Hy4Heat
demonstrating hydrogen for heat

Department for Business, Energy & Industrial Strategy

WORK PACKAGE 6

Conversion of Industrial Heating Equipment to Hydrogen

Hy4Heat WP6:

Conversion of Industrial Heating Equipment to Hydrogen

Final report

for

The Department for Business, Energy & Industrial Strategy

And Hy4Heat

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Disclaimer

1 Executive summary

1.1 Industrial decarbonisation and potential for hydrogen

The UK has recently become the first major nation to commit to reaching net zero greenhouse gas emissions by 2050[1,2]. Whilst significant progress has been made in many sectors, **the decarbonisation of heat and industry remains a challenge** and will drive significant changes to the natural gas grid over the coming decades. Many industry sectors are exposed to global competition, so are unlikely to be able to bear additional decarbonisation costs while maintaining competitive production costs with less regulated plants internationally. Manufacturing, which accounted for £186 billion of economic output (~10% UK) in 2017[3], provides an important contribution to the UK economy and requires support to decarbonise operations.

Greenhouse gas emissions associated with UK industry are estimated by the Committee on Climate Change to be 105 $MtCO_2e$/year (~21%), the second largest emitting sector after surface transport, with the main component being industrial combustion emissions[2]. Options for deep decarbonisation of industrial heat include CCUS (Carbon Capture, Utilization and Storage), and/or fuel switching to electricity, biofuels or hydrogen. The recent Industrial Fuel Switching Market Engagement Study[4] assessed the technical and economic challenges of the three fuel switching options. It concluded that hydrogen had the highest technical potential for fuel switching, reaching ~90 TWh/yr by 2040. This is in part due to its similarity to natural gas, which is the primary fuel used for the production of heat. More recent analysis to extend the scope of this work, suggests that full decarbonisation of stationary combustion in manufacturing is possible using hydrogen, CCUS, bio-energy with carbon capture and storage (BECCS) and electrification, with abatement costs for hydrogen estimated at £65-240/tCO_2e[2]. Wide-spread use of hydrogen is likely to involve re-purposing the natural gas distribution grid to carry hydrogen, as well as converting gas end-use technologies to run on hydrogen. There are a number of potential benefits to decarbonisation of heat through hydrogen, including:

- Potential to retrofit/convert existing natural gas equipment rather than full replacement, as well as maintaining similar processes and onsite set up.
- Potential for lower hydrogen retail fuel price per kWh than electricity, technology dependent.
- Reduced impact on the electricity grid and system benefits of hydrogen storage.

The Hy4Heat programme aims to establish if it is technically possible, safe, and convenient to replace natural gas with hydrogen in domestic and commercial appliances, as well as in industrial equipment. This will enable the government to determine whether to proceed to a community trial. This report summarises the findings from Work Package 6, focusing on hydrogen in industrial equipment. The study focused on converting current industrial natural gas heating technologies to use 100%[5] hydrogen, considering the evidence which must be available before a decision on the UK's decarbonisation pathway for heating could be made. **The aim of the study was to assess the technical requirements and challenges associated with industrial hydrogen conversion and estimate the associated costs and timeframes.**

[1] UK government press release, June 2019.
[2] Net Zero: The UK's contribution to stopping global warming, CCC report, 2019 and Technical Report
[3] House of Commons Briefing Paper , Manufacturing: statistics and policy
[4] Element Energy and Jacobs Consultancy 2018 Report. Note that this study excluded CHP and processes currently fuelled by internal fuels, electricity, waste and biomass.
[5] The purity of hydrogen delivered would be slightly less than 100%, but we are using '100%' for clarity on full conversion

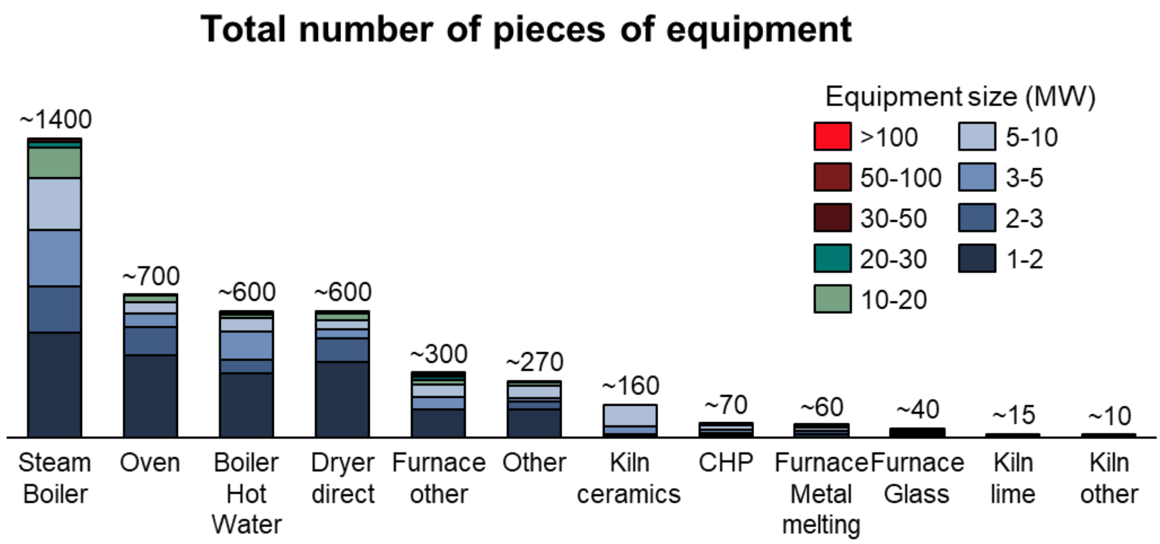
There were three main scope constraints for this study:

- Only industrial sites **connected to the <7 bar gas network were in scope of this study.** This is on the basis that those connected to the >7 bar gas network would not necessarily need to convert to hydrogen if only the <7 bar distribution system was repurposed.
- Equipment operating on at least some **natural gas (as opposed to other fossil fuels) and used primarily for production of heat**.
- **Equipment which is >1 MW_{th}**, focusing on the core industrial equipment of **boilers, furnaces, kilns and ovens** (which account for the large majority of industrial heating equipment), with some consideration given to Combined Heat and Power (CHP).

1.2 Industrial equipment market characterisation

Overall there were found to be around 4300 relevant pieces of industrial heating equipment (<7 bar network, >1 MW_{th}) operating on natural gas, accounting for ~70% of industrial gas consumption. One of the key components of this study was to characterise the industrial equipment market in terms of the type, number and capacity of equipment in each industrial subsector, to ensure a full understanding of the scale of the challenge. Figure 1-1 shows the resulting estimate of UK wide industrial equipment stock in scope. Boilers are the most prevalent equipment type, (also representing the greatest installed capacity), although direct heating equipment is often the most specialised, with a significant number of sector specific equipment types, such as ovens, dryers, kilns and furnaces. It should be noted that a significant amount of equipment, generally that with the highest capacity, is on sites connected to the >7 bar network and therefore excluded from these results.

Figure 1-1 Estimated amount of industrial natural gas heating equipment currently connected to the <7 bar network



1.3 Technical requirements, challenges and enablers

Key challenges to hydrogen conversion were found to include changes in heat transfer characteristics, increased NO_x emissions and changes in flue gas composition. There are multiple solutions of varying impact to these challenges, and no showstopping barriers were identified. Table 1-1 summarises the key technical challenges associated with using hydrogen for heat, and the related enablers, which either exist or are required.

Table 1-1 Key technical barriers to hydrogen conversion and their corresponding enablers. Impact of barrier rated on a colour scale which covers Red (showstopping barriers, none found), Orange, Yellow, to Green (least serious). See Table 6-1 for reasoning of impact rating.

Barriers		Enablers	Impacted equipment	Impact Rating
Technical	**Radiative Heat Transfer** – lower emissivity results in decreased radiant heat flux	Further experimental investigation on heat transfer balance, particularly in glass furnaces and kilns. Additives could be used to increase emissivity.	Furnaces, Kilns	
	Convective heat transfer – lower air requirement reduces the gas volume available to transfer heat.	Flue Gas Recirculation (FGR) increases gas volume, and is also beneficial elsewhere (e.g. NO_x emissions), equipment recalibration for indirect fired equipment.	All equipment	
	NO_x emissions – may be increased through higher flame temperature.	Technologies to mitigate this include Flue Gas Recirculation (FGR), steam addition and post-combustion treatment. Further work on low NO_x burners may also reduce emissions.	All equipment	
	Flue Gas Composition – e.g. increased moisture content with H_2 might impact product quality	Product specific tests required for some direct heating applications to evaluate impact and any possible mitigating actions (e.g. adjusting combustion parameters).	Direct fired equipment	
	Gas Engine Conversion for CHP	Period of R&D, small scale and large-scale trials. May require full replacement with potential new design, rather than retrofit.	Gas Engines	
	Piping and fittings (leakage risks and embrittlement)	Materials and standards currently exist for hydrogen piping. Site distribution systems would need to be checked for hydrogen compatibility and replaced if incompatible.	All sites	
	Hydrogen burner development, including materials	Burner materials currently exist, though further R&D by burner manufacturers is required.	All equipment	
Environment, Health and Safety	**Explosive Atmosphere Regulations** (DSEAR) - cost and space impact	Solution on a site by site basis – assessment of impact and new zoning requirements. Affected equipment and workstations might need to be moved or replaced.	All sites	
	Possible Emissions Re-permitting	Technical solutions to NO_x emissions. Standardisation and collaboration with Environment Agency over permitting requirements. Emissions monitoring required.	Some sites	
	Accident regulations (COMAH) risk – H_2 on site might push sites over aggregation limits	Solution on a site by site basis. Only a small number of sites may be affected. Re-permitting or reduced storage.	Very small number of sites	
Resources & Site	**Staff Training**	Training on H_2 equipment is available; requires resources and sufficient early warning of conversion to plan.	Industry Wide	
	Demo & implementation resource	Clear policy will allow for equipment manufacturers and sites to plan for the significant resources and training required for demonstrations and conversion	Demo Specific	
	Hidden Costs e.g. feasibility studies, site downtime etc.	Site by site basis. Further research into full implications and costs.	All sites	

In addition to the technical barriers summarised above, there are economic barriers to industrial hydrogen conversion, such as fuel costs, capital investment (shown below), and the financial impact of plant shutdown for conversion. These currently constitute a significant barrier for industry, and will need to be considered when assessing potential policy mechanisms to support conversion and deployment.

As a result of the differing combustion characteristics, existing natural gas equipment must be modified to operate on hydrogen without adversely affecting production rates and product quality. This study assessed which subcomponents would need replacement within each equipment type, including subcomponents such as the burner system, the induced draft fans, and the site-wide fuel distribution system.

It was found that the majority of industrial gas heating equipment could be retrofitted to operate on hydrogen, with some specific challenges still to be investigated and addressed. Generally, direct heating equipment is more challenging to convert due to possible impacts on the product, while indirect heating equipment such as boilers, is simpler. Some specific equipment types and challenges include:

- **Gas Engine CHP**, where issues around 'de-rating' and 'knock' (see section 4.4.1 on CHP) might necessitate replacement rather than conversion.
- **Glass furnaces**, which rely on radiant heat transfer to the product and the flue gas composition could have an impact on the product quality.
- **Food and Drink Ovens**, due to bespoke equipment and the possible impact on strict product quality standards.
- **Kilns**, where there are concerns around the impact of changes in flue gas composition, particularly the moisture content.

1.4 Cost of hydrogen conversion

A key factor in understanding the potential for hydrogen equipment in industry is the investment required to convert or replace existing equipment. The cost of retrofitting/replacing each subcomponent was estimated, with input from original equipment manufacturers, to assess the overall equipment conversion capex. The results are summarised in Table 1-2, split by equipment type and sector. Significant economies of scale are present in engineering works of this nature, so cost curves were applied to account for the range of sizes across industry. The conversion cost of a piece of equipment may be different between different sectors due to the different standards (e.g. ATEX compliance) of current equipment components, for example electrical control in the piece of equipment as well as in other ancillary equipment within the potentially expanded DSEAR zones. The requirements for future hydrogen equipment may also differ, e.g. the need for post combustion emissions reduction techniques such as selective catalytic reduction. In addition, equipment conversion costs also include estimates of Engineering Design, Project Construction and Management, Subcomponent Removal, Labour, Commissioning, and Estimated Contingency.

Table 1-2: Indicative estimated capex for converting some typical pieces of equipment from natural gas to hydrogen

Industry sector	Typical Equipment	Equipment Conversion Cost – Variation with Size (£ '000s)*		Conversion Cost for Typical Equipment (£ 000's)*	
		1 MW	10 MW	Example Size (MW)	Typical Cost
Food and Drink	Steam Boiler	170	690	20	1,040
	Oven	150	490	2	210
Chemicals	Steam Boiler	100	490	20	780
	Furnace	110	530	25	980
Vehicle Manufacturing	Hot Water Boiler	170	690	20	1,040
	Oven	150	490	5	340
	Direct Dryer	140	430	2	200
Basic Metals	Furnace	180	730	40	1,680
Paper	Direct Dryer	150	470	3	260
	Steam Boiler	190	750	20	1,140
Glass	Glass Furnace	200	800	25	1,390
Ceramics	Kiln	160	570	5	390
Lime	Lime Kiln	150	520	15	640
Other NM Minerals	Rotary Dryer	140	430	15	520
Elec and Mech Engineering	Hot Water Boiler	170	690	5	450
	Oven	150	490	3	260
	Steam Boiler	170	690	5	450

*All costs are in thousands of GBP

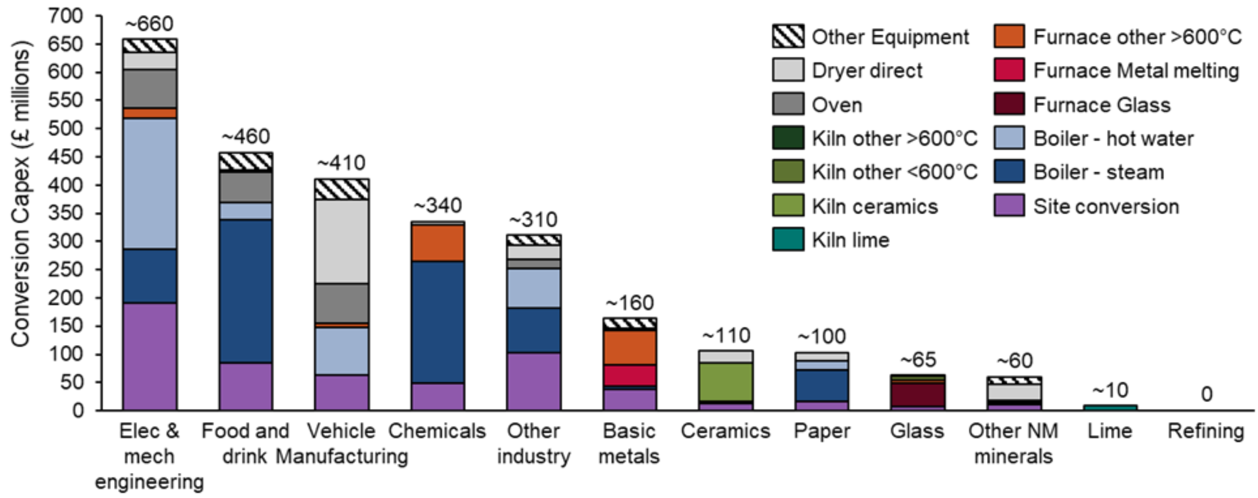
Beyond equipment, there are aspects of industrial sites which require modification, such as the site-wide gas distribution system. To represent this, a site level conversion cost was estimated based on the site size (total installed capacity of natural gas equipment), including a fixed engineering fee to capture this additional engineering cost.

The overall capital investment required to convert UK industrial sites and equipment was estimated at £2.7 billion[6], with a range of £1.0 - £3.9 billion due to remaining uncertainties. The site and equipment conversion costs were used in conjunction with the stock model of industrial equipment and sites to estimate a UK industrial conversion capex, with the sectoral breakdown shown in Figure 1-2. Sectors with many small sites (e.g. electrical and mechanical engineering) or many small pieces of equipment (e.g. vehicle manufacturing) dominate the overall cost. This capex value is a best estimate based on the information collected, engineering experience of the sectors and a small number of site visits. It is intended to provide a ballpark figure of UK wide conversion for the scope of this study and will differ from a bottom up, site by site approach for cost estimation. High and low sensitivity cases were undertaken to provide an indication of the uncertainty in the best estimate; the range in the total

[6] This figure is for sites and equipment on the <7 bar network; it excludes sites using <1 GWh/yr gas (sites/equipment assumed to fall within the commercial sector – covered in Hy4Heat Work Package 5) and excludes CHP (~25% gas demand) and re-permitting costs. See section 5 for more detail.

investment figure is estimated to be £1.0 - £3.9 billion, depending on factors such as ATEX compliance, site pipe lengths, hydrogen technologies required etc.

Figure 1-2 UK wide industrial conversion capex by sector and equipment type. Sites connected to the >7 bar network and CHP conversion are excluded.



In addition to this capital investment, there will be changes in operating costs for hydrogen equipment, such as the fuel costs, maintenance and consumables:

- **Energy costs** are of major concern to industrial sites, especially in those sectors in which they constitute a high proportion of overall costs. Currently, hydrogen fuel costs are significantly higher than natural gas, and the assumption throughout this study is that hydrogen will be available at a price which allows UK industry to remain competitive internationally post-conversion[7].
- **Other variable opex** includes consumables (e.g. nitrogen for purging transmission and distribution pipework) and directly involved labour; this is likely to increase by a small amount due to the need for further training, and increased use of purging consumables when using hydrogen due to its increased flammability risk. However, this will be a minor change.
- **Fixed opex** (including maintenance, spare parts, labour, overheads etc.) is generally estimated at 3% of equipment capex; due to the increase in procedural and environment, health and safety requirements involved in the use of hydrogen, it was estimated that the fixed opex might increase by ~15-20%.

Fixed and other variable opex is often a much smaller proportion of overall operating costs than fuel and capex.

1.5 Equipment development and demonstration

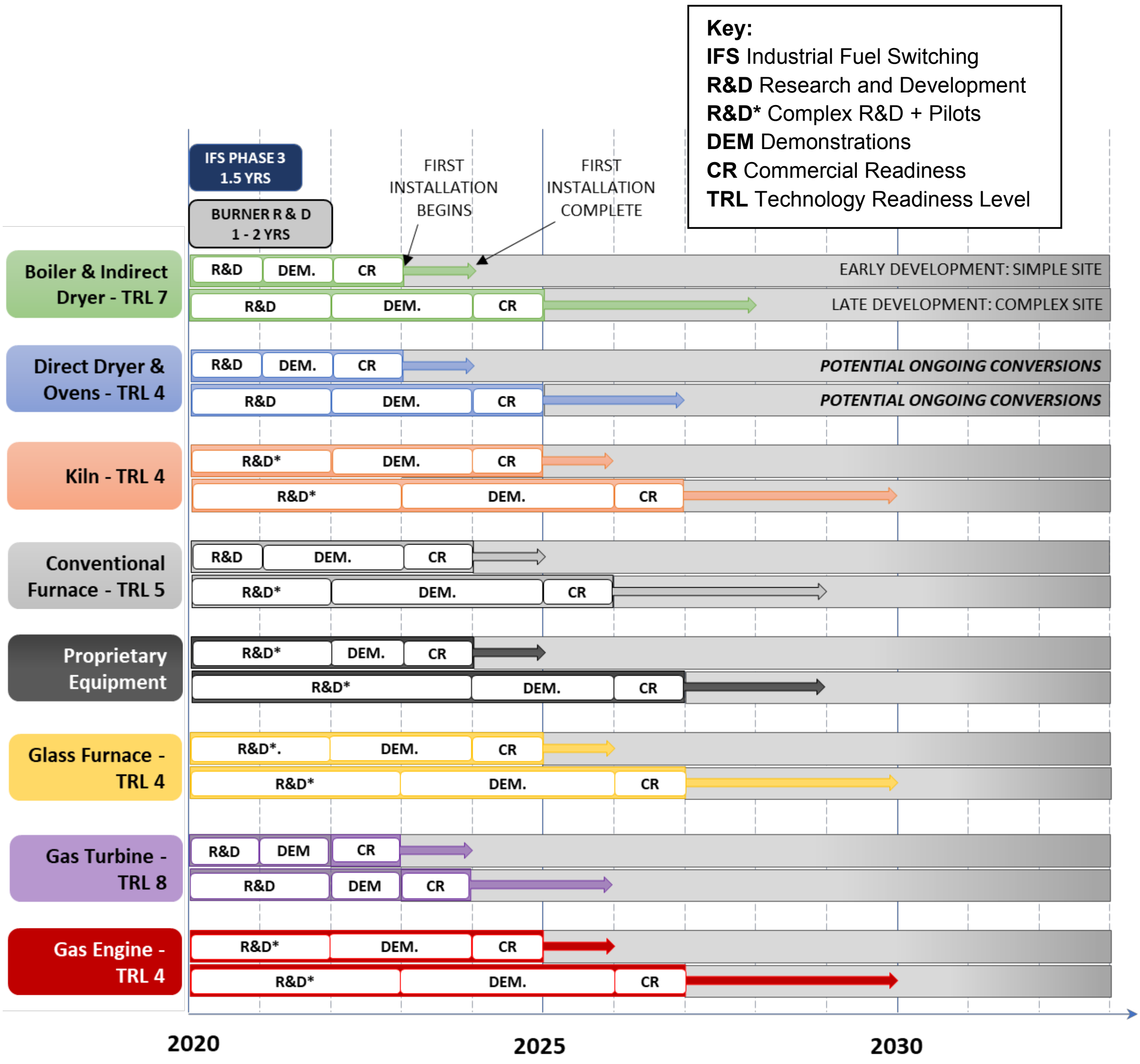
Whilst there are a few examples of 100% hydrogen equipment operating, significant development work is required to overcome the remaining challenges in many applications, alleviate industry concerns and reach the point of commercial readiness. Figure 1-3 shows the expected technology development timeline for each key equipment type, based on the current technology readiness levels (TRLs) and required length of R&D and demonstration. This timeline assumes sufficient financial support for these

[7] However, the scope boundary for this study is "behind the meter", and as such a detailed analysis of the hydrogen fuel price is outside of scope. Further investigation of this is ongoing through the government's Hydrogen Supply Programme.

demonstrations is available, and does not include commercial factors such as industrial investment cycles, which would impact implementation, but not technology development.

The level of evidence required to secure user acceptability of hydrogen equipment was found to vary by industrial sector and application, from OEM guarantees through to onsite application specific trials. Indirect fired equipment, such as boilers, may only require cross-sectoral trials and an OEM (Original Equipment Manufacturer) guarantee that equipment conversion would not adversely impact operations, as these equipment types are more general across sectors and applications. Direct fired equipment, such as kilns and furnaces, will generally require a greater level of demonstration to reach TRL 9 and secure user acceptability, due to potential impacts on product quality. Demonstrations and tests at a more application specific level are likely to be required for OEMs to provide guarantees. Beyond TRL 9 in the core equipment types, a small number of sites might require site and application specific tests, potentially due to stringent product quality requirements or particularly bespoke pieces of equipment.

Figure 1-3 Technology development timeline for industrial equipment showing time required for R&D, modelling, demonstration and commercial readiness



This study estimated the number and scale of demonstrations to reach TRL 9[8] for each equipment type (beyond which further site and application specific trials may be needed in some sectors). Overall it is estimated that around 25 demonstrations are required to reach TRL 9 across the key costed equipment types. It is critical that these demonstrations happen in the early 2020s to provide the required evidence before a decision is made on the long-term decarbonisation pathway for heat.

1.6 Recommendations

To ensure the option of using hydrogen for heat remains open, a number of steps must be taken in the near-term, addressing the current challenges and filling the remaining knowledge gaps. A few key recommendations are presented below, with more detail in section 8.2:

- **Demonstration programmes** are needed in the early 2020s to provide the required evidence of industrial equipment using 100% hydrogen before a decision is made on the long-term decarbonisation pathway for heat.
- **Determine a support mechanism for hydrogen conversion/use in industry,** evaluating different business models to understand who is bearing what cost burden, what funding and support needs to be available, and to clarify risk ownership. However, any industrial incentives should ensure the best decarbonisation option is delivered from a technical, cost and system perspective.
- **Modelling and lab scale tests for technically challenging equipment types** to understand potential impacts on equipment operation and product quality (e.g. flue gas atmospheres) at a detailed level and to channel the development of 100% hydrogen equipment.
- **Further technical development work around direct fired equipment and gas engine CHP** to overcome the remaining technical uncertainties and barriers. ‘Hydrogen ready’ equipment should also be investigated further, assessing technical challenges and costs of this approach.
- **Investigation of emissions control strategies** for each equipment type, particularly where NO_x control techniques are already in use on natural gas equipment, or if regulations become more stringent.
- **Increase awareness of hydrogen options within industry** through engagement with major manufacturers and industry bodies across the UK, e.g. dissemination via workshops with industry.
- **Investigation of different deployment strategies for hydrogen conversion**, examining the impact on costs of risks of approaches such as retrofit or ‘hydrogen readiness’, as well as regional vs. national mechanisms. Clarity on future hydrogen roll-out timeframes and mechanisms should be given as soon as possible to allow organisations to plan appropriately and mitigate impacts.
- **Detailed comparison of hydrogen with other decarbonisation options for each industrial sector**, determining the best option for each sector on a technical, economic and system-wide basis.
- **Further work on each industrial cluster to develop cluster specific costs and timelines** should take place, considering 100% hydrogen as well as other decarbonisation options such as electrification, biomass or CCS.

[8] Technology & system proven in operational environment

Contents

Glossary and Terminology

ATEX	'ATEX' is derived from the French title of the 94/9/EC Directive, referring to regulations around explosive atmospheres and equipment used in them.
Bar	Unit of pressure. Bar (or bara) refers to the absolute pressure, barg refers to pressure above atmospheric pressure.
BAT	Best Available Techniques
BAU	Business as usual
BEIS	Department for Business, Energy & Industrial Strategy
BHGE	Baker Hughes, a GE company is an industrial services company (part of General Electric)
BREF	BAT (Best Available Technology) Reference documents
CCS/CCUS	Carbon capture (utilization) and storage (of CO_2)
CH_4	Methane (primary component of natural gas)
CHP	Combined heat and power
CO	Carbon monoxide
CO_2	Carbon dioxide
COMAH	Control of Major Accidents and Hazards Regulations 2015
Direct heating	Process where the combustion gases come into contact with the product, such as in a kiln or oven.
DLE/DLN	Dry Low Emissions (or NO_x) – a type of burner technology in gas turbines
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations 2002
EC&I	Electrical Control and Instrumentation
EHS	Environment, Health and Safety
Equivalence Ratio	Ratio of actual fuel/air to stoichiometric fuel/air ratios. Represented by ϕ
EU ETS	European Emissions trading system (for trading CO_2 allowances)
FD Fan	Forced Draft Fan
FGR	Flue gas recirculation
FGT	Flue gas treatment
GDNO	Gas Distribution Network Operator
GT	Gas turbine (used in the context of a CHP technology)
H_2	Hydrogen
H_2O	Water (gaseous or liquid form)
ifs	Induced Draft Fan
IFS	Industrial fuel switching (referring to the 3 phase competition and the information from the phase 1 study)
Indirect heating	Process where the combustion gases do not come into contact with the product, such as heat using steam or hot water pipes.
Internal fuels	Fuels produced on the industrial site, often as a process by-product
IR	Infrared light
MCPD	Medium Combustion Plant Directive
Mol%	Molar percentage
MW_{th} (MW_e)	Thermal capacity unit of equipment - Megawatts thermal (Megawatts electrical)
NG	Natural Gas
NO_x, NO_2	Nitrogen oxides or Nitrogen dioxide

O&M	Operation and maintenance
OEM	Original equipment manufacturer
PER	Pressure Equipment Regulations 1999
PSSR	Pressure Systems Safety Regulations 2000
R&D	Research and development
SCR	Selective catalytic reduction
SGN	GDNO covering Scotland and the south east of England
SME	Small and medium-sized enterprises
SMR	Steam methane reforming
SNCR	Selective non-catalytic reduction
TRL	Technology readiness level
UV	Ultraviolet light

2 Introduction

2.1 Background

The UK has recently become the first major nation to commit to reaching net zero greenhouse gas emissions by 2050[9,10]. Since 1990, the UK has cut emissions by 42 per cent while the economy has grown by two thirds[11]. Whilst significant progress has been made in many sectors, the decarbonisation of heat and industry remains a challenge and will drive significant changes to the natural gas grid over the coming decades.

Greenhouse gas emissions associated with UK industry are estimated to be 105 $MtCO_2e/yr$ (~20%), the second largest emitting sector after surface transport[2]. Around two thirds of industrial emissions come from a small number of energy intensive sectors, such as iron and steel, cement and chemicals. Some emissions may be as a result of chemical processes which release carbon dioxide, but a large proportion come from the combustion of fossil fuels, primarily to produce heat. Options for deep decarbonisation of industrial heat include CCUS (Carbon Capture, Utilization and Storage), or fuel switching to electricity, biofuels or hydrogen, with the technical and economic challenges of the three fuel switching options assessed in the recent Industrial Fuel Switching Market Engagement Study[13]. The study covered just over half of fossil fuel use in manufacturing (120 TWh out of a total of 215 TWh) and identified 90 TWh of industrial energy use which could be switched to hydrogen by 2040. This included 15 TWh of demand for firing applications, for which biomass and electrification are rarely technically suited. More recent analysis to extend the scope of this work, suggests that full decarbonisation of stationary combustion in manufacturing is possible using hydrogen, CCUS, bioenergy with carbon capture and storage (BECCS) and electrification. Fuel-switching potential is considered in the main energy-intensive sectors including Chemicals, Food and Drink, Paper, Vehicles, Refining, Ethylene, Ammonia, Non-metallic minerals, Non-ferrous metals and Secondary steel production and processing. The abatement costs for hydrogen fuel-switching are estimated at £65-240/tCO_2e[10].

In 2017, manufacturing in the UK accounted for 2.7 million jobs (8% total), £186 billion of economic output (10%), 44% of UK exports and 70% of UK research and development spending[12]; hence industry is a crucial aspect of the UK economy, which must be futureproofed through providing the support required to decarbonise operations. There is significant BEIS (Department for Business, Energy and Industrial Strategy) funding available already for industrial research and innovation. For example, the 3 phase Industrial Fuel Switching competition allocates up to £20 million to stimulate early investment in fuel switching processes and technologies, so that a range of clean, cheap and reliable technologies are available by 2030 and beyond. There are other additional funds available for industrial decarbonisation and hydrogen supply, with more information available online[13].

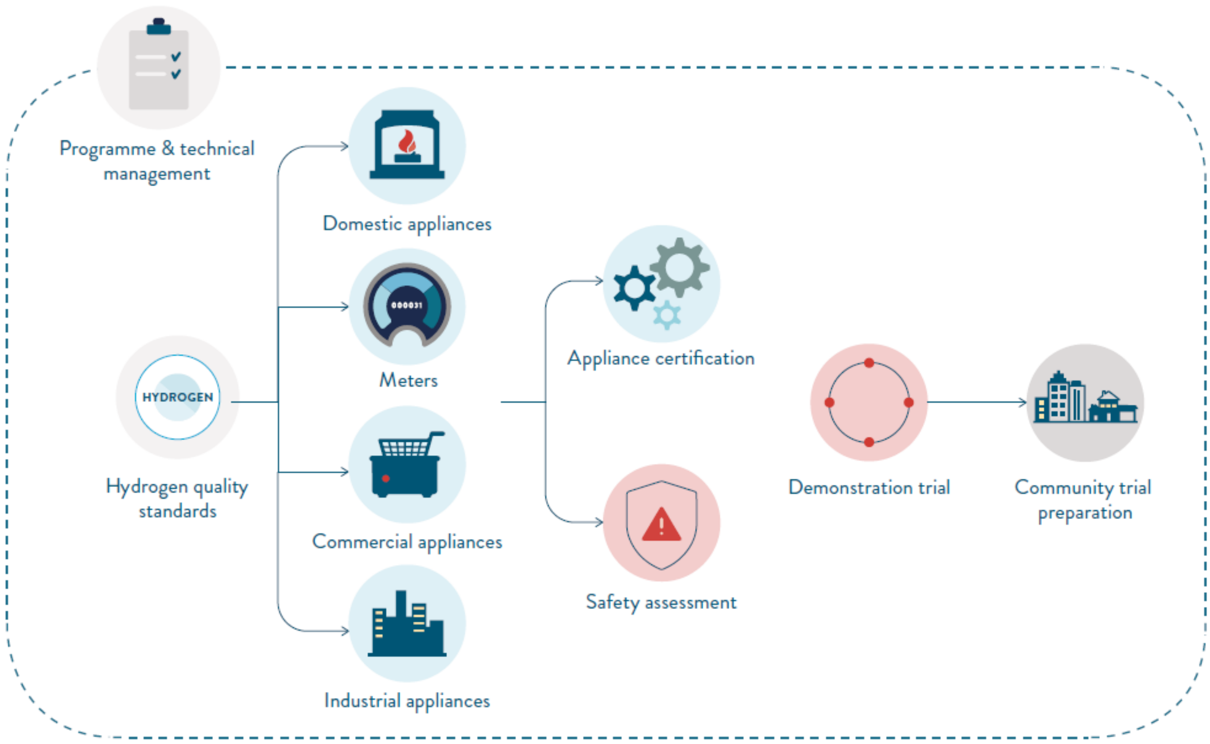
Natural gas comprises over 45% of industrial fuel consumption[14], transported through the national gas transmission system and local distribution system of pipework. Wide-spread use of hydrogen as an option for decarbonising heat may involve re-purposing the local natural gas distribution system to carry hydrogen, as well as converting gas end-use technologies to run on hydrogen. Significant uncertainty still remains around the technical and economic challenges and implications of this pathway, so a number of studies and demonstration programmes are planned to provide the required evidence.

[9] UK government press release, June 2019.
[10] Net Zero: The UK 's contribution to stopping global warming, CCC, May 2019 & Technical Report
[11] UK Clean Growth Strategy, 2017
[12] House of Commons Briefing Paper , Manufacturing: statistics and policy
[13] UK Government, Funding for low carbon industry
[14] DUKES Energy Consumption UK statistics table 4.04

2.2 Aim and scope

BEIS is looking at ways of decarbonising heat, and one of the options is replacing methane with hydrogen, which releases no carbon dioxide (CO_2) on use. There is significant evidence required before a decision can be made as to the future role for hydrogen, so a group of industry partners and experts are working to understand the implications as part of the Hy4Heat programme[15]. The aim is to establish if it is technically possible, safe, and convenient to replace natural gas with hydrogen in domestic and commercial appliances, as well as in industrial equipment. This will enable the government to determine whether to proceed to a community trial. The programme, which runs from 2018 to 2021, includes ten work packages, covering aspects such as hydrogen quality standards, certification, end-use equipment and safety, as shown in Figure 2-1.

Figure 2-1 Outline of the BEIS Hy4Heat programme



This report summarises the findings from Work Package 6, *Industrial Appliances – Understanding the market*[16]. The study focused on converting current industrial natural gas heating technologies to 100%[17] hydrogen, considering the evidence which must be available before a decision could be made. The key aims of the study were:

- **Characterise the industrial equipment**[18] market for each industrial subsector in terms of the number, type and capacity of heating equipment present.
- Assess **technical challenges** and constraints of hydrogen conversion, including equipment conversion requirements, feasibility, safety and site level changes.

[15] Hy4Heat website
[16] While appliance is used for consistency with domestic and commercial work packages, the term 'equipment' is used throughout this report as is more appropriate within industry. Industry here refers to the SIC code classifications shown in appendix 9.5.1, mainly referring to the manufacturing of products.
[17] The purity of hydrogen delivered would be <100%, but we are using '100%' for clarity on full conversion
[18] Where the term equipment covers industrial heating equipment currently using natural gas, focusing specifically on the core equipment types, within the scope constraints of the study. Industrial

- **Estimate the costs** associated with industrial hydrogen conversion, such as the capex for conversion itself and changes in the operational and maintenance costs.
- Understand the **equipment research**, development and demonstration work required for each of the key industrial equipment types (boilers, furnaces, kilns, ovens), including approximate timeframes for technology development.
- Highlight the **remaining challenges** and knowledge gaps which require further consideration.

There were three main scope constraints for this study. The first was that industrial **sites connected to the >7 bar gas network were out of scope**; this is because it has been assumed that these sites would not necessarily be required to convert to hydrogen if only the <7 bar distribution system was repurposed to hydrogen. Hydrogen production could be dispersed around the UK and injected into local or regional areas of the gas grid, with the national natural gas transmission system remaining in its current form. The second scope constraint was that this industrial work package focuses on **equipment >1 MW_{th}** (i.e. their thermal capacity exceeds 1 MW). This size constraint should capture large-scale industrial equipment and avoid overlap with the commercial workstream. The final scope constraint was that the work focuses on the **core equipment types** below, which account for the majority of equipment present in industry:

- High-heat, direct-fired kilns
- High-heat, direct-fired furnaces
- Steam-raising boilers
- Hot water boilers
- Low temperature processes for toasting, baking, grilling, roasting and drying

Combined heat and power (CHP) equipment, i.e. gas turbines (GTs) and gas engines (reciprocating engines) were considered, however the conversion to 100% hydrogen of **CHP has not been costed**, as this was outside of the scope of the study[19].

While other specialised equipment types (e.g. coffee roasters) were not explicitly evaluated for technical barriers to hydrogen conversion, it is anticipated that there will not be significant additional barriers to those already identified for the core equipment types. A high level estimate of the amount of non-core ("other") equipment and the corresponding cost of hydrogen conversion is included in our overall results.

It should also be noted that the study focused on equipment currently operating using at least some **natural gas (as opposed to other fossil fuels) and used primarily for production of heat**. Production and transmission of hydrogen were also outside the scope of this work, which concentrated on end-use on the industrial sites only.

2.3 Study approach

To build on the existing knowledge base and develop a comprehensive understanding of industrial equipment and the requirements and challenges of industrial hydrogen conversion, the study gathered data from a number of sources as well as engaging with a range of industrial stakeholders. Key components of the study are detailed below:

- **Stakeholder engagement** was a key pillar throughout the project, with input from gas distribution network operators (GDNOs), industry Associations, industrial sites and equipment manufacturers (OEMs), incorporated into all stages of the project. These were used to gather evidence, provide confidential datasets and test emerging findings of the study allowing

[19] For information on CHP, see section 4.4.1.

feedback on assumptions and results. An industry survey gathered data on around 70 industrial sites.

- A detailed literature review was carried out to identify the scope of previous work in this area, and to establish what data gaps needed filling to achieve the study aims.
- A detailed **model of the existing stock of natural gas consuming industrial heating equipment** was built using confidential gas consumption data from GDNOs and industry associations, broken down by sector, site size, and equipment type and size.
- **Technical modelling of hydrogen** as a fuel was carried out, helping to identify which equipment components require replacement and key technical challenges for future demonstration programmes to overcome.
- **Equipment conversion costs** were estimated by combining subcomponent conversion or replacement costs using information from OEMs, split by industrial sector and equipment type. Site conversion costs were also estimated through site visits by assessing on-site aspects such as pipework replacement costs, permitting and regulation.
- UK wide cost of industrial hydrogen conversion by sector was estimated by combining the total UK equipment stock with the estimated conversion costs of each piece of equipment.
- An **industry workshop** attended by 45 stakeholders was held to disseminate emerging findings from the study and gather feedback on the nature of evidence and equipment demonstration programmes required for industry to convert to hydrogen.

The following chapter sets out industrial gas consumption and the UK stock of industrial equipment on the <7 bar network, broken down by sector, site size, and equipment type. Chapter 4 describes the technical challenges and requirements for equipment conversion to hydrogen, with estimated costs and timelines for technology development detailed in Chapter 5. Chapter 6 highlights the key barriers to the use of hydrogen in industry, together with enablers and the required demonstration programmes for industry acceptance. Chapter 7 contains a summary of information on each of the key natural gas consuming industrial sectors, highlighting key processes and equipment as well as sector specific challenges to hydrogen conversion. The report concludes with a summary of the overall findings of the study and a range of recommendations for further work. Further details on methodology, stakeholder engagement and key assumptions is available in the appendices.

