May 2022

HyNet Industrial
Fuel Switching

HyNet
North West

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EXECUTIVE SUMMARY

Executive Summary

In November 2019, BEIS awarded Progressive Energy Limited ('PEL'), as lead bidder, £5.3M to deliver a Phase 2 programme of hydrogen fuel switching work, in partnership with NSG-Pilkington ('NSG'), Unilever and Essar. The programme of work had been defined and costed as part of the previous feasibility project, which was funded under Phase 1 of the Competition[1].

The original deadline to deliver this work was March 2021. The Covid-19 pandemic, however, presented unique challenges to the project teams, severely delaying any onsite work, procurement of equipment and forcing the team to work effectively in new ways. In recognition of this, BEIS made provisions to help mitigate the impact of this including an extension of twelve months for delivery of the demonstration work, which then concluded in March 2022.

To maximise value to Government and the tax-payer, the HyNet Industrial Fuel Switching (IFS) programme of work was developed with limited elements that are unique to their settings. This will allow the same approaches and evidence developed from the programme to be deployed at other locations around the UK and beyond.

The HyNet IFS programme supports the objectives of the wider HyNet North West ('HyNet') project, an integrated low carbon hydrogen and Carbon Capture and Storage (CCS) project. It will provide evidence to enable the participating (and wider) sites in the North West (and across the UK and beyond) to switch to low carbon hydrogen as soon as it is available in bulk from HyNet.

The 5GW capacity target for low carbon hydrogen production highlighted in the National Hydrogen Strategy was subsequently increased to 10GW by 2030 under the British Energy Security Strategy in April 2022[2,3]. As part of the UKRI IDC (Industrial Decarbonisation Challenge) funded North West Cluster Plan, regional modelling was undertaken, which estimated a total demand for low carbon hydrogen of 30TWh/annum by 2030[4]. HyNet has been designed to meet this level of demand in 2030, which would represent 38% of the entire UK target of 10GW.

The HyNet IFS programme was split into the following three main work packages:

1. On-site demonstration of hydrogen-firing in a float glass furnace at NSG's Greengate Works in St Helens;

2. On-site demonstration of hydrogen-firing in a boiler at Unilever's Port Sunlight plant; and

3. A Front-end Engineering and Design (FEED) study in relation to a new hydrogen-fired gas turbine combined heat and power (CHP) plant at Essar's Stanlow Refinery.

The key messages and lessons learned from the work can be summarised as follows:

In respect of hydrogen-firing in existing glass furnaces, the demonstration at NSG-Pilkington's Greengate Works has shown that:

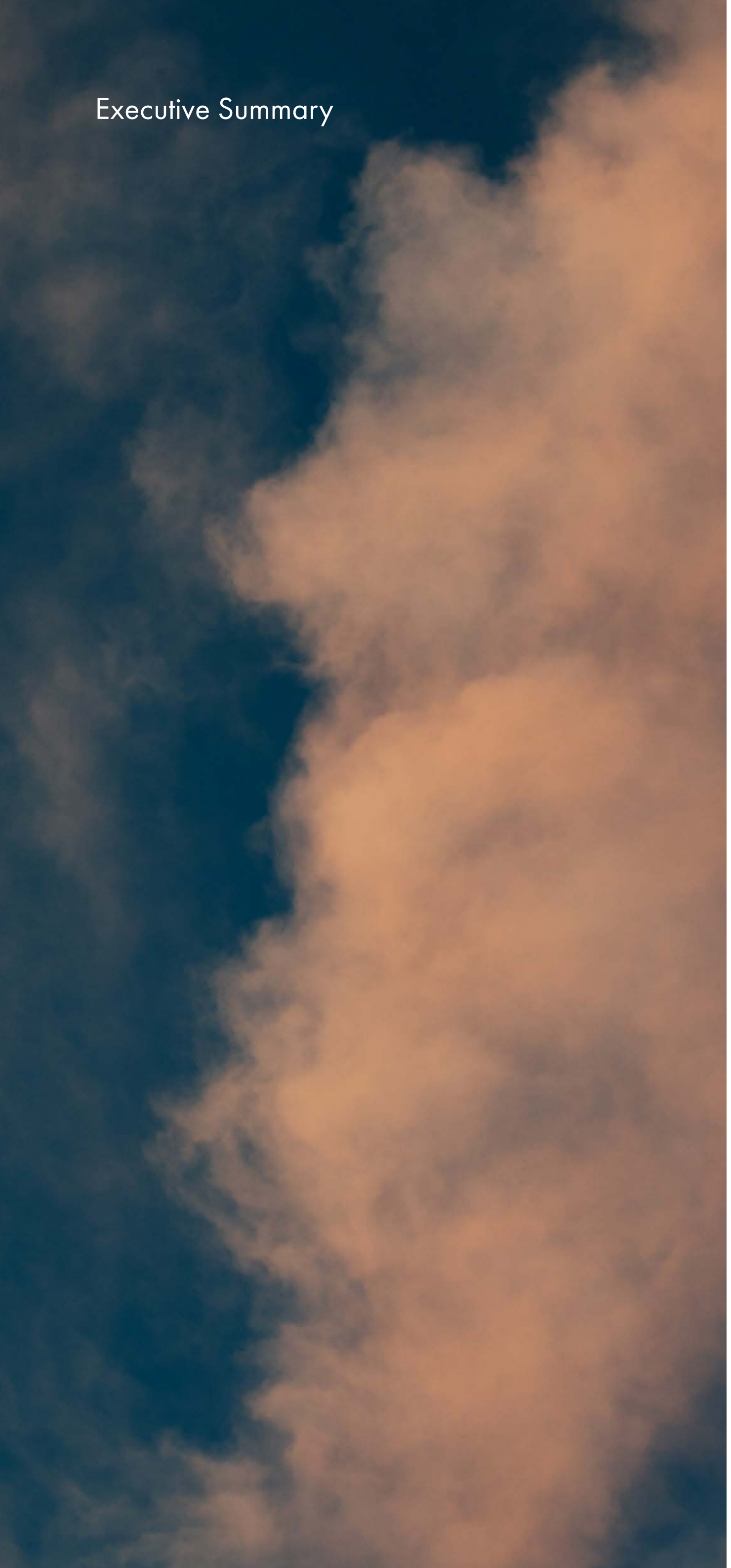
- The majority of energy use associated within glass furnaces, which is associated with the melting process and currently fuelled by natural gas, can be readily switched to hydrogen;
- At higher hydrogen levels, NO_x emissions may increase by 20-30%. This should be within the capability of existing abatement equipment at most large sites and so it is expected that environmental permits will not need to be amended to enable similar demonstration projects. However, switching to hydrogen in perpetuity may require some form of permit variation due to change in fuel source.
- The LHV efficiency of hydrogen-firing is likely to be unchanged compared with that of natural gas and the increase in soda levels should be within existing operating experience; and
- Operating on hydrogen should result in no impact on glass quality, either in terms of colour or fault density (bubbles and inclusions);
- The total cost for switching similar sites to hydrogen will be around £500k for in terms of plant and equipment costs.

In respect of firing of hydrogen in existing boilers, the demonstration at Unilever's Port Sunlight plant has shown that:

- Existing industrial package boilers can be switched to low carbon hydrogen, which is also likely to be the case for bespoke boiler designs;
- Package boilers can be operated on hydrogen within the NO_x thresholds set by the Medium Combustion Plant Directive (MCPD). However, furnace geometry is critical to meeting these limits and should be carefully assessed to inform burner design;
- Existing boilers will operate on hydrogen at very similar levels of efficiency when operating on natural gas (92.7% compared to 92.5%).
- The cost of a dual fuel natural gas/hydrogen burners is around 10% more than would be a standard natural gas burner, although this differential can be expected to fall for later projects;
- The findings from this work should be taken into consideration by BEIS in its ongoing Call for Evidence in respect of enabling or requiring the installation of hydrogen-ready industrial boiler equipment at industry sites.[5]

In respect of hydrogen-fired CHP plants, the FEED study relating to Essar's Stanlow Refinery has shown that:

- Contracts for new hydrogen-fired gas turbine plants can currently be procured, with suitable vendor performance guarantees, to operate on high levels of hydrogen alongside natural gas (the technology is at TRL 9 for blends up to 83%vol.). In some cases, this includes an agreed route-map for relevant turbine modifications to enable 100% hydrogen-firing before 2030;
- For associated new or existing Waste Heat Recovery Boilers (WHRBs) and fired heaters as part of a wider Combined Heat and Power (CHP) scheme, there should be a very high level of confidence that these can be fitted with 100% hydrogen-fired burners with suitable vendor guarantees;
- The additional Capex of a hydrogen-fired CHP scheme, compared with one fired by natural gas, is only around 1% of total Capex;
- The more significant additional cost is from duplication of equipment for hydrogen and natural gas (and in some cases, refinery gases). This will continue to be an issue for future developments until supply of hydrogen reaches greater levels of resilience;
- This additional equipment will also result in an increase in non-fuel operating costs. However, the non-fuel operating expenses associated with hydrogen would not be any greater than those associated with natural gas.

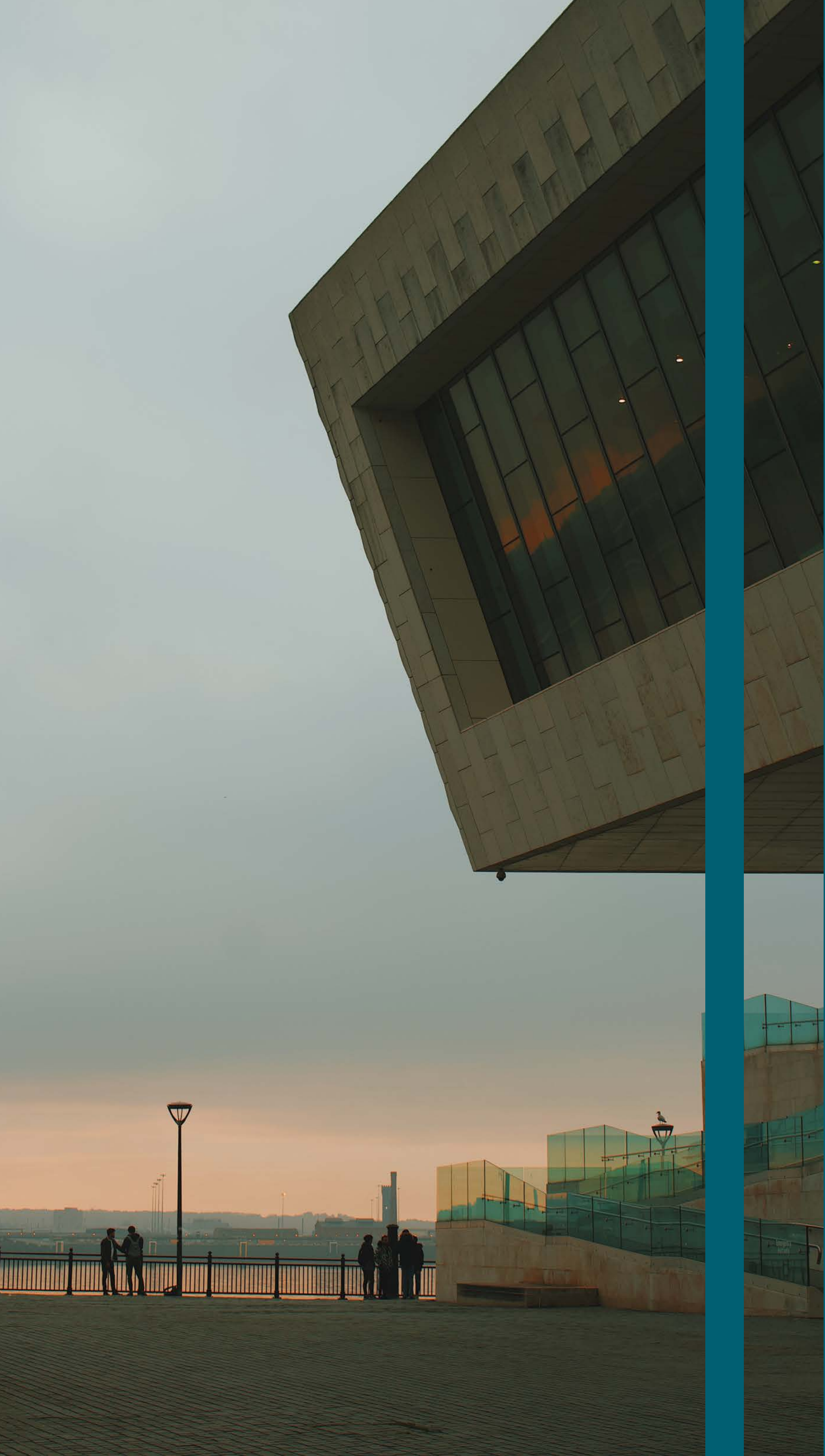


Once low-carbon hydrogen is available in bulk from HyNet and from other industry clusters in the UK, there will be a clear path to decarbonising significant amounts of industrial production via the solutions developed during this work programme:

- Decarbonisation of steam supply from boilers in the UK could result in savings of 5MtCO_2/annum. Together with the savings from switching of hot water boilers to hydrogen, this constitutes a major contributor to meeting future carbon budgets;
- There are over 50 glass-making sites in the UK, including those manufacturing fibre glass products. This equates to potentially converting 650- 700MWth (approximately 6 TWh/annum) of energy demand from natural gas to low carbon hydrogen, reducing UK emissions by approximately 1.2MtCO_2/annum;
- Sites across a range of sectors, including chemicals, paper and pulp, food and drink and automotive operate gas turbine CHP plants. Heat and power provision at these sites could be decarbonised by switching to new turbines running on hydrogen.

Availability of hydrogen is a critical consideration for design of commercial-scale demonstration projects:

- There is currently limited spare 'merchant' hydrogen available in the UK and a very limited number of suppliers which can provide the significant volumes needed for commercial-scale demonstration projects. Both in planning and during the demonstrations at both Greengate Works and Port Sunlight, hydrogen availability created significant issues, which caused both greater costs and delays to hydrogen-firing at both sites;
- BEIS has sought to address this challenge via both market engagement with potential hydrogen suppliers and the design of the second IFS programme, but it might also consider a further mechanism which addresses this fundamental deficit in supply;
- In the meantime, PEL is currently designing a new suite of demonstrations, funded by the second IFS Competition, which seeks to optimise hydrogen use, whilst still seeking to deliver the required level of evidence to enable long-term fuel switching;
- Once hydrogen is available in bulk from HyNet (and other regional hydrogen cluster projects) it is expected that this constraint to hydrogen supply will disappear.



1 | INTRODUCTION

1.1 BEIS Industrial Fuel Switching Competition

The main objectives of the Industrial Fuel Switching (IFS) competition run by the Government's department of Business, Energy and Industrial Strategy (BEIS) are;

- To determine the costs of switching industrial sites to hydrogen
- To prove that there is no detrimental impact upon existing plant and equipment
- To demonstrate that sites can operate in conformance with all safety regulations
- To prove that hydrogen can be fired in compliance with environmental permitting standards
- To enable participating and wider sites to switch to hydrogen as soon as it is available.

In November 2019, BEIS awarded Progressive Energy Limited ('PEL'), as lead bidder, £5.3M to deliver a Phase 2 programme of fuel switching work, in partnership with NSG-Pilkington ('NSG'), Unilever and Essar. The programme of work had been defined and costed as part of the previous feasibility project, which was funded under Phase 1 of the Competition.

The original deadline to deliver this work was March 2021. The coronavirus pandemic, however, presented unique challenges to the project teams, severely delaying any onsite work, procurement of equipment and forcing the team to work effectively in new ways. In recognition of this, BEIS made provisions to help mitigate the impact of this including an extension of twelve months for delivery of the work programme.

To maximise value to Government and the tax-payer, the HyNet IFS programme of work was developed with limited elements that are unique to their settings. This will allow the same approach and evidence developed from the programme to be deployed at other locations around the UK and beyond.

BEIS has since launched a new IFS Competition with the same two-Phase structure. Again, as lead bidder, PEL has bid for funding in partnership with a further five major industrial sites in the North West. At the time of writing, no formal public announcement has been made by BEIS in respect of the outcome of the process.

1.2 HyNet Industrial Fuel Switching Programme

The HyNet IFS programme supports the objectives of the wider HyNet North West ('HyNet') project described in Section 2.1. It will provide evidence to enable the participating (and wider) sites in the North West (and beyond) to switch to low carbon hydrogen as soon as it is available in bulk from HyNet. The programme is split into the following three main work packages:

1. On-site demonstration of hydrogen-firing in a float glass furnace at NSG in St Helens, as described in Section 3.0;
2. On-site demonstration of hydrogen-firing in a boiler at Unilever's Port Sunlight plant, as described in 4.0; and
3. A Front-end Engineering and Design (FEED) study in relation to a new hydrogen-fired gas turbine combined heat and power (CHP) plant at Essar's Stanlow Refinery, as described in Section 4.0.

The locations of the three sites are presented in Figure 1.1.

Figure 1.1: Location of HyNet IFS Programme Sites

1.3 Unlocking the Hydrogen Economy

In June 2019, consistent with guidance from the Committee on Climate Change (CCC), the Government set an ambitious target for the UK to achieve 'Net Zero' carbon dioxide (CO2) equivalent emissions by 2050. The production, distribution and use of low carbon hydrogen as a fuel is regarded by the CCC and Government as a key tool to achieve Net Zero.

In its Net Zero report, the CCC identified a UK demand for hydrogen of 270 TWh/y by 2050. Hydrogen, alongside electricity, will become the key energy carrier for the country in a Net Zero emission future. This was reinforced in the CCC's Sixth Carbon Budget, stating that the UK requires 90 TWh/y of low-carbon hydrogen by 2035 to avoid exceeding this emission budget.

To decarbonise and meet Net Zero, Government 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.[5 6]

This placed hydrogen as a key priority for the UK and highlighted the potential for it to make a major contribution to achieving Net Zero, setting a target for 5GW of low carbon hydrogen production by 2030. This is equivalent to approximately 40 TWh/annum of hydrogen, or 15% of the total 2050 CCC Net Zero Report target.

In August 2021, the Government launched its long-awaited National Hydrogen Strategy, which reinforced these targets.[7]

The Strategy further indicates a requirement of 7-20GW of installed capacity by 2035, and an annual expected hydrogen demand of 250-460 TWh/annum by 2050.

As acknowledged in the UK Hydrogen Strategy, in order to deliver a fully-functional low carbon hydrogen economy, all of the key elements will be required simultaneously: Supply, Demand, Infrastructure, Storage, People and Skills, Policy Frameworks and Financial Solutions. A full chain approach to development is critical; the only credible solution for the initial establishment of the hydrogen economy is a project that can deliver all of these elements together. Demand is a central pillar to this, and so the work funded by BEIS under the IFS Competition is a vital supporting programme for the Strategy.

The 5GW target for low carbon hydrogen production has subsequently been increased to 10GW by 2030 under the British Energy Security Strategy launched in April 2022[8]. This new strategy also commits to designing, by 2025, new business models for hydrogen transport and storage infrastructure, which will be essential to supply and fuel industry.

1.4 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 virus9. 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.[10] In respect of carbon capture and storage (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. Under the IDC programme, HyNet received £33M of support from Government (matched by £39M of consortium funding) to undertake the FEED and consenting aspects of the CCUS infrastructure required to support the deployment of low carbon hydrogen to industry (and other sectors).[11]

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.[12] [13] 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.[14]

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.

2 | HYNET OVERVIEW

HyNet Overview

HyNet was conceived by PEL in 2016 via support from National Grid (subsequently Cadent) under the Network Innovation Allowance (NIA) framework. 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.15

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.[16] This work defined the project concept for both hydrogen production and distribution, and CCUS. As presented in Figure 2.1, this included the following key features:

- CCUS-enabled hydrogen production (from refinery off-gas and natural gas) at Essar's Stanlow Manufacturing Complex;
- Hydrogen pipelines from the hydrogen production hub at Stanlow Manufacturing Complex to:
    - o Industrial and power generation sites;
    - o Injection sites for 'blending' hydrogen into the existing gas network;
    - o Major transport hubs; and
    - o Underground hydrogen storage caverns in the Cheshire Salt Basin.
- CO_2 pipelines;
- CO_2 storage in the Liverpool Bay oil and gas fields.

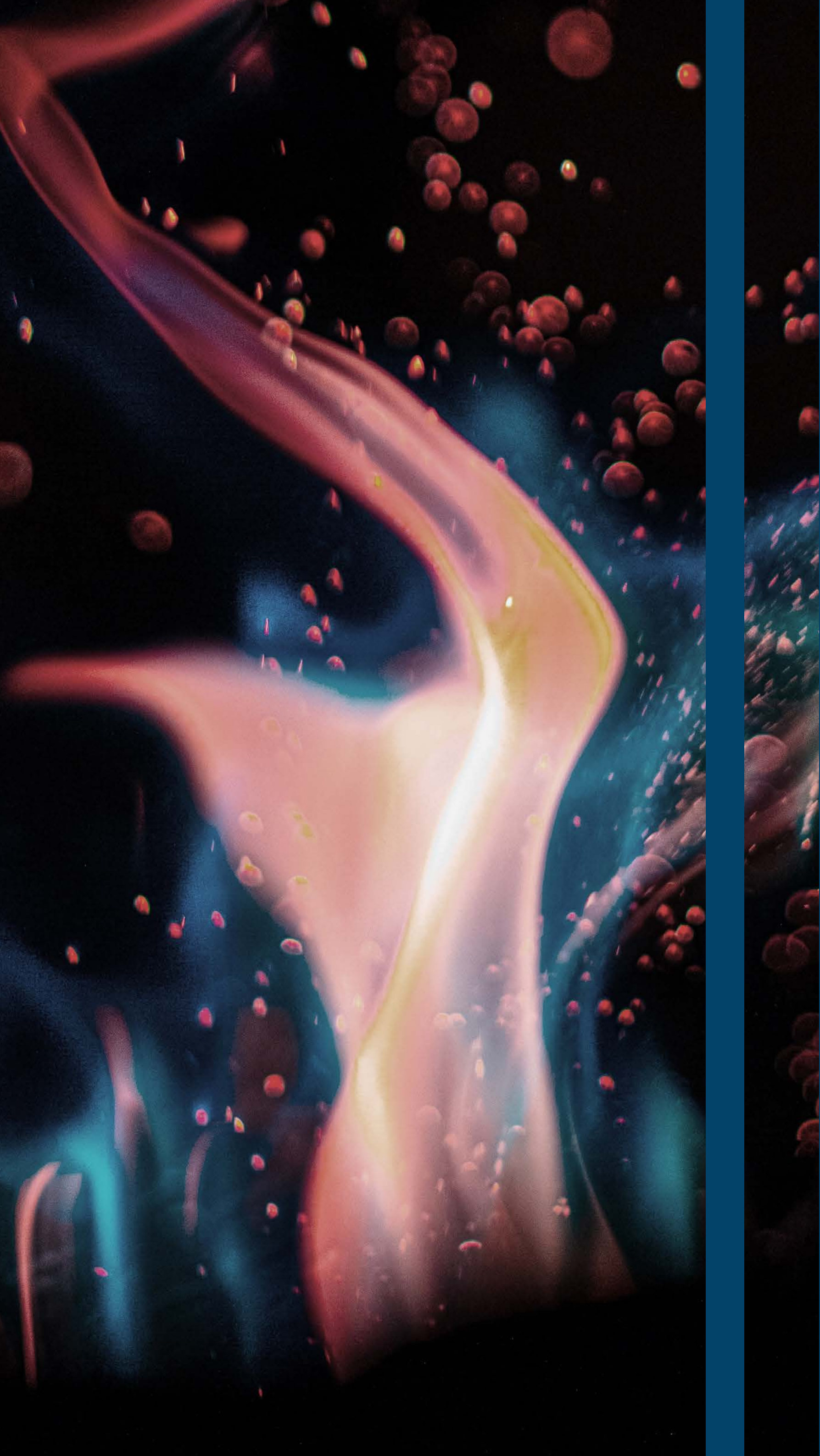
It is important to acknowledge that following further engineering and design over the last three years, the current project definition described here has not changed substantially from the above Reference Project.

