) system requirements.

Working groups were also set up for both the Interconnector UK (IUK) and Balgzand to Bacton Line (BBL) natural gas interconnectors at the outset of these projects and these working groups established the initial business rules for the interconnectors. Whilst these working groups may have had greater influence at the time, where there was limited existing regulation, the interconnectors are ultimately required to comply with relevant national regulations today.

The BBL “Trade & Transit Working Group” managed at that time by the Dutch Directorate-general for Energy and Telecoms within the Ministry of Economic Affairs, covered aspects requiring intergovernmental agreement that were not regulated by national law, such as agreements on jurisdiction, direction of gas flows, dispute settlement and fiscal regime. In terms of environmental and safety considerations, the working group helped establish a monitoring and inspection regime for the interconnector and coordinated policies covering such aspects as emergency measures and the suspension of operations.

# 3.8 Enabler 5:




## Develop the regulatory framework for the interconnector

**Proposed actions under this enabler:**

5.1 The UK Government to determine the delivery timeline for the domestic hydrogen economy in the context of demand and market ramp-up in Germany and Europe.

5.2 GB’s NESO to consider the potential need for links between a domestic hydrogen transport and storage network and new international hydrogen trade infrastructure as part of its anticipated role in strategic planning.

5.3 The German Government to assess how a potential interconnector is considered in the further planning of the hydrogen core network and that coordination between the onshore network operators and the operator(s) of the interconnector is enabled.

5.4 The German Government to coordinate the timeline with the expansion of AquaDuctus Section 1 and 2 and the completion of the core network and thus the connection of potential offtakers.

### 3.8.1 UK hydrogen value chain ramp-up delivery

To date there have been funding allocations for renewable (known as HAR1) and CCS-enabled hydrogen production projects, with a second round of renewable production funding currently in negotiation (HAR2).

All of these projects are expected to deliver to meet domestic demand by 2029.

To date, these projects have been focused on localised offtake and HAR1 is expected to achieve a total proposed deployment of 125MW; further production is expected to connect by 2029 through HAR2.

As discussed within Section 2.1.1, there is a potential pipeline of production projects in the UK, totaling 25.1 GW capacity by 2030.

As the hydrogen market is developing, the deployment timelines and scale of the future UK hydrogen market depend on a range of wider factors.

This includes the evolving policy landscape and market framework, securing robust offtakers, sufficient hydrogen transportation solutions, and the pace of funding support allocation.

The deliverability of this portfolio could be stimulated by a strong market signal of a developing European hydrogen market connected to the UK by the interconnector assessed within this study.

Therefore, this study recommends that the UK Government determines the delivery timeline for the domestic hydrogen economy, particularly hydrogen production, in the context of demand and market ramp-up in Germany and Europe.

To stimulate hydrogen deployment at a regional and national hydrogen level (rather than with localised offtake as is currently the case), funding support for the GB onshore network will be vital to the timely delivery of the networks.

In the UK, the Government have committed to developing a hydrogen transport business model.

The results of this next phase of strategic planning for transport and storage will be published in due course.

The Government's current minded to position is that projects which meet certain requirements will be able to apply within allocation windows to secure business model support.

The requirements for projects to apply for the first allocation window are currently being developed by DESNZ.

The previous consultation position included defined technical specifications and for the pipeline to be operational between 2028 and 2032, and to connect multiple producers and offtakers.

Timely allocation of the first and future rounds of funding will be critical to providing the market with sufficient market signals and supporting the delivery of the onshore routing connecting producers to the interconnector.

### 3.8.2 Strategic delivery of onshore networks

Whilst focus should be initially on unlocking agreements between producers and offtakers, the timely delivery of the onshore networks in the respective countries will be critical to enabling the physical flow of hydrogen between the countries. The onshore routing will be determined by the hydrogen network planning processes in the respective countries, which will then inform the interconnector project delivery approach and routing.

In Germany, the final proposal for the hydrogen core network was submitted by the network operators in July 2024 and was approved in October 2024.

From the UK perspective, in 2024 the NESO was commissioned by the UK, Scottish, and Welsh Governments to prepare the Spatial Strategic Energy Plan (SSEP) to identify the optimal locations, quantities, and types of energy infrastructure required for generation and storage, including hydrogen production, transport, and storage.

The methodology for the SSEP is currently in development and the first SSEP is expected to be published in Q4 2026. NESO will use the SSEP to support delivering the Centralised Strategic Network Plan (CSNP), which will provide a coordinated and longer-term approach to wider network planning.

This is likely to provide an informed view on how production will be connected to offtakers and, in the future, potential export locations. The CSNP publication is not expected until 2027.

**The timely delivery of the UK and German onshore networks will be critical to enabling the delivery of the interconnector.**

In the interim, the UK Government is expected to continue in its role as the strategic planner for hydrogen transport and storage infrastructure.

Activities to date have included reviewing the strategic case and optimal approach for core network development, the ongoing assessment of infrastructure needs to inform the future direction and focus of the transport and storage business models, and the role of DEVEX and innovation funding in enabling a broad and mature pipeline of projects.

Therefore, to inform the potential routing of the interconnector, this study recommends that onshore network planning activities are progressed in a timely manner.

This includes NESO, in the future, taking into account the needs for links between a domestic hydrogen network and infrastructure required to facilitate potential future trade when undertaking its hydrogen strategic planning.

This will ensure onshore hydrogen infrastructure can connect hydrogen producers to an interconnector's export terminals where necessary.

It is also recommended that an assessment is undertaken to determine the delivery timeline of the domestic hydrogen economy, including the onshore network in the context of the interconnector delivery programme.

The German Government also needs to ascertain that the interconnector is considered in the further planning of their hydrogen core network and that coordination between the onshore network operators and the operator(s) of the interconnector is enabled.

On the German side, the hydrogen core network is expected to cover 9,040 km by 2037. Possible import corridors are taken into account in the core network.

By the time the core network is completed at the latest, all potential large-scale offtakers will be accessible and connected to the hydrogen supply. Smaller offtakers will be connected via the gas distribution networks to be converted or through further network expansion.

From 2026, network development plans will be published every two years by the BNetzA, which will monitor the development of the natural gas network and the possible conversion of the distribution network from natural gas to hydrogen.

The conversion of natural gas networks to hydrogen could connect further industrial consumers of hydrogen.

The extent to which this appears economically viable and feasible for distribution network operators and whether these smaller industrial and commercial consumers are dependent on hydrogen or have other options for decarbonisation is the subject of current reviews and regulatory processes such as the network development plan.

The decisions of the German Government to implement the core network and the integration of hydrogen into the network development plans to be drawn up regularly will ensure the timely provision of the onshore network on the German side and thus enable the physical flow of hydrogen to German offtakers.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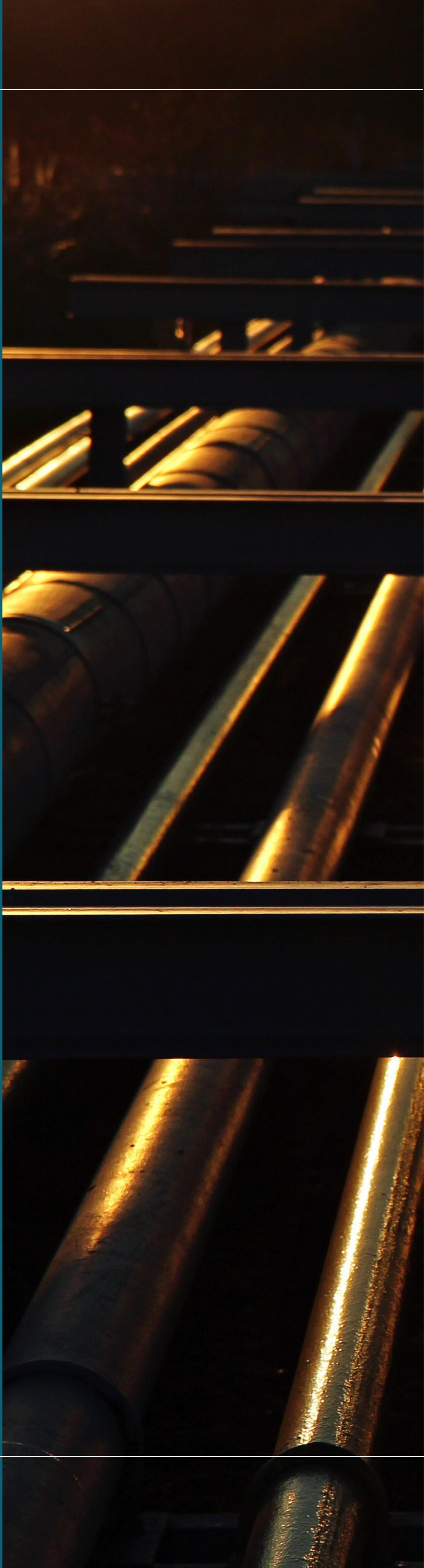
# 4

# Infrastructure Assessment

**Pipeline routes from key UK locations to the destinations required in this study are all technically feasible but require much further study and more certainty on how the two countries' networks will develop over the next decade.**

**Existing interconnectors and pipelines in the North Sea are unlikely to be available for conversion to hydrogen use due to their existing contract requirements of supply natural gas. These existing interconnectors currently provide security of supply of natural gas to the UK, with long term commercial contracts in place for gas supply.**



## 4.1 Infrastructure Basis

The basis of the infrastructure assessment for this report is to review hydrogen transportation from a UK landfall site to a German (or Belgium / Netherlands) landfall site via an interconnector pipeline.

It should be noted that additional equipment may be required in the future to allow for bi-directional flow such as additional compressor systems, however, this is considered a design development in future phases to avoid stranded CAPEX items and is therefore not part of the Base Case.

It does not consider the upstream production or downstream transportation / consumption requirements as shown in Figure 26 below.

The capacity for export to be used in this study for calculating pipeline sizes assumed be in the region of 1 – 4 GW based on existing estimates of UK hydrogen production potential. For the purpose of this study, these are illustrative scenarios, and in reality, could be significantly greater or smaller in the future than current expectations.

As the project progresses, further consideration should be given to installing sufficient / flexible capacity to accommodate all expected and future demands and production scenarios.

The route options used in this study are described in Section 1.3.2, Table 2.

The Base Case for this study is a connection from the UK to the AquaDuctus Offshore Pipeline System which will route hydrogen via the greater Wilhelmshaven area to the interconnection point, Bunde, for further connection to the downstream German onshore hydrogen core network. Section 1 of AquaDuctus is also part of Germany's hydrogen core network.

A review of the development of potential hydrogen export from the UK to continental Europe has been considered from several locations on the UK's east coast.

These locations considered several factors such as proximity to hydrogen production areas, existing interconnectors and the roll-out of potential future UK domestic network projects, such as Project Union.

This section of the report summarises the previous work that was carried out[20] and utilises that as a basis for discussion on routing new or existing pipelines to Germany, Netherlands or Belgium.

This analysis also covers the technical discussion of pipeline operations and sizing of any potential new pipelines.

## 4.2 Landfall Locations

A high-level review of the technical considerations around the landfall locations for the start and end points of any pipeline from the UK to Germany has been made in line with the Study Basis.

**A review of the development of potential hydrogen export from the UK to continental Europe has been considered from several locations on the UK's east coast.**

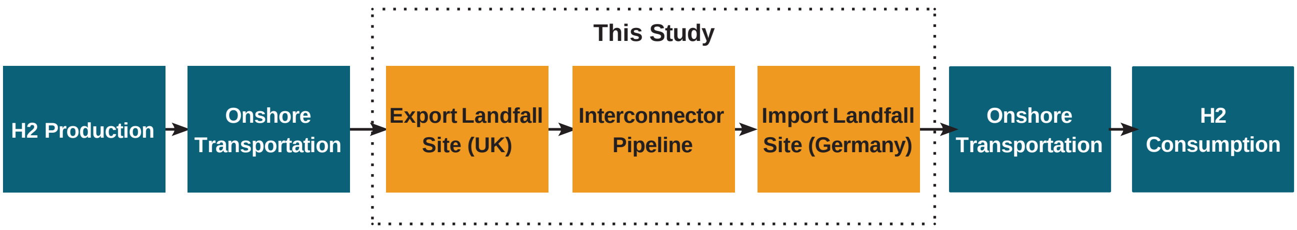



**Figure 26**
Infrastructure Study Boundary Basis

This work uses information from the previously issued UK to Mainland Europe Hydrogen Export Study [20] as the foundation for future assessment.

### 4.2.1 UK Options

A review of the announced UK electrolytic and CCS-enabled hydrogen production projects has been carried out and this data is shown in Figure 27.

This figure demonstrates the location of projects that to date have been offered, received, or shortlisted for receiving UK Government funding for commercial scale low-carbon hydrogen production.

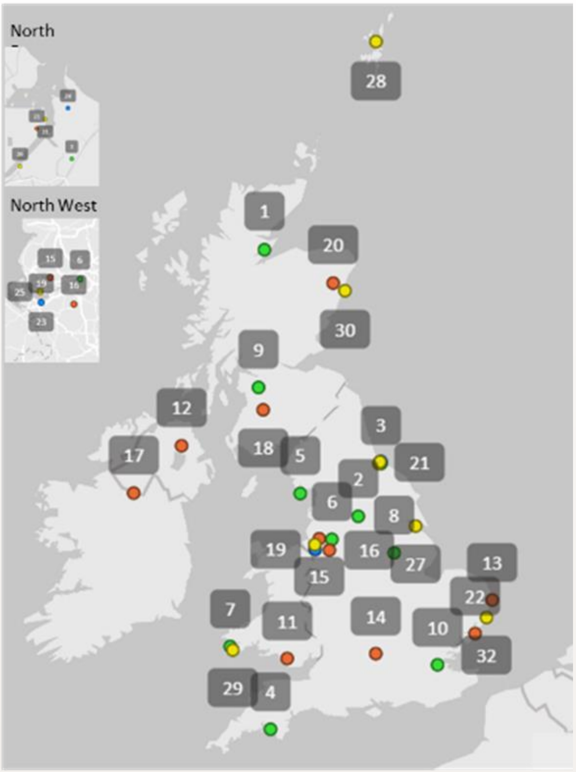
Indicative export locations have been selected based on proximity to hydrogen production clusters with the potential advantage in leveraging existing infrastructure, pipeline routings corridors and capability from existing gas landfalls.

**HAR1**

| Project Name | Developer | No. |
|---|---|---|
| Cromarty | Storegga | 1 |
| Bradford Hydrogen | Hygen | 2 |
| Tees Green | EDF | 3 |
| Langage Green Hydrogen | Carlton Power | 4 |
| Barrow Green Hydrogen | Carlton Power | 5 |
| Trafford Green Hydrogen | Carlton Power | 6 |
| West Wales Hydrogen | H2 Energy & Trafigura | 7 |
| HyMarnham | JG Pears | 8 |
| Whitelee Green Hydrogen | Scottish Power | 9 |
| Green Hydrogen 3 | HYRO | 10 |
| HyBont | Marubeni | 11 |

**NZHF Window 2**

| Project Name | Developer | No. |
|---|---|---|
| Grenian Hydrogen Speke | Grenian Hydrogen | 25 |
| Tees Green Methanol | EDF | 26 |
| Humber Hydrogen Hub 3 (H3) | Air products | 27 |
| Sullom Voe Terminal Green Hydrogen Project | Enquest Hydrogen | 28 |
| Pembroke 200 MW Green Hydrogen Electrolyser Phase 11 | RWE Generation | 29 |
| Aberdeen Hydrogen Hub | Bp Aberdeen Hydrogen Energy Limited | 30 |
| Tees Valley Hydrogen Vehicle Ecosystem (HYVE) | Exolum International UK | 31 |
| Suffolk Hydrogen | Hyrab Power | 32 |




**Projects offered support through windows 1 and 2 of the NZHF and HAR 1, and the CCUS enabled hydrogen projects in the Track-1 cluster sequencing process**

**NZHF Window 2**

| Project Name | Developer | No. |
|---|---|---|
| Ballymena Hydrogen | Ballymena Hydrogen | 12 |
| Conrad Energy Hydrogen Lowestoft | Conrad Energy | 13 |
| Didcot Green Hydrogen Electrolyser | RWE | 14 |
| Green Hydrogen St Helens | Progressive Energy | 15 |
| Green Hydrogen Winnington and Middlewich | Progressive Energy | 16 |
| Mannok Green Hydrogen Valley | Monnock | 17 |
| Knockshinnoch Green Hydrogen Hub Project | Renantis | 18 |
| Hynet HPP2 | Vertex | 19 |
| Kintore Hydrogen | Statera | 20 |
| H2 NorthEast | Kellas | 21 |
| Felixstowe Port Green Hydrogen | Scottish Power | 22 |

**CCUS Sequencing**

| Project Name | Developer | No. |
|---|---|---|
| Hynet HPP1 | Essar Energy Transition Hydrogen | 23 |
| bpH2 Teesside | bp | 24 |

**Figure 27**

Announced Hydrogen Production Projects: Net Zero Hydrogen Fund (NZHF) and Hydrogen Allocation Round 1 (HAR1). Data correct as of 2024.

The following existing natural gas pipeline interconnectors are shown in Figure 28:

- Bacton Gas Terminal (UK) to Zeebrugge (Belgium)
- Bacton Gas Terminal (UK) to Balgzand (Netherlands)
- Nyhamna (Norway) to Easington Gas Terminal (UK) (known as the Langaled Pipeline).

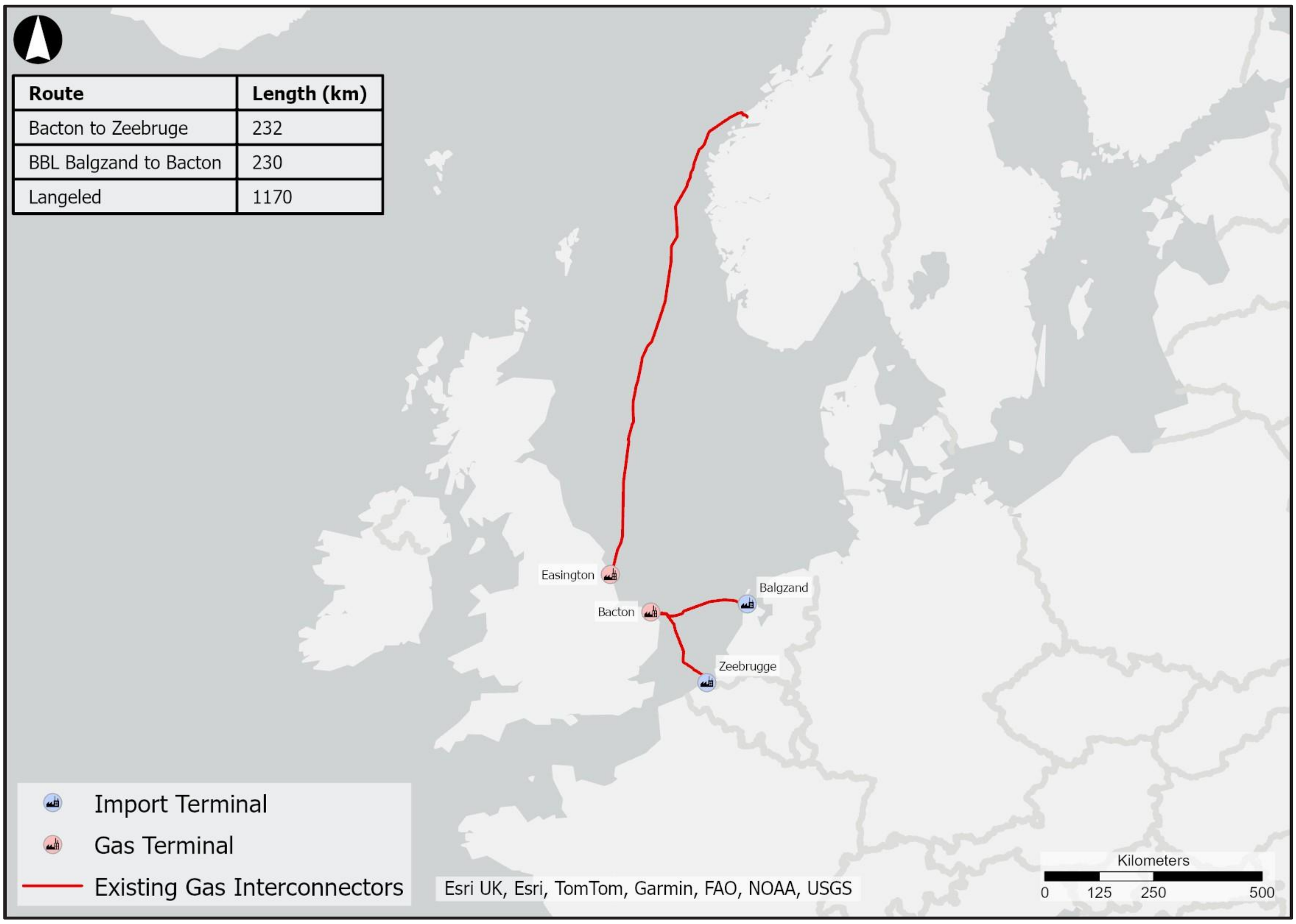
The Langaled Pipeline is not a point to point interconnector like those from Bacton, but demonstrates a potential route for gas flow from mainland Europe to the UK.

### 4.2.2 European Options

The options considered in this study for the European import terminal include the following countries with the assumption that the non-German locations will include the provision for onshore transmission of hydrogen to the German domestic hydrogen core network.

#### Germany

- The German Government has set out ambitions for a dedicated hydrogen core network that this new pipeline could tie-in to. Included in the network is the AquaDuctus project.



| Route | Length (km) |
|---|---|
| Bacton to Zeebruge | 232 |
| BBL Balgzand to Bacton | 230 |
| Langeled | 1170 |



**Figure 28**
Existing UK Gas Interconnectors

## 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.

## Belgium

– The Belgium Government is developing a hydrogen network with part of this route from Zeebrugge to Ghent already under construction by Fluxys. Belgium has an ambition to position itself as a hydrogen import hub.

Based on this, the following locations have been considered in this high-level analysis:

– Groningen (Netherlands)

– Emden and Wilhelmshaven area via AquaDuctus (Germany)

– Balgzand (Netherlands)

– Zeebrugge (Belgium)

## 4.3 UK Onshore Infrastructure

The onshore infrastructure required at the UK export location can be assumed to be typical and largely location agnostic.

There may be certain advantages to co-locating at existing gas terminal sites with infrastructure systems available such as utilities, control and supporting infrastructure available as systems that can be integrated into the design.

However, these have not been considered here and a general introduction to the facility requirements is provided below.

The hydrogen production systems and transportation to the export facility are not included within this study.

Therefore, the infrastructure assessment assumes an upstream boundary point of a tie-in to reliable source of hydrogen.

The following systems are assumed to be required at the export facility.

**There may be certain advantages to co-locating at existing gas terminal sites.**

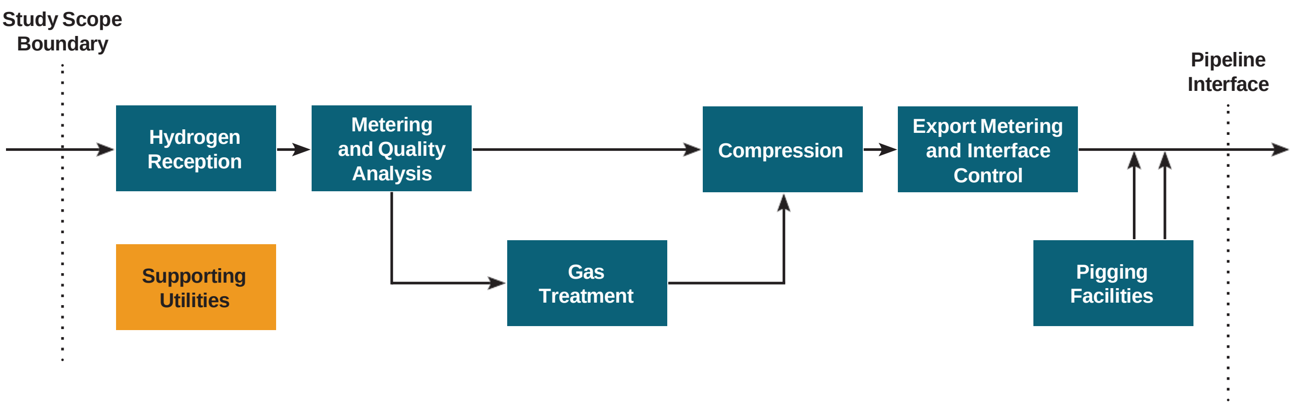



**Figure 29**

UK Export Facility Systems.

**The design of the export pipeline does not preclude the ability to allow bi-directional flow and could be used in this operating mode in the future.**

### 4.3.1 Hydrogen Reception Facilities

The hydrogen will be received from an external source outside of the scope of this study via an assumed pipeline.

The reception system will contain pipeline connections with valving and safety arrangements, and potentially buffer storage tanks (short term) to manage supply variations.

### 4.3.2 Gas Treatment

Should the hydrogen feed deviate from specification, then additional treatment facilities will be required prior to export.

In this scenario, hydrogen exiting the quality analysis system will be redirected to the gas treatment system which may include dehydration systems (e.g. Tri-Ethylene Glycol (TEG) or mol. sieve) or other purification systems such as Pressure Swing Adsorption (PSA).

### 4.3.3 Compression

Hydrogen will be compressed to the required export pressure with key considerations around compressor type, number of stages, capacity (and redundancy) and cooling requirements.

Compressor packages will generally include recycle systems and pressure safety systems.

### 4.3.4 Export Metering and Pipeline Interface

Export metering will be required to interface with the downstream user (either AquaDuctus or direct onshore user).

The high-pressure nature of the exported hydrogen will require dedicated pressure regulation and safety valve systems.

To allow the introduction of inspection vehicles (pigs) into the pipeline, pigging facilities will be required to launch (or receive in the case of reverse flow operation into the UK) pigs into the pipeline.

These facilities may be in the form of temporary facilities which are brought in when required (and therefore space should be made available in the plot plans of export facilities) or permanently installed pig traps.

Pigging operation is used for pipeline inspection and maintenance purposes.

### 4.3.5 Utilities

Supporting utilities will be required for the compression / export facility and will provide the ability to power, control and operate the facility safely.

The following is a non-exhaustive list of the utility requirements to support the above process systems:

- Cooling Medium to support the compressor package
- Power Supply (potentially with back-up generators)
- Uninterruptible Power Supply (UPS) for critical control systems
- Instrument Air
- Nitrogen
- Control and telemetry systems (SCADA system etc.)
- Fire Suppression Systems

## 4.4 European Onshore Infrastructure

The onshore reception infrastructure will require:

– Pipeline interface system including pigging facilities,
– Valving arrangements
– Pressure regulation system
– Metering and Quality Analysis systems

Depending on the upstream hydrogen supply model, further gas treatment systems may be required if it is anticipated that the supplied hydrogen could be out of specification for downstream customers.

These may involve the systems covered in Section 4.3.

The European Onshore Infrastructure facility will require a similar list of utility requirements shown in Section 4.3 depending on the downstream requirements.

There may be a requirement for compression facilities at the European Onshore Infrastructure facility to allow bi-directional flow back into the UK in an import scenario.

The design of the export pipeline does not preclude the ability to allow bi-directional flow and could be used in this operating mode in the future.

**Section 1 of AquaDuctus includes an offshore pipeline approximately**

**200 km**

**long, which is proposed to feature interconnection points for adjacent offshore hydrogen pipeline systems.**

## 4.5 AquaDuctus Offshore Pipeline System

AquaDuctus, a component of the AquaVentus initiative, is set to be a gigawatt-scale offshore hydrogen pipeline in the German North Sea. This pipeline aims to offer open access to various network users, such as producers of renewable hydrogen from offshore wind, on a non-discriminatory basis.

Planned by GASCADE, the AquaDuctus pipeline will link significant quantities of renewable hydrogen produced offshore in the North Sea with the European mainland and the developing European onshore hydrogen infrastructure system [56].

The project focusses on a scalable, demand-driven infrastructure with AquaDuctus planned to be developed in two sections.

The initial project section, Section 1, will comprise an offshore hydrogen pipeline to connect the first large hydrogen producing wind farm site SEN-1 located in the German Exclusive Economic Zone (EEZ) in the northwest of Helgoland with the German mainland and from there to European consumers via the downstream German hydrogen network infrastructure.

The hydrogen pipeline is planned to become the core of an interconnected offshore infrastructure between Germany and the North Sea countries of the Netherlands, Belgium, Denmark, Norway and the United Kingdom.

In this way, the European production and demand centres for renewable hydrogen will be interconnected.

By 2030, AquaDuctus Section 1 will connect to SEN-1, with a renewable hydrogen generation capacity of approximately 1 GW via offshore wind electricity generation.

The project includes an offshore pipeline approximately 200 km long, which is proposed to feature interconnection points for adjacent offshore hydrogen pipeline systems.

Additionally, Section 1 encompasses an onshore pipeline of about 100 km to ensure optimal connection to the downstream hydrogen network.

In February 2024, AquaDuctus Section 1 received state aid approval for funding from the European Commission under the “Important Projects of Common European Interest (IPCEI)” hydrogen framework[57] .