3 Industrial gas consumption, processes & equipment

3.1 Industrial energy consumption by sector

In the UK, industry accounts for a significant proportion of total energy consumption (~17%) and natural gas consumption (~20%)[20]. Figure 3-1 shows the breakdown of energy and gas consumption across the key industrial sectors, excluding fuel use as a feedstock[21]. The gas consumption data used in this study is a combination of ECUK statistics[22], DUKES CHP data[23], industry association input and confidential GDNO data. As can be seen, when only natural gas consumption is considered, certain sectors become more dominant: Chemicals, Food and drink, Electrical and mechanical engineering and Non-metallic minerals account for over 70% of gas consumption. Equally, there are some sectors which have comparatively lower natural gas consumption due to significant use of solid fuels or electricity. For example, cement and primary iron production primarily use coal and the paper industry uses significant biomass and waste. It is also worth noting that some sectors, such as cement and chemicals, have considerable CO_2 process emissions, making them larger contributors to total UK CO_2 emissions than their fuel consumption would suggest. The total industrial natural gas consumption of 113 TWh/yr includes gas used in industrial CHP units for both heat and electricity production, but excludes natural gas used as a feedstock chemical.

Figure 3-1 Annual energy consumption of UK industrial sectors (TWh/yr). Sector definition by SIC code can be found in appendix 9.5.1.

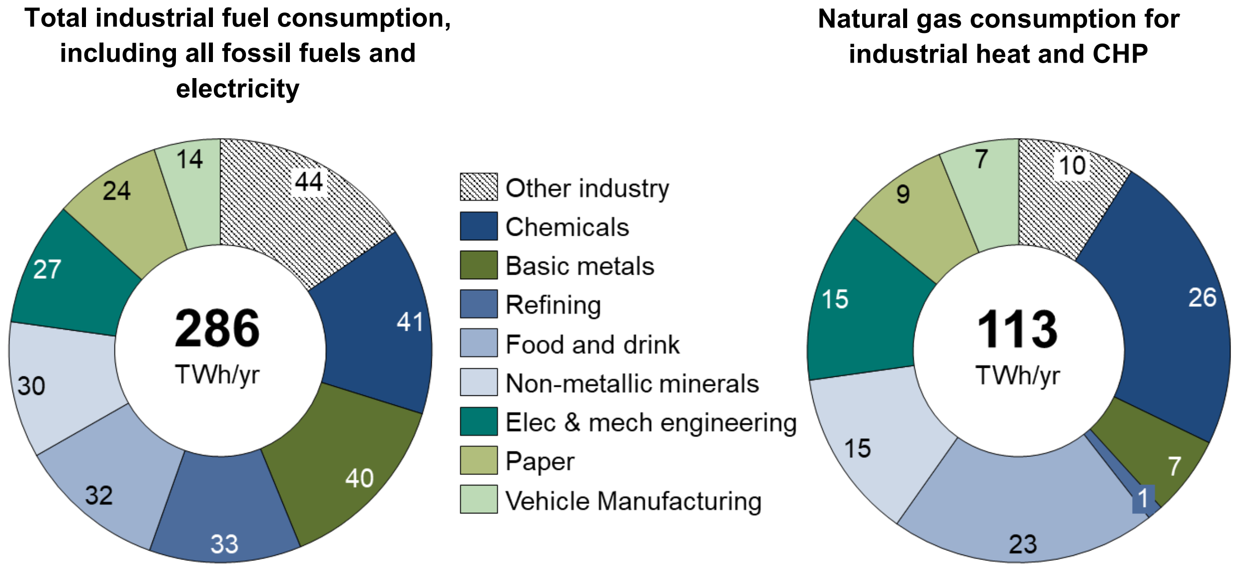
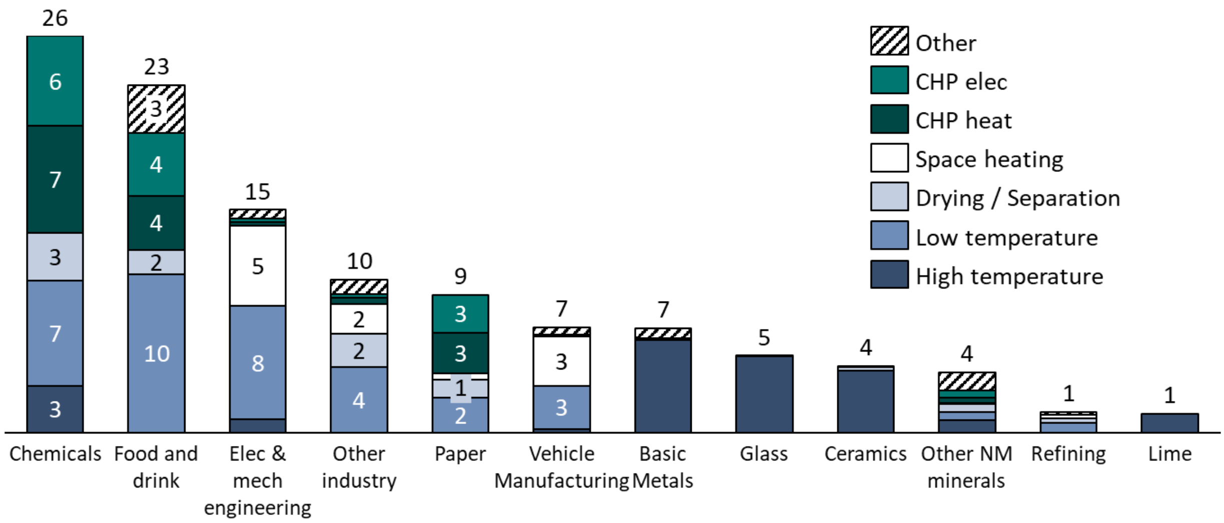


Figure 3-2 shows the total industrial natural gas consumption split by sector and end use process category[24]. The processes consuming natural gas vary widely by industry. Some sectors, such as Glass and Ceramics, consume almost exclusively high temperature heat in furnaces and kilns, while others such as Vehicle Manufacturing and Electrical and mechanical engineering use gas for low temperature

[20] Energy Consumption in the UK 2018 statistics: Section 1 Overall Energy consumption
[21] Coal use in blast furnaces is included, though partly used in reduction processes. The refining sector natural gas consumption is higher than this, but both feedstock use and some large scale power producing CHP units have been excluded. Significant internal fuels are also used for heat.
[22] Energy Consumption in the UK 2018 statistics: Section 4 Industry
[23] Digest of UK Energy Statistics 2018: Chapter 7 CHP
[24] Excluding natural gas use as a feedstock.

processes or space heating. CHP accounts for approximately 30% of overall industrial natural gas consumption, and is particularly prevalent in the Chemicals, Food and drink and Paper sectors.

Figure 3-2: Total Industrial Natural Gas Consumption in TWh/yr by End Use and Sector[24].

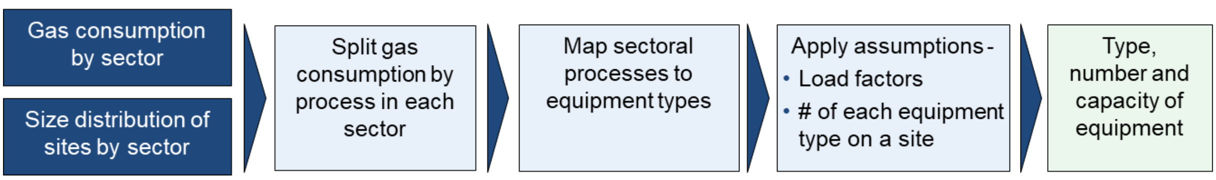


It was important for this study to understand what proportion of industrial sites were connected to the <7 bar gas network, to exclude those on the high pressure (>7 bar) system which may not be converted to hydrogen. Confidential site-level connectivity data from Cadent and SGN was used to estimate the proportion of sites connected to the <7 bar network of each site size in each sector. In general, it is the largest gas consuming sites which are connected to the >7 bar network (Local and National Transmission Systems). This results in much of the largest equipment falling outside the scope of the study; in particular much of the CHP capacity is connected to the >7 bar gas network due to typically large scale CHP units on larger sites.

3.2 Industrial sector processes and equipment

One of the key aims of the study was to characterise the UK industrial equipment stock. Considerable information was already available on the processes present in each sector from the sectoral Best Available Technology Reference (BREF) documents, Industrial decarbonisation roadmaps and Industrial Fuel Switching market engagement study. Further information was gathered on equipment and combined with the gas consumption data to estimate the type, number and capacity of natural gas heating equipment in industry, following the process in Figure 3-3. More information on the assumptions used during this process is present in appendix 9.5, although some industrial data is not shared due to confidentiality concerns.

Figure 3-3 Process used to characterise the industrial equipment in the UK



A summary of the key processes and equipment is given in Table 3-1. It should be noted that each process and piece of equipment is sector specific; for example, kiln firing in the ceramics sector will have different operational parameters, components and assumptions from a kiln in the lime or glass sectors. In addition to this range within the core equipment types, there are a number of other, more niche, equipment types within industry, e.g. coffee roasters, concentrated in sectors with a large number of different products, such as food and drink. However, there are a low number of these pieces of equipment, generally with a relatively low thermal capacity, so their impact on the cost of conversion is likely to be low. Further information on the gas consumption and processes in each sector can be found in Chapter 7.

Table 3-1 Key industrial processes and equipment.

Process (sector specific)	Equipment (sector specific)
Space heating	Boiler - steam
Steam raising	Boiler – hot water
Steel rolling	Furnace - glass melting
Steel melting	Furnace – metal melting
Metal melting other	Furnace – other <600°C
Cracking	Furnace – other >600°C
Steam reforming ammonia	Kiln – lime
Oven heating	Kiln - ceramics
Drying	Kiln – other <600°C
CHP - heat	Kiln – other >600°C
CHP - electricity	Dryer (direct)
Glass melting	Oven
Glass other (e.g. annealing)	CHP – reciprocating engine
Kiln firing	CHP – gas turbine
Raw material drying / milling	Other
High temperature other	
Low temperature other	
Other	

The scope constraints described in section 2.2, to focus on the <7 bar gas network and equipment >1 MW_{th}, were applied to the gas consumption and resulting equipment, as shown in Figure 3-4 below. As expected, it is generally the largest sites which are connected to the >7 bar gas network and the smaller sites which contain the majority of the <1 MW_{th} equipment. Some sectors have fewer sites, with high gas consumption at each (e.g. Paper, Refining); other sectors have a large number of smaller, low gas consumption sites (e.g. Electrical and mechanical engineering). Sectors such as Glass and Ceramics are relatively unaffected by these constraints and the majority of sites and equipment remains in scope.

Figure 3-4 Schematic of application of scope constraints to the natural gas breakdown across industrial sites.

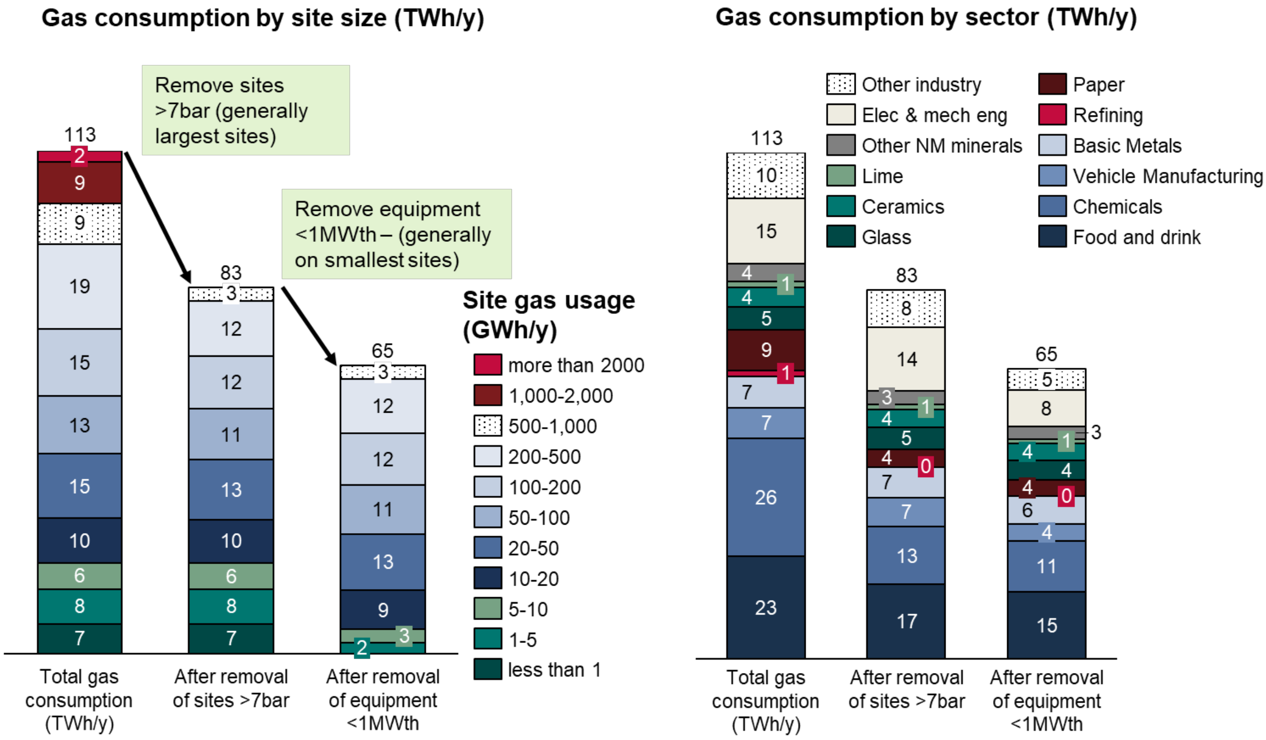
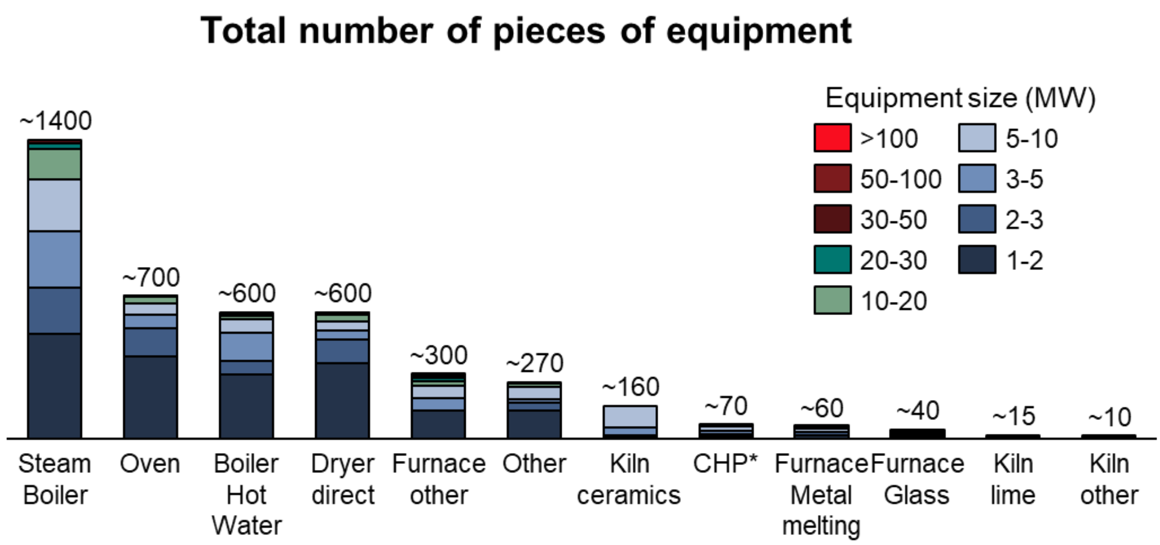


Figure 3-5 below shows the resulting estimate of UK wide industrial equipment stock in scope, in terms of the number of each equipment type currently installed. Boilers are the most prevalent piece of equipment, also represent the greatest installed capacity. There are also significant numbers of sector specific direct heating equipment, such as ovens, dryers, kilns and furnaces. Overall 4300 relevant pieces of industrial equipment operating on natural gas were modelled on the <7 bar network; however it should be noted that a significant amount of the largest equipment is on the >7 bar network and therefore excluded from these results.

Figure 3-5: Estimated number of each equipment type in industry. Only equipment on the <7 bar network and of >1 MWth is included. Capacity is in MW_{th}, with the exception of CHP, which is in MW_e.



The market is dominated by the large number of pieces of equipment which are small in capacity; for information on the distribution of capacity across appliances, see Appendix 9.5.3. Further details on the processes and equipment present **in each sector** can be found in Chapter 7 with the key assumptions in appendix 9.5.

While this chapter assessed the number, type and capacity of equipment present in UK industry, the subsequent chapter discusses the technical challenges involved in converting these industrial equipment types to hydrogen. Estimates of the cost of these conversions are presented in Chapter 5, for equipment and site modifications, as well as for the whole UK conversion.

4 Technical Challenges and Equipment Conversion Requirements

4.1 Key Differences between Hydrogen and Natural Gas Combustion

Two different sources of information were used to understand the key differences in requirements for converting fired equipment from natural gas to 100% hydrogen (H_2):

- Review of publicly available, relevant literature, and
- Computer modelling of hydrogen and methane (the primary component of natural gas) combustion using CHEMKIN software.

Information on the modelled scenarios (equivalence ratios, steam addition, flue gas recirculation [FGR] etc.) and results are presented in detail in appendix 9.3.

The combustion characteristics of natural gas and hydrogen are an important basis in understanding the impact of fuel switching on industrial processes. A brief summary of the key properties for each fuel is presented below, with their implications for conversion of industrial sites and equipment to 100% hydrogen discussed in section 4.1.2. The impact of this conversion on environment, health, and safety are then discussed in section 4.2.

4.1.1 Fuel and combustion properties

Wobbe Index (WI)

The WI is used to compare the combustion energy output of different fuels, based on their higher heating values and specific gravity. It allows a comparison of the energy content of the fuel flowing through a burner, operating using different fuels under the same flow conditions, and so is a useful metric to understand the interchangeability of fuels. Despite having similar values of WI, natural gas equipment often cannot directly run on 100% hydrogen because of other key differences in flame properties[25].

Lewis Number (Le)

This is the ratio of thermal diffusivity to the mass diffusivity of fuel and represents the sensitivity of flames to disturbances. Fuels with Le ≥1 are expected to be thermo-diffusively stable. The Le of hydrogen is approximately half that of methane (0.45 vs 1), which indicates a more unstable flame[26].

Flammability Limits

These are the limits (upper and lower) of fuel gas concentration in air which can be ignited at a given temperature and pressure. Hydrogen is highly flammable and, at ambient temperature and pressure, has much wider flammability limits (0.1-7.1 equivalence ratio) when compared to that of natural gas (0.5-1.67). This relates to a flammability range in % by volume of 4.4–15% for natural gas and 4.0–75% for hydrogen, and this wider flammability range of hydrogen raises health and safety questions, discussed further in section 4.2.

Flame Temperature

The adiabatic flame temperature (AFT or T_{ad}) is the theoretical maximum temperature that can be reached in complete combustion for a given equivalence ratio. Both the literature and the CHEMKIN modelling indicate that the AFT for a 100% hydrogen flame is approximately 200 K more than for a 100% methane flame under identical conditions, for all initial temperatures. For example, at an equivalence ratio of $\phi=1$ and an initial temperature of 100°C, the adiabatic flame temperature was

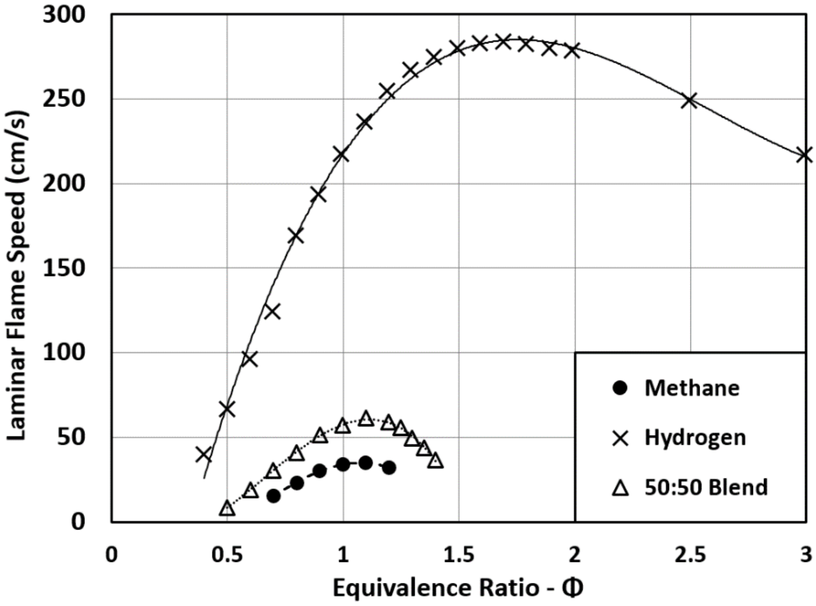
[25] Dodds PE, et al. Int J Hydrogen Energy 2015;40:2065–83. doi:10.1016/ j.ijhydene.2014.11.059
[26] Bouvet N. et al, Int IntJ Hydrogen Energy 2013. doi:10.1016/j.ijhydene.2013.02.098.

modelled to be ~2430 K for hydrogen compared to ~2260 K for methane. This increase in flame temperature impacts emissions performance, materials selection and efficiency for combustion devices.

Flame Speed

This characterises the flame propagation in combustion devices, providing an indication of combustion reactivity as well as flame intensity and stability, with hydrogen flames having a laminar flame speed up to an order of magnitude greater than methane flames, as shown in Figure 4-1. In methane/hydrogen blends, this varies non-linearly with H_2 content, increasing sharply at high H_2 contents[27]. This higher flame speed shows H_2 flames are very reactive and can be prone to flashback from the combustion chamber into the mixing zone.

Figure 4-1: Laminar flame speeds of H_2, Methane (CH_4) and 50 vol. % H_2-50 vol. % CH_4 in air at 300 K and 1 atm as a function of equivalence ratio. Reproduced[28].



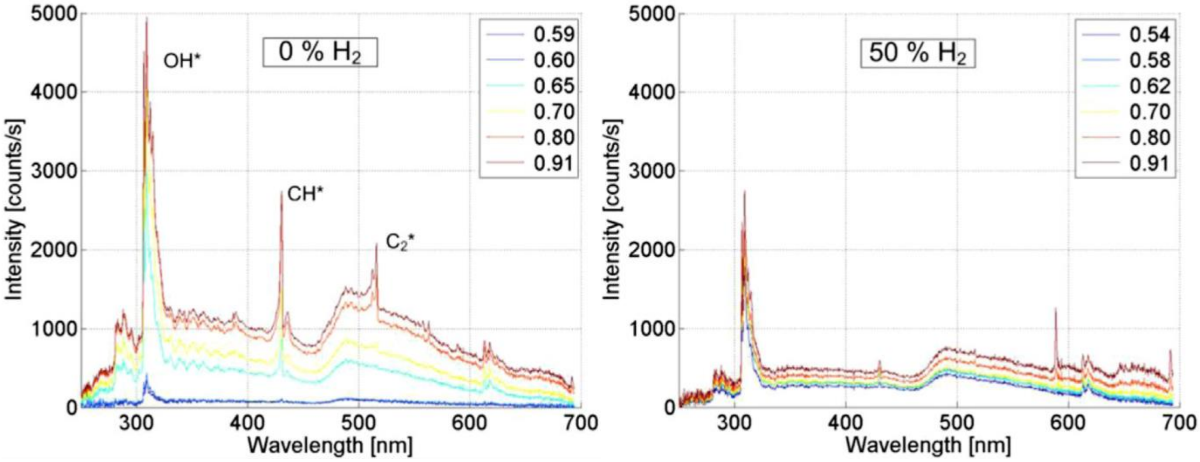
Heat Transfer and Emissivity

A hydrogen flame has a lower emissivity than a methane flame as a result of the reduced concentration of radiant species such as soot, CO_2, and hydrocarbon radicals[29]. This affects the radiative heat transfer from the flame, which is a balance between flame temperature, gas temperature and emissivity; with implications for equipment reliant on radiative heat such as glass furnaces. Figure 4-2 demonstrates the impact of increased hydrogen content in a methane flame (0% vs. 50% by mol.) on its emission spectrum.

Additionally, standard infrared flame detection is ineffective for a hydrogen flame due to the reduced luminosity, meaning ultraviolet detection is required.

[27] Sankaran R, Im HG. Combust Sci Technol 2006;178:1585–611. doi:10.1080/00102200500536217.
[28] Donohoe N, et al. Combust Flame 2014;161:1432–43. doi:10.1016/j.combustflame.2013.12.005.

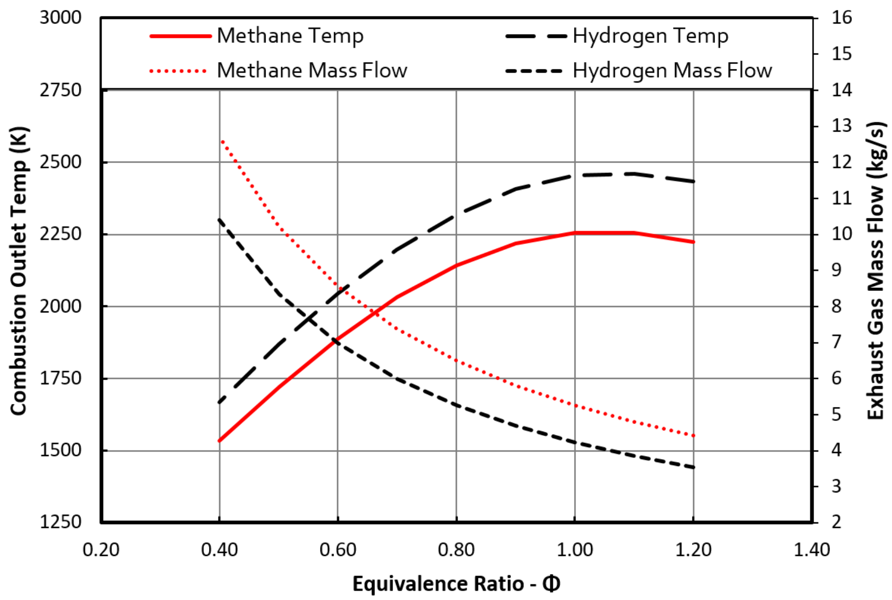
Figure 4-2: Emission spectrum of a premixed hydrogen-methane flame with 0% and 50% molar H_2 content at different equivalence ratios in an atmospheric rig. Data from[29].



Similarly, the chemistry of hydrogen combustion means that even though more hydrogen is required by volume for the same energy output, it requires ~20% less air by volume to produce a flame comparable to natural gas. This reduces the mass flow through the combustor and hence the convective heat transfer, with the flue gases modelled to leave the combustor approx. 200 K hotter, shown in Figure 4-3.

Flue gas recirculation can be used to increase the mass flow of air into the combustor, increasing the convective heat transfer and reducing the high flame temperature.

Figure 4-3: Combustion outlet temperature and mass flow of methane and hydrogen combustion (from CHEMKIN modelling)



[29] García-Armingol T et al. Int J Hydrogen Energy 2014;39:11299–307. doi:10.1016/j.ijhydene.2014.05.109.

A comparison of the key fuel and combustion properties of methane (the major component of natural gas) and hydrogen can be found in Table 4-1.

Table 4-1: Key fuel and combustion properties of hydrogen and methane[30,31,32]

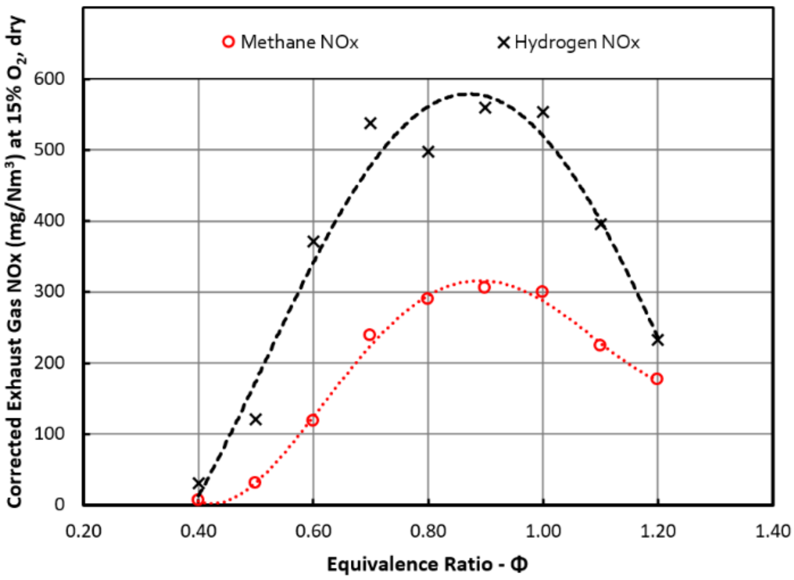
Property	Units	Methane (CH_4)	Hydrogen (H_2)
Wobbe Index Range	MJ/Nm^3	47-53	40-48
Lewis number[33]		0.999	0.437
Adiabatic flame temperature in air	°C	1960	2210
Calorific value (Higher Heating Value)	MJ/kg	55.5	141.8
Flammability range	% vol.	4.4-15.0	4.0-75.0
Laminar burning velocity	m/s	0.4	3.1

4.1.2 Impacts for Industrial Sites and Equipment

NO_x emissions and abatement

NO_x emissions will increase when natural gas or methane is blended or replaced with hydrogen (at the same equivalence ratios) as seen in Figure 4-4. This results from increased thermal NO_x due to the increased flame temperature when using hydrogen. To reduce this, a variety of techniques can be used, such as lean combustion or dilution. Lean combustion refers to burning fuel with excess air or oxygen, reducing the equivalence ratio, and hence reducing the adiabatic flame temperature and NO_x emissions. Dilution refers to the addition of an inert component to the combustion mix, which also decreases the adiabatic flame temperature and NO_x emissions. Methods such as adding nitrogen, steam or flue gases through flue gas recirculation (GDN) can be used.

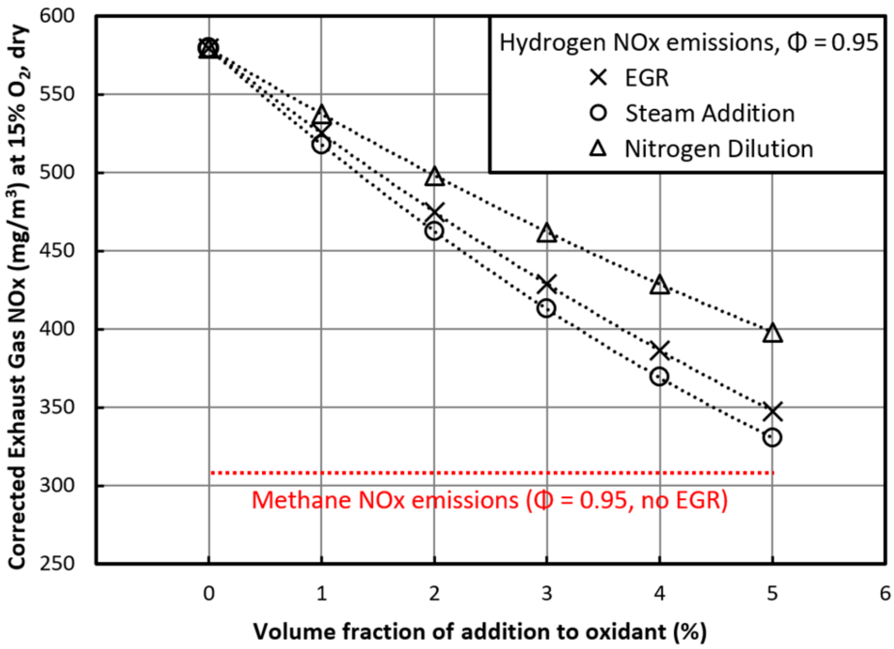
Figure 4-4: Exhaust gas NO_x concentration for hydrogen and methane, corrected to 15% oxygen, dry for an idealised combustor.



[30] CHEMKIN modelling results
[31] HyNet technical report
[32] Taamallah S et al. Appl Energy 2015;154:1020–47. doi:10.1016/j.apenergy.2015.04.044.
[33] At 300 K and 1 bar, for an equivalence ratio which produces an adiabatic flame temperature of 1660 K.

The CHEMKIN modelling undertaken found that steam addition and FGR were the most effective methods of NO_x reduction: small volume fraction additions (~5%) were able to reduce NO_x emissions to a level comparable with a methane flame of similar power and equivalence ratio. Addition of nitrogen was no more effective than air addition and would cost more due to requiring a nitrogen-air separator.

Figure 4-5: Assessment of NO_x reduction strategies for hydrogen combustion and the resulting emissions relative to natural gas combustion. EGR refers to exhaust gas recirculation, another term for flue gas recirculation (FGR).



Dry Low Emission (DLE) burners are used widely in gas turbines, reducing NO_x through pre-mixed, lean combustion, and this technology could be built on to reduce emissions in other equipment. These were developed for use on gas turbines to move away from the Wet Low Emission (WLE) methods to reduce NO_x emissions; steam and water addition. For further details on the modelling of NO_x abatement strategies see appendix 9.3. In addition to these, post combustion methods like selective catalytic reduction are available, which can be effective but are generally expensive to install.

Flame Positioning

A 100% hydrogen flame is shorter and positioned much closer to the burner tip than a methane flame under the same operating conditions. This is due to the higher flame speeds and lower ignition times. Conversely, first hand industry experience suggests that with high proportions of water or steam added to the fuel, the flame length can become substantially longer. This factor, combined with the increased flame temperature, has important implications on potential flame impingement and on material selection for the burner and combustor.

Heat Transfer and Balance

The lower emissivity and the reduced combustor mass flow rate changes the balance of heat transfer from a hydrogen flame compared to the natural gas case. The change in heat pickup between the radiant/convective sections of indirect equipment like steam boilers when switching from natural gas to hydrogen can be mitigated by adjusting the feed water split between the two sections. In direct fired equipment, flue gas recirculation can be used to increase the mass flow rate and improve convective heat transfer.

There is uncertainty over the impact these characteristics will have on equipment reliant on radiative heat transfer, such as glass furnaces, as this equipment has not been tested with 100% hydrogen. The impact will depend on the balance between the reduced emissivity of the flame, the emissivity of the flue gases and the difference in temperature between the combustion gases and the combustor itself. Hydrogen flames may need either an additive, such as acetylene, or increased amounts of fuel for radiative dependent applications.

Leakage

Hydrogen has a very low viscosity and a lower kinetic diameter than methane, so it is more difficult to prevent hydrogen systems from developing leaks, even in pipework that was 'leak tight' when tested with nitrogen. This requires higher standards of welds, joints and flanges than in natural gas pipework, and these standards are currently available. The high diffusivity of hydrogen ensures low concentration in air after leaks and, coupled with effective ventilation, can be further diluted below its flammability limit (~4%). The lower energy density of hydrogen means it produces substantially lower energy leakage rates.

Material Embrittlement

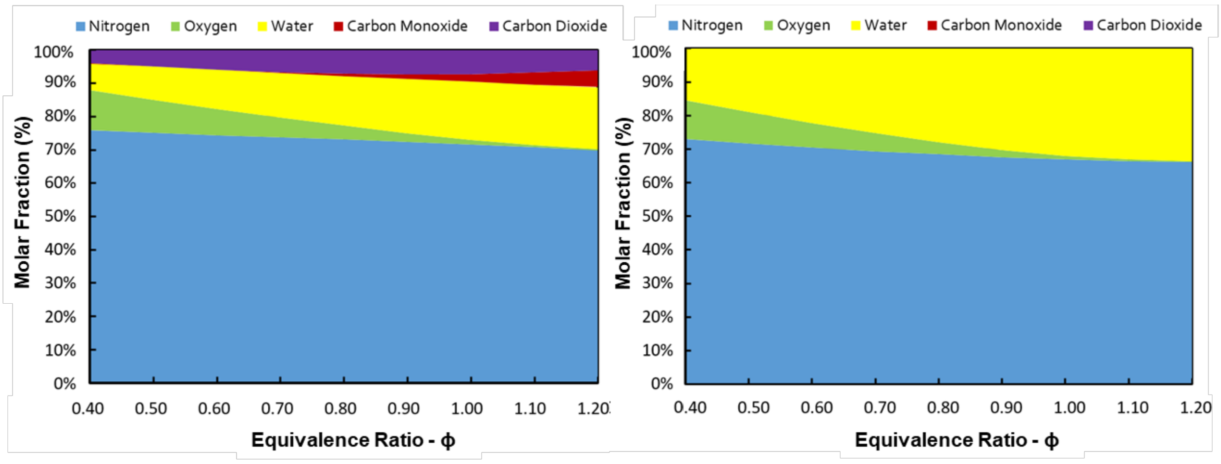
Hydrogen is absorbed by some containment and piping materials, which can result in loss of ductility or embrittlement. This process is accelerated at elevated temperatures and pressures. Engineering standards recommend appropriate materials for hydrogen designed systems, dependent on operating conditions. Example materials include common carbon steel grades (API 5L X52 and ASTM A 106 Grade B), austenitic stainless steels (high pressures and temperatures) and polyethylene piping. Due to the requirement for pipework to be made out of these materials, conversion of transmission and distribution pipework on industrial sites may be required.

Flue gas composition

Burning hydrogen changes the composition of the flue gas compared to using natural gas. While of little significance in indirect equipment like steam boilers, the change in flue gas composition can have a significant impact in direct fired equipment, where combustion gases come into direct contact with the product. In direct fired equipment where combustion gases are mixed with large quantities of fresh air before coming into contact with product (e.g. dryers operating at ~200°C), this is unlikely to be a major issue, although trials are needed. However, in some applications like glass furnaces or lime kilns, combustion gases are not mixed before product contact, and so changes in composition of flue gases could impact product quality, for example influencing the volatility of sulphate in glass furnaces. Of particular concern is the increased moisture content of flue gases, and the possible effects this might have within kilns, ovens and other direct fired equipment. The different flue gas compositions were modelled using Aspen HYSIS, with water (H_2O) content of the flue gases at ϕ=1 increasing from ~16 mol% with methane to ~30 mol% with hydrogen[34]. As the use of 100% hydrogen in these equipment types has not been investigated, further modelling and testing will be required to understand the impacts of this change in atmosphere and to evaluate any mitigating actions which may be required.

[34] For further details on the modelling see appendix 9.3.

Figure 4-6: Modelled flue gas composition for methane (left) and hydrogen (right) for a range of equivalence ratios. From Aspen HYSIS Modelling.



4.2 Environment, Health and Safety Considerations

Re-permitting

The Industrial Emissions Directive (IED) and Medium Combustion Plant Directive (MCPD) are mandatory emission limits for pollutants from equipment on industrial sites. The effect of changing fuels from natural gas to hydrogen will have a large impact on the amount of pollutants in combustion flue gases. The possible increase in NO_x emissions (an ~80% increase at ϕ=1, without any mitigation measures) when changing from natural gas to hydrogen may have an impact on the current permitting arrangement. While the limits on NO_x emissions for hydrogen rich fuels in the chemicals industry stipulated in the large combustion plant BREF (BAT – best available techniques – reference document) are slightly higher, this might not be applicable on a national switch to hydrogen. Technical solutions (e.g. flue gas recirculation) to reduce the NO_x emissions from hydrogen fuels to equivalent levels to natural gas will likely be required, given the low probability of sites being allowed to emit additional NO_x even with a new permit. These solutions are discussed in section 4.1.2, with further modelling results shown in appendix 9.3.

However, even if technical solutions reduce NO_x emissions to an equivalent level when equipment and sites are converted over from natural gas to hydrogen, the relevant environmental emissions permits may require review and a substantial variation could be required.