To reach a final investment decision (FID), HyNet must be successful in the negotiated phase of the Government's 'Cluster Sequencing' process, for which it has been selected as a priority Track 1 (Phase 1) cluster.[17] At the time of writing, bids are being evaluated as part of 'Phase 2' of the 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 at Stanlow Manufacturing Complex is one such site. 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 8.0. These are particularly important, as they will facilitate long-term investment in the required hydrogen and CCUS infrastructure.

Figure 2.1: Overview of the HyNet Project

KEY

- INITIAL PHASES OF CADENT'S H_2 PIPELINE
- FUTURE PHASES OF CADENT'S H_2 PIPELINE
- CO_2 TRANSPORTATION AND STORAGE SYSTEM
- FUTURE CO_2 PIPELINE CONNECTIONS
- INDUSTRIAL CO_2 CAPTURE
- CO_2 STORAGE
- LOW CARBON H_2 PRODUCTION
- UNDERGROUND H_2 STORAGE
- INDUSTRIAL H_2 USER
- FLEXIBLE H_2 POWER GENERATION
- CO_2 SHIPPING
- H_2 BLENDING FOR HOMES AND BUSINESS
- H_2 FUELLING FOR TRANSPORT
- H_2 FROM OFFSHORE WIND
- H_2 FROM SOLAR AND WIND



3 | HYDROGEN FIRING IN A GLASS FURNACE

Hydrogen Firing in a Glass Furnace

The glass industry uses approximately 6 TWh of heat annually in the UK, the vast majority from fossil fuel sources. Heat is used in both the melting and refining elements of the process. Given the direct-firing nature of the application and high temperatures required, hydrogen is an ideal low carbon energy source.

The operating furnace at NSG's Greengate works is designed to use 50MW of natural gas at any given time. Switching to hydrogen fuel would enable Greengate works to significantly reduce the current level of CO_2 emissions associated with the combustion of this natural gas.

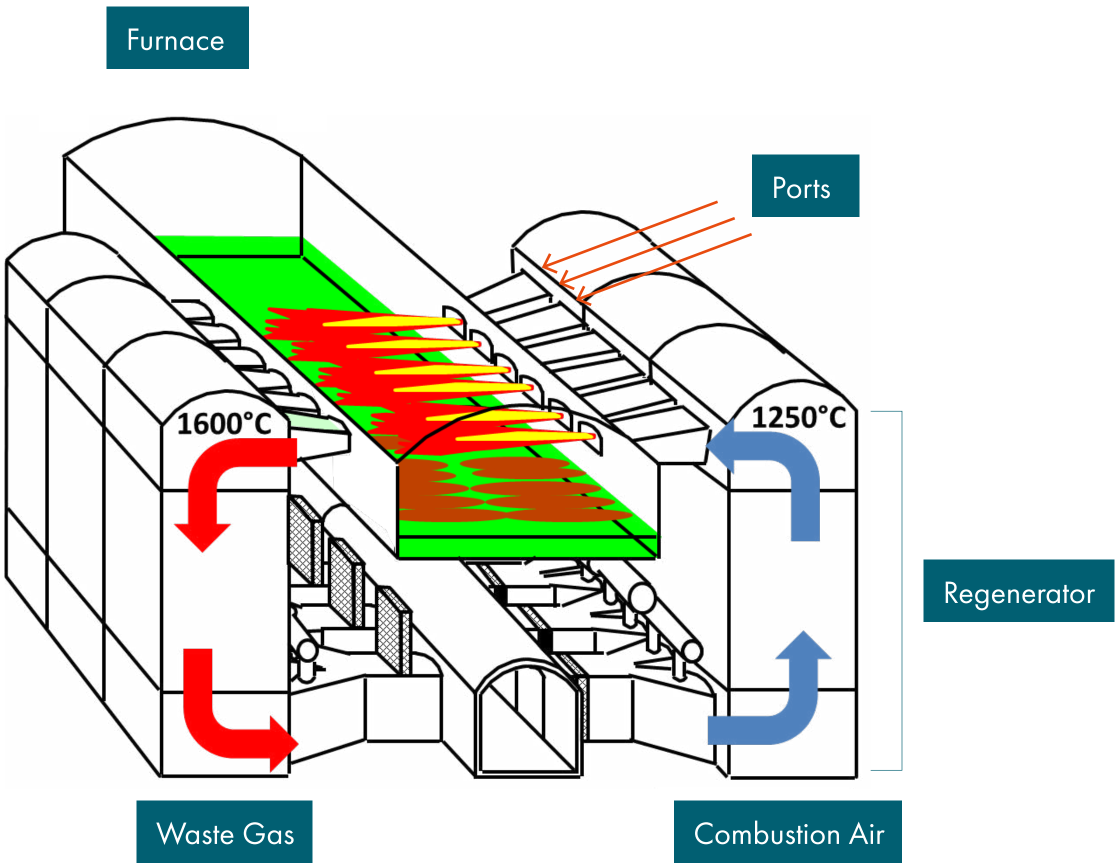
Under Phase 1 of the IFS Competition, the feasibility of using increasing proportions of hydrogen in a regenerative glass furnace was assessed by PEL and NSG. The subsequent Phase 2 demonstration at Greengate works was designed to validate the outcomes of the feasibility work, and to provide NSG with sufficient confidence to switch to hydrogen once it becomes available in bulk from HyNet.

Of particular importance is the demonstration of hydrogen's suitability in an existing furnace; production assets in the glass industry frequently operate for 15 years between shutdowns, and so decarbonisation of these assets will often rely upon an approach which enables decarbonisation without requiring a furnace overhaul.

3.1 Glass Furnace Description

A cross-fired regenerative glass furnace, which manufactures float glass, is typically between 10m and 13m wide and 30m to 40m long, with flames covering around half of this length. Successful operation requires heat release across the width of the furnace to ensure uniform melting of the blanket of raw materials floating on the surface of the glass. An indicative schematic is presented in Figure 3.1.

Figure 3.1: Schematic of a Cross-fired Regenerative Glass Furnace



The combustion air is fed into a hot regenerator to gain heat from the hot bricks. The gasses then pass from the regenerator into the furnace through connections, called ports, and fuel is introduced to the air stream at the port/furnace connection. There are several of these ports along the length of a furnace, the first port being the one nearest to the raw material entry point.

The system works on a periodic cycle. The fuel is fired for a set period on one side of the furnace and after around 20 minutes the fuel is shut off for around 60 seconds and the system reverses, such that the combustion air is fed up the newly heated regenerator on the opposite side of the furnace and the waste gases exit though the colder regenerator.

3.2 Initial Modelling

During the Phase 1 Feasibility Study stage, extensive modelling work was performed to investigate three key areas:

- **Flame luminosity and heat transfer;**
- **NOx emissions; and**
- **Refractory impacts.**

The CFD models showed luminosity decreasing according to the flame soot content. This raised a concern, to be tested during the Phase 2 demonstration, as to whether the heat from a hydrogen flame would transfer effectively to the raw materials, affecting fuel consumption.

In order to investigate NO_x emissions, initial modelling was performed using FLUENT. This modelling suggested that NO_x emissions from hydrogen firing would be very high, but this outcome was not consistent with existing data held by NSG. Consequently, NSG developed its own empirical model, which predicted a 33% increase in NO_x production, which is within the capability of existing abatement equipment. The modelling also investigated the effect of excess air on NO_x production.

Prior to the demonstration, the CFD combustion modelling was performed to determine suitable firing setups to maximise the chances of the trial's success. Further modelling by NSG suggested there would be a 30% increase in soda volatilization as a result of firing hydrogen, which again would be tested during the Phase 2 demonstration.

If a new-build hydrogen furnace were constructed, the refractory would be specified to be compatible with combustion of hydrogen. However, as mentioned above, given that glass furnaces frequently operate for 15 years between shutdowns, there is usually no opportunity to replace the refractory, and so it must be shown that the existing refractory is compatible with hydrogen firing.

3.3 Key Questions

The trial sought to validate the results of the modelling work outlined above, with four specific aims:

- **To demonstrate effective heat transfer to raw materials;**
- **To verify NO_x production within the capability of existing abatement equipment;**
- **To verify that increased soda production is within existing operating experience;**
- **To verify that glass quality is unaffected by use of hydrogen.**

3.3.1 Design of Hydrogen Supply to Burner

To service the entire 50MW load of the Greengate Works furnace would require nearly 1.5tph of hydrogen supply. In advance of a hydrogen distribution network being in place, sufficient hydrogen was not available to meet this full load. However, it was determined by NSG that validation of the model results could be obtained via operation on 100% hydrogen through a single port. As a result, the demonstration was designed to switch only Port 1 to 100% hydrogen, successful operation of which would prove that the melting end of the furnace, which is responsible for the majority of energy consumption, could be switched to hydrogen. In principle, this would be sufficient for NSG to make a future investment decision to contract for hydrogen supply and a network connection.

For supply to a single port, the most practical solution for hydrogen supply was delivery by tube trailer. Four tube trailer connections were installed, and the trailers were operated in pairs, so that two could provide hydrogen to the furnace while the other two were replaced, facilitating continuous operation at high flow rates over several hours.

As presented in Figure 3.2, BOC was contracted to supply hydrogen to the demonstration and to supply equipment for letting down the hydrogen from delivery pressure (which could be in excess of 200barg) to 10barg. The hydrogen was subsequently let down to 500mbarg in a secondary let-down station before being transported via new pipework to Port 1, where modifications to the fuel delivery system allowed hydrogen to be blended into the burner fuel supply, at proportions up to 100%.

The overall design and construction of the hydrogen system was managed by Otto Simon Limited (OSL). Particular challenges were the integration into the existing control system, and the routing of a new hydrogen pipe through a complex plant.

Figure 3.2: Tube Trailer with Primary Pressure Let-down Station

3.3.2 Demonstrating Safe Operation with Hydrogen

Safe operation using hydrogen was a primary focus of the design work. This was achieved through:

- Engagement of appropriate experts at each stage of the process, in particular BOC, which was able to reference multiple hydrogen delivery installations;
- Adherence to applicable codes of practice and design standards from bodies such as BCGA and ASME;
- Industry-standard assessments such as HAZID, HAZOP and Fault Tree Analysis; and
- Production of a detailed Trial Protocol document containing method statements for safe execution of all activities during operation of the trial.

3.3.3 Demonstration Plan

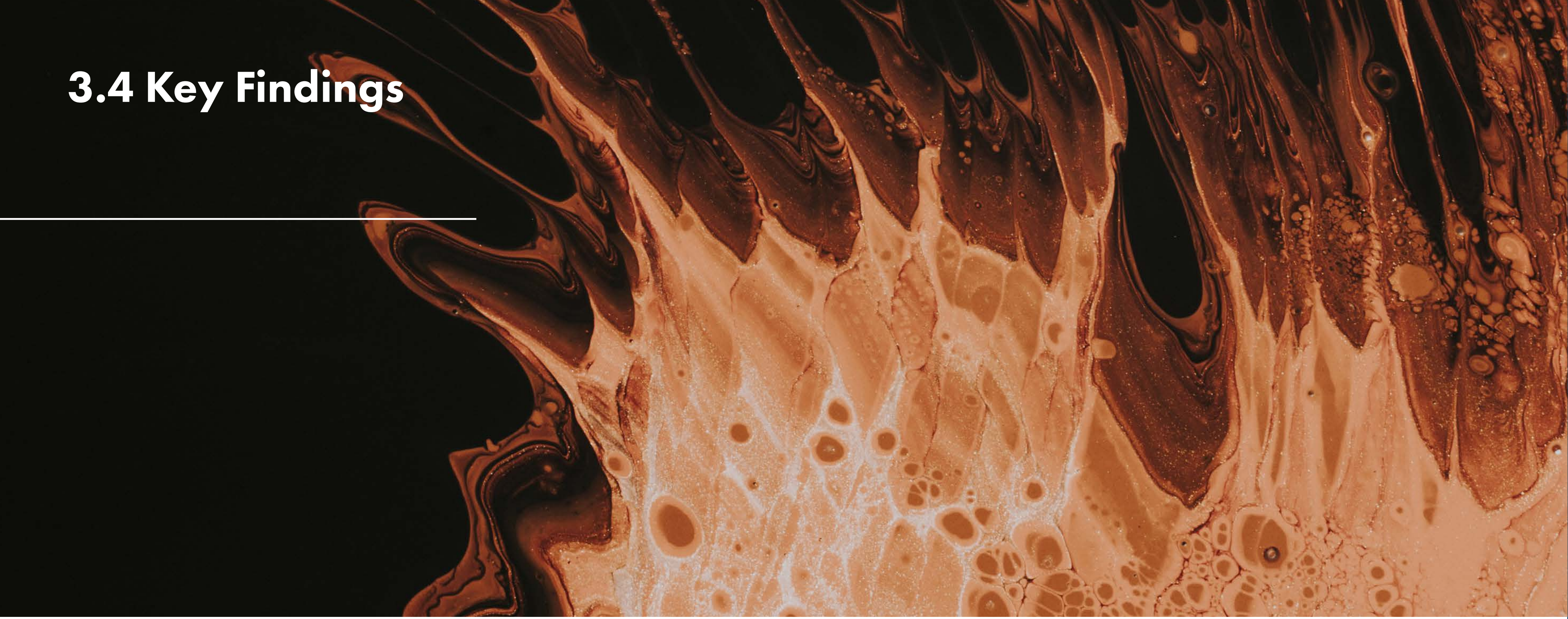
To address the key questions identified in Section 3.3, a gradual increase of hydrogen levels in the gas feed to Port 1 was planned. Each new hydrogen level was fired for around 3 hours to ensure that the effects were fully understood.

The proportions fired during each of the first six days are shown in Table 3 1. Once 100% hydrogen was reached on day 5, a longer-duration run was performed at this level.

Table 3.1: Proportions of Natural Gas and Hydrogen Fired in Port 1

	Natural Gas % by Volume	Hydrogen % by Volume
Day minus 1 baselines	100%	0%
Day 1 (am)	80%	20%
Day 1 (pm)	70%	30%
Day 2 (am)	60%	40%
Day 2 (pm)	50%	50%
Day 3 (am)	40%	60%
Day 3 (pm)	30%	70%
Day 4 (am)	20%	80%
Day 4 (pm)	10%	90%
Day 5 (am)	0%	100%
Day 6	0%	100%

3.4 Key Findings



Every aspect of the original model was verified by measurements during the demonstration. This showed that the models were robust and can be used for future research.

Regarding the key questions identified in 3.3:

- The effect of flame luminosity predicted by the model was realised in practise, and effective melting was achieved, demonstrating good heat transfer to the melt;
- At higher H_2 levels, NO_x production increased by 20-30%, but this is within the capability of existing abatement equipment at Greengate Works;
- The increase in soda levels was within existing operating experience; and
- There was no impact on glass quality, either in terms of colour or fault density (bubbles and inclusions).

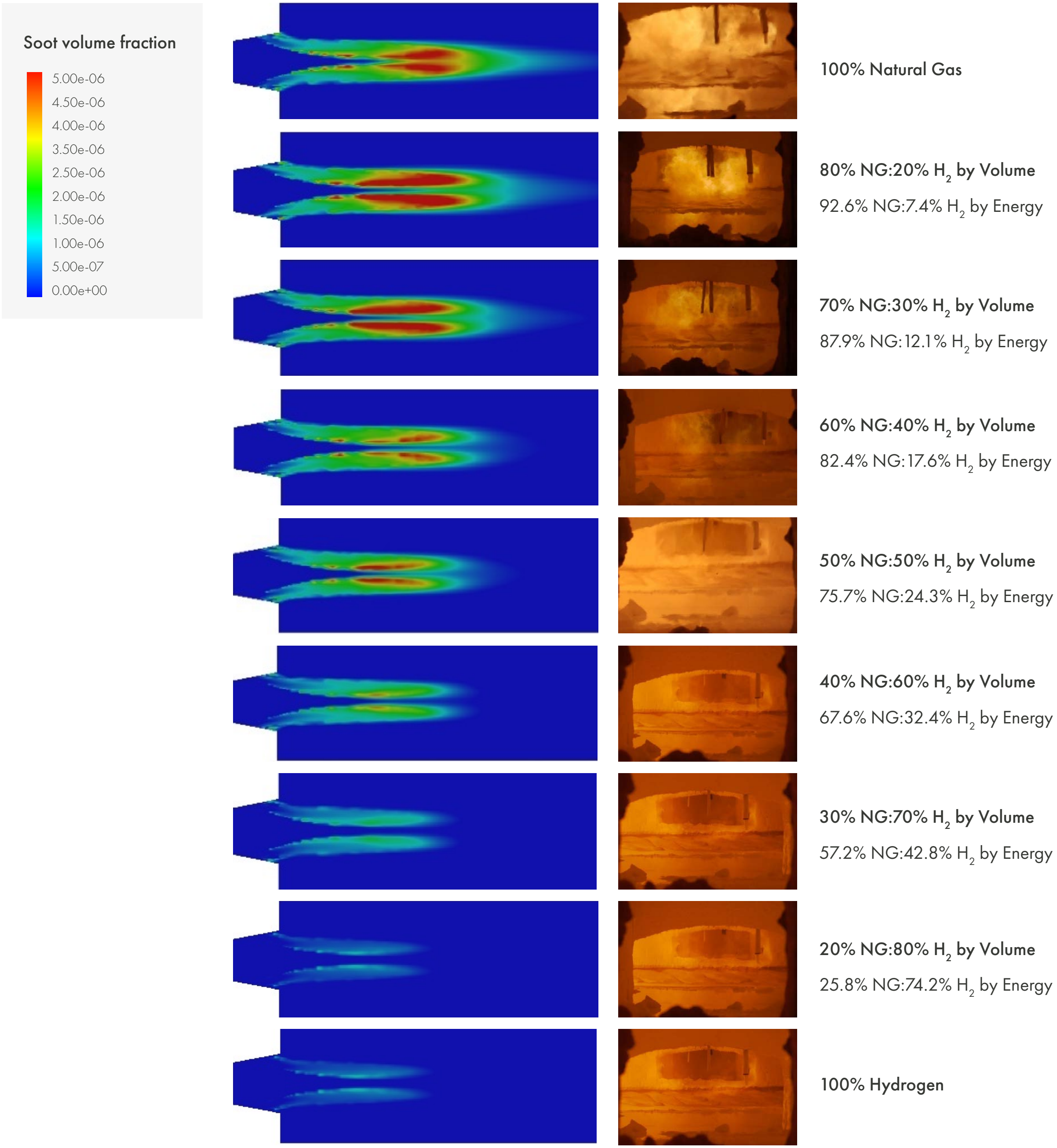
Consequently, the demonstration programme showed that, in terms of product quality and impact on plant and equipment, hydrogen is a viable fuel for glass melting. More detail on these findings is given below.

3.4.1 Flame Appearance

Figure 3.3 shows the comparison between the soot prediction in the model and the observed flame. The soot prediction is verified to be a good representation of the flame luminosity.

As the proportion of hydrogen was increased the flames became visibly less luminous and became effectively invisible for flames with 70% hydrogen and above, by volume (42% by energy). The proportion of hydrogen was ultimately increased to 100% with effective melting of the batch blanket achieved.

Figure 3.3: Predicted Soot Conc. (from CFD Model) and Flame Appearance

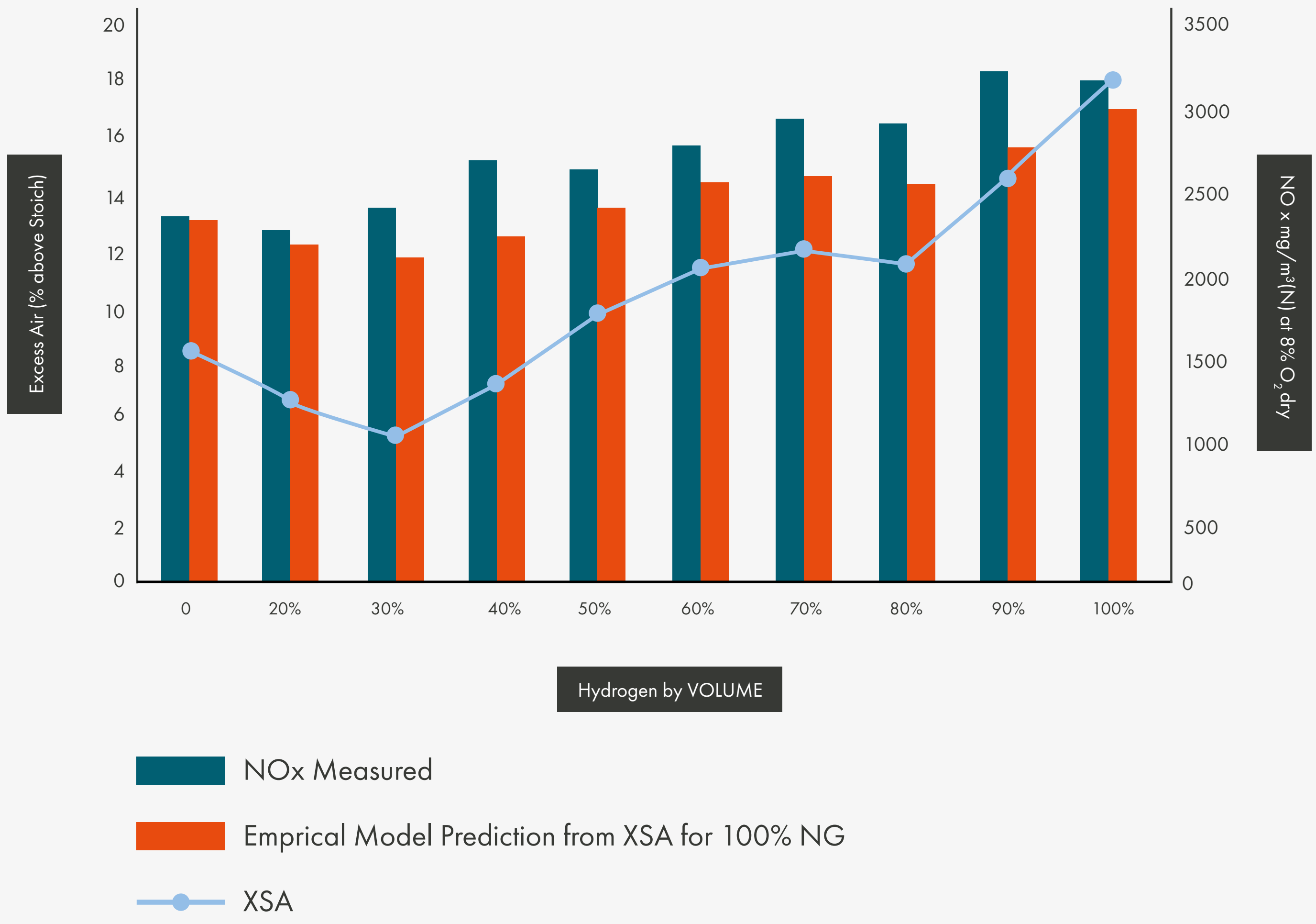


3.4.2 Measuring NOx Emissions

As described above, the initial NOx modelling relied on the empirical model developed by NSG. This empirical NOx model predicted that the NOx would increase by ~33% for 100% hydrogen compared with natural gas.

