Commercial Models for Future Hydrogen Production

Crown Estate Scotland

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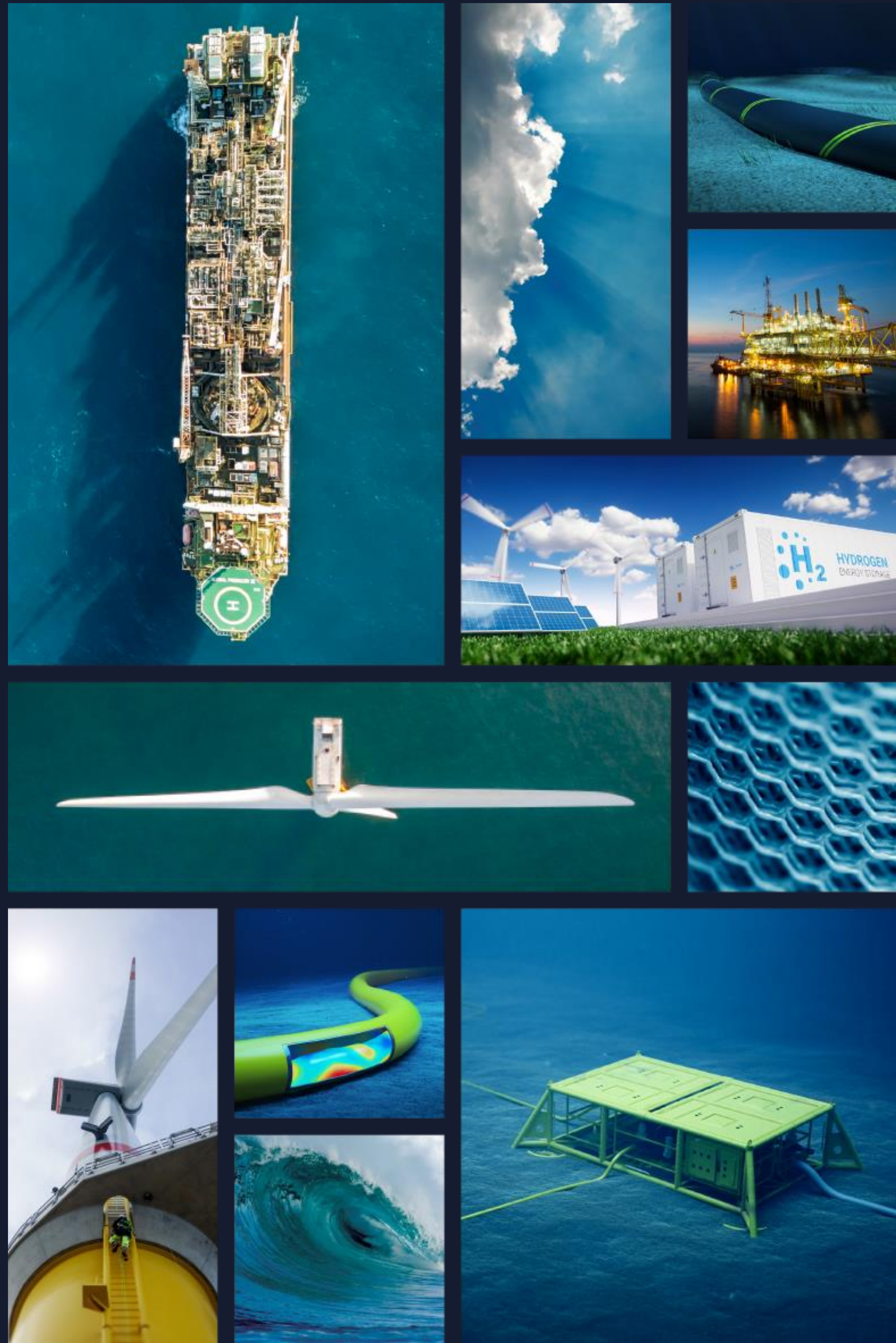

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A-400355-S00-Z-REPT-002

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EXECUTIVE SUMMARY

Introduction & Scope

Crown Estate Scotland recently concluded the ScotWind and INTOG leasing rounds, Early indications are that a significant number of these projects intend to consider green hydrogen production either as an offtake option or as a fundamental alternative to a transmission system connection. Crown Estate Scotland engaged Xodus to review and summarise potential strategic offshore infrastructure needed for hydrogen transport in Scotland, to analyse and justify anticipated costs and potential commercial models for the financing, ownership, and operation of offshore infrastructure for hydrogen transport, and to prepare recommendations for Crown Estate Scotland and partners.

Offshore Infrastructure

Pipeline size and potential routing has been established. This has been based on an estimate of potential hydrogen production from onshore, planned offshore and potential future offshore wind. A pipeline size of 32" has been assessed, which is capable of transporting approximately 2200 tonnes/day (peak) hydrogen. That corresponds to approximately 8% of the EU's target for import of hydrogen from outside of the EU by 2030.CAPEX for the pipeline is estimated at £2.7 billion.

Project Landscape

There have been several North Sea hydrogen pipeline projects announced recently, with Norway being a potential exporter of low carbon hydrogen by pipeline to the EU. Norway also has a history of public ownership of strategic energy infrastructure. It is clear that the potential for import of hydrogen by pipeline from Scotland is not visible on a number of EU / European illustrations of future hydrogen supply routes into the EU, therefore some effort in marketing this concept more widely is recommended.

Ownership Models

There are a range of roles that the public bodies can play in the creation and operation of a hydrogen pipeline export project. These range from a fully publicly owned and operated pipeline to a fully privatised ownership structure.

Key considerations that need to be taken into account include:

- Defining the role of the Scotland public bodies
- Uncertainty in the maturity in the hydrogen market and how a public body can de-risk to enable private investment
- The level of investment the Scotland plc is willing to spend to enable the creation of a hydrogen export pipeline
- The timing of monetisation to create value to Scotland

Recommendations – Short Term (2023)

- Increase visibility of Scotland's hydrogen pipeline export potential to the EU, and advance feasibility stage design.
- Define hydrogen certification rules and viable funding routes to support hydrogen transport.
- Define the role that Scottish Government wants to play.
- Engage with EU partners to explore MOUs or offtake agreements and explore with UK and EU governments business models for a hydrogen transport pipeline.

Recommendations – Medium Term (2024/5)

- Assess pipeline routing & landfall options and establish hydrogen supply timing from Scotwind.
- Define cross-border regulatory engagement requirements for hydrogen transport, and permit & consenting timelines.
- Engage with private enterprises to establish ownership structure.
- Formalise business model to enable clarity to investors on the opportunity and where it fits in the value chain.
- Commence marketing of hydrogen pipeline capacity.
- Commence engagement with lenders and "bankability" assessment.

Recommendations – Long Term (2026+)

- Carry out routing surveys and EIA.
- Pipeline design optimisation and design basis freeze.
- Define monetisation roadmap and ownership model over project lifecycle.
- Agree subsidy / funding business model that can support project through FID.
- Secure / formalise shippers and offtakers.

CONTENTS

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1 INTRODUCTION

Context

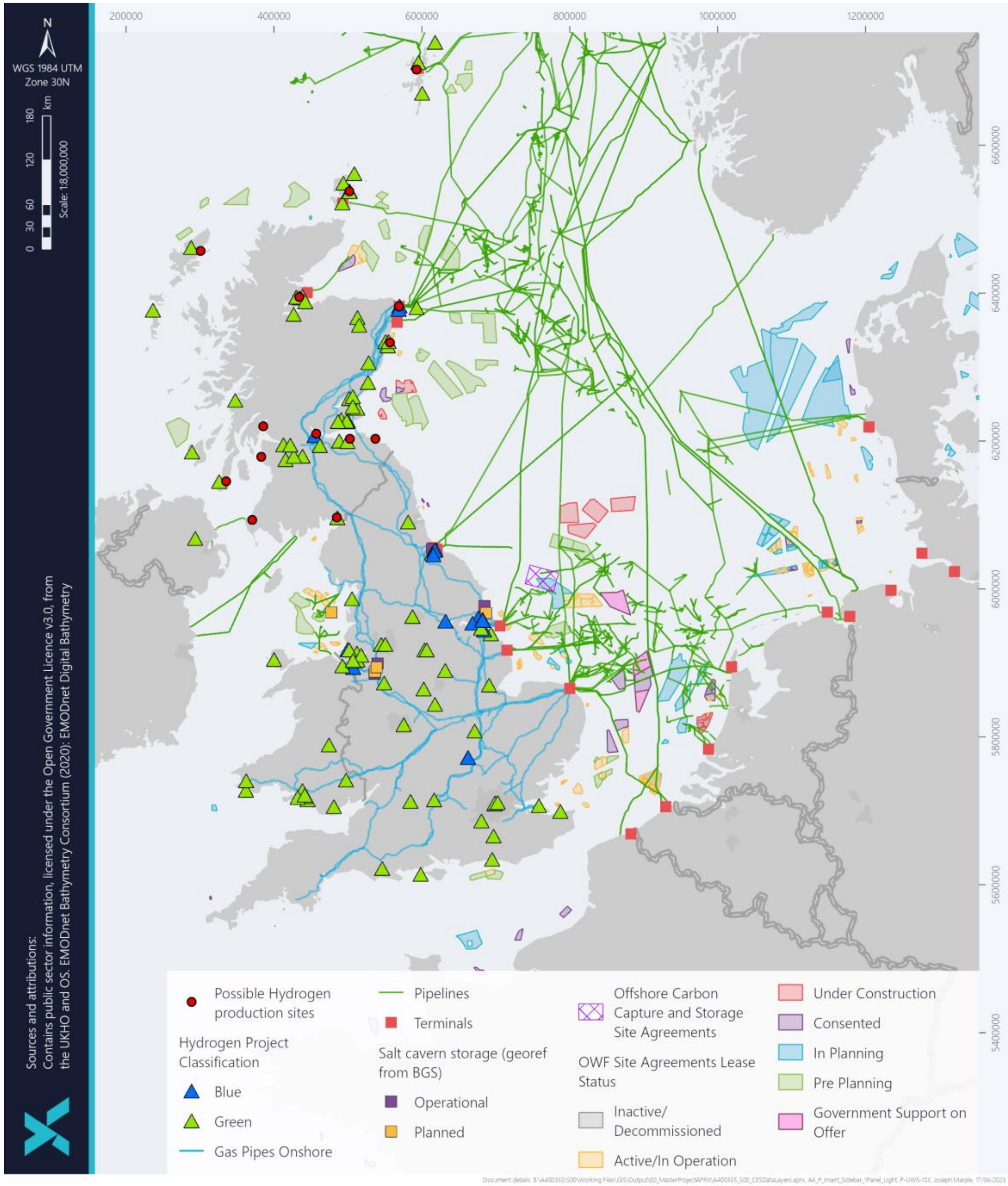
Crown Estate Scotland manages property – including buildings, land, coastline and seabed – on behalf of the Scottish people and has a significant role in the development of the blue economy, including responsibility for the rights to offshore renewable energy out to 200 nautical miles.

Crown Estate Scotland recently concluded the ScotWind and INTOG leasing rounds, Early indications are that a significant number of these projects intend to consider green hydrogen production either as an offtake option or as a fundamental alternative to a transmission system connection.

There are many policy discussions and projects under way investigating the different aspects of developing a green hydrogen industry in the UK. This study seeks to add to Crown Estate Scotland's understanding in relation to shared infrastructure models relevant to realising the full potential of ScotWind projects as drivers of the green economy.

Objective

To produce a report exploring different commercial models for the future development of strategic hydrogen infrastructure in and around Scottish waters.



2 SCOPE

Overview

Crown Estate Scotland engaged Xodus to deliver the following scope of work.

1. To review and summarise potential strategic offshore infrastructure needed for hydrogen transport in Scotland.
2. To analyse and justify anticipated CapEx and OpEx ranges for, and to evaluate potential commercial models for the financing, ownership, and operation of offshore infrastructure for hydrogen transport
3. To prepare recommendations for Crown Estate Scotland and public sector partners covering:
    - clear conclusions on the range of available approaches to deliver strategic infrastructure for hydrogen transport in Scotland,
    - recommendations on the different commercial options considered in part 2, and
    - recommendations for next steps which the public sector should consider, along with suggested timescales and priorities

Scope 1

Xodus have used GIS software to display the proposed locations of hydrogen production sites, along with domestic and international export destinations. Xodus have leveraged existing data compiled of planned offshore wind developments and domestic load centres through identifying and reviewing all the potential strategic offshore infrastructure required for hydrogen transportation in Scotland, including:

- For hydrogen transportation via pipeline: offshore pipelines in the North Sea in the form of new-built or existing pipelines.
- For maritime transportation of hydrogen (including in the form of ammonia or else): export terminals, ports, and jetties.
- Hydrogen transfer points for transmission and distribution
- Hydrogen injection points.
- Connections to offshore infrastructure for the purposes of connecting to domestic supply networks.
- Onshore and offshore hydrogen storage.
- International export routes.
- Existing and potential large-scale offshore renewable energy production sites.

Xodus have also identified and mapped existing, as well as proposed locations, of hydrogen infrastructure including:

- Hydrogen production sites
- Offshore renewable energy production sites.
- Domestic and international export destinations.

Scope 2

Building on the review undertaken in Scope 1, Xodus have analysed and justified anticipated CAPEX and OPEX ranges for the hydrogen transportation scenarios developed, and have evaluated potential commercial models for the financing, ownership, and operation of offshore infrastructure for hydrogen transport. This has considered ownership by a single entity (e.g., a public sector organisation, or a private enterprise) or shared ownership. This review has covered:

- An outline of current regulatory frameworks (economic and non-economic) and any potential reforms relevant to the development of offshore infrastructure for hydrogen transport.
- A review of relevant international case studies and the involvement of, and governance arrangements between, private and public institutions in the delivery of offshore infrastructure for hydrogen transport.
- A comparison with other relevant subsea infrastructure, such as delivery models for shared electricity transmission cables or gas pipelines. It should be noted that limited (if any) offshore infrastructure for hydrogen transport currently exists, therefore Xodus have built on governance arrangements from analogous sectors such as natural gas and CO2, leveraging the work carried out for the Dutch Ministry of Finance for CCS projects
- A presentation of credible commercial (funding and ownership) models for offshore infrastructure for hydrogen transport in Scotland

3 REVIEW OF STRATEGIC INFRASTRUCTURE

The Scottish Governments' Hydrogen Action Plan recognises the potential hydrogen export opportunity from Scotland to the rest of the UK and Europe. Scotland has set a ambition of 5 GW hydrogen production capacity by 2030 and by 2045 of 25 GW production with an estimate of 3.3 Mt per year exported (40-60% of the production target). To achieve this will require build out of the means of exporting to the UK and Europe. This will require large scale infrastructure, and some degree of common use infrastructure, serving multiple production facilities.

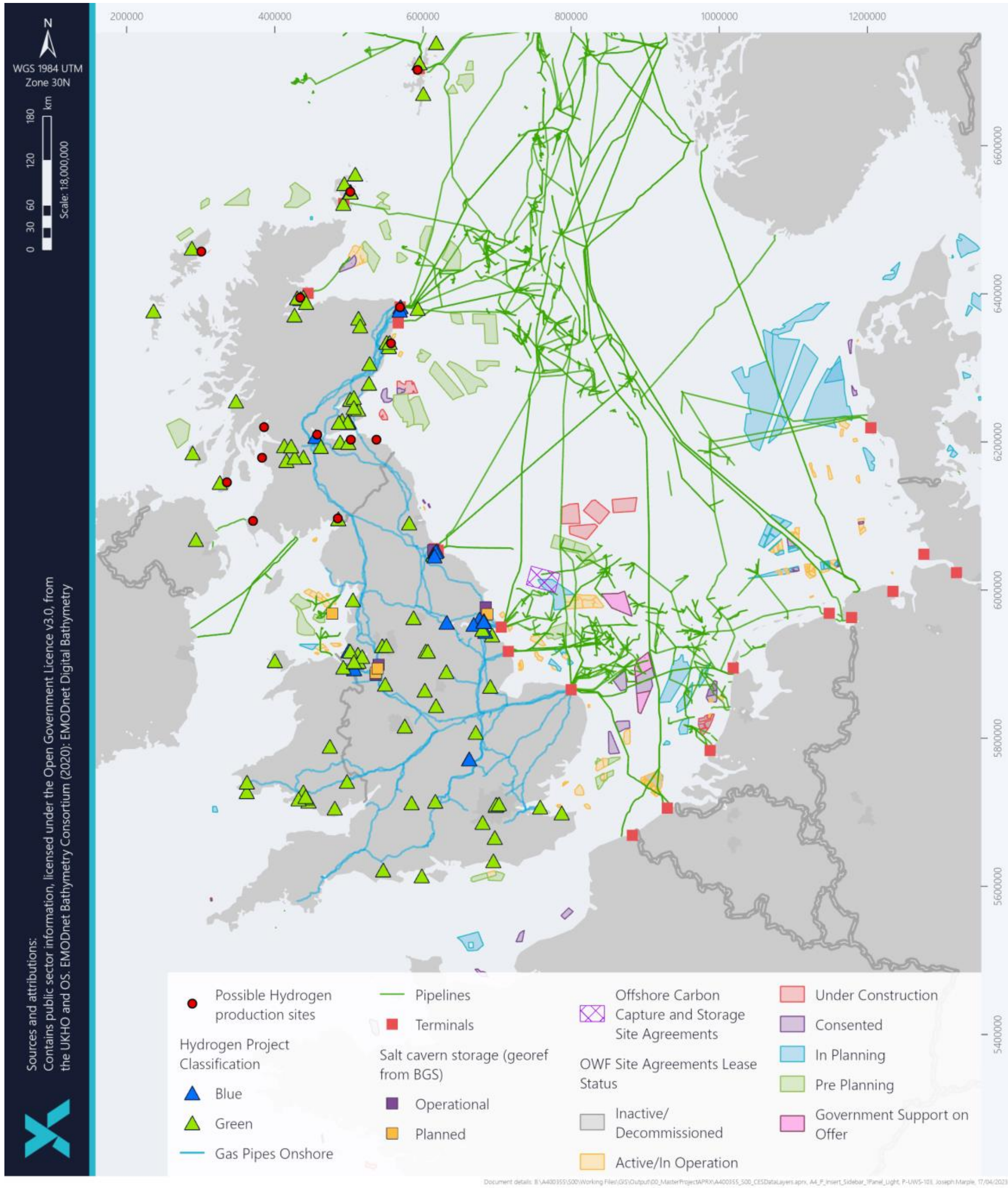
Xodus have used GIS software to display the proposed locations of hydrogen production sites, along with domestic and international export destinations. Xodus have leveraged existing data compiled on planned offshore wind developments and domestic load centres through identifying and reviewing all the potential strategic offshore infrastructure required for hydrogen transportation in Scotland, including:

- For hydrogen transportation via pipeline: offshore pipelines in the North Sea in the form of new-built or existing pipelines.
- For maritime transportation of hydrogen (including in the form of ammonia or else): export terminals, ports, and jetties.
- Hydrogen transfer points for transmission and distribution.
- Hydrogen injection points (to the existing gas network).
- Connections to offshore infrastructure for the purposes of connecting to domestic supply networks.
- Onshore and offshore hydrogen storage.
- International export routes.
- Existing and potential large-scale offshore renewable energy production sites.

