HyNet – the Road to Net Zero

North West Cluster Plan

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EXECUTIVE SUMMARY

This report has particular importance due to its focus on the hydrogen and carbon capture, utilisation and storage (CCUS) infrastructure being developed by the HyNet North West (‘HyNet’) Project. HyNet has received funding of £33M under the parallel IDC ‘Deployment’ programme from UKRI and BEIS (which has been ‘matched’ by £39M of consortium partner funding), which will fund the engineering design and consenting of the project. HyNet has also been selected by BEIS as a priority Track 1 (Phase 1) project in its ‘Cluster Sequencing’ process. This means it will be fast-tracked to deployment, with bilateral negotiations on business models starting in early 2022. A final investment decision (FID) is then expected in 2023 and the first phase of HyNet to begin operation by the end of 2025.

HyNet was conceived by Progressive Energy in 2016 via support from Cadent under the Network Innovation Allowance (NIA) and built upon in a subsequent NIA-funded report published in June 2018.[1] The report builds upon the original project concept and includes hydrogen production, distribution and CCUS. Consistent with the objectives of the IDC, it focuses on decarbonising industry, but also includes analysis of hydrogen demand from power generators, buildings and vehicles. The purpose of the work is to demonstrate how HyNet will be deployed over several phases and expanded both geographically and deeper into all sectors of the North West economy.

E.1.1 Government business models for hydrogen and CCUS

Ultimately, deployment of hydrogen and CCUS in the North West will be determined by the speed of deployment of Government business models. Several different models are required across the chain of hydrogen and carbon capture, utilisation and storage (CCUS) infrastructure to suitably manage risk and enable investment. These include Contracts for Difference (CfDs) for hydrogen production and CO_2 capture from industry, along with potential regulated asset base (RAB) models for hydrogen and CO_2 transport and storage. Members of the HyNet consortium are engaged with BEIS in a variety of working groups to support further development and refining of these models.

E.1.2 Deployment and expansion of underpinning CCUS infrastructure

CO_2 transport and storage infrastructure underpins both the direct capture of CO_2 from industry and the production of low carbon hydrogen by the HyNet project. In 2016, the

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[1] Cadent & Progressive Energy (2018) *HyNet North West: From Vision to Reality,* June 2018 https://hynet.co.uk/app/uploads/2018/05/14368_CADENT_PROJECT_REPORT_AMENDED_v22105.pdf

North West was specifically chosen as the location to develop HyNet due to the offshore oil and gas fields which are coming to end of economic life and so can be repurposed for CO_2 storage and hence gives the opportunity to reuse many physical assets reducing the cost of deployment.

The HyNet project will repurpose a significant length of existing natural gas pipeline between Connah's Quay and Point of Ayr Gas Terminal, for CO_2 transport. The pipeline is fit-for-purpose to essentially 'reverse-flow' CO_2 offshore for safe storage, whereby natural gas was historically brough onshore. Operation of the repurposed pipeline will start at relatively low pressures, which will then be increased such that by 2030 it will be capable of transporting up to $10MtCO_2pa$.

Consequently, only a relatively small stretch of new pipeline (between Stanlow and Connah's Quay) is required. Eni formally launched the DCO consenting process for the CO_2 pipeline network for HyNet in June 2021 with a non-statutory public consultation process and at the time of writing is shortly to launch a statutory consultation.[2]

As the requirement for CO_2 increases further in the 2030s, further storage capacity in gas fields in Morecambe Bay is likely to be required, which may be driven by further CCUS-enabled hydrogen production at Barrow in Cumbria. The Morecambe North and Morecambe South fields potentially have combined capacity for in excess of 1 Billion tonnes of CO_2, which would represent 100 years storage at 10Mtpa or 50 years storage should CO_2 capture across the HyNet project increase to 20Mpta.

E.1.3 Deployment of CO_2 Capture from Industry

Alongside low carbon hydrogen, the HyNet project will decarbonise industry in the North West via direct capture of CO_2 from a number of very large emitters. In 2030, it is estimated that $1.7MtCO_2pa$ will be captured from core HyNet consortium sites at Stanlow, Padeswood and Ince.

A significant additional tonnage of CO_2 may also be captured from 'other' sites, largely energy from waste (EfW) facilities, in the region. BEIS is actively considering how to support BECCS projects and has allowed EfW sites to bid into Phase 2 of Cluster Sequencing under the Industrial Carbon Capture (ICC) business model, and hence their inclusion in this analysis. It is also important to acknowledge that around half of the CO_2 from EfW facilities will be 'biogenic' and so result in 'negative' emissions. This is such that the total potential CO_2 captured directly from industry has been modelled as 3.5Mtpa in 2030, rising to 4.9Mtpa in 2040.

E.1.4 Deployment and expansion of the hydrogen network

There are a range of considerations in terms of planning the HyNet hydrogen network, the most critical of these relate to pipeline sizing and routing. At the time of writing,

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[2] See https://www.hynethub.co.uk/index.php?contentid=14

HyNet consortium partner, Cadent, has just launched a Development Consent Order (DCO) process (for Nationally Significant Infrastructure) for the first major phase of network development to be deployed in 2027.[3] The DCO will give consent to the first 80-90km of network, which will connect a number of major gas users and also a small number of network blending locations. The DCO process is such that Cadent must consult on options prior to selecting a preferred route, design and capacity.

Ahead of the DCO submission, an initial phase of network deployment is planned in 2025, which will connect major gas users in close proximity to the hydrogen production plant at Stanlow. There will also be a subsequent DCO process, for a further 350km of pipeline, to connect sites in Liverpool, South Lancashire, North Wales and further into Manchester by 2030. It is likely that this DCO will commence prior to the end of the current DCO process.

During the 2030s, the hydrogen network may be extended to supply the residential sector subsequent to a potential positive future policy decision being made on the use of hydrogen to heat homes. This decision would mean full network conversion in many parts of the HyNet area. To a large extent, this is likely to shape which further industry sites, which might not otherwise be connected to the network due to their relative isolation, are able to receive a future supply of hydrogen. Prior to 2040, three further major phases of geographical expansion of HyNet are possible, some of which extend beyond the North West into the West Midlands and further into North Wales.

E.1.5 Deployment and expansion of hydrogen production

The vast majority of hydrogen production prior to 2030 will come from the Stanlow Hydrogen Production Hub. Vertex Hydrogen (a joint venture company between Progressive and Essar) completed a Front-End Engineering and Design (FEED) study in August 2021, in partnership with the UK technology provider, Johnson Matthey (JM), for the first train of Low Carbon Hydrogen (LCH™) production.[4] Also, in August 2021, the HyNet project launched a public consultation process to support a 'hybrid' application for planning consent for the plant, which relates to both the first train and subsequent trains.[5] The Stanlow Hub will be built in phases, starting with initial 3TWh/annum of production in 2025 increasing to over 30TWh/annum by 2030.

As the HyNet project expands beyond 2030, it is envisaged that further new CCUS-enabled low carbon hydrogen capacity will be constructed away from Stanlow. Any production site must have access to CO_2 storage and therefore Barrow, which is located in close proximity to the offshore gas fields at Morecambe Bay appears to be a sensible location for a future production hub.

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[3] See www.hynethydrogenpipeline.co.uk

[4] See www.vertexhydrogen.com

[5] See https://hynethub.co.uk/index.php?contentid=68

Prior to 2030 and increasingly in the 2030s, a range of sources of electrolytic hydrogen – derived from electrolysis using power generated from wind, solar and tidal – will supply hydrogen into the HyNet pipeline network. At present, the HyNet partners are engaged in several development opportunities for electrolytic hydrogen production in the North West.

E.1.6 Deployment and expansion of hydrogen storage

The Cheshire salt basin presents a natural choice of area for the development of significant geological hydrogen storage infrastructure in the HyNet area. It has been used to store natural gas in bulk for decades and so is very well characterised.

The majority of storage to 2030 is required for seasonal balancing, with both hydrogen blending and dispatchable (low load factor) power generation requiring significant amounts of hydrogen to be stored in the build-up to winter. This storage will also provide network resilience and in case of any planned or unplanned shutdown of low carbon hydrogen production and in the longer term will be essential to managing the potential production intermittency associated with wind, solar and particularly larger offshore wind farms.

In 2015, HyNet partner, Inovyn, received a DCO for the Keuper natural gas storage complex. Inovyn has not since sought to develop this site for natural gas, but instead is currently seeking to a non-material change to the DCO to enable Keuper to be used for hydrogen storage as part of HyNet. Our modelling for this study suggests that the total storage required for 2030 is up to 1.3TWh, which equates to approximately 18 caverns. However, this is indicative only and Inovyn is currently undertaking a more detailed analysis as part of a FEED study.

The North West is blessed with a range of further geological assets, and as HyNet expands outwards in the 2030s, there are further locations at which hydrogen might be stored underground, including the onshore Lancashire Salt Basin and offshore in the East Irish Sea either in salt caverns or in depleted oil and gas reservoirs. Consequently, a lack of underground storage will not function as a constraint to wider deployment of hydrogen as an energy vector.

E.1.7 Growth in hydrogen demand

The demand modelled for 2030 is based on the priority to supply hydrogen to decarbonise large industrial sites, which are exposed to the UK Emissions Trading Scheme (ETS). Analysis of demand from industry has been undertaken on a ‘bottom-up’, site-by-site basis, taking to consideration geography and engineering constraints, which draws upon PEL’s experience running large scale hydrogen-firing demonstrations at both NSG-Pilkington’s Greengate Works and Unilever’s Port Sunlight site.

To reflect uncertainty, we have modelled both ‘Bull’ (high) and ‘Bear’ (low) scenarios for industrial hydrogen demand. The results from this analysis show that demand might range from 12TWh/annum under the Bear Scenario to 20TWh/annum under the Bull Scenario, with this demand coming from a range of sectors, including aerospace, automotive, ceramics, chemicals, food & drink, glass, metals and pharmaceuticals. Combined with hydrogen demand from the power generation, domestic and transport sectors, total hydrogen demand in 2030 is forecast to be in the region of 22-29TWh/annum, which results in avoided CO_2 emissions of 4.1-5.5Mt/annum.

In 2040, as HyNet expands geographically, and there is ‘deeper’ supply to hydrogen in existing areas, our modelling for this study shows that industry demand could grow to 17TWh/annum under the Bear scenario up to 24TWh/annum under the Bull scenario. Importantly, during the 2030s, there is likely to be a significant increase in demand from the power and domestic sectors, as full conversion of the existing gas network enables switching of domestic heating to hydrogen. This could result in total hydrogen demand across all sectors of 56-74TWh/annum.

E.1.8 Emissions avoided by HyNet

In 2030, total avoided emissions delivered by HyNet across all sectors of the economy range from 6.9MtCO$_2$pa under the Bear hydrogen scenario to 8.1MtCO$_2$pa under the Bull hydrogen scenario. This level of abatement increases to 16.3MtCO$_2$pa to 17.4MtCO$_2$pa in 2040.

In relation to industry specifically, avoided emissions in 2030 range from 5.1MtCO$_2$pa (Bear) to 6.4MtCO$_2$pa (Bull), rising to between 7.3MtCO$_2$pa and 8.4MtCO$_2$pa in 2040. In the context of current total direct emissions from industry in the North West of around 10MtCO$_2$pa (including those from energy from waste facilities, which may soon be subject to some form of carbon pricing), this represents a significant and critical contribution to decarbonisation.

E.1.9 Key messages

The key messages from this study can be summarised as follows:

- HyNet will spearhead the creation of a low carbon North West Industrial Cluster by 2030. This will be based on the deployment of hydrogen production, distribution and storage, along with CCUS infrastructure, which will be in place across a most of Liverpool City Region, Great Manchester, Cheshire, Flintshire and parts of Lancashire;
- The North West Industrial Cluster will potentially involve decarbonisation of over 50 major manufacturing sites. This will involve the supply of up to 20TWhpa of low carbon hydrogen and, combined with direct capture of CO_2 from industry, will reduce emissions from industry by up to 6MtCO$_2$pa by 2030;
- In the context of current total direct (‘Scope 1’) emissions from industry in the North West of around 10MtCO$_2$pa (including those from energy from waste facilities, which may soon be subject to some form of carbon pricing), this represents a significant and critical contribution to decarbonisation;

- Via the supply of low carbon hydrogen, HyNet can also make a material contribution to decarbonisation of wider sectors of the economy, including power generation, transport and buildings by 2030. Demand from these sectors might be up to 9TWhpa in 2030, which would result in total demand of nearly 30TWh;
- 30TWhpa of hydrogen production is equivalent to around 4GW of continuous peak output. HyNet, therefore, has the potential to deliver around 80% of the Government's 5GW target for hydrogen production in 2030, which was published in the National Hydrogen Strategy in August 2021.[6]
- HyNet can also make a material contribution to meeting the UK's 5th Carbon Budget. Given the need to reduce emissions by 56MtCO_2pa between the UK's 4th (2023-2027) and 5th (2028-2032) Carbon Budgets, the 8MtCO_2pa of abatement delivered by HyNet in the North West in 2030 equates to around 16% of this improvement;
- This level of deployment, however, is subject to Government putting in place a set of long-term business models for hydrogen and CCUS against which upfront investment from the private sector can be justified. The progress on these business models is mixed, with significant work still to do in many areas to enable investment;
- During the 2030s, the HyNet infrastructure can be expanded into to wider parts of Wales, Lancashire, Cumbria and the West Midlands to help industry meet Net Zero by 2040. Whilst HyNet is focused initially on industry, it will also support Liverpool City Region and Greater Manchester in meeting city-wide Net Zero targets for all sectors, which are set for 2040 and 2038 respectively;
- There is a total of around 200Mt of potential CO_2 storage in the Liverpool Bay oil and gas fields and a further 1Bt in the Morecombe Bay gas fields (when these cease production). Along with the large underground salt fields in Cheshire, Lancashire and offshore in Morecombe Bay, which will be used for hydrogen storage, this means that neither CO_2 nor hydrogen storage are likely to limit the significant expansion of HyNet;
- The foundation of HyNet will be CCS-enabled hydrogen production, which will enable investment in the core hydrogen distribution infrastructure. At the same time, the deployment of electrolytic hydrogen, produced from renewables and nuclear energy is expected to grow, enabled by the option to connect to the HyNet network to reduce transportation costs; and

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[6] HM Government, *UK Hydrogen Strategy*, August 2021 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf

- Measures, such as industrial energy efficiency, onsite renewables and electrification will also be need to be deployed to help the region meet Net Zero in 2040. These areas are explored in wider studies undertaken by Equans in support of the North West Cluster Plan.[7]

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[7] Equans (2022) *Electrolytic Hydrogen Recommendations Report*, February 2022

CONTENTS

1.0 INTRODUCTION AND REPORT CONTEXT

1.1 Decarbonising Industry

The North West Cluster Plan is funded by UK Research and Investment (UKRI) and the Department for Business, Energy and Industrial Strategy (BEIS) under the Industrial Decarbonisation Challenge (IDC) programme. This Phase 2 study follows earlier work and reporting which was published by Net Zero North West (NZNW), in August 2020.[1]

This report represents one element of the plan, albeit one which has particular importance due to its focus on the hydrogen and carbon capture, utilisation and storage (CCUS) being developed by the HyNet North West (‘HyNet’) Project. HyNet has received funding of £33M under the parallel IDC ‘Deployment’ programme from UKRI and BEIS, which has been ‘matched’ by £39M of consortium partner funding. This combined £72M is being used to deliver engineering design and consenting of hydrogen and CCUS infrastructure towards the consortium making a final investment decision (FID) in 2023 and the first phase of HyNet beginning operation by the end of 2025.

To reach FID, HyNet must also be successful in the negotiated phase of the Government’s ‘Cluster Sequencing’ process, for which is has been selected as a priority Track 1 (Phase 1) cluster.[2] At the time of writing, bids are being prepared for ‘Phase 2’ of the Cluster Sequencing process, which focuses on carbon dioxide (CO_2) capture sites, which will supply CO_2 to the transport and storage infrastructure funded under Phase 1. The HyNet hydrogen production plant is one such site. Detailed commentary on the business models which HyNet will negotiate support under if it is selected as one of the 2-3 clusters, is provided in Section 3.0. These are particularly important, as they will facilitate long-term investment in the required hydrogen and CCUS infrastructure.

In June 2019, the Government set into law the need for the UK to meet ‘Net Zero’ carbon dioxide (CO_2) emissions by 2050.[3] In the North West the aim is to achieve Net Zero well before this date. Towards this goal, for example, the Greater Manchester Combined Authority (GMCA) has set a date of 2038 and Liverpool City Region Combined Authority (LCRCA) a date of 2040.

To decarbonise and meet Net Zero, Government has recognised, in its 2020 ’10-point Plan’ and Energy White Paper, that decarbonisation of industry will depend both on direct capture of CO_2 from fuel use in manufacturing processes and on switching fuel use to low carbon hydrogen.[4] [5] HyNet provides the infrastructure for both of these alternatives and this report sets out how they will support industrial decarbonisation in 2030 and achieve Net Zero for industry as early as 2040.

In August 2021, the Government launched its long-awaited National Hydrogen Strategy.[6] This places hydrogen as a key priority for the UK and highlights the potential for it to make a major contribution to achieving Net Zero, and sets a target for 5GW of low carbon hydrogen production by 2030.

In its modelling of pathways to Net Zero, the CCC estimated that up to 175MtCO_2/annum will need to be stored (via pipeline networks and offshore storage reservoirs) in 2050.[7] It also stated that nearly 50MtCO_2/annum of this CO_2 would come from production of around 225TWh/annum of 'CCUS-enabled' hydrogen produced by 'advanced reforming' of natural gas.

Considering the UK only currently produces around 27TWh/annum of hydrogen (almost exclusively for use in chemical process industries), this might appear to be an ambitious goal. However, it is somewhat modest compared with both:

- The CCC's 2019 'progress' report to Parliament, which suggested that 270TWh of CCUS-enabled hydrogen would be necessary to meet Net Zero in 2050, with an interim target of 30TWh in 2030 stated in the 2021 progress report;[8] [9] and
- In particular, National Grid's 2021 Future Energy Scenarios (FES) report, under its 'System Transformation' scenario designed to meet Net Zero, which highlighted that 332TWh of CCUS-enabled hydrogen might be required.[10]

The Energy Networks Association also sponsored a report in 2020, under its 'Gas Goes Green' initiative, which focuses on a 'balanced' approach to meeting Net Zero. This work suggests that around 240 TWh/annum of hydrogen will be needed to meet Net Zero, alongside 200 TWh/annum of biomethane and bio-substitute natural gas (bioSNG). A similar amount of hydrogen demand is suggested under the 'low' scenario in a study published by Aurora Energy Research, rising to over 500TWh under the 'high' scenario.[11]

The variation in estimates across these reports is largely the result of different modelling assumptions around the overall decline in energy demand (as a result of energy efficiency measures) over the next three decades and the level of penetration of renewable electrification. What is consistent across all reports, however, is that significant amounts of hydrogen (and associated CCUS) will be required, across all sectors of the economy, for the UK to have any realistic prospect of meeting Net Zero in 2050. To put this fully in context, UK electricity demand in 2019 was 346TWh, and so to meet the forecast demand scenarios from CCC and National Grid requires a hydrogen energy system to be developed and constructed on a similar scale to the existing electricity system.[12]

It is clear that the magnitude of deployment required is recognised within the highest levels of Government, with Secretary of State Kwasi Kwarteng continuing to reiterate that hydrogen is the single area of greatest focus for his department.[13] This study demonstrates how the initial HyNet project can be expanded to help achieve this goal.

1.2 Super-charging the Recovery

The Government has indicated its desire to focus on low carbon infrastructure investment and employment as the most attractive approach to seeking a relatively swift bounce-back from the economic crisis brought about by the Covid-19 virus.[14] Deployment of funds into the low carbon economy will also fulfil the goal of meeting Net Zero, and thus such an approach might be considered as 'win-win'.

Much of the CCC's 2020 report to Parliament focused on how the Government might deliver a low carbon recovery to meet Net Zero.[15] In respect of CCUS (and hydrogen), it stated that Government must come up with "concrete and funded plans" for deployment in the mid-2020s. As such infrastructure will take several years to consent and construct, related policy mechanisms are needed immediately.

Prior to the impact of Covid-19, the Government had already begun to recognise the importance of hydrogen and CCUS, setting in motion a strategy based around the development of low carbon industrial clusters. Under the Industrial Strategy Challenge Fund, it has allocated £170M to fund the IDC programme as part of the Industrial Clusters Mission.[16]

The IDC is focused on the ambition to establish at least two low carbon industrial clusters by 2030 and the world's first Net Zero industrial cluster by 2040. This will help meet the goals of the Government's Industrial Strategy and Clean Growth Strategy, by driving the technologies, services and markets to produce low carbon industrial products.[17] [18] Previous work for HyNet suggested that such a transition in the North West (NW) alone, could result in GVA gains of around £31 Billion across the UK.[19]

The deployment of hydrogen as an energy vector will permeate all sectors of the economy, bringing about new skills and technologies, which drive wealth creation and economic growth. Hydrogen and CCUS represent technologies in which the UK has the opportunity to take a genuine global lead, exporting products and services both within the EU and beyond. Unlike other areas of current innovation in the energy sector, for example, battery storage, neither China, the US or any other nation has yet deployed hydrogen production, distribution and use, or 'full-chain' CCUS, at commercial scale.

The NW of England has some of the most advanced chemicals production and oil and gas sector expertise, with the latter needing to be progressively redeployed as the UK moves away from the fossil economy. These skills should be leveraged to support the post-Covid-19 economic recovery, expanding from a decarbonised industrial cluster both geographically, and more deeply into each sector of the economy.

1.3 Building on the Existing Evidence Base

HyNet was conceived by Progressive Energy ('Progressive') in 2016 via support from Cadent under the Network Innovation Allowance (NIA). The first phase of work, published in August 2017, considered two core locations within Cadent's regional gas networks; the North West and Humberside, as potential locations for deployment of the UK's first CCUS and hydrogen infrastructure.[20] The North West was chosen as the preferred location due to its close proximity to well-characterised depleted oil and gas fields for offshore storage of CO_2 and the low cost of reusing these assets and existing pipelines, along with equally close proximity to the Cheshire Salt Basin (currently used for storage of natural gas) for underground bulk storage of hydrogen.

