AECOM

Summary Report

Future of Hydrogen in Industry
Initial Industrial Site Surveys

Department for Business, Energy & Industrial Strategy

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1. Executive Summary

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. The evidence generated will inform strategic decisions in 2026[1] on the role of low carbon hydrogen as a replacement for natural gas heating, which will help determine whether and the extent to which parts of the gas grid are repurposed or decommissioned in the longer-term.

As part of the work on hydrogen heating, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. This study was focussed on industrial end users of natural gas and understanding the technical feasibility, economics and safety for them to switch to 100% hydrogen. This study is not intended to apply directly to non-industrial end users because of the differences between end user environments, gas pressures and the quantities of gas consumed which may have significant impacts on the Technical, Safety and Economic assessments conducted here.

The study has been completed in partnership with seven volunteer industrial sites located away from the industrial clusters and which will likely be impacted by decisions on the future of the natural gas grid[2]. For each of the sites a safety report and an overall engineering business case report were prepared to help understand the implications of switching to hydrogen and to compare those impacts at a high-level to a counter-factual decarbonisation option. Those reports are commercially sensitive, so the purpose of this summary report is to disseminate learnings to other industrial sites and to wider industry, whilst keeping the anonymity of the industrial sites that were studied.

The table below gives a summary of the nature of sites studied. These sites were chosen because of the range of applications and sectors meaning they may not be a representative sample of UK installations. Therefore, care needs to be taken with the outcomes of these reports, as further confirmatory work may need to be done to provide further confidence in any general conclusions. These sites contain a high proportion of direct fired equipment where the flame/ combustion products come into contact with the product. These are often more product specific compared to indirect applications such as boilers and heaters where water and steam is used to transfer heat to the process. For the sites studied over 90% of the installed gas equipment was used for process heat.

Case Study Organisations

Organisation	Industry Sector	Type of Gas Users	Annual Gas Use	Annual Total Energy Use
Site 1 – Other Industry 1	Primary Plastics	Industrial steam boilers, ovens, water heaters, space heaters, flare pilot & ignition packages	83,000 MWh	143,000 MWh
Site 2 – Food & Drink 1	Food & Drink	Industrial ovens, fryers, air handling units, water heaters	18,000 MWh	20,000 MWh
Site 3 – Metals 1	Non-ferrous metals	Furnaces, gas torches, burners, water heaters and space heaters	28,000 MWh	32,000 MWh
Site 4 – Vehicles 1	Vehicle Manufacturing	Industrial ovens, air handling units, recuperative thermal oxidisers, water heaters and space heaters	Limited site extent 29,000 MWh Whole site 246,000 MWh	Limited site extent 29,000 MWh (gas only) Whole site 364,000 MWh
Site 5 – Minerals 1	Non-metallic minerals	Aggregate dryer	35,000 MWh	35,000 MWh
Site 6 – Metals 2	Metal Packaging	Industrial ovens, recuperative thermal oxidisers, water heaters and space heaters	6,000 MWh	9,000 MWh
Site 7 – Food & Drink 2	Food & Drink	Germination kilning vessels, roasters, grain dryers, thermal fluid heaters, water heaters, space heaters	42,000 MWh	50,000 MWh

[1] https://www.gov.uk/government/publications/uk-hydrogen-strategy
[2] https://www.gov.uk/government/publications/industrial-decarbonisation-strategy

1.1 Overall Summary

The study has focused on the specialised equipment used on a number of sites with a significant proportion of direct fired applications. As such these may represent particular challenges compared to industrial users in general. The study has focussed principally on hydrogen, and while work was carried out on a counter-factual non-hydrogen alternative, this was to a lesser level of detail and was not intended to determine the optimal solution. Further studies should be carried out to develop these indicative findings and develop costing assumptions and sensitivities. Based on this work, hydrogen could offer a competitive option for industrial decarbonisation, subject to more detailed investigation on a site-specific basis.

Safety considerations for the use of hydrogen require continued study and assessment. An open collaborative approach across government, standards bodies, regulators and industry is required to help identify the required adaptations to sites, equipment and procedures. Some important safety work for hydrogen has already been done or is in progress, this includes the work on: Hy4Heat[3], HyStandards[4] and the updated draft of SR25[5] for hydrogen. It is hoped that the dissemination of this report and the further recommendations in the safety next steps helps support this progress.

The feedback from sites engaged with this work has been that the safety reports had increased their awareness the safety of hydrogen and moderately increased their concern about using hydrogen safely, but that the safety mitigations suggested were generally acceptable. The majority of sites were interested in using hydrogen after reviewing the reports and assuming there was a reliable supply of hydrogen available most sites could see hydrogen as a lead option for their sites. Sites also indicated that further support, work and guidance would be useful, and that being part of this study had made them more inclined to use hydrogen.

This report includes detailed recommendations on safety, emissions, cost, technical feasibility, demonstrations and applicability. It is for BEIS to assess the relative priority and need for these actions alongside priorities identified through other work.

1.2 Thematic site findings– Technical, Economic, and Safety

The site reports that have feed into this summary report considered Technical, Economic and Safety Assessments of site equipment and infrastructure, the key findings from these across the sites are elaborated below.

1.2.1 Technical assessment overview- site and end-use equipment

The technical assessment considered a series of options for full or partial hydrogen conversion along with a best non-hydrogen decarbonisation alternative. In addition to the question of whether an end-user item of equipment can be converted or replaced with a hydrogen fuelled alternative, the assessment considered supply infrastructure across the site, the associated control and instrumentation equipment and the ventilation around items of equipment and infrastructure including the gas network operator’s interface equipment.

1.2.1.1 Site Infrastructure Findings

Existing site infrastructure equipment and routing is a result of the current practice for natural gas installation, operation and maintenance under existing regulations. The revised design and installation guidance for hydrogen may result in significant modifications at site to bring the gas from the supplier to the end user. It was found that much of the existing natural gas piping and infrastructure on the sites requires replacement for use with hydrogen. Most often, this is due to the line capacity being insufficient for the hydrogen flow required to maintain the same energy flow to the end users. In the majority of sites studied approximately 50% or more the pipework would need to be replaced because it is undersized.

Based on visual inspection and records where available, metallurgy of the general piping material was found to be acceptable for hydrogen at most sites. However, in some cases there was little detail available on the specific grades of the material used, and so further work would be required to positively identify all materials within the natural gas infrastructure of a site if it is to be repurposed for hydrogen. The materials used for valves and pipe fittings were not assessed for hydrogen suitability. In particular, valve trims and non-metallic components at joints

[3] https://www.hy4heat.info/
[4] https://www.gov.uk/government/publications/hydrogen-skills-and-standards-for-heat
5 https://www.igem.org.uk/_resources/assets/attachment/full/0/66092.pdf

and valves require further investigations to identify the suitability of all the materials present and at this stage, there is no guidance whether screw fittings will be suitable for hydrogen due to leak tightness.

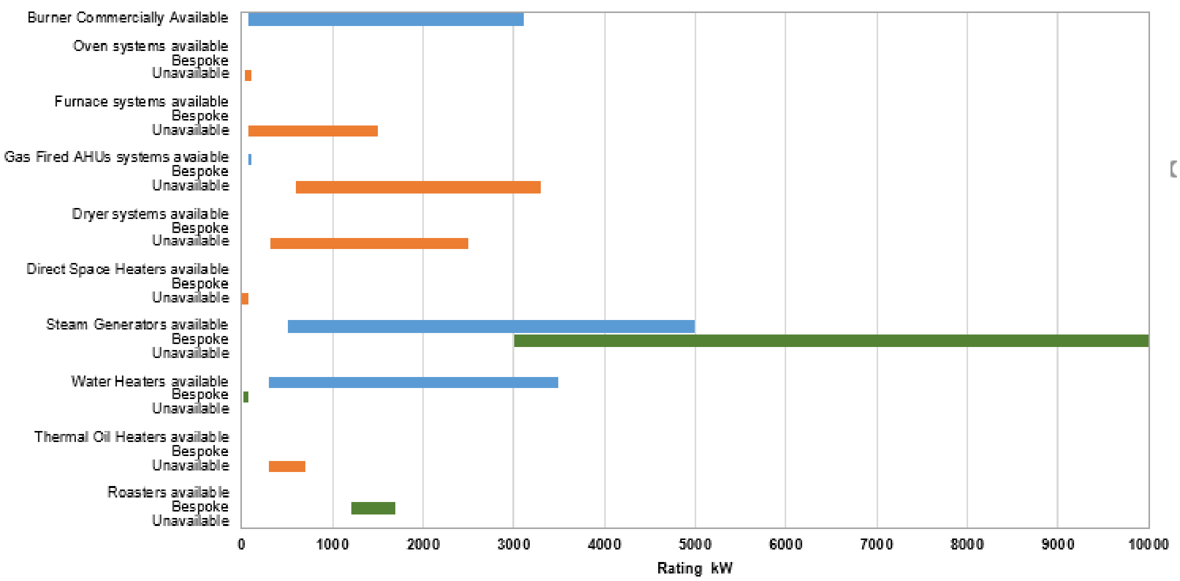
From visual inspection and calculation, the natural gas connection size into the sites appeared to be of adequate size in 3 cases, with 2 sites unknown because of uncertainty in future demand, and 2 sites undersized for future hydrogen. In general, the sites annual gas consumption is greater than their annual electrical consumption. Consequently, sites' current on-site electrical infrastructure is not generally designed for the capacity required for full electrification of the gas users and will need significant upgrades to be capable of handling the increased capacity. The electrical supply connection to sites, though outside the scope of this study, will likewise require upgrades in many locations.

1.2.1.2 End-Use Equipment

These site studies involved characterising industrial end-use equipment, then engaging with industrial equipment manufacturers to understand the feasibility of using hydrogen and their development work on hydrogen equipment, whilst also trying to assess alternative decarbonisation approaches. The work then assessed the engineering modifications required.

Hydrogen fired burners, steam generators and large water heaters are generally available, and development of certain other equipment is underway with a number of the manufacturers contacted. This is represented below in relation to the specific equipment needs of the 7 sites surveyed.

Indicative availability of hydrogen systems by rating base upon applications on site surveyed



In certain areas suitable technical solutions do not currently exist to address all of the challenges identified during this work (such as manual ignition and pre-mixed systems), and the switch to 100% hydrogen may make some sites and processes more challenging from a commercial perspective (such as the impact on direct drying processes and additional safety requirements affecting equipment).

Burner OEMs consulted indicated that for both retro-fits and new builds further work is required to understand and predict achievable Nitrogen Oxides (NOx) values. The burner manufacturers responding during this study believe they can meet the limits for new "other gaseous" fuels plant but may be unable to achieve the current targets for new natural gas plant contained in the Medium Combustion Plant Directive.

There is a risk that any early NOx guarantees offered are potentially more conservative than required and indicate a need for flue gas recirculation (FGR) or selective catalytic reduction (SCR) being specified when not necessary, increasing the capital and operating cost.

1.2.2 Economic Assessment Overview

1.2.2.1 CAPEX Costs

The cost estimates are typical of an early stage Association for the Advancement of Cost Engineering (AACE) Class 4 estimate with an anticipated accuracy of -30% and +50%. Assumptions include that existing systems have sufficient residual life to justify retrofitting of discrete components and that development will achieve

adequate NOx without external abatement. Where electrification is assumed no additional back-up power system has been specified.
For the majority of the sites the end use equipment accounts for over 75% of the hydrogen conversion cost.

Relative CAPEX categories for 100% hydrogen solution for each of the surveyed sites excluding indirect costs (Table 7 from section 2.4.1)

		Option 1 100% Hydrogen Solution				
Site	**Site Industry Sector**	Infrastructure	Direct Fired End Users	Indirect Fired End Users	Water Heating	Space Heating
1	Primary Plastics	8%	6%	81%	5%	0.0%
2	Food & Drink	1%	21%	42%	24%	12%
3	Non-ferrous metals	6%	85%	0%	9%	0%
4	Vehicle Manufacturing	1%	59%	36%	0%	4%
5	Non-metallic minerals	43%	57%	0%	0%	0%
6	Metal Packaging	26%	43%	6%	5%	21%
7	Food & Drink	5%	23%	72%	0.1%	0.3%

For the surveyed sites the 100% hydrogen solution is typically significantly cheaper on CAPEX terms than the best alternative (non-hydrogen) solution, which is most often electrification, due to the ability to retrofit and avoidance of new or reinforced electrical infrastructure. A hybrid hydrogen solution may offer a lower CAPEX option in some cases.

1.2.2.2 OPEX Costs

The cost estimates are typical of an early stage AACE Class 4 estimate with an anticipated accuracy of -30% and +50% and include variable operating costs due to fuel, utilities and carbon 'taxes' and allowing for the increase in fixed operating costs due to potential increases in staff or operating and maintenance costs beyond the existing baseline cycle.

A carbon 'tax' has been assumed to be levied on sites where they continue to produce CO_2 through ongoing fuel combustion onsite. This has been applied to the baseline scenario for all the sites and options on site, where there is the retention of CO_2 producing combustion equipment, and is based on carbon values, which have been used as an estimate of a maximal carbon tax that could be placed on emitters. Carbon values are an estimate of the total cost to society of each additional tonne of CO_2e emitted. These values are used in government policy appraisal to guide decision making.

Fixed operating costs including labour and maintenance have been calculated using equivalent hourly labour rates published in the SPONS handbook and by applying maintenance factors to the capital costs estimated. Variable operating costs have been calculated based on estimated annual energy consumption figures and CO2-equivalent emission values. Cost data for hydrogen has been sourced from the Hydrogen Production Costs 2021[6] report on the basis of central figures from the low carbon 'green' hydrogen projections, while the BEIS 2021 Green Book supplementary guidance has been used for natural gas, electricity and carbon prices.

Specific OPEX over a 20 year project life accounts for around 80% of the lifecycle costs calculated for hydrogen use cases (range of approximately 70-95%) . As a consequence the rates provided in these reference documents will have a large impact on the relative assessment of decarbonisation options and sensitivity analysis should be considered for future studies.

For the surveyed sites the 100% hydrogen solution is typically less expensive on OPEX than the best alternative (non-hydrogen) solution, which is most often electrification, but there are exceptions for example with the Other Industry site where the non-hydrogen alternative has smaller cost difference to the base case because of the potential to reduce energy consumption due to the higher efficiency of the electrical alternative. The hybrid hydrogen solution may have a higher OPEX option than 100% hydrogen in most cases, but again with exceptions.

[6] BEIS, August 2021, Hydrogen Production Costs 2021, ttps://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011506/Hydrogen_Production_Costs_2021.pdf

1.2.2.3 Overall Costs

For the surveyed sites the 100% hydrogen solution lifecycle cost is very site dependent and so is the difference to the best alternative (non-hydrogen) solution, which is most often electrification. Based upon the assumptions made, hydrogen can offer a competitive option for decarbonisation, subject to more detailed investigation on a site specific basis.

In certain instances, due to the required duty and temperature and the availability of electrification alternatives, hydrocarbon fuels have been retained in the case studies and renewable fuels such as biomethane have been considered as short term options. Where suitably sized electrification options do not exist it has been necessary to assume multiple electrical units in certain instances to replace one larger current gas-fired unit, leading to high costs.

In most cases, options involving full or partial electrification of processes have a much greater lifecycle cost than the 100% hydrogen solution. This was due to a combination of Capital and Operating costs along with the level of CO2 emissions per kWh of electricity on the long term marginal basis consumed during the projected 2025-2045 period, resulting in lower CO2 emission savings relative to the baseline compared to the hydrogen alternatives leading to high cost per tonne of CO2 abated.

Lifecycle Cost of CO_2 Avoided for Surveyed Sites Business Cases in £/t-CO2e avoided

		Option 1	Option 2	Option 3	
Site Number	**Site Industry Sector**	**100% Hydrogen Solution**	**Hybrid Hydrogen Solution**	**Best Alternative (Non-hydrogen)**	**Comment (Non-hydrogen)**
1	Primary Plastics	169	170	81	Electrification + NG where no electric option
2	Food & Drink	191	193	394	Electrification of all users
3	Non-ferrous metals	178	608	670	Electrification + NG where no electric option
4	Vehicle Manufacturing	169	202	314	Electrification + NG where no electric option
5	Non-metallic minerals	175	200	151	Existing natural gas supply replaced with biomethane
6	Metal Packaging	205	235	2376	Electrification of all users
7	Food & Drink	249	N/A	941	Electrification of all users

1.2.3 Safety Overview

A central focus of the work on hydrogen heating is the development of an evidence base to underpin decisions on the potential repurposing of parts or all of the gas grid to 100% hydrogen. The Health and Safety Executive (HSE) is working with BEIS to assess the safety implications of switching to 100% hydrogen. These initial site surveys provide initial safety related evidence, as well as helping to determine the optimal approach to the generation, collation and assessment of such evidence in relation to industrial sites.

Hydrogen has a lower ignition energy, wider flammable limits, is more explosive and has a lower detonation energy than natural gas. If no mitigation measures are implemented, there is a potential for a significant increase in explosion risks with greater potential for injuries, fatalities and equipment and building damage when operating with hydrogen. The larger volumetric flows of hydrogen, compared to natural gas at the same conditions, can also result in a significant increase in flammable gas cloud sizes from a leak orifice of a given size – in particular for areas where ventilation is poor. Additional risk controls were recommended at all sites surveyed to mitigate the additional risks associated with hydrogen such that risks would be broadly equivalent to operating with natural gas from a high-level qualitative perspective. These measures range from minor modifications, such as additional ventilation, to potentially redesigning and replacing major pieces of equipment.

The safety risk profile for sites with a developed Process Safety Management regime may be largely unchanged when using hydrogen and may only require relatively straight forward modifications to operate safely. Other sites are likely to require significant investment in new safety equipment or systems (e.g., ATEX rated equipment, updated fire and gas detection) to ensure that risks remain As Low As Reasonably Practicable (ALARP) to operate with hydrogen.

1.2.3.1 Key safety findings from the studies

Hazard Identification Workshops identified potentially new or increased risks associated with using hydrogen as a fuel and a qualitative evaluation of the difficulty of implementation of safety measures was conducted. It is important that individual industrial sites review their current gas systems and uses to determine their suitability to operate using hydrogen.

Equipment used in industrial sites typically has a long operating life and has often been in situ for a long period of time. Standards have been reviewed and updated in that period so while the equipment was acceptable at the time of installation, it may now not meet current best practice. Safety measures for legacy equipment will require detailed appraisal for hydrogen operation as this is a fundamental change from the original design that has the potential to invalidate existing safety measures.

There is a need to review and check that required safety standards and recommended good practice exist for hydrogen to support the design of safe equipment, infrastructure and sites, appropriate procedures and protective equipment. An example of this mentioned by Original Equipment Manufacturers, was that further work was required to understand the acceptability of EN 161 and EN 746, which are concerned with the safety requirements for burners and fuel handling systems that are part of industrial thermo-processing equipment.

Existing ventilation was found to be inadequate in terms of Dangerous Substances and Explosive Atmospheres (DSEAR) fire and explosion safety regulations[7] and IGEM/SR/25 hazardous area safety standards[8] for a number of locations for hydrogen service at all the surveyed sites. Equipment such as regulators, fan motors and other electrical equipment present in hazardous areas will be required to be ATEX certified as IIC-T1 for hydrogen, compared to the less stringent (and cheaper) IIA-T1 required for natural gas, due to hydrogen's greater flammability compared to natural gas. In many instances, it may be possible to introduce additional ventilation, or change pipe routings or component locations to mitigate the potentially increased zoning requirements as opposed to upgrading or replacing affected equipment.

The impact of hazardous areas on site design, infrastructure, equipment and ultimately costs, is affected by adverse conditions as defined in IGEM/SR/25[9]. A common source of adverse conditions identified from the sites surveyed was associated with rotating equipment, in particular, gas booster compressors. Adverse conditions result in significantly larger hazardous areas for hydrogen than for natural gas which can encompass previously non-ATEX rated equipment. No coastal sites were visited as part of this work, but it is likely that these sites may also require significantly increased hazardous areas for hydrogen operation if it is determined that they are in a corrosive environment and that adverse conditions apply.

The safety work identified common finding and issues that sites and equipment manufacturers need to consider including the implications of increased flammability range, ignition control, equipment design, suitability of materials for hydrogen duty, training and procedures.

As part of the safety work concerns with the following were identified at specific sites: use of gas booster compressors, impacts of changed combustion products, explosion venting, manual burner ignition, flares, screw and compression pipe fittings.

[7] The Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR) require employers to control the risks to safety from fire, explosions and substances corrosive to metals.
[8] The Institution of Gas Engineers and Managers (IGEM) SR/25 standard provides a procedure for hazardous area classification around installations handling hydrogen that provides a basis for the correct selection and location of fixed electrical equipment in those areas or other potential ignition sources.
[9] IGEM, "Hazardous Area Classification of Natural Gas Installations, IGEM/SR/25 Edition 2," 2010.

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Definitions

Term	Definition
AACE	American Association of Cost Engineers
ACPH	Air Changes Per Hour
AHU	Air Handling Unit
ALARP	As Low As Reasonably Practicable
ANSI	American National Standards Institute
API	American Petroleum Institute
ASHP	Air Source Heat Pump
ASME	American Society of Mechanical Engineers
ATEX	Abbreviation of “Devices intended for use in explosive atmospheres.” in French
BAT	Best Available Technique
BEIS	The Department for Business, Energy and Industrial Strategy
BMS	Burner Management System
BREF	Best Available Technique Reference Document
CAD	Chemical Agents Directive
CAPEX	CAPital EXpenditure
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMAH	Control of Major Accidents Hazards
DCO	Development Consent Order
DSEAR	[The] Dangerous Substances and Explosive Atmospheres Regulations
ELV	Emission Limit Values
EPS	The Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations
FGR	Flue Gas Recirculation
GDNO	Gas Distribution Network Operator
GKV	Germination and Kilning Vessels
H_2	Hydrogen
H_2O	Water
HA	Hazardous Area
HAC	Hazardous Area Classification
HAZID	HAZard IDentification
HAZOP	HAZard and OPerability Study
HHV	Higher Heating Value
HPHW	High Pressure Hot Water
HSE	Health and Safety Executive
IGEM	Institution of Gas Engineers & Managers
ISO	International Standards Organisation
KPI	Key Performance Indicator
Le	Lewis Number
LHV	Lower Heating Value
LOC	Loss of Containment
LPG	Liquid Petroleum Gas
LTHW	Low Temperature Hot Water
MAPP	Major Accident Prevention Policy
MCP	Medium Combustion Plant
MCPD	Medium Combustion Plant Directive
MPO	Main Plant Office
N_2	Nitrogen
NDMA	N-Nitrosodimethylamine

Term	Definition
NE	Negligible Extent
NSCR	Nonselective Catalytic Reduction
NG	Natural Gas
NOx	Oxides of Nitrogen
NSIP	Nationally Significant Infrastructure Project
NTP	Normal Temperature and Pressure
O_2	Oxygen
OEM	Original Equipment Manufacturer
OPEX	OPerating EXpenditure
PESR	Pressure Equipment (Safety) Regulations
PHAST	Process Hazard Analysis Software. Proprietary software developed by DNV
PINS	Planning Inspectorate
PLC	Programmable Logic Controller
PPA	Power Purchase Agreement
PSV	Pressure Safety Valve
QRA	Quantitative Risk Assessment
RGGO	Renewable Gas Guarantees of Origin
RGP	Relevant Good Practice
RTO	Recuperative Thermal Oxidiser
SCR	Selective Catalytic Reduction
SIL	Safety Integrity Level
SMS	Safety Management Systems
STP	Standard Temperature and Pressure (273.15K and 1 bara)
TPO	Tree Preservation Order
VOC	Volatile Organic Chemicals

2. Introduction

2.1 Project Overview

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. [10] The evidence generated will inform strategic decisions in 2026[11] on the role of low carbon hydrogen as a replacement for natural gas heating, which will help determine whether and the extent to which parts of the gas grid are repurposed or decommissioned in the longer-term.

As part of the work on hydrogen heating, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. This study was focussed on industrial end users of natural gas and understanding the safety, cost and feasibility for them to switch to 100% hydrogen. This study is not intended to apply directly to non-industrial end users because of the differences between end user environments, gas pressures and the quantities of gas consumed, which may have significant impacts on the Technical, Safety and Economic assessments conducted here.

The study has been completed in partnership with seven volunteer industrial sites located away from the industrial clusters and which will depend on the future of the natural gas grid. The sites were selected to represent a cross-section of industry in the UK and as such there is a range of sectors, company sizes, locations, and end use applications of natural gas.

A central focus of the work on hydrogen heating is the development of an evidence base to underpin decisions on the potential repurposing of parts or all of the gas grid to 100% hydrogen. The Health and Safety Executive (HSE) is working with BEIS to assess the safety implications of switching to 100% hydrogen. These initial site surveys provide initial safety related evidence, as well as helping to determine the optimal approach to the generation, collation and assessment of such evidence in relation to industrial sites. These site surveys have also gathered evidence on other factors likely to be important to end users such as the financial and permitting implications of hydrogen. Furthermore, this work helps to inform and shape potential future phases of industrial end user work within hydrogen heating, including further site surveys and hydrogen demonstration work.

2.2 Project Aims

The objectives of the project were to undertake initial site surveys of the seven industrial sites. These surveys have identified and assessed the site-specific technical, safety, cost, environmental and implementation considerations of switching from natural gas to 100% hydrogen.

Following completion of the site surveys this summary report has been prepared to identify challenges and considerations that may be common across industry and provide summary case studies to disseminate information and share learning. This summary report also identifies further work required to enable the transition from natural gas to hydrogen, including:

i. Significant assumptions that require validation through further development or site studies.

ii. Demonstration requirements (i.e. Research projects, technology demonstration).

iii. Further safety evidence.

iv. Amendments and expansion of accepted code of practice and guidance for sites.

2.3 Sites Selected

Seven industrial sites were selected to participate in the study. The sites were selected from a number of interested sites to represent a range of industrial sectors, from food & drink to vehicle manufacture, with a particular focus on sites with direct-fired applications away from industrial clusters. Additionally, sites were selected to cover a broad range of location types. Sites in Scotland and Wales were approached, but were then not able to participate in the site surveys. The energy consumption of the sites carried forward was also assessed to cover a range from small

[10] https://www.gov.uk/government/publications/industrial-decarbonisation-strategy
[11] https://www.gov.uk/government/publications/uk-hydrogen-strategy

to large users between 2,000 MWh and 500,000 MWh annual energy use. Table 1 provides information on the seven selected sites and where they sit within these selection criteria.

Table 1. Case Study Organisations

Organisation	Industry Sector	Type of Gas Users	Annual Gas Use	Annual Total Energy Use
Site 1 – Other Industry 1	Primary Plastics	Industrial steam boilers, ovens, water heaters, space heaters, flare pilot & ignition packages	83,000 MWh	143,000 MWh
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Site 7 – Food & Drink 2	Food & Drink	Germination kilning vessels, roasters, grain dryers, thermal fluid heaters, water heaters, space heaters	42,000 MWh	50,000 MWh

2.4 Site Survey Approach

The approach to the site surveys was to identify a pilot site for early engagement to prepare a consistent approach across the survey campaign and integrate any lessons learned. The surveys started with a kick-off meeting with site staff to outline the objectives, request information on site energy consumption, installed equipment and infrastructure and to make arrangements for the site visit itself. Once initial data had been received and reviewed the site survey was carried out in order to:

1) Meet with the site teams to understand their operation and decarbonisation initiatives.
2) Characterise the current site gas infrastructure and equipment.
3) Identify and assess the key impacts and considerations for the site should the gas grid be converted to hydrogen in terms of -
    i. Technical,
    ii. Safety,
    iii. Cost,
    iv. Environmental, and
    v. Implementation considerations.
4) Provide initial safety evidence and prioritisation in support of the Health and Safety Executive's (HSE) considerations on the safety of hydrogen.

Following each site visit a Hazard Identification (HAZID) session was held with the site team to identify potential hazards in the event of conversion to hydrogen based upon a systematic approach from the arrival of the gas on site at the gas meter, across the site gas distribution network to the gas consumers. Following on from the HAZID and in parallel with the technical assessment a site safety assessment was carried out considering the hazards, hazardous area assessment and consequence analysis. A concept design was developed for a 100% hydrogen solution based on the output of the technical assessment and recommendations of the safety evaluation. A concept design for the best alternative non-hydrogen decarbonisation solution was also developed. A techno-economic analysis was then performed for the 100% hydrogen and non-hydrogen business cases for comparison. A techno-economic analysis for a hybrid solution was also evaluated where suitable for the site.

Site specific reports with the full detail of the surveys and assessments were produced but due to their commercially sensitive nature these will not be published. Instead, the overall learnings are collated and presented within this summary report.

3. Summary of Key Findings

3.1 Technical Feasibility of Conversion

The study baseline assumes that **conventional natural gas** systems are replaced or modified to achieve an end state of equipment capable of running on 100% grid supplied hydrogen. This is achieved either by conversion of conventional systems to hydrogen-only operation or by installation of new upfront hydrogen-only equipment. Where used the term **hydrogen-ready** refers to equipment that is optimally designed to run 100% hydrogen but is initially configured to run on natural gas. This equipment may require a minimum number of components to be change at the point of switch over but will have been specifically designed to facilitate this process.

The technical assessment considered a series of options for full or partial hydrogen conversion along with a best non-hydrogen decarbonisation alternative. In addition to the question of whether an end-user item of equipment can be converted or replaced with a hydrogen fuelled alternative, the supply infrastructure across the site, the associated control and instrumentation equipment and the ventilation around items of equipment and infrastructure including the gas network operator's interface equipment need to be considered.

The following key findings are organised and presented from the common gas consuming end user equipment back though the site infrastructure to the site boundary interface. These are grouped into the common direct fired and indirect fired equipment in use on the industrial sites visited.