AquaDuctus Section 2 extends a further, approximately, 200 km offshore from the SEN-1 location to the remote areas of the German EEZ, to connect additional future hydrogen wind farm sites in EEZ Zones 4 and 5.

Provision of additional interconnection points will allow further connection of adjacent offshore hydrogen pipeline systems.

The AquaDuctus system will provide the opportunity for linking adjacent national hydrogen systems originating from Denmark, the Netherlands, Belgium and United Kingdom which opens the door for Europe-wide offshore hydrogen transport by pipeline.

The AquaDuctus design team has progressed the technical feasibility and legal planning of all phases of the project.


**Figure 30**
Indicative Routeing of Proposed AquaDuctus Pipeline System (© AquaDuctus).

**A conceptual design for the offshore hydrogen pipeline connecting the various hydrogen production sites for the different project phases has been developed.**

Commercial aspects, marketing potential, pricing and regulatory design options have been analysed and the permitting framework and boundary conditions established with the relevant authorities.

The feasibility study report has not been made available, but it is understood that the feasibility study also investigated the investment and operating costs for the complete pipeline system.

It should be noted the German Regulation currently rules out mixed connections for offshore hydrogen production in the EEZ as the Offshore Wind Energy restricts maritime areas eligible for hydrogen production exclusively to installations without connections to the electricity grid.

This is a key focus area when the Feasibility Study becomes available and could represent a barrier to progress for this project as a mixed connection project.

A feasible pipeline route with a potential German landfall at the greater Wilhelmshaven area for further connection to the German onshore hydrogen core network has been developed taking into consideration the technical, environmental and regulatory conditions.

The routing of the project will satisfy the environmental constraints associated with the crossing of the German Wadden Sea National Park, part of the largest unbroken system of intertidal sand and mud flats in the world and a Unesco World Heritage Site.

A conceptual design for the offshore hydrogen pipeline connecting the various hydrogen production sites for the different project phases has been developed. As part of this design, extensive hydraulic analyses have been performed to determine the required pipeline diameter and pressure rating.

It is assumed that a tie-in arrangement to the AquaDuctus system would be required including tie-in valves, control / instrumentation interfaces, safety measures and potentially pigging facilities.

Alternative design options may be available following further study and collaboration with AquaDuctus.

### 4.5.1 Operational Integration

The integration of multiple hydrogen producers into a single offshore pipeline system presents technical challenges with key issues related to product specification, pressure management, varying hydrogen properties, general operation, and safety.

The main AquaDuctus transmission pipeline in question is a large diameter, 48-inch line with a number of source connections which will require integration and interfacing between the developer of the UK connection and the AquaDuctus system operator.

### 4.5.2 Product Specification

Ensuring consistent hydrogen quality is crucial when multiple producers are involved. Variations in hydrogen purity, moisture content, and the presence of contaminants can affect the overall performance and safety of the pipeline system.

Standardising product specifications across producers is essential to maintain pipeline integrity and operational efficiency.

### 4.5.3 Pressure Management

Managing pressure within the pipeline is critical to prevent overpressure scenarios and ensure safe operation. With multiple producers, each contributing hydrogen at different pressures, maintaining a consistent pipeline pressure becomes complex.

Further study and collaboration with AquaDuctus is required in future design stages to minimise these risks.

### 4.5.4 Varying Hydrogen Properties

Hydrogen properties, such as density and viscosity, can vary based on production methods and conditions.

These variations can impact flow dynamics and pressure drop within the pipeline.

Understanding and accounting for these differences is necessary to optimise flow rates and ensure uniform distribution of hydrogen throughout the pipeline network.

It is anticipated that a defined hydrogen specification will be in place that hydrogen producers will have to adhere to and provide a consistent product to the export facility.

In addition, if there is a risk that varying hydrogen properties will be received, additional clean-up facilities will be provided at the export facility to ensure a consistent export product.

### 4.5.5 General Operation

Coordinating the operation of multiple producers requires robust communication and control systems.

Real-time monitoring and data sharing between producers and pipeline operators are essential to manage flow rates, detect anomalies, and respond to operational changes promptly.

Establishing clear operational protocols and contingency plans is vital for seamless integration.

### 4.5.6 Safety Considerations

Safety is paramount in hydrogen pipeline operations.

The presence of multiple producers increases the complexity of ensuring safe operation.

Key safety measures include:

- Leak Detection: Implementing advanced leak detection systems to quickly identify and address any leaks.
- Emergency Shutdown Systems: Ensuring that emergency shutdown systems are in place and can be activated remotely.
- Regular Inspections and Maintenance: Conducting regular inspections and maintenance to identify and rectify potential issues before they escalate.
- Training and Preparedness: Providing comprehensive training for all personnel involved in the operation and maintenance of the pipeline system.

**Significant further investigation is full understand and capitalise on the opportunity of repurposing existing gas interconnectors.**

## 4.6 Repurposing of Existing Gas Interconnectors

Figure 31 provides a detailed overview of the current gas pipelines located within the North Sea with potential connection to the UK[58].

A focus is made on the existing gas pipelines due to their operating pressures and pipeline materials.

There is an opportunity to evaluate the condition, purpose, and lifespan of these existing pipelines for potential re-purposing to support hydrogen transport in the future.

Several of these pipelines could be interconnected, supplemented by new-build pipelines, to create a comprehensive network linking the UK with continental Europe.

Consideration should also be made of current decommissioning regimes to ensure that re-use of North Sea infrastructure assets for the transport and storage of hydrogen are included.

Significant further investigation is required to fully understand and capitalise on this opportunity.

A report on the development of potential hydrogen export from the UK to continental Europe[20] considered the existing UK infrastructure and interconnectors and described the issues around converting them to hydrogen use.

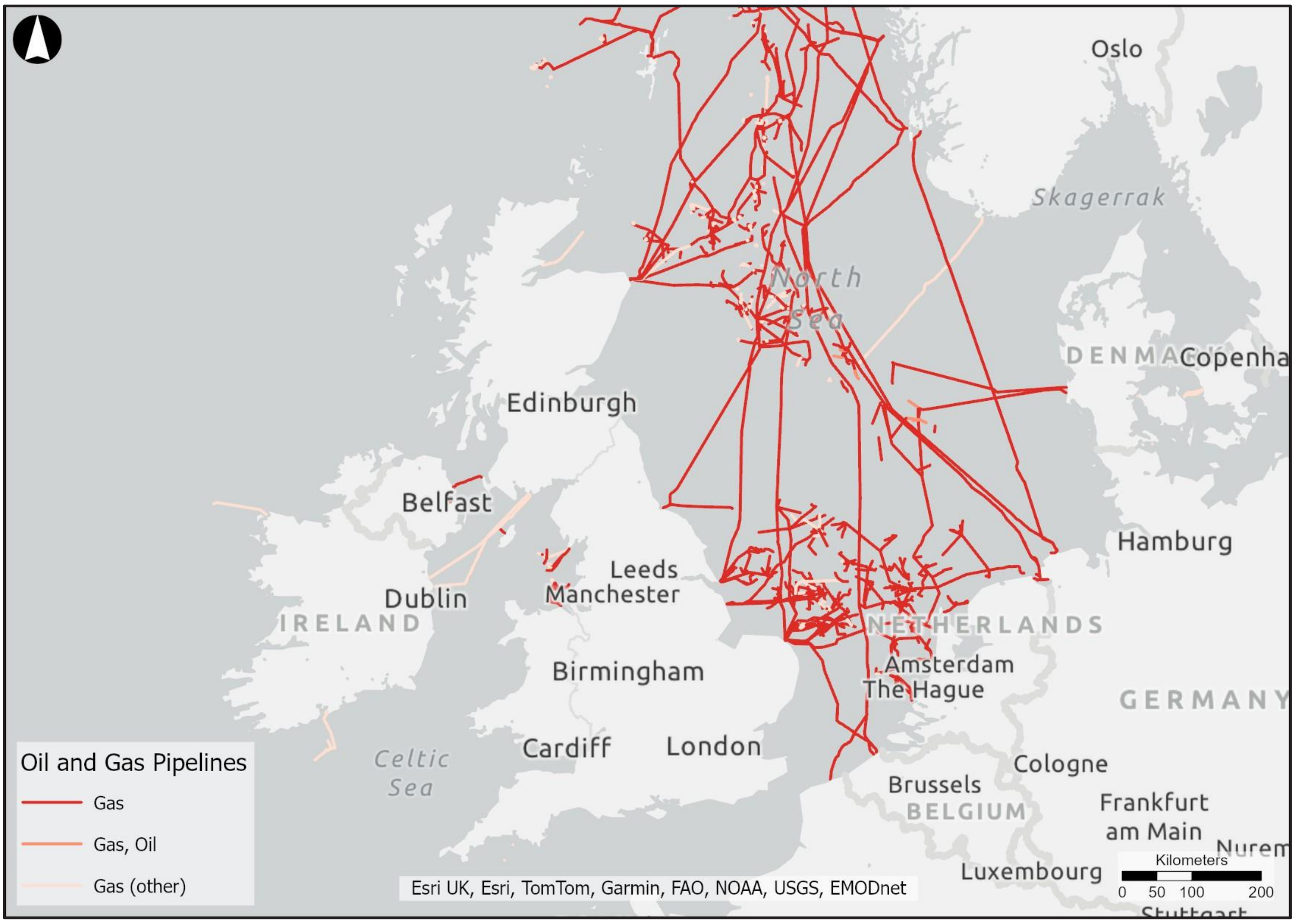



**Figure 31**
Existing Oil and Gas Pipelines in the North Sea [58]

This is summarised below for the following existing interconnectors:

1. Interconnector (Bacton to Zeebrugge, Belgium): Connects Bacton in the UK to Zeebrugge in Belgium.
2. BBL Connection (Bacton to Balgzand, Netherlands): Links Bacton in the UK with Balgzand in the Netherlands.
3. Langeled Pipeline (Nyhamna, Norway to Easington, UK): Runs from Nyhamna in Norway to Easington in the UK via the Sleipner offshore platform. It should be noted that Langaled is a pipeline system that could allow the transfer of gas from the UK to Norway via a series of linked pipelines (rather than a point-to-point interconnector).

The Base Case for this study is a new build pipeline with some of the technical differentiators and additional work of re-purposing existing pipelines / interconnectors discussed here.

The primary technical challenge is converting existing natural gas pipelines to hydrogen service.

There is a significant amount of detailed assessment required of the pressure rating, material compatibility, and capacity of each of the pipelines as well as a review of each section and component of an existing pipeline.

Additional infrastructure, such as compression stations and monitoring systems, may also be required to operate the hydrogen system safely and efficiently.

The availability of materials and components for conversion can affect the timeline and cost of the project with potential supply chain disruptions.

As discussed in Arup's previous report[20], 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 130-160barg), they are mostly constructed of high strength steels, also known as high grade steels.

**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 10.

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 11.

As shown in Table 11, 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 based on their sizing.

| | 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 |

**Table 10**
Design factor key limit on allowable pressure

| 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 | harg | 77 | 82 |

**Table 11**
Design conditions for repurposing the existing interconnectors to hydrogen service.

Due to the reduced MAOP, an additional compressor station at the European landfall site would most likely be required to achieve the entry pressure of the European core grid.

Further work is required to assess the impact of hydrogen transportation operation in terms of velocity within the pipeline and the limitations of the existing infrastructure.

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.

The conversion process involves multiple stakeholders, including pipeline owners and operators. Coordination among these parties is crucial for a successful transition.

Ensuring compliance with environmental regulations is a significant concern.

The high-level environmental risks with repurposing an existing pipeline include the multiple potential leak points and their impact on the surrounding environment.

The testing of these points is a primary concern and a mitigation plan is required to meet regulatory requirements during and after the conversion process.

Continuous monitoring and maintenance are essential to ensure the safe operation of converted pipelines with the need for advanced monitoring technologies possibly required.

In addition to the technical considerations to determine the suitability of the existing asset to be able to be converted to hydrogen service, the key consideration is the availability of these assets to be converted from their existing natural gas service.

These interconnectors currently provide security of supply of natural gas to the UK (and via the UK to Ireland), with long term commercial contracts in place for gas supply. Additionally, the UK Interconnectors also provide a route for central Europe to refill their natural gas storage over the summer months from GB exports.

The ability to take an existing asset out of natural gas service and the timing of any such repurposing will be dictated by the need for natural gas supply and the expiration of the gas supply contracts through these assets.

If this occurs substantially in the future, then the technical ability to repurpose these assets for hydrogen service may be compromised by the extended operational period supplying natural gas and the residual life remaining in the asset.

**Conversion of natural gas interconnectors to hydrogen use involves multiple stakeholders, including pipeline owners and operators. Coordination among these parties is crucial for a successful transition.**

## 4.7 New Interconnector Pipelines

A review has been carried out for routeing pipelines from the UK to the AquaDuctus Offshore Pipeline System as well as direct connection to Germany, Belgium and Netherlands.

This review utilises previous work looking into the major constraints of laying new pipelines in the North Sea.

Major constraints for pipeline routeing were identified from publicly available data sources and experience on other projects which include:

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

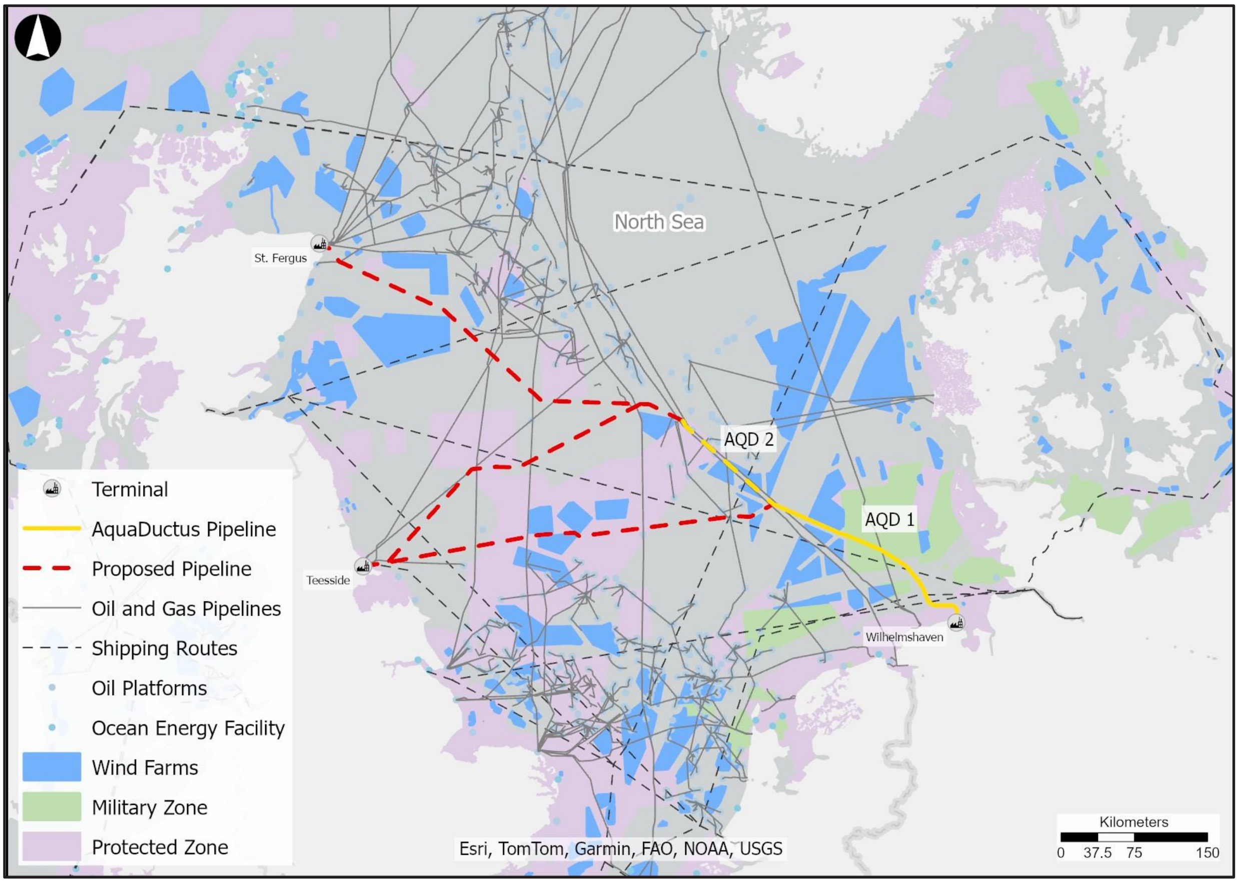



**Figure 32**

Potential Pipeline Routes from UK to AquaDuctus Offshore Pipeline System.

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.

### 4.7.1 UK to AquaDuctus Offshore Pipeline System

Data for the AquaDuctus pipeline route was received from Gascade and imported into ArcGIS, however, the locations and demarcations for the end of Section 1 were not included and therefore has been assumed for the purposes of this study.

Two indicative export locations have been used to indicate pipeline routes and the relative issues around the North Sea. Several locations could be used and have been discussed previously in the potential hydrogen export from the UK to continental Europe report[20].

Two locations have been used in this study to demonstrate this route; Teesside and St. Fergus.

There are multiple routeing options available which can be explored as the study progresses with integration of NZTC and other pipeline studies to be included.

The indicative routes shown here are for demonstration purposes.

Proposed pipeline routes from England (Teesside) and Scotland (St. Fergus) are shown in Figure 32.

These routes are to demonstrate the approximate lengths of pipeline required and the relative complexity of routeing through the different North Sea constraints.

It should be noted that a selection for the potential UK export site location has not been confirmed and these locations are used as an example in the diagram below.

The route alignment shows that the approximate pipeline lengths are:

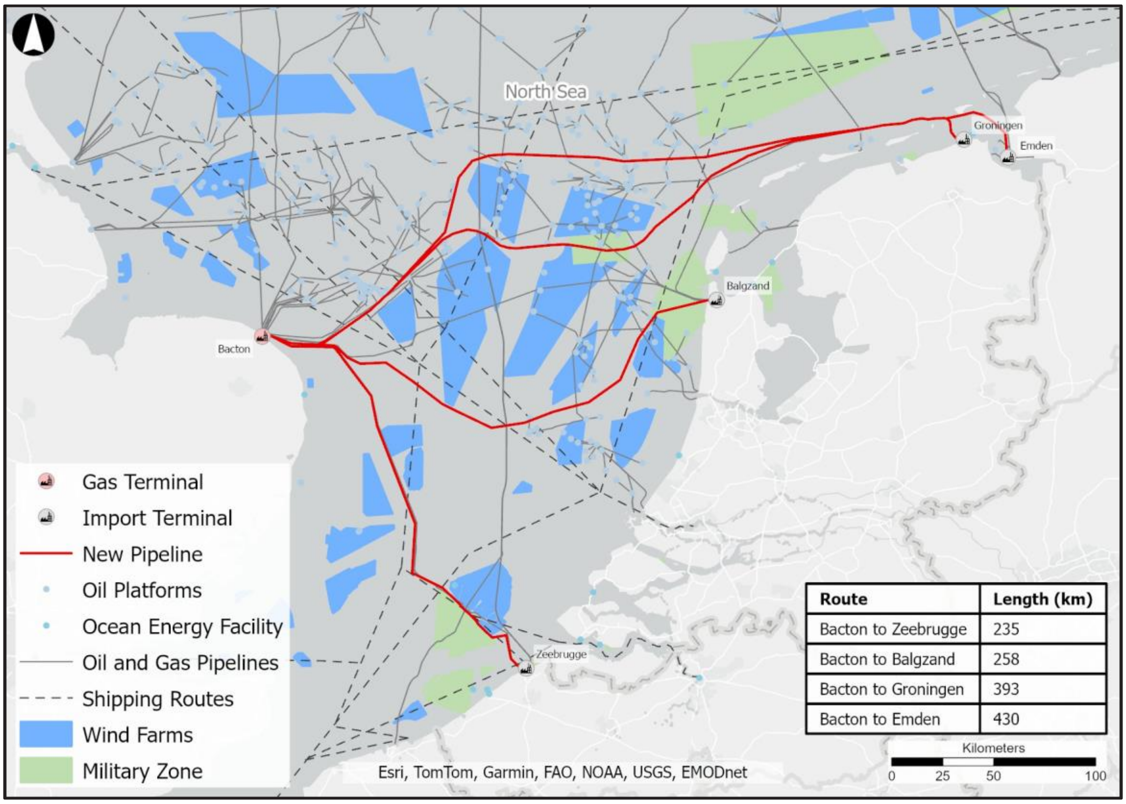
- St. Fergus to AquaDuctus Section 2 entry (Point 2), 432 km;
- Teesside to AquaDuctus Section 2 entry (Point 2), 391 km; and
- Teesside to AquaDuctus Section 1 entry (Point 1), 429 km.

The pipeline route shown from St. Fergus is shown to be technically feasible, with careful consideration required if the Section 2 extension of AquaDuctus does not materialise, of how the route would be extended to the Section 1 entry tie-in point as this will route through the existing protected areas.

Direct routing from the east coast of England to the assumed Section 1 AquaDuctus entry point will be challenging but feasible due to the number of constraints along the proposed routes.

It appears to be less challenging (from a constraints perspective) to route towards the north and tie-in at the proposed Section 2 entry point avoiding the protected areas directly to the east of Teesside.

**This review utilises previous work looking into the major constraints of laying new pipelines in the North Sea.**



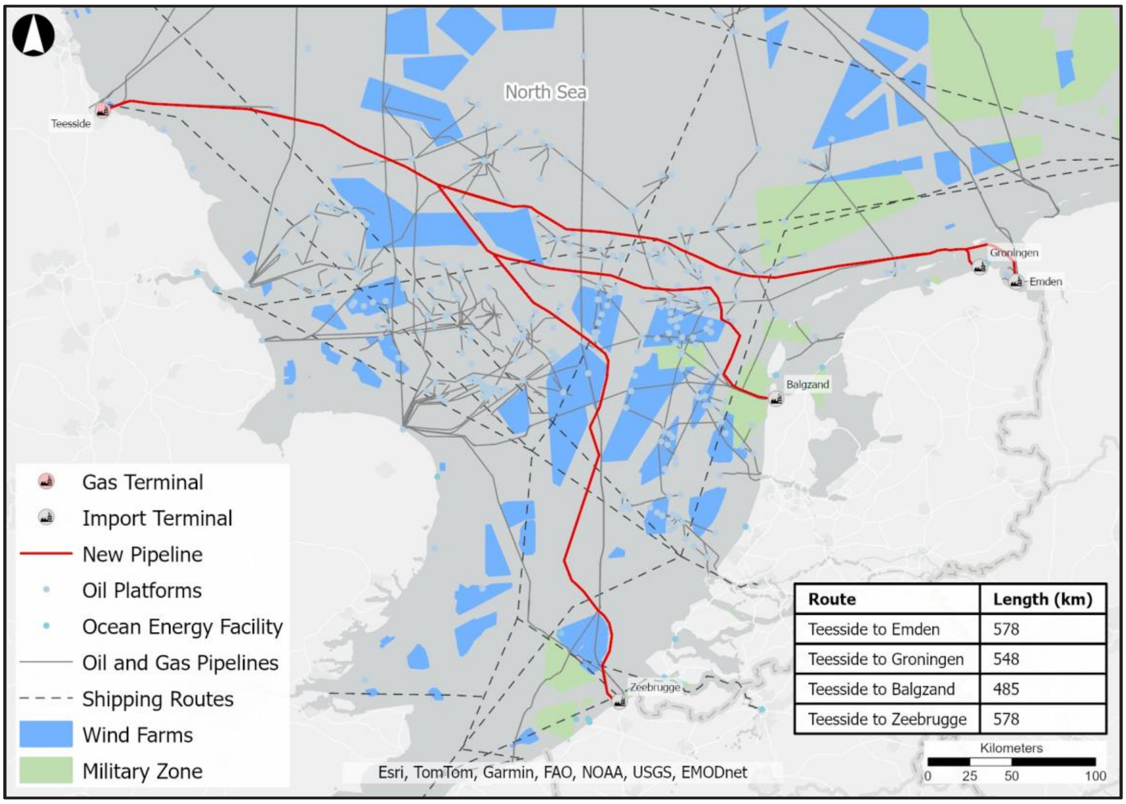
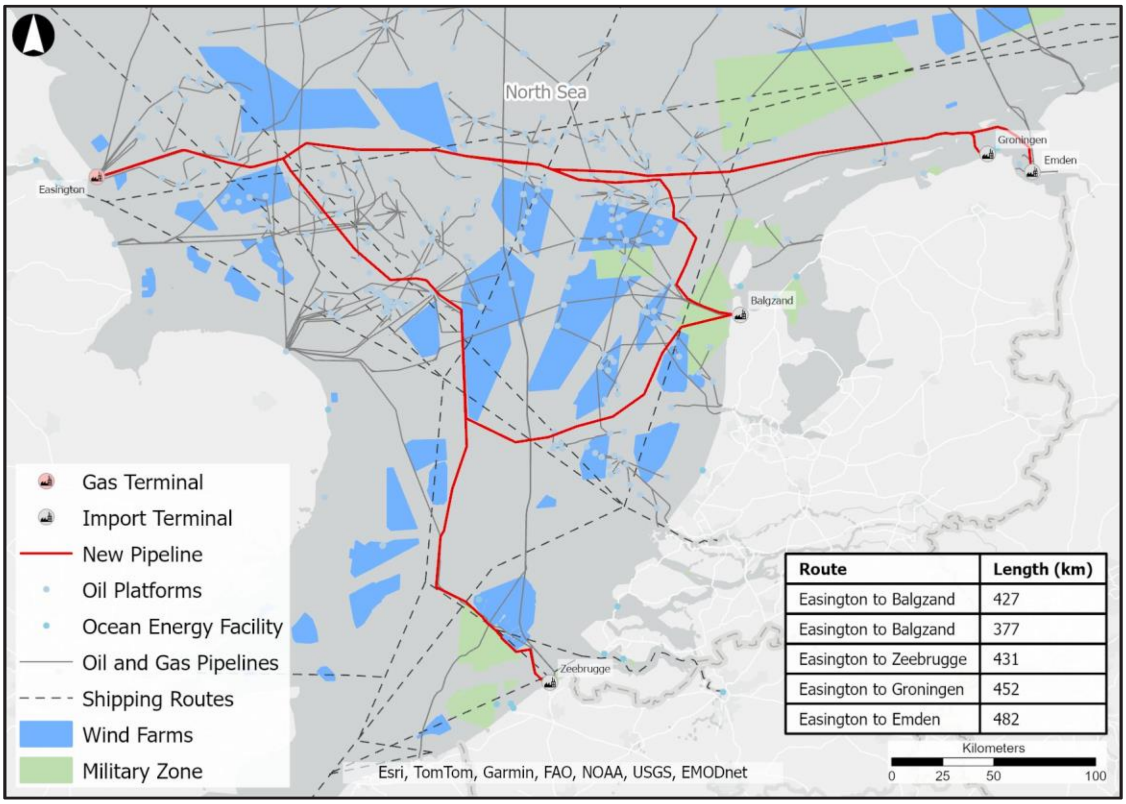
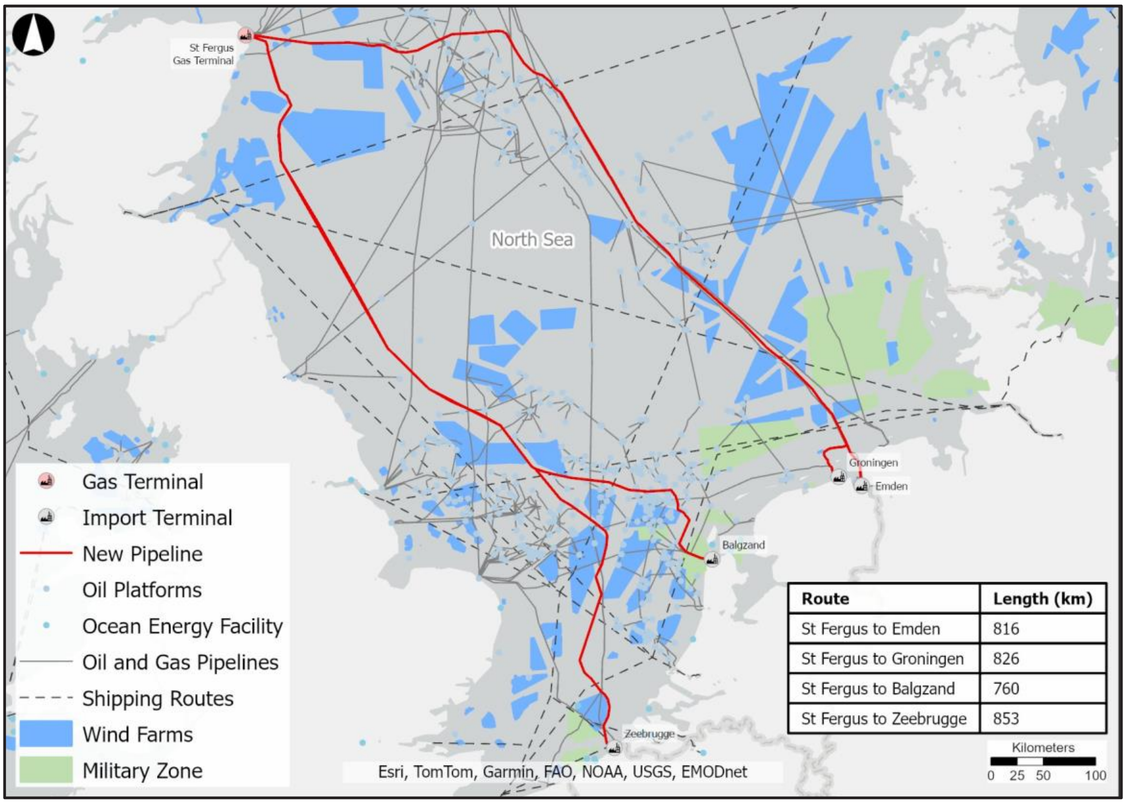




**Figure 33**

Potential Pipeline Routes from Bacton, Easington, Teesside and St. Fergus to Germany, Belgium and Netherlands.