COMAH

The Control of Major Accident Hazards Regulations 2015 (COMAH) aims to prevent major accidents involving dangerous substances and limit their consequences to operators, other people and the environment. Some industrial sites have specifically altered their practices in order to remove themselves from the regulations that can have a major impact on site operations and costs.

On-site storage of hazardous substances is a key criterion for COMAH thresholds. Hydrogen has a much lower limit than natural gas at 5 tonnes. If a site is not already covered by COMAH or currently storing natural gas on site, changing the gas supply from natural gas to hydrogen is unlikely to result in meeting the threshold as the volume of hydrogen stored in linepack is low. However, due to the rules around aggregation of substances, a few sites might be pushed over the threshold if they are storing other substances on site.

PER and PSSR

The Pressure Equipment Regulations 1999 and Pressure Systems Safety Regulations 2000 cover equipment with a gas distribution pressure >0.5 bar. While it is likely that gas pressures on the majority of industrial sites already exceed this, the increase in pressure necessary to provide the same calorific input when converting from natural gas to hydrogen might entail some additional safety considerations. In the case of equipment currently operating below 0.5 bar which could be pushed above this limit by the pressure increase, additional review and safety procedures would need implementation with associated costs. The costs of these are likely to be low in comparison to the other costs associated with conversion. If an increase in pipework diameter is selected to provide sufficient energy input, rather than a pressure increase, these regulations are unlikely to have an impact.

DSEAR and ATEX

Two European directives for controlling explosive atmospheres, commonly given the name ATEX, were incorporated into UK law in the Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR)[35]. This stipulates a specific risk assessment to classify various zones where hazardous explosive atmospheres may occur. Equipment in these zones must be regulated to protect from sources of ignition, with 'ATEX certified' equipment often significantly more expensive.

Under the IEC (International Electrotechnical Commission) classification[36], natural gas is a IIA group gas whereas hydrogen is classified higher at IIB+H_2 or above. This difference is due to the lower ignition energy and wider flammability limits of hydrogen, which means it needs more stringent control measures and higher rated equipment. Installed equipment certified for use with natural gas may not be compliant for use in a hydrogen system if it only meets the class IIA standard.

The sizes of zoning areas will also change when converting from natural gas to hydrogen. If delivery pressure is maintained (using a large pipework diameter to achieve equivalent energy supply), the resulting DSEAR zones were modelled to increase by up to 47%. If hydrogen is supplied at increased pressure to compensate for the lower volumetric energy density, the resulting DSEAR zones were modelled to increase by up to 62%. While increased ventilation can compensate for these, reducing the zones, this might not be practical in most industrial sites. Therefore, more subcomponents in equipment and in the surrounding area might need to be replaced to achieve compliance.

The impact of conversion on the zoning requirements is explored in more detail in appendix 9.3.

4.3 Equipment Conversion Requirements

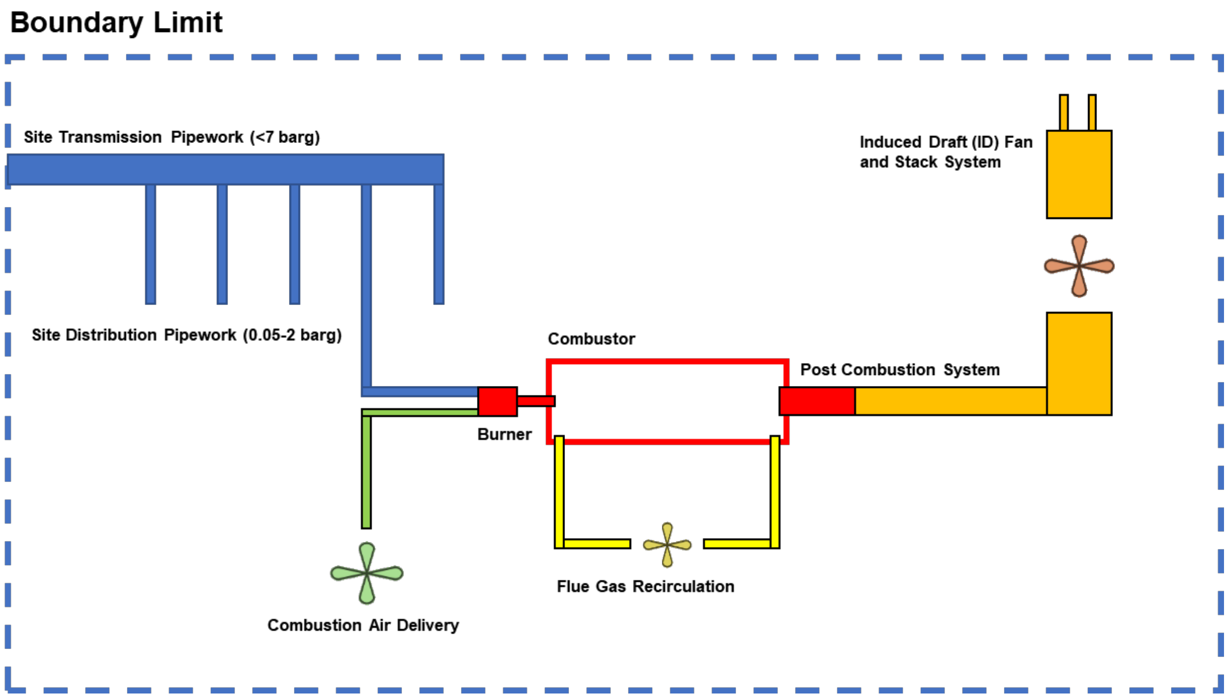
For all of the equipment considered, the term 'conversion' refers to making the whole system surrounding and including the piece of equipment, hydrogen compatible. In order to do this, certain components within the subsections of this system may require replacement, as shown in Figure 4-7 below. This is a key distinction between the approach for industrial equipment and the approach for smaller appliances within the domestic and commercial sector, where replacement of the entire appliance may be appropriate. This approach has been confirmed through industry engagement, with both industrial sites and original equipment manufacturers. None of the challenges identified around industrial hydrogen conversion were found to be showstoppers (with the possible exception of gas engine CHP – see section 4.4.1). However, conversion will be dependent on successful demonstration trials to address remaining knowledge gaps and provide the required evidence.

The technical challenges of conversion were considered and integrated into the requirements for retrofitting equipment. Equipment was broken down into subcomponents, shown below, which though different in scale, cost and operation, are general across all sites and equipment. Using input from

[35] HSE, ATEX and explosive atmospheres
[36] ISO/IEC 80079-20-1:2017

original equipment manufacturers (OEMs) and industrial sites, the capex cost of converting/replacing each subcomponent was estimated by industrial sector, equipment capacity and equipment type. The various subcomponents are shown below in Figure 4-7, with more information on the assumptions around these subcomponents in appendix 9.5.

Figure 4-7 Schematic showing the subcomponents of equipment



To estimate the total cost of conversion for a piece of equipment, the subcomponents which require replacement when converting to hydrogen were determined for each industry and equipment type, as shown in Table 4-2. This was based on technical impacts, engagement with OEMs and visits to industrial sites. Various assumptions have been made for each subcomponent:

- **Fuel Distribution –** Given the uncertainty around distribution pipe condition, pipework materials and the increased pressure requirement for hydrogen to deliver the same energy content as natural gas, it has been assumed that the majority of sectors require replacement of their on-site transmission and distribution pipework. The chemicals and refining sectors are an exception to this given the pipework materials and standards present on sites, as well as their use and knowledge of hydrogen.
- **Combustion Air System and Flue Gas Recirculation (FGR) –** To mitigate increased NO_x emissions, all equipment would have to install a technical method to reduce NO_x, such as FGR. In order to quantify a cost for this, the typical approach here is to either install FGR to both reduce NO_x and increase air flow into the combustor, or increase the capacity of current FGR systems. Current combustion air delivery systems (e.g. forced draft fan systems) are unlikely to be hydrogen ATEX compliant, except in the refining and chemicals sectors, and hence these will need to change, even though they may be capable of delivering the required air flow.
- **Burner System –** All burners will need changing as a result of increased fuel volume or pressure when delivering hydrogen and the increased thermal loading on the burner tips. The burner design chosen needs to reduce NO_x, reduce the risk of flashback, and use ultraviolet flame detection.
- **Post Combustion and Flue Gas Treatment –** Some direct fired equipment types are exempt from the Medium Combustion Plant Directive and are assumed to not require additional

modification, as the emissions limit is more relaxed. However, for indirect fired equipment, the emissions limit is likely to be lower, and hence further NO_x reduction methods such as selective catalytic reduction (SCR) are assumed to be required. In addition, FGR may not be enough to achieve NO_x emissions equivalent to natural gas within high temperature furnaces, and so these are assumed to also require SCR. Whether post combustion methods for NO_x reduction require implementation will depend on the effectiveness of other techniques such as increased FGR or steam addition.

- **Induced Draft (ID) Fans –** Similar to combustion air delivery, ATEX equipment compliance requirements are more stringent for hydrogen than for natural gas. All ID fans are assumed to require replacement because of this, except for those in the refining and chemicals sectors which mostly have appropriate ATEX compliant equipment already.
- **Electrical Control and Instrumentation (EC&I) –** This subcomponent represents a percentage-based approach for the replacement of all other electrical equipment that may fall within the (potentially expanded) DSEAR zone. Due to the more stringent ATEX requirements, all sectors are assumed to replace this bar the chemicals and refining sectors.

The above assumptions have been used in order to calculate a typical cost of conversion for a site within a specific sector using a piece of equipment. There will be a proportion of sites wherein the assumptions do not apply. However, the assumptions made are appropriate to calculate conversion capex in aggregate across all UK sites within the scope of the study. Furthermore, low and high sensitivities of conversion requirements and capex were calculated to represent the uncertainty and present the potential range in investment required; see appendix 9.5 for more details.

Table 4-2: Table to show which subcomponents of industrial equipment are likely to require modification or replacement on hydrogen conversion. x represents those that need replacement and ✓ represents those that are already capable of hydrogen operation

Subcomponents of industrial equipment	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Food and drink						
Steam Boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	✓	x	x
Direct dryer	x	x	x	✓	x	x
Chemicals						
Steam boiler	✓	x	x	x	✓	✓
Hot water boiler	✓	x	x	x	✓	✓
Oven	✓	x	x	✓	✓	✓
Furnace	✓	x	x	x	✓	✓
Direct dryer	✓	x	x	✓	✓	✓
Vehicle Manufacturing						
Steam boiler	x	x	x	x	x	x
Furnace	x	x	x	x	x	x
Direct dryer	x	x	x	✓	x	x
Oven	x	x	x	✓	x	x
Basic metals						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	✓	x	x
Furnace	x	x	x	x	x	x
Refining						
Steam boiler	✓	x	x	x	✓	✓
Furnace	✓	x	x	x	✓	✓

Subcomponents of industrial equipment	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Paper						
Steam Boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Direct dryer	x	x	x	✓	x	x
Glass						
Hot water boiler	x	x	x	x	x	x
Furnace Glass	x	x	x	x	x	x
Furnace >600°C	x	x	x	x	x	x
Lehr kiln	x	x	x	✓	x	x
Ceramics						
Hot water boiler	x	x	x	x	x	x
Ceramics kiln	x	x	x	x	x	x
Dryer Direct	x	x	x	✓	x	x
Lime						
Lime kiln	x	x	x	✓	x	x
Direct Dryer	x	x	x	✓	x	x
Other non-metallic minerals						
Hot water boiler	x	x	x	x	x	x
Kiln >600°C	x	x	x	✓	x	x
Dryer Direct	x	x	x	✓	x	x
Electrical and mechanical engineering						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	✓	x	x
Direct dryer	x	x	x	✓	x	x
Furnace	x	x	x	x	x	x

4.4 Other Equipment

4.4.1 Combined Heat and Power (CHP)

Combined heat and power is the simultaneous generation of electricity and heat in a single integrated system. Around 70% of the fuel used in CHP schemes (all sectors) in the UK in 2017 was natural gas[23]. CHP is dominated by gas engines and gas turbines, with gas engines generally smaller in capacity than gas turbines (though there exists a myriad of subcategories and other technologies).

Extensive research has gone into the use of fuel with high fractions of hydrogen (up to 100%) in gas turbines[37,38], with further development ongoing[39]. The high NO_x emissions from high temperatures in the combustion chamber have been tackled through lean, premixed combustion in Dry Low Emission (DLE) burners, and this burner technology has potential for application in other equipment. Whether existing gas turbines, designed to run on natural gas, can use 100% hydrogen fuel is uncertain, as some industrial sites have reported issues when using low Wobbe Index fuels. Thus, while there is a large evidence base for the new installation of equipment designed to run on 100% hydrogen[40], whether existing equipment is suitable for retrofitting and can be converted requires further detailed engineering work on a bespoke plant by plant basis. Conversations with a limited number of OEMs indicated they were investigating conversion and were comfortable it was possible for certain models, albeit with implications for asset lifetime currently[41].

On the other hand, gas engines present a more difficult proposition for conversion to hydrogen. When running with high fraction hydrogen fuels, there are established issues around knock[42] and derating[43], confirmed through engagement with original equipment manufacturers which have carried out trials. This might prevent the conversion of existing gas engine CHP plants to hydrogen, necessitating their replacement with new plants or alternative equipment as systems running on 100% hydrogen are still in the laboratory phase of testing, and with uncertain success. More R&D work on 100% hydrogen-fired gas engines is necessary at an academic/laboratory level before their conversion or replacement can be considered.

However, much of the CHP capacity in the UK, particularly large gas turbines, exists on sites connected to the >7 bar gas network, and would not necessarily need to convert to hydrogen. The smaller CHP units on industrial sites connected to the <7 bar network will need conversion or replacement, however the cost of CHP conversion was outside the scope of this study.

4.4.2 Fuel Cells

Indirect hydrogen fuel cells reform natural gas feedstock internally to produce hydrogen for the fuel cell. While there are no known examples of industrial deployment in the UK, there are some 1 MW scale systems deployed commercially[44], and there are examples of industrial deployment in Europe[45].

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[37] Brdar RD, Jones RM, GE IGCC technology and experience with advanced gas turbines. GE Power System, New York
[38] BHGE and Siemens provided information on ~50 and ~20 hydrogen fired gas turbines operating on hydrogen fractions between 5% and 100% by volume.
[39] A summary of recent developments in high fraction hydrogen turbines is available here.
[40] The 12 MW 100% hydrogen Enel Fusina Plant has been operating since 2009, also supplying heat to create heat to steam. Another system in Australia is currently in development.
[41] For example, the Dutch government is funding development of gas turbine retrofitting for 100% hydrogen.
[42] Engine knock is when the fuel/air mixture in the cylinder does not detonate in unison with the piston. This increases cylinder pressure and can cause premature engine failure.
[43] De-rating is where the engine output power is reduced to below its design power.
[44] The Event Complex Aberdeen has deployed a 1.4 MW fuel cell system.
[45] An industrial site in Switzerland has deployed a ~1 MW scale fuel cell system.

Conversion of existing natural gas feedstock fuel cells to hydrogen (effectively “turning-off” the reformer section) is not considered economically feasible, due to the high level of integration within the technology.

Few technology developers supply a direct hydrogen system, and there is a limited number in the UK. Industrial scale deployment in the UK is not known, however there are commercial examples such as the Arcola Energy fuel cell installed at the Kirkwall Harbour in Orkney, supplied with hydrogen from a 500 kW electrolyser on the island of Eday[46].

The current UK market for industrial scale hydrogen fuel cells, both indirect and direct, is small, corresponding to approximately 1 or less system per year. A transition of industry or the gas network from natural gas to hydrogen will focus development on direct hydrogen systems.

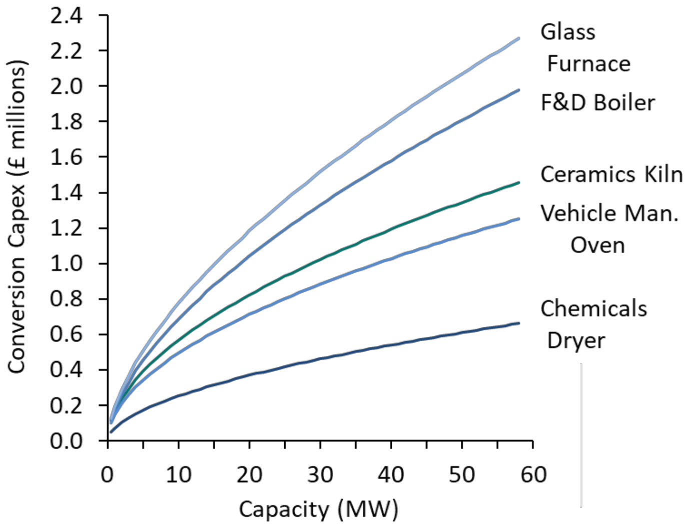
[46] Source available here.

5 Costs and Timelines

Beyond the technical feasibility of converting to hydrogen, conversion costs and associated timescales are important factors for decision making on the long-term heat decarbonisation pathway. The estimates of subcomponent costs were combined with the required replacement assumptions to calculate an estimated conversion capex for each equipment type by sector. A high-level estimate of this nature and immaturity is roughly equivalent to Association for the Advancement of Cost Engineering class 5 (-50% to +100%).

The conversion cost per equipment type by sector and scale are in the form cost curves (Conversion Capex - £ millions vs. Capacity - MW) for each relevant combination of equipment type and industrial sector, with a few examples shown below in Figure 5-1. The curves were then used to cost the large range of equipment across industry.

Figure 5-1: Cost curves for a sample of equipment types in specific industrial sectors



5.1 Capital cost of equipment conversion

Some indicative costs for the retrofit of equipment are shown in Table 5-1 below. It is important to note that as the equipment is being converted from natural gas to hydrogen, it was assumed that the combustor unit was not replaced, as this would effectively be a replacement of the whole piece of equipment. For example, if conversion to hydrogen occurred at the end of a glass furnace campaign, the furnace would need to be totally rebuilt at that time. Costs associated with rebuilding the furnace structure, and similar costs for different equipment types, were not included in the cost of retrofitting equipment as this would need to be done whether the equipment was converted to H_2 or not.

Significant economies of scale were found when estimating equipment conversion costs; for a given capacity, multiple smaller pieces of equipment cost more to retrofit than one large piece of equipment. This varied by equipment type and industrial sector, with scaling exponents varying from ~0.5 up to ~0.8. This aligns well with scaling exponents of ~0.6 when undertaking initial cost estimates within industry.

The same equipment type used within multiple sectors may have varying conversion costs due to differences between sectors and equipment end-use. This is partly due to sector specific standards for current equipment (ATEX compliant or not), and the impact of potentially increased DSEAR zone extents affecting other electrical and ancillary equipment.

Additional Equipment Costs Included

Additional percentage based costs for other key items have also been calculated. These costs are in addition to the equipment, material and cost of sales values calculated for each subcomponent, and are included in the costs of equipment conversion presented in Table 5-1:

- Engineering Design – 5% of total cost
- Project Construction and Management – 3% of total cost
- Removal – 5% of total cost
- Labour – 10% of total cost
- Commissioning – 2% of total cost
- Estimated Contingency – 12% on top of **all** other costs.

Table 5-1 Estimated capex for converting some typical pieces of equipment from natural gas to hydrogen

Industry sector	Typical Equipment	Equipment Conversion Cost – Variation with Size (£ '000s)*		Conversion Cost for Typical Equipment (£ 000's)*	
		1 MW	10 MW	Example Size (MW)	Typical Cost
Food and Drink	Steam Boiler	170	690	20	1,040
	Oven	150	490	2	210
Chemicals	Steam Boiler	100	490	20	780
	Furnace	110	530	25	980
Vehicle Manufacturing	Hot Water Boiler	170	690	20	1,040
	Oven	150	490	5	340
	Direct Dryer	140	430	2	200
Basic Metals	Furnace	180	730	40	1,680
Paper	Direct Dryer	150	470	3	260
	Steam Boiler	190	750	20	1,140
Glass	Glass Furnace	200	800	25	1,390
Ceramics	Kiln	160	570	5	390
Lime	Lime Kiln	150	520	15	640
Other NM Minerals	Rotary Dryer	140	430	15	520
Elec and Mech Engineering	Hot Water Boiler	170	690	5	450
	Oven	150	490	3	260
	Steam Boiler	170	690	5	450

*All costs are in thousands of GBP

5.2 Site conversion cost

There are two major costs that are attributed to conversion of a whole industrial site. These are:

- Site-wide replacement of natural gas transmission and distribution pipework, if required.
- Minimum fixed engineering cost for undertaking conversion work at a site.

These costs are in addition to the equipment and material costs for the subcomponents of each piece of equipment requiring conversion.

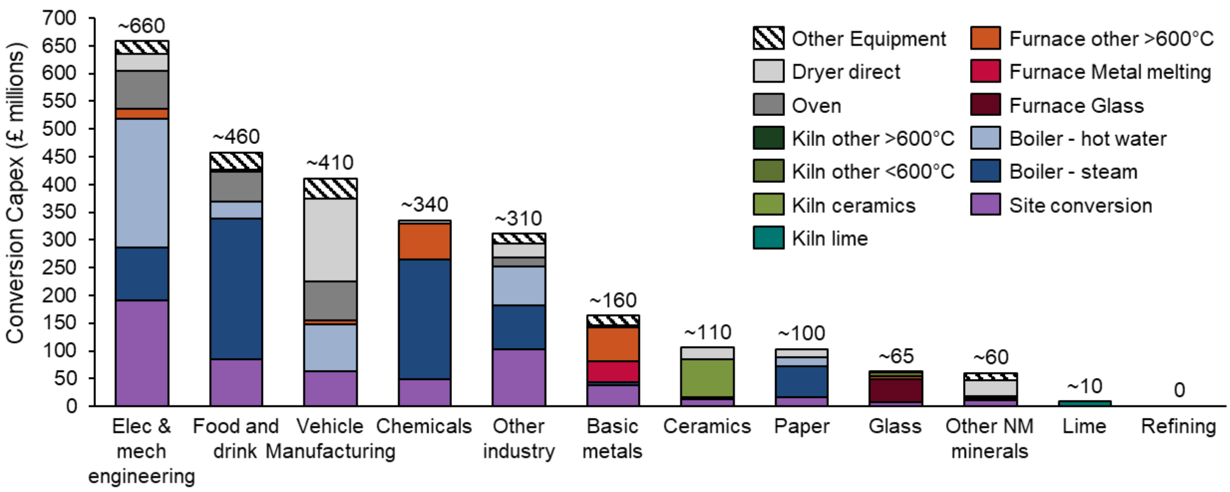
On site pipework costs are dependent on the number of pieces of equipment on site and the proximity of equipment to the connection to the local gas distribution network. Information gathered from DUKES, engagement with industry and visits to a range of industrial sites provided an indication of the length of piping required for different sectors. A sector dependent average value has been applied to the cost model. There will be significant variation on a site by site basis due to differences in footprint of sites and location of equipment.

For an engineering project of this type there will be a minimum level of effort required in terms of assessment of conversion options, review of requirements and initial design work. This will be required no matter the size of site or scope of work and will have a greater impact on the cost of conversion for sites that may only require a small number of components replaced. In order to capture this reduced economy of scale, a minimum fixed site wide engineering fee of ~£70,000 has been included.

5.3 UK wide capex for Conversion

The cost model was integrated with the calculated industrial equipment stock to give an estimated UK wide conversion capex for industrial equipment on the <7 bar network, presented by sector and equipment type below in Figure 5-2:

Figure 5-2: UK wide industrial conversion capex estimate by sector.



Assumptions

A list of key assumptions is presented below and described in more detail in appendix 9.5.5.

- **Sites with a gas consumption <1 GWh/y** were excluded, as they are likely to either be commercial in scope or only use natural gas in equipment which is commercial in nature, e.g. for hot water heating in offices.

- While **equipment of <1 MW_{th} thermal capacity** is out of scope, when a relevant industrial site is converted to hydrogen, these pieces of equipment will also need to be converted. The cost of the conversion of this equipment has been estimated and **is included** in the overall capex estimate for comprehensiveness.

Findings

The total UK wide cost of conversion was estimated at £2.7 billion, and a high-level breakdown is shown in Table 5-2:

Table 5-2 Overall UK industrial conversion capex

	(£ billions)
Site wide costs	0.6
>1 MWth Equipment cost	1.4
<1 MWth Equipment cost	0.7
Central Total Cost	2.7

A high fraction of the overall UK wide cost is within those sectors which have many small sites or many small pieces of equipment, such as Vehicle Manufacturing or Electrical and Mechanical Engineering. There is a significant amount of equipment <1 MW_{th} on relevant industrial sites, and due to the decreased economies of scale, these have a disproportionate impact on costs. In addition, converting many smaller sites is more cost intensive than one larger site.

The proportion of gas consumption on the >7 bar network means that some gas consuming equipment, in particular the largest pieces, are not included in the cost of conversion. For example, many pieces of equipment in the chemicals sector and all of the equipment in the refining sector are out of scope. The exclusion of CHP from the costs in scope also removes significant gas consumption in those sectors where it is present, such as Food and Drink, Chemicals and Paper.

The cost of conversion estimated here is the final conversion capex once technology is ready for commercial implementation. **It does not include costs of technology demonstration**. The demonstration costs are concentrated in those industries where the greatest technical challenges are, e.g. glass or ceramics, and those industries requiring many demonstrations due to very bespoke equipment/processes with a large effect on the final product, e.g. food and drink. More detail on the demonstrations required and the associated costs is available in section 6.2.

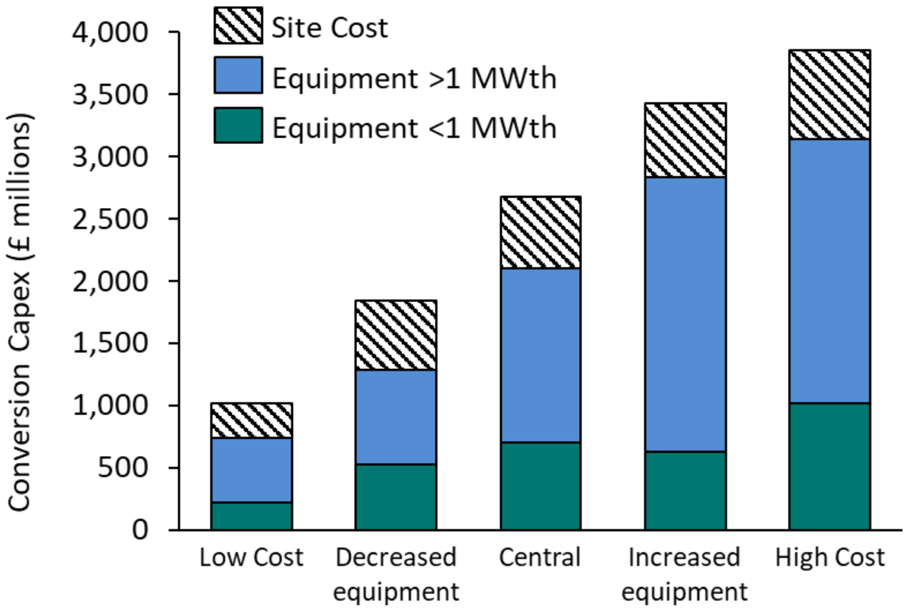
5.3.1 Sensitivities

A sensitivity analysis was conducted to understand the effect of some of the assumptions around costing. This was done to reflect the uncertainty in the modelling assumptions used and the figures calculated from them, and to understand the possible impact of this uncertainty. The various cases and their UK wide conversion costs are detailed in Table 5-3. The total conversion capex for these scenarios are broken down into site wide costs, equipment costs >1 MW_{th} and <1 MW_{th} and presented in Figure 5-3. For more information on the impacts of sensitivity cases, see appendix 9.5.6.

Table 5-3: UK wide Cost of Conversion Sensitivity Cases

Sensitivity Case	Change in Assumptions	Cost (£ billions)
Low Cost	• Decreased costs of subcomponents • Reduced engineering fees • More ATEX compliant electrical equipment • Limited site modification	1.0
Decreased equipment	• Higher thermal load factor (fixed at 0.8) • Reduces the resulting estimate of the number and capacity of industrial equipment in the UK	1.8
Central	See above.	2.7
Increased equipment	• Lower thermal load factor (66% of central case) • Increases the resulting estimate of the number and capacity of industrial equipment in the UK	3.4
High Cost	• All components require replacement • No ATEX compliant electrical equipment already present • Increased engineering fees	3.9

Figure 5-3: UK wide conversion capex for sensitivity scenarios



5.4 Operational costs

For the sectors reviewed, the dominant opex categories are:

- Feedstock
- Fuel
- Electricity

Fuel, consumables and fixed opex will be impacted by converting to hydrogen. However, consumables and fixed opex constitute a small proportion of the overall opex for the majority of industrial sectors.

5.4.1 Variable opex

Variable opex constitutes costs that vary with the site production output. In general, increased production is proportional to increased variable costs. However, this relationship may vary by industry. The major variable costs for all reviewed sectors are fuel, feedstock and other consumables. Feedstock costs will not change significantly, as businesses will operate on a certain production output and will not accept any impact on this due to conversion. For conversion to hydrogen, fuel costs are the major uncertainty and there may be some increase in consumables.

Fuel Costs

The scope boundary for this study is “behind the meter”, and as such costs associated with hydrogen as a fuel are outside of scope[47]. The assumption throughout this study is that hydrogen will be available at a price which allows UK industry to remain competitive internationally post-conversion.

However, given the extent of feedback during engagement with industry, it is pertinent to include their concerns with both the future cost of hydrogen and its availability. Energy costs are of major concern to industrial sites, especially in sectors where they constitute a high proportion of overall operational costs. Sites are actively investigating and implementing methods to reduce fuel consumption and increase energy efficiency, and are very sensitive to any potential fuel price changes.

Consumables

Consumables such as Nitrogen are used for purging transmission and distribution pipework. It is assumed that there may be an increase in the purging requirements when using hydrogen rather than natural gas. This is due to the increased flammability and leakage risk. Use of consumables is variable across sites and industries, and makes up a small fraction of opex in comparison to fuel. As such, any increase is immaterial given the maturity of the cost estimation and the other assumptions made.

5.4.2 Fixed opex

This accounts for a variety of costs including preventative and predictive maintenance, spare parts, labour, overhead, equipment taxes, insurance, and licences (if required). A replacement asset value approach is taken for a cost estimate of this maturity, where the annual fixed opex is quoted as a proportion of the total installed capex of the entire plant, usually ~3%.

The fundamental workings of a hydrogen fired system do not differ from a natural gas fired system. However, there may be an impact on fixed opex attributable to increased levels of staff training, reduced lives of equipment (such as burner tips) and more stringent safety procedures. These variations may *increase* the fixed opex by ~15-20%. Fixed opex varies widely by industry, though is often dwarfed by variable opex, depending on fuel and feedstock costs. Fixed opex can be anywhere from 1% *of total opex* to 20% or more of total opex, and hence the increase in fixed opex from hydrogen conversion could increase total opex by up to ~4%. However, in the majority of industries, fuel, electricity or feedstock costs are dominant, and so this increase will be relatively less significant.

5.5 Hidden Costs or Value

5.5.1 Remaining equipment lifetime

Without significant prior warning, a conversion roll-out will affect equipment that has not reached the end of its usable life. In this event, premature replacement of equipment components will be required

[47] Further investigation of this is ongoing through the government’s Hydrogen Supply Programme.

for a business to continue operating, incurring a financial penalty due to the lost asset value. However, the cost of installing these new components is already captured as part of the capex estimate for conversion, so the cost estimates in this chapter are the maximum additional cost over industrial business as usual (BAU), scope constraints considered.

Industry will be in a better position to plan asset investments[48] appropriately with advanced warning of either a localised or nationwide conversion to hydrogen. The longer the warning period and the higher industry confidence of hydrogen conversion is, the better prepared industrial sites can be when planning asset investments and the more likely it is that conversion can coincide with major equipment replacement; this would reduce the 'real' cost of conversion, with cost implications (over BAU) lower than that estimated above.

5.5.2 Environment, Health and Safety (EHS) Costs

There are potential further EHS costs associated with hydrogen conversion in addition to the ATEX compliance equipment costs already included in the capex conversion estimate. These costs are detailed below in Table 5-4 and are associated with environmental re-permitting and compliance with Control of Major Accident Hazards (COMAH) regulations.

As described in section 4.2, sites might need a substantial variation of their environmental permit. As well as application fees, other costs would include the measurement and validation of emissions from the converted equipment required for these permits. An indicative cost of approximately £35,000 - £150,000 per site was estimated from discussions with industrial sites, though it is recognised that this will vary substantially by site. This is of a similar order to the site wide costs included in the cost model (~£100k-200k per site). The requirements for re-permitting will be dependent on any changes to discharges to the environment from the site, such as emissions, water, noise etc, or changes to the accident and risk profile of the site because of the fuel change, such as varied storage and transmission.

The need for re-permitting could add significant cost to the UK wide conversion (~5% of the total) if all sites had to re-permit. However, in practice this will be applied on a case-by-case basis through engagement with the site inspector. A standardised or streamlined procedure could further reduce this impact.

The requirement for COMAH compliance, while of large significance to affected sites, would not contribute significantly to the scale of the UK cost of conversion. This is due to the low number of sites which may be affected.

Table 5-4: Proportion of sites affected by COMAH or re-permitting and their indicative cost

	Proportion of sites requiring this	Indicative Cost per site (/£)
Environmental Repermitting	Dependent on impact of changes to site (up to 100%)	~35k-150k
COMAH	Only a few sites (<5%)	~100k

[48] One possible approach to reduce conversion costs through planning, 'hydrogen ready' equipment, is discussed in more detail in section 6.3.

5.5.3 Other Hidden Costs

There are multiple other costs associated with conversion/retrofitting of equipment at an industrial site which are not considered part of the capex estimate.

- **Feasibility Studies and Demonstration programmes** – considered in more detail in Chapter 6, this is the cost of technology development required to provide sufficient confidence to industrial sites before conversion.
- **Operational and Commercial impacts of conversion outage** – Site conversions will require unplanned outages of equipment. This will be dependent on the site, sector, and timescale and mechanism for conversion of the gas grid. This will impact production revenues and may cause current or potential customers to turn to competitors over inability to maintain supply, especially for organisations with only one site.
- **Future capital cost of equipment replacement** – This refers to the additional cost of replacing converted equipment at end of life with equipment designed to run on 100% hydrogen, compared to the counterfactual where no switch to hydrogen took place and natural gas equipment is replaced. While new hydrogen equipment is currently more expensive than natural gas equipment and can only be provided on a bespoke basis, this cost difference is likely to reduce as demand for hydrogen equipment increases. Hydrogen equipment is expected to reach a comparable cost to natural gas equipment, with any cost increases likely to be small and only incurred at the end of equipment life.
- **Insurance premiums** – There may be an uplift in insurance premiums for sites using hydrogen rather than natural gas due to the higher perceived risk. This impact on opex is difficult to quantify and depends on the quality of guarantees and warranties provided by the equipment manufacturers and gas suppliers, and the safety processes put in place.
- **New warranties** – Modified warranties for the use of hydrogen within existing equipment which has been converted and retrofitted for hydrogen consumption could require additional work with the equipment manufacturers. This might be mitigated by incorporating original equipment manufacturers (OEMs) into the demonstration and conversion process from an early stage, such that they are informed and more likely to provide these guarantees.

5.6 Timelines for Technology Development

5.6.1 Current Use in Industry

There is some evidence of high percentage hydrogen fuel being used in industrial equipment, usually within industries that have hydrogen as either a feedstock or a product from chemical processes implemented on sites. Examples of UK sites are:

- Huntsman, who use hydrogen to make a reactant to then produce aniline
- Inovyn who utilise a chlor-alkali process and produce a hydrogen product stream.

Both these sites have installed or are installing boilers which can burn hydrogen and natural gas mixtures. In the case of Inovyn, the current boilers utilise a modified natural gas burner to burn up to 100% hydrogen with some success. Though hydrogen is a valued resource in oil refineries and is extracted from refinery fuel gas (RFG), the RFG which is burnt can still retain relatively large hydrogen fractions. In integrated steelworks, coke oven gas contains ~50% (by vol.) hydrogen and this is used as fuel for some pieces of equipment, though it is usually blended before use with blast furnace gas and basic oxygen gas, which contain <10% (by vol.) hydrogen[49]. Other evidence of hydrogen being used as a fuel in the UK outside of these industries is sparse due to its current cost and availability.

Similarly, internationally there is evidence of the use of hydrogen in industrial equipment, mainly within gas turbines. Original equipment manufacturers (OEMs) such as BHGE have conducted trials, with the 12 MW 100% hydrogen Enel Fusina Plant operating since 2009. BHGE provided information on approximately 50 hydrogen fired gas turbines based on 10 different frame types supplied to customers internationally. Similarly, Siemens have supplied turbines from 4–500 MW with 5%–100% hydrogen fractions on at least 20 occasions as of 2018. The petrochemicals and refining industry use hydrogen to fire furnaces at high volume fractions, with tests in the US firing up to 95% hydrogen fractions using low NO_x burners in 2011 by Chevron and John Zink Hamworthy[50]. The LIFE OPTIMELT project has demonstrated the use of syngas (a mixture of hydrogen and carbon monoxide) as a fuel within glass furnaces[51].

5.6.2 Technology Readiness Levels (TRLs)

TRLs for the different equipment types were estimated through literature review of the current level of usage in industry/research and information from OEMs, industrial associations, and industrial sites. The TRL scale used here aligns with the EU H2020 Definition, shown below in Figure 5-4, which is a modification of the original NASA TRLs developed from 1974.

For clarity, TRL 9 in the context of this report means that a system has successfully met performance requirements within an operational environment. To reach this may not require extensive hours of testing, but rather small periods of demonstration. In comparison, if a manufacturer were to supply equipment and offer a warranty period, reliability testing will be required. Rather than long term testing at the demonstration phase, this may be gathered using in service data from the initial customers in unison with testing by the manufacturer.

Figure 5-4 EU H2020 Technology Readiness Levels

1. **Basic principles observed**
2. **Technology concept formulated**
3. **Experimental proof of concept**
4. **Technology validated in lab**
5. **Technology validated in relevant environment**
6. **Technology demonstrated in relevant environment**
7. **System prototype demonstration in operational environment**
8. **System complete and qualified**
9. **Actual system proven in operational environment**

The estimated current TRL of each equipment type is shown below, with comments regarding the pilot and large-scale trials undertaken. The table also shows any key challenges, which are specific to a particular equipment type; these are in addition to more general challenges, such as emissions reduction strategies.

[49] Scunthorpe Integrated Steelworks BAT conclusions 2012
[50] Cliff Lowe et al, Energy Procedia 4 (2011) 1058-1065, doi:10.1016/j.egypro.2011.01.155
[51] The project uses a thermochemical regenerator to reform natural gas on site using hot flue gases.

Figure 5-5: Technology Readiness Levels for the key industrial equipment types. Details around the any previous trials and comments on potential issues specific to equipment types

Equipment Type	TRL	Hydrogen pilot previously completed?	Challenges specific to this equipment type
Boiler / Indirect Dryer	7	Y	-
Direct Dryer / Oven	4	U*	Flue Gas Composition – e.g. Moisture Content
Kiln	4	U*	Flue Gas Composition – e.g. Moisture Content, Heat Transfer Mechanism
Conventional Furnace	5	Y	Heat Transfer Mechanism
Glass Furnace	4	U*	Flue Gas Composition – e.g. Moisture Content, Heat Transfer Mechanism, Refractory Materials,
Gas Turbine	8	Y	Integrated systems
Gas Engine	4	Y – small scale only	Above 30% H_2, significant issues around knock and de-rating.
Proprietary Equipment[52]	3**	N	Potential issues around impact on product e.g. coffee

*U = Unknown – this indicates equipment where initial research has not provided evidence of a pilot study, however, there may be evidence available.

**The maturity of proprietary equipment is unknown at this time. An assumption has been made that hydrogen fuel will not have been considered in detail as there is limited market currently.

5.6.3 Timeline

Understanding of equipment TRLs, knowledge of demonstration programmes, consultation with industry and engagement with original equipment manufacturers (OEMs) informed the creation of an estimated technology development timeline, presented in Figure 5-6. This highlights the steps needed for technology development, up to commercial availability at an industrial scale. A fast and slow development timeline is presented for all of the equipment to provide an indication of the uncertainty involved in estimating the length of time required for the development process.