The intention for the trial was to keep the combustion stoichiometry constant across the different hydrogen proportions, to aid assessment of the impact on NOx production, but this proved not to be practical. Figure 3.4 shows that the NOx increase overall was close to the model predictions, despite the change in stoichiometry. It was found that NOx levels during hydrogen firing are 20-30% higher than from natural gas, under optimised stoichiometry, which is within the capability of existing abatement equipment at Greengate Works.

Figure 3.4: Modelled NO_x Emissions and Measured Excess Air (XSA)



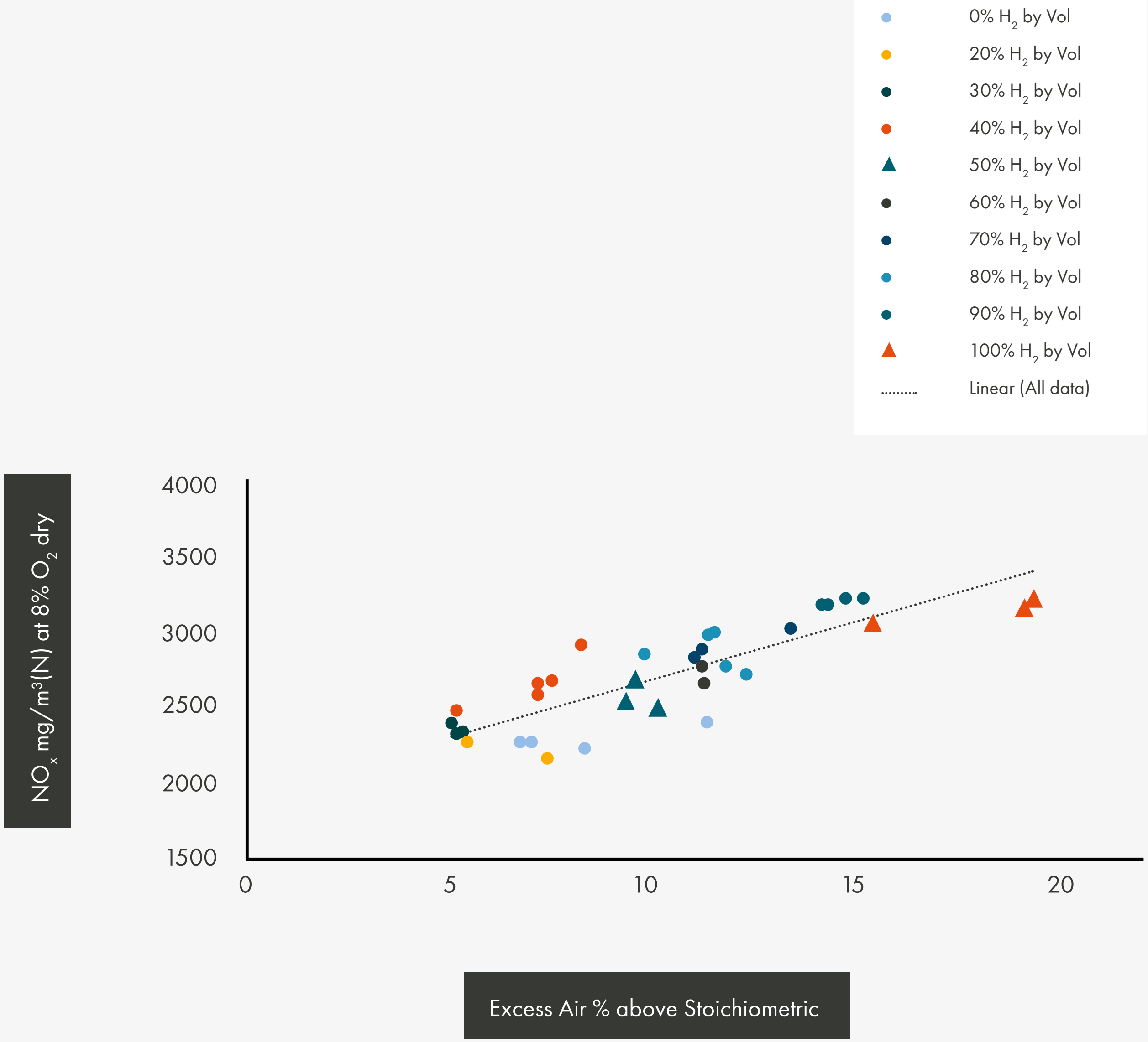
3.4.3 Effect of Excess Air on NOx whilst firing Hydrogen

The temperatures in the glass furnace are sufficiently high (1,500-1,600ºC) that the flame temperature of the combustion is only a minor contributor to NOx under natural gas firing, compared to excess air.

This is contrary to lower temperature combustion where flame temperature is a major contributor. It was important to assess whether excess air is still the dominant effect when operating on hydrogen.

Figure 3.5 shows NOx emissions measured throughout the demonstration, with several data points at each hydrogen level. This data shows a strong correlation between NOx production and excess air, confirming the importance of excess air when firing on hydrogen.

Figure 3.5: NO_x Emissions and Excess Air for different H_2:NG Blends



3.4.4 Efficiency of Operation

The data from the demonstration showed that lower heating value (LHV) efficiency of hydrogen-firing was unchanged compared with that of natural gas.

3.4.5 Planning and permitting

No additional planning consent or permit was required to undertake the demonstration at Greengate Works. In the glass-making sector, permitting is usually managed by the Local Authority rather than the Environment Agency, and in this case, St Helens Borough Council, was kept fully informed of the trial.

As mentioned above, the NO_x emissions observed during the demonstration were within the capabilities of the existing abatement equipment. As a result, it is expected that at most other large glass-making sites, to enable similar demonstration projects, permits will not need to be amended on NO_x grounds. However, switching to hydrogen in perpetuity may require some form of variation to existing permits due to the change in fuel source.

3.5 Costs of Switching to Hydrogen

The commercial deployment of switching glass furnaces to hydrogen will only happen once infrastructure for bulk, resilient supply and distribution of low-carbon hydrogen is in place. In the case of NSG's Greengate works, this relies upon the deployment of the HyNet project.

This is a fundamentally different modus operandi to the tube trailer supply model, which was necessary for the demonstration project. Many of the major costs of the demonstration, such as the pressure let-down infrastructure, will not be incurred under a pipeline supply scenario.

3.5.1 Capital Costs for Deployment

Due to the lower volumetric energy density of hydrogen, it is possible that new, larger pipes will be required for pipework from the on-site gas cabin to the burners. However, this will be subject to an assessment of whether alternative solutions such as increased operating pressure or gas velocities are feasible, and consequently such costs are not estimated here.

Based on conversion of all burner ports at Greengate Works, the following costs are estimated:

- Engineering design and safety assessments: £150k
- Additional mechanical equipment: £200k
- Electrical, control & instrumentation: £150k

Total costs for switching similar sites to hydrogen are therefore estimated at £500k. These costs might increase three-fold if new pipework is required, but these, and potentially the plant and equipment costs could likely be offset by the savings made by NSG and wider sites obligated under the UK Emissions Trading Scheme.

3.5.2 Non-fuel Operating Costs

The aforementioned 20-30% increase in NO_x levels is likely to increase consumables consumption in the NO_x abatement plant. Due to the different characteristics of hydrogen compared to natural gas, some operator training will also be required.

3.6 Decarbonisation Unlocked

3.6.1 At NSG's Greengate Works

The demonstration has shown that the melting end of the Greengate Works furnace can be decarbonised through switching to low carbon hydrogen. This constitutes the majority of the natural gas used on-site today. Once low-carbon hydrogen is available at scale and is being supplied to the site by the HyNet hydrogen pipeline, further work can be performed to determine the feasibility of switching the refining end of the furnace to operate on hydrogen.

3.6.2 Applicability to Other Sites

The technical solution demonstrated at NSG's Greengate Works is applicable to all other float glass manufacturing plants around the UK and globally. Sites of a similar scale in the UK are operated by St Gobain and Guardian Glass. Alongside NSG, these three companies are responsible for 70-80% of output from the sector. However, a number of smaller sites are also operating and the proposed solution is likely to be equally applicable to these sites.

The solution is also applicable to container glass manufacturers, as many use a similar melting furnace to that at Greengate Works; for example, that operated by Encirc at Elton (near Ellesmere Port), which is currently fuelled by around 800GWh/annum of natural gas. This plant is directly adjacent to Stanlow Manufacturing Complex, where the Vertex Hydrogen ('Vertex') Production Hub will be located, such that Encirc is an ideal candidate for early switching to hydrogen.[18]

PEL estimates that there is a total of around 55 glass-making sites in the UK, including those manufacturing fibre glass products. This equates to potentially converting up to 650-700MWth (approximately 6 TWh/annum) of energy demand from natural gas to low carbon hydrogen, reducing UK emissions by approximately 1.2MtCO_2/annum.

3.7 Key learnings

The demonstration at NSG's Greengate works has shown that the majority of energy use within a glass furnace (that associated with melting of raw materials) can be switched from natural gas to hydrogen.

Key learnings from the work include:

- When operating on hydrogen, effective heat transfer to the melt is maintained, and so LHV efficiency of operation is likely to be unchanged;
- At higher hydrogen levels, NO_x emissions may increase by 20-30%, but this should be within the capability of existing abatement equipment. As with natural gas-fired operation, excess air is an important determinant of NO_x production;
- Operation on hydrogen results in no impact on glass quality, either in terms of colour or fault density (bubbles and inclusions); and
- The total cost for switching similar sites to hydrogen will be around £500k in terms of plant and equipment costs.

4 | HYDROGEN FIRING IN A BOILER

Hydrogen Firing in a Boiler

Unilever's Port Sunlight manufacturing facility currently uses up to 15tph of steam, primarily raised from natural gas via two boilers, which were installed in 2011, as part of an integrated CHP plant, which also includes two gas engines. The focus of this work was upon the boilers only, although PEL is now engaged on further work funded by BEIS to progress the hydrogen-readiness of gas engines.

Steam from the boilers is used to manufacture home and personal care products, including major brands such as Domestos, Comfort, TRESemmé and Persil. Switching to hydrogen fuelled boilers would allow the site to significantly cut CO_2 emissions, with no need to change core equipment or any manufacturing operations.

There are a limited number of existing examples of hydrogen-fuelled boilers worldwide, but these are largely new-build designs. The demonstration at Port Sunlight was primarily designed to give Unilever sufficient confidence to switch an existing natural gas boiler to run on hydrogen. An additional outcome of the work was that the feasibility of replacing natural gas in industrial burner applications more widely would be demonstrated, and the required modifications to the burner and associated infrastructure determined.

4.1 Demonstration Structure

The demonstration was designed in the two following phases, for both of which Dunphy Combustion ('Dunphy') was commissioned to manufacture the burners and run the test programmes:

1

Phase 1 was essentially a trial on a representative 1.1MW system at Dunphy's test site in Rochdale. This work demonstrated the feasibility of the solution, and provided key design information for the design and production of the burner to be used at Port Sunlight;

2

Following successful completion of Phase 1, Phase 2 of the demonstration was to install a new 7MW, dual-fuel hydrogen/natural gas burner in one of two existing, identical boilers at Port Sunlight, and to supply the site steam load over an extended period while meeting all applicable regulatory standards. In addition, this work provided information on the practicalities and costs associated with safe use of hydrogen, and the comparative efficiency of operation.

4.2 Phase 1

Trials on Representative System

The aim of the Rochdale trial was to demonstrate that hydrogen can be used as a replacement for natural gas in the boilers at Unilever's Port Sunlight facility, and to finalise the design of the burner for use at Port Sunlight to ensure performance and regulatory requirements were met.

The following specific success criteria were agreed in order for the project to proceed to full-scale demonstration at Port Sunlight:

- Reliable and safe production of steam at the required temperature and pressure;
- Burner Modulation ratio greater than 5:1;
- Operation within NO_x limits in the flue of 200mg/Nm^3 at 3% O_2, in line with the Medium Combustion Plant Directive (MCPD); and
- Production of flue gas at sufficient temperature to prevent condensation in stack.

The trial also provided data on emissions of O_2, CO_2, CO, and NO when operating both on natural gas and hydrogen, and a comparison of likely visible plumes in each operating mode.

The burner performed well against the success criteria, achieving modulation ratio of 10:1, and NO_x emissions between 120 and 170mg/Nm^3 across the modulation range.

Perhaps the most important result was the low levels of NO_x emissions without the need for Flue Gas Recirculation (FGR). This meant that FGR was not specified for Port Sunlight, which reduced the capital costs and efficiency loss associated with such a system. It is worth noting, however, that tests using FGR were still run at Rochdale during Phase 1, which resulted in NO_x levels below 70mg/Nm^3.

4.3 Phase 2
Demonstration

Figure 4.1: Tube Trailer with Primary and Secondary Let-down Stations

4.3.1 Key Questions

Following the successful demonstration at Dunphy's site in Rochdale, the project proceeded to the Phase 2 demonstration. This constituted design, installation and operation of a 7MW burner in order to:

- Verify the outputs from the Phase 1 work at full commercial scale;
- Provide the Port Sunlight site's steam load for several hours a day over a period of several weeks
- Compare the performance of the burner on hydrogen to that using natural gas;
- Verify that no deterioration in boiler condition is caused by use of hydrogen.

Following successful execution of Phase 2, it was intended that Unilever would have sufficient evidence to enable a decision to switch both of its boilers to hydrogen once available from HyNet.

4.3.2 Design of Hydrogen Supply to Burner

Operating at its maximum firing rate, the hydrogen burner in place at Port Sunlight consumes around 180kg/hr of hydrogen. At 50% modulation (which is more representative of normal operation), fuel usage falls to around 90kg/hr.

At these volumes of hydrogen consumption, the most practical solution was deemed to be delivery of hydrogen by tube trailer to Port Sunlight. It was agreed that three trailers would be delivered each day and would operate in parallel, enabling several hours of continuous operation.

BOC was contracted to supply hydrogen to the trial, and to supply equipment for letting down the hydrogen from delivery pressure (which can be in excess of 200barg) to 10barg.

The hydrogen was subsequently let down to 300mbarg in a secondary let-down station designed by GHD, which acted as the design integrators for the project.

The hydrogen was then transported via new pipework into the CHP plant and to the dual-fuel burner fitted to the demonstration boiler.

One of the perceived challenges of working with hydrogen was the state of readiness of the supply chain. However, it was possible to source all equipment and instrumentation for hydrogen service from existing suppliers.

Phase 2
Demonstration

4.3.3 Design of Hydrogen Supply to Burner

The existing CHP plant at Port Sunlight consists of two identical CHP trains. Each train has a Jenbacher JMS 612 reciprocating engine to generate electricity, coupled to a conventional three-pass Danstoker boiler. The boiler raises steam from heat generated by natural gas combustion, supplemented by waste heat from the engines. The existing burners were supplied by Dunphy.

For the demonstration, Dunphy supplied a CE and UKCA-marked new dual-fuel natural-gas / hydrogen burner, which was installed in one of the existing boilers, as shown in Figure 4.2.

The burner is capable of firing 100% natural gas, 100% hydrogen or any combination thereof, the ratio of which can be varied in real time during operation. This is achieved by inclusion of separate combustion heads for the two fuels:

- A natural gas combustion head with of six gas poker nozzles, fixed to a gas annulus; and
- A hydrogen head consisting of six nozzles, flame plate and pilot ignition nozzle and electrodes, as presented in Figure 4.3.

Figure 4.2: New dual-fuel burner at Unilever's Port Sunlight Plant

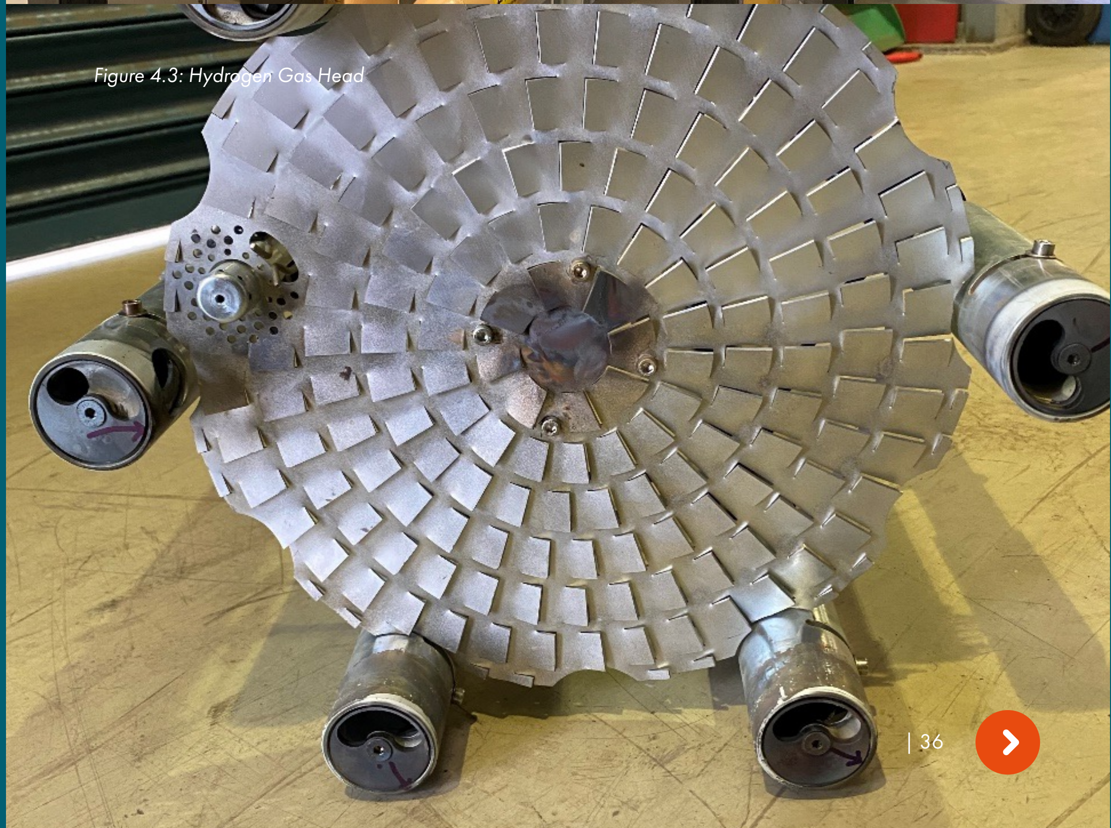


Figure 4.3: Hydrogen Gas Head

4.3.4 Demonstrating Safe Operation with Hydrogen

Safe operation using hydrogen was a primary focus of the design work. This was achieved via:

- Engagement of appropriate experts at each stage of the process, including BOC for hydrogen delivery and Dunphy for the hydrogen burner, both of which were able to reference multiple previous hydrogen installations;
- Adherence to applicable codes of practice and design standards from bodies such as BCGA and BSI;
- Industry-standard safety assessments such as HAZID, HAZOP and DSEAR Assessment;
- Production of a detailed Demonstration Protocol document containing method statements for safe execution of all activities during operation of the Demonstration.

Figure 4.4: Hydrogen Lower Flammability Limit Iso-surface

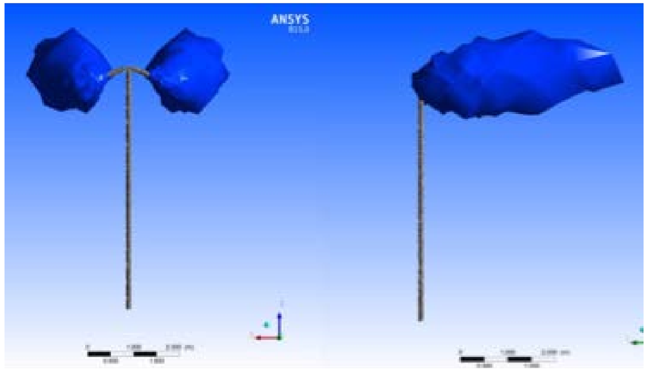
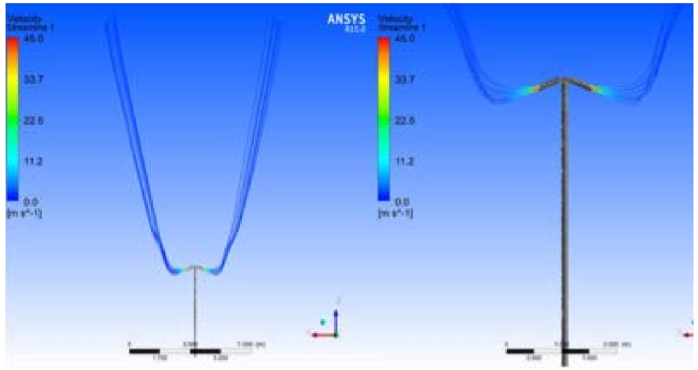


Figure 4.5: Hydrogen Release Streamline Profiles



The Port Sunlight facility is an Upper Tier COMAH site, due to the environmental impact of raw materials on site if released. Prior to operation, therefore, a comprehensive assessment was undertaken to ensure that the project neither introduced a new Major Accident Hazard, nor affected the basis of safety of other on-site processes.

The Hazardous Area Classification raised a question concerning the release of hydrogen from the vent stack of the secondary let-down station. In order to further investigate the extent of a potential flammable atmosphere, a CFD study was commissioned from ERM using ANSYS software.