The common modifications that were observed over both direct and indirect applications can be grouped into the following categories:

The following modifications are anticipated as the minimum required:

- Replacement of inlet piping to burner for capacity reasons and removal of threaded fixtures.
- Programmable Logic Controller and Burner Management System modifications.
- Flame-eye re-tuning.

It is likely that the following modifications will be required:

- Replacement of existing flame-eye or additional flame-eye specifically calibrated for hydrogen flame.

Note- The assessment work on equipment changes required for hydrogen as part of this project was done in parallel to and independent of the technical study that BEIS has recently commissioned on industrial hydrogen ready boilers. It has not been possible at this time to re-assess the work done on the range of appliances considered in this report to account for the industrial boiler study. Future work similar work should consider the findings from that work.

With respect to standards, one area of discussion with OEMs is the application of existing standards, written based on natural gas or diesel/gas oil, for hydrogen service, particularly EN 161 and EN 746, which are concerned with the safety requirements for burners and fuel handling systems that are part of industrial thermo-processing equipment. Package plant and associated fuel valve trains in the United Kingdom are typically specified for compliance with these standards to define the requirements for over and under pressure protection as well as the sizing of creep relief valves. Further work is required to understand the acceptability of EN 161 and EN 746 for hydrogen service and the impact the sizing of creep relief valves and the release from the tail pipe has on hazardous areas.

When considering alternatives to hydrogen for industrial decarbonisation, electrification was commonly selected as the counter factual, however for certain ovens, recuperative thermal oxidisers, and dryers found in this study biomethane or the retained use of natural gas may be a valid decarbonisation option. Biomethane, especially on 'virtual' basis can offer a rapid way of addressing CO2 emissions with minimal CAPEX implications especially for a for highly integrated site with applications that are challenging to decarbonise. However in the longer term there are significant supply issues to be addressed both in terms of securing supplies but also in the context of the wider policy on gas grid conversion.

3.1.1 Direct Fired Applications

'Direct fired' applications are those in which the energy release and products of combustion come into direct contact with the product or process environment. Energy transfer can occur through a combination of radiative and convective mechanisms.

Direct fired applications will generally be excluded from the requirements of the Medium Combustion Plant Directive (MCPD), as they use the gaseous products of combustion for direct heating, drying or other treatment of materials. This is particularly relevant as the MCPD imposes limits on allowable NOx emissions and in switching from natural gas to hydrogen NOx emissions are of concern, as the production of NOx is greater at the higher flame temperatures that can result from hydrogen combustion. However, limits on NOx may still be imposed if 'installation' listed activities are performed or where there is potential for product impact. Detailed discussion on MCPD and environmental permitting aspects can be found in section 3.3.6.

Best Alternative (non-hydrogen) solutions may include electrification and use of renewable energy sources or renewable energy power purchase agreements can provide an opportunity the in the short term for a site to reduce its emissions for existing use of electricity and where there is capacity to electrifying more equipment. Where capacity is not available there will be a longer term requirement to upgrade on-site and network supply capacity.

3.1.1.1 Ovens (Other Industry 1, Food and Drink 1, Vehicles 1, Metals 2)

The oven systems surveyed were not immediately suitable for hydrogen, and, while in some instances the oven burners for hydrogen were available, the flame detection and supply piping were not suitable, and modifications to convert would be required in all cases. In summary, the extent of the modification requirements for the ovens requires deeper consultation with the OEMs to either request they evaluate the thermal design or to acquire the data to enable a third party to independently evaluate the ovens and modifications required.

A number of oven Original Equipment Manufacturers (OEMs) were contacted as part of the study. Some OEMs have begun development work of hydrogen ready units, though they indicated without an increase in demand, these units are likely to remain demonstration and prototypes for the foreseeable future. Other OEMs had not started any development of hydrogen ready versions. Retrofit of hydrogen ready burners to existing ovens is feasible, however, oven systems are often bespoke, consisting of complex multi-burner systems. There are therefore a number of areas of further work to assess before considering conversion:

- Evaluation of the temperature profile within the oven and the ability to maintain the required temperatures in the required locations to prevent damage to contents from increased flame temperature. Repositioning of burners may be necessary.
- Evaluation of the theoretical heat transfer and any de-rating that may result from the conversion.
- Evaluation of impact of higher moisture content in combustion air e.g. required air changes within the oven and the fuel efficiency of the system.
- Evaluation of the effect on NOx emissions, impact of any additional NOx on the product, and whether further abatement is required.
- Evaluation of the impact on Volatile Organic Chemicals emission controls (for applications drying non-aqueous solvents).

The following modifications may be required in addition to the common modifications stated:

- Flue gas recirculation or Selective Catalytic Reduction to abate NOx emissions.
- Changes to air fan requirements for combustion stability, performance and emission reasons.
- Repositioning of burners to achieve temperature profiles.
- Replacement or modification of VOC emission abatement systems to maintain permitted limits.

The use of pre-mixed burner systems were observed on some of the ovens surveyed, these need further study to ensure that an explosion cannot occur within the pipework and cause further damage when using hydrogen due to the higher upper flammability limit and the higher flame speed versus natural gas.

Alternative decarbonisation options for ovens are available. Both induction and infrared ovens offer an electrical solution depending on rating. These may provide additional benefits including reduced energy consumption, more targeted heating, shorter heating times and reduced equipment footprint. However, in applications requiring high temperatures, high volumes and or high throughputs these may not be feasible solutions as was the case for Other Industry 1, Vehicles 1 and Metals 2. For example, infrared, unlike conventional ovens, require the surface to be heated to face the heating elements. This may require changing the orientation of items in the oven leading to a far larger footprint to maintain the original throughput, either through a single much larger oven or multiple oven units. If electrical options are not feasible, sites could purchase Renewable Gas Guarantees of Origin, matched to a biomethane injection to the gas grid, as a methodology to carbon neutrality subject to access to an on-going natural gas supply. Biomethane as an option will need further study as it will be dependent on short to medium term availability of supplies and the long term development of infrastructure policy. It is mentioned in the context of a solution which could be considered on a site specific basis. High temperature, high capacity applications are likely to favour combustion and point source carbon capture may offer potential solutions.

3.1.1.2 Furnaces (Metals 1)

The furnace systems surveyed were not immediately suitable for hydrogen, and, while in some instances the new burners would be suitable for hydrogen subject to appropriate certification requirements, the flame detection and supply piping were not suitable, and modifications to convert would be required in all cases. In summary, while it is feasible to convert the existing burners and there is sufficient space to undertake the work and install any proposed modifications, the costs are site specific and OEM quotes are required to confirm the most cost-effective option.

The extent of the modifications to convert holding and melting furnaces require consultation with OEMs to either request they evaluate the thermal design or to acquire the data to enable a third party to independently evaluate the furnace and modifications required. As well as determining the extent of any modifications required, the assessment should also evaluate the theoretical heat transfer and any de-rating that may result from the conversion. OEMs contacted are at different stages of hydrogen readiness, with certifying burners as hydrogen ready at production sites being identified as a potential problem due to current EU legislation. This may require verification of burners as suitable for hydrogen by third parties. However, one OEM contacted offers a wide range of hydrogen ‘ready’ burners that can handle various hydrogen fuel mixtures up to 100% hydrogen.

In the current market, hydrogen fired heat treatment furnaces are in development however they are not widely available to purchase. One OEM stated they are ready to supply hydrogen burners on a MW scale and have successfully tested a 200kW, 100% hydrogen fired burner that operates in flame and flameless modes. Additionally, it is claimed these burners emit less than 80 mg/Nm3 NOX emissions at 3% oxygen even at 100% hydrogen, meeting current standards required by the Medium Combustion Plant Directive (MCPD) for natural gas, and well below the 200 mg/Nm^3 at 3% O2 required for “other gaseous” fuels. While the function of these furnaces are different, the similar thermal rating and temperatures required make it reasonable that a burner of this type could be used in melting and holding furnaces such as those currently used in this sector. However, as heat treatment furnaces deal with solid castings as opposed to molten metal, they were not considered for this study and further study specific to melting and holding furnaces would be required to confirm this.

Alternative decarbonisation options for furnaces are to replace with electric induction holding or melting furnaces. Electric induction furnaces typically have capacities up to around 1 tonne, but site investigated required an output of ~40 tonnes, suggesting this technology is not yet feasible as an alternative. However, OEMs are working on large scale induction furnaces and 22,000 kW, 50 tonne furnaces have been commissioned. This will have significant implications for the electrical infrastructure and network connection capacity.

3.1.1.3 Gas Torches (Metal 1)

Gas torches were only encountered on the Metal 1 site, where they are used in a variety of open flame applications including localised heating, ignition of burners. Current commercially available systems (using methane, propane, hydrogen and acetylene) are often oxy-fuelled since these are often used for portable heating or high temperature welding and cutting and further work is required around safety controls and supply piping for fixed systems. In summary, replacement of the existing hydrocarbon based system requires careful consideration of safety controls and supply piping for fixed systems.

The adjustable gas burner torches encountered on site during this study were not capable of firing with hydrogen safely without some modification and as suitable hydrogen firing replacements are not currently commercially available, further work will be required to confirm suitable means of converting torches.

Further work is required to evaluate the temperature profiles required and the ability to maintain the required temperatures with hydrogen torches. The hazards associated with hydrogen leaks from manual control valves and shut off valves was not investigated and would require further investigation.

Torches that use hydrogen as a fuel source are commercially available today however most run on a hydrogen/oxygen mixture. These torches have a range of applications from small flames used in applications such as the jewellery industry to larger flames for commercial and industrial applications such as brazing. Typically, these torches produce the required oxygen and hydrogen through a small electrolyser that is supplied with the torch. Alternatively, the possibility of installing an oxygen supply to these torches, making use of any oxygen already stored on site with either piping or small storage cylinders could be considered. Further work is required to assess any safety implications associated with having oxygen pipes or storage cylinders in areas where there are open flames and high local temperatures.

The alternatives for decarbonising gas torches are limited. Currently hydrogen/oxygen torches can be bought that come with small electrolysers as part of the torch equipment package. OEMs in the UK offer a range of torches that include larger flames for commercial and industrial applications such as brazing, with an upper production limit of hydrogen of 9 litres per minute (<3kW). These could be used in certain situations as a potential option to decarbonise these torches, mainly for handheld applications, but for larger torches these will be unable to meet duty requirements. For this reason, the most likely alternative if natural gas is no longer available would be an independent propane or butane supply to the gas torches, however, these have a higher carbon intensity and as does not improve decarbonisation.

3.1.1.4 Direct Gas Fired Air Handling Units (AHUs) (Food and Drink 1, Vehicles 1)

Gas fired Air Handling Units (AHUs) for process use were encountered on a number of the sites. AHUs were encountered for both process heating where they provide a controlled supply of air heated to specific temperatures into process equipment such as ovens or dryers and also as space heaters where they were used to provide general space heating as covered under Space Heating (section 2.1.1.7).

Response from OEMs has been limited and so the extent of development activity on use of hydrogen in this equipment type is unclear. Burner equipment suppliers may not be actively addressing this application. Current system design where equipment is located within the equipment space will need careful review for use with hydrogen.

Existing burners and AHUs surveyed were not immediately suitable for hydrogen and will require substantial modifications to convert. Further work is required to understand the extent of changes required, with main areas of focus required being flame-eye suitability, emissions control, and modifications required to PLC/BMS. Where air supplied from AHUs is tightly controlled, in terms of humidity as well as temperature, the additional vapour from hydrogen combustion will also need assessed.

A range of AHU system OEMs were contacted to understand if there are hydrogen equivalents available or developing, however, there was no response. It would be possible to replace the burners for hydrogen equivalents, however, it is unclear at this stage if that is feasible. The extent of the modification requirements for the AHUs requires consultation with the OEMs (burners and AHUs) to either request they evaluate the thermal design or to acquire the data to enable a third party to independently evaluate the AHU and modifications required.

Several burner and equipment OEMs were contacted as part of this assessment, of these only one burner OEM confirmed they are working on the compatibility of their burners for AHUs.

Further study is required in terms of the DSEAR requirements within the AHUs where equipment is mounted within the enclosed ductwork to ensure appropriate electrical equipment rating and sufficient ventilation to disperse hydrogen, particularly when the AHU system is not in operation.

An alternative to direct hydrogen replacement could be to install hydrogen boiler(s) to generate a heating medium such as steam or high pressure hot water (HPHW) to distribute heat to the existing AHUs. This would require the removal of the existing burners and replacement with suitable coils in the AHUs. Calculations would need to be conducted to understand if a coil of either steam or HPHW would have sufficient heat density in the available space in comparison to existing burners. If this were not possible sites may require new AHUs and a Low Temperature Hot Water (LTHW) solution. This will have implications on energy efficiency and the replacement of direct with indirect heating may result in associated changes to treatment under MCPD capacity aggregation and emission limits.

An alternative decarbonisation approach in the absence of hydrogen, may be to replace the AHU for a LTHW equivalent. The LTHW could then be supplied by either a localised heat pump or a LTHW circuit from electric boiler(s), or for higher heat density requirements an electric steam boiler and steam coils in the AHUs could be installed. The energy efficiency implications for alternative options should be addressed during feasibilities studies.

3.1.1.5 Recuperative Thermal Oxidisers (RTOs) (Vehicles 1, Metal 2)

The Recuperative thermal oxidisers systems surveyed were not immediately suitable for hydrogen, and, while it is likely that hydrogen ready burners are available, the flame detection and supply piping are not suitable, and modifications to convert would be required. In summary, the extent of the modification requirements for RTOs requires further consultation with the OEMs to either request they evaluate the thermal design or to acquire the data to enable a third party to independently evaluate the modifications required.

Recuperative thermal oxidisers (RTOs) use natural gas as a primary fuel to incinerate the volatile compounds extracted from the process. Where existing burners are not immediately suitable for hydrogen, they will require substantial modifications to convert. Further work is required to understand the extent of change required, with main areas of focus being flame-eye suitability, emissions control, and modifications required to PLC/BMS.

The redesign/replacement of RTO units must ensure that the full quantity of VOCs from the process are removed and treated effectively. The internal design for the different flame characteristics, quantity of individual burners or pre-mixing the hydrogen and the inlet gas to improve the effectiveness of the RTO will all need to be considered.

Hydrogen fired RTO costs are therefore site specific and OEM quotes are required to confirm the most cost-effective option.

RTOs require high temperatures to ensure combustion of the volatile compounds. An alternative arrangement using a catalytic oxidiser, electric heater and heat recovery unit may be suitable depending on flow rate and temperature. However, the impact on retaining natural gas for this use generally has a low impact in comparison to other site gas users. Sites could look to purchase RGGOs as a methodology to carbon neutrality. RGGOs are 100% matched to a biomethane injection to the gas grid.

3.1.1.6 Dryers (Minerals 1, Food and Drink 2)

Existing dryers' burners are not immediately suitable for hydrogen and will require substantial modification to convert. Further work is required to understand the extent of change required, with main areas of focus being product impact and drying efficiency from additional water vapour, flame-eye suitability, emissions control, and modifications required to PLC/BMS.

Hydrogen ready dryers of the type, size and duty observed are currently not available, but consultation with OEMs confirmed that these are currently in development. It may be feasible to retrofit hydrogen burners to the existing dryers as hydrogen burners of the required duty are available, however the requirements will be unit specific and likely extensive and expensive.

Several burner and equipment OEMs were contacted as part of the project. Two OEMs confirmed that they can provide burners capable of firing a mixture of hydrogen and natural gas. There are limitations on the range of mixtures achievable in one burner head and multiple burner heads may be required in order to achieve flexibility sufficient to facilitate operation from 0 vol% through to 100 vol% hydrogen.

Neither burner manufacturers believe they can achieve the Nitrogen Oxides (NOx) target of 100 mg/Nm³ at 3% O2 as required by the Medium Combustion Plant Directive (MCPD) for new natural gas plant, however they can meet the 200 mg/Nm³ at 3% O2 required for new "other gaseous" fuels plant. This issue is an area of focus for both OEMs who are undertaking research to assess potential solutions both through burner head design and Flue Gas Recirculation (FGR). Both OEMs have demonstration units operating at their facilities and stated that further analysis would be required to confirm the ability to fire hydrogen and natural gas in a single burner.

The following modifications are likely to be required in addition to the common modifications stated:

- Replacement of existing flame-eye or additional flame-eye specifically calibrated for hydrogen flame (flame-eye OEMs contacted as part of the project have advised that it is unlikely existing flame eyes could be utilised and a replacement would be required).
- Changes to burner fan air requirements.

And potentially the following modifications may be required:

- Flue gas recirculation or SCR unit to abate NOx emissions.
- Replacement and/or upgrading of refractory.

In summary, while it is possible to undertake the work and install any proposed modifications, the costs are site specific and OEM quotes are required to confirm the most cost-effective option.

As an alternative electric air heaters are available to replace the burners, however the largest units that are widely available at present are circa 5 MW and there are a very limited number of suppliers that appear to offer units at the MW scale. Electric heaters that can be used as a like for like switch with a natural gas burner will need to be capable of high temperatures up to ~700°C given that the hot air stream is mixed with higher volume of lower temperate air to achieve the desired process temperatures. This beyond the range of most electrical heating options. A lower temperature higher flow electrically heated solution could be more optimal for some applications, however the impacts on the downstream air system are likely to extensive, preventing a like for like switch and requiring further site specific investigation. Some drying applications require very high temperatures which becomes unsuitable for electrical heating. For high duty and high temperature drying applications beyond the order of 5 MW / ~250°C electrical options may not be feasible. In this situation adopting a biomethane replacement for natural gas maybe the best alternative. Biomethane is essentially a near-pure source of methane produced either by “upgrading” biogas (i.e. the removal of CO2 and other contaminants present in biogas produced from the anaerobic digestion of organic materials) or through the gasification of solid biomass followed by methanation. Given the comparable characteristics of biomethane with current natural gas, it is likely that existing infrastructure would be compatible with minimal or no modifications.

3.1.1.7 Direct Fired Space Heating (Other Industry 1, Metals 1, Metals, 2, Vehicles 1, Food and Drink 2)

Direct fired space heaters are typically suspended from ceilings and can be either radiant heaters or sometimes air heaters referred to as AHUs These space heater AHUs were found in great number at the Vehicle site.

No suitable commercially available hydrogen direct fired space heaters have been identified and there are no indications of any current development in this area. Development of a hydrogen fired space heater does appear to be technically feasible however there currently appears to be no incentive for manufacturers to invest in the development and demonstration required. Given the relative scale of space heating against the sites’ main end users and availability of non-hydrogen alternatives the development is likely to remain lower priority.

The space heaters surveyed were found to typically be supplied with natural gas through small bore pipes with threaded connections which would require replacement, some are undersized for hydrogen use and the threaded pipe connections have a higher risk of leaks.

Table 2 below outlines the relative magnitude of non-process duty to provide space heating and hot water. These are based upon ratings and so in terms of actual energy consumed the values are likely to be even lower.

Table 2. Proportion of installed capacity between process and duty and space heating and hot water

Site Number	Site Industry Sector	Process rating	Space heating and hot water rating
1	Primary Plastics	98%	2%
2	Food & Drink	95%	5%
3	Non-ferrous metals	95%	5%
4	Vehicle Manufacturing	Not quantified	Not quantified
5	Non-metallic minerals	100%	0%
6	Metal Packaging	93%	7%
7	Food & Drink	99%	1%

An alternative heating technology solution will need to be evaluated if natural gas is no longer available. Indirect use of hydrogen is feasible through the use of a hydrogen fired boiler or hot water heater and steam or hot water fed space heaters. This will have implications on energy efficiency and the replacement of direct with indirect heating may result in associated changes to treatment under MCPD capacity aggregation and emission limits. Hydrogen hot water heaters of the required capacities are being developed and should be readily available within the next 5-10 years. This is most appropriate for replacement of convective space heaters which provide heat to the entire room and suited to occupied spaces such as small building volumes (e.g. control room or break room) rather than large building volumes (e.g. warehouse). In the case of radiant space heaters which provide heat to specific spaces, normally in buildings which are difficult to heat due to large openings and poor air tightness or are infrequently occupied further work is required to develop an appropriate hydrogen replacement.

Alternatively, electrical space heaters, electric calorifier with hot water fed space heaters, air source heat pumps with hot water fed space heaters or air source heat pumps with AHUs are commercially available and could be used to decarbonise this service. Again, the option selected will be dependent on whether convective or radiant heating is most appropriate for the location. The energy efficiency implications for alternative options should be addressed during feasibilities studies.

3.1.1.8 Flares (Other Industry 1)

One of the site surveys included a flare system to manage process emissions of flammable off-gases. In this specific instance the natural gas has three functions within the flare systems:

- As a fuel for the flare pilots.
- As a fuel for the flame ignition package, and.
- As a padding and purge gas within the flare seal pot.

Natural gas is used continuously to provide pilot flames for the site's flare and is critical to the site safety systems. It is industry practice, and expected by competent authorities, that there is a high-level of reliability and redundancy inherent within the design of this system. The primary reasons that natural gas is used in this capacity is the high reliability of the supply system, availability of the fuel and the technology maturity. If the security of supply of hydrogen is less than that of natural gas then it will increase the risk of an unignited flare scenario. As part of any change to the plant, a design and safety review will be required as standard industry good practice and will likely include a form of Hazard and Operability Study (HAZOP) and potentially an update of any previous Quantitative Risk Assessment (QRA) and Safety Integrity Level (SIL) assessments to ensure that the residual risk remains acceptable.

A key feature and requirement of flare pilots is their ability to maintain a stable flame to ensure that they are available to ignite a release from the process. Hydrogen produces a less stable flame than methane which, to avoid a higher risk of 'flame-out' scenarios, will require the pilots to be changed. If the pilots are not changed the "flame-out" occurrences will require the pilots to be reignited more frequently. As part of this study OEMs were contacted and they confirmed that they can offer pilots that would be suitable with 100 vol% hydrogen, however no reference list or proof of demonstration projects were provided.

Limited information was available for the current flare ignition package, however in theory it is possible to use hydrogen. Further work is required to understand the ability to convert existing equipment.

Both flare pilots and ignition packages require a fuel to maintain a constant flame and source of ignition in the event of a flaring event. Only viable options are hydrogen or a hydrocarbon-based solutions. Use of natural gas is unlikely to change in the interim (although this may be from compressed natural gas cylinders). The impact on retaining natural gas for this usage on emissions is negligible as the flare units are used very rarely and consumption is very low.

The prevention of air ingress into flare systems is often achieved through the water seal within the seal pot and through steam purging/sweeping the flare stack. A further layer of protection is a nitrogen back-up, and natural gas may be used as third layer of protection, though further work is required to understand if a third layer is required.

3.1.2 Indirect Fired Applications

'Indirect fired' applications are those in which the energy release and products of combustion do not come into direct contact with the product or process environment. The combustion energy transfers to and is conducted through a heat transfer surface into the product or process environment, the heat transfer surface physically separates the combustion from the product or process environment.

Indirect fired applications will generally be included under the requirements of the Medium Combustion Plant Directive (MCPD), as they use the gaseous products of combustion for indirect heating. This is particularly relevant as the MCPD imposes limits on allowable NOx emissions and in switching from natural gas to hydrogen NOx emissions are of concern, as the production of NOx is greater at the higher flame temperatures that result from hydrogen combustion. Limits on NOx may also be imposed if 'installation' listed activities are performed. Detailed discussion on MCPD and environmental permitting aspects can be found in section 3.3.6.

Note that because the site selection process largely prioritised direct fire applications there are potentially fewer examples of indirect applications than would be typical in a more randomised sample of industrial sites.

Best Alternative (non-hydrogen) solutions may include electrification and use of renewable energy sources or renewable energy power purchase agreements can provide an opportunity the in the short term for a site to reduce its emissions for existing use of electricity and where there is capacity to electrify more equipment. Where capacity is not available there will be a longer term requirement to upgrade on-site and network supply capacity.

3.1.2.1 Steam Generators (Other Industry 1)

Existing steam boilers were not found to be immediately suitable for hydrogen and will require substantial modification to convert. Further work is required to understand the extent of change required, with main areas of focus being ability to co-fire with process gases, flame-eye suitability, emissions control, and modifications required to PLC/BMS.

Note that there was only one large steam generator looked at and although the ability to co-fire with process gas is important for that site, it is not necessarily a major factor for other sites, compared to what might expect from a more representative sample.

Hydrogen ready steam boilers in the ~10MW output scale are currently in the demonstration phase of development, while smaller units of <5MW output and larger water tube boilers have progressed further to show some commercially available as 'hydrogen ready'. Assuming that the demonstration projects are successful and there is a wide roll-out of commercially available steam boilers there is an assessment to be made of the replacement option versus conversion of existing steam boilers.

The extent of the modifications require consultation with the OEMs (burners and boiler) to either request they evaluate the thermal design or to acquire the data to enable a third party to independently evaluate the steam boiler and modifications required. As well as determining the extent of any modifications required, the assessment should also evaluate the theoretical heat transfer and any de-rating that may result from the conversion.

Several burner and equipment OEMs were contacted as part of the project. Two OEMs confirmed that they can provide burners capable of firing a mixture of hydrogen and natural gas. There are limitations on the range of mixtures achievable in one burner head and multiple burner heads may be required in order to achieve flexibility sufficient to facilitate operation from 0 vol% through to 100 vol% hydrogen.

Neither burner manufacturers believe they can achieve the Nitrogen Oxides (NOx) target of 100 mg/Nm³ at 3% O2 as required by the Medium Combustion Plant Directive (MCPD) for new natural gas plant, however they can meet the 200 mg/Nm³ at 3% O2 required for new "other gaseous" fuels plant. This issue is an area of focus for both OEMs who are undertaking research to assess potential solutions both through burner head design and Flue Gas Recirculation (FGR). Both OEMs have demonstration units operating at their facilities and stated that further analysis would be required to confirm the ability to fire hydrogen and natural gas in a single burner.

The following modifications are likely to be required in addition to the common modifications stated:

- Replacement of existing flame-eye or additional flame-eye specifically calibrated for hydrogen flame (flame-eye OEMs contacted as part of the project have advised that it is unlikely existing flame eyes could be utilised and a replacement would be required).
- Changes to burner fan air requirements.

And potentially the following modifications may be required:

- Flue gas recirculation or SCR unit to abate NOx emissions.
- Replacement and/or upgrading of refractory.

In summary, while it is feasible to convert existing boilers the costs are site specific and OEM quotes are required to confirm the most cost-effective option.

The alternative option for the decarbonisation is to replace with electric steam boilers and either generate renewable power on site or purchase power via a 'green' renewable Power Purchase Agreement (PPA). Electric boilers are available at the required site pressures (~11 barg), however the largest units that are widely available at present are circa 4 to 6 MW, there are a very limited number of suppliers that offer units larger than this, electric boiler OEMs were contacted to confirm their offerings request budget quotations. The feasibility of an electric alternative option will need further study; a PPA will provide a short-term solution where there is capacity for electrifying more processes, but in the longer-term there may be a requirement to enhance the grid if electrical demand begins to increase above the grid's capacity.

3.1.2.2 Water Heaters (Other Industry 1, Food and Drink 1, Metals 1, Vehicles 1, Metals 2, Food and Drink 2)

Industrial Scale

For large, industrial scale water heaters providing process water heating, the extent of the modifications to the water heaters requires consultation with the OEMs (burners and water heater) to either request they evaluate the thermal design or to acquire the data to enable a third party to independently evaluate the water heater and modifications. As well as determining the extent of any modifications required, the assessment should also evaluate the theoretical heat transfer and any de-rating that may result from the conversion.

Several burner and equipment OEMs were contacted as part of the project. The OEMs confirmed they are currently developing hydrogen ready versions and results so far are promising.

The alternative for decarbonisation of the industrial scale water heaters is to replace them with electric water heaters and either generate renewable power on site or purchase power via a ‘green’ renewable PPA. Electric water heaters are available at the required temperatures from a number of OEMs.

Domestic Scale

Installed smaller, domestic type water heaters (boilers) were present at most of the sites but none were found to be immediately suitable for hydrogen. In the current market, there are water heaters capable of running on a 20% blend of hydrogen and natural gas. Hydrogen water heaters are currently being developed and prototyped by several water heater OEMs to run on 100% hydrogen as well as natural gas.

There are a number of funded programmes ongoing within this area of development, especially since the government’s Hydrogen Strategy was published in 2021 with the target to ensure up to 35% of the UK’s energy consumption comes from hydrogen by 2035. One example is the BEIS Hy4Heat programme which focussed on both the development of technologies capable of being hydrogen ready within households as well as investigating the changes required to hydrogen gas standards and certification. As part of the project, two OEMs developed prototypes certified for burning natural gas including blends of up to 20% hydrogen and being converted to burn 100% hydrogen.

OEMs are looking to produce commercially available models for 2025 following these demonstration projects. These hydrogen domestic boilers are likely to have similar costs to current natural gas water heaters.

The alternative options are reliant on sourcing renewable electricity to achieve the decarbonisation aim, and include an electric calorifier, or air source heat pump with hot water buffer tank.

3.1.2.3 Thermal Fluid Heaters (Food and Drink 2)

Thermal Fluid Heaters use oil as an intermediate heat transfer fluid to transfer heat from one location to another and include a heat exchanger to provide the process heat to the product. No suitable commercially available hydrogen ready thermal fluid heater packages have been identified. It may be feasible to retrofit a hydrogen burner to existing thermal fluid heaters as hydrogen burners of the required duty are available, however the requirements will be similar to that of retrofits of water heaters and unit specifics will require consultation with the OEMs.

The alternative option for the decarbonisation is to replace with electric thermal fluid heaters and either generate renewable power on site or purchase power via a ‘green’ renewable Power Purchase Agreement (PPA).