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




| Route | Length (km) |
|---|---|
| St Fergus to Emden | 816 |
| St Fergus to Groningen | 826 |
| St Fergus to Balgzand | 760 |
| St Fergus to Zeebrugge | 853 |

### 4.7.2 Direct Routes from UK to Germany, Netherlands or Belgium

A direct connection from England or Scotland to mainland Europe was considered as part of a previous study[20].

This study considered different options for exporting from the east coast of the UK to promising locations in Germany, Netherlands and Belgium.

Example pipeline routes from this study are shown below in Figure 33.

The above potential interconnector pipelines are summarised into one drawing in Figure 34.

## 4.8 Pipeline Sizing Assessment

### 4.8.1 Assumptions

The following cases have been used to provide an indicative pipeline sizing assessment to use in this study.

These values are high-level assumptions that could be exported to German, Belgium or Netherlands onshore connections or into the AquaDuctus system.

The AquaDuctus system is designed to provide a transport capacity of 20 GW and will initially receive 1 GW of hydrogen from the production site SEN-1.

The low- or mid-cases mentioned below could be integrated into the AquaDuctus system at connection points located at the end of either Section 1 or Section 2.

It is important to note that only Section 1 has received initial funding approval from the German Government and the State of Lower Saxony[59].

It is anticipated that the UK hydrogen production available for export would increase over time but has not been assessed as part of these study cases.

– Low-Case: 0.5 GW

– Mid-Case: 1 GW

– Upper Case: 4 GW

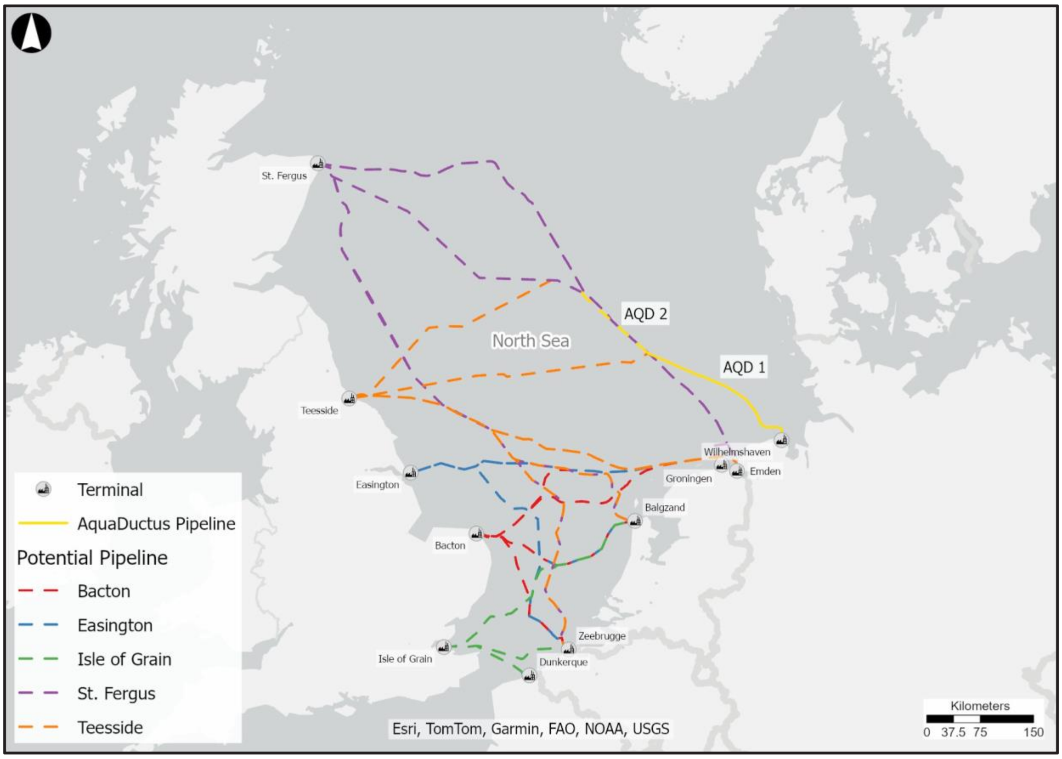



**Figure 34**

Potential Interconnector Pipelines from a number of UK east cost landfall sites (all sites and routes are indicative)

These values are initially selected as a Low-, Mid- and Upper-Case percentage figures of UK production that could potentially be available for export i.e. as percentages of total production from the UK Hydrogen Production Delivery Roadmap, published in December 2023[60], and other announcements such as the Scottish Green Export Scenario[61].

### 4.8.2 Preliminary Pipeline Sizing

This assessment focused on determining the appropriate approximate pipeline dimensions to handle varying capacities while maintaining typical acceptable pressure drop and velocity constraints.

These values are intended to provide high-level context to provide a bases to progress into future design phases.

The preliminary pipeline sizes considered follow standard nominal bore values at this stage however, it is noted that a non-standard size could be procured for this project if required.

The preliminary sizing range considered in this study is for pipeline diameters ranging from 24 inches to 48 inches.

To highlight the impact of pressure drop and velocity on pipeline sizing, a sensitivity of pipeline diameter has been carried out using an inlet pressure of 80 bar.

This value has been selected as a typical value similar to the MAOP of the existing gas interconnectors, see Table 11.

It should be noted that the pressure range required to meet the requirements of the AquaDuctus system could be higher and further work is required to align the design philosophies of these systems. Initially a static piping calculation was carried out to determine the operating range of different pipeline sizes.

This was subsequently followed by simulating the pipeline in Aspen Hysys to determine pressure drop and velocity at different points in the pipeline when the density of the hydrogen fluid is varying due to difference in pressure and temperature.

Figure 35 demonstrates the significant impact that pressure drop can have when selecting a pipeline size for a range of throughputs.

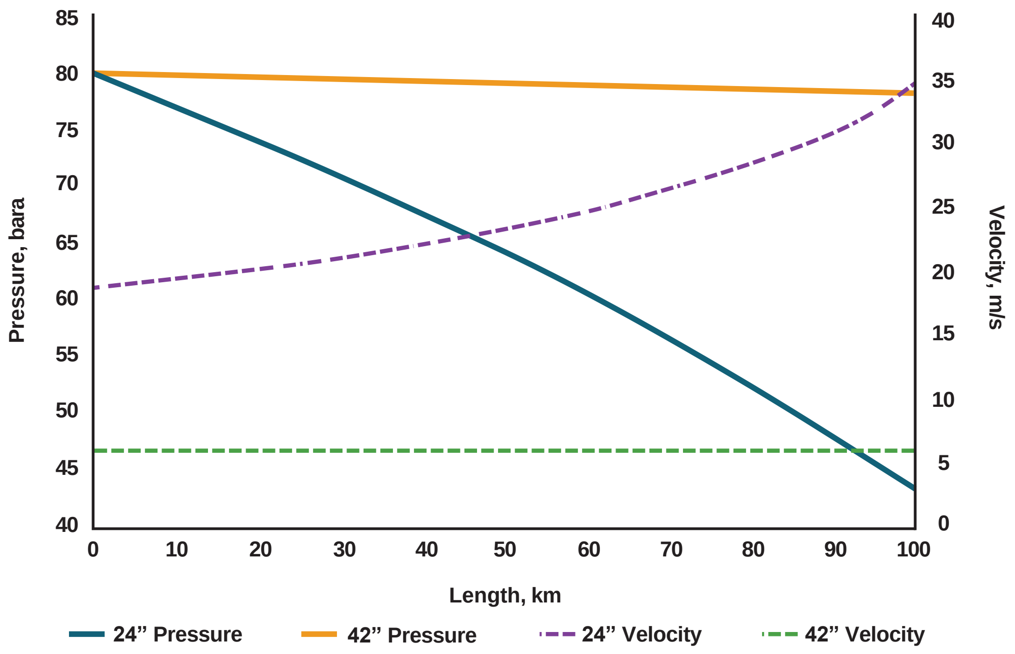



**Figure 35**

Comparison of 24” and 42” Pressure Drop and Velocity.

These values indicate that with a 4 GW throughput, a 42” pipeline would result in very little pressure drop over a length of 100 km whereas a 24” line would lose a significant amount of pressure available in the system.

The results of this analysis contextualise the importance of sizing pipeline diameters for the appropriate design cases and should be considered in further detail in subsequent design phases.

The preliminary sizing results were derived based on the following considerations:

– The pressure drop along the pipeline must be minimised to ensure efficient transportation of hydrogen. The acceptable pressure drop was determined based on industry standards.
– The velocity of hydrogen within the pipeline must be controlled to prevent issues such as erosion, noise, and potential safety hazards. The velocity constraints were set to ensure safe and efficient operation across all capacity scenarios.

The analysis involved evaluating the pipeline’s ability to handle the full range of capacities (0.5 to 4 GW) while adhering to the pressure drop and velocity constraints. A preliminary sizing assessment has been carried out which indicates the range of hydrogen capacities that fit within basic line sizing calculation parameters (acceptable pressure drop and velocity constraints).

This is shown diagrammatically in Figure 36 below.

A pipeline from the UK would need to be sized to provide the most flexibility in terms of capacity due to the unknown amount of hydrogen that could be transported.

Figure 36 was developed by setting a minimum velocity required of at least 5 m/s and a maximum pressure drop of 0.05 bar/100m at a nominal inlet pressure of 80 bar.

These restrictions are represented by the purple bars on Figure 36 with the average capacity highlighted with a red circle.

Therefore, a theoretical range for each size of pipeline is shown in terms of installed capacity. It should be noted that changing any of these assumptions will affect the capacity of the pipeline diameter shown.

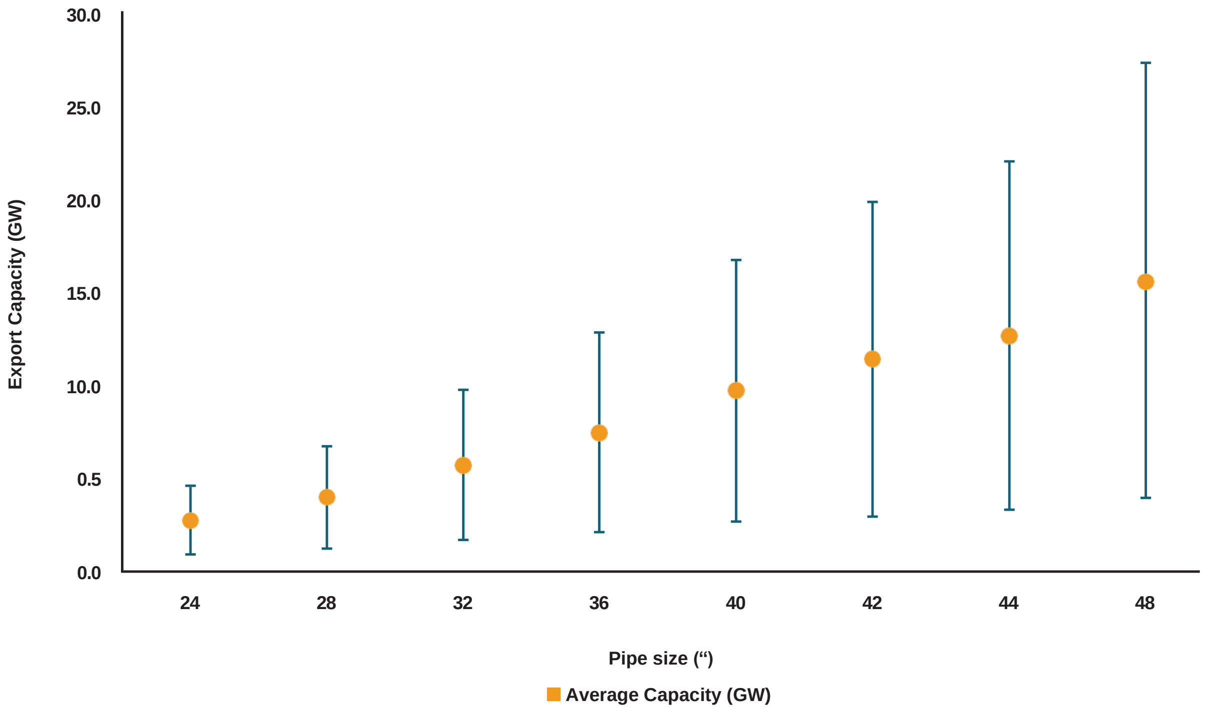



**Figure 36**
Approximate Capacity Constraints for Different Pipeline Size.

The following key points summarise the findings:

### 24-inch Pipeline:

At 24”, the 0.5 GW (low-) case does not reach the minimum velocity requirements and therefore is assumed to not be operable. This line size is marginally acceptable for the 1 GW capacity scenario, with higher pressure drops and velocities meaning that the system could operate within an acceptable range. At the 4 GW high-case, the system will be approaching the upper limits of the constraints and re-compression maybe required.

### 36-inch Pipeline:

This line size is shown to be adequate for both 0.5 GW and 1 GW capacity scenarios from a pressure drop perspective but below the acceptable range for velocity constraints and therefore not suitable. This line size is capable of handling the 4 GW capacity scenario.

### 48-inch Pipeline:

A 48” pipeline is assumed to be optimal for the 4 GW capacity scenario, maintaining pressure drops and velocities well within acceptable limits. However, it is significantly over-dimensioned for the 0.5 GW and 1 GW scenarios, resulting in velocities below initial acceptable range and minimal pressure drops.

Sizing a pipeline for this range of throughput (low to high cases) is difficult from a flow assurance perspective and therefore a compromise must be made in terms of size or throughput.

Further detailed analysis and optimisation will be required to finalise the pipeline dimensions and ensure compliance with all technical and safety requirements. In addition, selecting the appropriate inlet pressure to meet the outlet / tie-in pressure requirements should be a key focus as the design progresses.

## 4.9 Alternative Options for Further Development

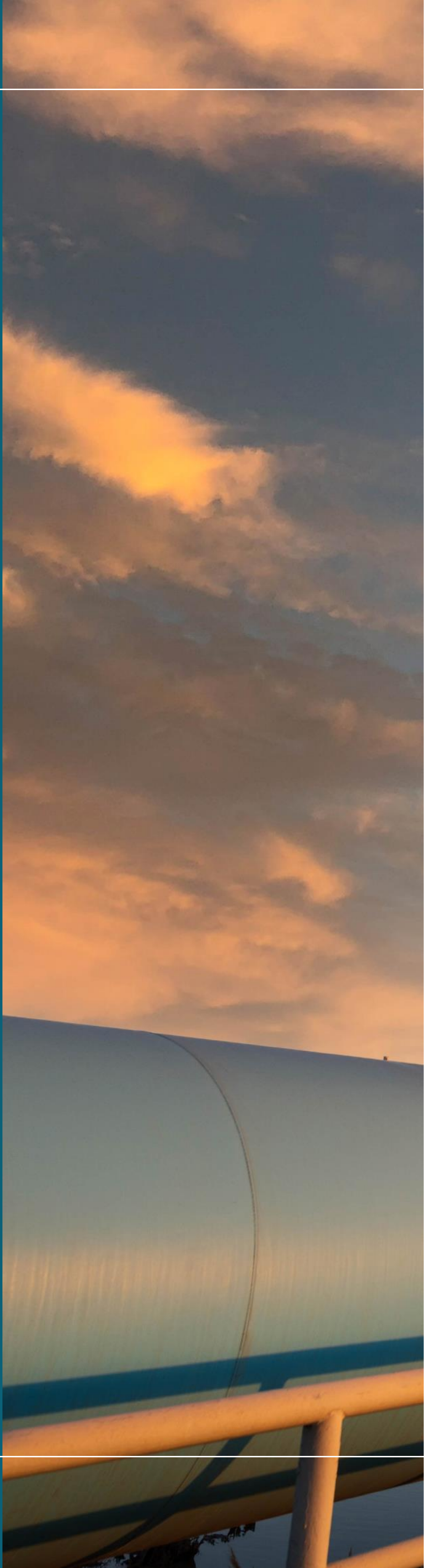
In order to increase the operational flexibility of the overall system development, alternative options could be considered in more detail in future design phases. The intent of these options is to allow for the phased development of export from the UK under low flow conditions in the early years and allow the system to grow as production and demand increases over time. The options for further development to manage volume/flow uncertainties and reduce potential pipeline costs include:

- Installation of 2 x parallel smaller diameter pipelines at same time to allow early low flow operation but provide futureproofing. The benefits of this should be compared with the negative issues of installing pipelines in parallel from a single lay barge. Discussions should be held with offshore pipeline installation contractors to discuss the practicalities of implementing this as a solution.
- Include a nitrogen ballasting case to increase the flowrate (and therefore fluid velocity) within the pipeline and discuss the implications of such a system (volume required, cost to produce, removal at destination etc.).
- Consider the utilisation of sections of existing pipelines within the North Sea and potentially route hydrogen from the UK to Europe via potentially daisy-chain arrangement of new infill pipelines between existing infrastructure.

# 5

# Focus Areas & Roadmap

**This study identifies four focus areas to be developed during the initiation period of a potential hydrogen interconnector between the UK and Germany.**



## 5.1 Focus Areas

Based on the analyses of regulations, business models, and commercial arrangements, as well as the high-level infrastructure assessment conducted, it is evident that the nascent international hydrogen market presents significant complexities in developing pipeline-based trade between the UK and Germany.

Consequently, key enablers and associated activities have been identified to support the realisation of this objective.

A detailed programme will need to be developed to manage the interdependencies across the delivery enabler actions.

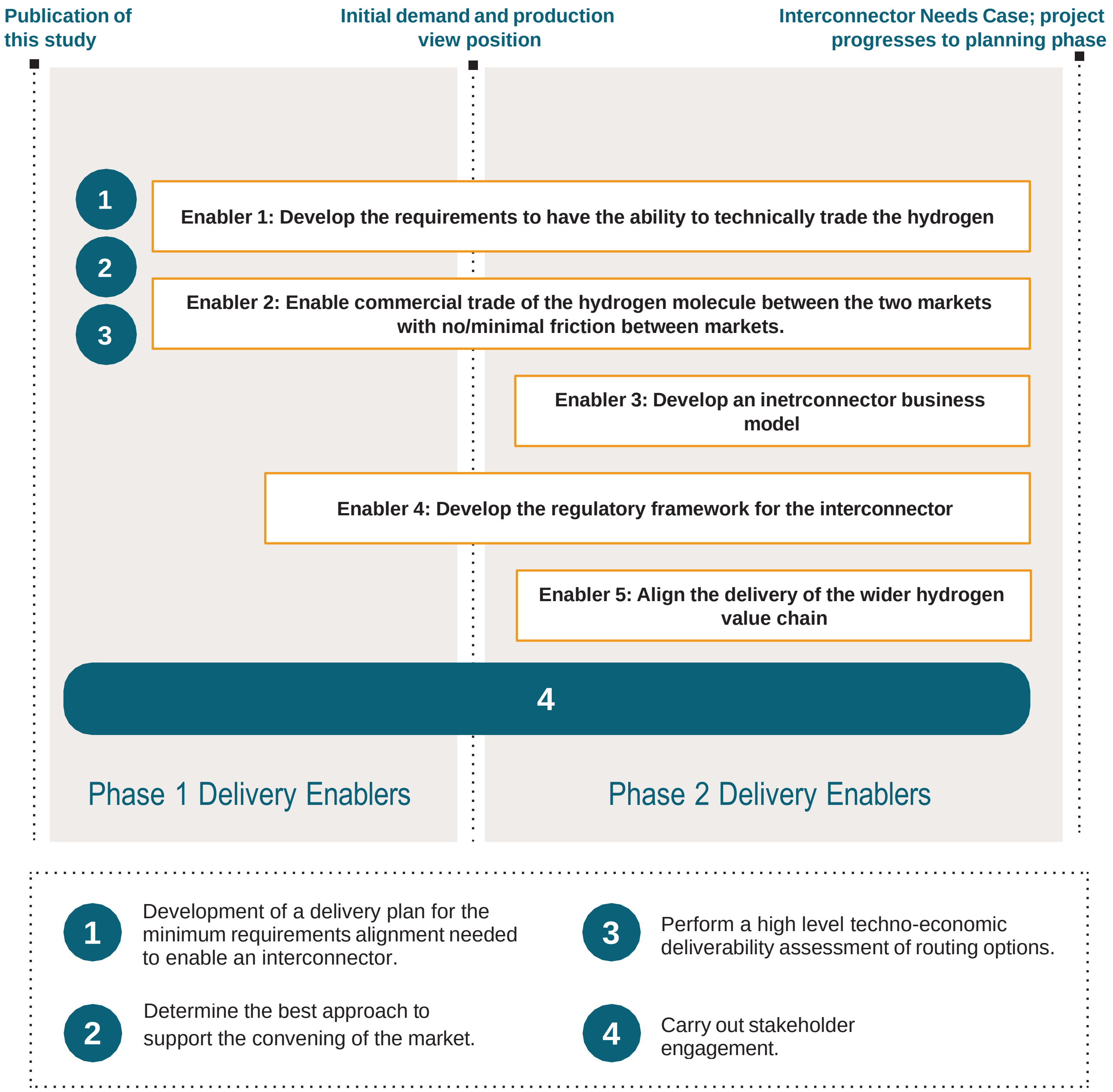



Figure 37

Focus Areas to enable a hydrogen interconnector.

However, four critical activities are recommended as focus areas that should be prioritised to initiate and support the development of these enablers following the publication of this study.

These are represented in sequence with the delivery enablers Figure 37.

**Focus 1:** Develop a delivery plan for the minimum regulatory alignment needed to enable an interconnector.

As identified in enabler 1, to enable the technical flow of hydrogen between the UK and Germany, it is necessary to understand the alignment between the regulatory frameworks.

This alignment will ensure compatibility of the technical and operational requirements, including hydrogen emissions standards, hydrogen certification schemes, and the interconnector technical codes and standards. Such alignment is crucial for the technical flow of hydrogen between the future networks of the two countries.

Further, to support the development of the cross-border market, and associated offtaker agreements, requires regulatory alignment between the UK and Germany. Given the long lead times associated with developing and aligning regulations, it is essential to identify a delivery plan.

This study recommends that the UK and German Governments collaborate to develop a comprehensive delivery plan for the minimum regulatory alignment needed to enable an interconnector.

This plan should address key areas such as establishing consistent and mutually recognised emissions standards for hydrogen production and use, harmonising certification schemes to ensure that hydrogen produced in one country is recognised and accepted in the other, and defining the technical requirements for the safe and efficient flow of hydrogen between the UK and German networks.

By addressing these areas, the UK and Germany can facilitate the integration of their hydrogen markets and support the broader goal of developing a sustainable hydrogen economy.

**Focus 2:** Determine the best mechanism to support the convening of the market.

Enabler 2 outlines the complexity of aligning market supply and demand to enable the commercial trade of hydrogen.

The primary challenge is that the hydrogen market is still in its infancy, necessitating several actions to successfully match supply with demand and facilitate commercial trade between the UK and Germany.

These actions include the UK and German Governments exploring market arrangements, assessing the potential production export capability, evaluating the potential offtaker requirements, and considering whether financial support mechanisms are necessary to ensure the commercial viability of future hydrogen trade, in compliance with WTO rules.

Alignment of the market supply and demand underpins the business case for an interconnector. Therefore, following the publication of this study, the UK and German Governments collaborate on determining a mechanism that they can utilise to manage the complexity of stakeholder engagement with offtakers, producers and network developers to align the market.

**Focus 3:** Perform a high-level techno-economic deliverability assessment of routing options.

To ensure market engagement and facilitate the development of producer and offtaker arrangements, it will be essential to understand the potential cost range of the interconnector to inform the commercial viability of the offtaker agreements.

Therefore, this study recommends that, the UK and German Governments, or an independent entity, conduct a high-level techno-economic deliverability assessment of potential route options.

This assessment should focus on evaluating the CAPEX and OPEX costs of the interconnector assets, as defined in this report in Figure 1, and potential route options to determine the high-level cost range of a potential interconnector.

Further, more detailed routing and techno-economic evaluations will be required in the initiation and planning phases of the interconnector project once more information on the developments of wider variables across the value chain materialise, for example, the production and demand profiles across the UK and Germany, respectively.

**Focus 4:** Carry out stakeholder engagement.

Given the nascent nature of the hydrogen market, it is crucial to engage with stakeholders across the hydrogen value chain to understand market challenges and stakeholder requirements, which will inform the interconnector business case.

This stakeholder engagement is essential across both phases of the delivery enablers.

**Phase 1 Delivery Enablers:**

Engagement with offtakers and producers is particularly important to understand potential demand and production capacity positions.

**Phase 2 Delivery Enablers:**

Broader engagement across the value chain is crucial to support the development of the interconnector needs case.

This study recommends that, following its publication, a comprehensive stakeholder engagement strategy be developed.

This strategy should build on the limited engagement carried out in this study to ensure that critical stakeholder requirements are considered during the initiation phase of the interconnector project.

It is important to recognise that this engagement must be conducted within the context of wider market development.

The stakeholders to be considered include, but are not limited to:

- Producers: To understand the landscape of development, including capacity, availability, and associated timelines to commercial operation dates.
- Onshore Network Developers: To understand development plans, geographical rollout, and associated timelines.
- Interconnector Operators: To further understand the operational requirements of an interconnector and identify potential future operators.
- Offtakers: To understand specific requirements, including timelines, quantum of demand, quality and specification requirements, and initial and future demand profiles.
- Regulatory Authorities: To understand existing regulations and development plans for hydrogen across the value chain.

- Storage Operators: To understand the development landscape in both countries and future availability to provide security of supply for offtakers.
- Supply Chain Providers: Focusing on providers of critical products upstream and downstream (such as electrolysers, compressors, special materials and alloys, seals and filters, etc.) and key contractors (EPC contractors, offshore pipe lay barge operators, etc.) to better understand future supply chain capability and capacity.

Various parties, including the UK and German Governments, entities supporting market convening, and potential independent stakeholders, will need to carry out stakeholder engagement across the two phases of delivery enablers to contribute to the development of the interconnector needs case.

### 5.2 Roadmap

Based on the 'Germany Base Case' outlined in Section 1.3.2, a comprehensive roadmap for the development of an interconnector project from the UK to Germany has been developed.

This roadmap follows a typical infrastructure project life cycle, detailing a high-level overview of the activities necessary during the Initiation and Planning phases to inform the FID.

It then continues through the Construction phase. While the Operations and Decommissioning phases are not included in this report, it is necessary to consider the activities required in these phases when developing a detailed delivery plan.

Given the nascent state of the hydrogen market and the lack of established hydrogen trade between the UK and Europe, additional activities and decisions will be required, linked to the other workstreams considered in this study.

Through analyses carried out across the hydrogen value chain, covering regulations, business models, and commercial arrangements, key activities and decisions have been identified throughout the project lifecycle.

This forms the basis for the development of a detailed project development programme, which will allow the dependencies and logic between activities to be established and further detailed.

The delivery enablers and focus area sequencing discussed in Sections 3.2 and 5.1 are activities to be carried out in the initiation phase of the project lifecycle.

The completion of the delivery enabler actions will support the development of an interconnector needs case.

Provided the interconnector project has suitably carried out the actions and decisions identified in the initiation phase of the roadmap and has met the outlined milestones, the project can progress to the planning phase.

The roadmap is presented in Figure 38.