The study sought to model a worst-case release from the vent stack and confirmed that, for the Port Sunlight configuration, there was no potential for a flammable atmosphere at ground level. Of wider interest is the clear illustration of the buoyancy of hydrogen, and its propensity to rise, even when released with downward momentum, as shown in Figure 4.4 and Figure 4.5.

Phase 2
Demonstration

4.3.5 Demonstration Plan

In order to address the key questions identified in Section 4.3.1, the demonstration was planned as follows:

1. **Perform Non-Destructive Testing (NDT) to establish initial condition of boiler**
2. **Commissioning phase:**
    a. Establish the base profile of operation on natural gas, achieving a turndown between 8:1 and 10:1;
    b. Establish a firing profile using 100% hydrogen and determine the turn down ratio achievable, expected between 8:1 and 10:1;
    c. Compare the combustion performance of Hydrogen against natural gas;
    d. Analyse the emissions including O_2, CO_2, CO, NO, NO_x and flue gas temperature produced by combustion of hydrogen;
    e. Determine if NO_x emissions are compliant with Medium Plant Combustion Directive (MCPD).
3. **Load-following operation:**
    a. Operate the boiler to meet site steam load for up to 8 hours per day over a four-week period;
    b. Compare thermal efficiency of operation on natural gas with operation on 100% hydrogen.
4. **Assess conditions of key components, such as nozzles and flame plates, at the end of the trial.**
5. **Perform a second NDT to assess whether hydrogen has caused change in condition of the boiler.**

Hydrogen operation was planned between 8am and 4pm Monday to Friday for a 4-week period. Outside of these hours, and in the event of supply interruption, the burner was switched back to natural gas-fired operation. To provide additional resilience for the site steam supply, a back-up boiler capable of supplying site steam load was leased to have on standby during the demonstration period.

4.4 Key Findings

Following commissioning, the new burner operated safely and reliably over a four-week period, meeting the Port Sunlight steam load and operating within all regulatory thresholds. The burner successfully modulated according to site load, and there was no impact on site operations.

As such, hydrogen conversion has been shown to be viable for existing industrial package boilers, and should also be considered for use in bespoke boiler designs. Once low-carbon hydrogen is available in bulk from HyNet, these boilers now have a clear pathway to decarbonisation.

Specific findings on the performance of the burner are detailed below.

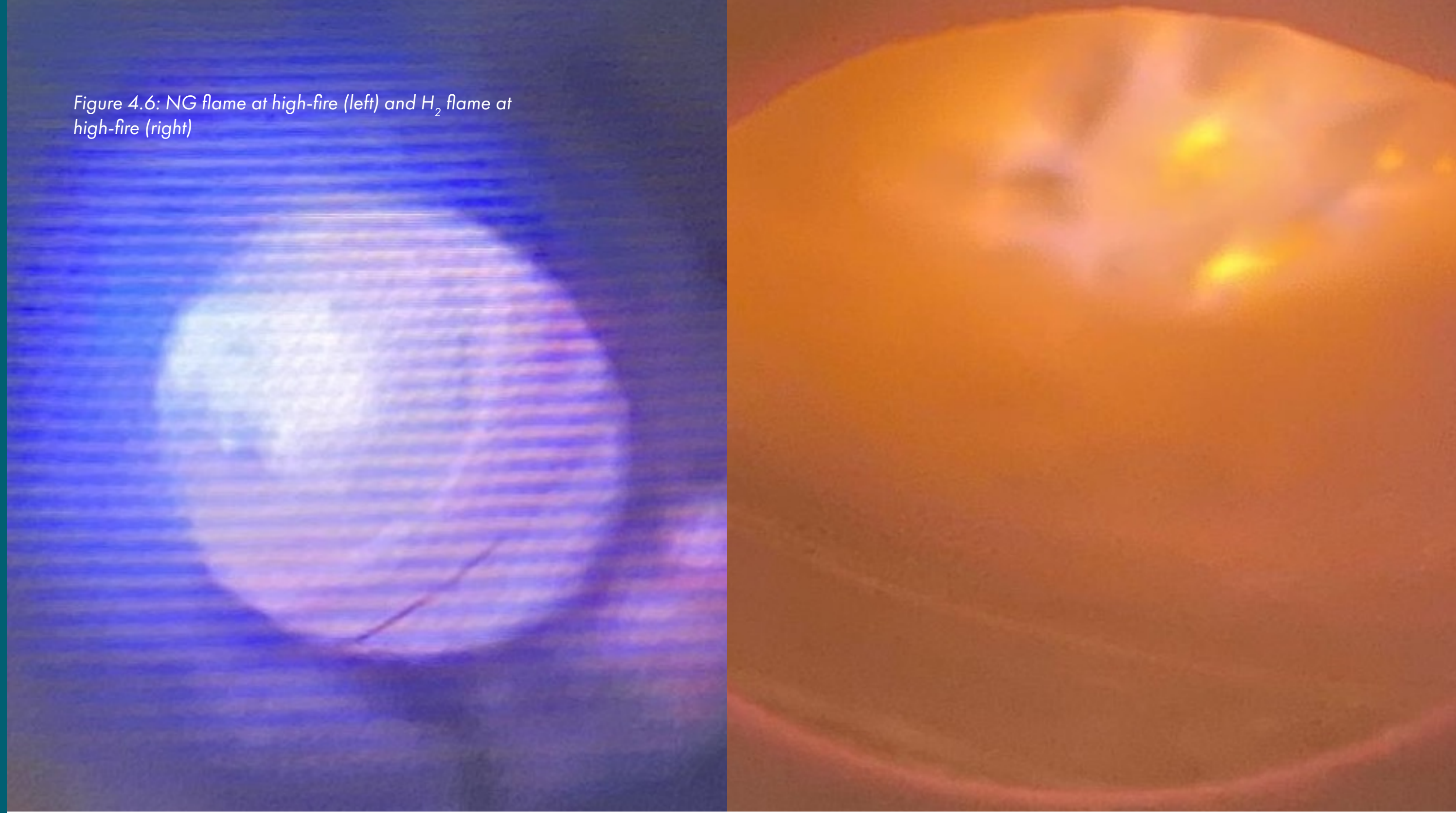


Figure 4.6: NG flame at high-fire (left) and H_2 flame at high-fire (right)

4.4.1 Hydrogen flame

The flame was found to be stable, and showed no form of lifting throughout the firing range, even when high levels of excess air were added to the combustion points.

The flame colour was reasonably opaque at low fire turning a 'dirty' orange at high-fire when compared to a natural gas flame, as presented in Figure 4.6.

The flame signal strength for hydrogen also indicated a steady value across low and high fire, identical to natural gas operation.

4.4.2 Combustion Air Requirements

As expected, due to combustion stoichiometry, the required air flow when operating on hydrogen was lower. For hydrogen-only burners, this will allow the use of smaller combustion air fans and motors. For dual-fuel applications, use of a variable speed drive on the combustion air fan will reduce electrical power demand.

4.4.3 NO_x emissions

NO_x emissions when operating on 100% hydrogen at Port Sunlight ranged from 156mg/m^3 at low fire to 187mg/m^3 at high fire, referenced to 3% O_2. This level is within the MCPD limit of 200mg/m^3 and as mentioned above, its achievement did not require FGR.

Although compliant with the MCPD, it was notable that NO_x levels were higher than expected based on the trial at Rochdale. Importantly, this was found to be a result of the furnace geometry of the boiler. Typical furnace geometry for low-NO_x applications is between 1.0 MW/m^3 and 1.4 MW/m^3, and the boiler at Rochdale was within this range.

However, the furnace heat release rate of the boiler at Port Sunlight is 1.7 MW/m^3 and also the furnace is both long and narrow. The combined effect of this furnace geometry and the fast flame speed of hydrogen resulted in a high thermal mass locating in front of the burner, increasing the levels of NO_x generated. To achieve the above performance, therefore, Dunphy undertook work to adjust the burner.

For wholly new plant, this issue can be solved through design of a boiler with appropriate furnace dimensions. However, this is not an option for switching of existing boilers to hydrogen for which adjustments to the burner may need to be made to ensure effective flame separation is achieved; this approach was validated at Port Sunlight.

4.4.4 Condensation & Pluming

The flue temperatures for hydrogen combustion at low-fire remained well above the dew point and therefore no excess moisture was witnessed within the boiler or flue ways. Pluming from the chimney exit and was observed to be similar to that witnessed when operating on natural gas.

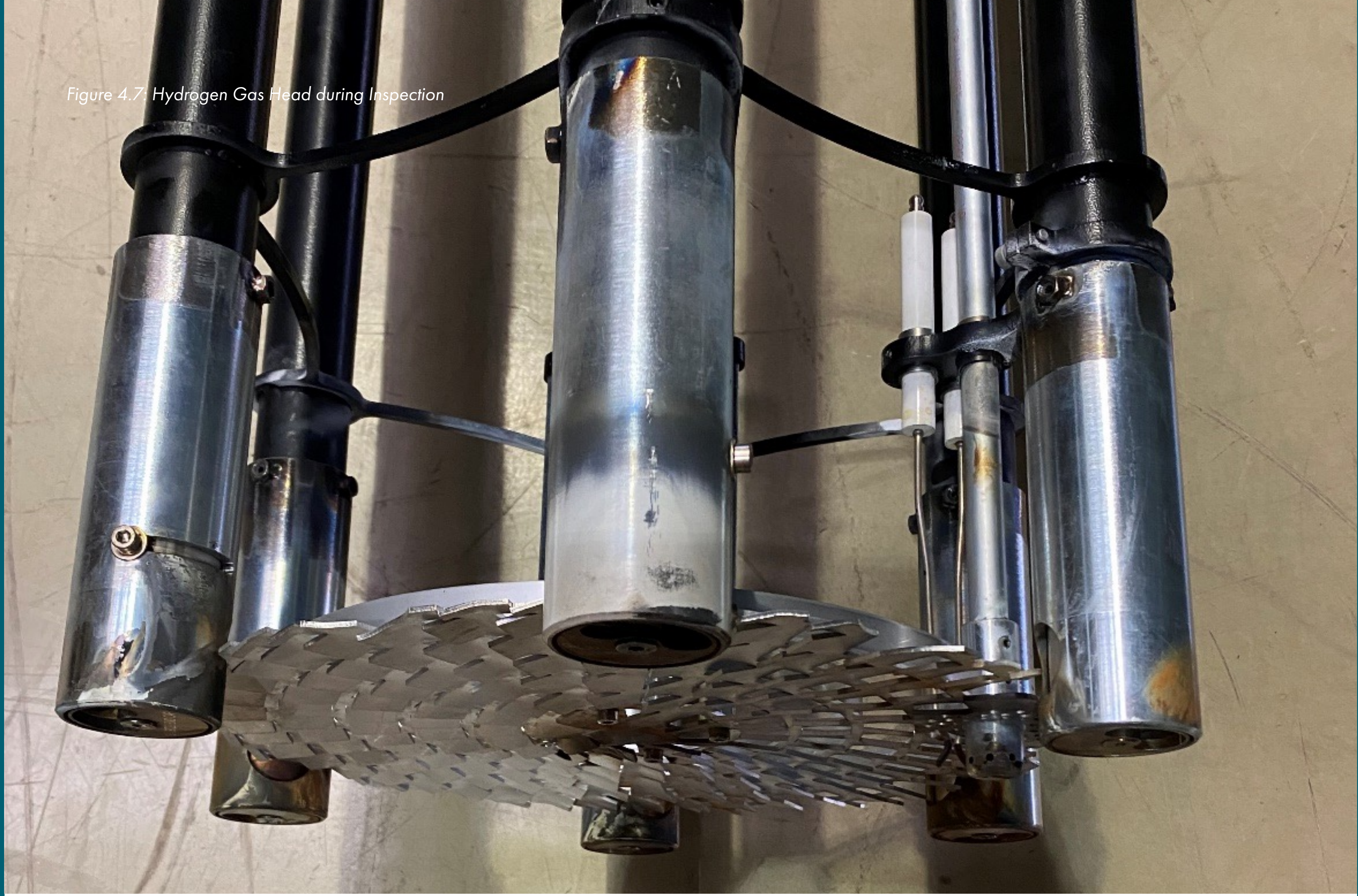


Figure 4.7: Hydrogen Gas Head during Inspection

4.4.5 Impact on Plant and Equipment

As presented in Figure 4.7, inspection of the hydrogen gas head following the demonstration indicated that the hydrogen had combusted at the nozzle tips as expected, providing the necessary flame stability for safe reliable combustion. There are no signs of deterioration on the flame plate or nozzles.

Furthermore, the post-demonstration NDT showed no change in the condition of the boiler following operation on hydrogen.

4.4.6 Boiler Efficiency

Boiler efficiency on each fuel was calculated based on fuel consumption, heat input from gas engines and steam output over a 7-hour period. The calorific value of natural gas varies within a prescribed range, and so a gas chromatograph was used to characterise the fuel.

The net efficiency of the boiler when operating on hydrogen was found to be 92.7%, compared to 92.5% on natural gas.[19] This shows that the boiler was comparably efficient in transferring the heat from the combustion products of both fuel sources.

4.4.7 Planning and Permitting

No additional planning consent or permit was required to undertake the demonstration at Port Sunlight. Fuel switching from natural gas to hydrogen at other sites using existing boilers is similarly expected to not require any change to existing planning consents.

Engagement was undertaken with the Environment Agency (EA) to determine whether any change to the existing permit would be required. This was deemed unnecessary, primarily due to the short duration of the demonstration and the fact that the boiler was expected to operate within the limits expressed in the existing permit. However, this outcome was very specific to the site, its permit and the duration of the demonstration and so cannot be wholly extrapolated to other sites. In particular, switching fuels in perpetuity may require some form of variation to existing permits.

4.5 Costs of Switching

The commercial deployment of switching natural gas boilers to hydrogen will only happen once infrastructure for bulk, resilient supply and distribution of low-carbon hydrogen is in place. In the case of Port Sunlight, this relies upon the deployment of the HyNet project.

This is a fundamentally different modus operandi to the tube trailer supply model, which was necessary for the demonstration project. Many of the major costs of the demonstration, such as construction of a hydrogen delivery compound and some of the pressure let-down infrastructure, will not be incurred under a pipeline supply scenario.

4.5.1 Capital Costs for Deployment

The Port Sunlight site has two 7MW Danstoker OPTI 1200 gas fired waste heat boilers each providing process steam and hot water to the site. The existing boilers are fitted with multi-fuel Dunphy burners configured to run on natural gas and light fuel oil.

As noted above, a large proportion of the demonstration equipment would not be required for deployment, and so much of the equipment described above is not relevant in terms of determining deployment Capex.

Deployment costs will depend upon whether fuel switching at a given site is to hydrogen only (i.e. should the existing natural gas grid be fully repurposed or a fully resilient hydrogen supply be available) or to dual-fuel natural gas and hydrogen.

The demonstration at Port Sunlight was based on the need for dual-fuel operation, which is most likely in the early days of a hydrogen network, when supply resilience will be lower than for the existing gas network.

The new burner and associated controls and instrumentation cost around £100k, which is a level which should be expected more widely for similar installations.

However, we would expect costs to fall for 'nth-of-a-kind' projects, whereby a greater number of suppliers are conversant with hydrogen. We would also expect around £100K for engineering design and safety assessments and so a total of £200K for similar switching projects.

For dual-fuel operation, new pipework to the hydrogen distribution network would also be required. The costs of this infrastructure would be more significant, but could likely be offset by the savings made by sites obligated under the UK Emissions Trading Scheme.

For sites switching at a later stage of deployment of the HyNet hydrogen distribution network, whereby switching might be to hydrogen only, the existing on-site natural gas pipework (subject detailed inspection) could be repurposed. Under this scenario, the work undertaken by Dunphy at Port Sunlight suggests that modifications could be made to existing burners at costs of up to £12k, dependent on burner size.

4.5.2 Non-fuel Operating Costs

Representatives from Veolia (the boiler operator on behalf of Unilever) were present throughout hydrogen firing, but this will not be required during normal operation on hydrogen, when the CHP plant runs unmanned.

The demonstration showed that the hydrogen burner can operate reliably for an extended period and so no significant additional costs are expected as a result of hydrogen firing, aside from some additional training of operational staff.

4.6 Decarbonisation unlocked

4.6.1 At Port Sunlight

The demonstration has shown that the boilers at Port Sunlight can be decarbonised through use of low carbon hydrogen. These boilers provide the entire site steam load, and so the pathway to decarbonising provision of heat and steam provision at Port Sunlight is clear.

Approximately 80% of the gas used at Port Sunlight, however, is used in the reciprocating gas engines. Fully decarbonising Port Sunlight energy provision, therefore, requires switching of these to low carbon hydrogen. As mentioned above, switching of gas engines to hydrogen is the subject of work being undertaken by PEL funded by the BEIS second Industrial Fuel Switching Competition.

4.6.2 Applicability to other sites

Work undertaken by the BEIS-funded Hy4Heat Programme estimated that there are 1,400 industrial steam boilers and 600 industrial hot water boilers above 1MWth in capacity operating in the UK, with a combined capacity of around 10GWth.[20] The majority of these are package boilers, and so the results of the demonstration at Unilever Port Sunlight are directly applicable to decarbonising this significant energy load.

These steam and hot water boilers are spread across a range of market sectors, which require 'indirect' heat for manufacturing; including chemicals, food and drink, paper and automotive. Furthermore, there is potentially another 4GWth of smaller steam and hot water boilers in the commercial sector, many of which could also, in principle, be switched to hydrogen using the approach demonstrated at Port Sunlight.

The demonstration therefore lays the groundwork for decarbonisation of a major swathe of the UK economy. The Hy4Heat work estimates that 28TWh of gas is used in steam raising annually; if fuel provision was switched to low carbon hydrogen, 5MTCO_2/annum could be saved. Together with the savings from conversion of hot water boilers, this constitutes a major contributor to future carbon budgets.

At the time of writing, BEIS has recently conducted a Call for Evidence in respect of enabling or requiring the installation of hydrogen-ready industrial boiler equipment at industry sites.[21] The demonstration at Port Sunlight constitutes clear evidence of the potential for switching existing boilers to low-carbon hydrogen and should be taken into consideration by BEIS as part of this wider work.

4.7 Key learnings

The demonstrations at Rochdale and at Port Sunlight enabled a far greater degree of confidence in the switching of existing package boilers from natural gas to hydrogen operation, and in the production of bespoke hydrogen boilers.

Key learnings from the work include:

- Existing natural gas package boilers converted to dual-fuel boilers can achieve stable long-term operation on hydrogen to meet site steam loads, and switch seamlessly between natural gas and hydrogen;
- Extended operation results in no deterioration of flame plate or nozzles, and no change in boiler condition;
- Such boilers can be operated on hydrogen within the NO_x thresholds set by the Medium Combustion Plant Directive (MCPD). However, furnace geometry is critical to meeting these limits and should be carefully assessed to inform burner design;
- Existing boilers will operate on hydrogen at very similar levels of net efficiency (92.7%) to when operating on natural gas; and
- The cost of a new dual fuel natural gas/hydrogen burner is around 10% more than would be a new 'standard' natural gas burner, although this differential can be expected to fall for later projects.

5 | HYDROGEN FIRING IN A GAS TURBINE

Hydrogen Firing in a Gas Turbine

This section focuses on an innovative Front-End Engineering Design (FEED) in respect of a 100% hydrogen fired Combined Heat and Power (CHP) plant at Essar's Stanlow Manufacturing Complex ('the Project').

Unlike the work at Unilever and NSG-Pilkington described above, it was not feasible to undertake a physical demonstration on a gas turbine via this programme for the following reasons:

- There is no existing gas turbine at Stanlow;
- The BEIS IFS Programme budget was not sufficient to support the construction of a new plant at the scale required;
- Gas turbine burner technology is more complex than furnace and boiler burners due to the higher operating pressure, tighter NO_x emissions controls and physical constraints of the combustion area between burner tip and turbine inlet;
- The gas turbine sized under consideration at Stanlow would require c.75MWth of hydrogen input. This quantity of Hydrogen could not be sourced in the current market.

Consequently, as part of Phase 1 of this programme, PEL ran a procurement process for an EPC contractor to undertake a FEED study in relation to a new plant at Stanlow. The goal of this work was to enable Essar to begin consenting of this plant in 2022, working towards a final investment decision (FID) in 2023 or 2024.

The tender process was won by Costain, which started the work in summer 2020.

Alongside the FEED, it should be noted that burner technology development on Hydrogen is firmly in the hands of original equipment manufacturers (OEMs), which have specific test facilities to enable the development of 100% hydrogen-fired gas turbines. Engagement with OEMs was therefore also essential to support this work.

Hydrogen Firing in a Gas Turbine

5.1 Project Basis of Design

The existing CHP arrangement at the Essar refinery is designed around six high-pressure (HP) boilers, although five are sufficient to supply the full heat and power demands for the majority of operation. The boilers are fed by a mixture of Refinery Fuel Gas (RFG) and Natural Gas, although they were originally designed to burn oil. The new gas turbine CHP would entirely replace this existing configuration.