Xodus have also identified and mapped existing, as well as proposed locations, of hydrogen infrastructure including:

- Hydrogen production sites
- Offshore renewable energy production sites.
- Domestic and international export destinations.

These data sources have been combined into the figure opposite. Each element is discussed on the following pages.



3.1 Offshore Pipelines

There is a dense network of offshore pipelines in the North Sea associated with oil and gas production. These lines vary in size and function from small diameter lines transporting reservoir fluids from subsea wells to processing facilities, to large diameter trunklines transporting processed gas from several production facilities to onshore terminals.

The large gas trunklines are the most analogous to what would be needed for large scale hydrogen transport. There are several trans-national export pipelines from Norway to the UK and EU, and two interconnector pipelines between the UK and EU which can operate in either flow direction.

Ownership of these large pipelines is by a small number of companies, with Gassled being the owner of several. With large gas resource and modest native demand, Norway is the major player in the North Sea both in terms of number of pipelines and total export capacity.

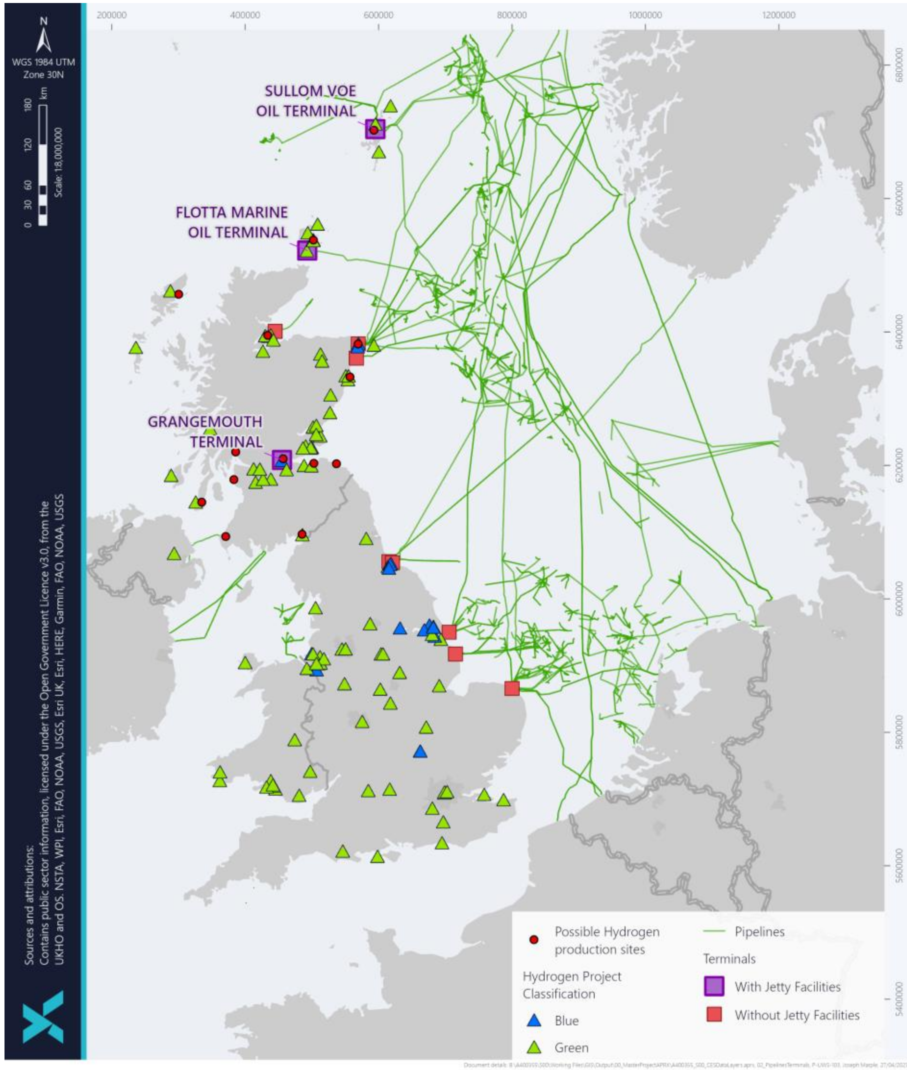
Published studies [Bacton Energy Hub, OGTC Re-Use of Offshore Pipelines for Hydrogen, SOWEC] that have reviewed the potential to repurpose offshore gas pipelines for hydrogen transport have concluded that this is unlikely to be feasible for a cross North Sea route, and all offshore hydrogen pipeline concepts that have been published to date are assuming new pipelines will be required. A significant reason for this is location and size of the existing lines, and the expected long remaining life in hydrocarbon service for the larger lines. While it may be technically feasible to repurpose pipelines, the locations and availability of the suitable lines make this unlikely in the 2030-2040 timescale. Pipelines could potentially be repurposed for storage – 100km of 32" line at 100bar can store approximately 16 GWh (HHV).

Existing gas trunklines have capacities in the range 75 – 300 TWh/year (HHV). This is equivalent (in energy terms) to approximately 2 – 8 Mt/year hydrogen.

Export pipeline terminal facilities are expected to include:

- Hydrogen reception & metering.
- Compression facilities, compressing hydrogen to 70-80 barg.
- Depressurisation facilities – these would consist of a facility to allow the contents of the pipeline to be safely evacuated in the event of a significant problem with the subsea pipeline (e.g. a major leak). This would normally be situated at a distance from the main facilities and any accessible areas in order to prevent any adverse consequence to people during depressurisation.

Existing gas terminals are also good candidates as sites for hydrogen injection into the existing gas network.



3.1 Offshore Pipelines

Facilities Required for Hydrogen Export by Pipeline

The schematic below shows the pipeline export facilities in context of power input from offshore wind and an assumed closely located Hydrogen production facility.

Pipeline export facilities could be co-located with a hydrogen production site. It has been assumed here that the ownership of the export facilities and export pipeline will be different than the hydrogen production facility, and that the export facility could serve multiple production facilities, and therefore the export facilities are shown as a separate facility.

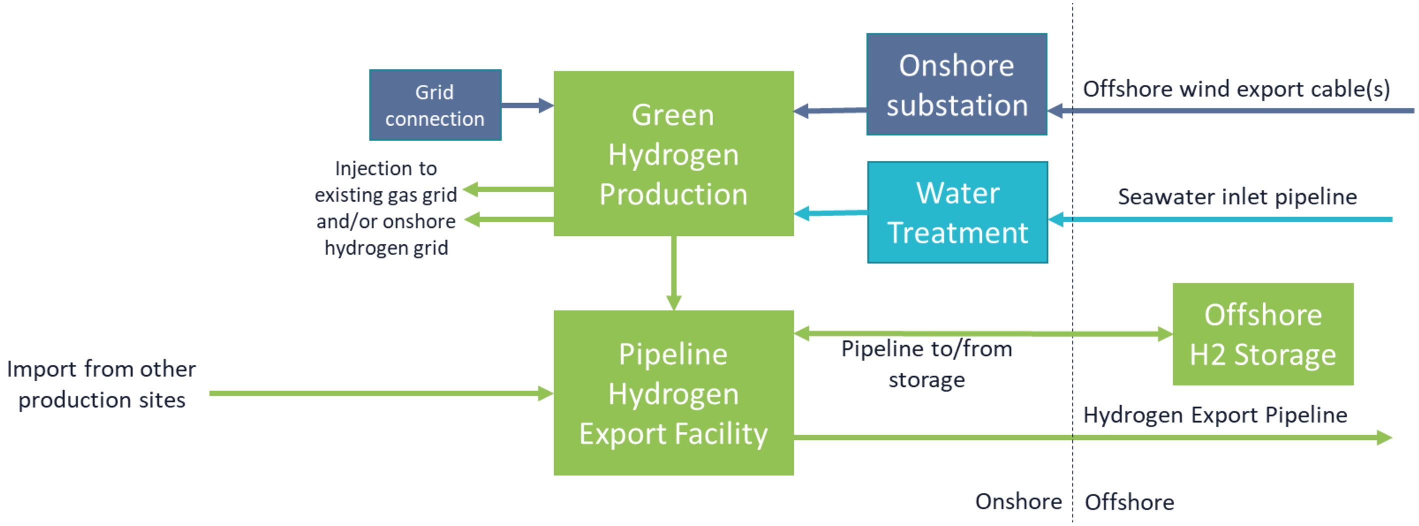
Within the Pipeline Hydrogen Export Facility boundary it is assumed there are:

- Compressors, drives and associated cooling facilities – approx. 2200 m2
- Metering of all input streams and of the hydrogen export stream – approx. 250 m2
- A flare system to allow the pipeline to be depressurised. – approx. 250 m2

Sizes shown above are based on an pipeline export facility designed for 5GW. Overall area is estimated at 3000m2, approximately 55x55m. Compression and metering facilities would approximately scale with capacity. The space required for a flare system is associated with a sterile area (safety area) and would remain approximately the same.

For comparison, a 2GW green hydrogen production site would be expected to have an area of approximately 130,000 m2 – i.e. the area required for the pipeline export systems is an order of magnitude lower than that required for the hydrogen production,

Cost of the onshore elements of a 5GW hydrogen export facility are expected to be in the order of £250M. It should be noted that there is very high uncertainty over the compression costs, which are the largest element of this cost, as large capacity hydrogen compression of this type is not available. Costs have been extrapolated from similarly sized hydrocarbon compression facilities, and cross-checked against the published BEIS Hydrogen Production cost assumptions, where compression is not costed explicitly, but is stated as adding approximately £1 / MWh to hydrogen production costs.



3.1 Offshore Pipelines

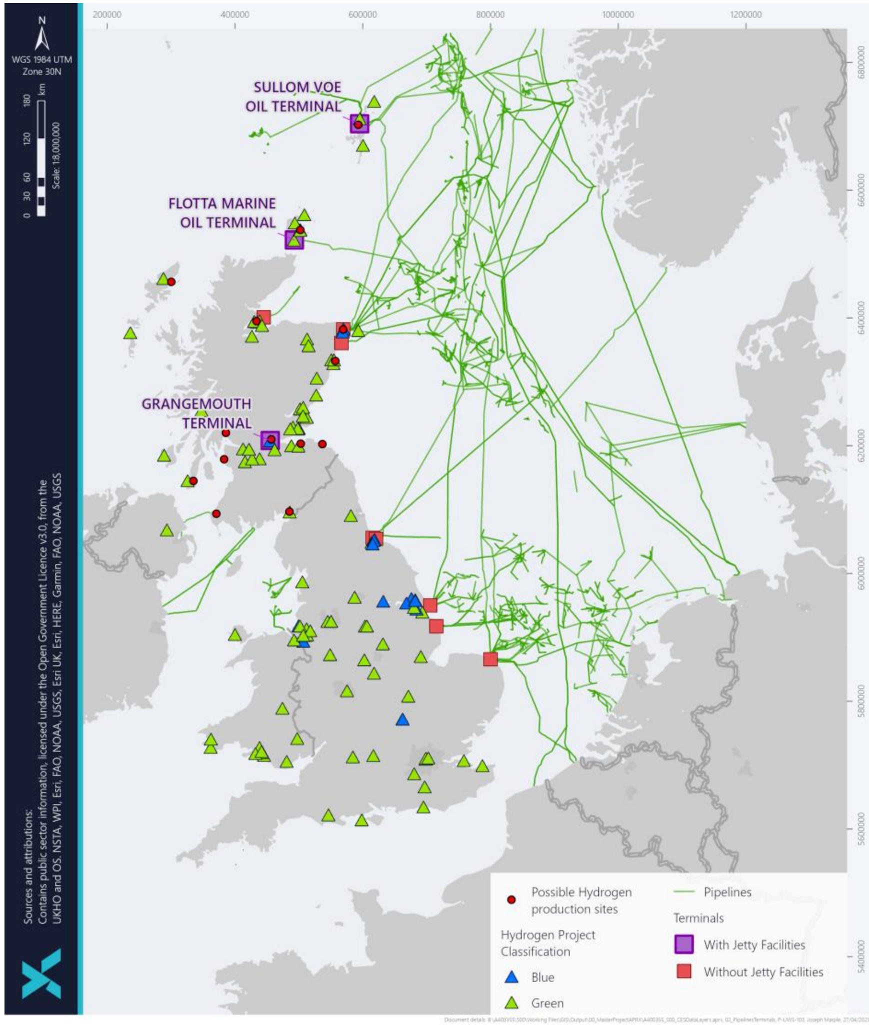
The major trunklines in the North Sea and their characteristics are listed below. Export capacity has been estimated from published gas molar volume capacities using a generic gas energy value.

Name	Route	Size and Length	Capacity, TWh / year	Ownership
Pipeline Systems from Onshore to Onshore				
Zeepipe 2A/B	Kollsnes - Draupner	40", 300km x 2	304	Gassled
Zeepipe-1	Sleipner – Zeebrugge	40", 813km	171	Gassled
Langeled	Nyhamna – Easington	44", 1166km	303	Gassled
Europipe II	Kårstø – Dornum	42" 658km	289	Gassled
Interconnector	Bacton – Netherlands	40", 232km	222	Fluxys
BBL	Bacton – Belgium	36", 230km	180	BBL
SIRGE	Shetland - St. Fergus	30" 233km	76	NSMP
Pipeline Systems from Offshore to Onshore				
Franpipe	Draupner – Dunkirk	42", 840km	222	Gassled
Norpipe	Ekofisk – Emden	36", 440km	180	Gassled
Statpipe	Kårstø/Heimdal - Draupner	28"-36", 586km	180	Gassled
Versterled	Heimdal - St Fergus	32", 360km	150	Gassled
FUKA (n)	Frigg-St Fergus	32", 130.5km	146	NSMP
FUKA (S)	Frigg-St Fergus	32", 174km	146	NSMP
FLAGS	Tampen+Brent - St. Fergus	36", 455km	134	Shell
SEAL	Central North Sea - Bacton	34", 475km	101	Shell
CATS	Central North Sea - Teesside	36", 405km	69	Kellas Midstream

3.2 Export Terminals and Export Shipping

Export of hydrogen by ship is very expensive as a compressed gas, due to the low volume density of compressed hydrogen, even at very high pressures. Forms in which large scale hydrogen export by ship is more likely are:

- As ammonia - particularly where the ammonia can be used directly,
- As methanol – particularly where the methanol can be used directly,
- In a liquid organic hydrogen carrier chemical (LOHC) - where hydrogen can be recovered at the delivery end and the chemical carrier reused
- As liquefied hydrogen – where the hydrogen is transport at very low temperature (-250°C)



Of these shipping of hydrogen as ammonia is the most likely at scale in the shorter term. There is already international shipping of ammonia, and the shipping technology is already mature. Green ammonia production is new, but rapidly developing. The chemical process (Haber-Bosch) will be as per current grey ammonia production, but modifications are needed to provide heat into the process through different means, and some hydrogen or electrical storage is likely to be needed in order to allow the ammonia plant to operate effectively. Ammonia tankers available currently have capacities in the range 22,500 – 60,000 m3. Larger tankers up to 80,000 m3 are in production.

A single 80,000m3 liquid ammonia vessel shuttling a 1000km route could export hydrogen at a rate of approximately 1500 tonnes/d (excluding energy use by the vessel and conversion process).

There are a number of ports in Scotland that have the capability to export hydrogen and/or hydrogen derived products (e.g. ammonia, methanol). The existing facilities are oil, LPG or chemical liquid products, so these would have to be adapted to export hydrogen or hydrogen products. These ports are:

- Sullom Voe – 3x oil and 1x oil/LPG jetties
- Flotta – 1x oil / LPG jetty
- Grangemouth / Hound point- jetties for oil, ethane, other liquid products

Export facilities for export of green ammonia by ship would need to include:

- Hydrogen reception & metering (a single ammonia plant could use hydrogen feedstock from multiple producers, assumed to arrive by on or offshore pipeline).
- Air separation unit (ASU - to provide the nitrogen needed)
- Haber Bosch production plant.
- Grid connection – to provide the electrical power needed for the ASU and the ammonia plant.
- Ammonia storage – equal to at least the volume of one tanker.
- Ship transfer facilities – pumps, metering, loading arms at suitable jetty facilities..
- Total footprint area of 20-30 ha.

3.4 Hydrogen Storage

Storage of hydrogen, or a hydrogen derivative, may be a requirement or may provide additional benefits when associated with export infrastructure.