**Through analyses carried out across the hydrogen value chain, covering regulations, business models, and commercial arrangements, key activities and decisions have been identified throughout the project lifecycle.**

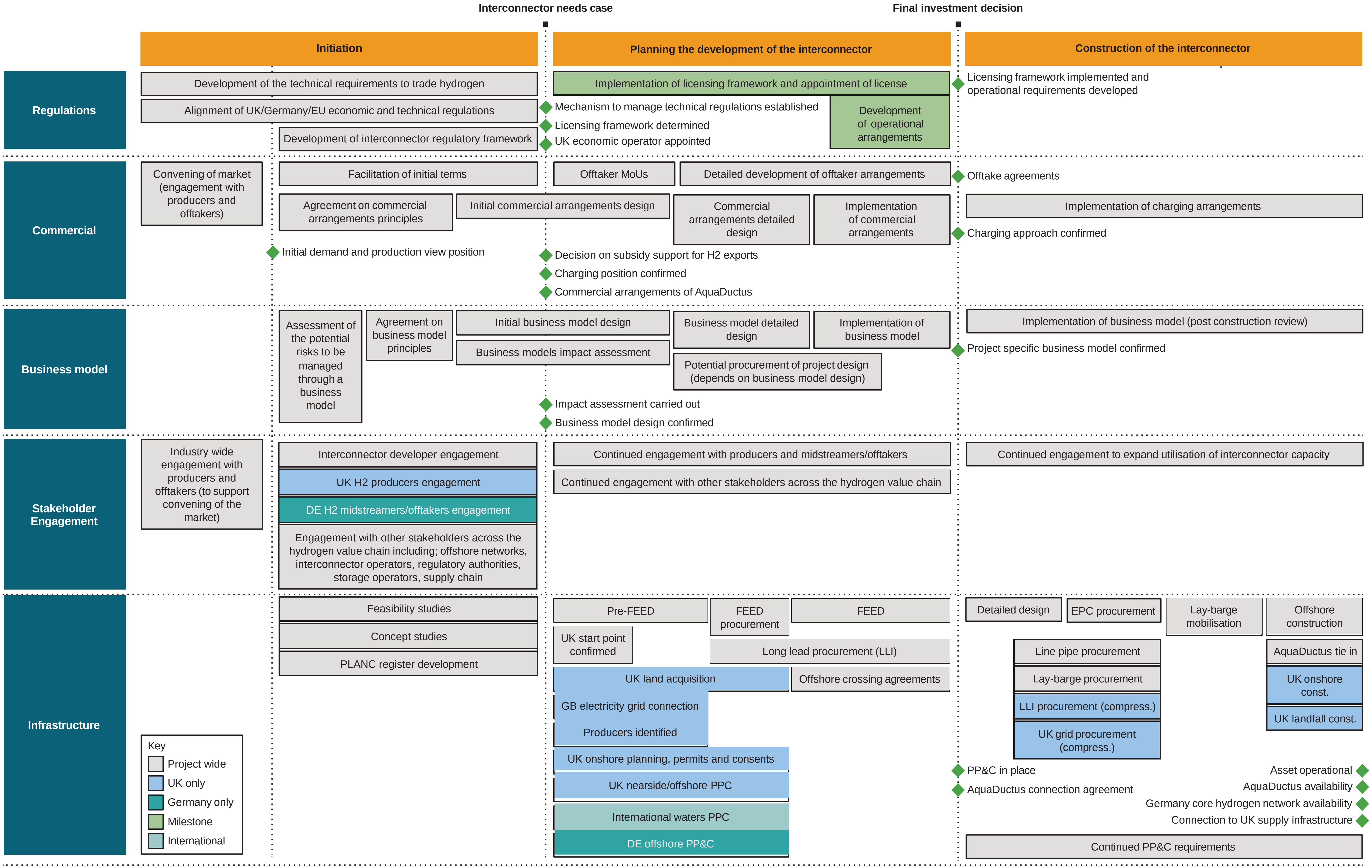



Figure 38: Roadmap, based on the 'Base Case'.

The focus areas and delivery enablers detailed in Section 5.1 represent the critical activities required during the initiation phase to enable the development of an interconnector.

The roadmap highlights that four activities should be carried out first to form an initial view of the production and demand positions in the UK and German, respectively:

1. Commencing the development of technical requirements to trade the hydrogen molecule.
2. Aligning the necessary UK and German economic and technical regulations.
3. Convening the market.
4. Engaging with producers and offtakers across the industry.

Following these initial activities, the other tasks in the initiation phase will need to be carefully managed and aligned to deliver the interconnector needs case.

From an infrastructure perspective, while it is important to conduct techno-economic feasibility studies to narrow down routing options, the primary significance of these studies is to provide further information to develop activities across the regulations, business models, and commercial swim lanes depicted in the roadmap and support market development.

This study has identified the technical feasibility of an interconnector pipeline from the UK to Germany, making the initiation phase activities related to the infrastructure of the interconnector less critical. Nonetheless, feasibility studies, concept studies, and the development of a Permits, Licences, Authorisations, Notifications and Consents (PLANC) register will be necessary to support the interconnector needs case and transition into the planning stage.

This study has delivered the prerequisite information needed to commence the interconnector initiation stage, as represented in the roadmap in Figure 38.

Further details of the activities that must be completed, at a minimum, during the initiation phase are provided in Table 13.

| Initiation Phase Activity | Description |
|---|---|
| Regulations | |
| Development of the technical requirements to trade hydrogen | The UK and German Governments will need to work together to align hydrogen emissions standards and respective hydrogen certification schemes where appropriate, working with the institutions, including the European Commission that hold responsibility for the establishment and implementation of the standards and certification schemes.<br>The UK and German Governments, or respective technical authorities, will need to work together to develop the technical operational requirements (including, for example, inlet pressures) associated with the flow of hydrogen between the two future networks. |
| Alignment of UK/Germany/EU economic and technical regulations | The UK and German Governments, and/or relevant regulatory authorities, will need to ensure alignment of associated regulations in order to ensure the viability of the project. This will feed into various other aspects of the initiation phase actions, including; stakeholder engagement and feasibility studies. Without this alignment the project will not be able to progress to planning. |

**Table 12**

Proposed Project Initiation Phase Activities & Decisions.

| Initiation Phase Activity | Description |
|---|---|
| Regulations | |
| Development of the interconnector regulatory framework | As identified in Enabler 4, Section 3.7, the UK Government will need to develop a regulatory framework to support hydrogen interconnector projects and review the existing natural gas licensing framework to identify necessary revisions for hydrogen equivalents. Concurrently, the UK and German Governments will collaborate to establish commercial operational requirements, including access, charging, balancing, and trading, as part of this regulatory framework.<br>Additionally, the German Government will assess EU-wide regulations to ensure hydrogen safety and technical integrity, with a similar review needed in the UK to harmonise applicable regulations. |
| Convening of market (engagement with producers and offtakers) | This activity should work hand in hand with the industry-wide engagement mentioned in the ‘Stakeholder Engagement’ row of the roadmap. Convening the market should be focused around matching up supply with demand via engagement with producers and offtakers. This will enable an initial idea of the demand and production positions to facilitate the subsequent activities in the initiation phase of the interconnector.<br>Engaging with offtakers and producers to understand the potential for agreements and exploring the best mechanism to facilitate these engagements is recommended. |
| Facilitation of initial terms (between producers and offtakers) | Following attaining an initial view of demand and production through producer/offtaker engagement, initial terms should be set out and agreed between identified eligible producers and offtakers. This will be critical to the success of the development of the interconnector due to the uncertainty and key risks for the hydrogen interconnector.<br>Whilst business model options can manage some key risks for the hydrogen interconnector, significant risks remain across the wider hydrogen value chain, particularly regarding offtaker demand, production capacity, and the connecting onshore networks. Unaddressed, these risks could lead to low utilisation of the interconnector, posing a significant financial risk to the Governments. It will be important to mitigate these risks in the initiation and planning phases of the interconnector development cycle by agreements for offtake. The facilitation of initial terms in the initiation phase to support this can be crucial for stakeholder certainty and development of the interconnector needs. |
| Agreement on commercial arrangements principles | Network charges aim to recover the costs of developing, operating, and decommissioning the interconnector. These costs include DEVEX, CAPEX, operational expenses OPEX, decommissioning expenses (DECOMMEX), depreciation, incentives, and taxes. As the specific structure of these costs will depend on the business model design, the commercial arrangements design should be done in parallel.<br>In the initiation phase it will be important that consideration is given to the near-term model support of the future development of the hydrogen market and that value is delivered to all stakeholders. Therefore, this study recommends that the overarching principles are agreed upon alongside the development and agreement on the principles of a business model. This approach will encourage early use of the interconnector and support its greater utilisation in the future.<br>The agreement of these principles should take into account the outputs of the stakeholder engagement and the feasibility studies. |
| Initial commercial arrangements design | Following the agreement on the principles of the commercial arrangements, the design of the commercial arrangements should be commenced, in parallel with the development of the initial business model design. This will support the interconnector needs case and should carry on into the planning phase. |

| Initiation Phase Activity | Description |
|---|---|
| **Business Models** | |
| Assessment of potential risks to be managed through a business model | At this stage of the initiation phase, it will be important to assess the potential risks, which should be managed through a business model. This will support the development of the business model design.<br>This study suggests that the assessment of potential risks to be managed through a business model should be carried out following confirmation of the initial demand and production view position. |
| Agreement on business model principles | Following the assessment of the risks to be managed through a business model, the principles of the commercial arrangements should be commenced, in parallel with the development of the initial business model design. This will support the interconnector needs case. The agreement of these principles should take into account the outputs of the stakeholder engagement and the feasibility studies. |
| Initial business model design | Several business models have been assessed in this study, detailed in Appendix A, identifying the options to be considered in the initiation of the interconnector. Once the principles have been agreed, the initial design should commence, in parallel to the design of the commercial arrangements. This will support the interconnector needs case and should carry on into the planning phase. |
| Business models impact assessment | At initiation, the outputs of early concept studies should inform the initial design and impact assessment of a preferred business model. A detailed assessment of the model options will need to be conducted once there is greater certainty on the route and technical parameters. This should be done in parallel to the engagement with potential project developers to understand their perspectives on delivery risks and the likelihood of private investment.<br>Additionally, the initial impact assessment should explore the scale of potential guarantee support required to manage revenue uncertainty. This will involve gathering comprehensive lifecycle cost information, initial technical details, and understanding utilisation scenarios. This activity should inform the decision on whether to design a joint business model between the connecting countries or individual models with agreed funding responsibilities and hence should be carried out in parallel to the initial business model design. This decision will depend on agreements regarding effort sharing and organisational responsibilities, especially in public ownership scenarios. For a connection to the AquaDuctus system, funding approaches and responsibilities must be confirmed between the UK and German Governments. |
| **Stakeholder Engagement** | |
| Industry wide engagement with producers and offtakers (to support convening of the market) | Given the nascent nature of the hydrogen market and trade with Germany, it is important that stakeholders are engaged across the value chain.<br>It will be particularly important for the project to engage with producers and offtakers at this stage to support the convening of the market and identification of the initial production and demand positions. |
| Interconnector developer engagement | The initial industry-wide engagement should identify interconnector developers to be engaged with further in the initiation phase.<br>This engagement will focus on further understanding the development requirements of an interconnector and identify potential developers |
| UK hydrogen producers engagement | The initial industry wide engagement should identify producers in the UK to be engaged with further in the initiation phase and onwards.<br>This engagement will focus on further understanding the production capacities available for hydrogen export and the producer requirements to support the facilitation of initial commercial terms. |

| Initiation Phase Activity | Description |
|---|---|
| **Stakeholder Engagement** | |
| German hydrogen midstreamers/offtakers engagement | The initial industry-wide engagement should identify offtakers in Germany to be engaged with further in the initiation phase and onwards.<br>This engagement will focus on further understanding the offtaker demand for hydrogen and the offtaker requirements to support the facilitation of initial commercial terms. |
| Engagement with other stakeholders across the hydrogen value chain including; onshore network developers, interconnector operators, regulatory authorities, storage operators, and supply chain providers | Onshore network developers, regulators, operators across the value chain, and supply chain stakeholders should also be engaged in the initiation phase to ensure their requirements are met and the project can progress successfully. |
| **Infrastructure** | |
| Concept Studies | Following confirmation of the initial demand and hydrogen production positions, specific concept studies will need to be carried out by the project developer. These should focus on defining the project's scope, identifying various infrastructure options, and conducting preliminary assessments of technical, financial, and environmental aspects.<br>The goal is to explore different approaches and solutions to deliver the interconnector project's objectives and determine whether the project idea is viable and worth pursuing taking forward to planning. Typically, this step should cover the process of down selecting to preferred route solutions. |
| Feasibility Studies | Feasibility studies should be carried out to further interrogate the concepts identified. These studies should assess the technical, economic, legal, regulatory, environmental, and social feasibility of the project providing more certainty around key project metrics.<br>These studies should include evaluating the design and construction methods, analysing costs and potential revenues, ensuring compliance with laws and regulations, and identifying potential risks and mitigation strategies. This activity should provide a comprehensive understanding of the project's viability, helping to provide stakeholder confidence around decision making. |
| PLANC Register Development | The development of a new build interconnector will require a significant number of consents and permits to be put in place for the onshore as well as the offshore sections 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. To understand and manage the process, a Permits Licences Authorisations Notifications and Consents (PLANC) Register is created and maintained throughout the project life cycle. It captures the potential permits, licences, and consents required to carry out the proposed works.<br>The PLANC Register lists all potential permits, licences, and consents that may be required for the development of the interconnector project. The PLANC Register is a working document. At the start of a project a detailed assessment of the consents and permitting requirements and a strategy for engagement with the various permitting authorities, other statutory bodies, and interested stakeholders will need to be developed. All disciplines will contribute to the register to confirm the permits, licences, and consents that will be necessary and those that will not. Initially all potential requirements are included to ensure that nothing is missed. As the project progresses, additional permits, licences, and consents may be required, and/or some of those detailed in the register may no longer be required and will be removed.<br>The time taken to obtain the required licences, permits, and consents will be influenced by the complexity of the application and the supporting information required. The PLANC Register will be used in conjunction with the project programme to track the key activities required to achieve project milestones. |

A

# Appendix A: Business Models

Today, the hydrogen market is in its infancy in the UK and Germany. Therefore, it is currently highly unlikely that a hydrogen interconnector would be commercially viable without a business model providing a revenue guarantee. This study has explored several possible business models including RAB, Cap and Floor as well as a capacity guarantee and identified how the business model would resolve potential risks on different levels.

Before the interconnector business model can be developed further, additional clarity is required on the hydrogen market arrangements between producers and offtakers as well as the technical parameters of the interconnector. Understanding these elements will provide a more informed view of the business model risks and the potential guarantee that may be required. The UK and German Governments also need to explore the best mechanism to facilitate engagement across the value chain, accelerating the creation of offtaker agreements and minimise low interconnector utilisation risk.

**The study has explored the potential market failures and how the adoption of different business models would either mitigate or reduce these market failures.**

## A.1 The need for a support regime

Where there are market barriers that prevent investment from developing infrastructure that has a confirmed needs case, the Government may need to provide support in the development phase to ensure a viable business model is put in place that supports investment if it is not forthcoming on its own.

For a first of a kind hydrogen interconnector there is significant uncertainty associated with supply and demand ramp up in the European and German hydrogen economy and therefore the amount of hydrogen that is likely to flow through the interconnector.

This creates revenue uncertainty for the interconnector asset owner, which in turn creates a barrier for private investors with regards to the level of risk that they would be exposed to in developing and operating a hydrogen interconnector.

Compared to the barriers associated with an onshore hydrogen transmission network, this is further compounded by the cost and demand/supply uncertainty associated with cross-border markets and competition between different hydrogen export/import corridors within Europe.

The study has explored the potential market failures and how the adoption of different business models would either mitigate or reduce these market failures. These business models consider how the revenues associated with the asset will be recovered and the potential support mechanism that may be required to provide revenue certainty.

## A.2 Scope of the business model

This study has explored the need to put in place a viable business model for the interconnector only, specifically the import/export terminals and the associated pipeline(s) connecting the UK and Germany.

Business models associated with the production, respective onshore networks and the offtakers are considered as outside of the interconnector boundary and therefore outside the scope of the interconnector business model and this study.

As presented in Figure 39, the business models for these elements are in development in both countries and are considered as key interfaces for the potential interconnector business model given the development status of the hydrogen market.

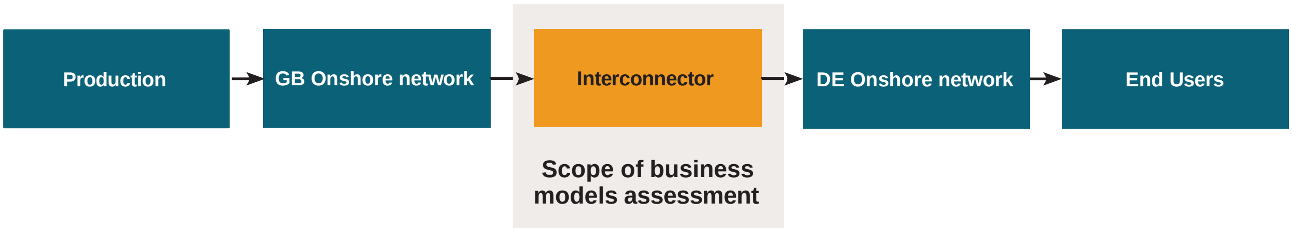



Figure 39
Hydrogen value and chain and business model boundary.

In assessing the potential business models options, several factors were considered out of scope at this stage, these are detailed in Table 13.

This includes: the revenue that may require revenue guarantee during the early development phase, how this support is provided and the associated split of guarantee between the respective Governments.

Whilst considered out of scope at this stage, these factors will need to be assessed in further studies as the model is further developed as they will shape the business model principles and associated impact assessments.

| Considerations | Description |
|---|---|
| Likely revenue support required | In the detailed assessment of the business models, it will be important to understand the full business case of the interconnector, specifically the cost structure (specifically the CAPEX & OPEX) as well as the financing. This will to be determine the minimum level of revenue that will need to be recovered through charging to finance the project. During the early market development phase, a guarantee is likely to be required to provide revenue certainty to ensure that investment is forthcoming to develop the project(s).<br>This study has not explored the potential scale of revenue support that may be required to provide sufficient revenue certainty. As part of the impact assessment, key cost elements that will impact the cost structure have been identified. |
| How business model support is provided | The assessment has looked at the business models agnostic of how the funding will be split between the respective countries and/or whether there will be two separate models. This will likely need to take into consideration the funding support that is provided for AquaDuctus Section 1 and potentially 2 (if selected as the preferred routing option) on how the business model support funding is shared. These factors will need to be explored further during business model design to understand the impact on the business case. These considerations will need to inform a value assessment, which will need to be undertaken by the respective Governments to determine the potential split of Government funding support. |
| Competitiveness of an interconnector compared to other options | The assessment does not consider the competitiveness of the hydrogen provided through the interconnector compared to alternatives (via other interconnectors or domestically produced) and specifically the impact of the potential transportation costs on the hydrogen price. The hydrogen cost and the cost of transportation compared to other options will be a significant driver in the utilisation of the interconnector in both the development and enduring phase. |
| Technical considerations onto the business model support | An initial assessment has identified the following technical considerations that are likely to impact the cost structure:<br>– Increasing the capacity or direction will have an impact onto the pressure management of the interconnector. Consideration will be needed within the business model on what assumptions will be made for compression, specifically how demand/supply is expected to evolve over time. This will have a CAPEX and OPEX impact.<br>– A potential tie-in to the AquaDuctus system vs direct land fall will have an impact on the technical requirements of the system (infrastructure and pipeline design) and therefore the potential level of compression required. |

Table 13

Out of Scope considerations

## A.3 Identified market failures and risks

The review of market failures has identified several material risks to be managed through the development of a business model.

These risks have been separated into high risks (identified as red) and medium/low risks (identified as amber).

Greater detail has been provided on the five identified high risks reflecting that these will need to be particularly manged through a business model.

### High business model risks

#### 1 Domestic vs non-domestic demand trade off

The respective countries have their own domestic demand decarbonisation targets as well as production capacity targets, particularly for 2030, as detailed in Section 2.

The UK has an overarching legal commitment to achieve net zero by 2050 and have a known production pipeline of over 250 UK projects under development, presenting a potential production capacity of 25.1 GW by 2030. Similarly, for demand the following targets have been set: net zero electricity system by 2030, decarbonisation of two industrial clusters by 2030 and to take a decision on the role of hydrogen in heating by 2026. Scotland has an earlier net zero target of 2045.

Germany has committed to achieve net zero by 2045 and negative emissions by 2050. In terms of hydrogen production, the updated National Hydrogen Strategy introduced the target of 10 GW of electrolyser capacity by 2030. Germany has set maximum sector emission targets (non-binding) for 2030 are intended to foster demand for zero or low-carbon technologies and approaches, including low-carbon hydrogen across a range of sectors including energy, industry, buildings and transport. These are further detailed in Section 2. Additionally, Germany is bound by the EU Effort Sharing Regulation, which requires the transport (excluding aviation), small industry, agriculture, buildings, and waste sectors to reduce their emissions by 50% compared to 2005 by 2030[62 26].

As a result, as the initial design assumes export of hydrogen from the UK to Germany there is a trade-off for the UK in terms of how domestically produced hydrogen is utilised, either for domestic or non-domestic use.

This trade off could result in two outcomes:

- The impact of a decision to use hydrogen non-domestically when there is domestic demand. This could prevent the UK from achieving its carbon emissions reduction ambitions or required to utilise other decarbonisation approaches as potentially greater cost to domestic offtakers.
- A UK decision to use the hydrogen domestically in the near term could result in offtakers agreeing contracts with other producers and not requiring UK production capability over the long term.

Both of these outcomes ultimately could result in lower utilisation of the interconnector and therefore create revenue uncertainty which either result in a significant market barrier or a significant guarantee requirement on the respective countries.

#### 2 Competitiveness of the hydrogen domestically/non-domestically.

The cost structure associated with UK produced hydrogen will either be driven by GB electricity prices or natural gas and CCUS input costs. There is a risk that the hydrogen produced in the UK is not competitive compared to alternative hydrogen sources produced with lower fuel input sources (i.e. hydrogen can be imported to Germany from alternative locations at a more competitive price). As a result, the hydrogen is not exported via the interconnector.

The impact of this risk is that:

- Production facilities have developed capacity with the intention of exporting are not able to recover the investment and reduces its production capacity and/or closes the facility preventing future domestic use. This could ultimately result in lower investor confidence in the UK hydrogen market
- The lower utilisation of the interconnector results in insufficient revenues to recover the interconnector cost, which therefore must be recovered from support funding.
- Should flowrates continue to reduce, they may reach the interconnector pipeline minimum operating threshold. Beyond this point, the pipeline would not be able to operate as it would not meet the minimum flow assurance requirements.

### 3 Lower demand realisation

There is a risk that demand does not materialise as expected and as a result there is insufficient interconnector capacity purchased/lower interconnector utilisation. This risk could be driven by several drivers, including offtakers are unwilling to commit to long-term offtake agreements, there shippers cannot book long term production/ interconnector capacity whilst the hydrogen market is in its infancy.

The impact of this risk is that:

- The lower utilisation of the interconnector results in insufficient revenues to recover the interconnector cost, which therefore must be recovered from support funding.
- Should flowrates continue to reduce, they may reach the interconnector pipeline minimum operating threshold. Beyond this point, the pipeline would not be able to operate as it would not meet the minimum flow assurance requirements.

### 4 Incorrect pipeline sizing compared to outturn market conditions

Given the current development status of the hydrogen market, it is likely that the demand in the initial operational years will be smaller than the potential demand in a more developed hydrogen market. As part of the engineering workstream, likely during the pre-FEED and ahead of signing the major construction contracts there will be a requirement to confirm the pipeline size. This decision will need to take into consideration both the initial and future expected interconnector utilisation.

There is a risk that the pipeline is sized for future expected utilisation and the differential between the initial and future expected interconnector utilisation is so significant that the initial utilisation is below the technically viable operating parameters. As a result, the pipeline would not be able to operate as it would not meet the minimum flow assurance requirements. Therefore, the lower utilisation of the interconnector results in insufficient revenues to recover the interconnector cost, which therefore must be recovered from support funding.

### 5 Delayed/slow decision on interconnector FID

There is a risk that a delayed market signal (specifically the development of the business model) to develop an UK-Germany interconnector prevents production and demand ramping up in the respective countries in line with the potential project development timeline.

The impact of this risk is that:

- Hydrogen production facilities either delay investment on capacity for export or only consider domestic demand options.
- Offtakers secure hydrogen from alternative sources and therefore do not require hydrogen through the interconnector.

Therefore, the lower utilisation of the interconnector results in insufficient revenues to recover the interconnector cost, which therefore must be recovered from support funding.

## Medium/low business model risks

| Medium/low identified risks | | | | |
|---|---|---|---|---|
| **Impact of risk:** | **Lower interconnector utilisation** | **Potential that the hydrogen does not meet the flow assurance levels** | **Pipeline connection is delayed** | **Additional CAPEX or OPEX costs** |
| Insufficient UK hydrogen production capacity. | ✔ | ✔ | | |
| Onshore hydrogen network is either delayed or does not develop to connect the producer to the offtakers to the interconnector. | ✔ | | ✔ | |
| Tie-in point to AquaDuctus system is not available in time or the extent of the AquaDuctus system is curtailed. | ✔ | | ✔ | |
| Insufficient capacity in the supply chain to design and construct the interconnector | | | ✔ | ✔ |
| The hydrogen supplied through the interconnector does not meet hydrogen certification scheme standard and as a result cannot secure long term capacity | ✔ | ✔ | | |
| Unaligned regulatory frameworks across UK/Germany/EU which prevents offtakers/producers from agreeing offtaker contracts | ✔ | ✔ | ✔ | |
| Shifts in the wider regulatory landscape creates uncertainty for hydrogen producers and offtakers resulting in lower supply/demand | ✔ | ✔ | ✔ | |
| Ability of the operator to maintain operability of interconnector system where short-term change of flow direction is required. | | ✔ | | ✔ |
| Increasing the capacity or direction of flow as the hydrogen market develops impacts the pressure management of the interconnector. | | ✔ | | ✔ |

## A.4 Assessment Framework

A framework has been set out for the business models assessment; the factors are presented in. In developing the assessment framework, the factors have been grouped into tiers to reflect the prioritisation of factors given the early status of the hydrogen market. Of first order priority is that the interconnector is investable, whilst also delivering value for the respective countries' consumers and customers of the interconnector.

Of second order, is the business model promotes the development of domestic and cross-border hydrogen markets whilst also being compatible with the business models that are being implemented domestically for hydrogen production and onshore networks in the respective countries. Additionally, it will also be important that the business model avoids complexity such not to impact onto the investability and compatibility with other business models.

The model applicability for future pipeline(s) is considered to be of a third order priority in the assessment of the interconnector. This is also the case for reducing business model support over time, recognising that this is a first a kind project and the hydrogen market is developing.

The assessment framework has been used to review the business models, highlighting advantages and disadvantages across the different factors including any red flags.

| Factor | Description | Priority |
|---|---|---|
| Value for money | – Business model will also need to consider the allocation of funding support between the UK and Germany, ensuring that the business model support is being paid for in the most economic and efficient manner and based on value received | 1 |
| Investable | – Business model provides revenue and returns that are sufficiently predictable for investors and mitigates risks that investors are not best placed to bear.<br>– The UK/Germany export/import market provides sufficient confidence that a market will be developed and maintained during the asset's life. | 1 |
| Promotes market development | – Encourages the development of a hydrogen import/export market, via cost reductions and certainty for users. It does not require on-going support e.g. subsidies.<br>– Business model design should incentivise efficiencies and certainty for users given the lack of competition in a bilateral agreement. | 2 |
| Compatible | – Compatible with other policies across the hydrogen value chain for UK/Germany and EU and does not result in double subsidisation.<br>– Compatible with how the onshore hydrogen transport business model is implemented/ expected to evolve. | 2 |
| Avoids complexity | – Business model avoids unnecessary complexity in design and can be implemented in a timely manner to provide exports/imports to both countries.<br>– Business model is easy for hydrogen producers and transport providers to understand and comply with.<br>– The business model needs to be able to transition smoothly between the development and enduring phases as the hydrogen market evolves and allows bi-directional flows. | 2 |
| Suitable for future pipeline | – Business model should be fit for purpose for first of a kind as well as any later projects, by considering the flexibility that may be needed from long term flow changes and opportunities to increase capacity in future. | 3 |
| Reduces support over time | – Business model allows support to reduce over time, specifically considering the impact of reducing revenue support on the costs faced by users/impact on investor confidence.<br>– Business model should be transparent in its reduction over time to not create additional revenue risk. | 3 |

Table 14

Assessment Framework.

## A.5 List of options for assessment

The following provides an overview of the business model options that were assessed, as presented within Table 15; this incorporates a mixture of public and private ownership models while the Merchant model represents the 'do nothing' option as part of the assessment.

The majority of these models are based on existing models that have been used for infrastructure development. Within the model descriptions, four possible cases have been described to provide theoretical explanations for how the models would work in practice. The four cases are presented within Table 16.

| Public Ownership Models | Private Ownership Models |
|---|---|
| – UK or German Government Ownership / Joint UK / DE Government Ownership<br>– Co-investment by Government | – RAB<br>– Cap and Floor<br>– CfD<br>– Government as a capacity booker<br>– OFTO Model<br>– Merchant model |

Table 15
Business models options for assessment.

| Case | Development phase<br>This phase captures from Day 1 of operations to when the hydrogen market is considered to be more developed (i.e. mid to late 2030s). | Enduring phase<br>This phase captures operations from the late 2030s onwards |
|---|---|---|
| 1 | Low utilisation one direction | Low utilisation one direction |
| 2 | Low utilisation one direction | High utilisation one direction or both directions |
| 3 | High utilisation one direction | High utilisation one direction |
| 4 | High utilisation one direction | Low utilisation one direction |

Table 16
Theoretical cases.