3.1.2.4 Fryers (Food and Drink 1)

Fryers have a burner system that heats continually circulating oil which itself comes in contact with the product. The OEM develops the burner and heat exchanger and were contacted as part of this assessment to investigate if hydrogen ready fryers are available, or if existing equipment could be modified to be hydrogen ready. The OEM are currently undertaking a feasibility study and trials. They are assessing both new systems and retrofitting. Cost implications of equipment is part of the study which is due to be completed in Q4 2022. Assuming that the demonstration projects are successful and there is a wide roll-out of commercially available fryers there is an assessment to be made of the replacement option versus conversion of existing equipment.

The extent of the modification requirements for the fryers requires deeper consultation with the OEMs to either request they evaluate the thermal design or to acquire the data to enable a third party to independently evaluate the modifications required. As well as determining the extent of any modifications required, the assessment should also evaluate the theoretical heat transfer and any de-rating that may result from the conversion. Note Hy4Heat WP5 have developed commercial/restaurant scale fryers.[12]

The requirements of fryers are comparable with those of direct fired ovens discussed in Section 3.1.1.1.

3.1.2.5 Indirect Ovens (Metals 2)

Indirect fired ovens have complex multi-burner systems which are manufactured by the OEM. The OEMs contacted as part of this study confirmed that converting to 100% hydrogen has not yet been considered and further analysis would be required to confirm the ovens' ability to operate with this fuel. There are currently no plans to investigate and test a hydrogen product range as there are alternatives to their gas heating curing oven systems through induction and there is limited demand from operators for a hydrogen fired oven.

The requirements of indirect fired ovens are comparable with those of direct fired ovens discussed in Section 3.1.1.1.

3.1.2.6 Roasters (Food and Drink 2)

The roasters use hot air generated by natural gas burners to heat and dry the product indirectly by conduction through the roaster drum walls. The existing roasters are not immediately suitable for hydrogen and will require substantial modification to convert. Further work is required to understand the extent of change required, with main areas of focus being NOx management and integrity of sealing between combustions gases and product to prevent undesired or harmful chemical by-product formation, flame-eye suitability, emissions control, and modifications required to PLC/BMS.

Hydrogen ready roasters of industrial sizes and duties are not currently commercially available. However, contact has been made with the roaster OEM and they have indicated that they are developing a hydrogen roaster and are planning to launch a large size roaster using hydrogen as fuel in 2023.This first hydrogen roaster will be capable of processing several tonnes of coffee beans, and plans for roasters for other foods stuffs are set to follow shortly after.

Alternatively, electrically heated roasters are commercially available at industrial size and duty, however due to being a batch roasting system there are large variations in the energy requirements during roasting and as such will require discussion with the site electricity supplier as to whether they can meet the peak and base load variation.

3.1.3 Site Infrastructure

Existing site infrastructure equipment and routing is a result of the current practice for natural gas installation, operation and maintenance under existing regulations. The revised design and installation guidance for hydrogen could result in significant modifications at sites to bring the gas from the supplier to the end user equipment.

For the piping suitability assessment, hydrogen systems are assumed to have the similar pressures as the natural gas systems which they are replacing.

The piping suitability has been based on assessing line velocity and pressure drop. Alternative scenarios are possible such as increasing line pressures, however this is likely not beneficial at individual sites where the equipment requires low gas pressures to operate, and existing piping design pressures are unknown.

Assessment of piping size suitability for hydrogen is done based on allowable maximum gas velocities of 20 m/s from IGEM/UP/2 for unfiltered gas for natural gas[13] and to avoid a pressure drop exceed 10% of the upstream pressure. (Maximum velocity allowable for filtered gas is 40 m/s but using this value would assume that filters are fitted at the site boundary and are serviced regularly. The implications on pressure drop would need to be assessed.)

Hydrogen lines have been assessed against a maximum gas flow velocity of 20 m/s at pressure conditions specified by the individual site, based upon IGEM standard for natural gas. In practice existing lines with values between 20 and 30 m/s may be retained subject to acceptable metallurgy and joint type provided they are risk assessed for vibration and pressure drop.

[12] https://www.hy4heat.info/wp5

[13] Institute of Gas Engineers & Managers (IGEM), IGE/TD/4, PE and steel gas services and service pipework

Line pressure drop criteria of 10% of inlet pressure and 0.1 bar per 100 m have been used to achieve an acceptable margin at the equipment interface. For this project minimum supply pressures of ~175 mbarg for industrial boiler or ~20 mbarg for domestic boiler are recommended.

It was found that much of the existing natural gas piping and infrastructure on the sites would require replacement for use with hydrogen. Most often, this is due to the line capacity being insufficient for the hydrogen flow required to maintain the same energy flow to the end users , whilst still having a gas velocity equal to or below 20m/s (some tolerance was allowed where this was not significantly over 20 m/s). The proportion of piping that was undersized varied considerably between sites, as shown in Table 3 and Figure 1. Some sites would require near full replacement of existing pipework, while for others it was found that sites had oversized piping for their natural gas demands. This is more likely where gas users and units have been decommissioned and removed over time, but in some sites the original lines have simply been oversized for their gas needs.

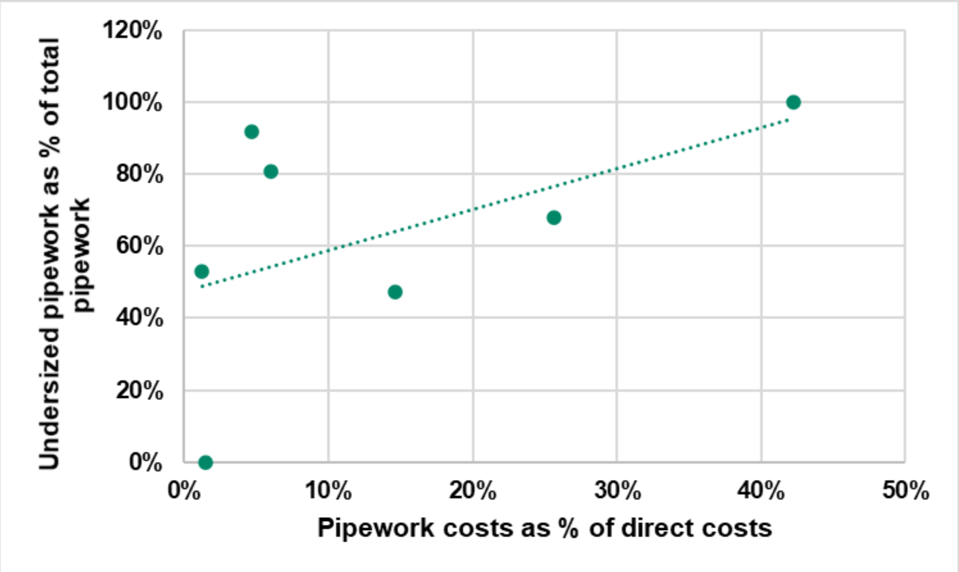
When replacing undersized piping and fittings consideration needs to be taken to the space available to accommodate the larger size and for the cost of removing the existing line. In many cases physical congestion and space constraints were witnessed in areas where lines would require replacement. This may lead to knock on effects of additional fittings and routing changes to accommodate the change.

During design development, the option of potential parallel replacement rather than re-use to limit down-time should be considered

Table 3. Proportion of pipework undersized and related pipework costs for each site

Site Number	Site Industry Sector	Proportion of pipework undersized	New pipework costs as proportion of total direct costs
1	Primary Plastics	47%	15%
2	Food & Drink	0%	1%
3	Non-ferrous metals	81%	6%
4	Vehicle Manufacturing	53%	1%
5	Non-metallic minerals	100%	42%
6	Metal Packaging	68%	26%
7	Food & Drink	92%	5%

Figure 1. Proportion of pipework undersized and related pipework costs for each site



Based on visual inspection and records where available, metallurgy of the general piping material was found to be acceptable for hydrogen at most sites. However, in some cases there was little detail available on the specific grades of the material used, and so further work is required to positively identify all materials within the natural gas infrastructure of the sites if it is to be repurposed for hydrogen. The materials used for valves and pipe fittings were not assessed for hydrogen suitability. In particular, valve trims and non-metallic components at joints and valves require further investigations to identify the suitability of all the materials present and at this stage, there is no guidance if screw fittings will be suitable for hydrogen due to leak tightness. The pipe fitting types were not assessed for hydrogen suitability, aside from excluding the use of screw fittings. It is also recognised that the positive identification of all materials used in a gas distribution system may be a difficult task on older sites. Bespoke jointing, such as compression fittings, and flexible connections were also seen at many sites and further investigation is required to identify their materials and to assess the leak tightness of pipe fittings of the existing system for hydrogen, and where they are unsuitable to identify suitable alternatives. Discussion and collaboration with OEMs are likely required where these bespoke parts form part of the end user interface. If additional material issues are identified subsequently then further replacement costs would be incurred.

On a number of sites, the piping routings do not appear suitable for hydrogen due to proximity to ignition sources and or location within occupied buildings. The recommendation of the study is to re-route these sections externally and underground most preferably to reduce the inherent risk from a leak. Particularly of note for these sites too was the recommendation to locate pressure let-down stations externally wherever possible. This reduces the pressure and thus extent of a release within buildings and also eliminates several significant leak sources from inside the building related to the regulating valves.

The pressure set points of pressure let-down stations should be reviewed against the pressure supply requirements of the end users to identify where setpoints can be lowered without impinging operability. It was found on a number of sites that it was possible to reduce the pressure setpoints to a level whereby the hazardous area classification reduced to Zone 2 of negligible extent.

Equipment present in any hazardous areas such as regulators, fan motors and other electrical equipment will require to be rated as IIC-T1 for hydrogen. In the majority of cases, it is likely to be preferable in terms of cost and safety to introduce additional ventilation to mitigate the increased zoning requirements as opposed to upgrading or replacing affected equipment to be ATEX compliant.

Ventilation in terms of DSEAR and IGEM/SR/25 was found to be inadequate in a number of locations for hydrogen service at all the surveyed sites. However, in most cases, this can be addressed with relatively minor modifications to increase ventilation and by suggestions above regarding line routings and pressure settings. Given the higher buoyancy of hydrogen than natural gas ventilation is most commonly required to be added at high level within buildings to prevent accumulation in roof spaces. Ventilation panels of the required area can be installed to increase building air changes at relatively modest cost in most cases. Further study at sites is required to determine full ventilation requirements.

Sites with low pressure gas supplies often use gas compressors also known as 'boosters' to supply end users with higher pressure requirements. Hydrogen generally requires 2.5 – 3.5 times more work to compress the same energy flow as natural gas. Therefore, sites with existing gas compressors which are used to raise the low-pressure gas supply will very likely require replacement with new units suitable for hydrogen service and capable of delivering the necessary work to raise the hydrogen pressure to required end user pressures. Additionally, it is likely that the ATEX rating of current compressors, particularly the motor, is not sufficient for hydrogen. Compressor OEMs were contacted to determine the current status of compressors within the relevant differential pressure and flowrate ranges required on the sites surveyed. None of the gas compressor OEMs currently offer a hydrogen ready model at the ~75mbarg pressure range, however, higher pressure units are readily available.

Furthermore rotating equipment is a vibration source and represents adverse conditions and consequently larger hazardous areas for hydrogen than for natural gas which can encompass previously non-ATEX rated equipment.

Existing gas detectors at the sites, where present, are calibrated for specific hydrocarbon species found in natural gas and will require replacement with detectors calibrated for hydrogen. Replacement of gas detection with H2 ready ones is only a priority where already installed. In general adding gas detectors where not currently installed is likely to be disproportionate unless there is a significant risk of gas accumulation. It is recommended that hydrogen leak detectors are installed at metering stations, pressure let-down stations and end users.

Implementation of hydrogen leak detectors is to be defined. It is noted that leak detectors used for hydrogen can have a relatively slow response time due to the buoyancy of hydrogen and so further work is required to understand what modifications would be necessary. Acoustic based leak detectors may be suitable for high pressure hydrogen systems above 2 barg, but are not suitable for the low pressures seen at most industrial sites. Further work is recommended to develop alternative detection strategies.

3.1.4 Gas Connection & Metering

From visual inspection the natural gas connection size into the sites appeared to be of adequate size in the 3 cases, with 2 sites unknown because of uncertainty in future demand, and 2 sites undersized for future hydrogen. Sites will need to hold discussions with their gas providers over modifications to their gas supply connection. Full investigation of the natural gas connections from the distribution network was beyond the scope of the study, and it has been assumed that there will be no disruptions to the hydrogen supply to the sites.

The pipework immediately downstream of the site gas receiving and initial pressure let-down was found to be undersized in around half of sites. For sites where this is the case the downstream isolation and meter will need to be replaced with larger sizes.

The site gas meters are expected to require either modification or more likely replacement in all cases. The main reason for this is due to one or a few the following: inadequate sizing for the hydrogen flowrate, inadequate volume flow measurement range for the hydrogen flowrate, inadequate ATEX rating for hydrogen, calibration and adjustment for hydrogen detection/measurement. Though flowmeters suitable for hydrogen flow measurement exist a recognised fiscal hydrogen flowmeter is still an area of further development and the possibility to modify existing fiscal natural gas flowmeters requires further investigation.

Typically, sites will have a meter shed or compound, a building that houses the gas metering and initial pressure let-down. Generally, these structures contain internal hazardous zones, however the introduction of hydrogen can lead to the zoning becoming more severe in both extent and classification. This can be mitigated by installing additional ventilation to the building near the roof level to disperse potential hydrogen leaks, the exact ventilation area required will be site specific. Additionally, where equipment is undersized for the hydrogen flow and larger sizes need to be installed it may be necessary to extend or replace the existing metering structure to accommodate this larger equipment.

During the site surveys several of the sites raised concerns over the security of supply for hydrogen. During initial implementation there is a concern that the hydrogen supply chain will have lower availability and reliability than the current natural gas supply chain. Dual fuel systems for all end users are not available or in development, thus further work is required to understand if back-up systems could be feasible, and this is likely to be site specific. Disruption in supply can have major impacts on sites, thus this is a key barrier that needs to be overcome.

3.1.5 Electrical Infrastructure

The electrical supply connection to sites is outside the scope of this study. The primary Option 1 is 100% replacement of natural gas end users with hydrogen. In the event of significant electrification options, the electrical supply connection to sites will require upgrades in many locations. The most common alternative decarbonisation option for the sites was identified as electrification. The major barrier to this solution will be the high variability of the energy loads for some major users. This peaking nature may be unpalatable for electricity suppliers and sites may struggle to agree an economically feasible supply contract. Discussions and investigation with the DNO and electricity suppliers will be required to resolve this risk.

In general, the sites annual gas consumption is far greater than their annual electrical consumption, typically a ratio ranging 12-54% was observed, with only one site having a higher electrical than gas consumption. Thus, sites' current on-site electrical infrastructure is not generally designed for the capacity required for full electrification of the gas users and will need significant upgrades to be capable of handling the far increased capacity. The electrical supply connection to sites, though outside the scope of this study, will likewise require upgrades in many locations.

Best Alternative (non-hydrogen) solutions may include electrification and use of renewable energy sources or renewable energy power purchase agreements can provide an opportunity the in the short term for a site to reduce its emissions for existing use of electricity and where there is capacity to electrifying more equipment. Where capacity is not available there will be a longer term requirement to upgrade on-site and network supply capacity.

3.2 Safety

An early-stage assessment of the safety implications of industrial users switching to 100% hydrogen gas, as a direct replacement for existing natural gas use, has been carried out based on these seven industrial sites spanning different industries, sizes and complexities. The objective of the safety assessments was to identify the most significant factors which may affect safety at each site and to provide recommendations as to how risks associated with a switch to hydrogen can be reduced. The following common process safety assessments have been performed:

1) A Hazard Identification (HAZID) Workshop to identify potentially new or increased risks associated with using hydrogen as a fuel. A qualitative ranking of risk pre and post implementation of mitigation measures were determined in the workshop along with a qualitative evaluation of the difficulty of implementation.
2) An initial Dangerous Substances and Explosive Atmospheres Regulations (DSEAR)[14] review, to identify potential changes to hazardous area classifications and requirements for control of ignition sources (e.g. ATEX[15] rated equipment). Appendix I.2 includes the anonymised DSEAR Assessments for the sites, that compare Hazardous Area Classifications (HAC) for natural gas and hydrogen.
3) A high level comparison of the potential consequences of fires and explosions assuming 100% hydrogen compared with the potential consequences arising from natural gas systems. Appendix I.1 includes the consequence modelling calculated for this project.

From a safety perspective, leaks from the high-pressure distribution system coming into the site have the greatest potential for damage and fatalities on neighbouring areas, because of the potential for leakage from pressure let-down and metering equipment, which is often housed in an enclosed building where hydrogen can accumulate. This initial study indicated that for the sites visited this would not be a significant issue, because the equipment was located in remote areas on industrial sites where the other industrial neighbours were a sufficient distance away that the change in risk from natural gas to hydrogen made no material difference to risk. This is a site and configuration specific risk and needs to be considered further if more site studies are done and whether there is generic work that can be done to better understand risks and consequences.

3.2.1 Common Findings and Issues

As a general finding, equipment used in industrial sites typically have a long operating life and quite often have been in situ for a long period of time. Standards have been reviewed and updated in that period so while the equipment was acceptable at the time of installation, it may now not meet current best practice. Safety measures for legacy equipment will require appraising from scratch for hydrogen operation as this is a fundamental change from the original design that has the potential to invalidate existing safety measures.

Hydrogen has a lower ignition energy, wider flammable limits, is more explosive and has a lower detonation energy than natural gas. If no mitigation measures are implemented, there is a potential for a significant increase in explosion risks with greater potential for injuries, fatalities and equipment and building damage when operating with hydrogen. The larger volumetric flows of hydrogen, compared to natural gas at the same conditions, can also result in a significant increase in flammable gas cloud sizes from a leak orifice of a given size – in particular for areas where ventilation is poor. Additional risk controls were recommended at all sites surveyed to mitigate the additional risks associated with hydrogen such that risks would be broadly equivalent to operating with natural gas. These measures range from minor modifications (e.g. additional ventilation) up to potentially redesigning and replacing major pieces of equipment.

3.2.1.1 Hydrogen Explosions

Where flammable clouds of hydrogen are ignited (assuming no detonation) the explosion overpressure radii are larger than for natural gas, but are in the same order of magnitude. Appendix I.1 outlines the comparative consequence modelling between hydrogen and natural gas calculated for this project. For COMAH sites in particular (such as Site 1 - Industrial Other) that store large quantities of flammable, toxic or environmentally harmful materials the impact of an increase in explosion diameter must be assessed carefully on a site by site basis. This is due to the potential for explosions to escalate by impacting nearby structures. This assessment is beyond the scope of this study, but the results could necessitate rerouting the hydrogen pipework or moving existing storage vessels/tanks. This could have significant cost implications. Explosion (deflagration) of hydrogen gas clouds is considered, but detonation of those clouds is not considered. If a deflagration to detonation transition (DDT) of a hydrogen gas cloud were to occur, then peak overpressures could exceed 10 barg. It is widely acknowledged that a DDT event is far more likely for confined or congested hydrogen explosions than equivalent natural gas explosions due to a much lower initiation energy for detonation[16]. An example of potential detonation sites particularly relevant to hydrogen could be pipe racks overhead, but in a wider sense it is also important to ensure that the areas around buildings with regulating equipment are clear of vegetation or other obstructions. Any DDT event would cause catastrophic damage to the immediate surroundings, but the damage caused in the far field tends to be broadly equivalent to a severe deflagration event. Missiles with sufficient energy to escalate could also

[14] "The Dangerous Substances and Explosive Atmospheres Regulations (SI 2002/2776)," 2002.
[15] "The Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations (SI 2016/1107)," 2016.
[16] "Figure D1 of Buncefield Explosion Mechanism, https://www.hse.gov.uk/research/rrpdf/rr718.pdf".

occur however the likelihood of missile impact is lower than for the associated overpressure effects. The conditions under which a DDT would occur are complex and therefore excluded from this high level modelling. and would need to be evaluated on a case by case basis. The risk of detonation in this case is most dependent on the physical layout of equipment, piping and vegetation, and steps to manage this can be taken.

3.2.1.2 Prevention of Internal Equipment Explosions

A particular concern is the adequacy of existing safety systems on combustion equipment to prevent internal hydrogen explosions. The adequacy of all gas combustion equipment and associated burner management systems (BMS) will therefore need to be checked with the supplier and upgraded or replaced prior to a switch over to 100% hydrogen. BMS reliability will need to be sufficiently high that risks can be demonstrated to be As Low As Reasonably Practicable (ALARP) when considering the increased severity of hydrogen explosions. Pre-mixed burners, where air is mixed with gas upstream of the burner itself, were identified on a number of sites; due to the higher flame speed and much wider flammable range for hydrogen these configurations may require significant changes or complete replacement to avoid the potential for damaging internal pipework explosions.

The security of gas systems against reverse air ingress into vents, flares and burner supply lines will need to be checked along with maintenance procedures to avoid air ingress and potential pipework explosions. Hydrogen has a much wider flammability range than natural gas meaning that comparatively small amounts of air ingress could create a flammable mixture internal to pipework.

3.2.1.3 DSEAR and Hazardous Areas

Employers are required by DSEAR[14,17] to undertake risk assessments of dangerous substances including natural gas or hydrogen and, where necessary, perform Hazardous Area Classification (HAC) to identify areas where a potentially explosive atmosphere could form. Preliminary DSEAR reviews were performed for the gas facilities on the sites visited to help identify potential impacts on HAC. Appendix I.2 includes the anonymised DSEAR Assessments for the sites that compare their current HAC with a calculated hydrogen HAC Outdoor gas supply pipework tends to result in a Zone 2 of Negligible Extent (NE) for the operating pressures commonly found at industrial sites (<2 barg) as long as the pipework was routed through uncongested areas (i.e. areas with good natural ventilation).

In the hazardous area assessments normal conditions are assumed (i.e. not adverse) unless otherwise indicated in the HAZID. Adverse conditions are defined in IGEM/SR/25[18] as when the gas is not clean or not dry, or is contained in vibrating equipment, or is contained in plant which is sited in a corrosive atmosphere, which includes coastal sites. The most common source of adverse conditions identified from the sites surveyed was associated with rotating equipment (vibration source), in particular, gas booster compressors. Adverse conditions result in significantly larger hazardous areas for hydrogen than for natural gas which can encompass previously non-ATEX rated equipment. No coastal sites were visited as part of this work, but it is likely that these sites would also require significantly increased hazardous areas for hydrogen operation.

3.2.1.4 Adequacy of building ventilation

For gas pipework and equipment located inside buildings or enclosures it was commonly found that sites existing ventilation arrangements would be inadequate for hydrogen and would lead to revised zones (typically Zone 2) encompassing unrated electrical and mechanical equipment. Whilst this equipment could in theory be replaced with ATEX rated equipment it will probably be more practicable to improve ventilation such that a Zone 2 NE can be defined instead or relocate the hydrogen equipment. This negates the requirement for ATEX rated equipment. Additional ventilation was often required at high level, in accordance with the IGEM guidance[19], as hydrogen is highly buoyant and could collect at roof level if high level ventilation is not present.

Where practicable, gas supply systems inside enclosures and buildings should operate below 100 mbarg, e.g. by locating pressure regulators outside buildings. Doing so leads to zones of NE as long as ventilation can be demonstrated to exceed 1.5 air changes per hour (ACPH). The available ventilation varied because some sites had much higher rates than this for other reasons, but will need to be checked for each site.

Applying draft IGEM guidance for hydrogen[19], some meter houses required increased ventilation area, especially at high level, to maintain the current zone classification for hydrogen service. HAC extents around vent tips would increase significantly with hydrogen and, depending on vent location and configuration, this could result in additional requirements for ATEX rated equipment versus natural gas. Vents with non-ideal vent tip configurations

[17] UK HSE, “Dangerous Substances and Explosive Atmospheres (DSEAR) - Approved Code of Practice and Guidance (L138 Second Edition),” 2013.
[18] IGEM, “Hazardous Area Classification of Natural Gas Installations, IGEM/SR/25 Edition 2,” 2010.
[19] IGEM, “Hazardous area classification of installations using hydrogen, IGEM/TSP/21/480 (DRAFT),” 11 Feb 2022.

(e.g. downwards or impeded) have the most significant implications for some sites with hazardous area radii increasing to encompass ground level equipment.

3.2.1.5 Ignition Control

Where Hazardous Areas are unavoidable, tighter ignition control will be required due to the much lower ignition energy of hydrogen (~10 times lower than natural gas). For example, to maintain compliance with the EPS (2016) Regulations[15], more stringent IIC-T1 ATEX rated equipment would be required versus an IIA-T1 ATEX minimum rating for natural gas. Every meter house surveyed was already fitted with electrical equipment which would be suitable for hydrogen service (IIC-T1 ATEX), but this cannot be assumed, and other locations that could potentially become hazardous areas often had unrated electrical equipment present; in some cases this included major plant items. Safe systems of work will need to be updated implemented including around sources of static charges, such as clothing, within hazardous areas and when performing maintenance work on gas systems due to the increased ignition risk. The update or development of site standard operating procedures and provision of a suitably qualified and experienced personnel will be necessary.

3.2.1.6 Equipment Design

Sites will need to ensure that all equipment associated with the existing natural gas system (e.g. pipework, instruments, burners, boilers, flame detectors, gas detectors etc.) is appropriately designed, operated and maintained in accordance with recommended good practices for hydrogen systems. Example considerations include: material compatibility, leak tightness, higher flame temperatures, lower energy density, higher volumetric flows. The security of gas systems against reverse air ingress will also need to be checked to prevent potential pipework explosions as hydrogen has a wider flammability range than natural gas.

Hydrogen embrittlement is a known issue, particularly for high strength steels, hydrogen effects on elastomers/polymers and other materials is an area of ongoing research. Further study is required to determine the material compatibility of the existing system. It is also recognised that the positive identification of all materials used in a site's gas distribution system may be a difficult task on older sites and therefore replacement is likely to be the safest solution.

Existing fire / flame detection and gas detectors will require recalibration or replacement to work for hydrogen. In general, adding gas detectors where not already installed is likely to be disproportionate except in areas where there is a significant risk of gas accumulation due to numerous leak sources or poor ventilation that cannot be improved.

3.2.1.7 Training and procedures

Sites will be required to update existing Risk Assessment Method Statements (RAMS) and Standard Operating Procedures (SOPs) associated with work on gas systems to reflect the difference in hazards posed by hydrogen compared to natural gas. For example, tighter control of electrostatic ignition sources will be required (e.g. anti-static clothing for personnel working within hazardous areas or during gas system maintenance) and purging and venting procedures will become more critical. From a wider perspective, there will also be a need to ensure that sufficient gas safe engineers trained and familiar with hydrogen are available to carry out installation and maintenance activities for the changeover to hydrogen. In some areas there is a higher tolerance operating with natural gas than with hydrogen, as there will be less margin for error safety procedures will require increased rigour.

Sites will be required to update personnel training such that they are aware of the hazards that hydrogen use entails. For example, hydrogen fires burn with a clear flame which could result in people on escape routes being unable to identify the edge of flames. This could lead to confusion and incorrect decision making during evacuations.

3.2.2 Specific Issue Examples

Alongside safety issues which are common across nearly all sites there were also a range of issues which were specific to only some sites.

3.2.2.1 Gas Boosters

Gas boosters are commonly used where there was a need to boost low pressure gas to the operating pressure of gas burners (e.g. industrial ovens). The integrity of existing gas boosters is unlikely to be adequate for hydrogen and were found in the DSEAR review to result in HAC Zone 2 extents of several meters. The following potential solutions are proposed (in preferential order):

a) It is inherently safer to remove the gas boosters entirely when switching to hydrogen if a gas supply at sufficient pressure is available.

b) Relocate gas boosters to a location where a hazardous zone can be tolerated (e.g. outside buildings).

c) If options a or b are not possible, high integrity seals could be fitted to avoid a hazardous area classification around the boosters. It is noted that these seals do exist for certain applications but are not commonplace for low pressure gas boosters and none were seen. Note that this mitigation approach is not currently covered by IGEM/SR/25[18].

3.2.2.2 Hydrogen Combustion Products

Due to the nature of hydrogen combustion (increased water content in products, higher flame temperatures lower radiation), there could be significant impacts on product quality or adverse reactions with materials in exhaust systems. The product quality is more pertinent to sites where final products are directly heated by a hydrogen flame or where combustion products flow over the product, rather than for water or air heating equipment. Some potentially complex cases were identified which will require further research at food manufacturers but also for paint curing ovens. Where reactive (e.g. metal) dusts may gather in exhaust systems there is a potential for an exothermic reaction to occur due to higher moisture levels in combustion gases.

3.2.2.3 Dust Explosions

Small primary explosions are capable of disturbing and dispersing accumulated combustible dust (e.g. on building surfaces) which can then escalate into a larger secondary dust explosion. The risk of dust explosions is managed by defining hazardous areas for dust, typically inside equipment, and by following good housekeeping practices to minimise the build-up of combustible dust outside of equipment. Whilst a hydrogen explosion could initiate a secondary dust explosion this hazard also exists when operating with natural gas.

3.2.2.4 Explosion venting

For any equipment with explosion venting (or explosion suppression) equipment present, this will need to be reviewed and major changes may be required due to the higher reactivity of hydrogen; in some cases this may not be practical to achieve with existing equipment.

