HyNet CCUS Pre-FEED

Key Knowledge Deliverable

WP1: Final Report

HyNet North West

EXECUTIVE SUMMARY

The Pre-FEED Final Report was generated as part of the Preliminary Front End Engineering and Design (pre-FEED) study for the HyNet Industrial CCUS Project. The HyNet CCUS pre-FEED project commenced in April 2019, and was funded under grant by the Department for Business, Energy and Industrial Strategy (BEIS) under the Carbon Capture Utilisation and Storage (CCUS) Innovation Programme.

Delivery of the project was through a consortium formed between Progressive Energy Limited, Essar Oil (UK) Limited, CF Fertilisers UK Limited, Peel L&P Environmental Limited, University of Chester, and Cadent Gas Limited. In addition, Eni undertook a parallel, integrated, but separately funded study of re-purposing their existing Liverpool Bay assets, the main outcomes of which are referenced in this report.

The main project objectives were as follows;

- To determine the technical feasibility of a full chain Industrial CCUS scheme comprising anchor loads from Stanlow Refinery and Ince Fertiliser Plant and storage in Liverpool Bay fields.
- To determine the optimised trade-off position between lowest initial cost and future scheme growth
- To determine capital and operating costs for the project to +/- 30% to support HMG development of a policy framework and support mechanism
- To undertake environmental scoping and determine a programme of work for the consent process

The project has significantly enhanced the engineering underpinning HyNet and will be used as the baseline to enter FEED and Consenting. Key outcomes are as follows;

- HyNet is a technically viable full-chain CCUS and hydrogen project, able to commence operation in 2025 with a pipeline solution, or in 2024 if an interim road / rail onshore transport solution is implemented.
- The project has been designed to be incrementally expandable, allowing low cost initial development with subsequent capacity upgrades as system flow rate constraints are encountered.
- The project will initially operate in 'Free Gas Flow Mode', with no intermediate compression between the capture plants and storage injection. Subsequent intermediate compression will be required for higher flow rates and a range of configuration options have been considered. Further work is required to identify the baseline configuration in the early stage of FEED.
- The onshore section of the CO_2 pipeline will operate throughout project life in gas phase. This allows a shorter, more cost effective route to be engineered for the newbuild section, and the existing offshore section can avoid being replaced, at least until flow rates of $5MtCO_2/yr$ are delivered at which point it becomes flow rate constrained. The existing section of onshore pipeline is unsuitable for dense phase due to pressure limitations and elevation profile.

- Work undertaken by Eni in support of the project has determined that the proposed reservoirs, Hamilton, Hamilton North and Lennox offer high quality storage opportunities. Furthermore, analysis of the potential for re-use of existing assets for CO_2 transport and storage has identified no show-stoppers and a risk based approach will be followed in subsequent project phases to determine what re-work is required to ensure they are fit for purpose for CO_2.
- The onshore pipeline route has been developed sufficiently to the point that survey work can now commence.
- Hydrogen production dominates the overall CO_2 system mass flow rate, with approximately 75% of system flow rate in 2030 from hydrogen production and the remainder from industrial capture from Ince Fertiliser Plant, Stanlow Refinery, Padeswood Cement Plant and Protos.
- The initial 'minimum viable project' transport and storage system is deliverable for a capital cost of ca. £250m, with early operation available at substantially lower cost than this, as system compression is not required in 'Free Flow Gas Mode'. Including operational costs, this results in transport and storage costs of <£30/t at 2MtCO_2/yr and <£10/t at 10MtCO_2/yr.

This document is one of a series of Key Knowledge Deliverables (KKD's) to be issued by BEIS for public information, as follows;

- HyNet CCUS Pre-FEED KKD WP1 - Basis of Design
- HyNet CCUS Pre-FEED KKD WP1 – Final Report
- HyNet CCUS Pre-FEED KKD WP2 - Essar Refinery Concept Study Report
- HyNet CCUS Pre-FEED KKD WP2 - Hydrogen Production Plant
- HyNet CCUS Pre-FEED KKD WP3 - Fertiliser Capture Report
- HyNet CCUS Pre-FEED KKD WP4 - Onshore CO2 Pipeline Design Study Report
- HyNet CCUS Pre-FEED KKD WP4 - CO2 Road Rail Transport Study Report
- HyNet CCUS Pre-FEED KKD WP5 - Flow Assurance Report
- HyNet CCUS Pre-FEED KKD WP6 - Offshore Transport and Storage
- HyNet CCUS Pre-FEED KKD WP7 - Consenting and Land Strategy

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1.0 INTRODUCTION

1.1 Project Background

HyNet was first conceived in 2016 as an integrated Hydrogen and Carbon Capture, Utilisation and Storage (CCUS) project to deliver widespread decarbonisation benefits across the North West region, with a particular focus on 'hard to reach' sectors of the economy, such as heat, industry, transport and flexible power. Following two feasibility studies[1,2] published in 2017 and 2018, an industry consortium was formed to deliver a pre-FEED level study for the full chain HyNet CCUS scheme. This study was undertaken from April 2019 to May 2020 and was funded by BEIS and partner contributions. Partners were:

- Progressive Energy
- Cadent
- CF Fertilisers
- Essar Oil UK
- Peel L&P Environmental
- University of Chester

In parallel, a technically linked, but self-funded study into the offshore transport and storage elements of the scheme was undertaken by Eni, current owners and operators of the Liverpool Bay Area (LBA) oil and gas assets.

The pre-FEED project has been delivered through seven integrated work packages, and this report constitutes the final over-arching summary report. Further details are contained within work package specific deliverables.

Work package structure for pre-FEED is as follows:

- Work Package 1 – Integration
- Work Package 2 – Refinery Capture
- Work Package 3 – Fertiliser Plant Capture

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[1] *The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project*, August 2017, Progressive Energy on behalf of Cadent (https://hynet.co.uk/app/uploads/2018/05/Liverpool-Manchester-Hydrogen-Cluster-Summary-Report-Cadent.pdf)

[2] *HyNet North West: From Vision to Reality*, May 2018, Progressive Energy on behalf of Cadent (https://hynet.co.uk/app/uploads/2018/05/14368_CADENT_PROJECT_REPORT_AMENDED_v22105.pdf)

- Work Package 4 – Onshore Transport
- Work Package 5 – Flow Assurance
- Work Package 6 – Offshore Transport and Storage (undertaken by Eni outwith the BEIS funded project)
- Work Package 7 – Land and Planning

1.2 HyNet Overview

HyNet North West is a significant clean growth opportunity for the UK. It is a low-cost, deliverable project which meets the major challenges of reducing carbon emissions from heat, industry, transport and flexible power.

The HyNet cluster is based on the production of hydrogen from natural gas integrated with CCUS infrastructure. In its Progress Report, the Committee on Climate Change (CCC) concludes that *'In order to develop the hydrogen options, which are vital in our net-zero scenarios, significant volumes of low-carbon hydrogen must be produced at multiple industrial clusters.'*

HyNet is a complete system of hydrogen production, hydrogen supply, hydrogen utilisation, carbon capture, transportation, and carbon sequestration located in a concentration of industry, existing technical skill base, and suitable geology. The close proximity of hydrogen production, utilisation, and carbon sequestration means that the HyNet system offers substantially lower capital cost and development risk compared to other potential clusters around the UK.

The new infrastructure for HyNet is readily extendable beyond the initial project and provides a replicable model for decarbonisation of other UK clusters.

Key Elements of the HyNet project are as follows:

- **CCUS Infrastructure:** CCUS infrastructure will be developed (using largely re-purposed oil and gas assets) to capture, transport and store CO_2 from industrial anchor sources. These anchor sources, an oil refinery and an ammonia plant, are amongst the UK's largest industrial emitters and provide immediate capture opportunities of 1.2MtCO_2/yr. Pipeline infrastructure will be sized at up to 10MtCO_2/yr to facilitate future phases of system growth, including capture from hydrogen production. Storage will be in the Liverpool Bay Area (LBA) gas fields currently nearing depletion and owned and operated by Eni. This pre-FEED report focuses on this element of the HyNet project.
- **Hydrogen Production:** Hydrogen production plants will be developed, initially at the Stanlow oil refinery site and subsequently across the region. These are based on the 350MW_{th} (HHV) hydrogen plant being developed under the Hydrogen Supply Project (see Section 1.3.2 below) and up to ten such plants are envisaged by 2030 to provide 30TWh/yr of low carbon hydrogen supply for the region.
- **Hydrogen Distribution, Storage and Use:** Hydrogen distribution infrastructure will be developed to transport hydrogen from the point of production to the point of use, along with hydrogen bulk storage underground to accommodate seasonal demand for heat and flexible power generation. The North West region

has the UK's largest concentration of existing underground gas storage assets, and studies are underway (Project Centurion and Project HySecure) to assess the feasibility of repurposing some of these for hydrogen storage and/or developing new storage caverns and associated surface infrastructure. Such storage will be required for daily and seasonal supply and demand balancing, as well as enabling the growth of electrolytic hydrogen produced from excess renewable power. The development of the Hydrogen Distribution network is currently the subject of a separate study, funded by Cadent under NIA (Network Innovation Allowance). The network is being sized for 30TWh/yr capacity by 2030, and is intended to be built out in phases over RIIO GD2 and RIIO GD3 (2021-26 and 2026-31 respectively).

- **Wider Expansion:** A 'Western Cluster' will be developed with industrial emissions and emissions from hydrogen production in South Wales being shipped to the North West for storage, alongside road and rail transport of emissions captured from remote point sources. Storage can be expanded from Liverpool Bay to Morecambe Bay, which is forecast to cease gas production in 2030 and has capacity for over 1.5btCO_2. By 2050, the total amount of CO_2 captured from a Western Cluster (comprising, Wales, the Midlands and the North West) could be up to 47.3MtCO_2/yr, from power generation, industrial capture, industrial fuel switching, hydrogen transport, and hydrogen network blending.

Figure 1.1: The North West Industrial Cluster

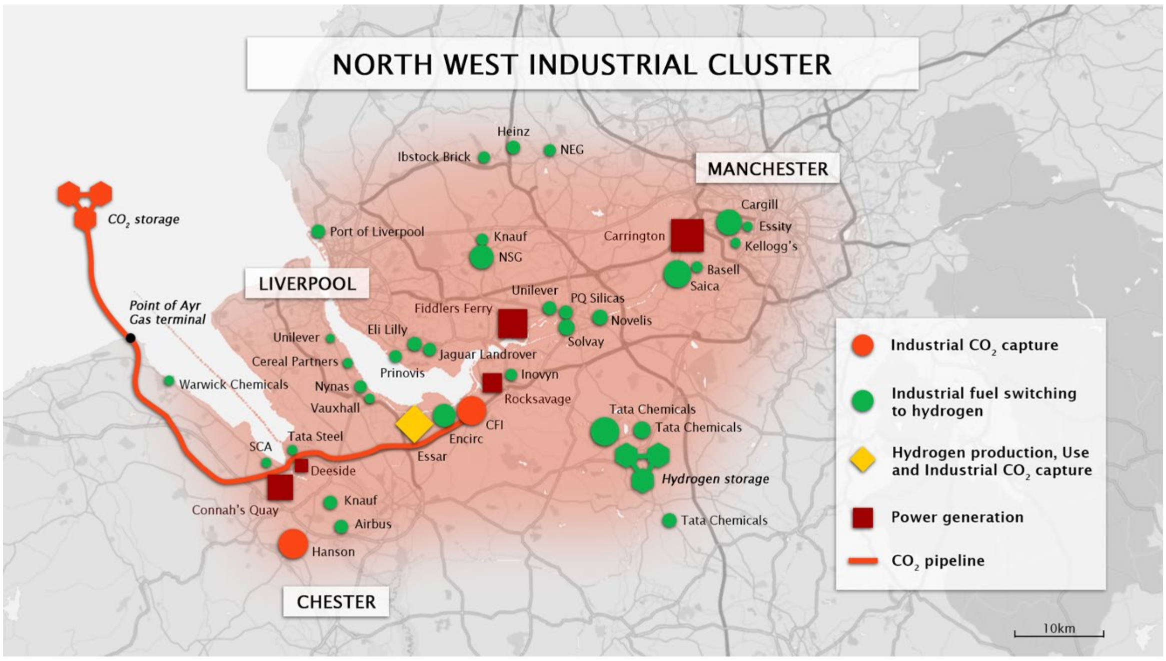
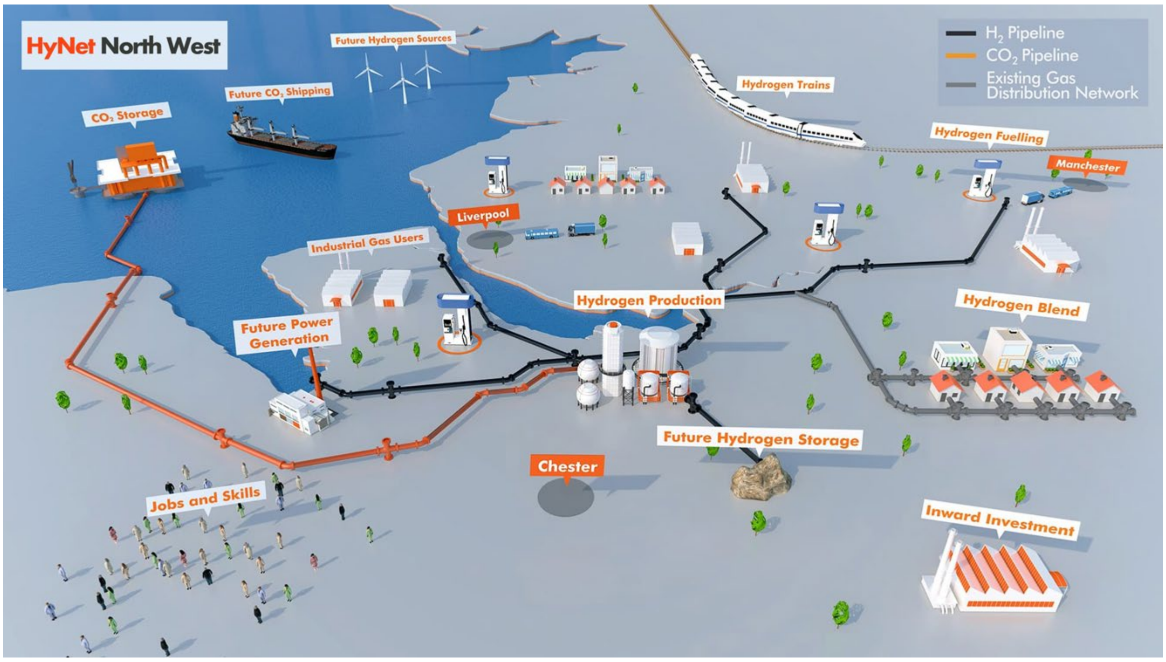


Figure 1.2: HyNet Infographic



1.3 HyNet Rationale

1.3.1 The UK Energy System

The world faces a climate crisis. Global emissions have continued to grow, despite clear scientific consensus on the causes and mitigations of climate change. The UK has been, for nearly two decades, at the forefront of action to tackle climate change, and passed the world's first legally binding emissions reductions target with the 2008 Climate Change Act. This Act committed the UK to delivering an 80% reduction in emissions by 2050, based on 1990 levels. Emissions in the UK are largely driven by energy use, although there are substantial emissions from other sectors, such as agriculture.

The Climate Change Act led to an unheralded reduction in emissions from the electricity sector which continues apace. Coal, the mainstay of UK electricity production since the earliest days of power generation, has been all but phased out. The growth of wind and solar generation has been remarkable, and, in 2018, low carbon sources (nuclear and renewables) accounted for 52.6%[3] of electricity generation.

However, electricity still represents only a relatively small proportion of the UK's total energy consumption. Fossil fuels remain the dominant source of energy supply, accounting for 79.4%3 of the total. Fossil fuels provide almost all energy for transport,

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[3] *Directory of UK Energy Statistics 2018*, July 2019, Department for Business Energy and Industrial Strategy, (https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/840015/DUKES_2019_MASTER_COPY.pdf)

given its storability and high energy density, and for domestic and industrial heat, given its low cost and the wide extent of the gas distribution network.

Furthermore, and equally importantly, fossil fuels provide the flexibility in our overall energy system due to their ability to be stored, and hence dispatched as required. The energy system is increasingly characterised by supply volatility, due to the increased penetration of non-dispatchable renewables, and increased 'peakiness' of demand, particularly as home-owners remove hot-water tanks and use condensing boilers to meet instantaneous heat demand. At times of peak energy demand, as exemplified by the 'Beast from the East' storm Emma on 1st March 2018, fossil fuels account for over 90% of total energy supply.

In developing our future energy system we therefore need to ensure that not only the annual aggregate demand is met by predominantly low carbon sources, but that the system can also support the flexibility to meet peak energy demand, which can be several multiples of the average. It is in this context that hydrogen plays an essential role.

In June 2019 the 80% emission reduction target was extended to net-zero requiring a 100% reduction in emissions. The CCC and the UK Government (HMG) agree that hydrogen and CCUS are essential technologies for successful achievement of this target.

The CCC has recommended the urgent deployment of CCUS on a cluster basis with integrated hydrogen production to address decarbonisation of a range of sectors, including heat, industry, transport and flexible power. To achieve the net-zero 2050 target, the CCC has determined that up to 178MtCO_2/yr of CCUS will be required across these sectors[4].

1.3.2 Hydrogen – Rationale and Production Methods

Hydrogen is a vector which delivers energy without carrying carbon and therefore with no carbon dioxide (CO_2) emissions at the point of use.

Hydrogen is not itself an energy source and must be produced using other sources of energy, such as wind generated electricity used to split water via electrolysis or conversion of hydrocarbon sources (e.g. reforming of natural gas, or potentially conversion of renewable biomass). Where the source is from fossil resources, then no carbon benefit is conferred unless the carbon is captured such that CO_2 is not released to

[4] *Net Zero – The UK's contribution to stopping global warming*, May 2019, The Committee on Climate Change (https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/)

the atmosphere, i.e. Carbon Capture Utilisation & Storage (CCUS). Where the source is biogenic, then conversion to hydrogen with CCUS is also a mechanism to remove carbon from the biosphere, known as BECCS (Bio-Energy Carbon Capture & Storage), a form of geoengineering.

Conversion of fossil resources to hydrogen with CCUS is a practical means of bulk production. In the context of CCUS, hydrogen as a vector allows the centralised capture of CO_2 for sequestration via transport and storage (T&S) infrastructure, whilst providing distributed low carbon energy to multiple users.

Hydrogen can be used to supply many parts of the energy system, often advantageously, for example: high temperature heat for industrial applications; rapid fill and range benefits for mobility; as well as the potential for low-cost diurnal or seasonal energy storage. Hydrogen is recognised as playing an important role in industrial transformation and delivering clean growth, and therefore has a role in the UK's industrial strategy. Hydrogen should be pursued where it offers the potential for economic advantages compared with other low carbon solutions, or where it unlocks benefits that cannot readily be delivered through alternatives.

The Committee on Climate Change (CCC) has recognised the important role that hydrogen plays in decarbonising the energy system in its Net-Zero report. For the UK to deliver a net-zero carbon energy system, it has explicitly identified the requirement for 225TWh/yr of low carbon hydrogen production with CCUS. The CCC also identifies 148TWh/yr electricity from 'gas with CCS plants', which could potentially be hydrogen fired. The CCC concludes '*In order to develop the hydrogen option, which is vital in our scenarios, significant volumes of low-carbon hydrogen must be produced at one or more CCS clusters by 2030, for use in industry and in applications that would not require initially major infrastructure changes (e.g. power generation, injection into the gas network and depot-based transport).'*

Hydrogen plays a role in all the emerging UK CCUS clusters. It is integral to the HyNet and Western Cluster for delivery to industry and as a blend to the gas network as well as unlocking mobility and dispatchable power benefits and synergistic links to the steel industry in South Wales.

Low Carbon hydrogen can be produced via three primary routes; electrolytic splitting of water using renewable electricity, reforming of fossil resources with CCUS, or conversion of renewable biomass with or without CCUS. Hydrogen produced from renewable resources is commonly referred to as 'Green Hydrogen', and from fossil resources with CCUS as 'Blue Hydrogen'.

Electrolytic Hydrogen

Production of hydrogen by electrolysis is a mature technology and is widely deployed internationally at scales of 100s of kWth capacity[5]. In the UK there are examples of

[5] http://www.itm-power.com/h2-stations

operational hydrogen filling stations at this capacity, and ITM is supplying a similar electrolyser for the HyDeploy project[6]. Projects are underway to scale up production such as Project Centurion[7] which is targeting around 75MW$_{th}$ of installed hydrogen capacity.

The cost of electrolytically-produced hydrogen depends on the capital cost of the equipment and crucially the cost of electricity and utilisation of the plant. Operating at high load factor reduces the capital cost element of the levelised cost, but means that at typical scales, electricity will need to be purchased at market prices, meaning that the input energy cost alone may be in excess of £100/MWh of hydrogen. Using constrained renewable resources will lower the cost of electricity and the carbon intensity, but the capital cost element rises with low utilisation. For example, offshore wind has a load factor of around 40%, but it is unlikely it could deliver economically with >10% constraint, which is a utilisation of the electrolysis plant of <4%. In this case, the capital cost element of electrolytic hydrogen production would be significant. Therefore, whilst electrolytic hydrogen has a role to play, particularly where it can assist with balancing the electricity network, it is expected to be a costly route.

Biohydrogen

Bioenergy with CCS (BECCS) is widely recognised as playing an important role in meeting our 2050 obligations. As identified by the CCC in its Net Zero report4, this means combining bioenergy with CCS, "whether for power generation, hydrogen production or production of biofuels". However, this requires development of reliable and financeable biomass gasification at scale, capable of delivering a syngas suitable for subsequent conversion (shifting) to hydrogen. It also depends on the consolidation of significant volumes of biomass supply chains to support financing and delivery of conversion plants. There is no doubt that production of biohydrogen will form an important part of delivering Net Zero, although these factors are likely to delay the uptake of biohydrogen, and potentially constrain capacity relative to reforming of gas with CCUS.

Conversion of Natural Gas with CCUS

Conversion of natural gas to hydrogen is a mature technology deployed internationally. It offers the potential for bulk low carbon hydrogen production considerably more cost effectively than electrolytic or biohydrogen. Therefore, whilst it is expected that there will be a mixture of hydrogen sources in the future, "blue hydrogen" is expected to be the dominant source, as assessed by the CCC. Two principal technologies are available:

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[6] https://hydeply.co.uk/
[7] https://www.itm-power.com/news-item/100mw-power-to-gas-p2g-energy-storage-feasibility-study

Steam Methane Reforming (SMR) and Advanced Reforming including Autothermal Reforming (ATR) or Gas Heated Reforming coupled with an ATR. Where there is a requirement to capture CO_2, it is recognised that Advanced Reforming is a more appropriate technology, as SMR gives rise to two separate CO_2 streams, one of which is at low pressure and low CO_2 concentration, while Advanced Reforming produces a single high- pressure stream for CO_2 capture.

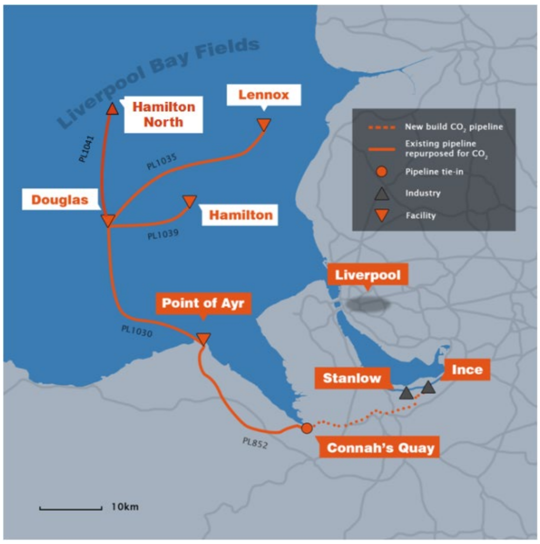
HyNet has selected Johnson Matthey's (JM) Low Carbon Hydrogen (LCH) technology for bulk hydrogen production as it offers lower cost, higher CO_2 capture rate, and scalability advantages. The technology also can process feeds other than natural gas such as Refinery Off-Gas (ROG), which is important in the context of HyNet.

Hydrogen production will eventually provide the bulk of CO_2 transported and stored by the HyNet CCUS system. It therefore forms an essential part of the wider HyNet project. The HyNet Hydrogen Supply Project, funded by BEIS, has enabled a site specific pre-FEED study of the JM LCH technology to be undertaken. This project is now partway through FEED.

1.4 HyNet CCUS - Full Chain Overview

The HyNet full chain CCUS system as described in this report comprises the following elements. These are set out in greater detail in Section 2.0:

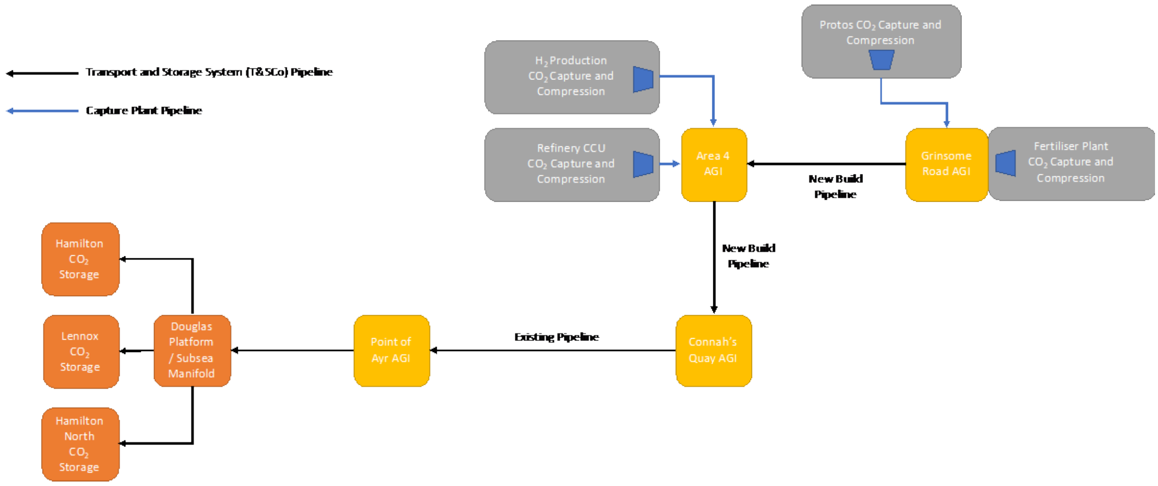
Figure 1.3: HyNet Map



- CO_2 Capture:
    - Ince Fertiliser Plant (CF Fertilisers)
    - Stanlow Refinery (Essar Oil UK)
    - Hydrogen Supply (Progressive Energy / Essar Oil UK)
    - Protos (Peel L&P Environmental)
- CO2 Transport:
    - Grinsome Road Above Ground Installation (AGI) adjacent to Ince Fertiliser Plant
    - Newbuild onshore pipeline (12”) from Ince Fertiliser Plant to Stanlow Refinery
    - Stanlow AGI within Stanlow Refinery boundary and adjacent to hydrogen production plant
    - Newbuild onshore pipeline (36”) from Stanlow Refinery to Connah's Quay
    - Connah's Quay AGI at connection point between newbuild and existing onshore pipelines

- Repurposed existing pipeline (24”) from Connah’s Quay to Point of Ayr
    - Compressor facility at Point of Ayr
    - Repurposed existing pipeline (20”) from Point of Ayr to Douglas Offshore Platform / Subsea Manifold[8]
    - Repurposed existing infield pipelines (multiple sizes) from Douglas Offshore Platform to Hamilton, Hamilton North and Lennox reservoir
    - Compressor facilities at Hamilton, Hamilton North and Lennox wellhead platforms
- CO_2 Storage:
    - Hamilton Reservoir
    - Hamilton North Reservoir
    - Lennox Reservoir
- System Operation:
    - Control
    - Metering
    - Monitoring and Verification

Figure 1.4: Full Chain Block Diagram



[8] Decision on whether to re-purpose Douglas Platform or replace with a new subsea manifold to be undertaken by Eni during FEED phase based on wider techno-economic assessment of platform re-use opportunities.

2.0 FULL CHAIN DESCRIPTION

2.1 Objectives

The objectives of the pre-FEED study, as set out in the pre-FEED Basis of Design document were as follows:

- To determine the technical feasibility of a full chain Industrial CCUS scheme comprising anchor loads from Stanlow Refinery and Ince Fertiliser Plant and CO_2 storage in Liverpool Bay fields;
- To determine the optimised trade-off position between lowest initial cost and future scheme growth which includes capture from additional industrial facilities and hydrogen production;
- To determine capital and operating costs for the project to +/- 30% to inform HMG development of a policy framework and support mechanism;
- To determine a programme of work for the FEED study (scheduled from 2020-2022); and
- To undertake environmental scoping and determine a programme of work for the consent process.

The pre-FEED study concentrated on initial mass flow rate scenarios up to 3MtCO_2/yr, with optionality for future expansion.

2.2 Initial Design Basis

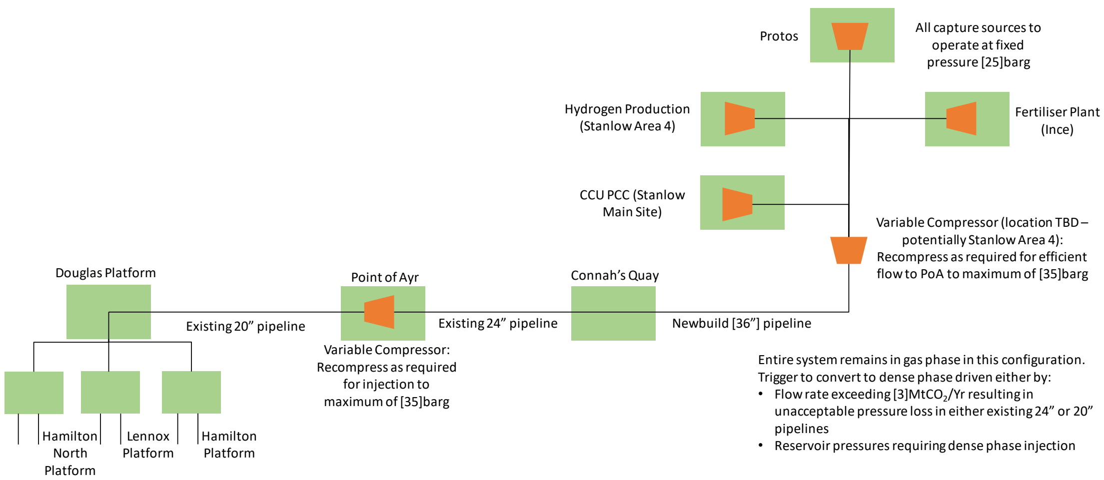
The pre-FEED Basis of Design (P1131.WP1.04.001) was published in April 2019 to act as the principal reference document for all work packages. Key elements were as follows:

2.2.1 System Configuration

The Design Basis set out initial operating modes in both gas and liquid phases to use as the basis of operational scenario workshops and flow assurance modelling.

The proposed system configuration at the commencement of the project envisaged a low pressure 'collector network' operating at 25barg, with a system compressor operating in the vicinity of the Stanlow site to compress to pipeline transport pressure. It was envisaged that this compressor would act as the control point for the System Operator to set the downstream system pressure for transport to Point of Ayr.

Figure 2.1: Design Basis Baseline System Configuration (Gas Phase)



Additional compression would be located at Point of Ayr to increase system pressure as required to allow for injection.

During the initial phases of project operation, the project would operate in gas phase throughout the system, with subsequent transition to liquid phase offshore. The design basis states *'The transition to liquid phase will be determined either by mass flow rates in the existing 24" or 20" pipelines leading to unacceptable pressure loss in the system, or reservoir pressures requiring liquid phase for injection.'*

This baseline system configuration was assessed and subsequently amended through operational scenario workshops and modelling, as described in Section 2.3 below.

It should be noted that onshore transport in liquid phase was discounted from the outset of the project for the following reasons:

- Maximum flow rate of 10MtCO_2/yr is achievable in a 36" pipeline from Stanlow to Connah's Quay with acceptable pressure loss in gas phase.
- The Stanlow to Connah's Quay pipeline route is complex and passes in close proximity to numerous urban conurbations. Consenting a liquid phase pipeline in this area would be challenging, and potentially lead to a much longer route to avoid built-up areas.
- The existing Connah's Quay to Point of Ayr pipeline has insufficient Maximum Allowable Operating Pressure (MAOP) to accommodate liquid phase transport. As such, replacement of this section of pipeline would be required for the onshore system to operate in liquid phase.

2.2.2 CO_2 Composition

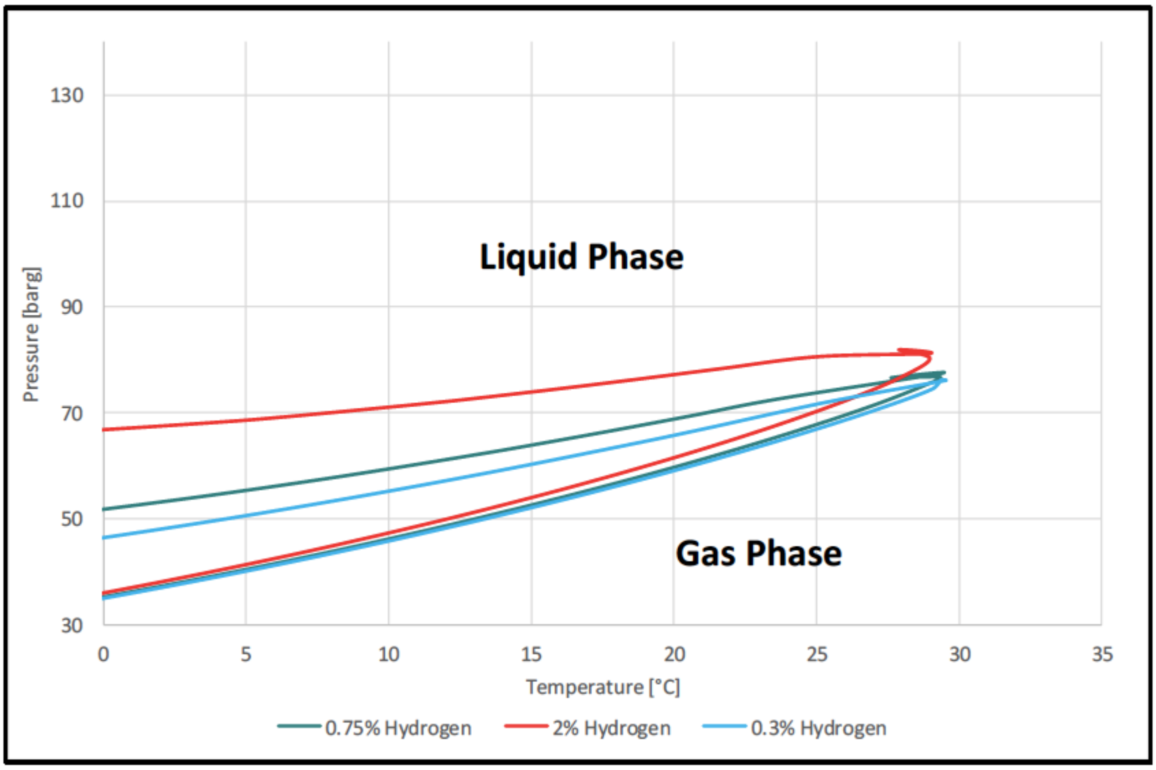
A system CO_2 composition specification was determined that was used for both the Transport and Storage (T&S) system and all capture plants. The design basis states *'All four capture plants in the Baseline Scenario (refinery, fertiliser plant, Protos and hydrogen production plant) will operate to the same specification, but, recognising that any individual capture plant may yield CO_2 of higher purity and that the CO_2 in the pipeline at any given time will be a blend from the four sources, this specification presents the worst case CO_2 purity envelope for consideration in the transport and storage assessment. All future sources will be required to meet the same specification.'*

Hydrogen content in the CO_2 stream presents the HyNet project with challenges and is the stream compositional parameter with the greatest influence on system design. Unlike in CO_2 captured from a pure combustion process (for example, post-combustion capture on a CCGT), there is the potential for relatively high levels of hydrogen to be present in the CO_2 captured from both the fertiliser plant and the hydrogen production plant. The presence of hydrogen in the CO_2 stream has a significant influence on the phase envelope of the stream, and hence the risk of incursion into the two phase region (see Section 2.2.3 below). In order to explore a range of operating scenarios, an upper and lower bound hydrogen content was set, at 2mol% and 0.75mol% respectively. During the modelling process a further low low case of 0.3mol% was also assessed (see Section 2.3 below).