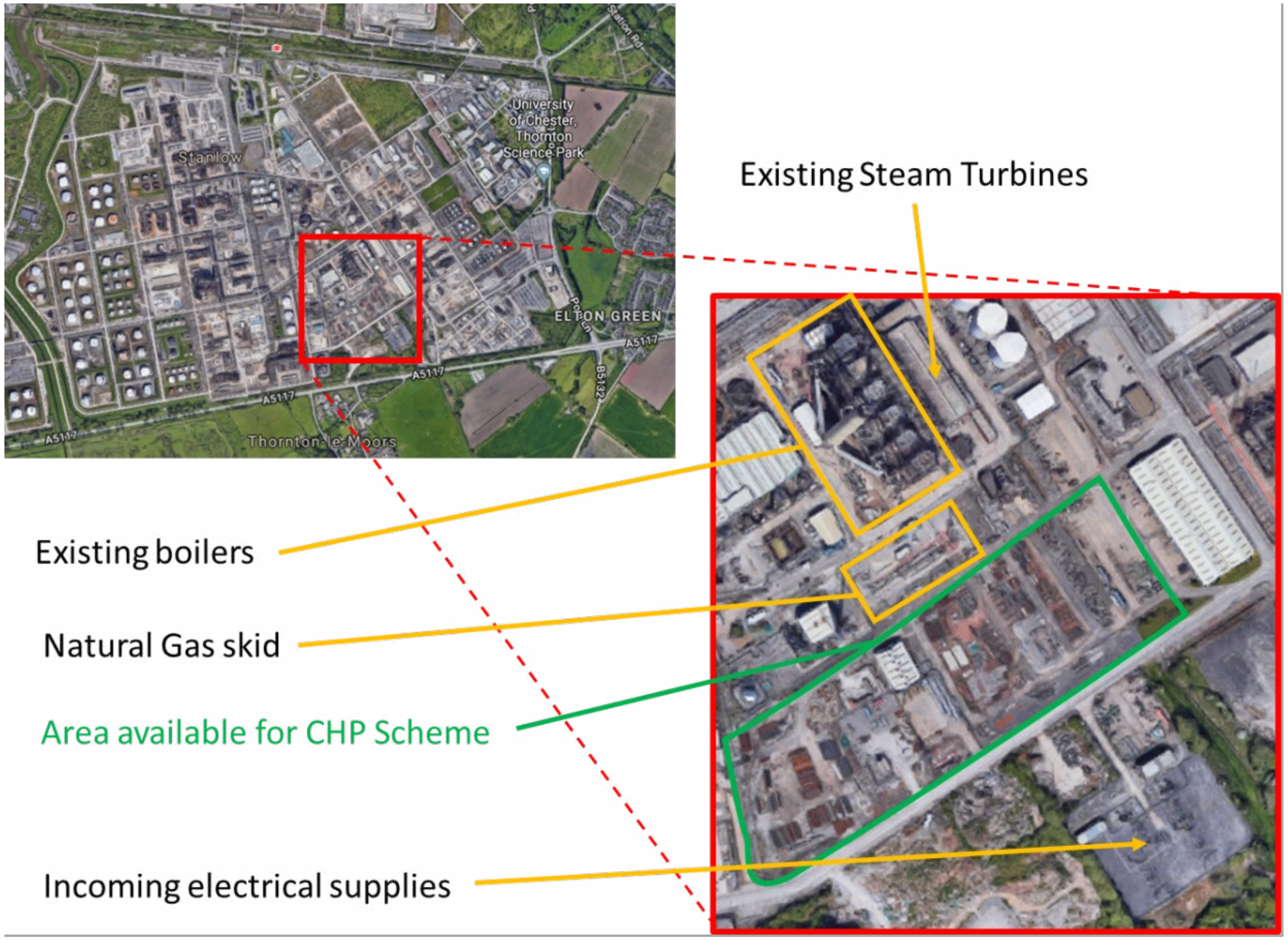
The design of the Project embodies the following principal process operations:

- The ability for the Gas Turbines to run on Hydrogen, Natural Gas, Refinery Dry Gas (RDG) and any mixtures thereof;
- The ability for any required duct-firing of Waste Heat Recovery Boilers (WHRBs) to run on Hydrogen, Natural Gas, Refinery Fuel Gas, and any mixtures thereof;
- The ability to meet the electrical demand of the site in its current operating mode on a peak demand day while satisfying the following hierarchy of priorities;
    - o Meet site electrical and steam demand – capacity and reliability;
    - o Operate on 100% hydrogen when available;
    - o GTs optimised for efficiency on hydrogen (even if at the expense of efficiency on other fuels); and
    - o Export excess power to the grid.
- Process disruption on the refinery does not occur as the result of a full load trip of 1 x GT & WHRB, i.e.:
    - o Sufficient steam header capacity;
    - o Back-up steam generation start-up times come in before steam header is depleted; and
    - o Electrical supply has backup from National Grid import for short term response until additional generation on-site is available.
- All operations must comply with all applicable directives on emissions, equipment supply and installation.

5.2 Plant Location and Layout

As presented in Figure 5.1, the Project will be constructed on land owned by Stanlow Manufacturing Complex, and situated to the south of this area, between the existing HP boiler house/ steam hall and the connection to National Grid.

Figure 5.1: Location of CHP on Essar Refinery



Plant Location and Layout

The Project would also extend beyond the plot identified above as available to include the tie-ins to the existing refinery as shown in Figure 5.2.

The Project is based on four identical WHRBs, with three of these being fed hot exhaust gases from gas Turbines. The fourth unit has space for a gas turbine should the future electrical demand of the refinery increase to a point where it is required. The layout for a single train (Train 1) is shown in Figure 5.3, with the generator transformer in the foreground, then the gas turbine generator package followed by the WHRB.

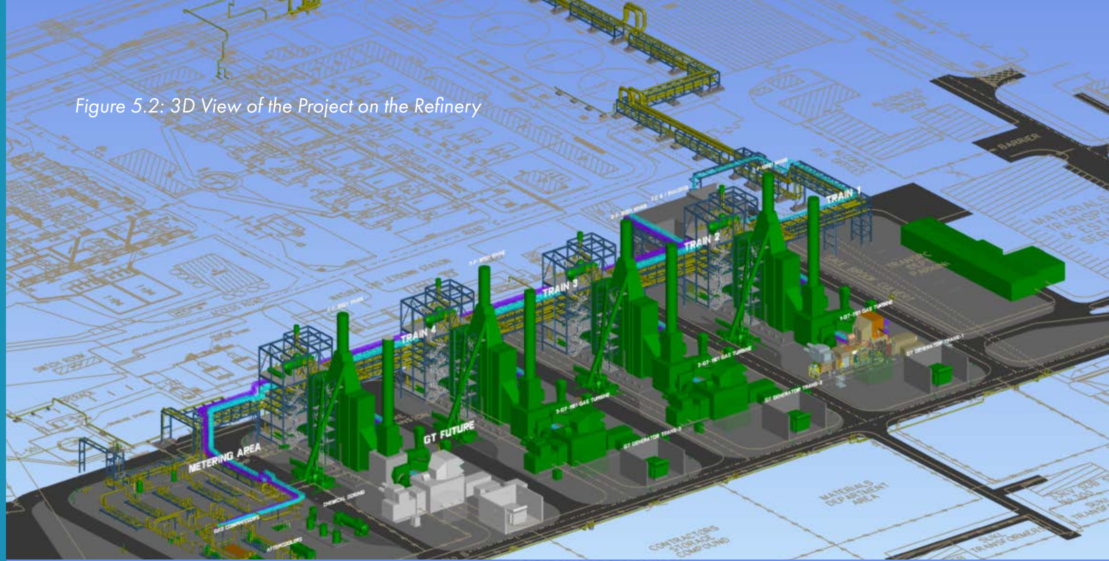


Figure 5.2: 3D View of the Project on the Refinery

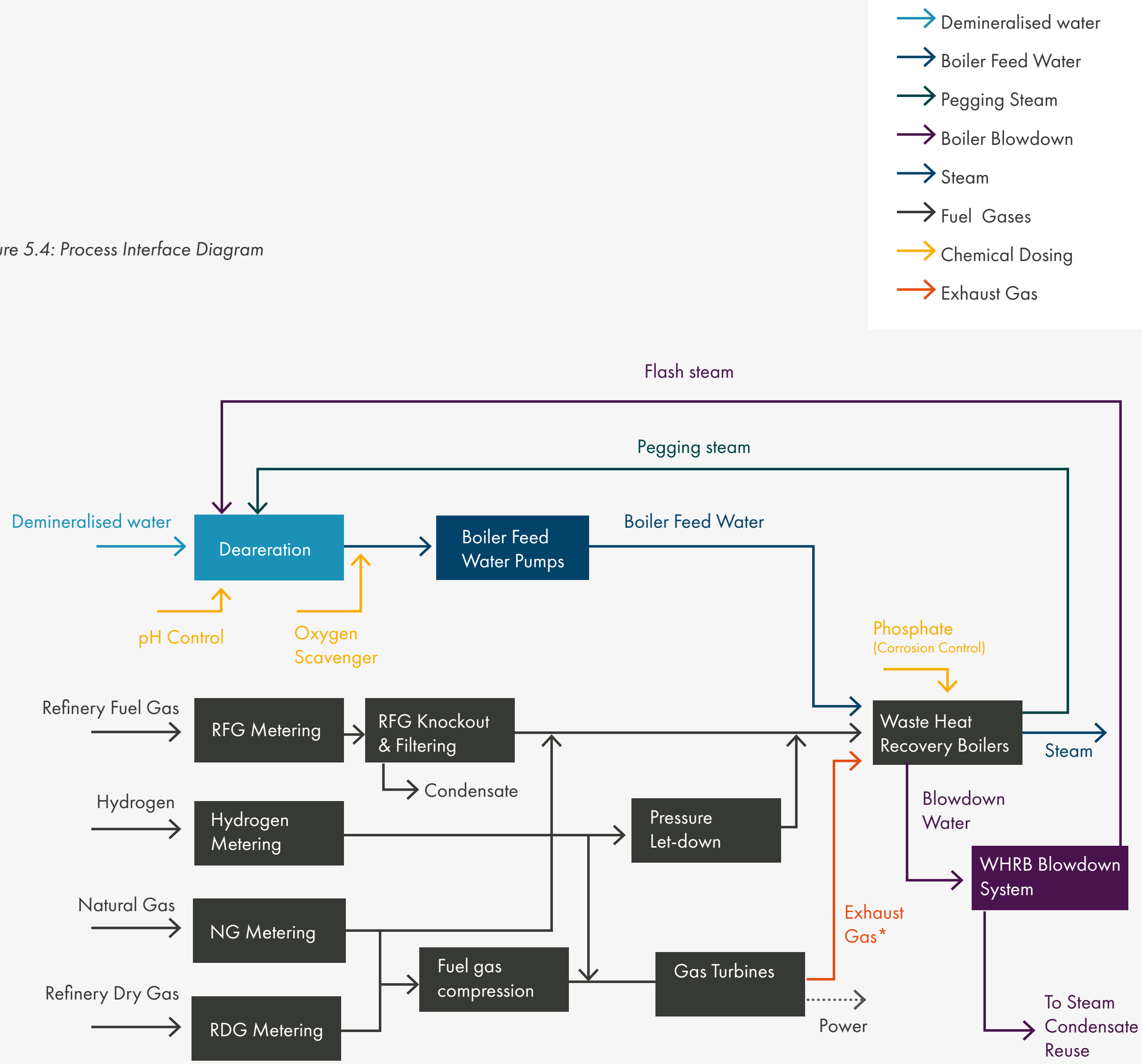
Figure 5.3: 3D View of Train 1

5.2.2 Process interfaces

The Project interfaces with multiple processes on-site. The primary inputs are the hydrogen fuel to the gas turbines and WHRBs, which have all been optimised for use on hydrogen fuel as the primary source, with all other fuel sources being only for back-up when hydrogen is not available.

This is to ensure resilience of operation of the plant to continue to provide heat and power to the refinery during planned and unplanned outages of hydrogen fuel supply. In the early years of hydrogen production this is expected to be less than 5% of the period of operation, reducing significantly as further hydrogen production becomes available in 2027 and beyond. The main process outputs are the electrical power and the process steam. A simple block diagram of the overall process interface is in Figure 5.4.

Figure 5.4: Process Interface Diagram

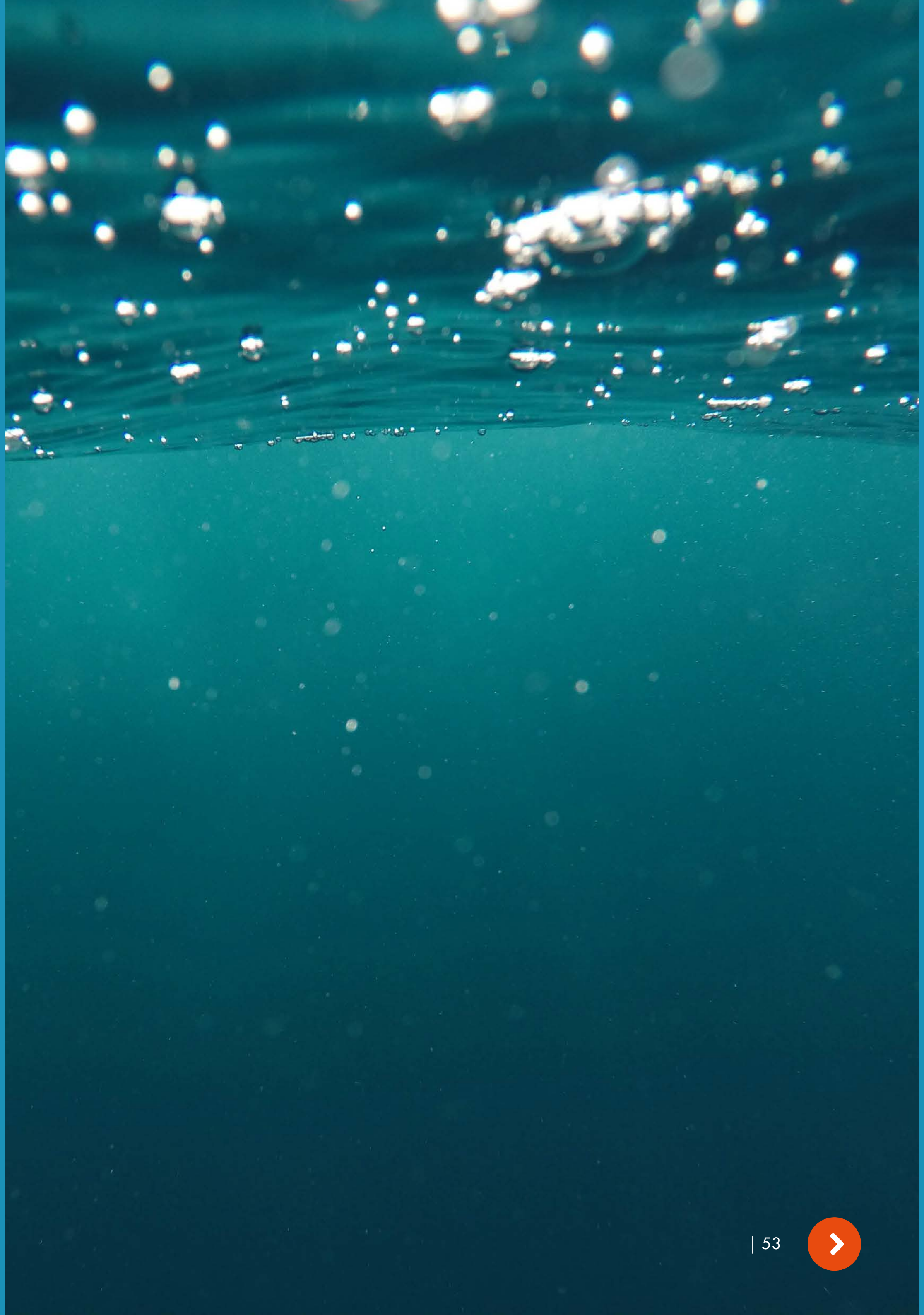


Notes: *Exhaust gas from 3 GTs used in WHRBs (with supplementary firing). 4th WHRB is unpaired to a GT (only fuel gas fired)

5.2.3 Safety Considerations

The FEED study applied the well-established process safety and hazard study processes already followed by Essar at Stanlow Manufacturing Complex. A suite of safety specific engineering deliverables was developed through the study to ensure compliance with regulatory requirements, such as DSEAR and ATEX. Process safety workshops (i.e. HAZID, HAZOP, etc) were undertaken through the process to identify, quantify and mitigate safety concerns to meet either the statuary requirements or to demonstrate ALARP.

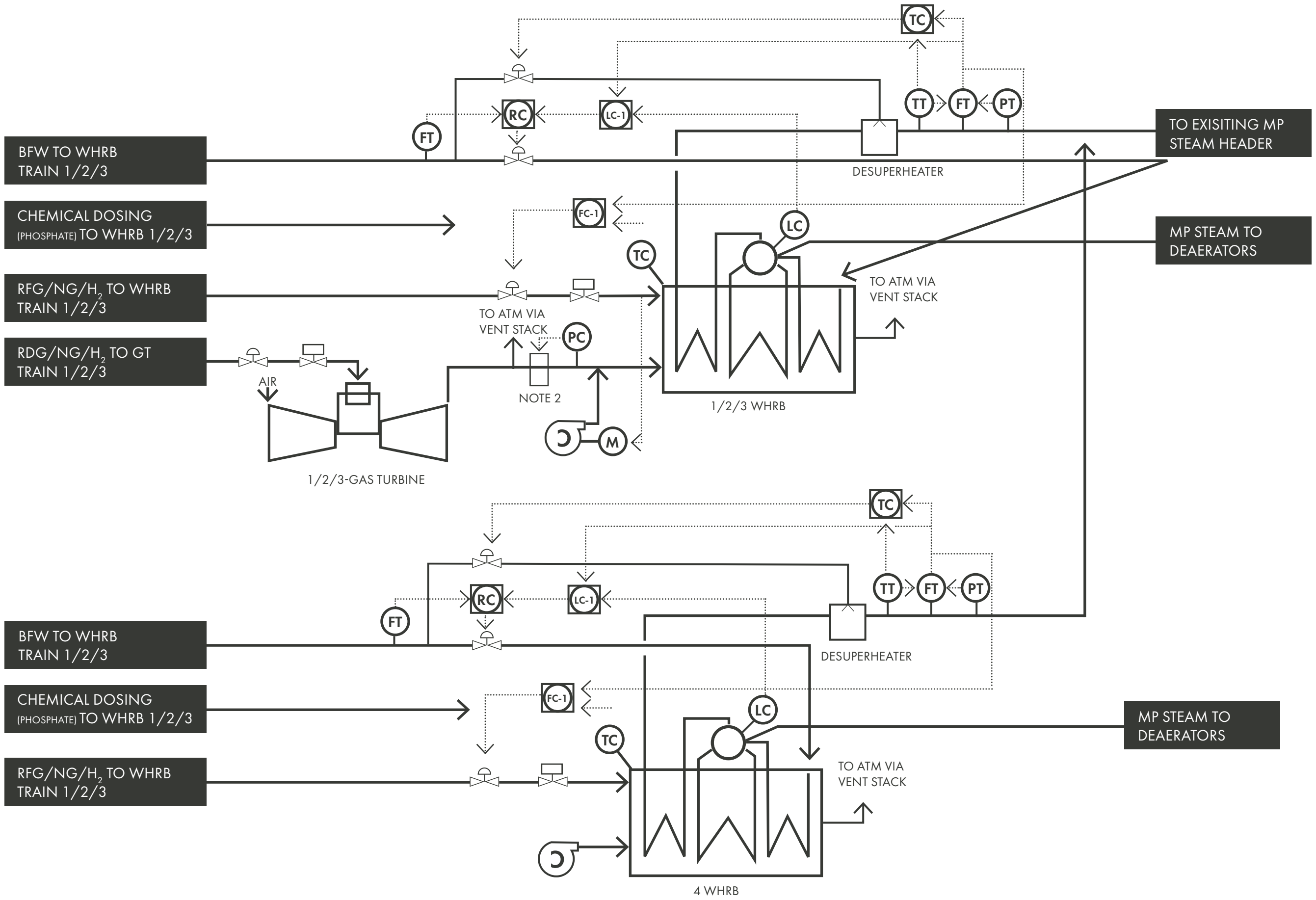
All of the potential fuels (including hydrogen) for the plant were assessed through fire, toxic and explosion consequence modelling. This informed the plant design to meet requirements, and areas to be addressed during detailed design. The presence and use of hydrogen give rise to different risks than other fuels, such as natural gas but none that can't be mitigated to a level which is the same as an existing natural gas-fired CHP. An example is the susceptibility to leaks, whereby hydrogen can escape more readily than natural gas. This is mitigated through design by greater degree of welded connections vs. flanged connections, altering the zoning requirements, and also partly by Hydrogen's inherent buoyancy resulting in faster dispersion.



5.3 Technology & Process

The two primary outputs from the Project are electrical power and medium pressure steam. As presented in Figure 5.5 the scheme will be 3 x 25MWe gas turbines which will provide electrical power to the refinery. The four WHRBs will each be capable of generating 4,000 tpd of MP steam at 340°C and 18.5 barg at the battery limit of the package. This configuration of technologies is relatively common across industries which have a significant heat and electrical power load.

Figure 5.5: Process Flow Diagram of Gas Turbine & WHRBs



5.3 Technology & Process

5.3.1 Turbine Design

The core gas turbine design differs very little from existing gas turbine variants which combust natural gas and other hydrocarbons. The specific elements which are required to combust hydrogen are almost entirely within the gas turbine burner and fuel gas distribution system. There are additional changes to the overall package supply of the gas turbine due to the high hydrogen content fuel. This requires adherence to several different elements of the Explosive Atmosphere Standard (IEC60079) due to the different fuel gases that are considered for use.

5.3.2 Emissions Abatement

Switching to a low carbon hydrogen-fired CHP is a critical element of decarbonising refinery operations at Stanlow. During the FEED study there was extensive interaction with both GT and WHRB OEMs to determine the current and future hydrogen capabilities in respect of both NO_x and CO_2 (related to efficiency).

A BAT assessment to ensure compliance with all legislative and permit requirements was also undertaken. This considered all the potential fuels on which the CHP could operate, with a focus on hydrogen.

5.3.3 NO_x emissions

Multiple suppliers made bid submissions for 100% hydrogen-fired WHRBs that will be (NO_x) emissions compliant. For the gas turbine suppliers, this was more challenging, with the most attractive commercial offer being for a maximum of 83%vol. This option was based on the use of Selective Catalytic Reduction (SCR). There was also a proposal for a 70%vol hydrogen solution (which has subsequently this has been revised upwards to 75%vol.) using dry low emission burners. Critically, several OEMs presented credible roadmaps to 100% hydrogen-firing (with NO_x thresholds) by 2030 and in some cases earlier than this.

The CHP as designed through FEED has multiple fuels which it is capable of operating on. It also has the capability to operate with three combinations of NO_x emission sources, each of which have their own emissions limits. The specific limits and relevant directive which sets the limit can be found in Table 5-1.

5.3 Technology & Process

5.3.4 CO_2 Emissions

Using the Hydrogen capability as offered on a commercial basis from the GT and WHRB suppliers through FEED it is possible to calculate the avoided CO_2 emissions for various operating scenarios. The energy demand from Stanlow Manufacturing Complex varies seasonally, by product mix and volumes, however a typical operating scenario for the CHP is the generation of 45MWe and 7,000 tpd of steam.

On this energy supply basis, along with the GT and WHRB Hydrogen capability, the CHP as a whole would be able to operate on 93%vol hydrogen and just over 81% hydrogen by energy. Projecting this mode of operation out across the year would result in emissions of 92ktCO_2/annum. By comparison, a conventional natural gas-fired CHP operating with the same electrical and steam output across a year would emit 486 ktCO_2/annum, an increase of 394 ktCO_2/annum. All of the GT suppliers have targets for 100% hydrogen capability, such that by 2030 the full CHP could run on 100% hydrogen avoiding all CO_2 emissions.

5.3.5 Plant performance

The CHP configuration and output performance is defined as :

- Three 3 Gas Turbines, each circa 25MWe ISO rating;
- Future fourth Gas Turbine, circa 25MWe ISO rating; and
- Four WHRBs, each capable of generating 4,000 tpd of MP steam at 340°C and 18.5 bar(g) either operating downstream of GTG, or independently with fresh air firing.