The timeline is a **technology development** timeline, up to the point where the conversion of existing industrial sites is **technically feasible at commercial scale**. The following key assumptions have been made:

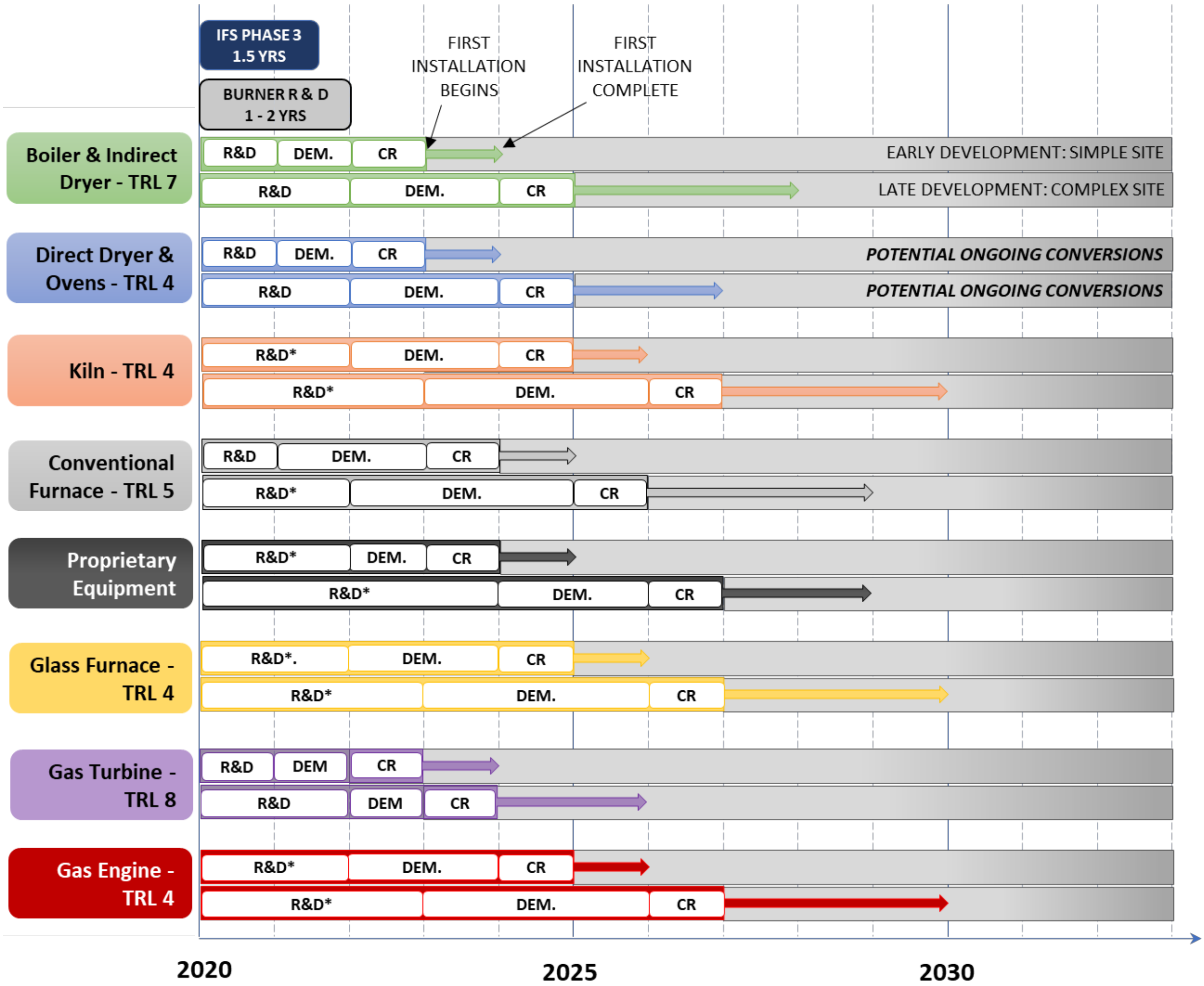
- **Company investment cycles** are not considered in this timeline, as they will not impact technology development, only influencing when each individual industrial site can invest in equipment conversion.
- There is **sufficient industry confidence of large-scale hydrogen deployment and adequate funding available** for equipment vendors and industrial sites to develop this technology. If this is not available, the rate of progress will be slower, and the timeline will be extended.

[52] Proprietary refers to specific, bespoke technology owned by the supplier and not used by others, for example coffee roasters.

Timeline Stages

- **IFS Phase 3**: Phase 3 of the BEIS Fuel Switching competition has allocated up to £17.8 million to alternative fuel demonstration projects in conjunction with industry. This programme is intended to be complete by April 2021 at which point the demonstration trials may have successfully shown use of 100% hydrogen in some industrial equipment. Other fuels also included in this competition are biomass and electricity. It is likely that significant further investment would be required.
- **Burner R&D**: The development of these equipment conversions relies on successful hydrogen burner research and development. Hydrogen burners do currently exist, though they are not perfected and off the shelf availability is limited. This R&D will overlap with the initial stages of equipment development, due to stages of iteration and integration throughout the development process. For more information on the technical issues see section 4.
- **R&D**: This is a research and development stage to overcome fundamental issues on individual components of the intended final system, for example burner re-design. This will include modelling and testing at the component level. This stage will also involve modelling of equipment before practical demonstration, using tools such as computational fluid dynamics (CFD) to inform demonstration design and operation. **R&D*** indicates equipment types where, due to more complex appliances and/or greater technical challenges to overcome, the research and development stage is likely to be more complex and last a longer period of time. For these equipment types, pilot scale tests will also likely be required before demonstration.
- **Dem. (Demonstrations):** This stage involves demonstration of the equipment system at a relevant scale to the intended industrial application. The tests required will differ dependent on equipment type, as equipment type influences the evidence required for OEMs to provide equipment guarantees, but will generally test implementations of equipment types at larger than pilot scale. This could happen on commercial sites (but not forming part of business as usual (BAU) operation), or at collaborative locations led by government or industry like the Catapult sites or Glass Futures. The time period for the demonstration phase includes front end engineering and design, procurement, installation, commissioning and a period of operational testing. For more information on these demonstrations, see section 6.2.
- **CR (Commercial Readiness)**: Following the completion of test scale demonstrations, it is assumed that the equipment manufacturers will want a period of time to validate results and confirm that they are confident to provide an equipment guarantee. This also incorporates time for equipment vendors to implement required modifications to manufacturing and begin developing supply chains etc. After this stage, it is assumed that equipment could be purchased and installed on site for BAU operation.
- **Installation:** This phase captures the possible timeline for first site installations, given a secure supply of hydrogen is available at a competitive cost. This includes feasibility/concept development, Front End Engineering Design (FEED), engineering, procurement, construction, testing and commissioning of equipment installation. This will vary dependent on complexity, scale, procurement and testing practices. Some equipment types have been assigned shorter implementations as these will generally involve supplying packaged equipment.

Figure 5-6: Technology development timeline



6 Barriers, Demonstrations and Enablers

6.1 Current barriers to hydrogen conversion

There are multiple challenges and barriers to overcome to achieve conversion to 100% hydrogen. The key technical and environment, health and safety (EHS) barriers are detailed in sections 4.1 and 4.2, including those which require further investigation through demonstration programmes. These technical barriers are summarised in Table 6-1 below, which includes potential solutions or mitigating actions to enable conversion.

The economic barriers to hydrogen conversion are discussed below in section 6.1.1, and are not contained in Table 6-1. These include some of the key concerns of industrial sites around competitiveness, potential cost to industry, and security of fuel supply, and will need to be taken into account when assessing potential roll out mechanisms for the conversion, and when determining the funding and support necessary for industry.

Table 6-1: Key technical barriers to hydrogen conversion and their corresponding enablers. Impact of barrier rated on a colour scale which covers Red (showstopping barriers, none found), Orange, Yellow, to Green (least serious).

	Barriers	Enablers	Impacted equipment
Technical	**Radiative Heat Transfer** – lower emissivity results in decreased radiant heat flux	Further experimental investigation on heat transfer balance, particularly in glass furnaces and kilns. Additives could be used to increase emissivity.	Furnaces, Kilns,
	Impact Rating: 🟠	This could have a large impact on the operation of equipment such as glass furnaces, which rely on radiative heat transfer. Due to a lack of trials, the impact of this and the effectiveness of additives to improve emissivity is unknown.	
	Convective heat transfer – lower air requirement reduces the gas volume available to transfer heat.	Flue Gas Recirculation (FGR) increases gas volume, and is also beneficial elsewhere (e.g. NO_x emissions), equipment recalibration for indirect fired equipment.	All equipment
	Impact Rating: 🟡	Reasoning for Rating: Though this might affect most equipment, robust technical solutions exist.	
	NO_x emissions – may be increased through higher flame temperature.	Technologies to mitigate this include Flue Gas Recirculation (FGR), steam addition and post-combustion treatment. Further work on low NO_x burners may also reduce emissions.	All equipment
	Impact Rating: 🟠	Reasoning for Rating: This will affect all equipment, as it is unlikely that NO_x emissions levels will become less stringent on fuel switching. Solutions exist, however some have a high cost associated.	
	Flue Gas Composition – e.g. increased moisture content with H_2 might impact product quality	Product specific tests required for some direct heating applications, to evaluate impact and any possible mitigating actions (e.g. adjusting combustion parameters).	Direct fired equipment
	Impact Rating: 🟠	This could have a large impact on some direct fired equipment, particularly where combustion gases are not mixed with additional air before product contact. The impact of this on product quality is unknown and trials are needed.	
	Gas Engine Conversion for CHP	Period of R&D, small scale and large-scale trials. May require full replacement with potential new design, rather than retrofit.	Gas Engines
	Impact Rating: 🟠	This significant challenge might necessitate full replacement of gas engines. However, as this only affects a small subsection of equipment, it is not a showstopping barrier.	
	Piping and fittings (leakage risks and embrittlement)	Materials and standards currently exist for hydrogen piping. Site distribution systems would need to be checked for hydrogen compatibility and replaced if incompatible.	All sites
	Impact Rating: 🟡	This barrier will have impact the cost of conversion, with some pipework needing replacement. However, hydrogen pipework currently exists.	
	Hydrogen burner development, including materials	Burner materials currently exist, though further R&D by burner manufacturers is required.	All equipment
	Impact Rating: 🟡	While bespoke hydrogen burners have previously been developed, further work is necessary to develop burners for all equipment types. There is confidence technical barriers to this are low.	

	Barriers	Enablers	Impacted equipment
Environment, Health and Safety	**Explosive Atmosphere Regulations (DSEAR)** - cost and space impact	Solution on a site by site basis – assessment of impact and new zoning requirements. Affected equipment and workstations might need to be moved or replaced.	All sites
	Impact Rating: ●	This will affect all sites; complying with extra regulations will have a large impact on site operations and the cost of conversion. However, the steps which need to be taken are known.	
	Possible Emissions Re-permitting	Technical solutions to NO_x emissions. Standardisation and collaboration with Environment Agency over permitting requirements. Emissions monitoring required.	Some sites
	Impact Rating: ●	Permit variations and additional monitoring for converted equipment might be needed on some sites, with resource implications. Cost impact likely to be low.	
	Accident regulations (COMAH) - H_2 on site might push sites over aggregation limits	Solution on a site by site basis. Only a small number of sites may be affected. Re-permitting or reduced storage.	Very small number of sites
	Impact Rating: ●	Though this will impact on operations of some sites, the number affected is likely to be very small and known measures can be taken to comply with COMAH regulations.	
Resources & Site	**Staff Training**	Training on H_2 equipment is available; requires resources and sufficient early warning of conversion to plan.	Industry Wide
	Impact Rating: ●	There will be a cost associated with training staff. This is likely to be low and training procedures are currently available.	
	Demo & implementation resource	Clear policy will allow for equipment manufacturers and sites to plan for the significant resources and training required for demonstrations and conversion	Demo or Site Specific
	Impact Rating: ●	Lack of resource, staff or skills could be a significant barrier; however, clear policy and sufficient support will help to mitigate this.	
	Hidden Costs e.g. feasibility studies, site downtime etc.	Site by site basis. Further research into full implications and costs.	All sites
	Impact Rating: ●	While hidden costs of conversion have been considered, some unquantified 'hidden costs' (e.g. cost of site downtime) could potentially be significant.	

6.1.1 Economic Barriers and Business Impact

Competitiveness

The most commonly raised industry concern around conversion to hydrogen was maintaining or improving both domestic and international economic competitiveness. From a domestic perspective, this requires a level playing field between businesses located in different parts of the UK. If different areas were to be switched over to hydrogen at different times, care needs be taken to ensure that the overall cost of natural gas and hydrogen systems to the industrial sites are equal. It was suggested that this should consider the price of carbon, fuel and the capital investment required for conversion.

From the perspective of international competition, some industries such as vehicle manufacturing and metal production are more vulnerable than others, such as asphalt production. Fuel switching and decarbonisation programs need to consider the international competitiveness of these UK industries, preventing offshoring and carbon leakage of energy intensive industry abroad. Thus, future energy costs need to be benchmarked to those abroad, potentially through subsidising some of the cost of hydrogen.

Disruption from Site Conversion

Conversion of sites and equipment will require extended, unplanned shutdown periods on the majority of industrial sites. The length of this period will be highly variable on a site by site basis, with these shutdowns potentially lasting up to 2 months, depending on site complexity. The impact of this may be somewhat mitigated through alignment with maintenance schedules and planned shutdowns[53], provided there is sufficient warning of conversion, but will not be completely removed. The inherent loss of revenue associated with this period of reduced production is likely to have a large impact on industrial sites, notwithstanding loss of custom due to any uncertainty surrounding equipment operation and reliability after the conversion. Single sites with no capacity at other sites are likely to be hit hardest by this, as they have no ability to share load with other sites in other parts of the UK potentially undergoing conversion at different times. This lost revenue will need to be considered when planning conversions and will need to be accounted for in any analysis of decarbonisation options.

Security of Fuel Supply

Security and quality of fuel supply is an important concern for all energy intensive industrial sites. When converting the natural gas grid to hydrogen, consideration needs to be taken to ensure sufficient redundancy is available throughout the transition period and further forward. For example, if hydrogen production in a region is to be provided through a relatively small number of large, centralised facilities, contingency and redundant capacity needs to be available for any issues which may arise. If different areas of the UK are converted at different times, larger redundancy is required in the regions which convert first, both due to the problems inherent with first applications and due to the lack of redundancy from interconnection between different gas local distribution zones.

6.1.2 Other Barriers

Lack of Industry Knowledge

The level of industry knowledge around the decarbonisation options, and 100% hydrogen specifically, is still relatively low. Many industrial sites, especially smaller ones, are not actively engaging with 100% hydrogen technology and understanding of the technological barriers, requirements and opportunities is generally limited. This reduces the number of sites and companies which would potentially get involved with fuel-switching initiatives such as demonstration projects. Industry engagement through workshops around the UK can help tackle this, combined with wide dissemination of the results of this and similar studies.

Staff Training

Additional training will be required to ensure workers on site are aware of the risks associated with hydrogen, understand the safety procedures in place and are confident when operating hydrogen fired equipment. This training is available, and it is assumed that staff will need to complete it before working in the vicinity of hydrogen equipment. All current staff will require this at the time of conversion and all

[53] The length and frequency of shutdowns is highly variable by industrial sector and subsector. Some sites/equipment operate on annual shutdowns, commonly 1-2 weeks but up to a few months in length (seasonal production), while other equipment such as glass furnaces can operate continuously for up to 20 years without shutting down.

future new staff as well. Refresher courses may also be required. Early warning of conversion will help mitigate the impact of this, enabling staff to be trained well in advance and practice new procedures to enable the transition to be as seamless as possible.

Hydrogen Burner Manufacturers

Though some hydrogen burners were found to be available, only a few burner manufacturers currently supply them. Some are bespoke hydrogen burners[54], while others are modified natural gas burners. Manufacturers are driven by their customers, and there is currently a lack of demand for hydrogen burners. Though not the largest component of the cost of conversion, development of burner technology is a key part of making equipment conversion possible, for example developing low NO_x hydrogen burners or integrating other NO_x mitigation strategies such as FGR. Burner manufacturers need to be integrated into the demonstration programmes to provide guidance and experience with firing hydrogen and to improve and optimise the performance of burners in different applications.

Hydrogen Purity

The impact of impurities on combustion would be minimal. Any carbon monoxide (CO) or CH_4 would burn, nitrogen is already present in the combustion air at much higher percentages than what would be expected from hydrogen production and H_2O is a combustion waste product. There are current engineering standards[55] which provide limits on impurities and new purity standards are being investigated[56].

First hand industry experience indicates that high proportions (~3 mol%) of H_2O in the hydrogen supply would impact the flame structure, radiative heat transfer and potentially impact the end product in direct heating applications. For feedstocks and fuel cells with catalysts, sulphur and carbon monoxide are severe catalyst poisons, with research ongoing to improve catalyst resistance to impurities and to remove CO from H_2 supplies through low temperature preferential oxidation[57].

Non-fuel use of Natural Gas

The largest use of natural gas in industry is as a fuel for the production of heat. However, a limited number of industrial sites use natural gas for other purposes, such as feedstock use in chemical processes or as a reducing agent.

Examples of natural gas use as a reducing agent include some emissions reduction or metal processing applications, some of which involve partial combustion to produce carbon monoxide. This is unlikely to pose a significant barrier to gas network conversion due to the small scale and potential for alternatives. The small quantity of natural gas required means that it could be transported to sites by road, or in some applications natural gas could be replaced by hydrogen or other reducing gases.

Feedstock use of natural gas could constitute a barrier to the conversion of the entire gas network to hydrogen (i.e. including the >7bar network). However, in the subsectors which use natural gas as a feedstock (e.g. hydrogen, ammonia, methyl methacrylate, acetyls, and ethylene production) all of the sites identified in this study were found to be located on the >7 bar gas network. These sites would therefore not be affected if the <7 bar network was converted over to hydrogen. There are likely to be a small number of sites which consume natural gas as feedstock connected to the <7 bar network, however these are very likely to have minimal natural gas consumption, and non-fuel use is not seen as a significant barrier to the conversion of the <7 bar gas network to hydrogen.

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[54] Toyota have developed a low NO_x hydrogen burner currently being used on a forging line in a Japanese plant.
[55] Hydrogen Fuel Quality – Product Specification BS ISO 14687:2018
[56] For more information on purity, see Hy4Heat Work Package 2 – Hydrogen Purity.
[57] Lina Cao et al., Nature 565, 631-635 (2019), DOI: 10.1038/s41586-018-0869-5

6.2 Demonstration

6.2.1 Demonstration Trials to reach TRL 9

Demonstration trials are required to validate the use of 100% hydrogen for each of the identified equipment types. These could be at individual industrial or original equipment manufacturer (OEM) sites or at a collaborative location such as a catapult site. To reach TRL 9[58] for these converted equipment types, a number of demonstrations are needed, with the capacity of the trial dependent on the range of equipment sizes in industry. In most cases, demonstrations will support commercial availability of equipment up to ~20x larger than the scale tested, though in some more technical equipment such as kilns a factor of ~5-10x larger is more appropriate.

An estimate of the number of demonstrations required to reach TRL 9 was developed, based on engagement with industry and OEMs. For instance, boilers are a standard piece of equipment and do not necessarily need sector specific demonstration (however some sites suggested they would still want some application or site-specific testing). A collaborative approach would be more effective for large footprint and capital-intensive equipment such as glass furnaces and kilns, where a small number of demonstration facilities (1-2) could be used to test a variety of applications such as different ware types and glass colours. For some equipment types, incremental trials could be undertaken on currently operating equipment, such as replacing one individual natural gas burner with a hydrogen fired burner and documenting the impact.

Level of Evidence

The level of evidence required before conversion differs by industrial site and equipment type. Some sites will only require an OEM guarantee that equipment conversion would not adversely impact operations. Generally, indirect fired equipment such as boilers will fall into this category, as these equipment types have less impact on product quality and are more general across industrial sectors. Evidence to allow OEMs to provide these guarantees will be obtained from a small number of cross sector technology demonstration trials.

Other equipment types, generally direct fired equipment, will need a greater level of demonstration, as data from more detailed tests at a more specific level is required for OEMs to provide guarantees. Sectors may choose to do their own application specific trials, due to the large impact that some of these equipment types can have on product quality, e.g. ceramics kilns, and the expertise within industry itself. When sufficiently integrated with OEMs, the demonstrations to achieve this (and the previous level of evidence) will achieve TRL 9 for the equipment types explored. This section explores the number of demonstrations required to gather evidence up to this level and their costs, which will cover the large majority of sites.

On a low number of sites, the sector wide demonstrations may not be applicable, and the site might require a site or equipment specific demonstration of the technology, to gather specific evidence above TRL 9. This might be because of product quality requirements, a particularly bespoke piece of equipment, or proprietary equipment, where the equipment technology is owned by the site operator. The demonstrations necessary to gather this evidence, and their associated costs, are estimated in section 6.2.2, although considerable uncertainty remains around the number of these trials required and their cost.

Estimated Costs of Demonstration

To estimate the cost of demonstrating a piece of equipment, an approach was utilised which was similar to that used when assessing the cost of conversion. The required capex for conversion of the relevant

[58] See section 5.6.2 for definition and discussion of TRLs.

equipment was combined with an additional factor to account for both the additional complexity of the demonstration projects and reduced costs on UK wide roll-out.

The demonstration costs assume that there is appropriate equipment on sites, perhaps unused back-up equipment, and that this equipment can be converted to hydrogen without significant disruption to site operation. It was noted from industry feedback that in some sectors, e.g. glass, there is little availability of back-up or unused equipment to act as a demonstration project. If these pieces of equipment are not available, a new piece of equipment will need to be used for a demonstration project (with a total installed cost assumed to be 4x the cost of converting), though using new equipment is not ideal to demonstrate the **conversion** of existing natural gas consuming equipment to hydrogen.

To provide sufficient evidence that the equipment functions in a similar way to the natural gas equipment, an operational time period of 100 hours was assumed per demonstration. This period is deemed suitable, in the majority of cases, for equipment to undergo performance testing[59]. However, in equipment with longer start-up times that could be used to test multiple products/wares, such as kilns and glass furnaces, a longer fired operation period of 900 hours has been assumed, including a start-up period. Operation and maintenance (O&M) costs were estimated at 10% of total installed cost costs per annum due to increased monitoring and measurement procedures around the demonstration. These costs relate to the demonstration projects themselves, excluding a number of other potential costs associated with demonstration projects which are highlighted below.

Table 6-2 Indicative estimate of the number and cost of industrial demonstrations on hydrogen conversion required to reach TRL 9, excluding some other potential costs highlighted below.

Technology	Capacity (MW)	Number of Demos	Capex – converting existing equipment (£ m)	Capex – new facility (£ m)	Estimated total opex (£ m)	Estimated total fuel costs (£ m)[60]
Boiler	1.5	2	0.8	3.2	0.06	0.02
Boiler	10	2	1.8	7.2	0.14	0.15
Direct Dryer	3	3	1.8	7.2	0.2	0.07
Direct Dryer	10	2	2.2	8.6	0.2	0.15
Furnace	20	3	5.0	20	0.6	0.5
Glass Furnace	10	2	2.7	11	0.5	1.4
Lime Kiln	5	1	1.0	4.0	0.08	0.3
Kiln	2	3	1.8	7.2	0.5	0.4
Oven	1	4	1.4	5.6	0.2	0.03
Oven	3	2	1.0	3.8	0.07	0.05
Total		**~24**	**~20**	**~80**	**~2.4**	**~3.0**

[59] Reliability testing is not included in these cost estimates, as it is equipment specific and may be gathered through the first conversions that take place, or through demonstrations running for longer (discussed in Future Fuel Costs section below).
[60] A hydrogen price of 7.6 p/kWh was assumed for these demonstrations.

The total estimated capex, opex and fuel costs[61] for these demonstration trials is approximately **£25 million** if existing back-up equipment is adapted for demonstration projects and rises to approximately **£85 million** if new facilities are required, excluding the costs highlighted below. The reduced cost and the greater applicability of utilising existing back-up equipment means this option is preferable if feasible, dependent on compatibility of available sites. However, the real figure is likely to be between the two estimates, given the differing approaches required for different equipment types. These estimates, as for the conversion cost of equipment, corresponds approximately to the Association for the Advancement of Cost Engineering class 5 (-50% to +100%).

This number of demonstration trials would provide evidence for conversion of each equipment type to 100% hydrogen at the appropriate equipment capacity and to the required level of maturity to cover the large majority of sites, as previously defined. The trials would take place along the timeframe suggested in the development timeline, and multiple trials of the same equipment would occur in parallel, most likely at different locations.

Demonstration costs for typical equipment present in each sector are presented in chapter 7. These estimate the range between the lower cost of converting a back-up piece of equipment for a demonstration project to the higher cost of a demonstration involving installing a new piece of equipment.

Future Fuel Costs

If the demonstration trials are successful, sites where these trials have taken place may want to continue operating the facility either for longer term hydrogen testing, or to supplement ongoing operations. This approach could be a beneficial evidence gathering exercise to help understand the operation and reliability of converted equipment, and could be incentivised, potentially through subsidising hydrogen costs and supporting availability. While fuel costs for the short demonstration periods of ~100 hours each are a relatively small proportion of the overall cost, the fuel costs for the ongoing operation of this equipment would be much larger (per annum fuel costs could be more than the demonstration’s capex).

Other Potential Costs

The demonstration costs presented are focused around the equipment conversion and operation within the demonstrations, and do not account for any costs associated with:

- Disruption to site operation and production.
- Raw materials required for the demonstration, e.g. the actual inputs to the process
- Detailed feasibility studies conducted for equipment characterisation, involving computational modelling work e.g. CFD.
- Project management and labour costs for the demonstration programmes.
- Any necessary permitting for demonstration facilities.
- Any necessary civil works associated with the programmes.
- Demonstration costs for other equipment not included in this cost estimate (e.g. CHP, equipment on >7 bar network)

[61] The cost of the fuel required for these demonstrations is particularly sensitive to the length of time the demonstrations run for (see discussion on Future Fuel Costs).

6.2.2 Additional Product/Site Specific Trials

While achieving commercial availability is a necessity for conversion, this level of evidence may be insufficient for some sites and sub-sectors. Specific individual trials for some complex and variable equipment types were deemed necessary to determine whether strict product quality standards were met, particularly in the food and drink industry. For example, equipment such as biscuit ovens would need trialling to understand the effect of the change in flue gas composition on product quality.

These trials would only be applicable to small subsections of industry, and likely specific sites due to the bespoke nature of equipment and intellectual property considerations. While these would not necessarily fit the mould of demonstration programmes, due to the lower applicability of the evidence gathered to wider industry, undertaking these trials would still require some form of incentive or encouragement from government. This study estimated that ~100 total trials may be required, as shown below in Table 6-3, although there is considerable uncertainty associated with this figure.

Table 6-3: Indicative estimated number and cost of overall 'demonstrations' required for conversion of industry to hydrogen

Technology	Number of Demonstrations	Estimated total cost – converting existing equipment (£ m)	Estimated total cost– new facilities (£ m)
Boiler	4	3.1	11
Direct Dryer	40	40	135
Furnace	2	4.7	15
Glass Furnace	4	8.1	24
Lime Kiln	2	8.9	27
Kiln	10	2.4	8.4
Oven	35	16	54
Total	**~97**	**~80**	**~275**

6.3 Other Barriers and Enablers

Public Perception

Environmental sustainability is an increasingly important aspect facing industrial and commercial organisations, and public perception has an impact on business decisions. Large industrial sites engage with the surrounding community and public pressure can have an impact in some sectors on operational decisions around decarbonisation, emissions and sustainability. There is evidence of moves towards renewable only electricity supply, energy efficiency programmes and growing use of internal fuels, such as biomass in the Paper and Food and Drink sectors, though there has been limited progress on the decarbonisation of industrial heat. Strong public support for deep decarbonisation could be a powerful enabler to incentivise industry to decarbonise heating, potentially through switching to 100% hydrogen providing the public do not see the use of hydrogen in industry as a health and safety risk.

Original Equipment Manufacturer (OEM) supply chain

OEMs are a key part of any potential conversion or replacement of existing equipment, as well as being integral to the success of demonstration programmes. However, there are a number of difficulties associated with the supply chain. For a UK wide conversion of industrial equipment, there needs to be sufficient capacity and skilled labour within OEMs. The necessary level depends on the speed of roll-out, with faster roll-out requiring more labour to cope with the increased rate of equipment conversion.

The globalisation of industry also means that some key OEMs may be based abroad, for example relevant ceramic kiln manufacturers are mainly based in Germany and Italy. If there is insufficient global demand for hydrogen equipment, global suppliers are not incentivised to develop them. The global nature of the supply chain also adds difficulties when trying to integrate OEMs into demonstration and R&D projects in the UK, if their R&D facilities are based abroad, though this might be mitigated through using locations and equipment on appropriate sites. That being said, the majority of OEMs have significant UK presence and early investment in low carbon technology is key for OEMs to maintain their market share, given the global move towards a low carbon future. Support for OEMs undertaking R&D or testing of 100% hydrogen equipment will allow their workforce to develop sufficient expertise to make the potential conversion of equipment to 100% hydrogen possible.

Carbon Emissions Allowances and Taxes

The price of carbon emissions is a powerful driver towards industrial fuel switching by providing a financial incentive to decarbonise. Raising the price of carbon emissions or fossil fuels in the UK provides an increased incentive for industries to invest in fuel switching. Carbon emissions are viewed by some industrial sites as a potential risk, considering the potential for future increases in the carbon price, especially for sites competing on a global stage. Any approach must consider the potential for carbon leakage and minimise the outsourcing of energy intensive industry to other areas of the world.

‘Hydrogen Ready’ Equipment

To reduce the impact of conversion on industry, it might be possible to develop ‘hydrogen ready’ dual-fired equipment which can fire both hydrogen and natural gas. While burner systems which can fire both 100% natural gas and 100% hydrogen are technically challenging, new equipment could possibly have two sets of nozzles within the same burner, with the remaining components suitable for both fuels. If dual-fired equipment was implemented to replace any end of life natural gas equipment in advance of hydrogen conversion, this would reduce the labour and capex requirements at conversion. While this equipment would likely be more expensive on installation, the conversion may only involve replacement of burners (or parts of burners), resulting in substantially less shutdown and labour required at the time of conversion.

However, for industrial equipment, the capability of firing hydrogen is only one part of the system wide design. While a dual fired burner may be technically possible to install, there are multiple other considerations when making an industrial site hydrogen ready, as discussed within this report. For example, compatibility of and requirements for:

- Electrical equipment
- Distribution pipework
- Emissions reduction equipment
- Flame detection equipment

Dependent on industry confidence in a large-scale hydrogen roll out, industrial sites may not wish to make the early investment and site wide changes required to make the site and equipment ‘hydrogen ready’ at the end of equipment life, before hydrogen fuel is available. Sites might rather replace equipment with natural gas fired equipment and convert the site and equipment at the point of hydrogen conversion. The preferred approach will vary widely on a site by site basis, dependent on the time between equipment end of life and the point of conversion, industry confidence in hydrogen roll-out, the length of shutdown time saved through ‘hydrogen readiness’, and the scale and timing of investment required for the different cases. There is significant uncertainty around the concept of ‘hydrogen ready’ sites and equipment, and more detailed investigation is required to understand its feasibility, potential advantages/disadvantages, and possible support mechanisms to incentivise industry uptake.

Roll Out Mechanism

The potential conversion of industry on the <7 bar gas grid will be a large undertaking, and how the conversion roll out proceeds will have impact on the costs. This could potentially be mitigated through the use of a ‘hydrogen ready’ approach or dual fired equipment (whether with two sets of burners, or only requiring a minor burner conversion) when any equipment is replaced going forward. This requires a warning given well in advance of conversion, as some industrial equipment can operate for over 40 years.

While a decision this far in advance is not feasible, industry feedback suggests that the longer the warning period and the higher industry confidence in a large-scale hydrogen roll out is, the more investment planning can reduce the overall cost of conversion. These cost savings from better planning are achieved by reducing the remaining lifetime of the equipment subcomponents which are replaced and aligning plant maintenance schedules to the conversion schedule. Though outside the scope of this project, a gradual regional conversion through the conversion of different local distribution zones at different times was mentioned as a possible mechanism to reduce risk and mitigate the lack of available skilled labour. Further research is necessary around the impact of different signalling times and roll out mechanisms on the risks and cost of conversion.

7 Sector specific information

The following chapter aims to outline some key information relating to each of the 11 key sectors assessed in this work. It covers statistics on energy consumption, processes and natural gas equipment. There is then a summary of key sectoral barriers and enablers for hydrogen conversion, with estimated costs and technology development timeframes. It should be noted that each of these categories is explained in more detail in other chapters of the report.

Food and Drink

Sector Background

88% Heat from Natural Gas

21 TWh/yr heat consumption

~400 Sites using >5GWh/yr gas

Economic contribution: Approx. 450,000 employed in the sector, with £31 billion GVA, 17% of UK manufacturing.

Heat Use: 21 TWh/yr of heat used in sector. Dominated by natural gas in boilers/CHP. 11 TWh/yr of electricity also used in sector.

Sector features: Majority of sites (97%) SMEs. Very diverse sector with a wide range of products and bespoke equipment used. Sector risk averse due to importance of product safety and quality.

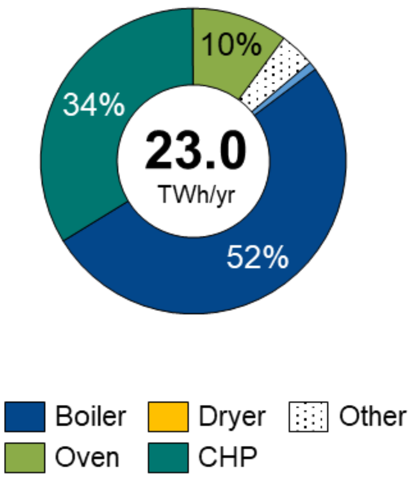
Natural Gas consumption

Key characteristics: Some large sites present in sector connected to >7 bar gas network, with majority of CHP.

Relevant Processes: Wide range of processes, with hot water and steam production most important. Drying, evaporation, pasteurisation, baking and sterilisation also key.

Relevant Equipment: Boilers and CHP are most significant gas equipment, accounting for ~70% of gas consumption. Ovens and other direct fired equipment such as roasters/dryers also important.

Relatively low thermal load factor: ~0.35 due to batch production and seasonal variation in demand, though varies by equipment type.

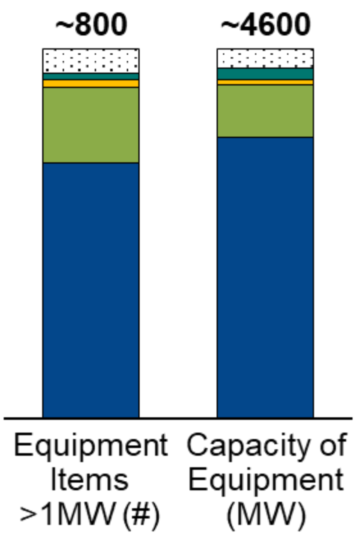


Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Boilers span a large range of sizes, up to 50 MWth (larger boilers generally connected to >7 bar network).
- Low number and capacity of CHP on <7 bar gas network, as generally connected to >7 bar network.
- Ovens generally small, with multiple on those sites which utilize them, with sizes up to 10 MWth.
- Relatively large number of equipment pieces <1MWth present on industrial sites due to large number of small sites

Equipment Lifetime: Typical lifetime of boilers is 30-35 years. Typical lifetime for direct fired equipment such as ovens is approx. 20-25 years.



Food and Drink

Key Challenges for H_2

Heat Transfer Mechanism: The balance of convective/radiative heat, and the composition and amount of flue gases means product specific testing needed for possible impact on product quality, as well as equipment demonstrations.

Bespoke Equipment: Large range of products in sector means equipment is bespoke and designed for strict product quality standards. Product specific testing needed for H_2, made difficult as some OEMs based outside of the UK.

Notable Cross-Sector Challenges: NO_x emissions, HSE familiarity, Flue Gas Moisture Content (see Section 4.13 and 6.1 for more information).

Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result. Large number of small sites/equipment pieces in sector, making conversion more expensive. For more details on methodology see Chapters 4 and 5.

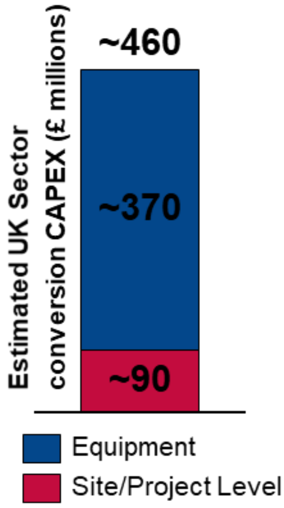
Typical **10 MW Boiler** estimated conversion CAPEX: **£0.7 million**

Typical **1 MW Oven** estimated conversion CAPEX: **£0.15 million**

Demonstration Requirements: Boilers need demonstration, though not necessarily sector specific. Direct fired equipment such as ovens/roasters need high level of demonstration, potentially product specific, as have extensive impact on product quality and due to diverse range of products. For more detail, see Chapter 6.

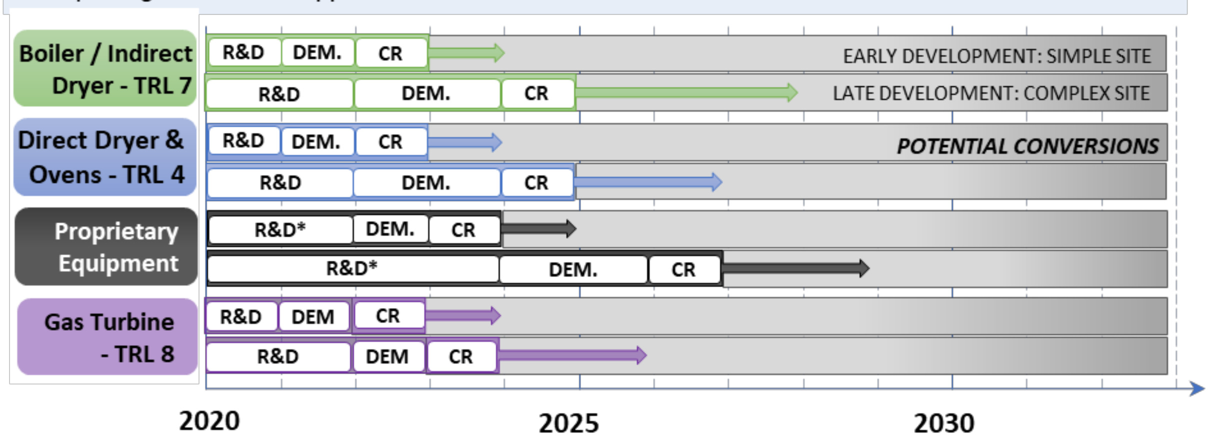
10 MW Boiler estimated initial demonstration cost: **£1 - 4 million**

1 MW Oven estimated initial demonstration cost: **£0.3 - 1.5 million**



Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Chemicals

Sector Background

~90% Heat from Natural Gas

25 TWh/yr heat consumption

~400 Sites using >5 GWh/yr gas

Economic contribution: Approx. 140,000 employed in the sector, with £14.7 billion GVA.

Heat Use: 25 TWh/yr of heat used in sector. Dominated by natural gas in boilers/CHP.

Sector Features: Sites span a range of sizes, from large integrated chemicals plants, but also a significant number of SMEs. Diverse sector with a wide range of products, though gas consuming equipment common across sector. Long periods between shutdowns, especially on larger sites.

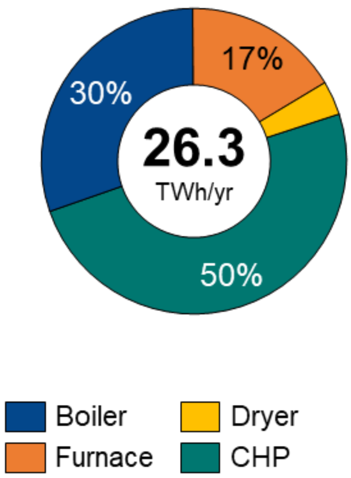
Natural Gas consumption

Key characteristics: Significant number of large sites in industry clusters with the majority of these connected to >7 bar gas network. Significant additional CHP gas usage in major power producers such as Grangemouth not included.