2.2.3 CO_2 Phases, System Pressures and Erosion Velocities

Maintaining safe and reliable operation are key system design objectives. It was determined at the outset of the project that two phase flow in the system was to be avoided in all instances (including start-up and shut-down), with the exception of the injection wells. The phase diagram for 0.3 / 0.75 / 2 mol% CO_2 streams is shown below.

Figure 2.2: Phase Diagrams for CO_2 Stream with variable H_2 content



By setting design margins to include parameters such as Equation of State (EoS) uncertainty, shutdown / cooldown allowances and alarm settings, a minimum operating pressure for liquid phase above the bubble point was set, and similarly, a maximum operating pressure for gas phase below the dew point was set.

It can be seen from the phase diagram above that hydrogen content has little impact on system operability in gas phase, but the difference between 0.3% and 2% can provide as much as 20bar additional operability envelope in the liquid phase.

Full details of the phase envelopes and design margins can be found in the Flow Assurance Design Premise document, reference HYN01-01 Revision 4.

The following erosion maximum velocities were set:

- 5 m/s in carbon steel pipeline for liquid phase
- 20 m/s in carbon steel pipeline for gas phase
- 30 m/s in CRA (Corrosion Resistant Alloys) or lined (pipeline and wells) for gas or liquid phase.

2.2.4 System Temperatures

A T&S maximum operating temperature of 20°C was set, based on environmental considerations on previous projects[9]. This is set as the inlet temperature into the system from the capture plants, and the maximum outlet temperature from system compression at Point of Ayr.

2.2.5 System Mass Flow Rates

A number of mass flow rate scenarios were determined for system modelling as follows:

Figure 2.3: System Mass Flow Rate Scenarios

Scenario	Maximum Flow Rate ($MtCO_2$/yr)	Maximum Instantaneous Flow Rate (kg/s)	Cumulative Storage ($MtCO_2$/yr)	Sources
Baseline	3.0	105.7	70.3	Ince Fertiliser Plant Stanlow Refinery Protos Hydrogen Production Plants
Low	1.2	42.3	28.7	Ince Fertiliser Plant (0.4Mt) Stanlow Refinery (0.8Mt)
Mid	5.9	207.7	128.0	Ince Fertiliser Plant Stanlow Refinery Protos Additional Industrial Capture Hydrogen Production Plants
High	10.0	352.5	193.0	Ince Fertiliser Plant Stanlow Refinery Protos Additional Industrial Capture Hydrogen Production Plants

The precise make-up of individual sources over time remains uncertain, but the range of scenarios represents a useful range for system assessment. They have been used as follows:

- Baseline: Used as the baseline mass flow rate for reservoir modelling studies and compressor configuration assessment by Eni. This has become the basis of the 'Flexible Project' as described in Section 2.3 below.
- Low: Used as a minimum mass flow rate for defining the low cost start up project. This has become subsequently reduced to 1$MtCO_2$/yr and has become the basis for the 'Minimum Viable Project' as described in Section 2.3 below.

[9] *K02 White Rose Full Chain Basis of Design*, Capture Power Limited, December 2015 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/532014/K02_Full_Chain_Basis_of_Design.pdf

- High: Used as a maximum mass flow rate for defining sizing of new system assets (such as newbuild pipeline and compressors). This has become the basis for the 'Max Project' as described in Section 2.3 below.

Figure 2.4: Annual Mass Flow Rates

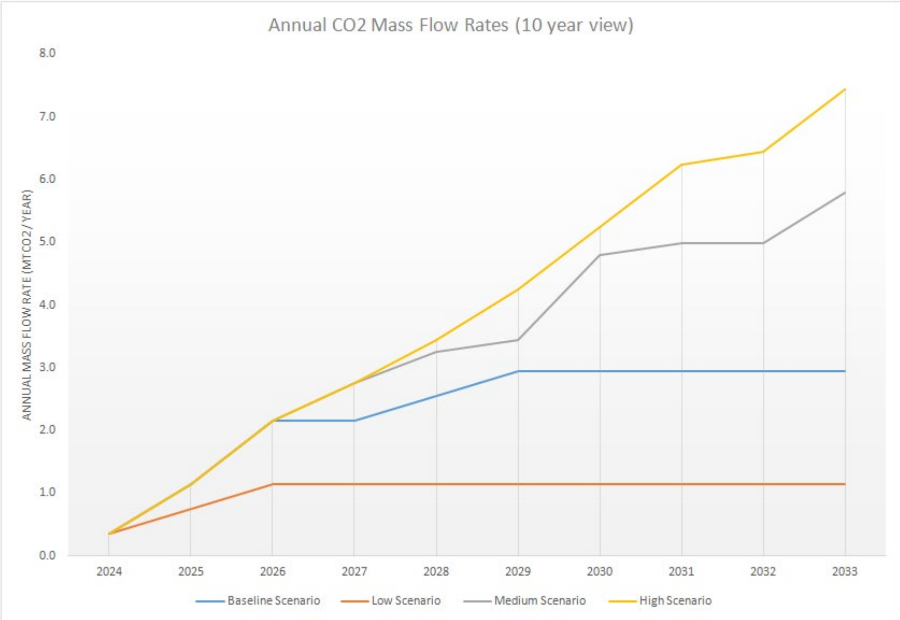
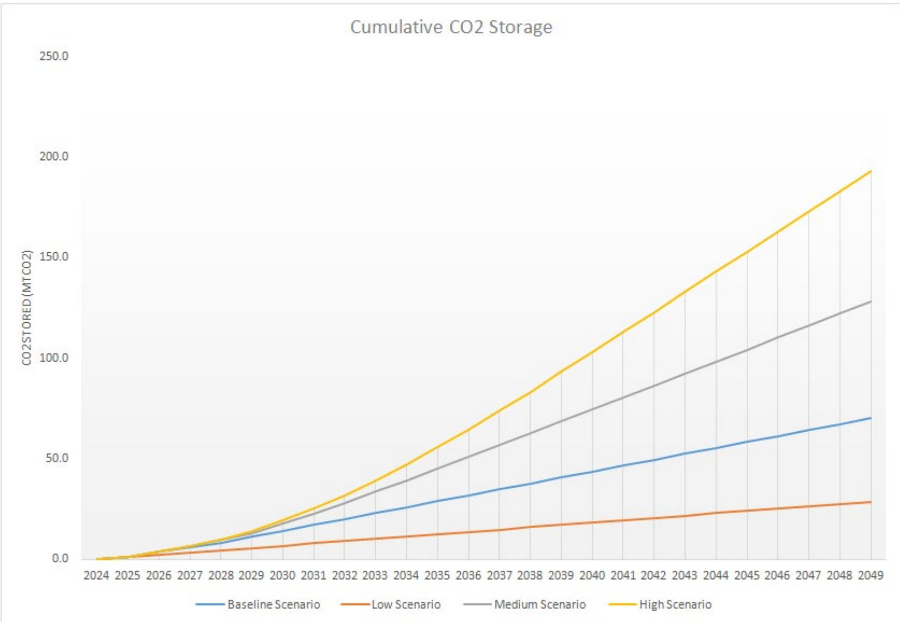


Figure 2.5: Cumulative CO_2 Stored



2.2.6 Reservoirs and Fill Sequence

Three reservoirs in Liverpool Bay are suitable for CO_2 storage, namely Hamilton, Lennox and Hamilton North. The Basis of Design called for consideration of alternative fill sequences, namely sequential and in parallel. A system configuration of parallel fill has been determined in the pre-FEED Phase to be used for FEED, and the rationale for this is set out in Section 2.3 below.

The Basis of Design set out reservoir descriptions and parameters as follows:

- Hamilton is a largely depleted gas field site and is one of the largest of a series of fields located in the Liverpool bay area of the East Irish Sea. It is located around 40km south of the large Morecambe Bay gas field and is some 23km from landfall at Merseyside. The field was discovered in June 1990 with first gas delivered in February 1997. Hamilton is notable for its significant pressure depletion and its shallow depth, which has resulted in it being identified as one of the most suitable CO_2 storage sites in UK waters[10]. The field has high storage efficiency and is estimated to have a total storage potential of 125 $MtCO_2$ in liquid phase. Hamilton's capacity to securely store CO_2 in liquid phase will be subject to further assessment in the pre-FEED study.
- Lennox is an oil field with a gas cap. It is part of the Liverpool Bay complex of fields in the East Irish Sea and is located around 20 km east of Hamilton field, and around 15km from shore. Lennox was discovered in June 1990 with first production early in 1996. Lennox oil production is exported via offshore loading directly into tankers, and its gas production from the gas cap is exported via Douglas. The gas depleted gas cap provides a storage volume, with an estimated total storage potential of 80 $MtCO_2$ in liquid phase[11]. Lennox's capacity to securely store CO_2 in liquid phase will be subject to further assessment in the pre-FEED study.
- Hamilton North is a largely depleted gas field, 8km to the north of the Hamilton field. First production was in December 1995. The field is estimated to have a total storage potential of 23 $MtCO_2$ in liquid phase[12]. Hamilton North's capacity to securely store CO_2 in liquid phase will be subject to further assessment in the pre-FEED study.

Storage volumes have been revised in pre-FEED and this is set out in Section 2.3 below.

[10] Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource, Energy Technologies Institute, April 2016

[11] Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource, Energy Technologies Institute, April 2016

[12] Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK, Report No. COAL R308, DTI/Pub URN 06/2027, October 2006

2.3 Design Basis Changes for FEED

During the pre-FEED study, a number of evolutions to the Design Basis were made as analysis and system assessment progressed. It is anticipated that the FEED Basis of Design will be based on the pre-FEED Basis of Design, with the following key changes.

2.3.1 System Configuration

2.3.1.1 Capture Plant Compression

Rather than having a centralised compressor at Stanlow, it was determined that a more flexible, and more capital efficient system was to have separate compressors at each capture site. Key parameters in this decision were as follows:

- A centralised compressor would need to be sized for flow rates from each capture source. With actual flow volumes and date of connection of each source uncertain, this would have required the centralised compressor to either have been designed and built in a modular way, adding complexity, or for it to be over-sized from the outset, adding additional capital to the initial project. Furthermore, the compressor would have to be designed to operate with maximum flowrates from multiple sources down to a minimum turndown on a single source, requiring a wide range of operational mass flow rates – this would require recirculation configurations, reducing operational efficiency of the compressor solution.
- A centralised compressor would mean that flows to this location from individual capture sources would be at lower pressure, therefore requiring larger pipe sizes, and hence capital cost.
- An initial system operability review indicated that the initial system operability mode would be as ‘free flow gas’, that is no intermediate system compression or pressure control within the transport and storage system.

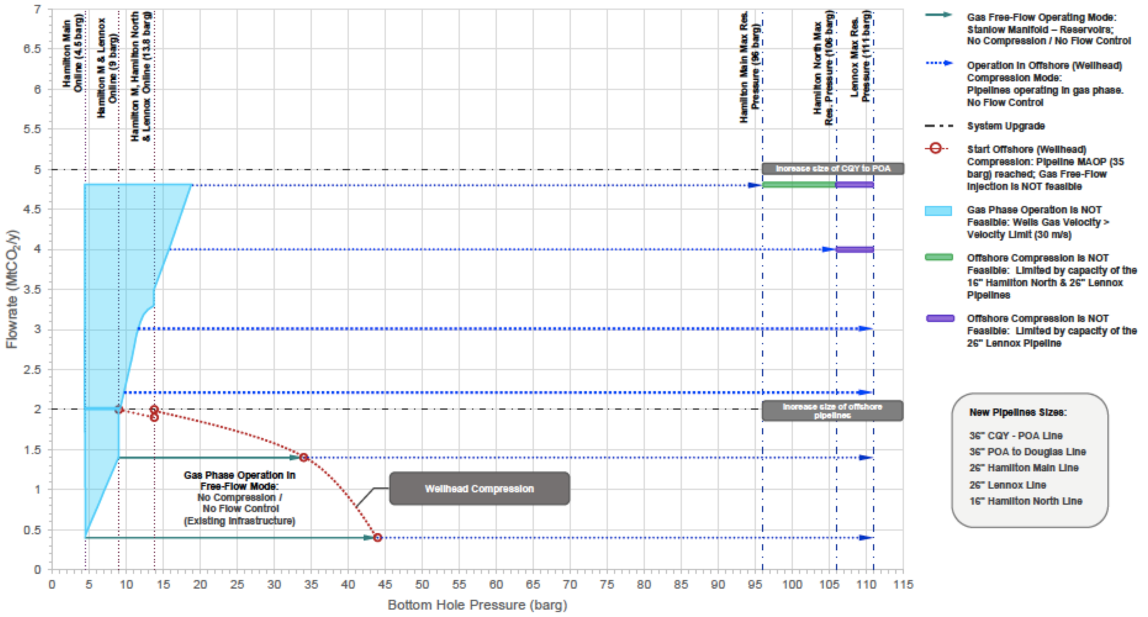
It was therefore determined to set the individual capture plants compressor outlet temperature requirements to the T&S limit of 20°C, and then maximise system pressure while remaining in the two phase flow region. This would provide maximum duration of system operation in the free flow gas phase without the need to install intermediate compression.

2.3.1.2 System Compression

The length of time that the system can operate in ‘free flow gas’ phase is determined by system constraints. A complex process of system constraint mapping was determined in the pre-FEED flow assurance work and forms one of the key outcomes of the project.

Constraints mapping is set out in detail in the Flow Assurance Report (project deliverable HYN01-03). An example of constraint mapping is shown in Figure 2.6 below.

Figure 2.6: Example Flow Assurance Constraints Map



In ‘free flow gas’ phase the system ceases to function when there is insufficient driving pressure from the capture plant compressors to ensure injection into the reservoirs. This in turn is a function of both reservoir bottom hole pressure (BHP) and system mass flow rates. The system mass flow rate determines the pressure loss in the system, and hence the arrival pressure at the wellhead. Arrival pressure at the wellhead needs to be greater than BHP to ensure injection.

At the point that system constraints are encountered, and ‘free flow gas’ mode is no longer available, system interventions are required. This is initially in the form of compression, and the system can then continue to operate until a subsequent constraint is encountered, when further intervention is required, either in the form of additional compression or pipeline sizing increases.

A range of compression configurations have been considered to explore how to manage the transition from ‘free flow gas’ mode to the maximum flow rate scenario, which requires dense phase offshore. This section sets out a number of these configurations, which remain the subject of study. The project aims to select a preferred configuration ahead of commencement of FEED, although it is expected that this will be reviewed during the first few months of FEED before a final configuration is confirmed.

In the configurations set out below, pipelines in gas phase are denoted in green, while pipelines in dense phase are denoted in blue. From the start of the project, two-phase flow in the pipelines was rejected as a design solution due to concerns over the ability to model flow accurately, and the physical loading concerns on pipeline components. However, late in the pre-FEED study the subject of two-phase flow was re-considered, and this may be a viable system configuration. A two-phase flow scenario has not been included in the diagrams below.

Case A (illustrated below in Figure 2.7 toFigure 2.9) introduces compression at PoA and the wellhead platforms and achieves a system mass flow rate of 3.3 to 4.0MtCO_2 / yr. Case A1 replaces the existing Douglas Platform with a subsea manifold (detailed further in 2.6.3.2), while case A2 retains the Douglas Platform. From a system configuration and flow assurance perspective these scenarios are virtually identical, and the decision will be driven by an economic assessment of the cost of a new subsea manifold compared with the ongoing maintenance costs of the Douglas Platform. At this point, the retention of the Douglas Platform is considered to be the design baseline.

Case A3 introduces compression on the Douglas Platform rather than at PoA, but this is deemed as not viable due to the requirement to increase pressures in the onshore pipeline section above the 35barg system limit.

It should be noted that all transition cases A1 to A3 require a PoA outlet temperature of 50C, which is above the current Basis of Design and, while this is acceptable from a design perspective, it poses a project risk as environmental permitting of this will need to be considered. To reduce this higher temperature requirement, two-phase flow is being reconsidered in the offshore network.

Figure 2.7: Transition Case A1 – Compression at PoA and wellhead and replacement of Douglas Platform with subsea manifold

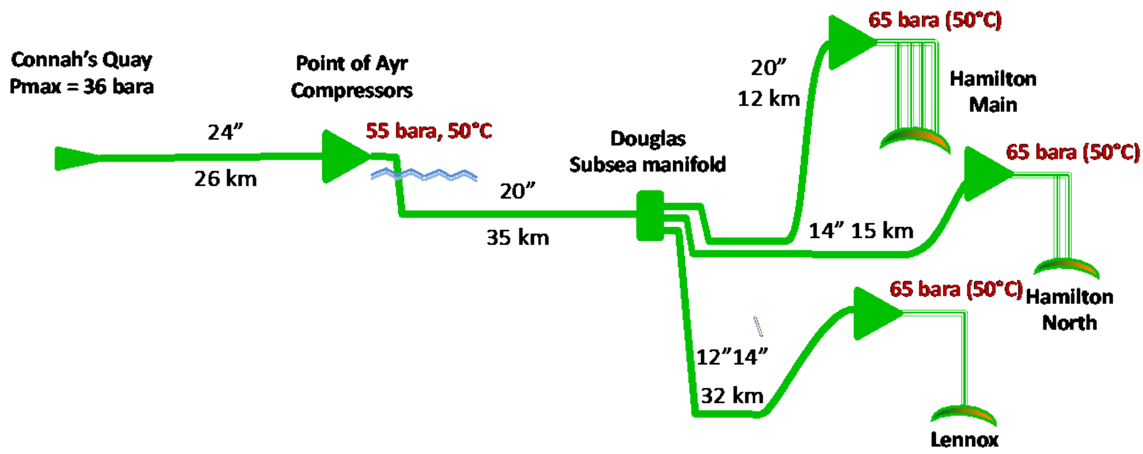


Figure 2.8: Transition Case A2 - Compression at PoA and wellhead and retention of Douglas Platform

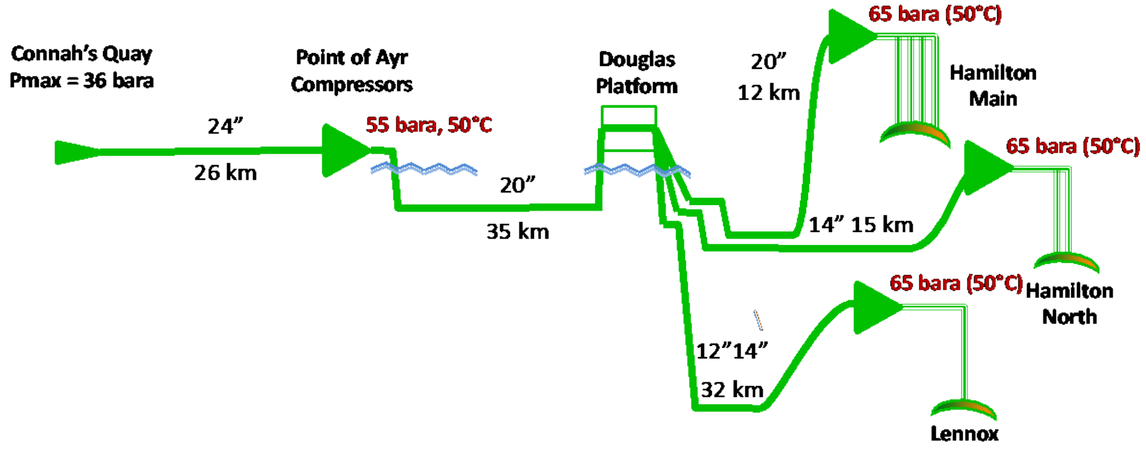
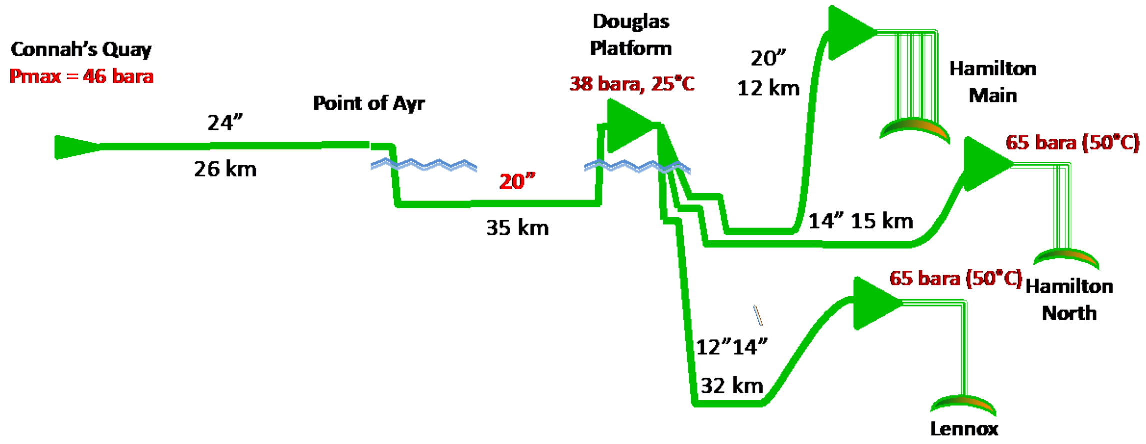


Figure 2.9: Transition Case A3 - Compression at Douglas and wellhead



To deliver higher system flow rates, dense phase is required in the offshore pipelines. This will necessitate the replacement of a number of offshore lines that currently have insufficient operating pressures. Given that these will operate in dense phase, the size of the lines can be relatively small. These are denoted in blue dashed lines in Cases B1 and B2 below.

As the project moves to dense phase offshore, the system flow rate constraint is the existing onshore pipeline between Connah's Quay and PoA, which is limited to 5MtCO_2 / yr and has insufficient operating pressure to operate in dense phase. To mitigate this constraint, the final phase of system upgrade will see the replacement of the existing 24in line with either a new 36in line (to allow for continuous pigging from Stanlow to PoA), or, alternatively, a new, parallel 24in to the existing 24in with both being operated together to provide sufficient mass flow rate capacity.

Figure 2.10: Transition Case B1 - Dense Phase compression at PoA

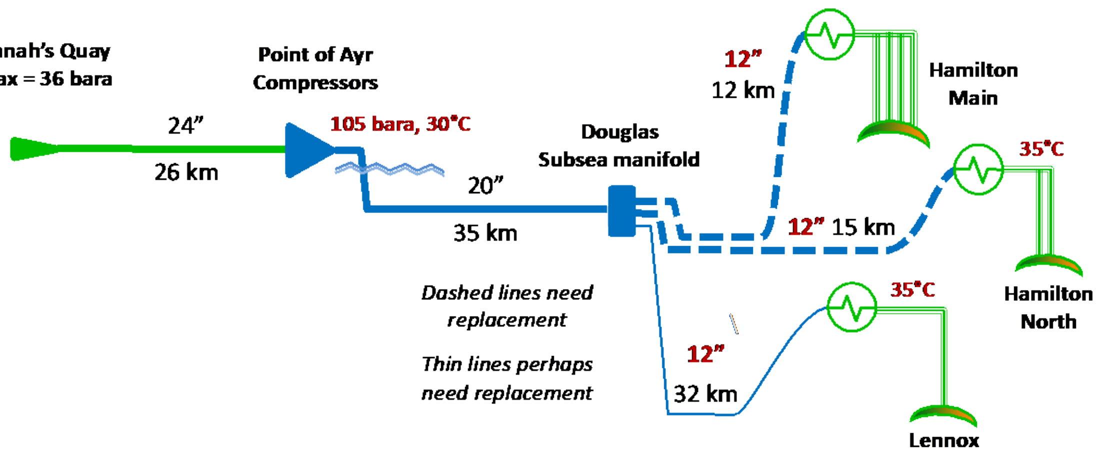
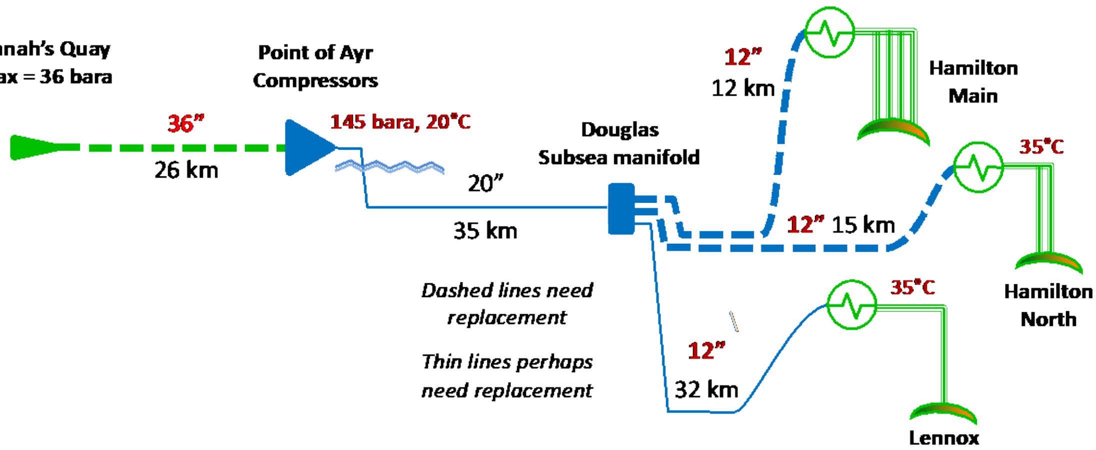


Figure 2.11: Transition Case B2 - Dense Phase compression at PoA and replacement of onshore pipeline section



As set out above, further work is being undertaken at select a preferred concept to be taken into FEED.

2.3.2 CO_2 Composition

In the pre-FEED phase flow assurance modelling was undertaken with hydrogen concentrations of 0.3 / 0.75 / 2 mol%. Of these, 0.3 mol% gives the greatest system operability as there is significant margin between the bubble point and the pipeline MAOP. However, this requires the highest level of expenditure at the capture plants to achieve this specification of hydrogen.

Having reviewed the options, the system is deemed sufficiently operable at 0.75 mol%, and this is achievable by all capture plants. This will therefore be the specified maximum hydrogen concentration in the CO_2 stream composition for FEED.

The following two further amendments will be made to the CO_2 stream composition specification for FEED:

- Water: Reduction from <250ppmv to <50ppmv to ensure no hydrate formation
- H_2S: Reduction from <200ppmv to <5ppmv due to Health and Safety considerations – (note: awaiting final confirmation and agreement between partners)

2.3.3 CO_2 Phases, System Pressures and Erosion Velocities

The confirmation of the hydrogen specification will finalise the phase envelope to be used for FEED. No additional changes to system pressures and erosion velocities are expected for the FEED phase, although a review of design margins will be required.

2.3.4 System Temperatures

A critical component of the acceptability of Alternative B (as set out above) is the outlet temperature of the compressor at Point of Ayr. If this temperature is limited to 20°C, as per the pre-FEED Basis of Design, a compressor outlet pressure of 55bara leads to two-phase flow, which is unacceptable to the project.

Given the criticality of this design constraint, a review is required ahead of FEED. By way of comparison, the White Rose project set the following pipeline temperature specifications9:

Figure 2.12: White Rose CCS Project Pipeline Temperature Specifications

	Design Temperature		Normal Operating Temperature	
	Max / °C	Min / °C	Max / °C	Min / °C
Onshore Pipeline	25	0	20	5
Pumping Station Outlet Temperature	50	-46	30	4.5
Offshore Pipeline	40	0	29.3	1

2.3.5 System Mass Flow Rates

The scenarios set out for the pre-FEED Basis of Design will largely form those for FEED, although there will be some simplification and changing of titles. The following mass flow rates are proposed for FEED:

Figure 2.13: Mass Flow Rate Scenarios for HyNet FEED

Scenario	Maximum Flow Rate ($MtCO_2$/yr)	Sources
Minimum Viable Project	1.0	Ince Fertiliser Plant Hydrogen Production Plant (1x)
Flexible Project	3.0	Ince Fertiliser Plant Stanlow Refinery Hydrogen Production Plant (3x)
Max Project	10.0	Ince Fertiliser Plant Stanlow Refinery Additional Industrial Capture Hydrogen Production Plants to provide 30TWh/yr

Minimum Viable Project is set such that it can operate in free flow gas mode with no intermediate compression or system pipeline pressure or capacity increases.

Flexible Project is set to provide a scenario for a range of alternative capture options, with additional system capacity being met by the installation of intermediate system compression, and, if Alternative B is the chosen solution, no pipeline pressure or capacity increases.

Maximum Project is set to meet the upper case design case for HyNet in the North West, with up to 8$MtCO_2$/yr from hydrogen production, and 2$MtCO_2$/yr from industrial capture.

2.3.6 Reservoirs and Fill Sequence

During the pre-FEED study, Eni identified that their preferred system configuration was to pressure-equalise the reservoirs through a manifold at Douglas. The starting pressure for each reservoir is slightly different, and so they would be commissioned sequentially, and as soon as the lowest pressure reservoir was brought up to the pressure of the second reservoir, they would be connected. The third reservoir would be connected in a similar process.

This approach provides maximum system resilience, as, with multiple injection wells for each reservoir, storage can continue in the event of any particular well failure, either through a different well in the same reservoir, or, if necessary, by shutting down a particular reservoir. By coupling the reservoirs together, it maximises storage volumes prior to moving to liquid phase injection, therefore delaying investment in compression Capex.

As the project moves into liquid phase, injection at each well will be flow controlled separately via the choke and pressure equalisation across the reservoirs will no longer be necessary.

2.3.7 Storage Volume

Eni's reservoir modelling work has identified that storage volumes are slightly lower than those assumed at the start of the pre-FEED phase. Storage volumes to be used for FEED are as follows (see Section 2.6.2.2):

- Hamilton Main: 103Mt
- Hamilton North: 34Mt
- Lennox: 58Mt
- Total: 195Mt

2.4 Capture

The HyNet system is designed to capture CO_2 from a range of existing and new-build industrial sources of process emissions and from hydrogen production plants. All capture plants must meet the same CO_2 specification (both stream composition and temperature / pressure) allowing the system to operate on any combination of capture plants. Capture plants that have been specifically assessed during the pre-FEED project are set out below.

2.4.1 Ince Fertiliser Plant (CF Fertilisers)

The full work package report was issued as project deliverable P1131.WP3.04.002 in December 2019.

2.4.1.1 Background

CF's fertiliser manufacture operation at Ince currently separates outs a total of about 450,000 tonnes of CO_2 per annum, a portion of which is captured as part of the production process and sold to a third-party, leaving a residual emission of approximately 330,000 tonnes p.a. It is the largest single separated CO_2 source in the North West and represents a significant opportunity to underpin and enable the early development of the HyNet CO_2 transportation and storage network.

The integrated manufacturing facility is a major producer of UK agricultural fertiliser. CF currently have limited carbon cost exposure under EU-ETS Phase 3, however this position changes under Phase 4 which comes into effect in 2021. As a business they are constantly seeking opportunities to minimise exposure to these costs, as well as striving to maintain a competitive position in the wider world marketplace. Reducing EU-ETS allowances, coupled with forecast increases in carbon costs, puts significant commercial pressure on the future viability of the site. CCUS is an attractive option to tackling these potential threats, especially given the significant volumes of CO_2 currently separated at the plant already. Additionally, CF also perceive benefits from the potential marketing value of 'low carbon' fertilisers and feedstock products that a local CCUS network would enable. They are therefore motivated to support this study and explore options and understand costs for CO_2 capture and export from their site.

2.4.1.2 Process Overview

The CF plant at Ince manufactures ammonia using the Haber-Bosch (H-B) process. The H-B is a nitrogen fixation process and is currently the most common technology used to produce ammonia. The integrated site operation produces solid fertiliser for direct despatch to customers as both bagged and bulk product.

Key components of the Ince manufacturing facility are:

- Ammonia plant
- Nitric acid plant
- Ammonium Nitrate plant
- NPK plant
- Packaging and despatch plant

The plant uses Natural Gas as the base feedstock and as part of the production process it removes CO_2 from its process stream using solvent based capture technology.
The site has two main emission points: process CO_2 from the amine plant and flue gas from the Steam Methane Reformer (SMR) stack. CO_2 emitted in the flue gas is outside the work scope of this study.

A proportion of the captured CO_2 from the amine plant is purified and compressed to 20barg for liquified storage in ‘bullet’ tanks by a third-party. This is exported by road tanker and sold into the industrial gas market (supplying multiple industries). This existing compression plant is unsuitable for use as part of the HyNet project because of lack of spare compression capacity and existing commercial arrangements.

2.4.1.3 Existing CO_2 Capture, Composition and Mass Flow Rates

The plant generates Carbon Dioxide (CO_2) as a by-product of the Steam Methane Reformation of the natural gas feedstock which is carried out to produce hydrogen for ammonia manufacture. The CO_2 is removed by a two-stage capture process using an amine solution. Approximately 1.2 tonnes of CO_2 are produced per tonne of ammonia manufactured.

A proportion of this CO_2 is recovered, purified and liquefied on site for sale into the industrial gas market. The remaining CO_2 is currently discharged to atmosphere via a high-level vent attached to one of the two CO_2 absorber columns.

An additional emission of approximately 0.6 tonnes of CO_2 per tonne of ammonia occurs in the flue gas from the steam-raising boiler. Capture of this CO_2 would require the construction of a post-combustion CO_2 absorption and stripping system which is likely to be expensive, and, as mentioned in section 2.2, is outside the scope of the Pre-FEED study.

The typical composition of the recovered CO_2 from the ammonia plant is 97.8 mol%, with hydrogen typically at 2 mol%, but within a range of 1.2-2mol%. As set out in Section 2.2.2 this is outside the project Basis of Design specification (0.75mol%), and so the treatment of the existing CO_2 stream formed a significant element of the work package.

Currently, the maximum production rate is 1,150 tonnes/day of ammonia, which generates 1,393 tonnes/day (58 tonnes/hour) of process CO_2.

2.4.1.4 CO_2 Treatment and Compression Concept

A range of options were looked at for hydrogen removal from the existing CO_2 stream and the preferred solution was identified as the addition of a new high-pressure flash vessel in the aMDEA (activated Methyl Diethanolamine) stream from the first stage CO_2 absorber column to the low-pressure flash vessel.

The original Basis of Design for the fertiliser capture plant set out a compressor configuration of 3 50% duty compressors, which was subsequently revised during the pre-FEED project to a single compressor of 100% duty, with the possible future addition of an additional 50% duty compressor should additional CO_2 become available.

The compressor will be fed by a single CO_2 bower sized to accommodate the full CO_2 output of the facility (i.e. the combined third-party offtake and the proposed export CO_2). The blower is rated at 900kW and the compressor at 3.3MW. Cooling and drying is also required to meet the CO_2 pipeline specification.

2.4.1.5 Plant Description and Layout

The proposed plant layout is shown in Figure 2.14 below. A full description of the scheme can be found in the work package specific pre-FEED report.

In summary, the original ammonia plant is shown in black and the existing CO_2 pipes in green. New CO_2 pipes, compressors, driers etc are shown in purple, and the location of the new tower in red. Condensate return pipes are shown in blue.