### A.5.1 UK or Germany public ownership

Under this model, the asset would be 100% owned by one or both of the Governments. This means that the Governments would provide the funding for both the development and construction of the asset. During operation, gas shippers, through a charging model, would be required to purchase capacity to allow for the flow of hydrogen through the interconnector.

The revenue received through the provision of capacity would be recovered against the cost incurred by the Governments during development and operational phases. This model could see the asset ownership transition to another model with a competition held to transfer the asset from public to private ownership. How the model would operate under the different cases is described in Table 17.

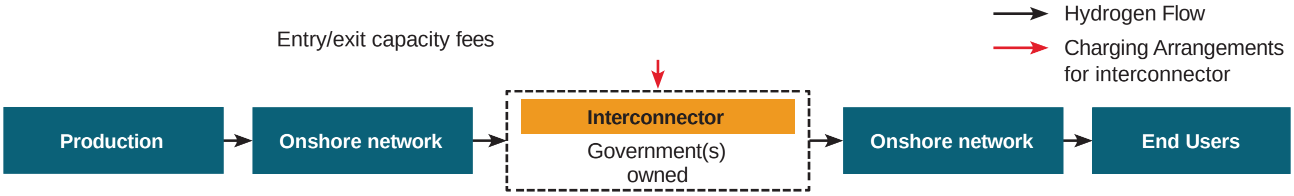



Figure 40

UK or Germany public ownership.

| Case | Development phase | Enduring phase |
|---|---|---|
| 1 | Charges associated with the low amount of capacity booked is recovered against the Government investment. | The low utilisation means that there continues to be revenue uncertainty and potentially low revenue secured. Therefore, remains under Government ownership as insufficient investment case under the merchant model. |
| 2 | | Higher utilisation results in higher charges recovery and therefore potential to transition away from public ownership to a private model (i.e. merchant case) if sufficient certainty on the future returns. |
| 3 | Given the higher utilisation of the interconnector, the Government(s)' recover a higher amount of charges against the Government investment. | Higher utilisation results in higher charges recovery and therefore potential to transition away from public ownership to a private model (i.e. merchant case) if sufficient certainty on the future returns. |
| 4 | | The low utilisation means that there continues to be revenue uncertainty and potentially low revenue secured. Therefore, remains under Government ownership as insufficient investment case under the merchant model. |

Table 17

UK or Germany public ownership.

### A.5.2 Co-investment by Government

Under this model, the asset would be co-owned by one or both of the Governments and private investment.

A split of ownership would be agreed with the ability for the Government(s) to reduce its share at a later date when there is sufficient market confidence.

The private ownership would receive the revenue first up to an agreed point, after this point the Governments would receive revenue returns which would be recovered against the cost incurred by the Governments.

The privately financed element of the asset could be financed through one of the private models, for example RAB or Cap and Floor. This model could see the asset ownership transition to another model with a competition held to transfer the asset from public to full private ownership.

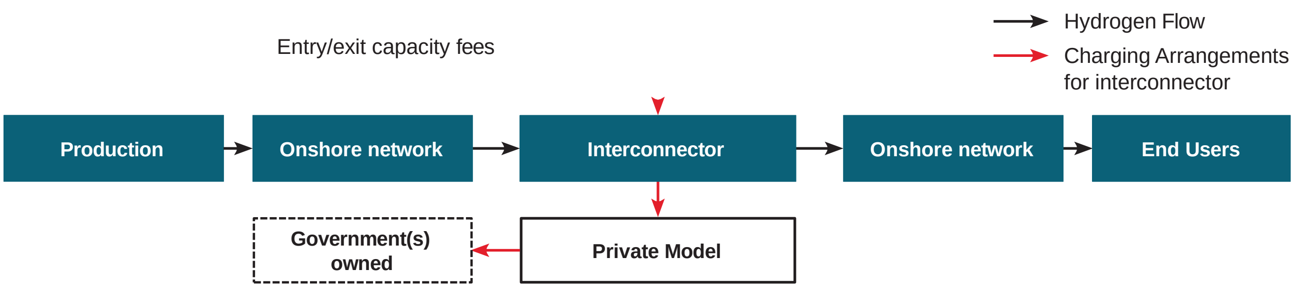



Figure 41
Co-investment by Government.

<table>
<tr><th>Case</th><th>Development phase</th><th>Enduring phase</th></tr>
<tr><td>1</td><td rowspan="2">The low utilisation means that the private owner(s) receive their revenue share first and the Government(s) are required to provide some revenue guarantee if the utilisation does not meet the agreed revenue return for the private owner(s)</td><td>The low utilisation means that the asset remains under partial Government ownership as there is insufficient investment case for the public ownership share to be transferred to private ownership.</td></tr>
<tr><td>2</td><td>The high utilisation means that there is a business case for the public share to be transitioned to full private ownership.</td></tr>
<tr><td>3</td><td rowspan="2">The higher utilisation means either the Government(s) provide a lower revenue guarantee or are able to receive some of the revenues against the publicly owned share.</td><td>The high utilisation means that there is a business case for the public share to be transitioned to full private ownership.</td></tr>
<tr><td>4</td><td>The low utilisation means that the asset remains under partial Government ownership as there is insufficient investment case for the public ownership share to be transferred to private ownership.</td></tr>
</table>

Table 18
Co-investment by Government.

## A.5.3 Regulated Asset Base (RAB)

Under this model, the asset would be privately owned, and the owner and operator of infrastructure would earn a regulated return on asset costs. A regulator would determine the ‘allowed revenue’ over a specified period, which reflects costs incurred and a fair rate of return.

This model is widely deployed in both the UK and Germany for gas networks, after the networks were privatised, and planned onshore hydrogen networks.

The infrastructure owner would be required to submit CAPEX and OPEX information for the asset for a defined period to inform the associated regulated return.

The organisation that sets the RAB model could be either or both Governments respectively, or the Governments would appoint this responsibility to another organisation for example a regulator or TSO.

The charges to recover the agreed revenue would be shared across customers; in the development phase, the Government(s) could act as the guarantor for the RAB to allow for charges to support the development of the hydrogen market.

The interconnector developer could start to make a regulated return under this model during the construction phase, providing greater certainty of the timing of the returns.

There are multiple options for the guarantee approach however the most appropriate approach has not been considered in the model design.

In the longer term, depending on how the hydrogen market develops, the role of Government(s) as a guarantor could be reduced or removed once there are sufficient customers for the costs to be shared as described in Table 19.

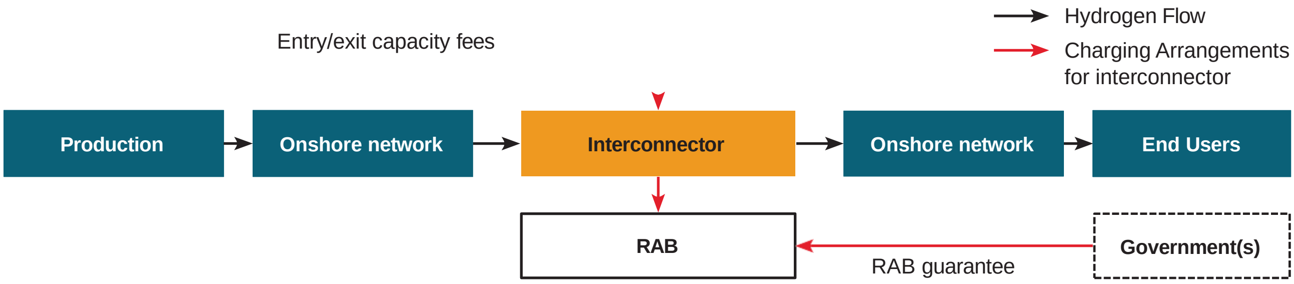



Figure 42

RAB Model.

| Case | Development phase | Enduring phase |
|---|---|---|
| 1 | RAB model determines the charges that are applied for hydrogen flows through the interconnector. This process determines the charges that will be shared across customers and how much is paid by the Government(s) as the guarantor for the remaining charges. | The lower utilisation means that the Government(s) continue to be the guarantor for the regulated return under the model. |
| 2 | | The increased demand means that there is sufficient, stable and sizeable customer base for the charges to be spread efficiently for the Government(s) to withdraw the guarantor role for the RAB model. |
| 3 | As per the base scenario, however, the Government(s) would be required to contribute a lower amount to the charges to recover the RAB given the increased customer base. | The increased demand means that there is sufficient, stable and sizeable customer base for the charges to be spread efficiently for the Government(s) to withdraw the guarantor role for the RAB model. |
| 4 | As per scenario 3. | The lower utilisation means that the Government(s) continue to be the guarantor for the regulated return under the model. |

Table 19

RAB Model.

### A.5.4 Cap and floor

Under this model, the asset would be privately owned and the Owner and Operator of the interconnector receives a revenue cap and floor set for a specified period.

This model has been utilised for the GB share of electricity interconnectors developed since the early 2010s.

Under this model, the investor receives certainty that their revenues will be between a defined range; if the floor, the minimum revenue, isn't reached through the recovery of network charges, under the model the owner receives a top up of the allowed revenue to the floor level.

If revenues exceed the cap, the surplus revenue about the cap is transferred back to relevant customers/consumers.

The cap and floor levels are determined based on the asset costs across its lifespan including development costs.

The organisation that sets the cap and floor could be either or both Governments respectively, or organisations that are appointed to deliver this responsibility by the Government(s) for example a regulator or TSO.

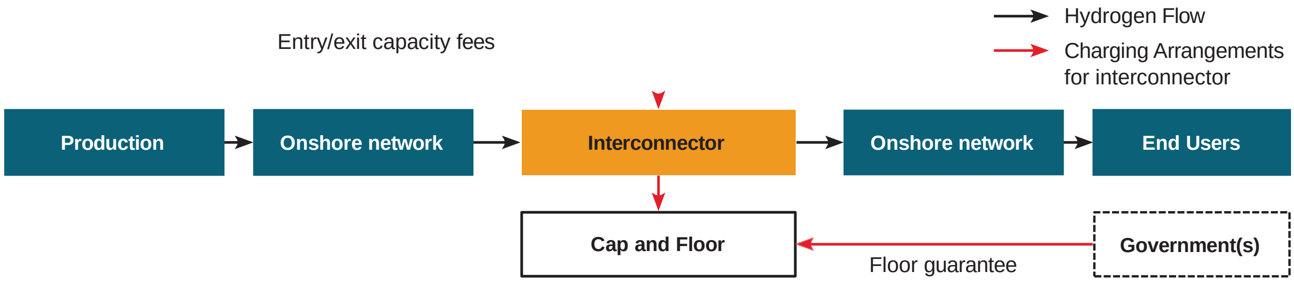



Figure 43
Cap and Floor Model.

| Case | Development phase | Enduring phase |
|---|---|---|
| 1 | Cap and floor determines the charges that are applied for hydrogen flows through the interconnector. This process determines the charges that will be shared across customers and how much is paid by the Government(s) as the guarantor for the floor payment. | The low utilisations means that the Government(s) continue to be the guarantor of the floor payment. |
| 2 | | The increased demand means that there is sufficient, stable and sizeable customer base for the charges to be spread efficiently for the Government(s) to withdraw its guarantor role on the floor payment. |
| 3 | As per scenario 1, however, the Government(s) would be required to contribute a lower amount to the floor given the reduced customer base. | The increased demand means that there is sufficient, stable and sizeable customer base for the charges to be spread efficiently for the Government(s) to withdraw its guarantor role on the floor payment. |
| 4 | | The low utilisations means that the Government(s) continue to be the guarantor of the floor payment. |

Table 20
Cap and Floor Model.

It would be the role of this organisation(s) to assess the full life costs (including DEVEX, CAPEX and OPEX information) for the project to determine the costs that are economic and efficient, and therefore the associated cap and floor levels.

The charges would be shared across customers and in the development phase, the Government(s) could act as the guarantor for the floor payment to allow for charges to support the development of the hydrogen market.

The framework could include a mechanism for the cap and floor levels to be reviewed on an agreed incremental basis, for example every five years to determine if the levels are still economic and efficient or require adjustment taking in consideration how the hydrogen market is developing.

In the longer term, depending on how the hydrogen market develops, the role of Government(s) as a guarantor could be reduced or removed once there are sufficient customers for the costs to be shared.

## A.5.5 Contracts for difference

Under this model, the investor receives revenue certainty through an agreed strike price that is an agreed price that if the market price is below the strike price, an external funding provider will pay the difference to the asset owner between the strike price and the market price. If the price is above the strike price, the asset owner returns the surplus. This model has been adopted in the UK for several electricity generation assets, for example offshore wind and Hinkley Point C nuclear power station; it has also been used for the UK hydrogen production facilities funded through the Hydrogen Business Models.

Whilst this model has been used for generation assets, it has not been used for network assets.

The external funding provider would either be the Government(s) or an appointed organisation that would undertake an assessment of the project cost information to determine costs are economic and efficient, and therefore should be included within the strike price assessment. The market price would be set at the level that is being paid by customers or through the utilisation of a reasonable counterfactual value and the Government(s) would pay the difference. In addition to the strike price, the Government(s) would act as capacity guarantees to ensure a minimum payment is received by the asset owner to recover economic and efficient costs.

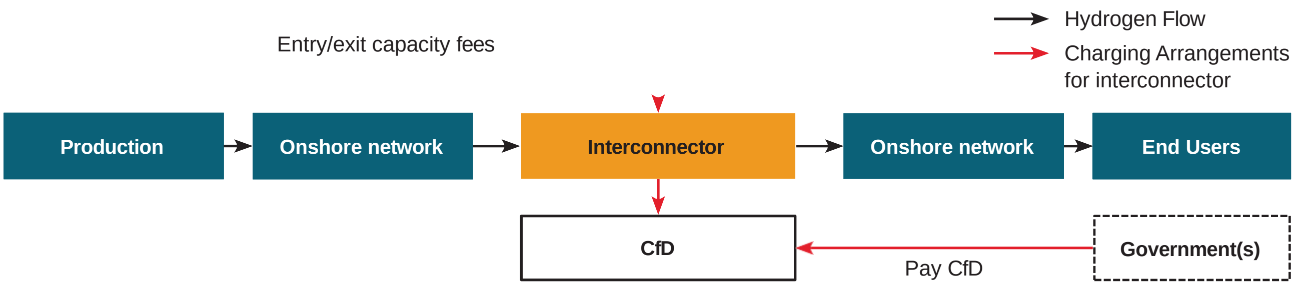



Figure 44
Contracts for difference.

| Case | Development phase | Enduring phase |
|---|---|---|
| 1 | Strike price is determined and Government(s) are the guarantor for the CfD. Government(s) act as capacity | Strike price is determined and Government(s) are the guarantor for the CfD. Government(s) act as capacity guarantee. |
| 2 | Strike price is determined and Government(s) are the guarantor for the CfD. Government(s) act as capacity | Strike price is determined and Government(s) are the guarantor for the CfD. Reduced need for capacity guarantee. |
| 3 | As per scenario 1, however a lower capacity guarantee is required given the higher utilisation of the interconnector. | Strike price is determined and Government(s) are the guarantor for the CfD. Reduced need for capacity guarantee. |
| 4 | As per scenario 1, however a lower capacity guarantee is required given the higher utilisation of the interconnector. | Strike price is determined and Government(s) are the guarantor for the CfD. Reduced need for capacity guarantee. |

Table 21
Contracts for difference.

A mechanism would be included within the business model design such that when the hydrogen market is considered to be sufficiently developed, and there is less utilisation of the CfD over a defined duration, the mechanism is removed.

### A.5.6 OFTO Model

Under this model, the Owner and Operator of the interconnector receives an agreed revenue stream (covering the cost of the asset and financing) by an organisation for a specified period. The OFTO (Offshore transmission owner) Model is currently utilised for the development of UK offshore electricity transmission infrastructure. Under this model, the asset would be developed privately by an organisation that would provide detailed cost information to form the basis of the tender revenue stream calculation; it is not assumed that this model would include a competition for the ownership rights as per the original UK OFTO model.

The organisation that sets the revenue stream could be either or both Governments respectively, or organisations appointed this responsibility for example a regulator or TSO. The charges would be shared across customers and in the development phase, the Government(s) could act as the guarantor for the revenue stream to allow for charges to support the development of the hydrogen market. In the longer term, depending on how the hydrogen market develops, the role of Government(s) as a guarantor could be reduced or removed once there are sufficient customers for the costs to be shared.

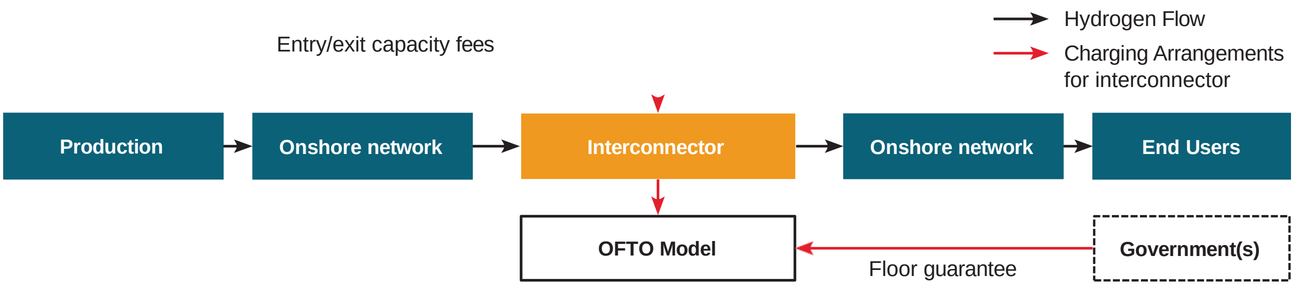



Figure 45
OFTO Model.

| Case | Development phase | Enduring phase |
|---|---|---|
| 1 | Tender revenue stream (TRS) determines the charges that are applied for hydrogen flows through the interconnector. This process determines the charges that will be shared across customers and how much is paid by the Government(s) as the guarantor for the TRS payment. | The lower utilisation results in the Government(s) continue to be the guarantor of the TRS payment. |
| 2 | | The increased demand means that there is sufficient, stable and sizeable customer base for the charges to be spread efficiently for the Government(s) to withdraw its guarantor role on the TRS payment. |
| 3 | As per case 1, however, the Government(s) would be required to contribute a lower amount to the TRS given the reduced customer base. | The increased demand means that there is sufficient, stable and sizeable customer base for the charges to be spread efficiently for the Government(s) to withdraw its guarantor role on the TRS payment. |
| 4 | | The lower utilisation results in the Government(s) continue to be the guarantor of the TRS payment. |

Table 22
OFTO Model.

### A.5.7 Government as a capacity booker

The Government(s) would reserve an agreed amount of capacity on the interconnector, which provides a baseline revenue.

This would be based upon a revenue of the costs of the asset to agree a reasonable level of return.

During the duration of the asset's life, the asset owner would be encouraged to resell this capacity, however, if they fail to secure a buyers for this capacity, the Government(s) would act as a capacity buyer of last resort.

The model could be designed such that support is 'staircased' down at agreed points to reflect specific points where the hydrogen market is considered to be more established.

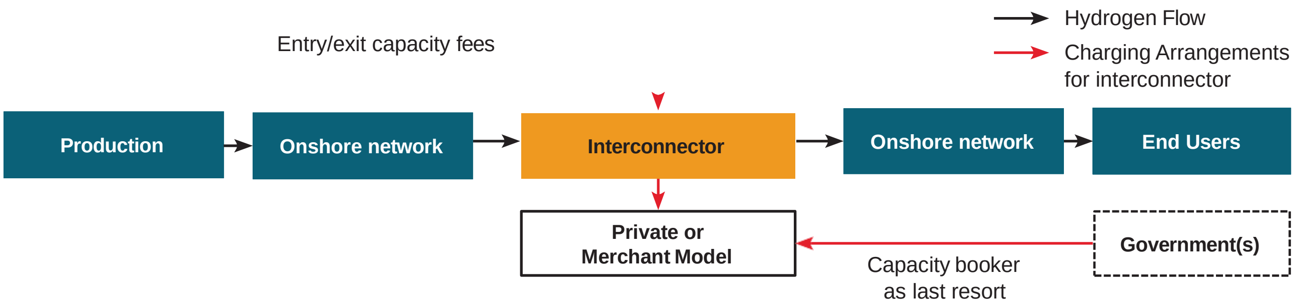



Figure 46
Government as a capacity booker.

| Case | Development phase | Enduring phase |
|---|---|---|
| 1 | The agreed capacity that the Government(s) purchase is agreed and implemented | The agreed capacity amount is likely to remain at a similar level. |
| 2 | | The agreed capacity amount is reduced. |
| 3 | As per case 1, however, the Government(s) would be required to contribute a lower amount to the TRS given the reduced customer base. | The agreed capacity amount is reduced. |

Table 22
Government as a capacity booker.

## A.6 Assessment summary

An assessment has been undertaken against all the factors as detailed in the following sections.

Each of the business models have been scored for each factor to assess how the risks under the different cases have been managed.

The scoring has been applied using the following approach:

1. the adoption of the business model fully resolves the risks identified.
2. the business model adoption partially resolves the risks, however, some risks remain.
3. significant risk remains for the assessment factor after the business model is applied.

Table 25 provides an overview of the assessment for the Value for Money and Investable factors; the remaining factors assessment is detailed in Table 25.

The overall scoring is summarised in Table 24.

| Model | Value for Money | Investable | Promotes market development | Compatible | Avoids complexity | Suitable for future pipeline | Reduces support over time |
|---|---|---|---|---|---|---|---|
| Public Ownership models (UK/German Gov Ownership and Joint UK/German Ownership) | 2 | 3 | 2 | 2 | 3 | 2 | 2 |
| Co-investment by Government(s) | 3 | 2 | 2 | 2 | 2 | 2 | 2 |
| RAB | 2 | 2 | 1 | 1 | 2 | 1 | 2 |
| Cap and Floor | 2 | 2 | 2 | 2 | 2 | 1 | 3 |
| CfD | 3 | 2 | 2 | 2 | 2 | 2 | 3 |
| Government as capacity booker | 2 | 2 | 2 | 3 | 2 | 3 | 3 |
| OFTO | 2 | 2 | 2 | 2 | 2 | 1 | 3 |
| Merchant Model | 1 | 3 | 3 | 2 | 1 | N/A | N/A |

Table 24
Assessment summary

| Model | Value for Money | Investable | Wider Considerations |
|---|---|---|---|
| Public Ownership models (UK/ German Gov Ownership and Joint UK/German Ownership) | 3 | 3 | |
| | – The respective Governments would be responsible for the full funding of the interconnector and therefore exposed to the full demand uncertainty risks.<br>– Tariffs above the cost of the investment would be returned to consumers, however, the scale of this would be subject to market factors.<br>– The opportunity of innovation and competition that would be expected from private developers whom are experienced in developing similar infrastructure is not utilised and therefore could result in the project cost/cost of infrastructure being higher than under a private model.<br>– If the model is later transferred to one of the private ownership models through a market tendering exercise, there would be the opportunity for the respective Governments to recover some (or all) of the initial investment cost. | – The respective Governments are exposed to the full risks of the project.<br>– This model could be used in the short term to support the development of the infrastructure and then could be transferred to one of the private models. This transfer could occur once major risks are reduced in their impact, for example demand uncertainty. | – Consideration to be given as to whether the newly established GB Energy would be an appropriate vehicle for the GB public ownership element. |
| Co-investment by Government(s) | 3 | 2 | |
| | – The respective Governments would be responsible for the half of funding of the interconnector and therefore exposed to the half of the demand uncertainty risks.<br>– For the Government share, the tariffs above the cost of the investment are returned to consumers, however, the scale of this would be subject to market factors.<br>– The opportunity of innovation and competition that would be expected from private developers whom are experienced in developing similar infrastructure is not utilised and therefore could result in the project cost/ cost of infrastructure being higher than under a private model.<br>– If the model is later transferred to be fully under one of the private ownership models, there would be the opportunity for the respective Governments to recover some (or all) of the initial investment cost. | Investor perspective<br>– Co-investment shares the risks between the investor and the Governments, and therefore reduces the financial risk exposure of financial investment of the private share.<br>Government perspective<br>– The Governments are exposed to half of the demand/supply uncertainty risk.<br>– This model could be used in the short term to support the development of the infrastructure and then could be transferred to one of the private models. This transfer could occur once major risks are reduced in their impact, for example demand uncertainty. | – Consideration would be needed as to how this model is established and the roles/responsibilities of the respective parties.<br>– Consideration would be needed as to the split between how the revenues are shared between the Government and non-Government investment. |
| RAB | 2 | 2 | |
| | – The RAB guarantee will be set based on actual project costs plus an allowed return and therefore ensuring that the project’s cost is efficient.<br>– The recovery of the allowed revenue profile could be shaped to match the profile of the expect hydrogen market development.<br>– The Government(s) will only be required to provide the guarantee and will therefore have certainty over their financial exposure during the project.<br>– Costs associated with the capacity guarantee will need to be recovered either through subsidies or another mechanism in the absence of demand. This support is likely to be higher in the initial phases to manage the commercial impact on the offtakers and depending on how the hydrogen market develops, may reduce over time. | – The model is well understood model as it has been deployed on other assets.<br>– It provides a stable view of the revenue that will be received, which is not subject to the demand uncertainty. The RAB Guarantee provides a level of revenue certainty to the interconnector owner.<br>– Given the emerging market, the RAB guarantee partially manages risk associated with demand uncertainty.<br>– The revenue collection contract under the RAB model would result in balance of risks between developer and offtakers that drives greater efficiency in delivery. | – Demand uncertainty risk remains for the market as a whole as offtake agreements will still be required for hydrogen trading to have a customer base to recover charges.<br>– Supply uncertainty is not fully resolved through the capacity guarantee unless mechanisms are put in place to ensure that the agreed capacity is available irrespective of demand uncertainty.<br>– A regulator will need to be appointed and a counterparty will need to be appointed for the guarantee.<br>– Consideration needs to be given to how the capacity payment is recovered, specifically whether recovered through offtakers, consumer bills or taxation and how this is spread between GB and German consumers. |

Table 25

Priority 1 assessment factors evaluation.

| Model | Value for Money | Investable | Wider Considerations |
|---|---|---|---|
| Cap and floor | 2 | 2 | |
| | – The cap and floor will be set based on actual project costs plus an allowed return. The Government(s) will only be required to provide the capacity guarantee up to the 'floor' and therefore has certainty over the exposure during the project.<br>– Depending on how the hydrogen market develops, a protection would be in place (the cap) that allows for initial investment fees to be recovered if excessive returns on capacity sales were being made. Any returns above the 'Cap' could be recovered against the initial capacity guarantee, enabling the opportunity to recover the initial investment.<br>– Costs associated with the capacity guarantee will need to be recovered either through subsidies or another mechanism in the absence of demand. This support is likely to be higher in the initial phases to manage the commercial impact on the offtakers and depending on how the hydrogen market develops, may reduce over time. | – This is a well understood model that has been deployed on other assets.<br>– The 'floor' provides a minimum level of revenue certainty to the interconnector owner of the revenue that will be received. It is assumed that the floor will provide a reasonable return. Given the emerging market, the floor partially manages risk associated with demand uncertainty.<br>– Making returns above the floor will be dependent on the interconnector flows, which will be subject to demand/supply factors.<br>– Utilisation of the cap reduces the revenue potential that could be achieved through a merchant model in a highly developed hydrogen market. Whilst this can be managed through an agreed frequency of review, the cap will need to continuously reflect the risks taken by consumers in the initial phases. | As per RAB model |
| CfD | 3 | 2 | |
| | – The CfD and Capacity Guarantee would be allocated in a similar manner to the UK HPBMs. It would be based on project specific cost information and therefore reflection of the required investment plus an additional revenue allowance.<br>– A counterfactual will be needed to determine what would be an appropriate strike price and premium to operate the pipeline. Given the differences in how a hydrogen pipeline may need to operate compared to alternative options, there may be limited information to provide an informed view on the required premium and/or the strike price to inform the model.<br>– Costs associated with the capacity guarantee will need to be recovered either through subsidies or another mechanism in the absence of demand. This support is likely to be higher in the initial phases to manage the commercial impact on the offtakers and depending on how the hydrogen market develops, may reduce over time. | – The Capacity Guarantee is critical to the CfD business model approach providing the investor with a level of certainty over the expected revenue to be received.<br>– This model has not previously been used for a transmission assets, however, it has widely been used for generation assets. Given that it has not been used on other transmission assets, it may be challenging to set a counterfactural for a strike price.<br>– Typically, CfD contracts are for 15 years, whereas other models are designed to last for longer periods; an exception to this is the 35-year CfD for Hinkley Point C. If the contract duration was to remain in line with 15 years, this may not manage the risks sufficiently for the investor.<br>– Compared to other models (i.e. RAB model) the cost recovery would occur post construction, which results in the developer taking on greater risk allocation and potentially resulting in construction overruns. | As per RAB model. |
| Government as capacity booker | 2 | 2 | |
| | – Once the maximum level of capacity that the Government is expected to book is determined, the Government would have certainty over the amount of exposure that they be subjected to. | – Would provide a level of certainty over the revenue that is expected to be recovered. | As per RAB model. |
| OFTO | 2 | 2 | |
| | – The OFTO guarantee will be set based on actual project costs plus an allowed return.<br>– The Government(s) will only be required to provide the guarantee and therefore has certainty over the exposure during the project.<br>– Costs associated with the capacity guarantee will need to be recovered either through subsidies or another mechanism in the absence of demand. This support is likely to be higher in the initial phases to manage the commercial impact on the offtakers and depending on how the hydrogen market develops, may reduce over time. | – It is a well understood model that has been deployed on other assets and generally considered to be low risk model.<br>– The OFTO model is designed to provide a stable view of the revenue that will be received, which is not subject to the demand uncertainty. The OFTO Guarantee provides a level of revenue certainty to the interconnector owner. It is assumed that the guarantee will provide a reasonable return.<br>– Given the emerging market, the OFTO guarantee partially manages risk associated with demand uncertainty. | As per RAB model, plus:<br>– Typically, this model has been used for the tendering of GB offshore transmission assets, this model could be used well as a second phase approach if a public model was selected |
| Merchant Model | 1 | 3 | |
| | – Compared to the other models, this model would result in the lowest consumer/bill impact as no business model support funding would be provided.<br>– The lack of support to manage the demand uncertainty, is likely to prevent investment and therefore, may limit the development of the hydrogen markets, and as a result the carbon reduction impact in the respective countries. | – Fully financed by private sector and therefore there are no requirements for public funding.<br>– The asset owner would be fully exposed to demand and supply risks as to be able to recover the investment they are likely to have to have higher charges. As a result, offtakers may resort to alternative transportation options. Overall, the exposure to the demand risks would create significant revenue uncertainty that is likely to prevent investment. | – Competition from other more investable energy projects may mean this project would struggle to find investment |

Table 25

Priority 1 assessment factors evaluation.