Potential uses for hydrogen storage, and the types of storage that could support these are:

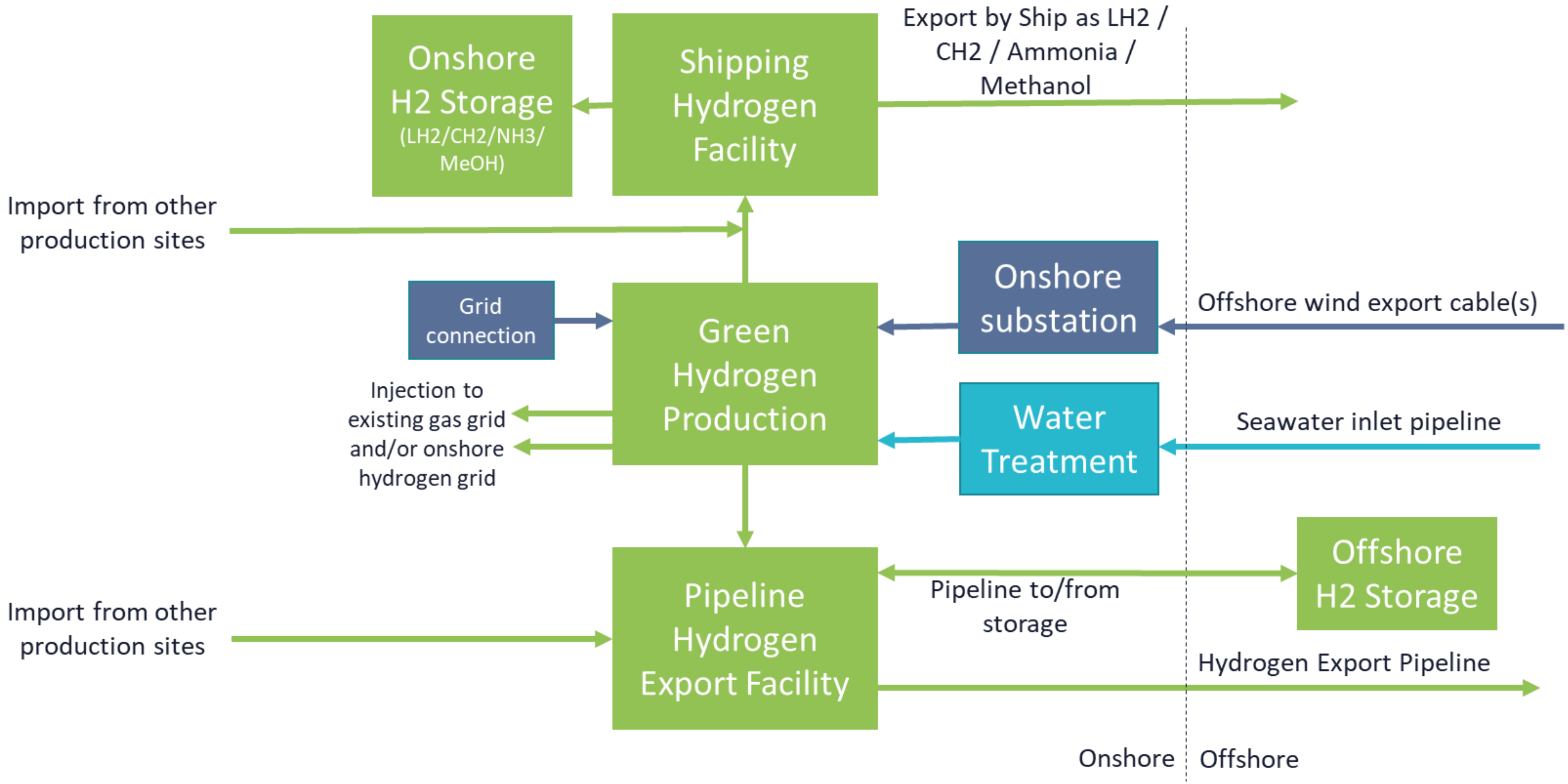
- Operational benefits / local distribution – small scale storage of hydrogen for distribution to local users, for example hydrogen fuelling, allows these systems to operate independently of production infrastructure. Most likely to be in the form of compressed gas cylinders. Port of Aberdeen and Subsea 7 are investigating subsea hydrogen storage for this purpose, where compressed gas cylinders are integrated into a subsea structure located underwater near the Port.
- Operational continuity – storage used as a buffer between a variable source and a downstream production plant (for example, an ammonia production plant) that requires to operate continuously. Storage volumes would typically be related to the plant capacity and of the order of days of hydrogen feedstock. Medium scale – above ground storage cylinders (smaller plants), salt caverns / line rock caverns (larger plants).
- Rapid offloading – storage used to balance very different production and export rates, particularly required when shipping hydrogen or a derivative. This production rate will be continuous at a lower rate. The ship loading rate will be much higher and will happen periodically. Storage at a minimum of one ship storage volume is a requirement. Assuming a liquid product is being shipped storage is likely to be above ground tanks (methanol / eFuels), vessels (ammonia) or spheres (liquid hydrogen).
- Capacity buffering – similar to operational continuity / interseasonal variation, but specific to pipeline export, there may be benefit in upstream storage associated with major pipeline export infrastructure as this would allow the pipeline to operate at capacity for a higher proportion of the time – allowing a smaller pipeline to deliver a higher average capacity.
- Interseasonal variation – if there are major seasonal variances between either the supply or the demand for hydrogen then large scale storage could be used to allow either continuous production or continuous demand. Large scale storage is most likely to be subsurface in salt caverns (smaller) or in depleted gas reservoirs or aquifers (larger).

Salt caverns are constructed within subsurface salt deposits, and are a proven method for storing gas. They can only be constructed where suitable salt deposits exists however, and such deposits are not present onshore in Scotland. BGS have (2005) performed preliminary assessment of offshore salt deposits for gas storage, this identified potential opportunity in the outer Forth and Central North Sea areas, however no strong candidates were identified. https://itportal.nstauthority.co.uk/information/papers/BGS_Report1.pdf

Edinburgh University have been evaluating offshore geology and suitability for subsurface hydrogen storage. The HyStorPor project is due to report findings in July 2023. Evaluations are at a preliminary / academic level and we are not aware of any specific subsurface hydrogen storage prospects.

3.4 Offshore Pipeline And Export Terminal Infrastructure

Hydrogen export infrastructure could be developed as a dedicated solution serving a single hydrogen producer and delivering to a single offtaker, or it could develop as part of a larger integrated export hub. The figure below illustrates potential integration of hydrogen production with pipeline export, offshore storage, gas grid connection and shipping export.

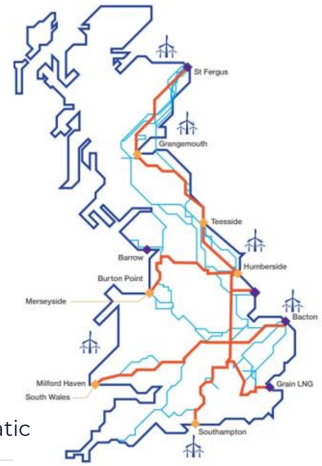


3.2 Domestic Gas Network Connections

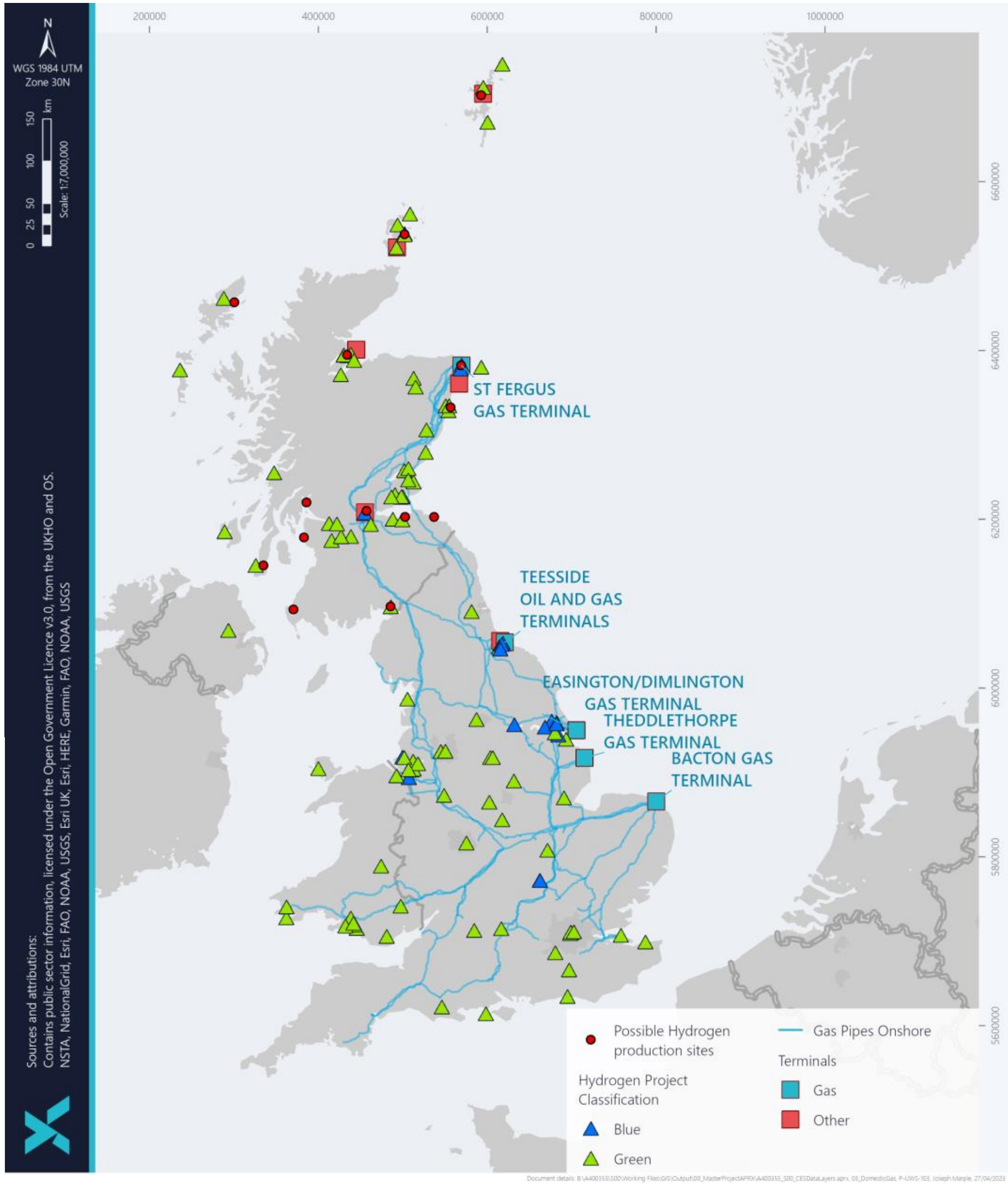
The principal connections into the UK onshore gas transmission system in Scotland are at St. Fergus. Other East coast UK gas terminals and are shown highlighted on the map opposite.

Project Union is a National Gas project which is investigating the potential for a new onshore hydrogen gas transmission network. Blending of hydrogen into the existing gas network is also being assessed. Opportunity to connect into such a system would present potential competition to an offshore hydrogen backbone. This would particularly be the case if there was a decision made by UK Government to allow hydrogen blending into the domestic gas grid, as this would immediately create a very easy to access demand for UK produced hydrogen.

A 'value for money' indication is due this year on hydrogen blending, and there is still significant uncertainty over hydrogen for heating as a decarbonisation strategy. This uncertainty on domestic demand could be a risk to achieving enough momentum behind an offshore export pipeline, in that hydrogen production developers may see a route to market through blending into the domestic gas network as an easier route to market, and may hold off on seriously looking an export route until these decisions have resolved.



Project Union Schematic



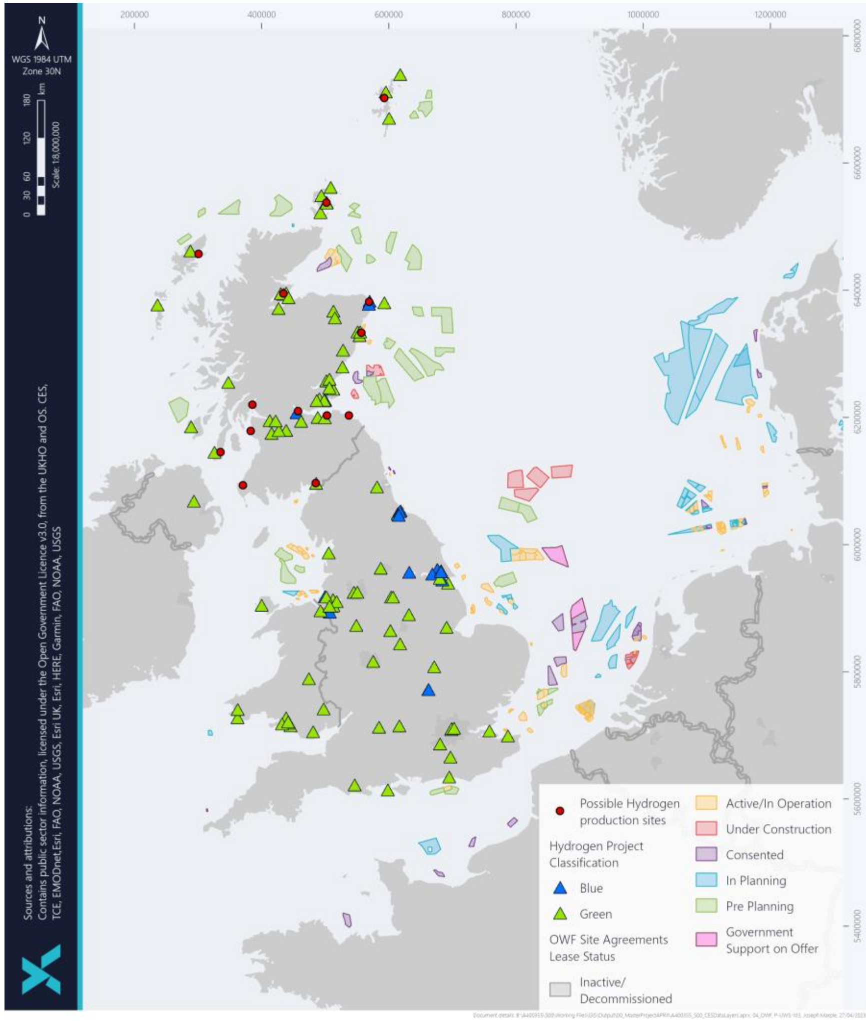
3.3 Offshore Renewable Energy Generation

There is a rapidly growing offshore wind market developing in the UK, and particularly in Scotland. EU countries and Norway are also rapidly increasing their offshore wind production targets. The map highlight active, under construction and consented offshore wind farms in the region as well as wind farms in the planning and pre planning stages.

Focussing on Scottish offshore wind potential, the recent Scotwind and INTOG rounds have announced 33 GW of seabed licencing awards, of which 28.2 GW is on the East side of Scotland and could export to the EU (as electrons or as hydrogen).

Potential offshore wind and hydrogen build out cases are presented in section 4.3. Scotwind and INTOG awarded areas on the East side of Scotland are listed below.

Lead Applicant	Round	MW	Lead Applicant	Round	MW
BP and EnBw	Scotwind	2,907	Bluefloat Energy	Innovation	99.45
SSE Renewables	Scotwind	2,610	Bluefloat Energy	Innovation	99.45
Renatis	Scotwind	1,200	Simply Blue Energy	Innovation	100
SPR	Scotwind	2,000	BP	Innovation	50
Vattenfall	Scotwind	798	ESB	Innovation	100
Thistle Wind Partners	Scotwind	1,008	Flotation Energy	TOG	560
Thistle Wind Partners	Scotwind	1,008	Cerulean Winds	TOG	1,008
Renatis	Scotwind	1,000	Harbour Energy	TOG	15
Ocean Winds	Scotwind	1,000	Cerulean Winds	TOG	1,008
Renatis	Scotwind	500	Cerulean Winds	TOG	1,008
SPR	Scotwind	3,000	Flotation Energy	TOG	1,350
Floating Energy Allyance	Scotwind	960	TotalEnergies	TOG	3
RIDG	Scotwind	2,000	Harbour Energy	TOG	15
Ocean Winds	Scotwind	500			
Mainstream RP	Scotwind	1,800		**TOTAL**	**28,206**
ESB Asset Management	Scotwind	500			

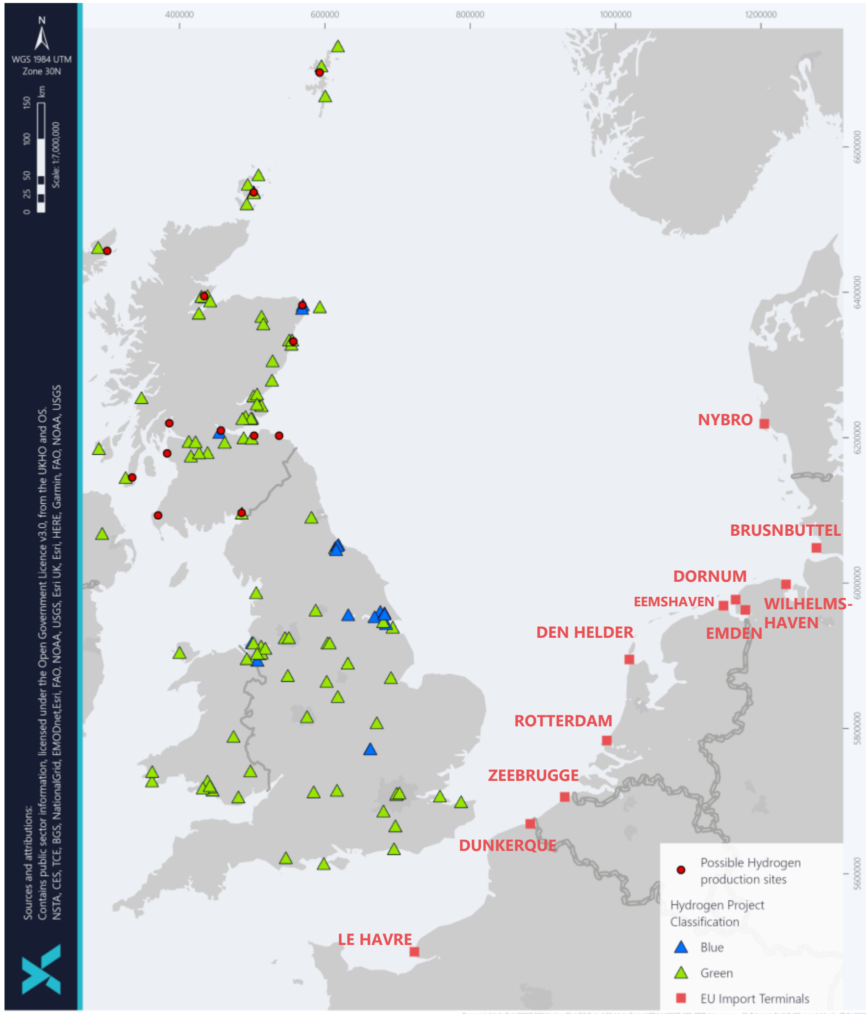


3.4 Import Terminals

Potential import terminals in the EU are indicated as red squares on the map opposite. All , apart from Dornum, have been identified as entry points into the proposed onshore European Hydrogen Backbone (EHB).