The configuration of a GT delivering electrical power and the WHRB delivering medium Pressure steam results in high efficiency CHP. On hydrogen, overall plant efficiency was modelled to be greater than 72% on a HHV basis, or greater than 80% on a LHV basis. There is potential for this to be further improved, as a conservative approach to flue gas temperature for plume buoyancy was taken. During detail design this can be aligned with an emissions dispersion model to optimise stack temperature from the FEED study basis of 136°C down to approximately 90°C.

5.3.6 Flexibility

The CHP plant, as specified in the Basis of Design and as designed through FEED, has a significant amount of flexibility built-in to meet the demands of refinery operations. In addition to the ability to operate on hydrogen as the primary fuel, the design enables back-up fuels to be used in the event of hydrogen being unavailable, to ensure a continuous and safe supply of power and steam to the refinery.

One of the most onerous areas of flexibility is the fast ramp rate on steam supply to mitigate the unplanned unavailability of another steam producing unit. The BoD requirement was a rate of change of 42tph of steam in 5 minutes. Three of the four potential suppliers of the WHRB provided bids could meet this. In context, the total steam supply from one WHRB is 166tph, and so an increase in steam supply of 42tph represents a 25% increase in output in 5 minutes.

5.3.7 Availability and Reliability

A Reliability, Availability and Maintainability (RAM) evaluation of the CHP plant was performed through FEED. The RAM study was based on the CHP Inside Battery Limits (ISBL) scope and therefore did not include any steam supply from the CO boiler and Medium Pressure Boiler House (MPBH), which are being retained, or for electricity supply from the DNO (Distribution Network Operator) connection to the site or the other onsite turbo-alternators.

Both operational and production availability of steam and electrical generation have been determined for the Project. These are defined as:

Operational Availability

Proportion of time that the equipment item or system is operational (i.e. working as required) during its lifetime. Only considers 'operating' and 'failure' states. Operational availability is calculated as the total time the item/system is in service divided by the total system lifetime. Operational availability is affected only by system outages. Periods in which the system is operating at part load are not considered to contribute to operational unavailability.

Production Availability

Proportion of actual production over the production forecast or production demand for a given period of time. Production availability is not only affected by system outages, but also by operation at part load.

The operational and production availability for steam and electricity generation based on the new CHP configuration as per the project terms of reference, is approximately 100% for the new system within the battery limits, including unplanned and planned maintenance.

5.3.8 Process Safety

At the commencement of FEED, a Health & Safety and Environmental Management Plan (HASEMP) was developed and agreed. This document set out the road map to design safe delivery within the overall schedule of FEED activities.

It followed the framework for management of process safety which has been adopted from the Energy Institute model and comprises the following four high level components:

1. Process Safety Leadership;
2. Risk Identification & Assessment;
3. Risk Management; and
4. Review and Improvement.

The process safety performance targets which were applied to the FEED phase of the Project are as follows:

- Ensure design compliance with all HSE legislation applicable in the UK and company policies advised by PEL and Essar;
- Ensure hazards and risks as a result of the Project are identified and assessed using appropriate information and approaches;
- Meet Costain's requirements that design and engineering is undertaken in accordance with procedures and work processes consistent with the requirements of ISO 9001:2015 Quality Management Systems and ISO 14001:2015 Environmental Management;
- Ensure design outputs during all stages of design meet the objectives of reducing risk to people (including workforce and general public), environmental and property to a level that is As Low As Reasonably Practicable (ALARP). The requirement for formal demonstration of ALARP is as specified in the FEED study Process Safety Management Plan (PSMP);
- Similarly, all risks to the environment are to be identified and the design must demonstrate that it meets the requirements of the Best Available Techniques (BAT) principle set down in the Environmental Permitting Regulations – with the emphasis on maximising efficiency and minimising waste. Plant and equipment selection shall be based on a methodology that considers BAT.

The full suite of safety documents produced during FEED included:

- HASEMP;
- PSMP;
- ENVID, HAZID, HAZOP and SIL Study Reports;
- BAT Assessment Report;
- ALARP Demonstration Report;
- Fire, Toxic and Explosion Consequence Modelling;
- Passive and Active Fire Protection Philosophies and Specification;
- Fire and Gas Philosophy and Specification; and
- DSEAR report and Hazardous Area Classification Assessment

Moving forward into detailed design the Safety Action Close-out Report will provide a record of the close-out and status of all actions from the design assessments and safety studies at the end of FEED.

5.4 Execution

5.4.1 Project Delivery Structure

The basis of design through FEED was for an Engineering, Procurement and Construction (EPC) delivery model to take the project from an investment decision to commercial operation.

5.4.2 Project Schedule

The schedule for delivery of the project was built up to full Level 2.5, and consists of 949 activities. This level of detail was developed such that a meaningful overall duration, critical path and uncertainty analysis could be identified. The high-level tasks associated with the EPC element of the project schedule are shown in Figure 5.6.

Figure 5.6: Stanlow CHP Level 1 EPCM Based Execute Phase Schedule

PEL EPC LEVEL 1 Overview	Start	Finish
Milestones		
Commence Project	Jan-24	-
Ready to Operate	-	Aug-27
Risk Allowance (80% Certainty)	-	Nov-27
Engineering		
Detailed Engineering & Design	Jan-24	Oct-25
Design Reviews	Feb-25	Jun-25
Follow-on Engineering	Nov-25	Dec-26
Procurement & Works Subcontracts		
Long Lead & Major Equipment	May-24	Apr-26
Balance of Plant	Dec-24	Apr-26
Works Subcontracts	Oct-24	Dec-25
Offsite Fabrication		
PAR's & PAU's	Oct-25	Aug-26
On-Site Construction		
Demolition, Groundwork & Enable	Feb-25	Aug-25
Piling	Sep-25	Jan-26
Underground Construction	Jan-26	Apr-26
ISBL Multidiscipline Construction	Dec-25	Jan-27
OSBL Multidiscipline Construction	Jan-26	Nov-26
Cable Pulling Campaign	Aug-26	Oct-26
Completions		
Testing & Precommissioning	Sep-26	Feb-27
Commissioning, Start-Up & Trials	Nov-26	Aug-27

5.4 Execution

5.4.3 Managing Project Risks

A Risk and Opportunity Register was created within one month of commencing the FEED and was reviewed regularly (as a minimum monthly) throughout FEED with the latest version of the register included within each monthly progress report. At the end of FEED the register was reviewed and re-issued and it will be the primary starting point for follow on work and detail design.

5.4.4 Plant Constructability

A Constructability and CDM HAZID review workshop was held as part of FEED to assess the constructability of the proposal and review the hazards associated with the FEED design.

The purpose of the Constructability Review was to identify aspects of the design that facilitate an optimum construction methodology and to identify and recommend any improvements which:

- Enhance constructability;
- Improve safety during construction and future operations by reducing risk;
- Improve accessibility during construction and operating phase; and
- Reduce risks during future modifications and end of life demolition.

The Constructability Review assessed and challenged the engineering FEED design sequentially by engineering discipline scope. The purpose of the CDM HAZID activity was to identify hazards which could potentially arise in the construction and future operational CHP plant phases.

The review was focused on hazards that are site-location specific, unusual, and/or not likely to be obvious to a competent contractor or other designer. It was emphasised in the review that the exercise was not a design review and is not intended to replicate the other mandatory hazard and risk review meetings, such as HAZOP, process HAZID etc. The CDM HAZID Review was conducted using key word prompts and identified a number of hazards which will require mitigation and control measures to be developed and implemented as the design progresses.

5.4.5 Commissioning, Handover & Performance Testing

A fully detailed procedure will be developed during the detailed design phase of the project for the commissioning and start-up of the Project. Throughout commissioning and start-up, refinery steam supply must be maintained, as such, a phased approach will be implemented for the decommissioning of existing equipment and commissioning, start-up and tie-in of the new equipment.

A full steam and condensate system inspection will be performed before initial start-up including the instrument loop checks and control valve stroking checks. Equipment and piping shall be as clean as possible to avoid contamination. A rigorous flushing/cleaning procedure shall be used prior to commissioning of the system. A system leak check shall performed.

The deaerators shall be chemically cleaned and passivated as per supplier's recommendation. Facilities (such as silencers) will be provided to allow initial commissioning activities, and also ongoing maintenance and inspection activities.

Commissioning of the plant is built up as part of the overall EPC schedule with dates and durations in Figure 5.6 on page 59. From initial testing and pre-commissioning activities on the first unit, through to completion and handover on the final unit will take approximately 11 months.

Within this period there will be performance tests to demonstrate specific plant attributes and capabilities. These will be defined within the EPC contract and sub-contracts with equipment suppliers.

During the FEED process appropriate international codes and standards were assessed to which these tests would be completed. For the gas turbines, ISO 2314, ISO 3977 and API 616 will be applied. For the Waste Heat Recovery Boilers, BS EN 12952 (Part 15) covers acceptance testing. This covers the major equipment, whilst other equipment will also have the appropriate directive, regulation, standard or code of practice applied.

5.5 Consenting & permitting

5.5.1 Development Consent Order

UK government guidance applicable to the consenting process for onshore generating stations is that those with a capacity above 50MWe in England and Wales are considered to be 'Nationally Significant Infrastructure' and must seek a Development Consent Order (DCO). Projects with a generating capacity of 50MWe and below are considered under the provision of the Town and Country Planning Act 1990 which has a shorter and less onerous determination process.

The DCO process will be the critical path to delivery of the Project, with no construction work being legally permitted unit full approval for the build is granted. The anticipated Execute Kick-Off date applied in the schedule developed as part of the FEED activity is therefore based on progressing a DCO for the Project.

This project represents a relatively straight-forward DCO, as it is entirely contained within the fence line of the refinery and doesn't require any 3rd party land access, lease or compulsory purchase orders. The initial phase is to complete the environmental impact assessment (EIA) and to conduct non-statutory and statutory consultations. It is expected that this phase could be completed with a year.

Once the DCO submission has been formally submitted there is then a statutory timeline to decision by the Planning Inspectorate and the end of the 'challenge' period of between 17 and 18 months. The total overall duration from initiation to decision could therefore be expected to take around 30 months.

5.5.2 Environmental Permit

Essar holds a single environmental permit for the wider Stanlow Manufacturing Complex (permit number EPR/FP3139FN). This permit controls the overall site emissions to water, air and land. The Project would fall under a variation to this permit as a point source emission to air, in the same way that the existing HP boilers (which the Project will replace) have limits set on parameters to be monitored, to the specific level and the monitoring frequency.

The specific limits are set by the Environment Agency (EA), with reference to the applicable emissions directives and best available techniques. Detailed engagement with the EA through the consenting process will define the limits which will be set in the environmental permit. However, as part of the FEED process, a thorough review of the relevant directives determined the minimum acceptable limits, which are summarised in Table 5 1. These thresholds were used in the supplier engagement as the minimum requirements for supply of equipment.

Table 5.1

Summary of Emissions to Air Limits

		GT and WHRB Operating Scenario		
	Emission type / fuel gas scenario	**GT exhaust via bypass stack & GT exhaust via WHRB** - (no supplementary firing) at 15% Oxygen 1 2	**GT exhaust via WHRB** - (with supplementary firing) at 15% Oxygen	**GT offline** - (or not installed); WHRB with duct firing only at 3% Oxygen
NO_x	1. Natural Gas	50 mg/Nm^3	50 mg/Nm^3 monthly average	100 mg/Nm^3 monthly average
	2. Refinery Dry Gas (GT) 3. Refinery Fuel Gas (WHRB) 4. NG/20%H_2 blend	75 mg/Nm^3 monthly average	75 mg/Nm^3 monthly average	100 mg/Nm^3 monthly average
	5. HyNet Hydrogen	120 mg/Nm^3	200 mg/Nm^3 monthly average	200 mg/Nm^3 monthly average
SOx	1. Natural Gas 4. NG/20%H_2 blend	No specific value set. BAT principles apply	35 mg/Nm^3 monthly average	35 mg/Nm^3 monthly average
	2. Refinery Dry Gas (GT) 3. Refinery Fuel Gas (WHRB)	No specific value set. BAT principles apply	35 mg/Nm^3 monthly average	35 mg/Nm^3 monthly average
	5. HyNet Hydrogen	N/A – SOx not generated in combustion of H_2	N/A – SOx not generated in combustion of H_2	N/A – SOx not generated in combustion of H_2
CO	1. Natural Gas 2. Refinery Dry Gas (GTG) 3. Refinery Fuel Gas (WHRB) 4. NG/20%H_2 blend	100 mg/Nm^3	100 mg/Nm^3 monthly average	100 mg/Nm^3 monthly average
	5. HyNet Hydrogen	N/A - CO not generated in combustion of H_2	N/A - CO not generated in combustion of H_2	N/A - CO not generated in combustion of H_2
Dust	1. Natural Gas 2. NG/20%H_2 blend 3. HyNet Hydrogen	N/A – no dust limit stated	N/A – no dust limit stated	N/A – no dust limit stated
	4. Refinery Dry Gas (GT) 5. Refinery Fuel Gas (WHRB)	N/A – no dust limit stated2	10 mg/Nm^3 daily average 5 mg/Nm^3 yearly average	10 mg/Nm^3 daily average 5 mg/Nm^3 yearly average

Notes:
1.Emission limits set out in accordance with Directive 2010/75/EU Annex V Part II with the following conditions apply: (a) no validated monthly average value exceeds the relevant emission limit values; (b) no validated daily average value exceeds 110 % of the relevant emission limit values; (c) in cases of combustion plants composed only of boilers using coal with a total rated thermal input below 50 MW, no validated daily average value exceeds 150 % of the relevant emission limit values; (d) 95 % of all the validated hourly average values over the year do not exceed 200 % of the relevant emission limit values.
2.As per BAT conclusions, dust limits are for boilers and do not apply to GTs.

5.6 Capital Costs vs Natural Gas Equivalent

As presented in Table 5 2, the total estimated Capex for the plant was built up to an AACE class II estimate of £176.8 Million (M).

The elements where the use of hydrogen contributed to an additional cost vs. natural gas were in:

- The fuel gas supply system
- The gas turbine package; and
- The waste heat recovery boiler package.

Within these elements, much of the additional cost is associated with the requirement for the plant to operate on a range of fuels, for the purpose of supply and operational resilience. An example of this is the duplication of equipment, such as fuel gas pipework, for the natural gas supply and again for the hydrogen supply.

For the actual gas turbine, the range of pricing from OEMs ranged from £27.4M to £36.4M for the 3 x 25MWe turbines. Some of the bids specifically included the increased cost associated with hydrogen, which was £1.2M in respect of the OEM with the highest hydrogen option.

On the WHRB there was no specific line-item cost associated with hydrogen, although an earlier study conducted on behalf of Essar secured a budgetary proposal for a non-hydrogen fired WHRB.

Using this price, plus normalising the scope of supply and allowing for escalation for the 2 years between the non-hydrogen proposal and this FEED study, resulted in a difference of less than £500k compared with the quote from the preferred WHRB OEM.

The above analysis suggests that the additional Capex of a hydrogen-fired CHP compared with that for a natural gas fired CHP is very small; in this case only around 1% of total Capex. The more significant additional cost is from duplication of equipment, which will continue to be an issue for future developments until supply of hydrogen approaches the same level of resilience as is the current situation for natural gas.

Table 5.2
Cost Estimate Comparison

	CapEx Estimate Range (£MM GBP)	CapEx Cost Used for AACE Class II Estimate (£MM GBP)	Specific Hydrogen Elements
Gas Turbines Package (3 x 25MWe)	£27.4 - £36.4	£33.8	£1.2
Waste Heat Recovery Boiler (4 x 166 tph Units)	£21.3 - £28.3	£21.3	£0.5
Fuel Supply System* (compressor & conditioning)	£5.8 - £7.5	£6.2	£0.3
Total Project Cost		**£176.8**	**£2.1**

**Note that this installation did not require a Hydrogen fuel gas compressor as the Hydrogen will be delivered at pressures above 40 bar (g), and only requires a delivery pressure of around 20 bar (g). An installation where Hydrogen fuel gas compression is required would add significant cost. For example if hydrogen supply pressure was 10 bar (g) then the compressor cost for a single GT to raise pressure to 20 bar (g)) would add a further £3 million GBP.*

5.7 Non-fuel operating costs

The additional equipment associated with the ability to run on multiple fuels (hydrogen, natural gas and refinery gases) will result in an increase in non-fuel operating costs.

However, through the FEED study it was determined that the non-fuel operating expenses associated with hydrogen would not be any greater than those associated with natural gas.

The largest single non-fuel operating cost on a plant of this nature is maintenance of the gas turbine. The inspection intervals and maintenance periods from the gas turbine OEMs for operation on Hydrogen were the same as those for natural gas.

5.8 Applicability to other sites

Across the HyNet hydrogen distribution network there are a significant number of similar CHP schemes in operation today, and the same is true of the other industrial clusters in the UK.

The completed FEED study gives very high confidence for both new build and retrofit of 100% hydrogen-fired burners into a range of applications, such as WHRBs, fired boilers, fired heaters, etc. This is primarily due to the relatively simple (in comparison to gas turbines) low operating pressure for fuel supply (i.e. typically in the 100s of millibar range), and the physical space available in which to control the low NO_x flame. The information received back from the WHRB OEMs shows a significant installed base of high (>90%) or 100% Hydrogen boilers in commercial operation. Consequently, hydrogen use in WHRBs could be regarded as at Technology Readiness Level (TRL) 9.

The high hydrogen capability currently available from the gas turbine OEMs is also applicable to both new and existing installations. With roadmaps from Siemens, MHI, and Solar to deliver higher hydrogen percentages on applicable gas turbines for this application, and across tier wider fleet, there is significant scope for decarbonizing gas turbine-based CHP schemes.

Natural gas, however, remains the fuel of choice for most CHP generators:

- In 2019, 69% of the total fuel use was natural gas;
- CHP plants accounted for 7.9% of the UK's total gas demand in 2019, up slightly from 7.3% in 2018;
- The proportion of CHP generated using renewable fuels (biomass or biomethane) increased slightly from 17.4% in 2018 to 18.8% in 2019; and
- In 2020 the UK installed base of CHPs consumed 68,896 GWh of natural gas, which unabated would release 12.7 million tonnes of CO_2.

Fuel switching CHP schemes in the UK away from natural gas to low carbon hydrogen therefore represents a significant decarbonisation opportunity. The proposed wider HyNet North West hydrogen (and CCUS) infrastructure represents a key facilitator to this switch, as discussed in detail in the following Sections.

5.9 Key Learnings

The FEED study into a 100% Hydrogen fired CHP at the Stanlow refinery has enabled a far greater understanding of the current capability of suppliers within the global market for the provision of equipment, their technology readiness levels, CapEx and OpEx.

The key learnings from this study include:

- WHRBs are already available to fire on 100% Hydrogen with emissions compliance to the Industrial Emissions Directive. These have a Technology Readiness Level (TRL) of 9. This is also true of more conventional fired boilers without heat recovery;
- Gas turbines lag behind on hydrogen readiness. Whilst not at TRL9 for 100% Hydrogen, they are at TRL9 for emissions compliant blends up to 83% by volume in the size range for this project;
- The gas turbine manufacturers that were engaged through the process have targets for 100% Hydrogen capability by 2030. Siemens had the best roadmap to achieving this, and had executed the most significant demonstrations of Low NO_x hydrogen firing. Solar also had a well-developed product, testing and demonstration site with high Hydrogen capability (83% by volume), but this was with post combustion selective catalytic reduction rather than the preferred low NO_x burners;
- Hydrogen does not significantly increase the overall project CapEx Vs a natural gas-fired CHP. High hydrogen delivery pressures via pipeline are one enabler for this as it avoids the need for dedicated hydrogen compressors; and
- Until supply of hydrogen reaches greater resilience, there will be additional capital and non-fuel operational costs associated with duplication of equipment for hydrogen and natural gas.

6 | PROJECT DEVELOPMENT PLAN

Project Development Plan

The ultimate benefit of the deployment of the technical solutions and projects delivered during this programme of work will be in helping enable the UK to meet Net Zero whilst at the same time delivering long-term global competitiveness of UK manufacturing.

Realisation of these benefits via commercialisation of the related solutions is intimately tied to deployment of the wider HyNet hydrogen production, distribution and CCUS infrastructure. The following approach to commercialisation is described in this specific context, although it is also acknowledged that similar deployment of hydrogen production and distribution infrastructure in other areas of the UK would also contribute to commercialisation:

1 Sharing of technical and commercial evidence to enable investment and securing of hydrogen supply and network connection

a. The evidence from the three projects will now be used by the related sites as a basis for a future investment decision in respect of the deployment of capital to enable switching to hydrogen and connection to the HyNet network as soon as practically possible;

b. The evidence will also be used by the three sites to demonstrate to the HyNet consortium partners, namely Vertex Hydrogen ('Vertex') and Cadent, that the manufacturing facilities are 'hydrogen-ready', which will further influence the pipeline routing and allocation of supply capacity;

c. More widely, via the knowledge transfer activities associated with the programme of work, information will be shared with other sites across the UK, to enable investment in other geographies.

2 Securing of relevant consents for all elements of HyNet project infrastructure (2019-2023):

a. Alongside the required technical evidence, relevant consents must be secured for all hydrogen and CCUS-related infrastructure. Such consents, particularly those relating to hydrogen and CO_2 pipelines, are subject to ongoing Development Consent Order (DCOs applications). The granting of these consents will be critical to enabling commercialisation;

3 Successful engagement with Government in respect of a long-term support mechanisms for hydrogen and CCUS (2019-2023):

a. Neither the proposed solutions nor any other element of the HyNet project will be deployed without long-term support mechanisms for hydrogen and CCUS. PEL has played a key role in engaging with Government as part of the CCUS Advisory Group (CAG), BEIS Expert Working Groups, the CCUS Ministerial Council and the Hydrogen Advisory Council (HAC), all of which have helped shape the current policy landscape.

b. The HyNet project was selected as a Track 1 Cluster under Phase 1 of the Government's Cluster Sequencing process and Vertex's production plant at Stanlow Manufacturing Complex is currently awaiting the outcome of the Phase 2 process. Securing suitable long-term support under these mechanisms is essential to the HyNet project proceeding to deployment and thus enabling the technical solutions associated with the HyNet IFS programme. Further information in respect of the Vertex Hub is presented in Section 7.0;

c. Cadent, the local gas network operator and HyNet partner which will operate the hydrogen distribution network is currently engaging with BEIS and Ofgem in respect of how funding for the HyNet hydrogen distribution network,which will be essential for transporting hydrogen to the three sites, might be unlocked. BEIS has committed to designing a suitable business model to support new hydrogen networks, but this is currently very much in its infancy, and must be significantly accelerated if the solutions are to be deployed in the mid-late 2020s. Again, further information on the Hydrogen Network is presented in Section 7.0;

4 Securing investment for deployment of HyNet (2019-2023):

a. PEL continues to engage closely with the investment community, such that relevant funders are primed and ready to allocate suitable finance as soon as the required long-term support mechanisms are in place. Without such investment in HyNet, the proposed solutions will not be commercialised in the North West.