This initial study was built upon in a subsequent NIA-funded report published in June 2018.[21] This work defined the project concept for both hydrogen production and distribution, and CCUS. As presented in Figure 1-1, this included the following key features:

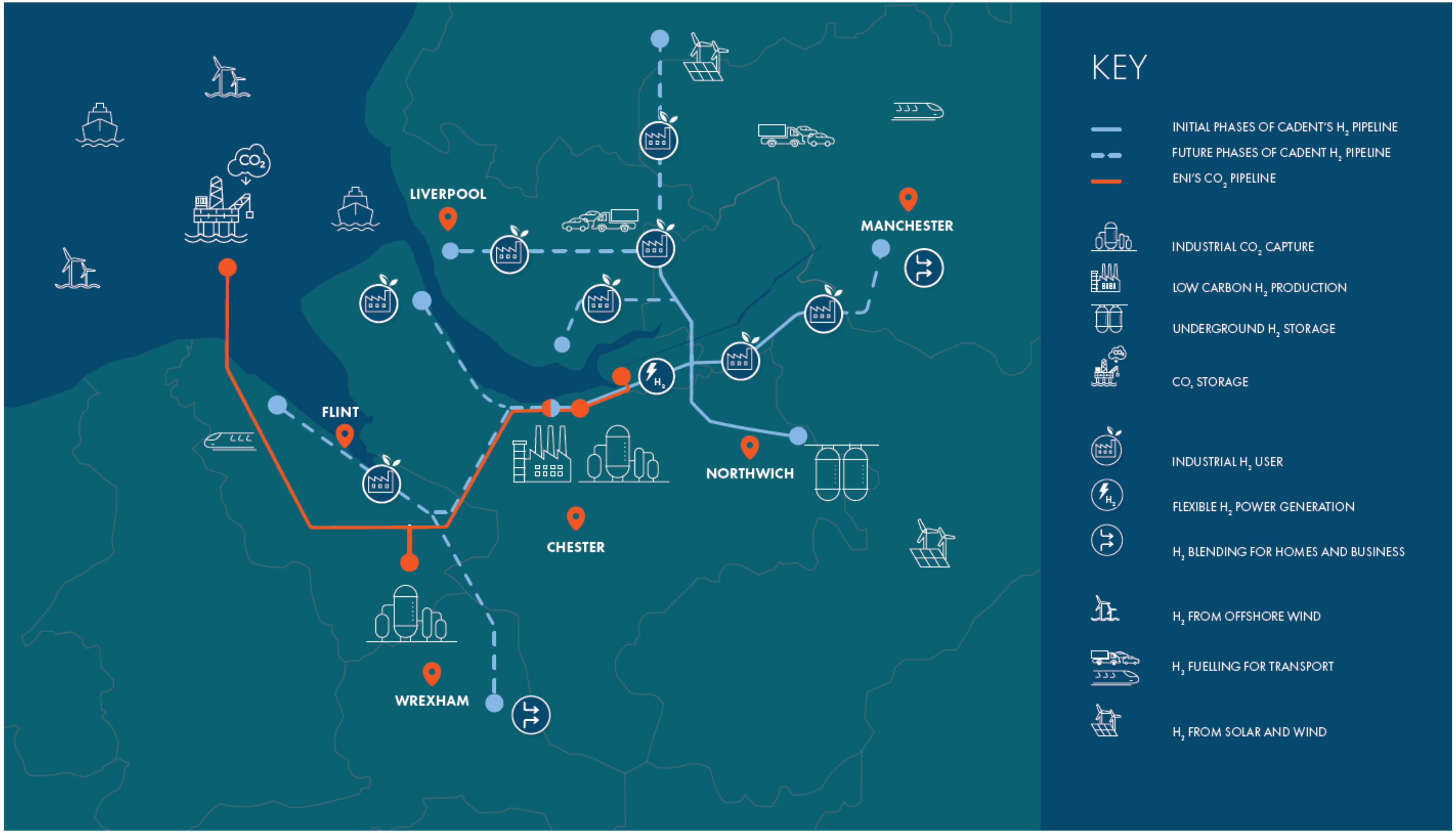
- CCUS-enabled hydrogen production (from refinery off-gas and natural gas) at Essar's Stanlow Refinery;
- Hydrogen pipelines from Stanlow Refinery to:
    - Industrial sites;
    - Power generation sites;
    - Sites for injection of a 'blend' of hydrogen into the existing natural gas network;
    - Major transport hubs; and
    - Underground hydrogen storage caverns in the Cheshire Salt Basin.
- CO_2 pipelines:
    - From CF Fertilisers in Ince to Stanlow Refinery (new pipeline);
    - From Stanlow refinery to Connah's Quay Power Station (new pipeline);
    - From Connah's Quay and Point of Ayr Gas Processing Terminal (repurposing to CO_2 of an existing natural gas pipeline); and
    - From Point of Ayr to the Liverpool Bay oil and gas fields (repurposing to CO_2 of an existing natural gas pipeline).
- CO_2 storage in the Liverpool Bay oil and gas fields.

The concept was defined as part of a 2018 'Reference Project'. This work demonstrated that:

1) Hydrogen production and distribution must be underpinned by an appropriately sized CO_2 transport and storage network;
2) The cost of hydrogen production and distribution will be lower as a result of this network being 'shared' with industrial users from which CO_2 is directly captured;
3) The hydrogen network can be extended to incorporate:
    a. Additional sources of demand for hydrogen (both inside and outside the core HyNet area); and
    b. Further sources of supply of hydrogen, including those from other CCUS-enabled production sites and from 'electrolytic' hydrogen production (from either renewables or nuclear power).

It is important to acknowledge that following further engineering and design over the last three years, the current project definition described in this report has not changed substantially from the above Reference Project.

Figure 1-1: HyNet Project Concept



2.0 SCOPE AND OBJECTIVES

2.1 Objectives

A range of objectives and potential outputs were described in the grant application submitted to UKRI for the North West Cluster Plan project. These are reflected in the following goals for this study, which are to undertake or provide:

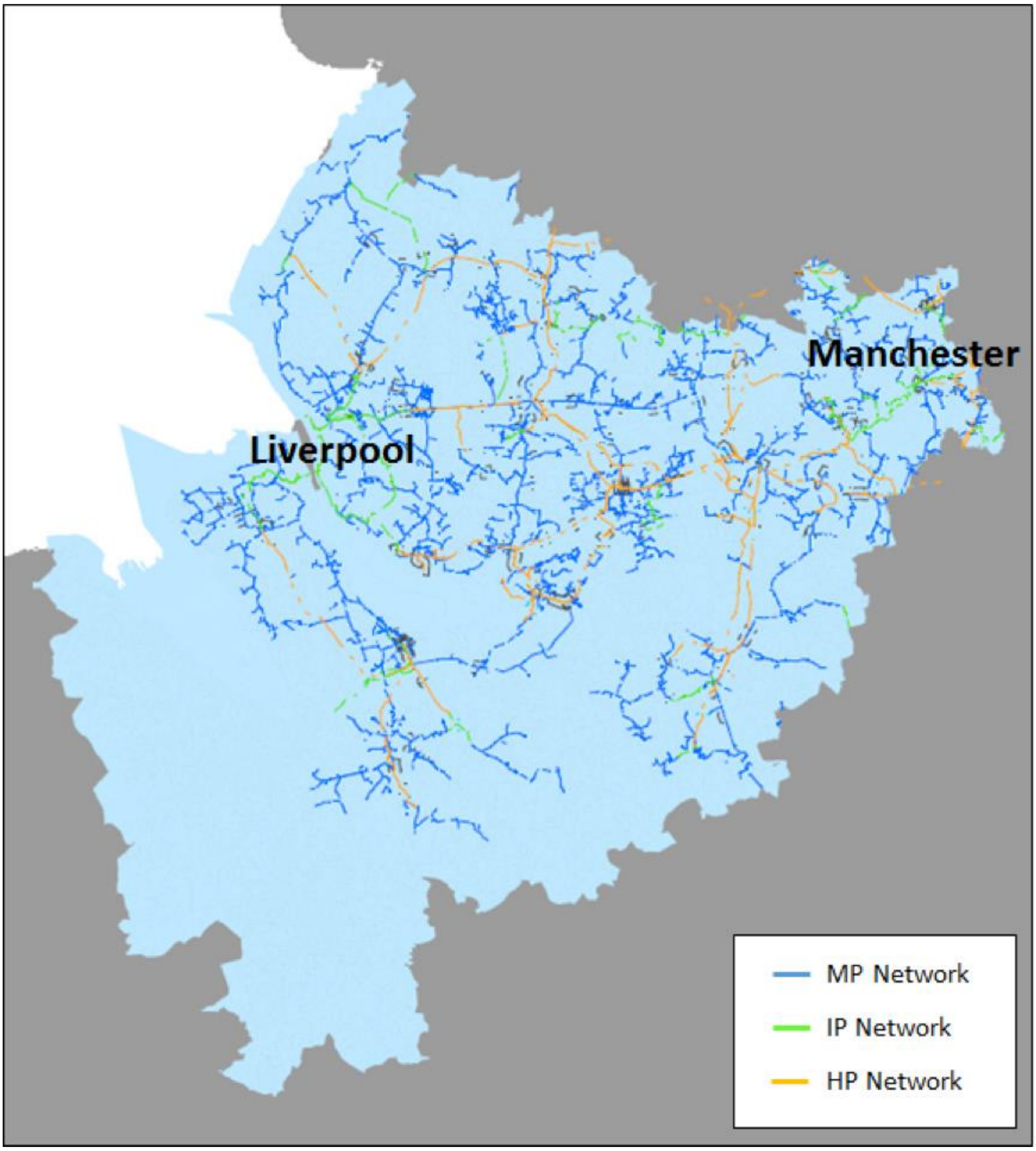
- Analysis of business models, which are currently under development by Government, that are required to support hydrogen and CCUS infrastructure deployment;
- Hydrogen and CCUS system modelling to demonstrate a roadmap to both 2030 and to Net Zero for industry *by* 2040;
- An indicative (or 'conceptual' design) of a hydrogen distribution network to supply industry sites; and
- Indicative routing in respect of the planned CO_2 transport network.

2.2 Scope of Analysis

2.2.1 Geography and the Core HyNet Cluster

There is a core cluster 'area' upon which HyNet deployment will largely be focused through to 2030. This area is shown in Figure 2-1. It has been selected to include the vast majority of major industrial and power emitters in the region (and to encompass the major gas distribution network entry points to enable a 'blend' (up to 20% vol.) of hydrogen to be supplied across most of the Liverpool, Manchester and Cheshire). The area also includes the large Cheshire salt basin, where natural gas is currently stored underground, and in which caverns for hydrogen storage will be constructed.

Figure 2-1: Core HyNet Area and associated Gas Distribution Network Tiers



The postcodes for the above region are given in Table 3.1.

Table 2-1: Spatial Layer used for Hydrogen Demand Modelling in 2030

City or Town	Primary Postcode Identifier	Secondary Postcode Identifier
Liverpool	L	All
Manchester	M	All
Chester	CH	All
Warrington	WA	All
Crewe	CW	6 to 10 only
Preston	PR	8 to 9 only
Wigan	WN	All
Llandudno	LL	11 to 14

As HyNet expands to 2040, a slightly wider spatial layer has been applied to incorporate some major industrial sites in Lancashire, Cumbria and other parts of Greater Manchester. At this time, it is also possible that the parts or all of the existing natural gas *distribution* network may have been converted to hydrogen, which is explored in the scenario modelling presented in Section 6.1. At a qualitative level, we have also presented information in relation to:

- Potential wider supply of hydrogen from Cumbria, which might be facilitated by conversion of existing natural gas *transmission* pipelines to hydrogen; and
- The potential to expand the CO_2 capture network to the Peak District 'cluster' of cement and lime production sites.

2.2.2 Industry

The focus of the analysis in this study is upon decarbonisation, either via fuel switching to hydrogen or direct capture of CO_2, of those sites being targeted for conversion by the HyNet consortium. These are major emitters, which are (largely) obligated under the UK Emissions Trading Scheme (UK ETS) and includes sites across a range of sectors; from glass, cement and ceramics to food and drink, chemicals, paper and pulp and automotive.

Analysis of the potential to decarbonise smaller industrial sites, either via electrification or 'non-networked' hydrogen production is being undertaken by other NW Cluster Plan partners.

2.2.3 Other Sectors

Whilst the focus of the Cluster Plan is squarely upon industry, the hydrogen production and network infrastructure (supported by the associated CCUS infrastructure) deployed as part of HyNet will also enable decarbonisation of several other key sectors of the economy and therefore the benefits associated with such supply need to be taken into consideration in the wider economic analysis being undertaken as part of the Cluster Plan.

These sectors include:

- Hydrogen power generation:
    - Hydrogen will function as a fuel in the same way as natural gas does today, enabling ‘flexible’ power generation, which will not only help ‘balance’ the electricity grid, but will also enable greater amounts of offshore wind, solar, tidal (or so called ‘intermittent’ renewables) to be deployed;
- Network blending of hydrogen and potential network conversion to hydrogen for domestic and commercial heating:
    - Network blending involves injection of up to 20% vol. hydrogen into the existing gas network as has been demonstrated in the HyDeploy project, which is providing critical evidence to support deployment of blending into the wider network as part of HyNet;[22]
    - Full conversion of the network to ultimately decarbonise household and commercial heating and other appliances may take place in the 2030s, depending upon the evolution of the evidence base derived from the Hy4Heat and H21 projects and future work funded by BEIS and the Gas Distribution Networks (GDNs).[23] [24] The likelihood of network conversion also depends upon the policy mechanisms and business models to be put in place by Government, along with the success of the Government’s ‘Hydrogen Village’ trial, which it is hoped will begin operation by 2025.
- Use as hydrogen as a fuel for vehicles and wider transportation:
    - There has been significant development of some forms of hydrogen vehicles in particular cars, with the likes of Toyota and Hyundai bringing models to the UK market, and fleets of buses are also now being deployed in cities including Liverpool.[25] Slower progress has been made in respect of HGVs, even though these are better suited to fuelling by hydrogen than battery electrification. In the future, supply of hydrogen for transport may represent a large part of the market, but until fuel is available far more widely from HyNet (and other regional hydrogen deployment), the market will remain relatively small, likely until the early 2030s.

3.0 BUSINESS MODELS FOR HYDROGEN AND CCUS

3.1 Framing the Investment Challenge

The UK currently relies on three energy vectors; electricity and natural gas across multiple consumer sectors and petrol/diesel for use in the transport sector. To achieve Net Zero emissions use of these latter two vectors must be phased out, other than using natural gas for CCUS-enabled hydrogen production or where direct CO_2 capture is installed.

Hydrogen has the potential to substantially replace natural gas and to complement intermittent renewables for electricity production and can also replace petrol and diesel in some transport applications, alongside electrification being used for the remainder. Consequently, by 2050 the UK will rely on a combination of low, zero or negative carbon electricity and low, zero or negative carbon hydrogen, along with direct capture of CO_2 from industry and power generation. As described in Section 1.0, HyNet is the pathfinder initiative in the UK to achieve this outcome.

The growth plan described in this report involves a progressive, multiphase, build-up of hydrogen use across an increasing number of market sectors; from an initial hydrogen production hub at Stanlow Refinery in Cheshire which expands over time to consumers in more distant locations in the North West.

The need is for hydrogen to be deployed as rapidly as possible, both in respect of climate change – early carbon reduction has more impact in helping to limit global climate than later reduction – and with regard to economics – the cost of carbon emissions for some industrial users is set to make some manufacturing industries in the UK unattractive before 2030. Correspondingly, 'first mover' advantage in a growing hydrogen market is material. As described above, GMCA is targeting net zero emissions by 2038 and LCRCA is seeking to achieve the same goal by 2040. Both cities will rely on major hydrogen use to achieve these objectives.

The rate of expansion is driven by:

- The determination (and enacting in law) of a market framework and relevant business models to support hydrogen (and CCUS);
- Timescales for regulatory approval of new infrastructure; and
- To a lesser extent, technical constraints on end use for some limited industrial sectors and sites, for which evidence for switching does not yet exist.

The introduction of a market framework and associated business models is essential to enable private sector investment to both create and expand the market for hydrogen. In the absence of this framework there is still currently no market demand for hydrogen from industry as low carbon hydrogen costs more than the natural gas it replaces and the (albeit rapidly growing) cost of UK Emissions Allowances (UKEAs) is not yet sufficient to drive change. The availability of this framework is therefore the single greatest limitation on the widespread adoption of hydrogen as a fuel source.

3.2 Cluster Sequencing Process

As mentioned above, the HyNet cluster has recently been selected under Track 1 of Phase 1 of the Government's Cluster Sequencing process. This was essentially a competitive process between regional CCUS (and hydrogen) clusters, with the 'prize' being a seat at the table to negotiate levels of support for CO_2 transport and storage (T&S) under the business model framework described in Section 3.6.1. HyNet was selected alongside the 'East Coast Cluster' and the process of negotiation with Government for both clusters will begin in early 2022. To reach FID, HyNet must also be successful in this process.

At the time of writing, bids are being prepared for 'Phase 2' of the Cluster Sequencing process, which focuses on carbon dioxide (CO_2) capture sites, which will supply CO_2 to the transport and storage infrastructure funded under Phase 1. The HyNet hydrogen production plant is one such site. In respect of support for hydrogen production, for successful Phase 2 projects, a similar negotiated process with Government will commence later in 2022, with contracts to be signed by mid-2023. The rationale for, and likely structure of, the supporting business is described in detail in Section 3.3.

Wider business models, to support the deployment of hydrogen networks and storage infrastructure are being developed in parallel, but outside of the Cluster Sequencing process, as described in Sections 3.4 and 3.5.

3.3 Potential Business Models for Hydrogen Production

Business models for supporting hydrogen production have been considered by industry extensively over the past two years. The CCUS Advisory Group (CAG) published a report in July 2019, comparing model approaches, with a further report submitted to Government in December 2019.[26]

Subsequently, Progressive developed a 'Heads of Terms' for a Hydrogen CfD, which provides a solid basis against which investment in low carbon hydrogen production for HyNet, and other similar projects, can be driven forward. BEIS subsequently published a consultation on hydrogen business models in August 2021, which reflected many of these key terms.

This section summarises the basis for selection of the preferred business model and describes its application to HyNet.

3.3.1 Functional Requirements

The following key functional requirements of the business model were defined by Progressive in its early engagement with BEIS:

- Enable bankable investments, delivering to multiple consumer markets

To achieve the 475TWh of all low carbon hydrogen production suggested in the 2020 FES scenarios (for 2050) implies a capital requirement on production alone of £30-40Bn. Hence high confidence is need in the business model selected to reduce the cost of capital. Structurally models which allocate risk appropriately, to those best able to manage it, are likely to be more cost effective.

Low carbon hydrogen can replace natural gas as an energy vector, meeting needs across multiple market sectors. Even very early in the development of HyNet, hydrogen from the Stanlow production hub will supply industry, power and a range of gas network consumers. Any support regime must recognise this and enable opportunities for supply of hydrogen to other parts of the energy system, particularly to markets where it can deliver effective decarbonisation compared with alternatives.

- Support the growth of an emergent market for hydrogen

  Whilst the potential for hydrogen is recognised and technical barriers are understood and manageable, in the absence of a market framework which allows investment there is currently no market for low carbon hydrogen. A key requirement is that the business model must be structured to increase consumer demand from a very low base in a way that enables rapid market expansion, enabling hydrogen to make material and growing impact on achieving decarbonisation targets. Business models which are understood by investors and have a degree of resilience and continued application, as the current nascent market expands, are strongly preferred.

  Consistent with an emergent market, the business model should be compatible with likely future developments. For example, the price of carbon will change over time, and the regime must be able to accommodate such change. This has been addressed under the Electricity Market Reform (EMR) process via the electricity CfD regime, where the cost of carbon and change in energy mix flows through to the wholesale electricity price. The out-turn level of subsidy varies accordingly to maintain the agreed strike price.

  Given the range of potential opportunities hydrogen offers for decarbonisation, as well as wider developments in each of the sectors, the balance of uses will change over time. Any regime should be able to accommodate the implications of such changes, at a minimum for the projects already funded, even if new projects are supported differently

- Minimise disturbance to existing markets

  The existing natural gas market is well established and mature, albeit somewhat volatile at the time of writing. Gas is a commodity with a price set in a competitive market. Whilst ultimately it may be replaced by hydrogen, the current gas market will persist for perhaps two further decades and hence it is important that the business model selected to enable the introduction and growth of hydrogen does not adversely perturb the existing market.

- Be technology agnostic

  The selected business model must also be technology agnostic. Reforming of fossil fuels with separation and storage of CO_2 is currently the lowest cost technology available for the manufacture of hydrogen in large quantities. There are a number of such reforming technologies. A business model for the production of CCUS-enabled hydrogen using reforming technologies is the essential requirement.

  Biomass can also be pre-processed to enable hydrogen to be produced by reforming technologies and when coupled with CCUS this allows a net reduction in emissions – so called negative emissions. This is an efficient means of producing negative emissions and a business model which can be adapted to reward the use of biomass feedstocks producing hydrogen with negative emissions would provide a real benefit. Given that existing reformers, as planned as part of low carbon hydrogen production for HyNet, can provide CO_2 capture rates of 97%, only a small amount of negative emissions are required to create zero emission hydrogen.

  Electrolytic hydrogen production, using renewable or zero carbon (i.e. nuclear) electricity is complementary to CCUS-enabled hydrogen and the selected business model should also enable investment. Currently, however, electrolytic hydrogen is considerably more expensive than CCUS-enabled hydrogen and and hence project selection should not be solely based on price.

These principles were well reflected in BEIS’ Business Model consultation, as shown in Table 3-1.[27]

Table 3-1: Business Model Design Principles

Principle	Description
Promotes market development	Model should incentivise producers to seek and develop sources of demand for hydrogen and promote its use
Promotes market competition	Model should not create barriers to market entry, enable abuse of market power, or provide an enduring competitive advantage to first movers compared to later market entrants
Investable	Model should provide sufficient predictability over revenues and returns to investors and mitigate risks which investors are not best able to bear
Value for money	Model should be effective in achieving its intended purpose at the lowest possible cost to government and prevent excessive returns to developers
Reduces support over time	Model should allow for revenue support to producers to reduce over time (within and between contracts) by being responsive to evolving market conditions and encouraging learning, innovation, and cost reductions over time
Suitable for future pipeline	Model should be fit for purpose for First of a Kind (FOAK) projects as well as n^{th} of a kind projects with minor or reasonable adjustments
Compatible	Model should be compatible with other policies across the value chain and should not result in double subsidisation of the same units
Technology Agnostic	Model should be applicable to a range of production technologies (provided they meet the low carbon hydrogen standard and do not create an enduring competitive advantage for one technology over another)
Size Agnostic	Model should be applicable to a range of project sizes and should not incentivise inefficient sizing of production plants
Avoids unnecessary complexity	Model should avoid unnecessary complexity in its design, implementation and administration, and be transparent for producers to comply with

3.3.2 Comparison of Potential Business Models

The decision on the business model to adopt to enable hydrogen deployment is for Government. The scope of HyNet provides a valid test of the efficacy of the various model options. Progressive has been, and continues to be, closely involved with Government in examining options and has concluded that the preference set down below reflects the best balance between the need to attract cost effective private sector investment and Government's need to ensure that any support is limited and cost effective.