For the purpose of this study, Emden has been assumed as the pipeline landing point as this is the shortest and therefore lowest cost route to mainland Europe and also allows the route of an existing pipeline (Norpipe) to be followed. The use of Emden is purely illustrative, and strong cases exists for routes to other import terminal locations.

TERMINAL	COUNTRY	DESCRIPTION
Dunkerque	France	The largest terminal in continental Europe, Dunkerque is already connected directly to France and Belgium with two separate pipelines.
Zeebrugge	Belgium	Zeebrugge is the location of the Zeepipe terminal. Additionally, Belgium intends to become an import and transit hub in the EHB and Zeebrugge is proposed act as an energy hub.
Den Helder	The Netherlands	Den Helder is the terminal for the BBL gas interconnector and the NOGAT pipeline system. Den Helder is being investigated by the Dutch government for its potential as a hydrogen hub.
Rotterdam		The Rotterdam Port Authority is working towards introducing a large-scale hydrogen network across the port complex to transform Rotterdam into an international hydrogen
Dornum	Germany	Dornum is the receiving terminal of the Europipe I gas pipeline
Emden		The Emden terminal is the receiving terminal of the Norpipe gas pipeline. Emden Energy Park is encouraging a regional hydrogen-based economy..
Wilhelmshaven		Proposed German national hub for hydrogen with local hydrogen production and import of hydrogen via ammonia.
Hamburg		Hamburg is the site of the proposed Hamburg Green Hydrogen Hub.
Nybro	Denmark	Nybro is currently the entry point for the Danish offshore gas systems.



4 FUTURE OFFSHORE HYDROGEN TRANSPORT INFRASTRUCTURE

The Russia-Ukraine war has accelerated the need for energy imports to the EU to replace gas, and hydrogen is being strongly targeted as a vector. The EU's hydrogen demand target has been doubled in the REPowerEU plans to 20Mt per year by 2030, with 10 Mt per year of this imported from outside the EU.

Given the large potential offshore energy resource in Scotland, the emerging large hydrogen demand in the EU is a potential route to market for offshore wind developers. If hydrogen can be produced long term and a competitive price, this increasing demand could be a route to market for future offshore wind development rounds in Scottish waters.

The EU is considering import of hydrogen from diverse sources including from the North Sea and Baltic regions to the North, from North Africa and the Middle East to the South and from central Europe (including Ukraine) to the East. MOUs have been signed between Canada and Germany for export of green ammonia from production sites in Nova Scotia and Newfoundland.

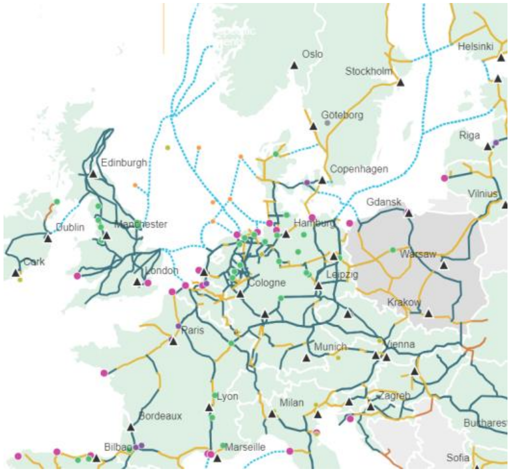
An advantage of the North Sea area (UK and Norway) is the relative proximity and relatively shallow water depths. Over distances of up to 1500-2000km hydrogen can be transported by pipeline without the need for intermediate compression. This results in transportation costs and transportation energy penalties that are relatively low compared with other transport means such as ammonia, methanol, LOHC or cryogenic liquid hydrogen. That in turn means higher production costs (higher input energy costs) can be tolerated without other regions out competing.

It is expected that hydrogen export infrastructure will emerge as a mix of liquid transport by ship (initially as ammonia) and pipeline transport of hydrogen gas.

In response to this emerging demand, a number of offshore hydrogen production projects are emerging in the North Sea area, which are illustrated overleaf. Note that these projects are all at early stages, and some are purely illustrative/conceptual.

Key announcements have been:

- **Norway / Germany H2 Pipeline** – RWE/Equinor/Gassco
  Export of blue and green hydrogen from Norway to Germany for hydrogen-ready, gas-fired power plants..
- **AquaDuctus** – Offshore H2 pipeline to Germany – fluxys / Gasunie
  Plan for phased development of a hydrogen pipeline transporting hydrogen produced offshore Germany to shore. Initial 15MW phase, scaling to 1GW / 150km, with design for further expansion offshore.
- **European Hydrogen Backbone Link** - NZTC led consortium inc. CES
  Investigating the feasibility, costs and design aspects of a pipeline connecting Scottish production sites to mainland Europe. Co-funded by Scottish Government and industry
- **MOHN** – German Federal Government / Fraunhofer IEG / Cruh21
  German federal government programme focussed on cross-border collaboration in the North Sea Region.



4.1 Proposed Hydrogen Pipelines To EU (1)

In recent months several hydrogen pipelines projects have been proposed to import hydrogen to the EU.

AquaDuctus – Offshore H2 to Germany

NZTC – European Hydrogen Backbone Link

RWE / Equinor – Norway / Germany H2 pipeline

MOHN – German Federal Gov. (Cruh21 / Fraunhofer IEG)

4.1 Proposed Hydrogen Pipelines In North Sea (2)

North Sea Gas TSOs Declaration

On April 24th 2023 as part of the North Sea Energy Summit gas TSOs from 8 countries published a declaration of intent to work together to accelerate development of hydrogen production and of a hydrogen pipeline network covering the North Sea Region.

The graphic opposite is taken from the published document and should be noted as illustrative only.

A key element of the document is centred around the transmission infrastructure and actions required to support development of this infrastructure – see ‘Our call for action’ extract.

Of the TSOs involved it is noted that Gassco, fluxys, Gasunie, Gascade and Energinet either have existing offshore gas pipeline infrastructure ownership or have well developed offshore gas pipeline projects. National Gas in the UK has onshore assets only, and the illustration reflects this, with any hydrogen production from Scottish sits being shown connected to an onshore UK hydrogen pipeline network.

Collaboration of this kind to address some of the current uncertainty and misalignment between UK and EU would be a positive outcome that would support development of any third party infrastructure development.

It is notable that in both this document and in publications and illustrations relating to the European Hydrogen Backbone, there is no clear offshore pipeline route shown from Scotland to mainland Europe. Promoting the opportunity for offshore pipeline export of hydrogen from Scotland to such forums would increase visibility of this option on the EU stage, to initiatives such as this and to the European Hydrogen Backbone.

Ref: [Gas TSO declaration - EN.indd (grtgaz.com)]

Our call for action

In order to make it happen, gas and electricity TSOs, future hydrogen network operators, policymakers and stakeholders have to cooperate on key aspects of the future energy system in the North Sea. The gas TSOs put forward the following key action points:

- A cost-benefit methodology and its implementation for the optimal deployment of electricity and hydrogen in a long-term perspective and addressing cross-border cost allocation and financing issues between countries, alongside with possibilities to initiate bilateral initiatives;
- Supporting the development of a legal and regulatory framework for the optimal deployment of the necessary hydrogen transmission infrastructure, in order to enable market players to make commitments and enable TSOs/HNOs to build the infrastructure;
- Supporting the development of a legal and regulatory framework for the optimal deployment of the necessary CO_2 transmission infrastructure, in order to enable market players to make commitments and to build the infrastructure;
- The development of a market framework enabling the early deployment of the offshore hydrogen value chain, in order to supply hydrogen at competitive prices for downstream markets;
- The Harmonisation of hydrogen interoperability and quality parameters for the offshore backbone, in order to enable trading across transmission systems without unnecessary barriers;
- The speeding-up of permitting processes and maritime spatial planning (master plan), with the involvement of electricity and gas TSOs;
- Establish a system of working groups with the gas and electricity TSOs, future hydrogen network operators, policymakers and other relevant stakeholders to ensure an optimal cross-country coordination in tackling the above-mentioned action points.

4.2 Potential Scotland-Germany Pipeline Route

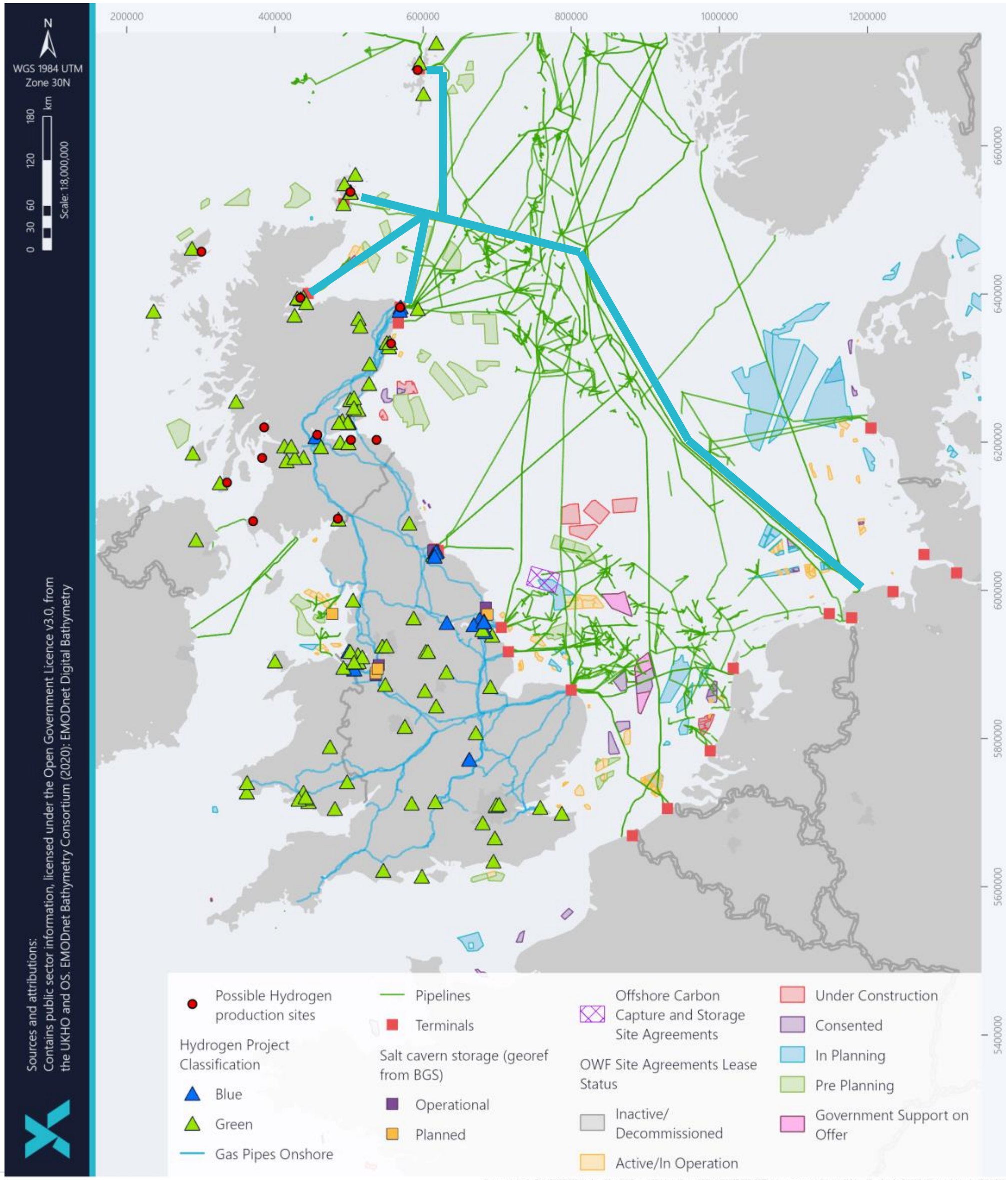
CES are part of NZTC's Hydrogen Backbone project which has reviewed potential routes (onshore and offshore) for new hydrogen pipelines to connect hydrogen produced in Scotland to Europe.

The most direct route is an offshore route to Germany. This has the advantage of also being able to largely follow existing pipeline routes, which helps with respect to availability of technical information on the route and on minimising environmental impact.

A single large pipeline with input spurs from different production areas is proposed. The route is indicated on the infrastructure map (schematically, not an engineered route). Input spurs are shown from Shetland, Orkney, Cromarty Firth and St Fergus.

The assumptions for the pipeline that have been used to generate cost estimates are:

- Rationale for new pipeline: It is considered unlikely that suitable lines (large diameter, making landfall in Europe) would have clear availability for hydrogen in a timescale that would allow development of export infrastructure in a timeline that could support Scotwind and future developments looking to come online before 2040.
- Route:
  - Length - 1000km main backbone from Orkney, 1500km total (incl spurs)
  - No / location of feeds - 4 (Shetland, Orkney, Cromarty Firth, St Fergus)
  - no. of countries the line passes through – UK / Denmark / Germany
  - Landing location(s) in Europe - Germany
- Size – linked to capacity – see following slides for capacity vs required size.
- Operating pressure - 80 barg max. entry / 10 barg min. arrival.
- Materials – X52 carbon steel, concrete coated
- Intermediate compression requirements – none.
- Hydrogen Production Potential – based on available wind resource / potential areas offered. This has been assessed by estimating potential and % developed as hydrogen for onshore wind, INTOG, Scotwind and a nominal estimate for future development beyond this. Low and High estimates have been made. Hydrogen production has been estimated based on the stated assumed wind capacity factor, and an assumed electrical demand of 55kWh / kg Hydrogen produced.



4.3 Hydrogen Production Potential

		Installed Wind Turbine Capacity - GW				tonnes Hydrogen per day (tpd)			
SOURCE	Assumed capacity factor	Total Capacity	Capacity in Pipeline Catchment	Capacity developed as hydrogen - low	Capacity developed as hydrogen - high	Peak - low	Average - low	Peak - high	Average - high
ONSHORE	26%	20	6	1.5	3	720	187	1440	374
		20GW ambition by 2030. 9GW in operation. Approx. 12GW additional capacity to be developed by 2030.	Assumes 50% the 12GW future in catchment area - North of Scotland & Northern Isles	25% of catchment sites	50% of catchment sites				
INTOG	50%	5.4	5.4	1.4	2.2	672	336	1056	528
				assumption based on 50% of IN and 20% of TOG project capacity (i.e. effectively assumes 1 TOG project supplies O&G + hydrogen production)	assumption based on 50% of IN and 40% of TOG project capacity (i.e. effectively assumes 2 TOG projects supplies O&G + hydrogen production)				
SCOTWIND	50%	27.6	20.4	5.1	10.2	2448	1224	4896	2448
			East coast SW sites, including Shetland clearing areas	assumption based on 25% of sites in catchment area	assumption based on 50% of sites in catchment area - high case is based on the gap between the current holistic network design position & awarded Scotwind areas				
SCOTWIND FUTURE	50%	40	30	15	22.5	7200	3600	10800	5400
		unknown - but assuming a figure higher than current SCOTWIND to represent extent of areas available & impact of 1st round on reducing riks	assume 75% is East of Scotland & Northern Isles	assumption based on 50% of sites in catchment area. Assumption that future Scotwind would be more likely to target export opportunities and that would be more likely to mean hydrogen as route to market	assumption based on 75% of sites in catchment area. Assumption that future Scotwind would be more likely to target export opportunities and that would be more likely to mean hydrogen as route to market				
ROUND 4	40%	not included							
GERMANY	40%	not included							

4.4 Pipeline Capacity

Three capacity scenarios were identified using the production potential on the previous page:

- Low (indicated by blue border) includes onshore low and INTOG low production.
- Mid (indicated by green background) includes onshore high, INTOG high and SCOTWIND low production
- High (indicated by red text) includes onshore high, INTOG high, SCOTWIND high and SCOTWIND+ high production

Based on the inlet and outlet pressure assumptions, and the assumption of no intermediate compression, this gives the hydrogen production capacity and expected pipeline sizes below. Note that pipeline sizes are shown for peak and average hydrogen production rates. If an offshore wind farm is dedicated to hydrogen production, the average rate represents the average rate of production through life. In reality the plant will operate at 100% (peak) capacity for some periods, and at a capacity less than that at other times. The pipeline sizing is based on pressure drop and/or gas velocity constraints, therefore if there is no intermediary hydrogen storage upstream of the pipeline, it must be sized to handle the peak rate. Using the mid case as an example, there is potential to use a 32" line if upstream storage was used to pass a steady hydrogen production rate to the pipeline inlet, whereas a 42" line is needed to handle the equivalent peak rate with no upstream storage. This difference is size corresponds to a difference of £700M.

A single 42" line could handle the Mid case at peak rates (i.e. assuming no upstream storage). Assuming large scale hydrogen storage is developed, that then allows effective capacity to increased by up to a factor of 2 (this factor will depend on the size of storage made available). To give capacity for the high case, a second pipeline would be needed.

A pipeline size that covers the Mid case peak rate has been carried forward as the basis for the commercial assessment. A 32" line has been selected. This would allow a peak flow rate corresponding to the average output of approximately 10GW installed offshore wind generation, or to the peak production rate from approximately 5 GW installed offshore wind. A scenario is envisage where there is initially 5GW (or less) electrolyser capacity from offshore wind, with potential for the pipeline capacity to be used ore efficiently either by incorporating hydrogen storage upstream, or be using electricity from the grid to 'ullage fill' capacity in the pipeline when wind speeds were low.