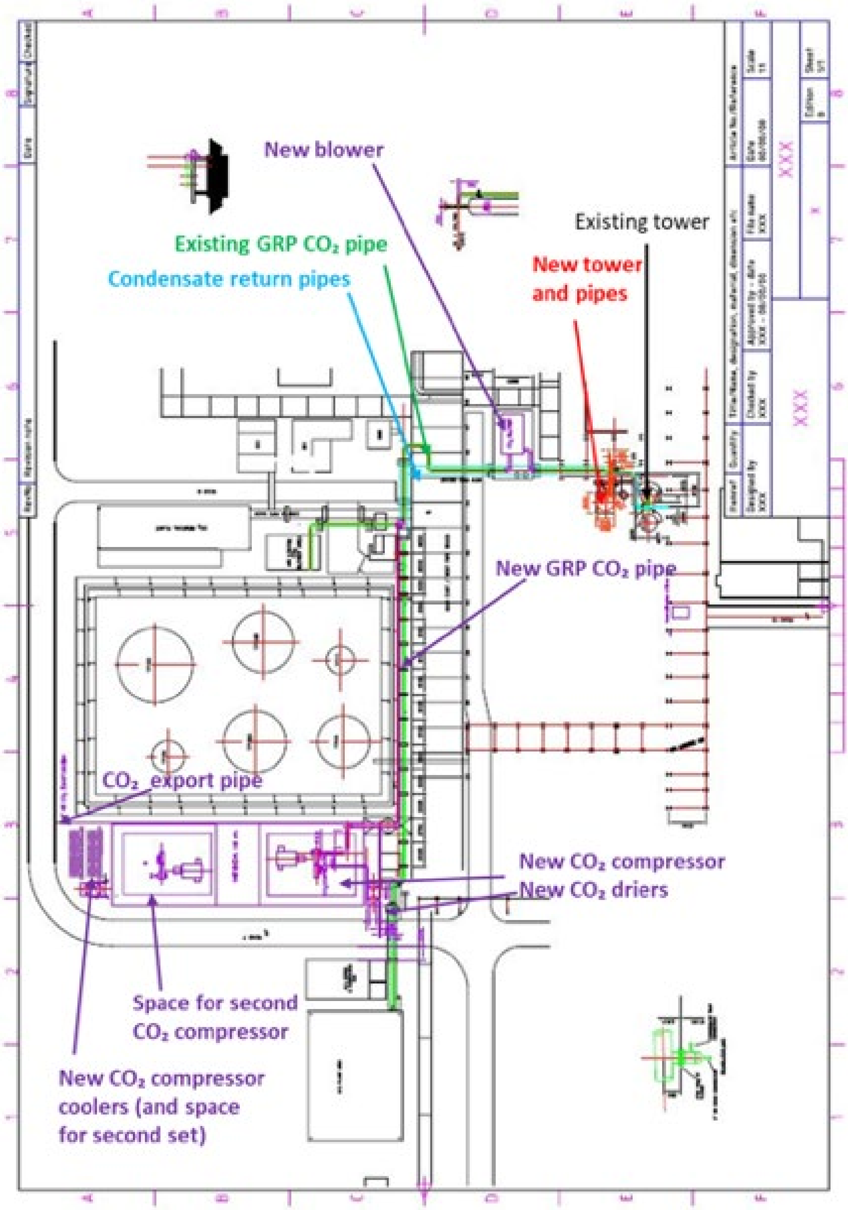
It is planned that the new column will utilise an existing concrete base and foundation, left following the removal of a redundant column.

The existing 30” NB GRP pipelines are suitable for the full CO_2 flowrates and pressures. Using these will minimise the site work that would have been incurred providing access scaffolding, attaching new weldments and replacing the existing arrangements. A break-in to the existing 30” NB pipes will be made to include the blower, again, using an existing concrete plinth (subject to its suitability being confirmed during FEED). The blower controls will ensure that existing pressure conditions at the top of the tower are unchanged, ensuring plant operational parameters are unaffected by the modifications.

A new section of 30” GRP pipe will take CO_2 not required by the third party to the west end of the site where it will be compressed and dried before exporting it from the site. Heat generated during the compression will be removed by low plume hybrid cooling towers at the north of the site. Space has been allocated for a second compressor, drier and coolers to export the balance of the CO_2 in the event that there is no longer third-party offtake of CO_2.

Consideration has been given to constructability, and it is believed that thoughtful use of mobile cranes and out-of-outage works can be used to install the additional equipment without affecting the critical path of a routine shut-down of the plant.

Figure 2.14: Ince Fertiliser Plant CO_2 Capture and Compression Plant Layout



2.4.1.6 Cost Estimate and Conclusions

A cost estimate was undertaken to AACE Level 4, which, including risk and contingency, gave a Capital Cost (Capex) of £29.36m. Full details of the cost estimating approach can be found in project deliverable P1131.WP3.04.002.

Figure 2.15: Fertiliser Plant Capture Plant Capital Cost Estimate (£)

Work Breakdown		Equipment	Material	Labour	Subcontract	Contractor Soft Costs	Total
000	Site Preparation, Enabling and Facilities			123,263	3,243,770	324,377	3,691,410
100	Additional Stripper Tower	2,368,507	86,270	904,518		604,206	3,963,503
200	CO_2 Pipe and Blower up to Compressor	2,837,254	100,722	1,036,931		780,253	4,755,161
300	CO_2 Compressor Facility	6,086,497	216,070	2,131,182	857,550	1,652,512	10,943,812
400	CO_2 Compressor Water Coolers	107,249	3,809	39,856		36,183	187,096
500	CO_2 Dryers	567,000	20,652	222,109		194,154	1,003,915
600	High Pressure CO2 Piping		24,737	1,402		184	26,323
700	CO2 Metering Equipment		808,701	37,200	320,227	231,395	1,397,524
Total Base Cost		**12,775,211**	**489,461**	**4,779,489**	**4,101,320**	**3,823,267**	**25,968,749**
Risk and Contingency P80							
7.3%							1,895,718
5.8%							1,498,396
Total							**29,362,864**

2.4.1.7 Areas for Consideration in FEED Phase

Key areas for further consideration in the FEED phase are as follows:

- Compressor specification optimisation, taking into consideration future capacity growth requirements and resilience
- Onsite pipeline routing, as the location of the interface to the T&S system moved during the course of the pre-FEED study to a new AGI located at the West end of the Ince Fertiliser Plant boundary.
- Confirmation of the suitability of the existing 30" GRP line for the full CO2 export flow
- Laboratory analysis of the gas to measure the Hydrogen content of the CO_2 from various process points to confirm the assumptions made in this report and allow better reconciliation with the modelling results
- Development of P&ID (Piping and Instrumentation Diagram) for integration of recovered hydrogen stream into plant fuel gas system

2.4.2 Stanlow Refinery (Essar Oil UK)

2.4.2.1 Background

Stanlow Refinery (Essar Oil UK) is one of the largest CO_2 emitters in the UK, emitting over 2MtCO_2/yr. UK Net Zero targets will require that facilities such as this must be decarbonised. While around 60% of emissions can be mitigated through fuel switching of process heaters and the Combined Heat and Power (CHP) plant from natural gas to hydrogen, the residual process emissions from the Catalytic Cracker Unit (CCU) require the deployment of post combustion capture processes.

The CCU is one of the most important processes on the Stanlow Refinery site. It is used to convert the high-molecular weight hydrocarbon fractions of petroleum crude oils into more valuable products such as components in petrol and diesel.

The CO Boiler is the final stage of Catalytic Cracking Unit. In the Regenerator carbon deposition on the catalyst is burnt off in an oxygen lean atmosphere. This produces a low calorific value effluent gas which, owing to its volume, has a substantial heat content. The regeneration gas is fully combusted in the CO Boiler which raises a substantial amount of high pressure steam.

The CO Boiler flue has a high CO2 concentration which makes it a good target for CO2 capture, but it also contains both NOx (nitrous oxides) and SOx (sulphurous oxides) as well as catalyst fines. The CO Boiler flue gas therefore requires major clean-up steps before the CO_2 can be recovered in the CO2 Removal Unit.

The pre-FEED project examined the technical feasibility of a post combustion Carbon Dioxide Capture Unit (CDCU) physically adjacent to the CCU. Compression and drying of the recovered CO_2 to 35 barg is included within the boundary of the CDCU facility.

2.4.2.2 Existing CO_2 Composition and Mass Flow Rate

CO_2 mass flow rate from the cracker varies annually dependent on production volumes, Flue gas composition is greater than 15 mol% CO_2 with majority of the balance being Nitrogen. This high concentration of CO_2 in the flue gas makes it a suitable target for post combustion capture using a chemical absorption process.

2.4.2.3 CO_2 Treatment Process Overview and Compression Concept

The full processing train of the proposed Carbon Dioxide Capture Unit (CDCU) overall block flow diagram (BFD) is shown in Figure 2.16 below.

The CO Boiler flue gas stream is very low pressure, only slightly above atmospheric, containing around 16 mol% CO_2. For this application amine-based CO_2 removal processes are preferred to physical absorption processes. Physical absorption processes are more suited to gas streams which have a high CO_2 partial pressure, such as synthesis gas. Chemical absorption processes are the natural choice for high volume, low pressure gas streams where the CO_2 partial pressure is low.

There are numerous CO_2 recovery processes many of which are licensed processes. The basis of this study is 90% CO_2 capture using MEA (mono-ethanolamine). This is an open art process, often used as a benchmark process. Licensed processes are generally a little more energy efficient and lower capital cost. MEA therefore provides the worst case.

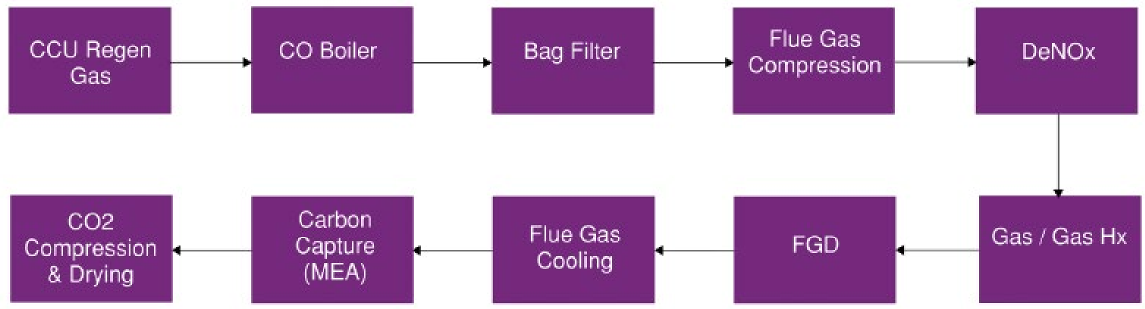
The CO Boiler flue gas also contains NOx (nitrous oxides), SOx (sulphurous oxides) and dust (catalyst fines) all of which must be removed before the Amine unit. Catalyst fines, primarily aluminium and silicon oxides, originate from the CCU Regenerator. These are the very fine particles which are not removed in the cyclone separators in the Regenerator.

NOx and SOx both cause irreversible degradation of the amine solution, greatly increasing operating cost and down-time. Dust must also be removed as this will quickly accumulate in process equipment causing serious blockages.

Leaving the CO Boiler, the flue gas is only a slight positive pressure, insufficient to overcome the pressure loss of all of the process units in the processing train. Some booster compression is therefore required to overcome the pressure loss of the processing train, such that the treated gas from the Amine unit can be routed back to the stack where it is vented to atmosphere.

The catalyst fines are very abrasive and therefore the Flue Gas Blower is downstream of the Dust Filter. This may lead to a very slight negative pressure at the inlet to the Blower.

Figure 2.16 - CDCU (Carbon Dioxide Capture Unit) Block Flow Diagram



A range of technology options were assessed for the gas clean-up processing stages.

In all of the all options considered the technology employed for CO_2 removal is MEA, with the alternative processes only considering where the NOx removal takes place i.e. whether this is within the CO Boiler itself or whether an external DeNOx unit is retrofitted to duct work downstream of the CO Boiler.

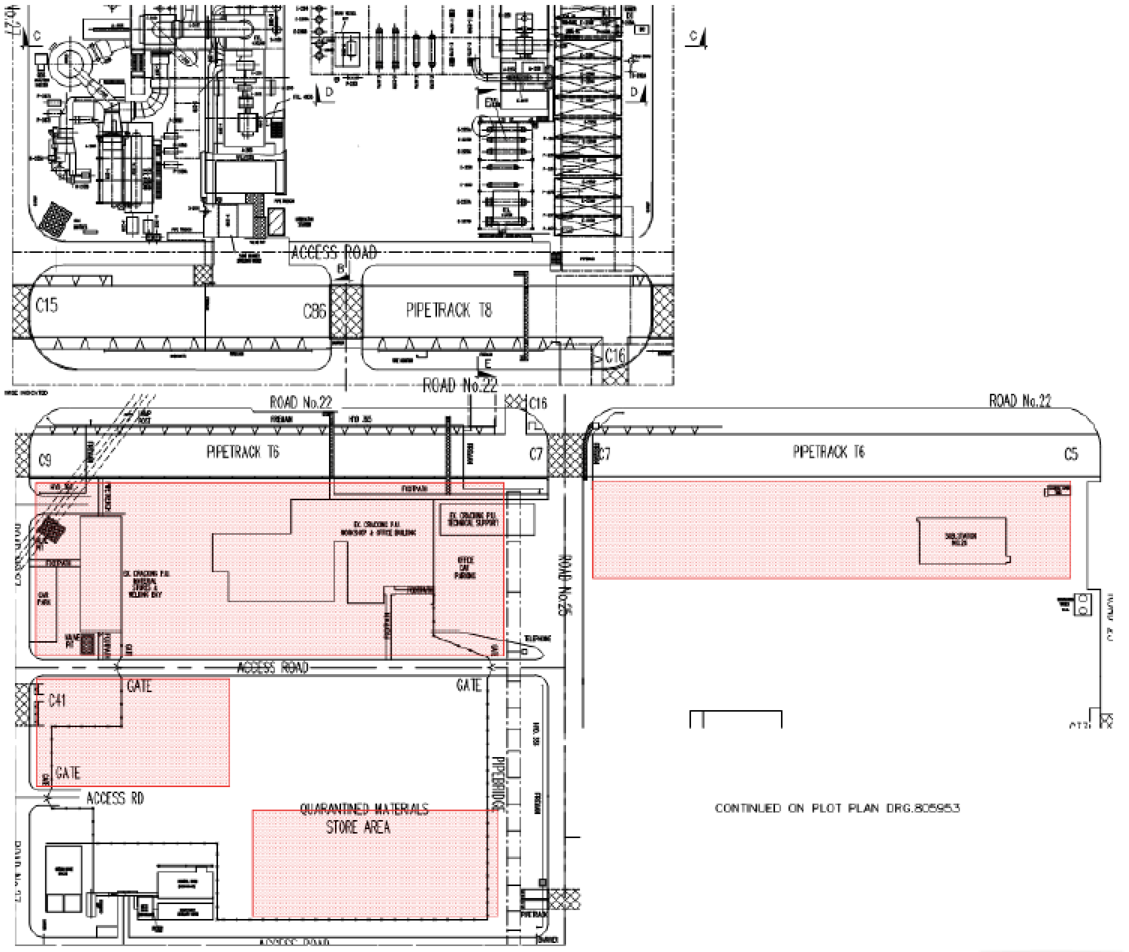
Key process challenges to be considered included:

- CO Boiler: The break-in to the CO boiler is of critical importance to the scheme as this needs to be accommodated during a scheduled turnaround. Similarly, the CO boiler relief case is of critical safety importance to the site. Options for this were considered in pre-FEED, but further assessment is required in FEED.
- NOx Removal: The presence of NO_2 will cause amine solvent degradation, significantly increasing consumables and hence operating costs. NO_2 removal is therefore critical ahead of the MEA capture process. Several options were considered, including standalone SCR (Selective Catalytic Reduction) and a replacement CO Boiler with integrated NOx removal. For this case, cost assessments of both the standalone SCR and the replacement CO Boiler with integral SCR were pursued.
- De-sulphurisation: The CO Boiler flue gas must also be de-sulphurised to minimise solvent degradation in the MEA capture process. This has been accomplished in two stages in this study. The first stage is bulk SOx removal and the base case technology adopted in this study is wet limestone scrubbing.
- Utility Requirements: The system requires significant utilities and services, particularly electrical and low pressure steam. The provision of these services was outside the scope of this pre-FEED study but is being considered as part of the wider HyNet project.

2.4.2.4 Plant Description and Layout

A plot plan was generated to illustrate the positioning of the unit adjacent to the CCU. The scale of the plant is readily apparent, and close consideration of constructability will be required in the next phase of the study.

Figure 2.17: Stanlow Refinery Carbon Dioxide Capture Unit (CDCU) Plot Plan



A 3D model of the plant was also generated. A number of screen shots are set out below:

Figure 2.18: CDCU Dust Filter

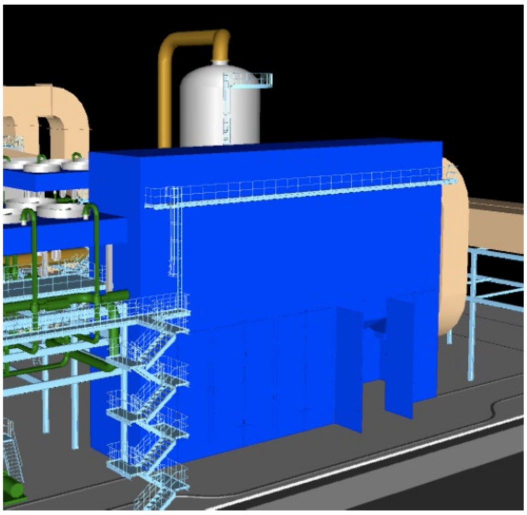


Figure 2.19: CDCU Gas / Gas Heat Exchanger

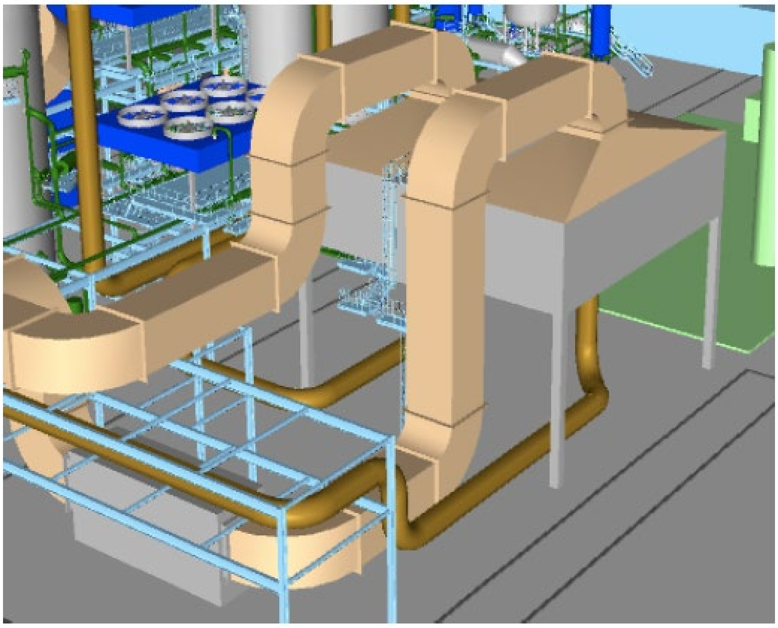
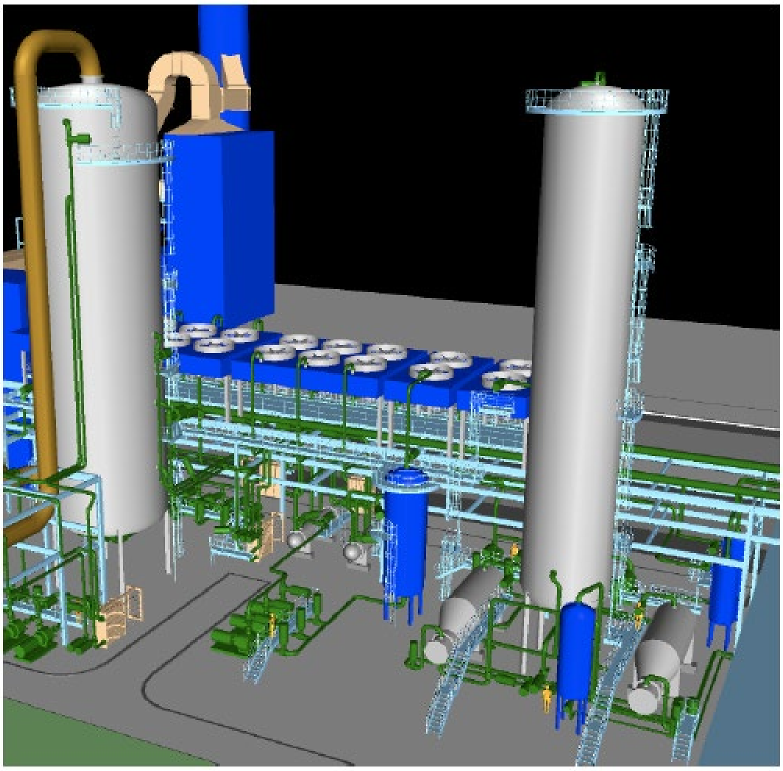


Figure 2.20: CDCU Amine Unit



2.4.2.5 Cost Estimate and Conclusions

A Cost Estimate was undertaken to AACE Level 5 (+/- 40% range) for three option combinations. The major equipment breakdown of these and the associated TIC (Total Installed Cost) is shown in Figure 2.21 below. Of these estimates the first column is taken as the baseline design option for inclusion in the whole project cost model (Standalone SCR with Wet FGD).

Figure 2.21: Refinery Capture Plant Capital Cost Estimate (£)

	Option 2 (Stand-alone SCR) with Wet FGD	Option 3 (New COB with integral SCR) with Wet FGD
Major Equipment		
CO Boiler tie-in + Dampers + Ductwork	3,600,000	N/A
CO Boiler with integral SCR + Dampers + Ductwork	N/A	16,630,000
Bag Filter	3,320,000	3,320,000
Flue Gas Compression	2,090,000	2,090,000
De-NOx (SCR)	4,200,000	N/A
Gas-Gas HX	2,100,000	2,100,000

Wet FGD	14,910,000	14,910,000
SNOx FGD	N/A	N/A
DC Cooler / Caustic Wash	2,500,000	2,500,000
MEA Unit	22,070,000	22,070,000
CO_2 Compression and Drying	6,180,000	6,180,000
Services and Utilities	5,180,000	5,180,000
Total Major Equipment	66,150,000	74,980,000
Bulks (Piping, Electrical, Instrumentation, Steelwork etc)	36,500,000	37,200,000
Construction	77,300,000	80,400,000
Indirects		
Construction Management	17,000,000	18,300,000
Engineering & Procurement (inc. FEED and Detailed Design)	46,800,000	50,300,000
Scaffolding, Craneage, Temp Facilities et	21,200,000	22,800,000
Total Indirects	85,000,000	91,400,000
TOTAL INSTALLED COST	**264,950,000**	**283,980,000**

The costs set out above, provided by a third party consultant, exclude contingency but include a significant cost estimate for engineering and procurement including FEED and Detailed Design. On reflection, we consider these costs to be too high, and so, for the purposes of inclusion in the whole project cost model, the following adjustments have been made:

- Total Cost Estimate - £264.95m, of which:
  - Major Equipment Cost - £66.15m
  - Bulks (Piping, Electrical, Steelwork etc) - £36.50m
  - Construction - £77.3m
  - Indirects - £85.00m, of which:
    - Construction Management - £17.00m

    - Engineering and Procurement (inc. FEED and Detailed Design) - £46.80m
    - Scaffolding, Craneage, Temp Facilities - £21.20m
- Reduction in Engineering and Procurement by £20.00m to £26.80m
- Inclusion of Contingency at 20% on revised total - £48.99m
- Revised Total (including Contingency) - £293.94m

A total cost estimate of £293.94m has therefore been used in the whole project cost model.

2.4.2.6 Areas for Consideration in FEED

Numerous areas were identified for further consideration in FEED, including:

- Gas/Gas Exchanger: There is an option to remove this unit, venting the sweet gas from the amine absorber. This requires discussion with the regulator.
- Cooling Water Make Up: This has not been fully addressed within the scope of this study and requires detailed evaluation in the next phase.
- Wastewater Recovery: There are numerous places where wastewater streams are produced, including purge from the DCC Circulation Loop, CO_2 compression condensate and purge from the Amine lean solution. Some of these streams can be re-used without treatment and this should be considered further.
- CO_2 Compressor: Configuration of this compressor, along with the pipeline routing across site to the tie-in point to the T&S export pipeline needs to be addressed.
- Steam Demand: Integration of the CDCU with the wider evolution of steam demand and supply on the Stanlow site is an important part of the HyNet project, and is being considered as part of the HyNet Fuel Switching, which is considering the production of low carbon steam from a hydrogen-fired CHP unit.

2.4.3 Hydrogen Production Plant (Progressive Energy / Essar Oil UK)

CO_2 capture from the hydrogen production plant was not explicitly included as part of the BEIS funded HyNet CCUS pre-FEED work scope. However, a pre-FEED package of work was separately funded and delivered in parallel to the CCUS pre-FEED, working to the same CO_2 T&S specification as the other capture plants.

The technology selection for the HyNet hydrogen production plant is Johnson Matthey's Low Carbon Hydrogen ATR/GHR. The pre-FEED report has been completed and published on the BEIS website[13].

[13] *HyNet Low Carbon Hydrogen Plant Phase 1 Report for BEIS*, November 2019, Progressive Energy, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866401/HS384_-_Progressive_Energy_-_HyNet_hydrogen.pdf

Each 350MWth (HHV) plant will capture 600ktCO_2/yr. A preliminary plot plan has been produced as part of the pre-FEED which locates three such units within Stanlow Refinery, which will need to be partionable as a standalone site if required by a future plant operator.

Stanlow Refinery will also be home to a complex AGI (Above Ground Installation) where CO_2 import and export pipelines, hydrogen export and natural gas import pipelines are all co-located. This is covered in further detail in Section 2.5.1.

2.4.4 Protos (Peel L&P Environmental)

Protos is a newly developed regional industrial hub of 54Ha, located between CF Fertiliser Plant and Stanlow Refinery. The site is already home to a 21.5MW biomass facility fuelled with waste wood, and planning permission has been granted on the site for a BioSNG plant and a full-scale waste plastic to hydrogen plant generating 2 tonnes of hydrogen per day.

While Protos is at an early stage in its development, it is intended that it is a hydrogen and CCUS ‘ready’ site, allowing new tenants to connect as required.

For the purposes of pre-FEED, it was assumed that up to 400ktCO_2/yr would be captured from a number of individual developments at Protos and connected via a collector network into the HyNet T&S system at the Grinsome Road AGI, adjacent to Ince Fertiliser Plant. This flow rate, in conjunction with the flow rate from the Fertiliser Plant was used to size the pipeline from Grinsome Road AGI to Stanlow AGI. Protos would operate as per the other capture plants and would be required to meet HyNet T&S system CO_2 composition, temperature and pressure specifications.

2.5 CO_2 Transport

2.5.1 Pipeline

2.5.1.1 Introduction

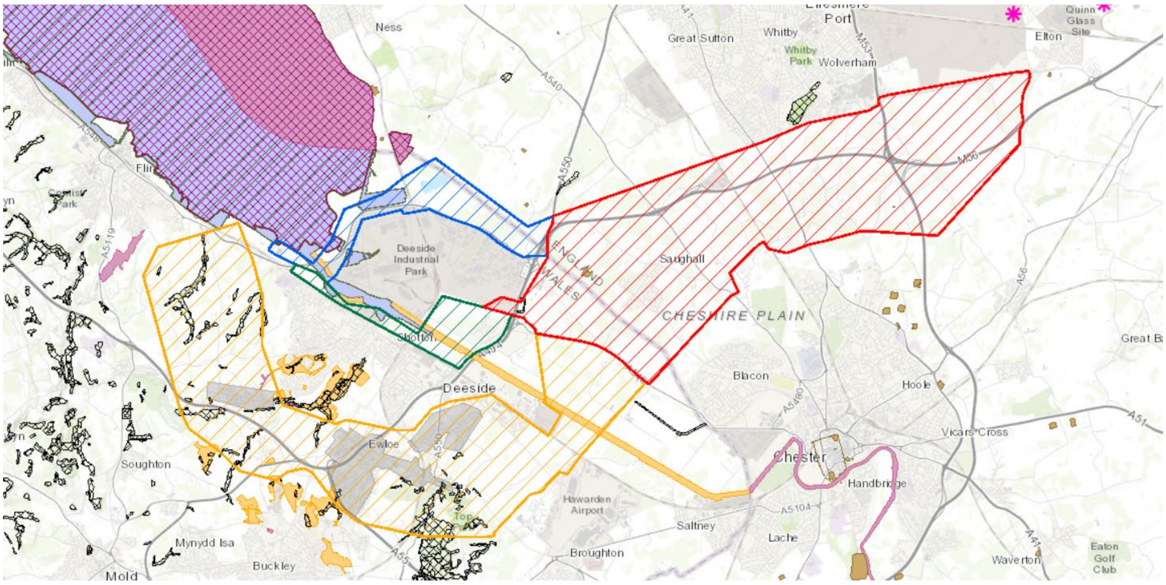
The primary focus of the pipeline work package in pre-FEED was to determine a low-cost, deliverable and consentable pipeline route from Stanlow AGI to Connah’s Quay AGI, where the pipeline would connect to the existing 24” pipeline to Point of Ayr. Key routing considerations were as follows:

- Targeting existing easements as advised by Progressive Energy
- Targeting an unconstrained pipe route
- Limiting the number of potential difficulties in the pipe route

- Avoiding environmental and ecological areas of concern
- Avoiding existing major utilities

Eight route options were identified with 3 of the options having small variations on their route giving a total of 14 route options contained within 3 corridors.

Figure 2.22 Pipeline routing corridors



2.5.1.2 Basis of Design

Key pipeline design parameters were identified in the pipeline Basis of Design Document (1189-PROG-ME-SPC-001):

- Fluid Classification: The CO_2 stream is deemed to be classified as a Category E fluid (ref. Table 1 from BS PD 8010-1). In the absence of specific PADHI+ guidance for CO_2, the same PADHI+ distances have been used as Natural Gas.
- Design Pressure: 49.6barg
- Maximum Operating Pressure: 35.0barg
- Pipeline Outside Diameter: 914.4mm
- Standard Pipe Wall Thickness: 12.7mm
- Proximity Pipe Wall Thickness: 19.1mm
- Material Grade: L415ME (X60)

2.5.1.3 Environmental Constraints

At an early stage in the pipeline routing process, an Environmental Constraints report was generated to identify areas to be avoided. Key high-level international, national and regional environmental and land use constraints datasets have been compiled for the defined Area of Search. The constraint data has been collated using readily available information held within the public domain. The data has been downloaded from web-based sources to provide project specific mapping. The following constraints formed the basis of this stage of the study:

- Special Area of Conservation (International)

- Special Protection Area (International)
- World Heritage Sites (International)
- Ramsar sites (International)
- Site of Special Scientific Interest (National)
- National Nature Reserve (National)
- Local Nature Reserves
- Registered Parks and Gardens (National)
- Scheduled Monuments (National)
- Grade I, Grade II and Grade II* Listed buildings (National)
- Ancient Woodland (National)
- National Parks (National)
- Areas of Outstanding Natural Beauty (National)
- Landscape Character Areas (National)
- National Trails and Long Distance Footpaths
- RSPB Reserves
- Flood Zones
- Heritage Coast
- Country Parks
- National Trust Land
- Open Access/Common Land
- Agricultural Land Classification
- National Cycle Route
- National Cycle Network Link Cycle Route
- Regional Cycle Route
- MOD Establishments (over 1ha)
- Regionally Important Geological and Geomorphological Sites
- Countryside and Rights of Way Act 2000 (CRoW) Section 15 Land
- CRoW Access Land

In addition key local environmental and land use constraints datasets have also been compiled for the defined Area of Search. The constraint data has been collated using readily available information held within the public domain and free of charge (i.e. no consultation letters have been issued to consultees as part of this study). The following constraints formed the basis of this stage of the study:

- Public Rights of Way
- Local Geology Sites
- Local Wildlife Sites (note data limitations below)
- Conservation Areas
- Historic Landfill Sites

- Planning/Housing Allocations (from Local Plans)
- Green Belt

Illustrative examples of output constraint mapping are shown in Figure 2.23 and Figure 2.24 below for two out of three route corridors:

Figure 2.23: Environmental Constraints Mapping

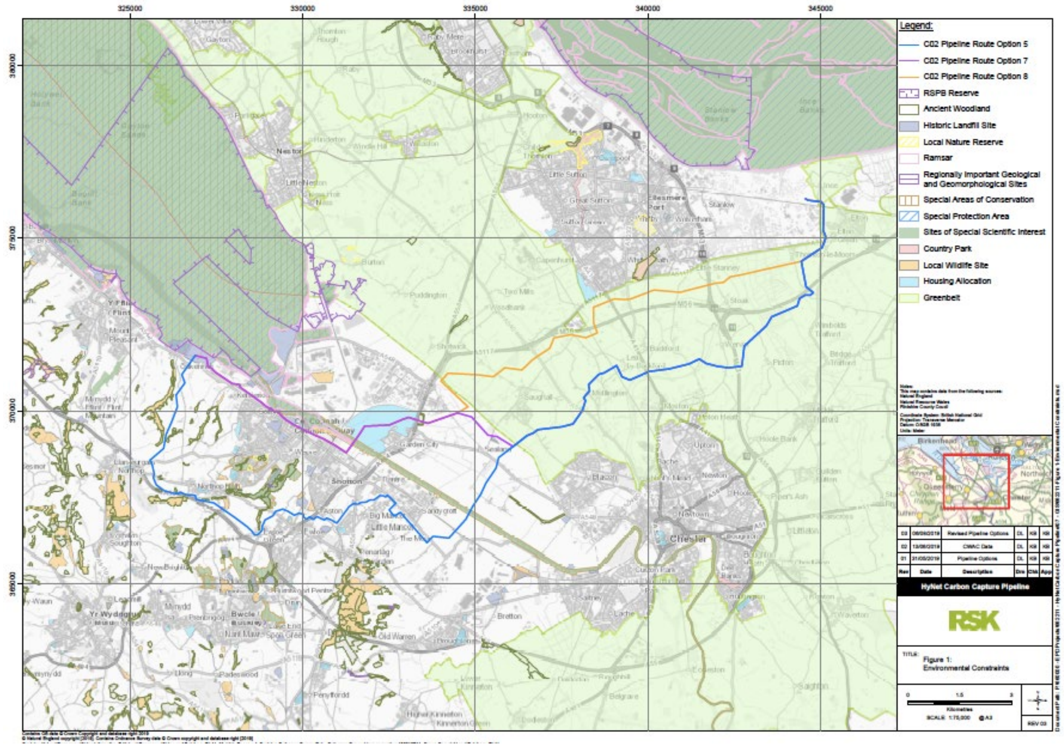
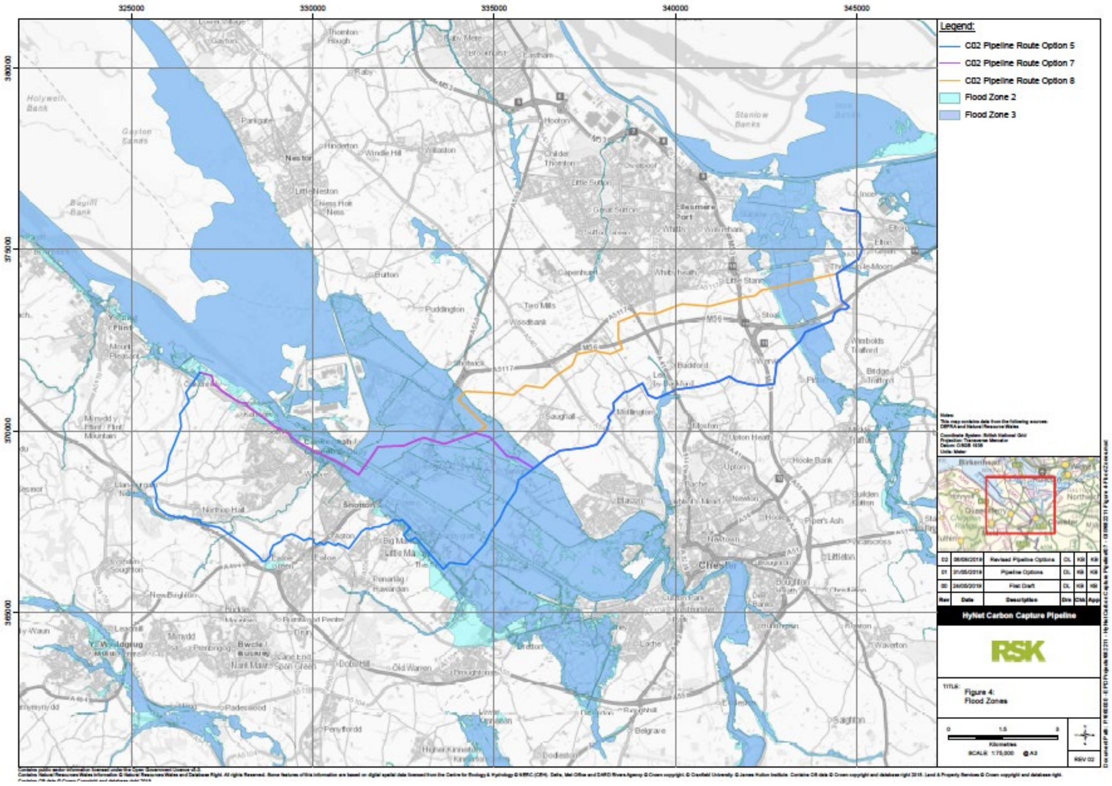


Figure 2.24: Flood Zones Mapping



2.5.1.4 Routing Selection

To enable a comparative overview of all the route options, an assessment was undertaken to downselect to a shortlist against the following parameters:

- Red identifies one of the following:
    - High cost compared to other options
    - Longer length compared to other options
    - More potential difficult than other options
- Amber identifies ones of the following:
    - Similar cost compared to other options
    - Similar length compared to other options
    - Similar potential difficulties compared to other options
- Green identifies one of the following:
    - Lower cost compared to other options
    - Shorter length compared to other options
    - Fewer potential difficulties compared to other options

Considering the assessment above, and, in conjunction with the consultants involved in the pre-FEED activity. An option ranking was derived to form the basis of further route appraisal work in FEED.