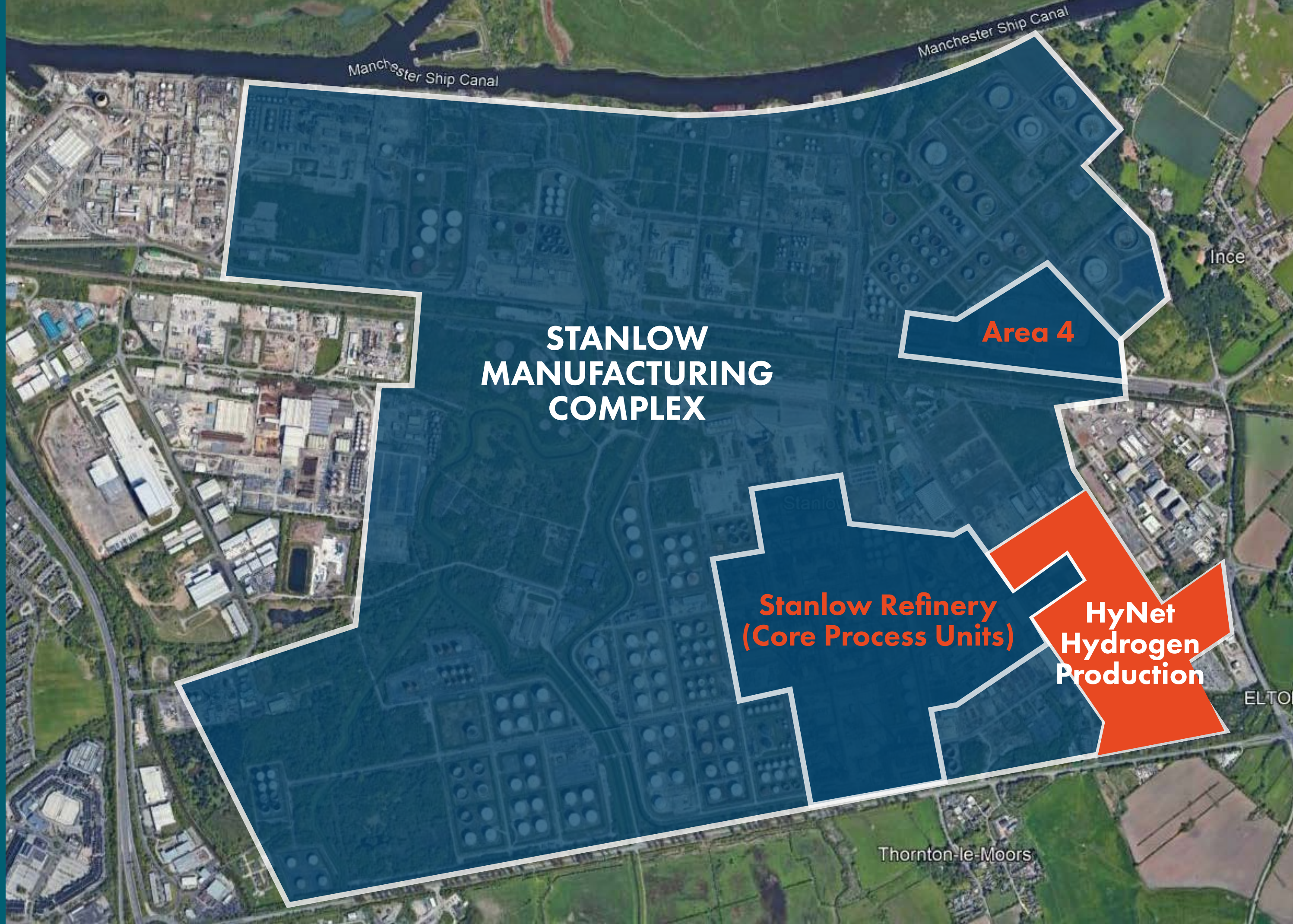
5 Securing investment for further deployment Phases of HyNet (2024-2030):

a. Following deployment and successful operation of the solutions at NSG, Unilever and Essar, there will be sufficient evidence to enable deployment of the proposed solutions at other similar sites within the HyNet area. For example, at Encirc Glass, which is located adjacent to Stanlow Manufacturing Complex, and at a vast number of sites which operate boilers and a number of further sites operating gas turbines in the area.

7 | HYDROGEN FUEL PRODUCTION & DISTRIBUTION

HyNet Hydrogen Production

As described above, deployment of the three technical solutions will not happen without build-out of the HyNet hydrogen production and distribution infrastructure, and consequently further information on these core elements of HyNet is provided below.



7.1 HyNet Hydrogen Production

During the last three years, parallel work has been taking place in respect of the development of a hydrogen production hub at Stanlow Manufacturing Complex, now led by Vertex. The three sites operated by Unilever, NSG-Pilkington and Essar, along with all other sites associated with the first three phases of HyNet deployment will be supplied by the Vertex hub.

The strategic location of the Hub at Stanlow enables production to be fuelled by both refinery off-gas (ROG) and to supply wider onsite operations, including the CHP plant, to decarbonise the refinery. The location of the Hub within the wider complex is presented in 7.0.

7.7.1 HyNet Hydrogen Production

Work funded by BEIS under the Hydrogen Supply Competition included a full FEED study and was followed by an application for planning consent for the first 1GW of production capacity. The FEED study has been completed and Vertex is currently awaiting the outcome of the application for planning consent.

Table 7.1: Deployment Profile for HyNet Hydrogen Production.
Notes: 1. In 2030, 3TWh/annum will be used to underpin HyNet operations

Plant	Hydrogen (kNm^3/h)	Hydrogen (MWth - HHV)	Hydrogen (TWh/annum)	Cumulative (TWh/annum)[1]
1	100	350	3	3
2	200	700	6	9
3	400	1400	12	21
4	400	1400	12	33

PEL and Essar, as joint venture partners in Vertex, recently published a report on the BEIS-funded FEED study.[22] This presents the technical detail relating to the proposed hub, which will use UK company, Johnson Matthey's Low Carbon Hydrogen (LCHTM) technology.

As part of the North West Cluster Plan, regional modelling was undertaken, which estimated a total demand for low carbon hydrogen of 30 TWh/annum by 2030, to put the region on the trajectory to achieve Net Zero by 2050.[23] The ambition of HyNet is to switch approximately 45% of the region's natural gas consumption with low carbon hydrogen by 2030.

To meet the forecasted growth in demand for hydrogen in the region, the HyNet Hydrogen Production Hub is to be developed and constructed in phases. The design throughput of each Plant is shown in Figure 7.2.

As mentioned above, the Vertex Hub is also currently awaiting the outcome of Phase 2 of the Government's Cluster Sequencing process. Assuming the project is selected by BEIS, it will proceed into commercial negotiation process associated with Hydrogen Business Model (HBM) support. It is likely that the HBM will cover the cost difference between the cost of hydrogen and that of natural gas, as described further in Section 8.0.

As part of the BEIS-funded work, a detailed financial model was produced based on the inputs developed through the programme. The output from that assessment showed a Levelised Cost of Hydrogen (LCoH) that is broadly consistent with the range of hydrogen costs developed by BEIS in the Hydrogen Strategy. Subject to Government finalising the HBM and selection of the Vertex project under Phase 2 of Cluster Sequencing, the project will build upon this model to facilitate commercial negotiations for HBM support.

7.2 HyNet Hydrogen Distribution

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 the gas distribution network.

These are the locations on the gas network where natural gas is currently injected from the National Transmission System (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.[24] 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.

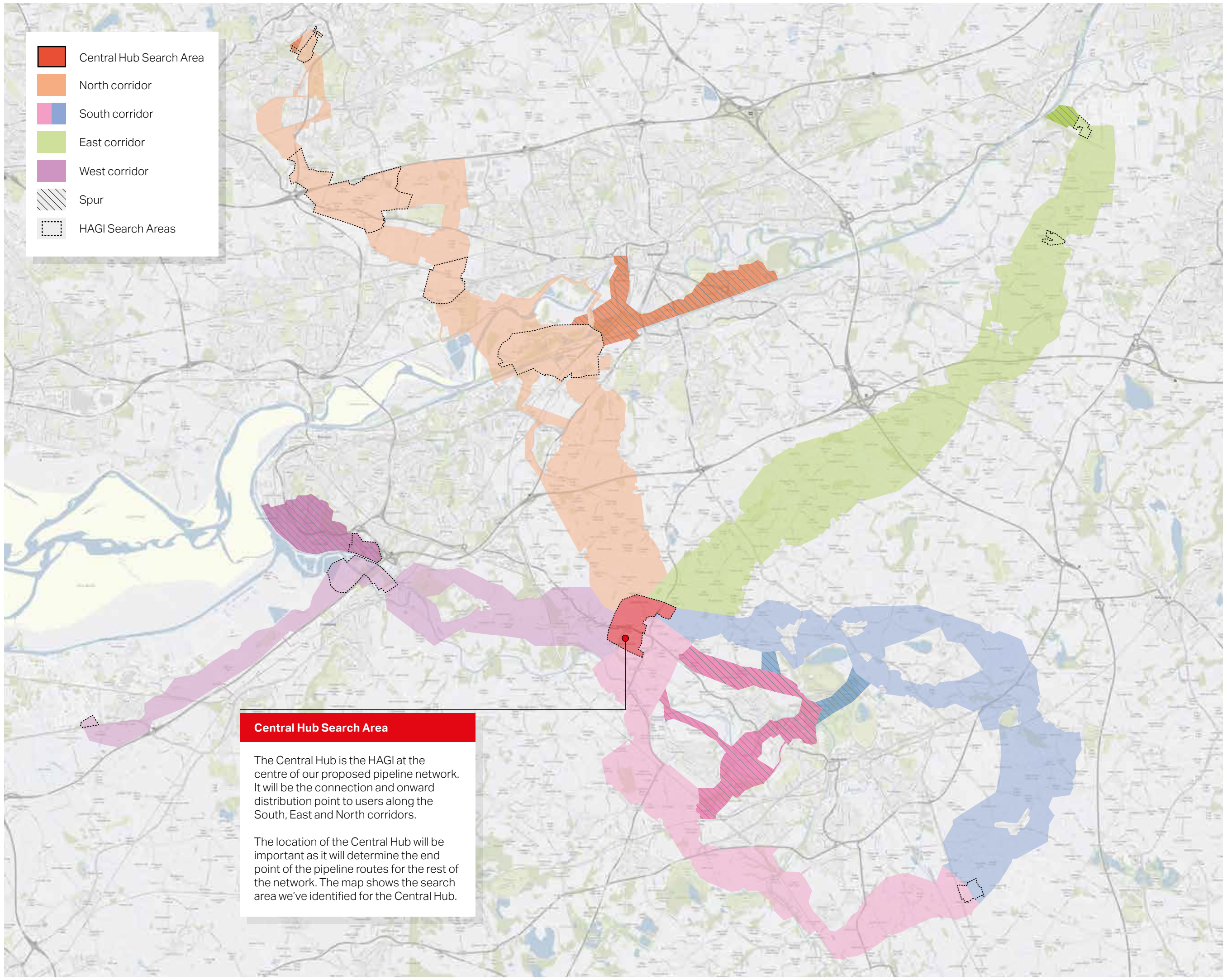
At the same time, the network routing must take into consideration the need to connect other suppliers of hydrogen. At the present time, no applications for planning consent have been submitted by any major suppliers other than the planned HyNet production hub at Stanlow, but this is likely to become more of a factor in later phases of network development.

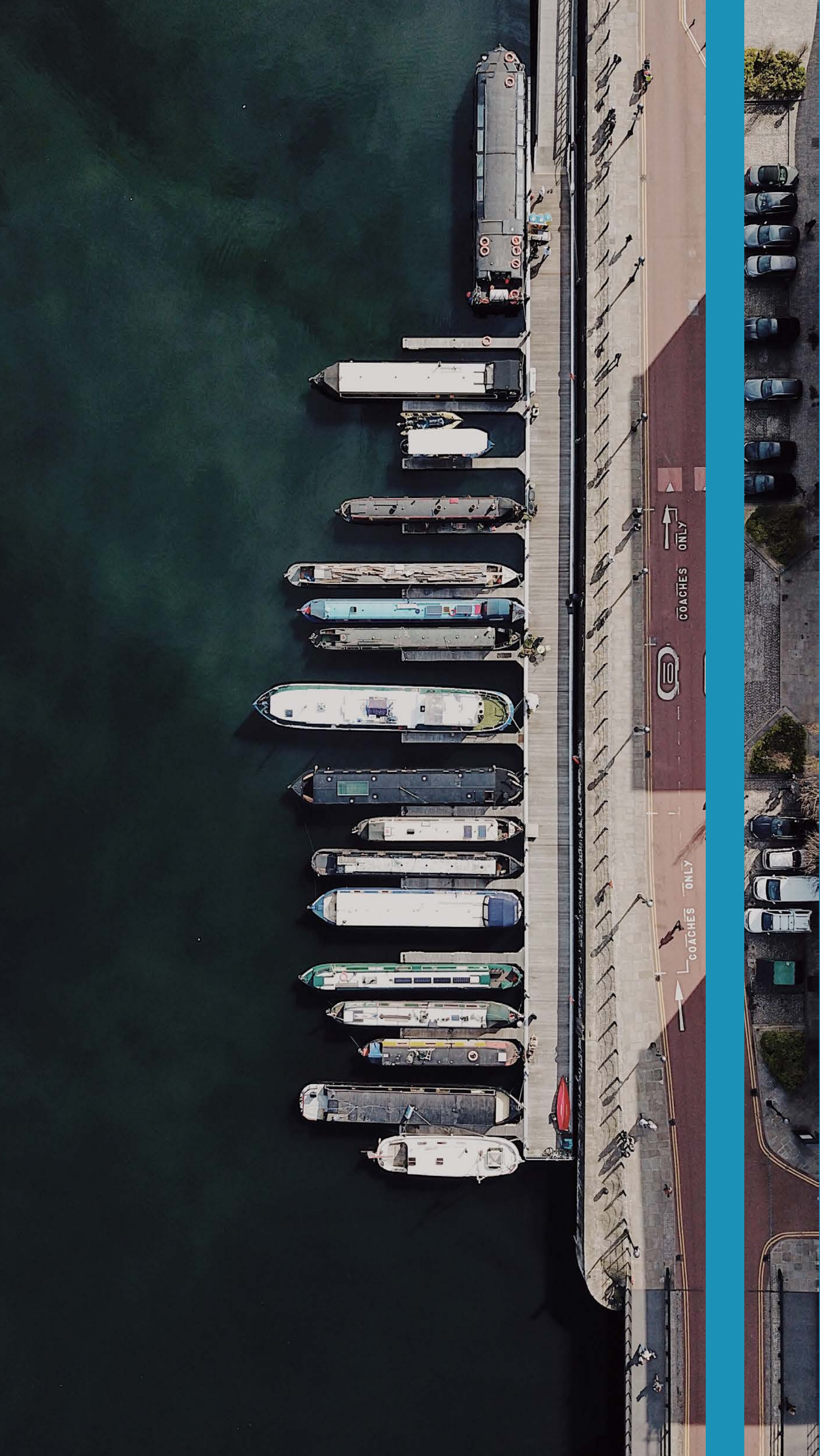
The HyNet network is being built in phases, but the early 'feeder' lines need to be designed to be sufficiently large to carry enough gas to incorporate demand which is connected in the later phases of deployment.

HyNet consortium partner, Cadent, is currently engaged in a DCO process 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.[25] The DCO process is such that Cadent must consult on options prior to selecting a preferred route and so at this stage only broad routing corridor options from the non-statutory consultation can be shown, as presented in Figure 7.3.

Ahead of submission of the current DCO application, 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.

Figure 7.3: Proposed HyNet Hydrogen Network Routing Corridors





8 | BUSINESS MODELS FOR INDUSTRIAL FUEL SWITCHING TO HYDROGEN

8.1 Business Models

8.1.1 Hydrogen Production

As mentioned above, at the time of writing, Vertex is awaiting the outcome of the 'Phase 2' of the Cluster Sequencing process, which focuses on CO_2 capture sites including the HyNet Hydrogen Hub. In respect of HBM support for hydrogen production, successful Phase 2 projects will enter a negotiated process with Government, which will commence later in 2022, with contracts to be signed during 2023.

The HBM is a revenue support mechanism to cover the difference between the cost of hydrogen and that of natural gas and will enable producers to sell hydrogen to industry, for example NSG-Pilkington, Essar and Unilever, at prices comparable to natural gas. BEIS has recently published a consultation response in respect of design of the instrument.[26] This is accompanied by a set of 'Indicative' Heads of Terms for the associated contract.[27]

The HBM is essentially a contract for difference (CfD) similar to that which has been in place to support renewable electricity generation since 2014. It is a long-term contract between an electricity generator and a Government counterparty, for example, 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 the Government Counterparty to the generator, and vice versa.

In simple terms, 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 the Government Counterparty 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. The HBM is likely to function broadly in this manner, albeit there are a number of nuances described in the Heads of Terms document.

Alongside the core hydrogen production from the Vertex Hub, PEL intends to deploy green hydrogen production to supply industry in the area. The first meaningful support for such projects will come via BEIS' 'joint allocation' round for the Net Zero Fund and HBM, which will commence later in 2022, with contracts to be signed by late 2023.[28] These projects will be an order of magnitude smaller than the Vertex plant, but green hydrogen production is expected to ramp up further in the 2030s.

8.1.2 Hydrogen Distribution

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 and storage.

In the HBM consultation, BEIS states that networks will not be funded under the HBM, but that it has commissioned consultants to undertake research to help it better understand distribution infrastructure requirements. It also states that it intends to consult on proposals later in 2022 and that a related new working group is to be set up as part of the Hydrogen Advisory Council.

Networks are critical to enabling a range of end-uses of hydrogen, including the manufacturing sector, and to reducing the costs of production and distribution. Business model development to support hydrogen distribution must therefore be accelerated as a critical, strategic priority.

8.1.3 Hydrogen Storage

There is also currently not yet a business model in place to support the deployment of hydrogen storage infrastructure, albeit again BEIS has confirmed that major storage projects will not fall within the scope of the HBM. Again, this issue needs addressing rapidly by Government.

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 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.

Government must progress work with Ofgem in respect of these potential models as soon as possible, or this will delay deployment of the solutions funded under this programme of work.

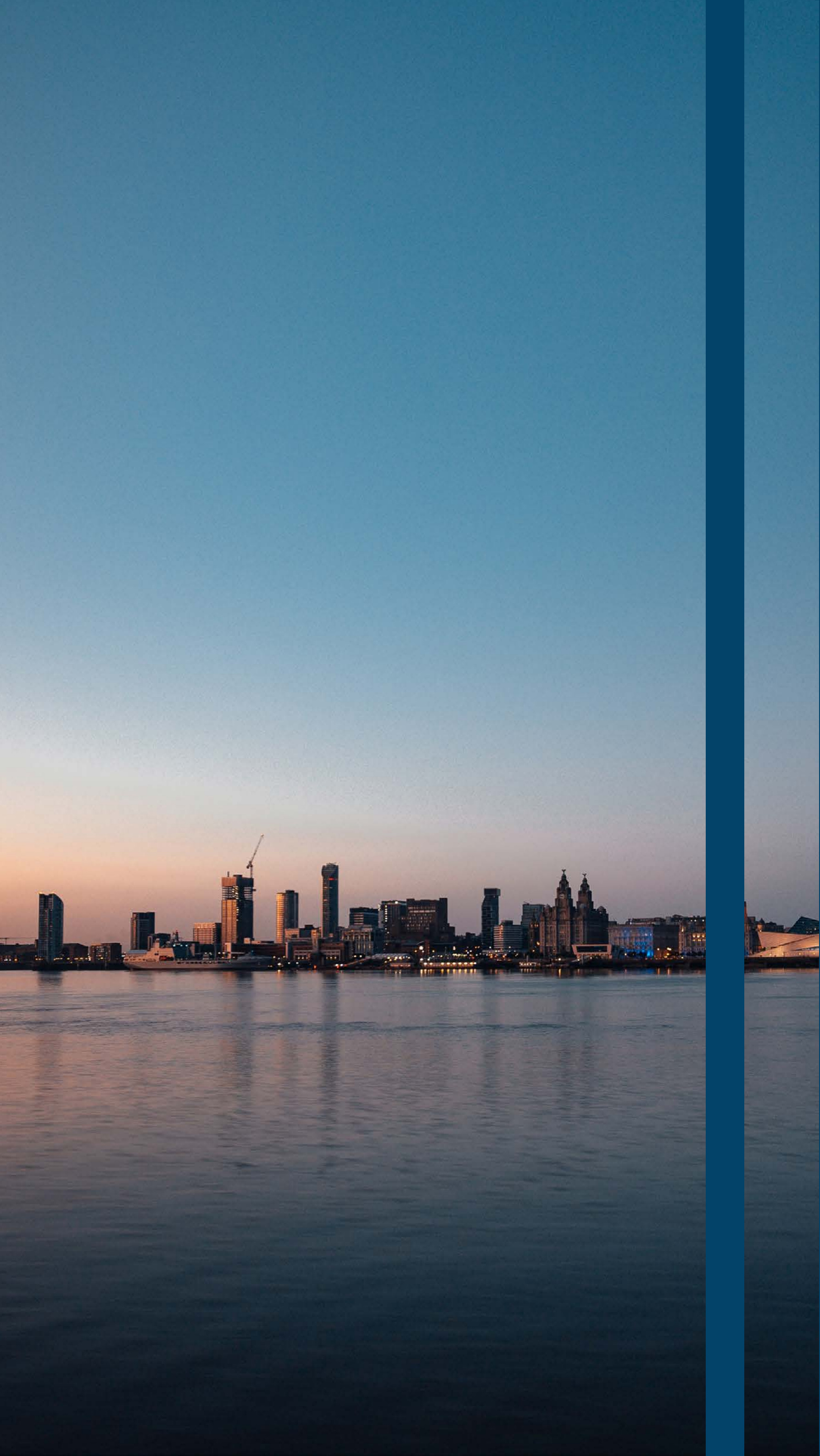
8.2 Enabling CO_2 Transport & Storage Models

The HyNet project relies upon CO2 transport and storage infrastructure. With such enabling infrastructure, there can be no production of low carbon hydrogen.

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.[29] 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 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 various consultations have taken place on specific points of detail. The RAB-based approach is now known as the TRI (Transport and Storage Regulatory Investment Model) and HyNet partner, Eni (as the operator of the existing Liverpool Bay oil and gas infrastructure) is currently in negotiations with Government on support under this model under Phase 1 of the Cluster Sequencing process.



9 | NET ZERO FUTURE UNLOCKED BY HYNET

Net Zero Future Unlocked

HyNet's ambition is to become a key part of the low carbon energy infrastructure in the North West of England and North of Wales, enabling the area to thrive in a low emission landscape.