		Wind Capacity developed as hydrogen included in Scenario	Total capacity developed as hydrogen - GW	Peak hydrogen production - tpd	Average hydrogen production - tpd	Pipeline size (range) - based on peak rate	Pipeline size (range) - based on average rate
Scenarios	Low	Onshore Low – 1.5 GW INTOG Low – 1.4 GW	2.9	1392	523	26-28"	18"-20"
	Mid	**Onshore High – 3 GW INTOG High – 2.2 GW Scotwind Low – 5.1 GW**	**10.3**	**4944**	**2126**	**42" +**	**30 - 32"**
	High	Onshore High – 3 GW INTOG High – 2.2 GW Scotwind High – 10.2 GW Scotwind Future High – 22.5 GW	37.9	18192	8750	3 off 42" or 2 off 42" plus intermediate compression	2 off 42"

4.5 Pipeline CAPEX / OPEX / Development Schedule

High level costs have been estimated for a 32" main backbone line from Flotta, with connecting spurs from Sullom Voe, Cromarty Firth and St. Fergus. The estimate is considered Class V.

The costs for the main backbone line (just under 1000km in length) are approximately £2,000M, with £700M for the three spur lines.

The costs is strongly influenced by the pipeline design pressure and it is considered that balancing pipeline pressure, capacity and cost would be a key next step in the design process. Higher pressure means more capacity, but also mean higher wall thickness and higher pipeline procurement costs. Over a very long pipeline there is considerable optimisation opportunity.

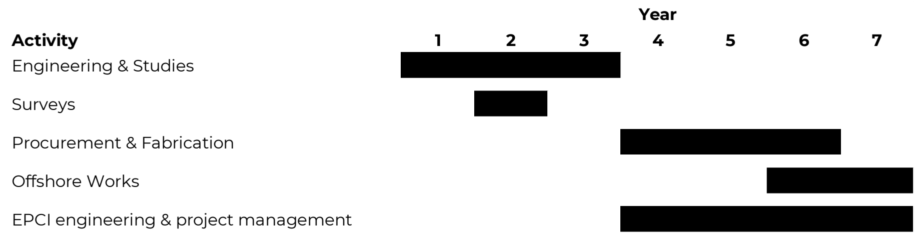
Major risks in the cost estimates are:
- Steel / linepipe costs – particularly due to quantities required.
- Installation vessel availability and costs.
- Seabed condition – surveys are needed to understand the seabed conditions and to remove uncertainty on costs associated with pipelay and pipe on-bottom stability. There is potential for early reduction of these uncertainties when following existing pipeline routes, particularly if information from previous surveys can be accessed / shared.

In terms of scale, this pipeline is on the same scale as the Langeled and Nordstream projects – i.e. this would be one of the longest offshore pipelines on a global scale. It would be world leading if a conventional offshore gas pipeline, and certainly world leading as an offshore hydrogen pipeline.

A total development schedule of 7 years has been estimated. This is broken down as 3 years pre-FID, with this duration expected to be driven by the timeline needed to complete route surveys and achieve the permits and consents required. Further study into the permit process and available data may be able to reduce that timeline. From FID, a 4 year project duration is estimated. The critical path is assumed to be procurement & coating of linepipe. Installation is assumed to be complete within 2 years. Further study may be able to reduce that further – though linepipe and installation vessel availability are seen as the major risk to schedule.

OPEX is estimated at £20M per year average, covering inspection and integrity management activities.

COST BLOCK	£M
Procurement and Fabrication	1,202
Offshore Works	411
Installation Contractors Engineering and Management	161
COMPANY Costs	266
Insurance	53
Contingency	703
TOTAL (£M)	**2,797**



A potential 7 year project schedule, with 3 years to FID, could align with Scotwind and INTOG developments, making hydrogen a valid route to market, but for this to happen the recommendations laid out in section 8 would need to be implemented to firm up on the support and subsidy mechanisms, remove regulatory uncertainty, and to connect suppliers with demand, such that a decision on hydrogen vs. grid can be made by developers in an appropriate timeframe. This certainty of route to market would need to be in place to allow FID, which sets a timeframe of 2 – 3 years ahead of intended start-up.

5 PROJECT DEVELOPMENT PROCESS

The overall project development process is outlined below. The following sections (sections 6 – 9) discuss the regulatory, ownership, funding and financing options available to this type of project.

Initiate
- Renewable hydrogen objectives
- Considerations on hydrogen specific regulation in both UK and EU

EOI
- Scottish Government to gauge private sector interest in the project by increasing visibility, providing information on the objectives and expected outcomes
- Consider various funding mechanisms available from UK/EU
- Renewable hydrogen value chain will require significant collaboration and alignment

Ownership
- Various ownership models to consider, each based on different scenarios of supply & demand private sector interest
- Each model offers different monetisation opportunities for the public sector throughout project lifecycle
- Contracting models to determine level of involvement from the private sector throughout the project lifecycle and appropriate transfer of risk

Revenue Model & Creditworthiness
- Pipeline payment mechanisms
- Counterparty risk allocations
- Creditworthiness implications

Business Model & Viability Gap Support
- Business model will require consideration on the infancy of hydrogen market
- Project will require de-risking to reach FID stage
- Viability gap will need to be addressed

Financing
- Optimise cost of capital through a combination of debt and equity
- Various lender options, each with different capacities and terms
- Determine appropriate lender for H2 project based on combination of above and level of risk each lender is willing to adopt

H2 Export Pipeline Project
- From feasibility to FID, project will require funding through equity or grants
- CES should engage with lenders throughout the development stage to define the financing package and optimise the capital structure ratio

6 REGULATORY REVIEW - HYDROGEN IN CONTEXT OF SCOTLAND AND EU

Both Scotland and the EU have committed to a future where hydrogen plays a significant role in decarbonising energy systems.

Scotland / UK

Item	Description
Strategy	• Scotland to be a leading producer and exporter of hydrogen • 0.45 Mt of renewable hydrogen by 2030 • UK – decarbonization of existing UK hydrogen supply
Hydrogen Supply	• By 2030 10GW (UK) & 5GW (Scotland) of hydrogen • Approx. 0.45 Mt of **renewable hydrogen** produced annually by 2030, increasing to approx. 3.3 Mt by 2045 • ScotWind has potential to deliver 27.6 GW of offshore wind power
Hydrogen Demand	• UK industry uses approx. 0.7 Mt of grey hydrogen at present • Industry, Transport, Heating
Hydrogen Export	• By 2045, approx. 2.5 Mt exported to the UK and EU • Proximity to growing centres of hydrogen demand in Europe
Funding Support	• Scotland's Emerging Technologies Fund • UK Net Zero Hydrogen Fund • UK Hydrogen Business Model

EU

Item	Description
Strategy	• REpowerEU - Domestic market creation - International imports to the EU - Transparency and coordination - Streamline existing financing instruments • 20 Mt of renewable hydrogen by 2030
Hydrogen Supply	• 10 Mt produced in Europe • EU current renewables generation is not enough to meet the needs. An estimated 500 TWh of additional renewable electricity is needed to meet EU targets
Hydrogen Demand	• Import 10 Mt of hydrogen by 2030
Hydrogen Export	• Focus is on import rather than export • Canada – Germany Hydrogen Alliance MoU • EU signed MoUs with: Namibia, Egypt, Kazakhstan, Morocco to develop renewable hydrogen value chains
Funding Support	• European Hydrogen Bank • Innovation Fund • Connecting Europe Facility – Energy • Horizon Europe

6.1 Regulatory Review

The current regulatory framework for natural gas can be amended with minimal changes to accommodate hydrogen regulation. The key uncertainty remains on hydrogen certification and price/funding mechanics.

Item	Scotland (UK)	EU	Risk	RAG
Hydrogen Certification	• Gas Act 1986 includes hydrogen in the definition of 'Gas', making it subject to regulation within the gas network • Definition of green hydrogen and certification is still being finalized, with a plan by 2024	• Required to extend principles of EU legislation that cover gas networks to hydrogen networks • Renewable Energy Directive – Delegated Act to define under which conditions hydrogen can be considered as an RFNBO.	• Hydrogen infrastructure will remain quite limited until late 2020s • Hydrogen certification regime is yet to be fully established and tested • EU using a regulatory model based on extensive natural gas network	
Hydrogen Price Mechanics	• Business model development ongoing, but current view for hydrogen generation is a CfD style support mechanism • For Hydrogen transport and storage numerous models are still being explored.	• Prices for gases shall be formed on the basis of demand and supply • Entry-Exit system, cross border tariffs removed	• Assumptions on size of the market and how the market will develop • Integration of supply and offtakers and viability gap will need to be established • Network operators will be required to agree on appropriate revenue sharing mechanisms	
Funding Support	• UK Research and Innovation • Net Zero Hydrogen Fund	• Clean Hydrogen Partnership • European Hydrogen Bank	• Funding support for hydrogen pipelines is still evolving and will require engagement with Governments to provide initial funding and clarity of role within hydrogen export infrastructure	
Blending	• Decision to be made by Government end of 2023 on role of blending for heating		• The role of blending has not yet been established within hydrogen networks	
Hydrogen Pipelines	• Gas Safety Management Regulations 1996 • Pipeline Safety Regulations 1996	• TEN-E Regulation • ACER • CEER	• Regulatory regime can be adapted to accommodate hydrogen transportation via pipelines	
Environmental Permitting	• EIA Regulations • Planning Act (include hydrogen manufacture, storage and transportation facilities)	• EIA Regulations • Germany – Federal Act for the Protection of Nature	• Environmental permitting for hydrogen pipeline is likely to be comparable to natural gas pipeline	
Licencing and Consents	• Petroleum Act 1998 (amend 'Relevant substances' to include hydrogen) • Energy Act 2008 (amend 'Gas' to include hydrogen)	• Germany – Federal Mining Act	• Would require cross-border consent between Scotland and EU which would be achieved through Government negotiations. • This has been achieved previously for natural gas pipelines and interconnectors	

6.2 EU RFNBO Hydrogen Certification

The commission have issued detailed rules to define what constitutes renewable hydrogen in the EU with the adoption of two Delegated Acts required under the Renewable Energy Directive. These rules are to ensure that RFNBO fuels are only produced from **additional** renewable electricity generated at the same time and area as production.

Direct Renewable Electricity Connection

- Connected directly or same installation
- Generating installation came into operation not earlier than 36 months before the electrolyser installation
- Electricity generator is not connected to the grid, or a smart metering system ensures no electricity is taken from the grid

Grid Renewable Electricity Connection

- Average proportion of renewable electricity exceeded 90% in previous calendar year
- Emission intensity of grid connection is lower than 18 gCo2eq/MJ. Provided:
    - One or more PPAs are established with renewable electricity generators for an amount at least equivalent
    - Temporal (1 month to 2030 then 1 hour) and Geographical correlations conditions are met
- Electricity used to produce is consumed during an imbalance settlement period. Provided:
    - Renewable energy sources were redispatched downwards
    - Reduced the need for redispatching by a corresponding amount.
- Where above are not met:
    - Comply with conditions on additionality, temporal correlation and geographic correlation

<u>UK Green Hydrogen Certification</u>

- Meet a GHG emissions intensity of 20 gCo2e/MJ
- GHG intensity data per 30 min settlement period

CertifHy®

Initiated at the request of the European Commission and is financed by the Clean Hydrogen Partnership to help drive the development of the clean hydrogen market.

6.3 EU Funding Mechanisms

A number of EU funding support mechanisms exist to support decarbonisation technologies for EU member states.

Item	Connecting Europe Facility	Recovery and Resilience Facility	InvestEU	European Hydrogen Bank
Objectives	• Accelerate investments in Europe's transport, energy and digital infrastructure networks. • Key EU funding investment for targeted infrastructure investment at EU level	• Mitigate economic and social impact of COVID-19 and make economies more sustainable • EU proposed to make targeted amendments to RRF Regulation to integrate REPowerEU chapters	• Provide support to physical and human capital investment • Promote EU policy in making EU climate neutral by 2050	• To stimulate and support investment in sustainable hydrogen production • Accelerating investment and bridging investment gap for EU to produce 10 mt domestically by 2030 and 10 mt imports
Relevance for Hydrogen Imports	• No explicit funding for international hydrogen projects • Funds could be used for infrastructure projects that also benefit imports (e.g. cross border pipelines)	• No explicit funding for international hydrogen projects • Aims of RRF relate to ramp-up of hydrogen economy also benefiting from imports	• Similar to CEF and RRF, no direct investments are foreseen for international projects • InvestEU can support development of the hydrogen economy by promoting clean and sustainable	• Focus on domestically produced hydrogen initially • Future years will help facilitate import of foreign produced hydrogen, no clear support at this stage
Financing Details	• CEF will dedicate at least 60% of its budget to EU climate objectives • Projects must qualify as PCIs	• Funding is disbursed in form of non-repayable financial supports and loans	• Funds allocated under indirect management scheme through European Investment Bank Group • InvestEU may provide funding in form of grants and loans for demonstration of new technologies	• Bridge to enable hydrogen production cost to be more competitive • Auction rounds commence in Autumn 23 with EUR 800 m available
Budget	• EUR 5.84 billion, out of which 15% should be allocated to cross-border renewable energy projects	• EUR 337.97 billion in grants • EUR 389 billion in loans	• EUR 372 billion	• EUR 3 billion
Type of Support	• Mix of grants, procurement and financial instruments	• Mix of grants, procurement and financial instruments	• Mix of loan/guarantee and other financial instruments	• Auction
Payment modalities	• Lump sum payments	• Performance based	• Lump sum payments	• Lump sum payments

6.4 German Funding – H2 Global

A new hydrogen focused funding support mechanism has been established by German government to accelerate hydrogen import to Germany and the EU.

Objective
To support ramp-up of green hydrogen and hydrogen derivatives to initiate imports to Germany and the EU as quickly as possible.

Role
H2Global acts as contractual partner between supply and demand side at an interface in the supply chain.

Compensates for the differential costs between higher purchase and sales prices. Differential costs are covered by public grants

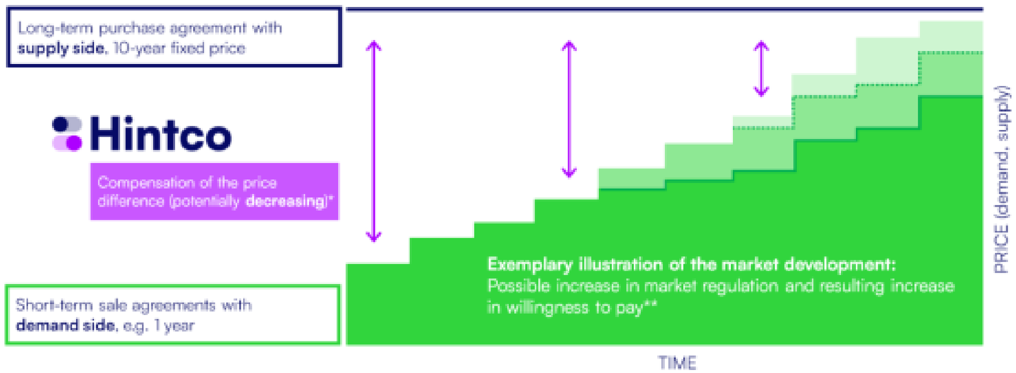
Structure
Similar approach to CfD with a competition based bidding procedure and long term purchase agreement with supply side at 10 year fixed price and short-term sales contracts on the demand side.

Enables funding gap between supply prices and demand prices to be bridged through grants.

Funding Source
First H2 Global window is from the German Federal Ministry for Economic Affairs and Climate Action (BMWK).

H2Global will establish foreign trade partnerships with countries in which green hydrogen can be produced efficiently due to their geographical location. BWMK will provide funding of EUR 900 million.

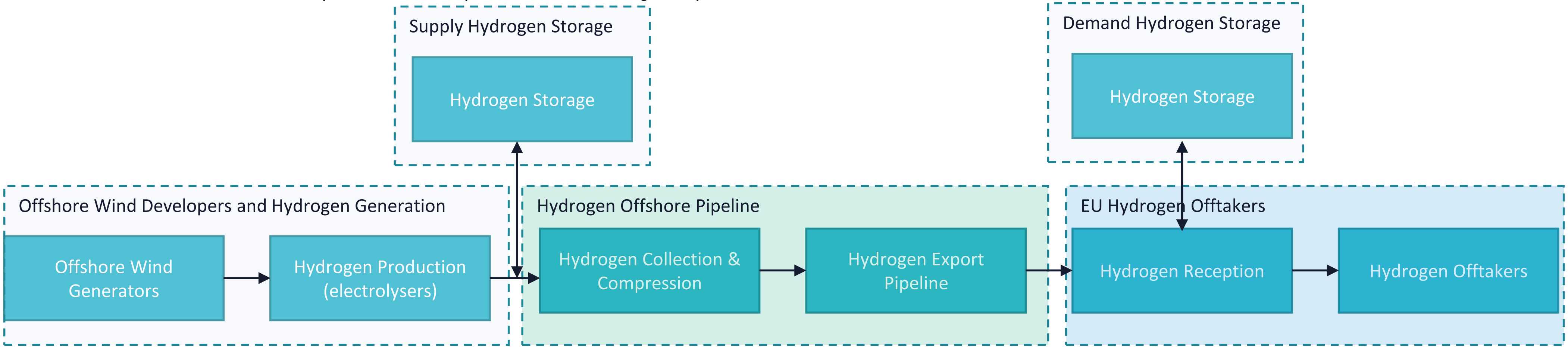
H2Global will engage with other public entities to provide further funding. Scotland/UK should assess whether involvement would support roll out of hydrogen generation and export capability to EU market.