2.5.1.5 Cost Estimates

A cost estimate for each option was undertaken to support decision making between routes. These cost estimates were not undertaken to a specified AACE Class Estimate, but, given the level of engineering undertaken in pre-FEED, are considered to be commensurate with an AACE Level 4 +/- 30%.

An illustrative midpoint cost summary is set out in Figure 2.25 below:

Figure 2.25: Construction Cost Estimate for Pipeline Route (£)

Description	Quantity	Total Cost
Open cut road crossings	26	780,000
Trenchless road crossings	22	6,600,000
Trenchless river crossing	3	2,250,000
Trenchless canal crossing	1	300,000
Junction / Pig Trap Facilities	3	225,000
Existing Utilities	1	30,000
Trenchless rail crossing	4	1,400,000
Forged bends	300	3,600,000
Pipework laid in rural areas	28350m	49,612,500
Pipework laid in built up areas	5000m	12,500,000
	Total Estimate	**77,297,500**

An estimate has not been developed for the section of 12” pipeline from Grinsome Road AGI to Stanlow AGI. The capital cost estimate for the main section of pipeline from Stanlow AGI to Connah’s Quay AGI is £2.3m/km. Given that the section from Grinsome Road to Stanlow is smaller diameter, and of considerably lower engineering complexity, a parametric estimate of £1.5m/km has been used to generate a capital cost estimate of £3.75m for this section over its 2.5km length. A further 20% allowance has been included for contingency, giving a total cost estimate as follows:

- Grinsome Road to Stanlow - £3.75m
- Stanlow to Connah’s Quay - £77.30m
- Contingency @ 20% - £16.21m
- Total Cost Estimate - £97.26m

2.5.2 Rail / Road

2.5.2.1 Introduction

In parallel with the development of the pipeline, a study into a rail / road option as an alternative for onshore CO_2 transport was undertaken. While the pipeline remains the baseline HyNet concept, a rail / road transport option provides system flexibility, and allows the following project risks and opportunities to be addressed:

- Pipeline DCO Consent: There is a risk that the pipeline DCO consent, which is the overall project critical path, is significantly delayed, putting back in the in-service date. A road / rail option does not require DCO consent and can be developed in a relatively short time frame, therefore protecting the project against delays in consent. While not a suitable solution for high mass flow rates, it presents a feasible option for lower mass flow rates at the start of project life.
- Distributed sources of CO_2: Construction of a network of CO_2 pipelines across the country to multiple sources of distributed CO_2 emissions is not necessarily cost-effective, or easily consentable. However, while the focus of the majority of CCUS development projects is within clusters located on the coast, there are a number of major emitters located substantial distances inland from these clusters. Developing a viable road / rail transport solution will allow these sources to be connected to the HyNet system in future.

2.5.2.2 Basis of Design

The Basis of Design is set out in the project deliverable 5189899-PM-BOD-001 and a summary is presented here.

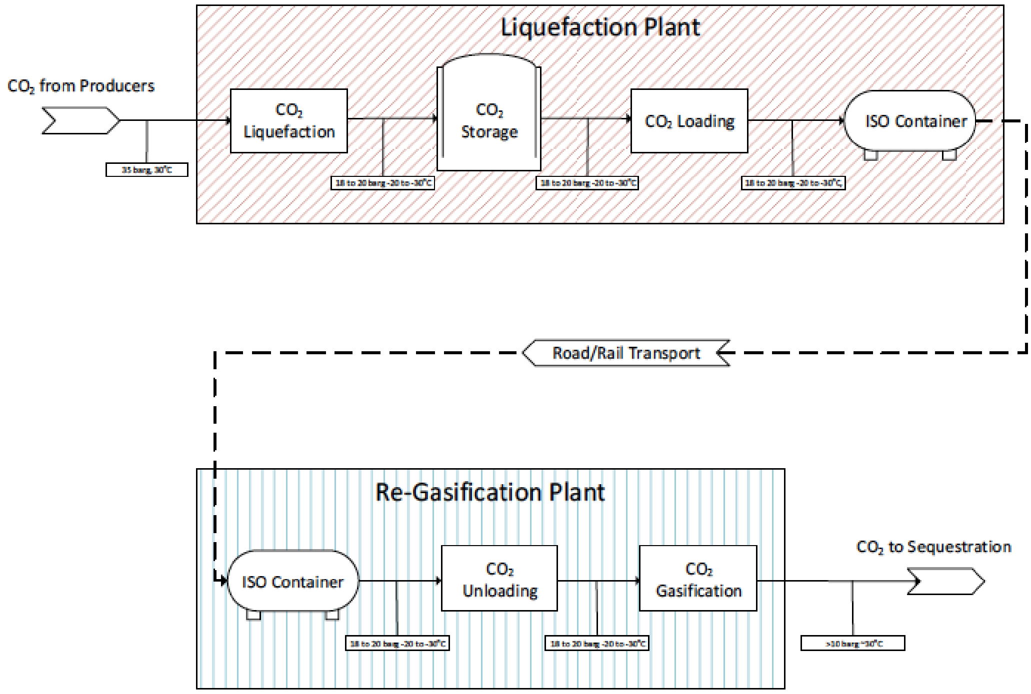
The proposed scheme will take CO_2 from Stanlow Refinery and Ince Fertiliser Plant at the outlet to the capture plant compressors (as set out in Sections 2.4.1 and 2.4.2) at HyNet T&S CO_2 composition, temperature and pressure specifications. It is recognised that if this option is pursued there is design optimisation that could be pursued at the capture plants. This gives an annual mass flow rate of 1.2MtCO_2/yr, which is the 'low' case as set out in the original project Basis of Design (Section 2.2.5)

The scheme will transport the CO_2 to either Point of Ayr or Connah's Quay, where it will be stored and processed to meet appropriate pipeline injection parameters. Existing rail and road networks and infrastructure will be used wherever possible. Standard cryogenic tanks will be used for CO_2 transport to minimise costs.

2.5.2.3 Option Identification and Downselection

A baseline process design was undertaken to generate appropriate CO_2 conditions (temperature and pressure) for road and rail transport. The process design liquified CO_2, provided storage and loading and, at the receiving end of the process provided storage, unloading and gasification to pipeline conditions. The Block Flow Diagram is shown in Figure 2.26. The process design identified plot space requirements, which in turn allowed identification of options for loading / unloading.

Figure 2.26: Block Flow Diagram for Rail / Road Transport



Seven options were considered:

- Rail Options (all adjacent to, or in close proximity to existing rail infrastructure)
    - Option 1 – Encirc Glass
    - Option 2 – Protos
    - Option 3 – Ince Fertiliser Plant
    - Option 4 – Stanlow Refinery
- Road Options
    - Option 5 – Encirc Glass
    - Option 6 – Ince Fertiliser Plant
    - Option 7 – Stanlow Refinery

Unloading at Connah's Quay was discounted at an early stage in the process, due to the proximity of rail infrastructure and land availability for gasification at Point of Ayr. All options therefore utilised Point of Ayr as the unloading point.

The rail solution requires 2 trains to be in operation, each of 25 wagons with 2 ISO containers per wagon, and each train making 2 journeys per day. Each train is 400m long, and this has been utilised to design loading and unloading infrastructure. A rail routing study was undertaken to determine length, route availability (measure of axle loading) and gauge (measure of maximum height and width for railway vehicles).

The road solution requires 55 HGVs to be in operation, each transporting 1 ISO container, and each making 3 journeys per day.

Figure 2.27: Representative CO_2 Road Transport HGV

Option down-selection was based on:

- Technical Feasibility
- System Cost
- Comparative Risk
- Network Expansion
- Flexibility
- Carbon Accountancy
- Reliability
- Development Cost

Option 4, a rail solution with loading at Stanlow Refinery, was determined to be the most appropriate solution for further study. Subsequently, a further option based on a 0.4MtCO_2/yr low flow case from Ince Fertiliser Plant was also selected for a further review.

2.5.2.4 Rail Option (1.2MtCO_2/yr with loading at Stanlow Refinery)

Following the down-selection process, the Stanlow Refinery rail solution was engineered to a level commensurate with providing cost estimates.

The rail transport solution was in line with that identified during the optioneering phase, with an additional focus placed on operational philosophy. This highlighted operational restrictions on Sunday, which identified that buffer storage would be required for at least 24 hours, subsequently reflected upwards to 36 hours to accommodate additional buffer capacity. Storage capacity is a significant contributor to overall system Capex and opportunities to reduce storage should be considered in the next phase of development.

At the Point of Ayr facility the regasification plant and associated storage was located to the south of the existing gas processing facility as a process safety decision. Utility provision at Point of Ayr will be a fundamental requirement of this solution, as up to 12MW electrical heating is required for regasification. It is likely that this will be provided from the existing Point of Ayr local substation, but this will require further investigation in FEED. To provide an upper bound cost estimate, it was assumed for the purposes of this study that a new substation would be required.

2.5.2.5 Road Option (0.4MtCO_2/yr with loading at Ince Fertiliser Plant)

A simple study was conducted to look at a low cost solution for using a road transport solution at Ince Fertiliser plant with a single plant mas flow rate of 0.4MtCO_2/yr.

Working on the basis of operating for 5.5 days per week on a 9hr shift per day, 24 HGVs would be required (noting that, for cost optimisation, it would potentially be possible to operate the HGVs on a multi-shift pattern, but this has not been considered at this point). Transport costs are a significant element of Opex (along with plant energy costs), and, as such, focus should be placed on optimising this in the next phase of the project. The process design of the loading and unloading facilities is as per that of the rail option, albeit on a reduced scale.

2.5.2.6 Cost Estimate

The AACE Class 4 capital cost estimate for the baseline rail option (as per Section 2.5.2.4) is as follows:

Figure 2.28: Rail Transport Option Capital Cost Estimate (£)

Work Breakdown		Equipment	Material	Labour	Subcontract	Contractor Soft Costs	Total
000A	Site Preparation, Enabling and Facilities (A1)			609,903	16,050,090	1,605,009	18,265,002
000B	Site Preparation, Enabling and Facilities (A1)			608,615	16,016,195	1,601,619	18,226,430
100	Liquefaction - Stanlow	18,102,480	659,364	6,626,191	1,114,050	4,617,942	31,120,029
200	Transport Containers and Rail Siding – Stanlow and Point of Ayr		1,616,644	1,307,546	5,060,550	575,577	8,560,317
300	CO_2 Storage - Stanlow	20,404,750	743,222	6,473,370		5,433,887	33,055,230

400	CO_2 Loading	235,657	198,841	190,893		149,948	775,342
500	CO_2 Unloading	235,657	198,841	190,893		149,948	775,342
600	CO_2 Regasification and Storage – Point of Ayr	24,666,798	1,675,467	10,481,780	945,000	7,805,299	45,574,345
Total Base Cost		**63,645,344**	**5,092,382**	**26,489,195**	**39,185,885**	**21,939,233**	**156,352,041**
Risk and Contingency P80							
7.3%							11,413,699
5.8%							9,021,512
Total							**176,787,253**

Given the high cost of the rail option, particularly in comparison the pipeline option, further consideration was given to a low cost road solution with an annual mass flow rate of 0.4MtCO_2/yr, as set out in Section 2.5.2.5. The capital cost estimate is as per Figure 2.29 below, although it should be noted that this is based on a lower level of engineering rigour than the rail study, and should therefore be considered an AACE Class 5 estimate.

Figure 2.29: Road Transport Option Capital Cost Estimate (£)

Work Breakdown		Equipment	Material	Labour	Subcontract	Contractor Soft Costs	Total
000A	Site Preparation, Enabling and Facilities (A1)			335,220	8,821,602	882,160	10,038,983
000B	Site Preparation, Enabling and Facilities (A1)			325,113	8,555,610	855,561	9,736,285
100	Liquefaction - Ince	9,140,400	332,929	3,269,601	776,550	2,331,716	15,851,198
300	CO_2 Storage - Ince	3,400,791	123,870	1,078,895		905,647	5,509,205
400	CO_2 Loading	56,557	47,722	45,814		35,987	186,082

500	CO_2 Unloading	56,557	47,722	45,814		35,987	186,082
600	CO_2 Regasification and Storage – Point of Ayr	6,787,342	461,023	2,704,069	945,000	2,382,268	13,279,703
Total Base Cost		**19,441,649**	**1,013,267**	**7,804,529**	**19,098,763,15**	**7,429,329**	**54,787,539**
Risk and Contingency P80							
7.3%							3,999,490
5.8%							3,161,241
Total							**61,948,271**

This capital cost estimate is considered to be much more acceptable for a relatively short term interim solution (as mitigation for delayed pipeline consenting), particularly if the liquefaction equipment installed at Ince could be modularised and deployed at alternative dispersed sources of CO_2 in the future, and the gasification equipment at Point of Ayr could have continuing use as a receiving point for road shipments.

The levelized cost of road / rail transport has a much stronger component of operating cost than other elements of the project, given the requirement for transport fuel and operators, and, as such, a specific operating cost assessment was undertaken rather than simply rely on a proportion of capital cost.

Figure 2.30: Road Transport Option Annual Operating Cost Estimate (£)

Cost Element	Annual Cost
Plant Opex	1,200,000
Plant Personnel Costs	340,000
Transport Opex (inc. fuel and personnel)	3,560,000
Total	**5,100,000**

2.5.2.7 Areas for Consideration in FEED

Given the significant opportunities the road / rail transport option opens up the long term development of the HyNet project, coupled with the risk mitigation of delays to the pipeline consenting, it has been decided to progress this work package into the FEED phase. The Basis of Design will focus on a flexible design that can accommodate a mass flow rate of up to 1.0MtCO_2/yr, sufficient for both Ince Fertiliser Plant and the Hydrogen

Production Plant (the refinery capture plant is scheduled for commencement of operation in 2027 and is therefore unlikely to require road / rail transport as a mitigation for pipeline consenting delays). Key areas of focus in the FEED phase should include:

- Optimisation of process design, particularly compression, with capture plants considering future transition to pipeline operation
- Optimisation of operational philosophy to minimise storage capacity requirements and transport costs
- Development of flexible liquefaction solution, potentially modularised, such that it can be re-used at alternative, dispersed facilities after the pipeline is commissioned
- Safety assessment to consider implications of storage on COMAH (Control of Major Accident Hazards) designations, and consideration of major accident hazard potential of transporting significant volumes of CO_2

2.6 Offshore Transport and Storage

Over the period January 2019 to May 2020, Eni has conducted a range of technical studies to assess the feasibility of a Carbon Capture and Storage project using their existing LIverpool Bay assets. This scope of work was carried out in conjunction with the BEIS funded HyNet CCUS Innovation Project led by Progressive Energy, but funded entirely by Eni. The results of this work have been provided by Eni to Progressive Energy under licence for the purposes of providing an integrated, full chain HyNet CCUS project report.

2.6.1 Pre-Feasibility Summary Report

The Eni Pre-Feasibility Summary Report brings together the findings from a range of technical studies and sets out the overall project description, the baseline system configuration (with alternatives) and was written to meet the requirements of the Eni internal project Assurance Review.

The Liverpool Bay Area (LBA), with its off-shore fields of Hamilton, Hamilton North and Lennox, was identified as one of the best sites for CO_2 storage in a 2015/16 Government sponsored study[14]. These fields are approaching the end of the operative life (the cessation of production is expected to commence in 2024 and potentially earlier dependent on prevailing oil and gas prices) and their use for such application provides

[14] Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource, Energy Technologies Institute, April 2016

for the project an opportunity of possible re-use of some infrastructure, while for Eni a saving or deferral of abandonment costs.

CO_2 coming from industrial facilities in the Merseyside region will be transported via a newbuild pipeline to Connah's Quay, and from there to the coast (Point of Ayr) using an existing natural gas pipeline. From Point of Ayr a pipeline, previously used to transport natural gas inland from the fields, will be re-purposed to transport CO_2 off-shore to a process platform (Douglas) and from there to the reservoirs, where it will be permanently stored.

Phase 1 of the project considers the Baseline Scenario, where CO_2 production increases from initial 1.0 $MtCO_2$/yr in 2025 up to 3 $MtCO_2$/yr in 2029 and then remains constant (see Baseline Scenario described in Section 2.2.5). Initial system operation was defined to be in the gas free flow mode with subsequent system compression being required. A range of system configuration options were assessed, in line with those set out in Section 2.3.1.2, to provide baseline cost estimates. It was identified that subsequent growth to higher system flow rates (up to 10$MtCO_2$/yr) would require transport in the dense phase, and the timing of this increase in mass flow rate would influence system configuration decisions to be taken ahead of FEED.

The base assumption of the study is that all the existing facilities in Eni's scope, previously used for natural gas transport, will be re-purposed at maximum extent. This minimises development cost and risk.

2.6.2 Reservoir Assessment

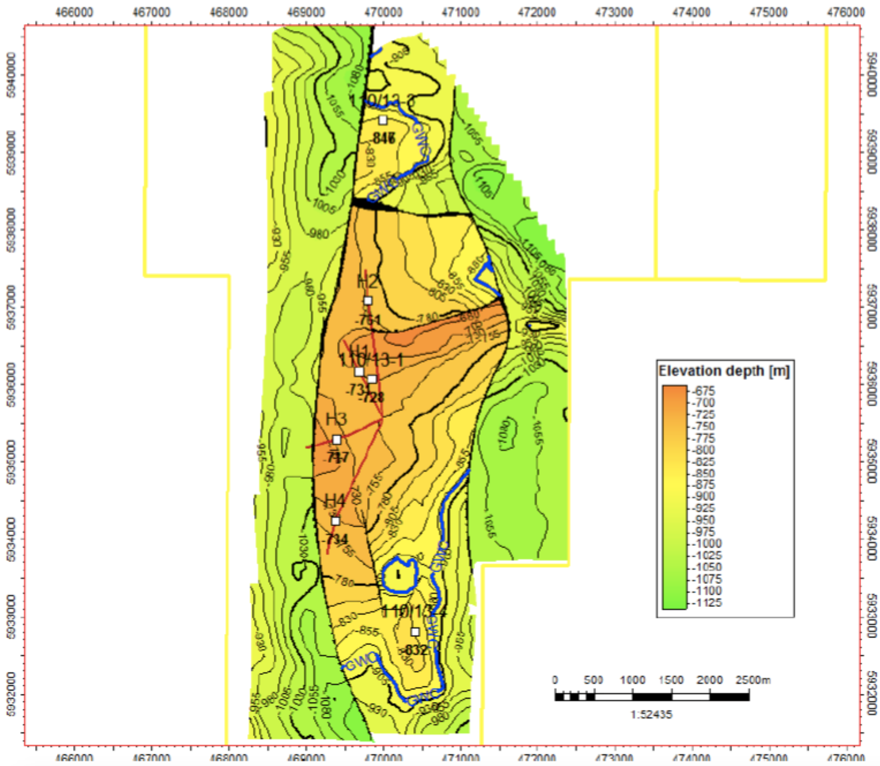
2.6.2.1 Reservoir Overview

Hamilton

Hamilton Field was discovered in 1990 by well 110/13-1 and the Hamilton North Field by well 110/13-5 in 1991.

The Hamilton Field structure is a simple horst block, about 10 km long and 3 km wide, with a slight dip to the East, North and South. The structure trends North-South and is cut by minor East-West and North-South faulting. All faults within the field have sand-to-sand contact and do not provide barriers to gas flow. This has been confirmed by pressure data from the development wells. The trap is provided to the North and South by dip closure. The crest of the structure at the reservoir level is at around 2300 ft TVDSS (True Vertical Depth Sub Sea) with the gas-water contact being at 2910 ft TVDSS.

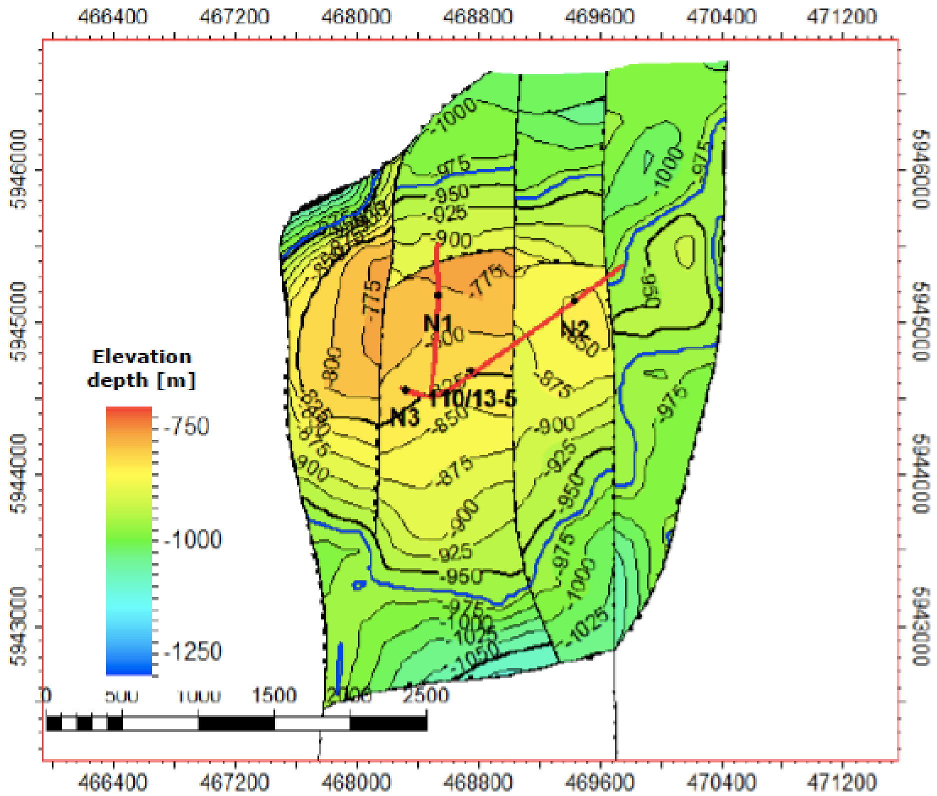
Figure 2.31: Hamilton Reservoir



Hamilton North

Hamilton North Field block lies at the Northern end of the Hamilton horst feature running through Block 110/13. It is a simple fault block 3 km long and 2 km wide with the main dip to the South. The Northern part of the field is progressively down-faulted by a set of E-W trending faults, which are antithetic to the main East-West boundary fault to the Deemster Platform. The crest of the structure at the reservoir level is at around 2600 ft TVDSS with the gas-water contact being at 3166 ft TVDSS.

Figure 2.32: Hamilton North Reservoir



Lennox

Lennox field was discovered in 1992 by exploration well 110/15-6. The well targeted a four-way dip closed structure identified on 2D seismic lines shot between 1981 and 1990. Well 110/15-6 was drilled on the crest of the structure and encountered a 744 ft gas column overlying a 143 ft oil column. The Lennox Field is divided into two panels by a large North-South trending synthetic fault. The Eastern panel exhibits faulting and fracturing associated with antithetic faulting related to the major bounding fault, whilst the Western panel exhibits little to no faulting. The crest of the structure is at c. 2500 ft TVDSS. The gas-oil contact (GOC) and OWC at initial conditions were at 3257 ft and 3400 ft TVDSS respectively. Despite the field being divided into two separate structural panels, at initial conditions the fluid contacts were continuous across the fault. The Lennox Field came on stream in February 1996. Its production life can be divided into two phases: (1) oil rim production, and (2) gas cap production, primarily during gas cap blowdown.

For all of the 3 fields the reservoir target is represented by the Triassic-aged Ormskirk Sandstone Formation. It consists of fluvial and aeolian sandstones of variable grain size. The quality of the Ormskirk Sandstone reservoir has been found extremely high with average porosities of 14-19%. The top seal is provided by the Mercia Mudstone Group which consists of a cyclic sequence of sandy mudstones and halites. The Rossall and Mythop halites are each less than 50 ft thick and the Preesall Halite has a thickness of between 500 and 730 ft.

Figure 2.33: Liverpool Bay Reservoir Summary

	Hamilton Main	Hamilton North	Lennox
Volume in place	124x10^6 boe (gas)	42x10^6 boe (gas)	95x10^6 bbl (oil) 42x10^6 boe (gas)
Production start-up	1997	1996	1996
Initial condition	97 bar, 31.6°C	106 bar, 29.4°C	115 bar, 34.4°C
Well type	2 Deviated 2 High Angle	3 Deviated	2 Deviated 4 Horizontal 8 Multi Drain Horizontal
Development strategy	Natural Depletion	Natural Depletion	Oil Rim Development w/GI Gas Cap Blowdown
Current pressure (Jan 2020)	7 bar	8 bar	22 bar
Current recovery factor (RF) (Jan 2020)	96%	97%	54% (Oil); 86% (Gas)

2.6.2.2 Reservoir Modelling Summary

Reservoir modelling was undertaken to assess the Baseline Scenario which sees 72MtCO_2 injected over a 25 year project life. The three LBA reservoirs, Hamilton Main, Hamilton North and Lennox are nearing cessation of production. Cumulative production as of December 2019 is as follows:

- Hamilton Main (gas): 18.3x10^9 Sm^3 (RF 95.8%)
- Hamilton North (gas) : 6.3x10^9 Sm^3 (RF 97.2%)
- Lennox (oil and gas): 12.9x10^9 Sm^3 (RF 85.9%)

Separate reservoir models were built for each field (Hamilton, Hamilton North and Lennox) using up to date production data, and were history matched. To simulate injection, the reservoirs were numerically coupled to represent the manifolding of the three reservoirs (i.e. they are pressure equalised).

The identified injection strategy ensure that the three fields experience a comparable repressurisation trend during the injection period. In this “coupled scenario”, the stocked CO_2 mass results to be subdivided as follows:

- Hamilton Main: 38Mt

- Hamilton North: 17Mt
- Lennox: 17Mt

Dynamic simulations results indicate the following number of wells needed for each field:

- Hamilton Main: 4 wells
- Hamilton North: 2 wells
- Lennox: 1 well

Under current assumptions, geomechanical preliminary assessment concludes that cap rock integrity is not affected by the CO_2 injection process, as the maximum reached pressure is lower than the original reservoir pressure. Preliminary numerical modelling to predict thermal induced fractures shows that, when occurring, thermal fractures are confined into the reservoir section and do not impact on the cap rock integrity.

Geochemical studies are on-going to characterize fluids-formation rock interactions. Three cores (one for each field) have been acquired, sampling a total of 15 rock plugs on which laboratory analysis are currently being performed. The resulting composition of the sampled intervals will be the input for the static geochemical model to assess rock – formation water – injected CO_2 interaction phenomena.

While the reservoir modelling has focused on the Baseline Scenario (3MtCO_2/yr), a total storage volume assessment was undertaken to inform decisions on higher flow rate scenarios. As a reliable estimate of the fracturing pressure has not been determined due to a lack of fracture pressure measurements across the LBA basin, the upper reservoir pressure limit under CO_2 injection has been set to the initial reservoir pressure at the start of production. Storage volumes assessment are as follows:

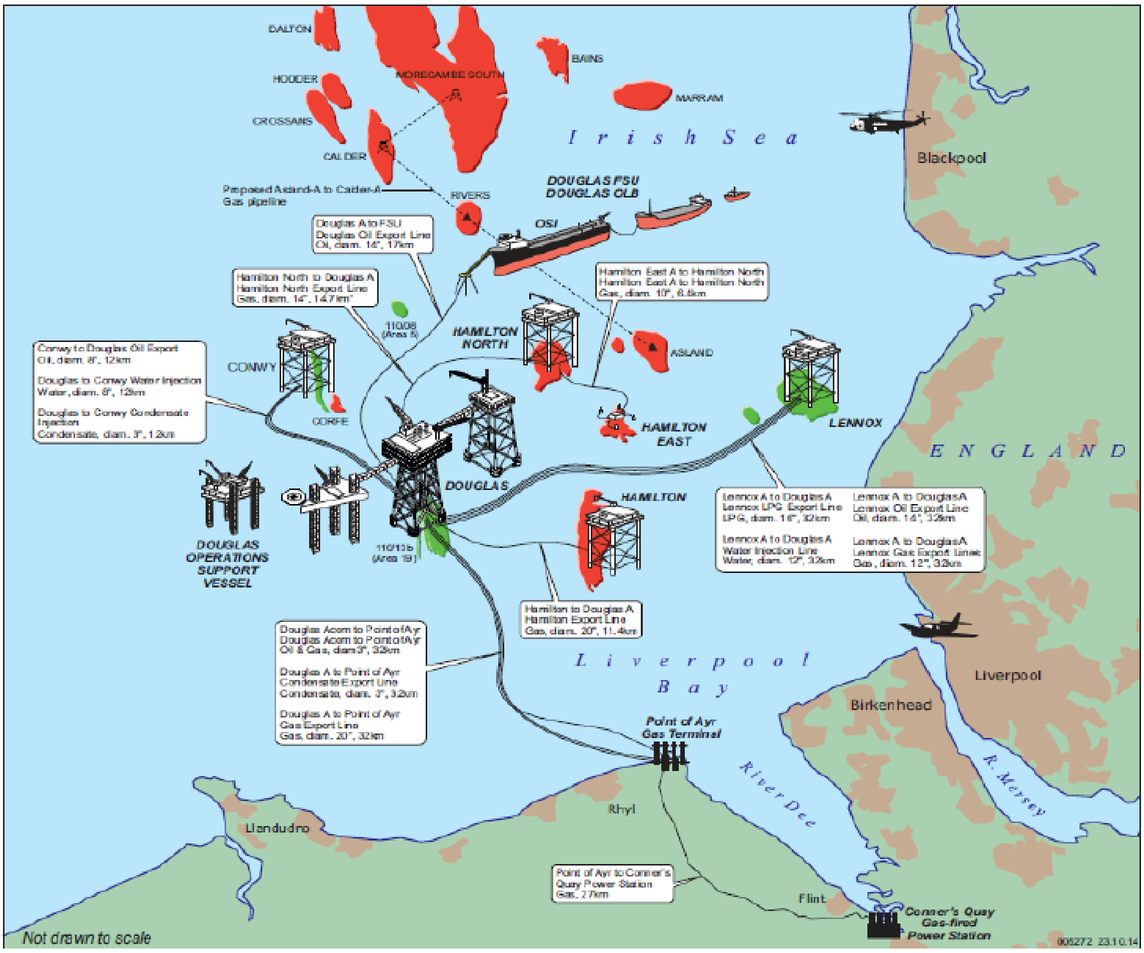
- Hamilton Main: 103Mt
- Hamilton North: 34Mt
- Lennox: 58Mt
- Total: 195Mt

While further reservoir modelling work is required in subsequent project phases, particularly looking at increased injection rates, geomechanical fault analysis and geochemical modelling, the Integrated Reservoir Study concludes that Hamilton, Hamilton North and Lennox fields are suitable CO_2 reservoir storage candidates for LBA CCS Project.

2.6.3 Existing Facilities Description and Lifetime Extension Assessment

Eni's Liverpool Bay assets currently comprise a range of facilities that have been considered for re-purposing for CO_2 transport and storage. These consist of platforms, pipelines and wells.

Figure 2.34: Liverpool Bay Assets



2.6.3.1 Platforms

Hamilton, Hamilton North and Lennox are three fields located in the East Irish sea and are part on Eni UK's LBA asset. Each field is serviced by a separate platform, all of which are tied back to the main Douglas production platform.

The normally unmanned Lennox field has been developed by means of a simple unmanned wellhead platform with minimal facilities. Gas free flows from the Lennox platform to Douglas. There are no spare well slots on the Lennox platform.

The normally unmanned Hamilton and Hamilton North fields are developed via two not normally manned steel platforms which are remotely controlled from the Douglas platform. Each platform is equipped with well control equipment, initial processing facilities and utility systems. There are two spare well slots on Hamilton North and one spare well slot on Hamilton.

Figure 2.35: Hamilton Platform

Existing LBA platform assets are detailed as follows:

Figure 2.36: LBA Existing Platform Assets

Platform	Type	Water Depth (m)
Douglas Wellhead (DW)	Wellhead Platform	29.2
Douglas Process (DD)	Process Platform	29.2
Douglas Accommodation (DA)	Accommodation Platform Jack-Up	29.2
Lennox (LD)	Wellhead and Process Platform	7.2
Hamilton (HH)	Wellhead Platform	25.8
Hamilton North (HN)	Wellhead Platform	22.1

All offshore platforms were installed in 1995 with a design life of 30 years, with the exception of the DA platform which operated as a drilling jack-up for 12 years before being converted to a fixed installation, so the design service life is 42 years. The lifetime extension assessment concluded the following:

- DA platform: a lifetime extension can be considered, but it is not recommended. The platform is not redundant and was not designed to be a permanent installation. In case of re-use or lifetime extension diver assisted NDT are absolutely necessary on most of the leg connection in order to identify possible fatigue cracks. Increase of topside weight on this platform is not recommended;

- DD platform: a lifetime extension can be considered, since no significant damage has been found so far and results from analyses recently performed do not highlight any significant criticality as long as topside loads are not increased. NDT on fatigue prone connections shall be considered in case of lifetime extension.
- DW platform: a lifetime extension can be considered, since no significant damage has been found so far and results from analyses recently performed do not highlight any significant criticality.
- HH platform: a lifetime extension can be considered, since no significant damage has been found so far and results from analyses recently performed do not highlight any significant criticality as long as topside loads are not increased. NDT on fatigue prone connections shall be considered in case of lifetime extension. Based on the documentation, it seems that HH platform can also accommodate from 200 t to 400 t of additional permanent loads on its topside.
- HN platform: a lifetime extension can be considered, since no significant damage has been found so far and results from analyses recently performed do not highlight any significant criticality as long as topside loads are not increased. NDT on fatigue prone connections shall be considered in case of lifetime extension. Based on the documentation, it seems that HH platform can also accommodate from 200 t to 400 t of additional permanent loads on its topside.
- LD platform: a lifetime extension can be considered, since no significant damage has been found so far and fatigue life of all welded connection is always higher than 300 years. Results from analyses recently performed do not highlight any significant criticality Based on the documentation, it seems that HH platform can also accommodate from 200 t to 400 t of additional permanent loads on its topside.

HH, HN and LD platforms are all proposed to be used for the HyNet project for injection. Depending on the chosen system configuration, these platforms may require either heating or compression facilities to be installed. The lifetime assessment indicates that these platforms can accommodate the additional loads associated with these facilities. While further work is required in FEED to further analyse these platforms, the conclusion from this phase of work is that no showstoppers have been identified in the lifetime extension and repurposing of these assets.

The DA, DD and DW platforms are not necessarily required for the HyNet project, as a subsea manifold has been considered to provide the valving requirements for splitting the flow to the respective injection platforms. However, given that DD and DW lifetime extensions could be considered, the decision on whether to retain these platforms or opt for a subsea manifold will predominantly be determined by cost / benefit analysis.