3.2.2.5 Manual Burner Ignition

In some cases where burners are currently lit by hand, for example, it may not be safe to continue to do so when using hydrogen. An alternative burner arrangement (e.g. controlled by BMS) or a specific engineering assessment demonstrating that the current arrangement is safe for hydrogen will be required. Similarly, as hydrogen burns with a clear flame, handheld gas torches may need to be upgraded to have flame detection and automatic shutdown, but it is unknown if such devices exist with adequate reliability. An alternative solution is to explore installing a separate fuel supply (e.g. propane) just for handheld torches or if impurities are added to the hydrogen supply to ensure the flames remain easily visible. The clear flame of hydrogen fires could result in accidental burns to workers, unintended ignition of flammable or combustible materials and difficulty in determining if the gas torch is lit resulting in accidental gas releases.

3.2.2.6 Flares

Further investigation is required to confirm if hydrogen can be reliably used as a pilot flame for flare stacks including in poor weather conditions.

3.2.2.7 Screw and Compression Fittings

Investigation is also required into the leak tightness of screw and compression jointing techniques, along with material compatibility, for hydrogen service.

3.2.3 Safety Conclusions

The safety risk profile for some sites (for example Other Industry 1 which is an industrial site with a developed Process Safety Management regime) is likely to be largely unchanged when using hydrogen and may only require relatively straight forward modifications to operate safely. Other sites (for example Food and Drink 1 and 2 and Vehicles 1) would require significant investment in new safety equipment or systems (e.g. ATEX rated equipment, updated fire and gas detection) to ensure that risks remain As Low As Reasonably Practicable (ALARP) to operate with hydrogen, due to its higher explosivity. It is not clear that suitable technical solutions currently exist to address all of the challenges identified during this work, and the switch to 100% hydrogen could make some sites and processes very challenging to convert. It will be important that, industrial sites review their current gas systems and uses for their suitability to operate using hydrogen. The following are some key points for industrial sites to consider alongside a qualitative ranking of the relative difficulty of implementation based on the sites surveyed to highlight which safety recommendations may be difficult or costly to implement:

1) The properties of hydrogen are sufficiently different to natural gas that existing risk assessments will need to be updated for hydrogen service. (Difficulty of implementation: Low).

2) Pipe sizes, materials and jointing methods in use onsite could require changes for hydrogen service when considering the lower energy density of hydrogen, the risk of hydrogen embrittlement, hydrogen leak tightness and higher hydrogen flame temperatures. (Difficulty of implementation: Medium to High - depending on gas system complexity).

3) Burners and burner management systems (BMS) will need to be reviewed and updated, to ensure safe operation, including combustion air flows, purge cycles, flame detection, gas isolation systems, the potential for air ingress and explosion relief. Premix burners may be a particular issue due to the potential for an explosion in the supply pipework for hydrogen. (Difficulty of implementation: Medium to High – common issue across all sites visited, difficulty rating is dependent on number of burners and burner complexity).

4) Hydrogen is flammable to much higher concentrations in air than natural gas and a flame can propagate much faster leading to a much greater explosion hazard if air is present. A more thorough approach to design, maintenance and operation to prevent air ingress into gas pipework (e.g. reverse flow, purging procedures) will be required. (Difficulty of implementation: Low to Medium - common issue across all sites visited, difficulty ranking depends on gas system complexity).

5) Hazardous area extents around pressure relief vents can increase significantly for hydrogen and could now encompass non-ATEX rated equipment. This needs to be checked and is a particular issue for “non-ideal” vent configurations (e.g. goose neck vents). (Difficulty of implementation: Low to Medium – for the majority of sites visited minor changes to vent configurations can avoid this issue).

6) Enclosures and buildings may not have sufficient ventilation, including at high level, to avoid hydrogen accumulating to flammable concentrations. Hydrogen has a higher volumetric flow than natural gas at the same hole size and pressure (~3 times greater) and is more buoyant. (Difficulty of implementation: Low to Medium – for the majority of sites visited only minor changes to add ventilation is required but some sites may require more extensive improvements).

7) DSEAR risk assessments and Hazardous Area Classifications will need to be updated to reflect operating with hydrogen. (Difficulty of implementation: Low).

8) Hazardous areas are expected to increase and equipment located with hydrogen hazardous areas (e.g. a Zone 2 area) will require enhanced ATEX ratings suitable for hydrogen or an alternative solution. (Difficulty of implementation: Medium to High – for the majority of sites problematic hazardous areas can be avoided by improving ventilation or re-routing gas pipework. Where hazardous areas cannot be avoided installing ATEX rated equipment could be very costly).

9) Site procedures (RAMS, SOPs etc) will need updating to reflect the extra hazards posed by hydrogen, such as increased ignition risks from electrical items and electrostatic charges (e.g. clothing), higher volumetric flows during venting and adequacy of inerting procedures. (Difficulty of implementation: Low).

The reference point for this has been to apply current knowledge base and identify where challenges arise rather than to directly review the adequacy of the existing RGP through a gap analysis approach. By adherence to Relevant Good Practice (RGP) for design and operation of any future hydrogen gas supply system the likelihood of a Loss of Containment (LOC) will remain broadly equivalent to current natural gas systems. There are potentially significant increases in explosion risk when switching to hydrogen and there will be a need to consider additional mitigation measures to help control this risk, in particular for combustion equipment. The ultimate requirement will be to demonstrate that risks associated with a change to hydrogen as a fuel have been reduced to ALARP. This is considered to be achievable by sites implementing RGP, but it is anticipated that there will be significant costs for some sites to achieve this. RGP for using hydrogen as a fuel is at a comparatively early stage of development but will build on lessons learnt from decades of natural gas use alongside hydrogen experience from the process industries. For industrial sites, the greatest need for RGP relates to the design, construction and operation of hydrogen combustion equipment. There needs to be ongoing assessment of safety standards in order provide adequate guidance for the RGP.

3.3 Planning and Consenting Requirements

The need for planning permission can only be fully evaluated once the design has developed to a sufficient point that the modifications required to the process, buildings and groundworks is fully understood. The type of planning permission required and examining authority will depend on the extent and type of work to be undertaken. The majority of the requirements relevant to a fuel switching project are defined by the following two acts of parliament:

- Town and Country Planning Act 1990, and.
- Planning Act 2008 (nationally significant infrastructure projects).

In the instances where the modifications do not necessitate a planning application, it is important to note that other consents may be required. The following list is not exhaustive but illustrates some of the other permissions or consents that are most likely to be required when fuel-switching:

- building regulations.
- works to protected trees.
- hazardous substances consent.
- environmental permits/licences, and.
- COMAH.

Table 4 provides a summary of the impact of the acts and regulations listed above in the case where the sites are completely converted to 100% hydrogen service. Note that subject to not increasing storage on site, the use of grid supplied hydrogen is unlikely to change threshold values. Any existing COMAH sites will need to update their submission to cover change of use, major accident hazards, quantitative risk assessments and safety cases, however in the context of this study none of the sites would change their COMAH status as a result of conversion to hydrogen.

Table 4. Summary of impact of planning and consenting requirements on sites modifications

Act/Regulation	Impact on Site 1	Impact on Site 2	Impact on Site 3	Impact on Site 4	Impact on Site 5	Impact on Site 6	Impact on Site 7
Town and Country Planning Act 1990	Yes	No	Yes	Yes	Yes	Yes	Yes
Planning Act 2008	No	No	No	No	No	No	No
Building Regulations 2010	Further design detail required	No	Further design detail required	Further design detail required	Further design detail required	Further design detail required	Further design detail required
Works to Protected Trees	Further design detail required	No	Further design detail required	Further design detail required	Further design detail required	No	Further design detail required
Hazardous Substances Consent	No	No	No	No	No	No	No
Environmental Permits	Yes	Further design detail required	Yes	Yes	Yes	Yes	Yes
COMAH	No	No	No	No	No	No	No

3.3.1 Town and Country Planning Act 1990

The Town and Country Planning Act 1990 provides a framework for local authorities to implement national and regional level planning policies. “Local” planning permission is only needed if the work being carried out meets the statutory definition of ‘development’ which is set out in section 55 of the Town and Country Planning Act 1990. Changes categorised as ‘Development’ on existing sites to be considered when fuel switching include:

- building operations (e.g. structural alterations, construction, rebuilding, most demolition).
- material changes of use of land and buildings, and.
- engineering operations (e.g. groundworks).

There are categories of work that do not amount to ‘development’ or are classed as a ‘permitted development’ where; the building operations do not materially affect the external appearance of a building. The term ‘materially affect’ has no statutory definition but is linked to the significance of the change which is made to a building’s external appearance; and a change in the primary use of land or buildings, where the before and after use falls within the same use class.

For the proposed modifications to the sites surveyed it is anticipated that “local” planning permission will be required for:

- construction of extensions to or new metering buildings.
- construction of new hydrogen let-down station(s), and.
- construction and modifications to existing pipework that involves groundworks and increased footprint.

3.3.2 Planning Act 2008

The Planning Act 2008 is an Act of the Parliament of the United Kingdom that governs the process and criteria for approving major new infrastructure projects of national significance. Projects classified of national significance are required to obtain permission by the means of a development consent order (DCO), which is decided upon by the Planning Inspectorate and the Secretary of State. Applications and the examination process for a DCO are substantial and from application to decision can take between 15 months and two years.

Nationally significant infrastructure projects (NSIPs) are large scale projects falling into five general categories:

- Energy.
- Transport.
- Water.
- Wastewater, and.
- Waste.

The proposed developments on the sites surveyed associated with fuel switching from natural gas to hydrogen, do not meet the criteria for a nationally significant infrastructure project and thus will not be subject to a development consent order (DCO).

However, the new hydrogen supply line installed by the gas distributor may be subject to a DCO and impact the overall project timeline if the hydrogen pipeline feeding the site meets the following criteria:

- Either
  - the pipeline must be more than 800 millimetres in diameter and more than 40 kilometres in length, or.
  - the construction of the pipeline must be likely to have a significant effect on the environment.
- The pipeline must have a design operating pressure of more than 7 bar gauge, and.
- The pipeline must convey gas for supply (directly or indirectly) to at least 50,000 customers, or potential customers, of one or more gas suppliers.

3.3.3 Building Regulations 2010

The Building Regulations 2010 are a set of standards that cover the design, construction and modification of buildings to ensure the safety and health of people in and about those buildings. The regulations are defined in a series of ‘Approved Documents’ covering the technical requirements of construction work.

Building regulations are likely to apply for the following proposed modifications:

- Demolition activities.
- Installation of major equipment in occupied buildings.
- Changes to load bearing walls within buildings, where cut-outs are required for passing pipes through, and.

- Installation of new structures.

Applications and approval for building regulations is not required by the developer if the works are completed by someone registered with the 'competent person scheme'.

3.3.4 Works to Protected Trees

A Tree Preservation Order (TPO) is an order made by a local planning authority in England to protect specific trees, groups of trees or woodlands in the interests of amenity. An Order prohibits the following without the local planning authority's written consent:

- cutting down of trees.
- topping of trees.
- lopping of trees.
- uprooting of trees.
- wilful damage of trees.
- wilful destruction of trees.

Where trees are present in the vicinity of proposed changes to sites a check of the local authorities TPO register is recommended for any works that may require removal of trees.

3.3.5 Hazardous Substances Consent

Hazardous Substance Consent is typically required when substances on a site are at, or in excess of the 'controlled quantity' as set out in the Planning (Hazardous Substances) Regulations 1992 and as amended by the Planning (Control of Major-Accident Hazards) Regulations 2005. Hydrogen is named as a hazardous substance with a controlled quantity threshold of 2 tonnes. The requirement to notify the Local Authority in relation to HSC would need to be reviewed on a case-by-case basis and early engagement is recommended.

In some circumstances, where an existing consent is already held, hazardous substances consent is not required for a minor change to the type and quantity of substances stored. Consent is not required where the hazardous substances authority receives confirmation from the COMAH competent authority of:

- The details of the minor change, including details about how substances are to be kept and used.
- that the minor change will not result in a change to consultation zones.
- that the minor change will not result in a change to the status of the establishment under the Seveso III directive, and.
- that any hazardous substances that are held without hazardous substances consent in reliance on this exemption are kept and used in accordance with the details set out in the notice from the COMAH competent authority.

The anticipated inventory of hydrogen within the piping systems is far less than the 2 tonnes in all the sites surveyed and this would be expected to be true for most other industrial sites. The threshold may be exceeded if additional hydrogen storage is required to mitigate security of supply concerns. Without additional storage that exceedance of the controlled threshold is not foreseen due to the introduction of additional lines to supply hydrogen to a site's end users.

3.3.6 Environmental Permits

A facility or mobile plant may be required to hold an environmental permit whereby the activities undertaken could:

- Pollute the air, water or land.
- Increase flood risk, or.
- Adversely affect land drainage.

The Environmental Permitting (England and Wales) Regulations 2016 (as amended) (EP Regulations) consolidate and replace the Environmental Permitting (England and Wales) Regulations 2010 and define the classification and requirements for different activities, listed in Schedule 1 of the EP Regulations 'Schedule 1 Listed Activity'.

The two aspects of the EP Regulations that are potentially applicable to sites considering a hydrogen switch are:

- an ‘installation’ – an industrial facility carrying out a Schedule 1 Listed Activity, such as the manufacture or other business that produces potentially harmful substances, for example a landfill site, a large chicken farm, a food factory, a furniture factory, a dry cleaners, a petrol station, and.
- a medium combustion plant or specified generator.

Around half of the sites surveyed were classed as installations due to conducting Schedule 1 Listed Activities. These sites are operating under environmental permits, each with their own specific requirements and emission limits. It is not anticipated that a switch to hydrogen would change a site’s classification as an ‘installation’. Sites that carry out Schedule 1 Listed Activities under the EP Regulations will have a requirement to employ ‘Best Available Techniques’ BAT, as defined within their relevant industry sector BAT Reference documents (BRefs).

In switching from natural gas to hydrogen the potential impact on NOx emissions needs to be understood, as the production of NOx is greater at the higher flame temperatures that may result from hydrogen combustion. Sites with NOx emission limits within their permits are therefore potentially sensitive to any impact and may need to install additional BAT mitigation such as flue gas recirculation (FGR) or selective catalytic reduction (SCR). FGR is still a developing technique for hydrogen and has challenges such as flame stability and efficiency, SCR is a developed technique but has significant cost implications on both CAPEX and OPEX.

In most cases, even if not classed as an ‘installation’, sites will be classed as medium combustion plants (MCPs) and will be subject to the MCP controls of the EP Regulations. The MCP Directive (MCPD) covers combustion plant with a thermal input of more than or equal to 1 MW_{th} and less than 50 MW_{th} burning any fuel. MCPD was implemented in the UK by the EP Regulations in 2018 for new plants. For existing plants, there is an ongoing phased introduction of the MCP controls. Smaller plants less than 5 MW_{th} are required to comply by 1 January 2029 while larger plants 5 – 50 MW_{th} are required to comply sooner by 1 January 2024.

There are however several exclusions from MCPD, including for direct fired applications where the combustion gases themselves are used for direct heating, drying or other treatment of materials. Some major users are therefore considered excluded from the MCPD, however due to their indirect heating other major users are covered under MCPD.

For MCPD, the main area of concern in switching from natural gas to hydrogen is the NOx emissions. The MCPD stipulates that NOx emissions for ‘natural gas’ from new MCPs (other than gas engines and turbines) shall not exceed 100mg/Nm³ at 3% O_2 while ‘other gases’ shall not exceed 200mg/Nm³ at 3% O_2. Hydrogen combustion is currently classified under the ‘other gases’ criteria. One area of concerns for developers is whether the limit for hydrogen will be reduced to that required currently for natural gas, in the event of an extensive roll-out of hydrogen combustion equipment displacing natural gas. Further guidance is required on this by the regulator to ensure plants are not retrofitted for hydrogen to meet the 200mg/Nm³ value only to need to complete additional work relatively shortly after.

The MCPD only controls emissions to air, and therefore does not require a site to complete a Best Available Technique (BAT) assessment.

Similarly as for sites with NOx limits on their listed activity permits, sites covered by MCPD may need to consider installation of NOx mitigation such as FGR or SCR. Use of either FGR or SCR will add significant cost impact for hydrogen solutions.

When considering the applicable Environmental Permits the site should consider Environment Agency guidance in regard to the Environmental Permitting (England and Wales) Regulations 2016, and the carrying out of any Schedule 1 Part A(1) Regulated Process, any Medium Combustion Plant or Specified Generator Activities or Part A(2) or Part B regulated processes. The following flowchart maybe adopted to support preparation of any permit variations:

Does site have an Environmental Permit under the Environmental Permitting (England and Wales) Regulations 2016 (as amended) Y/N ?			
If YES – is it a Schedule 1 Part A(1) Regulated Process?			**If NO – BAT not applicable.**
If YES - obtain a copy of the permit for site (or the Permit reference number, if not readily available) and review.	**If NO – are there any Medium Combustion Plant or Specified Generator Activities carried out?**	**If NO – Part A(2) or Part B regulated process. Obtain a copy of the permit for site (or the Permit reference number, if not readily available) and review.**	Consider whether hydrogen would lead to any new environmental controls that may change whether the process is regulated.
Identify the Part A listed activity and the relevant BAT Reference Guidance.	**If YES – obtain a copy of the permit for site (or the Permit reference number, if not readily available) and review.**	Consider impact of hydrogen on permitted elements.	
Consider impact of hydrogen on permitted elements.	Consider impact of hydrogen on permitted elements – note MCP controls only consider air emissions.	Approach Local Authority to discuss a variation to the Permit to enable hydrogen usage.	
Approach the Environment Agency to discuss a variation to the Permit to enable hydrogen usage.	Approach the Environment Agency to discuss a variation to the Permit to enable hydrogen usage – check only emissions to air need consideration and there are no BAT implications.	Prepare an Environmental Permit variation application to cover the use of hydrogen including any assessments required (air modelling, supporting BAT (Part A2 only), updated water emissions etc. (Part A2 only)).	
Prepare an Environmental Permit variation application to cover the use of hydrogen including any assessments required (air modelling, supporting BAT, updated water emissions etc.).	Prepare an Environmental Permit variation application to cover the use of hydrogen including air modelling assessment if required.	Submit Environmental Permit variation to add hydrogen to the Local Authority	
Submit Environmental Permit variation to add hydrogen to the Environment Agency.	Submit Environmental Permit variation to add hydrogen to the Environment Agency.		
If YES and unable to obtain copy of permit for site – identify the likely Part A listed activities based on knowledge of site operations and proceed as above.			

3.3.7 COMAH

The COMAH Regulations apply to sites with significant inventories of “dangerous substances” and are intended to prevent major accidents and to limit the consequences to people and the environment of any accidents which do occur. Dangerous substances are defined in the COMAH Regulations and hydrogen is a named substance due to the physical hazards it presents (explosive and flammable). The requirement to notify HSE in relation to COMAH would need to be reviewed on a case by case basis and early engagement is recommended.

The requirements differ according to the classification of the site with both lower and upper-tier sites required to:

- notify the competent authority of the substances and inventory on site.
- prepare a major accident prevention policy (MAPP), and.
- develop a safety management system (SMS).

In addition, upper-tier sites must:

- prepare a safety report and update it every five years, or following any significant changes or new knowledge about safety matters.
- prepare and test an internal emergency plan for the site.
- supply information to the local authority for external emergency planning purposes, and.
- provide certain information to the public about the activities.

The switch from natural gas to hydrogen is unlikely to impact sites significantly enough to bring them within the requirements of COMAH where they do not already fall within a COMAH tier. The hydrogen inventory stored in the on-site pipework needs to be included in the Hazardous Substance Consent and COMAH assessments, however this is generally of less than 50 kg. The anticipated inventory of hydrogen within the piping systems is far less than the 5 tonnes lower tier threshold in all the sites surveyed and this would be expected to be true for most other industrial sites. The threshold may be exceeded if additional hydrogen storage is required to mitigate security of supply concerns. Sites were reluctant to consider adding local on-site high pressure buffer storage. Without additional storage that exceedance of the controlled threshold is not foreseen due to the introduction of additional lines to supply hydrogen to a site’s end users. Exceptions to this will be site’s where the current inventories of dangerous substances already place them very close to the thresholds of the lower or upper tier, as COMAH applies aggregation, this could change the sites status. Sites should conduct an assessment at an early design stage to assess if the hydrogen inventory is likely to impact their COMAH classification. In general site with an existing COMAH regime and those already using some hydrogen on site have robust process safety management arrangements and will experience less impact on their safety culture and controls than for other sites

In line with good practice, all sites even those not classified under COMAH, should conduct an update of documentation as well as supporting assessments to reflect changes in the process descriptions, drawings, end use of hazardous substances and safeguarding.

3.4 Commercial and financial implications

This study has been carried out during a period of extreme volatility terms of supply chain, commodity and energy prices. The work has been based on based upon an average cost of ATR hydrogen with carbon capture derived from Hydrogen Council’s report while the BEIS 2021 Green Book supplementary guidance has been used for natural gas, electricity and carbon prices. The cost year basis for the CAPEX, OPEX and Lifecycle Cost estimate is Q4 2021 as the cost estimate was completed in Q2 2022 and the cost data received in recent months have been subject to large variations and inconsistencies as a result of the impact of uncertainty in energy prices.

The following section focusses on the project costs, however, has not considered the individual business planning cycles to implement major capital projects. The time scales required for sites to transition to a hydrogen grid will depend upon their long term budgetary planning cycle as well as time required for planning and consenting activities.

3.4.1 Capital Cost

Capital costs have been determined utilising a combination of cost-curves, past project benchmarks, quotes from OEMs and the industry recognised SPONS handbooks, with equipment and/or inflation factors being applied where appropriate. Allowances have been made for the brownfield nature of the projects with insufficient survey activities having taken place at this stage of the project development.

The accuracy of these estimates is typical of an early stage AACE Class 4 estimate with an anticipated accuracy of -30% and +50%. The basis year for the calculations is Q4 2021.

Table 5 provides the estimated specific CAPEX for the business cases evaluated for each surveyed site in units of £ per tonne of CO_2e avoided over a 20 year project life on the assumption of converting the existing infrastructure where possible and avoiding new build. If existing systems do not have 20 years residual life to justify the retrofitting of discrete components then this may increase the lifecycle cost of the hydrogen option and change the differential with the electrification option

Option 1 is 100% replacement of natural gas end users with hydrogen. Option 2 is referred to as a hybrid solution where certain end users were changed to use electrical heating.

Option 3 is intended as a non-hydrogen counterfactual and is often full electrification. Where the replacement of an equipment item with an electrical or hydrogen option is not feasible, then the original equipment is assumed to continue operating with natural gas. It is recognised that in the future natural gas may not be available through a national gas grid. For the electric option the capital cost of back-up power has not been considered. The need for back-up power based upon the comparative reliability of the electrical and gas grid has not been considered. Conversely, sites expressed some concern over the reliability of a future hydrogen grid.

Table 5. Specific CAPEX Estimates for Surveyed Sites Business Cases Evaluated in £/t-CO2e avoided

		Option 1	Option 2	**Option 3**	
Site Number	**Site Industry Sector**	**100% Hydrogen Solution**	**Hybrid Hydrogen Solution**	**Best Alternative (Non-hydrogen)**	**Comment (Non-hydrogen)**
1	Primary Plastics	7	7	31	Electrification + NG where no elec option
2	Food & Drink	29	29	63	Electrification of all users
3	Non-ferrous metals	15	16	350	Electrification + NG where no elec option. High cost of electric options due to replacement vs modification
4	Vehicle Manufacturing	8	9	31	Electrification + NG where no elec option
5	Non-metallic minerals	14	14	0	Existing natural gas supply replaced with biomethane
6	Metal Packaging	45	117	1762	Electrification of all users High cost of induction and IR ovens due to throughput requirements
7	Food & Drink	75	N/A	631	Electrification of all users High cost of electric options due to replacement vs modification

As can be seen in Table 5, for the surveyed sites the 100% hydrogen solution is typically significantly cheaper on CAPEX than the best alternative (non-hydrogen) solution, which is most often electrification, due to the ability to retrofit and avoidance of new or reinforced electrical infrastructure. A hybrid hydrogen solution may offer a lower CAPEX option in some cases. Capital costs are for work within the site boundary for on-site work and exclude electrical or gas grid reinforcement or works up to the site. Where equipment is upgraded or retrofitted it is assumed that the ongoing cost of maintaining the plant are included in the existing asset management plans for the site. This assumption will have a significant impact if hydrogen conversion is also expected to cover for full asset replacement of end of life equipment. The connection and offsite costs of any gas network upgrades for hydrogen and wider electrification upgrades will also be key factors in the full cost of sites decarbonising.

Figure 2. Specific CAPEX breakdown for business cases for each of the surveyed sites

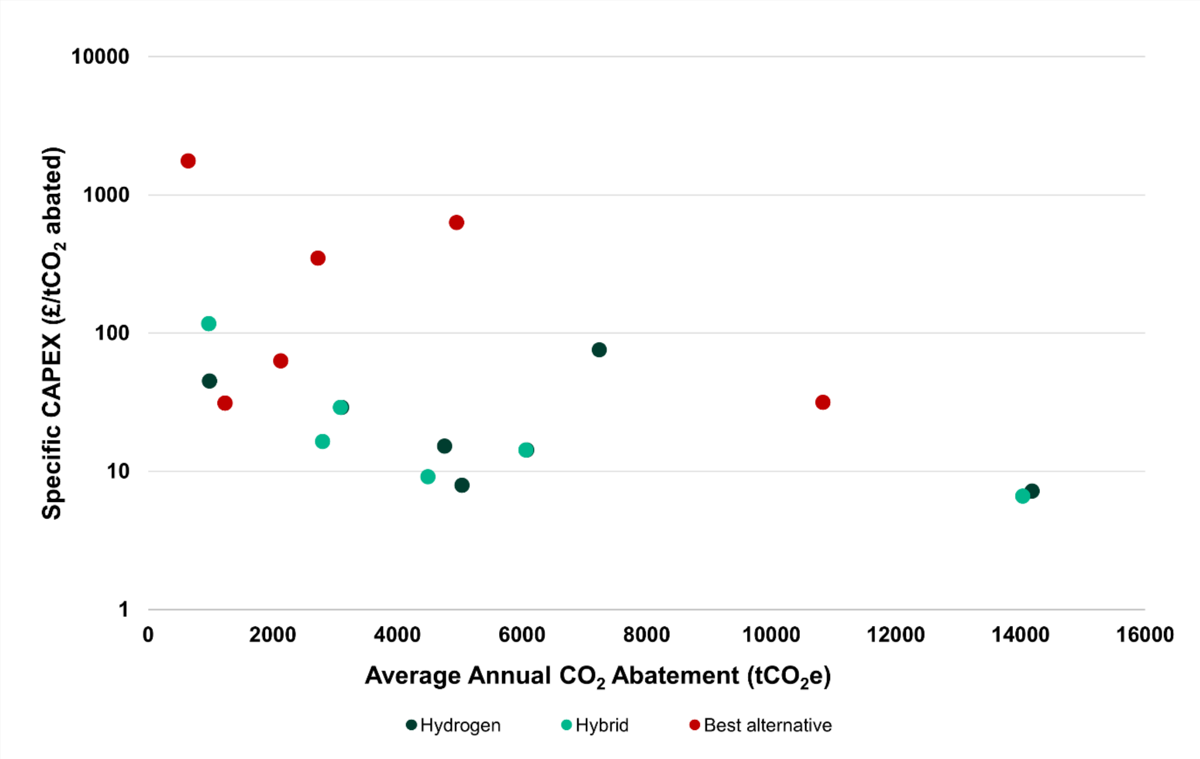


Figure 3 provides a breakdown of the specific CAPEX into categories of users, infrastructure and indirect costs[20] for the 100% hydrogen solution for each of the surveyed sites. As can be seen, the end users account for the majority proportion of the direct costs. When determining the capital cost, a high level estimate of construction time was built up to account for direct and indirect costs, however the effects of disruption to product and any outages were not included for this level of study. Optimisation of work to minimise down time will be a significant factor for site because of the high cost of lost production. Existing production schedules have been developed around existing plant maintenance cycles and those options which would involve less disruption to operations have not received credit for this in the capital cost comparison.

[20]The indirect costs assumed include variable, fixed costs and allowances. Variable indirect costs considered were: Project Management, Works Management and Supervision, Travel and Accommodation, Site Facilities, Insurance and Permits, Corporate Costs. Fixed Indirect costs considered were: Design, Mobilisation, Contingency and Profit. Allowances considered in the indirect costs were: Design development and Brownfield integration.

Figure 3 Specific CAPEX categories for 100% hydrogen solution for each of the surveyed sites

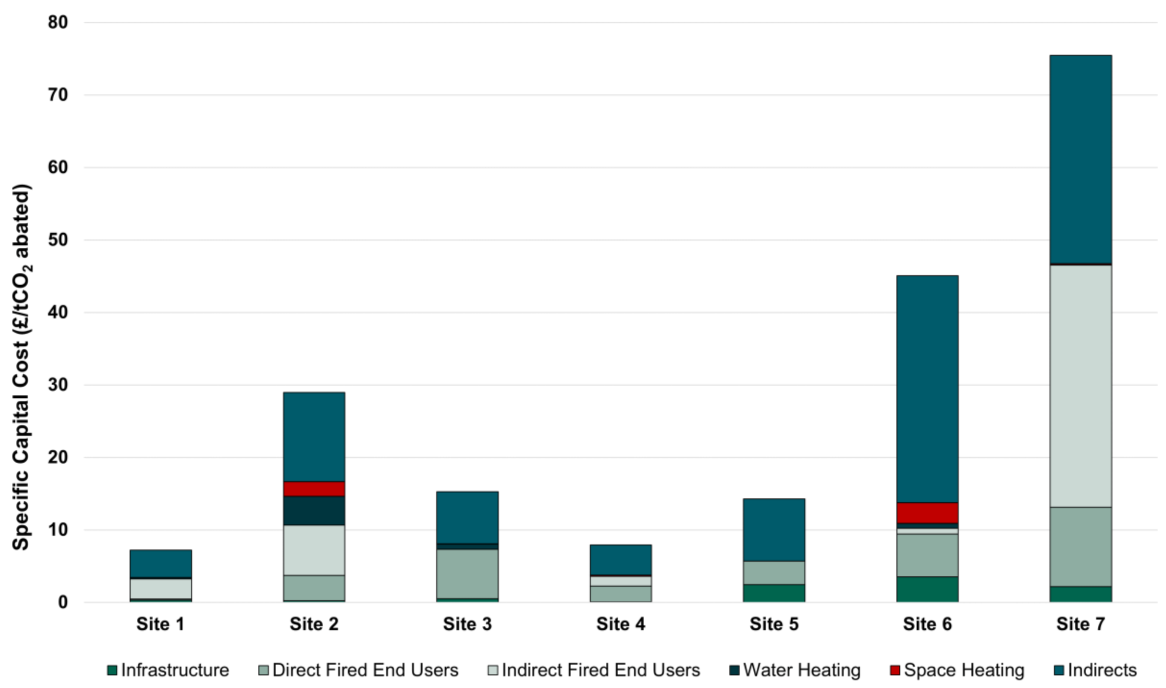


Table 6 provides the relative proportion of these CAPEX categories on a per site basis normalised to 100%. Averaged across the sites investigated for hydrogen conversion, indirect costs account for approximately 52% of the CAPEX with approximately 43% on end user conversion and 5% on site infrastructure.