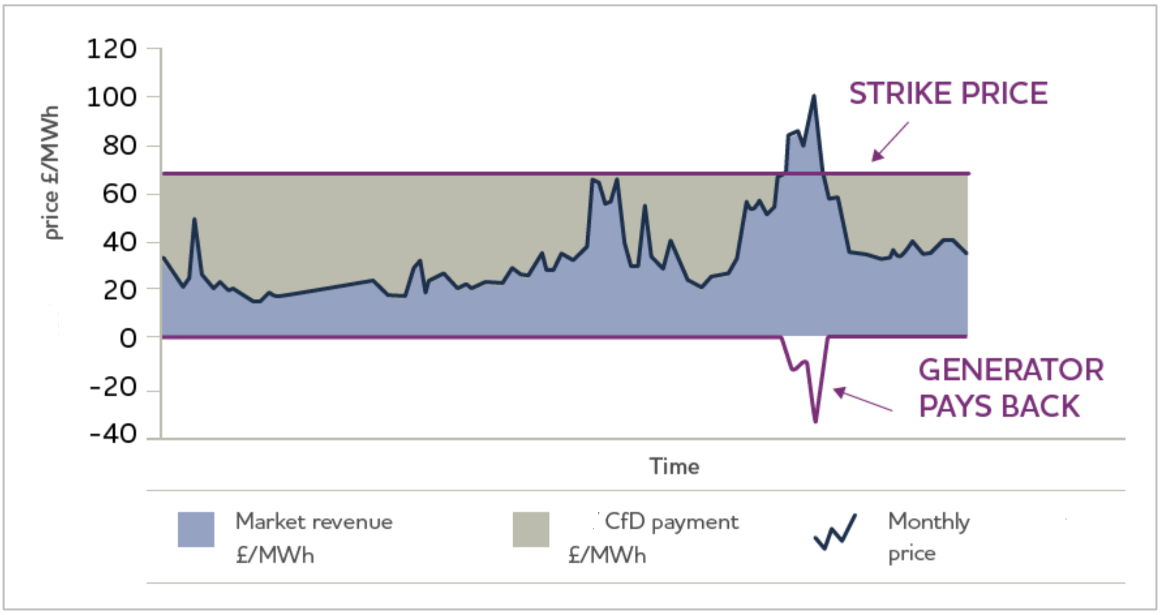
There are two broad approaches, a regulated market and a free market.

1) Under a Regulated Asset Base model a regulator grants a licence to an entity, which gives it the right to collect revenues to achieve an agreed regulated return on the assets which it delivers and operates. This approach is commonly used for capital intensive infrastructure and in situations where a natural monopoly exists, for example gas and electricity distribution and transmission networks. In most cases, it is the regulated entity which delivers and operates the assets, but in others, such as the case of Thames Tideway in the water sector, the investment, ownership and operation of the specific assets is undertaken by a third party, with the required revenues collected by the regulated entity from its consumers.

   The principle of the RAB regime is that the entity is overseen by a Regulator, in this case, Ofgem, and the operating entity is permitted to make an agreed return, which is reassessed periodically on the assets it owns. The return is received irrespective of the performance of the assets, resulting in low risk and hence allowing a low cost of capital.

2) Free market approaches rely on the creation of a competitive market that drives investment in new assets. This may be achieved by creating an obligation on suppliers to a particular market which can be discharged at lower costs by supporting investment in new plant or by creating a market instrument which is awarded competitively to incentivise investment in new plant. Both approaches have been used to support decarbonisation of electricity generation:
   a. The Renewable Obligation put an obligation on electricity suppliers to supply a set percentage of their electricity to the market with renewable generation, or pay a set 'buyout' price to discharge the obligation, the level of which was above the cost of producing renewable generation.
   b. Since 2014 support for renewable generation has also been provided by a market instrument, Contracts for Difference, CfDs. The CfD is a long-term contract between an electricity generator and a Government counterparty, the Low Carbon Contracts Company (LCCC). The contract enables the generator to stabilise its revenues at a pre-agreed level (the 'Strike Price') for the duration of the contract. Under the CfD, payments can flow from LCCC to the generator, and vice versa. When the market price for electricity generated by a CFD Generator (the Reference Price) is below the Strike Price set out in the contract, payments are made by LCCC to the CFD Generator to make up the difference. However, when the reference price is above the Strike Price, the CfD Generator pays LCCC the difference. This is illustrated in Figure 3-1.

Figure 3-1: Illustrative Example of a Contract for Difference



A high-level comparison of the three business models, against the functional requirements described in Section 3.3.1, is given in Figure 3-2.

Figure 3-2: Overall Comparison of Business Model options

Requirement	RAB	Obligation	CfD
Enable bankable investments, delivering to multiple markets	Achievable with very low cost of capital	Annual cash flow not well-defined limiting bankability	Achievable as well-defined, long-term cash flows
Support growth of a nascent market for hydrogen	Achievable. RAB licensee incentivised to invest to grow	Achievable although long term sales contracts can be challenging for innovative technologies	Achievable. Proven to be successful in renewable electricity markets
Reduce support costs over time	Reduction in costs relies on adoption of lower cost technologies. Requires strong regulator	Achieved if large uptake in project investments at less than buy out costs	Achievable. Competitive auction shown to be effective in electricity
Not perturb existing market	As hydrogen market expands, impact on suppliers and consumers increases	Better suited to creation of new market	Achievable

The broad conclusion, of this analysis is that an Obligation is not attractive to investors, and whilst both a regulated business model (as part of a wider RAB) and market model based on a hydrogen CfD could both work, the CfD option is preferred. The rationale for this choice can be summarised as follows:

- Obligation - Key Pros and Cons

  This is a mechanism that has been used and is understood by the market for the production of low carbon energy. The RO for electricity production successfully enabled renewable generation to gain a foothold in the energy mix. However, in 2014 in the light of experience, Government moved to a CfD regime in order to (a) to avoid over rewarding (when the underlying commodity price moved upwards) and (b) to provide better revenue certainty to investors and therefore lower costs of capital.

  The Renewable Transport Fuels Obligation (RTFO) has delivered a proportion of renewable bio-fuel for the transport sector. However, most of the fuel is imported and very few new plants were constructed in the UK. Cash flows are inherently uncertain and in fact many of those plant that were constructed defaulted on their debt commitments. These now only operate because the new owners were able to acquire them at heavily written down prices, and so they can now operate on a marginal cost basis.

  Viewed from the perspective of an investor in hydrogen production in HyNet, an Obligation has major disadvantages:

  - An obligation does not readily provide a secure income stream, and this is dependent on the headroom between the obligation level set and the level of delivery achieved. Consequently, risk to investors is high;
  - Given the range of potential markets and values for low carbon hydrogen as a commodity, setting the headroom and buyout certificate price could be challenging; and
  - The forecast value of an obligation will always be discounted by investors. To achieve the required level of build-out will require a significantly higher premium and socialised cost to consumers than if the income stream were guaranteed.

- Regulated Asset Base – Key Pros and Cons

  The RAB approach would allow investment without needing a firm long-term demand for hydrogen to underpin it and is therefore well suited to enabling the first plants. However, as demand grows with both CCUS-enabled and electrolytic hydrogen produced from a range of innovative technologies with differing risk profiles and characteristics supplying different markets, this stretches the concept of a fixed asset return implicit in a RAB. Furthermore, as the company will be supplying into otherwise competitive markets this will inevitably result in inefficiencies and unanticipated consequences.

With hydrogen production, no natural monopoly is involved and whilst the total capital required over time is tens of £Billion, the Capex associated with CCUS-enabled hydrogen is only ~25% of the levelized cost. Consequently, the gains from securing a particularly low cost of capital by developing a regulated business structure are limited. Electrolytic hydrogen produced from electrolysis using renewable electricity is more capital intense, but is not available at a scale and with the certainty of output to enable the hydrogen distribution network infrastructure to be developed.

- CfD – Key Pros and Cons

  A hydrogen CfD offers a parallel to the proven track record of wider CfDs in attracting investment and driving lower costs for renewable generation in the electricity sector, particularly for offshore wind generation. Strike prices for CfDs for offshore wind have decreased from initial values of ~ £160/MWh to close to £40/MWh in less than a decade with a range of equity investors committing funds. Project debt has been forthcoming, minimising the cost of capital. CfDs are also understood and accepted by investors.

  It is likely that investment in hydrogen production for HyNet could be secured if a similar CfD were available, if properly designed to enable appropriate risk management between the parties.

In its 'minded to' position in the consultation, BEIS has firmly identified a 'Variable Premium' model as its selected approach. This is effectively a CfD arrangement based on a private contract between a body such as the LCCC and the developer.

3.3.3 Hydrogen CfD Design Principles

As described above, a Hydrogen CfD offers clear benefits over alternatives as the mechanism to support delivery of the Hynet 2030 hydrogen expansion plan, along with those associated with other geographical clusters.

In the electricity market a CfD is a long-term contract between an eligible electricity generator and a Government backed counterparty, the LCCC, which is executed against a generic set of terms and conditions.[28] These terms and conditions are the starting point against which to develop a hydrogen CfD.

The terms of the standard CfD apportion risk between LCCC and project owners. Business as Usual (BaU) risks are taken by the project owners as they are best placed to manage them. Risks that are beyond their control require the involvement of Government. A hydrogen CfD would adopt the same principle. The key differences between a power generation investment and a hydrogen production investment are as follows:

3.3.3.1 Strike Price, Reference Price and Price Discovery

As described above, the purpose of the CfD is to bridge the gap between the market value of hydrogen and the cash flow needed to enable the investment. Hydrogen replaces natural gas, but is produced by reformation of the natural gas, and the cost of doing this results in an increase in price which is not yet valued by gas customers. The strike price is the price at which investment in the hydrogen production plant can be justified.

So that the CfD focusses efficiently on offsetting the costs of the reformation process, variations in gas prices need to be removed by indexing the strike price to gas prices. The reformation process involves costs which vary over the term of the contract (15-20 year) of the contract. These can be corrected by including an appropriate level of indexing to costs (through the Consumer Price Index) and electricity price (electricity is used in compressors and other process equipment)

The Reference Price is the underlying 'price' of hydrogen assumed to be secured from the market. The dominant use for hydrogen is to replace the combustion of natural gas to generate heat. Hence the Reference Price is the price of the natural gas that it replaces. Low or zero carbon hydrogen is replacing natural gas with its embodied carbon and over time and dependent on Government policy, the expectation is that the value of avoiding carbon emissions and hence the value of hydrogen will increase.

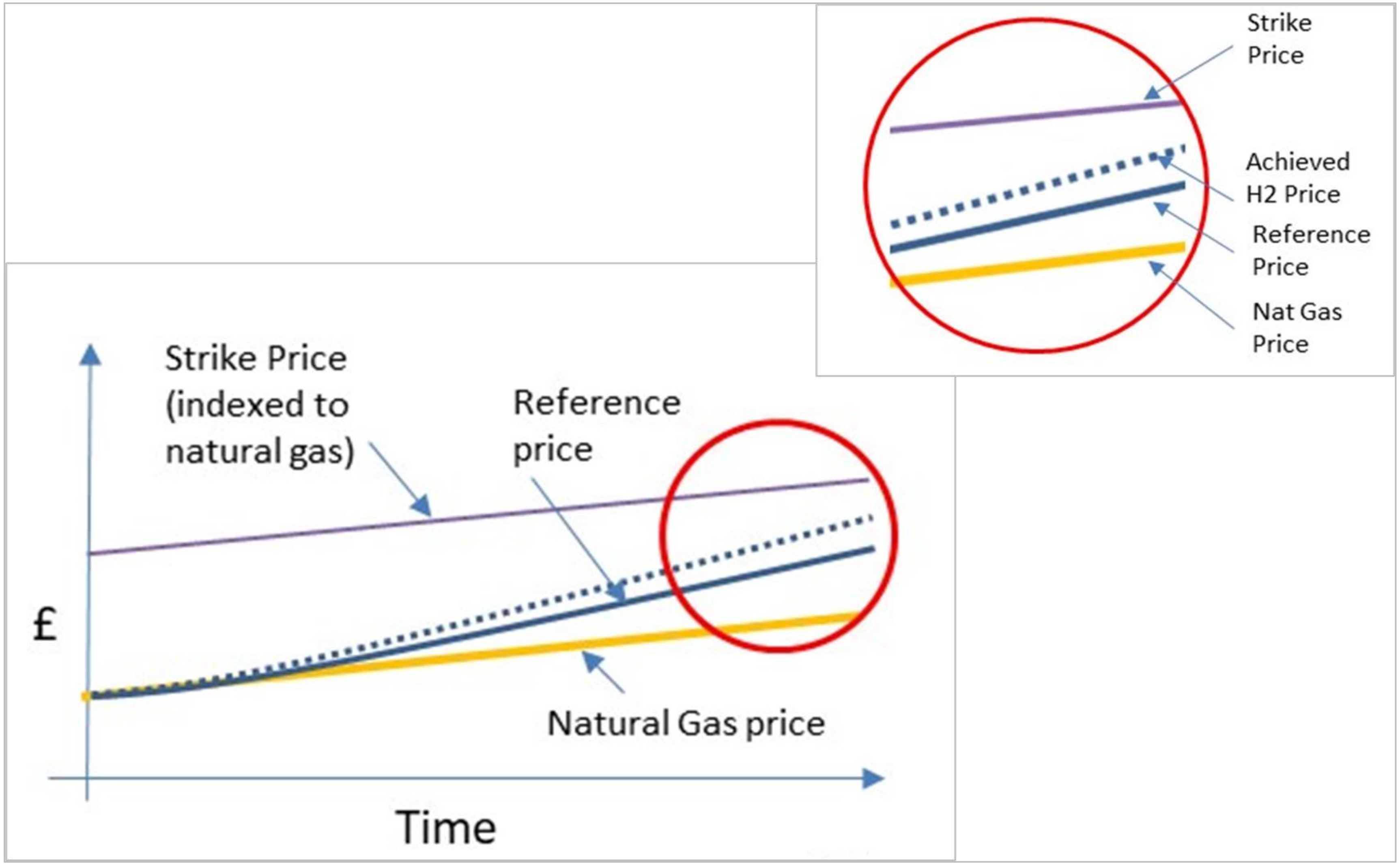
The achieved sale price for hydrogen will depend on the extent to which consumers value using low carbon hydrogen rather than unabated gas or another fossil fuel. As carbon prices increase over time, companies exposed to the UK ETS will find conversion to hydrogen use an increasingly attractive option. Progressive has proposed that the benefit of the increased income above the Reference Price should be shared between Government and the producer. This provides an incentive for producers to seek to secure increased prices for their hydrogen and a benefit to Government of reducing the level of support paid. As shown schematically in Figure 3-3, this 'price discovery mechanism' will help to drive price equality when hydrogen prices require no support.

This is the model that BEIS has proposed in its consultation. It has acknowledged that the underlying counterfactual today is natural gas, and so this should provide a floor to the reference price. It has also explicitly recognised that to grow the hydrogen market and provide an incentive for users to fuel switch, the carbon benefit needs to accrue to the user:

> *"If the price at which they can buy hydrogen is the same as their existing fuel (i.e. natural gas plus the carbon price) then there are no ongoing cost savings to justify switching to hydrogen."*[29]

However, it is recognised that there may be markets which value hydrogen at a greater value, such as in the transport sector, and therefore the producer should be incentivised to secure a better price in that case, in order to reduce the level of subsidy required. The exact mechanism is to be determined, but the price discovery mechanism proposed above provides that function. Longer term, in a fully tradeable market there should be an independent index for hydrogen, akin to the Heren index for natural gas, and for projects coming on stream at that stage, then this would logically provide the reference price.

Figure 3-3: Schematic of Hydrogen Price Discovery Mechanism



3.3.3.2 Volume Protection

Supply of low carbon hydrogen in place of fossil fuels is a new market. The HyNet development plan described in earlier chapters shows that initially hydrogen can only be supplied to a small number of consumers, dominated by industrial companies. The counterparty risk from individual companies together with the absence of the alternatives before a new hydrogen distribution network has been put in place means that the supply volume is uncertain. The resultant cash flow risk makes financing extremely challenging, if not impossible in a nascent market.

Hence for early projects a degree of protection is needed in the CfD to underwrite a minimum cash flow to enable financing of hydrogen production. This is a crucial element of the CfD necessary to ensure investment in early hydrogen production projects and is an important part of the business case for investment in the accompanying new hydrogen distribution network. The protection level must be set against the fixed costs for the plant involved and designed to enable financing of the plant but set at a level which provides an incentive for the plant owners to find replacement consumers.

A balanced, demand-driven design is proposed. By mirroring protection against reduced demand, the plant owner is incentivised to create more demand by receiving a small contribution to their fixed costs, and satisfying this through debottlenecking the plant.

The issue, and the requirement for the regime to address this is recognised in BEIS' Business Model consultation. At present the preferred model does this via a sliding scale, which rewards early units of hydrogen at a greater level, making a greater contribution to fixed costs in order to offset the risk of demand reduction. Whilst this may provide some protection, further engagement is required with the investment community to establish if this provides a sufficient solution for a nascent market.

Over time, as the hydrogen market expands, more distribution infrastructure is put in place and the number of consumers increases, the need for this protection is reduced and in a developed market it would fall away entirely.

3.3.4 Interaction with CO_2 Transport and Storage

Access to CO_2 transport and storage (T&S) infrastructure is a crucial enabler. In reviewing the experience gained in the CCUS Commercialisation Programme, which was abandoned in 2015, Government, the National Audit Office and industry were all agreed that it was crucial to decouple CO_2 T&S from CO_2 capture, this avoiding what are termed as 'cross-chain risks'.

The HyNet consortium is pleased that Government, in its Consultation on Business Models in 2019, recognised the need for separate business models for CO_2 T&S and CO_2 capture. HyNet has been developed on the premise that such cross-chain risk will be managed.

Plant financing relies on the assumption that counterparty risk associated with non-availability of the T&S system is fully managed. If the low carbon hydrogen production plant delivers 'in-spec' CO_2, then it will continue to receive CfD payments, even if the T&S

provider cannot take and store the CO_2 produced - and neither the hydrogen producer nor its customers will be penalised for the emissions involved.

Similarly, the income received by the T&S system owner will not be exposed to the operation of low carbon hydrogen production or other CO_2 capture plants connected to the system.

Should the payments to the T&S owner be 'sleeved' through low carbon hydrogen production and other CO_2 capture plants, it is clearly necessary that these are included within, and additional to, the downside fixed payment associated with volume protection described above.

BEIS' Business Model consultation explicitly recognises the 'chain-on-chain' risk and the need for this to be addressed. Further details are being developed with regard to the exact mechanism which is used.

3.3.5 Compatibility with existing markets

The market dynamics of the gas market are unchanged by the introduction of hydrogen CfD. As in electricity supply, the achievable sale price of hydrogen will vary between market sectors. For example, in the transport sector, the RTFO can be discharged with hydrogen. Transport fuels are valued at ~£50/MWh and enhanced further by the RFTO. This is considerably above the historic price of natural gas and hence if not excluded from this market, hydrogen may secure a price well above the prevailing hydrogen price in the heat market. The actual hydrogen price secured is dependent on the price to supply hydrogen to users as well as the production cost. This is modest if the filling station is close to the hydrogen distribution system.[30] It is relevant to note that the hydrogen distribution system which forms part of HyNet will expand across the North West rapidly through the mid-to-late 2020s. Importantly the price discovery mechanism described above allows the support received from the CfD to be adjusted downwards minimising the cost of support.

In the power market, low or zero carbon hydrogen may replace natural gas as a fuel for gas turbines (and gas engines) – the extent to which this is possible is machine dependent. As discussed in the accompanying report (for the North West Cluster Plan) developed by Uniper, full hydrogen substitution is expected to be possible for some new machines in the late 2020s.[31]

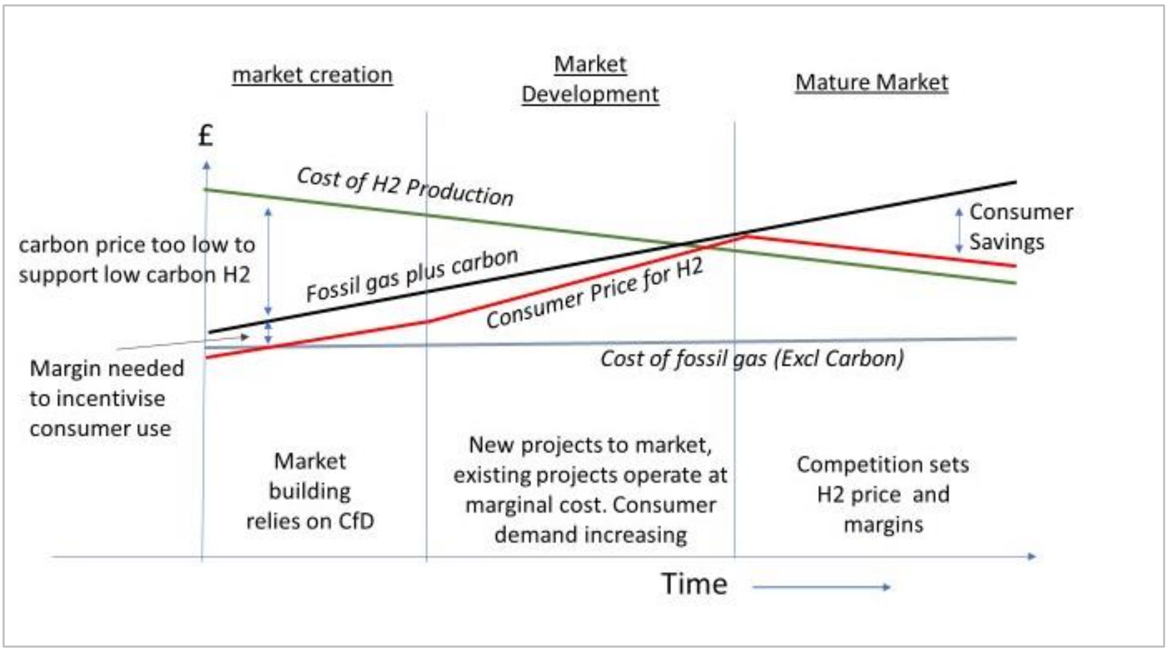
A power investor may choose to compete directly with unabated plant by simply purchasing hydrogen at close to the natural gas price. Alternatively, as Government is considering introducing a power CfD designed to allow investment in generation with CCUS, an investor in hydrogen fuelled generation may choose to pay the full hydrogen production cost and seek a power CfD. This CfD appears to be designed specifically to ensure that the plant has priority dispatch. A further alternative is for hydrogen to be purchased with the benefit of the hydrogen CfD and for the power generation cost only to be underwritten by one of the new power CfDs which are specifically designed to ensure that the plant is dispatched. Given that the market for fossil generation is to balance an increasing tranche of offshore wind and other renewable generation a further option is for Government to provide a capacity contract. Government is able to choose which routes are available.

3.3.6 Hydrogen Market Development

The creation and expansion from a nascent hydrogen market is illustrated in Figure 3-4. Initially only consumers exposed to the UK ETS have a financial incentive to reduce emissions. However, the exposure is insufficient to justify the cost of replacing natural gas with hydrogen and the risk to stable plant operation. The CfD bridges this gap. Early adopters in this phase of the market may require a degree of capital support to offset the costs of conversion or possibly see a cost saving by receiving hydrogen at a lower price than natural gas (on an energy basis) to manage conversion cost and risk. As confidence grows, and more consumers have the opportunity to utilise hydrogen rather than natural gas, demand grows and the required margin compared to the price of natural gas plus carbon cost decreases.

The marginal cost of hydrogen production from early plants decreases once capital has been repaid, reducing prices in a competitive market. Technology improvements in both CCUS-enabled and electrolytic hydrogen bring further cost reductions until the cost of production matches the cost of natural gas plus carbon cost. Subsequently prices are determined by competitive market dynamics.

Figure 3-4: Market Development – the Hydrogen Value Proposition



3.4 Hydrogen Distribution Business Model

Gas distribution currently operates as a regulated business with a separation between transmission across the country and distribution to end consumers. The aim of HyNet is to reduce the carbon intensity of the gas supply to customers, ultimately by replacing natural gas with hydrogen. The existing regulated gas distribution arrangements offer a natural framework to provide funding for the creation of hydrogen distribution infrastructure under the Regulated Asset Bases (RABs) of the GDNs.