2.6.3.2 Subsea Manifold

An option has been considered to bypass the existing Douglas complex, allowing its decommissioning and removal and replaced with:

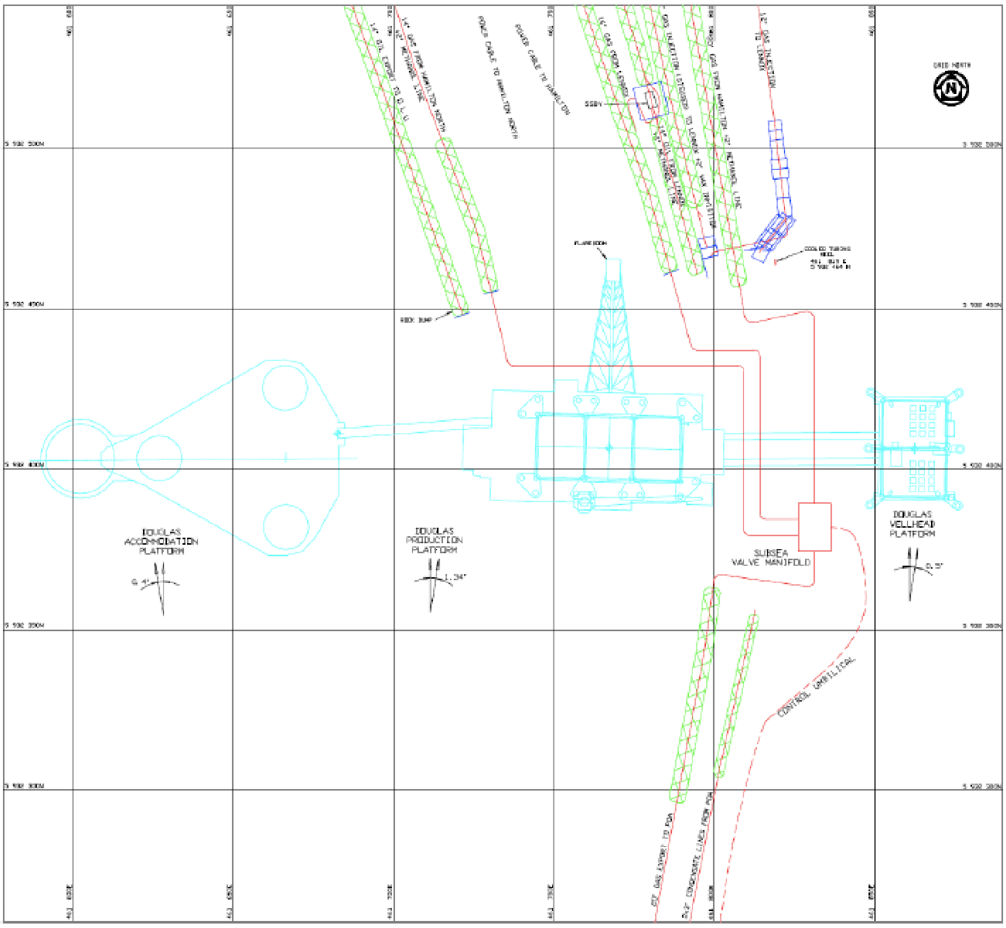
- A Sub Sea Valve Manifold (SSVM) controlled from Point of Ayr connecting existing 20” pipelines from Point of Ayr to Douglas with the existing pipelines going to Hamilton, Hamilton North and Lennox Platforms
- New pipeline spools to connect relevant pipelines with Manifold at Douglas site
- New power supply and control umbilicals network from Point of Ayr to satellite platforms that are currently controlled from Douglas complex.

The preliminary conceptual layout of the SSVM is shown in Figure 2.37 below, illustrating its connection to existing pipelines.

A schematic of the SSVM has been generated, which provides for continuation of pigging from Point of Ayr to Hamilton platform along a continuous 20in line. Two branches connect to the Hamilton North 14in and Lennox 16in lines, each of which can have temporary pig launching facilities attached to allow for pigging of these lines.

Remote control of the facility will be via an umbilical coming from Point of Ayr to a Subsea Control Module (SCM) which will provide hydraulic power to the SSVM. It may prove possible to utilise an existing 3in line from PoA to provide hydraulic pressure as a cost saving measure rather than lay a new umbilical. While no design work has been undertaken for the SSVM at this point, it is estimated to have dimensions of approximately 15m x 10m x 6m and require a mudmats shallow foundation. Estimated weight is around 250-300t in air.

Figure 2.37: Douglas Subsea Manifold Arrangement



2.6.3.3 Pipelines

Existing LBA pipeline assets are as follows:

Figure 2.38: LBA Existing Pipeline Assets

Pipeline Number	From	To	Purpose	Length (km)	Nominal Diameter (inch)	Design Pressure (barg)
PL852	CQY	PoA	Sales gas	26.4	24	99

PL1030[15]	PoA	DD	Gas export from Douglas	32.1	20	149
PL1039	DD	HH	Gas export from Hamilton	11.4	20	99
PL1041	DD	HN	Gas export from Hamilton North	14.6	14	99
PL1035	DD	LD	Associated gas from Lennox	32.1	16	99
PL1034	DD	LD	Oil export from Lennox	32.1	14	99
PL1036A	DD	LD	Gas production from Lennox	31.8	12	149

Eni assessed the current condition of the LBA pipelines by reviewing the Pipeline Annual Report 2017 to provide an overview of the condition, inspection results and maintenance status of each pipeline and any major pipeline activities carried out during 2017.

Eni applies a risk based approach to pipeline integrity management i.e. all the threats to the pipeline integrity are analysed, associated risks are evaluated and the appropriate risk mitigation actions are assigned. The extent and the frequency of the risk mitigation measures are driven by the risk level formally defined in the pipeline risk assessment.

The main threats to the existing Eni LBA pipeline system are corrosion (external and internal) and third party interaction and activities. The risk mitigation measures are mainly inspections, testing and corrosion management activities.

Fitness for Purpose statements are available for all pipelines from the 2017 report. PL1030 was identified has having a free-spanning section which has subsequently received rock-bagging remediation attention.

The lifetime extension assessment concluded the existing pipelines being considered in the project can be considered as candidates for requalification for possible life extension of their design life/ CO2 service use study as there does not appear to be any significant “show stoppers” and pipelines appear to be in reasonably good condition given their age.

[15] PL1030 also includes PL908, a short section of onshore pipeline

2.6.4 Well Assessment

2.6.4.1 Basic Well Design

All of the wells are currently utilised as gas producers[16], producing from the Triassic Ormskirk Sandstone Formation. All wells utilise a similar well design with TVDs ranging from 3150ft to 4150ft. Hamilton has 4 wells, Hamilton North has 3 wells, and Lennox has 13 wells.

Most of the wells are highly deviated or horizontal, including several multi laterals at Lennox. The wells utilise a 20” conductor, set between 460ft and 520ft MD and cemented to surface. A 13 3/8” surface casing is then set at 1686-2335 ft-MDRT (1520-2080 ft-TVDRT) and cemented to surface. Following this, a 10 ¾” x 9 5/8” or 9 5/8” production casing is set:

- Above the top reservoir for cased perforated completions (Hamilton and Hamilton North wells plus L-09), except for Lennox-01 which was side-tracked from a 9 5/8” window and has a 7” liner set above the top reservoir.
- Within the reservoir for open hole and slotted liner completions (All remaining Lennox wells)

All of the Hamilton wells plus Lennox-09 are completed with cased and perforated 7” liners with 7” tubing. Lennox-01 is completed with a cased and perforated 5” liner with 7” tubing due to the above mentioned side-track. Lennox-06 has an open hole completion with 5 ½” tubing. The remaining Lennox wells are completed with 7” x 5 ½” slotted liners with 5 ½” tubing, except Lennox-13 which has 4 ½” tubing.

It should be noted that many of the Lennox wells have had the open hole and slotted liner completions plugged with bridge plugs due to high water cut. These wells have had the tubing and production casing perforated higher up the wellbore to restore production. Several of the cased-perforated wells have had the lower perforations plugged with bridge plugs, also due to water loading.

2.6.4.2 Well Operations and Service Activity

Well integrity is monitored real time and uploaded to the Eni Real Time Well Integrity Tool which monitors and records a range of integrity metrics. This tracks the well integrity status as well as trends in well integrity metrics to identify higher risk areas including scheduled critical valve tests.

[16] Several of the current gas production wells have been converted from oil production or gas injection.

All well service activity is currently completed in Liverpool Bay from the Irish Sea Pioneer (4 legged jack up barge) as the platforms are small and have no crane facilities to allow purely e-line operations. It is assumed that the ISP will remain in the field during any CO_2 injection life for the purpose of well servicing. If this assumption is inaccurate, another method of well servicing will be required which may drive up well OPEX costs.

2.6.4.3 Well Options for Injection

A study has been undertaken to identify the available well options for injection of CO_2 into Lennox, Hamilton and Hamilton North as part of the HyNet project. The options that have been identified are:

- Use existing wells in current condition
- Workover existing wells
- Side-track existing wells
- Drill new wells

Option 1 – Well Re-Use

The first option evaluated is the reuse of the wells as is. This could be considered with no additional CAPEX. This option is however contingent on the following outstanding work scopes which will be finalised prior to the next phase of the project:

- FLUP cement study to determine the feasibility of existing cement for CO_2 storage applications
- Materials study to determine the feasibility of existing wellbore metallurgy for CO_2 storage applications
- Finalisation of pressure, temperature and injection rates.

These studies attempt to reduce risk in several areas identified as high risk areas. These are:

- Corrosion of production casing (below packer) and packer due to free water and CO_2 mixture inside wellbore
- Degradation of production liner/production casing cement from contact with reservoir fluids and CO_2 mixture
- Corrosion of production liner/production casing from contact with reservoir fluids and CO_2 mixture

A risk assessment has been drafted, pending the results of above mentioned studies. If the wells are to be re-used, an increased level of monitoring should be considered. A monitoring programme and frequency will be developed during the next phase of the project if wells re-use is selected as the preferred technical option.

Wells re-use has by far the lowest initial cost and has the added benefit of deferring well P&A (Plugging & Abandonment) expenditure to the end of field life with no additional complications to the well P&A plan. It is, however, the most uncertain option at this stage but, if further studies can demonstrate that the inherent risks can be cost-effectively mitigated, then it could prove to be the most attractive.

Option 2 – Existing Well Workover

If the ongoing studies mentioned above conclude that the corrosion of tubulars and the degradation of cement from the outside of the well is an acceptable risk, but the risk of corrosion of the production packer and production casing from the inside is unacceptable, then well workover could be a suitable solution.

The envisaged workover would remove the completion, install a suitable corrosion resistant scab liner and install a new completion. This would protect the production casing and packer area from corrosion and remove the risk of a leak to the annulus in the caprock/overburden. A risk assessment will be completed once the above-mentioned studies have been completed.

This option has the benefits of reduced cost compared to new wells or side-tracking as well as deferring well P&A costs to the end of field life. The installation of cemented scab liners however, could complicate well P&As and lead to higher overall P&A cost. The intervals for setting P&A barriers needs to be thoroughly considered in any scab liner installation design. The installation of scab liners will also reduce the well diameter across the reservoir which may limit injection rates.

Option 3 – Existing Well Side-Track

If the risk of wells re-use is deemed unacceptable and cannot be alleviated through a well workover, the reservoir can be P&A'd with a rock to rock, CO_2 resistant cement plug immediately above the production packer. Following this, it could be side-tracked and a 7" liner installed with CO_2 resistant cement extending 500-1000 ft above the reservoir through the cap rock.

It should be noted that no reservoir targets have been provided at this stage and therefore, the well trajectory has not been analysed. Final feasibility of any sidetrack is contingent on the reservoir target. A risk assessment has also been drafted, pending the results of above mentioned studies. Final reservoir target could impact side-track feasibility.

This option has the benefits of installing CO_2 resistant tubulars and cement in all fluid contact areas of the wellbore and maintains a minimum 7" nominal flow path. It does however, come with a significant cost and also requires P&A of the reservoir section prior to side-tracking.

Option 4 – Drill New Wells

The final option is to drill new wells. It is assumed that this option will require new wellheads and Xmas trees. It is also likely that new platforms will be required as there are very few platform slots available. It is assumed that these wells will be of similar design to the existing well stock but with corrosion resistant alloy tubulars and CO_2

resistant cement. A cost estimate for this is given below. No risk assessment has been done for this option at this stage as the well will be designed to be ALARP.

This option is the highest cost by far. It also brings forward all well P&A cost and potentially platform decommissioning cost. It is however the lowest risk option as wells can be designed for CO_2 storage from the outset.

2.6.5 Flow Assurance

2.6.5.1 System Flow Assurance and Facilities Specification

In parallel to the work undertaken by Progressive Energy on whole system flow assurance, Eni undertook a range of studies to inform compression configuration options, and hence capital cost estimates. The results of this work are set out in the configuration options discussed in Section 2.3.1. No firm conclusion has been reached at the end of this project phase on the optimal system configuration for compression, and this is the subject of ongoing joint work between Progressive Energy and Eni prior to commencement of FEED.

The flow assurance work set out above has provided operational parameters for compressor specification. By determining suction and discharge pressures and temperature limits, compressor sizing and duties have been determined, which in turn have been used to derive the Capex and Opex costs set out in Section 2.6.6 below. Compression is assumed to be electric drive, and wellhead compression therefore requires the provision of power to the platforms. Specification of umbilical power and control cables from Point of Ayr[17] to the platforms has been included in the cost estimates.

2.6.5.2 Injection Flow Assurance

The Hamilton field is unique as a CCS site due to its pressure depletion (predicted to be less than 10 bara at the time of abandonment). Due to significant pressure depletion compounded by excellent reservoir quality, injection pressure at the bottom hole is expected to be very low during the early stages of injection life. If a well injection rate is not properly controlled, injection temperature at the bottom hole can be extremely low because CO_2 expansion is associated with the Joule–Thomson (JT) effect and fluid temperature can decrease in line with the dew point line. Low injection temperature at the bottom hole has an adverse impact on injection performance since cold fluid increases the risk of hydrate formation in the perforation tunnels and/or pore throats of the reservoir rock, and induces cyclic thermal stress.

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[17] While at this stage in the project development, a power connection from Point of Ayr (PoA) to the offshore platforms is considered as the most logical baselilne, a connection from the nearby offshore substation platform at Gwynt y Môr offshore windfarm is also a possibility. This should provide a lower Capex option as the cable run is shorter and avoids a landfall section.

Understanding fluid behaviour in the injection wells is therefore very crucial, especially in the Hamilton field where the pressure in the wells is significantly lower than other typical CCS projects. Using Olga flow assurance software, and a representative Hamilton well, a range of injection scenarios was considered across a range of flow rates and reservoir pressures.

A wider range of operational injection rates becomes available with higher fluid temperatures at the wellhead and/or with higher reservoir pressures, as this raises the temperature above the hydrate formation at the bottom hole. Lower injection rates imply more favourable conditions since the fluid can be heated up by surrounding formation and less frictional pressure loss in the well results in less fluid temperature drop due to JT effect. Also, due to the very low initial pressure of the Hamilton field, it is predicted that gas velocity will be very high at the early stages of injection life. Limiting the gas velocity will result in reduced injection rates.

It can therefore be concluded that, at the early stage of the project, with very low bottom hole pressures, flow rates need to be managed carefully.

2.6.6 Cost Estimates

2.6.6.1 Capex

Eni have developed Capex and Opex estimates as part of their internal assurance process. The estimate was derived based on an Equipment Factored Methodology starting from the Preliminary Equipment List prepared by Engineering. Given the applied methodology, the information available and the Brownfield nature of the project, this cost estimate has an expected accuracy range +/- 40%. Contingency has been applied at 20%, Owners Cost at 12% of EPC (Engineering, Procurement and Construction) Scope and Risk and Profit at 10% of EPC Scope.

Cost estimates were derived for three scenarios as follows:

- Scenario 1.1: This is the baseline gas phase configuration, referred to as Alternative A1 in Section 2.3.1 above. It comprises gas phase compression at Point of Ayr, with further compression at the wellhead platforms when BHP constraints are reached. No pipeline upgrades are required. Maximum flow rates of up to 3MtCO_2/yr can be achieved.
- Scenario 1.2: This is referred to as Alternative A3 in Section 2.3.1 above with compression undertaken on the Douglas Platform, rather than at Point of Ayr. No pipeline upgrades are required. Maximum flow rates of up to 3MtCO_2/yr can be achieved.
- Scenario 2: This is the baseline dense phase scenario, referred to as Alternative B in Section 2.3.1 above. Compression is required at Point of Ayr and some heating

is required at the wellhead platforms to accommodate the Joules-Thomson effect. Pipeline upgrades are required for the infield pipelines as current pipelines have insufficient MAOP ratings to operate in dense phase (with the exception of the Lennox Pipeline PL1036A).

Figure 2.39: Offshore Transport and Storage Capex Estimate (£)

Capex Summary (k£)	Scenario 1.1	Scenario 1.2	Scenario 2
Phase	Gas Phase	Gas Phase	Dense Phase
Configuration	Douglas Subsea Manifold Point of Ayr Compression Wellhead Compression	Douglas Platform Compression Wellhead Compression	Point of Ayr Compression
Max Flow Rate	$3MtCO_2/yr$	$3MtCO_2/yr$	$10MtCO_2/yr$
Onshore Compression	40,636	-	80,684
Offshore Compression	27,625	68,479	-
Heaters	-	-	3,759
Power Cables and Umbilicals	40,958	33,977	47,601
Control Room	7,696	7,696	7,696
Manifold	12,351	-	12,351
Pipeline	-	-	40,582
Seismic Baseline Monitoring[18]	-	-	-
Drilling	5,100	5,100	5,100
Total Technical Cost and Risk and Profit	**134,366**	**115,252**	**197,773**
Owners Cost	16,124	13,830	23,733

[18] Seismic Baseline Monitoring excluded at this stage (pending further studies to be performed within the CO_2 Licence work programme).

Contingency	30,098	25,816	44,301
Total Execution	**180,588**	**154,899**	**265,807**

The main differences among the 3 scenarios are derived from the differences in scope and can be explained as follow.

- Scenario 2 is the only scenario that requires new pipelines.
- Scenario 2 has more expensive equipment and materials due to the larger compressors and requires 24 MW Heaters on the platforms.
- Due to the heating requirement, the demand for power is considerably higher and the Power Cables required have a larger section and higher procurement cost. No major differences have been assumed in the cost for laying the power cables where big part of the cost is due to the mob/demob of the vessels.
- Scenario 1.2 has no Manifold. Together with the Manifold, the 32km of Umbilicals are removed and substituted by a Power Cable from Point of Ayr to Douglas Platform.

For the financial modelling set out in Section 5.2.1 below an early case has also been considered, in which no T&S system compression is required as the project is operating in free flow gas mode. This is indicatively estimated to have a Capex of £88.9m, although it should be stressed that this has not been substantiated in any detail by Eni, and is based simply on a reduction of compression costs from Scenario 1.1 above.

2.6.6.2 Opex

Opex cost estimates were derived on using an Activity Based Costing (ABC) approach. Opex estimates for Scenarios 1.1 and 1.2 are set out in Figure 2.40 below.

Figure 2.40: Offshore Transport and Storage Opex Estimate

Cost Type	Description	Annual Cost (£m / yr)
General and Administration	15 personnel	£2.1m
Insurance		£1.0m
Maintenance	Compressor maintenance	£4.0m
Operation and Production	Pipeline pigging MMV	£5.0m
Logistics	Support vessel (x1)	£6.5m

	Helicopter (x1) Logistics Base	
Well Service / Integrity	7 wells with 1 intervention per year	£4.0m
Compression Costs	12.4MW (Point of Ayr) until 2028 10MW (Wellheads) from 2029	£10m
	Average Yearly Cost	**£32.6m**

In Scenario 2, the annual yearly Opex increases to £49.1m due to the increased energy consumption of compressors and heaters.

The above Opex figures represent estimated costs for full system throughput in any given configuration, and, as such, in the financial model set out in Section 5.2.1 below the variable cost elements have been pro-rated for lower mass flow rate scenarios.

3.0 OPERATION, CONTROL AND METERING

Operation, Control and Metering Philosophy was set out in project deliverable P1131.WP5.04.001 in August 2019 based on the then system configuration. While some aspects of system configuration have evolved from this point, much of the philosophy remains valid and forms a baseline for FEED. This chapter highlights points of deviation from the above-referenced project deliverable.

3.1 Operations Philosophy

3.1.1 Normal Operation Objectives

Operating objectives of the full-chain system are as follows:

- Safety: Demonstration of ALARP (As Low As Reasonably Practicable) approach to system safety throughout design and operation.
- Regulatory Compliance: Compliance with all applicable UK and International regulations, permits and consents, including the Development Consent Order for the pipeline and the CO_2 Storage Permit.
- Availability: Maximised system availability in order to minimise requirements for capture plants to vent. Individual capture plant availability is specified as 90% in the Project Basis of Design and transport and storage system availability is specified as 99%. System availability to be maximised by minimising number and duration of shutdowns, and, where possible, to align transport and storage shutdowns with capture plant shutdowns.
- Operations: Operate the system in steady-state wherever possible, with minimal number of planned and unplanned shutdowns to optimise efficiency of transport and storage.
- Unplanned shutdowns: Minimise number of unplanned shutdowns and any associated CO_2 venting.
- Stakeholder Engagement: Ensure all aspects of operation and maintenance are planned and discharged to minimise impact to local stakeholders.

3.1.2 Normal Operating Philosophy

The normal operating philosophy is to operate the system in steady state from multiple capture plants with single or multiple stores in operation.

The Project Basis of Design identifies 4 initial capture sources as follows:

- Stanlow Refinery (existing operations)
- Ince Fertiliser Plant (existing operations)

- Protos
- Hydrogen Production (co-located at Stanlow Refinery)

The CO_2 generating production operations at Stanlow Refinery, Ince Fertiliser Plant and the Hydrogen Production plant are all intended to run at continuous steady state over a multi-year period with only minor fluctuations in output. Capture sources at Protos are yet to be defined, but these are expected to operate in a similar continuous flow pattern.

Nonetheless, each of the capture sources will undertake both planned and unplanned shutdowns, and the T&S system is therefore designed to accommodate any combination of flows from the capture sources, with a system minimum flow rate of 0.2MtCO_2 / year, calculated as 50% flow from the smallest currently defined capture source, Ince Fertiliser Plant.

3.1.3 Pressure Control

In the free flow gas phase of the project there is not intended to be any active pressure control in the system beyond the outlet of the capture plants (all set to deliver 35Barg at the junction point for the capture plants at Stanlow).

When compression is introduced into the system, outlet pressure will be a function of the compression ratio of the compressor, and the arrival pressure at the inlet, which in turn is a function of pressure loss along the pipeline. While the offshore system remains in gas phase, it is not intended that there is any further flow control in the system beyond the compressor outlet.

When the system has transitioned into liquid phase offshore, flow control to each injection well will be controlled by the choke valve on each of the injection wells, allowing each injection well to be controlled individually.

Note: this section has changed from the original Operation, Control and Metering Philosophy document(P1131.WP5.04.001 August 2019) due to evolution in system configuration.

3.1.4 Line Pack

In the gas phase, line pack gives significant flexibility of operation, as the compressibility of CO_2 allows the capture plants to continue to operate for a period of time in the event of an injection shutdown or other non-availability of the downstream T&S network. In this instance, the capture plants would continue to inject CO_2 into the transport and storage network, increasing the pressure in the line until either an alternative injection well became operational, the non-availability of T&S was rectified or, alternatively, the capture plants moved into re-circulation, vent and eventual shutdown.

3.1.5 CO_2 Injection

Where possible, CO_2 injection will operate on a continuous basis to avoid repeated pressure and temperature cycling of the well. The number and configuration of the wells at each reservoir to be used for CO_2 injection has been explored at length during pre-

FEED, but not yet finalised, as wellstock risk assessments are required to be completed to conclude decisions on which wells can be re-used.

In the gas phase, no platform heating is required, as flow assurance modelling has demonstrated that pressure let-down in the well is minimal, resulting in only minor Joules-Thomson cooling such that the CO_2 remains within the allowable temperature envelope of the well.

In the liquid phase, minimum wellhead arrival pressure will be determined by ensuring avoidance of the two phase regime. This will be considerably higher than the reservoir pressure at the start of liquid phase operations, resulting in significant pressure-let down through the well and resultant cooling from the Joules-Thomson effect. In this instance, wellhead heating will be required to ensure well temperatures remain above hydrate formation temperatures and within the material specification for the well.

Wellhead heating control will utilise a closed loop control mechanism using a well temperature sensor to adjust heating input to ensure well temperatures remain above a specified minimum.

Injection start up, shutdown and operational control (both pressure and temperature) will be managed remotely.

Note: this section has changed from the original Operation, Control and Metering Philosophy document(P1131.WP5.04.001 August 2019) due to evolution in system configuration.

3.1.6 Capture Plant Start Up

This document does not cover commissioning, and this section refers to system start-up post shutdown.

3.1.6.1 Stanlow Refinery and Ince Fertiliser Plant

The purpose of the Hydrogen Production Plant is to manufacture low-carbon hydrogen, and capture of CO_2 is an integral requirement of producing in-specification hydrogen. However, in the circumstance that the T&S system is unavailable and there is ongoing demand for hydrogen the Hydrogen Production Plant may operate whilst venting the CO_2 in unabated mode.

The start-up sequence is as follows. As the plant starts up, hydrogen product is diverted to flare until both the reforming process and capture plants are fully operational. Similarly CO_2 will continue to be vented until the CO_2 T&S specification is met. At this point a control signal will be sent from the hydrogen capture plants to the T&S control room, and when the T&S system is ready to accept transfer of CO_2 then the capture plant valve will be opened, CO_2 will flow into the T&S system, and venting of CO_2 will cease.

3.1.6.2 Hydrogen Production Plant

The purpose of the Hydrogen Production Plant is to manufacture low-carbon hydrogen, and so it is less likely that it will operate in unabated mode than Stanlow Refinery or the Ince Fertiliser Plant. However, in the circumstance that the T&S system is unavailable and there is ongoing demand for hydrogen that cannot be met with, for example, natural gas, the Hydrogen Production Plant may operate in unabated mode.

The start-up sequence is similar to that of Stanlow Refinery and Ince Fertiliser Plant, in that the hydrogen production plant will start-up independently of the associated capture plant. When the Hydrogen Production Plant is operating appropriately, the flue gas will be diverted to the capture plant and emissions will continue to be vented until the CO_2 T&S specification is met. At this point a control signal will be sent from the capture plants to the T&S control room, and when the T&S system is ready to accept transfer of CO_2 then the capture plant valve will be opened, CO_2 will flow into the T&S system, and venting of CO_2 will cease.

3.1.6.3 Protos

There is currently insufficient definition of proposed capture plants to determine a start-up sequence.

3.1.7 Transport and Storage System Start Up

This document does not cover commissioning.

3.1.7.1 Pressurised System Start-Up

The design intent of the system is to retain system pressurisation throughout the lifetime of the system. As such, the majority of system shut-downs will result in pressurised CO_2 being retained in the system. The majority of system start-ups will therefore take place using a pressurised scenario.

The shut-down circumstances will determine the level of residual pressure in the system, which will determine the start-up sequence. The system start-up sequence will require capture plants, compression plant and injection plant to be available, all of which will go through their own start-up sequence. For example, if the capture plants were shut-down before the T&S system in the gas phase, the residual system pressure would be below normal operating pressure and start-up would be in the reverse sequence. Alternatively, if the injection system was shut down first, residual pressure would be above normal operating pressure (but would remain within appropriate safety levels), and system start-up would be to commence injection prior to bringing capture plants back on line to enable the return of the system to normal operating pressure.

3.1.7.2 Unpressurised System Start-Up

Unpressurised system start-up will take place only during initial commissioning, or following an emergency shutdown that required, or resulted in, a depressurisation of the system. The start-up sequence in this instance would follow that of initial commissioning and is not covered in this document.

3.1.8 Planned Shutdown

The aim of a planned shutdown is to retain residual system pressure as close to normal operational pressure as possible, therefore ensuring ease of start-up post shutdown. System planned shutdowns are therefore coordinated by the System Operator (SO) to ensure, as far as practicable, simultaneous shutdown of system elements and to ensure operating conditions do not exceed design limits.

A planned shutdown does not initiate any venting and will leave the system such that start-up can be undertaken without local intervention being required.

3.1.9 Non-planned and Emergency Shutdown

Non-planned and emergency shutdowns (ESD) do not automatically initiate any venting or system valve closure, other than offshore storage platform CO_2 ESD valves and well isolation valves.

The system will be designed such that the majority of non-planned and emergency shutdowns can be reset from the central control room. However, some circumstances will result in system 'lockout', which will require manual attendance at one or more points in the system to reset.

3.1.9.1 Emergency Arrangements

The System Operator (SO) will be responsible for managing emergency arrangements for all elements of the system beyond the capture plant battery limit. These will include development and management of emergency procedures, liaison with local and national stakeholders as required and the management of annual emergency exercises to test the procedures.

Management of emergency arrangements within the battery limit of the capture plant resides with the capture plant operators.

3.1.10 Venting

Venting is a non-routine activity and requires careful coordination between operating parties, stakeholders and regulators. It will be subject to pre-determined procedures with sign-off from suitable qualified operators under a regime approved by the safety regulator, in a similar process to the onshore gas industries (for example, IGEM/GL/6 is Industry Guidance for the safe control of operations).

3.1.10.1 Venting Requirements

Venting is required for a number of reasons, including safety, process, operations and maintenance and, in some circumstances, emergency management. Specifically, the venting system is required to:

- Prevent out-of-specification CO_2 entering the T&S system;
- Provide a means for removing out-of-specification CO_2 from the T&S;
- Support maintenance activities;
- Provide overpressure/thermal relief;
- Provide a means for controlled system depressurisation;
- Support the isolation of high pressure systems (e.g. using double block and bleed arrangements); and
- Support commissioning of the Full Chain.

The venting strategy and venting system performance should satisfy the needs of:

- Health and safety;
- Plant protection (avoidance of damage);
- Plant operability and maintainability (both routine and in upset conditions);
- Minimising fiscal loss due to loss of CO_2; and
- Environmental impact.

3.1.10.2 Venting System and Operations

The venting system will include permanent venting facilities at each capture plant, at the PoA compression facility and at each wellhead. In addition, there may be a permanent venting facility at CQY subject to the output of Flow Assurance assessment.

Temporary venting facilities will be made available as required along the onshore pipeline section to support maintenance requirements (for example, to isolate a short section of pipeline for repair or replacement following third party damage using a double block and bleed arrangement), or for venting PIG traps.

System venting will be co-ordinated by the SO, but each party will be responsible for the design, operation and maintenance of their own venting equipment and procedures.

Venting system at the capture plants will be sized for venting of maximum mass flow rates by diverting to the main plant stack. This is to allow venting in the event of out of specification CO_2, or unplanned shutdown of the transport and storage system. Transport and storage system venting systems will not be sized for maximum mass flow rates as they are used primarily for maintenance depressurisation and emergency relief cases. They will also be used for pipeline depressurisation following cessation of flow, which can take place at a lower rate than normal system mass flow rate.

3.1.10.3 2.8.3 Venting Considerations

Pipeline depressurisation will result in high pressure CO_2 (in either gas or liquid phase) rapidly expanding to atmospheric pressure, with significant cooling effects being encountered. Procedures need to be developed which ensure venting rates do not result in over-cooling of the venting system, particularly if deployed in cold temperatures.

Modelling of dispersion for permanent vents will be required as part of the Environmental Impact Assessment, along with a noise assessment for venting operations.

3.1.11 Pipeline Inspection

In Line Inspection (ILI) will be undertaken on a regular basis (subject to results of previous inspections and performance of the pipeline corrosion protection systems) using Pipeline Inspection Gauges (PIGs). ILI runs will be coordinated by the SO and will require a constant flow rate of CO_2. The baseline design is for the newbuild Stanlow to CQY pipeline to be 36" while the existing CQY to PoA pipeline is 24". This will require PIG trap facilities to be located at PoA. It is expected that the existing sections of pipeline will be subject to more frequent inspections than newbuild sections.

The purpose of the ILI activity is to identify pipeline defects such as corrosion (internal or external) and damage. Identified defects would be subject to expert analysis, and, if required, repair activity, which can usually be discharged without full depressurisation (although repair activities may be subject to lower operating pressures).

3.2 Control Philosophy

3.2.1 Full Chain Control Philosophy

System control will comprise multiple separate interfacing, but not integrated, systems comprising the Transport and Storage (T&S) control system and the capture plant control systems.

The T&S system will be owned and operated by the SO and managed from a permanently manned control centre. The system will comprise control of the following elements of the chain:

- 'System Entry' valves at each capture plant
- Pipeline block valves
- Compressors
- Wellhead control (choke valves and heaters)

The capture plant control systems will be integrated into existing plant control systems, allowing integrated operation of the capture plant with existing production systems. Operation of the capture plants will be visible to the T&S control system via exchange of interfacing information, but the T&S control system will be unable to control operations at the capture plant.

The system control handover point will be the 'System Entry' valve that controls entry of source CO_2 into the T&S network (noting that this is the system Battery Limit). This will be controlled by the T&S control system and will only be opened when the T&S system is ready to accept flow of CO_2 and when the CO_2 is within specification limits. In the event of CO_2

moving outside specification during system operation, the T&S control system will decide on whether to take action to close the valve, noting that some excursions will require instantaneous closure while others can tolerate continuing flow, but potentially time limited.

3.2.2 Full Chain Control System Design

The Transport and Storage (T&S) control system will be designed using existing, control system technology with an advanced level of technology maturity.

The system will be designed to allow all aspects of routine operation to be carried out remotely (i.e. from the control centre), with no on site manual interventions required. System operation will be automated, with system operators engaged in a supervisory capacity only. Consideration should be given ensuring operator workload remains within industry best practice guidelines at both the upper and lower end of the work spectrum.

A management information system will be developed to record and display operational monitoring data. Real-time interfacing data from the capture plants will be visible in the management information system such that starts, stops, trips and CO_2 specification data is visible to all parties in the chain.

3.2.3 Safety Control Systems

Industrial safety systems will be integrated into the design to ensure the safety of the public, operating personnel, the environment and system assets from the inherent dangers of the process. The key safety systems are set out in the following sections.

3.2.3.1 Emergency Shutdown

Emergency shutdown (ESD) systems will be installed at the capture plant, the compressor facility and the wellhead. These systems ensure that the system remains in a safe state and are responsible for tripping the relevant plant if there is an excursion from design limits.

3.2.3.2 CO_2 Composition Analysis

CO_2 composition will be analysed by the capture plant within the system battery limit and real time data provided to the T&S control system. Excursions from the CO_2 specification will result in actions being taken by the T&S system, including the potential closure of the system entry valve which is controlled by the T&S system. The range of CO_2 parameters to be measured are set out in the system CO_2 specification in the Project Basis of Design.

It is not considered necessary to undertake full compositional analysis of the CO_2 elsewhere within the chain as all capture sources are required to meet the same specification.

3.2.3.3 Fire and Gas Detection System

Fire and gas detection systems will be installed at any permanent system installations, including the capture plants, block valves (if appropriate), compressor facility and offshore platforms. The systems will reliably detect, alarm, and, if necessary automatically instigate system shutdown procedures.

3.2.3.4 CO_2 Detection Systems

CO_2 detection and monitoring schemes will be implemented on sections of the full chain for the safety of the public and operating personnel. CO_2 detection systems will be implemented at all permanent system installations and, where appropriate and feasible, on sections of the onshore pipeline.

3.2.3.5 Pressure Protection Systems

Capture plants and the compressor facility will be equipped with Pressure Protection Systems to protect downstream systems from over-pressure. The system will comprise shut-off isolation valves with appropriate sensors and logic controllers, and will be designed to operate automatically.

3.3 Metering and Monitoring Philosophy

3.3.1 Full Chain Metering Philosophy

Metering is required at various points in the chain. Upstream metering at the capture plant boundary is required for fiscal purposes – the measurements at this point will determine commercial outcomes for the parties in the project. Downstream metering at the offshore platform and the wellhead are required to confirm pipeline integrity and enable reservoir management, and, as such, are not required to deliver fiscal levels of performance.

A wide range of metering technologies are available, but technology selection remains a challenge for CCUS applications due to complexities such as phase change, variations in mass flow rate and impurities. This section does not set out proposed metering technologies, but rather, sets out the system metering requirements for implementation in the FEED phase.

3.3.2 Metering

3.3.2.1 Capture Plant

Export of CO_2 will be measured at the battery limit of each capture plant. This is a key part of the commercial process (noting that the policy framework, and hence the commercial structure for industrial carbon capture is not yet determined), and metering is therefore required to fiscal standards. The Peterhead CCS project determined this to be better than +/-2.5% in line with EU-ETS requirements for carbon accounting, although other references quote +/-1%. Clear requirements will need to be set and agreed with the appropriate regulators in the FEED phase to enable detailed metering system design.

3.3.2.2 Transport

No metering is required in the transport system.

3.3.2.3 Storage

Platform metering is required to record the flow of CO_2 delivered by the pipeline. Platform metering provides an integrity check for pipeline containment and is therefore not required to be of fiscal standard. Lower levels of accuracy can be tolerated than at other, upstream, metering locations.

As it is proposed to utilise multiple wells across multiple reservoirs, metering at each wellhead is required for reservoir management purposes. As per platform metering, these are not required to be of fiscal standards.