### A.6.2 Priority 2 & 3 assessment factors

| Model | Priority 2 | | | Priority 3 | |
|---|---|---|---|---|---|
| | **Promotes market development** | **Compatible** | **Avoids unnecessary complexity** | **Suitable for future pipeline(s)** | **Reduces support over time** |
| UK or German Government Ownership & Joint UK / German Government Ownership | 2 | 2 | 3 | 2 | 2 |
| | Potentially lower cost of capital for the infrastructure may enable lower network charges and enable entry of more market participants. However, may require initially high public funding and new public structures which may delay process in the beginning.<br>Model design should include a path to full privatisation as the market development progresses. | UK: There are limited examples of Government ownership of infrastructure assets, however, the introduction of GB Energy could be a potential ownership option. Public ownership could be aligned with the onshore RAB model once the charging implications are understood.<br>Germany: If a Government were to own the infrastructure, strict governance structures would need to be introduced to ensure that operations are independent of political influence and in line with regulatory requirements. Would constitute a significant deviation from the onshore network. | Complexity in the beginning may be considerable, both between the two Governments in building a joint structure as well as in interplay with market actors. However, may enable a trade-off with lower cost of project implementation over time. | Model is not suited to future pipelines as it creates an increased burden on respective Governments' public purse. Further, the development of future pipelines would likely be contingent on a well-developed needs case that justifies further investment, which would suggest that there is an opportunity for private investment/market competition to develop the project. | Support may be phased out as asset is transitioned to private ownership. The timing of the transition will be dependent on how the market develops. |
| Co-investment by Government(s) | 2 | 2 | 2 | 2 | 2 |
| | Potentially lower cost of capital for the infrastructure may enable lower network charges and enable entry of more market participants, as state assumes a portion of the risk. May require high public funding but would likely be easier to implement than full public ownership as this model may build on existing structures e.g. TSOs Consideration would be needed on how network charges are set and how they influence market development on both sides. Model should include a path to full privatisation as market progresses. | UK: There are limited examples of Government ownership of infrastructure assets, however, the introduction of GB Energy could be a potential ownership option. Public ownership could be aligned with the onshore RAB model once the charging implications are understood.<br>German: Different ownership model than onshore network (privately owned) but may be compatible nevertheless. In Germany, other types of infrastructure (e.g. transport) are often financed through various models of public-private partnerships | Less complex than full public ownership as the model may build on existing structures, however UK and DE would need to agree on their respective share of investments.<br>On German side public co-investments are not covered by public spending ceiling, which may facilitate allocation of funds. | Model is not suited to future pipelines as it creates an increased burden on respective Governments' public purse. Further, the development of future pipelines would likely be contingent on a well-developed needs case that justifies further investment, which would suggest that there is an opportunity for private investment/market competition to develop the project. | Transition to full private ownership is possible, if utilisation in enduring phase is given. |
| RAB | 1 | 1 | 2 | 1 | 2 |
| | This model has good precedence in the natural gas sector and would facilitate transition and/or fuel switch from fossil technologies to hydrogen as well as the entry of new market participants. The model ensures cost recuperation and stable long-term cash flows which increases attractiveness for investors. | UK: The principles of this model would align with the onshore model currently in development, which is also the RAB model.<br>German: The principles of this model would align with the onshore model, which is similar (regulated fees, long-term amortisation, mechanism for cost recovery) to the RAB model but not identical (RAB typically no precisely defined time frame for amortisation, typically no federal compensation if amortisation is not achieved) | While RAB model itself can be implemented swiftly, the necessary public guarantee mechanism would add a layer of complexity. Legal framework, organisational responsibility, covered asset based, time plan, exit options, risk-sharing would all have to be jointly considered and decided. | Model design allows for the approach to be transferred over to future interconnectors projects. | Guarantees may be capped and shared between the private operators and the public authorities, e.g. through a retention to be paid by private operator. |
| Cap and floor | 2 | 2 | 2 | 1 | 3 |
| | This model can ensure a predictable return through the floor, which facilitates market entry for producers and shippers, as investors have a certain level of security. Compatibility with domestic production support mechanisms in the UK may incentivise market entry of additional producers when domestic demand is satisfied. Supply and demand side risks are still present, however, and therefore pose risk to public guarantor and may require additional support instruments. | UK: Model principles for the onshore and offshore assets would generally be aligned.<br>DE: Model principles do not align with the management of the onshore network. However, the approach is quite similar to CfD approach which enjoys support by Government and could be applied in Germany. | The model would require political agreement regarding the regulatory and organisational responsibility of cap/floor setting. This would add some complexity in the ramp-up phase | Model design allows for the approach to be transferred over to future interconnectors projects with potential for model to be allocated through a competitive window approach. | Actual revenue stream depends on utilisation. Low utilisation may require continued public support; strong market development may minimise support. |

Table 26 Priority factors 2 & 3 assessment factors evaluation.

| Model | Priority 2 | | | Priority 3 | |
|---|---|---|---|---|---|
| | **Promotes market development** | **Compatible** | **Avoids unnecessary complexity** | **Suitable for future pipeline(s)** | **Reduces support over time** |
| CfD | 2 | 2 | 2 | 2 | 3 |
| | Narrative as per Cap and Floor assessment | UK: Model principles for the onshore and offshore assets would generally be aligned.<br>DE: Model principles do not align with the principles of the onshore network. However, CfD approach enjoys support in Germany. | The model would require political agreement regarding the regulatory and organisational responsibility of strike price setting and for provision of the capacity guarantee. This would add some complexity in the ramp-up phase | Model design allows for the approach to be transferred over to future interconnectors projects.<br>Depending on how developed the future hydrogen market is at the point of the future pipelines coming forward, a counterfactual may still be needed to determine what would be an appropriate strike price and premium to operate the pipeline. | Support/difference to strike price depends on hydrogen market development and utilisation of interconnector, so there is a risk, that external funding provider cannot reduce support over time or has to increase support in example case 4. |
| Government as a capacity booker | 2 | 3 | 2 | 3 | 3 |
| | Narrative as per Cap and Floor assessment | UK: Model does not align with the onshore model of RAB.<br>DE: Model principles do not align with onshore network and it could be challenging to secure support if Government acts as buyer of last resort. This could be risky if not matched by offtake. | The model would require political agreement regarding the capacity secured. This would add some complexity in the ramp-up phase | More complicated model to transfer as would need to consider the interaction between different assets and whether there is a minimum level of capacity across all assets rather than on a per asset basis. | Support could be stepped down through a staircasing of the capacity booked, this will be subject to the development of the hydrogen market |
| OFTO Model | 2 | 2 | 2 | 1 | 3 |
| | This model can ensure a predictable return, which facilitates market entry for producers and shippers, as investors have a certain level of security. Compatibility with domestic support mechanisms in DE and UK may incentivise market entry of additional producers when domestic demand is satisfied. Regulatory/ organisational responsibility of floor setting has to be considered. Supply and demand side risks are still present, however, and therefore pose risk to public guarantor and may require additional support instruments. | UK: Model principles for the onshore and offshore assets would generally be aligned.<br>DE: Model principles do not align with the management of the onshore network. However, the approach is quite similar to CfD approach which enjoys support by Government. | The model would require political agreement regarding the regulatory and organisational responsibility of the setting of the revenue stream. This would add some complexity in the ramp-up phase | Model design allows for the approach to be transferred over to future interconnectors projects. | Actual revenue stream depends on utilisation. Low utilisation may require continued public support; strong market development may minimize support. |
| Merchant model | 3 | 2 | 1 | N/A | N/A |
| | Both supply and demand uncertainty would increase cost of financing. High CAPEX for interconnector without any support mechanism would lead to prohibitively high network charges, considerably impairing market development. | UK: As seen with electricity interconnectors, merchant and RAB model can be deployed together, however the revenue uncertainty could act as a barrier.<br>DE: Model principles for the onshore and offshore assets would generally be aligned but risk of monopoly. If there is only one interconnector available, it could potentially be owned and operated by a single private investor/ company/ consortium, leading to concerns about monopoly power. | Low complexity for implementation, however, market development may not proceed overall. | N/A | N/A |

Table 26 Priority factors 2 & 3 assessment factors evaluation.

### A.6.3 Wider considerations

During the assessment, the following factors, in Table 27, were identified as requiring further consideration in the design of the business model across all of the business models.

## A.7 Risks remaining after business model

As part of the assessment, the project has identified the risks that are likely to remain after the business model is applied, these are presented in Figure 48.

For the interconnector element, the significant risks are predominantly reduced through the development of the business model as the model (and the associated guarantee) provides greater certainty of revenues.

| Factor | Considerations | |
|---|---|---|
| Value for money | Potential for competition | The design of several of the models allow for the possibility of competing the project concept, either at early or late stage of development. This would mean that the respective Governments could progress the development to either an early development phase (i.e. an initial concept with connection locations and size as) or close to operation and then hold a tendering event allowing project developers to submit bids to secure the asset, in a similar style to the UK's offshore transmission assets. This could allow for the project to be developed to a sufficient level to reduce some of the risks (particularly around offtakers and production capacity) and potential to recover some of the vested development IP on behalf of the respective Governments. This could be an option if private investment is not forthcoming or is not developing the project in line with identified requirements. |
| Promotes market development | Interaction with charging regimes | Consideration will be needed on how network charges are set and how they influence market development on both sides. |
| Compatibility | Aquaductus business model alignment | Compatibility with Aquaductus would need further consideration (particularly the approval of phase 2 design) to ensure the investment approaches are aligned. |
| | UK Onshore planning | From a UK perspective, the location and capacity of interconnectors would need to be explored through the onshore network planning activities and the SSEP to ensure alignment in infrastructure build out and the hydrogen production capacity. |
| | UK production funding | UK hydrogen production that is funded through the HPBM or NZHF would not be eligible for export. If this policy was to change, consideration would need to be given as to whether there is double subsidisation of the hydrogen market. |
| Suitable for future pipeline(s) | Guarantee allocation | If the guarantee mechanisms only cover fixed asset base of initial interconnector, it has to be considered if this would hamper development of potential further interconnection capacity or if the guarantee mechanism could dynamically cover additional interconnection capacities depending on the hydrogen markets develop. However, the initial interconnector capacity would be required to capture the first of a kind project risks and would have to account for all potential future market entries of producers/offtakers which may place burden on the public guarantee mechanism due to low utilisation in ramp-up phase. |

Table 27

Wider considerations assessment.

However, some of the significant risks, as identified within Appendix A.3, are not managed through the deployment of the interconnector business model and therefore continue to pose challenges to the development of the interconnector.

These risks include those associated with the end user, thereby offtakers are unwilling to lock into long term contracts whilst the hydrogen market is still in development.

This as a result continues to the create the risk of lower interconnector utilisation than expected and therefore increases the guarantee impact on the respective Governments. Similarly, challenges remain for the production element of the supply chain.

This includes that the domestically produced hydrogen is not competitive compared to alternatives and/or there is insufficient domestic production capacity and therefore there is lower supply realisation through the pipeline than expected.

This risk can be partially mitigated through long term offtaker contracts that provide certainty. Further, the value chain is subject to risks associated with the deployment timeline of the respective GB and German onshore networks to ensure the flow of hydrogen between production and end use.

Therefore, during the implementation of the model, the respective Governments will need to consider how these risks are managed.

Whilst these are significant risks that will need to be managed by mechanisms outside of the interconnector business model, these risks are not exclusive to the UK-German interconnector project and would apply to other similar interconnector projects.

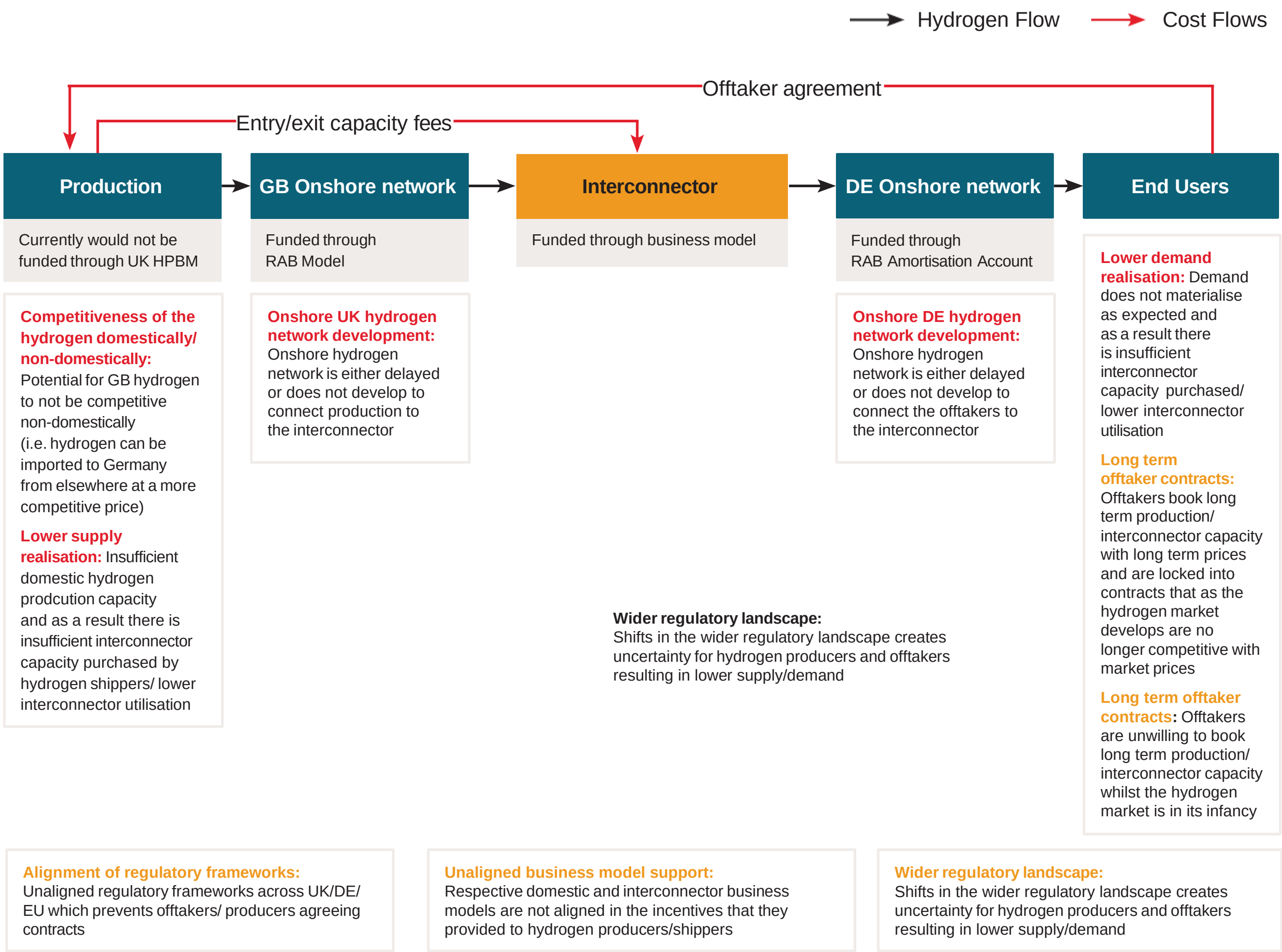



Table 47

Remaining risks after interconnector business model applied.

## A.8 Conclusions

Whilst the business model options have the potential to manage some of the key risks for the interconnector, several significant risks remain across the wider hydrogen value chain.

The uncertainty associated with the offtaker demand and production capacity as well as the subsequent connecting onshore network.

Unmitigated these risks could result in low utilisation of the interconnector and therefore a significant risk for the Government(s) of limited recovery against the provided guarantee revenue provided.

To manage this risk by stimulating the utilisation of the interconnector, securing offtake agreements and interconnector capacity ahead of financial investment decision will be necessary.

Certainty over the offtaker agreements should in turn provide greater confidence to the production and network development elements to support their development.

Therefore, this study recommends that offtaker engagement is undertaken to examine the potential for early long-term offtake agreements.

Given the engagement required between offtakers and production facilities, it is also recommended that the Governments explore the best mechanism to support the convening of the market.

In terms of the interconnector business model, given the status of technical design, which is currently at concept stage, it is too early to rule out or select a preferred business model options of those that have been assessed.

Once there is greater certainty on the route and associated technical parameters, specifically capacity, as well engagement, a detailed assessment of the models should be undertaken.

Further, in parallel, initial engagement should be undertaken with potential project developers to understand their perspective on the interconnector delivery risks and whether private investment would be forthcoming to deliver the asset.

Across all of the interconnector business models, there is the need to explore the scale of potential guarantee support that may be required to manage the revenue uncertainty risk during the development and enduring stages.

**Once there is greater certainty on the route and associated technical parameters, specifically capacity, as well engagement, a detailed assessment of the models should be undertaken.**

This will require full lifecycle cost information, particularly CAPEX and OPEX, and technical information, including the pipeline size and operating requirements, as well as a greater understanding of the potential utilisation scenarios of the interconnector, including potential offtakers and offtaker agreements.

A detailed assessment will be needed of whether the guarantee approach, including a review of the subsidisation (UK onshore network approach) or an amortisation account (German onshore network approach) options.

To inform the detailed business model design, a decision is required on whether the business model is designed as one joint model between the connecting countries or whether models are developed by the individual connecting countries with agreed funding responsibilities between the respective Governments.

Underpinning this decision will require the agreement on the effort sharing and organisational responsibilities between the two countries to support the development of the interconnector, particularly in the event of a public ownership model.

For the option that involves a connection into the AquaDuctus system, a decision will be needed on how the AquaDuctus funding is considered within the business model.

For the option that connects to the Netherlands or Belgium, an agreement will be needed between the three Government (UK, German and Dutch/Belgian) to confirm the funding approach and the associated responsibilities.

This will also be the case for any further development of other countries wanting to participate within utilising the interconnector.

Finally, there is a trade-off between operational and commercial requirements of the interconnector. The decision on the interconnector's size will be driven by several factors including near term and long term demand, operational requirements, deliverability and cost.

As the hydrogen market is in development, the demand for the interconnector is expected to evolve as the hydrogen market develops.

Therefore, there is likely to be a differential between near term and long term demand, however, there will be technical restrictions on how the interconnector will be able to operate based on the size.

As a result, an assessment will need to be undertaken to determine the feasible operating requirements based on both near term and long term demand.

**As the hydrogen market is in development, the demand for the interconnector is expected to evolve as the hydrogen market develops.**

# B

# Appendix B: Commercial Arrangements

Similarly to the business model, further work is required associated with the hydrogen market arrangements between producers and offtakers as well as further clarity on the technical parameters of the interconnector before a complete assessment can be undertaken on the business model risks and potential guarantee that may be required.

## B.1 Linkage between the business model and network charging

Network charges are designed to recover the costs associated with developing, operating and decommissioning the interconnector.

This incorporates the following cost items: DEVEX, CAPEX, OPEX, DECOMMEX, depreciation, incentives, tax and any incentives placed on the operator as presented within Figure 48.

The exact structure of the costs that are to be recovered through the network charges will be dependent on the business model design as discussed in Appendix A.2.

As the hydrogen market is in early development, in the UK the domestic charging arrangements are currently in development alongside the hydrogen transport business models; there currently has been limited detail provided on the proposed.

For Germany, as detailed in Appendix B.3, the domestic charging arrangements are being developed as part of the wider EU Hydrogen and Decarbonised Gas Market Package.

Currently there has been no need to develop hydrogen charging in Germany.

This section provides an overview of the existing approach to charging for the current natural gas interconnectors and potential options for the arrangements that could be utilised for the UK and Germany interconnector.

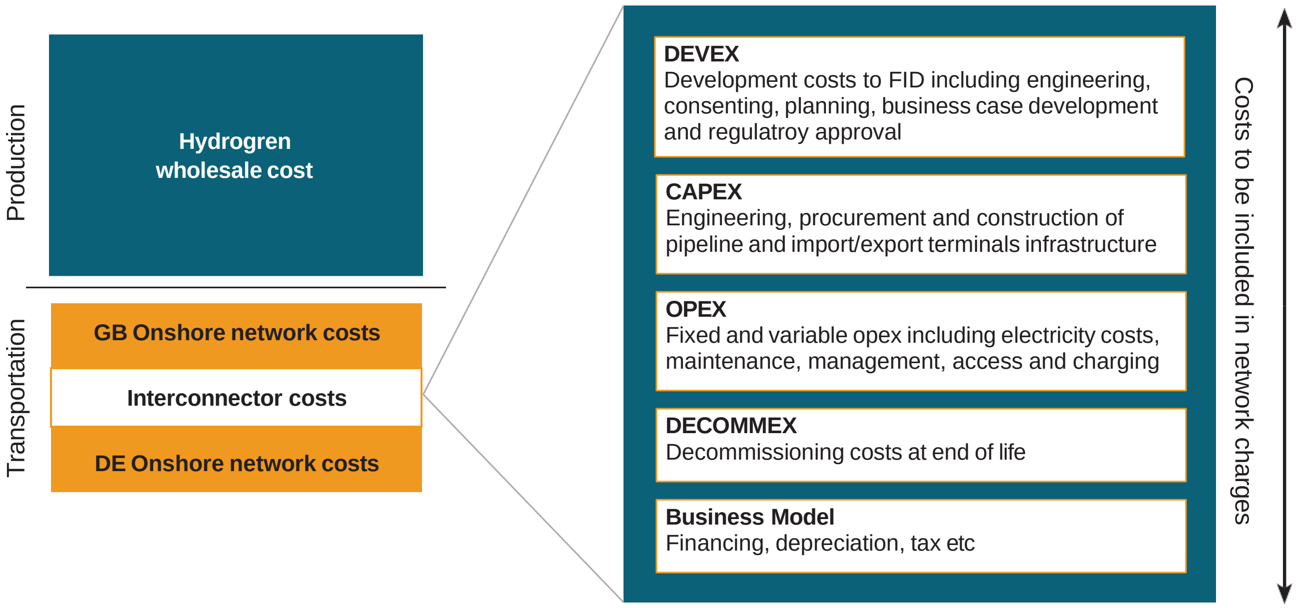



Figure 48

Scope of network charges.

## B.2 Current approach on natural gas interconnectors

To recover these costs, asset owners auction capacity on their interconnectors recovering the tariffs for the agreed capacity allocated.

Currently, these auctions can be held for multiple durations, i.e. annual, seasonal, quarterly, monthly and daily. These network charges are then incorporated into the overarching price incurred by the end user which are predominately domestic, industrial and commercial users whereas in the interconnector case, it will be the hydrogen industrial demand offtakers.

This section provides an overview of the current approach of natural gas interconnector charging, charging options and how charges will need to be managed during the development and enduring operational phases.

### B.2.1 Charging Approach

Currently interconnectors utilise auction platforms to provide entry and exit capacity for their interconnectors, which sets the associated tariffs for the interconnector in alignment with European Regulation of Commission Regulation (EU) 2017/459 also known as the Capacity Allocation Mechanism (CAM) Code.

The reserve tariffs, as discussed below, are approved by the respective regulators and are set based on a range of factors; these factors include market factors, the asset's cost structure, particularly CAPEX and OPEX and expected short-term and long-term demand. In several circumstances, booking incentives can be applied.

This includes transactions with three plus years of successive annual capacity products, bidirectional 10+ years of annual capacity products as well as within year annual/ season bidirectional products.

Currently interconnectors provide the following duration of charges for the various capacity frequencies:

- Annual: up to 15 years ahead
- Seasonal (offered as consecutive quarters of Calendar Q4 & Q1 and Q2 & Q3): up to 15 years ahead
- Quarterly: up to 15 years ahead
- Monthly: up to 1 year ahead

Capacity can either be purchased on a firm or interruptible basis and can also be set to indicate demand direction with charges higher in one direction compared to another.

For purchased capacity, the interconnector owners enter into Interconnector Access Agreements (IAA) with shippers as the contractual terms for the transportation of natural gas.

This details the commercial arrangements associated with invoicing, gas quality, claims and disputes processes and communication and exchange of information procedures.

This agreement is governed by the Interconnector Access Code (IAC) which covers transportation services, allocation of gas, balancing and trade notifications, charging, quality requirements and operating conditions. The IAC requires approval from the regulator(s).

The IAA and IAC allow for capacity to be sold in a secondary market, where those that have already purchased capacity through the primary market are able to sell their booked capacity to other market participants.

### B.2.2 Access Rules and Charging Methodologies

Natural Gas interconnectors are licenced and required to comply with both UK and European regulations. These regulations required the interconnector owners to publish their Access Rules, Charging Methodologies and their Charging Statements.

For the Charging Methodology, the licence requirements dictate that the licence must provide detailed information on an annual basis of the calculation of charges for access to the interconnector.

This includes charges associated with congestion management, ancillary services for the interconnector and the onshore system, and payments to users in the event of the loss of capacity.

The Methodology must be published for industry consultation for a minimum of 28 days and subsequently to secure approval of the Methodology, provide the regulator with a revised Methodology and associated stakeholder feedback.

The regulator has a maximum of three months to approve the Methodology; this review will be undertaken in accordance with the regulator's wider objectives on charging methodologies. Modifications to the approved Charging Methodology can be undertaken, subject to stakeholder consultation and regulatory approval.

As part of the Access licence requirements, the interconnectors are required to provide access and maintain detailed access records for seven years including the associated tariffs or charges and the associated conditions.

If it is not either technically or economically viable for capacity to be provided, current gas interconnectors are required to submit evidence to both the entity requiring the access and the regulator providing detailed evidence of the technical and/or economic challenges.

## B.3 Current EU regulations for hydrogen charging

On 4th August 2024, the EU legislative Hydrogen and Decarbonised Gas decarbonisation package came into force, comprising of the Regulation (EU) 2024/1789[63] on the internal markets for renewable gas, natural gas and hydrogen ("H2 Regulation") and Directive (EU) 2024/1788[64] on common rules for the internal markets for renewable gas, natural gas and hydrogen ("H2 Directive").

The Hydrogen Regulation and Directive updates the existing European gas market regulation, the Gas Regulation EC 715/2009 and the Gas Directive 2009/73/EC).

The H2 Regulation will apply from 5 February 2025 and EU Member States have time until 5th August 2026 to transpose the new rules of the Hydrogen Directive into national law.

The regulations focus on hydrogen's dedicated regulatory framework and infrastructure.

It establishes a regulatory framework for a staged development of a competitive dedicated hydrogen infrastructure.

This includes objective and non-discriminatory third-party access on the basis of regulated access tariffs for hydrogen networks and hydrogen storage units with a transition phase of negotiated access possible until 31st December 2032; as well as negotiated access for hydrogen terminals and obliging the hydrogen network operators to follow the general balancing rules as of 1st January 2033.

The Hydrogen Regulation and Directive encourages an integrated network planning for power, gas and hydrogen.

It aims to coordinate and plan the power, gas and hydrogen networks between Member States, regulators and operators on all levels.

It is creating an entity for European distribution system operators with mandatory participation for natural gas distribution network operators and voluntary participation for hydrogen distribution network operators.

The entity will also closely cooperate with the electricity and natural gas transmission network system operators and the network association for hydrogen transmission network operators, known as the European Network of Network Operators for Hydrogen (ENNOH), which is to be incorporated by 2027.

The ENNOH's focus will be on developing relevant hydrogen grid codes and developing EU-wide, non-binding ten-year network development plans for the hydrogen sector.

Article 59 of the Hydrogen Directive states that adjacent and affected hydrogen transmission network operators of interconnectors shall bear the costs of the project and may include them within their respective tariff systems, subject to approval by the regulatory authority.

If the hydrogen transmission network operators identify a substantial gap between benefits and costs, they may design a project plan, including a request for cross-border cost allocation (CBCA), and submit it jointly to the regulatory authorities concerned for joint approval.