*The actual amount of the price difference at the time of the auction depends on the real H2 price development. The capital requirements of the HINT.CO GmbH are accordingly linked to the purchase quantities actually guaranteed in the HPA and the H2 price development.
**Exemplary illustration

7 OWNERSHIP MODELS – VALUE CHAIN

Hydrogen offshore pipeline is part of a broader hydrogen ecosystem, which will require alignment across the value chain with collaboration between offshore wind generators, and hydrogen offtakers in EU. The hydrogen pipeline will likely need to be unbundled from production (as described by EU)

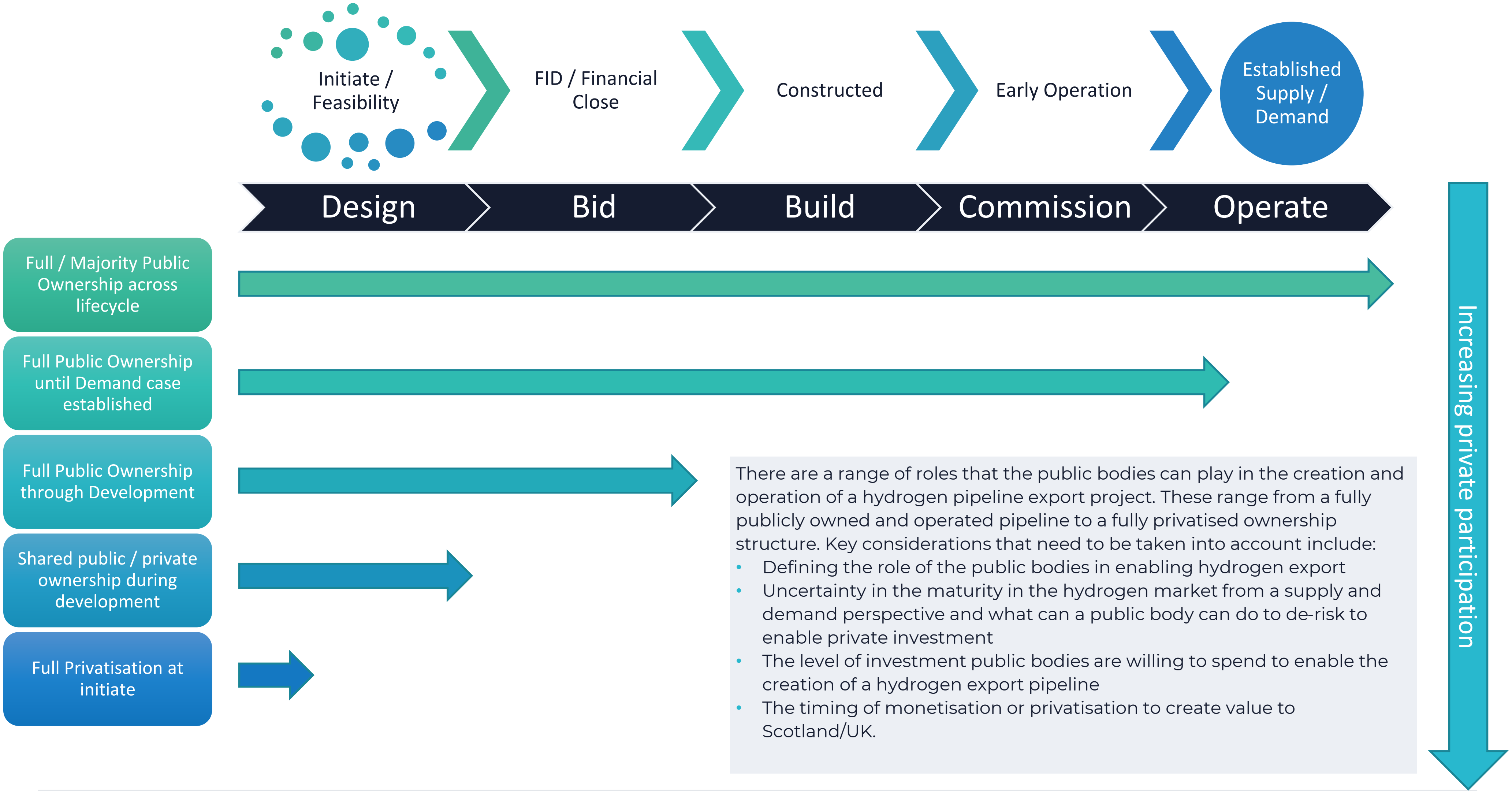


Item	Description
Role	• To generate electricity and hydrogen for offtake
Structure	• Privately led consortiums
Revenue Stream	• Offtake contract with users
Government Role	• Lease support for offshore wind • CfD funding for offshore wind/hydrogen producers
Risks	• Consenting of offshore wind • Consenting of hydrogen plant • Securing offtake contract

Item	Description
Role	• To transport hydrogen from supply to demand centre
Structure	• Public, Private or PPP
Revenue Stream	• Tariffed revenue from shippers
Government Role	• Defining hydrogen transport business model • Engagement with offtakers to support hydrogen production
Risks	• Environmental permitting • Large CAPEX • Requires established hydrogen market (supply + demand)

Item	Description
Role	• Offtake of hydrogen for decarbonization
Structure	• Public and Private
Revenue Stream	• Green products, reduced ETS liability
Government Role	• Subsidy support to offset viability gap between existing fuel and hydrogen cost
Risks	• Higher input costs • Intermittent supply of renewable hydrogen

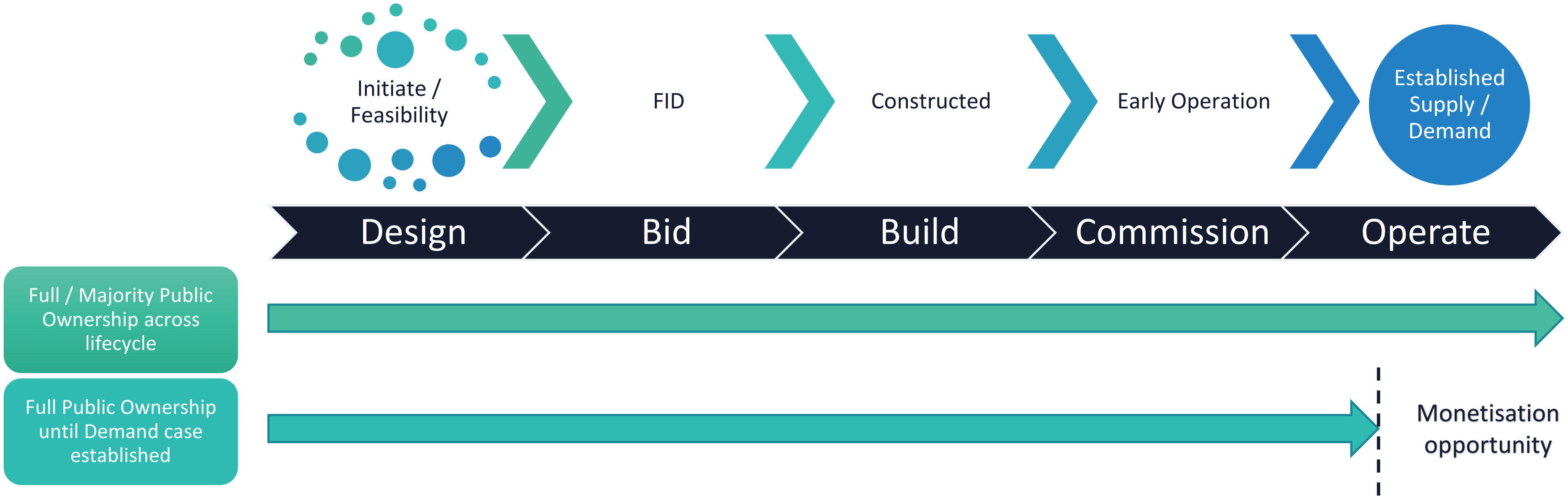
7.1 Summary Overview Of Ownership Models Across The Lifecycle



There are a range of roles that the public bodies can play in the creation and operation of a hydrogen pipeline export project. These range from a fully publicly owned and operated pipeline to a fully privatised ownership structure. Key considerations that need to be taken into account include:

- Defining the role of the public bodies in enabling hydrogen export
- Uncertainty in the maturity in the hydrogen market from a supply and demand perspective and what can a public body can do to de-risk to enable private investment
- The level of investment public bodies are willing to spend to enable the creation of a hydrogen export pipeline
- The timing of monetisation or privatisation to create value to Scotland/UK.

7.2 Ownership Models Across The Lifecycle: Highly Uncertain Supply & Demand Case



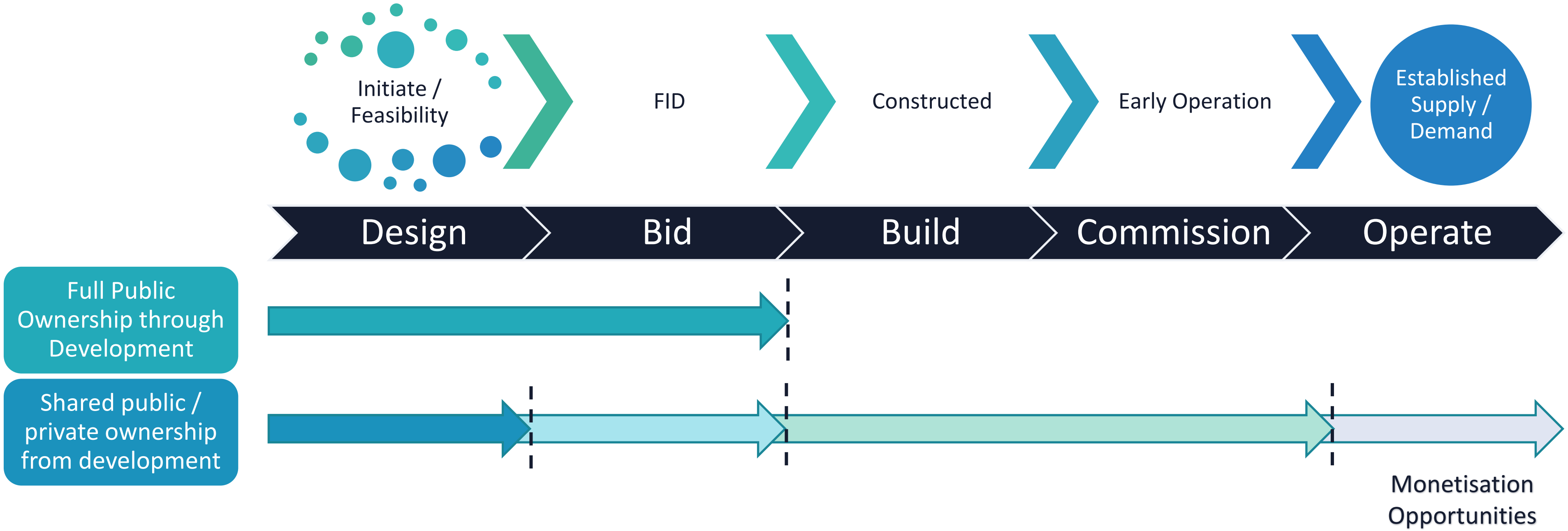
Drivers

- Scotland views H2 export as strategic and wants nationalised export infrastructure to enable export of future hydrogen production
- Private sector appetite for investment in an immature market means public investment is required to derisk the route to market
- There remains uncertainty in
  - Business model
  - Hydrogen Supply
  - Hydrogen Demand in EU and creditworthy offtakers
- Public ownership within the project can provide confidence to private investors that there is a supportive framework to develop hydrogen export infrastructure. This can potentially support acceleration of the project through the role of public ownership.

Implications for public body

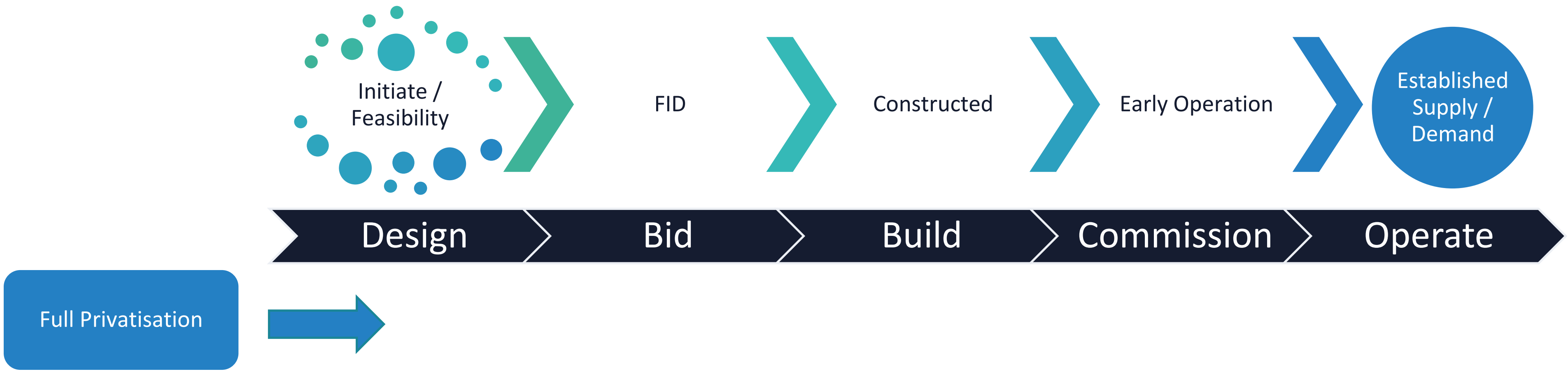
- Derisk project through nationalised export infrastructure
- Requires high level of involvement of public sector to create, design, build, own and operate a strategic infrastructure
- Engagement with offtakers and relevant Governments to create credible demand to support hydrogen supply
- High capital spend for Scotland to enable derisking of a credible export route for hydrogen generated in Scotland.
- Derisk development of H2 supply in Scotland
- Future monetization opportunity exists when supply and demand is established where a partial or full privatization can be realised

7.3 Ownership Models Across The Lifecycle : Proven Demand Case And Established Revenue Model



Drivers	Implications for public body
• Scotland views H2 export as strategic, but requires private capital and expertise to design, deliver and operate the project • Evidence that there is some certainty in supply/demand through MOUs / offtake agreements but not sufficient for a fully private ownership • Revenue model is understood and being established for hydrogen export	• Scottish government provides no / low return equity to incentivise private capital and de-risk the project • Requires upfront public spend to frame the opportunity and provide initial derisking • Engagement with hydrogen supply and potential offtakers is required to frame the opportunity and export potential • Monetisation opportunities exist at each stage of the project lifecycle to form a co-partnership with private enterprises • Scotland could retain a minority stake over the asset lifecycle to enable visibility of the hydrogen export pipeline. This has been achieved in Norway and Netherlands for natural gas pipelines.

7.4 Ownership Models Across The Lifecycle : Commercial Privately Led Development And Operation

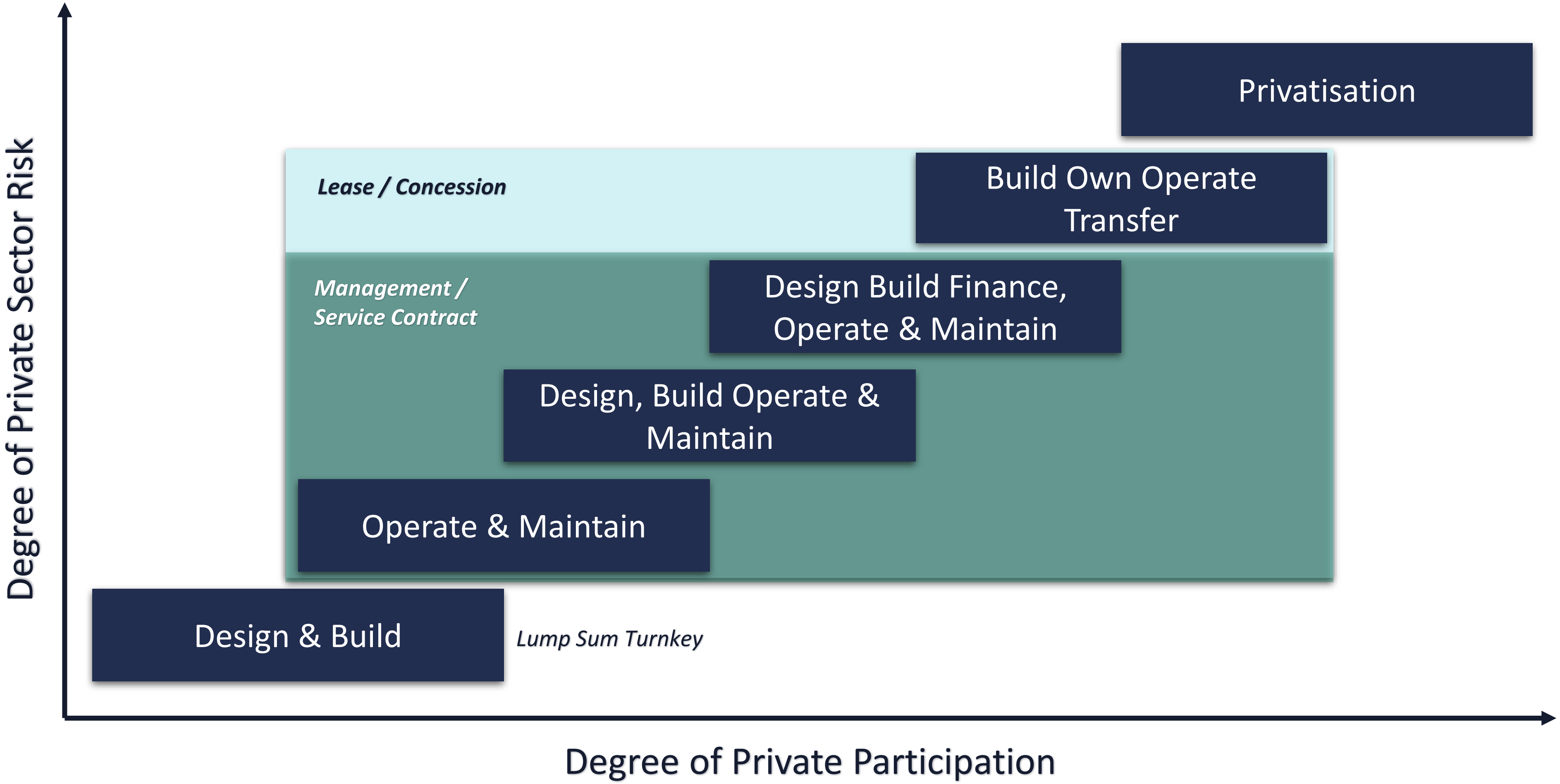


Drivers	Implications for public body
• Hands off approach and let the private enterprise develop the pipeline. • Clear incentive for private sector • Clarity on business model and subsidy support will be required initially until market is established	• Scottish government has no equity in the project • Subsidy funding is likely still required in infancy of the project and operation due to viability gap between supply and demand costs which will impact pipeline revenue model • Timeline is dictated by the private sector

7.5 Risk allocation, project efficiency & Public Private Partnership (PPP's)

Public Private Partnerships	• With constrained public budgets, this has led governments to pursue collaborations with the private sector. Known as public private partnership (PPPs) for the financing, construction and/or operation of assets that are typically large scale, capital intensive and long life assets. • Whilst a broad term with many interpretations, for this report it's defined as 'a cooperative arrangement between the public and private sectors that involves the sharing of resources, risks, responsibilities and rewards with others for the achievement of join objectives'. • By pursing a PPP, the public sector's objective is to maximise VFM and ensure the effective use of scarce public funds on a capital project • An inherent conflict arises with the VFM objective as the private sector seek to realise corporate goals by generating cash flow and profits. Central to the alignment of both public and private sector objectives, and maximising the benefits in the form of project efficiency, is the equitable, mutually acceptable distribution of risks and rewards.
Infrastructure Project Risk Allocation	• In large scale infrastructure projects, there is potential for risks to be misallocated to parties that don't possess the right level of knowledge, resources and capabilities to manage them effectively • In such cases this can increase the likelihood of risks events occurring such as cost overruns, late delivery, safety incidents, poor service quality, expensive contract renegotiations, disputes, inefficiencies from poorly defined responsibilities and the impact of consequences if they do arise. • With risk transfer incurring a cost in the form of a profit incentive, where there is a misallocation amongst stakeholders this can result in higher than necessary project risk premiums. This compromises efficiency and erodes the overall strength of the PPP value for money proposition.
Project Efficiency	• To minimise overall project risk and achieve the highest levels of productive efficiency, two key principles must be followed: • Firstly, allocate on the basis that the party has the right capabilities to manage outcomes. • And secondly, that the party can manage the specific risk(s) at the least cost. This translates into cost reductions, performance improvements and in effect minimizing both the total management costs of the public and private sector.