Relevant Processes: Steam production most important processes. Drying, cracking also key, with some processes requiring direct high temperature heat.

Relevant Equipment: Boilers and CHP are most important equipment, accounting for ~80% of gas consumption. Furnaces and direct fired equipment like dryers important.

Relatively low thermal load factor (~0.35) due to some equipment only utilized on start up or simply as back up for CHP, though varies by equipment type (furnaces higher load factor).

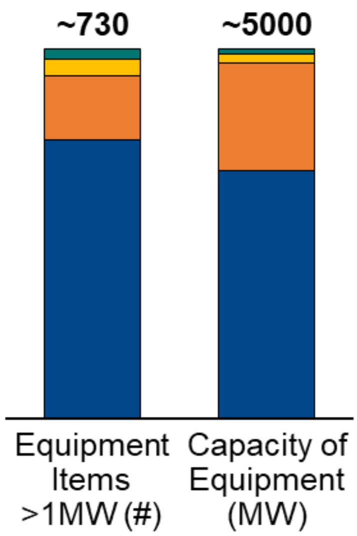


Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Low number and capacity of CHP on <7 bar gas network, as generally connected to >7 bar network.
- Boilers span a large range of sizes, up to 30 MWth (larger boilers connected to >7 bar network).
- Furnaces fewer in number, as mainly on large sites connected to >7 bar network, but generally large, with sizes up to 100 MWth. Some furnaces run solely on internally generated by-product fuels.
- Relatively few equipment <1MWth present on industrial sites due to integrated processes, utilizing indirect heating through steam.

Equipment Lifetime: Typical lifetime of boilers is 30-35 years. Typical lifetime for direct fired equipment such as furnaces is approx. 20-25 years.



Chemicals

Key Challenges for H_2

Gas Engines: Significant number of gas engines present in the sector, with issues from knock when using H_2 as fuel. Significant R&D needed, with equipment replacement rather than conversion a possibility.

Natural Gas Feedstock: A few sites need natural gas feedstock for producing products such as ammonia and methyl methacrylate, though on the >7 bar network. Widespread H_2 availability provides opportunity for feedstock use.

Notable Cross-Sector Challenges: NO_x emissions, Infrequent shutdowns (see Section 4.13 and 6.1 for more information).

Conversion Requirements and CAPEX

Equipment in the sector likely to be ATEX compliant, with sites familiar with H_2 and HSE requirements. Low cost due to large proportion (~55%) of gas consumption on >7 bar network. For more details on methodology see Chapters 4 and 5.

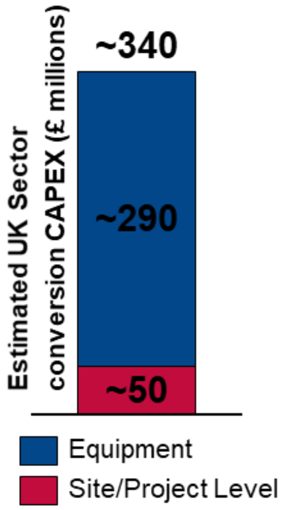
Typical **10 MW Boiler** estimated conversion CAPEX: **£0.5 million**

Typical **20 MW Furnace** estimated conversion CAPEX: **£0.8 million**

Demonstration Requirements: Though H_2 boilers operating in sector, 100% H_2 boilers require further cross-sector demonstration. Furnaces and Dryers need a higher level of demonstration, due to importance of heat transfer profile and shape of furnace, though could happen outside of UK. For more detail, see Chapter 6.

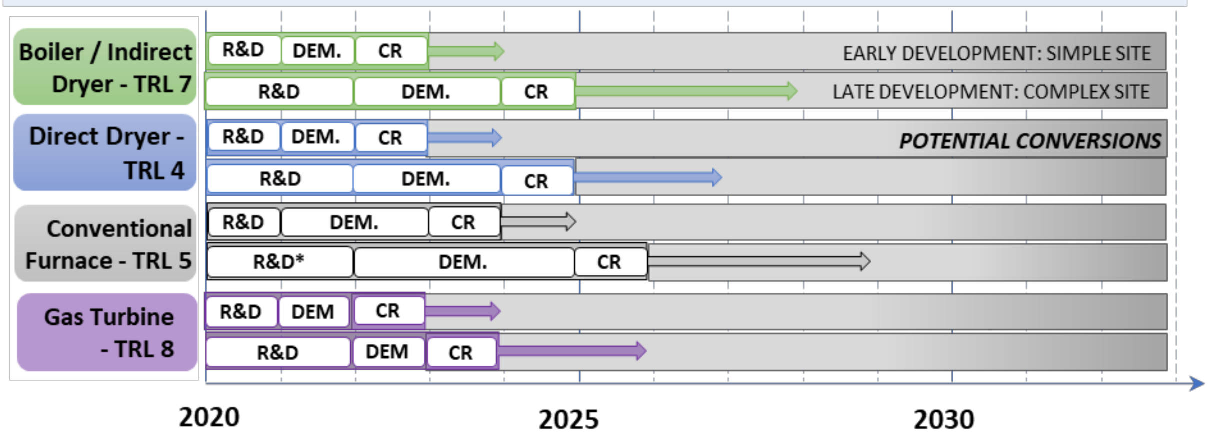
10 MW Boiler estimated initial demonstration cost: **£1 - 4 million**

20 MW Furnace estimated initial demonstration cost: **£2 - 7 million**



Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Vehicle Manufacturing

Sector Background

>90% Heat from Natural Gas

~7.5 TWh/yr heat consumption

~200 Sites using >5 GWh/yr gas

Economic contribution: Approx. 186,000 employed in the sector, producing 1.7 million cars and contributing £20.2 billion in GVA (2017).

Heat Use: 7.5 TWh/yr of heat used in sector. Mainly natural gas consumption, with a small contribution from electricity and petroleum products. 5 TWh/yr of electricity used in the sector.

Sector Features: Generally consists of large manufacturers, with significant global competition. R&D for most large manufacturers based overseas.

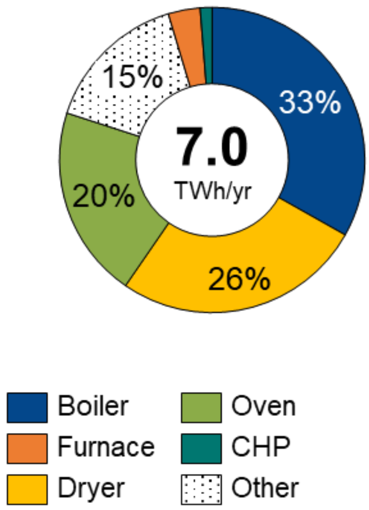
Natural Gas consumption

Key characteristics: Similar processing stages across sector, though some sites use indirect heating and others entirely direct fired. Few sites connected to >7 bar gas network.

Relevant Processes: Paint shop most significant energy user, with space heating consuming significant natural gas. Drying, curing, welding, pressing processes also important.

Relevant Equipment: Gas fired ovens/dryers to generating direct heat. High pressure hot water boilers used for indirect heating and space heating on some sites.

Low thermal load factor, (~0.25) due to use of equipment when needed, as well as lower utilization of whole plants.

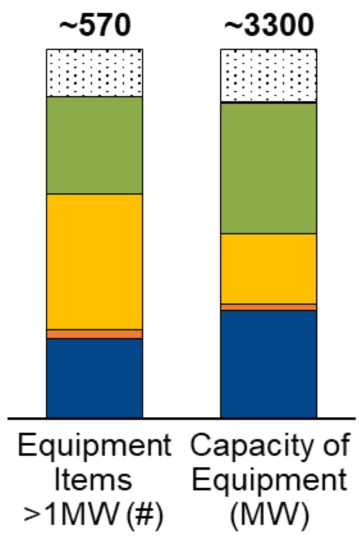


Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Some sites have a large amount of their space and process heating demands met through high pressure hot water boilers up to 20 MW in size.
- Majority of gas is consumed in many small ovens, dryers and other equipment for direct process heating. There can be hundreds of these on large site, though many are smaller than 1 MWth.
- A few sites use furnaces for engine casting.

Equipment Lifetime: Typical lifetime of boilers is 30-35 years, though lifetime of direct fired equipment generally lower at 20-25 years.



Vehicle Manufacturing

Key Challenges for H_2

Flue Gas Moisture Content increases when burning H_2. Further experimentation and demonstrations are needed to determine impact on paint curing/drying as well as other processes. Dilution of combustion gases to increase air temperature by small amount might make effect negligible.

Global industry: Sufficient support for competitiveness needs to be available, otherwise industry closure and offshoring is a distinct possibility. R&D for many companies is largely based offshore, with innovations introduced there first.

Notable Cross-Sector Challenges: NO_x emissions, HSE familiarity (see Section 4.13 and 6.1 for more information).

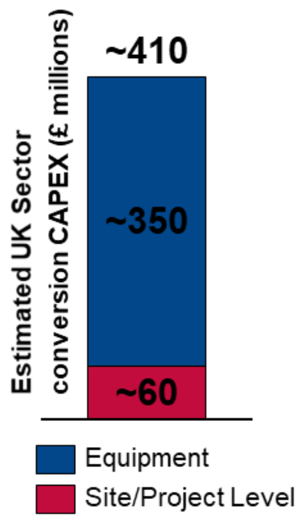
Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result. **Large amount of small equipment** in sector, making conversion **significantly more expensive.** For more details on methodology see Chapters 4 and 5.

Typical **5 MW Oven** estimated conversion CAPEX: **£0.34 million**

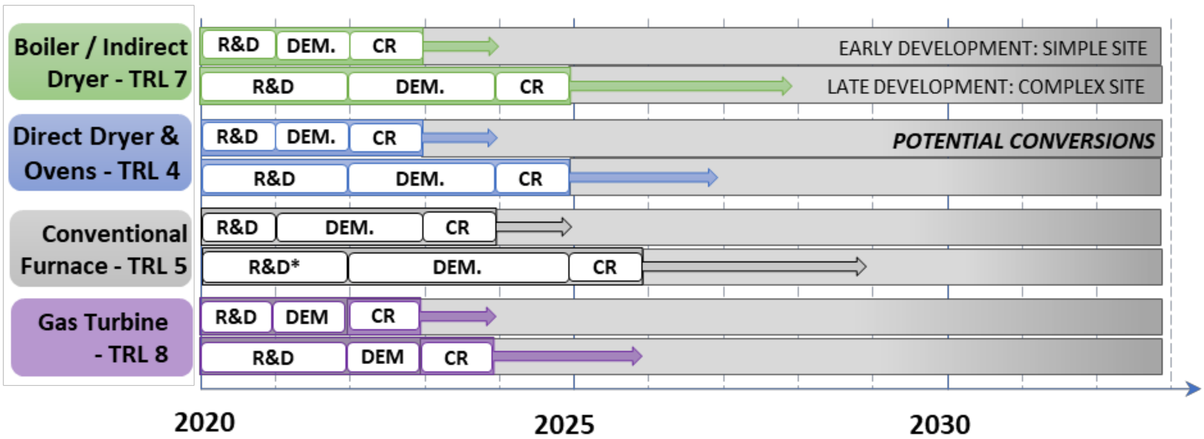
Demonstration Requirements: Boilers need demonstration, though not necessarily sector specific. Direct fired equipment needs greater range of demonstrations. This doesn't have to happen in UK, as most companies have R&D based abroad, e.g. Toyota's example of using low NO_x H_2 burners in Japan. For more detail, see Chapter 6.

3 MW Oven estimated initial demonstration cost: **£0.6 - 2 million**



Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Basic Metals

Sector Background

14% Heat from Natural Gas

37 TWh/yr 'heat' consumption

~120 Sites using >5 GWh/yr gas

Economic contribution: Approx. 40,000 employed in the sector, with £11 billion in revenues,

Heat Use: 37 TWh/yr of 'heat' used in sector. Dominated by coal/coke used in blast furnaces in primary iron manufacture (also used for reduction). Gas primarily used in steel finishing and non-ferrous metal manufacturing.

Sector Features: Majority of sites large manufacturers, with significant global competition. Range of products, though similar processing stages across sector.

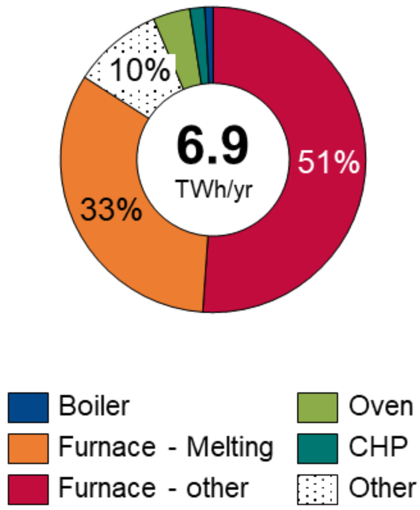
Natural Gas consumption

Key characteristics: Gas consumption split approx. 70:30 between Ferrous and Non Ferrous metals. Few sites connected to >7 bar gas network.

Relevant Processes: Steel rolling and melting. Non-ferrous metal melting, particularly aluminium. Heat treatment of metals. Heating of molten metal channels and ladles.

Relevant Equipment: Gas fired steel finishing/rolling furnaces, as well as metal melting furnaces. Soaking pits, heat treatment furnaces and ovens also important.

Relatively high thermal load factor, (~0.50) due to some batch loading and redundant/excess equipment, though varies by equipment type.

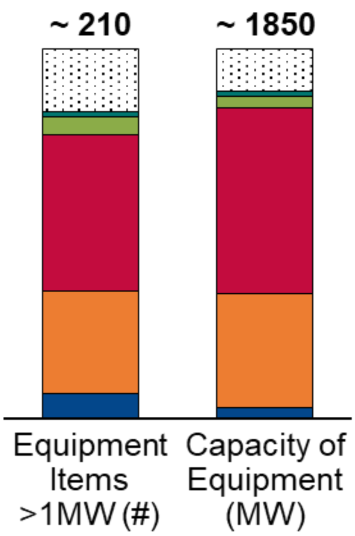


Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Generally one large furnace on a site and a number of smaller pieces of equipment for further processing/treatment of product.
- A few very large furnaces present in sector, with sizes up to >100 MWth. These are used for metal melting/reheating.
- Relatively small amount of equipment <1MWth present on large, industrial sites.

Equipment Lifetime: Typical lifetime of furnaces is 30-40 years



Basic Metals

Key Challenges for H_2

Heat Transfer Mechanism: The balance of convective/radiative heat, and the composition and amount of flue gases might mean a redesign of heat treatment and other furnaces. Equipment modelling and experimental investigation needed.

Embrittlement: Hydrogen can penetrate into steel causing embrittlement, additional processing steps (baking) may be required to achieve product quality. Product specific testing with regards to strict quality standards necessary e.g. aviation.

Declining industry in UK, with new investment low. Sufficient support needs to be available, otherwise industry closure and offshoring is a possibility.

Notable Cross-Sector Challenges: NO_x emissions, HSE familiarity (see Section 4.13 and 6.1 for more information).

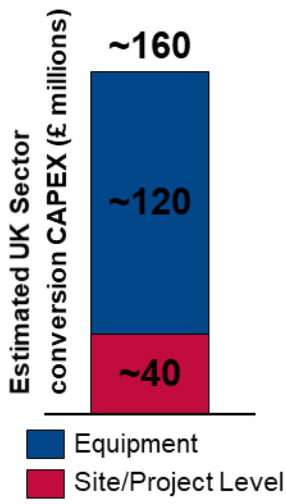
Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result. For more details on methodology see Chapters 4 and 5.

Typical **20 MW Furnace** estimated conversion CAPEX: **£1.1 million**

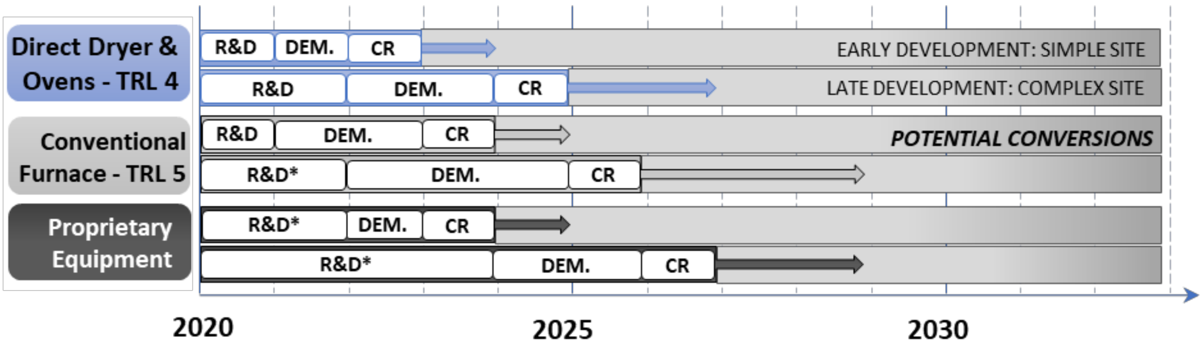
Demonstration Requirements: Both small and large furnaces in the sector need demonstration, though global scope means not necessarily in the UK. Some knowledge around hydrogen use, with scope for process switching to direct reduction e.g. HISARNA / HYBRIT. For more detail, see Chapter 6.

20 MW Furnace estimated initial demonstration cost: **£2 - 7 million**



Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Refining

Sector Background

<10%
Heat from Natural Gas

12.9
MtCO^{2}e/yr (2017)

~4
Sites using >5 GWh/yr gas

Economic contribution: Over 20,000 employed in the refining sector, with direct value to economy of ≈£2.3 billion (2013). 12.9 $MtCO_2$ emissions (2017).

Heat Use: in sector dominated by refinery fuel gas in furnaces and boilers, though integrated CHP plants also play role.

Sector Features: Six major sites operating in the UK. One small bitumen refinery also. Long periods between shutdowns, generally 4-6 years.

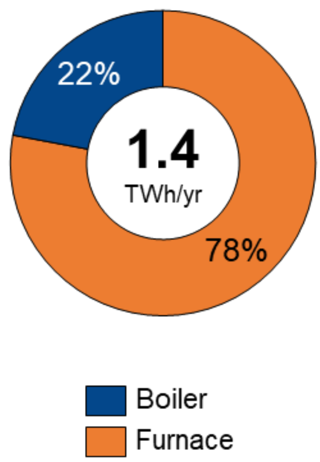
Natural Gas consumption (excluding CHP and feedstock)

Key characteristics: 2/6 major refining sites not connected to the natural gas network. None of the other 4 are connected to the <7 bar network, with **all connected to the >7 bar distribution network**. Significant additional gas consumption (≈7 TWh/yr) from major power producers (mostly CHP plants) whose heat and electricity output are integrated into refining sites.

Aside from CHP and power stations, natural gas generally blended with refinery fuel gas in low proportions (≈10% Natural Gas).

Relevant Processes: Distillation, Reforming, Isomerisation, Cracking, Calcining, Hydrotreatment, Catalyst Regeneration, Steam Generation etc. Feedstock use of natural gas for SMRs on 2/6 refining sites.

Relevant Equipment: Furnaces, steam boilers and CHP most important equipment in sector.

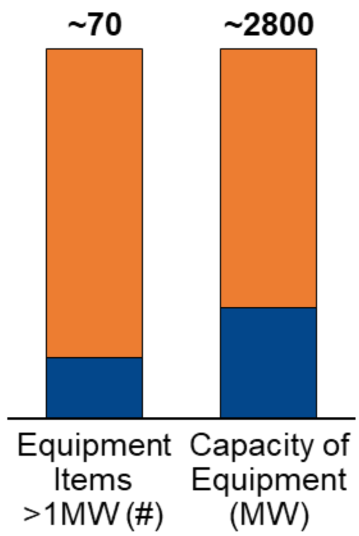


Natural Gas Consuming Equipment

Equipment Capacity:

- These figures are for equipment which blend a small portion of natural gas with the refinery fuel gas systems to maintain constant pressure. Includes some gas/oil dual fired equipment.
- Additional ≈50 pieces of equipment on sites which do not use natural gas
- Furnaces span range from 10-100+ MWth, while boilers generally large in capacity, (50–100 MWth).

Equipment Lifetime: Typical lifetime of boilers and furnaces is in the region of 30-35 years.



Refining

Challenges/Opportunities for H_2

Bespoke Equipment: Equipment in the sector is bespoke to application and refinery. General demonstration trials difficult if converting input of natural gas to H_2. However all refineries using natural gas on > 7 bar network, and low proportions of natural gas used in most equipment.

Hydrogen Producer: Refining sector produces large amounts of hydrogen, with opportunities to supply hydrogen to demonstration projects or clusters near refineries. Can be used to kick start hydrogen economy.

Notable Cross-Sector Challenges: NO_x emissions, Infrequent shutdowns (see Section 4.13 and 6 for more information).

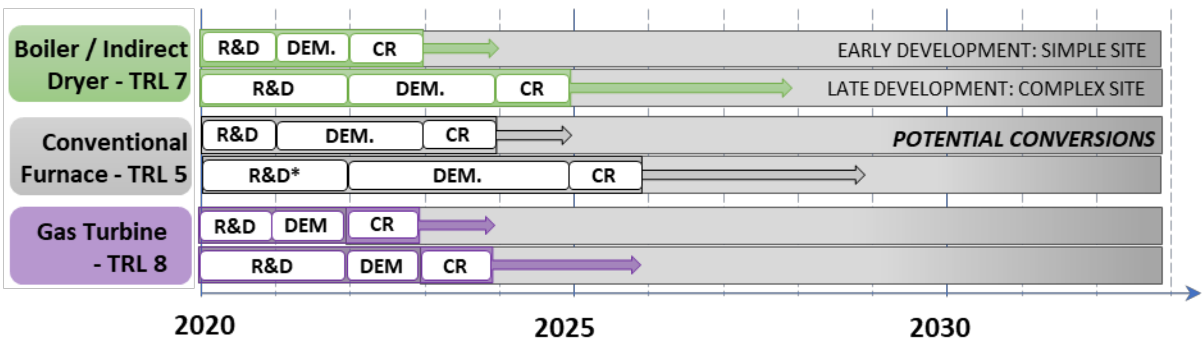
Conversion Requirements and CAPEX

Equipment in the sector likely to be ATEX compliant, with sites familiar with H_2 and HSE requirements. As equipment only blends a small proportion of natural gas with into refinery fuel gas system, equipment may not need conversion. CHP may need conversion, though **all sites on > 7 bar gas network** so not necessary if only converting <7 bar network. Conversion costs not presented as no equipment within project scope. For more details on methodology see Chapters 4 and 5.

Demonstration Requirements: Though some use of H_2 in equipment globally and experience of refinery fuel gas, **if converted**, equipment would require further demonstrations. Bespoke nature of equipment would mean greater number of demonstrations needed, with concerns around heat transfer profile and shape of furnaces. Demonstration costs not presented as no equipment within project scope. For more detail, see Chapter 6.

Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Paper

Sector Background

50% Heat from Natural Gas

~13 TWh/yr heat consumption

~75 Sites using >5 GWh/yr gas

Economic contribution: Approx. 25,000 directly employed in the sector, with £6.5 billion turnover (2016).

Heat Use: 13 TWh/yr of heat used in sector. Dominated by CHP due to ratio of heat to electricity demand with 60% of paper produced in UK produced on a site using CHP. Use of biomass and waste fuels recently becoming more prevalent.

Sector Features: Sites few in number but relatively large in scale. Homogenous sector, with equipment and processes similar across plants.

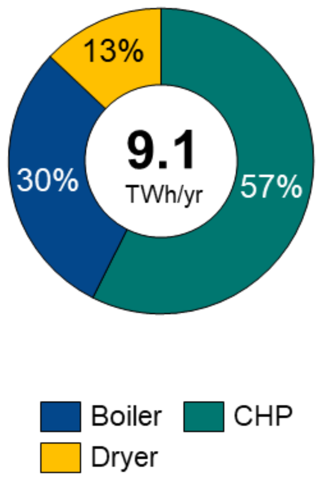
Natural Gas consumption

Key characteristics: A few very large sites consume a large amount of gas, mainly in CHP. Relatively high proportion of gas usage on >7 bar network (~55-60%) due to these sites.

Relevant Processes: Hot water and steam production most important processes. This is used for pulping, drying refining and finishing. Some drying heat is direct fired.

Relevant Equipment: Boilers and CHP are most important equipment, accounting for ~85% of gas consumption. Direct fired dryers are also important.

Relatively high thermal load factor (~0.55) due to continuous process running at full capacity, though some boilers only used as back up for CHP.

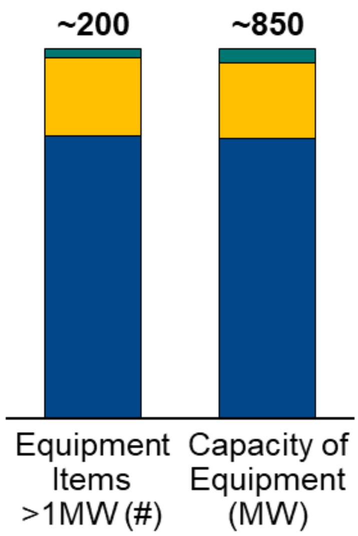


Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Boilers span a large range of sizes, up to >20 MWth (larger boilers connected to >7 bar network).
- Lower number and capacity of CHP on <7 bar gas network, as some sites connected to >7 bar network.
- Direct fired dryers generally fewer in number, as some are <1 MWth.
- Relatively low amount of equipment <1MWth present on industrial sites due to integrated processes, utilizing indirect heating through steam from larger central boilers.

Equipment Lifetime: Typical lifetime of boilers is 35-40 years. Typical lifetime for direct fired dryers is approx. 25-30 years.



Paper

Key Challenges for H_2

Other fuel switching options: Many sites have already moved away from natural gas to reduce carbon emissions through biomass and waste derived fuels, so little push to convert to hydrogen.

Investment: Small margins and long equipment lifetimes in sector mean investment needs adequate support.

Notable Cross-Sector Challenges: NO_x emissions, HSE familiarity (see Section 4.13 and 6.1 for more information).

Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result. Low cost due to large proportion (~55%) of gas consumption on >7 bar network. For more details on methodology see Chapters 4 and 5.

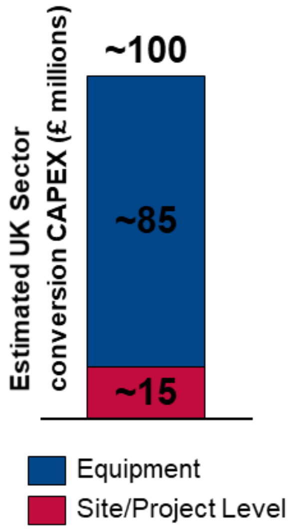
Typical **10 MW Boiler** estimated conversion CAPEX: **£0.75 million**

Typical **5 MW Dryer** estimated conversion CAPEX: **£0.33 million**

Demonstration Requirements: Equipment in the sector relatively general, with a lower amount of specific demonstration required. Boilers need some demonstration, though not necessarily sector specific. Direct fired dryers require demonstration in sector. For more detail, see Chapter 6.

10 MW Boiler estimated initial demonstration cost: **£1 - 4 million**

3 MW Dryer estimated initial demonstration cost: **£0.7 – 2.5 million**



Technology Development Timelines

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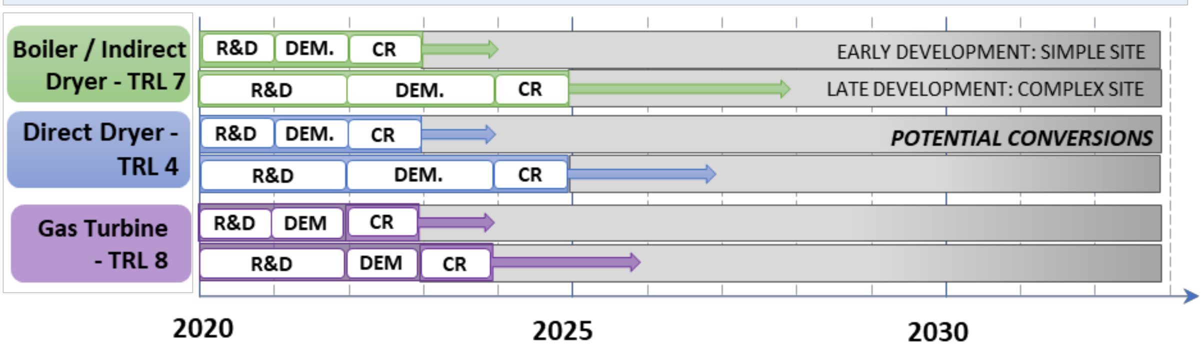


Glass

Sector Background

85% Heat from Natural Gas

6.5 TWh/yr heat consumption

~33 Sites using >5 GWh/yr gas

Economic contribution: Approx. 6500 directly employed in the sector, with £1.3 billion in revenues.

Heat Use: 6.5 TWh/yr of heat used in sector. Dominated by natural gas in the glass furnace, though ~10% of heat supplied by electricity through 'electric boost'.

Sector Features: Small number of large manufacturing sites. 2 main products, float and container with similar processes used across sector.

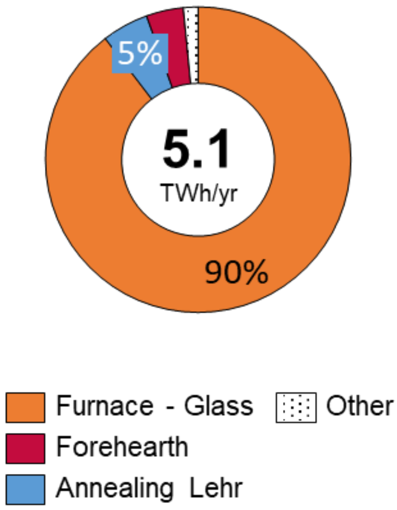
Natural Gas consumption

Key characteristics: Few sites connected to >7 bar gas network.

Relevant Processes: Melting raw materials in furnace the key process. Conditioning, annealing, moulding, forming and pressing also important.

Relevant Equipment: Gas fired glass melting furnaces, annealing lehrs. Forehearths also important for container glass.

High thermal load factor, (~0.75) due to continuous operation of equipment, though stated capacity includes the fact that burners inside furnaces only fire for ~50% of the time.

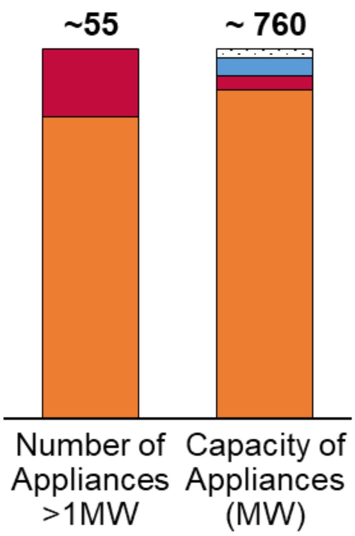


Appliances (on <7 bar network)

Natural Gas Equipment Capacity:

- Generally one or two large glass furnaces on a site and a number of smaller appliances for further processing/treatment of product.
- Glass furnaces present in sector have sizes up to 40 MWth.
- Relatively large number of appliances <1MWth present on large, industrial sites, with most forehearths and annealing lehrs falling below this threshold.

Equipment Lifetime: Typical lifetime of furnaces is 10-20 years, after which they are rebuilt.



Glass

Key Challenges for H_2

Heat Transfer Mechanism: The lower flame luminosity of H_2 is a key barrier as the dominant heat transfer mechanism for glass melting is radiation. Equipment modelling and experimental investigation needed, and potentially a fuel additive to increase the flame luminosity.

Refractory Materials: Higher flame temperature with H_2 might mean different refractory materials are needed, though these are available.

Very infrequent shutdowns (10-20 years) causes difficulty converting equipment over to different fuel type. Sufficient warning and support necessary to enable conversion or compensation for early shutdown and rebuild.

Notable Cross-Sector Challenges: NO_x emissions, Flue gas composition, HSE familiarity (see Section 4.13 and 6.1 for more information).

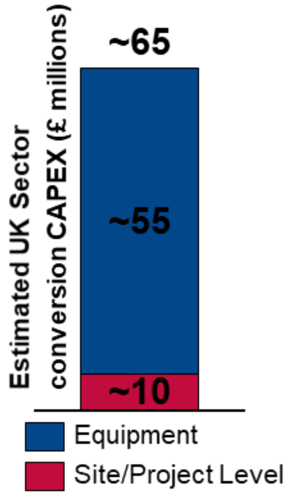
Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result. Relative low conversion cost due to fewer, larger pieces of equipment. For more details on methodology see Chapters 4 and 5.

Typical **20 MW Furnace** estimated conversion CAPEX: **£1.2 million**

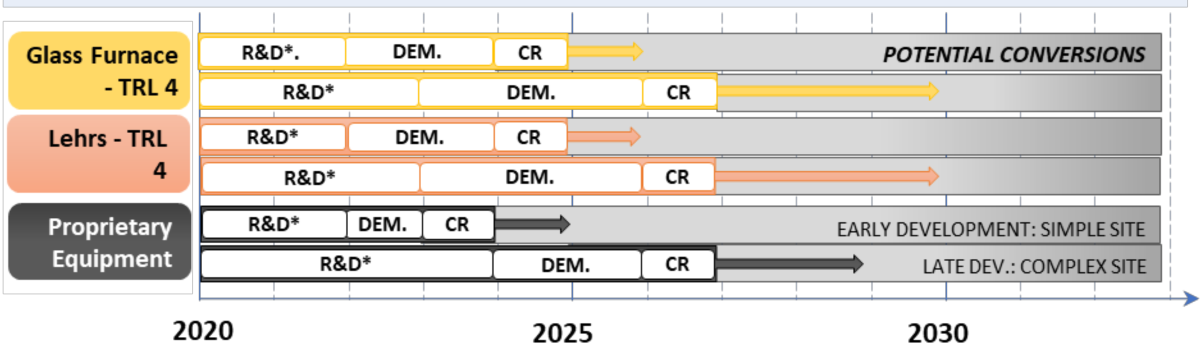
Demonstration Requirements: Glass furnaces will need significant demonstration, and due to bespoke equipment designs some will need to be site specific. Smaller equipment like lehrs relatively simple, so lower demonstration level needed. Some knowledge in sector around hydrogen use, though only as blanketing atmosphere. Glass Futures collaborating across industry for technology development purposes. For more detail, see Chapter 6.

10 MW Furnace estimated initial demonstration cost: **£1.5 - 6 million**



Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Ceramics

Sector Background

95% Heat from Natural Gas

4.7 TWh/yr heat consumption

~33 Sites using >5 GWh/yr gas

Economic contribution: Approx. 20000 directly employed in the sector, with £2 billion in revenues (2016).

Heat Use: 4.7 TWh/yr of heat used in sector. with an additional 0.7 TWh/yr of electricity used. Dominated by natural gas in kilns and dryers.

Sector Features: 100 major companies in the UK, manufacturing diverse range of products, with a large proportion being SMEs. Also as a large number of other microbusiness. Processing stages similar across sector.

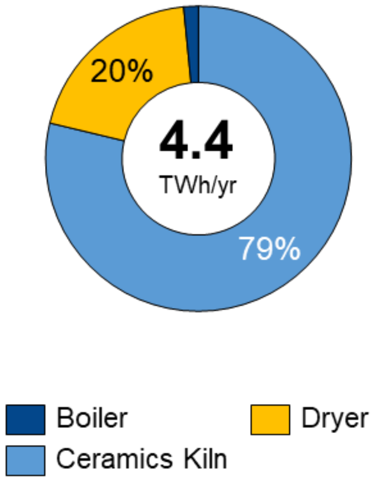
Natural Gas consumption

Key characteristics: Few sites connected to >7 bar gas network.

Relevant Processes: Firing raw materials in kilns key process. Drying, forming and finishing also important.

Relevant Equipment: Gas fired ceramics kilns, both smaller batch kilns and larger tunnel kilns. Dryers are also key, with their heat requirements lower than expected due to prevalence of heat recovered from the kiln. Some hot water boilers present in sector.

Relatively low thermal load factor, (~0.40) due to burners in kilns not firing all the time, as well as some batch operation of equipment.

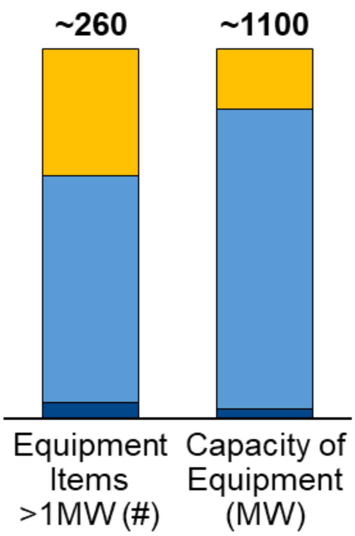


Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Generally one large kiln on brick/tile sites, with multiple smaller kilns on tableware sites. These typically range up to 10 MW.
- Dryers generally smaller in gas consumption, due to waste heat recovered from kiln, ranging up to 5 MW in size, with some <1 MWth.
- Relatively small amount of equipment <1MWth present on industrial sites, with some small kilns, some dryers and hot water boilers falling below this category.

Equipment Lifetime: Typical lifetime of kilns is over 40 years, though partial refitting and replacement occurs throughout life. Dryer lifetime in region of 20-30 years.



Ceramics

Key Challenges for H_2

Heat Transfer Mechanism: The balance of convective/radiative heat, and the composition and amount of flue gases poses problem for heat profile during firing in kilns. Equipment modelling and experimental investigation needed.

Refractory Materials: Higher flame temperature with H_2 might mean different refractory materials needed if impingement present, though these are available.

Flue Gas Moisture Content increases when burning H_2. Further experimentation and demonstrations are needed to determine impact on and mitigation measures for the drying process and kiln firing.

Notable Cross-Sector Challenges: NO_x emissions, HSE familiarity (see Section 4.13 and 6.1 for more information).

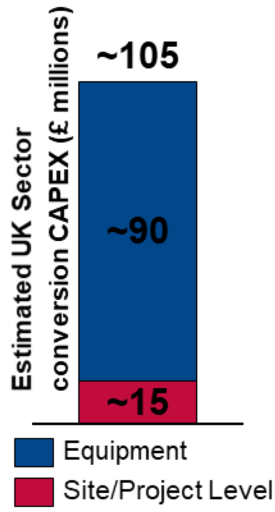
Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result. Cramped and space constrained legacy sites might present increased expenses for site conversion. For more details on methodology see Chapters 4 and 5.

Typical 5 **MW Kiln** estimated conversion CAPEX: **£0.4 million**

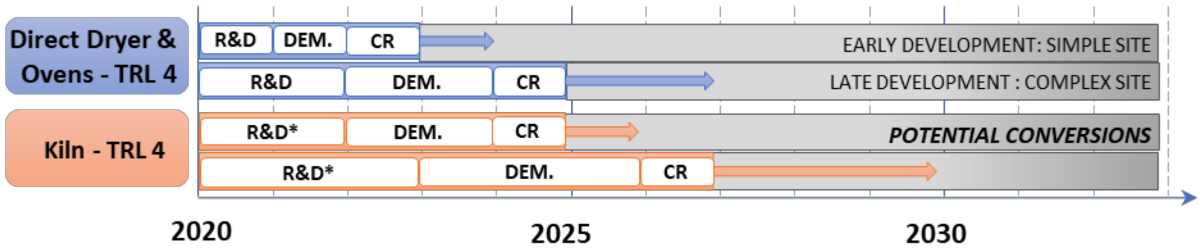
Demonstration Requirements: Kilns will need significant demonstration, and due to bespoke equipment designs some will need to be site specific. Dryers also need demonstration, particularly around the increased moisture content of flue gases. Most OEMs based abroad, with associated difficulties encouraging demonstrations in UK. For more detail, see Chapter 6.

2 MW Kiln estimated initial demonstration cost: **£0.8 - 3 million**



Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Lime

Sector Background

65% Heat from Natural Gas

1.8 TWh/yr heat consumption

6 Sites using >5 GWh/yr gas

Economic contribution: Approx. 300 directly employed in the sector, producing 1.5 Mt of industrial lime.