Table 6. Relative CAPEX categories for 100% hydrogen solution for each of the surveyed sites

		Option 1					
Site	**Site Industry Sector**	Infrastructure	Direct Fired End Users	Indirect Fired End Users	Water Heating	Space Heating	Indirect costs
1	Primary Plastics	4%	3%	39%	2%	0%	52%
2	Food & Drink	1%	12%	24%	14%	7%	43%
3	Non-ferrous metals	3%	45%	0%	5%	0%	47%
4	Vehicle Manufacturing	1%	28%	17%	0%	2%	53%
5	Non-metallic minerals	17%	23%	0%	0%	0%	60%
6	Metal Packaging	8%	13%	2%	1%	6%	69%
7	Food & Drink	3%	14%	44%	0%	0%	38%

Table 7 restates these figures more directly excluding the indirect cost elements.

Table 7. Relative CAPEX categories for 100% hydrogen solution for each of the surveyed sites excluding indirect costs

		Option 1				
Site	**Site Industry Sector**	Infrastructure	Direct Fired End Users	Indirect Fired End Users	Water Heating	Space Heating
1	Primary Plastics	8%	6%	81%	5%	0.0%
2	Food & Drink	1%	21%	42%	24%	12%
3	Non-ferrous metals	6%	85%	0%	9%	0%
4	Vehicle Manufacturing	1%	59%	36%	0%	4%
5	Non-metallic minerals	43%	57%	0%	0%	0%
6	Metal Packaging	26%	43%	6%	5%	21%
7	Food & Drink	5%	23%	72%	0.1%	0.3%

There are a number of cost assumptions at this level of design development.

Cost implications of moving existing storage vessels/tanks or buildings due to changes in site risk assessments are not considered.

Potential additional capital costs related to redesigns to prevent or mitigate the effects of air ingress to hydrogen systems are not considered.

In the CAPEX assessment where retrofit/upgrade options are considered, the explosion venting is assumed to be adequate for hydrogen.

In the CAPEX assessment where retrofit/upgrade options are considered, the upgrade of the burner management systems is assumed within the costing. Burners and burner management systems (BMS) will need to be reviewed and updated, to ensure safe operation, including combustion air flows, purge cycles, flame detection, gas isolation systems, the potential for air ingress and explosion relief. Premix burners may be a particular issue due to the potential for an explosion in the supply pipework for hydrogen.

For the CAPEX and OPEX estimates no costs have been calculated for NOx reducing measures for hydrogen burners. The study assumes that been that OEMs will provide compliant systems, whilst recognising that the Best Applicable Techniques are developing. External means are available. Flue gas recirculation technology and Selective Catalytic Reduction are examples that could be deployed with CAPEX and OPEX implications to the cost to hydrogen options.

The design life assumed for the lifecycle cost is 20 years. This is typical for an engineering project involving process plant equipment. Items which have been retrofitted are also assumed to have a design life of 20 years. The base equipment may be significantly older, and may not last a further 20 years, however the replacement of this existing equipment will form part of the existing plant plan. If retrofit items do not last 20 years this may increase the lifecycle cost of the hydrogen option and change the differential with the electrification option.

3.4.2 Operating Cost

Fixed operating costs including labour and maintenance have been calculated using equivalent hourly labour rates published in the SPONS handbook and by applying maintenance factors to the capital costs estimated. Variable operating costs, i.e., fuel, utilities and carbon taxes, have been calculated based on estimated annual energy consumption figures and CO2-equivalent emission values. Cost data for hydrogen has been sourced from the Hydrogen Production Costs 2021[21] report on the basis of central figures from the low carbon ‘green’ hydrogen projections. Hydrogen costs have been based upon Chart 6.4 levelized cost of hydrogen at central fuel prices for PEM electrolysis, where PEM electrolysis is the highest LCOH technology for green hydrogen production,

[21] BEIS, August 2021, Hydrogen Production Costs 2021, ttps://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011506/Hydrogen_Production_Costs_2021.pdf

assuming that maximum and minimum bounds are represented by the extremes of curtailed and industrial retail values. A mark up of 40% is assumed between LCOH and retail pricing to account for profit margin and costs associated with transportation and storage based upon gas market trends. Green Book supplementary guidance has been used for natural gas, electricity and carbon prices.

To correct the cost basis for this study, the UK GDP deflators have been used from Table 19 of the BEIS' Green Book supplementary guidance. As an example, 2021 basis gas costs from a 2020 basis dataset would have been multiplied by the deflator (2021 basis)/ deflator (2020 basis) which in this example is 101.1/100. This function has been applied to fuel and electricity costs and carbon value costs.

In the OPEX assessments the contribution of the combustion of process off-gases or volatile organic compounds has been considered on a site by site basis. The OPEX analysis has generally focussed on the influence of the external utilities on operating cost.

For the OPEX estimates no costs have been calculated for NOx reducing measures for hydrogen burners.

A carbon 'tax' has been assumed to be levied on sites where they continue to produce CO_2 through ongoing fuel combustion onsite. This has been applied to the baseline scenario for all the sites and options on site, where there is the retention of CO_2 producing combustion equipment, and is based on carbon values, which have been used as an estimate of a maximal carbon tax that could be placed on emitters. A carbon value of £245/tCO_2e is assumed based on the Central value from Table 3 of the Green Book supplementary guidance for 2021. Greenhouse gas emissions values ("carbon values") are used across government for valuing impacts on GHG emissions resulting from policy interventions. They represent a monetary value that society places on one tonne of carbon dioxide equivalent (£/tCO_2e). They differ from carbon prices, which represent the observed price of carbon in a relevant market (such as the UK Emissions Trading Scheme).

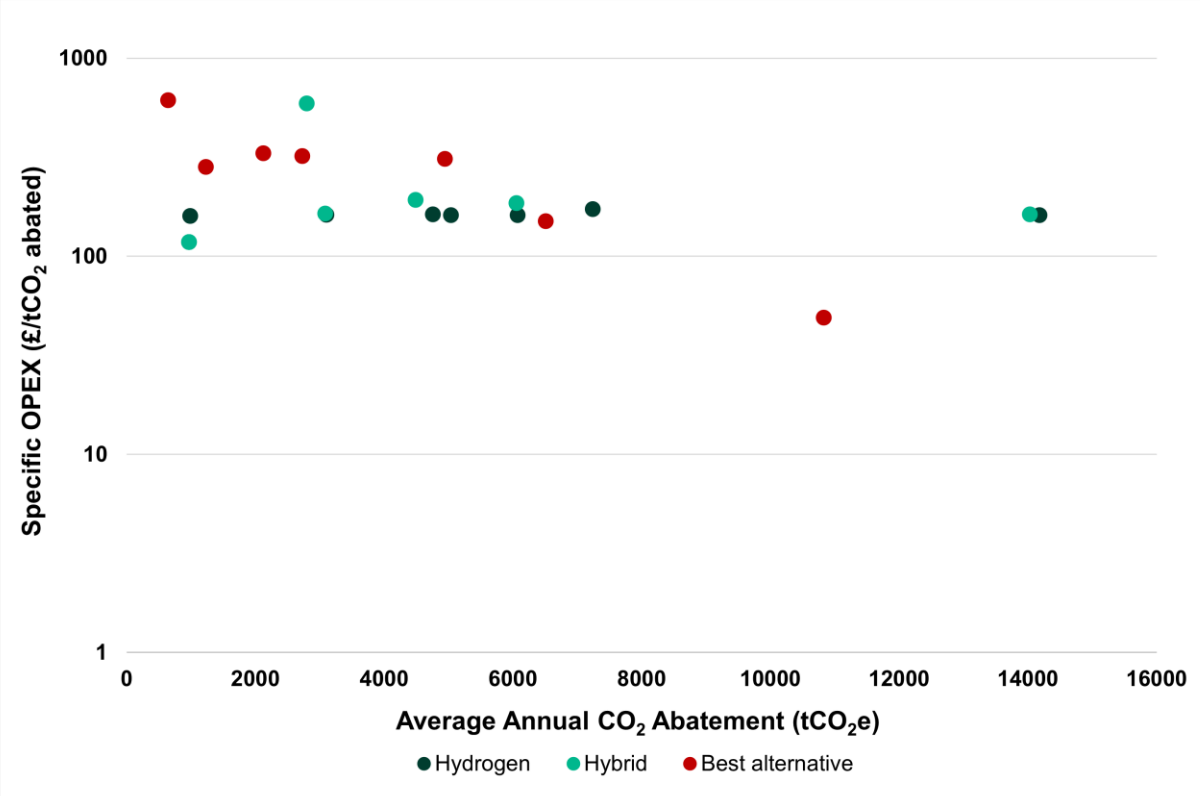
Table 8 provides the estimated specific OPEX for the business cases evaluated for each surveyed site in units of £ per tonne of CO_2e avoided over a 20 year project life on the basis of calculating variable operating costs due to fuel, utilities and carbon taxes and allowing for the increase in fixed operating costs due to potential increases in staff or operating and maintenance costs beyond the existing baseline.

Table 8. Specific OPEX Estimates for Surveyed Sites Business Cases Evaluated in £/t-CO2e avoided

		Option 1	Option 2	**Option 3**	
Site Number	**Site Industry Sector**	**100% Hydrogen Solution**	**Hybrid Hydrogen Solution**	**Best Alternative (Non-hydrogen)**	**Comment (Non-hydrogen)**
1	Primary Plastics	161	163	49	Electrification + NG where no electric option
2	Food & Drink	162	164	331	Electrification of all users
3	Non-ferrous metals	163	592	320	Electrification + NG where no electric option
4	Vehicle Manufacturing	162	193	283	Electrification + NG where no electric option
5	Non-metallic minerals	161	186	151	Existing natural gas supply replaced with biomethane
6	Metal Packaging	160	118	613	Electrification of all users
7	Food & Drink	173	N/A	310	Electrification of all users

As can be seen in Table 8, for the surveyed sites the 100% hydrogen solution is typically less expensive on OPEX than the best alternative (non-hydrogen) solution, which is most often electrification, but there are exceptions. For example, with the Other Industry site where the non-hydrogen alternative has smaller cost difference to the base case because of the potential to reduce energy consumption due to the improved efficiency of the electrical alternative. The hybrid hydrogen solution may have a higher OPEX option than 100% hydrogen in most cases, but again with exceptions.

Figure 4. Specific OPEX breakdown for business cases for each of the surveyed sites



3.4.3 CO_2e Emissions

The annual consumption of fuel for each surveyed site in each business case was based on key assumptions that the hydrogen fired burners will have the same thermal efficiency as the existing natural gas fired burners and the electrical heated options have 100% electrical to thermal efficiency. Exceptions were made where available equipment data indicated that new equipment efficiencies would be significantly changed, and account was taken of processes that utilise by-products as part of their fuel supply and the impact the changes would have on these. The consumption values along with the values for CO_2-equivalent emissions from the different energy sources were used to calculate the anticipated annual CO_2-equivalent emissions in each business case evaluated. The annual and cumulative emissions for each case were calculated for the period 2025 – 2045.

The CO_2-equivalent values used for hydrogen from different generation pathways were based on values published by the Hydrogen Council[22]. Hydrogen is not included in the 2021 greenhouse gas emissions data set and so The Hydrogen Council data (Exhibit 1) expressed in $kgCO_2e/kgH_2LHV$ has been corrected to $kgCO_2e/kWhH_2$ HHV on the basis of 33.3 $kWhLHV/kgH_2$ and 120 MJ/kg and 141.8 MJ/kg on LHV and HHV basis respectively. For the CO_2 emission assessment all hydrogen is assumed to derive from renewable sources, and thus produces low CO_2 emissions 'green' hydrogen using electrolysis from wind sources. It may be more economical to produce hydrogen from non-renewable sources with higher CO_2 emissions. However it is expected that supplies will be controlled by the Low Carbon Hydrogen Standard. For all other energy sources, values were taken from the BEIS Green Book 2021 supplementary guidance[23]. These values are displayed in Figure 5. Note that the effect of NOx abatement measures or any change on NOx emissions or fugitive emissions are not reflected in the carbon intensity values.

In the CO_2e assessments the combustion of process off-gases or by-products is generally not considered even when useful energy is currently derived from this. The CO_2 emission assessment has focussed on the change due to displacement of natural gas. It is recognised that replacement with hydrogen or electrification may not impact

[22] Hydrogen Council, "Hydrogen decarbonization pathways: A life-cycle assessment", January 2021
[23] BEIS, "Valuation of energy use and greenhouse gas emissions for appraisal", October 2021. Available online at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1024054/1.Valuation_of_energy_use_and_greenhouse_gas_emissions_for_appraisal_CLEAN.pdf

the site emissions due to say the combustion of process arising VOCs, so gas grid conversion does not necessarily address 100% decarbonisation of the site.

Figure 5. Assumed CO_2-equivalent emissions for energy sources for the period 2020 – 2050

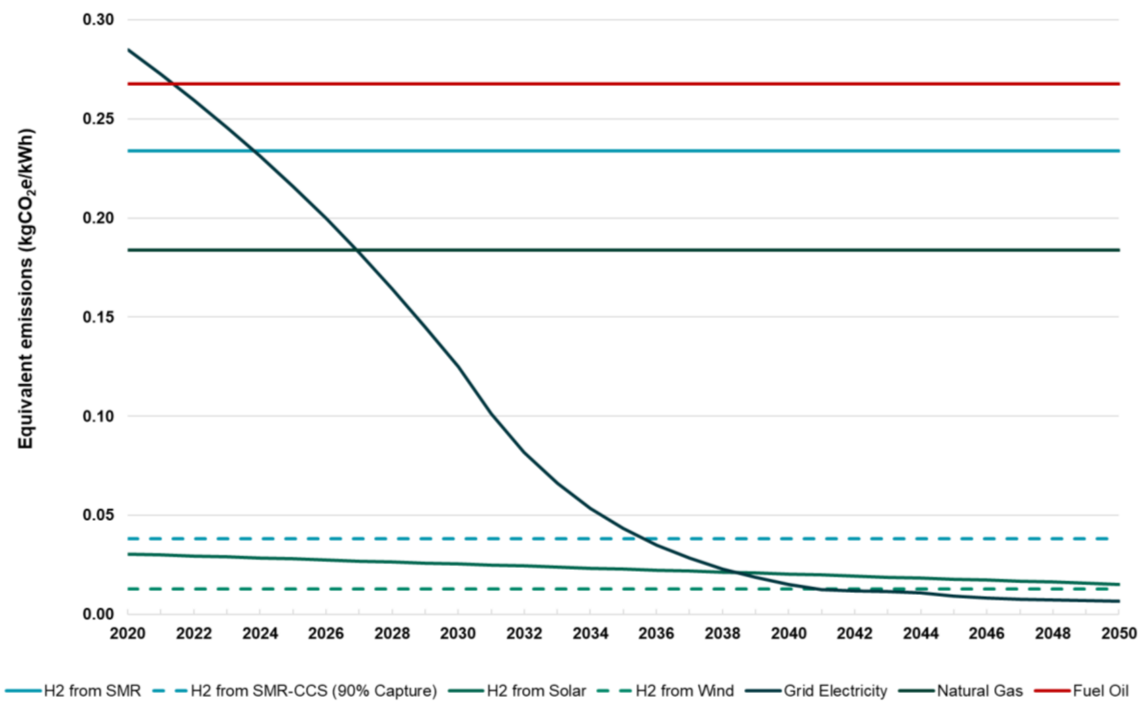


Table 9 provides the estimated CO_2-equivalent emissions avoided for the business cases evaluated for each surveyed site in terms of percentage reduction over a 20 year project life.

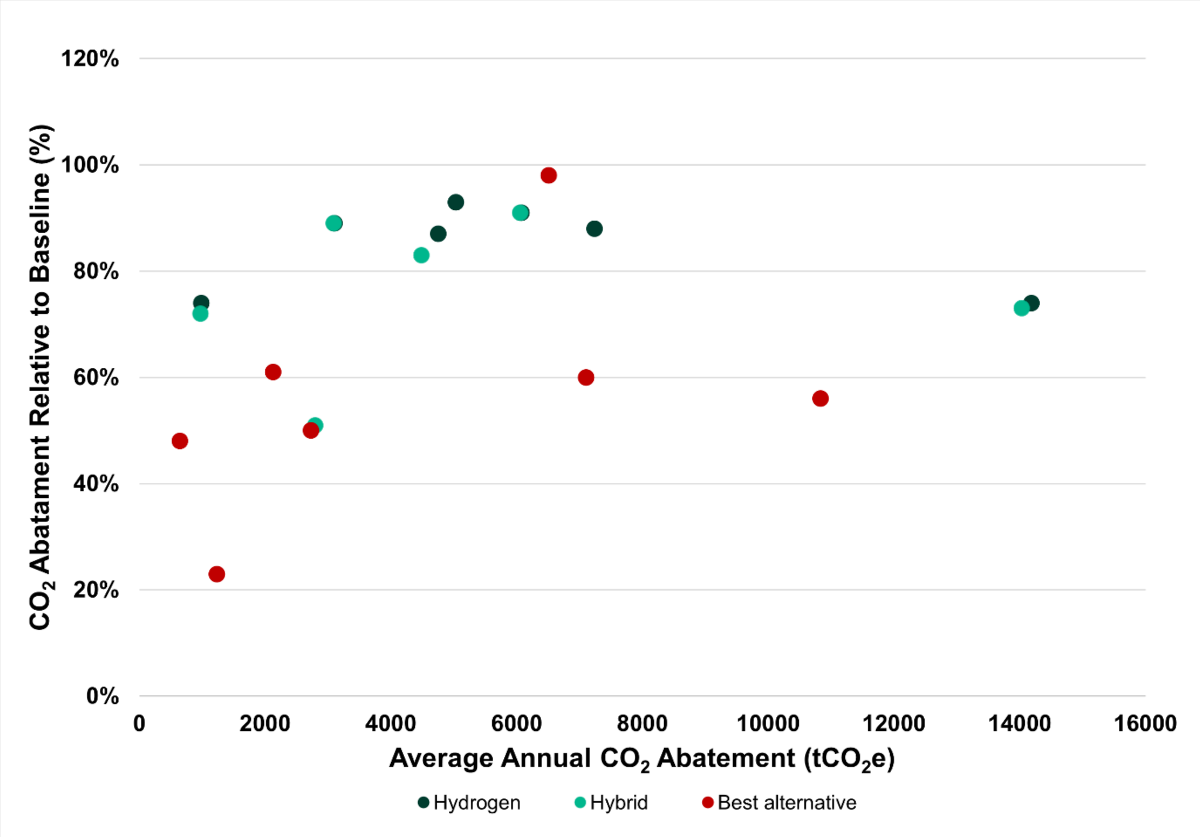
Table 9. CO_2-equivalent Emissions Avoided for Surveyed Sites Business Cases

		Option 1	Option 2	Option 3	
Site Number	**Site Industry Sector**	**100% Hydrogen Solution**	**Hybrid Hydrogen Solution**	**Best Alternative (Non-hydrogen)**	**Comment (Non-hydrogen)**
1	Primary Plastics	74%	73%	56%	Electrification + NG where no elec option
2	Food & Drink	89%	89%	61%	Electrification of all users
3	Non-ferrous metals	87%	51%	50%	Electrification + NG where no elec option
4	Vehicle Manufacturing	93%	83%	23%	Electrification + NG where no elec option
5	Non-metallic minerals	91%	91%	98%	Existing natural gas supply replaced with biomethane
6	Metal Packaging	74%	72%	48%	Electrification of all users
7	Food & Drink	88%	N/A	60%	Electrification of all users

As can be seen in Table 9, for the surveyed sites the 100% hydrogen solution typically gives a greater reduction in CO_2e emissions than the best alternative (non-hydrogen) solution, which is most often electrification. The hybrid hydrogen solution is generally shown to be similar to 100% hydrogen in most cases.

In the case of the vehicle manufacturing site the study scope was limited to subset of the users because of the large number of gas fired equipment on site.

Figure 6. CO_2 abatement for business cases in each of the sites surveyed



Note none of the sites surveyed were expected to fall under the Emissions Trading Scheme (ETS) for CO_2 emissions thus no cost for ETS is included in relation to aggregated combustion capacity in excess of 20MWTh for units greater than or equal to 3MWTh.

3.4.4 Lifecycle Cost

The lifecycle cost of CO_2 avoided in each business case has been determined based on the estimated lifetime cost of the plant and the anticipated volume of CO_2-equivalent emissions avoided relative to the 'business as usual' baseline case during the plant lifetime.

The lifetime cost is a sum of the total contractor CAPEX and the difference in cumulative OPEX relative to the baseline plant over the plant lifetime, where the plant design life is defined as 20 years and represents an increase in lifecycle cost due to conversion. The formula used for this calculation is shown in Equation 1.

Equation 1. Lifecycle cost of CO_2 avoided calculation

$$Lifecycle\ cost\ (£/tCO_2e) = \frac{Total\ Contractor\ CAPEX\ (£) + \Delta Cumulative\ OPEX\ (£/20yr)}{Cumulative\ CO_2\ Avoided\ (tCO_2e/20yr)}$$

The cost year basis for the lifecycle cost is Q4 2021 as with the CAPEX and OPEX calculations.

Table 10 provides the estimated lifecycle cost of CO_2-equivalent emissions avoided for the business cases evaluated for each surveyed site in units of £ per tonne of CO_2e avoided over a 20 year project life.

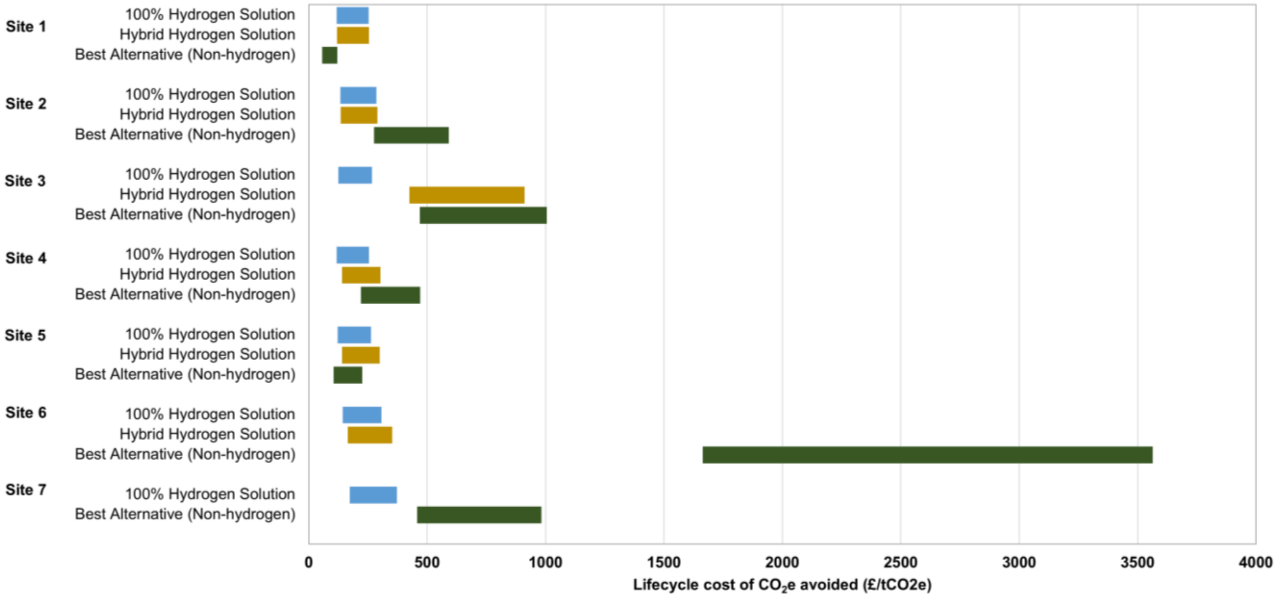
Table 10. Lifecycle Cost of CO2 Avoided for Surveyed Sites Business Cases

		Option 1	Option 2	**Option 3**	
Site Number	**Site Industry Sector**	**100% Hydrogen Solution**	**Hybrid Hydrogen Solution**	**Best Alternative (Non-hydrogen)**	**Comment (Non-hydrogen)**
1	Primary Plastics	169	170	81	Electrification + NG where no electric option
2	Food & Drink	191	193	394	Electrification of all users
3	Non-ferrous metals	178	608	670	Electrification + NG where no electric option
4	Vehicle Manufacturing	169	202	314	Electrification + NG where no electric option
5	Non-metallic minerals	175	200	151	Existing natural gas supply replaced with biomethane
6	Metal Packaging	205	235	2,376	Electrification of all users
7	Food & Drink	249	N/A	941	Electrification of all users

As can be seen in Table 10, for the surveyed sites the 100% hydrogen solution lifecycle cost is very site dependent and so is the difference to the best alternative (non-hydrogen) solution, which is most often electrification. The hybrid hydrogen solution is generally shown to be more expensive than the 100% hydrogen option in most cases. In most cases, options involving full or partial electrification of processes have a much greater lifecycle cost than the 100% hydrogen solution. This was due to a combination of Capital and Operating costs along with the level of CO2 emissions per kWh of electricity on the long term marginal basis consumed during the projected 2025-2045 period, resulting in lower CO2 emission savings relative to the baseline compared to the hydrogen alternatives leading to high cost per tonne of CO2 abated.

Figure 7 presents a plot of the lifecycle cost of CO_2e avoided for each of the business cases evaluated for the seven surveyed sites. The range of each bar represents the -30% and +50% uncertainty for the class IV estimates basis performed.

Figure 7. Lifecycle cost of CO_2e avoided for the business cases evaluated for the surveyed sites



The economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing are likely to be a key barrier to implementation.

4. Conclusions

The following key findings and conclusions were identified from the initial site surveys and safety assessments:

1) Safety

   a) Burners and burner management systems (BMS) will need to be reviewed and updated, to ensure safe operation, including combustion air flows, purge cycles, flame detection, gas isolation systems, the potential for air ingress and explosion relief. Premix burners may be a particular issue due to the potential for an explosion in the supply pipework for hydrogen.

   b) Based on visual inspection and records where available, the surveys identified that the metallurgy of existing natural gas pipework is generally suitable for hydrogen service. However, due to the age of the sites and infrastructure there are insufficient records to positively confirm all materials utilised.

   c) The surveys identified that the natural gas systems typically contain multiple threaded pipe fittings which are unlikely to be suitable for hydrogen service and may necessitate replacement. In addition, specialist or unique fittings were observed which require further investigation for suitability.

   d) DSEAR risk assessments and Hazardous Area Classifications will need to be updated to reflect operating with hydrogen. Hazardous areas are expected to increase and any electrical or mechanical equipment located within the calculated hazardous area extents (when assuming pure hydrogen) are required to have an IIC-T1 (or IIB+H2-T1) ATEX rating to reduce the likelihood of igniting hydrogen gas clouds and ensure ongoing compliance with the EPS 2016 Regulations. For the majority of sites surveyed there is no or very limited electrical equipment on the sites with sufficient ATEX ratings, exceptions being sites already handling similar dangerous substances. Dependent on further DSEAR studies certain equipment may require upgrades.

   e) Enclosures and buildings may not have sufficient ventilation, including at high level, to avoid hydrogen accumulating to flammable concentrations. Hydrogen has a higher volumetric flow than natural gas at the same hole size and pressure (~3 times greater) and is more buoyant.

   f) Some sections of existing natural gas routings on sites are not generally suitable or best practice for hydrogen. Re-routing of these lines should be considered to avoiding piping congestion in hazardous areas, to minimise pipe runs and let-down stations in internal locations to minimise hydrogen pressures and leak sources within buildings. Further work to review pressure setpoints should also be considered to reduce the severity of leaks. Development of RGP will form part of the wider work considering the guidance and standards required by industry.

   g) Ventilation in terms of DSEAR and SR25 is inadequate in a number of locations for hydrogen service on all sites, but in most cases can be addressed with relatively minor modifications to increase ventilation and by suggestions in the previous point. Hydrogen has a higher volumetric flow than natural gas at the same hole size and pressure (~3 times greater) and is more buoyant.

   h) Given the buoyancy of hydrogen (and natural gas) ventilation is most commonly required to be added at high level within buildings to prevent accumulation in roof spaces. Further study at sites is required to determine full ventilation requirements. This should include a review of requirements for standard gas metering enclosures by the gas suppliers. Increased attention should be paid to vegetation encroachment around these less frequented areas to avoid increased detonation risk in the event of leakage.

   i) Existing gas detectors at the surveyed sites, where present, are calibrated for specific hydrocarbon species found in natural gas and will require replacement with detectors calibrated for hydrogen. It is recommended that hydrogen leak detectors are installed at metering stations, pressure let-down stations and end users. Hydrogen specific (electrochemical) leak detectors are recommended over catalytic (LEL) technology.

   j) The implementation of hydrogen fuel switching will require some modifications to systems and personnel training at the sites. The extent of these changes and upskilling will be somewhat dependent on the sites experience handling dangerous substances. Site procedures (RAMS, SOPs etc) will need to be updated and staff will need to be trained for hydrogen hazards such as clear burning flames, increased flammability, increased ignition risks from electrical items and electrostatic charges (e.g. clothing), higher volumetric flows during venting and adequacy of inerting procedures.

k) By adherence to Relevant Good Practice (RGP) for design and operation of any future hydrogen gas supply system the likelihood of a Loss of Containment (LOC) will remain broadly equivalent to current natural gas systems. There are potentially significant increases in explosion risk when switching to hydrogen and there will be a need to consider additional mitigation measures to help control this risk, in particular for combustion equipment. The ultimate requirement will be to demonstrate that risks associated with a change to hydrogen as a fuel have been reduced to ALARP. This is considered to be achievable by sites implementing RGP, but it is anticipated that there may be significant costs for some sites to achieve this. RGP for using hydrogen as a fuel is at a comparatively early stage of development but will build on lessons learnt from decades of natural gas use alongside hydrogen experience from the process industries. For industrial sites, the greatest need for RGP relates to the design, construction and operation of hydrogen combustion equipment. There needs to be ongoing assessment of the completeness and rate of development safety standards in order provide adequate guidance for the RGP and to understand what further action may be required in this area

2) Emissions

a) Burner OEMs consulted indicated that for both retro-fits and new builds further work is required to understand and predict achievable NOx values. There is a risk that any early NOx guarantees offered are potentially more conservative than required and indicate a need for flue gas recirculation (FGR) or SCR being specified when not necessary, increasing the capital and operating cost.