The EU Hydrogen and Gas Package also mentioning specific rules for tariffs at import terminals operated under third-party access.

Transparent, objective, and non-discriminatory tariffs should apply at hydrogen storage facilities and import terminals.

Infrastructure under regulated third-party access (rTPA) should provide information on tariff derivation, tariff methodology, and tariff structure.

The Directive also insists that hydrogen storage and import terminal tariffs should be subject to approval of the national regulatory authority (NRA) – but can't be modified by the NRA if rTPA applies.

Tariffs should be published prior to their entry into force. The Directive stipulates that transparency on hydrogen supply tariffs and prices should also be ensured by suppliers for final customers. It includes information on the tariff name.[65]

## B.4 Charging options

The objectives of the charging regime will be to enable the interconnector owner to recover their costs plus a reasonable return and for the offtakers to receive economic charges that support their decarbonisation business case.

Further, the overarching principles associated with a charging regime are to ensure that they are clear in this objective, are shared with industry in a transparent manner, are non-discriminatory and therefore are fair in their application as well as being compliant with wider regulations in the respective countries.

For the emerging hydrogen market, it will also be important that the charging arrangements are able to evolve as the market develops with minimal market disruption.

There are several options for how the charging arrangements for the interconnector could be designed, these are summarised in Figure 49 and detailed below.

### B.4.1 Option 1 – Capacity Auctions

The option of auctions to purchase capacity is the approach undertaken by the current natural gas interconnectors. As described above, auctions are held for a variety of access durations.

The auctions are held on a market platform at defined points using dynamic pricing driven by several factors including the asset cost structure and market factors.

Whilst auctions are held, reserve prices are set which are approved by the respective regulators.

In adopting this approach, there are the following considerations:

- Auctions are only effective as a market-based mechanism when there is sufficient liquidity and participants to allow for competitive pricing. In the early development phase of the interconnector, depending on the demand from offtakers, there is a risk that there may be insufficient liquidity in the market.
- Depending on the confirmed demand from offtakers in the development phase, there is a risk that if there are limited market participants to socialise the interconnector cost in manner that is equitable for the interconnector developer, the tariffs set through this mechanism may act as a market barrier to offtaker agreements.
- As an interim, in the ramp-up phase, a first-come first-served approach for capacity allocation in a transparent and non-discriminatory process via an open market platform could be utilised. To ensure that this is economic and efficient as the market develops, a base range would need to be set for the charging arrangements to minimise any potential barriers. This facilitates market entry for first users and decreases bureaucratic effort. As soon as capacity becomes scarcer as the market progresses, the allocation of capacity could be transferred to the auction approach. These options are currently being explored through public consultation by NRA in Germany for the onshore network.

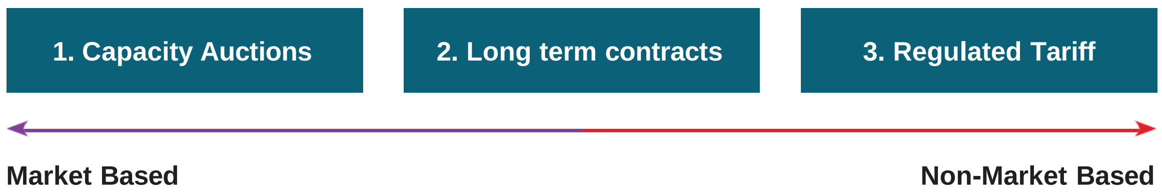



Figure 49
Charging approaches.

– This option could be implemented later in the asset's lifespan as the hydrogen market develops and there are a greater number of market participants. This should result in higher liquidity/market forces in determining the market price.

### B.4.2 Option 2 – Bilateral long-term contracts

Access to the interconnector and the associated network charges could be set based on bilateral long-term contracts, for example 15-year contracts between the shipper and the offtaker.

The tariffs would be set based on a transparent charging methodology, which would require regulatory approval.

The longer contract duration would provide greater certainty over the network tariffs and therefore could result in the asset owner providing reduced tariffs compared to those that would have been provided through shorter duration contracts.

In adopting this approach, there are the following considerations:

– The long-term contracts would be based on the costs reviewed as part of the business model implementation and would require a regulator to approve the charging methodologies.
– The nascent status of the hydrogen market may mean that shippers and offtakers are unwilling to sign up to long-term contracts unless they have long-term certainty over where the hydrogen will be coming from. However, is it possible in certain circumstances that market participants may want to secure long-term capacity. For example, if offtakers have signed long-term contracts, they may also want to secure long-term capacity to have greater certainty over the expected charges. Further, shippers may also have an interest in booking long-term capacity and then serving short-term H2 demand.
– Further, the approach to allocating the long-term contracts in the near term will need to take into consideration the expected profile of future demand. This will be necessary to determining how the tariffs in the initial operational period are socialised and evolve as demand grows.

### B.4.3 Option 3 – Regulated tariffs

A non-market-based approach is the option for a regulated tariff, which is set in alignment with the potential business model to allow for recovery of the interconnector costs and a sufficient rate of return.

This approach is similar to the grid tariffs that are being set by BNetzA for the onshore German hydrogen network and the GB retail market domestic price cap which sets a maximum tariff that consumers can be charged. The tariff would be based on project specific information with a regulator determining either setting parameters for a minimum and/or maximum tariff that could then be charged to end users.

In adopting this approach, there are the following considerations:

– As discussed, currently for natural gas interconnectors the regulator is involved in approving the network tariffs, however this approach would require greater involvement of the regulator in setting the network charges. This would require the regulator to have high visibility of the asset costs and operating procedures.
– Depending on the number of market participants which the tariffs are socialised amongst, there is a risk that tariffs set through this option may act as a market barrier to offtaker agreements as the network tariffs are high unless mitigations are implemented. Engagement with offtakers could be undertaken through consultation and market surveys to understand potential market barriers and the required mitigation actions.

## B.5 Option Considerations

### B.5.1 Combining Approaches

In designing the approach for the network tariffs, there is the possibility to adopt different approaches for different operational periods of the interconnectors' life span.

For example, an approach could be selected in the near term to manage potential risks in the early development phase and then move to another approach at a later point when the hydrogen market is more developed.

As presented in Figure 50, the regulated tariff, fully socialised and long-term contracts (with subsidy support) could be implemented in the development phase of the interconnector where there is greater uncertainty over demand.

Under these options, the tariffs would be set by the regulator and then, taking into account the potential subsidy, support would be shared amongst initial network users.

As the market develops and there is greater liquidity and locational factors influencing the network utilisation, auctions and location factors could be utilised to ensure that the tariffs are socialised across end users in an economic and efficient manner.

In a similar manner to the NZHF allocation, the intention to transition from a development charging option to a later model once certain criteria have been achieved could be signalled to end users during the design of the tariffs.

This would provide potential users with sufficient certainty over how the regime will evolve.

### B.5.2 Size of charging base and implications for the business model

As the hydrogen market is emerging the number of users in the initial operational period is likely to be lower than when the hydrogen market is mature.

This means that the pipeline is likely to be at a lower utilisation and the recovery of the network charges could create a market barrier for offtakers if they were exposed to tariffs that reflected the full asset costs.

As a result, an intervention is likely to be needed to reduce the early movers' exposure to the network costs. The UK and Germany have adopted different approaches to the guarantee for the respective onshore networks, which are detailed below.

**As the hydrogen market is emerging the number of users in the initial operational period is likely to be lower than when the hydrogen market is mature.**

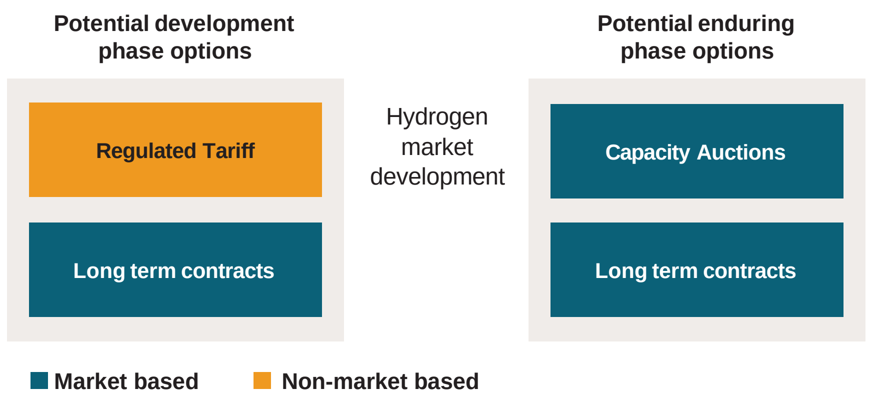



Figure 50
Potential transition of options.

For the purposes of the assessment, where a guarantee has been assumed within the mechanism design, the design is agnostic as to whether it is a subsidy or more long-term guarantee instrument, such as an amortisation account. However, when the design of the mechanism progresses, the approach to the guarantee will need to be considered in detail. The following provides a summary of the respective approaches being developed for the onshore networks:

1. Subsidy:
   The UK is proposing to adopt a subsidy through a hydrogen transport revenue support contract, which is countersigned by a UK Government arm's length organisation.
   This subsidy will effectively act as a top up mechanism covering the difference between the RAB model and the agreed network charges.
   The subsidy design is in development and will either be recovered through the Exchequer and/or a levy. This subsidy will be used in the early deployment of the hydrogen network to manage the impact of network charges on early adopters of hydrogen.
2. Amortisation account:
   Together with the market players, the German Government has developed a financing concept that incentivises private-sector investment and enables the hydrogen core network to be fully financed via network charges.
   The concept includes subsidiary financial protection by the state against unforeseeable developments and prevents very high charges from jeopardising the hydrogen ramp-up in the first few years.
   For this reason, the grid fees for hydrogen consumers are capped so that the initially high investment costs are not passed on, in full, to the few initial users. In the early ramp-up phase, the cap on the ramp-up fee results in a difference between high investment costs and low income from grid fees due to few initial users.
   This difference is booked in an amortisation account with interest.
   If more users are connected to the grid at a later date and the income from grid fees gradually exceeds the costs for grid construction and operation, the resulting shortfall in the amortisation account is offset and the account will balance itself over time.
   If the amortisation account is not balanced by 2055 for reasons that cannot be foreseen today, a subsidiary state guarantee will take effect.
   The federal Government will then make up the remaining shortfall and the operators of the hydrogen core network will contribute up to 24 per cent of the shortfall.
   A long-time frame was chosen for the amortisation account with the target year 2055 in order to ensure full financing from grid fees even if the hydrogen ramp-up is delayed.

A further option could be that the Government(s) enable a minimum level of capacity-bookings in the interconnector, by supporting long-term production contracts, such as under the German H2Global mechanism which organises a double auction via its own foundation and the German state bears any differences up to a certain limit between the purchase and sale price by financing the foundation.

This study recommends that further technical assessment and demand engagement is undertaken to understand the cost structure of the interconnector and potential end users during the development phase.

This information can then be utilised to determine the most appropriate mechanism to manage network costs during periods of lower offtakers.

### B.5.3 Other charging design considerations

In designing the charging arrangements, the following should be considered:

- Currently the charging methodologies for natural gas interconnectors are developed and approved on an annual basis. Following the design of the business model and greater certainty over the potential utilisation of the hydrogen interconnector, the frequency of setting the charging methodologies should be considered.
- The design of the charging arrangements for the GB onshore network are in early development and the tariffs for the interconnector will need to be developed in coordination with the onshore tariffs.
- Currently gas interconnectors keep records for all access and charging agreements for a duration of seven years. Given the support that is likely to be required in the development phase of the hydrogen market, this study recommends that this period is extended to ensure that there are sufficient records to support the implementation of business model support approach i.e. amortisation account.

## B.6 Conclusions

The approach to the charging regime is dependent on the structure of the business model and the associated interconnector total expenditure.

As noted within the business models, further technical information and market engagement is required to progress the business model design, which in turn can support the design of the charging arrangements.

There are several options that can be adopted for the charging arrangements, ranging from market-based approaches to non-market-based approaches.

In the near term, market-based charging approaches are less likely to be suited to a nascent hydrogen market as there will be limited wider market trading compared to that currently seen within the natural gas market which provides sufficient market signals for the current interconnector arrangements.

Regulated tariffs or bilateral contracts are likely to provide sufficient certainty for both the interconnector and offtakers.

Depending on how the hydrogen market develops, it may be appropriate to transition to a market-based approach when there is sufficient market liquidity.

**There are several options that can be adopted for the charging arrangements, ranging from market-based approaches to non-market-based approaches.**

Therefore, it is critical to ensure that the near-term model does not preclude the development of the future hydrogen market and continues to deliver value for the offtakers, interconnector owner and the Governments.

Further, a guarantee mechanism will be required at least in the near term to maintain charges at an economic level for offtakers as the hydrogen market develops.

As a result, this study recommends that in parallel to the business model design, the respective Governments agree on the overarching principles of the charging regime to progress a design that encourages early users of the interconnector as well as enabling greater utilisation of the interconnector in the future.

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C

# Appendix C: Regulatory Analysis

Development of economic and technical regulations are required across several areas including hydrogen standards, certification, technical and operating frameworks as well as a licencing framework for the interconnector and wider market participants.

## C.1.1 Introduction

The following appendix provides a summary of the economic and technical regulations for the UK and Germany with regards to a hydrogen interconnector.

As detailed in Section 3.7, the approach to regulation in the respective countries is driven by the wider policy and legislative landscape and therefore there are differences in the drivers and approaches to regulation, which is reflected in the following sections.

In relation to the scope of this study these sections focus on the following:

1. Market framework regulation in relation to interconnectors;
2. Technical regulations pertaining to the construction and operation of offshore pipelines and;
3. Low-carbon hydrogen standards and certification.

## C.1.2 UK Regulation

### C1.2.1 Economic Licencing

The regulatory landscape for natural gas and hydrogen is set out in the Gas Act 1986 and the Energy Act 2023.

Ofgem acts as the economic regulator for natural gas and has commenced activities regulating hydrogen, including the assessment of hydrogen projects undertaken by the existing natural gas networks and the design of the hydrogen transport business model.

Ofgem regulates the sector through licencing frameworks, which set out the roles and responsibilities of organisations within the energy sector; they fundamentally enable the regulator to ensure that the interests of current and future consumers are protected (whilst also enabling innovation and competition).

Based on the licencing framework, the regulator facilitates a process to allocate licences to appropriate organisations and will take actions to update the licences to ensure that they are in line with current policy, market, and technical requirements.

Acting as a transporter, shipper, supplier, and interconnector are licenced under separate licences; the existing unbundling rules mean that an interconnector operator cannot act as a shipper, supplier, or transporter.

As a consequence of hydrogen being captured by the definition of “gas” within the Gas Act 1986, a hydrogen interconnector would be subject to the licencing framework set out within that Act.

However, these licencing frameworks and associated regulatory requirements were developed with the trade of natural gas in mind and therefore may not be suitable for hydrogen, given the potential differences in a future hydrogen market and the commodity of hydrogen itself.

It is recommended that the UK Government should therefore review the suitability of the existing licencing framework for a hydrogen interconnector; this includes reviewing whether Ofgem should continue to act as the regulator for a hydrogen interconnector and whether the existing remit and powers of Ofgem provide sufficient clarity on their role.

Further, if a decision is taken to develop and grant a new interconnector licence for a hydrogen interconnector under the existing provisions of the Gas Act 1986, the UK Government and Ofgem would need to review the suitability of the existing gas interconnector licence and licence conditions to ensure that they align with the development of the hydrogen market and associated hydrogen policies.

This may result in either modifications to the existing licence or development of a new interconnector licence and licence conditions for hydrogen only. Notwithstanding the existing legislative framework for a hydrogen interconnector licence, the process associated with developing the licence and licence conditions itself may be time and resource intensive.

For the purposes of any business model support, the licencing framework will need to be in place ahead of the interconnector project taking FID. Firstly, this will have to incorporate the business model requirements within the licence.

This will ensure that the business model support conditions are formalised in a manner that provides the interconnector developer with certainty of the proposed support and the regulator with the ability to protect consumers in the event of non-delivery or poor performance by the licenced entity. Secondly, this is to provide the interconnector developer with confirmation of the wider regulatory framework, including charging, access, balancing, and codes compliance.

In terms of ownership unbundling, the existing unbundling rules contained within the provisions of the Gas Act 1986 will apply unless further action is taken.

This means that, as with the natural gas sector, a gas interconnector licence cannot also hold a gas transporter, gas supplier, or gas shipper licence.

Further legal analysis is needed to determine if these existing unbundling rules are of value, and to what extent an exemption from them may be possible or preferable given the nascent status of the hydrogen market.

#### C.1.2.2 Economic regulatory framework for the interconnector

Current energy sector licencing frameworks generally set out requirements associated with operational arrangements, charging, and access (specifically third-party access) requirements and compliance with codes included in licence conditions. This framework will also set out regional cooperation requirements as well as underpinning the information requirements for the business model.

The key elements of the regulatory framework for operating the interconnector include the codes that the interconnector must comply with, the access arrangements, the charging arrangements to recover the interconnector investment and finally the balancing arrangements.

Codes and the licencing framework are required to ensure the interconnector operates within economic and technical bounds and there is sufficient coordination with the users of the interconnector. Under The Gas Act 1986, the existing natural gas codes and access arrangements would apply to hydrogen.

The key code that existing interconnectors have to comply with is the Uniform Network Code, which includes a section on European Interconnection focussed on the interconnection points, providing the overarching regulatory framework managing the interactions between the GB system and EU member states.

It provides the framework for the following:

- Capacity Management:
  how capacity at the interconnection points is allocated, including the processes for auctions, bundling, and withdrawal of capacity.
- Nominations and Allocations:
  the framework for users to nominate the amount of gas they intend to flow through interconnection points and details how these nominations are matched and allocated to enable accurate and fair distribution of gas flows.
- Incremental Capacity:
  procedures for assessing demand for additional capacity, designing incremental capacity projects, consulting with stakeholders, and obtaining regulatory approval.
- Operational Rules:
  the operational rules, including the management of differences between nominated and actual gas flows through the Operational Balancing Account (OBA) and procedures for handling transportation constraints and emergencies.
- Financial Provisions:
  the charges for capacity and the fees for demand indication applications, ensuring transparency and fairness in financial transactions related to gas transportation.

The licencing framework requires that the licencee set out their access rules and charging rules, which must be reviewed on an annual basis to ensure that it aligns with relevant charging methodology objectives.

As part of the allocation of access to the interconnector, Interconnector Access Agreements (IAAs) between the interconnector operator and shippers are used to define the general terms and conditions to access interconnector capacity.

The national regulatory authorities of countries on either side of the interconnector must approve the IAA. This ensures coordination between the interconnector and onshore networks in the respective countries.

Once a shipper signs an IAA, it is then bound to the Interconnector Access Code (IAC) which outlines access rules for interconnector capacity in more detail, including arrangements for capacity allocation, balancing, charging, and system operation.

This study recommends that the existing natural gas arrangements are reviewed to determine their appropriateness for the developing hydrogen market.

In terms of charging rules, natural gas interconnector licences require interconnectors to submit a charging methodology for access to interconnectors which must be approved by the regulator. Charges are included in IAAs between interconnectors and shippers.

This process ensures that interconnectors do not charge monopoly prices to shippers and charges are transparent. This study recommends that these arrangements are reviewed to determine their appropriateness for a developing hydrogen market and hydrogen interconnector.

Further information is included in Appendix B on the potential commercial arrangements.

In interconnector access codes, it is typical that shippers are responsible for balancing on an hourly basis. This means ensuring gas entering the system is equal to gas taken out of the system.

### C.1.2.3 Pipeline construction, use, and decommissioning regulations

The regulatory framework for offshore oil and gas pipeline construction and use is mostly governed by the Petroleum Act 1998[66].

The North Sea Transition Authority (NSTA) serves as the UK regulator for the offshore oil, gas, hydrogen, and carbon storage sectors.

It is responsible for authorising the construction and operation of offshore pipelines within these industries in the UK's offshore areas, including the relevant territorial seas and the UK Continental Shelf (UKCS), as outlined in Part 3 of the Petroleum Act 1998.

The NSTA is the business name of the Oil and Gas Authority, a company given functions under the Energy Act 2016[67].

A Pipeline Works Authorisation (PWA) is required to construct and use new subsea pipelines in the UKCS and territorial seas.

PWA applications are made to the NSTA via the PWA Portal system, with supporting technical, operational, and geographical data that relate to the system operation and efficiency of pipelines to be authorised.

Throughout the PWA process, the NSTA consults relevant authorities, such as the HSE and the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED), to share relevant technical information and to seek input on the PWA application[68].

The Petroleum Act 1998 (Specified Pipelines) Order 2011, as amended[69] specifies a description of pipelines (for the purposes of section 24(2A) of the Petroleum Act 1998) for which a PWA is required. This includes pipelines "used in relation to" the exploration or exploitation of petroleum, the conveyance of hydrogen, and the unloading or storage offshore of oil gas, carbon dioxide, and hydrogen.

Part 4 of the Petroleum Act 1998 (applied to offshore carbon capture, usage and storage (CCUS) via section 30 of the Energy Act 2008[70], governs decommissioning of offshore installations and offshore pipelines.

The provisions for decommissioning of offshore oil and gas and CCUS installations protect the taxpayer from decommissioning liabilities. The Secretary of State, through OPRED, is generally the regulator although Scottish ministers have functions for decommissioning of CCUS infrastructure.

Part 4 of the Petroleum Act 1998 aims to ensure that those who have benefited from the exploitation or production of oil and gas bear the responsibility for decommissioning.

Section 29 of the Petroleum Act 1998 enables the Secretary of State to serve notices requiring the recipient to submit a costed decommissioning programme for approval and to carry it out.

On 6th September 2023, Order 2023[71] was laid before the UK Parliament, was approved and came into force on 27th September 2023.

This was an extension to the PWA regime, under the Petroleum Act 1998, to include offshore hydrogen pipelines, making the NSTA the consenting authority.

This amendment means that if offshore hydrogen pipelines are covered by Part 3 of the Act, they also fall under the decommissioning provisions in Part 4.

The change in legislation also extends the licensing regime of the Energy Act 2008 to designate hydrogen as a gas under section 24.

The Government also used the power in section 7(1) of the Energy Act 2008 to ensure the model clauses set out the Offshore Gas Storage and Unloading (Licensing) Regulations 2009[72] reflected this designation.

This enables the NSTA to issue offshore licences for activities listed under section 2(3) of that Act in respect of hydrogen, including offshore hydrogen storage. Additionally, the NSTA can consult with OPRED on decommissioning costs and repurposing existing offshore infrastructure for hydrogen transportation and storage.

OPRED administers the 2020 Offshore EIA Regulations and the Habitats Regulations.

The changes designate hydrogen as a gas under section 2(4) of the Energy Act 2008, bringing hydrogen pipelines and storage under the 2020 Offshore EIA Regulations and the Habitats Regulations, making OPRED the decommissioning and environmental regulator for offshore hydrogen transport and storage.

These changes enable the NSTA to grant PWAs for offshore hydrogen pipelines and issue storage licences, while OPRED manages the decommissioning regime.

This ensures new hydrogen pipelines and storage facilities fall within the existing environmental assessment and regulation framework, simplifying the approvals process.

#### C.1.2.4 Pipeline and storage environmental regulations

As noted above, the Petroleum Act 1998 is the principal legislation governing a consenting regime for submarine pipelines (Part 3), as well as decommissioning of offshore installations and pipelines (Part 4) in the territorial seas and UKCS. This is supplemented by the Energy Act 2008.

The Offshore Oil and Gas Exploration, Production, Unloading and Storage (Environmental Impact Assessment) Regulations 2020 ("the 2020 Offshore EIA Regulations")[73] apply to activities related to proposed offshore oil and gas exploration and production, gas unloading and storage, and storage of carbon dioxide ("offshore projects").

They make provision for the Secretary of State's consideration of the environmental impacts of proposed offshore projects when deciding whether to agree to the NSTA's grant of consent for such projects.

The 2020 Offshore EIA Regulations require that projects listed in Schedules 1 – 3 are subject to Regulations 5 – 7 before the Secretary of State can agree to the grant of consent by the NSTA for the project.

The projects listed under these Schedules 1 – 3 refer to pipelines for the transport of oil, "combustible gas" or chemicals. For these purposes, combustible gas means any combustible substance which forms a gas at normal pressure and temperature, and which consists wholly or mainly of methane, ethane, propane, or butane, as designated under section 2(4) of the Energy Act 2008[70].

The Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001 ("the Habitats regulations")[74] provide the legislative framework for the protection of a national network of protected sites.

Regulation 5 of the Habitats Regulations stipulates that, prior to granting any licence, consent, authorisation, or approval under the Petroleum Act or Energy Act for a proposed activity likely to have a significant effect on a relevant protected site, either individually or in combination with other plans or projects, the Secretary of State must conduct an appropriate assessment (a Habitats Regulations Assessment) of the implications for the site, considering its conservation objectives.

This includes consulting appropriate nature conservation authorities. The Secretary of State will generally not agree to the grant of consent unless he/she is satisfied there will be no adverse effect on the site, although the Secretary of State can do so if there are imperative reasons of overriding public interest.

By requiring hydrogen pipelines to be covered under the PWA regime for their construction and/or use, the provisions of the Habitats Regulations would apply, and a habitats consideration would be required to be undertaken by the Secretary of State before a PWA is granted by the NSTA.

These Habitats Regulations would also apply to an installation carrying out any activity listed under section 2(3) of the Energy Act 2008, including gas storage.

### C.1.2.5 Hydrogen standard

The maximum allowed emissions associated with low-carbon hydrogen are regulated through the Low Carbon Hydrogen Standard (LCHS).

The LCHS sets out a GHG emission intensity calculation methodology for eligible pathways, a monitoring, reporting and verification (MRV) framework, and requires producers to provide a plan for fugitive hydrogen emissions.

To be eligible for a government subsidy from the HPBM, production projects must demonstrate that they can produce standard-compliant hydrogen and projects only receive a subsidy for volumes of hydrogen which meet the LCHS criteria. The Standard has been updated twice since its first publication.

Version 3 of the Standard was published in 2023 and DESNZ will continue to review the Standard to ensure it remains fit for purpose[8].

- Compliance with the standard allows producers to demonstrate that their hydrogen is of a sufficiently low-carbon state to meet wider carbon reduction targets. To be considered low-carbon, producers are required to have a GHG emissions intensity equal to or lower than 20g CO2e/MJ LHV. The definition of system boundary in the Standard for what is to be included for production within the GHG emission intensity calculation methodology is given as follows:
- The GHG Emission Intensity Calculation Methodology shall follow a ‘point of production’ System Boundary. This only covers Scope 1 Emissions, Scope 2 Emissions and Partial Scope 3 Emissions of the Hydrogen Production Facility, as set out in the Emission Categories in Equation 1. It excludes any emissions related to the distribution or use of Hydrogen Product and excludes any emissions prior to the collection of a Waste or Residue feedstock.
- The GHG emissions from the construction, manufacturing, and decommissioning of capital goods (such as production equipment, any upstream pre-processing equipment, vehicles, storage assets), business travel, employee commuting, and upstream leased assets are not within the scope of the Standard.
- GHG emissions associated with hydrogen processes after the Hydrogen Production Facility gate (for example, off-site Hydrogen Storage, off-site liquefaction, off-site hydrogenation into a hydrogen carrier) are not within the scope of the Standard. However, if processes are located onsite at the Hydrogen Production Facility and Inputs or Outputs to these processes are not separately metered (or measured) from the Hydrogen Production Facility, the GHG emissions associated with operating these processes shall be accounted for within the Standard. For example, the GHG emissions associated with operating any Buffer Storage or any onsite Hydrogen Storage after purification and compression, where the Hydrogen Production Facility does not separately meter the electricity input to these processes, are considered within scope and shall be accounted for.

Equation 1 referenced below includes the emissions associated with purification and compression within the production facility.

$$E_{Total} = E_{Feedstock\ Supply} + E_{Energy\ Supply} + E_{Input\ Materials} + E_{Process\ CO_2} + E_{Fugitive\ non-CO_2} + E_{CO_2\ Capture\ and\ Netwrok\ Entry} - E_{CO_2\ Sequestration} + E_{Solid\ C\ Distribution} + E_{Compression\ and\ Purification} + E_{Waste/Residual\ Counterfactual}$$

Equation 1

UK LCHS GHG Emission Intensity Calculation[8]

### C.1.2.6 Hydrogen certification scheme

To verify compliance with the LCHS, the UK Government is planning to launch a low-carbon hydrogen certification scheme.

The scheme will enable hydrogen producers and end users to prove the low-carbon credentials of their hydrogen and could earn a 'green premium' by selling certificates to buyers.

Over the course of 2023, DESNZ consulted with the industry on the design of the scheme and published their Government Response [75].

This confirmed high-level policy positions that the scheme is intended to be voluntary, government-led, and delivered by the Low Carbon Contracts Company (LCCC). As the UK takes a technology agnostic approach to hydrogen production, LCHS compliant hydrogen will be certified as 'low carbon' regardless of the production pathway.

The Government Response also confirmed that the chain of custody would be mass balance, where the certificates would stay bundled with the hydrogen through the supply chain, and not be traded separately.