Heat Use: 1.8 TWh/yr of heat used in sector. Dominated by natural gas in high calcium lime kilns, though solid fuels in dolomitic lime and captive lime plants also important.

Sector Features: 6 large manufacturing sites, producing high calcium lime. Generally, isolated legacy sites, sometime co-located with cement sites. Process emissions contribute ~70% of CO_2 emissions.

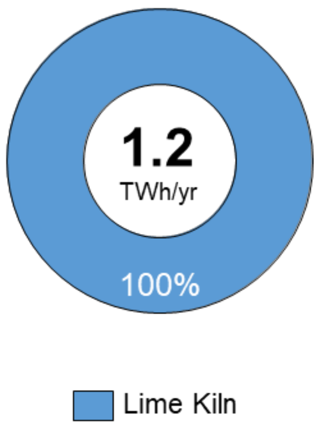
Natural Gas consumption

Key characteristics: Few sites connected to >7 bar gas network.

Relevant Processes: Firing raw materials in high calcium lime kilns is the key process, and the only significant natural gas consumer.

Relevant Equipment: Lime kilns. Newer kilns are parallel flow regenerative kilns, mostly made by one OEM, whereas older kilns are of various different types such as fixed vertical kilns.

High thermal load factor, (~0.75) due to continuous process. Some backup kilns also on sites.

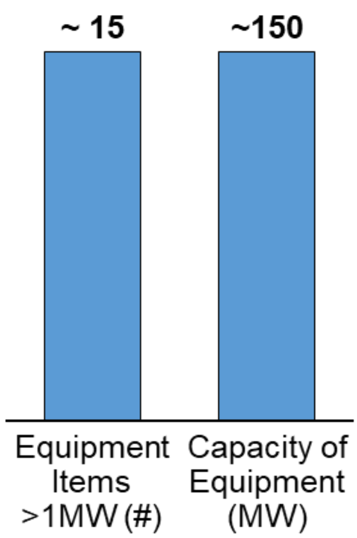


Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Typical numbers of lime kilns on sites range from 1 up to 4. Kilns generally of similar sizes ranging from 5 MW up to 25 MW.
- No significant equipment <1MWth present on large industrial sites.

Equipment Lifetime: Typical lifetime of lime kilns is over 30 years, though partial refitting and replacement occurs throughout life.



Lime

Key Challenges for H_2

Heat Transfer Mechanism: The balance of convective/radiative heat, and the composition and amount of flue gases poses problem for heat profile during firing in lime kilns. Equipment modelling and experimental investigation needed.

Flue Gas Moisture Content increases when burning H_2. This may have a large impact on lime, which reacts exothermically with water. Further experimentation and demonstrations are needed to determine impact on and possible mitigation measures.

Equipment in sector is either legacy equipment, or designed outside the UK. Ensure significant H_2 market for OEM investment into equipment development.

Notable Cross-Sector Challenges: NO_x emissions, HSE familiarity (see Section 4.13 and 6.1 for more information).

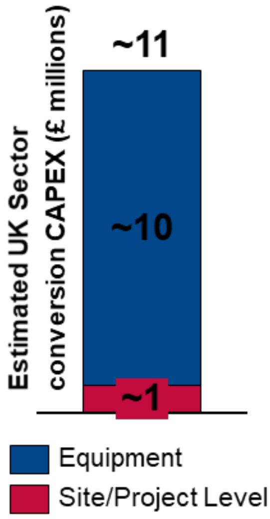
Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result. Cramped legacy sites might present increased expenses for site conversion. For more details on methodology see Chapters 4 and 5.

Typical **10 MW Kiln** estimated conversion CAPEX: **£0.5 million**

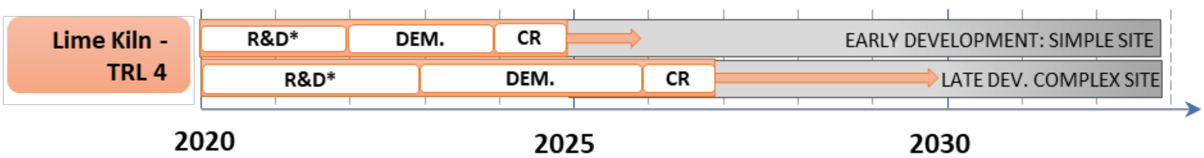
Demonstration Requirements: Lime kilns will need significant demonstration, and due to legacy equipment some will need to be site specific. This needs to focus on effects of the change in heat transfer mechanism and the increased moisture content of flue gases. For more detail, see Chapter 6.

5 MW Kiln estimated initial demonstration cost: **£1.2 - 4 million**



Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Other Non-Metallic Minerals

Sector Background

25% Heat from Natural Gas

~13 TWh/yr heat consumption

~60 Sites using >5 GWh/yr gas

Economic contribution: Approx. 35,000 directly employed in the sector, with approx. £5 billion in revenues.

Heat Use: Approx. 13 TWh/yr of heat used in sector. Dominated by solid fuel e.g. coal, biomass, waste derived fuel, in kilns for cement manufacture.

Sector Features: Fragmented sector, with diverse range of products and processes employed. a large proportion being SMEs. Key subsectors include Cement, Asphalt, Rockwool, Salt, Gypsum, Plaster and Abrasive Products.

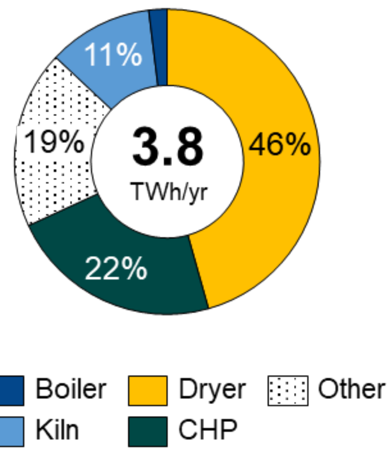
Natural Gas consumption

Key characteristics: Few sites connected to >7 bar gas network. Cement manufacture uses little natural gas only used in a few dryers/secondary appliances on sites.

Relevant Processes: Raw material and product drying particularly important. Melting, calcining, evaporation of solution mined salt and separation also important.

Relevant Equipment: Gas fired dryers, kilns and boilers are main equipment types, though specific equipment used is subsector dependent. Some CHP present in sector.

Relatively low thermal load factor, (~0.35) due to variation in demand meaning equipment not operational all the time. Some batch operation of equipment also present in the sector.

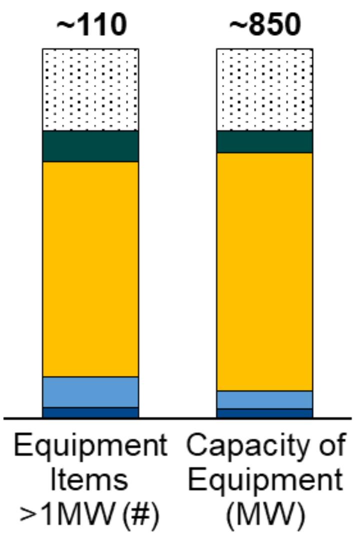


Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Generally one large piece of equipement on sites. In subsectors like Asphalt, these are rotary dryers used with very low load factor due to time constraints on product, resulting in appliances up to 30MW.
- High proportion of other equipement present due to large range of products with diverse manufacturing stages.
- Relatively small amount of equipment <1MWth present on industrial sites, with some small kilns, some dryers and boilers falling below this capacity.

Equipment Lifetime: Typical dryer lifetime in region of 15-25 years. Typical lifetime of other appliances is longer, approximately 25-35 years.



Other Non-Metallic Minerals

Key Challenges for H_2

Heat Transfer Mechanism: The balance of convective/radiative heat, and the composition and amount of flue gases poses problem for heat profile in rotary dryers. Equipment modelling and experimental investigation needed.

Flue Gas Moisture Content increases when burning H_2. Further experimentation and demonstrations are needed to determine impact on and mitigation measures for drying processes and kiln firing.

Notable Cross-Sector Challenges: NO_x emissions, HSE familiarity (see Section 4.13 and 6.1 for more information).

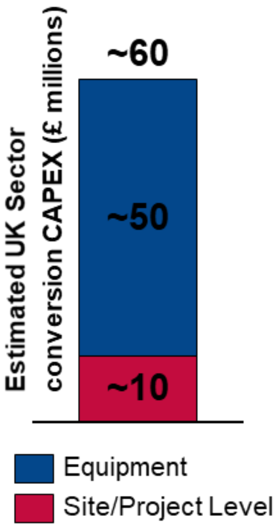
Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result. For more details on methodology see Chapters 4 and 5.

Typical **15 MW Dryer** estimated conversion CAPEX: **£0.5 million**

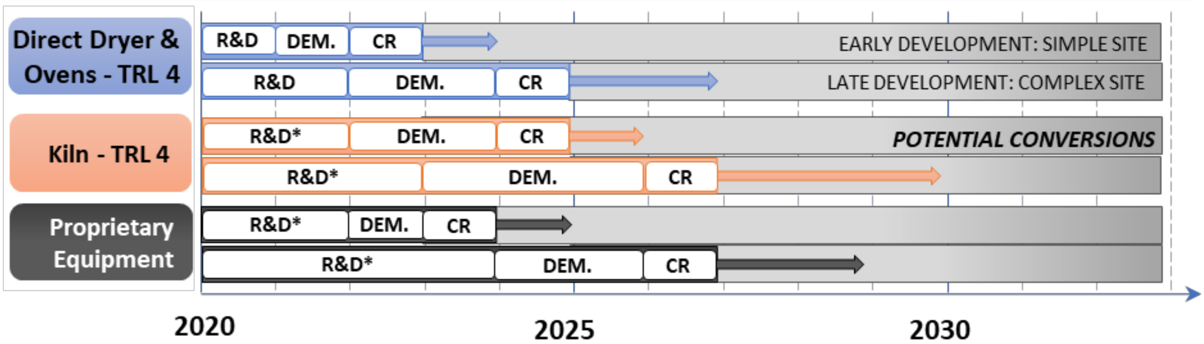
Demonstration Requirements: Significant demonstration needed in the sector due to variety of processes, products and equipment. Dryers will need demonstration around the heat transfer differences and the increased moisture content of flue gases. For more detail, see Chapter 6.

10 MW Dryer estimated initial demonstration cost: **£1.3 – 4.5 million**



Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



Electrical and Mechanical Engineering

Sector Background

>95% Heat from Natural Gas

15 TWh/yr heat consumption

~600 Sites using >5 GWh/yr gas

Economic contribution: Approx. 700,000 employed in the sector, contributing approx. £45 billion in GVA.

Heat Use: 15 TWh/yr of heat used in sector. Nearly all natural gas consumption. Significant electricity use in sector for non-heat processes, 13 TWh/yr.

Sector Features: Very diverse sector dominated by SMEs with processes varying widely. Fragmentation and diversity could lead to difficulty in cohesive fuel switching initiatives/demonstrations. Sector Includes SIC 2007 codes 25, 26 ,27, 28.

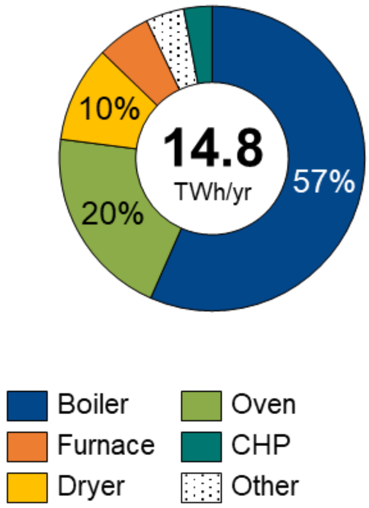
Natural Gas consumption

Key characteristics: Many small sites, with few sites significant enough to be connected to >7 bar gas network.

Relevant Processes: Highly variable processes across industry. Space heating most significant energy user, with low temperature process heating also important. Other processes such as forging, moulding, drying, tempering, welding, pressing etc.

Relevant Equipment: Gas fired boilers, both hot water and steam. Furnaces/heaters/ovens/dryers to generate direct heat. Direct fired equipment varies widely across subsectors, though boilers largely similar.

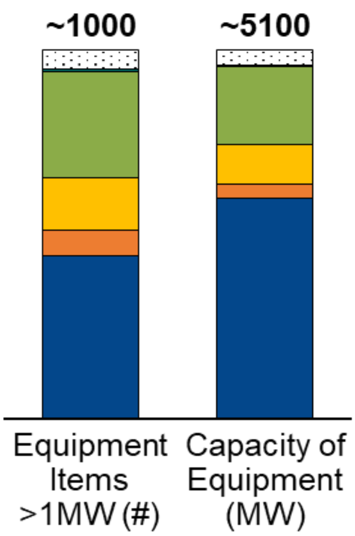
Low thermal load factor, (~0.30) due to use of equipment when needed, as well as non-continuous operation of plant.



Equipment (on <7 bar network)

Natural Gas Equipment Capacity:

- Equipment generally small due to low gas consumption on each of a large number of sites.
- Some sites have a large amount of their space and process heating demands met through hot water/steam boilers, up to 30MW in size.
- Majority of gas is consumed in many small pieces of equipment <1 MWth.
- **Equipment Lifetime:** Typical lifetime of boilers is 30-35 years, with other equipment generally having a lifetime of 20-25 years.



Electrical and Mechanical Engineering

Key Challenges for H_2

Large expense from converting many small pieces of equipment and sites over to H_2. Many of these sites are SMEs, with little scope to overcome lost production when converting. Sufficient support for conversion necessary.

Diverse Equipment: Large range of products in sector means direct fired equipment is diverse and possibly designed for specific products. Demonstration needed to show H_2 equipment can meet product quality standards.

Notable Cross-Sector Challenges: NO_x emissions, HSE familiarity (see Section 4.13 and 6.1 for more information).

Conversion Requirements and CAPEX

Equipment in the sector unlikely to be ATEX compliant, with additional subcomponents replaced as a result.. **Large number of small sites and equipment** in sector, making conversion **significantly expensive.** For more details on methodology see Chapters 4 and 5.

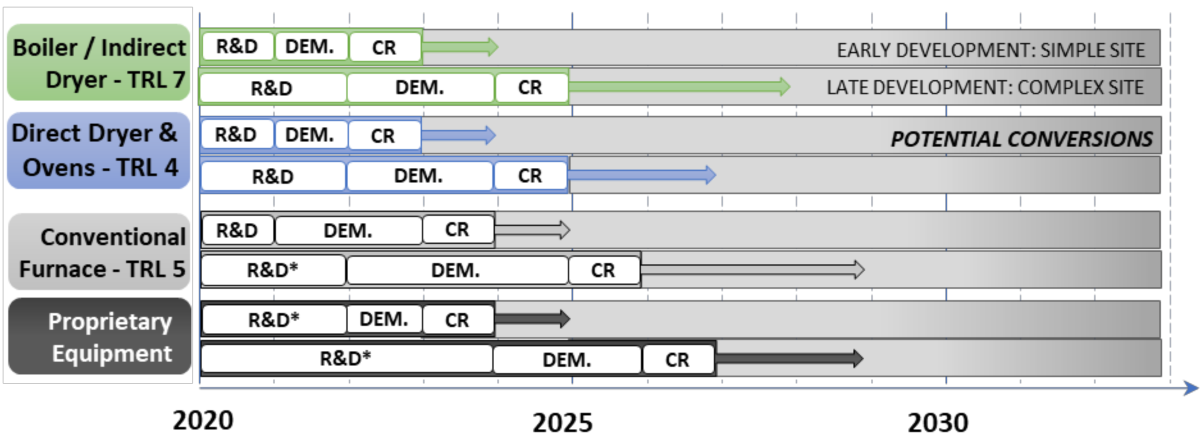
Typical **1.5 MW Boiler** estimated conversion CAPEX: **£0.2 million**

Demonstration Requirements: Boilers need demonstration, though not necessarily sector specific. Direct fired equipment needs greater range of demonstrations, possibly subsector/product specific. Fragmentation of subsectors might make disseminating results of fuel switching demonstration difficult. For more detail, see Section 6.

1.5 MW Boiler estimated initial demonstration cost: **£0.4 – 1.6 million**

Technology Development Timelines

Steps are Component R&D, (* denotes more complex R&D), Demonstrations, Commercial Readiness (OEMs providing equipment guarantees), and Installation periods. Timeline assumes adequate government support available for these demonstrations. See Section 5.6 for more info.



8 Conclusion and Recommendations

8.1 Overall Conclusions

8.1.1 Equipment in UK industry

Overall there was estimated to be approximately 4300 relevant pieces of natural gas consuming industrial equipment (>1 MW_{th}, on <7 bar gas network) in UK industry. Boilers were the most common of the equipment types, though there was a large range of different direct fired equipment. A large number of pieces of equipment <1 MW_{th} capacity was also found to be present on industrial sites, which will also need to be converted to hydrogen, though a significant proportion of these are likely to be packaged in nature. There is a significant natural gas usage on the >7 bar network (~30 TWh/yr), which covers the majority of CHP and equipment >50 MW_{th}.

8.1.2 Technical Feasibility

The conversion of the existing natural gas consuming equipment stock to hydrogen fuel was established to be technically feasible for a large majority of equipment types. Some technical challenges still need testing through demonstrations, particularly around the effect on direct fired equipment; including changes in heat transfer, flue gas composition, materials selection and NO_x emissions. No showstopping barriers were identified, however particular challenges remain for gas engine CHP around knock and derating when using hydrogen as a fuel. While further research might overcome these issues, gas engines may need replacement rather than conversion.

Hydrogen equipment is likely to achieve similar performance to natural gas fired equipment. There is a high likelihood that, without mitigating measures, there will be a consequential increase in NO_x emissions due to the higher hydrogen flame temperature. However, these mitigation measures are relatively well established and are included in the estimates of conversion capex in this report. These include lean combustion, FGR, steam or air addition and post combustion mitigation using SCR and SNCR (selective non-catalytic reduction).

8.1.3 Costs of Conversion

The capex of conversion was estimated to be approximately £2.7 billion in the central case. This included equipment conversion and site level pipework and engineering fees, but not research, technology development and demonstration. Conversion capex was dependent on equipment type and industrial sector, and the capex to convert sites will vary widely. A sensitivity analysis performed on the capex for conversion gave a range of £1.0 – 3.9 billion for the UK wide capex for conversion. The change in non-fuel opex was also considered, which could result in an overall increase of up to ~5% of total opex, attributed to increased level of staff training, consumables for purging, reduced lives of equipment (such as burner tips) and more stringent safety procedures.

Other costs such as re-permitting and COMAH compliance could have impact the UK wide cost for conversion (up to ~5% of total capex).

8.1.4 Industry Uptake and Timelines

Industry was found to be generally positive about decarbonisation. Throughout this project there were significant concerns raised around fuel costs and ensuring competitiveness of UK industry while fuel switching. Concerns were also raised around the impact of the conversion on product quality in key direct fired equipment types, as well as concerns around the impact on health, safety and operational costs.

To address the technical concerns, a program of demonstrations to achieve TRL 9 (commercial availability) was suggested, along with a technology development timeline in the region of 5-10 years dependent on equipment type. This was based on a clear government signal for hydrogen conversion in combination with incentives to undergo these demonstration programs, similar to the IFS Phase 3 funding. Delays in signalling or lack of funding availability will extend this timeline.

8.2 Recommendations

To ensure the option of using hydrogen for heat remains open, a number of steps must be taken in the near-term, addressing the current challenges and filling the remaining knowledge gaps.

The technical and economic recommendations are **critical** to deploying 100% hydrogen at scale in UK industry. Funding programmes are urgently required to drive all the necessary R&D activities to fill technical knowledge gaps and enable decision making. Following this, the incentive mechanism and hydrogen conversion strategy should be developed in the medium term. The recommendations around collaboration and other investigations are largely aimed at facilitating the optimal transition pathway in terms of cost, regulation and timeframes.

Technical

- **Modelling and lab scale tests for technically challenging equipment types** to understand potential impacts on equipment operation and product quality (e.g. flue gas atmospheres) at a detailed level and to channel the development of 100% hydrogen equipment.
- **Further technical development work around direct fired equipment and gas engine CHP** to overcome the remaining technical uncertainties and barriers. 'Hydrogen ready' equipment should also be investigated further, assessing technical challenges and costs of this approach.
- **Technical research around emissions control strategies** for each equipment type, particularly when NO_x control strategies are already in use on natural gas equipment. Collaboration with the Environment Agency to define appropriate emissions limits for hydrogen combustion for all UK industrial sectors/applications.

Economic

- **Demonstration programmes** are needed in the early 2020s to provide the required evidence of industrial equipment using 100% hydrogen before a decision is made on the long-term decarbonisation pathway for heat. Due to the lack of near-term drivers for industrial hydrogen conversion, government support may be required to drive the necessary development activities.
- **Determine a support mechanism for hydrogen conversion/use in industry,** evaluating different business models, assessing what funding and support needs to be available, and to clarify the ownership and sharing of the risks associated with conversion. However, any industrial incentives should ensure the best decarbonisation option is delivered from a technical, cost and system perspective.

Collaborative

- **Increase awareness of hydrogen options within industry** through engagement with major manufacturers and industry bodies across the UK. This could take the form of workshops to disseminate the options presented in this and similar studies or further interviews with industry stakeholders.
- **Intra-sectoral collaboration on pilot and demonstration scale trials** to allow effective use of test facilities or back-up/unused equipment. Further research on synergies across industrial sectors and equipment that may minimise demonstration costs is recommended.
- **Collaboration and discussion with regulating bodies** e.g. Environment Agency on emissions and HSE for health and safety regulations to develop/refine regulations and plan for effective roll-out.

- **Development of a knowledge sharing network** to facilitate information transfer between experts, OEMs, industrial sectors, hydrogen producers and other organisations.

Further Investigation

- **Investigation of different deployment strategies for hydrogen conversion**, examining the impact on conversion costs and risks. This should consider approaches such as retrofit or 'hydrogen readiness', as well as regional vs. national mechanisms. Clarity on the future hydrogen roll-out timeframes and mechanisms must be given as soon as possible to allow time for organisations to plan investments and major site works appropriately.
- **Comprehensive review of the site level cost impact** of conversion, involving detailed explorations of the impact and cost of additional H&S requirements on sites and assessment of the proportion of natural gas pipework on industrial sites which would require replacement.
- **Detailed comparison of hydrogen with other decarbonisation options for each industrial sector**, determining the best option (100% hydrogen, biofuels, electrification, CCUS, etc.) for each sector on a technical, economic and system-wide basis.
- **Further research on the impact of conversion outage on operations and costs** needs to be undertaken, and measures to minimise and mitigate this impact, e.g. 'hydrogen readiness', need to be considered and assessed.
- **Investigation of decarbonisation options for industrial equipment out of this study's scope** including equipment on the >7 bar gas network, CHP and the small amount of equipment within niche equipment types, to assess the feasibility and cost of possible decarbonisation options, including 100% hydrogen.
- **Further work on each industrial cluster to develop cluster specific costs and timelines** is recommended to reduce uncertainties associated with future deep decarbonisation of industry. This work should consider 100% hydrogen as well as other decarbonisation options such as electrification, biomass or CCS.
- **Review the original equipment manufacturer (OEM) supply chain** to understand resource availability for R&D, demonstration and implementation of hydrogen technologies in the UK. Investigation of the location and R&D capacity of all key equipment suppliers should be completed to understand whether steps are required to further build capabilities in the UK.

9 Appendix

9.1 List of Contributing Stakeholders

Industry Associations	
Nick Sturgeon	Chemicals Industry Association
Richard Woolley	Chemicals Industry Association
David Morgan	Confederation of Paper industries
Stephen Reeson	Food & Drink Federation
Jon Flitney	British Ceramic Confederation
Andrew McDermott	British Ceramic Confederation
Diana Casey	Mineral Products Association
Bec Hooper	Mineral Products Association
Matthew Croucher	SMMT
Andy Roberts	UK PIA
Dave Dalton	Glass Futures (and British Glass)
Aston Fuller	Glass Futures (and British Glass)
Mark Pudner	British Glass
Paul Pearcy	British Glass
Frank Aaskov	MakeUK/EEF (Energy Intensive Users Group)
Geoff Noon	MTA
Adrian Rhodes	CEA
David Kilpatrick	CEA
Gas network operators	
Lorna Millington	Cadent
Bethan Winter	WWU
Steve Edwards	WWU
Emma Buckton	NGN
Liam Mclean	NGN
Adam Madgett	NGN
Mark Wheeldon	SGN
Industry	
Andy Doran	Novelis
Martin Hills	CEMEX UK
Matt Derbyshire	Tarmac Cement and Lime
Peter Grosvenor	Tarmac Cement and Lime
Debbie Baker	CF Fertilisers
Mike Walton	CF Fertiliser
Phillip McNaughton	British Sugar
Zbigniew Szewczyk	Encirc
Steve Roper	Encirc
Martin Gannon	Liberty Speciality Steels
Colin Pritchard	Petroineos (Grangemouth)
Colin Hawthorne	Jaguar Land Rover Ltd.
Simon Mansfield	Jaguar Land Rover Ltd.
Rob Robson	BOC

Michael Laverick	Portmerion Group
Reg Booth	Portmerion Group
Jenny Cook	Portmerion Group
Roy Jackson	Portmerion Group
Stephen Smith	Churchill China
John Shipman	Huntsman Polyurethanes
James Wood	Huntsman Polyurethanes
John Malpas	Toyota
Shawn Humphrey	Toyota
Robert Taylor	Nestle
Mark Gregory	Nestle
Richard Stevenson	Inovyn
Dave Rudd	Inovyn
John Naughton	Allied Glass
Selomit Gomez	Allied Glass
Andrew Keeley	Pilkington Glass
Chris Peet	Nissan
Rebecca Wales	Nissan
OEMs / vendors	
Michael Welch	Siemens
Luca Mungai	BHGE
Carl Blewer	Unit Birwelco
Sudhir Arora	Unit Birwelco
Lee Thompson	Honeywell Thermal Solutions
Richard Withnall	Greens Combustion
Richard Spires	Wood plc
Chris Pritchard	Nu-way
Rainer Huesing	Keller
David Champneys	Boustead International Heaters
Paul Rowley	Byworth Boilers
David Pym	Fives Pillard
Patrick Holdsworth	Dunphy
Andy Robinson	Dunphy
Phil Kemp	Saacke
Information provided	Innio (Jenbacher)
Information provided	Wartsila
Information provided	Therser UK
Hy4Heat	
Jeremy Few	Hy4Heat Arup
Heidi Genoni	Hy4Heat Arup
Stephanie Tyson	Hy4Heat Arup
Adam Baddeley	Hy4Heat Progressive Energy
Mark Crowther	Hy4Heat Kiwa
Chris Manson-Whitton	Hy4Heat Progressive Energy
Mike Cairns-Terry	Hy4Heat Progressive Energy
Expert input	

Nilay Shah	Imperial College
Nixon Sunny	Imperial College
BEIS	
Phil Cohen	BEIS
Jon Saltmarsh	BEIS
Amy Salisbury	BEIS
Jenna Owen	BEIS
James Dobing	BEIS
Matt Hitchens	BEIS
Duncan Leeson	BEIS
Matilda Rogers	BEIS
Yasmin Ali	BEIS
Solmaz Parsa	BEIS

9.2 Summary of Non-Confidential Stakeholder Engagement Findings

This section provides a summary of some of the key comments from each industrial sector. These represent the views of some of the stakeholders in the industry and are not necessarily representative of the views of the report authors.

9.2.1 Food and Drink

Food and Drink Federation provided confidential data showing the detailed breakdown of gas consumption by subsector.

Sector

- Energy consumption relatively low proportion of production costs at approximately 2%. Varies by subsector, but generally low compared to other industrial sectors.
- Sector EU ETS emissions are 2.4 $MtCO_2$. Total UK emissions 2017 are approximately 8.1 $MtCO_2$ accounting for small sites, CHP and exported energy.
- High pressure and low-pressure steam is an arbitrary distinction. Many plants have high pressure ring mains and then lower the pressure for applications. Ring mains may be 10-20 bar but applications often lower.
- UK boiler stock in the sector is often packaged boilers, especially on the smaller sites. The highest capacity of 14 ft packaged boilers is around 20 MW.
- Utilisation – this will be highly variable – some sites will be at high load factor running 24/7, while some will have a lower utilisation. Load will also vary over the day/week/shift patterns/product. Load changes also vary seasonally – if processing agricultural products directly may be a link to seasonal production (which is often smoothed using storage), winter can increase demand for space heating and the autumn/pre-Christmas season is always busy for many sites.
- Oversizing – varies by subsector/process/equipment type. Oversizing generally higher in boilers, as some kept ticking over on standby.
- Approximately 90% of heat is produced from natural gas. The rest is mainly oil or coal, mainly in off gas grid sites.
- Dryers sizes span large range from smaller dryers (<1 MW_{th}) up to large animal feed dryers where the largest is around 35 MW_{th}. A few kilns present in sector for co-products.

Conversion

- Increased moisture content of flue gases might be an issue in direct fired equipment. Less impact on high temperatures >400°C, but the vast majority of equipment operates at lower temperatures ~200°C where there will be an impact on product quality. There might be an impact on instrumentation due to humidity.
- Little experience with COMAH in the sector. Might not be an issue as may not be pushed over threshold when converting to H_2.
- **Very specific equipment in the sector, with a large range of products and each product is bespoke. The food and drink sector has strict quality standards so testing might need to go on a product specific basis for direct fired equipment.**
- New Food and drink BREF has recently been issued and going through review at the moment. Every site will have to have their permit reviewed in next 4 years. Might need to get hydrogen incorporated into this discussion early.

- Timelines – sites hesitant to commit to doing whole conversion in the same year. They would need confidence to convert and have tested equipment. Around a 5 year horizon to implement anything through planning, regulation, 2 year build phase etc
- Some legacy equipment is present in the sector which has changed fuel multiple times, sometimes with the OEM no longer operating. Converting this old equipment stock over to hydrogen may be prohibitive either technically (too high NO_x) or economically.
- Main concerns are bespoke direct fired roaster equipment as well as the HSE effects on permitting ATEX etc.

9.2.2 Chemicals

Sector

- Feedstock use of natural gas – hydrogen, ammonia, methyl methacrylate, acetyls, and ethylene production are the main feedstock users of natural gas. These sites are connected to the >7 bar gas network.
- £14.7bn GVA including pharmaceuticals. Employment 140,000.
- Location – clusters represent the most concentrated areas of production but the largest chemical producing region is the north west where production is more spread-out (Merseyside and Manchester)
- Load factors: boilers used with low thermal load factor compared to the high production load factor. This is due to some being used as top up and back up for CHP and others just for start-up. Some also used only as a hedge position when electricity is expensive and steam compressors uneconomic to run.
- Furnaces generally 1 per site for cracking and ammonia. For other furnaces the thought is still be just 1 on a site where the site has them.

Conversion

- Cracking feedstocks to produce ethylene gives hydrogen rich feedstock / by-product. The H_2 produced could be used for tests and trials located close to plants.
- If government wants to switch big processes, they need financial compensation for either the assets viable lifetime or the cost of replacement.
- Safety report updates – surely there would be add on costs for technical 'fixes', regulatory costs (HSE currently charges £180 per hour for reading reports as well as site inspection time).
- A comparison should be done to determine the relative environmental impact between the reduction in CO_2 emissions and the increase in NO_x emissions
- In sites integrated with fuels such as refinery fuel gas, the range in quality of gas would be too great for them to control. Compositional change on variation of blend would be difficult as refinery gas much heavier than hydrogen (ethane propane etc). Would need segregated fuel systems as the Wobbe number of H_2 and NG might be too different. It's difficult to balance load between systems, as current capability to exchange fuel gas and NG important. However, sites with significant internal fuel usage likely to be on the >7 bar network.
- Would need to have zonal conversion of local grids as don't have construction resources to convert UK over a short time period.
- Impact / cost is a lot more than just permitting etc. Physically adding emissions abatement options and rearranging plant etc. Emissivity may mean you need to redesign heater boxes etc. New kit and space required.
- Practical considerations around hazardous issues: many chemicals sites already use hazardous substances so this wouldn't be that different as they are used to working with certain procedures. COMAH present already on a significant number of sites.
- Some boilers which burn gas mixtures containing hydrogen present in the sector, up to an example of a boiler burning 100% hydrogen.
- Due to the reduced luminosity of the flame and no CO_2 in flue gases, infrared (IR) and ultraviolet (UV) flame detection might be necessary for safety.

- Heterogeneous sector with significant processes that would need to be trialled. COMAH sites and speciality equipment in chemicals – sites aren't keen to be first movers or impact their costs or COMAH status.

9.2.3 Vehicle Manufacturing

Sector

- Engineering development is mainly outside the UK for all but Jaguar Land Rover. Companies develop the future technologies; working abroad and then they are rolled out around the globe.
- Sector very much in global competition. Need sufficient support from government to decarbonise otherwise offshoring of manufacturing a very distinct possibility.
- Companies generally use the same kind of equipment, designed and built by the same (few) companies.
- Equipment: some companies have water based process heating with the majority in boilers. Others have very little hot water requirements and with all equipment being direct fired.
- Many small pieces of direct fired equipment on sites for heating in Paint Shop, Heating, Ventilation and Air Conditioning (HVAC) etc. up to a few MW in scale.

Conversion

- Generally, the hot combustion gas is mixed with a much larger flow of fresh air to increase the temperature by a small amount. For example, heating to 18-21°C in the spray booths, and around 150°C in the ovens. This dilution means the increased moisture content of the combustion gases with H_2 possibly less of an issue, though humidity in spray booths must be controlled.
- Level of evidence: they are using equipment made by OEMs, and they didn't develop this. They would expect the OEMs to develop and demonstrate the technology. Ultimately it would boil down to cost but has to be 100% reliable. Testing doesn't need to be on site for most equipment types e.g. burners and boilers, so long as the OEM is confident and has proof. For the paint shop it may be more critical to run application specific trials.
- Flue gas recirculation might be tricky to retrofit on old boilers.
- Timescales: potentially looking 2025-2030 before you could convert anything with confidence. After that once the equipment is available, wouldn't necessarily be installed until there is an incentive / new installation of equipment on site anyway / requirement. There would need to be a strong signal from government to invest in boiler houses and a clear timeline.
- Given the age and configuration of existing combustion systems concerns around increased flame length, flame temperature, NO_x emissions, gas pressure and permeability of existing mains are all key worries that would need to be answered through trials and demonstration projects.
- Toyota has developed a low NO_x direct fired H_2 burner for use in an assembly line in Japan. This could provide evidence as a pilot test, though intellectual property considerations around demonstrations are important.

9.2.4 Basic Metals

Sector

- Steel sector used around 4.9 TWh of natural gas in 2018
- Lifetimes – rebuilds on metal melting furnaces are approximately every 2 years. Out of operation for 2 weeks during these.
- No internal fuels on pure steel sites. British Steel, Scunthorpe and Port Talbot will mix in internal fuels, but that may be it.
- Steel rolling includes reheating of steel prior to rolling
- Steel melting is mainly electric for some sites, though does consume some natural gas.
- Metal treatment furnaces also important.
- Generally, plants would run at a high load factor, frequently running 24/7 all furnaces (2 weeks annual shutdown). Demand fluctuation might mean lower utilisation of production capacity.

Conversion

- Safety: immediate reaction is around the risk associated with 'theoretically much more dangerous' fuel. Need understanding how hydrogen reacts in all sorts of different environments. Some sites already regulated under DSEAR due to explosive metal powder/dusts.
- Investment cycles determined globally
- Heat Transfer and Air Flow - Would need to look at the flame temperature as flame sets off the thermal flow round the furnace; burner fires either across roof or side wall and is sized so that the correct flame gives the right air circulation. Flame Temperature and Size have effect, as well as heat transfer balance.
- Money is spent reducing the H_2 content of high quality steel due to embrittlement. With H_2 burners the amount of uncombusted H_2 would have to be strictly controlled, otherwise might have impacts on strict safety standards / product quality, e.g. for aerospace material fuels.
- Would take significant time to convert, lots of plant disruption. No more replacement for 25 years after each furnace replacement, they maintain as long as possible, just some upgrades.
- NO_x levels are a concern. They are already needing to try and reduce their NO_x and will struggle with the new NO_x levels.
- Level of evidence / testing: you'd want a like-for-like trial. NADCAP and other audits and standards require testing to satisfy the requirements, independently audited twice a year. They would want this level of evidence on furnaces in terms of scale and application. Monitor data loggers through the whole furnace and do tests on the steel right through the process. Large scale demos with considerable testing. Need product buyers to be involved in the transition and conversion to promote understanding with regards to product quality constraints.
- Global demonstration programmes (e.g. Swedish Steel Plant switching to H_2 in HYBRIT project) are an opportunity in the steel sector due to the sector's global scope.

9.2.5 Refining

High level information on the major equipment using either refinery fuel gas, natural gas (or gas/oil dual-fired) on refining sites was provided by UK PIA.

Sector

- **Out of the six refineries in the UK, only four are connected to the natural gas grid. These four refineries are all connected to the >7 bar gas network.**
- For the four refineries that use NG, it is either used to fuel gas turbine units by itself, or introduced into one or more headers for the Refinery Fuel Gas (RFG) system to maintain a constant working pressure. The RFG system then distributes mixed RFG/NG to units across the sites. Any conversion to hydrogen firing would therefore require reconfiguration of the gas systems or conversion of the whole site at the same time (with possible replacement of the gas distribution system).
- One small bitumen refinery present in sector as well.
- 2 refineries operate SMRs, using either natural gas or petroleum gases are feedstock. These could be used as a source of H_2 for trials in the local area. Refineries also produce H_2 as a by-product of cracking, so significant potential for integration of refining sector as a H_2 supplier. Refining could kick start local hydrogen markets for demonstrations.
- Significant new investment is being made at Valero Pembroke with a new NG-fired CHP plant (£100m) and at Esso Fawley with an SMR and additional gas oil hydrotreater (£800m).
- The major product processes carried out in UK refineries include distillation, vacuum distillation, reforming, catalytic cracking, alkylation, isomerisation, hydrocracking, coking and calcining, desulphurisation and hydrotreatment. Combustion in boilers and furnaces, hydrogen recovery and production, sulphur recovery and catalyst regeneration are secondary processes required to carry out the main production processes.
- Outage frequencies are expected every 4-6 years.
- Hydrogen in refinery gas is a valuable resource for refineries – they remove hydrogen from this to use in processes (hydrotreaters/hydrocrackers) rather than burning it.

Conversion

- Natural gas replacement with H_2 would have a significant effect on equipment such as CHP plants or integrated power producers which entirely burn natural gas. Replacing blended natural gas with H_2 (~5-10% natural gas currently blended with refinery fuel gas to retain constant pressure) would affect this equipment but be less significant.
- Industry often has a 4-5 year major turnaround cycle. So need a couple of years after technology validation before anything can happen.
- Refining has suffered high cost for implementing new regulations; as a result some refineries closed. This is one of the risks that needs to be taken into account for any conversion.

9.2.6 Paper

Sector

- Papermaking sector direct CO_2 emissions are about 1.6 $MtCO_2$ per annum if you include the emissions from all associated CHP plant. It could be argued that since some of these emissions are related to generation of electricity for export they should not be counted – nevertheless, the emissions arise at these mills and CHP plant and are attributed to those plant in the EU ETS accounts
- There are 46 paper mills in the UK right now. The smallest consumes ~5 GWh of gas each year (and it's a tiny mill). There are two further very small sites that make hand-made paper.
- There are approximately another 200 or so paper conversion sites in the UK. Some 30 of them will have process stream requirements and they'll have boilers (1 or 2 per site) of between about 2 and 10 MW capacity. The other sites will only have boilers for space heating.
- Some 15%-20% of sector drying heat is directly supplied (i.e. gas burners) and the rest comes from steam.
- Proportion of sites which use CHP: 60% by production tonnage (paper mills only, of course). By number of paper mill sites, it's only 30%.
- There are 15 paper mills that have CHP plant. Some have one engine, some two.
- There were about 100 boilers & gas CHP plants in the papermaking sector. So – approximately – that would mean about 85 boilers.