Monitoring of CO_2 injection chemical composition is required under the Geological Storage of Carbon Dioxide Directive, but this is deemed to be met by aggregation of the onshore data gathered at the capture plants.

3.3.3 Monitoring

The Oil and Gas Authority (OGA), as the regulator accountable for determining offshore storage CO_2 permits, requires that any application for such a permit contains a Monitoring Plan. The Monitoring Plan is required to 'establish an environmental baseline and to assess whether injected CO_2 is behaving as expected, and to detect if any unexpected migration or leakage occurs.'

Guidance for monitoring plans can be found in the OGA document 'Carbon dioxide storage permit application guidance'. Monitoring techniques can include, but are not necessarily limited to:

- Time Lapse Seismic, 4C Seismic - for certain storage sites seismic data monitoring may be appropriate to detect the movement of injected CO_2 plume into the formation. This can either be a time-lapse seismic monitoring where 3D surveys are repeated at various intervals over time, or as a 4C seismic survey where Ocean Bottom Cables are permanently installed and able to record the shear (S) waves as well as the compressional (P) waves. A baseline seismic survey will be required prior to commencing injection of CO_2. The value of deploying these techniques will be dependent on the depth and geology of the storage site and shall be reviewed on a case by case basis.
- Gravity Surveys - requires sea floor measurements and a baseline survey.
- Micro-seismicity - for certain storage sites it may be appropriate to drill an observation well with recording tools to detect micro-earthquakes in the vicinity of the well bore.
- Regular pressure build-up testing - to determine formation limits and connectivity
- Multi-well testing using observation wells - characterise flow paths and geological connectivity. For example, a permanent pressure observation well completed just above the cap-rock could provide a very sensitive CO_2 leak detector
- CO_2 Injection and Production Rates – The quantities of CO_2 injected into the storage site need to be carefully monitored and explanations provided for any unexpected changes in well injectivity.
- Tracer Testing - to more precisely determine CO_2 flow pathways within the storage site.

- Core Analysis – Data from cores obtained from new injection wells can yield valuable information on the effects of injecting CO_2 into the formation. Core testing can also yield valuable information on parameters such as the rate of CO_2 trapped by dissolution by other formation fluids (e.g. water), which will help gauge confidence in the long term storage behaviour and risks.
- Seabed Monitoring – Monitoring of the seabed above the storage site to identify CO_2 leakage.

A preliminary long term monitoring plan is also required at the point of application for a storage licence to provide for post closure monitoring of the storage sites.

4.0 CONSENTS

Numerous consents will be required to enable the HyNet project to be constructed and operate. In the pre-FEED phase, focus was placed on the two most critical consents, namely the onshore pipeline Development Consent Order (DCO) and the offshore Storage Licence and Permit.

4.1 Development Consent Order (DCO)

4.1.1 Requirements

The proposed development of pipelines which exceed 16.093km in length is a NSIP (Nationally Significant Infrastructure Project) as defined in Section 141(g)[19] and Section 21 of the Planning Act 2008 (PA2008). Under Section 31 PA2008 a DCO is required to develop a NSIP. Under Section 37(1) PA2008 this can only be granted if an application for it is made to the Secretary of State (SoS). The newbuild section of pipeline from Stanlow to Connah's Quay exceeds this threshold and is therefore designated as an NSIP requiring a DCO.

The remainder of the elements of the HyNet project would comprise development (with the exception of the change of use of the existing pipeline and the use of the existing fields for storage which do not constitute development) but would not, in their own right, constitute NSIPs. It is expected that any of these elements that do comprise development would be capable of comprising either ancillary development under Section 120 of the PA2008 or Associated Development as defined by Section 115 PA2008[20]. It is therefore a project decision as to which elements of the project beyond the pipeline should be included in the DCO application.

In Wales, prior to the enactment of the Wales Act 2017, the PA2008 only made limited provisions for the inclusion of 'Associated Development' in the DCO. This position has now changed following the passing of the Wales Act 2017 and the inclusion on Associated Development is now possible.

HyNet will also be an Environmental Impact Assessment (EIA) development under the Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 and as such, the DCO application will be accompanied by an Environmental Statement (ES).

[19] The construction of a pipe-line other than by a gas transporter. The proposed development would fall within this definition of S.66 Pipelines Act 1962.

[20] Further guidance provided in DCLG (Department for Communities and Local Government) Guidance on associated development applications for major infrastructure projects April 2013

4.1.2 Process

The DCO process is underpinned by seven pieces of primary legislation, over 40 pieces of secondary legislation, 18 advice notes and 11 guidance notes.

As noted above, the PA2008 created a new development consent regime for NSIPs in the fields of energy, transport, water, waste-water and waste. Applicants can expect to receive permission within 16 to 18 months from an application being submitted for examination.

The regime allows applicants to secure consent for the principal element of the development together with ancillary elements which are subordinate but integral to the development. It also allows for 'Associated Development' where there is a direct relationship between associated development and the principal development. It should therefore either support the construction or operation of the principal development, or help address its impacts and should be subordinate to the principal development. It should be proportionate to the nature and scale of the principal development but may provide additional capacity to serve another proposed major infrastructure project.

The PA2008 also allows for a range of other consents to be included within the DCO, such as environmental licences and permits. It may also be used to secure additional powers such as the rights to enter third party land to conduct surveys[21] or the rights to compulsory acquire land or rights over land[22]. There is a c. 12 month lead in time for access via these powers.

There is also the flexibility, where the specifics of a project cannot be fully defined at the time of an application, to define a range of parameters, against which the realistic worst case scenario (in terms of environmental effects) can be assessed.

The process follows five key stages:

- Pre-application
- Application Acceptance
- Pre-Examination
- Examination
- Decision

The project has sought legal opinion on the scope of the DCO application, and a decision has been reached to include the 36" NSIP pipeline, associated AGIs and the 12" pipeline

[21] Section 53 of the PA2008
[22] Section 122-124 of the PA2008

from Grinsome Road AGI to Stanlow AGI. While capture plants could be included in the DCO application as associated development, planning permission for these developments will be undertaken under the Town and Country Planning Act 1990, determined by the local authority.

4.1.3 Relevant Policy Context

There is a substantial body of national planning and other Government strategies of relevance to the HyNet scheme. It provides a significant level of support for the project. A brief summary is provided below.

4.1.3.1 National Planning Policy

National Policy Statements

The Government has published National Policy Statements (NPS) in respect to nationally significant energy infrastructure projects. The SoS must, subject to certain exceptions, decide DCO applications in accordance with the relevant NPS.

The Overarching NPS for Energy (EN-1) sets out the Government's policy for delivery of nationally significant energy infrastructure. It is supplemented by a further technology specific NPS for Gas Supply Infrastructure and Gas and Oil Pipelines (EN-4). It is recognised that there is not a specific NPS for CCUS projects, but it is unlikely that this will be rectified in time to support the HyNet DCO application. Previous projects, including White Rose and the current Net Zero Teesside project have passed, and are passing through the DCO process without a CCUS specific NSIP.

There is a presumption in favour of granting consent to applications for energy NSIPs (unless any more specific and relevant policies set out in the relevant NPSs clearly indicate that consent should be refused).

EN-1 explains that 'The UK must therefore reduce over time its dependence on fossil fuels, particularly unabated combustion. The Government plans to do this by improving energy efficiency and pursuing its objectives for renewables, nuclear power and carbon capture and storage'. The NPS recognises that 'Carbon Capture and Storage has the potential to reduce carbon emissions by up to 90%'.

EN-1 recognises16 the ability to use CCUS on industrial processes that emit a large amount of carbon. Encouragement is given to enabling pipeline networks to facilitate their use as part of a wider carbon dioxide pipeline network by building in greater capacity than may be needed for initial project(s). NPS EN-4 underlines the important role that gas and oil pipelines play.

A series of Generic Impacts to be assessed are set out in Part 5 of EN-119. They are not intended to be exhaustive and should be read together with the technology-specific impacts.

National Planning Policy Framework (NPPF)

Paragraph 5 of the NPPF is explicit that the Framework does not contain specific policies for NSIP, which are determined 'in accordance with the decision-making framework set out in the PA2008 and relevant national policy statements for major infrastructure'.

However, matters that the decision-maker considers important and relevant when making decisions on applications for development consent are also applicable and may include the NPPF (as confirmed by Paragraph 5 of the Framework).

Moving to a low carbon economy is specifically recognised as part of the 'environmental' objective – one of three overarching objectives of the planning system. Similarly, it is clear that the planning system 'should support the transition to a low carbon future' and should 'support renewable and low carbon energy and associated infrastructure'. Local Planning Authorities are required to take a positive approach to such developments in plan making and the determination of planning applications.

4.1.3.2 Planning Policy Wales

Planning Policy Wales (PPW) provides the national planning policy framework in Wales. It shares a similar approach to the NPPF in terms of delivering sustainable development. In doing so, the decarbonisation of society is set out as a Key Planning Principle. The economic and environmental considerations which, along with social considerations, represent the three strands of sustainable development, specifically refer to having regard to how the proposal would support the achievement of a low carbon, innovation in Wales and the degree to which it would support decarbonisation and the transition to a low carbon economy. Environmental sustainability is recognised as encompassing encourage decarbonisation and prevent the generation of waste and pollution.

4.1.3.3 Other National Policy / Strategies

The UK Government's recognition of the essential role that hydrogen and CCUS will play in delivering a Net Zero economy is increasingly clear in more recent policy documentation that can be cited in support of the DCO application. The following policy documents all offer substantial support to projects such as HyNet:

- The Clean Growth Strategy, October 2017 (updated April 2018)
- Driving Clean Growth: CCUS Cost Challenge Taskforce Report, July 2018
- Industrial Strategy: Building a Britain Fit for the Future, November 2017 (updated June 2018)
- Clean Growth: The UK Carbon Capture and Storage Deployment Pathway, November 2018
- Clean Growth: Transforming Heating, December 2018
- Industrial Clusters Mission, December 2018

4.1.4 Strategy and Programme

4.1.4.1 The Case for HyNet

NPSs are clear that it is not necessary to demonstrate a need for NSIPs and introduces a presumption in favour of development for energy-related NSIPs (subject to no specific policies in NSPs indicating that consent should be refused – there are no such policies in this case). HyNet Phase 1 would therefore benefit from the presumption.

There is a consistent and strong level of support for this type of technology in national planning policy and Government strategies. These documents recognise the potentially significant benefits that such developments can deliver in terms of:

- Moving to a net zero carbon economy
- Reducing emissions from existing industrial process
- Contributing to the UK's global reputation as a leading innovator in this emerging field
- Support the 'clean growth' of the UK economy – a central facet of the
- Government's plan for future economic growth
- Putting in place the necessary infrastructure for the use of hydrogen to deliver further de-carbonisation of the economy (delivered by later phases of HyNet)

In addition, it is expected that a range of social and economic benefits will be secured by the development itself.

The DCO application will substantiate the case in favour, providing the supporting information and assessments to quantify the benefits arising. It will also demonstrate that the proposed development has evolved such that it's routing and design has avoided or minimised impacts (or if unavoidable incorporates suitable mitigation measures), such that there are no unacceptable impacts arising.

4.1.4.2 Compulsory Acquisition

The consortium will undertake to seek private negotiations for voluntary agreements with landowners and occupiers, before going public on the details of its intention to develop, i.e. before the informal non-statutory process commences. This would satisfy a requirement that it has sought to acquire the land interest by voluntary agreement before seeking compulsory acquisition powers.

Compulsory acquisition powers will be sought for all land within the order limits to provide certainty of delivery of the scheme. It is expected that the powers will seek permanent and temporary rights for construction and maintenance purposes even where voluntary agreement has been reached.

The application will therefore need to demonstrate that the HyNet scheme will result in a compelling case that the project was in the public interest – the test for compulsory purchase order rights to be granted – as set out above. The case presented in the application will have particular regard to the extent it will align with Government priorities and strategies and the environmental, social and economic benefits of the project.

4.1.4.3 Programme

The consortium has developed a challenging but realistic programme in order to achieve consent by December 2023 / January 2024. It has been developed having regard to the statutory requirements of the PA2008 and associated guidance, notably the requirements around effective and comprehensive consultation (considered further below). It has been informed by a thorough understanding of the DCO process and the statutory requirements. The overall strategy has been devised to achieve this programme.

4.1.4.4 Consultation

The strategy for the project proposes three stages of pre-application consultation. This will consist of the following stages:

- Non- Statutory (informal) – Project launch and 'Pipeline Corridor Consultation'
- Stage 1 – Statutory (formal) Consultation on 'Preferred Route Consultation'
- Stage 2 – Statutory (formal) Consultation on 'Route Refinements'

A multi-stage strategy for pre-application consultation involving both non-statutory and statutory consultation is a PINS-accepted approach for linear NSIP schemes such as the HyNet pipeline project. The proposed strategy shares similar principles to recently accepted NSIP projects including the Southampton to London pipeline project (90km aviation fuel pipe submitted in May 2019) and the Thorpe Marsh Gas Pipeline project (19.1 km buried gas pipeline approved by PINS in 2016).

The strategy recommends frontloading consultation at the informal stage with potential prescribed consultees, local and host authorities, potential people with interest in the land (PILs) and local communities. These early discussions on the high-level potential pipeline route will provide feedback in the general alignment of the route and identify any unknown consultees which may need to be captured by the statutory stages of consultation.

Informal, non-statutory consultation is followed by the preparation of the required Statement of Community Consultation (SOCC) in consultation with the neighbouring and host authorities. The statutory, formal consultation must deliver the commitments made in the published SOCC (under Section 28 of the PA2008). During the two subsequent stages of formal, statutory consultation on the 'Preferred route' and subsequent 'Design refinements' would occur simultaneously under Sections 42, 43, 44, 47 of the PA2008.

During Stage 1 formal consultation on the 'Preferred route', the Preliminary Environmental Information is made available. This approach follows DCLG's 2015 guidance to consult when proposals are firm enough to enable consultees to comment, in a meaningful way on the proposals. At the second stage of formal consultation on 'Design refinement' the draft ES would be made available.

This approach is considered to be sufficiently comprehensive to enable/ the requirements of the PA2008 and associated guidance to be met.

Consultation with Landowner and Occupier Stakeholders

The landowners and occupiers along the proposed pipeline corridor are a fundamental stakeholder within the consultation process and require to be identified at an early stage and certainly prior to the non-statutory informal process, not least to be able to identify them. Prior to the non-statutory informal process, it is anticipated that landowners and occupiers will be contacted as follows.

Land Referencing

- Undertaking a land registry search to identify all known freehold and leasehold occupations, together with address details if known.
- Contacting landowners and occupiers by letter for confirmation details of ownership and occupation.
- Searching the electoral roll for missing landowner and occupier details.
- Identifying landowners and occupiers on the ground if cannot be identified by other sources i.e. land is not registered.
- Seeking confirmation from landowners and occupiers for proof of ownership and occupation.
- Meetings with landowners and occupiers on the ground to confirm ownership and occupation and they are indeed a stakeholder, together with required contact information.

Discussions on the Proposed Pipeline Corridor

- Meetings with landowners and occupiers to ensure that there are no obstacles along the route of the pipeline corridor that cannot be recognised by any other source.
- Meetings with landowners and occupiers to identify any proposed developments already agreed to, legal documents have been secured for and/or planning permissions are about to be or have been submitted for other developments along the pipeline corridor.
- Meetings with landowners and occupiers for confirmation of any underground apparatus that may affect the pipeline corridor.

4.1.5 Environmental Scoping

As a pre-FEED project deliverable a Draft Environmental Scoping was produced (Reference 662211-1 (01)). The Draft Environmental Scoping report is intended to form the basis of a subsequent submission to the Planning Inspectorate as part of the application process for a Development Consent Order, but, at this point, the scoping report remains in draft as a number of elements of the project remain to be finalised (such as number and location of block valves) and no consultation has been undertaken.

The Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 (as amended) herein referred to as the 'EIA Regulations', implement the requirements of the European Directive on environmental impact assessment (EIA) into UK law. The HyNet onshore pipeline (hereon referred to as the Proposed Project) falls within Schedule 2 of these regulations (item 10(k) as a pipeline for the transport of carbon dioxide streams for the purposes of geological storage).

For Schedule 2 projects, an EIA is needed if significant environmental effects are likely to arise from implementation of a development. Based on current available information, it is assumed that the Proposed Project, given its scale, would require an EIA. Progressive Energy will inform PINS under Regulation 6 of the EIA Regulations of its intention to submit an Environmental Statement (ES).

Regulation 10(1) of the EIA Regulations allows a prospective applicant to ask PINS (on behalf of the Secretary of State) for a scoping opinion, which would set out the scope and level of detail of the information to be provided in the ES. Scoping is not a mandatory requirement, however, the scoping opinion is an important document and the EIA Regulations require the ES to be based on the most recent scoping opinion adopted.

Scoping allows for an early identification of the likely significant effects applicable to the EIA Regulations (in particular Schedule 4) and also provides opportunity to agree where aspects and matters can be scoped out from further assessment.

The purpose of the Environmental Scoping Report (once finalised and submitted to PINS) will be to support a request for a scoping opinion for the Proposed Project.

4.1.5.1 Scoping Area

The scoping boundary is a 500m-wide corridor approximately 34 km in length and reflects the preferred route corridor for the new build pipeline (hereon referred to as the Scoping Corridor). A 40 m temporary working width is expected, though this may need to widen or reduce in specific locations. A standard 12m easement for future maintenance will generally be required.

Further detailed work will be undertaken to design the pipeline route and to determine the preferred final alignment (the DCO application boundary, however it is anticipated that it will fall within the 500m-wide Scoping Corridor. Further work will be undertaken to identify the land that is likely to be required for the temporary construction compounds, laydown/storage areas, and access/haul routes connecting to the pipeline corridor from nearby highways. This work is not yet complete, and as such, it is likely that some of these areas may fall outside of the initial Scoping Corridor identified in this report.

However, these areas will be identified within the application boundary for the project. The area within the Scoping Corridor is located within the boundary of Cheshire West and Chester Council, England, and Flintshire County Council, Wales.

4.1.5.2 Approach to Environmental Impact Assessment

The purpose of Environmental Impact Assessment (EIA) is to provide a systematic analysis of the likely impacts of a proposed development in relation to the existing (baseline) environment. This is reported in an Environmental Statement (ES), which provides information to stakeholders, including those from whom consents and authorisations are sought, to enable them to assess the likely environmental impact and make an informed decision on the proposed development.

The Draft Scoping Report has been prepared to set out the proposed approach to EIA for the Proposed Project. This report includes the identification of methodologies to allow the assessment of likely significant effects on environmental aspects (for topics to be scoped into the EIA). Matters that are proposed to be scoped out from further assessment are also identified for agreement with PINS.

The methodologies for the assessments provided in this Draft Scoping Report vary from topic to topic. All of the assessments, however, will typically involve a process of interaction between engineering design, planning and environmental considerations, with a view to avoiding or reducing significant adverse effects on the environment. This will include refinements to the proposed route of the pipeline where appropriate.

All representations received during the scoping process will be considered and used to inform the EIA process.

The objectives of the EIA process will be:

- To gather data regarding the baseline environment (socio-economic, biological, and physical);
- To ensure through engagement and consultation with statutory and nonstatutory organisations that concerns about effects on the environment from the Proposed Project are identified and fully considered;
- To work together with the engineering and design teams to develop an environmentally sensitive project design; and
- To assess the potential environmental impacts during the construction and operational phases of the Proposed Project and suggest mitigation measures to be implemented where required.

The assessment of impacts will be achieved by establishing a robust understanding of the environmental baseline and then predicting the potential impact of key development activities on that baseline. Predictions of impact will be based on a combination of professional judgement, expert knowledge and modelling where appropriate. The definition of what constitutes a significant impact for each environmental aspect will be determined by clear and sensible, pre-defined assessment criteria, as discussed further below.

The EIA process will be carried out in the following stages:

- Preparation of a Scoping Report (this document).
- Pre-application consultation (with prescribed consultees, local and host authorities, potential people with interest in the land (PILs) and local communities) including preparation of a Preliminary Environmental Information Report (PEIR).
- Baseline data collection.
- Assessment of likely significant environmental effects.
- Identification of mitigation and enhancement measures.
- Preparation of an ES.

The EIA for the Proposed Project will comprise desk studies and baseline surveys, assessment of impacts, development of mitigation measures, and identification of residual impacts. The EIA will satisfy the requirements of Schedule 4 of the EIA Regulations and will include a description of the development comprising information on the site selection process, a description of the site, design and size of the development, a description of the aspects of the environment likely to be significantly affected by the development, the likely significant effects of the development on the environment and mitigation measures required to minimise potentially significant effects.

The output of the EIA process will be the ES which will be submitted with the DCO application and will report on the outcomes of the above stages. The ES will be a public document available to all. As part of the pre-application consultation process a PEIR will be prepared to enable consultees (both specialist and non-specialist) to understand the likely environmental effects of the Proposed Project and to inform consultation responses during the preapplication stage. There is no prescribed format as to what PEIR should comprise. It is expected that the PEIR will take the form of a draft ES, setting out the findings of surveys and assessments available at the time of publication.

4.1.5.3 Proposed Scope of EIA

Temporal Scope

The EIA will address the following stages of the proposed development:

- Construction – all those works, activities and processes that will be required to build the Proposed Project, including preparatory works; and
- Operation and maintenance – the developed project completed and in operation, planned and unplanned maintenance activities undertaken.

Construction of the Proposed Project is anticipated to take place between 2023 and 2025 and the intensity and scale of construction will vary along the route during this period. The ES will set out the anticipated construction programme and the assessment of construction effects will be related to the programme described.

The Proposed Project is anticipated to be operational from mid-late 2025. The assessment will consider all likely significant operational effects.

Spatial Scope

The spatial (or geographic) scope is the area over which the EIA will consider potential effects. The extent of the study area for the EIA is not a fixed width, but is tailored at the outset to cover the area over which there may be significant environmental effects depending on the environmental topic being considered i.e. whilst the Scoping Corridor for the purposes of routeing the pipeline is a fixed width, the study area where environmental effects may occur varies dependent on the topic.

A study area will typically take account of the distance over which changes to the environment are likely to occur as a result of the construction and operation of the Proposed Project. In addition to the permanent land take requirements, it will also address land which is temporarily needed for construction.

In addition to the physical extent of the Proposed Project, the extent of the individual study areas will be influenced by two principal factors:

- The nature of the baseline environment; and
- The manner in which the effects are likely to be propagated.

Technical Scope

The environmental topics to be considered and the spatial extent of the assessment proposed for each is referred to as the technical scope.

Section 5(2) of The Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 (as amended) states that EIA must identify, describe and assess in an appropriate manner, in light of each individual case, the direct and indirect significant effects of the proposed development on the following factors:

(2) (a)population and human health;

(b)biodiversity, with particular attention to species and habitats protected under Directive 92/43/EEC(1) and Directive 2009/147/EC(2);

(c) land, soil, water, air and climate;

(d) material assets, cultural heritage and the landscape;

(e) the interaction between the factors referred to in sub-paragraphs (a) to (d).

(3) The effects referred to in paragraph (2) on the factors set out in that paragraph must include the operational effects of the proposed development, where the proposed development will have operational effects.

(4) The significant effects to be identified, described and assessed under paragraph (2) include, where relevant, the expected significant effects arising from the vulnerability of the proposed development to major accidents or disasters that are relevant to that development.

The following topics have been considered:

- Landscape and Visual
- Ecology
- Historic Environment and Cultural Heritage
- Flood Risk and Water Resources
- Socio-Economics and Tourism
- Land Use and Agriculture
- Noise and Vibration
- Traffic and Transport
- Ground Conditions
- Air Quality
- Human Health

Climate Change

It is acknowledged that the overall HyNet North West project is a significant clean growth opportunity for the UK. It will assist in meeting major challenges of reducing carbon emissions from industry, domestic heat and transport and in achieving the 100% Net Zero binding legal obligation as recently adopted by the UK Government. The benefits of the Proposed Project in terms of climate change will be addressed within the EIA with reference to national planning and other Government strategies of relevance to the project. The design of the Proposed Project will take into consideration the need to minimise the carbon footprint of the design and build elements such as minimising use of resources both in the form of energy and in the materials used. Potential effects of sea level rise on the Proposed Project will be assessed as part of the hydrology and flood risk assessment. Given the above, it is not proposed to prepare a separate chapter to address significant effects of the Proposed Project on climate change as part of the ES.

4.2 Storage Licence and Permit

Eni UK applied for a CO_2 storage licence from the Oil and Gas Authority (OGA) in December 2019. Subject to due process it is assumed that the licence will be granted in mid 2020. A programme of work will be discharged to allow a storage permit to be applied for in 2022, and it is expected that the permit will be granted in 2023.

5.0 FINANCIAL MODEL

5.1 Cost Estimating

All the work packages in pre-FEED were subject to Capital Cost (Capex) cost-estimating. The aim throughout was to achieve a consistent AACE Level 4 Estimate across all work packages commensurate with a level of project definition of 'study or feasibility'. The AACE definition for Level 4 gives an estimate accuracy range – the approach in this study has been to achieve levels of +/-30% across all work packages. Where this level of cost estimate has not been achieved, this has been specifically noted in the relevant chapter.

5.1.1 Capital Costs (Capex)

Capital cost estimates for each work package include risk and contingency on a work package specific basis which is set out in the relevant chapters. Where this has not been included in the original estimate, an allowance has been made of 20%.

The system capital costs can be summarised as follows from Sections 2.4 to 2.6:

Figure 5.1: HyNet System Capital Costs

Transport and Storage		Industrial Capture		Hydrogen Production			Hydrogen Distribution
Onshore Transport	Offshore Transport and Storage	Fertiliser Plant Capture	Refinery Capture	1xATR	2xATR	6xATR	Network and Grid Entry
£97m	£181m[23] £155m[24] £265m[25]	£29m	£294m	£254m	£404m	£1140m	£270m[26]

[23] See Scenario 1.1 in Section 2.6.6: This is the gas phase scenario with onshore compression at Point of Ayr and a subsea manifold replacing the Douglas Platform, giving a mass flow rate up to 3MtCO_2/yr.
[24] See Scenario 1.2 in Section 2.6.6: This is the gas phase scenario with offshore compression at Douglas Platform, giving a mass flow rate up to 3MtCO_2/yr.
[25] See Scenario 2 in Section 2.6.6: This is the dense phase scenario with onshore compression at Point of Ayr giving a mass flow rate up to 10MtCO_2/yr and requiring replacement of infield pipelines.
[26] Note that costs of the Hydrogen Distribution network have been excluded from the final cost of abatement calculations,. It was considered that distribution infrastructure in other low carbon sectors (e.g. renewable electricity) is not included in abatement cost calculations, and, in order to keep approaches aligned as far as possible, the Hydrogen Distribution network costs have been excluded here.

5.1.2 Operating Costs (Opex)

Operating Cost (Opex) estimating was achieved on the basis of known utility loads where possible, with an allowance made for other operating costs based on a proportion of Capex. The road transport solution has had a greater focus on operating cost assessment given that, proportionally, it is a high Opex solution. Similarly, the offshore transport and storage element of the HyNet project was subject to a specific Opex cost estimate that is detailed in Section 2.6.6

5.2 Financial Model

5.2.1 Scenarios

A HyNet financial model has been built to assess total capital costs, costs of abatement and required levels of support for elements of the full chain project. A number of scenarios have been considered:

Figure 5.2: Financial Modelling Scenarios

Scenario	1	2	3	4	5	6
Fertiliser Plant Capture ($MtCO_2$/yr)	0.4	0.4	0.4	0.4	0.4	0.4
Hydrogen Production ($MtCO_2$/yr)		0.6 (1xATR)	1.3 (2xATR)	1.3 (2xATR)	3.8 (6xATR)	8.8 (14xATR)
Refinery Capture ($MtCO_2$/yr)				0.8	0.8	0.8
CO_2 System Configuration	Free Flow Gas[27]	Free Flow Gas	Gas Phase Compression	Gas Phase Compression	Gas Phase Compression	Dense Phase
Total Mass Flow Rate ($MtCO_2$/yr)	**0.4**	**1.0**	**1.7**	**2.5**	**5.0**	**10.0[28]**

[27] For the Free Flow Gas scenarios, the Eni offshore transport and storage Capex and Opex figures have had compression elements removed.

[28] By this stage in the HyNet development programme it is expected that other industrial sources, such as Padeswood Cement Plant and Protos will also be connected to the network, but, at present financial models for these have not been determined as they are at pre-feasibility stage. As such, they are not included in the Scenario 6.

5.2.2 Business Model Assumptions and Returns

Business models for CCUS have not yet been published, and, as such, assumptions have been made about how, and where in the CCUS Chain, support is injected. The following assumptions have been made:

- Transport and Storage: It is assumed that Transport and Storage assets will be a Regulated Asset and financially operate as a RAB system (RAB = Regulated Asset Base). An allowable revenue is set by the Regulator such that the Transport and Storage Company (T&SCo) receives a fixed return on capital employed. This is the Revenue = WACC*RAV model + Opex model, where WACC = Weighted Average Cost of Capital and RAV = Regulated Asset Value. In this financial model allowed revenue is set to earn T&SCo a fixed rate of return. The actual value set by the Regulator will be a function of a range of parameters including risk allocation, leverage, market rates for debt and assumptions on rates of return for equity. 10% is considered an appropriate starting point for modelling purposes. The allowed revenue is paid through the capture plants as a 'pass through' cost. In addition, operating costs are included in a single over-arching 'T&S Fee', which is passed through to the Capture Plants on a £/t basis.
- Industrial Capture Plants: It is assumed that Capture Plants will be merchant assets and receive a support mechanism in the form of a CO_2 CfD (Contract for Difference). The CfD will pay a support revenue to the Capture Plant on a £/t basis according to the formula Revenue = Quantity Captured * (Strike Price – Reference Price). There is ongoing debate about the Reference Price, which, in a context of global carbon pricing with no leakage, should be set as the carbon price. However, in the context of other jurisdictions not applying the same level of carbon pricing as that imposed by EU-ETS, this construct is difficult to justify. As such, an approach has been taken to set the Reference Price to zero, making the CfD a premium payment rather than a true Contract for Difference. The CfD Strike Price (or premium) is set to cover operating costs, plus a risk premium of 25% to cover uncertainties around operating efficiency and volumes captured. It is envisaged that this CfD Strike price will be revisited on a periodic basis. Capital costs are covered under a separate mechanism, which provides a repayment of capital deployed over 5 years at a fixed rate of return. A fixed rate of return of 12% has been chosen as a starting point to represent Capture Plants existing internal hurdle rate.
- Hydrogen Plants: It is assumed that Hydrogen Plants will be merchant assets and receive a support mechanism in the form of a Hydrogen CfD. The CfD will pay a support revenue to the Hydrogen Plant on a £/MWh basis according to the formula Revenue = Quantity Produced * (Strike Price-Reference Price)). The Strike Price is set to include operating costs, capital costs and T&S Fees, and the reference price is set to the price of natural gas, allowing Hydrogen to be sold into the market at the prevailing cost of natural gas (with an adjustment for carbon price), therefore not penalising consumers for switching to low carbon hydrogen. The return on capital employed in the Hydrogen Plant is set to 10%.

It is considered that these are all reasonable assumptions for a baseline financial assessment of HyNet. However, the model is very sensitive to Business Model assumptions, both in the key principles of the model, and the quantitative elements such as rates of return and repayment periods. Care should be taken in comparing different projects that key assumptions are normalised.

5.2.3 Baseline Financial Model Results

The model outputs a number of key parameters for each scenario as follows:

- Transport and Storage Costs (£/tCO_2) – Total cost of Transport and Storage, including capital and operating costs, calculated on a £/t basis
- Capture Plant CfD (£/tCO_2) – Required CfD payment, required over life of the project, to cover Capture Plant operating costs, plus a risk premium of 25%
- Capture Plant Capex Repayment – Required Capex repayment, required over 5 years, to cover capital costs at a return of 15%
- Hydrogen Plant CfD (£/MWh) – Required Strike Price, required over life of the project, to cover Hydrogen Plant capital costs at a return of 10%, operating costs and T&S fees.
- Total CO_2 Abated (tCO_2) – Sum total of CO_2 abated across all capture and hydrogen plants over 25 year project life
- Total Support – Total support provided by Government over all project CfDs and Capex repayments.
- Abatement Cost (£/tCO_2) - Total support cost of abatement, calculated on a £/t basis

Figure 5.3: Financial Model Results (Base Case)

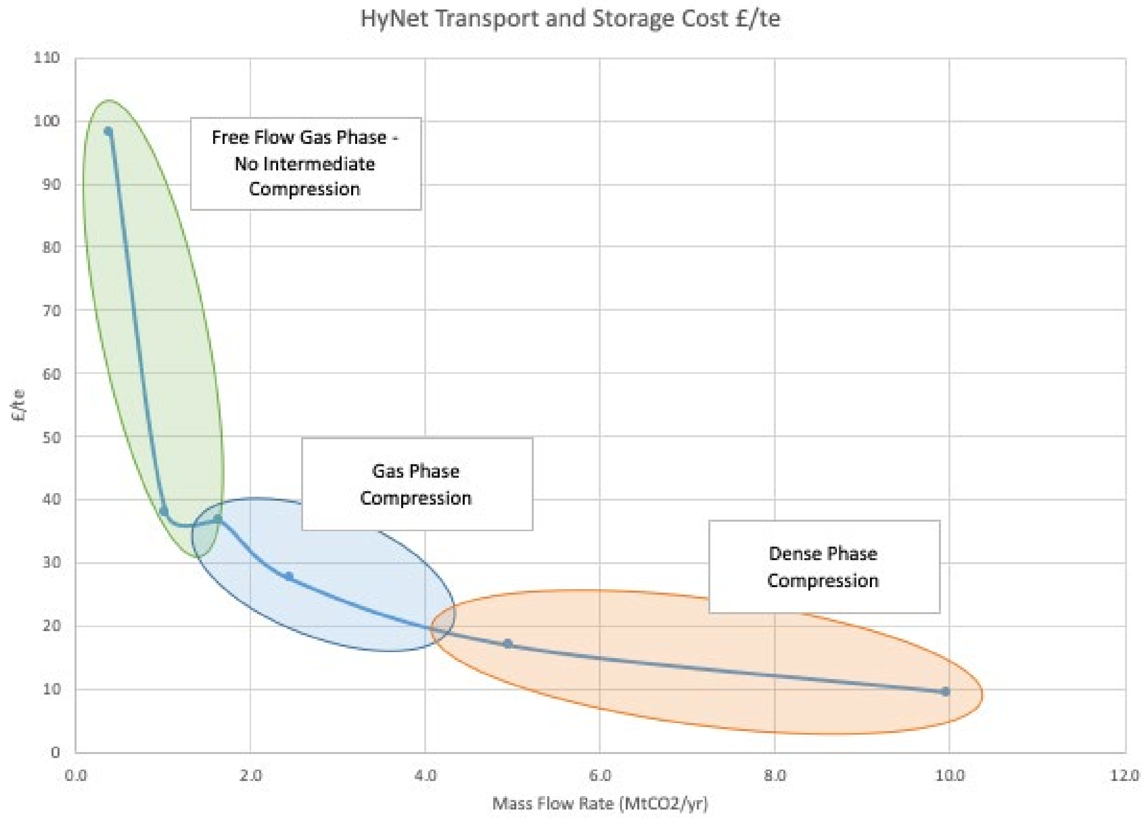
Scenario	1	2	3	4	5	6
Sources	Fertiliser Plant	Fertiliser Plant + 1xATR	Fertiliser Plant + 2xATR	Fertiliser Plant + 2xATR + Refinery	Fertiliser Plant + 6xATR + Refinery	Fertiliser Plant + 14xATR + Refinery
Mass Flow Rate (MtCO_2/yr)	0.4	1.0	1.7	2.5	5.0	10.0
Transport and Storage Costs (£/t)	98.0	38.1	36.6	27.5	17.0	9.6
Fertiliser Plant CfD (£/t)	13.5	13.5	13.5	13.5	13.5	13.5

Fertiliser Plant Capex Repayment – 5 years (£/t)	21.0	21.0	21.0	21.0	21.0	21.0
Refinery CfD (£/t)				57.00	57.00	57.00
Refinery Capex Repayment – 5 years (£/t)				92.44	92.44	92.44
Hydrogen Plant CfD (£/MWh)		43.1	41.6	41.6	40.4	39.9
Total CO_2 Abated - 25 years (Mt)	10	25	39	55	117	220
Total Support Costs – 25 years (£m)	1157	2952	4972	6615	13371	24345
Abatement Costs (£/t)	115.7	118.5	126.8	119.5	115.7	110.8

Key results of note are as follows:

- Transport and Storage Costs: There is, as is to be expected, a significant reduction in Transport and Storage costs per tonne as mass flow rates are increased, as the capital costs are amortised over a larger volume. There is a discontinuity in this reduction between Scenarios 2&3, as this marks the point in project evolution at which the project switches from Free Flow Gas mode to requiring intermediate system compression, as set out in Section 2.3.1. Similarly, between Scenarios 4&5, compression to dense phase is required, which marks a further step up in capital and operational costs, but this is offset by the increased flow volumes.
- Industrial Capture Costs: There is a significant difference between the required CfD level for the Fertiliser Plant and the Refinery. This is because the CO_2 is essentially already captured in the Fertiliser Plant, and requires drying and compression only at relatively low energy expenditure, whereas at the Refinery the full energy costs of capture are borne by the project.
- Abatement Costs: These remain relatively flat with volume mass flow rate, largely because increased costs of capture from Hydrogen Production and the Refinery (compared to the Fertiliser Plant) offset the reduction in Transport and Storage costs with volume. For the final scenario, the expected reduction in abatement costs due to the cost benefit of scaling up Hydrogen Production are offset by the introduction of the Hydrogen Distribution network into the abatement cost.