The required changes must include both new pipelines and re-licensing of existing assets, and interactions with end consumers. System operation of the combined hydrogen and gas system will require potentially far-reaching changes. Hence there is a strong case for the existing gas distribution businesses to lead the roll out of hydrogen distribution infrastructure. Given that the aim is widespread change of all regional networks and the reduction of CO_2 emissions represents a universal benefit, there is a clear case for funding being sourced from all gas consumers, not just those in which hydrogen distribution infrastructure is first created.

As described below, Government is relatively advanced in terms of determining business models to support hydrogen production, but is in the very early stages of considering how best to fund distribution. Networks are critical to enabling a range of end-uses of hydrogen and to reducing the costs of production and distribution. Business model development must therefore be accelerated as a critical priority.

3.5 Business Models for Hydrogen Storage

Large scale hydrogen storage will be necessary to balance supply and demand of hydrogen, and to provide system resilience. Storage in salt caverns is widely accepted to be the most cost effective and least visually impactful way to achieve this. There is plenty of salt and demand for brine in Cheshire for the creation of suitable caverns for high pressure storage of gas including hydrogen. The operation of hydrogen storage salt caverns is closely associated with both the low carbon hydrogen production facilities and the hydrogen distribution network. As such, there are two potential operating models, which can be summarised as follows:

1) Storage functions in much the same way as natural gas storage today:
    a. Storage supports the development of a hydrogen market, by operators purchasing hydrogen during periods of excess supply, and selling it during periods of excess demand;
    b. Return on investment is achieved on the price difference between low and high periods of demand;
    c. Hydrogen distribution is operated by the GDN as for natural gas today.
2) Storage is an integral technical component of the hydrogen distribution network:
    a. Storage is provided as a commercial service to the GDN for the hydrogen distribution network, which is operated as a Regulated Asset Base (RAB);
    b. The GDN is responsible for filling storage when excess hydrogen is available, and for meeting demand by using available hydrogen production capacity supported by storage draw-down.

The pros and cons of each of the above models are explored in Table 3-2.

Table 3-2: Pros and Cons of Business Models

	Pros	Cons
1	Same operating model as with natural gas today, so understood. Shortage of storage opportunities around the UK could make this a very attractive proposition in the medium to long-term when balancing will become increasingly challenging.	Investment will only be attractive with an active, liquid market – this will not be in place for some time. Storage development will lag behind until investors can see that there will be sufficient price differentials to mitigate the investment risk. Not clear if this model can work if hydrogen supply is supported via CfD.
2	Simple. Encourages rapid development of multiple sources of hydrogen supply, and extension to other geographical areas without their own underground storage.	Risk of storage becoming the drag on hydrogen uptake due to lack of investment certainty. GDNs require certainty that investment in storage capacity will happen in parallel with the hydrogen network development. Risk that hydrogen supply may develop faster at low utilisation and Return on Investment (RoI).

Guidance from the regulator on acceptable costs of hydrogen storage service provision to the network RAB will enable storage contracts to be secured and investment decisions taken.

3.6 Business Models for CCUS Infrastructure

3.6.1 CO_2 Transport and Storage

In the UK's previous round of CCUS projects, the Commercialisation Programme, which ran from 2012 until its cancellation in 2016, single entities were formed which carried full-chain risk from capture to store. The projects were anchored on power production, and all the downstream costs of CO_2 transport and storage (T&S) were integrated into the cost of producing low carbon power, which was to be supported by a power CfD (Contract for Difference). This had the consequence of loading full-chain risk onto the single entity, which priced the risk into the CfD strike price – it also meant that the cost of over-sizing the CO_2 T&S infrastructure for future users was borne by the initial strike price. Finally, as the full chain was being funded from the private sector with limited risk backstopping from government, the cost of capital required by debt and equity providers was inevitably high.

The CCUS Cost Challenge Task Force, which reported in 2018, recommended a different approach.[32] It set out the formation of geographical clusters, underpinned by a multi-user CO_2 T&S network, socialising the network costs and providing government backstopping to key risks. This was a deliberate step away from the high-cost point to point approach of the Commercialisation Programme. Furthermore, the report highlighted that the preferred business model for shared CO_2 T&S infrastructure was a Regulated Asset Base (RAB) model. This well-established business model is used to economically regulate monopolistic networks in the UK, including gas, electricity and water. It is well understood by investors globally, and the stable regime results in low cost of capital.

Since 2018, government has been developing the RAB model for T&S to the point where it is now a well-advanced concept, and consultations are underway on specific points of detail. In a recent consultation, government has indicated a minded-to position to appoint Ofgem as the economic regulator (while, at the same time, recognising that there are key interactions with other regulators, such as the Oil and Gas Authority, which is the technical regulator for CO_2 storage).

The RAB-based approach is now known as the TRI (Transport and Storage Regulatory Investment Model) model and details were first published by government in December 2020. A further update, published in May 2021, sets out the following key responsibilities of the T&S Company (T&SCo):[33]

- Development, construction, financing, operation, maintenance, expansion, and decommissioning of the T&S network;
- Ownership of the onshore and offshore transportation network, and obtaining the licence and permit for the storage site, under the Energy Act 2008;
- Operation of the T&S network to ensure the operational parameters are within specified limits, manage network access, perform network planning, and administrate sector specific tasks;
- Review of the CO_2 metering and compositional analysis equipment installed by the users at the point of connection1; and
- Ensuring that the transportation and long-term storage of CO_2 is safe, efficient, and compliant with defined requirements.

Economic regulation will be similar to that undertaken for gas and electricity networks, with the regulator setting key paramaters such as allowed revenues, outputs and incentives, uncertainty mechanisms and duration of the regulatory period. The allowed revenue is set according to the standard formula:

$$\text{Allowed revenue} = (\text{WACC} \times \text{RAV}) + \text{Depreciation} + \text{Opex} + \text{Decom} + \text{Adjustments}$$

Where:

- WACC: Weighted average cost of capital to reflect expected cost of financing and reflective of risks to be borne by T&SCo;
- RAV: Regulated asset value which reflects efficiently incurred capital investment plus development costs;
- Depreciation: Payment to reflect depreciation, with exact structure (ie straight-line or backloaded) to be set by the regulator;
- Opex: Efficiently incurred operational expenditure;
- Decom: An allowance to cover end of project decommissioning;

- Tax: An allowance to cover tax liabilities;
- Adjustments: An adjustment to allowed revenue to accommodate adjustments for pass through costs (e.g. insurance costs) and any required true-ups further to the Output and Incentive structures.

Overall, industry is of the view that the model is a suitable basis for investment in T&S infrastructure and that there are no show-stoppers in the proposed approach. Furthermore, given the well-established nature of the construct, it is likely to secure low cost investment, therefore driving down costs for users, and making CCUS more cost effective overall.

At the time of final sign-off of this report, a further update has been just been published by BEIS.[34] Unfortunately, it has not been possible to incorporate analysis of this update here.

3.6.2 CO_2 Capture from Industry

The majority of industrial decarbonisation delivered by the HyNet project will be through the use of hydrogen to fuel switch away from natural gas. The market framework to allow this transformation is expected to be the Hydrogen CfD (Contract for Difference), which is set out in detail in Section 3.3. However, within the HyNet project there are a number of current, and potential future sources of process CO_2 – that is, CO_2 which is produced as a direct result of the chemical process used to manufacture the end product. These emissions cannot be mitigated by fuel switching, and can only be addressed through direct capture of emissions at these process facilities. In the HyNet region, this accounts for approximately 2-4MtCO2/yr.

At present, it is cheaper for these process industries to emit CO_2 than it would be to capture the CO_2 and to pay the fees for transport and storage. In order to make industrial CCUS economically viable for such industries, there needs to be a market framework which provides revenue support such that it is the same cost, or cheaper, for companies to capture and store CO_2 as it is to emit.

As described in Section 3.2, projects are currently bidding into Phase 2 of the Government's Cluster Sequencing process for the opportunity to negotiate business model support for CO2 capture. This includes not only the HyNet hydrogen production hub at Stanlow, but several other projects within the HyNet cluster.

BEIS is currently finalising the market framework, which is expected to take the form of an Industrial CO_2 CfD, which provides a payment between the cost of capture and a reference price. While the basic model is relatively simple, there is considerable complexity, particularly in the subject of how to treat free allowances issued under the UK ETS.

The CfD is set for a fixed period (likely to be 10 years plus a five year extension) and is split into two sections:

- Capital Repayment: Capital investment in the capture plant is repaid over a shorter period (up to 5 years) with a return commensurate with the cost of

capital for that particular company, determined through bilateral negotiation; and
- Opex Recovery: Operating costs for the plant (including the costs of using the T&S system, treated as a pass-through) set as a 'strike price' for the duration of the contract, less a reference price (a pre-determined price trajectory set at the start of the contract design to represent an assumed carbon price) and subject to further adjustments for forfeited free allowances.

While the structure of this mechanism is increasingly complex, it is designed to ensure that the industrial company can capture carbon but not be placed at material disadvantage to international competition, but at the same time minimising the opportunity for the industrial company to inadvertently profit from the process.

3.6.3 Power CCUS

The Dispatchable Power Agreement (DPA) is intended to cover technologies which have CCUS technology applied directly to a thermal power plant, including pre-combustion, post-combustion, and oxy-fuel technologies. This encompasses both new build CCUS power plants and retrofitted CCUS power plants. In addition, hydrogen-fired power plants which are standalone from hydrogen production infrastructure could be considered under the DPA, although this would be dependent on the development of an appropriate hydrogen business model.

BEIS published the most recent guidance on the design of the DPA in May 2021.[35] The DPA will be private law contract between the LCCC and the project company. It will be funded by power consumers and the existing LCCC mechanism for funding.

The DPA is essentially a power CfD with difference payments replaced by an availability payment and a variable payment. The variable payment is a very complex formula, designed to ensure that the CCUS plant dispatches just ahead of higher carbon alternatives, to maximise the contribution of those plants to decarbonization.

3.6.4 BECCS

As mentioned above, coupling of energy generation from biomass with CCUS allows a net reduction in emissions – so called negative emissions. In its 6th Carbon Budget Report, the CCC highlighted that to meet Net Zero in 2050, Bioenergy CCUS (BECCS) would need to play a key role and that a significant proportion of related deployment might come via the production of biohydrogen coupled with CCUS.[36]

At present, there is no associated business model to fund the negative emissions element of BECCS projects. Government has recently communicated to industry that the associated GGR (Greenhouse Gas Removal) model will not be available for some time. BEIS intends to consult on options later in 2022 and so it is probably at least two years behind the wider industrial carbon capture (ICC) model described in Section 3.6.2.

However, BECCS projects can seek support under the ICC model (see Section 3.6.2) via the Government's Phase 2 Cluster Sequencing process, described in Section 3.2. There are some restrictions around how this is applied to such projects, particularly around wider monetisation of negative emissions, but with flexibility to exit the ICC mechanism in future if such markets are more attractive and so this does allow carbon capture at EfW facilities to be financed.

To support the case for a BECCS business model, Government is seeking to fund relevant demonstration projects. The following two projects located close to the HyNet CO_2 pipeline at Peel NRE's 'Protos' site, have received funding from BEIS to design related demonstrations: [37]

- The INBECCS project, led by Bioenergy Infrastructure Group (BIG); and
- The Biohydrogen project, led by Advanced Biofuel Solutions.

Furthermore, Viridor is a core member of the HyNet consortium partner in respect of deploying BECCS at its energy from waste (EfW) plant at Runcorn, whilst others are also considering similar projects.[38]

This activity is such that the North West is likely to be at the vanguard of BECCS deployment, thus playing a significant role in meeting the national Net Zero target.

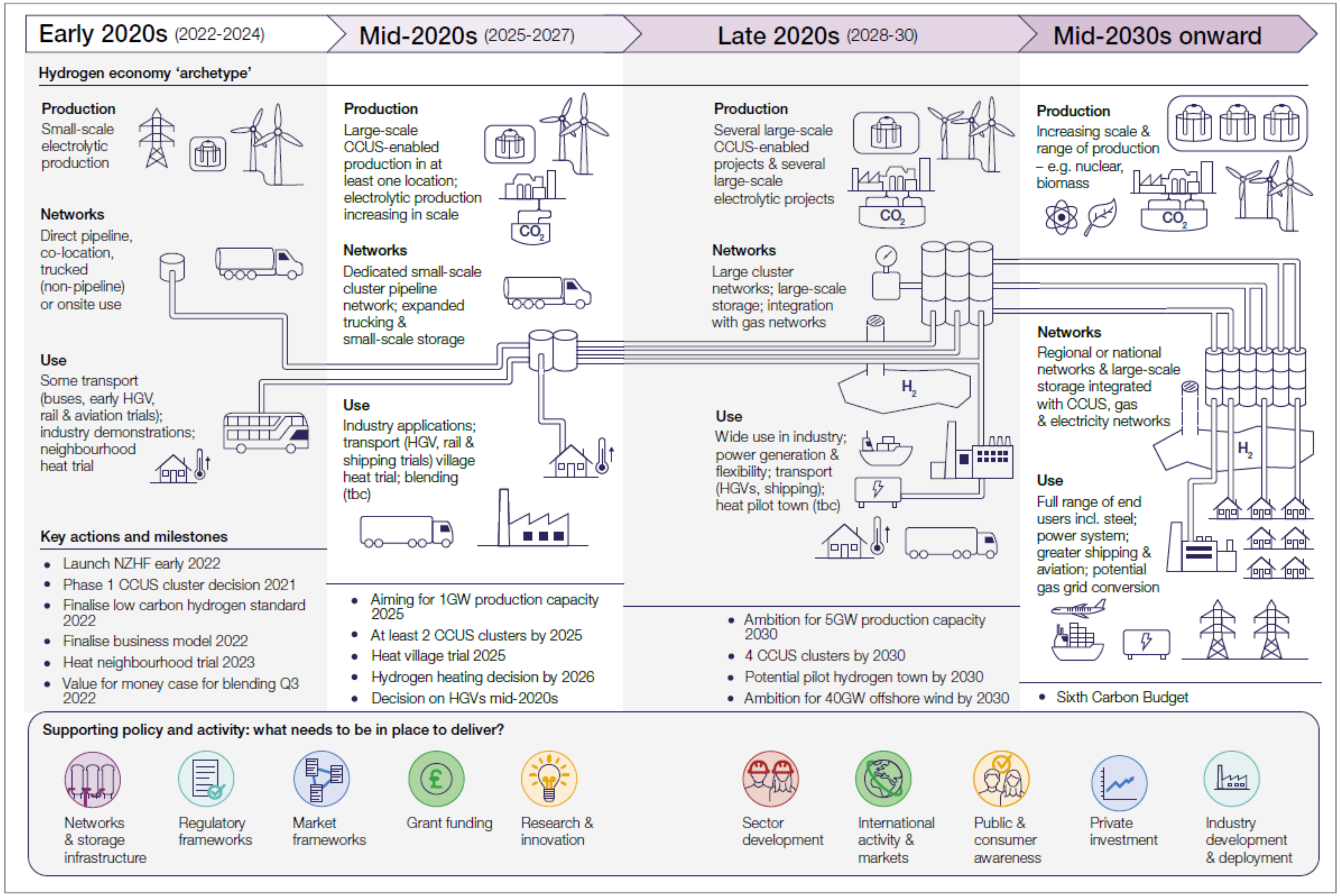
3.7 Integration of Policy and Regulatory Mechanisms

As demonstrated by the challenges experienced by previous Governments' attempts over the last decade or so, funding low carbon hydrogen and CCUS projects is a complex issue. Having been a shortlisted bidder in the 2015 CCUS Commercialisation Programme, with a project that sought to produce hydrogen, Progressive has significant experience and expertise in respect of the integration of business models which is required to make projects like HyNet happen.

In the recent UK Hydrogen Strategy, Government set out a range of uses for hydrogen and the infrastructure needed to enable these uses, as presented in Figure 3-5. Ultimately, for the market to develop in any meaningful way, support is needed for all these uses and this support needs to come in a variety of forms. In Figure 3-6, therefore, we have sought to provide a comprehensive picture of the participant entities and associated policy and regulatory mechanisms needed to enable hydrogen and CCUS projects.

It is likely that things will not proceed exactly as set out in Figure 3-6, but the intention is to put forward a relatively well developed 'straw-man' so that policy-makers and regulators can better comprehend the role of each organisation and how each entity needs to interact across the chain from hydrogen production to offshore CO_2 storage.

Figure 3-5: Hydrogen Economy in the 2020s



Hydrogen economy 'archetype'

Early 2020s (2022-2024)

Production
Small-scale electrolytic production

Networks
Direct pipeline, co-location, trucked (non-pipeline) or onsite use

Use
Some transport (buses, early HGV, rail & aviation trials); industry demonstrations; neighbourhood heat trial

Key actions and milestones

- Launch NZHF early 2022
- Phase 1 CCUS cluster decision 2021
- Finalise low carbon hydrogen standard 2022
- Finalise business model 2022
- Heat neighbourhood trial 2023
- Value for money case for blending Q3 2022

Mid-2020s (2025-2027)

Production
Large-scale CCUS-enabled production in at least one location; electrolytic production increasing in scale

Networks
Dedicated small-scale cluster pipeline network; expanded trucking & small-scale storage

Use
Industry applications; transport (HGV, rail & shipping trials) village heat trial; blending (tbc)

- Aiming for 1GW production capacity 2025
- At least 2 CCUS clusters by 2025
- Heat village trial 2025
- Hydrogen heating decision by 2026
- Decision on HGVs mid-2020s

Late 2020s (2028-30)

Production
Several large-scale CCUS-enabled projects & several large-scale electrolytic projects

Networks
Large cluster networks; large-scale storage; integration with gas networks

Use
Wide use in industry; power generation & flexibility; transport (HGVs, shipping); heat pilot town (tbc)

- Ambition for 5GW production capacity 2030
- 4 CCUS clusters by 2030
- Potential pilot hydrogen town by 2030
- Ambition for 40GW offshore wind by 2030

Mid-2030s onward

Production
Increasing scale & range of production – e.g. nuclear, biomass

Networks
Regional or national networks & large-scale storage integrated with CCUS, gas & electricity networks

Use
Full range of end users incl. steel; power system; greater shipping & aviation; potential gas grid conversion

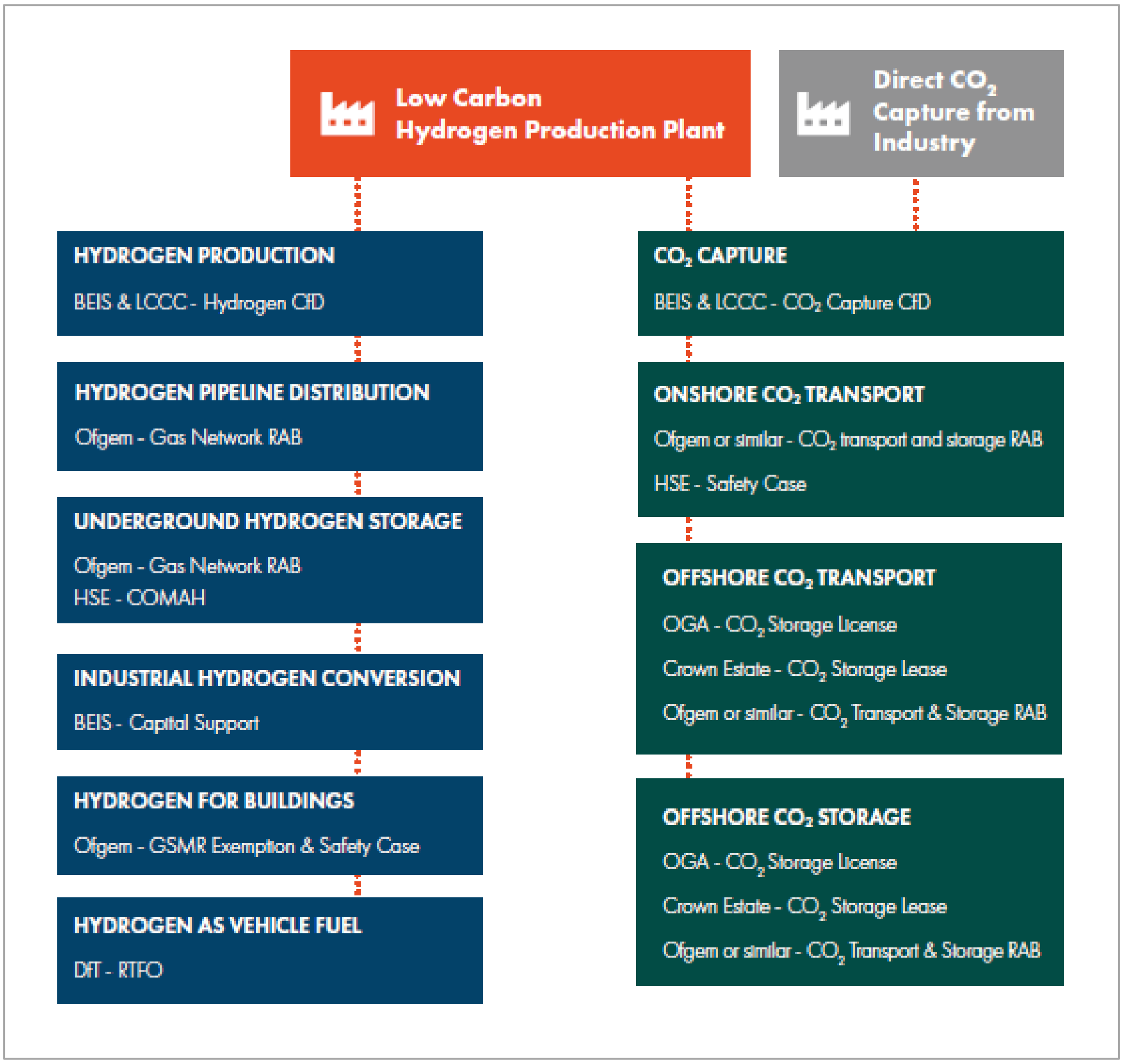
- Sixth Carbon Budget

Supporting policy and activity: what needs to be in place to deliver?

Networks & storage infrastructure
Regulatory frameworks
Market frameworks
Grant funding
Research & innovation
Sector development
International activity & markets
Public & consumer awareness
Private investment
Industry development & deployment

Source: BEIS, 2021

Figure 3-6: Enabling Policy and Regulatory Mechanisms for H_2 and CCUS



4.0 PLANNING LOW CARBON HYDROGEN AND CCUS INFRASTRUCTURE

The growth of low carbon hydrogen as a fuel for industry, heating, power and transport across the NW and beyond, will require a resilient supply and distribution system capable of meeting the demand range, including during supply interruptions.

In the UK energy market, there are clear limitations to the extent to which the deployment of hydrogen supply and storage infrastructure can be planned or optimised 'centrally'. A range of different actors will lead these deployments in response to market signals from a range of policy mechanisms and business models. However, it is important to consider how such deployment might be undertaken and phased to minimise costs for future hydrogen customers, which are currently supplied by natural gas via existing GDNs.

4.1 Network Sizing and Routing Considerations

4.1.1 Network Sizing

The basic principle for deployment of the hydrogen pipeline network for HyNet is that network capacity will run ahead of supply capacity, and supply capacity will run ahead of demand such that the whole system is demand, rather than supply constrained. Some forms of future demand will arise from sites and developers, which had never previously considered hydrogen, but on learning of the pipeline passing nearby and understanding the relevant business models, will be economically driven to switch away from natural gas.