9.1 Delivery at Pace to Support Local Ambition

The North West has set some of the country's most aggressive emission reduction targets:

- Chesire West and Chester Council (CWaC) has announced its Climate Emergency response plan, targeting Net Zero no later than 2045;
    - As a result of the concentration of industry in the north of the borough, it is the fourth highest emitting of all local authorities in the UK. CWaC have labelled this "a challenge, a responsibility, and an opportunity".[30]
    - HyNet is a critical part of CWaC's strategy: "Of all the interventions set out in the Climate Emergency Response Plan, HyNet is the most transformative and offers the greatest potential for carbon reduction".
- Greater Manchester City Region has also announced a pathway to carbon neutrality by 2038, citing the requirement for deployment of hydrogen trains to meet this target.[31]
    - A need for substantial quantities of hydrogen, and specifically HyNet, is also identified in the Greater Manchester decarbonisation pathway.[32]
- Liverpool City Region has announced a Net Zero target by 2040.[33]

HyNet's delivery schedule, supported by rapid deployment of production plants, the re-use of transport and storage assets, co-location with Stanlow Refinery and utilisation of previously-consented hydrogen salt cavern storage, will facilitate these regions meeting their ambitious targets.

9.2 Supporting Government's Energy Strategy

The Ten Point Plan set out ambition to deliver 1 GW of low carbon hydrogen by 2025.34 As the first major target for the UK's deployment of the hydrogen economy, these early stages will set the tone and expectation for the later stages of roll-out.

The Vertex Hydrogen Production Hub is uniquely positioned to support this Ten Point Plan target, by delivering 35% of this total capacity. Without the delivery of Plant 1, this critical interim commitment will be missed. HyNet can also provide up to 40% of the 10 GW low carbon hydrogen target set for the UK by 2030 in the Energy Security Strategy.35 This had been uplifted from the previous 5GW target in the Hydrogen Strategy.36

9.3 HyNet by 2030

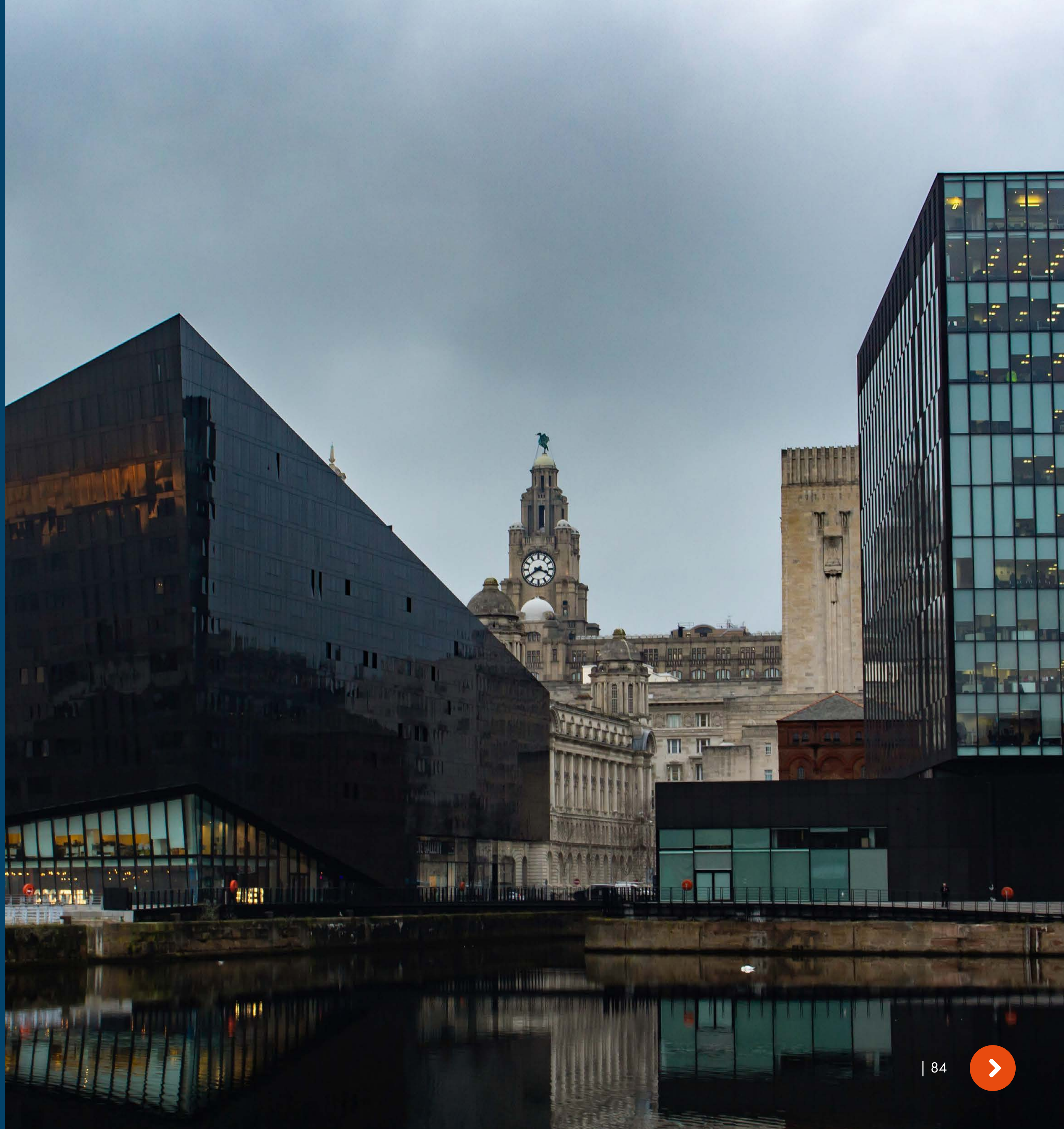
By 2030, HyNet can supply consumers with 30TWh/annum of low carbon hydrogen. This is an ambitious but achievable goal, which relies on HMG policy supporting customer use of hydrogen.

It also takes into consideration that the demand for hydrogen is nascent but growing rapidly, and that hydrogen production and delivery (distribution network and storage) infrastructure is not yet in place. By this stage, hydrogen production, distribution and storage infrastructure will be in place across a wide part of Liverpool City Region, Great Manchester, Cheshire, Wrexham, Flintshire and parts of Lancashire.

While ambitious, HyNet has been deliberately planned to be delivered in distinct, achievable stages to ensure that the first phase is delivered as soon as 2025, with expansion happening shortly thereafter to deliver widespread decarbonisation of the economy by 2030.

9.4 HyNet by 2040

By 2040, the North West of the UK is expected to be a thriving, Net Zero, industrial cluster. HyNet extension opportunities beyond 2030 are being investigated by Work Package 4 of HyNet North West's delivery programme funded by the Governments IDC. These will align with other decarbonisation projects across the region being explored within the North West Industrial Cluster Plan, under the leadership of Net Zero North West.

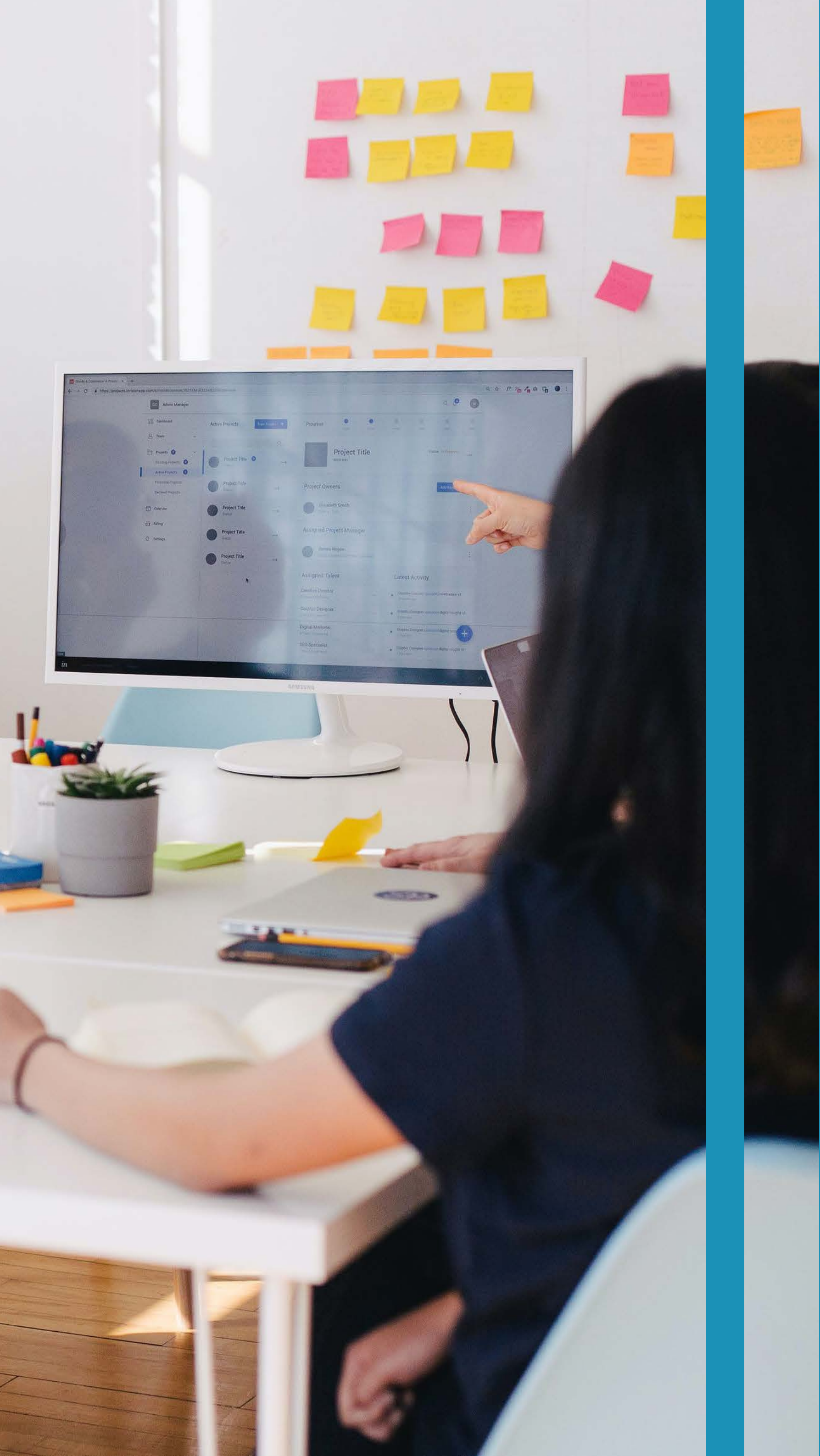


10 | KNOWLEDGE TRANSFER

The key messages from the work set out in this report have been (and will continue to be) shared externally through a number of knowledge transfer activities:

- The publishing of this report;
- Three knowledge dissemination webinars with the HyNet Hydrogen Users Group, which comprises over 40 major manufacturers located in the North West and North Wales;
- Two webinars with a cross-section of BEIS attendees, to share the key findings from the work;
- Two launch events involving local political and council stakeholders, including the Metro-Mayor of Liverpool, Steve Rotheram;
- Two demonstration visits (to Port Sunlight and Greengate Works) from relevant manufacturers in the North West, which operate boilers and/or furnaces;
- A forthcoming wider public dissemination event to share the key findings more widely with industry across the UK;
- Engagement with the consortium producing the North West Industrial Cluster Plan, which is funded under the IDC programme;
- Further ad-hoc meetings throughout the project with a range of stakeholders including public bodies (national and local); key market influencers including trade bodies and consultants; industry including multiple potential hydrogen users and the supply chain to support development of the hydrogen market; the investment community; engineering institutions and regulatory bodies.
- The HyNet website, which was updated during the programme;
- The production of videos to bring to life the demonstration projects; and
- Social media activities to promote the work to a wider audience.

The key learnings to date for external projects "are described in section 11. Following publication of this report, the project team will continue to seek opportunities to promote and share the work completed and lessons learned



11 | KEY MESSAGES & LESSONS LEARNED

Designing and subsequently running a demonstration project during a global pandemic presented a range of unique challenges. We have not sought to describe these in this report, as it is hoped that they will remain unique to the period associated with this programme of work and so any lessons learned not be applicable to future programmes.

The key messages and lessons learned from the HyNet IFS Programme are summarised in the following section:

In respect of hydrogen-firing in existing glass furnaces, the demonstration at NSG-Pilkington's Greengate Works has shown that:

- The majority of energy use associated within glass furnaces, which is associated with the melting process and currently fuelled by natural gas, can be readily switched to hydrogen;
- At higher hydrogen levels, NO_x emissions may increase by 20-30%. This should be within the capability of existing abatement equipment at most large sites and so it is expected that environmental permits will not need to be amended to enable similar demonstration projects. However, switching to hydrogen in perpetuity may require some form of permit variation;
- The LHV efficiency of hydrogen-firing is likely to be unchanged compared with that of natural gas and the increase in soda levels should be within existing operating experience; and
- Operating on hydrogen should result in no impact on glass quality, either in terms of colour or fault density (bubbles and inclusions);
- The total cost for switching similar sites to hydrogen will be around £500k for in terms of plant and equipment costs.

In respect of hydrogen-firing in existing glass furnaces, the demonstration at NSG-Pilkington's Greengate Works has shown that:

- Existing industrial package boilers can be switched to low carbon hydrogen, which is also likely to be the case for bespoke boiler designs;
- Package boilers can be operated on hydrogen within the NOx thresholds set by the Medium Combustion Plant Directive (MCPD). However, furnace geometry is critical to meeting these limits and should be carefully assessed to inform burner design;
- Existing boilers will operate on hydrogen at very similar levels of efficiency (92.7%) when operating on natural gas;
- The cost of a dual fuel natural gas/hydrogen burners is around 10% more than would be a standard natural gas burner, although this differential can be expected to fall for later projects;
- The findings from this work should be taken into consideration by BEIS in its ongoing Call for Evidence in respect of enabling or requiring the installation of hydrogen-ready industrial boiler equipment at industry sites.

In respect of hydrogen-fired CHP plants, the FEED study relating to Essar's Stanlow Refinery has shown that:

- Contracts for new hydrogen-fired gas turbine plants can currently be procured, with suitable vendor performance guarantees, to operate on high levels of hydrogen (up to 83%vol.) alongside natural gas. In some cases, this includes an agreed route-map for relevant turbine modifications to enable 100% hydrogen-firing before 2030;
- For associated new or existing Waste Heat Recovery Boilers (WHRBs) and fired heaters as part of a wider Combined Heat and Power (CHP) scheme, there should be a very high level of confidence that these can be fitted with 100% hydrogen-fired burners with suitable vendor guarantees;
- The additional Capex of a hydrogen-fired CHP scheme, compared with one fired by natural gas, is only around 1% of total Capex;

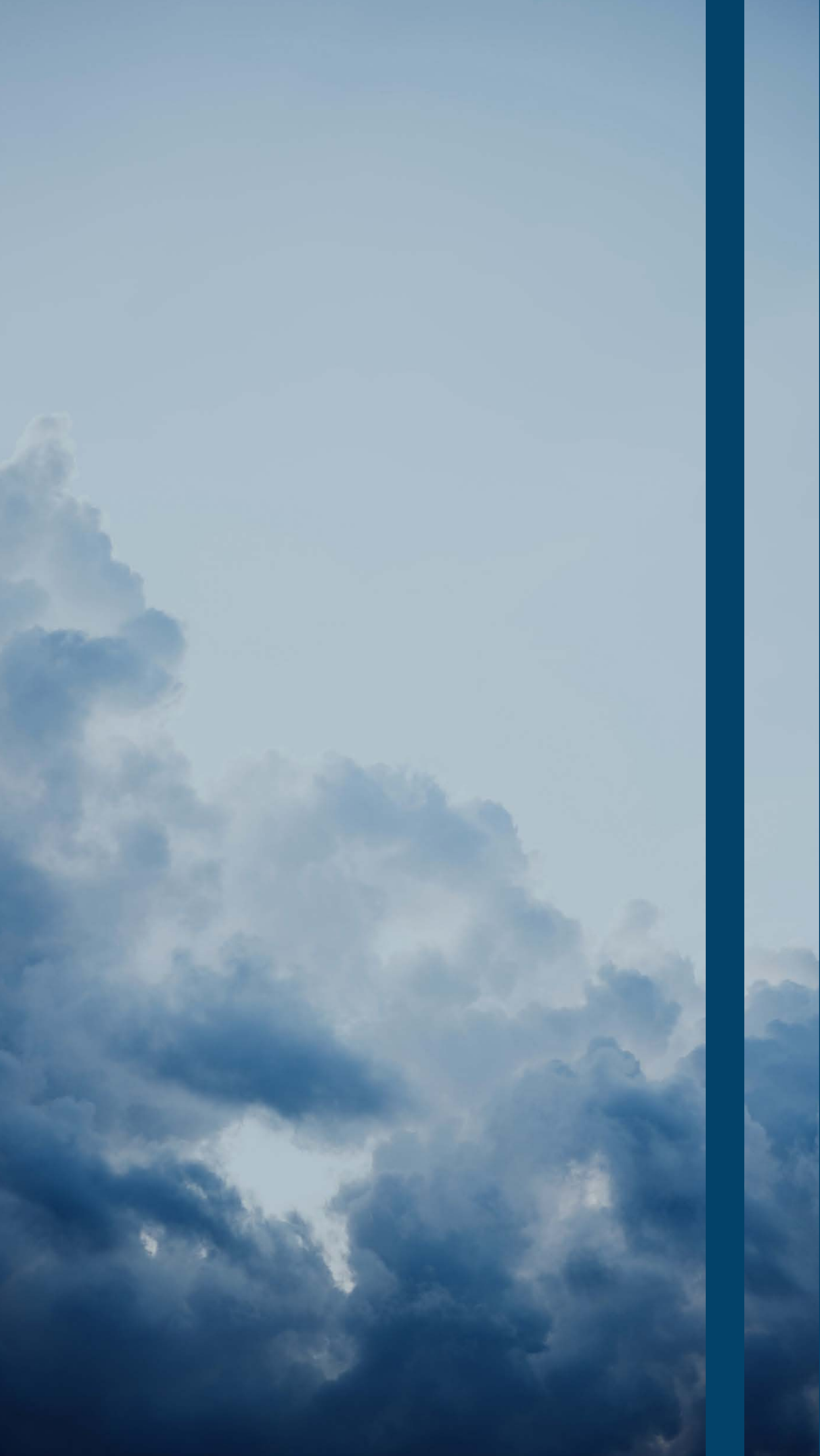
  The more significant additional cost is from duplication of equipment for hydrogen and natural gas (and in some cases, refinery gases). This will continue to be an issue for future developments until supply of hydrogen reaches greater levels of resilience;
- This additional equipment will also result in an increase in non-fuel operating costs. However, the non-fuel operating expenses associated with hydrogen would not be any greater than those associated with natural gas.

Availability of hydrogen is a critical consideration for design of commercial-scale demonstration projects:

- There is currently limited spare 'merchant' hydrogen available in the UK and a very limited number of suppliers who can provide the significant volumes needed for commercial-scale demonstration projects;
- Both in planning and during the demonstrations at both Greengate Works and Port Sunlight, hydrogen availability created significant issues, which caused both greater costs and delays to hydrogen-firing at both sites;
- BEIS has sought to address this challenge via both market engagement with potential hydrogen suppliers and the design of the second IFS programme, but it might also consider a further mechanism which addresses this fundamental deficit in supply;
- In the meantime, PEL is currently designing a new suite of demonstrations, funded by the second IFS Competition, which seeks to optimise hydrogen use, whilst still seeking to deliver the required level of evidence to enable long-term fuel switching;
- Once hydrogen is available in bulk from HyNet (and other regional hydrogen cluster projects) it is expected that this constraint to hydrogen supply will disappear.

Once low-carbon hydrogen is available in bulk from HyNet and from other industry clusters in the UK, there will be a clear path to decarbonising significant amounts of industrial production via the solutions developed during this work programme:

- Decarbonisation of steam supply from boilers in the UK could result in savings of 5MtCO_2/annum. Together with the savings from switching of hot water boilers to hydrogen, this constitutes a major contributor to meeting future carbon budgets;
- There are over 50 glass-making sites in the UK, including those manufacturing fibre glass products. This equates to potentially converting 650-700MWth (approximately 6 TWh/annum) of energy demand from natural gas to low carbon hydrogen, reducing UK emissions by approximately 1.2MtCO_2/annum;
- Sites across a range of sectors, including chemicals, paper and pulp, food and drink and automotive operate gas turbine CHP plant. Heat and power provision at these sites could be decarbonised by switching to new turbines running on hydrogen.



APPENDICES

Glossary

Acronym	Definition
ATEX	Equipment for potentially explosive atmospheres (adapted from French)
ALARP	As Low As Reasonably Practicable
BAT	Best Available Technology
BEIS	Department for Business, Energy & Industrial Strategy
CAPEX	Capital Expenditure
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
CFD	Computational Fluid Dynamics
CfD	Contract for Difference
CHP	Combined Heat & Power
CO^2	Carbon Dioxide
COMAH	Control of Major Accident Hazards
DCO	Development Consent Order
DNO	Distribution Network Operator
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations
EA	Environment Agency
EPC	Engineering, Procurement and Construction
EPCM	Engineering, Procurement and Construction Management
FEED	Front End Engineering Design

Acronym	Definition
FGR	Flue Gas Recirculation
FID	Final Investment Decision
GDN	Gas Distribution Network
GT	Gas Turbine
H_2	Hydrogen
HAZID	Hazard Identification (Study)
HAZOP	Hazard and Operability (Analysis)
HBM	Hydrogen Business Model
HMG	Her Majesty's Government
IDC	Industrial Decarbonisation Challenge
IFS	Industrial Fuel Switching
HHV	Higher Heating Value
kW	Kilowatt
LCoH	Levelised Cost of Hydrogen
LHV	Lower Heating Value
LCCC	Low Carbon Contracts Company
LTS	Local Transmission System
MCPD	Medium Combustion Plant Directive
mg	Milligram
MPBH	Medium Pressure Boiler House
$MTCO_2$	Megatonnes of Carbon Dioxide
MW	Megawatt

Glossary

Acronym	Definition
MWh	Megawatt Hour
Nm_3	Normal Cubic Metres
NDT	Non-destructive Testing
NG	Natural Gas
NIA	Network Innovation Allowance
NO	Nitrous Oxides
NTS	National Transmission System
NZHF	Net Zero Hydrogen Fund
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
PEL	Progressive Energy Limited
PSMP	Process Safety Management Plan
RDG	Refinery Dry Gas
RAM	Reliability Availability and Maintainability
RAB	Regulated Asset Base
ROG	Refinery Off-Gas
T&S	Transport and Storage
TRL	Technology Readiness Level
TWh	Terawatt Hour
WHRB	Waste Heat Recovery Boilers
XSA	Excess Air

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