3) Cost

a) For the surveyed sites the 100% hydrogen solution is typically significantly cheaper on CAPEX than the best alternative (non-hydrogen) solution, which is most often electrification, due to the ability to retrofit and avoidance of new or reinforced electrical infrastructure. A hybrid hydrogen solution may offer a lower CAPEX option in some cases.

b) For the surveyed sites the 100% hydrogen solution is typically less expensive on OPEX than the best alternative (non-hydrogen) solution, which is most often electrification, but there are exceptions. The hybrid hydrogen solution may have a higher OPEX option than 100% hydrogen in most cases, but again with exceptions.

c) For the surveyed sites the 100% hydrogen solution typically gives a greater reduction in CO_2e emissions than the best alternative (non-hydrogen) solution, which is most often electrification. The hybrid hydrogen solution is generally shown to be similar to 100% hydrogen in most cases.

d) For the surveyed sites the 100% hydrogen solution lifecycle cost is very site dependent and so is the difference to the best alternative (non-hydrogen) solution, which is most often electrification. Use of electrification results in high lifecycle costs due to a combination of Capital and Operating costs along with the level of CO2 emissions per kWh of electricity on the long term marginal basis consumed during the projected 2025-2045 period. This results in lower CO2 emission savings relative to the baseline compared to the hydrogen alternatives leading to a higher cost per tonne of CO2 abated. The hybrid hydrogen solution is generally shown to be more expensive than the 100% hydrogen option in most cases.

e) Averaged across the sites investigated for hydrogen conversion, indirect costs account for approximately 52% of the CAPEX with approximately 43% on end user conversion and 5% on site infrastructure modifications.

4) Technical Feasibility

a) There are commercially available hydrogen equivalents of the following end users:

- Burners, of various types, suitable for installation as part of boiler, furnace, oven, RTO, dryer, water heaters, and thermal fluid heater packages (75 – 3,100 kW).
- Complete boiler (steam) steam generator packages (<5,000 kW)[24].
- Complete boiler (hot water) water heater packages (300 – 3,500 kW).
- AHUs (~100 kW).
- Flare pilots (~32 kW flare pilot).

[24] Complete package refers to a single purchased unit of all components of a gas end user (e.g. heating coils, pumps, air systems, vessel, housing, burners, flue system, ancillaries, etc as applicable).

b) There are no commercially available ‘off the shelf’ hydrogen equivalents and limited reference projects, but some bespoke projects and commercial development for hydrogen equivalents has been identified of the following end users:

- Boiler (steam) steam generators (~10,000kW).
- ‘Domestic’ type boilers (hot water) water heaters (20 – 80 kW).
- Roasters (1200 – 1,700 kW).
- Oven and fryers (550 – 1,200 kW).

c) There are no commercially available hydrogen equivalents for the following end users:

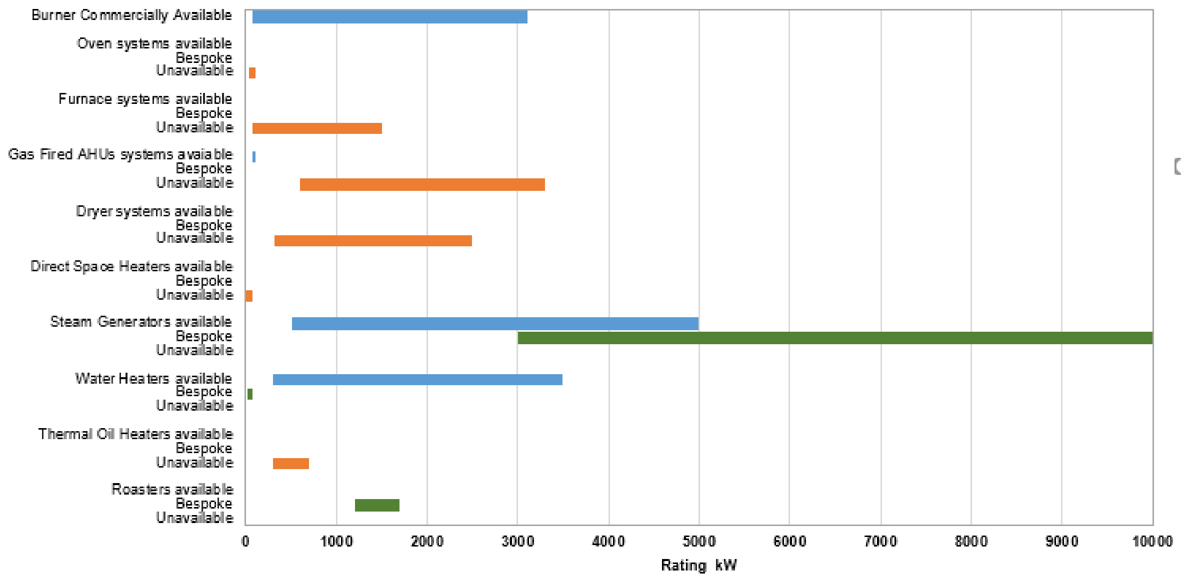
- Specialty ovens, with non-standard burners (30 – 100 kW).
- AHUs (600 – 3,300 kW).
- Direct fired space heaters (11 – 75 kW ceiling suspended units).
- Gas fired torches (various kW).
- Flare ignition package (flame front generator).
- Complete furnace packages (75 – 1,500 kW).
- Complete dryer packages (325 – 2,500 kW).
- Complete thermal fluid heater packages (700 kW).

d) While package boilers (steam) of the size of those surveyed are commercially available there are very few reference plants operating with 100 vol% hydrogen.

e) The line capacity of existing natural gas lines is often insufficient for the hydrogen flow required to maintain the same energy flow to the end users. The proportion of piping that was undersized varied considerably between sites. Some sites would require near full replacement of existing pipework, while for others it was found that sites had oversized piping for their natural gas demands and replacement requirements would be minimal.

Figure 8 presents a plot of the commercial availability of equipment suitable for the specific requirements seven surveyed sites. Note that this a targeted assessment focused on the site rather than a comprehensive survey of end user types and their market readiness. As can been seen, the burners are generally commercially available for integration into systems such as boilers, furnaces, ovens and fryers, RTOs, dryers, water and thermal fluid heater packages, however the translation into off the shelf packages system relies on the availability of that end market and the cost competitiveness of the product. Manufacturers are operating in a price sensitive market and so development of specific units may be more realistic for the bespoke engineered opportunities rather than standardised volume products.

Figure 8. Availability of end users for the surveyed sites



5) Applicability

   a) The key barriers to complete substitution for natural gas are:

   - Hydrogen security of supply. During initial implementation there is a concern that the hydrogen supply chain will have lower availability and reliability than the current natural gas supply chain. Dual fuel systems for all end users are not available or in development, thus further work is required to understand if back-up systems could be feasible, and this is likely to be site specific.
   - Economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing.
   - Number of end users of natural gas do not have commercially available hydrogen equivalents.
   - A key barrier to the most common alternative decarbonisation option of electrification will be the high variability of the energy loads for some major users. This peaking nature may be unpalatable for electricity suppliers and sites may struggle to agree an economically feasible supply contract. Discussions and investigation with the DNO and electricity suppliers will be required to resolve this risk.

5. Recommendations

The following issues were identified as requiring further study to better understand the implications of a potential switch to hydrogen as a fuel:

1) Safety

   a) Further work is required to understand the acceptability of EN 161 and EN 746 for hydrogen service and the impact the sizing of creep relief valves and the release from the tail pipe has on hazardous areas. EN 161 and EN 746 are concerned with the safety requirements for burners and fuel handling systems that are part of industrial thermo-processing equipment.

   b) Further study is required to identify the impact on potential ignition sources as a result of more energy sources becoming electrified, for example the use of electric vehicles onsite or impacts of car charging points. This is important to consider as industrial equipment is potentially being replaced with hydrogen equipment, which will have a larger hazardous area and a lower ignition energy.

   c) The lower flame stability of hydrogen could result in an increased risk of flame out on gas fired systems. Where gas firing is part of safety critical systems further study is required to demonstrate that hydrogen can be as reliable as natural gas.

   d) The use of pre-mixed burner systems was observed on some of the ovens surveyed, these need further study to ensure that an explosion cannot occur within the pipework and cause further damage when using hydrogen due to the higher upper flammability limit and the higher flame speed versus natural gas.

   e) Further analysis is required to identify if providing explosion relief on combustion equipment would be “reasonably practicable” when also considering the existing risk controls in place (e.g. BMS). It is noted that providing explosion relief for hydrogen explosions is more challenging than for dust or natural gas explosions due to the higher flame speeds involved. Whilst consideration of explosion relief panels was cited as a potential mitigation option, further work would be required to establish the effectiveness and best practice guidance for such systems for hydrogen applications.

   f) Further work is recommended to develop alternative hydrogen leak detection strategies beyond standard gas detectors that can have a relatively slow response time due to the buoyancy of hydrogen.

   g) From a safety perspective, leaks from the high-pressure distribution system coming into the site have the greatest potential for damage and fatalities on neighbouring areas, because of the potential for leakage from pressure let-down and metering equipment, which is often housed in an enclosed building where hydrogen can accumulate. This initial study indicated that for the sites visited this would not be a significant issue, because the equipment was located in remote areas on industrial sites where the other industrial neighbours were a sufficient distance away that the change in risk from natural gas to hydrogen made no material difference to risk. This is a site and configuration specific risk and needs to be considered further if more site studies are done and whether there is generic work that can be done to better understand risks and consequences.

h) Ongoing assessment of safety standards is required in order provide adequate guidance for the RGP.

i) Further work is recommended for specific hazards associated with the use of manual control valves and shut off valves for hydrogen systems.

2) Emissions

a) Medium Combustion Plant Directive (MCPD) stipulates that NOx emissions for 'natural gas' combustion plant shall not exceed 100mg/Nm³ at 3% O2 while 'other gases' shall not exceed 200mg/Nm³ at 3% O2. Clarity is required to determine if the limit for hydrogen will be reduced to that required currently for natural gas following an extensive roll-out of hydrogen combustion equipment. Note this is relevant to indirect fired equipment as direct fired equipment is generally excluded from MCPD.

b) Engagement with SCR OEMs to discuss specifications and requirements of suitable units where NOx abatement is required.

3) Cost

a) The study has focussed principally on hydrogen, and while work was carried out on a counter-factual non-hydrogen alternative, this was to a lesser level of detail and was not intended to determine the optimal solution. Further studies should be carried out to develop these indicative findings and develop costing assumptions and sensitivities. Based on this work, hydrogen could offer a competitive option for industrial decarbonisation, subject to more detailed investigation on a site specific basis.

b) Further refinement of the cost estimate basis for end user equipment conversion and new-build to identify the most cost-effective option. This should include condition assessment and detailed inspection of equipment considered for reuse in order to determine remaining asset life and continued discussion with OEMs.

c) OPEX costs accounted for approximately 80% of the lifecycle costs calculated for hydrogen use cases (range of approximately 70-95%) and approximately 60% for hon-hydrogen use cases (range of approximately 25-100%)[25] , therefore differences in energy efficiency between different technologies and fuels can have a significant impact on the overall lifecycle cost of a decarbonisation pathway. This means that if technologies such as heat pumps or infrared ovens can be provided with the scale, temperature, duty and configuration required for an industrial process, then the efficiency gains they could have over a combustion equivalent could have a significant impact on the optimal pathway for sites. For the industrial sites studied in this study 90% of the installed equipment was used to fire processes, with a relatively high proportion of direct fired high temperature ,process specific equipment which made electrification options at sites particularly challenging. Future work should consider this and whether there are site archetypes where the nature of processes and energy use maybe more favourable to electrification.

d) The effects of disruption and outages on the overall lifecycle cost has not been included and further work will be required to optimise any hydrogen conversion with production scheduling.

e) The connection and offsite costs of any gas network upgrades for hydrogen and wider electrification upgrades will also be key factors in the full cost of sites decarbonising.

4) Technical Feasibility

a) Additional engagement and responses required from OEMs to better understand the extent of modifications required, NOx guarantees, and impacts on operation (e.g. temperature profiles, efficiencies, thermal rating, control system changes, material suitability, equipment durability). This should consider the implications of recent BEIS work on Hydrogen Ready Industrial Boilers.

[25] The higher range in the non-hydrogen represents the different decarbonisation options that is mostly electrification but also includes biomethane, where the Capex will range from complete replacement for electrification and no change for biomethane.

b) Further work is required by OEMs, particularly of complete packages, to develop commercial hydrogen versions of their equipment ranges. Availability of funding to support their development could encourage OEMs who are hesitant to invest prior to major hydrogen uptake or switchover. An assessment will have to be made by government as to the extent to which existing programmes like IETF, Industrial Hydrogen Accelerator, Industrial Fuel Switching 1 & 2, and the Industrial Clusters programme provide sufficient imperative to manufacturers.

c) Further work is required for OEMs to develop hydrogen ready boosters/compressors for low pressure applications.

d) Further work and study are required to understand the impact of the higher moisture content from hydrogen combustion on processes such as ovens and dryers, and if this will have an impact on air flow rates, product flow rates, quality, and fuel consumption. Some potentially complex cases were identified involving combustion products which will require further research at food manufacturers.

e) Further work is required to positively identify all materials within a site's natural gas infrastructure if it is to be repurposed for hydrogen, in particular valve trims and non-metalling components at joints and valves. Whilst hydrogen embrittlement is a known issue, particularly for high strength steels, hydrogen effects on elastomers/polymers and other materials is an area of ongoing research. Further study is required to determine the material compatibility of the existing system. It is also recognised that the positive identification of all materials used in a gas distribution system may be a difficult task on older sites, such that the more cost/time efficient assumption may be parallel construction replacement, this may be mandated based on the line capacity and size of the pipework required for hydrogen versus natural gas.

f) Though flowmeters suitable for hydrogen flow measurement exist, a recognised fiscal hydrogen flowmeter is still an area of further development and the possibility to modify existing fiscal natural gas flowmeters requires further investigation.

g) Further work is required to understand the potential demands on the supply chain to assess the changes required for bespoke end-user equipment, and to provide equipment at the rate required for a potential conversion or retrofitting.

5) Applicability

a) The sample size for these studies was small, therefore there should be consideration as to how the indicative findings from these surveys can be confirmed by further work to validate the case study conclusions.

b) It is recommended that further work is conducted to complete assessment of a site in a coastal or corrosive location. Through the assessment of such a site the impact of assuming adverse conditions[26] can be investigated and evaluated, particularly in reference to hazardous area extents.

c) The surveyed sites were chosen to look particularly at direct fire processes in dispersed sites and were intended as a pathfinder to identify areas of further work. There is a good degree of variation in the type, scale, and temperatures of the processes considered, but they may not be representative of industry as a whole, should more of the heat demand in sites be indirect heat users. Consideration of the total demand for indirect fired end users may present different opportunities and issues around decarbonisation should equipment be to more suitable for modification or electrification. This may mean that they are easier to decarbonise, but may be subject to different thresholds and limits under combustion plant directives. Additionally, not all industry sectors have been investigated. Further groups of site assessments could be considered to ensure a fully representative view of industry is produced.

The following demonstration requirements have been identified:

1) Boilers and burners of the sizes at the surveyed sites are installed in large numbers within the UK in both manufacturing, chemical and food sectors. However, from consultation with many of the OEMs very few have examples of firing on 100 vol% hydrogen. Most units that do exist are demonstration units only and are not in continuous operation. Further demonstration of a retrofit on an operating site would be

[26] Adverse conditions as defined in IGEM, "Hazardous Area Classification of Natural Gas Installations, IGEM/SR/25 Edition 2," 2010

beneficial. The demonstration will offer the greatest value if the results are publicly available and in particular:

a) Establishing de-rating factors.

b) NOx emission levels both with and without emission controls (FGR or SCR).

c) Ramp rates.

d) Flame stability and reliability.

BEIS programmes such as Industrial Fuel Switching and the Industrial Hydrogen Accelerator programme are investigating these areas.

2) It has been noted that sites often talk in terms of kW capacity rather than flow rates so using similar language could improve a site's understanding of guidance documents. Leak models are currently based on either volume or mass release rates, a new model that uses the concept of energy flow (i.e. kW) could be useful for future modelling work allowing for direct comparisons of a "like for like" gas supply.

3) Initial research has shown there to be no 100 vol% hydrogen reference sites for furnaces or ovens. Furnace and oven demonstrations will offer the greatest value if the results are publicly available and would offer particular benefits in the following areas:

a) Understanding of the higher fuel moisture content on efficiency and quality.

b) Understand the impact of lower flame radiant heat.

c) Ramp rates.

d) NOx emission levels both with and without emission controls (FGR or SCR).

Appendix A Hydrogen Characteristics

To better appreciate the implications of decarbonising industry with hydrogen, the following section discusses the key differences between hydrogen and methane as a fuel and implications that has on combustion equipment and power generation facilities.

Table 11. Properties of Hydrogen, Methane and Propane[27,28]

Parameter	Unit	Hydrogen	Methane	Propane
Molecular weight	g/mol	2.016	16.040	44.097
Density at STP	kg/m³	0.09	0.72	2.01
Self-ignition temperature[a]	K	845 - 858	813 - 905	760 - 766
Minimum ignition energy	mJ	0.02	0.29	0.26
Flammability range in air	vol%	4 - 75	5 - 15	2.1 - 10
Adiabatic flame temperature	K	2318 - 2400	2158 - 2226	2198 - 2267
Burning velocity	cm/s	237	42	46
Laminar flame speed (max)	cm/s	325	45	38
Lower heating value (mass)	MJ/kg	118.8	50.0	46.4
Higher heating value (mass)	MJ/kg	141.8	55.5	50.4
Lower heating value (vol.)	MJ/Sm³	10.8	35.8	91.21
Higher heating value (vol.)	MJ/Sm³	12.8	39.7	99.03
Wobbe index (LHV basis)	MJ/Sm³	40.7	47.9	73.3
***Standard conditions refer to 273.15K and 1 bara**				

A.1 Combustion Characteristics

Heat of Combustion

The lower heating value (LHV) of hydrogen at 10.8 MJ/Nm³ is less than a third of that of methane at 35.8 MJ/Nm³. This lower energy density means that, for a given duty, the volumetric flow of hydrogen would be over three times that of methane. This may result in constraints within the fuel distribution network or the combustion equipment, causing a restriction in flow and de-rating of the plant capacity.

Wobbe Index

The Wobbe Index is used as a measure of operability of a selected fuel and is determined by the volumetric LHV and the densities of the fuel and air. Whilst methane and hydrogen have similar Wobbe index values they will provide the same heat output and, providing the index remains in the range 30 – 50 MJ/m^3, combustion systems designed for natural gas can be used with hydrogen without large scale modifications. The Wobbe Index is commonly used in the design of gas turbine systems, but it is not infallible as the index does not account for variations in combustion properties such as burning velocities[27].

Lewis Number

The Lewis number is an indicator of flame stability and the sensitivity of flames to disturbances. It is defined as the ratio of thermal diffusivity to the mass diffusivity of a fuel. Fuels with Le ≥1 are expected to be relatively stable. The

[27] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422
[28] Botha J.P. and Spalding D. B., 1954, *The laminar flame speed of propane/air mixtures with heat extraction from the flame*, Available from: https://doi.org/10.1098/rspa.1954.0188

Le of hydrogen is approximately half that of methane (0.45 vs 1), which indicates a more unstable flame[29] and without modifications to burners and control systems may decrease plant availability.

Adiabatic Flame Temperature

The Adiabatic Flame Temperature is the equilibrium temperature of products when the reactants are notionally burned at a defined pressure without transferring heat to the environment. The adiabatic flame temperature for hydrogen is significantly higher than for methane. This results in more than three times the thermal NOx production and is an indicator of NOx emissions. This characteristic determines the maximum temperature of the combustor, and consequently the construction materials, and its efficiency. Therefore, an increased temperature can increase efficiency but may negatively impact burner equipment due to overheating[27].

Flame Speed

The flame speed is the velocity at which the unburned gases propagate into the flame. The flame speed affects the burning rate, position of flame front, flashback risk and flame stabilisation. The maximum flame speed of hydrogen is approximately seven times faster than for methane, and this higher flame speed increases the risk of the flame burning closer to the injection points, travelling back into mixing passages or burning too close to liner walls, leading to damage. This risk increases as the hydrogen content in the fuel is increased and with increasing combustion inlet and flame temperature. As a result, combustion systems configured for methane (or natural gas) operation may be unsuitable and combustors designed specifically for the different combustion conditions of high hydrogen content fuels will need to be developed. Turbulent flame speed is considered more important than laminar flame speed, as the flame speed increases in the turbulent zone. With the increased flame speed, the combustion durations of hydrogen blends are reduced, and the flame is shortened. This has the potential to lead to shorter combustion chambers, reducing the combustion residence times, lowering the NO formation and cooling requirements.

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[30]. This also results in a hydrogen flame having a lower luminosity and requires ultraviolet flame detection rather than infrared flame detection typically used in natural gas applications.

The stoichiometric combustion concentration of hydrogen in air (assuming air is made of 21% of oxygen and 79% of nitrogen) is 29.6 vol% with the air content of 70.4 vol% and is represented by the following chemical equation[31]:

$$2\ H_2 + (O_2 + 3.76\ N_2) \rightarrow 2\ H_2O + 3.76\ N_2 \qquad \Delta H = 572\ kJ$$

This is different from methane, as each methane molecule needs two oxygen molecules to react fully as shown in the following equation:

$$CH_4 + 2\ (O_2 + 3.76\ N_2) \rightarrow CO_2 + 2\ H_2O + 7.52\ N_2 \qquad \Delta H = 890\ kJ$$

From the perspective of oxygen demand, 22% less oxygen is required for the same energy release burning hydrogen compared to methane.

Hydrogen combustion = 572 kJ ÷ 1 mol O_2 = 572 kJ/mol O_2

Methane combustion = 890 kJ ÷ 2 mol O_2 = 445 kJ/mol O_2

Relative Oxygen Demand = 445 kJ/mol O_2 ÷ 572 kJ/mol O_2 = 78% of methane

Thus, the impact of converting to hydrogen does not negatively impact the combustion air requirement, and the fans suitable for natural gas firing should be capable of providing more combustion air than required by the equivalent hydrogen system.

Flammability

Hydrogen has a lower flammability limit and wider flammability range (in air) than methane, resulting in increased safety issues in the event of leaks or discharges. This will result in different procedures and safety / exclusion

[29] Bouvet N. et al, Int IntJ Hydrogen Energy 2013. doi:10.1016/j.ijhydene.2013.02.098.
[30] García-Armingol T et al. Int J Hydrogen Energy 2014;39:11299–307. doi:10.1016/j.ijhydene.2014.05.109.
[31] IGEM, 2021, Reference Standard for low pressure hydrogen utilisation, IGEM/H/1, UK.

zones. Research has shown that there is a gap in the understanding of flammability limits (especially upper flammability limit), particularly under high hydrogen concentrations and elevated temperature[27].

A.2 Material Characteristics

Leak Potential

Due to its small molecule size, hydrogen has the potential to diffuse through seals that might be considered airtight or impermeable to other gases. Therefore, traditional sealing systems used with natural gas will potentially need to be replaced with alternative arrangements, e.g. welded connections.

Hydrogen diffusion through polyethylene materials (PE80) has been investigated and found to be five times higher than for natural gas but was still considered negligible (annual loss of 0.0005 – 0.001% of transported volume)[32] .

Embrittlement

Hydrogen can be absorbed by some materials which will result in embrittlement and the loss of ductility. This is caused by the interaction of hydrogen atoms with the crystal lattices of the material and is accelerated at elevated temperatures and pressures. One material particularly susceptible to this is cast iron. Existing design codes provide guidance on appropriate materials for hydrogen systems depending on operating conditions but it is recommended that materials such as lower strength carbon steels e.g. API 5 5L grades (X52 or lower), austenitic stainless steels or polyethylene (PE80 or PE100) are adopted[33].

A.3 Environment, Health and Safety Implications

COMAH

The COMAH Regulations apply to sites with significant inventories of dangerous substances, and are intended to prevent major accidents and to limit the consequences to people and the environment of any accidents which do occur.

The additional requirements on site operators when classified as COMAH sites are not insignificant, and often drive developers in the specification of storage and design of their site in order to remove the obligations that would result from being classified as a COMAH site. The threshold value for hydrogen is an order of magnitude lower than that of natural gas as shown in Table 12. The switching of fuels from natural gas or diesel to hydrogen may result in increased numbers of power generators' sites being COMAH classified, and will influence the maximum storage capacity of hydrogen on site.

For sites supplied with natural gas the maturity and reliability of the distribution networks mean that on-site storage of natural gas is not typically required, however hydrogen supply chains are not as mature and on-site storage is more likely to be required as site owner's seek to ensure security of supply and operation.

Table 12. COMAH thresholds for dangerous substances[34]

Substance (threshold units = tonnes)	Lower tier threshold	Higher tier threshold
Natural gas	50	200
LPG	50	200
Diesel	2,500	25,000
Hydrogen	5	50

32 A. Brown, July 2020, Hydrogen: The future fuel today, Hydrogen Transport, IChemE
33 A. Brown, July 2020, Hydrogen: The future fuel today, Hydrogen Transport, IChemE
34 HSE, 2015, *The Control of Major Accident Hazards Regulations 2015*, 3rd Edition, HSE, UK.

Dangerous Substances and Explosive Atmospheres Regulations

The Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR) require employers to control the risks to safety from fire, explosions and substances corrosive to metals. The Regulations implement two European Directives[35]:

- the safety aspects of the Chemical Agents Directive 98/24/EC (CAD); and.
- the Explosive Atmospheres Directive 99/92/EC (ATEX).

DSEAR require facility owners to carry out a hazardous area classification (HAC) exercise wherever there is a potential for flammable gas/air mixtures to form, be that due to leaks or deliberate venting. The HAC will identify and class areas into zones and minimum protection (ATEX) rating of electrical equipment within the respective zones.

Hydrogen will result in larger zones or necessitate a higher ventilation rate than would be required for natural gas due to the lower LFL and the higher volumetric leak rates that result from Hydrogen being a smaller molecule.

Hydrogen is easier to ignite than methane and is classified as a Group IIC gas, whereas methane/natural gas is considered less hazardous and classified as a Group IIA gas. Therefore, the equipment to be used within hazardous areas identified for hydrogen will need to be of a higher standard than currently required for NG installations.

Pressure Equipment (Safety) Regulations

The Pressure Equipment (Safety) Regulations (PESR) regulate the design, manufacture and conformity assessment of pressure equipment and assemblies with a maximum allowable pressure greater than 0.5 barg[36].

For facilities with high pressure gas, the PESR apply widely and will not have any impact on the design or operation of the plant. However, when retrofitting facilities where only low gas pressures have been previously required, it may be desirable to increase the operating pressure to accommodate the lower energy density of Hydrogen to avoid de-rating of piping and equipment. Where the resulting pressure would exceed 0.5 barg then the equipment, assemblies and components within the system will need to be checked to ensure they comply with the requirements of the PESR and, if not, will require replacement.

Environmental Permitting

For new build sites and retrofitting to existing facilities, the principal environmental permitting implications of fully hydrogen fired combustion plant, when compared to a similar natural gas application, are the potential for higher NO_x generation and the resulting need to implement post-combustion emission controls such as SCR.

For sites that include production of hydrogen using electrolysis, water availability and abstraction requirements will be of significant environmental concern.

[35] HSE, 2013, *Dangerous substances and explosive atmospheres*, 2nd Edition, HSE, UK.
[36] Office for Product Safety and Standards, 2021, *Pressure Equipment (Safety) Regulations 2016 Guidance*, Ver. 3, BEIS, UK

Appendix B Case Study: Site 1 (Other Industry)

B.1 Project Introduction

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. As part of this work, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. BEIS has appointed AECOM to undertake this study to assess the impact to industrial end users of switching from natural gas to 100% hydrogen.