This approach is such that new customers can be confident that energy or fuel is available, which is critical to enabling investment decisions relating to industrial conversion and the development of low carbon flexible power generation. Consequently, if, due to rapid market development, hydrogen demand accelerates exponentially, the production, distribution (and storage) system can absorb this to a degree before it needs to expand further.

It is important to size the network according to the largest likely peak demand from all users. This is because it is relatively inexpensive to increase the capacity of the pipeline from the outset compared with attempting to add additional pipelines later on, which would involve further consenting and permitting along with another phase of construction, all which would come at considerable cost.

At the same time, it is important to ensure that the additional costs of 'oversizing' the initial network to meet future demand do not make the costs of the project unattractive, both in absolute terms and in respect of the levelised cost of (CO_2) abatement (LCoA) delivered by switching to low carbon hydrogen. This is a delicate balance, and it is therefore a challenge to which the HyNet consortium, and particularly Cadent, as the most likely operator of the hydrogen network, is devoting considerable attention to at present. It is the subject of significant ongoing work from both a:

- A technical perspective:
    - In respect of flow assurance analysis across the network, including interaction with the hydrogen storage infrastructure; and
- A commercial and regulatory perspective:
    - In respect of how the new hydrogen network will be funded, as discussed in Section 3.4.

Another important consideration in respect of planning network infrastructure is the specific ‘nature’ of the future demand profile for hydrogen. Gas network operators tend to use a combination of forecasts of ambient temperature and ‘wind chill’ to predict demand on the network, i.e. forecasting is primarily related to external weather variables.

As the energy system develops, however, particularly in response to electrification, it will be necessary to overlay further variables into such models when forecasting demand for hydrogen, including:

- Wind speed and sunlight:
    - As some heating becomes electrified, there will be greater or lesser demand for hydrogen for heating according to the output from wind and solar farms;
    - As wind speed falls, flexible generation is called upon to meet demand. This flexible generation, known as ‘peaking plant’ is increasingly provided by gas-fired assets (both turbines and reciprocating engines) connected to gas distribution networks. This marks a significant shift from most gas generation assets being combined cycle gas turbines connected to transmission networks. With increasing penetration of renewables and the retirement of historic baseload, the requirement for flexible generation has grown significantly, to the extent that it is now a noticeable element of the demand profile at gas distribution network level. It is expected that the majority of future flexible power generation will be hydrogen-fired.
- Battery electric vehicle (BEV) charge times:
    - Similar to the usual peaks in gas and power demand during weekday mornings and early evenings, there are likely to be new peaks on the electricity network when households and business charge BEVs. At such times, there may be a lack of power for other activities and so hydrogen-fired generation will be called upon to help meet the peak in demand.

In addition to the existing approach used by GDNs, which is based on data on heat variables, therefore, the above information can in the future be used to:

1) Support planning of new hydrogen networks and associated storage infrastructure; and

2) Provide day-ahead information to National Grid in respect of required gas flows into distribution networks from the National Transmission System (NTS).

In the future, assuming such models are adopted, this will help optimise both network planning and operations, thus reducing the cost for the customer. It is also likely to be sensible to develop such systems in partnership with Electricity Distributed Network Operators (DNOs); for example, Electricity North West (ENW) and/or SP Energy Networks (SPEN) in respect of hydrogen and natural gas networks in the North West.

4.1.2 Network Routing

At the same time, the route of the HyNet hydrogen pipeline network will be determined to a large extent, by a number of core ‘demand’ anchors. These are both major industrial and power generation sites, along with a small number of ‘offtakes’ for blending hydrogen into on the gas distribution network. These are the locations on the gas network where natural gas is currently injected from the NTS into Cadent’s local transmission system (LTS). These represent the points at which a blend of hydrogen will initially be injected into the network at up to 20% by volume, as is being demonstrated by the HyDeploy programme.[39] These offtakes also provide the initial locations (along with further locations required to ensure full network coverage) for injection should full conversion of the existing network to 100% hydrogen be undertaken in the future.

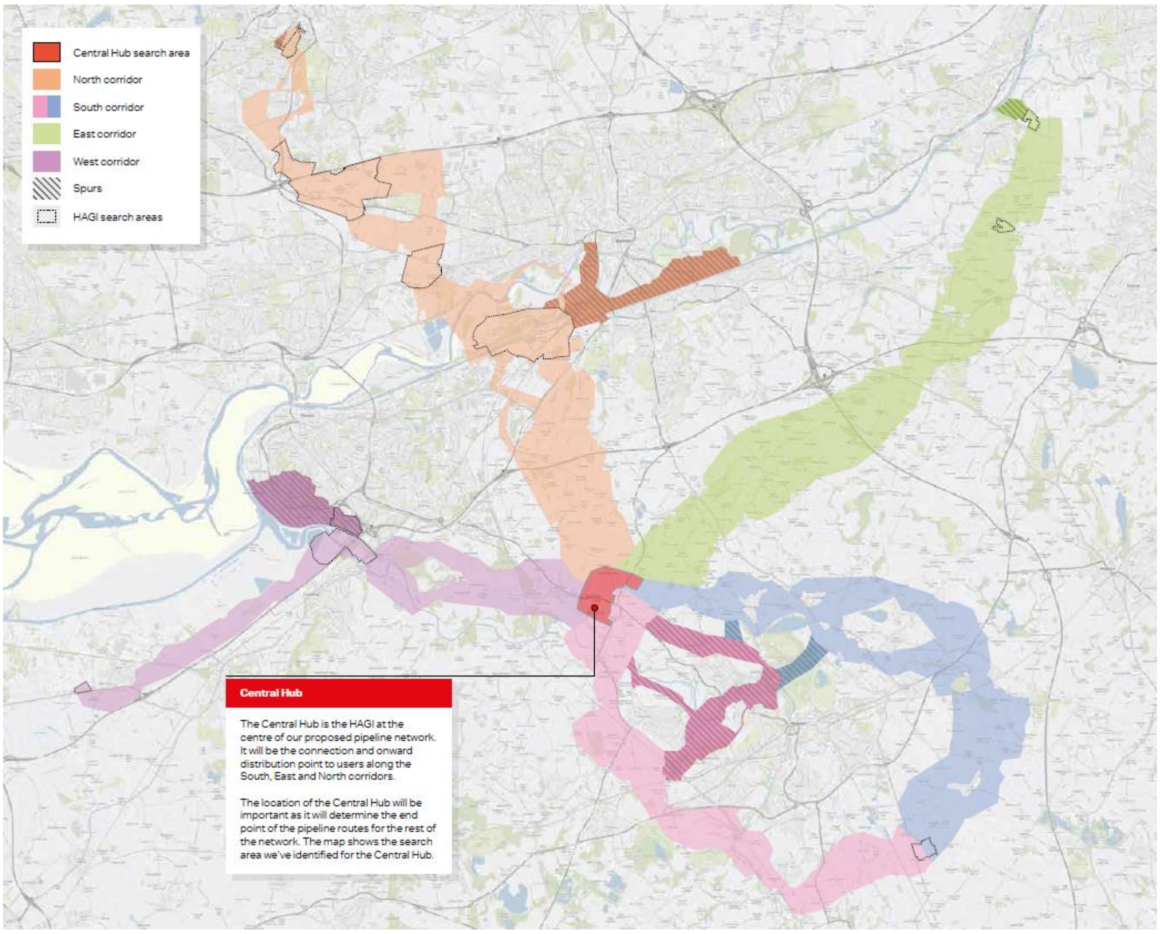
At the same time, the network routing must take into consideration the need to connect other suppliers of hydrogen. At the present time, no applications for planning consent have been submitted by any major suppliers other than the planned HyNet production hub at Stanlow, but this is likely to become more of a factor in later phases of network development. It is worth noting in this context that deployment of the network is likely to attract and incentivise new sources of electrolytic hydrogen, which might locate themselves near to the network infrastructure. This is because such plant, which are likely to be relatively small in the late 2020s, will be provided with both a secure off-take market, and have no need for expensive, above-ground storage, which might otherwise be required. In the 2030s, however, the potential supply market might look rather less nascent and therefore new pipeline routes might be largely defined by new sources of production being identified, as discussed in Section 0.

4.1.3 Current Status and 2030 Deployment

The HyNet pipeline is being built in phases, but the early ‘feeder’ lines need to be designed to be sufficiently large to carry enough gas to incorporate demand which is connected in the later phases of deployment.

At the time of writing, HyNet consortium partner, Cadent, has just launched a Development Consent Order (DCO) process (for Nationally Significant Infrastructure) for the first major phase of network development.[40] The DCO will be to consent the first 80-90km of network, which will connect a number of major gas users and also a small number of network blending locations. The DCO process is such that Cadent must consult on options prior to selecting a preferred route and so at this stage, we can only present broad routing corridor options from the non-statutory consultation, as presented in Figure 4-1.

Figure 4-1: Proposed HyNet Hydrogen Network Routing Corridors



Central Hub

The Central Hub is the HAGI at the centre of our proposed pipeline network. It will be the connection and onward distribution point to users along the South, East and North corridors.

The location of the Central Hub will be important as it will determine the end point of the pipeline routes for the rest of the network. The map shows the search area we've identified for the Central Hub.

Based upon initial flow assurance modelling to a Pre-FEED level, the feeder pipelines will be sized to transport a minimum of 30TWh/annum of hydrogen. It should be noted that the pipeline must be sized to meet an increase in demand well beyond 2030, as trying to lay new or larger pipelines later can be equally costly as the initial deployment. The final design and capacity, however, is subject to the ongoing FEED study and DCO process led by Cadent.

Ahead of the DCO submission, an initial phase of network deployment is planned in 2025, which will connect major gas users in close proximity to the hydrogen production plant at Stanlow – this small network will not require a DCO. There will also be a subsequent DCO process, for a further 350km of pipeline, to connect sites in Liverpool, South Lancashire, North Wales and further into Manchester by 2030. It is likely that this DCO will commence prior to the end of the current DCO process.

4.2 Hydrogen Production to 2030

4.2.1 CCUS-enabled Hydrogen Production

CCUS-enabled hydrogen production can be more easily scaled via the addition of new lines or ‘trains’ at existing production sites. The associated business model, however, as discussed in Section 3.0, and therefore different nature of how supply is likely to be financed, is such that it is far more intrinsically linked to demand than is distribution. In simple terms, the costs of production will not be socialised across gas customers and so attraction of private sector finance will depend on customers buying a large proportion of output capacity (although noting that Government will provide a level of volume protection).

The vast majority of hydrogen production in the pre-2030 period will come from a series of plants to be located at the Stanlow hub. Progressive and Essar completed a Front-End Engineering and Design (FEED) study in August 2021, in partnership with the technology provider, Johnson Matthey (JM), for the first train of Low Carbon Hydrogen (LCH^{TM}) production. This design is based on JM's proprietary auto-thermal reforming (ATR) technology, which offers higher efficiencies and greater compression of CO_2 than conventional steam methane reforming (SMR).[41] Also in August 2021, the HyNet project launched a public consultation process to support a 'hybrid' application for planning consent for the plant, which relates to both the first train and subsequent trains.[42]

The planned deployment of hydrogen production capacity at Stanlow through to 2030 is presented in Table 4-1. As mentioned above, this level of capacity is designed to ensure that the distribution network is not supply-constrained, and so broadly reflects potential levels of maximum demand presented in Section 5.0.

Table 4-1: LCH^{TM} Capacity Deployment to 2030

	2025	2026/7	2028	2030
Annual LCH^{TM} Deployment (TWhpa)[1]	3	6	12	12
Cumulative LCH^{TM} Deployment (TWhpa)[1]	3	9	21	33

Notes:

1. Hydrogen production is presented gross of parasitic load of around 10% of hydrogen used to fuel the LCH^{TM} process

4.2.2 Electrolytic Hydrogen Production

A range of sources of electrolytic hydrogen – derived from electrolysis using power generated from wind, solar and tidal – will increasingly 'plug-in' to the HyNet pipeline network. Whilst these sources will be important to enable meeting of the UK's Net Zero target, their intermittency is such that in the short to medium term, they alone will not provide sufficient security of supply for hydrogen customers, nor are they likely to operate at sufficient scale in this period to provide the basis for initial investment in a pipeline network.

Electrolytic hydrogen currently has a far greater cost per unit of hydrogen produced than CCUS-enabled hydrogen. Subject to the determination of the current BEIS consultation on business models for hydrogen production (see Section 3.3), therefore, prior to 2030 any deployment is likely to be somewhat lower than for CCUS-enabled hydrogen production.[43] We have therefore not devoted analysis to pre-2030 deployment in this report, but do undertake related analysis for the 2030-2040 period in Section 4.4.2.2. Furthermore, a concurrent study led by Equans as part of the North West Cluster Plan, considers both the potential locations and scale of electrolytic hydrogen generation.[44]

4.3 Hydrogen Storage to 2030

The hydrogen demand profile from industry will be relatively 'flat' once there are multiple manufacturing sites connected to the network. However, demand from both power generation and heating will be highly variable. Demand for heating will be driven by ambient temperatures, whilst demand from flexible power generation sites will be driven by both network demand and amount of renewables generation, with low wind conditions in particular driving a need to dispatch hydrogen-fuelled dispatchable generation. Alongside hydrogen supply infrastructure, therefore, bulk hydrogen storage assets will be required to help manage fluctuations in demand.

Bulk underground storage in salt caverns enables the network to support peak instantaneous demand whilst the low carbon hydrogen production fleet can be designed and built to cover the annual average level of demand. There is a complex balance to determining the optimum amount of storage to maximise flexibility, balancing and resilience. Such network design issues are being addressed as part of ongoing distribution network modelling work and the ongoing FEED study in respect of the HyNet hydrogen network.

Bulk storage of hydrogen also provides network resilience in case of any planned or unplanned shutdown of any low carbon hydrogen production capacity. This is critical, particularly in the early phases of operation, whereby there are only very limited supply nodes compared with the current natural gas LTS, which as mentioned above, has a range of entry points from the NTS, feeding in from an array of different sources of supply.

As discussed above, the hydrogen network will also enable renewable sources of electrolytic hydrogen to be transported at low cost. Bulk storage also will be essential to managing the intermittency associated with wind, solar and particularly larger offshore wind farms, as hydrogen production from these comes onstream in later years. In addition, the proposed Mersey Tidal project being developed by LCRCA, may be a further large source of generation.

4.3.1 Characterisation of the Cheshire Salt Basin

The Cheshire salt basin presents a natural choice of area for the development of significant geological hydrogen storage infrastructure in the HyNet area. This avoids the need for long hydrogen pipelines across the country and therefore significantly reduces both the cost and timeline associated with the development and deployment of these assets.

The Cheshire salt basin is ideally situated and provides natural gas storage capacity to the existing NTS and LTS, and therefore a strong understanding of the conditions and constraints involved in the area, already exists. The salt fields have a total area approaching 1800 km^2, with the salt formations beginning at a depth of several hundred meters. As presented in Table 4-2, there are a range of existing and consented natural gas storage projects in Cheshire, comprising 1,503 million m^3 of natural gas.

Table 4-2: Existing and Planned Natural Gas Storage in Cheshire

Site Name	Number of Caverns	Lead Operator / Developer	Status	Year of Start of Operation	Capacity (Million m^3 natural gas)
Holford	8	Uniper	Operating	2013	160
Stublach	28	Storengy	Operating	2014-2020	400
Hole House	4	EDF Trading	Operating	2001	75
Holford H-165[4]	1	Cadent	Operating	1984	0.2
Hill Top	10	EDF Trading	Operating	2016	20
King St	9	King St Energy	Consented	n/a	348
TOTAL					**1,003**

In addition to the storage sites presented in Table 4-2, in 2015 Inovyn received a DCO for the Keuper natural gas storage complex. It has not sought to develop this site for natural gas, but instead is currently seeking to vary the DCO to enable Keuper to be used for hydrogen storage as part of HyNet.

In order to ensure structural integrity, salt caverns must be suitably spaced. The spacing is calculated based on the mechanical and physical properties of the surrounding salt, considering permeability, yield strength and the behaviour under cyclic forces from cavern use. Information presented in an ETI report suggests that around three times the cavern radius is required between the perimeters of each cavern.[45] This is a key determinant of the total land area required.

Although the salt caverns are fixed volume cavities, they can be operated across a range of pressures to provide flexible storage capacity within a pre-defined range. The storage capacity of each cavern is defined by the 'operational pressure window' of the cavern. This window exists because the maximum pressure achievable is limited by the porous structure of the surrounding rock, as well as the structural integrity of the cavern. The minimum operating pressure is determined by the depth of the cavern and hence the compressive force exerted by the surrounding rock. Therefore, when storing gas, salt caverns are operated between these two pressures, giving rise to a maximum working capacity. Linked to this is the need to maintain similar pressures in surrounding caverns to prevent excessive stressing of the rock between caverns.

4.3.2 Modelling of Hydrogen Storage Requirements in 2030

Modelling has been undertaken to provide an estimate of the number of caverns required in the Cheshire salt fields to balance the potential demand on the HyNet hydrogen network. To determine this, data in relation to the Cheshire salt basin in a

2018 report from the Energy Technologies Institute (ETI) has been used, along with evidence from existing natural gas salt cavern storage operators in Cheshire.[46] The assumptions used in the model are presented in Table 4-3. However, it should be noted that a FEED study, led by HyNet consortium partner, Inovyn, is currently being undertaken to determine the design of the caverns and so the data presented in Table 4-3 should be regarded very much as indicative only.

Table 4-3: Assumptions used in Modelling of 'a Representative Cavern'

Parameter	Assumption
Cavern roof depth (below ground level)	545m
Cavern volume	300,000 m^3
Nominal operating temperature	25.2 °C
Working pressure range	30-105 barg
Working capacity	1,800 tonnes H_2
Storage capacity	72,000 MWh H_2 (HHV)

To model the need for hydrogen storage, the hourly production level was compared to the total hourly demand (across each day of the year) from each sector and an excess or deficit was identified for each hour. An excess indicated that hydrogen would need to be injected into the storage caverns and a deficit indicated a need to draw hydrogen out from the caverns. This interplay between supply and demand allowed a profile of total storage requirement in 2030 to be constructed and the development of a quantitative estimate of the maximum storage capacity required.

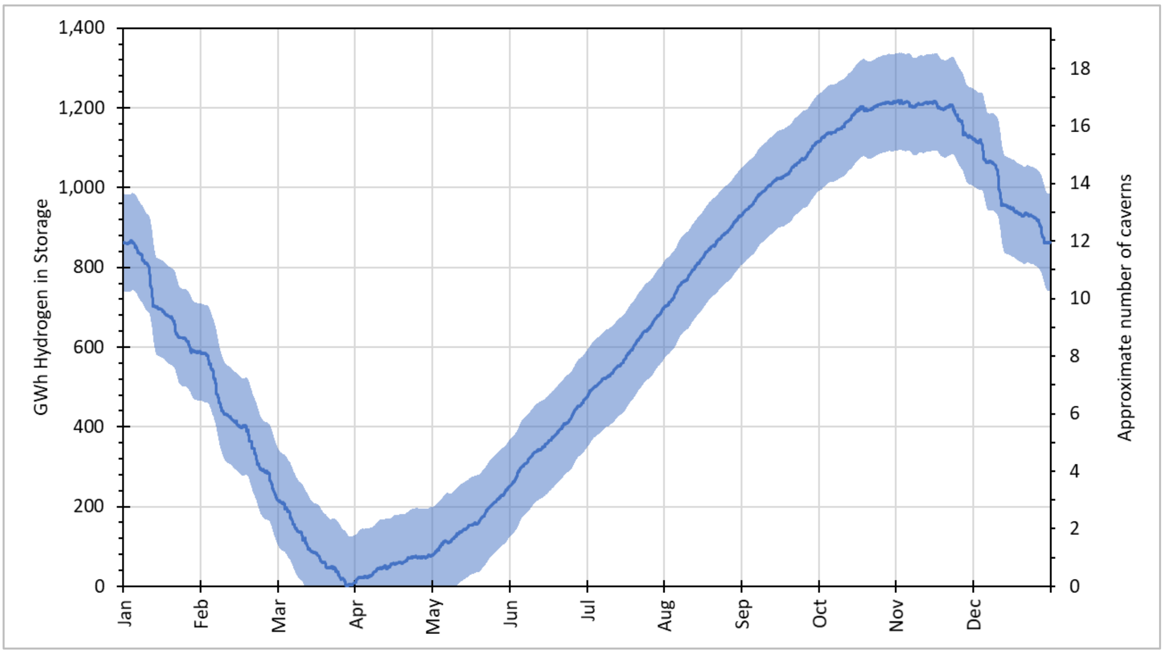
Figure 4-2 shows the results from the hourly modelling of demand. The majority of storage is required for seasonal balancing, with both blending and dispatchable (low load factor) power generation requiring significant amounts of hydrogen to be stored in the build-up to winter. It should be noted, that this analysis is based on the profiles of wind demand and air temperature for three consolidated years only. The outcome, therefore, may be somewhat different for other years and so as mentioned above, far more comprehensive work is being undertaken by HyNet consortium partner, Inovyn, prior to finalising storage design.

The solid line in Figure 4-2 indicates the particular scenario modelled and the shaded area accounts for uncertainty in the modelling assumptions, such as weather and hydrogen demand profile variability. Consequently, the total storage required for the 2030 system was found to be up to 1.3TWh. Using a 'representative cavern' for the Cheshire salt fields, as described in Table 4-3, this equates to approximately 18 caverns (or 366m Nm^3).

To put this total requirement in context, the Stublach Natural Gas Storage Facility currently operating in Cheshire (one of several such facilities) consists of 20 caverns and is quoted to have a total storage capacity of 400m Nm^3. Consequently, the facility required by HyNet in 2030 comes within the bounds of current normal practice, albeit for storage of hydrogen rather than natural gas.

As this modelling assumes a flat hydrogen production profile from the fleet of low carbon hydrogen production plants, this represents a maximum cavern requirement by 2030. As demand for hydrogen grows further beyond 2030, however, particularly in respect of network blending (and potentially full network conversion) and from the dedicated flexible power sector, both which have very ‘peaky’ demand profiles, additional storage capacity will be required.

Figure 4-2: Indicative Total Hydrogen Storage Profile in 2030



4.3.3 Peak Flows

Understanding the maximum gas flows to and from the storage caverns is essential to ensure pipelines are sized to sufficient capacity. If the pipeline connections to storage caverns are too small the gas velocity will reach unacceptably high levels, incurring frictional pressure drop penalties as well as mechanical vibrational stresses on the pipe walls. The proposed operational characteristics for hydrogen in 2030 are similar to those experienced by for natural gas.

4.4 Extension of HyNet Infrastructure to 2040

Building on the infrastructure design for 2030, as described in Sections 4.1 to 4.3, the deployment of further extended supply, distribution and storage capacity will be based on the principle that there must be a clear and wider linkage between:

- Hydrogen production capacity;
- Hydrogen distribution capacity;

- Hydrogen storage capacity; and
- The CCUS transport and storage system 'flow rate' capacity.