Conversion

- Package equipment and indirect equipment like steam boilers need only a few demos overall.
- Once technology and hydrogen are available, should be only 2-3 years for implementation, with 5 year payback expected.
- Paper not very specific as low pressure steam boilers very generic so demonstrations don't necessarily need to be completed in the sector / application. Paper sector is going to be a follower, nobody wants to demonstrate or be early adopter as already use biomass and have cut emissions significantly.

9.2.7 Glass

British Glass provided an estimate of the number of large-scale gas fired furnaces within each thermal input range. There are also smaller pieces of equipment such as pot furnaces and toughening ovens, with the number estimated through other data.

Sector

- Downstream sites carry out toughening or manipulating of the flat glass (500C heating then cooling).
- The majority of glass furnaces are gas fired regenerative, with the burners firing for 15-30 minutes on one side before switching to the other side. This is incorporated into the rated capacity.
- Operate constantly for approx. 15 years before a full rebuild (essentially new furnace in same location).
- Little equipment is ATEX compliant – will need to upgrade. Workers generally at least 10m away from the burners though.
- They have temperature limits which they cannot exceed. 1700°C is too hot for them because silica is used to construct the furnace crown. Melts at 1620-1660°C. Starts to rain off the crown if too hot. Needs to be no direct contact between flame and crown. Some glass furnaces use fused cast alumina bricks which can withstand temperatures up to 1700-1800°C. Potentially other materials used in some furnaces that can also withstand higher temperatures.
- The burners themselves are not complex burners. Pipework to a convergent nozzle. Fuel is ignited due to the heat in the furnace.
- Combustion air fans used on the inlet and induced draft fans after the waste gas abatement system (bag filter or electrostatic precipitator).

Conversion

- Safety zones around furnaces designed around the DSEAR, increase of 50% would have large effect.
- Level of evidence: Test rig and run the two fuels side by side would be useful for demonstration to ensure equivalent function. Large scale industrial demonstration suggested in a glass furnace of reasonable scale. Probably one for float glass, one for container. Need to operate for multiple years due to confidence needed to make the 15-20 year investments for furnaces.
- Emissivity of the flame and the balance between radiative and convective heat transfer very important to the glass furnace, with some key concerns around the hydrogen flame here.
- Approx. £45 million for 37.5 MW glass furnace (0.9 GWh per day). All the ancillaries and refractories have to be changed with it. £1.2 million for conversion sounds reasonable.
- Hydrogen with some biofuel blending is being looked at to improve the luminosity of the flame.
- If you take a typical 250-300tpd furnace the rebuild cost will be around 5 to 7 million and the new cost will be 10 to 14 million not including any civil works.
- Timescale - overall 5 years is reasonable from inception to start of operations for a new investment; most investments require 2-3 year payback.

- Glass Futures is a good example of a cross industry collaborative approach towards demonstrations and intellectual property management.

9.2.8 Ceramics

British Ceramic Confederation provided details on the gas consumption distribution of sites.

Sector

- There are approx. 100 major companies in the UK, operating across approx. 150 sites, manufacturing a diverse range of products. A large proportion of these companies are SMEs. Companies spread across UK though a concentration in Staffordshire.
- Porosity of the ware is higher in the middle of the batch than at the edges. Potential issue around heat transfer mechanism within the tunnel itself.
- The kiln structure (combustor) can run for a long time. No need to replace as long as regular maintenance is implemented.
- Each kiln requires approximately a 2 week outage per year for maintenance and cleaning.
- Dryers – All sites have dryers. Some electric dryers; majority are gas fired dryers; some are integrated using waste heat recovery from the kiln, but these will be gas consumption will be in the dryer to regulate temperature. 100% of sites with a dryer.

Conversion

- Many sites are legacy sites with different pipework running all over factory. Extraction pipework would require changing. Lots of seals, valves and flow meters – joints would need welding if possible.
- Big concern is around moisture content of flue gas given the end goal of ceramic manufacture is to remove moisture.
- Very limited space – any increase in zoning size would have a major impact on production – staff work in close proximity to burners operating in kiln.
- Kiln demonstrations for different sub sectors will be required – tableware, tiles, bricks etc.
- Pipework will need to be replaced. Welds won't have been done with this in mind.
- Timeline – don't have an initial pilot. Pilot on a small number of burners on an existing kiln, build up from that. Manufacturing of kilns based abroad, and large kiln builders are engaged with this. This takes a significant number of years, but people are only starting to engage with it now. A few different kiln demonstrations necessary – different techs for brick/tableware etc.

9.2.9 Lime

British Lime Association shared confidential details of approximate site gas consumption distribution and number of lime kilns (excluding organisation names). Indicated 6 sites with 19 operational natural gas consuming lime kilns in the region of 5 – 20 MW_{th}. Further details on gas consumption available but confidential.

Sector

- **11 operational sites. 6 of these consume natural gas, these being the major high calcium lime manufacturers. 1 dolomitic lime site uses solid fuel, as process is similar to Cement, and 4 small captive high calcium lime plants use solid fuel.**
- Kilns: some are redundant on sites. While running they will run most of the time but maintenance about 8 hours a week. Gas supply to the kiln is turned off during this maintenance and is boxed up to retain heat.
- The legacy equipment is unlikely to be brought back into use, so don't necessarily need to convert to hydrogen, although could potentially be used for trials. Gives flexibility to convert some to hydrogen while running another on natural gas.
- Quality of kilns. Some operators run kilns at low heat requirements as product is a mixture of lime and limestone (not fine lime) but the purity requirements some manufacturers have are quite stringent as some goes into water purification. This could be a concern for hydrogen conversion.

Conversion

- Permitting: there would be a direct impact in terms of the EA cost of permit variation and associated cost in terms of the consultation and modelling to get the application correct.
- They would expect Maerz (the OEM for all new lime kilns in the UK) to determine whether the kiln could be converted, they are designing the control system, injectors etc. Advice from them would drive their capital expenditure programme. They would need to be involved in the demonstration programmes.
- Heating (radiative): Maerz kilns may need significant alterations. Shaft kilns are bespoke, and they would have to review the way that they operate
- Level of Demonstration - Full scale production demonstrations for long time needed, even if all was being done was changing burners. Before network conversion to H_2 need to prove converted kiln and newly designed kiln that runs on H_2 (or dual fired).
- Significant process emissions – CCS would additionally be needed and might be a better option for lime sites.
- **Water content of flue gases would be significant challenge, as water is big problem. CaO reacts vigorously with H_2O, causing concerns over product quality, efficiency, lifetime and safety. Could possibly compensate for this but might need kiln modifications.**

9.2.10 Other Non-Metallic Minerals

Sector

- Cement sites use little natural gas, and not in the main process kilns; in some cases, this is due to sites being off-grid and if these sites were connected, they may be able to use natural gas / hydrogen. Generally natural gas is used to a small extent in ancillary equipment such as rotary dryers. Hydrogen being considered as a potential fuel switching option for cement kilns which don't currently use natural gas (though doesn't account for process CO_2 emissions).
- Asphalt sites consume a significant portion of sector natural gas. Lots of rotary dryers in ~250 sites distributed around country to reduce product travel time. Of these ~40 use natural gas powered rotary dryers.
- Rotary dryers' large thermal capacity but low load factor as inconsistent demand for product.
- Capacities – 10-20MW thermal rotary driers and some in 20-30 range.
- Number of pieces of equipment per site: max 2 rotary driers per site. Majority of other minerals sites which have kilns likely to have 1 or 2 kilns.

Conversion

- Need proof in similar application (e.g. rotary dryers) at a similar scale to condone conversion. Don't necessarily need a demonstration in their specific sector, but must be the equipment used in a similar application.
- Biggest risk is the technical one around it not working on day one when installed and the resulting lost production.
- Could start conversion at a plant which is less production critical as they can cover the volume from another plant.
- Permitting: sites are up to EU levels, so would need a different regulatory environment to get those re-permitted. A permit change is min £15-20k and large variation is costlier and more complex.
- Sites can be quite small and space restricted, though some sites are isolated near quarries etc.

9.2.11 Summary of Non-Confidential OEM Engagement Findings by Equipment Type

This section provides a summary of some of the key comments from OEMs in each equipment type. These represent the views of some of the OEMs and are not necessarily representative of the views of the report authors.

Gas Engines

- Hydrogen can be fired in gas engines to a fraction ~30%.
- Some gas engines can go beyond 50% hydrogen (spark engines), with adjusted compression and power
- The main issues are an increase of knock when firing hydrogen, and that firing hydrogen requires a larger fuel inlet system that may result in more than 30% derating in the engine capacity.
- Other issues include increase in explosion limits and NO_x emissions; in the case of NO_x emissions, this might require much large SCRs in the exhaust, which are already used in some gas engines.

Gas Turbines

- Drive for new products and converting existing gas turbines for high hydrogen content refinery fuel gas to decrease flaring or replace its use in boilers.
- 100% hydrogen firing is available on the GE10 currently. GE is confident that 100% hydrogen firing is also possible on the new MS5000 and MS6000 frames and possibly MS7000.
- NO_x emissions remain problematic due to the high firing temperature. While development of DLE/DLN burners have been successfully tested, this does not reduce NO_x emissions down to the single digit level limits, and an SCR is still required. Alternatively, steam or water injection can bring the NO_x levels down at the cost of demineralised water and added equipment. Dilution of the Fuel gas with inert gasses (N_2 or flue gas) will decrease the NO_x but there is little experience with this industrially.
- Other issues include: the increased risk of flashback for high amounts of H_2, a change in the explosion risk characteristics, the possible requirement to use a standard fuel for start-up and shutdown.
- Conversion to hydrogen will not require significant derating of gas turbines.
- The use of 100% hydrogen would probably shorten maintenance intervals from 3 to 1.5 or 2 years.
- Conversion of existing GTs should be assessed individually. Careful assessment of gas detection, burner configuration and fuel system are required. H_2 fractions below 5% are not considered a problem and could be fired without any adaptations to current equipment.

Burners

- Burner manufacturers were found to have supplied burners for use up to 100% hydrogen, usually in applications in the refining or chemicals sector, with a hydrogen rich by-product or refinery fuel gas stream.
- Due to the very high flame temperatures, the material of the gas tip is an important issue.
- Flame stability is not an issue, but the flame can burn very close to the nozzle tips, making material selection more difficult.

- High frequency noise can be an issue, which can be solved with silencing.
- Some burners using up to 100% hydrogen use diffusion concepts to provide reduced NO_x, and DLE/DLN burners have been development to minimise NO_x emissions.
- 100% hydrogen burners are available that guarantee no risk of flashback
- It was suggested that there might be insufficient skilled labour to convert all equipment in the UK from natural gas to hydrogen in a short space of time, necessitating a phased approach.

Boilers

- Boiler manufacturers work closely with burner manufacturers to provide appropriate specifications for their clients, but generally burner manufacturers take the lead on the technical combustion aspects.

Kilns

- Kiln manufacturers not currently developing hydrogen firing kilns, the focus is more on current customers and their requirements.
- Some kiln manufacturers do not see a future market for hydrogen fired kilns.
- Many of the larger kiln manufacturers are based abroad. Brick and roof tile kilns are generally manufactured in Germany, and wall tile kilns are generally manufactured in Italy.

Heaters/Furnaces

- Generally international standards such as API 560 or ISO 13705 are important differentiators for equipment manufacturers. Client specifications can also be very bespoke.
- Burners are purchased from specialist burner suppliers, and then integrated into the equipment system.
- Manufacturers confirmed they have supplied designs for up to 90% hydrogen, with this upper limit simply because of the natural composition of the by-product gas used to fire these heaters, and not down to any technical limitations.
- An example of a small hydrogen burner (~50 kW) has been utilised for a single application.
- Little impact is foreseen on the main furnace or heater combustor in conversion to hydrogen outside of burner replacement and possible NO_x control mechanisms.
- Efficiency with hydrogen is thought to increase slightly, with a slight decrease in waste heat recovery potential.
- Manufacturers didn’t see higher flame temperatures as much of an issue for the furnace. However, the gas delivery system and burners will need some attention.
- Changing fuel to H_2 will mean lower capacity needed for post combustion system (stacks ID fans etc).
- NO_x emission will tend to be higher but can probably be managed within UK limit with the latest low NO_x burner.
- One issue is how to approach leak testing with hydrogen.
- In general, no large issues were foreseen with conversion to hydrogen.

9.3 Combustion Modelling Results

Figure 9-1: Adiabatic flame temperature (K) for methane (left) and hydrogen (right), for initial temperatures from 273 K to 573 K

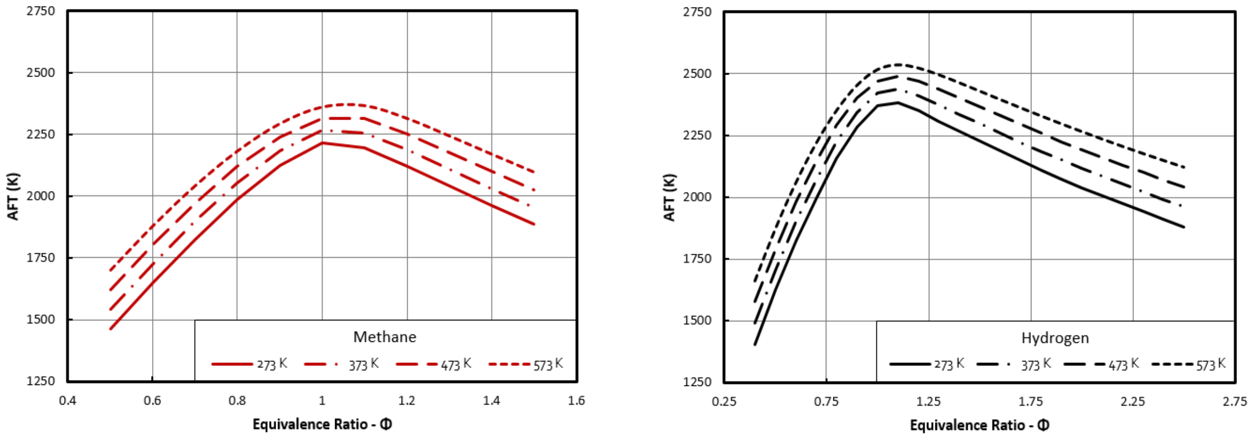


Figure 9-2: Laminar flames speed (cm/s) for methane (left) and hydrogen (right)

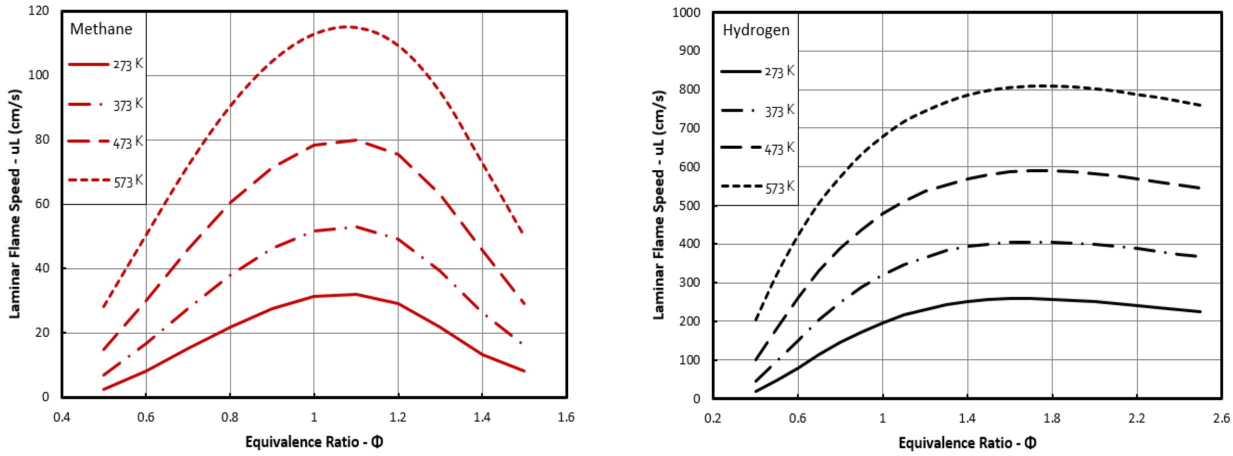


Figure 9-3: Calculated ignition delay times (ms) for methane and hydrogen

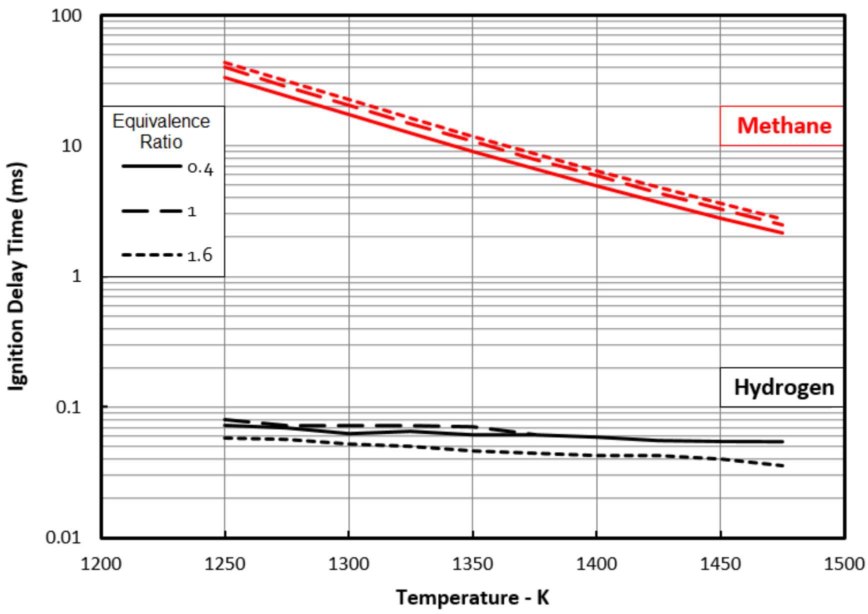


Figure 9-4: Extinction strain rates (1/s) for methane (left) and hydrogen (right)

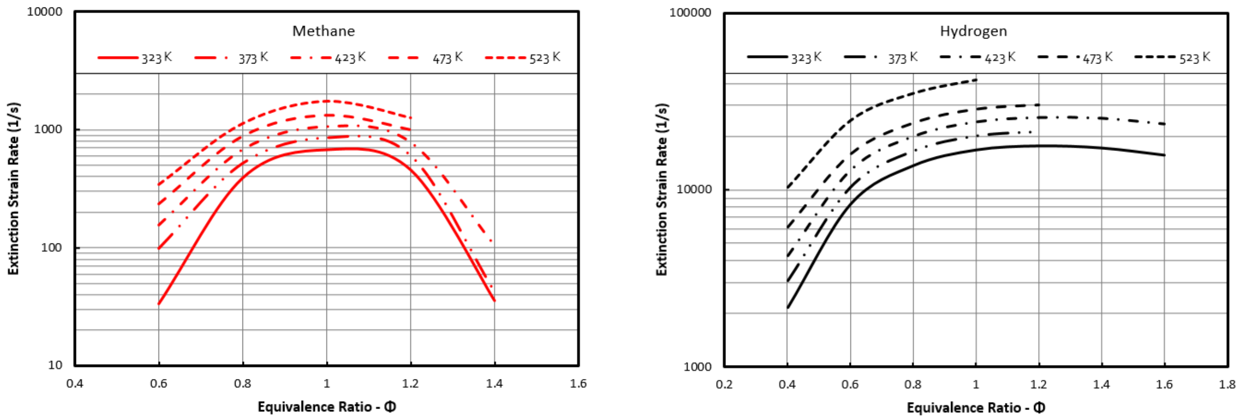


Figure 9-5: Calculated combustor exit temperatures (K) and mass flows (kg/s)

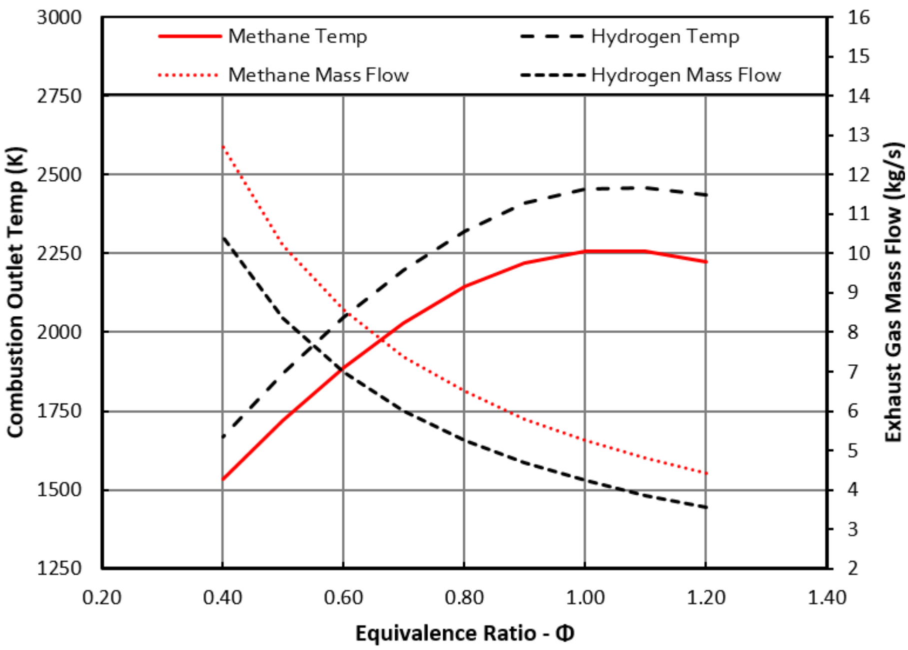


Figure 9-6: Calculated exhaust gas oxygen and NO_X concentrations

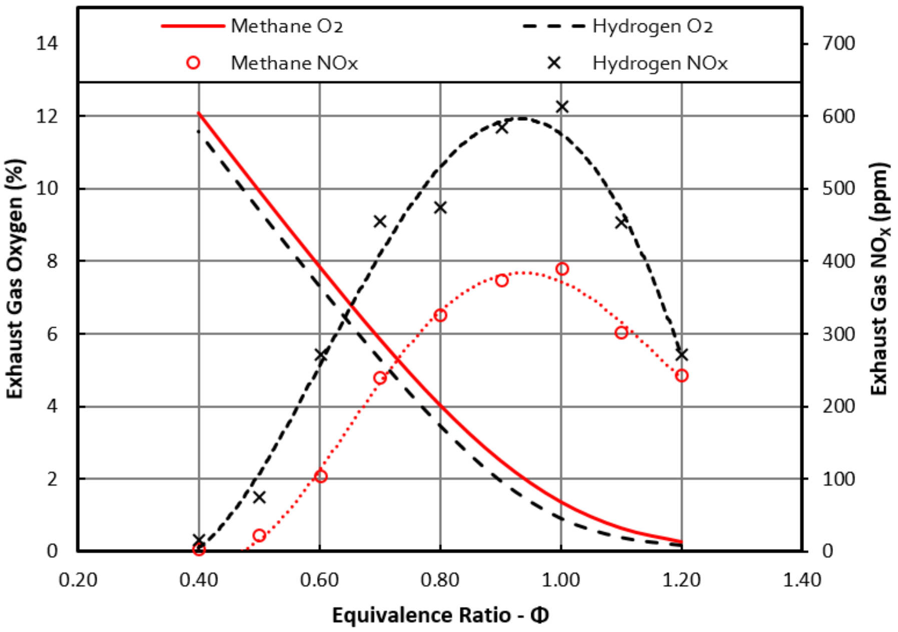


Figure 9-7: Exhaust gas NO_x concentration corrected to 15% Oxygen, dry for idealised combustor

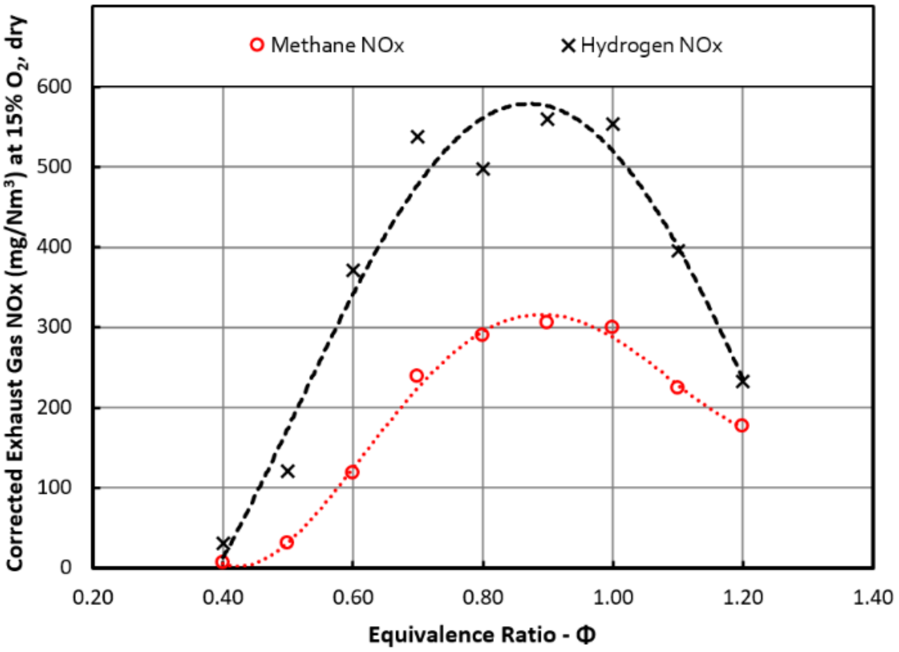


Figure 9-8: Comparison of calculated concentrations of major species at combustor exit for methane combustion (left) and hydrogen combustion (right). From Aspen HYSIS modelling.

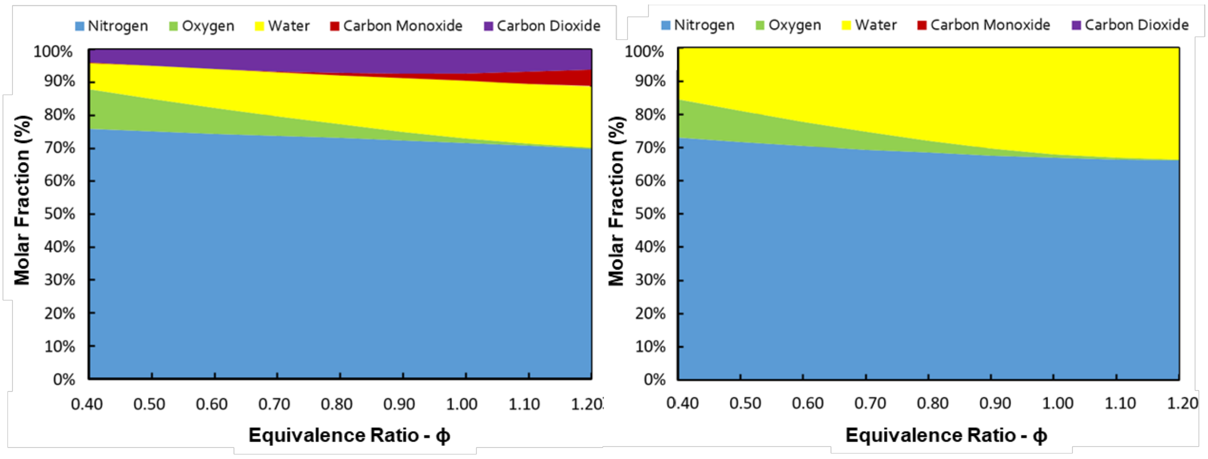


Figure 9-9: Comparison of combustion air flows for 14.5 MW hydrogen and methane flames

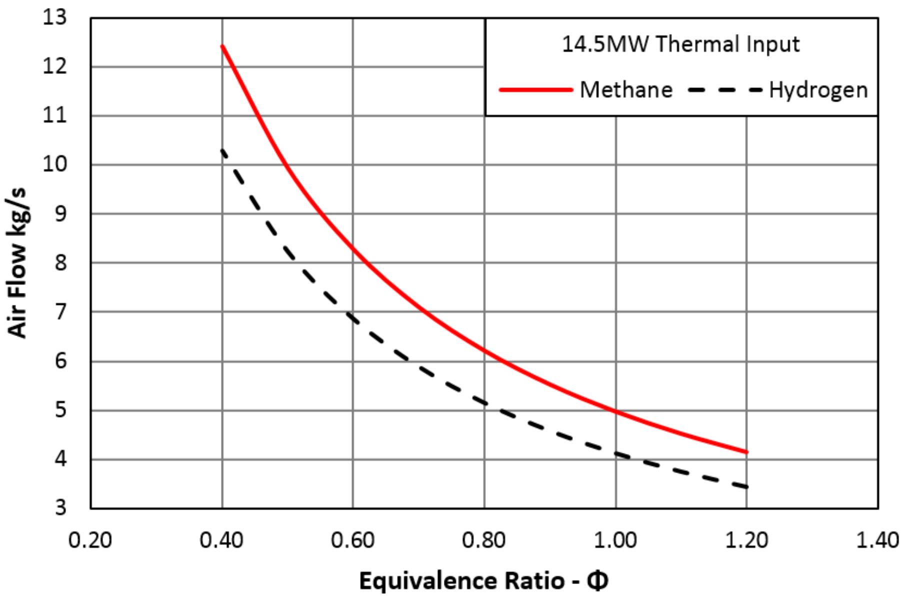


Figure 9-10: Calculated effect of nitrogen addition to oxidant on NO_x emissions in mg/Nm3 (14.5 MW flame, Φ=0.95)

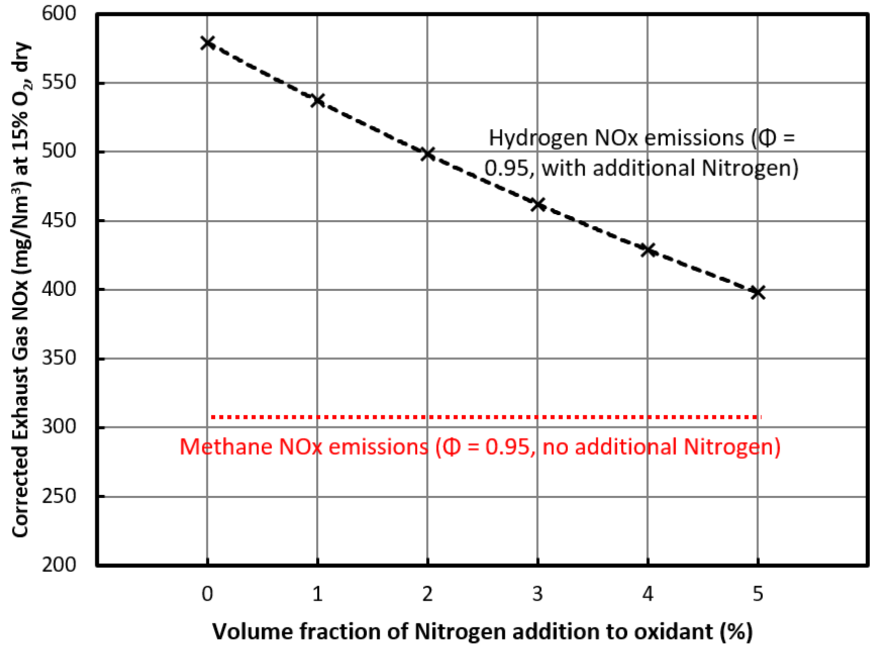


Figure 9-11: Calculated effect of steam addition to oxidant on NO_x emissions in mg/Nm3 (14.5 MW flame, Φ=0.95)

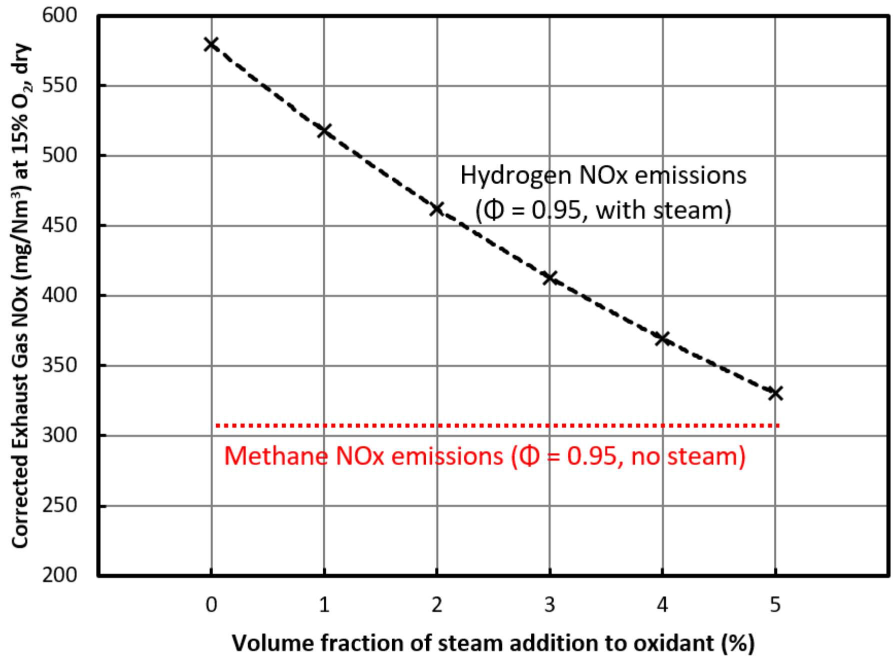
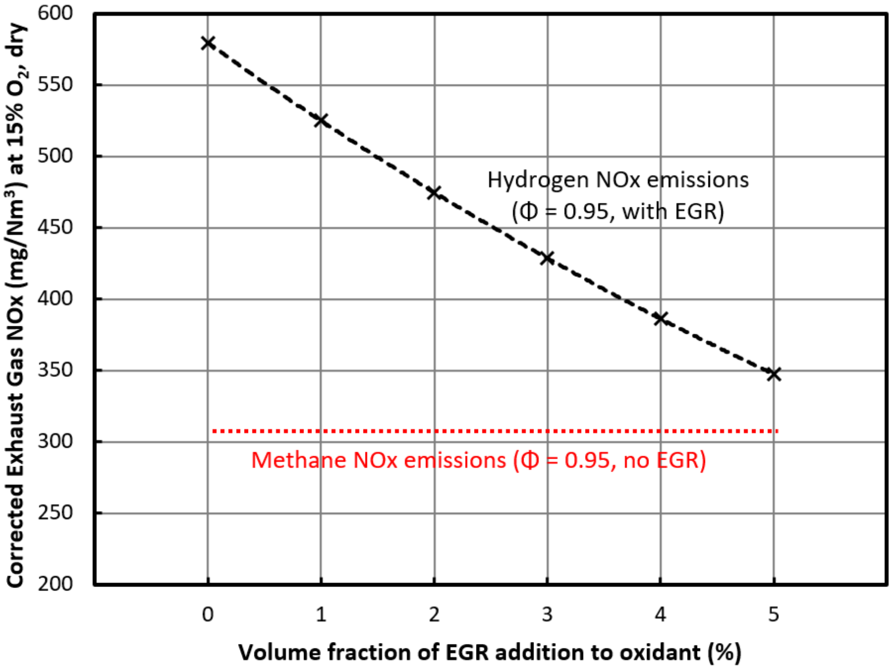


Figure 9-12: Calculated effect of Exhaust/Flue Gas Recirculation (EGR/FGR) on NO_x emissions in mg/Nm3 (14.5 MW flame, Φ=0.95)



9.4 DSEAR and ATEX zoning requirements

In order to assess the implications of replacing methane with hydrogen as far as the zoning of hazardous areas around the combustion plant and fuel supply systems, a standard DSEAR Risk Assessment procedure was used for a variety of potentially hazardous fuel release scenarios. For each release scenario, a potentially explosive hazardous volume (V_z) was calculated as a function of the fuel mass release rate against the ventilation change in the region under consideration, in accordance with BS EN 60079-10-1:2015[62] (other standards such as the Quadvent model from the Health and Safety Laboratory[63] may also be used). It is this hazardous volume that was then risk assessed to define the potential zone extent (in the form of a spherical radius) and the resultant classification. The presence of obstructions, such as equipment or walls, in the vicinity of a leak location must be taken into account when carrying out a DSEAR assessment. For open areas with *good* ventilation this efficiency factor is specified 1-2. If classified as *fair* (obstructed through equipment, or the presence of a wall), then it is specified 3, and if *poor* (confined by several walls or large obstacles), graded 4-5.

[62]BS EN 60079-10-1:2015 Explosive atmospheres – Part 10-1: Classification of areas — Explosive gas atmospheres.
[63] Details and information available here

Maintaining Current Supply Pipe Pressures (by increasing pipework diameters)

Figure 9-13: Comparison of zonal extents for "secondary" leak (unexpected and resulting from an operational fault), outdoors, from 2.50 mm² orifice

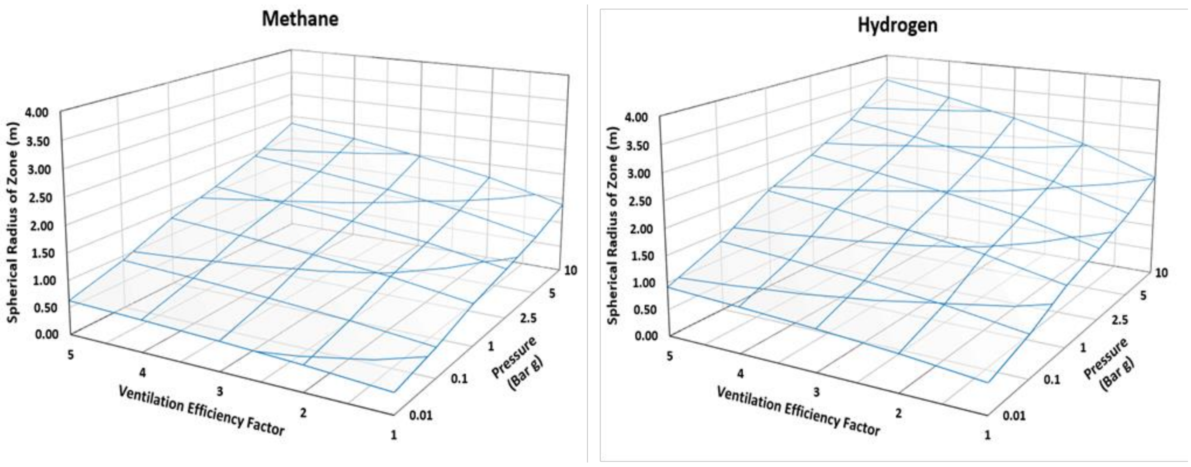
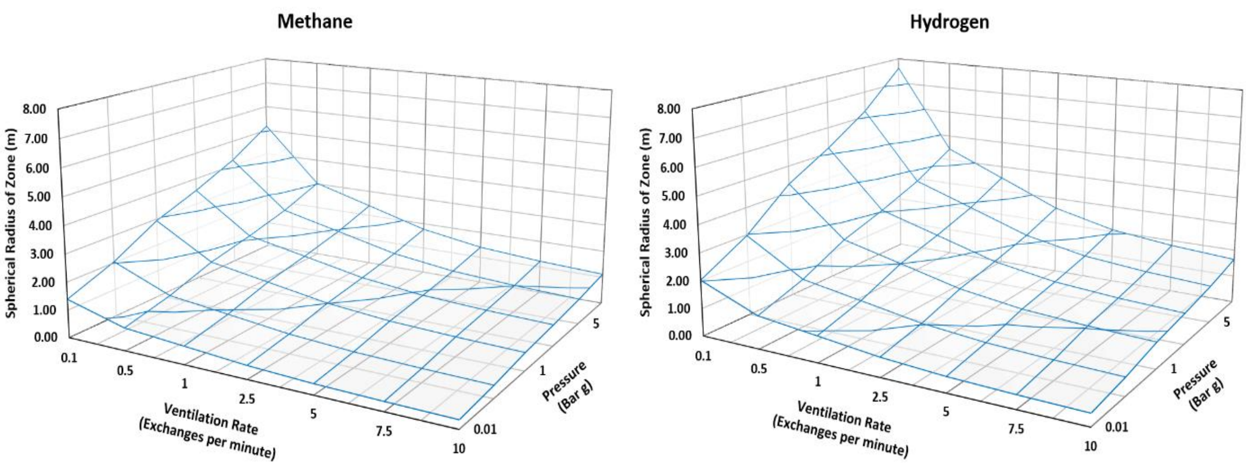


Figure 9-14: Comparison of zonal extents for "secondary" leak, indoors, from 2.50 mm² orifice into 200m³ room with poor ventilation efficiency



Increasing Pipe Pressures

Figure 9-15: Comparison of spherical zone extents for Methane and Hydrogen for a "secondary" leak, outdoors, from 2.50 mm^2 orifice with fair ventilation. Hydrogen pipe pressure increased to maintain overall energy flow.