The objectives of the project were to undertake initial site surveys of seven volunteer industrial sites. These surveys characterise the current site infrastructure, identify and assess the site-specific technical, safety, cost, environmental and implementation considerations of switching from natural gas to 100% hydrogen and provide initial safety evidence and prioritisation that support HSE's considerations on the safety of hydrogen.

B.2 Site Information

The site manufactures polymer resins for use in a wide variety of products. The site consumes approximately 50,000 MWh of natural gas per year and 60,000 MWh of electricity. Natural gas consumption has been reduced in recent years through maximising recovery of off-gases for combustion, replacing the need for natural gas.

End users of natural gas at the site include industrial boilers, a polymer removal oven, space and water heaters, flare pilots and a flare ignition package, the largest of these energy consumers being the industrial boilers.

Natural gas is supplied to the site at an operating pressure of 6 barg. The metering compound was not accessed during this study and so the metering compound equipment has not been assessed.

The on-site infrastructure consists of:

- 6 barg supply header from the site boundary.
- 6 barg let-down station which reduces the gas pressure to 3 barg.
- 3 barg distribution header, and a.
- low pressure let-down which reduces the 3 barg supply to 56 mbarg.

The natural gas pipework at the site is constructed of carbon steel and is significantly oversized for the required duty due to decommissioning of process units over time.

B.3 Business Case Evaluation

The three business cases analysed are outlined in Table 13 . These options have been evaluated based on capital cost, operating cost and lifecycle cost. The costs are the differential cost between the decarbonisation case and the existing baseline plant and are based on the assumption of converting the existing infrastructure where possible and avoiding new build.

Table 13. Definition of cases for evaluation- Site 1 (Other Industry)

	Option 1	Option 2	Option 3
Description of option:	**100% Hydrogen Solution:** All users converted for hydrogen service	**Hybrid Hydrogen Solution:** Select users converted for hydrogen service, others operating on natural gas	**Best Alternative (non-hydrogen) Solution:** Electrification of users where possible, natural gas where no electric option is available

The capital cost, operating cost and lifecycle cost estimates are presented in Figure 9, Figure 10, and Figure **11** respectively.

Figure 9. Capital cost estimate for the business cases evaluated- Site 1 (Other Industry)

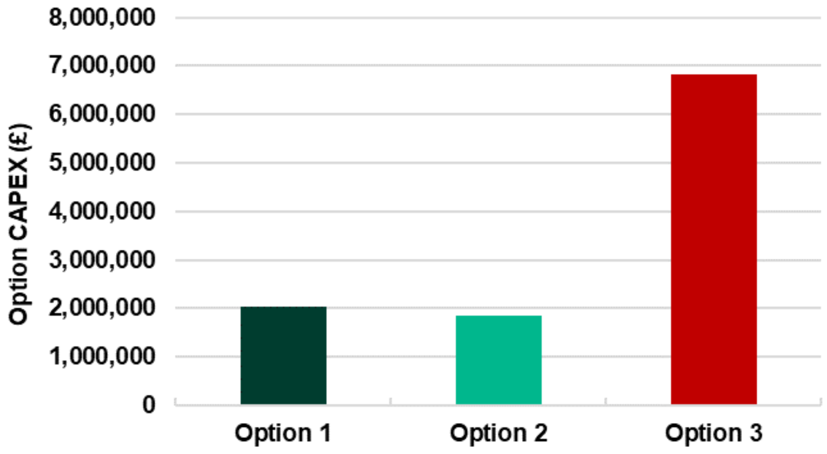


Figure 10. Operating cost estimate for the business cases evaluate- Site 1 (Other Industry)

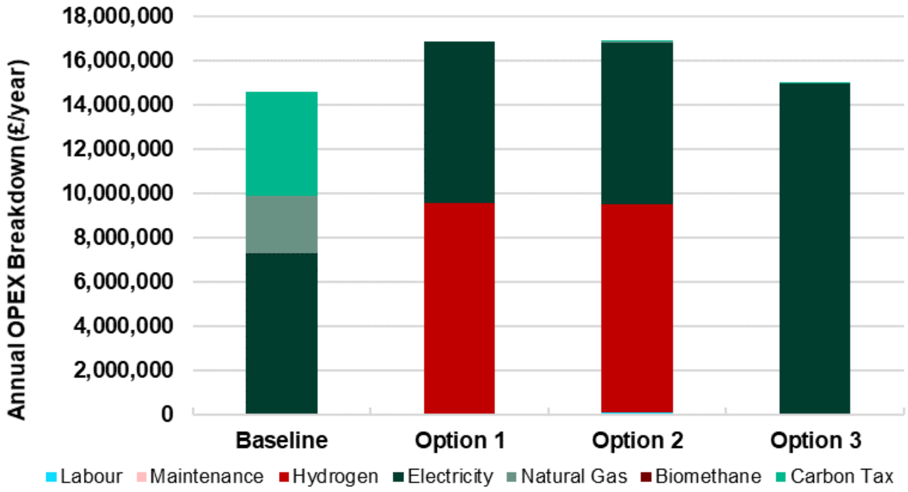
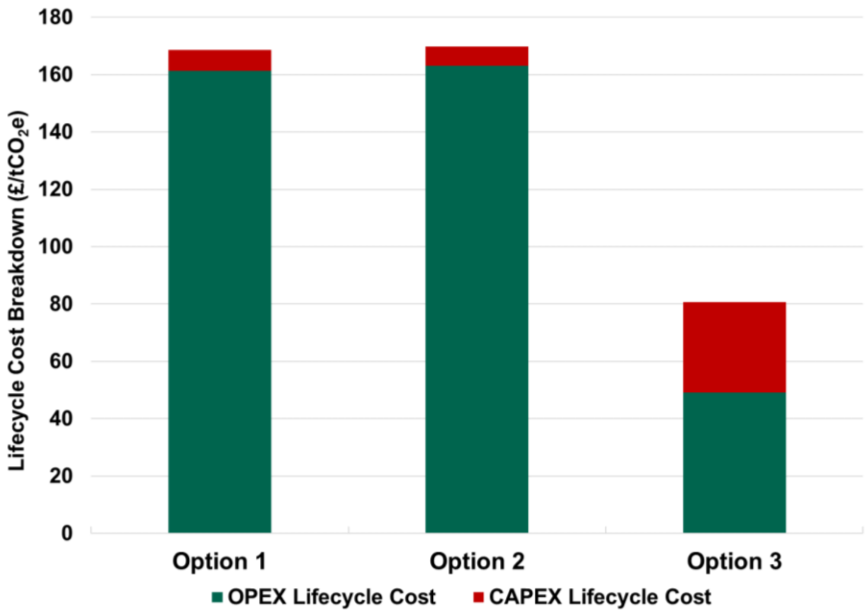


Figure 11. Lifecycle cost estimate for the business cases evaluated- Site 1 (Other Industry)



B.4 Technical Challenges of Conversion

Most of the natural gas end users at the site would require major modifications to enable hydrogen service.

The production of steam is key to the operation of the site and requires a very high degree of reliability and availability, and so the boilers are provided with a liquid burner that can fire diesel as a back-up fuel. There is a perceived risk that there will be greater reliance on the back-up systems and increased risk of loss of fuel availability to the boilers when switching to hydrogen service. The disadvantage of this solution is increased infrastructure resulting in increased CAPEX, OPEX, maintenance and complexity.

The boilers at the site currently utilise waste gases from the process plant to avoid flaring of these gases. These waste gases a pose a technical challenge for specifying and designing hydrogen fired boilers as the combustion characteristics of these waste gases is variable and generally significantly different to hydrogen. In order to address this wide range of characteristics, there is a potential that multiple gas burners would be required.

There are a number of commercially available hydrogen fired options at the required size for replacing the existing space and water heaters. Alternatively, these could be replaced with electric heaters or air source heat pumps.

The polymer removal oven is a direct fired application and the OEM has not developed a 'hydrogen-ready' equivalent. Further work is required to evaluate the temperature profiles within the oven and the ability to maintain the required temperatures in the main chamber of the oven to prevent damage to the moulds and equipment being cleaned when using hydrogen.

A key feature and requirement of flare pilots is their ability to maintain a stable flame to ensure that they are available to ignite a release from the process. Hydrogen produces a less stable flame than methane which, to avoid a higher risk of 'flame-out' scenarios, will require the flare pilots to be changed, otherwise the pilots will be required to be reignited more frequently. OEMs were contacted and confirmed that they can offer flare pilots that would be suitable with 100 vol% hydrogen, but no proof of demonstration projects was provided.

B.5 Summary of Conclusions

The following key findings were identified from the initial site survey and safety assessment:

- Site is an industrial petrochemical site with established process safety management structures, capable of adopting hydrogen as a future fuel.
- Existing natural gas lines in the 6barg system are over-sized for current fuel demands and as a result have sufficient capacity for the increased volume flows associated with hydrogen.
- Hydrogen security of supply - during initial implementation, there is a concern that the hydrogen supply chain will have lower availability and reliability than the current natural gas supply chain.
- Economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing could be a barrier to implementation.
- Number of end users of natural gas do not have commercially available hydrogen equivalents.
- A means of co-firing the waste gases on the boilers with hydrogen, or other utilisation of this fuel, needs to be identified.
- The majority of instruments and electrical equipment in the vicinity of the proposed hydrogen infrastructure already have an ATEX rating of IIC-T1 or better. As a result, the impact of fuel switching from natural gas to hydrogen is not as extensive as it could be.
- Ventilation in terms of DSEAR and SR25 is generally adequate or can be addressed with minor modifications.

B.6 Further Considerations

The site has features that may not be applicable to other similar sites such as natural gas pipework being oversized, equipment already having an ATEX rating of IIC-T1 or better and buildings mostly all having adequate ventilation for hydrogen service. All of these factors may incur additional capital expenditure for other sites when converting for hydrogen service.

Furthermore, due to its large chemical inventory, this site is already an upper-tier COMAH site. This may not apply to other sites, which may be subject to additional COMAH requirements when switching to hydrogen service should on site storage be required.

It is recommended that future studies on switching to hydrogen at similar sites involve additional engagement with end user OEMs, further refinement of cost estimate basis, assessment of ability to maintain temperature profiles within direct fired ovens, and the stability of flare pilot flames and flare tip material durability.

Appendix C Case Study: Site 2 (Food and Drink 1)

C.1 Project Introduction

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. As part of this work, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. BEIS has appointed AECOM to undertake this study to assess the impact to industrial end users of switching from natural gas to 100% hydrogen.

The objectives of the project were to undertake initial site surveys of seven volunteer industrial sites. These surveys characterise the current site infrastructure, identify and assess the site-specific technical, safety, cost, environmental and implementation considerations of switching from natural gas to 100% hydrogen and provide initial safety evidence and prioritisation that support HSE's considerations on the safety of hydrogen.

C.2 Site Information

The site is a food manufacturing facility which produces snack food. The site consumes approximately 20,000 MWh of natural gas per year and 2,000 MWh of electricity.

End users of natural gas at the site include process ovens, fryers, an air handling unit, hot water heaters and boilers used for water and space heating. Approximately 85% of the site's energy consumption is attributed to the ovens and fryers.

Natural gas is supplied to the site via a 2 barg network. The on-site infrastructure consists of 28 mbarg distribution supply. This is then regulated locally to 20 mbarg for the gas users. A number of the ovens and fryers use gas boosters to increase the pressure to approximately 78 mbarg local to the end user equipment.

The natural gas pipework at the site is constructed of carbon steel and is significantly oversized for the required duty.

C.3 Business Case Evaluation

The three business cases analysed are outlined in Table 14 . These options have been evaluated based on capital cost, operating cost and lifecycle cost. The costs are the differential cost between the decarbonisation case and the existing baseline plant and are based on the assumption of converting the existing infrastructure where possible and avoiding new build.

Table 14. Definition of cases for evaluation- Site 2 (Food & Drink)

	Option 1	Option 2	Option 3
Description of option:	**100% Hydrogen Solution:** All users converted for hydrogen service	**Hybrid Hydrogen Solution:** Select users converted for hydrogen service, others replaced with electric alternatives	**Best Alternative (non-hydrogen) Solution:** Electrification of all users

The capital cost, operating cost and lifecycle cost estimates are presented in Figure 12, Figure 13, and Figure 14, respectively.

Figure 12. Capital cost estimate for business cases evaluated- Site 2 (Food & Drink 1)

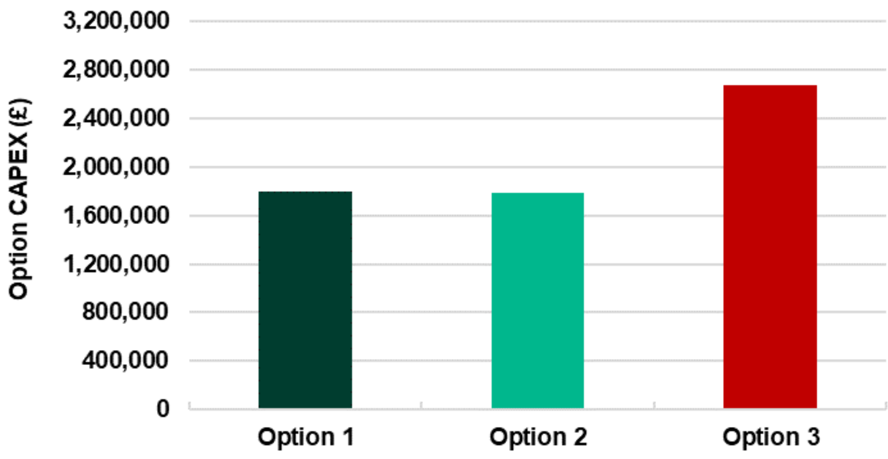


Figure 13. Operating cost estimate for business cases evaluated- Site 2 (Food & Drink 1)

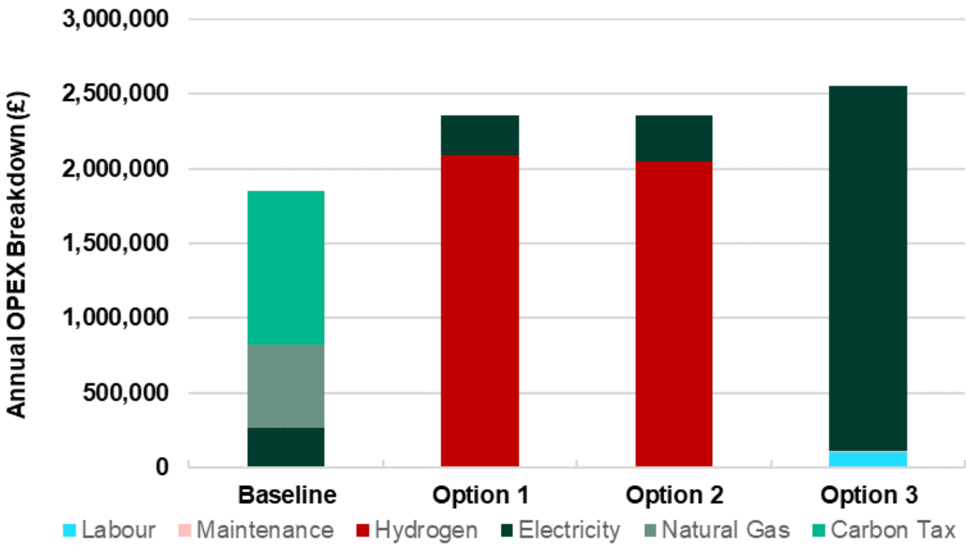
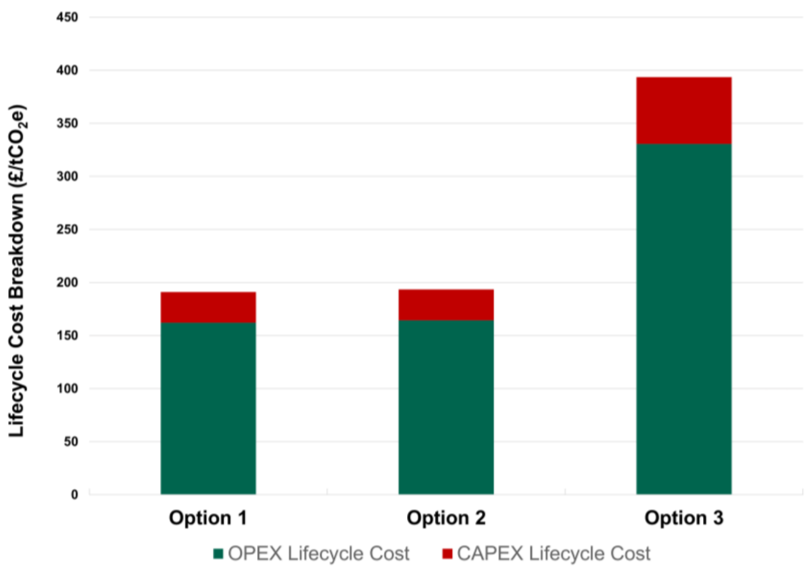


Figure 14. Lifecycle cost estimate for the business cases evaluated- Site 2 (Food & Drink 1)



C.4 Technical Challenges of Conversion

The existing pipework is oversized and is therefore sufficient to carry the required thermal duty of the existing ovens and fryers. There are currently hydrogen boilers being developed and prototyped by several boiler OEMs that could replace the current water heaters and boilers at the site.

The ovens operate at high temperature and have complex multi-burner systems. A key part of this process is control of the moisture content of the product and a switch to hydrogen may pose potential challenges which will need to be assessed.

The extent of the modification requirements for the ovens and fryers requires in-depth consultation with the OEMs to evaluate the thermal design or to acquire the data to enable a third party to evaluate the oven and fryer modifications required. As well as determining the extent of any modifications, the theoretical heat transfer and any de-rating required should be evaluated.

The air handling unit is located just below the roof, with the gas pipework running at high level within the building. There may be a requirement to install localised ventilation above the AHU and pipework infrastructure to allow hydrogen to be dispersed in the event of a leakage.

Further study is required to understand the implementation of hydrogen in terms of the design of the AHU and heat transfer system as this was not accessible during the site survey. There is very limited information available of AHU conversion to hydrogen.

C.5 Summary of Conclusions

The following key findings were identified from the initial site survey and safety assessment:

- There are currently no commercially available hydrogen equivalents for the process ovens or fryers.
- A high-level review has revealed the existing natural gas pipework is sufficient to deliver heat capacity required to the end users with hydrogen.
- Ventilation in terms of DSEAR will require further study at the end users to determine full requirements.
- Inventory of hydrogen required is unlikely to impact on COMAH regulations.
- There are no or very limited electrical equipment on the site with ATEX rating of IIC-T1 or better.
- Economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing could be a barrier to implementation.
- There is a mixture of weld and screw fittings in the pipework at the site. At this stage there is no guidance if a screw fitting will be suitable for hydrogen.
- The site will likely need an upskill of both staff and supply chain to operate, design and manage hydrogen safely.

C.6 Further Considerations

The site's natural gas pipework is oversized which may not be the case for other sites. This would incur additional capital expenditure for other sites when converting for hydrogen service. Furthermore, applicability of COMAH regulations should be assessed on a site-by-site basis as the lower-tier threshold may be met if the site includes hydrogen storage.

It is recommended that future studies on switching to hydrogen at similar sites involve early engagement with end user OEMs, further refinement of cost estimate basis, further work to understand the impact of higher moisture content in hydrogen fuel on processes such as ovens, further work on AHU conversion to hydrogen and assessment of suitability of screw fittings or availability of specialised alternatives for hydrogen service.

Appendix D Case Study: Site 3 (Metals 1)

D.1 Project Introduction

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. As part of this work, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. BEIS has appointed AECOM to undertake this study to assess the impact to industrial end users of switching from natural gas to 100% hydrogen.

The objectives of the project were to undertake initial site surveys of seven volunteer industrial sites. These surveys characterise the current site infrastructure, identify and assess the site-specific technical, safety, cost, environmental and implementation considerations of switching from natural gas to 100% hydrogen and provide initial safety evidence and prioritisation that support HSE's considerations on the safety of hydrogen.

D.2 Site Information

The site recycles aluminium and copper and carries out on-site metallurgical analysis.

The site energy consumption has reduced in recent years due to the COVID-19 pandemic which led to limited production. The site is currently operating at reduced capacity. For the purpose of this assessment, it is assumed that the site would continue to operate in this way.

The current natural gas consumption at the site is between 20,000 and 30,000 MWh per year and electricity consumption is around 5,000 MWh per year. End users of natural gas at the site include industrial furnaces, gas torches, space and water heaters and domestic boilers.

Natural gas is supplied to the site via a 2 barg network. The on-site infrastructure consists of:

- 2 barg gas grid connection let down to 190mbarg and passing through metering shed.
- Natural gas foundry main line at 190mbarg.
- Underground line at 190mbarg.
- Let down to end users at 90mbarg from main line with further reduction to 30mbarg occurring further downstream, and.
- Separate supplies at 75mbarg.

The natural gas pipework at the site is all constructed of carbon steel.

D.3 Business Case Evaluation

The three business cases analysed are outlined in Table 15 . These options have been evaluated based on capital cost, operating cost and lifecycle cost. The costs are the differential cost between the decarbonisation case and the existing baseline plant and are based on the assumption of converting the existing infrastructure where possible and avoiding new build.

Table 15. Definition of cases for evaluation- Site 3 (Metals)

	Option 1	Option 2	Option 3
Description of option:	**100% Hydrogen Solution:** All users converted for hydrogen service	**Hybrid Hydrogen Solution:** Select users converted for hydrogen service, others operating on alternative fuel supply	**Best Alternative (non-hydrogen) Solution:** Electrification of users where possible, natural gas where no electric option is available

The capital cost, operating cost and lifecycle cost estimates are presented in Figure 15, Figure 16, and Figure 17 respectively.

Figure 15. Capital cost estimate for business cases evaluated- Site 3 (Metals 1)

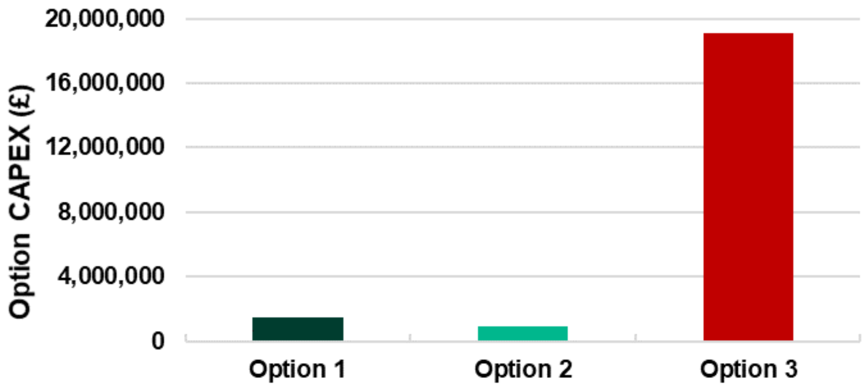


Figure 16. Operating cost estimate for business cases evaluated- Site 3 (Metals 1)

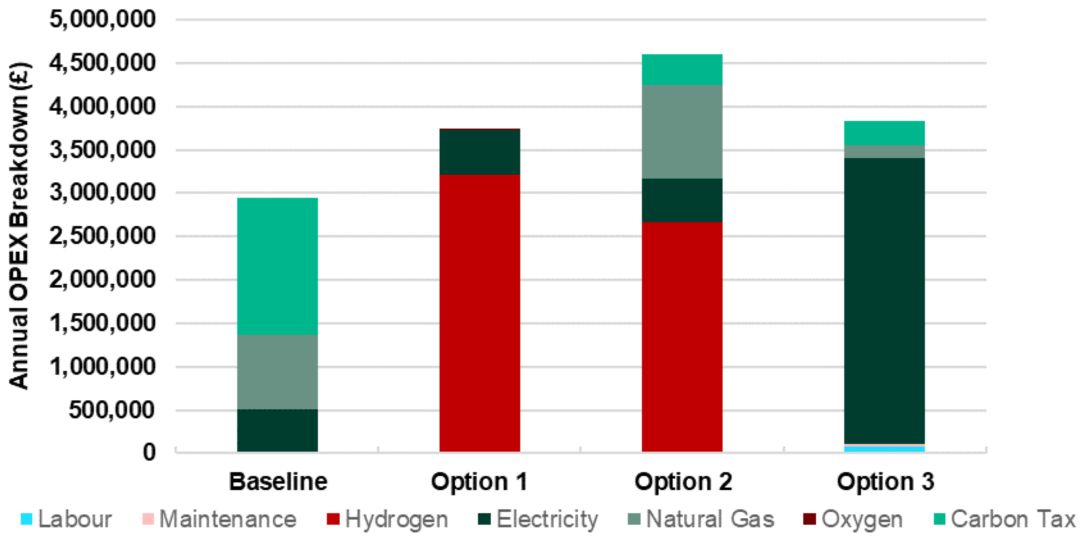
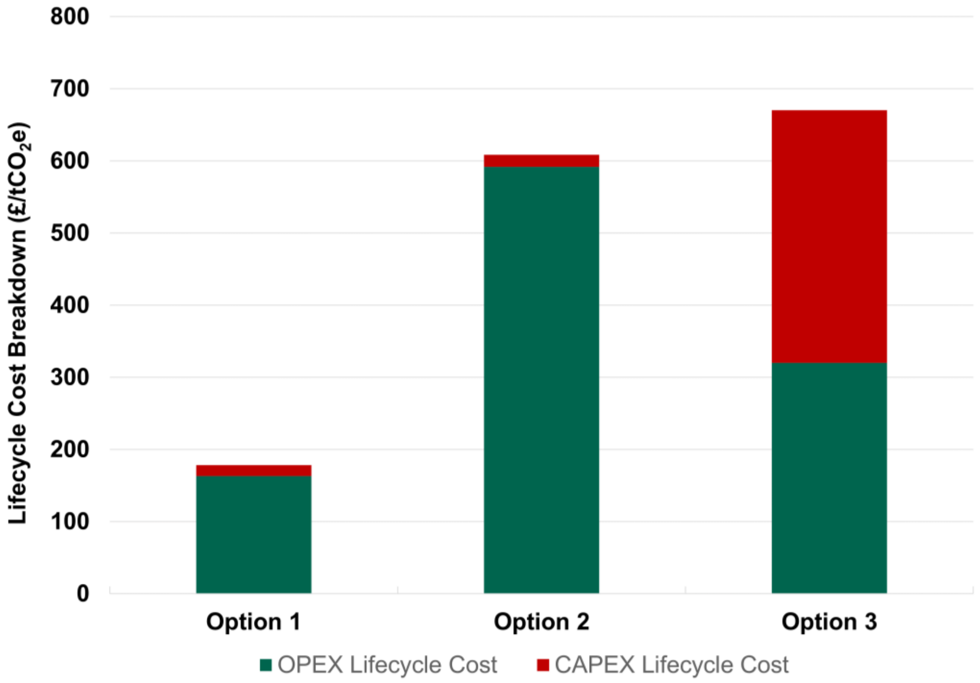


Figure 17. Lifecycle cost estimate for business cases evaluated- Site 3 (Metals 1)



D.4 Technical Challenges of Conversion

Most of the natural gas end users at the site would require major modifications to enable hydrogen service.

At current capacity, the existing natural gas grid connection and most of the natural gas pipework is oversized and would not need replaced for hydrogen service. However, this would not be the case if operating at 100% capacity.

The production of metal requires a high degree of reliability and availability, particularly during the melting of metals onsite. An abrupt loss of gas supply could lead to temperature dropping in the furnaces and the solidification of the molten metal, resulting in costly disruption to output.

Hydrogen fired heat treatment furnaces are in development but are not widely available in the market. The extent of the modifications to the furnaces requires in-depth consultation with the OEMs to evaluate the thermal design or to acquire the data to enable a third party to evaluate the oven and fryer modifications required. As well as determining the extent of any modifications, the theoretical heat transfer and any de-rating required should be evaluated.

During the casting process, molten metal is poured in the casing moulds which are pre-heated by gas fired torches to prevent moisture build up in the moulds and feed channels. The current system of gas torches onsite is not suitable for hydrogen conversion. Further work is required to evaluate the temperature profiles required from the current torches and the ability to maintain the required temperatures on the casting tracks and anywhere molten metal is poured. Gas torches that use hydrogen as a fuel source are commercially available today many of which run on a hydrogen/oxygen mixture. Further work is required to assess the implications of additional oxygen pipes or storage cylinders in the foundry areas where there are open flames and high local temperatures.

There are currently hydrogen boilers being developed and prototyped by several boiler OEMs that could replace the current water heaters and boilers at the site.

D.5 Summary of Conclusions

The following key findings were identified from the initial site survey and safety assessment:

- For certain users, the existing natural gas pipework is insufficient to deliver heat capacity required to the end users after conversion to hydrogen.
- Number of end users of natural gas do not have commercially available hydrogen equivalents.
- Ventilation is generally adequate or can be addressed with minor modifications, however some sections of the gas supply pipework would need to be rerouted to avoid congested regions and significant ignition sources.
- There are no or very limited electrical equipment on the site with ATEX rating of IIC-T1 or better.
- The site will likely need an upskill of both staff and supply chain to operate, design and manage hydrogen safely.
- During initial implementation there is customer concern that the hydrogen supply chain will have lower availability and reliability than the current natural gas supply chain.
- Economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing could be a barrier to implementation.

D.6 Further Considerations

At the current capacity, most of the site's natural gas pipework is oversized which may not be applicable to other sites. This would incur additional capital expenditure for other sites when converting for hydrogen service. However, the rerouting of pipework necessary at this site might not be required for other sites, which could reduce the capital costs.

It is recommended that future studies on switching to hydrogen at similar sites involve early engagement with end user OEMs, further refinement of cost estimate basis, further studies on safety of hydrogen use in furnaces and torches and further work to confirm the compatibility of seals for operation with hydrogen.