The significant potential hydrogen flow rates in 2040, combined with the level of uncertainty associated with planning for such a long time period ahead, is such that it would not be meaningful to seek to plan infrastructure deployment to any great level of detail in this report. However, in the Sections below, we have described how the 2030 infrastructure might be extended in terms of both:

- Geography - to serve a greater number of industry sites, both in terms of potential:
  - Hydrogen supply; and
  - CO_2 transport and storage.
- Depth – to provide greater capacity to service industry sites in existing areas; again, both in terms of hydrogen supply and CO_2 transport and storage.

For all sectors, we have considered Bull and Bear scenarios, which demonstrates the level of uncertainty relating to forecasts nearly 20 years into the future.

4.4.1 Hydrogen Network

During the 2030s, the hydrogen network may be extended to supply the residential sector subsequent to a potential positive future policy decision being made on the use of hydrogen to heat homes. This decision would mean full network conversion in many parts of the HyNet area, as defined in Section 2.2.1. To a large extent, this is likely to shape the extent to which further industry sites, which might not otherwise be connected to the network due to their relative isolation, are able to receive a future supply of hydrogen.

Beyond the initial phase of deployment to 2030, three further major phases of geographical expansion of HyNet are possible, albeit these extend beyond the North West. These phases of expansion are summarised as follows, with full postcode data provided in Table 4-4 to Table 4-6. In combination, these areas incorporate 24% of the UK's total population:

- Phase 1 - the core area of Liverpool and Manchester, Cheshire (and Deeside), Warrington and Wigan along with some post codes in Crewe, Preston and Flintshire (see Section 2.2.1);
- Phase 2 – this area comprises the remaining post codes in Crewe, Preston and Llandudno, plus Blackburn, Bolton, Blackpool, Oldham, Stockport and Stoke-on-Trent;
- Phase 3 – comprises demand in Lancashire, Telford, Walsall, Wolverhampton, Dudley, Birmingham, Worcester and Coventry; and
- Phase 4 - incorporates demand in the Wales and West Utilities (WWU) network area, including Hereford, Shrewsbury and Llandridrod Wells.

Table 4-4: Spatial Layer for HyNet Expansion Modelling – Phase 2

City or Town	Primary Postcode Identifier	Secondary Postcode Identifier
Crewe	CW	1-5, 11-12 and 98
Preston	PR	0-7, 11, 25-26
Llandudnno	LL	15-78
Blackburn	BB	All
Bolton	BL	All
Blackpool	FY	All
Oldham	OL	All
Stockport	SK	All
Stoke-on-Trent	ST	All

Table 4-5: Spatial Layer for HyNet Expansion Modelling – Phase 3

City or Town	Primary Postcode Identifier	Secondary Postcode Identifier
Lancashire	LA	All
Telford	TF	All
Walsall	WS	All
Wolverhampton	WV	All
Dudley	DY	All
Birmingham	B	All
Worcester	WR	All
Coventry	CV	All

Table 4-6: Spatial Layer for HyNet Expansion Modelling – Phase 4

City or Town	Primary Postcode Identifier	Secondary Postcode Identifier
Hereford	HR	All
Llandridnod Wells	LD	All
Shrewsbury	SY	All

4.4.2 Hydrogen Production

4.4.2.1 CCUS-enabled Hydrogen Production

As the HyNet project expands beyond 2030, new low carbon hydrogen capacity will be constructed away from Stanlow due to constraints on the HyNet CO_2 pipeline system mass flow rate and storage volumes in Liverpool Bay. Any production site must have access to CO_2 storage and therefore Barrow, which is located in close proximity to the offshore gas fields at Morecambe Bay appears to be a sensible location for a future production hub. In addition, siting hydrogen production at Barrow:

- Has the potential to enable the use of currently 'undeveloped' gas reserves from other fields (than Morecambe Bay) in the East Irish Sea as feedstock for low carbon hydrogen production:
  - There are potentially large reserves of natural gas in adjacent reservoirs which could become economic once a market for hydrogen is established.
- Is favourable in terms of its good connections to the NTS for both:
  - Natural gas supply for low carbon hydrogen production; and/or
  - Hydrogen offtake either in respect of a blend into the NTS, or should some NTS pipelines be fully converted to hydrogen in the future.
- Could facilitate the development of a new liquified natural gas (LNG) terminal in the North West (none currently exist) with ships delivering feedstock for low carbon hydrogen production.

The existing Barrow Gas Terminals are operated by Spirit Energy, of which Centrica, at the time of writing, remains the majority shareholder. It is anticipated that similar levels of hydrogen production to those set out for Stanlow in Section 4.2.1 (up to 30TWh), could be deployed at Barrow by 2040.

4.4.2.2 Electrolytic Hydrogen Production

At present, the HyNet partners are engaged in several development opportunities for hydrogen supply from both onshore wind and solar photovoltaic sites, and from offshore wind located in the East Irish Sea, which may feed into the HyNet network in the 2030s. Similarly, the partners have also engaged with LCRCA in respect of the proposed Mersey Tidal project, which is currently in the 'pre-FEED' stage of development.

It is too early in the project lifecycle to determine whether any of these operators or assets will generate electrolytic significant hydrogen for supply into the HyNet network. However, by way of example, an initial estimate of the potential amounts of hydrogen which might be produced by offshore wind is set out below.

Existing offshore wind assets are generally all supported by either the Renewable Obligation (RO) or power CfD. For as long as support under these mechanisms endures for each site, it is more challenging for these assets to be diverted to hydrogen production. However, some operators may switch their assets to hydrogen production either prior to, or following expiry of, 15-year RO or CfD contracts, which will depend upon:

- The physical integrity of the assets and remaining estimated lifetime required to justify investment in an electrolyser and associated infrastructure;
- The fall in price of electrolysers and associated infrastructure over the next decade or so as a result of technology 'learning'; and
- The value of PPAs for hydrogen compared with those for electricity (taking into consideration the RO or CfD support).

The Crown Estate has recently awarded leases under 'Round 4' of its offshore wind leasing competition. For these planned Round 4 assets (and those from future rounds), the potential production of hydrogen will largely depend upon the hydrogen business model and whether:

- It is attractive compared with electricity equivalent (currently the power CfD); and
- Whether, to receive support, there needs to be a direct connection between the wind farm and the electrolyser or if this can be done via a 'sleeving' arrangement and use of grid electricity (and if this is still subject to all grid charges).

As discussed in Section 3.3, such issues are being consulted on by BEIS as part of the ongoing Hydrogen Business Models consultation.[47] However, as a statement of intent, the consultation states that BEIS is minded to invite project applications in 2022, for assessment against defined evaluation and eligibility criteria, followed by a bilateral process with selected projects to enable final investment decisions to be made from 2023.

Details of all existing offshore wind assets and those planned under Round 4 are presented in Table 4-7, alongside the potential hydrogen production from each site if all electricity production was used for electrolysis. This assumes that corresponding electrolysers are sized to maximise their load factor, with smaller assets maximising their output. However, in reality some developers, which can operate the wind farm and electrolyser as integrated assets, may install larger electrolysers to maximise hydrogen production when power prices are low, thus reducing Opex per unit of output, but with a higher Capex.

The analysis in Table 4-7 shows that the current and planned offshore wind generation of nearly 7GWe in the East Irish Sea, could potentially produce in excess of 12TWhpa of hydrogen by 2040. In reality, this is very likely to be a significant overstatement of the amount of electrolytic hydrogen which will be produced from these offshore wind sites. It also puts in context the significance of the 30TWhpa planned to be produced by HyNet production hub at Stanlow by 2030. However, this analysis does not take into consideration production from later Crown Estate lease rounds or that from other forms of renewables, including onshore wind and solar, along with tidal, for which it is too early to determine the scale of the proposed Mersey tidal project.

Table 4-7: Existing and Round 4 Offshore Wind Assets

Operator	Asset Name	Status	First Commercial Operation	Landfall / Location of Substation	Peak Output Capacity (MWe)	Potential Annual H_2 Production (GWh)[1]
Orsted	Barrow	Operational	2006	Heysham	90	158
	Burbo Bank	Operational	2007	Wallasey (Wirral)	90	158
	Burbo Bank Extension	Operational	2017	Rhyl (N Wales)	258	452
	Walney 1	Operational	2012	Heysham	367	644
	Walney 2	Operational	2012	Thornton (Blackpool)		
	Walney Extension	Operational	2018	Heysham	659	1,156
	West of Duddon Sands	Operational	2014	Heysham	389	682
RWE	North Hoyle	Operational	2003	Rhyl	60	105
	Gwynt y Mor	Operational	2015	Bodelwyddan	576	1,010
	Rhyl Flats	Operational	2009	Towyn	90	158
	Robin Rigg West	Operational	2010	Seaton	90	158
	Robin Rigg East	Operational	2010	Seaton	84	147
	Awel y Mor	In consenting	tbc	Bodelwyddan	576[2]	1,010
Vattenfall	Ormonde	Operational	2011	Heysham	150	263
BP/EnBW	Site 4 (Round 4)	Pre-consenting	tbc	tbc	1,500	2,631

	Site 6 (Round 4)	Pre-consenting	tbc	tbc	1,500	2,631
Offshore Wind Ltd	Site 5 (Round 4)	Pre-consenting	tbc	tbc	480	842
Total					**6,959**	**12,204**

Notes:

1. Analysis assumes:
    a. 47% wind load/capacity factor (based on annual hourly load factors of four different offshore wind farms)
    b. 65% electrolyser efficiency
    c. That the electrolyser is sized to 40% of peak output, which gives it a 77% load factor
    d. Hydrogen production is prioritised over electricity production at all times
2. At the time of writing, RWE had not publicly confirmed an output capacity, and so for the purposes of this analysis we have used the same value as for Gwynt y Mor

4.4.2.3 Opportunities for Hydrogen from Nuclear Generation

Moorside Nuclear Power Station at Sellafield in Cumbria was originally a development project proposed by NuGen for three reactors situated close to the Sellafield site, with total capacity of 3.4 GWe. NuGen was a subsidiary of Westinghouse Electric Company (a subsidiary of Toshiba), which entered administration in 2018, ultimately leading to the failure of the project.

The rejuvenation of the nuclear sector has been stimulated by the 2018 'Nuclear Sector Deal', under which the sector aims to achieve a target of a 30% reduction in the cost of new build projects by 2030 and to deliver a long-term vision of innovation-led growth and successively lower generation costs.[48]

The Moorside Clean Energy Hub was born out of the Nuclear Sector Deal and out of the previous Moorside Nuclear Power Station project. The Hub now involves two core projects:

- An EDF-led consortium, which is seeking to build 3,200MWe of European Pressurised Water ("EPR") reactors:
    - EDF plans to use its experience on Hinkley C (and potentially Sizewell B) and replicate the design to reduce the costs and time required to develop and build Moorside.
- A consortium led by Rolls Royce is seeking to build Small Modular Reactors ('SMR'):
    - In 2019 Rolls Royce received £18M of Government funding to start designing its SMR system and now expects to deliver SMR complexes within 5 years, from construction to first power delivered. It is reported to be aiming to complete the first plant (potentially at Moorside), rated at 470MW, by the early 2030s.

Hydrogen can be produced from nuclear power via two processes: high temperature electrolysis, and through high temperature thermochemical dissociation of water. The intent at Moorside is that 'excess' electricity, when electricity prices on the grid are low due to low demand and/or high supply (i.e. windy weather), will be used for hydrogen production via electrolysis. Thermochemical water splitting could take place at any time that the nuclear reactors were in operation, as these designs are intended to operate at high temperature.

It is likely that first-to market hydrogen production, as is being supported under the IDC Deployment programme and the Government's Cluster Sequencing process, will supply (either directly or indirectly industrial customers whose demand profiles are typically reasonably constant through the year. Later to market supply, such as nuclear hydrogen from the Moorside Clean Energy Hub, is more likely to be left with a market characterised by high seasonal and diurnal variability. Servicing these markets will require sufficient available storage to accommodate around half a year's production – up to 8 TWh from the Moorside EPR. The potential availability of a repurposed NTS pipeline capacity between Moorside (Sellafield) for linepack and large hydrogen storage capacity (Barrow/East Irish Sea) presents a possible opportunity for such storage, which means that Moorside appears to be a good location for hydrogen production from nuclear generation.

By 2040, assuming hydrogen demand is insufficient to justify production of hydrogen from nuclear and as the penetration of renewables on the electricity grid drives down the load factor required from nuclear) it may become attractive to dedicate increasing proportions of output from Moorside to hydrogen production. Based on very high-level analysis, it is reasonable to assume that 30% of baseload power from Moorside (3,670MWe peak) could be directed to hydrogen production, so producing around 10TWhpa of hydrogen by 2040.

4.4.3 Hydrogen Storage

By 2040, the early low carbon hydrogen plants developed in the 2020s and 2030s will (to the extent that they are technically proficient) be able to 'load follow', as the capital investment will be have been written-down. However, there will still be a need to manage fluctuations in demand using a considerable amount of geological hydrogen storage capacity.

As mentioned above in respect of 2030, new hydrogen storage caverns can easily be deployed in the Cheshire salt basin, as has been common practice over the last few decades for natural gas. Natural gas storage represents a challenging business model today, and as the UK moves towards a hydrogen economy, it will become even less attractive to operators. As a result, there is potential to repurpose either existing assets (or certainly consents) to hydrogen storage. Whilst evidence is required to demonstrate the viability of repurposing such fields, this may represent an opportunity to deploy significant storage capacity for HyNet in the 2030-2050 period at relatively low cost.

In addition to the considerable storage capacity available in the Cheshire salt basin, as HyNet expands outwards, there are further locations at which hydrogen might be stored underground. These include:

1) The onshore Lancashire salt basin:
    a. A planning application for 19 caverns to store natural gas at Preesall was awarded a Development Consent Order in 2015.[49] The project developer, Halite, has not progressed the project to financial close, and so the project (and potentially the DCO) might either be repurposed for hydrogen storage or a similar application be made for hydrogen caverns.
2) Offshore in the salt basin in the East Irish Sea:
    a. Stag Energy's proposed Gateway project was proposed as the first development of this nature in the UK.[50] Stag was seeking to develop a working gas storage capacity of 1.52 Billion m^3 in 20 caverns at a location 24km from Barrow, where gas would have been processed onshore. It received planning consent in 2008, but it is understood that the company failed to progress an associated liquefied natural gas (LNG) terminal and so the storage project has not been progressed. Again, this project might be repurposed for hydrogen storage.

3) Offshore in depleted oil and gas reservoirs:
    a. This approach is yet to be fully proven, but assuming the sound structural integrity of reservoirs, it should be entirely possible. It therefore represents a further potential option if cost competitive with salt storage options. One of the Morecambe Bay gas fields, for example, may be a suitable option for hydrogen storage in the future.

In addition to underground hydrogen storage in salt caverns, the use of ammonia as an energy storage vector potentially facilitates above-ground, low cost, bulk liquid storage. In principle, ammonia could be produced via steam methane or auto-thermal reformation, with CO_2 captured and stored in the same way as planned for HyNet. This approach has been recently assessed as part of a UK Government-funded feasibility study involving Siemens and Engie.[51] The report from that study suggests that the cracking process to convert ammonia to hydrogen might be as high as £123/MWh, which suggests it is cost-prohibitive. Whilst it should be noted that the cost of new energy technologies tends to reduce significantly over time, the approach may only be suitable whereby ammonia is used directly as a fuel rather than converting it to hydrogen. This is already possible in modified gas engines and has been tested in small gas turbines.

4.5 CCUS Infrastructure in 2030 and 2040

4.5.1 CO_2 Transport and Storage in 2030

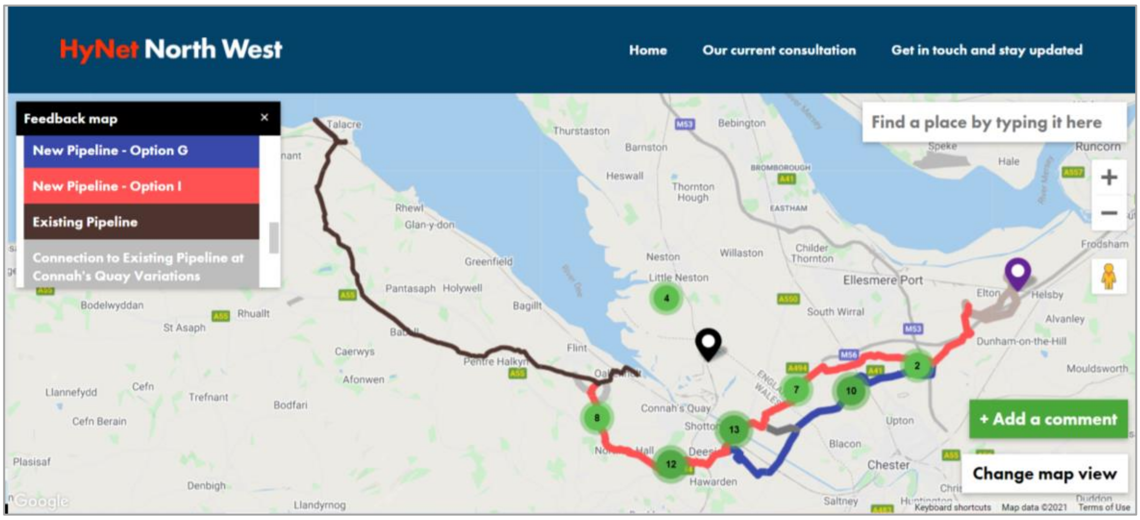
As described in Section 1.3, the North West was selected as the location to develop the HyNet project due to:

1) The local natural assets:
    a. Offshore oil and gas fields which are coming to end of economic life and can be repurposed for CO_2 storage; and
    b. The Cheshire Salt Basin, which is currently used for natural gas storage, but is also suitable for hydrogen storage.
2) The ability to reuse many physical assets to reduce the costs of deployment; and
3) It being host to the largest manufacturing sector in the UK with related high levels of emissions resulting from natural gas.

In terms of the second of these benefits, the HyNet project will repurpose a significant length of existing natural gas, pipeline between Connah's Quay and Point of Ayr Gas Terminal, and between Point of Ayr and wellhead platforms at the Hamilton, Hamilton North and Lennox fields, for CO_2 transport. All relevant asset integrity studies undertaken by Eni, as the CO_2 transport and storage operator for HyNet consortium, indicate that the pipeline is fit-for-purpose to essentially 'reverse-flow' CO_2 offshore for safe storage, whereby natural gas was historically brough onshore. Operation of the repurposed pipeline will start at relatively low pressures, which will then be increased such that by 2030 it will be capable of transporting up to $10MtCO_2pa$.

Consequently, only a relatively small section of new pipeline (between Stanlow and Connah's Quay, approximately 34km) is required. Eni formally launched the DCO consenting process for the CO_2 pipeline network for HyNet in June 2021 with a non-statutory public consultation process.[52] The route of the proposed new stretch of onshore pipeline cannot therefore yet be formally determined, albeit the public consultation platform enables stakeholders to comment on potential options, as presented in Figure 4-3.

Figure 4-3: Consultation Options for CO_2 Pipeline Route



To facilitate the long-term storage of 10MtCO_2pa, the Hamilton, Hamilton North and Lennox oil and gas fields in Liverpool Bay will be repurposed by Eni, for CO_2 storage. Further information on these fields is provided in earlier HyNet reports.[53] The Hamilton field was also characterised in a Government-sponsored report as one of the most suitable fields for CO_2 storage in the UK and is very well characterised by Eni.[54] These three fields will provide around 200Mt of CO_2 storage capacity which provides 20 years of storage at 10Mtpa.

As the requirement for CO_2 increases further in the 2030s, further storage capacity in gas fields in Morecambe Bay is likely to be required. This is discussed further in Section 4.5.2 in respect of the subsequent period to 2040.

4.5.2 CO_2 Transport and Storage in 2040

Further to the analysis in Section 4.5.1, the HyNet consortium has not identified any other industrial sites in the North West to which it would be sensible to route the CO_2 pipeline and install a related capture plant. However, there are several major emitters in the adjacent Peak District area, which have significant process emissions and so cannot be decarbonised with hydrogen, and therefore a CO_2 pipeline to these sites is a potential future solution.

As discussed in Section 4.4.2.1, in the 2030s further CCUS-enabled hydrogen production may be deployed at Barrow in Cumbria, for which it would ultimately make sense to store CO_2 at the nearby offshore gas fields in Morecambe Bay via repurposing of existing natural gas pipelines from Barrow. The Morecambe North and Morecambe South fields potentially have combined capacity for in excess of 1 Billion tonnes of CO_2, which would represent 100 years storage at 10Mtpa or 50 years storage should CO_2 capture across the HyNet project increase to 20Mpta. Again, further information on these fields is provided in earlier HyNet reports.[55]

Should further CO_2 storage (in addition to 10Mtpa) be required in the 2030s to service emitters in the core HyNet area (see Section 2.2.1) or from a new Peak District 'mini-cluster', a new CO_2 pipeline from Merseyside to Morecambe Bay might be considered as part of the HyNet expansion project. Consequently, neither the capacity of the initial planned CO_2 pipeline network, nor the availability of sufficient CO_2 storage in Liverpool Bay, are barriers to hydrogen deployment exceeding 30TWh/annum or to further direct capture of CO_2 from industry in the 2030s.

4.5.3 Direct CO_2 Capture from Industry

As described above, along with supply of low carbon hydrogen, the HyNet project will decarbonise industry in the North West via direct capture of CO_2 from a number of very large emitters.

In many cases, the cost of CO_2 capture at industry sites is more expensive than decarbonisation using hydrogen as not only do you need a network connection, but the proportion of CO_2 in flue gas generated from natural gas is often relatively low, thus requiring large capture plant, with greater relative Capex. Exceptions are:

- Sites which have significant 'process' emissions which can't be decarbonised using hydrogen, for example, cement production whereby a large proportion of the CO_2 generated is from carboniferous materials rather than fuel input; and
- Some chemicals production sites, for example, fertiliser production, whereby CO_2 is separated from other gases as part of the existing production process.

As presented in Table 4-8, it is estimated that 1.7MtCO_2pa will be captured from core HyNet consortium sites at Stanlow, Padeswood, Ince and Runcorn. A significant additional tonnage may also be captured from 'other' sites in the region. The majority of these additional sites are EfW facilities processing either fully or partially biogenic wastes. At present, the EfW sector sits outside the UK ETS, but as described in Section 3.6.4, BEIS is actively considering how to support BECCS projects and has allowed EfW sites to bid into Phase 2 of Cluster Sequencing under the ICC business model. Consequently, we have included EfW within the scope of industrial emissions for the purpose of this analysis.

In this context, it is also important to acknowledge that around 1.4Mtpa of the CO_2 from EfW facilities will be biogenic and so result in negative emissions, as described in Section 3.6.4. This additional benefit is presented in Table 4-8 such that the total potential CO_2 directly captured from industry is up to 5.9Mtpa.

For the purposes of this report, we have assumed that there is no difference in total potential between 2030 and 2040, although this probably considerably underestimates the latter potential. However, as described in Section 7.0, we have assumed greater deployment in the 2040 scenarios.