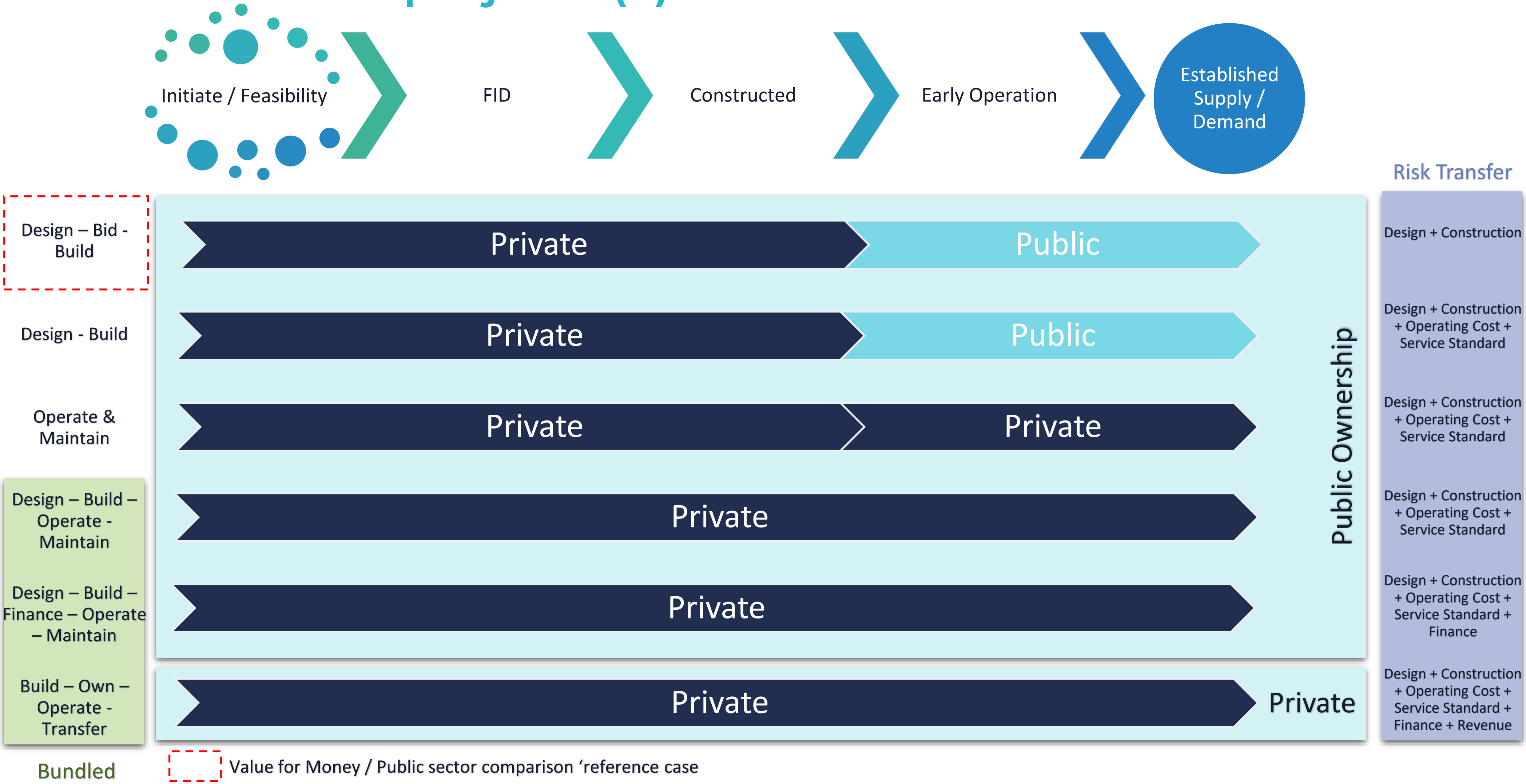
7.6 Contracting Models That Enable Private Sector Participation Across The Lifecycle For Creditworthy Infrastructure Projects (1)



7.6 Contracting Models That Enable Private Sector Participation Across The Lifecycle For Creditworthy Infrastructure Projects (2)

Design & Build	• Single point of accountability for design and construction • Can enable construction to begin before design is complete • Integration risk transferred to the private sector • Strong owners authority required by the public sector
Operate & Maintain	• Performance obligations for contractor – availability, uptime, safety etc. • Ownership and financing risk retained by the public sector • Strong asset management capability required by public sector to manage performance
Design, Build, Operate & Maintain	• Integrated design, construction and O&M helps achieve value for money • Ownership and financing risk are retained by the public sector • Integration risk for D&B, and O&M are transferred to the private sector. • Strong owners authority / asset management capability required by the public sector across the lifecycle
Design, Build, Finance, Operate & Maintain	• Integrated design, construction and O&M helps achieve value for money through incentivizing private sector to provide whole of life / full cycle value • Financing risk transferred to the private sector
Build, Own, Operate, Transfer	• Private sector designs, builds, operates and maintains the asset over a medium to long-term period • Ownership transferred to the public sector via concession or lease type arrangement • Focus on service quality and performance • Financing risk transferred to the private sector or shared. • End of period the asset is transferred back to the public sector – either freely or a fee in a defined condition
Privatisation	• Private sector acquires the asset either via a long-term lease or a partial / full acquisition. • Risk is fully assumed by the private sector • Leverage private sector's capability to manage and operate the asset more efficiently

7.6 Contracting models that enable private sector participation across the lifecycle for creditworthy infrastructure projects (3)



8 OWNERSHIP MODELS - CASE STUDIES

Case studies of comparable infrastructure and ownership models are presented on the following pages.

- Offshore natural gas pipelines UK/Norway
- ADNOC / ARAMCO hydrocarbon pipelines
- CCS in the Netherlands and Norway
- Gas and Electricity Interconnectors

8.1 Case Study – Offshore Natural Gas Pipelines UK/Norway

UK has a fully privatised, unregulated, offshore pipeline business model focused on domestic supply. Whereas Norway has a private/public ownership structure and has adopted a regulated asset base model with a focus natural gas export to Europe / UK given the strategic nature of its resource.

Item	UK	Norway - Gassled
Ownership	• Private	• Public / Private, with Transmission System Operator (Gassco)
Business Model	• Unregulated business model, fully merchant • Tariff (£/mcf) based revenue model, typically with Send or Pay volumes commitments. Costs can be passed through to Shippers or borne by pipeline owner	• Regulated business model • Tariffs determined based on regulated return including reimbursement of CAPEX and OPEX, paid by Shippers • Send or pay model still applies
Description	• Unregulated, privately owned (no state ownership of oil companies monetizing the resource) • Focused on supply of gas to meet domestic demand • Originally developed to supply large gas fields to shore and evolved over time to capture new fields • Originally owned by IOCs such as Shell, BP, TOTAL, but has been divested to dedicated infrastructure companies	• Key export infrastructure to supply European gas demand • State-owned minority interest • Dedicated operating company (Gassco) • Mature asset, with infrastructure owners / pension funds as owners
Owners	• Kellas Midstream, NSMP, Ancala, Shell, BP, Enquest	• Gassled – Petoro (public), Cape Omega, Hav Energy, Silex Gas, Equinor (public/private)
Operator	• Owners or dedicated O&M service providers	• Gassco, with governance from the Norwegian Government
Risk allocation and creditworthiness	• No UK state ownership of oil companies in UK sector, • Resource developed through private sector concessions • Route to market for upstream resource monetisation • High confidence and clear demand case for upstream developers financing and funding the pipeline • High creditworthy counterparty	• Aligned with public ownership of Equinor and Petoro and provides route to market • Support government take & tax revenues • High confidence and clear demand case in Europe • High creditworthy counterparty
Attractiveness	• Privately led capital with minimal cost to public purse	• Provides integration of public / private model with governance retained by Norwegian government.

8.2 Case Study – ADNOC / Aramco Hydrocarbon Pipelines

ADNOC/Aramco are national oil companies who were able to monetise their midstream infrastructure to institutional investors. Investment driven by established supply and demand cases and credit worthy counterparties.

Item	Considerations
Ownership	• Public initially, and subsequent monetisation of midstream infrastructure with minority interests to private capital
Business Model	• Regulated return • Tariff based revenue model with minimum volume commitments for oil and gas pipelines
Description	• Middle East National Oil Companies (NOCs) sale and 20 year lease back of midstream pipeline infrastructure to institutional investors. • Total of $50 billion of investment from institutional investors in return for a minority stake in pipeline infrastructure and tariff based revenue model • Would require established market demand to enable long term contracted view to enable lower cost of capital providers (infrastructure funds) • Likely to occur in later life as demand and supply is well established.
Owners	• ADNOC, Saudi Aramco
Investors	• BlackRock, GIC, KKR, EIG
Risk allocation and creditworthiness	• Long term, stable operating track record • Clear visibility and certainty over costs and performance standards • Strong visibility and confidence in demand case • High creditworthy counterparty • Requires established market demand to enable long term contracted view to enable lower cost of capital providers • NOC retains majority share and operatorship
Attractiveness	• Enables public owned entity to release material capital on owned infrastructure asset at a given point in time.

8.3 Case Study – CCS in Netherlands / Norway

CCS is an evolving technology. Aramis (Netherlands) and Northern Lights (Norway) are both privately led CCS initiatives, but supported by the Government through subsidies (SDE++) or subsidised costs (Norway) to enable deployment.

Item	Aramis CCS	Northern Lights CCS
Ownership	• Private/Public consortium	• Private consortium, with public subsidy on cost
Business Model	• Regulated business model • Tariff on CO2/tonne for an agreed rate of return	• Regulated business model • Tariff on CO2/tonne for an agreed rate of return
Description	• Emerging technology to decarbonise. • Aramis delivering "open access" system to enable future build out of third party CO2 volumes and storage facilities • Aramis privately led, but public interest support mechanisms from Dutch Gov't through ETS waivers and SDE++ Subsidy (15 years), which is equivalent to CfD style mechanism	• Emerging technology to decarbonize • Privately led initiative by Equinor, with government funding of 80% of CAPEX and OPEX ($2.4 billion) over 15 years • Phased development to support initial 1.5 MTPA CO2 capture, with capacity up to 5 MTPA and marketed to Europe
Owners	• Shell, Total Energies, Gasunie (public), EBN (public)	• Equinor, Shell, TOTAL Energies
Operator	• Aramis (Shell / Total Energies)	• Equinor
Risk allocation and creditworthiness	• High creditworthy counterparty, public financial package provided • Policy and regulatory supported demand case	• High creditworthy counterparty, public financial package provided • Policy and regulatory supported demand case
Attractiveness	• Minority interest of Government in project to enable visibility in project • CfD style mechanism provides downside protection to emitters if ETS price is above cost of CCS project	• Cost (CAPEX/OPEX) support enabled project to reach FID and provide certainty to investors • CCS viewed as strategic to Norway to enable future CO2 import industry to store CO2 from North West Europe.

8.4 Case Study – Interconnectors

Item	Gas Interconnector	Electricity Interconnector
Ownership	• Private	• Private / public partnership with Transmission System Operator
Business Model	• "Merchant", but commercial terms subject to strict regulation by UK and Belgium National Regulatory Authorities • Long term ship or pay contracts or multi-year contracts • Capacity can be offered on a regulated public auction platform	• Regulated • New Interconnectors will have a cap and floor system for a 25 year period
Description	• Bi-directional gas interconnector between UK and Belgium • Monopolised infrastructure, but regulated to ensure gas is transported competitively • Regulated by OFGEM under specific Gas Interconnector licences which allow the licensee to participate in the operation of gas interconnector which is defined as co-ordinating and directing the conveyance of gas into or through a gas interconnector and making such interconnector available for the conveyance of gas • Pipeline operates as merchant asset, that is without an allowed revenue or guaranteed captive demand typical of a monopoly infrastructure operator • Shippers can book long, multi-year or short term contracts with Interconnector through regulated public auction platform	• Regulated by OFGEM and aligns to EU legislation for revenue generation • Cap and floor mechanism regulates how much money a developer can earn in operation, providing developers a minimum return (floor) and a limit on the potential upside (Cap) for a 25 year period. • Interconnectors make revenue in wholesale market from congestion revenues. Congestion revenues are dependent on existence of price differences between markets at either end of the interconnector • Interconnection capacity is allocated to the market via market-based methods, i.e. auctions and trading arrangements on electricity interconnectors are governed by Interconnector licence.
Owners	• Interconnector UK, Fluxys, SNAM	• National Grid, Moyle Interconnector, BritNed,
Operator	• Interconnector UK	• Transmission System Operator
Risk allocation and creditworthiness	• Key infrastructure to supply UK / Europe with natural gas • Credit worthy shippers, usually utility companies • Established supply and market demand for natural gas • Seasonal swings in demand, now changed due to Russian invasion • Clear visibility and certainty over costs and performance standards	• Key infrastructure to supply UK/Europe with bi-directional electricity • Established supply and demand for electricity • Unbundled ownership, i..e generators cannot be owners in electricity • Clear visibility and certainty over costs and performance standards • Credit worthy counterparties and regulated
Attractiveness	• Key infrastructure to enable energy security with bi-directional capability • Private led consortium with capacity booked through auctions and is market demand driven	

9 COMMERCIAL REVENUE MODELS, VIABILITY GAP SUPPORT, FINANCING AND COMPETION

The following section discusses:

- Examples and characteristics of different commercial revenue models, how they aim to allocate risk, and implications of each on project creditworthiness.
- Examples of 'viability gap' support mechanisms and pros and cons of each of these
- Funding requirements through the project lifecycle for the pipeline described in section 4.5.
- Financing options and applicability of these to this project
- The competitive landscape.

9.1 Commercial Revenue models, risk allocation and creditworthiness implications for the pipeline project

Commercial model	Demand Commitment Level	Pipeline Payment Mechanism	Counterparty Risk Allocation	Project Creditworthiness Implications
Send or Pay	• Volume dependent • Minimum agreed contractual volumes between producer and buyer	• User based fee based on demand • Cost pass through in the tariff • Cover CAPEX, OPEX & Margin	• Pipeline is directly exposed to credit risk of the downstream buyers • Downside volume risk is transferred to the hydrogen producers (i.e. developers) as pipeline and buyers are compensated if agreed volumes not me. Some indirect credit risk exposure therefore to the producers	• Moderate-high confidence required in the volume forecasts • Credit enhancement provided by production and destination country public financial support package • Viability gap support could be provided by both producing and destination countries
Reasonable Endeavours	• Volume dependent • Variable volumes	• User based fee based on demand • Cost pass through in the tariff • Cover CAPEX, OPEX & Margin	• Downside revenue risk is retained by the pipeline • Pipeline exposed to direct credit risk of the downstream buyers, indirect risk exposure to the producers	• High confidence / certainty required in the volume forecasts • Credit enhancement provided by destination country public financial support package • Viability gap support could be provided by both producing and destination countries
Capacity Auctions	• Commitment not dependent on demand	• Fixed fee for capacity	• Downside revenue risk is retained by the pipeline in event that sufficient capacity payments cannot be secured • Direct exposure to credit risk of the upstream producers who are marketing the production, indirect exposure to the credit risk of the downstream buyers	• Moderate-high confidence required in the volume forecasts • Credit enhancement provided by production and destination country public financial support package • Viability gap support could be provided by both producing and destination countries
Hybrid (fixed + variable)	• Partially dependent on volumes • Fixed minimum capacity payment • User based fee based on demand	• Combination of fixed and user based fee	• Downside revenue risk is shared by the pipeline and either (or shared between) the producers and off takers (dependent on commercial model)	• Moderate-high confidence required in the volume forecasts • Credit enhancement provided by production and destination country public financial support package • Viability gap support could be provided by both producing and destination countries

9.2 Viability Gap support mechanisms underpinning business & Funding Models (1)

A range of business and funding models exist for a hydrogen export pipeline

Three broad categories of business model exist which currently are being explored for hydrogen transport in the UK, but could be applicable to an export system:
- Regulated Returns
- Contractual Payment
- Fully Merchant

The appropriate business model will need to consider the infancy of the hydrogen market and ability for appropriate de-risking to enable the project to reach FID. Also any viability gap that may exist. Given the pipeline will be a cross-border project, engagement with the EU or German Government will need to carried out to determine the contractual arrangement between hydrogen producers in Scotland and hydrogen users in Germany or the EU. A summary of the business models is provided in the following pages.