Figure 5.4: Decreasing Costs of T&S with Increasing Mass Flow Rates



5.2.4 Sensitivity Assessments

Key sensitivities have been assessed as follows:

Rates of Return

- Low Case: Reducing Rates of Return from 10% to 8% for T&SCo, 12% to 10% for Capture Plants and 10% to 8% for the Hydrogen Plant yields a reduction in abatement costs of approximately 6-9% across the scenarios.
- High Case: Increasing Rates of Return from 10% to 12% for T&SCo, 12% to 15% for Capture Plants and 10% to 12% for the Hydrogen Plant yields an increase in abatement costs of approximately 6-9% across the scenarios.
- The abatement cost is relatively insensitive to Rate of Return on capital, as a large part of the support mechanism over a 25 year project life is supporting operating costs, rather than capital returns, particularly for the hydrogen plant

Figure 5.5: Rate of Return Sensitivity Assessment

Scenario	1	2	3	4	5	6
Transport and Storage Costs (£/t)						
Base Case	98.0	38.1	36.6	27.5	17.0	9.6
Low Rate of Return	88.5	34.5	33.1	24.9	15.2	8.8
High Rate of Return	108.0	42.2	40.3	30.4	18.6	10.5
Abatement Costs (£/t)						
Base Case	115.7	118.5	126.8	119.5	115.7	110.8
Low Rate of Return	106.0	109.5	117.6	112.2	108.5	104.1
High Rate of Return	126.1	128.5	137.0	128.0	123.4	118.0

Figure 5.6: Transport and Storage Costs

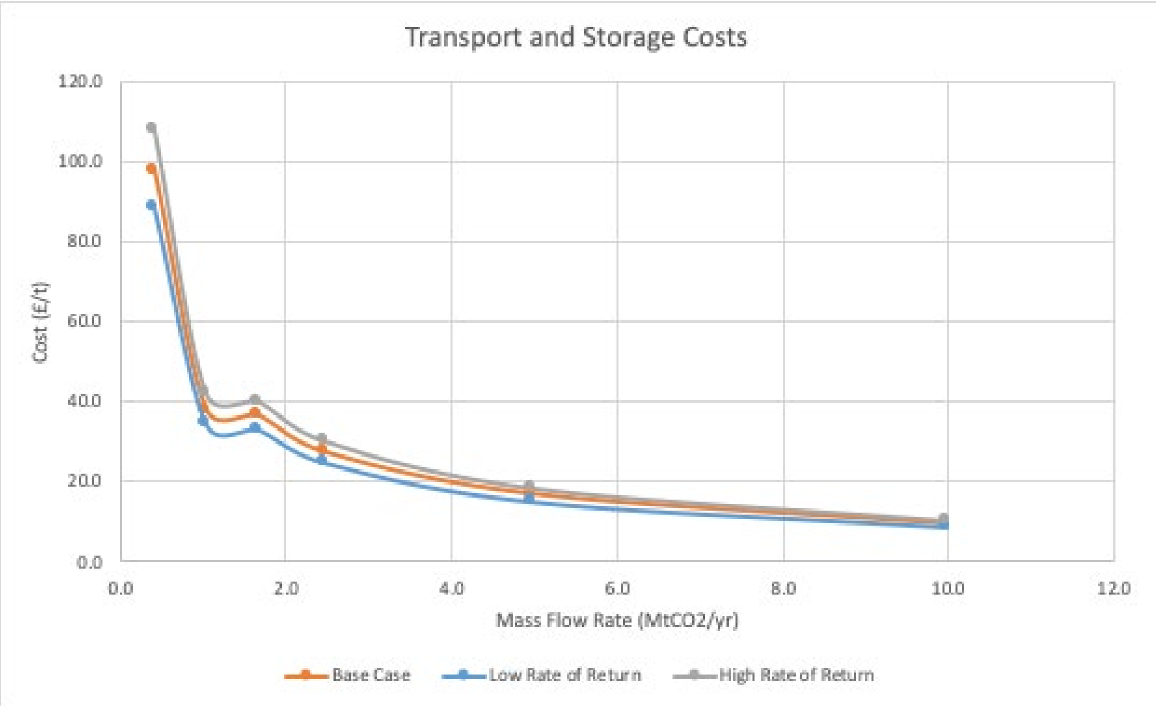
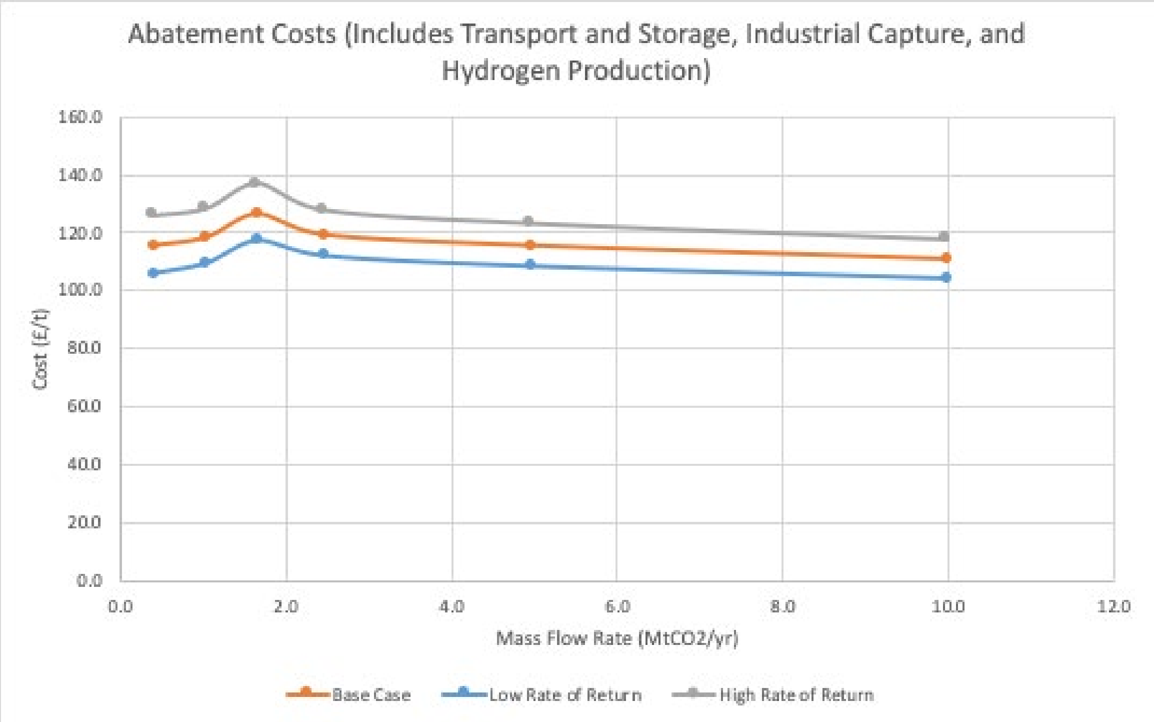


Figure 5.7: Abatement Costs



Electricity Costs

- Base Case: A base case of £90/MWh has been used for all project electricity consumption at Capture Plants and Hydrogen Production, including compression. Transport and Storage operating costs are modelled simply as a proportion of capital costs, whereas in reality, there would be a direct link to electricity costs to reflect the costs of compression in scenarios 3, 4 and 5. Future iterations of the model will capture this.
- Low Case: A low case of £50/MWh has been modelled to reflect the opportunity to utilise captive power plants on Capture Plant sites, therefore significantly reducing the cost of electricity.
- The abatement cost for the higher flow rate scenarios drops by approximately 13% for a reduction in electricity cost from £90/MWh to £50/MWh. The effect is less marked at low flow rates, as the electricity consumption at the Fertiliser Plant is a relatively small proportion of overall system operating costs at this flow rate.

Figure 5.8: Electricity Cost Sensitivity Assessment

Scenario	1	2	3	4	5	6
Transport and Storage Costs (£/t)						
Base Case (£90/MWh)	98.0	38.1	36.6	27.5	17.0	9.6
Low Electricity Cost (£50/MWh)	98.0	38.1	33.7	25.5	14.9	8.4
Abatement Costs (£/t)						
Base Case (£90/MWh)	115.7	118.5	126.8	119.5	115.7	110.8
Low Electricity Cost (£50/MWh)	111.0	108.9	113.2	107.3	102.1	97.3

Other Sensitivities

- Capital Grant: Consideration is being made by Government for the introduction of a capital grant to cover a proportion of the capital cost. This would have the effect of reducing abatement cost, as no returns would need to be paid on the proportion of the capital cost that was covered by a grant.
- Contingency: Prudently, relatively high levels of contingency have been included throughout the project (20% unless specifically noted otherwise), and this is on top of a cost estimate that is +/- 30%. Reducing levels of contingency will reduce abatement costs, and this will be further explored in FEED as cost estimates improve.

5.3 Financial Model Next Steps

The financial model to support pre-FEED provides a good sense of the key financial metrics of the HyNet project. When compared with alternative routes to decarbonising the ‘hard to reach’ sectors of the economy, such as domestic heat, transport and industry, the abatement costs presented are attractive.

There are a number of areas of refinement for the model that will need to be considered through FEED. These include:

- Business Models: Simple business models have been used in the financial model to reflect current direction of travel, following the BEIS consultation on business models and discussions / feedback in the BEIS CCUS Expert Working Groups. Any changes in assumptions following publication of the business models at the end of 2020 will need to be captured in a revised financial model.
- Additional Capture Sources: No financial modelling has been undertaken for either the Protos site or the potential future connection at Padeswood cement. These both have the potential to be relatively low capture cost projects, therefore reducing abatement costs overall.

- Additional Project Elements: The financial model does not include any costs for a Control Centre and associated telemetry. This is provisionally estimated at £10m, and is therefore a potential increase in Transport and Storage Capex of approximately 5%, and is within the bounds of current contingency levels. Similarly, the financial modelling to date has not addressed the road / rail transport scenario.
- Operating Costs: Treatment of Opex for most elements of the project has been relatively simplistic to date, based on a simple proportion of capex for Operation and Maintenance (O&M) costs, plus utility costs where energy consumption has been assessed. Full assessment of operating costs, including staffing, will be required during FEED, as Opex is a major driver of abatement cost.
- Entity Structure and Leverage: Entity structure and leverage are a key element of returns on equity in regulated assets, and, following publication of the business models and views on regulatory structures, this element of the model will need to be appropriately adjusted.
- Tax: All modelling undertaken today is pre-tax, and, in conjunction with the point above on Entity Structure and Leverage, this will need to be refined ahead of FID to reflect actual returns.
- Inflation: Inflation will need to be modelled.
- Decommissioning: No allowance has been made for decommissioning of newbuild CCUS assets, although it is expected that existing oil and gas assets will have their existing decommissioning liabilities transferred to T&SCo, or held by the parent company.

6.0 EXECUTION PLAN

The HyNet project was first conceived in 2016 and has progressed through three stages of development to date as follows:

- Origination: 2016-2017, delivered by Progressive Energy under contract to Cadent and funded via NIA (Network Innovation Allowance).
- Feasibility: 2017-2018, delivered by Progressive Energy under contract to Cadent and funded via NIA.
- Pre-FEED: 2019-2020, delivered by an industry consortium led by Progressive Energy funded by partner contributions and BEIS.

The next phase of the project is to achieve Final Investment Decision (FID), or, dependent on the construction execution plan multiple, linked FIDs. This will be delivered through a three year FEED and Consents project phase.

To achieve a FID, a range of engineering, consenting and commercial outcomes are required which are set out in detail in Section 6.1 below. The DCO process, as set out in Section 4.1 is the critical path to FID, and is forecast to take 28-36 months.

This section sets out the proposed project structure, timescales and phases to achieve FID and a top level plan for the construction and commissioning phase of the project.

6.1 FEED and Consents

6.1.1 Objectives

The primary funding vehicle to achieve FID is the deployment strand of the forthcoming UKRI (UK Research and Innovation) IDC (Industrial Decarbonisation Challenge) grant fund. The main IDC deployment fund is a £132m pot set up to support the development of one or more low carbon industrial clusters. It is expected that funding applications will open in July 2020, with submissions in September and award in the late 2020. Our FEED and Consents plan will assume the majority of work commences in Q1 2021, with some critical path items commencing ahead of this.

The HyNet plan is to submit a full chain Hydrogen / CCUS project into the IDC funding process. The full chain project will include Hydrogen Production, Distribution and Storage to deliver 30TWh of low carbon hydrogen by 2030 and industrial capture from three major existing emitters (Fertiliser Plant, Refinery and Cement Plant). The FEED and Consenting phase will comprise a number of discrete, but technically linked work packages with the following specific objectives:

- To produce Engineering and Process Documentation sufficient to complete detailed engineering, procurement and construction of the project.
- To secure all necessary Consents and Permits to undertake construction and operation of the project, including, but not limited to Storage License and Permit, Development Consent Order, and any further consents as required by local planning authorities
- To develop Capital and Operational Cost estimates to AACE Class 2

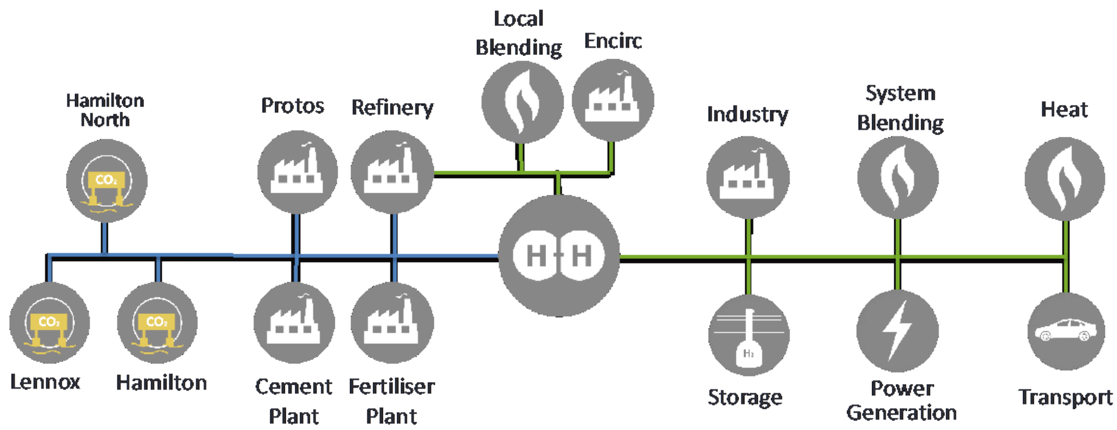
- To develop a project Execution Plan, including schedules, cost plans, organisational structure and staffing plans
- To develop a Procurement contracting strategy, and, where required, identification of contractors and long lead time items
- To develop the Commercial Agreements for project delivery, including contracts with the appropriate Government counterparty for the revenue support mechanism.
- To develop a Risk Management Plan

It is expected that these requirements will also align with Final Investment Decision (FID) requirements for any potential future third party investor.

6.1.2 Structure

Full-chain project FEED is currently expected to be delivered through a project consortium including Progressive Energy, Eni, CF Fertilisers, Essar Oil UK, Peel L&P Environmental, Cadent and Hanson Cement. A partner for hydrogen storage is expected as well. The commercial and governance relationships between these parties are yet to be determined. Figure 6.1 below shows a representation of the full-chain system, with the CO_2 network denoted in blue, and the H_2 network denoted in green.

Figure 6.1: Full Chain HyNet System



FEED will include the following work packages, although this remains subject to revision during the FEED planning activity in Q1 2020:

- Work Package 1: Cross Chain Integration - Progressive Energy Lead

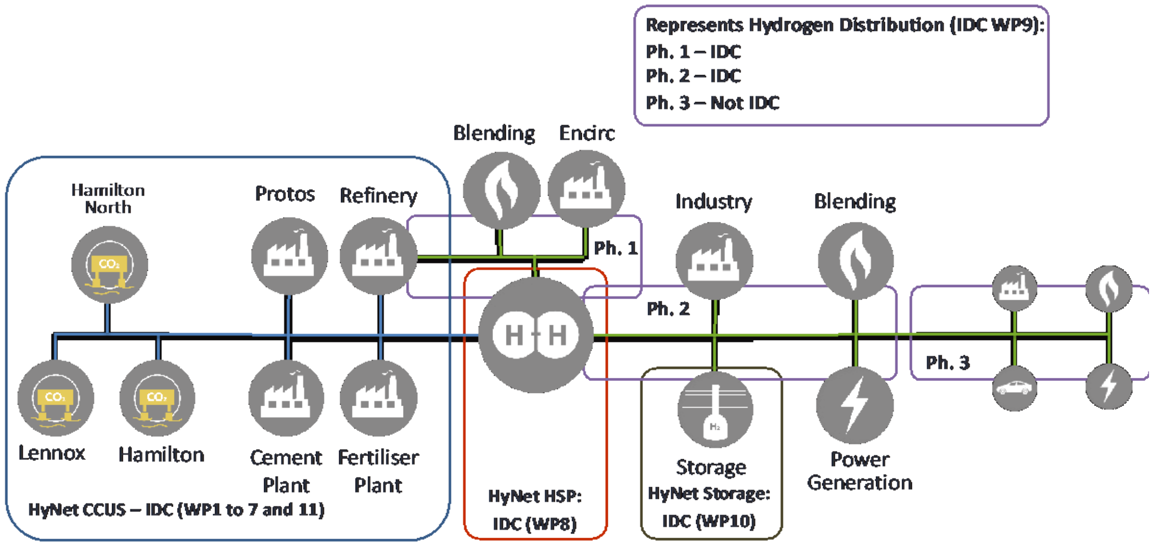
- Work Package 2: Onshore Transport[29] - Progressive Energy Lead
- Work Package 3: Offshore Transport - Eni Lead
- Work Package 4: Offshore Storage - Eni Lead
- Work Package 5: Fertiliser Plant Capture - CF Lead
- Work Package 6: Refinery Capture - Essar Lead
- Work Package 7: Protos Capture - Peel L&P Environmental Lead
- Work Package 8: Hydrogen Production - Progressive Energy Lead (note: this package of work has commenced under separate funding. Technical integration into the remainder of the FEED programme of works will be undertaken by Progressive Energy)
- Work Package 9: Hydrogen Distribution – Cadent
- Work Package 10: Hydrogen Storage – Partner TBC
- Work Package 11: Cement Plant Capture – Hanson Cement (note that this remains subject to approval from the Hanson Board)

The project baseline is to use a pipeline to convey CO_2 from Stanlow to Point of Ayr, as, over the medium to long term, this is the lowest cost and most practicable method for the conveyance of high mass flow rates. However, as set out in Section 2.5.2, this requires a DCO which drives the programme critical path. To mitigate this, a study into an interim road / rail transport solution was conducted in pre-FEED, and it is planned to take this into FEED. This will either be delivered as a sub-package within Work Package 2, or alternatively, as a stand-alone package.

Figure 6.2 below illustrates the work package structure. The CCUS element of the project is covered by packages 1 to 7 and 11 (in the light blue box) and the Hydrogen element of the project is covered by packages 8 to 10. It should be noted that the hydrogen distribution network will be delivered in three phases across RIIO-GD2 and RIIO-GD3.

[29] The system battery limit between Onshore transport and Offshore transport work packages is defined to be at the Connah’s Quay tie-in point. The Offshore transport package therefore includes the onshore section of pipeline from Connah’s Quay to Point of Ayr, but is defined as Offshore transport for ease of work package naming.

Figure 6.2: Full-Chain HyNet System Showing FEED Work Packages



From Figure 6.2 above it can be seen that the hydrogen distribution network will be constructed in multiple phases. Phase 1 will comprise small scale local supply in the close vicinity of Stanlow refinery. Phase 2 will comprise 80km of pipeline to connect production at Stanlow refinery to approximately 16TWh of annual demand with the pipeline being routed East towards Manchester, north towards Liverpool and St.Helens and south to the Cheshire salt cavern storage location. Phase 3 will construct a wider network to connect to southern Lancashire, North East Wales and across the Liverpool City Region and connect up to 30TWh/yr of demand. The IDC funding application will include FEED and Consenting for Phases 1&2 only.

6.1.3 Execution

Each partner will be responsible for determining their own execution strategy. It is expected that this will be through a combination of in-house delivery and subcontracting.

Subcontracted packages will be tendered in the majority of instances, although, in specific areas where there is clear merit in flowing through work directly from pre-FEED, some packages may be single-sourced.

Some work packages will require multiple subcontract packages. For example:

- Work Package 1: Cross Chain Integration
    - Subcontract Package 1.1 – Technical Integration, including whole system flow assurance, safety and commissioning

    - Subcontract Package 1.2 – Project Integration, including document management, interface management, consents register, schedule integration and whole system risk management
- Work Package 2: Onshore Transport
    - Subcontract Package 2.1 – FEED Engineering
    - Subcontract Package 2.2 – Consents (noting that this may have multiple subcontracts for land-agenting, stakeholder consultation and surveys).
    - Subcontract Package 2.3 – Consents Legal Support

Technical and project integration between the work packages will be discharged through Work Package 1.

6.2 Construction and Commissioning

While the Construction phase procurement strategy has not yet been determined, it is envisaged that construction will take place through multiple construction work packages in a similar work breakdown structure to that put in place for FEED.

Commissioning will be undertaken on a work package by work package basis, with full-chain system commissioning coordinated and managed by the Transport and Storage System Operator.

6.3 Operations

Following commissioning, the HyNet system will transition into steady state operations with additional sources of CO_2 supply connected over time.

System operations will be managed by the respective asset owners with clear delineation of operational accountability between Capture Plants and the Transport and Storage system.

As set out in Section 3.0, operational control of the Capture Plants will be the accountability of the respective Capture Plants. The Transport and Storage System Operator will not have operational control of the capture plants, but will be able to close down their access to the system should the CO_2 be out of specification.

All Capture Plant maintenance work and scheduling will be the accountability of the respective Capture Plants. However, the Transport and Storage System Operator will hold regular liaison meetings with Capture Plants with the objective of aligning maintenance windows wherever possible. Similarly, if the Transport and Storage System Operator requires certain flow conditions in the pipeline to manage a PIG operation, then this will be discussed and agreed in advance at the liaison meetings with the Capture Plants.

It is envisaged that the Transport and Storage System will have a permanently manned control room, although the location and design of this facility is yet to be determined. The Transport and Storage System Operator will be accountable for day to day operation of the network, management of maintenance, and the facilitation of connections (both entry and exit connections as required) to the network.

6.4 Delivery Schedule to Operations

The pre-FEED programme of work has enabled clear identification of the onshore pipeline DCO as the critical path to the commencement of HyNet operation. It has also enabled the identification of a road / rail transport solution as an interim mitigation measure in the event that either the baseline pipeline DCO programme is considered unacceptable, or if there are delays in the execution of this programme.

A more detailed FEED and Consenting execution schedule is being developed as part of the IDC submission but, for the purposes of this report, a Level 1 schedule has been created which is shown in Figure 6.3 and Figure 6.4 below. The schedule highlights a number of key issues for consideration:

- **Critical Path – Pipeline DCO:** The critical path for the baseline pipeline programme is illustrated in red. The programme from commencement of DCO activities to the DCO being granted is 3.5 years, with 2 years of pre-application activity and 1.5 years of determination. Assuming that everything else is in place for FID at the point that consent is granted, FID takes place in Q1 2024 and system operations commence by the end of 2025. Given that considerable work has been undertaken in pre-FEED to select a route, identify environmental constraints and landowners, there is a potential opportunity to reduce this programme by up to a year. However, we believe that 3.5 years is the most credible baseline programme at this point based on professional advice received to date. This will be subject to further exploration and refinement during FEED planning.
- **Alternative Critical Path – Road / Rail Transport Option:** The benefit of the road / rail transport option (and, in particular, the road solution) is that it does not require a DCO, and, compared to the pipeline option, it requires much less linear, cross-country infrastructure to be constructed, therefore leading to an operational in-service date by Q4 2024, a year ahead of the pipeline option. As such, this is being pursued into FEED as a viable schedule mitigation strategy with a go / no-go decision required on this strategy by the end of 2022.
- **Fertiliser Plant Capture:** It is expected that this plant will provide the CO_2 for system commissioning. However, given the engineering FEED activity, consenting and construction is considered relatively simple, there is significant float in this programme. This is currently represented by a gap of a year between completion of FEED and consenting and the FID process, which is planned to be aligned (although separate) with that of the Transport and Storage system.
- **Refinery Capture:** As set out in Section 2.4.2, further work is required at pre-FEED stage to undertake a technology selection process. Following this phase of work and a stage-gate review, a 2 year FEED and consenting process is envisaged,

leading to an earliest FID date of Q1 2024. Construction phase scheduling has not been included in the Level 1 plan, as this is highly dependent on the Stanlow Refinery turnaround plan. Understanding what elements of the project can be constructed before, during and after scheduled turnarounds will be a critical element of the FEED activity.

- **Cement Plant Capture:** The Padeswood cement plant was not included in the pre-FEED programme of work undertaken to date. It is planned that a pre-FEED level of activity will be undertaken in 2021 to assess capture technologies and the pipeline spur connection to the main pipeline route and then, subject to a stage gate, a 2 year FEED and consenting phase will be undertaken. As per the Refinery Capture plant, this would lead to a FID date of Q1 2024, after which construction can progress (subject to outage planning at the cement plant). If such a programme were followed, the Cement Plant would be available to connect to the Transport and Storage system in the same timeframe as commissioning of the main pipeline system. However, this is dependent on a capture technology being available and tested at appropriate scale prior to full scale deployment at Padeswood. This will be assessed further in the pre-FEED phase.
- **Hydrogen Production (1st Unit):** The first hydrogen production plant is currently in the FEED engineering phase which is scheduled to complete in Q1 2021. The project is expected to be FID ready, subject to appropriate policy frameworks being in place to facilitate investment, by Q4 2021. A 3 year construction and commissioning programme gives an operational date of Q1 2025. This is almost a year ahead of the baseline pipeline Transport and Storage system operational date, but given the necessity to urgently establish a new hydrogen market, this would still be advantageous to unlock progress. It does illustrate the opportunity that the road / rail solution provides to close this schedule gap. Alternatively, the programme can hold some float and align the operational date with that of the Transport and Storage system although this holds back hydrogen market creation.
- **Hydrogen Distribution (Phases 1&2):** The HyNet Hydrogen Distribution network will be built in three phases, with phases 1&2 shown in the Level 1 plan:
    - Phase 1: Distribution to Essar refinery and a small network in close proximity to Stanlow Refinery to provide local network blending and distribution to adjacent industrial consumers.
    - Phase 2: High pressure (up to 45barg) distribution network of approximately 80km in length from Stanlow Refinery to Partington / Warburton (Greater Manchester Combined Authority), St.Helens (Liverpool City Region) and the Cheshire Salt Caverns providing distribution to up to 16TWh/yr of hydrogen demand. DCO required. To be constructed during RIIO GD2 (2021-2026).
    - Phase 3: High pressure (up to 49barg) distribution network of 250-300km in length further into Greater Manchester, to southern Lancashire, across Liverpool City Region and North East Wales providing distribution to up to 30TWh/yr of hydrogen demand. DCO required. To be constructed during RIIO GD3 (2026-2031).

- **Hydrogen Storage:** Hydrogen storage will be required to balance supply and demand on both a daily and seasonal basis. While industrial loads have relatively flat profiles, demand for domestic heat is highly variable and demand for flexible power generation is largely driven by the wind power generation profile. A DCO will be required for the storage caverns and the Level 1 schedule shows the first caverns becoming available in Q4 2026, driven by both the DCO timescale and the construction schedule. Further caverns will be progressively commissioned to match system demand requirements.

Figure 6.3: HyNet Delivery Programme - Level 1 Schedule CCUS

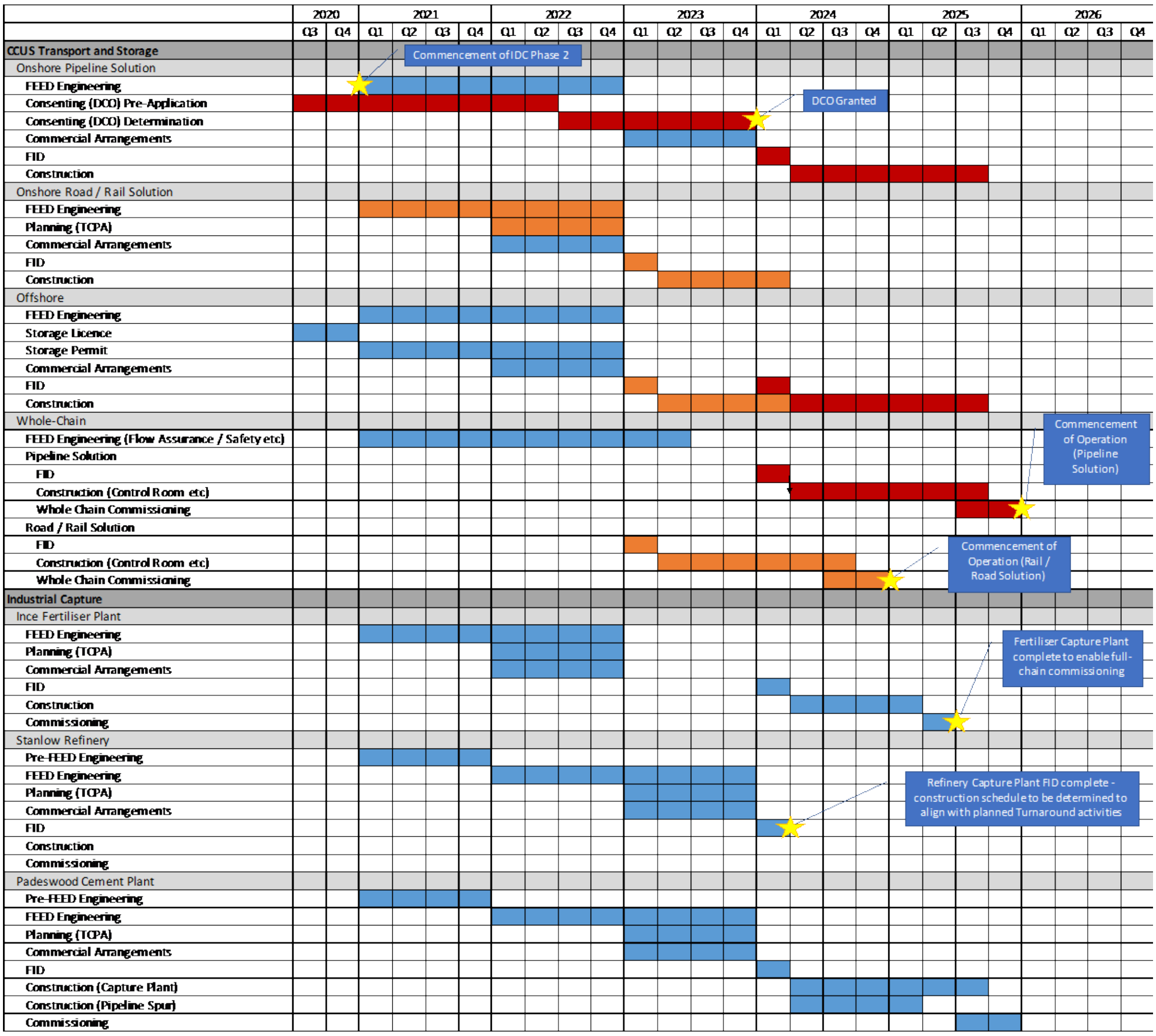
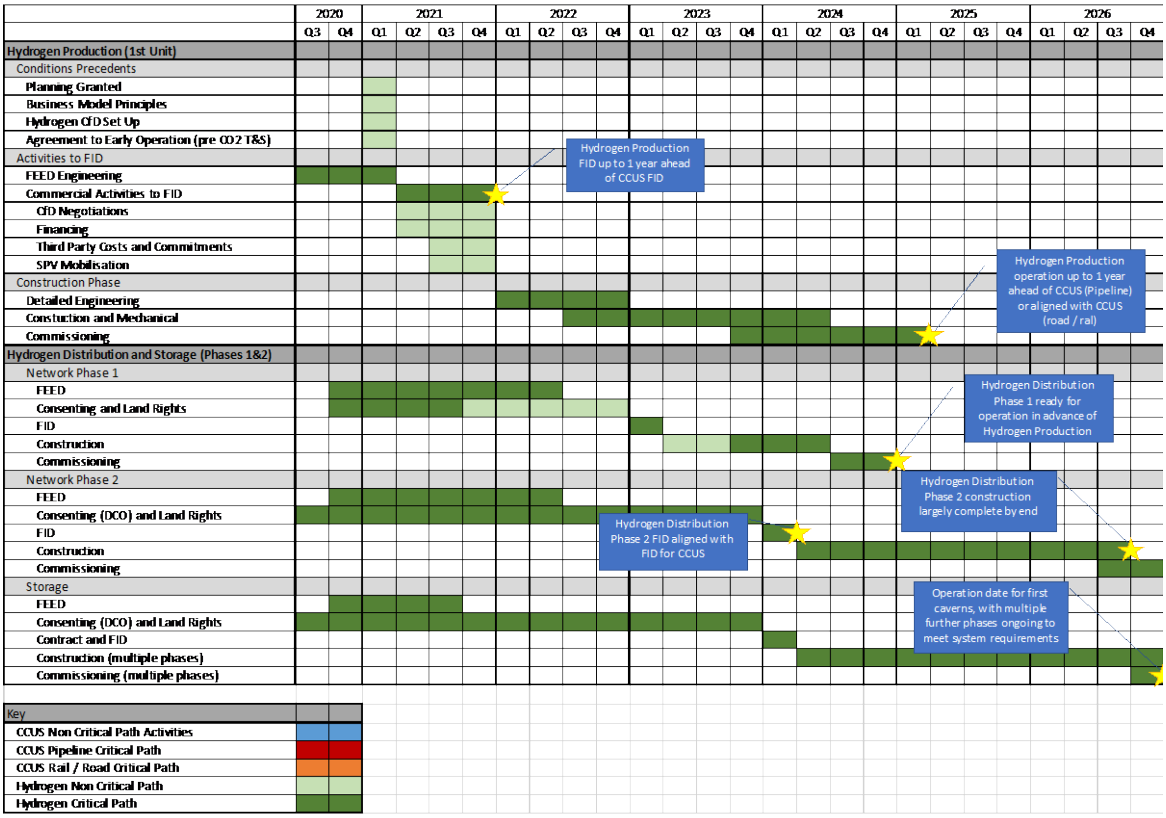


Figure 6.4: HyNet Delivery Programme - Level 1 Schedule Hydrogen



7.0 RISKS

7.1 Approach

The HyNet project has been developed specifically to minimise risk. The major risks inherent in a CCUS project which drive cost and schedule outcomes are primarily, but certainly not wholly, related to offshore elements of the project where investigation and mitigation costs are significantly higher than those onshore.

The HyNet project uses depleted gas reservoirs in Liverpool Bay. These reservoirs are currently operational and are very well characterised, and, with a robust O&M regime in place, the existing asset status is well understood. This therefore minimises much of the complex and expensive reservoir characterisation work required on other projects to provide storage confidence.