Table 4-8: Total Potential CO_2 Capture from HyNet sites

Plant Name	Operator	Sector	Total CO_2 (tCO_2pa)	Total Bio-CO_2 (tCO_2pa)
Stanlow	Essar Oil (UK)	Refining	800,000	-
Padeswood	Hanson Cement	Cement	480,000	-
Ince	CF Fertilisers	Chemicals (Ammonia)	400,000	-
Runcorn	Viridor	Energy from Waste	460,000	460,000
Other[1]	n/a	Multiple	875,000	975,000
Negative Emissions	n/a	Multiple	n/a	1,435,000
MAXIMUM TOTAL CAPTURE			**5,885,000**	

Notes:

1. At the time of writing, we understand that a number of other sites have bid into the Phase 2 of the Government's Cluster Sequencing process. Due to commercial confidentiality, these cannot be named individually here, but it is worth noting that all of these are either partially or wholly BECCS projects, which could deliver negative emissions

5.0 HYDROGEN DEMAND IN 2030

As described in Section 4.1, the design philosophy for HyNet is to focus on building the supply and distribution infrastructure, which is not supply-constrained, i.e. that which can be easily expanded to cater for growing demand, and which will deployed incrementally over time.

The analysis below represents scenario modelling to demonstrate how demand could develop to 2030. Again, as described in Section 4.1, in reality the hydrogen network will be deployed as per the DCO processes which are being led by Cadent, and users will either be directly connected to the initial 'feeder' pipelines in the network, or will connect later via spurs from the feeders. This will determine both the rate and sequencing of industry connections.

Cadent and Progressive (as part of Vertex Hydrogen) currently have in place 27 Memorandums of Understanding (MoUs) with industry sites to work together towards supply of hydrogen and connection to the network for each of those sites.

The speed of take-up of hydrogen supply and connections, however, is largely dependent upon policy mechanisms and business models for hydrogen and CCUS, as described in Section 3.0. Most importantly, the speed of deployment will be driven by whether the HyNet hydrogen production hub is selected as a preferred CO_2 capture site in Phase2 of the Government's Cluster Sequencing process. To reflect the currently levels of uncertainty, we have focused below on what we call 'bull' and 'bear' scenarios.

5.1 Industry Demand Scenario Modelling

The demand build-up modelled for 2030 is based on construction of the low carbon production hub at Stanlow linked to a hydrogen distribution network, hydrogen storage infrastructure, and a CCUS transport and storage system. The priority is to supply hydrogen to decarbonise large industrial sites, which are exposed to the UK ETS, the increasing costs of which provide a clear rationale for sites seeking to reduce emissions. Analysis of demand from industry has been undertaken on a 'bottom-up', site-by-site basis.

For most sites in the North West, Progressive has been able to understand the current energy infrastructure. Critically, therefore, for existing equipment, whether this be boilers, gas engines, gas turbines, furnaces, kilns or other direct-firing applications we are able to determine:

- How easily, from a technical perspective, this can be switched to hydrogen; and
- The extent to which core equipment (i.e. a boiler, kiln or furnace itself) requires replacement.

Our analysis has been informed by working closely with a range of sites since HyNet's origination in 2016, along with evidence gathered from the HyNet Industrial Fuel

Switching programme. This has received £5.2M funding from BEIS, and includes hydrogen demonstrations in a glass furnace at NSG-Pilkington's Greengate Works in St Helens, in a boiler at Unilever's Port Sunlight site, and a Front-end-engineering and design (FEED) for a new hydrogen CHP at Stanlow Manufacturing Complex.[56] BEIS are currently assessing submissions from Progressive for follow-on fuel switching trials across a further range of industries in the North West.

This analysis has shown that fuel switching to hydrogen represents an opportunity to use most existing heat generation infrastructure, potentially in many cases only replacing burners and controls. For most sites, therefore, it is a case of *conversion* to hydrogen rather than replacement of major plant. This is fundamentally simpler than switching to electrification to biomass, which, in most instances, will require considerable levels of existing onsite infrastructure replacement.

The exception to this general rule is combined heat and power (CHP) installations; whether either reciprocating gas engines or gas turbines. In many cases, aside from those whereby relatively new machines are already in place, existing engines or turbines will need to be replaced to enable firing of 100% hydrogen. In both cases, however, manufacturers are currently undertaking detailed engineering and testing to bring hydrogen-ready engines and turbines to market.

The HyNet Industrial Fuel Switching Programme work will not only effectively make these three sites (Unilever, NSG-Pilkington and Essar) 'hydrogen-ready' but the work has been designed to be applicable to other similar sites, both within the NW and the wider UK. This will enable the extension of hydrogen supply to a wide industrial base as the HyNet project expands to 2030 and beyond. Funding from the Industrial Energy Transformation Fund (IETF), to which BEIS and HM Treasury have allocated £315M and the second round of the IFS Competition, may be used to support some deployment of early industry conversions assuming that a business model, as described in Section 3.0, is available to bridge the difference in costs between natural gas and hydrogen.

The modelling approach for industry sites can be summarised as follows:

- Determination of Greenhouse Gas (GHG) emissions data for all sites located within the HyNet area (as defined in Section 2.2.1) using the UK ETS database for 'Regulated Installations', which is maintained by the Environment Agency:[57]
    - Or for the limited number of large sites outside the ETS, emissions data has been provided by the site itself.
- Using 'expert judgement' a small number of sites have been excluded as being too small and/or distant from the route of the hydrogen distribution pipelines expected to be in place by 2030;
- As described above, based on knowledge of what technologies are used to generate heat and power at each site, and the age of that equipment, expert judgement has been used to determine whether the site is likely to be able to switch to hydrogen by 2030 (or instead by 2040);

- Exclusion of some sites, or a proportion of the emissions from some sites, which produce significant ‘process’ emissions, which cannot be fuel switched to hydrogen; for example, those in the cement sector. As mentioned above, such emissions require the use of direct on-site CO_2 capture on the plant itself. For sites with both fuel and process emissions, an ‘adjustment’ factor has been applied, which recognises the balance between emissions from plant amenable to fuel switching and plant which requires direct capture.

For the 2030 modelling, we have not assumed that there are any energy efficiency gains to be made from fuel switching to hydrogen. This is because the vast majority of sites will be using existing boilers, furnaces and kilns.

As mentioned above, to reflect the currently levels of uncertainty around the deployment profile for HyNet, we have modelled both ‘bull’ and ‘bear’ scenarios, which can be summarised as follows:

- Bull scenario:
    - Assumes all selected sites in the core HyNet area, which can feasibly switch to hydrogen by 2030 do so, and up to their maximum conversion potential.
- Bear scenario (2030):
    - Assumes the vast majority of the same sites switch to hydrogen but only up to a lower proportion (based on expert judgement) of their total switching potential;
    - Assumes that some sites, which are either both outlying and relatively small, or those which are located in the Wales and West (and not Cadent) natural gas network, are not switched to hydrogen until after 2030.

The results from this analysis are presented in Table 5-1. The total estimated hydrogen demand is from 20TWhpa under the Bull Scenario to 12TWhpa under the Bear Scenario.

Table 5-1: Hydrogen Demand from Industry in 2030

Sector	**Hydrogen Demand (TWh/annum)**	
	Bull	**Bear**
Aerospace	192	0
Automotive	309	309
Ceramics	102	57
Chemicals	4,396	3,552
Food & Drink	2,195	769
Glass	2,063	1,210
Metals	527	323
Paper & Pulp	1,592	480
Pharmaceuticals	349	64
Refining	7,303	5,465
Misc.	777	2
TOTAL	**19,805**	**12,230**

5.2 Modelling of Other Demand for Hydrogen

As highlighted above, to inform planning of the design, routing and required capacity of hydrogen and CCUS infrastructure development, it is necessary to also consider the other forms of hydrogen demand in 2030.

5.2.1 Dedicated Power generation

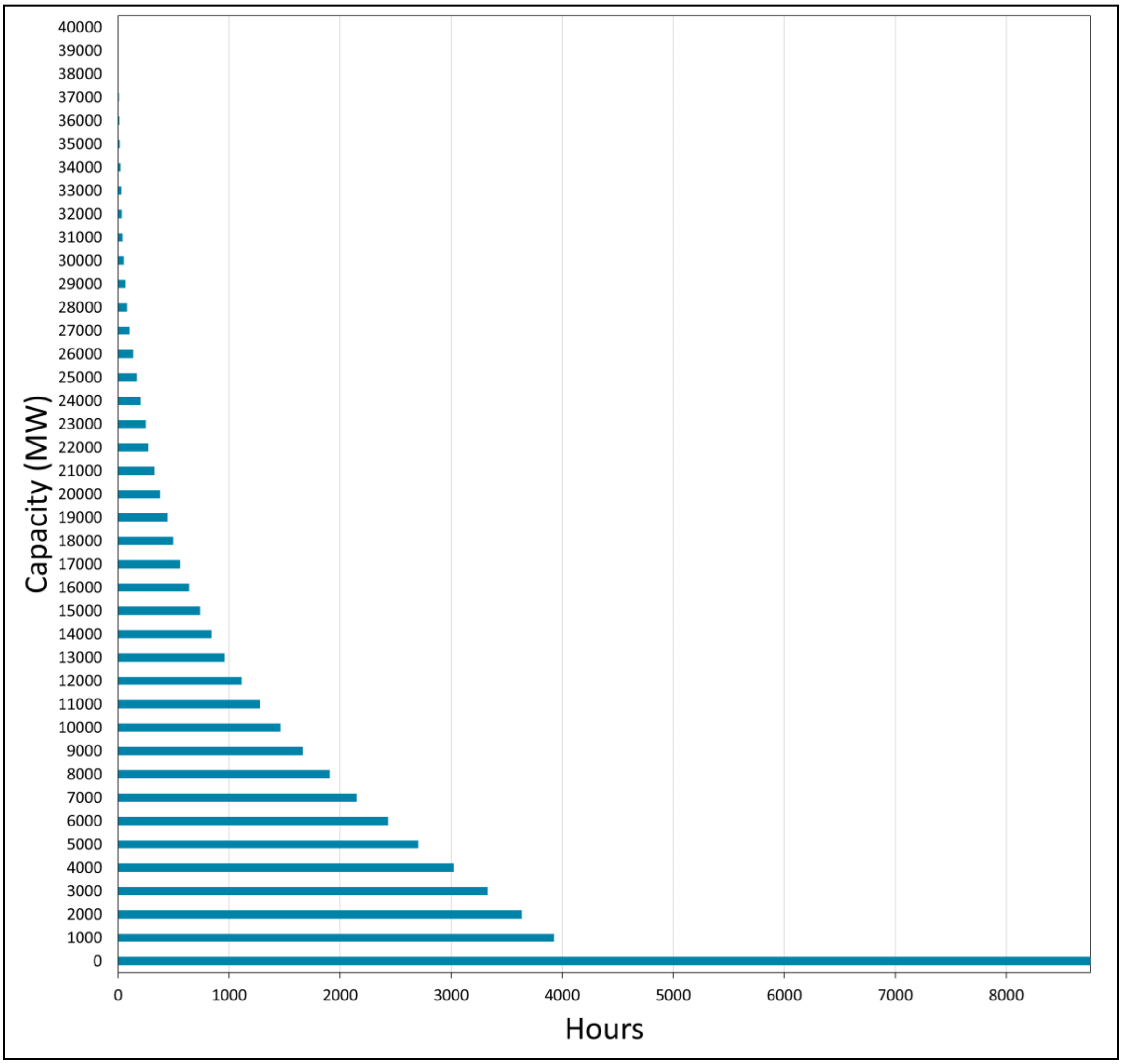
By 2030, there will be considerable additional offshore wind (and other renewables) operating on the UK power system. This largely intermittent capacity will effectively sit at the top of the ‘merit order’ and all other generation capacity will need to flexible to ‘fill in the gaps’ to meet demand and balance the electricity grid.

The analysis for this study has used the whole UK data set and has been undertaken using the ‘Pathfinder Plus’ model and the assumptions in National Grid’s ‘Two Degrees’ scenario as a basis to assess the amount of flexible generation required to balance intermittent generation.[58] This suggests that significant levels of flexible capacity will be needed across the UK to help manage the electricity system in 2030. This need case has been further highlighted by data from 2021, which indicates that it has been one of the lowest wind years on record.

Gas turbines which can fire hydrogen are expected to be available to provide this flexible generation and will be called upon to do so to meet demand when levels of offshore wind generation are low. This scenario, under which 44GWe of wind generation and 10GW of interconnectors with other European countries has been assumed, results in the ‘load duration curve’ presented in Figure 5-1. This shows, for example, that, at a national level, the first 1,000MW of flexible capacity in the merit order will operate at around 40% load factor (around 4,000 hours/annum), but the majority of the required capacity will operate at far lower load factors. Only the most efficient plants will be called on to operate. Dependent on the business models available, plants might also need to seek revenues from services provided to the electricity Transmission or Distribution System Operators (DSOs & TSO), such as current ‘Frequency Response’ services.

A similar, but more detailed analysis of this issue is provided by Uniper in its parallel study to support the development of the North West Cluster Plan.[59]

Figure 5-1: Load Factors for Flexible Power in 2030



The focus of the analysis for this study is upon large scale ‘combined cycle’ gas turbine (CCGT) plants rather than smaller ‘peaking’ plant. Modern, new CCGTs operating across the UK (and most other countries) today can achieve >60% electrical efficiency. A few such plants may be put in place, but as noted above, the load factor of most flexible generation will be relatively low. At very low load factors, capital costs must be minimised and ‘simple’ cycle gas turbines may be preferred for large installations. For these, efficiency is lower, typically ~40% but full load can be reached much faster than combined cycle arrangements. As such, in addition to grid balancing, they are ideal for ‘peak lopping’ or ‘frequency control’ applications.

The development of such flexible turbines which can operate largely or wholly on hydrogen is moving quickly, driven by work, in particular by manufacturers including Siemens, GE and MHI. This work is such that suitable technologies should be available to support deployment of major flexible power generation well ahead of 2030. Again, more detailed analysis of associated technology developments is provided in the report by Uniper.[60]

There are currently three large CCGT plants (Rocksavage, Connah's Quay and Carrington), operating in the HyNet area. HyNet is engaging closely with Uniper and the other respective operators and ultimately, there is scope for all three plant to switch some of their generation to hydrogen. Prior to 2030, however, the extent to which these plant will switch to hydrogen will be constrained by the operating parameters of the existing gas turbines and the guarantees that associated OEMs will support for hydrogen firing.

In addition, a further plant, led by Carlton Power, received planning consent in 2010 for a plant at Carrington near to ESB's existing CCGT plant. Carlton is still actively seeking to develop the plant and has engaged with HyNet on supply of hydrogen and potential connection to the network, and with OEMs in respect of the capability of new turbines to operate on hydrogen. The potential to operate on a lower carbon fuel mix than natural gas adds to the business case for deployment of the plant.

Key data in respect of these four plants are provided in Table 5-2.

Table 5-2: Current and Potential Future CCGT Fleet in HyNet Area

CCGT Plant	Operator	Operating Since	Electrical Capacity (MWe)
Carrington Power	ESB	2016	910
Trafford Power	Carlton Power	-	1,520
Connah's Quay	Uniper	1996	1,380
Rocksavage	Intergen	1998	810
TOTAL			**3,960**

In respect of the above four plant, HyNet has access to the following information:

- Current load factors; and
- Maximum proportion of natural gas that can be switched to hydrogen by 2030; and
- Current and future plant electrical efficiencies.

Such information, however, is commercially confidential and cannot be shared in this report. However, the related datapoints have been modelled alongside future likely plant load factors, based on the analysis above, to determine an estimate of hydrogen demand in 2030 of 4.86TWh. As flexible power generation does not relate directly to industry, we have not sought to reflect any uncertainty (in the form of Bull and Bear scenarios) in the modelling for 2030.

5.2.2 Hydrogen demand from the existing gas network

Ultimately, to meet Net Zero, fossil gas use will need to cease and much of the gas network will need to be converted to transport hydrogen. An assessment of the conversion issues in the Liverpool and Manchester city and metropolitan areas, including the required injection points has been undertaken, and further work is ongoing, as part of the H21 project.[61] Technical challenges 'downstream' of the meter have also been explored as part of the Hy4Heat work programme sponsored by BEIS.[62]

In January 2021, the Energy Networks Association, under its Gas Goes Green programme, published a detailed plan to deliver the UK's hydrogen networks.[63] This describes in detail the transition needed from now to 2040, which involves a blend of hydrogen initially injected into the network, followed by early conversion of parts of network to 100% hydrogen.

In respect of full network conversion, the Government is funding the first hydrogen Village demonstration to commence in 2025. Cadent has bid into the related competitive process and it is possible that this project will take place in the North West as 'HyNet Homes'. The learning from this demonstration would then be used to support network-wide deployment as soon as this can be feasibly delivered, potentially in the 2030s.

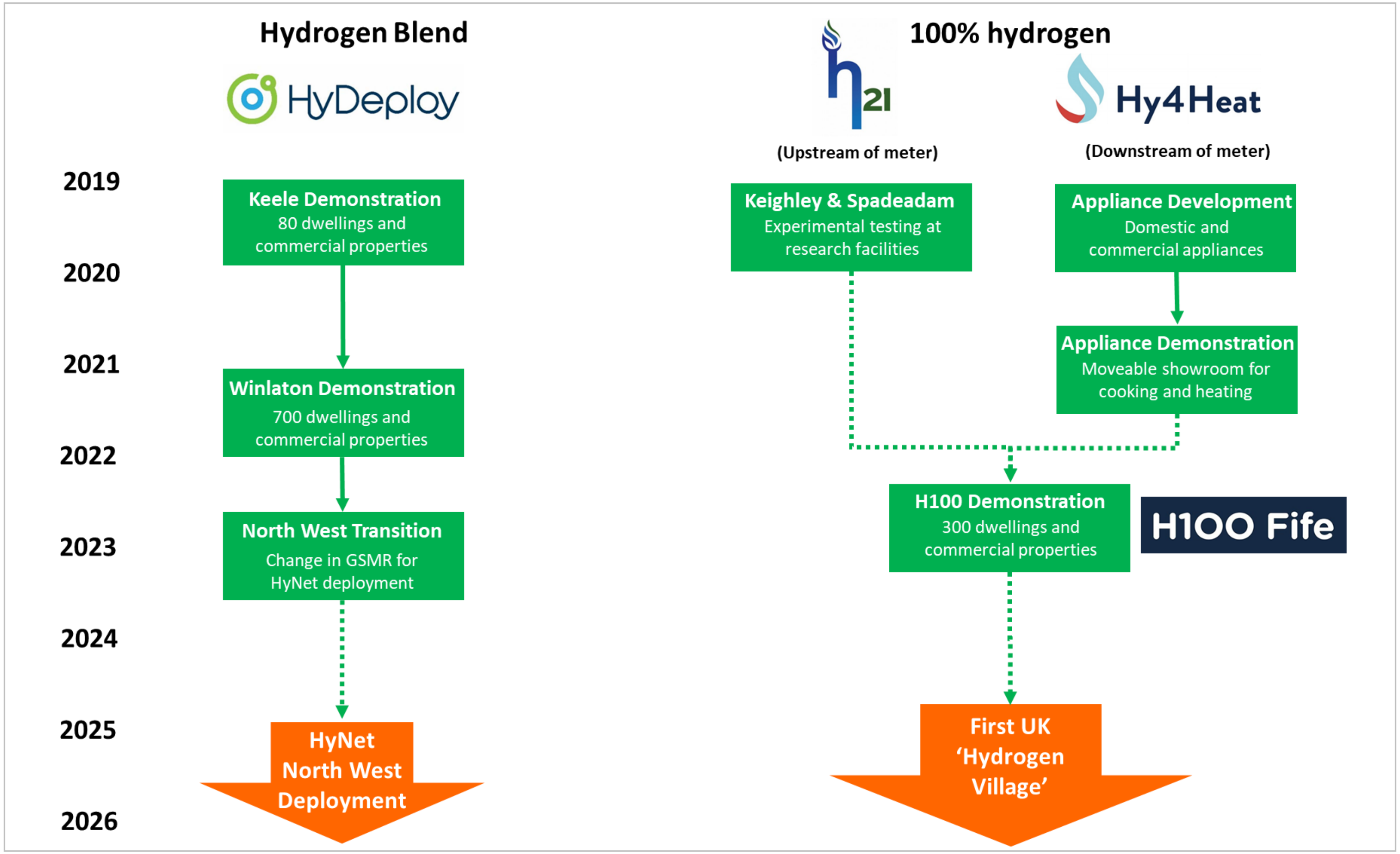
As highlighted in previous HyNet-related reports (see Section 1.3), the project is designed to be both low cost and operational by the mid-2020s. Full network conversion will be a complex and long process and therefore HyNet is therefore initially focused on delivering a blend of hydrogen (with natural gas) into the existing distribution network. The initial phase of injection will reach around two million gas customers and will represent a meaningful level of decarbonisation with effectively zero disruption to households and businesses. To support the deployment of blending, the Energy Networks Association has recently published a 'Delivery Plan' on behalf of all UK gas networks.[64]

As part of the HyDeploy project, a consortium led by Cadent and Progressive Energy has recently completed a demonstration of injection of hydrogen into a 'closed' gas network at Keele University with a blend of up to 20%vol. hydrogen supplied to both housing and commercial properties. The second phase of HyDeploy is now underway and involves a hydrogen blend being injected into a 'public' gas network operated by Northern Gas Networks (NGN) in Winlaton (part of the Municipal Borough of Gateshead, Tyne and Wear). Again, Cadent and Progressive are project partners and the demonstration is supplying around 700 dwellings alongside some commercial properties.

As part of both of these demonstrations, HyDeploy has gained an exemption, awarded by the Health & Safety Executive (HSE) from the Gas Safety Management Regulations (GSMR), as the current regulations preclude the injection of levels of hydrogen >0.1%.

A third phase of HyDeploy project in the NW is also being considered by Ofgem and Cadent. This would be a larger trial than at Winlaton and would pave the way, from a regulatory perspective, for deployment of a hydrogen blend more widely across the network, to reach around two million gas customers.

Figure 5-2: Demonstration and Deployment of Hydrogen Blend and 100% Conversion



The modelling in this report undertaken in respect of deployment of the blend assumes 20%vol. hydrogen (around 7% by energy) is injected into relevant points on the network. These points correspond with seven current locations where the NTS supplies natural gas into the LTS, which then carries gas to the lower pressure tiers on the distribution network.

The configuration of the network and the direction of gas flow is such that injection into the network will result in the blend being supplied to the majority of the HyNet area. The location of these injection points will influence the routing of the hydrogen pipeline, alongside the need to connect industry and power generation sites, as discussed above.

Full conversion of the network is not included in the 2030 demand model for this study. It is possible, however, that prior to 2030, some deployment might occur as part of the Government's plans for a Hydrogen Village (and subsequent 'Hydrogen Town'). Furthermore, some new major housing (and commercial) developments might be built as 'hydrogen-ready' and so be supplied with 100% hydrogen.

The existing flows of natural gas at each injection point, along with the corresponding demand for the blend, is presented in Table 5-3. The data on existing gas flows was sourced from National Grid Operational Data.[65] From this, the demand from relevant industrial customers, which will be supplied with 100% hydrogen via the new dedicated network has been 'netted off'.

For blend injection, as this does not relate directly to industry, we have not sought to reflect any uncertainty in modelling for 2030. However, the Bull and Bear scenarios have been modelled for 2040 to reflect greater levels of uncertainty in that longer timeframe.

Basing the demand on current levels of gas use by homes provides an upper bound for hydrogen demand for network blending in 2030, which can be used to guide the sizing of the pipeline distribution network and level of underground storage required. In reality, however, primarily driven by greater energy efficiency and insulation of homes, along with some potential shifts towards electrification of domestic heating with (full electric or 'hybrid') heat pumps, network demand is expected to have reduced by 2030. However, this analysis assumes that there is no reduction in gas demand in 2030, although a suitable reduction in demand has been modelled for the 2040 scenario in Section 6.2.2.