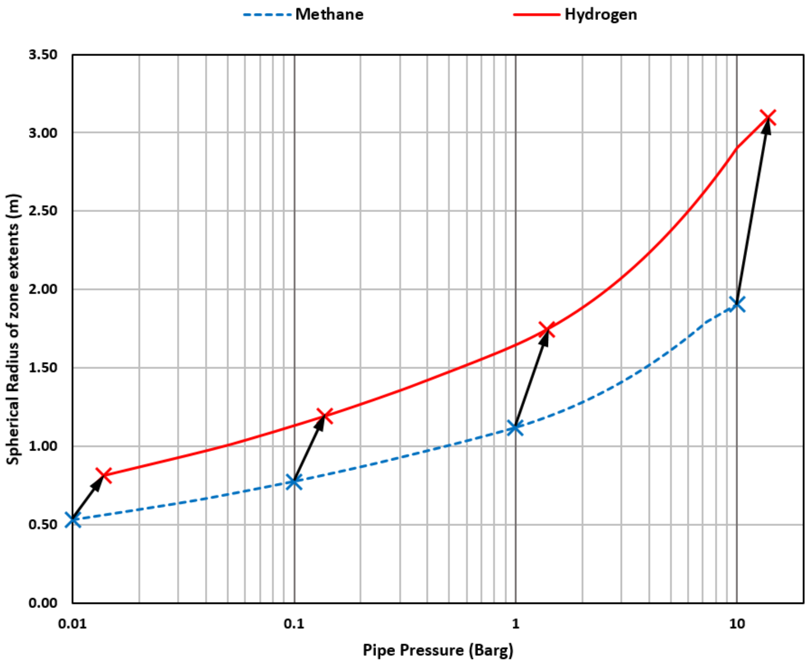
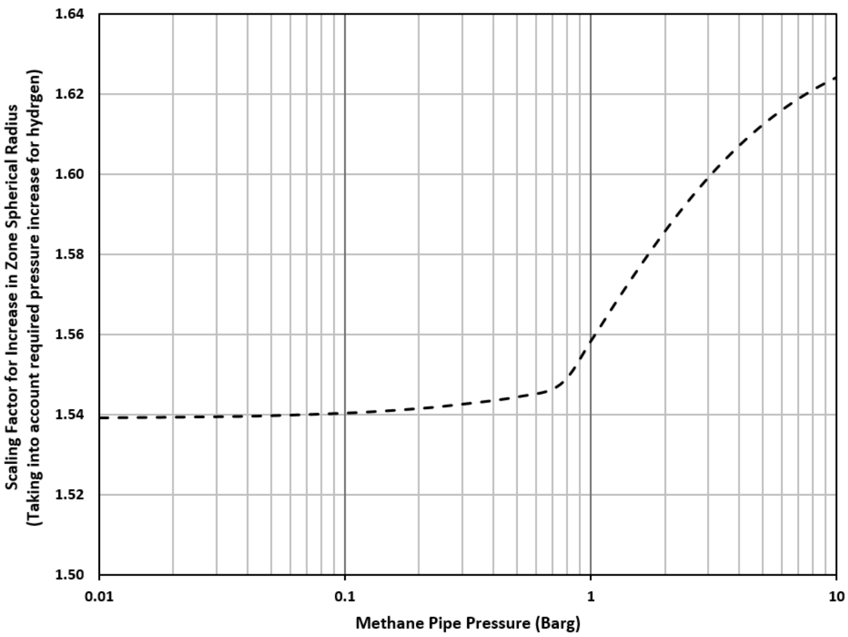


Figure 9-16: Scaling factor for increase in spherical zone extents when switching from Methane to Hydrogen. Pipe pressure for Hydrogen increased to maintain overall energy flow.



Maintaining ATEX Zone Sizes

Figure 9-17: Pressure and Pipe Diameter Scaling Factor required to Maintain ATEX Zone Sizes

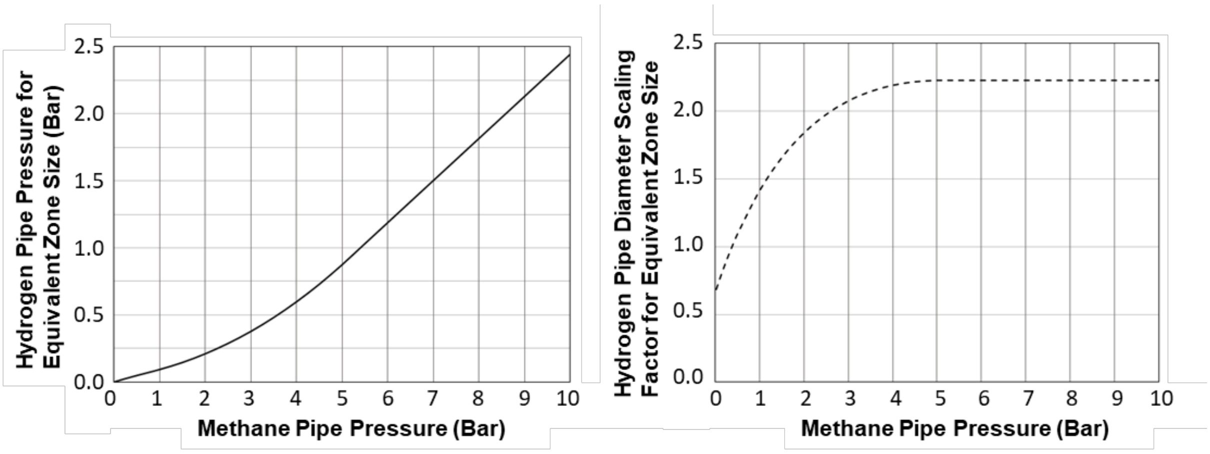
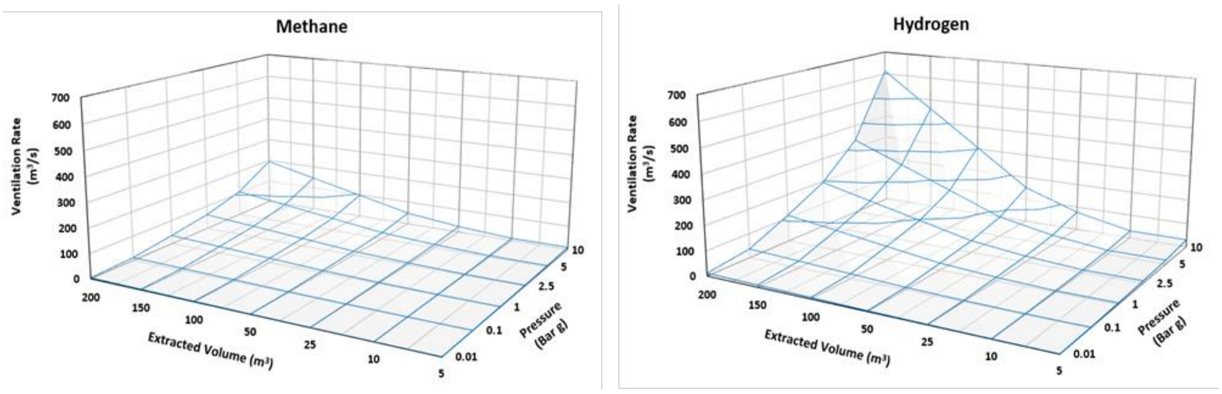


Figure 9-18: Ventilation Rates - Comparison of ventilation rates (m^3/s) for methane and hydrogen to produce Zone 2NE (a "zone of negligible extent") from a "secondary" leak, indoors, from 0.25 mm^2 orifice with a 'fair' ventilation factor



A summary of the key points when comparing methane and hydrogen as fuels from a DSEAR point of view are as follows:

- The physical properties of hydrogen are such that when compared to methane it will have less resistance to flow through both physical control hardware (valves and regulators), and leak pathways. However, due to its lower volumetric energy content, a significantly larger flowrate of hydrogen is required in order to maintain the total energy output of any combustion system when switching over from methane.
- In switching a pipe supply network over from methane to hydrogen, if the pipe pressures are kept constant, the size of any subsequent DSEAR zoning will increase due to the difference in gas properties and the wider explosion limits of hydrogen. Based upon calculations, it is predicted that the zoning distanced for hydrogen will be 47% larger than the equivalent distances used for methane, if system pressures are maintained. However, in order to maintain total energy flow it may be necessary to increase the size of pipework used to compensate for the lower energy content of hydrogen by volume.
- If the intention when switching from methane to hydrogen is to maintain as much of the supply infrastructure as possible, then in order to flow the increased volumes of gas required to

maintain the same overall power, it may be necessary to increase some of the system pressures. Any increase in system supply pressure will further exacerbate that seen in switching from methane to hydrogen as a fuel, with up to a 62% increase in hazardous zonal distances calculated for some scenarios.

- It is possible to maintain current hazardous zone sizes in switching from methane to hydrogen through either the use of lower system supply pressures or increased ventilation rates (indoors). In order to operate with reduced system pressures, larger pipe diameters and hardware with higher flow coefficients are required to maintain the overall energy flow, which may be unfeasible on some industrial sites. Higher ventilation rates can be used in indoor environments to maintain hazardous zone sizes, although in many applications the required increase in extraction may not be feasible, and other solutions (such as reducing pressures) may also be required.

9.5 Methodology and Assumptions Tables

9.5.1 SIC Classifications

Table 9-1: SIC 2007 codes used in the classification of industrial sectors

Industrial Sector	SIC 2007 Codes included
Food and drink	10, 11, 12
Chemicals	20, 21
Vehicle Manufacturing	29, 30
Basic metals	24
Refining	19
Paper	17,18
Glass	08, 23 (partly)
Ceramics	08, 23 (partly)
Lime	08, 23 (partly)
Other NM minerals	08, 23 (partly)
Electrical & Mechanical engineering	25-28
Other Industry	13-16, 22, 31, 32, 36, 38

9.5.2 Industrial Stock Model Assumptions Tables (where not confidential)

Table 9-2 Key assumptions used to build the stock model of industrial equipment

Assumption / Input	Confidence level	Dependent on	Evidence sources
Site gas usage (AQ) distribution by sector	4/5	Sector	Confidential GDNO site level data; EU ETS data; industry survey; industry associations
Proportion of gas usage connected to <7 bar	3/5	Site size (AQ), sector	GDNO (Cadent and SGN) site level connectivity data; industry survey
Proportion of natural gas usage in each process/ equipment type	4/5	Sector	Fuel switching study[64]; DUKES; ECUK; industry survey; tested with industry associations.
Number of pieces of equipment of each type per site	3/5	Sector, site size	Industry survey; Industrial site calls and visits; EE and Advisian experience; tested with industry associations
Load factor of each equipment type	3/5	Equipment type, sector	Literature (EU ETS data); EE and Advisian experience; tested with industry associations and sites
Equipment capacity (output)	3/5	Equipment type, sector, site size, process gas consumption	Calculated from site gas consumption and assumptions above. **Results tested with industry associations**.

Table 9-3 shows the estimated distribution of gas consumption across industrial site sizes. Table 9-4 shows the corresponding estimated number of sites in each gas consumption band. It should be noted that these are estimates based on the data collected in the study (as above), rather than accurate real-world values. Some data points have been omitted due to confidentiality concerns around energy consumption, and these values are replaced with an asterix (*). It should be noted that sites with a gas consumption of less than 1 GWh/yr are outside the scope of the study and some of these sites may be commercial in nature, but classified under the industrial SIC code due to being associated with an industrial sector.

64 IFS Industrial fuel switching market engagement study https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/764058/industrial-fuel-switching.pdf

Table 9-3 Estimated distribution of gas consumption across site sizes. Site size is measured by the annual gas consumption in GWh/yr and presented banded. (*) omitted due to confidentiality.

	Site gas consumption band (GWh/yr)										
	<1 GWh/yr	1-5	5-10	10-20	20-50	50-100	100-200	200-500	500-1,000	1,000-2,000	>2000 GWh/yr
Sector											
Food and drink	2%	4%	4%	11%	13%	13%	17%	17%	*	*	0%
Chemicals	3%	5%	3%	8%	14%	8%	8%	22%	9%	*	*
Vehicle Manufacturing	5%	9%	7%	13%	18%	15%	17%	15%	0%	0%	0%
Basic metals	4%	4%	4%	7%	12%	11%	21%	28%	*	*	0%
Refining	0%	0%	0%	0%	0%	0%	*	*	*	*	*
Paper	0.5%	2%	2%	4%	5%	4%	14%	*	*	*	*
Glass	1%	1%	1%	0%	3%	5%	10%	47%	*	*	0%
Ceramics	2%	2%	2%	2%	18%	63%	*	*	0%	0%	0%
Lime	0%	0%	0%	0%	0%	*	*	*	0%	0%	0%
Other NM minerals	1%	5%	3%	8%	8%	17%	16%	*	*	0%	0%
Elec & mech engineering	21%	20%	15%	17%	18%	3%	6%	0%	0%	0%	0%
Other industry	14%	11%	8%	8%	14%	13%	21%	0%	11%	0%	0%

Table 9-4 Estimated distribution of number of sites by site size. Site size is measured by the annual gas consumption in GWh/yr and presented banded.

	Site gas consumption band (GWh/yr)										
	<1 GWh/yr	1-5	5-10	10-20	20-50	50-100	100-200	200-500	500-1,000	1,000-2,000	>2000 GWh/yr
Sector	Number of sites by site size										
Food and drink	3082	329	115	141	81	34	23	9	*	*	0
Chemicals	2488	347	107	124	98	28	12	17	*	*	*
Vehicle Manufacturing	2211	279	77	62	29	15	9	3	0	0	0
Basic metals	1207	163	39	30	22	11	12	6	*	*	0
Refining	0	0	0	0	0	0	*	*	*	*	*
Paper	98	75	20	21	14	5	8	*	*	*	*
Glass	391	33	7	0	6	4	4	9	*	*	0
Ceramics	379	42	10	6	22	34	*	*	0	0	0
Lime	0	0	0	0	0	*	*	*	0	0	0
Other NM minerals	82	42	14	20	9	8	4	*	*	0	0
Elec & mech engineering	11485	836	317	179	85	9	5	0	0	0	0
Other industry	8847	631	119	65	52	20	16	0	2	0	0

Table 9-5 Estimated proportion of sites connected to the <7bar gas network in each size band.

	Site gas consumption band (GWh/yr)										
	<1 GWh/yr	1-5	5-10	10-20	20-50	50-100	100-200	200-500	500-1,000	1,000-2,000	>2000 GWh/yr
Sector	% sites connected to <7bar network										
Food and drink	100%	100%	98%	97%	94%	79%	65%	89%	*	0%	0%
Chemicals	100%	100%	98%	100%	90%	86%	75%	18%	0%	0%	0%
Vehicle Manufacturing	100%	100%	100%	100%	100%	100%	67%	100%	0%	0%	0%
Basic metals	100%	100%	100%	100%	95%	100%	100%	100%	100%	0%	0%
Refining	100%	100%	100%	100%	92%	0%	0%	0%	0%	0%	0%
Paper	100%	100%	100%	100%	100%	100%	75%	100%	0%	0%	0%
Glass	100%	100%	100%	100%	0%	100%	100%	100%	100%	0%	0%
Ceramics	100%	100%	90%	100%	91%	91%	100%	0%	0%	0%	0%
Lime	100%	100%	100%	100%	100%	100%	100%	67%	0%	0%	0%
Other NM minerals	100%	100%	100%	100%	89%	100%	100%	50%	16%	0%	0%
Elec & mech engineering	100%	100%	100%	97%	94%	44%	100%	63%	16%	0%	0%
Other industry	100%	100%	98%	97%	92%	90%	81%	63%	0%	0%	0%

Table 9-6 Gas consumption split by process for each industrial sector (TWh/yr)

	Estimated annual gas consumption by sector and process (TWh/yr)											
Process	Food & drink	Chemicals	Vehicle Man.	Basic metal	Refining	Paper	Glass	Ceramics	Lime	Other NM miner.	Elec & mech eng	Other industry
Steel rolling	-	-	-	3.53	-	-	-	-	-	-	-	-
Steel melting	-	-	-	0.77	-	-	-	-	-	-	-	-
Cracking	-	1.68	-	-	-	-	-	-	-	-	-	-
SMR ammonia	-	1.54	-	-	-	-	-	-	-	-	-	-
Steam raising	11.28	7.94	-	0.06	0.30	2.33	-	-	-	-	3.01	3.46
Oven heating	2.34	-	1.42	0.27	-	-	-	-	-	-	-	-
Drying	0.20	0.95	-	-	-	1.19	-	0.87	-	-	1.51	2.20
Space heating	0.60	-	2.31	-	-	0.37	-	0.07	-	0.07	5.34	1.98
CHP heat	3.61	7.10	0.05	0.06	-	2.70	-	-	-	0.35	0.23	0.41
CHP electricity	4.15	5.96	0.04	0.05	-	2.54	-	-	-	0.50	0.21	0.23
Glass melting	-	-	-	-	-	-	4.57	-	-	-	-	-
Glass other	-	-	-	-	-	-	0.25	-	-	-	-	-
Kiln firing	-	-	-	-	-	-	-	3.47	1.23	-	-	-
Raw material drying / milling	-	-	-	-	-	-	-	-	-	1.93	-	-
Metal melting other	-	-	-	1.51	-	-	-	-	-	-	-	-
High temp other	-	1.13	0.24	-	1.06	-	0.20	-	-	0.42	0.84	-
Low temp other	-	-	1.84	-	-	-	-	-	-	-	3.01	0.87
Other	0.86	-	1.07	0.66	-	-	0.08	-	-	0.71	0.60	0.99
Total	**23.04**	**26.29**	**6.96**	**6.91**	**1.37**	**9.13**	**5.10**	**4.40**	**1.23**	**3.99**	**14.76**	**10.13**

Table 9-7 shows the estimated load factors applied to each piece of equipment in each sector. It should be noted that these figures incorporate both any operational downtime where the equipment is not operating and also equipment which does not operate at full **thermal** capacity. There is assumed to be no additional redundancy except for boilers at 50%. These are averages across industry, and the values will in reality vary substantially in specific applications.

Process	Estimated load factor of each equipment type											
	Food & drink	Chemicals	Vehicle Man.	Basic metal	Refining	Paper	Glass	Ceramics	Lime	Other NM miner.	Elec & mech eng	Other industry
Boiler - steam	0.50	0.35	-	0.45	0.70	0.60	-	-	-	-	0.55	0.60
Boiler - water	0.39	-	0.40	-	-	0.36	-	0.40	-	0.40	0.40	0.40
Furnace - Glass	-	-	-	-	-	-	0.75	-	-	-	-	-
Furnace - Metal	-	-	-	0.55	-	-	-	-	-	-	-	-
Furnace other <600°C	-	-	-	-	-	-	-	-	-	-	-	-
Furnace other >600°C	-	0.70	0.40	0.45	0.70	-	0.75	-	-	-	0.45	-
Kiln lime	-	-	-	-	-	-	-	-	0.75	-	-	-
Kiln ceramics	-	-	-	-	-	-	-	0.40	-	-	-	-
Kiln other <600°C	-	-	-	-	-	-	0.75	-	-	-	-	-
Kiln other >600°C	-	-	-	-	-	-	-	-	-	0.80	-	-
Oven	0.35	-	0.25	0.55	-	-	-	-	-	-	0.30	0.50
Dryer direct	0.30	0.60	0.18	-	-	0.60	-	0.50	-	0.25	0.30	0.50
CHP	0.43	0.47	0.27	0.36	-	0.47	-	-	-	0.42	0.27	0.37
Other	0.35	-	0.25	0.35	-	-	0.50	-	-	0.30	0.30	0.50

Table 9-7 Estimated load factors for each equipment type by sector.

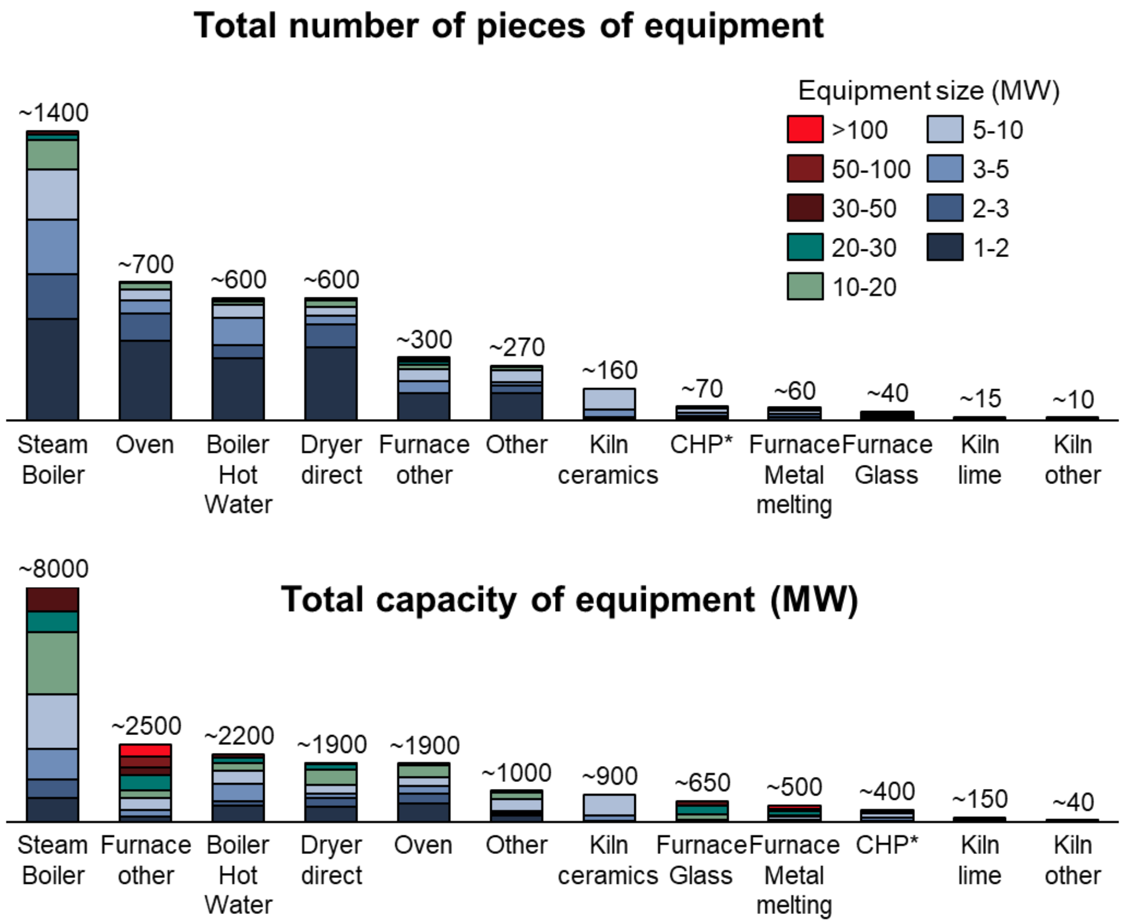
9.5.3 Industrial Equipment Stock Model Results

The UK industrial equipment stock was characterised in terms of number, type and size, through the process shown in Figure 3-3; this starts from natural gas consumption statistics by industrial sector and process, and then uses the above assumptions to break this down into equipment types and estimate the number. Table 9-8 details the number of pieces of industrial equipment in each thermal capacity size range calculated by the stock model of industrial equipment. Figure 9-19 shows the number and capacity of each equipment type in industry. There is uncertainty associated with these figures, as discussed in section 5.3.1. Equipment <1 MW is included only indicatively as it is out of scope for this study.

Table 9-8 Estimated number of industrial equipment of each size and type on the <7 bar network. These numbers are estimates, rather than exact values of equipment present.

Technology	Estimated number of equipment of each size on the <7bar network												
	Thermal Capacity Size Range (MW)												
	<1MW	1-2	2-3	3-5	5-10	10-20	20-30	30-50	50-100	>100	**Total # >1 MW**	Capacity >1 MW_{th} (MW)	Total capacity (MW)
Boiler – steam	~6000	505	223	271	249	143	28	18	0	0	~1,500	~7,600	~9,500
Boiler – hot water	~3500	309	64	139	62	21	9	<5	0	0	~600	~2,200	~4,200
Furnace Glass	~30	7	<5	<5	8	13	12	<5	0	0	~40	~650	~700
Furnace Metal melting	~300	16	16	<5	16	<5	5	<5	<5	<5	~60	~520	~570
Furnace other >600°C	~1300	134	~10	61	56	20	20	6	6	<5	~300	~2,500	~2,800
Kiln lime	0	0	0	0	<10	<10	0	0	0	0	~15	~150	~150
Kiln ceramics	~40	~10	~10	~40	~100	<10	0	0	0	0	~160	~880	~920
Kiln other <600°C	~100	0	0	0	0	0	0	0	0	0	0	0	~40
Kiln other >600°C	~10	<5	<5	<5	<5	<5	0	0	0	0	~10	~40	~40
Oven	~3000	397	133	68	51	31	<5	<5	0	0	~700	~1,900	~2,600
Dryer direct	~3000	364	111	44	42	34	8	<5	<5	0	~600	~1,900	~3,300
CHP	~50	12	10	18	20	6	<5	0	0	0	~70	~400	~440
Other	~1200	137	37	16	60	16	<5	0	0	0	~270	~1,000	~1,500

Figure 9-19: Estimated number and capacity of each equipment type in industry. Only equipment on the <7bar network and of >1MW$_{th}$ is included. Capacity is in MW$_{th}$, with the exception of CHP, which is in MW$_e$.



9.5.4 Subcomponent Cost Assumptions

Project Costs

The approach here is to apply these percentage and fixed fee-based costs on top of the equipment and material costs that are calculated separately in each tab of the worksheet:

- Labour Costs – 10% of total cost (e.g. if total cost was 100k, labour would be 10k of this)
- Engineering Design – 5% of total cost (same as labour above) with minimum fixed value
- Removal Cost – 5% of total
- Project and Construction Management - 3% of total cost (same as labour above) with minimum fixed value
- Commissioning Cost – 2% of total
- Estimating Contingency – 12% on top of everything once calculated total cost

The additional fixed fees for engineering design and project and construction management are a minimum fee that are additional to the overall fee as a site wide cost. .

Fuel Distribution - Site Wide Cost

Two separate systems were assumed – a site wide transmission and a site wide distribution system

Transmission:

- Max pressure 10 barg based on current 7 barg gas network connection and 40% estimated increase in pressure for hydrogen to deliver the same energy quantity
- Typical pipe diameter – 12”
- STD pipe schedule based on low pressure system
- Material is low carbon steel (API 5L X52 or ASTM A 106 Grade B)

Distribution:

- Assumed pressure 1 barg based on site visit distribution to burners and 40% estimated increase in pressure for hydrogen to deliver the same energy quantity
- Typical pipe diameter – 1-4”
- STD pipe schedule based on low pressure system
- Material is low carbon steel (API 5L X52 or ASTM A 106 Grade B)

Distance of pipe network is dependent on sector and site total number of pieces of equipment.

Pipe fittings – 45% of total pipe cost

Cost of Sale – 10% of pipe and fittings cost (transportation etc)

Combustion Air Delivery - Equipment Specific Cost

- Forced Draft Fan may require replacement dependent on ATEX
- Cost estimate for FD fan has been used
- Multiple estimates have been gathered and extrapolated to calculate an approximate cost per MW
- Cost of Sale – 10% of fan cost (transportation etc)

Fuel Gas Recirculation - Equipment Specific Cost

- To increase air mass flow into the combustor and reduce NO_x emissions.
- Based on cost estimate from government source for installation of FGR onto a current site
- Estimate includes piping cost
- Cost of Sale – 10% of fan and pipe cost (transportation etc)

Burners - Equipment Specific Cost

- Burner material cost estimates have been taken from multiple sources
- Extrapolation methods have been applied to get a cost relationship to burner capacity
- Cost of Sale – 10% of Burner Cost (transportation etc)
- Number of burners will be different for different equipment types. This has an impact on overall burner cost as more smaller burners is more expensive

10 MW example – Equipment type and approximate number of burners.

- Boiler - 1
- Furnace Glass – 8 (Glass furnaces generally only fire half the burners at any one time and their stated capacity is based on this. This has been considered in the model)
- Lehr Kiln (<600°C) - 25
- Furnace (>600°C) - 12
- Kiln (>600°C) - 50
- Oven - 20
- Dryer Direct - 1

Post Combustion System – Flue Treatment - Equipment Specific Cost

- Based on Selective Catalytic Reduction system. Two sources for costs – retrofitting and large-scale SCR on industrial site.
- Calculate a £/kW cost for both estimates
- Also include pipe fitting cost – same methodology for fuel delivery system however, only one type of pipe
    - 1 barg pressure
    - 12" pipe diameter
    - STD pipe schedule
    - Material is low carbon steel
- Distance of pipe network is dependent on sector and site total equipment size.
- Pipe fittings – 45% of total pipe cost
- Cost of Sale – 10% of pipe and fittings cost (transportation etc)

ID Fans and Stack System - Equipment Specific Cost

- Assuming stack itself will not require replacement. Volume of flue gas does not change considerably, permitting review will be required to understand emission profile and dispersion of flue gases.

- Induced Draft Fan will require replacement
- Multiple estimates have been gathered and extrapolated to calculate an approximate cost per MW
- Cost of Sale – 10% of Fan cost (transportation etc)

Electrical Control and Instrumentation - Applied to both Equipment and Site Costs

- Use a percentage of overall cost approach to capture any change in EC&I required as a result of ATEX
- 0% if all equipment is ATEX
- 5% if some equipment is ATEX but zone increase captures other
- 15% if all equipment requires modification to ATEX compliance

9.5.5 Equipment Cost Assumptions

Sites with natural gas consumption <1 GWh/y

Sites with a natural gas consumption <1 GWh/y were not considered industrial natural gas consumers, and so were not included in the cost of conversion. These sites are likely either to be commercial in scope, e.g. a mechanic/repair workshop in the Vehicle Manufacturing sector, or to only have equipment on site which is commercial in nature, e.g. an industrial cement site that only uses natural gas for hot water heating in offices. These sites are very unlikely to have any industrial scale equipment >1 MW_{th} on site.

Equipment <1 MW_{th}

The estimate of capex does include those pieces of equipment <1 MW_{th} on relevant industrial sites. It was found that a significant number of pieces of equipment, e.g. lehrs in the glass sector or small burners/dryers in the vehicle manufacturing sector, were both industrial in nature and < 1MW_{th}. This equipment was present on sites which have significant gas consumption, either due to the large numbers of relatively small pieces of equipment or due to other, larger equipment types present on the same site. If the site was converted to hydrogen, these smaller pieces of equipment would also need conversion to hydrogen.

To cost this equipment, it was not appropriate to extrapolate the cost curves below 1MW_{th}. This is because the exact number and size of these pieces of equipment was highly uncertain, and there are important differences between this small equipment and their larger counterparts (e.g. would not require flue gas recirculation implementation in small dryers); which make some of the assumptions and subcomponent replacement invalid. A linear fit based on the equipment capacity was applied for this equipment <1 MW_{th} using the cost per unit capacity (£/MW) for 1 MW equipment from the cost curve. Even so, the large number and relatively high capacity of these, combined with the lack of economies of scale, means they present a significant proportion (≈25%) of the UK wide capex for conversion to H_2 in the central case.

9.5.6 Cost Sensitivities

Assumptions

Central Case

Table 9-9: Table to show which subcomponents of industrial equipment are assumed to require modification or replacement on hydrogen conversion. x represents those that need replacement and ✓ represents those that are already capable of hydrogen operation. Central Case.

Subcomponents of industrial equipment

	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Food and drink						
Steam Boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	✓	x	x
Direct dryer	x	x	x	✓	x	x
Chemicals						
Steam boiler	✓	x	x	x	✓	✓
Hot water boiler	✓	x	x	x	✓	✓
Oven	✓	x	x	✓	✓	✓
Furnace	✓	x	x		✓	✓
Direct dryer	✓	x	x	✓	✓	✓
Vehicle Manufacturing						
Steam boiler	x	x	x	x	x	x
Furnace	x	x	x	x	x	x
Direct dryer	x	x	x	✓	x	x
Oven	x	x	x	✓	x	x
Basic metals						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	✓	x	x
Furnace	x	x	x	x	x	x
Refining						
Steam boiler	✓	x	x	x	✓	✓
Furnace	✓	x	x	x	✓	✓

	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Paper						
Steam Boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Direct dryer	x	x	x	✓	x	x
Glass						
Hot water boiler	x	x	x	x	x	x
Furnace Glass	x	x	x	x	x	x
Furnace >600°C	x	x	x	x	x	x
Lehr kiln	x	x	x	✓	x	x
Ceramics						
Hot water boiler	x	x	x	x	x	x
Ceramics kiln	x	x	x	✓	x	x
Dryer Direct	x	x	x	✓	x	x
Lime						
Lime kiln	x	x	x	✓	x	x
Direct Dryer	x	x	x	✓	x	x
Other non-metallic minerals						
Hot water boiler	x	x	x	x	x	x
Kiln >600°C	x	x	x	✓	x	x
Dryer Direct	x	x	x	✓	x	x
Electrical and mechanical engineering						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	✓	x	x
Direct dryer	x	x	x	✓	x	x
Furnace	x	x	x	x	x	x

Low Cost Case

- Burner costs reduced by factor of 1.2
- Site wide fixed fee reduced by ~50%
- Proportion of subcomponents requiring replacement decreased:

Table 9-10: Table to show the proportion of subcomponents of industrial equipment which are assumed to require modification or replacement on hydrogen conversion in the Low Cost sensitivity case.

Subcomponents of industrial equipment	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Food and drink						
Steam Boiler	0.5	0.25	1	0.5	0.25	0.5
Hot water boiler	0.5	0.25	1	0.5	0.25	0.5
Oven	0.5	0.25	1	0	0.25	0.5
Direct dryer	0.5	0.25	1	0	0.25	0.5
Chemicals						
Steam boiler	0	0.5	1	0.5	0	0
Hot water boiler	0	0.5	1	0.5	0	0
Oven	0	0.5	1	0	0	0
Furnace	0	0.5	1	0.5	0	0
Direct dryer	0	0.5	1	0	0	0
Vehicle Manufacturing						
Steam boiler	0.5	0.25	1	0.25	0.25	0.25
Furnace	0.5	0.25	1	0.25	0.25	0.25
Direct dryer	0.5	0.25	1	0	0.25	0.25
Oven	0.5	0.25	1	0	0.25	0.25
Basic metals						
Steam boiler	0.5	0.25	1	0.25	0.25	0.25
Hot water boiler	0.5	0.25	1	0.25	0.25	0.25
Oven	0.5	0.25	1	0	0.25	0.25
Furnace	0.5	0.25	1	0.25	0.25	0.25
Refining						
Steam boiler	0	0.5	1	0.5	0	0
Furnace	0	0.5	1	0.5	0	0

Subcomponents of industrial equipment	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Paper						
Steam Boiler	0.5	0.5	1	0.5	0.25	0.5
Hot water boiler	0.5	0.5	1	0.5	0.25	0.5
Direct dryer	0.5	0.5	1	0	0.25	0.5
Glass						
Hot water boiler	0.5	0	1	0.5	0.25	0.25
Furnace Glass	0.5	0	1	0.5	0.25	0.25
Furnace >600°C	0.5	0	1	0.5	0.25	0.25
Lehr kiln	0.5	0	1	0	0.25	0.25
Ceramics						
Hot water boiler	0.5	0.5	1	0.25	0.5	0.5
Ceramics kiln	0.5	0.5	1	0	0.5	0.5
Dryer Direct	0.5	0.5	1	0	0.5	0.5
Lime						
Lime kiln	0.5	0.5	1	0	0.5	0.5
Direct Dryer	0.5	0.5	1	0	0.5	0.5
Other non-metallic minerals						
Hot water boiler	0.5	0.25	1	0.25	0.25	0.25
Kiln >600°C	0.5	0.5	1	0	0.5	0.5
Dryer Direct	0.5	0.25	1	0	0.25	0.25
Electrical and mechanical engineering						
Steam boiler	0.5	0.25	1	0.25	0.25	0.25
Hot water boiler	0.5	0.25	1	0.25	0.25	0.25
Oven	0.5	0.25	1	0	0.25	0.25
Direct dryer	0.5	0.25	1	0	0.25	0.25
Furnace	0.5	0.25	1	0	0.25	0.25

High Cost Case

- All Electrical Control and Instrumentation needs replacement:
- Removal percentage increased to 10%
- Labour Percentage increased to 15%
- Estimated contingency increased to 15%
- All subcomponents (except combustor) need replacement:

Table 9-11: Table to show which subcomponents of industrial equipment are assumed to require modification or replacement on hydrogen conversion in the High Cost sensitivity case. x represents those that need replacement and ✓ represents those that are already capable of hydrogen operation.

Subcomponents of industrial equipment

	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Food and drink						
Steam Boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	x	x	x
Direct dryer	x	x	x	x	x	x
Chemicals						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	x	x	x
Furnace	x	x	x	x	x	x
Direct dryer	x	x	x	x	x	x
Vehicle Manufacturing						
Steam boiler	x	x	x	x	x	x
Furnace	x	x	x	x	x	x
Direct dryer	x	x	x	x	x	x
Oven	x	x	x	x	x	x
Basic metals						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	x	x	x
Furnace	x	x	x	x	x	x
Refining						
Steam boiler	x	x	x	x	x	x
Furnace	x	x	x	x	x	x

	Fuel distribution system	Combustion Air system & FGR	Burner system	Post combustion system & FGT	ID fans	EC&I
Paper						
Steam Boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Direct dryer	x	x	x	x	x	x
Glass						
Hot water boiler	x	x	x	x	x	x
Furnace Glass	x	x	x	x	x	x
Furnace >600°C	x	x	x	x	x	x
Lehr kiln	x	x	x	x	x	x
Ceramics						
Hot water boiler	x	x	x	x	x	x
Ceramics kiln	x	x	x	x	x	x
Dryer Direct	x	x	x	x	x	x
Lime						
Lime kiln	x	x	x	x	x	x
Direct Dryer	x	x	x	x	x	x
Other non-metallic minerals						
Hot water boiler	x	x	x	x	x	x
Kiln >600°C	x	x	x	x	x	x
Dryer Direct	x	x	x	x	x	x
Electrical and mechanical engineering						
Steam boiler	x	x	x	x	x	x
Hot water boiler	x	x	x	x	x	x
Oven	x	x	x	x	x	x
Direct dryer	x	x	x	x	x	x
Furnace	x	x	x	x	x	x

Impacts

Site wide costs

The number of sites and pieces of equipment impact site wide costs more than other characteristics such as equipment capacity. Load factor, as it only adjusts the capacity of equipment does not have a drastic impact on site wide costs compared to the low and high cost scenarios, where site costs have been adjusted to capture the possible cost variation across sectors and sites.

Equipment Costs

The cost of replacing equipment <1 MW_{th} reduces in both the increased and decreased load factor cases. For the increased load factor case, this is due to the decreased overall capacity of equipment <1 MW_{th} (this equipment is costed linearly with capacity – see appendix 9.5.5). For the decreased load factor case, a large proportion of equipment, previously <1 MW_{th}, now has capacities >1 MW_{th} due to the reduced load factor, and so the capex for converting equipment <1 MW_{th} decreases. The UK wide cost with the greatest sensitivity to the load factor assumptions is the cost of converting the equipment >1 MW_{th}. These costs increase with decreased load factor, due to the resultant higher capacity and number of pieces of equipment >1 MW_{th}, and vice versa. For the cost scenarios, the expected change in costs are obtained due to changes in subcomponent costs and the necessary level of subcomponent replacement.