The risk profile for the project, on a balanced outcome basis (i.e. probability * consequence), is therefore dominated by programme and commercial risks, rather than technical. While technical risks clearly do exist, these are considered to be within normal industry acceptable limits, and can be managed through normal major project execution methodologies. The programme and commercial risk profile is largely driven by the HMG support regime and is, therefore, somewhat outside the ability of the project to manage directly.

The following sections provide narrative overviews of the main project risk areas through to FID and construction, although it focuses on the period to FID. A full risk register can be found in A.3.0. At this point no quantitative assessment of overall project risk has been undertaken via a Monte Carlo, or other such method. This will be undertaken during the FEED phase of the programme.

7.2 Technical

At an overall project level, technical risks are considered to be relatively minor. While there are a significant number of engineering issues to be addressed, the project uses existing technologies and supply chains. Key technical risks include:

- Ensuring CO_2 quality at the capture plant meets system requirements. This is mitigated through a sensitivity study undertaken in the pre-FEED phase to determine optimal pipeline CO_2 compositional specification, and then ensuring that this specification is part of the baseline Basis of Design for all capture plants.
- Determining optimal system configuration development for expansion. The HyNet project is relatively unusual when considered alongside other CCUS developments in that it largely makes use of existing assets. As such, this pre-

determines certain aspects of the system configuration, such as pipeline lengths, sizes and well configurations. As the system expands, both in terms of flow rate and stored volume of CO_2, decisions need to be taken about when and how to expand the system to mitigate flow and storage constraints. This is mitigated through the development of a range of system configurations in pre-FEED and further work, currently underway, to determine the preferred configuration concept prior to commencement of FEED.

- Securing necessary confidence in field storage suitability. This is mitigated in large part through the recent operational history of the facility, coupled with the engineering work programme to secure a storage licence and permit.
- Technical Standards for hydrogen pipelines are not available today and the safety regulatory structure for CO_2 pipelines remains undeveloped. However by way of mitigation, the approach taken on previous CCUS projects such as White Rose will be adopted on HyNet, which is to adopt a safety case driven approach with early regulatory engagement. Hydrogen standards are in development with IGEM and specialist consultants through a programme in partnership with the Gas Distribution Networks.

7.3 Programme

The dominant factor in the project execution programme is securing consent for both CO_2 and hydrogen pipelines. Both pipelines will be deemed to be nationally significant infrastructure and, as such, require Development Consent Orders (DCOs) to be granted. While the DCO process is lengthy and thorough, consent is likely to be granted if due process is followed, particularly as HyNet is directly aligned with national policy. Key planning risks include:

- Land access for surveys, although the DCO provide compulsory access rights if required. This will be mitigated by early stakeholder engagement ahead of full DCO activity launch, coupled with development of a comprehensive land strategy.
- Land purchase for development, although the DCO provides compulsory purchase rights if required. This will be mitigated by development of a land strategy, which will be designed to avoid compulsory purchase where possible. The route, as currently determined, does not require purchase and demolition of any existing buildings and runs either in existing roadways or through countryside, which can be returned to original use post construction.
- Survey results requiring pipeline re-routing, which leads to cost and schedule impacts, although this is mitigated in part by the extensive desktop work to date to inform routing choices.
- Stakeholder objections, mitigated by ensuring that the project is directly aligned with local and national climate change policies.

More broadly, the potential programme delay caused by issues in the DCO process as set out above, is mitigated by the parallel development of the interim road / rail transport solution, as described in Section 2.5.2.

7.4 Policy

HyNet cannot be constructed without a policy framework in place from HMG which provides a return on investment for developers of the capture plants and the pipelines. This policy framework is being developed by Government, but remains the single biggest risk area for the project. Key policy risks include:

- Lack of timely development of investable policy instruments for hydrogen production, industrial carbon capture, and carbon dioxide transport and storage project elements. This is mitigated through the formation of the CCUS Expert Working Groups by BEIS, and confirmation of the timeline to publish policy frameworks at a Heads of Terms (HoT) level by the end of 2020. Furthermore, there is clear political will at Ministerial level for models to be developed in this time period. In the absence of such models, securing investment for FEED will remain challenging. Models will need to be translated into full executable contracts in time for FID.
- Lack of clarity on risk allocation and ownership between various actors in the CCUS full-chain, mitigated by the same policy framework activity as set out above.

7.5 Commercial

The commercial structure for HyNet is complex, as there are multiple development projects, all of which are technically and commercially inter-related. For example, the hydrogen distribution network is reliant on the hydrogen production plant, but these are being developed by separate delivery consortia, under different commercial frameworks (the hydrogen distribution network is likely to be a regulated asset, and the hydrogen production network is likely to be a private, merchant asset, operating under a CfD structure). Similarly, the industrial capture plants are being developed through a separate process to the CO_2 transport and storage system, but each is commercially reliant on the other. Key commercial risks include:

- Development of commercial agreements between actors in the CCUS and hydrogen value chain, to include, but not be limited to;
    - Industrial capture plant and CO_2 transport and storage system
    - Hydrogen production plant and CO_2 transport and storage system
    - Hydrogen production plant and hydrogen distribution network
    - Hydrogen distribution network and hydrogen storage
    - Hydrogen production plant and hydrogen users

- Development of commercial agreements between actors in the CCUS and hydrogen value chains and HMG (or HMG backed counterparty, such as the Low Carbon Contracts Company (LCCC)). This will be mitigated by the development of the HoT for the business models, which will provide the framework for these commercial agreements.

8.0 LESSONS LEARNT

This section sets out lessons learnt on the project which may be applicable to other projects at a similar stage of development. Inevitably, when looking at a project with the benefit of hindsight, a range of improvements in both execution and outcome can be identified – however, the majority of those identified relate to additional work of benefit that could have been undertaken at this stage in the project, but budget limitations precluded their delivery.

8.1 Project Execution

Success Criteria: At the start of the project a clear identification of project success criteria should have been established, both at a whole project and work-package specific level. Ongoing project management could then have assessed progress against these success criteria. In reality, it was clear to all project participants that success was determined by the establishing of technical viability of a full chain CCS project, and this was achieved. There are a range of other success criteria that would have been helpful to determine at an early stage, such as identifying regulatory barriers, identifying socio-economic benefits etc.

Change Management: A change management process was utilised on the project for more substantive changes of technical definition. Nonetheless, a wider change management process could have been utilised to manage changes of scope, programme and budget to provide tighter project controls.

Risk Management: A robust risk assessment has been undertaken in the concluding phase of the project that has formed the basis of the project risk assessment moving into FEED. While this was a useful process and yielded a valuable outcome, intermittent risk assessments throughout the project would have been helpful to consider how risks emerged and were mitigated through the pre-FEED process.

Document Management: Documents were version controlled and formally released as part of milestones. However, the process of final check and review with partner organisations, particularly for Key Knowledge Deliverables (KKDs) that are issued into the public domain, has proved more time-consuming than originally expected. A setting out of document review timescales from the outset would have helped mitigate this issue.

Stakeholder Management: The focus of the pre-FEED activity was a technical, desktop study to determine the feasibility of the project and outline cost estimates. The scope did not extend to stakeholder engagement. However, given further budget, early stage engagement with key stakeholders, such as local councils and Members of Parliamenet would have been beneficial. This activity has gathered pace in the period between the end of pre-FEED and the commencement of FEED, but the benefits of early stakeholder engagement cannot be over-emphasised, not least as the majority of the stakeholders subsequently engaged with have become vocal supporters for the project, which is helpful in securing further development funding.

8.2 Technical

Pipeline Route Appraisal Methodology: We assessed a wide range of pipeline route options, which will prove beneficial during the DCO consultation process as we can demonstrate that a number of routes have been considered. However, we did not set out a clear set of ranking criteria at the commencement of the routing assessment and only considered this at the end of the process. A clear set of ranking criteria at the commencement of the process would potentially have yielded a more objective output. Since the pre-FEED study we have commenced the DCO activity, and this has involved setting a wide range of ranking criteria and re-assessing all routes against these.

Refinery Pre-FEED Clarity of Objectives: There was not absolute clarity of objectives across all parties at the commencement of the pre-FEED on the Refinery, resulting in a mismatch of expectations around the range of solvents considered. The end result of the work package was a valuable piece of work, setting out that a post-combustion capture unit could be engineered into the existing space envelope within the refinery and that the captured CO2 could meet the required compositional specification for the pipeline. However, this was undertaken only against a generic solvent, as budgetary constraints limited the ability to engage with proprietary solvent vendors, and a subsequent round of pre-FEED, focused on solvent selection, will now be undertaken prior to FEED commencement.

Decisions Register: A number of significant decisions were taken relatively early in the project on technical issues such as pipeline sizing and overall system configuration. These decisions were arrived at through assessments of a range of operational assessments and workshops, but records of the basis of the decisions were not kept as clearly as they could have been. This has led to decisions needing to be re-visited at the start of the FEED activity – all the major decisions have been upheld, but time and effort could have been saved by an improved decision register at the early stage of the pre-FEED process.

8.3 Commercial

Cost Model: The project cost model was only constructed at the end of pre-FEED, at which point it was recognised that different work packages had used different assumptions on areas such as contingency, deployment timescales etc in their individual costings. This led to a considerable amount of reconciliation activity in the cost model to generate a cohesive outcome. Developing the outline of the cost model at the start of the project along with estimate criteria, would have made the development of the final cost model an easier process.

Future Commercial Relationships: While the business models (and hence the risk allocations) for CCS / Hydrogen deployment are yet to be finalised by BEIS, the project had the opportunity to start to develop commercial relationships between parties – for example, a Heads of Terms between a capture plant and the transport and storage company. This would clearly need to have been further evolved during subsequent project phases, but would have helped provide clarity on issues such as battery limits and metering. Future projects in a similar phase should look to develop outline commercial relationships in parallel with developing technical solutions.

9.0 ACKNOWLEDGEMENTS

We would like to thank all the individuals and organisations who have participated in this project. Everyone involved in the project has demonstrated great flexibility and sense of purpose towards the wider ambition of decarbonisation at scale. Early stages of project development are characterised by tight budgets and significant ambiguity in project definition – HyNet pre-FEED has had both in spades and yet our partners, subcontractors and staff have worked together to create a project of real potential to both the region and the nation. Everyone should be proud of what they have achieved.

Our particular thanks to the following organisations.

Partners

- Progressive Energy
- Essar Oil (UK) Limited
- CF Fertilisers UK Limited
- Peel L&P Environmental Limited
- University of Chester
- Cadent Gas Limited

Collaborators

- Eni

Subcontractors

- Burges Salmon
- Fisher German Priestner
- Pace Flow Assurance
- RSK
- Saith
- SNC Lavalin
- Turley
- Wood

10.0 ACRONYMS

AACE	American Association of Cost Engineers
ABC	Activity Based Costing
AGI	Above Ground Installation
ALARP	As Low As Reasonably Practicable
ATR	Autothermal Reforming
BBL	Barrel
BECCS	Bio-Energy Carbon Capture & Storage
BEIS	Department for Business, Energy and Industrial Strategy
BF	Blast Furnace
BFD	Block Flow Diagram
BHP	Bottom Hole Pressure
BOE	Barrel of Oil Equivalent
Capex	Capital Cost
CCC	Committee on Climate Change
CCU	Catalytic Cracker Unit
CCUS	Carbon Capture Utilisation and Storage
CDCU	Carbon Dioxide Capture Unit
CfD	Contract for Difference
CHP	Combined Heat and Power
COMAH	Control of Major Accident Hazards
CRA	Corrosion Resistant Alloy
CRoW	Countryside and Rights of Way Act 2000
CQY	Connah's Quay
DCLG	Department for Communities and Local Government
DCO	Development Consent Order
Devex	Development Cost
EIA	Environmental Impact Assessment
EPC	Engineering, Procurement and Construction
EoS	Equation of State
ES	Environmental Statement
ESD	Emergency Shutdown
FEED	Front End Engineering Design
FGD	Flue Gas Desulphurisation
FID	Final Investment Decision
GLWS	Gowy Local Wildlife Site
HMG	Her Majesty's Government
HoT	Heads of Terms
HX	Heat Exchanger
IDC	Industrial Decarbonisation Challenge
IGEM	Institution of Gas Engineers and Managers
JM	Johnson Matthey
LBA	Liverpool Bay
LCCC	Low Carbon Contracts Company

LCH	Low Carbon Hydrogen
MAHP	Major Accident Hazard Pipeline
MAOP	Maximum Allowable Operating Pressure
MDRT	Measured Depth from Rotary Table
MEA	Mono-ethanolamine
MOD	Ministry of Defence
NIA	Network Innovation Allowance
NPPF	National Planning Policy Framework
NPS	National Policy Statement
NSIP	Nationally Significant Infrastructure Project
O&M	Operations and Maintenance
OGA	Oil and Gas Authority
OHX	Overhead Cable Crossing
Opex	Operating Costs
P&A	Plugging and Abandonment
P&ID	Piping and Instrumentation Diagram
PADHI	Planning Advice for Developments near Hazardous Installations
PEIR	Preliminary Environmental Information Report
PIG	Pipeline Inspection Gauge
PILs	Potential People with Interest in the Land
PINS	Planning Inspectorate
PoA	Point of Ayr
PPW	Planning Policy Wales
Pre-FEED	Pre Front End Engineering Design
RAB	Regulated Asset Base
RAV	Regulated Asset Value
RF	Recovery Factor
RIIO (GD)	Revenue = Incentives + Innovation + Outputs (Gas Distribution)
ROG	Refinery Off Gas
SCR	Selective Catalytic Reduction
SCM	Subsea Control Module
SMR	Steam Methane Reforming
SOCC	Statement of Community Consultation
SOS	Secretary of State
SSVM	Subsea Valve Manifold
T&S	Transport and Storage
T&SCo	Transport and Storage Company
TVDSS	True Vertical Depth Subsea
TVDRT	True Vertical Depth Rotary Table
UKRI	UK Research and Innovation

WACC	Weighted Average Cost of Capital

APPENDICES

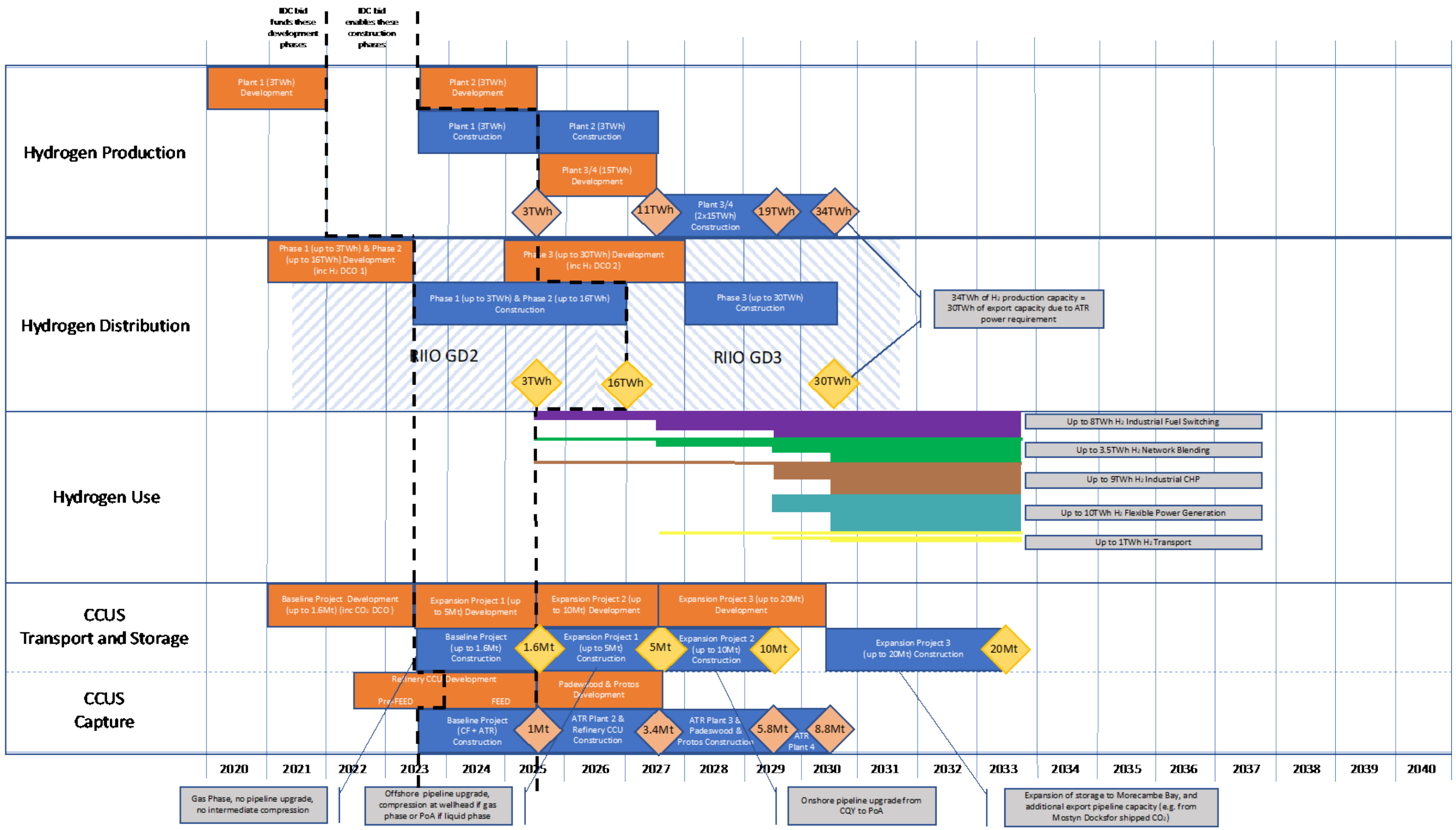
A.1.0 MASTER DOCUMENT LIST

Document Title	Document Number	Revision	Date	Responsible
Work Package 1 - Integration				
Basis of Design	P1131.WP1.04.001	1.0	May 2019	PEL
Project Management Plan	P1131.WP1.04.002	1.0	May 2019	PEL
Mass Flow Rate Technical Note	P1131.WP1.04.003	1.0	February 2019	PEL
Mass Flow Rate Scenarios	P1131.WP1.04.004	1.0	May 2019	PEL
Eni FEED Planning Technical Note	P1131.WP1.04.005	1.0	December 2019	PEL
Pre-FEED Final Report	P1131.WP1.04.006	1.0	May 2020	PEL
Work Package 2 – Refinery Capture				
Basis of Design	17202116-8111-RP-001	A1	July 2019	Wood
Options Report	17202116-8111-RP-002	01	August 2019	Wood
Concept Study Report	720063-8820-RP-0003	F2	March 2020	Wood
Work Package 3 – Fertiliser Plant Capture				
Basis of Design	P1131.WP3.04.001	1.0	July 2019	PEL
Pre-FEED Report	P1131.WP3.04.002	1.0	December 2019	PEL
Work Package 4 – Onshore Transport				
Carbon Dioxide Pipeline Pre-FEED Study Basis of Design	1189-PROG-ME-SPC-001	1	May 2019	Saith
Carbon Dioxide Pipeline Design Study Report	1189-PROG-ME-RPT	7	February 2020	Saith
Environmental Constraints Report	662211	00	September 2019	RSK
DRAFT Environmental Scoping Report	662211	02	May 2020	RSK

HyNet Road Rail CO_2 Transport Feasibility Study Basis of Design	5189899-PM-BOD-001	P02	July 2019	SNC Lavalin
HyNet Road Rail CO_2 Transport Feasibility Study Optioneering Study Report	5189899-PM-REP-007	A01	October 2019	SNC Lavalin
HyNet Road Rail CO_2 Transport Feasibility Study Final Report	5189899-PM-REP-013	A01	December 2019	SNC Lavalin
HyNet Road Rail CO_2 Transport Feasibility Study – Rough CF Fertilisers Study (Road Option)	805460-0001-I-40-TNT-0002	A2	March 2020	SNC Lavalin
Work Package 5 – Flow Assurance				
Operation, Control and Metering Philosophy	P1131.WP5.04.001	1.0	August 2019	PEL
Pre-FEED Flow Assurance Design Premise	HYN01-01	04	April 2020	Pace
Flow Assurance Operational Scenarios	HYN01-02	02	November 2019	Pace
Flow Assurance Report	HYN01-03	02	April 2020	Pace
Work Package 6 – Offshore Transport and Storage				
Liverpool Bay Carbon Capture and Storage Project Pre-Feasibility Report	1.1	1	May 2020	Eni
LBA CCS Project Integrated Reservoir Study	1.2.1	00	March 2020	Eni
Liverpool Bay CCS Project Basecase Scenario Simulation	1.2.2	00	March 2020	Eni
Liverpool Bay Carbon Capture and Storage Project Flow Assurance Study	1.3.1	00	April 2020	Eni

Liverpool Bay Carbon Capture and Storage Project Facilities Description and Sizing	1.3.2	00	April 2020	Eni
Liverpool Bay Area Assets Life Extension Studies	1.3.3	1	February 2019	Eni
LBA CCS Subsea Valve Manifold Scenario Technical Note	1.3.4	00	April 2020	Eni
Liverpool Bay CCS Project Flow Assurance Presentation	1.3.5	00	March 2020	Eni
Pre-FEED for HyNet Project: Flow Assurance Study for Injection Wells	1.3.6	00	February 2020	Eni
LBA CCUS Wells AR1 Screening Study	1.3.7	00	April 2020	Eni
Work Package 7 – Land and Planning				
HyNet North West Phase 1: Consenting and Land Strategy	N/A	N/A	April 2020	Turley

A.2.0 HYNET LEVEL 0 DEVELOPMENT PLAN



A.3.0 PROJECT RISK REGISTER

	Consequence				
Probability	Very Low	Low	Medium	High	Very High
Very Low					
Low					
Medium					
High					
Very High					

Consequence	Cost (Capex and / or Opex)	Schedule	H&S
Very Low	<0.1%	0 to 5 days	Recordable injury but return to work the same day
Low	0.1% to 1%	5 to 10 days	Recordable injury requiring medical attention but returning to work the same day
Medium	1% to 5%	10 to 20 days	Recordble injury requiring reassignment of duties due to medical attention
High	5% to 10%	20 to 40 days	Lost time injury
Very High	>10%	> 40 days	Fatality

Probability	
Very Low	<10%
Low	10% to 30%
Medium	30% to 50%
High	50% to 70%
Very High	70% to 80%

			Pre-Mitigation Assessment			Post-Mitigation Assessment			
Category	Risk Title / Outcome	Risk Description	Consequence	Probability	Outcome	Consequence	Probability	Outcome	Mitigation
Technical (1)	CO2 specification	Capture plants are unable to meet pipeline CO2 specification, or are only able to do so at significant Capex penalty	Medium	Medium		Medium	Very Low		Sensitiity assessment undertaken during pre-FEED flow assurance work has provided an optimised CO2 specification which capture plants can meet
	CO2 release modelling and assessment	No dispersion modelling, inventory calculations or hazard range assessments have been conducted in pre-FEED to determine the requirement for intermediate block valves along the pipeline route. This may pose a risk to planning if further land is required for block valve locations or pipeline route amendments.	High	Medium		High	Low		CO2 dispersion and inventory modelling will be undertaken at an early stage of FEED to mitigate design concerns and set a baseline for FEED / consenting. Options will be considered for accelerating this work ahead of FEED commencement.
	System configuration for expansion	Agreement on system expansion configuration (particularly location and type of compression) is not optimised	High	Low		Medium	Very Low		A range of configuration options are being assessed during pre-FEED extension work, with a preferred concept to be selected ahead of commencement of FEED.
	Environmental constraints - outlet temperatures	System operating temperatures are critical in designing the optimal system configuration, and these may be limited by environmental considerations, particularly around the compressor outlet temperature at Point of Ayr.	High	Medium		High	Low		There is no established 'rule book' for outlet temperatures for pipeline landfalls, and so a project specific environmental assessment will be required. Two-phase flow will allow lower temperatures to be used in the pipeline, but two-phase flow presents its own project risks. This will be further evaluated at commencement of FEED.
	Field storage suitability	Storage fields found to be unsuitable for storage, or only able to store lower volumes than expected	Very High	Low		Very High	Very Low		Storage fields are well-characterised as they are currently operated as natural gas production reservoirs. Further reservoir modelling has been undertaken during pre-FEED which confirms storage suitability. Storage licence and permit process will further assess storage suitability to the satisfaction of the regulators.
	Asset repurposing	There is a risk that existing assets (primarily pipelines and wells) are not fit for purpose for CO2, requiring asset replacement or significant additional remediation.	High	Low		High	Very Low		Work has been undertaken to review existing assets, and no showstoppers have been identified. However, this will need to be further examined during FEED. It is expected that for pipelines, mitigation can take the form of replacing certain sections if required (none identified to date), lining, replacement of corrosion protection etc. For wells, a risk based approach is being undertaken to asset re-use, and a range of incremental interventions / options is available at increasing cost.
	Onshore dense phase	The project has sought to minimise risk from CO2 pipeline failure by designing the onshore section of pipeline to operate in gas phase throughout the project lifecycle. However, there is a short section of onshore pipeline from the proposed Point of Ayr compressor station to the landfall which will operate in dense phase which will require appropriate design and planning consideration.	Medium	Low		Medium	Very Low		The MAOP of the section of onshore pipeline from Point of Ayr to the landfall has sufficient MAOP to operate in dense phase, and periodic maintenance inspections indicate that it is in good condition. From an engineering perspective, the risk of operating in dense phase is low, but permitting may present a risk. Early engagement with the HSE during FEED and proximity assessments will help mitigate this risk.
	Technical standards	Technical standards are not yet developed for hydrogen pipelines, and, when they are developed they may conflict with decisions taken on HyNet, requiring re-work.	High	Medium		Medium	Low		Early engagement with regulators is underway (particularly EA and HSE), but regulatory uncertainty remains. Following engineering best practice in the development of a safety case regime will be the best approach in the absence of a confirmed set of techical standards and regulatory guidance.
	Refinery capture plant - technology selection	Standard amine capture technologies require significant space envelope and energy use. Alternative, proprietary solvents are being considered which may improve performance, but at increased technical risk.	High	High		Medium	Medium		A standard MEA solution has been reviewed during pre-FEED which has given an upper bound space and energy use envelope. A further technology selection project phase will be undertaken prior to commencing FEED, which will optimise technology selection

			Pre-Mitigation Assessment			Post-Mitigation Assessment			
Category	Risk Title / Outcome	Risk Description	Consequence	Probability	Outcome	Consequence	Probability	Outcome	Mitigation
Technical (2)	Metering specification	Metering requirements are currently not clear and may evolve to require significant capex and ongoing opex to meet	High	High		Medium	Medium		Space envelopes and cost estimates have been included in the pre-FEED work but early work on metering specifications will be required at the commencement of FEED.
	Measurement, Monitoring and Verification (MMV)	MMV requirements are currently not clear and may evolve to require significant capex and ongoing opex to meet	High	High		Medium	Medium		MMV strategy will be developed in conjunction with the regulator during the storage licence and permit process. Cost estimates have been made.
	Emergency shutdown and venting	Safety assessment work during FEED may identify shutdown / failure cases that require significant inventory to vent, therefore requiring additional block valve locations and / or pipeline re-routing.	Very High	Medium		Medium	Low		The onshore pipeline has been developed to operate in gas phase, therefore reducing the CO2 inventory to be vented in an emergency. Dispersion modelling will clarify venting requirements during FEED.
	Utilities connections	Numerous elements of the project require utility connections - these may require network reinforcement, giving rise to programme delays.	Medium	Medium		Medium	Low		Major utility connection requets, particularly for hydrogen production, are underway. Further utility connection requirements will be programmed in at an early stage of FEED.
	Battery limits	Lack of clarity of battery limits and interface definition may give rise to re-work, or work scope being missed between partners.	High	Medium		Medium	Low		Battery limits have been defined for FEED planning purposes. At the commencement of FEED, clear interface documentation will be generated, and formal interfaces will be managed by the PMO subcontractor.
	Planning approval	A project decision is required as to whether repurposing of existing onshore assets should be included as part of the newbuild pipeline DCO. Not including the re-purposed assets presents project risk in terms of the ability to compulsory purchase land for pipeline amendments. Including the pipeline risks complicating, and hence delaying, the DCO.	High	Medium		High	Low		Legal advice has been obtained which indicates that inclusion of the onshore pipeline in the DCO is not required from a planning perspective, but it does provide the project with powers which will support its real-estate strategy. Further advice will be obtained and a decision made before this becomes critical path.
	Regulatory approval	Numerous regulators need to be engaged with to ensure the success of the HyNet project, including HSE and EA. Regulatory requirements are not clear in these areas, particularly for emerging technologies, and regulatory approval may require re-work, and hence programme impact.	Very High	High		High	Medium		Early engagement with regulators is underway (particularly EA and HSE)
Health and Safety	Operational safety incident during FEED	Operational safety risks are considered minor during FEED, but there is potential for an operational safety incident during normal office-based work, or, during survey work.	High	Low		High	Very Low		Only contractors with demonstrable safety management systems will be utilised, and appropriate risk assessments will be put in place ahead of survey work commencing.
	Operational safety incident during Construction	Operational safety risks are considered high during construction due to the complexity of construction required across multiple sites from multiple contractors.	High	Medium		High	Low		Only contractors with demonstrable safety management systems will be utilised, and appropriate risk assessments will be put in place ahead of construction work commencing under appropriate CDM regulations.
	Process safety	Process safety risks may not be identified during the design phase and hence mitigated, presenting a risk into construction and operation.	Very High	Medium		Very High	Very Low		All aspects of the design will be subject to HAZID / HAZOP studies to identify and mitigate process safety risks.
	COMAH	COMAH assessments may identify elements of the project as Top Tier sites, requiring site design rework	Medium	Medium		Medium	Low		COMAH assessment work is underway at an early stage of the HSP FEED design process, allowing site re-working if necessary.
	Safety case	It is expected that the onshore pipeline and offshore facilities will operate under safety cases to be approved by the relevant regulator. Lack of clarity on the structure / content of these safety cases may require significant re-work.	High	Medium		Medium	Low		Safety cases from previous pipeline projects (e.g. White Rose) will be used as exemplars.

Category	Risk Title / Outcome	Risk Description	Pre-Mitigation Assessment			Post-Mitigation Assessment			Mitigation
			Consequence	Probability	Outcome	Consequence	Probability	Outcome	
Programme	Land Access for pipeline surveys	Land access for pipeline surveys may be slow or expensive to negotiate, therefore impacting programme.	Medium	Medium		Medium	Low		A land strategy will be determined at an early stage in the FEED and consentig phase which is common across the project. If survey access is not forthcoming, ecological survey work form public vantage points will be considered, and, if necessary, compulsory access rights will be pursued through the DCO process.
	COVID-19 limits land access for surveys	Ongoing COVID-19 restructions may limit access to private land for surveys	Medium	Low		Low	Very Low		Appropriate social distancing measures will be observed.
	Land purchase / easement for construction	Land purchase or easement negotiation may lead to programme delays and cost increases	High	Medium		Medium	Medium		A land strategy will be determined, which will provide an upfront payment for survey access and an option agreement for future construction access and easements. Experienced land agents will be employed to undertake this negotiation, with appropriate legal support.
	Survey results require rework, particularly pipeline re-routing	Survey results, either ground investigation, topographical or ecology may require pipeline re-routing	High	Low		High	Very Low		Extensive desktop work has been undertaken prior to survey commencement to mitigate many risks, but ecological habitats remain an area of risk and may result in pipeline re-routing. However, a wide pipeline corridor has been included in the FEED phase to allow for evolution of the pipeline routing.
	Stakeholder concerns	Stakeholders, particularly local communities may raise concerns over the HyNet project	Very High	Medium		Very High	Low		Stakeholder consultation will be inherent in the HyNet development strategy, and this will commence ahead of survey work. Linking the HyNet project to the wider regional and national decarbonisation agenda will help mitigate this risk.
	Pipeline ecology surveys	Pipeline ecology surveys are critical path in the DCO application and need to be undertaken across a 12 month period. If any critical seasonal surveys are missed, a 12 month programme delay is encountered.	Very High	Medium		Very High	Low		Early funding is being sought for DCO critical path ecology surveys to mitigate this risk.
	DCO judicial review	The DCO decision may be subject to a Judicial Review, leading to programme delays	Medium	Medium		Medium	Medium		A judicial review period is included in the DCO schedule
	Planning applications under Town and Country Planning Act	Numerous elements of the project will require planning permission under Town and Country Planning. There is a risk that the complexity and scale of these applications may give rise to objections and delays.	High	Medium		High	Low		Early engagement with the local planning authorities has already commenced, setting out the full HyNet context and the likely planning requirements.
	Construction supply chain	With multiple clusters under development there is a risk that insufficient skilled construction resource is available to meet the construction schedule.	High	Medium		High	Low		ECITB (Engineering Construction Industry Training Board) has recently completed a review of skills availability for the energy transition and concluded that this is a risk at a national level, and therefore beyond the ability of HyNet to manage directly. However, early engagement of the industry is underway through the FEED tendering process.
	Construction scheduling	Construction scheduling needs to work around appropriate ecological windows, which may result in construction schedules being extended.	High	Low		High	Very Low		Early stage construction schedules are under development by pipeline FEED contractors and will be further refined at an early stage of FEED in conjunction with the consenting contractor
	HyNet unsuccessful in IDC Phase 2	HyNet may be unsuccessful in its Phase 2 IDC bid, resulting in a signficant programme delay.	Very High	Medium		Very High	Low		HyNet has been succesful in IDC Phase 1, and therefore stands a good chance of progressing through Phase 2 - however, in the event of non-selection, funding will be sought from IETF / CCUS Infrastructure Fund and other such vehicles.

			Pre-Mitigation Assessment			Post-Mitigation Assessment			
Category	Risk Title / Outcome	Risk Description	Consequence	Probability	Outcome	Consequence	Probability	Outcome	Mitigation
Commercial	Partners unable to meet IDC Phase 2 match funding requirements	IDC Phase 2 requires partners to provide match funding. This match funding may not be forthcoming due to cashflow constraints as a result of COVID-19.	High	Medium		High	Medium		Reduced levels of match-funding may be mitigated through additional contributions from other partners, or alternatively, state aid rules may be amended under the COVID-19 temporary framework.
	Development of Commercial Agreements between actors in HyNet full chain	Reaching FID will require appropriate commercial agreements, with suitable risk apportionment, to be agreed between all actors in the chain to ensure cross-chain risk is appropriately managed. There is a risk that developing these agreements will lead to delay to FID and / or cost increases.	Very High	Medium		Very High	Low		HyNet partners are members of the BEIS CCUS Business Model expert working groups and will use this forum to ensure appropriate business models, with suitable risk allocation, are put in place to allow commercial agreements to progress between partners.
	Development of Commercial Agreements between actors in HyNet full chain and HMG counterparties	Reaching FID will require appropriate commercial agreements to be in place with HMG counterparties (such as LCCC) and regulators (such as Ofgem) to ensure that the investment is 'bankable'	Very High	Medium		Very High	Low		As above
	Development of land access / use Agreements	Land access, particularly for pipeline survey and construction will require liaison and agreements to be reached with individual landowners. There is a risk that this process may delay the project, or lead to significant cost increases.	Very High	Medium		Very High	Low		See 'Land Access' risk above
	Offtake and feedstock contracts	Offtake and feedstock contracts will be required for a number of the elements of HyNet and which will underpin its bankability (subject to appropriate policy frameworks being in place to manage, for example, demand risk). Delays in securing such contracts will delay FID.	High	Medium		High	Low		Offtake risk for HSP will largely be managed through the proposed business model framework. Other contracts, such as natural gas supply, are considered to be industry standard and low risk.
	Commercial failure of partner	HyNet is developed through a consortium of major industrial partners. Commercial failure of any one of these partners, which is a heightened risk due to COVID-19, will pose a significant threat to the delivery of the project.	Very High	Very Low		Very High	Very Low		HyNet has multiple capture partners, so the failure of any individual capture partner is not terminal for the wider project.
Policy	Policy Framework for all actors in HyNet Full Chain	HyNet is not financially viable without an appropriate policy framework which gives investors the opportunity to earn a return. Such a policy framework needs to be in place ahead of FID, and, ideally, to secure third party investment for FEED. Failure to put in place such a framework will delay HyNet delivery.	Very High	High		Very High	Medium		See 'Development of Commercial Agreements' risk above
	Risk Allocation between actors in HyNet Full Chain	The Policy Framework needs to clearly identify and allocate risks between parties in the full chain project and HMG (or its representatives). Risk allocation is key to low cost CCUS delivery and the contract structure for FID.	Very High	High		Very High	Medium		See 'Development of Commercial Agreements' risk above