Table 5-3: Current NG Flows and Blend Demand at Injection Points in 2030

Injection Point	Current Natural Gas Flow (GWh/annum)	Blend Demand in 2030 (GWh/annum)
1	19,198	1,248
2	13,743	893
3	6,427	418
4	2,327	151
5	2,160	140
6	7,475	486
7	355	23
TOTAL	**51,686**	**3,360**

5.2.3 Transport

Great strides have been made to decarbonise electricity supply in the UK, such that the biggest sectoral contributor to emissions is now the transport sector. Analysis by the Committee on Climate Change (CCC) showed that in 2017 transport accounted for 28% of all greenhouse gas emissions.[66] The transport sector also has a significant impact on air quality with many local authorities taking action to reduce the level of roadside nitrous oxides (NOx). Data published by the CCC shows that transport emissions, including international aviation, have increased by 14% since 1990 and it argues that current government policies are insufficient to deliver the required reductions in emissions.

In 2019, Cadent undertook the 'HyMotion' project, for which a related report was published, which set out to:[67]

1) Determine the current status of different types of hydrogen vehicles and whether they were ready for deployment in the UK;
2) Assess the potential for cost reduction associated with the use of hydrogen vehicles compared with the current baseline;
3) Determine to what extent deployment of hydrogen vehicles could contribute to decarbonisation of the transport sector in the North West in 2030 (and 2050);
4) Set out a roadmap for deployment; and
5) Highlight any technical barriers to deployment and how these might be overcome via design and demonstration.

The data presented in Table 5-4 for potential demand from hydrogen vehicles in 2030 is drawn from the HyMotion work, which modelled five different scenarios for vehicle deployment and fuel use ('very low', 'low', 'medium', 'high' and 'very high'). For this study, we have drawn upon the medium HyMotion scenario, which results in demand of 1.06TWh/annum. Full details of the rationales behind use of each of these data points can be accessed in the related HyMotion report.[68]

There is a high level of uncertainty relating to demand from the transport sector, but again, as this does not relate to industrial demand, we have not reflected this in the modelling for 2030.

Table 5-4: Potential Demand for Hydrogen from Vehicles in 2030

Vehicle Type	Hydrogen Demand (TWh)
Cars	0.19
Vans	0.02
Buses	0.04
Rigid HGVs	0.34
Articulated HGVs	0.11
Trains	0.36
TOTAL	**1.06**

5.3 Total Hydrogen Demand

Based on the analysis presented above, It should be noted that whilst the majority of this demand will be supplied by the Hydrogen Production Hub at Stanlow, there is also likely to be some supply from sources of electrolytic hydrogen, as discussed in Section 4.2.2.

Table 5-5 presents total demand of 22-29TWhpa of hydrogen in 2030. The difference between the Bull and Bear scenarios reflects the following uncertainty in relation to the speeds of:

- Policy development and the finalisation of suitable business models to fund hydrogen (and CCUS) deployment;
- Deployment of the hydrogen network, given the need to get multiple planning consents (including at least one DCO for the main feeder lines);
- Deployment of the CO_2 pipelines, which again are subject to at least one DCO; and
- Decision-making by corporate boards in respect of switching sites to operate on hydrogen.

It should be noted that whilst the majority of this demand will be supplied by the Hydrogen Production Hub at Stanlow, there is also likely to be some supply from sources of electrolytic hydrogen, as discussed in Section 4.2.2.

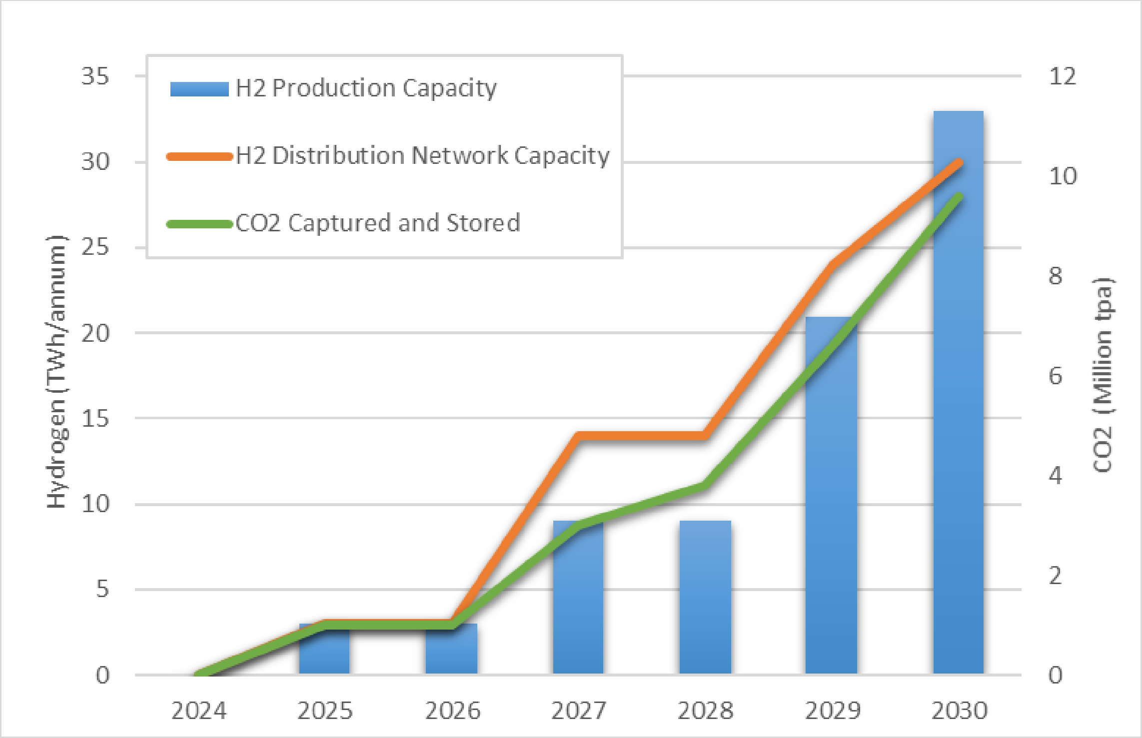
Table 5-5: Total Hydrogen Demand in 2030

Sector	Bull Hydrogen Demand (TWhpa)	Bull Hydrogen Demand (TWhpa)
Industry	**19.81**	**12.23**
Large Power Generation	4.86	
Network	3.36	
Transport	1.06	
TOTAL	**29.09**	**21.51**

5.4 Deployment Profile to 2030

To service the level of demand described above, the deployment profile for the HyNet hydrogen infrastructure is presented in Figure 5-3 alongside the amount of CO_2 that will be stored from both low carbon hydrogen production and direct CO_2 capture from industry (as described in Section 4.5.3 and explored further in Section 7.0). As discussed in Section 4.1, hydrogen network capacity is deployed ahead of hydrogen production such that the system is not supply constrained.

Figure 5-3: Indicative Infrastructure Deployment Profile to 2030



6.0 HYDROGEN DEMAND IN 2040

As described in Section 4.1, the design philosophy for HyNet is to focus on building the production and distribution infrastructure, which is not supply-constrained, i.e. that which can be easily expanded to cater for growing demand, which will happen incrementally over time. Hence the hydrogen network infrastructure which is deployed in 2030 within the core HyNet area is ultimately designed to cater for further demand which comes through in the 2030s.

In addition, a potential second CCUS-enabled hydrogen production hub to be located at Barrow, deployment of potentially significant electrolytic hydrogen production from offshore wind and from the potential Moorside Nuclear development (all discussed in Section 4.4.2, will likely result in further build-out of new network infrastructure.

To a large extent this will be driven by demand from:

- The flexible power generation sector, as:
  - Major CCGT sites ‘re-power’ with hydrogen, and operate at times of low output from offshore wind; and
  - Smaller, hydrogen peaking plant are deployed to balance the electricity network.
- The residential sector, as swathes of the existing natural gas pipeline network are potentially converted to hydrogen to decarbonise housing stock.

Demand from industry will also increase during the 2030s, both from within the core HyNet area and in wider parts of the North West. In this context, it should be noted that, as customers increasingly demand low carbon products, the availability of hydrogen will both:

1) Encourage the expansion of operations and manufacturing of products at existing industry sites; and
2) Attract new industry to the region.

The extent to which growth in demand occurs will also depend upon the level of deployment before 2030, which is driven largely by the speed and ambition of Government expressed within the hydrogen and CCUS business models described in Section 3.0. The approach in the following sections is therefore to present the outputs from similar Bull and Bear scenarios shown for 2030 in Section 5.0, to reflect the level of uncertainty associated with this type of modelling exercise.

6.1 2040 Industry Demand Scenarios

The Bull and Bear scenarios for 2040 can be summarised as follows:

- Bull Scenario:
  - The existing gas network in the North West is wholly converted to hydrogen, and so all sites without technical constraints, switch to full operation on hydrogen; and

  - Full network conversion means all major emitters around Manchester, in Cumbria and Lancashire have access to hydrogen and switch away from natural gas.
- Bear Scenario:
  - The existing gas network is not converted to hydrogen and the dedicated hydrogen network is not extended to include any sites outside of the core HyNet area; but
  - However, all sites within the core HyNet area are switched more ‘deeply’ to hydrogen if not already fuelled with 100% hydrogen in 2030.

The modelling approach for 2040 again assumes that there are no energy efficiency gains to be made from fuel switching to hydrogen. Whilst many sites will have installed new heat and power generation equipment, it is unlikely that either electrical or thermal efficiency will have increased materially during this period.

The results from the modelling are presented in Table 6-1. The total estimated hydrogen demand is from 24TWhpa under the Bull Scenario to 17TWhpa under the Bear Scenario.

Table 6-1: Hydrogen Demand from Industry in 2040

Sector	**Hydrogen Demand (TWh/annum)**	
	Bull	**Bear**
Aerospace	311	0
Ammonia	1,250	1,250
Automotive	309	309
Ceramics	409	114
Chemicals	4,405	3,193
Food & Drink	2,656	1,399
Glass	2,063	2,063
Metals	619	546
Paper & Pulp	2,677	1,291
Pharmaceuticals	827	349
Refining	7,324	6,738
Misc.	986	0
TOTAL	**23,835**	**17,251**

6.2 Other Sectors

6.2.1 Dedicated Power Generation

As discussed in Section 5.2.1 with regard to the situation in 2030, but to an even greater extent by 2040, there will be considerable additional offshore wind (and other renewables) operating on the power system. All other generation capacity will therefore need to 'fill in the gaps' and also balance the electricity grid.

In 2050, it is likely that far greater levels of offshore wind generation will be operating than the 44MW modelled for 2030. Flexible generation from hydrogen will therefore operate at lower load factors, but at the same time,greater generation capacity will be required to fill the gaps in offshore wind generation.

As described above, there are currently three large existing CCGT plant (Rocksavage, Connah's Quay and Carrington), which are currently operating in the core HyNet area. For the purposes of this modelling, in the 2030s it is assumed that the two oldest of these existing plants (Rocksavage and Connah's Quay) are repowered to operate on 100% hydrogen at the same output capacity as previously operated on fossil fuels, utilising the maximum possible grid connection capacity. The third site at Carrington, is operated at lower levels of hydrogen to reflect that it may not be repowered until after 2040.

At the same time, it is assumed that the other CCGT site in Carrington, for which Carlton Power received planning consent in 2010 (but is still seeking to reach financial close), is also switched to 100% hydrogen, having operated at lower levels prior to 2030.

These assumptions, along with the load factors modelled for each site, are presented in Table 6-2. Again, as flexible power generation does not relate directly to industry, we have not sought to reflect any uncertainty within the model. This approach results in total hydrogen demand from CCGT sites of over 11 TWhpa by 2040.

Table 6-2: Indicative Annual Hydrogen Demand from CCGT Stations in 2040

Site	Operator	Capacity (MWe)	Hydrogen (%)	Load Factor (%)	Electrical Efficiency (%)	Hydrogen Demand (GWth)
Carrington	ESB	910	100%	15%	50%	2,391
Connah's Quay	Uniper	860	100%	15%	50%	2,260
Trafford	Carlton Power	860	100%	15%	50%	2,260
Rocksavage	Intergen	810	100%	15%	50%	2,129
TOTAL		**3,440**				**9,040**

6.2.2 Hydrogen Demand from the Existing Gas Network

As discussed in Section 1.0, it will not be commensurate with meeting Net Zero for the gas distribution network to be transporting any material levels of natural gas in 2040. Either the network will largely have been decommissioned in favour of full electrification (with some smaller networks remaining utilising biomethane), or the network will have been either wholly or partially re-purposed for hydrogen.

The work that has been undertaken and is currently ongoing as part of the H21 and Hy4Heat projects is providing a wealth of evidence in relation to network and appliance conversion.[69] [70] This suggests that the technical challenges both upstream and downstream of the meter can be suitably addressed ahead of 2040.

The success of full network conversion to hydrogen will depend upon:

- Practical challenges associated with switching millions of customers from natural gas to hydrogen, which will take several years; and
- The establishment of long-term policy support mechanisms, which are required to enable such a transition, as explored in Section 3.0.

It has been assumed in this analysis that full network conversion from the mid-2030s will be possible. Towards this full conversion of the network, Cadent is evaluating the potential for a 100% hydrogen trial, which may be funded by Government as the UK's first Hydrogen Village in the North West from 2025. The learning from this trial would then be used to support network-wide deployment as soon as this can be feasibly delivered.

As for the 2030 hydrogen blend described in Section 5.2.2, the modelling for 2040 assumes that hydrogen is injected into all points on the network within the core HyNet area where the NTS supplies natural gas into the LTS. This functions as a sound estimate of current natural gas demand, although in reality, there is likely to be a need to inject into lower pressure tiers of the network for full conversion.

In summary, the following approach to modelling 2050 demand has been taken:

- Bull scenario:
  - Full network conversion at all network injection points in core HyNet area;
  - A fall in energy demand of 28% (based on National Grid's FES 2020 assumptions for 2050, pro-rata'd for 2040);
- Bear 2040
  - Full network conversion at a subset of injection points which are most likely to receive a pipeline connection, i.e. larger injection points, which are also near large industrial emitters to be switched to hydrogen; and
  - Again, a fall in energy demand of 28%.

Based on the above assumptions, Table 6-3 shows that total annual hydrogen demand for heating buildings in the core HyNet area might be between 24TWh and 35TWh .

Table 6-3: Hydrogen Demand from Buildings in 2040

Injection Point	Bull Scenario (TWh/annum)	Bear Scenario (TWh/annum)
1	13.16	13.16
2	9.42	9.42
3	4.41	-
4	1.60	-
5	1.48	1.48
6	5.12	-
7	0.24	-
TOTAL	**35.4**	**24.1**

6.2.3 Transport

As for the modelling undertaken for 2030, for modelling of likely demand from the transport sector, data modelled as part of the 'HyMotion' project undertaken by Cadent in 2019 has been used.[71] For that study, both low and high scenarios were modelled, and therefore the median value between these two scenarios has been applied here. Also, only data for the core HyNet area was modelled, and so this has been extrapolated for extension of the network into Lancashire, Cumbria and wider Manchester on a pro-rata basis in terms of current populations.

The above approach results in a total of 5TWh of demand from the transport sector in 2040, as presented in Table 6-4. There is a high level of uncertainty relating to this demand, but again, as this does not relate to industry, we have not reflected this in the model.

Table 6-4: Potential Demand for Hydrogen from Vehicles in 2030

Vehicle Type	Hydrogen Demand (TWh)
Cars & Vans	1.09
Articulated HGVs	0.88
Rigid HGVs	2.01
Buses	0.18
Trains	1.09
TOTAL	**5.24**

6.3 Total Hydrogen Demand in 2040

Based on the analysis presented above, Table 6-5 presents total hydrogen demand of 56-74TWhpa in 2040. This demonstrates the potential of the HyNet project to expand both geographically and more deeply into the economy across all sectors to potentially deliver over 30% of the 225TWhpa of hydrogen modelled by the CCC as required to meet the UK's Net Zero target.[72] This growth potential emphasises the importance of supporting the initial phases of HyNet and other similar hydrogen cluster projects.

This analysis also shows that because the HyNet project's primary focus is upon industry in the early years to 2030, there is only a further 4TWh of demand from major industrial emitters in 2040, with the vast majority of network and supply expansion being to serve other sectors of the economy. This demonstrates the potential of HyNet to rapidly decarbonise the North West industrial cluster.

It should be noted that whilst a significant amount of this demand will be supplied by the Hydrogen Production Hub at Stanlow, there is also likely to be considerable supply from sources of electrolytic hydrogen, particularly from offshore wind, as discussed in Section 4.4.2.2.

Table 6-5: Total Hydrogen Demand in 2040

Sector	Bull Hydrogen Demand (TWhpa)	Bear Hydrogen Demand (TWhpa)
Industry	23.84	17.25
Large Power Generation	9.04	
Network	35.43	24.06
Transport	5.24	
TOTAL	**73.54**	**55.59**

7.0 DEPLOYMENT PROFILE AND AVOIDED EMISSIONS

The analysis presented in Sections 5.3 and 6.3 in respect of potential hydrogen demand and in Section 4.5.3 relating to direct CO_2 capture from industry, now enables us to present the total avoided CO_2 emissions which can potentially be delivered by HyNet in 2030 and in 2040.

In 2030, total avoided emissions delivered across all sectors of the economy range from 6.9$MtCO_2$pa under the Bull hydrogen scenario to 8.1$MtCO_2$pa under the Bear hydrogen scenario. This level of abatement increases to 16.3$MtCO_2$pa to 17.4$MtCO_2$pa in 2040.

In relation to industry specifically, avoided emissions in 2030 range from 5.1$MtCO_2$pa to 6.4$MtCO_2$pa, rising to 7.3$MtCO_2$pa to 8.4$MtCO_2$pa in 2040. In the context of current total direct ('Scope 1') emissions from industry in the North West of around 10$MtCO_2$pa (including those from energy from waste facilities, which may soon be subject to some form of carbon pricing), this represents a significant and critical contribution to decarbonisation.

Table 7-1: Potential Total Avoided CO_2 Emissions from HyNet in 2030

Sector	**Bull H_2 Scenario ($MtCO_2$pa)**	**Bear H_2 Scenario ($MtCO_2$pa)**
Hydrogen to Industry	3.64	2.25
Hydrogen for Large Power Generation	0.89	
Hydrogen Blend to Network	0.62	
Hydrogen for Transport	0.35	
Direct Capture - Industry (Fossil CO_2)[1]	2.27	
Direct Capture - Industry (BECCS)[1] [2]	1.18	
Emissions from CCUS[2]	0.84	0.70
TOTAL	**8.12**	**6.86**

Notes:

1. A 'probability factor' of 75% has been used to model direct CO_2 capture from industry sites which are not owned and operated by core HyNet partners. Only those which have made firm commitments and allocated meaningful budget to project development are included
2. Captured emissions from BECCS are 'doubled' in terms of abatement in this context, as they deliver negative emissions
3. Emissions from the full chain of CCUS (including those from CCUS-enabled hydrogen production) are estimated at 10% of total emissions avoided. This is an indicative assumption only used for the purposes of this study

Table 7-2: Potential Total Avoided CO_2 Emissions from HyNet in 2040

Sector	Bull H_2 Scenario ($MtCO_2pa$)	Bear H_2 Scenario ($MtCO_2pa$)
Hydrogen to Industry	4.39	3.17
Hydrogen for Large Power Generation	1.66	
Hydrogen Blend to Network	6.52	
Hydrogen for Transport	1.70	
Direct Capture - Industry (Fossil CO_2)	2.76	
Direct Capture – Industry (BECCS)[1]	2.15	
Emissions from CCUS[2]	1.81	1.69
TOTAL	**17.37**	**16.28**

Notes:

1. Captured emissions from BECCS are 'doubled' in terms of abatement in this context, as they deliver negative emissions
2. Emissions from the full chain of CCUS (including those from CCUS-enabled hydrogen production) are estimated at 10% of total emissions avoided. This is an indicative assumption used only for the purposes of this study

8.0 KEY MESSAGES

The key messages from this study can be summarised as follows:

- HyNet will spearhead the creation of a low carbon North West Industrial Cluster by 2030. This will be based on the deployment of hydrogen production, distribution and storage, along with CCUS infrastructure, which will be in place across a most of Liverpool City Region, Great Manchester, Cheshire, Flintshire and parts of Lancashire;
- The North West Industrial Cluster will potentially involve decarbonisation of over 50 major manufacturing sites. This will involve the supply of up to 20TWhpa of low carbon hydrogen and, combined with direct capture of CO_2 from industry, will reduce emissions from industry by up to 6MtCO_2pa by 2030;
- In the context of current total direct ('Scope 1') emissions from industry in the North West of around 10MtCO_2pa (including those from energy from waste facilities, which may soon be subject to some form of carbon pricing), this represents a significant and critical contribution to decarbonisation;
- Via the supply of low carbon hydrogen, HyNet can also make a material contribution to decarbonisation of wider sectors of the economy, including power generation, transport and buildings by 2030. Demand from these sectors might be up to 9TWhpa in 2030, which would result in total demand of nearly 30TWhpa;
- 30TWhpa of hydrogen production is equivalent to around 4GW of continuous peak output. HyNet, therefore, has the potential to deliver around 80% of the Government's 5GW target for hydrogen production in 2030, which was published in the National Hydrogen Strategy in August 2021.[73]
- HyNet can also make a material contribution to meeting the UK's 5th Carbon Budget. Given the need to reduce emissions by 56MtCO_2pa between the UK's 4th (2023-2027) and 5th (2028-2032) Carbon Budgets, the 8MtCO_2pa of abatement delivered by HyNet in the North West in 2030 equates to around 16% of this improvement;
- This level of deployment, however, is subject to Government putting in place a set of long-term business models for hydrogen and CCUS against which upfront investment from the private sector can be justified. The progress on these business models is mixed, with significant work still to do in many areas to enable investment;
- During the 2030s, the HyNet infrastructure can be expanded into to wider parts of Wales, Lancashire, Cumbria and the West Midlands to help industry

meet Net Zero by 2040. Whilst HyNet is focused initially on industry, it will also support Liverpool City Region and Greater Manchester in meeting city-wide Net Zero targets for all sectors, which are set for 2040 and 2038 respectively;

- There is a total of around 200Mt of potential CO_2 storage in the Liverpool Bay oil and gas fields and a further 1Bt in the Morecombe Bay gas fields (when these cease production). Along with the large underground salt fields in Cheshire, Lancashire and offshore in Morecombe Bay, which will be used for hydrogen storage, this means that neither CO_2 nor hydrogen storage are likely to limit the significant expansion of HyNet;
- The foundation of HyNet will be CCS-enabled hydrogen production, which will enable investment in the core hydrogen distribution infrastructure. At the same time, the deployment of electrolytic hydrogen, produced from renewables and nuclear energy is expected to grow, enabled by the option to connect to the HyNet network to reduce transportation costs; and
- Measures, such as industrial energy efficiency, onsite renewables and electrification will also be need to be deployed to help the region meet Net Zero in 2040. These areas are explored in wider studies undertaken by Equans in support of the North West Cluster Plan.[74]

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