Category	Business Model	Business Model Description	Pro	Con	Viability Gap Support
Regulated Returns	Regulated Asset Base (RAB) with allowed revenue	• Hydrogen pipeline owner would agree an "allowed revenue" with a regulator ahead of the price control period • Allowed revenue would be conditional on operational performance targets being met • Users charged in accordance with agreed methodology (e..g CAPEX + OPEX + cost of debt) • Revenues would be subsidised by an external funding mechanism whilst hydrogen economy in its infancy	• Provides guaranteed regulated return which would provide investors with certainty • RAB model well understood infrastructure business model • Deferred investment recovery approach tackles challenges in early hydrogen market	• Risk transferred to external subsidy (e.g. public body) until hydrogen economy matures • High CAPEX of pipeline will incur highly subsidised component and risk of exposure to cost overruns	Yes until hydrogen economy matures
	Revenue Cap and Floor	• Hydrogen pipeline owner and operator would agree on revenue cap and floor with regulator for a specific period • Owners and operators able to recover revenues from users up to cap, with the floor being the minimum amount the provider could recover • If floor not reached, revenue would be topped up to minimum threshold through the subsidy and if the cap is exceeded, excess revenue would be transferred to the subsidy funder	• Well understood for UK interconnector business • Provides guaranteed minimum floor that could protect downside risk for investors • Excess revenue transferred to subsidy funder	• Specified period uncertain and linked to hydrogen demand • Risk transferred to external subsidy provider (e.g. public body) until hydrogen economy matures	Yes until hydrogen economy matures

9.2 Viability Gap support mechanisms underpinning business & Funding Models (2)

Category	Business Model	Business Model Description	Pro	Con	Viability Gap Support
Contractual Payment	Contract for Difference	• Owner would agree on a strike price for operating the asset. • Asset owners paid a variable premium by external funding provider and receive a subsidy covering the additional cost of transporting hydrogen	• Manages price risk, and could utilise Hydrogen Global mechanism • Could be bundled into offshore wind CfD • Long term (15 yr) contract	• Uncertain supply and demand and small user base would remain • Does not regulate returns	Yes
	Capacity Availability	• Operators would be paid to provide transport capacity when and where required. • Payments would be made on existence and capacity of pipeline, rather than use.	• Mitigates risk of revenue uncertainty as users pay for capacity	• Small number of users, could mean low capacity bookings initially • May prohibit open access system if users overbook • Does not regulate returns	Yes
	Government offtake front stop / long term capacity booker	• Government agree to reserve a certain volume of transport capacity for a defined number of years. • Providers would prioritise resale of this capacity with the Government acting as the offtaker of last resort if that capacity remained unsold. • Volume / capacity reserved would be equal to that necessary and proportionate to de-risk investment	• Derisking of uncertain supply and demand with Government backstop	• Government ultimately on hook for capacity if supply / demand fails to meet expectations • Does not regulate returns	Yes
Public / Private Partnership	Government Equity Investment support (i.e. no / low return capital)	• Government co-invest in pipeline as it is considered to be of strategic importance.	• Provide confidence and enable additional private sector capital • Lower the amount of revenue that a facility would need to cover costs • Greater confidence to investors and mitigate against demand and supply uncertainty	• Higher public funding required • Underwriting supply/demand	Yes
Full Privatisation	Merchant	• No business model and market forces would determine investment • Revenues would be uncertain and market driven	• Minimal public funding required	• Revenues would be uncertain which could act as deterrent to investors	No

9.2 Viability Gap support mechanisms underpinning business & Funding Models (3) - Conclusions

A regulated business model for hydrogen transport is most likely, with a RAB approach the direction of travel.

Given Scotland Hydrogen export pipeline will likely be monopolised, as the aim of for multiple users to utilise a single piece of infrastructure, a regulated business model is likely the preferred business model.

- RAB is well established within the UK market and also within Norway for export of natural gas to Europe. CCS / Hydrogen within the UK is already exploring RAB business models for domestic transport of CO2 and Hydrogen
- A Cap and Floor business model is well established in cross-border electricity interconnectors.

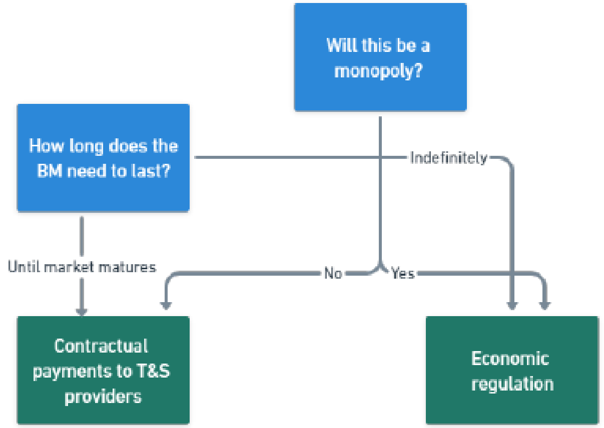
The lack of a hydrogen market today prevents a fully merchant business model to exist given the uncertainty in revenue and required funding gap to build the infrastructure.

Contractual business models, such as CfD and capacity allocation for the pipeline is more appropriate within electricity and power market and has supported sectors like offshore wind. Contractual business models could support the early evolution of a hydrogen transport business model, but it is unlikely to be suitable in the long term. This could be blended with a regulated return business model to enable some form of support during development.

The contractual business model would likely be challenged by the EU, who are considering a regulated approach to hydrogen transport, which will likely include third party countries (e..g Scotland).

It is likely that contractual business models could be applied to the generator / hydrogen producer, but not for the hydrogen pipeline export system which will need to be unbundled from the hydrogen production value chain.

BEIS Business Model Framework



Status	Cost (£mm)
Pre-FID	25
Post-FID	2,771
Total	2,797

9.3 Funding / Project Lifecycle

Sponsor equity or grants will be required to support the project until FID. During the development phase the project should engage with lenders to define the financing package and optimise the capital structure (debt/equity) ratio. For infrastructure projects a 80/20 could be realised, but may need further government support given immaturity of hydrogen market.

Financing

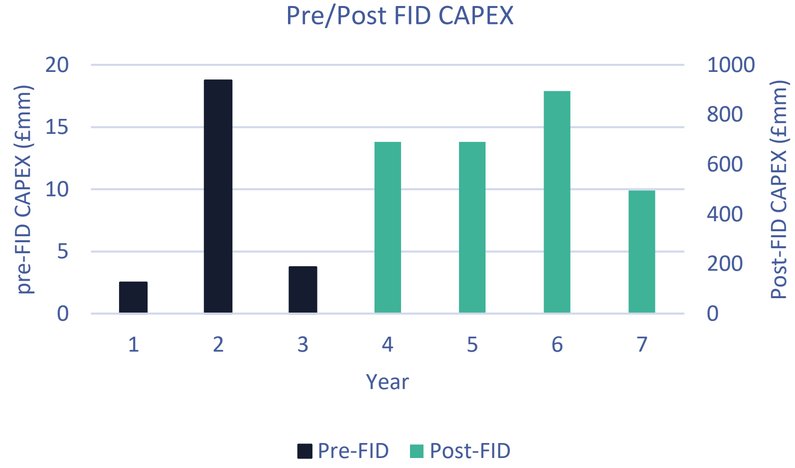
- From feasibility to FID, funding will need to be equity or through grants
- The cost of equity should fall at each de-risking milestone. The principal milestones being
    - FID when the project would have a contractual framework substantially fixing the capital cost
    - Completion of the project
- The preferred capital structure will be a combination of debt / equity to reduce the cost of capital
- A debt/equity ratio of 80/20 could be considered, reducing the equity commitments post-FID from £2.7 billion to £555 million, with a debt facility of £2.2 billion.
- Debt from lenders will reduce the cost of capital for the pipeline
- Engagement with financial intuitions and lenders should be sought early on in the process to reduce delays in the process

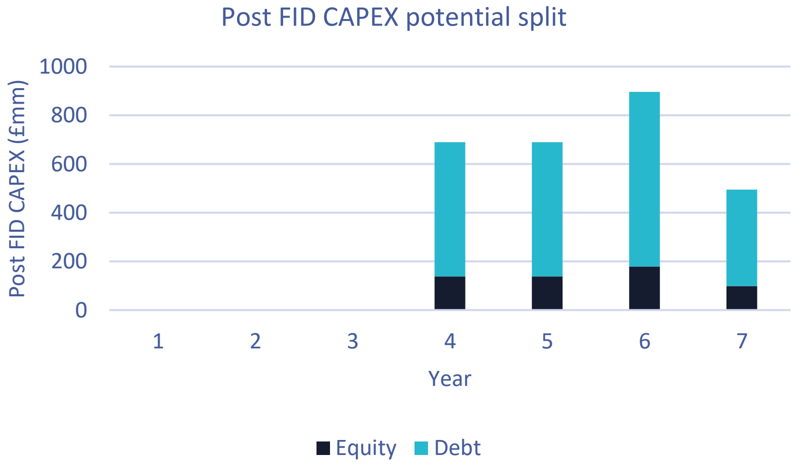
Bankability

Lenders will carry out due diligence and a "bankability" assessment to determine that they are satisfied that the key risks have been addressed.

What is typically required for Bankability will depend on the lending institution, but for a hydrogen export pipeline project is likely to consider:

- Clear business model that underpins revenues
- Long term contracts between suppliers and offtakers with high creditworthiness
- Limited or no price exposure, with government support
- Environmental Impact Assessment
- Pipeline routing





9.4 Financing Options

Large capital outlay is required, a combination of debt and equity will be needed to optimise the cost of capital and funding requirements. The level of debt estimated (£2.2 billion) could be supported by commercial banks, but it is likely that a combination of debt providers would be involved including concessional lenders in the offtake countries to support energy transition objectives.

Lender Options	Description	Lender names	Capacity (£ Billion)	Term (years)	Features	Applicable to H2 Project
Concessional Lenders	• Banks that make loans below market rates to further the aims of their institution • Typically from host country or from regional development institutions • Energy Transition initiatives will align well to funding support from European	• EIB • UKIB • SNIB	Up to 1	Up to 20	• Offer below market pricing • Accepts political risk	Likely that EIB or equivalent will support energy transition initiatives
International and Domestic Commercial Banks	• Experienced in providing project finance to large scale infrastructure projects • Lend for profit or build broader banking relationships • European banks have declared targets to support energy transition initiatives	• 20-30 banks	Up to 3	7-20	• Flexible to the project • More stringent on downside risk	
Project Bond Market	• Subset of debt capital market • Similar to commercial banks, and are returns driven, but investors are focusing on ESG related targets or have dedicated ESG funds • Bonds are fixed interests and tend to offer longer term		Up to 2	Up to 20	• Requires credit rating	
Export Credit Agencies	• Government owned or supported agencies to support export of goods and services from their country • Achieved by offering direct loans or guarantees linked to the value of the exported goods	• UKEF	Up to 3	Up to 16	• Linked to procurement • Accept political risk • Focused on supporting export of goods	Could support supply chain in construction phase
Development Banks	• Mandate to support development of less developed countries globally or in specific regions • Typically focus on lower income countries	World Bank, IFC	0.1 to 0.2	Up to 20	• Focused on developing countries	Not developing country

Source: Oxford Energy Institute, Financing a world scale hydrogen export project

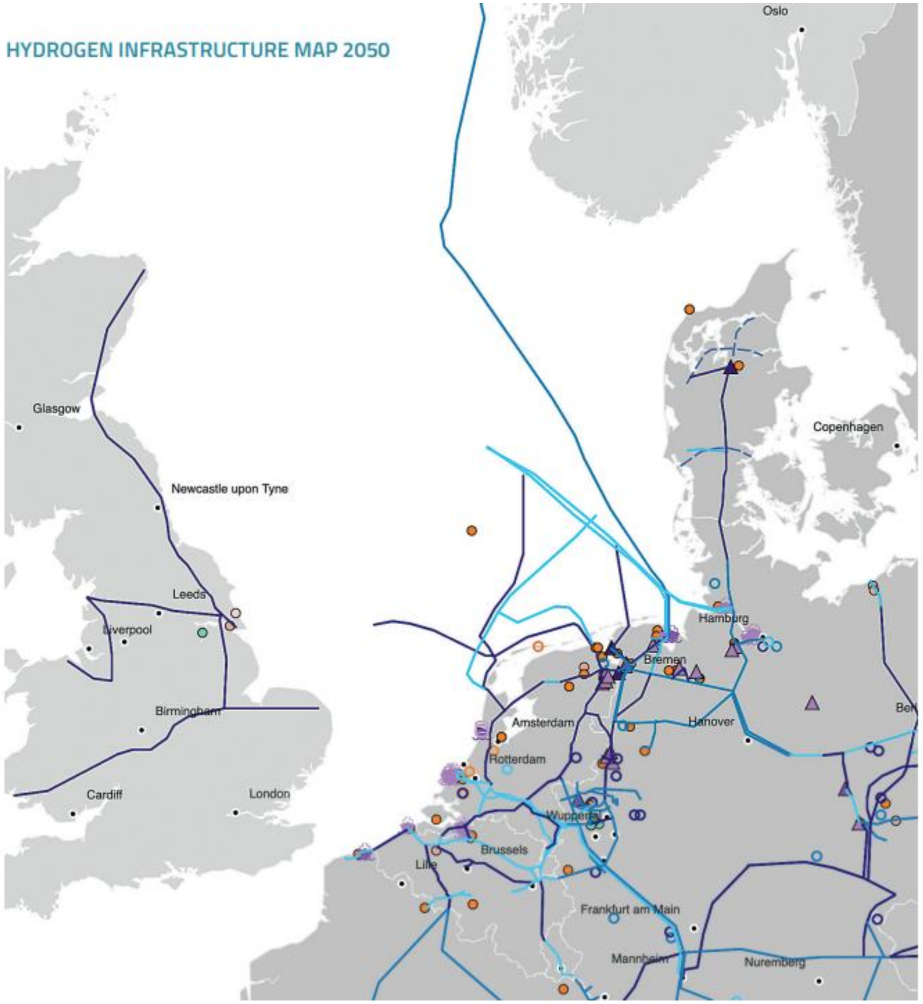
9.5 Competitive Landscape

Scotland could be competing with other EU countries and Norway to supply hydrogen to Northern Europe. Currently there isn't visibility of Scotland's ambition at an EU level, as demonstrated by the recent Learnbook on H2 Supply Corridors

European Clean Hydrogen Alliance – Learn book on Hydrogen Supply Corridors identified a number of potential hydrogen corridors for the North Sea to supply Europe with hydrogen.

A Scotland hydrogen export pipeline is currently not featured within the North Sea Hydrogen supply corridor in 2030, 2040 or 2050 scenarios considered by European Clean Hydrogen Alliance.

Scotland may be competing with other EU (Netherlands / Belgium) and non-EU (Norway) for supply of hydrogen to demand centres in Northern Europe.



10 CONCLUSIONS: OWNERSHIP MODELS

Three ownership models exist, with varying degrees of investment required and hydrogen market maturity requiring public sector funding to enable export.

← Increasing Scottish public body equity investment

	Full Public Ownership	Shared Ownership	Full Privatisation, but still requires subsidy to bridge viability gap
Drivers	• Scotland views H2 export as strategic and decision to either have H2 nationalised export infrastructure or unable to attract private sector investment due to current uncertainty in: • Business model • Hydrogen supply timing • Demand	• Scotland views H2 export as strategic, but requires private capital and expertise to deliver and fund the project through a co-investment model. • To transfer risks to the private sector, Scotland public body would need to demonstrate project creditworthiness that includes clear supply / demand signals through mechanisms such as MOUs / offtake agreements • Revenue model established	• Limited appetite for Scotland public equity investment in pipeline and allow private enterprise develop the pipeline. • Clear incentive for private sector • Clarity on business model and subsidy support initially required until market is established
Implications	• De-risk project through nationalised export infrastructure • High CAPEX for Scotland public sector • De-risk development of H2 supply in Scotland	• Scottish government provides no / low return equity to crowd in private capital • Requires upfront public spend to frame the and market the project and provide initial de-risking	• Scottish government has no equity in the project with potentially limited influence. Timeline is dictated by the private sector • Subsidy funding likely still required to provide viability gap between cost of hydrogen and use case
Monetisation Opportunities for Public Sector	• When H2 market is established with clear demand and revenue model. Public body could sell minority stake or full privatisation depending on strategic rationale • This is unlikely to occur until a track record has been established and could take a number of years post operations commencement.	• Retain minority stake throughout lifecycle • Farm-down through project lifecycle at key milestones such as FID, Financial Close or Operational phase, providing multiple monetisation opportunities.	• Pipeline is privately owned, limited monetisation opportunity for Scotland.

11 RECOMMENDATIONS

Recommendations for CES and partners are laid out as short medium and long term actions. Responsibility for the Long Term actions may sit with others, depending on the ownership model pursued. Where recommendations are shown italicised, it is known that actions are already underway however the recommendation is to accelerate or re-focus these actions.

	Short Term (2023)	Medium Term (2024/2025)	Long Term (2026+)
TECHNICAL	• Increase visibility of Scotland's hydrogen export pipeline to EU as a credible solution • Secure budget for feasibility design of pipeline	• Assess pipeline routing and landfall options • Establish hydrogen supply timing from Scotwind	• Carry out pipeline routing surveys • Carry out Environmental Impact Assessment • Design optimisation and design basis freeze to firm pipeline size and capacity.
REGULATORY	• *Define Hydrogen Certification rules.* Ideally ensure alignment with EU so that producers can meet both UK and EU requirements with a single development strategy. • Establish viable funding routes to support hydrogen transport options	• Define cross-border engagement requirements between Scotland / EU for hydrogen transport • Define clear permit & consenting pathways and timings.	
OWNERSHIP	• Define role that Scottish Government wants to play in terms of fully nationalised export infrastructure or co-investment model	• Depending on ownership model, engage with private enterprises to establish ownership structure	• Define Scotland monetisation roadmap depending on desired exit strategy and ownership model preference over project lifecycle
COMMERICAL / BUSINESS MODEL	• To establish project credibility, continue to engage with EU partners to explore MOUs or offtake agreements as done by Norway. • *Explore with UK Government and EU appropriate business models for a hydrogen transport pipeline (regulated vs. contractual)*	• Formalise business model to enable clarity to investors on hydrogen pipeline and how it interacts with the rest of hydrogen value chain • Commence marketing of hydrogen pipeline capacity • Commence engagement with lenders and carry out preliminary "bankability" assessment	• Agree subsidy / funding business model that can support project through to FID • Secure / formalise offtakers • Secure / formalise shippers