The current position is that the certificates will be issued in MWh, which aligns with the EU RED II and emerging European Hydrogen Guarantees of Origin. DESNZ is now continuing to develop the detailed design of the scheme.

A hydrogen producer will have the choice to demonstrate low-carbon hydrogen standard compliance using certification.

Selling certified low-carbon hydrogen within the UK could earn a 'green premium', alternatively, producers may choose to export the hydrogen, in which case they would not currently be eligible for a potential 'green premium'.

Despite there being no information on the size of the 'green premium', it is preferable if UK producers that exported hydrogen to Germany have UK certificates recognised or exchanged for an equivalent certificate in Germany.

This would mitigate the risk that hydrogen producers are disincentivised from exporting in the future.

The UK Government recognises the importance of giving industry confidence and outlines that the scheme will facilitate both imports and exports.

Prior to the scheme's launch, the Government will outline its planned approach to achieving international alignment in standards and certification, consistent with the UK's obligations under the World Trade Organisation (WTO).

Additionally, the Government may consider future legislation to support the scheme's robustness as participation increases.

## C.1.3 German Regulation

### C.1.3.1Interaction of German and EU Regulations

Since Germany is firmly embedded in the EU, its energy regulations more broadly and its regulations on hydrogen more specifically are fundamentally shaped by policies passed by the EU.

In the context of this study, the distinction between EU regulations and EU directives is relevant. Whereas EU regulations are binding and apply in their entirety to all EU member states at their date of passing, EU directives set out common and binding goals for all EU member states, but member states are to devise their own regulations, i.e. they are required to transpose the directive into national law (usually within two years), to ensure that the common goals are met.

The EU's Hydrogen and Decarbonised Gas Market package [76] [77] ("EU gas package" from here onwards) was passed in May 2024, setting out a regulatory framework for the hydrogen market across the European Union. It consists of Directive (EU) 2024/1788 and Regulation (EU) 2024/1789. Provisions outlined in the directive must be transposed into national law by mid-2026.

Therefore, there is some certainty over the direction of the regulations, however, some are yet to be confirmed in domestic law and are subject to change.

Art. 53 of Directive (EU) 2024/1788 states that interconnectors located outside the EEZ are not subject to EU and German law, so that bilateral agreements are required. Under this bilateral agreement question of regulation and deviating rules can be adopted.

The hydrogen and gas package addresses the repurposing of gas pipelines for the transportation of hydrogen, including offshore, the applicability of the gas regulatory framework to the hydrogen regulatory framework in general, the regulation of interconnectors, the financing of cross-border infrastructure (including interconnectors with third countries), and technical agreements with third-party countries.

Further, it covers network tariffs and network access, capacity and organisation, unbundling, balancing, and network planning and coordination.

### C.1.3.2 Economic regulatory framework for the interconnector within the EEZ

The planning and regulation for pipelines and therefore for the national hydrogen network development is stipulated by the Energy Industry Act (Energiewirtschaftsgesetz)[78] and envisages a two-step approach.

Firstly, a hydrogen core network development plan was developed by the association of gas transmission operators in Germany (FNB) and approved by the BNetzA in October 2024[79].

Secondly, a regular integrated network development planning for gas and hydrogen is to be set – the first draft plan is to be finalised by the middle of 2025 and is to be approved by the BNetzA by the middle of 2026. The planning of hydrogen interconnectors is part of these processes[80].

Offshore gas pipelines are not automatically subject to the economic regulatory framework. The EnWG does not explicitly stipulate inclusion of offshore hydrogen pipelines, but the explanatory document mentions that hydrogen pipelines in the EEZ can be included in the integrated network development planning for gas and hydrogen. Although, it remains to be seen if the network development planning will include hydrogen pipelines in the EEZ and what repercussions this will have on their status within the economic regulatory framework. The Federal Network Agency would be likely responsible for the economic regulation of the interconnector.

For regulation of hydrogen pipelines and networks through the EnWG it will also be decisive how the EU gas package will be transposed into national law (EnWG).

According to the EU gas package, interconnectors within the EEZ are to be operated by hydrogen transmission network operators and congestion management rules are to be established.

Moreover, the involved member state must inform the European Commission of the cooperation and either a bilateral agreement between the member state and the third country or an international agreement between the EU and the third country must be concluded.

If the interconnector is not classified as a 'project of common interest' (PCI), the hydrogen transmission operators or another party taking forward the interconnector project are to bear the costs for financing the interconnector.

The costs may be covered through user fees, which are to be approved by the relevant regulatory bodies. Should hydrogen transmission operators identify a significant divergence between benefits and costs, they can file an application for cross-border cost allocation.

This application must include a cost-benefit analysis and a business plan assessing the project'sfinancial viability.

From 2033 onwards, transmission network operators are required to put a system of financial compensation in place, which is to act as a safeguard should no tariffs be charged for access.

Lastly, hydrogen network operators are allowed to conclude technical agreements with third countries regarding the operation of pipelines (Directive (EU) 2024/1788; Regulation (EU) 2024/1789).

Existing legal regulation through the EnWG stipulates that hydrogen network operators must grant access and connection to third parties to hydrogen networks on reasonable and non-discriminatory terms, by means of negotiated network access. Under the EU gas package, network tariffs in the European hydrogen market are initially allowed to be market-based, following a negotiated access approach.

From 2033 onwards, network access will be based on regulated third party access.

From the same year onwards, the EU requires that hydrogen networks are organised as entry-exit systems (instead of via contractual paths), with access being based on firm capacity (interruptible capacity is only permitted if firm capacity cannot be offered by the network operators).

For infrastructure that is completed before 1st January 2028, the maximum duration for capacity contracts is 20 years. For infrastructure completed after this date, the maximum duration is 15 years (shorter durations may be imposed by regulatory authorities).

The ENNOH is an association of future hydrogen transmission network operators that will be responsible for the EU-wide Ten Year Network Development Plan (TYNDP) and for harmonised technical and operational rules, is to create an online platform where tariffs for each network point can be published[81].

If contractual congestion occurs, the transmission system operator has to offer the unused capacity on the primary market, network users may re-sell or sublet their unused contracted capacity on the secondary market.

In the EU, balancing at natural gas interconnectors follows the Balancing Network Code (BAL NC) (Regulation (EU) 312/2014[82]).

The BAL NC ensures that shippers have appropriate incentives to balance their inputs and offtakes.

For instance, shippers face financial penalties if their imbalance exceeds certain thresholds.

The SO acts as a residual  balancer and balancing occurs on an hourly basis.

The EU gas package provides some general insights into the EU's approach to the balancing of hydrogen networks, including that hydrogen network operators will be responsible for the balancing from 1st January 2033 (or earlier, if so decided by the regulatory authority) and the announcement of the establishment of a network code.

Balancing is to be market-based and occurs on a trading platform "or by means of balancing services in accordance with the network code" (Directive (EU) 2024/1788 and Regulation (EU) 2024/1789).

However, these provisions are not specific to interconnectors and require further elaboration by national Governments.

While the German BNetzA is developing balancing rules for the onshore network, similar provisions are lacking for the interconnector.

Although the BNetzA is already developing a basic capacity and access model as well as a balancing model for the national hydrogen network, it is unclear if and how they would be applicable for the offshore hydrogen pipelines. Secondly, an exemption from the EU gas package rules could be considered but such an option would require thorough legal analysis.

On behalf of separation of ownership of different assets along the value chain, the EU requires that any network activities are kept separate from production and supply activities (vertical unbundling) with ownership unbundling as the default rule.

Member states may instead decide to designate an independent hydrogen transmission network operator in accordance with the rules for an Independent System Operator (ISO) for natural gas or may also designate an integrated hydrogen network operator according to the rules for an Independent Transmission Operator (ITO) for natural gas.

Horizontal unbundling is to be achieved by ensuring that any activities by a hydrogen transmission network operator related to the transmission or distribution of natural gas and/or electricity are independent "at least in terms of its legal form" (Directive (EU) 2024/1788[64]).

To conclude, the economic regulatory framework for the offshore hydrogen interconnector in Germany will depend on further progress in framework development, both in network planning of interconnectors as well as transposition of the EU gas package into national law.

Further clarification of these two issues is expected once the Government has passed legislation to implement the EU gas package and the BNetzA finalised the NEP process. In the meantime, the BNetzA is to publish a report, by 30th June 2025, to evaluate market development and hydrogen network regulation and to make suggestions for future design.

### C.1.3.3 Licencing

Prior approval is required for laying of pipelines. The project developer must submit an application to the relevant state authority, accompanied by documents detailing the nature and extent of the proposed project.

This includes an assessment of any potential negative effects on legal interests, such as life, health, property, and public interests. Additional regulations are specified under the legal framework of the Federal Mining Act (BBergG)[83].

The BBergG stipulates that a mining licence is required (Section 133 (4) in conjunction with Section 133 (1) No. 1 BBergG).

This is issued by the competent state authority. "In the North Sea region, this is the State Office for Mining, Energy and Geology in Clausthal-Zellerfeld. The mining authorities check whether the project is in conflict with the mining law"[83].

### C.1.3.4 Pipeline construction, use, and decommissioning regulations

The gas transport infrastructure in Germany must be planned, constructed, and operated in a way to assure safety and technical integrity and to comply with spatial planning and environmental protection requirements.

There are two separate offshore (maritime) areas and one onshore area with different laws and institutional responsibilities and procedures in place in this respect. In the following sections, an overview of the regulatory requirements and gaps for those aspects is given.

The Planning and Plant Authorisation Law includes legislation for the planning and authorisation of hydrogen infrastructure.

Planning law concerns regulations on the national state, the federal state and the municipal level, while plant authorisation law concerns the construction and operation of plants for the production, transport, and use of hydrogen.

With regard to which steps are legally required for the approval of the necessary parts for the hydrogen infrastructure, it may be necessary to harmonise the approval regulations in order to eliminate regulatory imbalances between the states involved in an import corridor, which could lead to significant time disparities for the construction of the corridors.

In German law, these are essentially:

- The Spatial Planning Act (Raumordnungsgesetz - ROG),
- The Building Code (Baugesetzbuch - BauGB),
- The Environmental Impact Assessment Act (Gesetz über die Umweltverträglichkeitsprüfung - UVPG), and
- The Federal Immission Control Act (BundesImmissionsschutzGesetz - BImSchG).

These regulations are modified in certain areas by the Energy Industry Act (EnWG) for the development of a hydrogen import corridor on German territory. Section 43 EnWG regulates the establishment and expansion of hydrogen networks in Germany.

The construction, operation and modification of hydrogen pipelines, including the connecting pipelines of landing terminals for hydrogen with a diameter of more than 300 millimetres, shall require planning approval by the authority responsible under federal state law for procedures pursuant to Section 43 (1) sentence 1 number 5.

The Environmental Impact Assessment Act shall also apply to hydrogen networks accordingly. For the approval of gas and hydrogen pipelines, Spatial planning and urban land use planning need to meet the requirements set in the Spatial Planning Act (Raumordnungsgesetz – ROG).

For exact pipeline routing there are different institutional responsibilities and procedures in place. On the land and in the territorial sea (<12 NM from the coast), spatial planning und planning approval follows a procedure according to the EnWG and the GasHDrLtgV Ordinance.

The approval process is under the responsibility of the respective state authority (Lower Saxony or Schleswig-Holstein in the case of the North Sea). In the EEZ (Exclusive Economic Zone; >12 NM, <200 NM from the coast) spatial planning and planning approval for pipelines is set in the Federal Mining Act (Bundesberggesetz, BbergG). A mining permit by the respective competent state authority (for the North Sea - the State Office for Mining, Energy and Geology - LBEG) and an approval from the BSH are required. Furthermore, spatial planning is carried out within the Maritime Spatial Plan and the Area Development Plan (FEP) whose basis is the Wind Energy at Sea Act (WindSeeG).

For planning approval, it is also required to satisfy environmental requirements (e.g., with respect to species and area protection) according to the Environmental Impact Assessment Act (UVPG) - see the next section.

With the aim of allowing quicker planning and development of hydrogen pipelines, the EnWG stipulates that the construction of hydrogen pipelines is in accordance with prescribed limits for the latest start of operation, in the overriding public interest and serves public safety.

The EnWG explicitly requires that gas transport systems must be installed and operated in such a way that technical safety is guaranteed (Section 49 of the Energy Industry Act - EnWG). Compliance with the generally recognised rules of technology is presumed if the technical rules of the German Technical and Scientific Association for Gas and Water (DVGW – Deutscher Verein des Gas- und Wasserfaches) are observed.

#### C.1.3.5 Pipeline and storage environmental regulations

To plan and construct an offshore pipeline in Germany, authorisation from the BSH is also required. The BSH assesses whether the project aligns with the standard use and exploitation of the waters above the continental shelf and the airspace above these waters (Section 133 para. 4 in conjunction with Section 133 para. 1 no. 2 BBergG).

A more detailed explanation of the authorisation requirements and reasons for refusal is provided in Section 133(2), sentence 1, in conjunction with Section 132(2), no. 3 of the BBergG.

Authorisation can only be denied if public interests, such as the use of shipping lanes, flora, and fauna, are negatively impacted, or if there is a risk of marine pollution.

Key practical concerns include the pipeline’s routing in line with spatial planning regulations, the correct laying technique and depth, as well as species and nature conservation.

Once authorisation is granted, the project falls under the supervision of the BSH. If necessary, the BSH can issue directives to ensure the proper execution of the project[83].

To ensure that environmental protection is taken into account, an environmental impact assessment (Umweltverträglichkeitsprüfung - UVP) is required under certain circumstances for pipeline construction projects, in accordance with the Environmental Impact Assessment Act (Gesetz über die Umweltverträglichkeitsprüfung - UVPG).

A UVP is carried out for certain projects that may have a significant negative impact on the environment. These projects are specifically designated in Annex 1 of the UVP Act.

As a rule, a certain size or performance value is a key parameter.

According to the UVPG, an UVP obligation may exist not only for new projects, but also for modification projects. This is the case if the modification alone or the entire modified project exceeds the corresponding size or performance values for the first time, Section 9 UVPG.

Finally, the UVP obligation can be triggered not only by one project alone, but also by the fact that several projects of the same type, which are carried out by one or more project sponsors and are closely related (cumulative projects), collectively reach or exceed the relevant values, Sections 10 et seq. UVPG.

Annex 1 of the UVPG defines the projects that are subject to an UVP. According to Number 19.2.1 of the Annex, gas supply pipelines within the meaning of the Energy Industry Act with a length of more than 40 km and a diameter of more than 800 mm (32 inch) are subject to an UVP.

The UVP is a dependent part of the authorisation procedure for projects that have a particular impact on the environment.

The UVP comprises the early identification, description, and assessment of the significant environmental impacts of a project.

As part of the authorisation procedure with UVP, the public authorities and the authorities whose remit is affected by the project are involved.

They can comment on the project and the expected environmental impacts. The result of the UVP is then taken into account when deciding on the permissibility of the project.

For certain public and private projects, an UVP is used to identify, describe and assess adverse effects on environmental assets (environmental impacts) at an early stage and in a comprehensive manner in accordance with standardised principles and with public participation, and the results are then taken into account in the administrative decision.

Protected environmental assets are people (in particular human health), animals, plants, biodiversity, land, soil, water, air, climate, landscape, cultural heritage, other material assets and their respective interactions, Section 2 (1) UVPG. Environmental impacts are the direct and indirect effects of a project on these protected assets. The susceptibility to serious accidents or disasters relevant to the project is also considered an environmental impact, Section 2 (2) UVPG.

The adoption of a Hydrogen Acceleration Act is currently being discussed in Germany, the main aim of which is to place hydrogen infrastructure in particular public interest. This might have an impact on the environmental impact assessment and the approval procedures.

### C.1.3.6 Hydrogen Standard

The EU Renewable Energy Directive (RED) II and the associated delegated acts outline the rules, i.e. standards, relevant to renewable hydrogen.

There are several revisions of the RED, with RED III being the most recent. The RED covers “renewable fuels of non-biological origin” (RFNBOs), and RED II recognised renewable hydrogen as a RFNBO in the transport sector. RED III extended this recognition to hydrogen used in the industry and building sector (European Parliament 2023; FfE, 2023; PwC, 2023).

RED II and the associated delegated acts on Articles 27 and 28 specify that each hydrogen producer must be able to report that each consignment of hydrogen:

- has life cycle GHG emissions that are 70% lower than the reference value of 94gCO2e/MJ. Emissions from inputs, processing, transport, distribution, and end use are to be included (well-to-wheel approach);
- has been produced via electrolysis using renewable energy that fulfils the criteria of additionality and temporal and geographical correlation (Delegated Regulation (EU) 2023/1184 and Delegated Regulation (EU) 2023/1185).

In April 2024, the European requirements for RFNBOs were implemented at the German national level in the 37th Federal Immission Control Ordinance (37. BundesImmissionsschutzverordnung – 37. BImschV).

For low-carbon fuels, including low-carbon hydrogen (but excluding renewable hydrogen in the EU context), standards are similar in that life cycle GHG emissions must be 70% lower than the reference value of 94 gCO2e/MJ (Directive (EU) 2024/1788 and Regulation (EU) 2024/1789).

The methodology for the GHG assessment will be outlined by the EU Commission in a delegated act, which is to be adopted by 5th August 2025 the latest (European Commission 08.12.2023).

### C.1.3.7 Hydrogen Certification Scheme

In the EU, no overarching hydrogen certification scheme is planned. Instead, private schemes are to be used[84]. According to Art. 30(4) (EU) 2018/2001, the EU can recognise voluntary schemes to confirm that these are in line with the rules of the second Renewable Energy Directive

(Directive (EU) 2018/ 2001 (RED II)) and the associated delegated acts (Delegated Regulation (EU) 2023/1184 and Delegated Regulation (EU) 2023/1185).

Currently, six voluntary certification schemes have applied for recognition by the EU Commission. Certification bodies, which need to be accredited by an accreditation body, or a competent authority (Art. 11 (EU) 2022/996) will perform the audits on behalf of the voluntary scheme.

In December 2024, three of the voluntary certification schemes (CertifHy, REDCert, and ISCC) secured formal recognition as RFNBO certification schemes at the EU level.

The three remaining certification schemes are still awaiting technical assessment and formal recognition (European Commission n.d.).

For low-carbon fuels, i.e. Including for low-carbon hydrogen (but excluding renewable hydrogen in the EU context), provisions are outlined in the EU gas package (Directive (EU) 2024/1788 and Regulation (EU) 2024/1789). These mirror the rules for RFNBOs in the RED II.

Since the delegated act specifying the GHG assessment methodology for low-carbon fuels is still outstanding, no (voluntary) certification schemes that are compliant with the gas market package have been developed yet.

#### C.1.3.8 Offtake Regulation

Germany has set itself the ambitious target of achieving net zero emissions by 2045, for which the sufficient availability of low-carbon hydrogen will be crucial.
This is due in particular to the prominent role of the industrial sector in the German economy.

With a high share of hard-to-abate emissions and processes that cannot be electrified, the industrial sector will rely heavily on the availability of hydrogen to achieve its decarbonisation targets. In addition, the energy and transport sectors (especially heavy-duty vehicles, shipping, and aviation), and possibly the heating sector, will need to use hydrogen to reduce their emissions.

The German Government is therefore seeking to incentivise the purchase of low-carbon hydrogen by these sectors.

While Germany used to have binding sectoral emission reduction targets in its climate protection programme, where each individual sector had to correct for short comings, the latter provision was dropped in 2024 so that shortcomings in one sector can now be compensated for by other sectors (Umweltbundesamt, 16.08.2024).

This reduces the pressure on individual sectors to comply with their targets but retains some pull effect with regards to the implementation of low-carbon approaches and technologies, including low-carbon hydrogen, as all sectors collectively must still achieve the overall target.

The non-achievement of individual sectors can only be offset by other sectors to a certain extent.

Additionally, Germany is bound by the EU's sectoral targets. These are established in the EU's Effort Sharing Regulation (ESR) in the form of binding annual emission reduction targets for different sectors (transport excluding aviation, small industry, agriculture, buildings, and waste) within each MS for the years 2021 to 2030.

According to the ESR, Germany has to reduce its emissions in the covered sectors by 50% compared to 2005 by 2030 (European Commission, n.d.a).

However, a report by the German Environment Agency suggests that Germany will not be able to meet this target, with the transport and building sectors performing particularly poorly (Umweltbundesamt, 2024).

In its updated national energy and climate plan (Nationaler Energie- und Klimaplan (NECP)), the German Government therefore outlines 16 measures with which it seeks to increase emission reductions in all covered sectors, including, for instance, energy efficiency improvements and a reform of the grid fees (BMWK, 2024c).

Should Germany nevertheless miss the emission reduction target, it is obliged to purchase emissions certificates to make up the difference.

In the industry sector, low-carbon hydrogen uptake will, inter alia, be incentivised with the transposition of the EU's specifications in the Industrial Emissions Directive into national law.

This will introduce more stringent emission limits for around 13,000 industry plants in Germany (Umweltbundesamt, 29.07.2024).

Beyond these general emission reduction targets, RED III introduced specific targets for the uptake of RFNBOs, and with that renewable hydrogen, in the industry and transport sector.

In the industry sector, 42% of hydrogen used for energy and non-energy purposes must be supplied in the form of RFNBOs by 2030.

This increases to 60% in 2035. This requirement can be reduced by 20% if the respective MS meets its national contribution to the overall EU emission reduction target and the share of hydrogen from fossil fuels is not higher than 23% in 2030 and 20% in 2035.

In the transport sector, RFNBOs must make up a minimum of 1% in the share of renewable energy supplied to the sector in 2030. RED III also covers the building sector, however here, no specific targets were introduced for RFNBOs. Instead, the overall target for the share of renewable energy was set at 49% in 2030, with separate, MS specific targets applying to heating and cooling systems (Linklaters, 12.10.2023).

At the national level, the German Government has devised and amended several regulatory acts in the power and building sector to encourage a shift to low-carbon hydrogen where useful.

Following an amendment to the Combined Heat and Power (CHP) Act in 2023, new CHP plants with a capacity above 10GW must be H2-ready to receive funding (Federal Ministry of Housing, Urban Planning and Development (BMWSB), 2023; Federal Ministry of Justice, n.d.).

In the building sector, the Building Energy Act (Gebäudeenergiegesetz) was amended in 2024 requiring newly installed gas heating systems to be hydrogen compatible if the building is located within a designated hydrogen area (BMWSB, 2023; German Parliament, 2023).

However, preference is given to renewable-based technologies, such as heat pumps, and the extension of district heating.

#### C.1.3.9 Offtake Funding

As outlined in section 2.5.3, the German Government has set up a number of funding programmes, most notably the CCfD scheme and the Federal Fund for Industry and Climate Action to encourage the uptake of low-carbon hydrogen by different sectors. Germany is the first EU member state to use a CCfD scheme.

**KEY**
- 🔴 policy/regulations yet to be developed
- 🟠 policy/regulation in development
- 🟢 policy/regulation developed

| Value chain element | Area of regulation | UK Approach | German Approach | Is alignment needed between the UK and German approach? |
|---|---|---|---|---|
| Interconnector | Licencing and unbundling of the interconnector | 🟠 Hydrogen is covered within the 1986 Gas Act. An assessment is required to determine whether the existing requirements are appropriate for hydrogen as they were designed for natural gas. | 🔴 Approach to be determined based on business model approach and on unbundling requirements, depending on the transposition of the EU gas package and on inclusion of offshore pipelines in EEZ in the network development plan (draft to be published in 2025). | Yes |
| | Regulatory framework: Network codes, charging, access and balancing | 🟠 Hydrogen is covered within the 1986 Gas Act. An assessment is required to determine whether the existing requirements are appropriate for hydrogen as they were designed for natural gas. | 🟠 Rules for access, capacity usage and balancing are already partly set or in development (NRA - BNetzA). Implications for the offshore pipelines will depend on inclusion of offshore pipelines in the Gas and hydrogen network development plan (draft to be published in 2025) on the transposition of the EU gas package. | Yes |
| | Pipeline construction, use and decommissioning regulations | 🟢 Existing Oil & Gas Primary Legislation has been updated to include hydrogen as a named gas. | 🟠 The existing legal framework for gas is being updated and the requirements of the EU hydrogen and gas market package are being successively transposed into national legislation. | No |
| | Pipeline and storage environmental regulations | 🟢 Existing Oil & Gas Primary Legislation has been updated to include hydrogen as a named gas. | 🟠 The existing legislation for gas shall apply to hydrogen. Where necessary, legislation will be adapted (partly on the basis of EU regulations). | No |
| Production | Hydrogen certification scheme | 🟠 Certification scheme is in development. | 🟠 Approach of voluntary application schemes in the EU, five schemes have applied for recognition by the EU Commission. | Yes |
| | Hydrogen standard | 🟢 Hydrogen standard developed. | 🟢 Hydrogen standard developed. | Yes |

Table 28.
Regulation status summary.

# D

# Appendix D: References

## Appendix D References


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## Abbreviations and Acronyms

The following abbreviations and acronyms are used throughout this document:

| Abbreviation | |
|---|---|
| **ACER** | Agency for the Cooperation of Energy Regulators |
| **BMWK** | Bundesministerium für Wirtschaft und Klimaschutz<br>(Federal Ministry for Economic Affairs and Climate Action of Germany) |
| **BNEF** | Bloomberg New Energy Finance |
| **BNetzA** | Federal Network Agency (Bundesnetzagentur) |
| **BSH** | Federal Maritime and Hydrographic Agency |
| **CAM NC** | Capacity Allocation Mechanism Network Code |
| **CAPEX** | Capital Expenditure |
| **CCS** | Carbon Capture and Storage |
| **CCUS** | Carbon Capture, Utilisation, and Storage |
| **CCfD** | Carbon Contracts for Difference |
| **CfD** | Contracts for Difference |
| **COD** | Commercial Operation Date |
| **DE** | Germany |
| **DECOMMEX** | Decommissioning Costs at the end of life |
| **DESNZ** | Department for Energy Security and Net Zero |
| **DEVEX** | Development Expenditure |
| **EHB** | European Hydrogen Backbone |
| **ENNOH** | European Network of Network Operators for Hydrogen |
| **EEZ** | Exclusive Economic Zone |
| **EIA** | Environmental Impact Assessment |
| **e-SAF** | Electro-Sustainable Aviation Fuel |
| **EU** | European Union |
| **FID** | Final Investment Decision |
| **FEED** | Front End Engineering Design |
| **FES** | Future Energy Scenarios |
| **GB** | Great Britain |
| **GHG** | Greenhouse Gas |

| Abbreviation | |
|---|---|
| **HAR** | Hydrogen Allocation Round |
| **HoTs** | Heads of Terms |
| **HPBM** | Hydrogen Production Business Model |
| **HSBM** | Hydrogen Storage Business Model |
| **HTBM** | Hydrogen Transport Business Model |
| **IAA** | Interconnector Access Agreement |
| **IAC** | Interconnector Access Code |
| **IAM** | Implicit Allocation Mechanism |
| **IPCEI** | Important Projects of Common European Interest |
| **IPs** | Interconnector Points |
| **LCCC** | Low Carbon Contacts Company |
| **LCHS** | Low Carbon Hydrogen Standard |
| **LCOH** | Levelized Cost of Hydrogen |
| **LCOT** | Levelized Cost of Transport |
| **LHV** | Lower Heating Value |
| **LNG** | Liquefied Natural Gas |
| **LOHC** | Liquid Organic Hydrogen Carriers |
| **MoU** | Memorandum of Understanding |
| **MS** | Member State |
| **NBP** | National Balancing Point |
| **NESO** | National Energy System Operator |
| **NHC** | National Hydrogen Council |
| **NHS** | National Hydrogen Strategy |
| **NIC** | National Infrastructure Commission |
| **NSTA** | North Sea Transition Authority |
| **NZHF** | Net Zero Hydrogen Fund |
| **NZTC** | Net Zero Technology Centre |
| **BNEF** | |

| Abbreviation | |
|---|---|
| **OFTO** | Offshore Transmission Owner |
| **OPEX** | Operational Expenditure |
| **OPRED** | Offshore Petroleum Regulator for Environment and Decommissioning |
| **PLANC** | Permits, Licences, Authorisations, Notifications and Consents |
| **PWA** | Pipeline Works Authorisation |
| **RAB** | Regulated Asset Base |
| **RED** | Renewable Energy Directive |
| **RFNBO** | Renewable Liquid and Gaseous Fuels of Non-Biological Origin |
| **rTPA** | Regulated Third Party Access |
| **SMEs** | Small and Medium-sized Enterprises |
| **SO** | System Operator |
| **SSEP** | Strategic Spatial Energy Plan |
| **TYNDP** | Ten Year Network Development Plan |
| **T&S** | Transport & Storage |
| **TRS** | Tender Revenue Stream |
| **TSO** | Transmission System Operator |
| **UK** | United Kingdom |
| **UKCS** | United Kingdom Continental Shelf |
| **UNC** | Uniform Network Code |
| **UVP** | Environmental impact assessment (Umweltverträglichkeitsprüfung) |
| **UVPG** | Environmental Impact Assessment Act (Gesetz über die Umweltverträglichkeitsprüfung) |
| **WTO** | World Trade Organisation |

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