Appendix E Case Study: Site 4 (Vehicles)

E.1 Project Introduction

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. As part of this work, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. BEIS has appointed AECOM to undertake this study to assess the impact to industrial end users of switching from natural gas to 100% hydrogen.

The objectives of the project were to undertake initial site surveys of seven volunteer industrial sites. These surveys characterise the current site infrastructure, identify and assess the site-specific technical, safety, cost, environmental and implementation considerations of switching from natural gas to 100% hydrogen and provide initial safety evidence and prioritisation that support HSE's considerations on the safety of hydrogen.

E.2 Site Information

The site manufactures motor vehicles and associated processes including, metal pressing and forming, spot welding, paint coating, injection moulding, axle welding and surface coating, aluminium forging, engine machining, engine assembly and final vehicle assembly. Due to scale of the plant, it has not been feasible to assess the implementation of converting to hydrogen at a whole site level.

The site currently consumes approximately 200,000 MWh of natural gas per year and 100,000 MWh of electricity. This has reduced in recent years through a combination of electronic part shortages and the COVID-19 pandemic.

End users of natural gas at the site include low temperature hot water (LTHW) boilers, air handling units, process ovens, recuperative thermal oxidisers (RTOs) and casting process burners.

The gas supply pressure is regulated to 350mbarg in a metering compound feeding two parallel underground pipelines. These parallel pipelines reach a common header which feeds a line to the paint shop and a second line which supplies another gas network. The on-site distribution infrastructure consists of a 350mbarg supply until regulation at point of use at the gas asset valve train.

E.3 Business Case Evaluation

The three business cases analysed are outlined in Table 16 . These options have been evaluated based on capital cost, operating cost and lifecycle cost. The costs are the differential cost between the decarbonisation case and the existing baseline plant and are based on the assumption of converting the existing infrastructure where possible and avoiding new build.

Table 16. Definition of cases for evaluation- Site 4 (Vehicles)

	Option 1	Option 2	Option 3
Description of option:	**100% Hydrogen Solution:** All users converted for hydrogen service	**Hybrid Hydrogen Solution:** Select users converted for hydrogen service, others replaced with electric alternatives	**Best Alternative (non-hydrogen) Solution:** Electrification of users where possible, natural gas where no electric option is available

The capital cost, operating cost and lifecycle cost estimates are presented in Figure 18, Figure 19, and Figure 20, respectively.

Figure 18. Capital cost estimate for business cases evaluated- Site 4 (Vehicles)

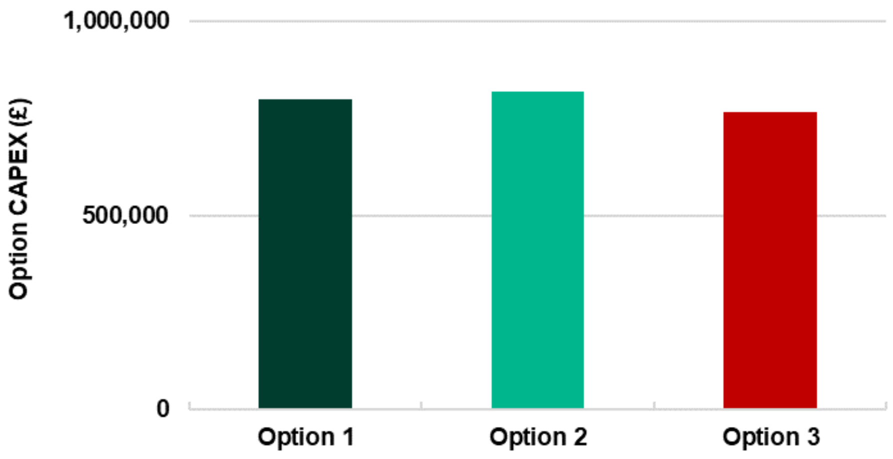


Figure 19. Operating cost estimate for business cases evaluated- Site 4 (Vehicles)

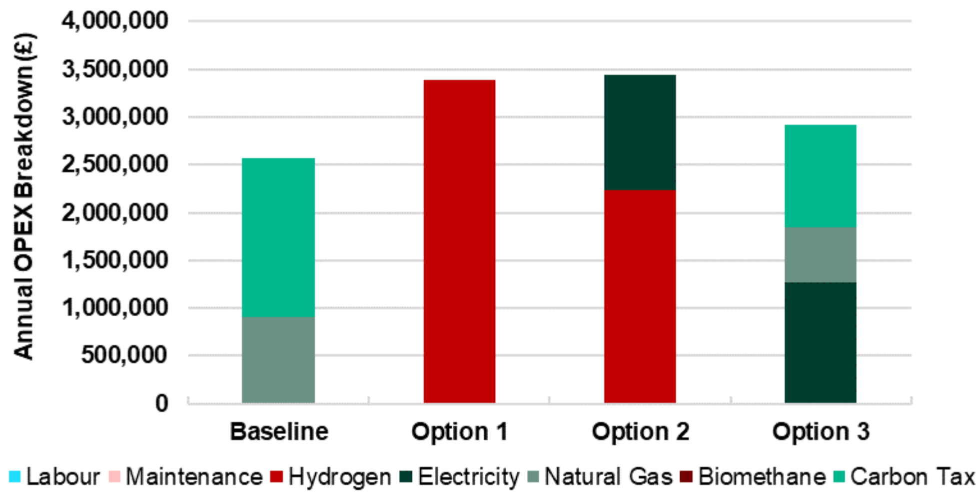
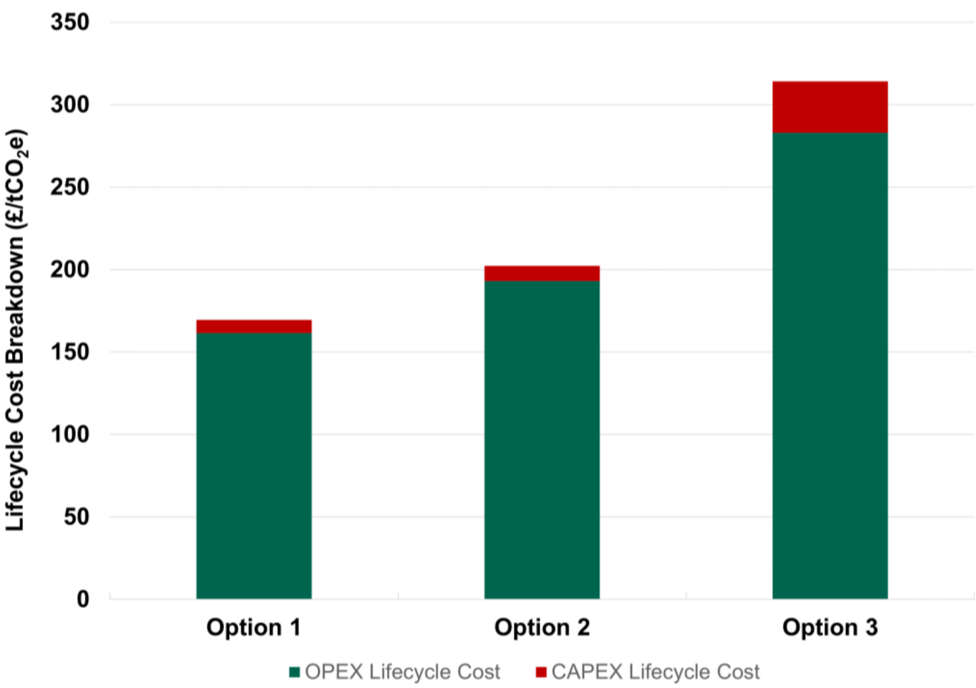


Figure 20. Lifecycle cost estimate for business cases evaluated- Site 4 (Vehicles)



E.4 Technical Challenges of Conversion

The site's natural gas pipework would need major modifications to enable hydrogen service. The natural gas fiscal metering at the site is contained within a secure compound and so the full extent of work required to the metering system is unknown.

All of the natural gas end users at the site are expected to require major modifications to enable hydrogen service.

There are currently hydrogen boilers being developed and prototyped by several boiler OEMs that could replace the current water heaters and boilers at the site.

The ovens' primary process requirement is to evaporate and drive off moisture from the painted items. The circulating hot air is required to be warm enough and have sufficient available saturation to absorb the moisture. For conversion to hydrogen service, the impact of any increase moisture content on the saturation levels of the circulating air must be assessed. Additionally, the change in flame profile may require re-positioning of the burner and the change of fuel characteristics may impact the air flow requirements within the ovens, potentially changing fan sizes and heat duty.

The air handling unit is located just below the roof, with the gas pipework running at high level within the building. There may be a requirement to install localised ventilation above the AHU and pipework infrastructure to allow hydrogen to be dispersed in the event of a leakage.

Further study is required to understand the implementation of hydrogen in terms of the design of the AHU and heat transfer system as this was not accessible during the site survey. There is very limited information available of AHU conversion to hydrogen.

The recuperative thermal oxidisers use natural gas a primary fuel to incinerate the volatile compounds extracted from the paint booths at high temperature. The existing burners can be replaced with a hydrogen equivalent.

E.5 Summary of Conclusions

The following key findings were identified from the initial site survey and safety assessment:

- Due to the large number of natural gas end users, it was not feasible to assess the implementation of converting to hydrogen at a whole site level. Therefore, there may be further technical challenges to address.
- For certain users the existing natural gas pipework is insufficient to deliver heat capacity required to the end users.
- There are no or very limited electrical equipment on the site with ATEX rating of IIC-T1 or better.
- The site will likely need an upskill of both staff and supply chain to operate, design and manage hydrogen safely.
- Inventory of hydrogen required is unlikely to impact on COMAH regulations.
- Number of end users of natural gas do not have commercially available hydrogen equivalents.
- Economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing could be a barrier to implementation.
- Ventilation in terms of DSEAR will require further study at the end users to determine full requirements.

E.6 Further Considerations

This site's natural gas pipework does not have sufficient capacity for hydrogen service and there are no or very limited equipment items on the site with the necessary ATEX rating. The capital cost of hydrogen conversion for other sites may be reduced if the modifications required are not as extensive as they are for this site. Applicability of COMAH regulations should be assessed on a site-by-site basis as the lower-tier threshold may be met if the site includes hydrogen storage.

It is recommended that future studies on switching to hydrogen at similar sites involve early engagement with end user OEMs, further refinement of cost estimate basis, further work to understand the impact of higher moisture content in hydrogen fuel on processes such as ovens and on paint quality and further work on the effects of hydrogen on elastomers and polymers.

Appendix F Case Study: Site 5 (Minerals)

F.1 Project Introduction

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. As part of this work, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. BEIS has appointed AECOM to undertake this study to assess the impact to industrial end users of switching from natural gas to 100% hydrogen.

The objectives of the project were to undertake initial site surveys of seven volunteer industrial sites. These surveys characterise the current site infrastructure, identify and assess the site-specific technical, safety, cost, environmental and implementation considerations of switching from natural gas to 100% hydrogen and provide initial safety evidence and prioritisation that support HSE's considerations on the safety of hydrogen.

F.2 Site Information

The site is an asphalt production plant which consumes between approximately 30,000 and 40,000 MWh of natural gas per year and 2,000 MWh of electricity.

There is a single natural gas end user at the site which is an aggregate dryer.

Natural gas is supplied to the site at an operating pressure of 2 barg.

The on-site infrastructure consists of:

- 2 barg supply header from the site boundary to a 2 barg let-down station and metering shed.
- 2 barg let-down and metering station, consisting of a particulate filter and two control valves fitted in series with independent pressure control instrument loops to let the natural gas down to a pressure of 350 mbarg.
- 350 mbarg distribution header that feeds the asphalt dryer burner, and.
- Low-pressure let-down station reducing the 350 mbarg supply to 300 mbarg using a single slam-shut type regulator.

The natural gas distribution pipework from the connection point is constructed of carbon steel and the remaining length of the pipe to the burner location is MDPE (medium density polyethylene).

The majority of the natural gas distribution pipework is either buried or located outdoors with good ventilation. The metering shed is the only enclosed area with the natural gas distribution pipework.

F.3 Business Case Evaluation

The three business cases analysed are outlined in Table 17 . These options have been evaluated based on capital cost, operating cost and lifecycle cost. The costs are the differential cost between the decarbonisation case and the existing baseline plant and are based on the assumption of converting the existing infrastructure where possible and avoiding new build.

Table 17. Definition of cases for evaluation- Site 5 (Minerals)

	Option 1	Option 2	Option 3
Description of option:	**100% Hydrogen Solution:** End user converted for hydrogen service	**Hybrid Hydrogen Solution:** End user converted for hydrogen service, others biodiesel as back-up fuel	**Best Alternative (non-hydrogen) Solution:** Existing natural gas supply replaced with biomethane

The capital cost, operating cost and lifecycle cost estimates are presented in Figure 21, Figure 22, and Figure 23, respectively.

Figure 21. Capital cost estimate for business cases evaluated- Site 5 (Minerals)

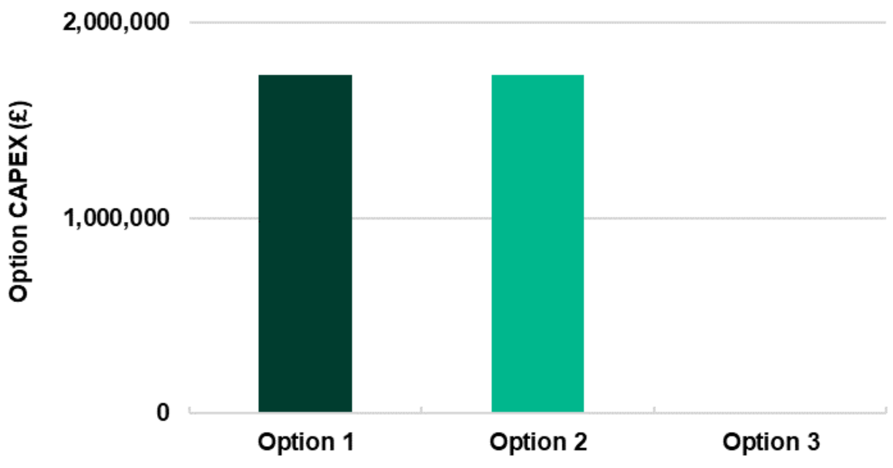


Figure 22. Operating cost estimate for business cases evaluated- Site 5 (Minerals)

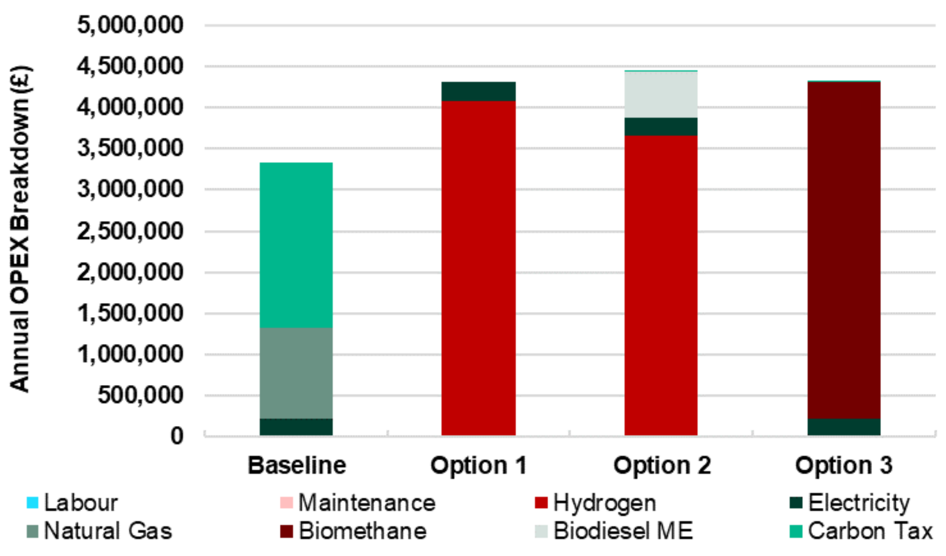
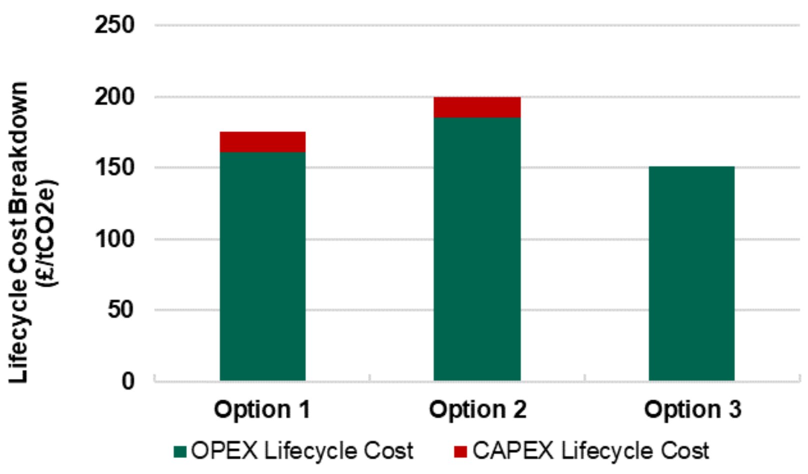


Figure 23. Lifecycle cost estimate for business cases evaluated- Site 5 (Minerals)



F.4 Technical Challenges of Conversion

The site's existing natural gas infrastructure, including grid connection, fiscal metering and pipework, would require major modifications to enable the switch from natural gas to hydrogen.

The operation of the aggregate dryer is critical to the operation of the site and requires a very high degree of reliability and availability, and so the dryer is provided with a dual fuel gas and liquid burner that can fire diesel as a back-up fuel. There is a perceived risk that there will be greater reliance on the back-up systems and increased risk of loss of fuel to the burner when switching to hydrogen service.

Discussions with OEMs found that burners capable of firing up to 100 vol% hydrogen are in development. To be able to achieve flexibility sufficient to be facilitate operation from 0 vol% to 100 vol% hydrogen as well as liquid fuels, multiple burner heads may be required.

The alternative is to retain the dryer liquid burner and continue to use diesel as a back-up as is currently utilised at the site, or switch to using biodiesel or another low carbon liquid fuel such as HVO. A feasible electrical alternative for the dryer could not be identified.

F.5 Summary of Conclusions

The following key findings were identified from the initial site survey and safety assessment:

- Existing natural gas lines do not have sufficient capacity for the increased volume flows associated with hydrogen and will require replacement.
- The site operating procedures and existing safety management systems will require to be updated to reflect hydrogen hazards (e.g., need for tighter ignition control).
- Due to the lack of experience in handling hydrogen, training will be required for personnel to ensure they are suitably trained in the hazard of clear burning flames associated with ignited hydrogen releases and provide emergency teams with infrared (IR) cameras to help detect hydrogen jet fires.
- The venting from the meter shed should reviewed to ensure the hazardous area extent does not impinge with vehicles using the adjacent road.
- There are no or very limited electrical equipment on the site with ATEX rating of IIC-T1 or better.
- Economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing could be a barrier to implementation.

F.6 Further Considerations

This site's natural gas pipework does not have sufficient capacity for hydrogen service and there are no or very limited equipment items on the site with the necessary ATEX rating. The capital cost of hydrogen conversion for other sites may be reduced if the modifications required are not as extensive as they are for this site. However, the majority of the pipework for this site is either buried underground or located outdoors providing adequate ventilation, which may not be the case for other sites. Ventilation requirements should be assessed on a site-by-site basis.

It is recommended that future studies on switching to hydrogen at similar sites involve early engagement with end user OEMs, further refinement of cost estimate basis, further work on the effects of hydrogen on elastomers and polymers and investigation of an alternative design for the bellows connection could be identified which minimises or eliminates the hazardous area extent around the gas connection.

Appendix G Case Study: Site 6 (Metals 2)

G.1 Project Introduction

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. As part of this work, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. BEIS has appointed AECOM to undertake this study to assess the impact to industrial end users of switching from natural gas to 100% hydrogen.

The objectives of the project were to undertake initial site surveys of seven volunteer industrial sites. These surveys characterise the current site infrastructure, identify and assess the site-specific technical, safety, cost, environmental and implementation considerations of switching from natural gas to 100% hydrogen and provide initial safety evidence and prioritisation that support HSE's considerations on the safety of hydrogen.

G.2 Site Information

The site produces metal cans and pails and consumes between 5,000 and 6,000 MWh of natural gas per year and around 3,000 MWh of electricity.

Natural gas end users at the site include process ovens and space and water heaters.

Natural gas is supplied to the site at an operating pressure of 21 mbarg.

The on-site infrastructure consists of:

- 21 mbarg supply header from the site boundary to the metering area, consisting of a gas meter for the building, service isolation and control valves, and a regulator,
- Metered 21 mbarg supply header to tee-off junction which supplies the following:
  - Gas boosters to increase pressure to 75mbarg for one of the process oven, and.
  - All remaining natural gas end users operating at 21mbarg.

The natural gas distribution pipework from the connection point to the metering equipment and throughout the site to the individual end users appears to be carbon steel.

G.3 Business Case Evaluation

The three business cases analysed are outlined in Table 18 Table 18. These options have been evaluated based on capital cost, operating cost and lifecycle cost. The costs are the differential cost between the decarbonisation case and the existing baseline plant and are based on the assumption of converting the existing infrastructure where possible and avoiding new build.

Table 18. Definition of cases for evaluation- Site 6 (Metals 2)

	Option 1	Option 2	Option 3
Description of option:	**100% Hydrogen Solution:** End user converted for hydrogen service	**Hybrid Hydrogen Solution:** Select users converted for hydrogen service, others replaced with electric alternatives	**Best Alternative (non-hydrogen) Solution:** Electrification of all users

The capital cost, operating cost and lifecycle cost estimates are presented in Figure 24, Figure 25, and Figure 26, respectively.

Figure 24. Capital cost estimate for business cases evaluated- Site 6 (Metals 2)

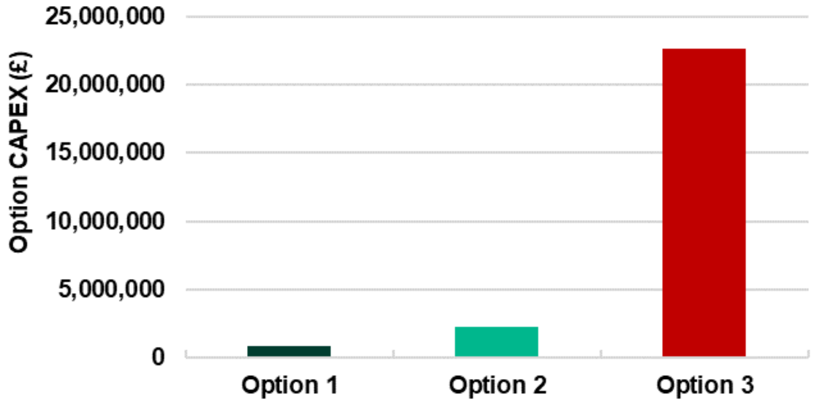


Figure 25. Operating cost estimate for business cases evaluated- Site 6 (Metals 2)

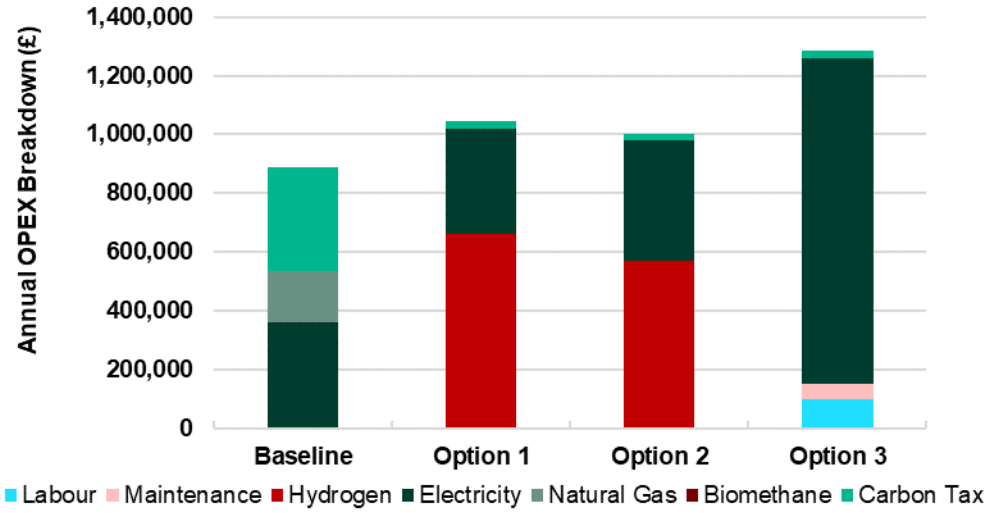
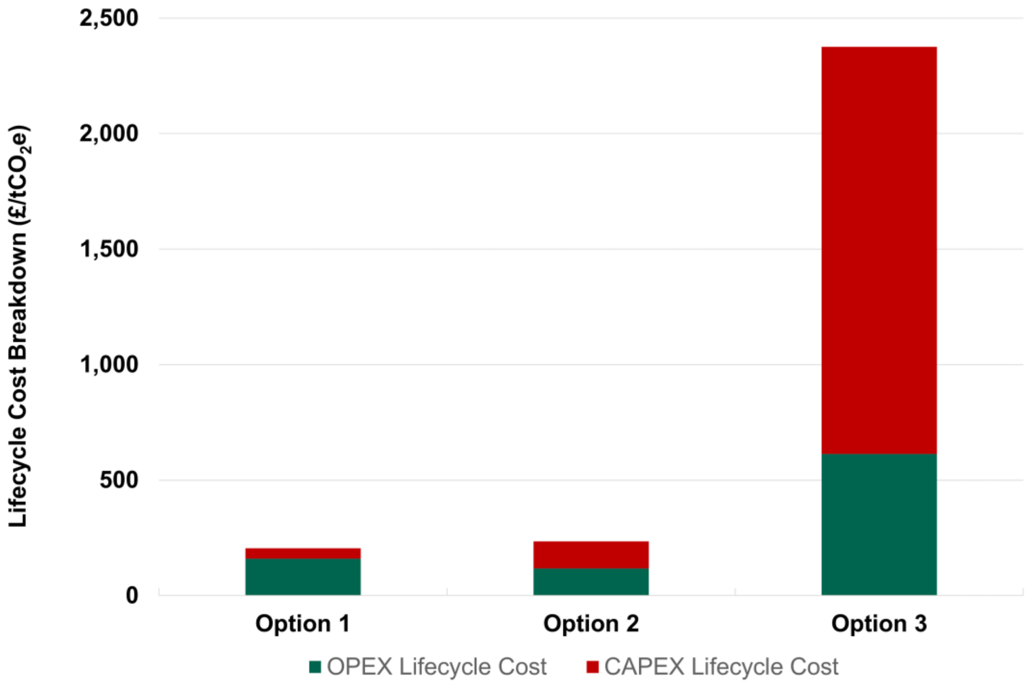


Figure 26. Lifecycle cost estimate for business cases evaluated- Site 6 (Metals 2)



G.4 Technical Challenges of Conversion

The site's grid connection and some of the natural gas pipework would need no change to enable hydrogen service. The natural gas fiscal metering at the site would require to be replaced to cope with the increased flow of hydrogen expected. Gas boosters (supplying the direct fired oven) will require replacement to raise the increased gas flow to the necessary pressure and installation of a new motor with a suitable ATEX rating.

There are currently hydrogen boilers being developed and prototyped by several boiler OEMs that could replace the current water space and water heaters at the site.

The OEM of the process coating oven has made several modifications to the original design, including the installation of a recuperative thermal oxidiser. The burner within the RTO is compatible with a 100% hydrogen fuel as reported within the burner's specification. However, modifications to the flame-eye will be required to ensure that the flame is detected throughout operation.

Due to the differences in flame temperature and emissivity of hydrogen compared to natural gas, the RTO may require some modifications to ensure that a suitable quantity of VOCs are removed to avoid exceeding the site's emission limits as well as providing sufficient heat to the oven's main section. A complete evaluation of the entire oven by the OEM or a third party will need to be investigated to confirm whether the oven will need a major modification during conversion to 100 vol% hydrogen. Modifications may to be required to maintain the NO_x levels at the outlet of the RTO. A potential option is selective catalytic reduction (SCR).

The OEMs of the other process ovens at the site were contacted and stated that the ovens are not currently hydrogen ready and only operate with either natural gas or propane as the fuel source. The burners within these ovens use an air-gas mixer unit attached to each burner to help control the temperature of the oven. These burners are manufactured by the OEMs specifically for their ovens and therefore cannot be easily replaced by another commercially available product with an equivalent thermal output.

G.5 Summary of Conclusions

The following key findings were identified from the initial site survey and safety assessment:

- The coating oven is the largest end user on site and may only require a slight modification to the flame detection system as the existing burner is hydrogen ready. Other process ovens will require further work to develop bespoke designs.
- Some of the natural gas supply lines have insufficient capacity for hydrogen service and will need replaced. The main supply to the site appears to be over-sized and therefore may not need replaced.
- The surveys identified that the natural gas systems typically contain multiple threaded fixtures which are not suitable for hydrogen service and will necessitate replacement.
- There are no or very limited electrical equipment on the site with ATEX rating of IIC-T1 or better.
- Ventilation around the gas boosters is unlikely to be satisfactory for hydrogen. The design will need to be changed to include high integrity seals, or the system redesigned to avoid the use of booster compressors, or the compressor location could be changed.
- The implementation of hydrogen fuel switching may result in significant changes to systems or personnel training.
- Economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing could be a barrier to implementation.

G.6 Further Considerations

Most of this site's natural gas pipework does not have sufficient capacity for hydrogen service and there are no or very limited equipment items on the site with the necessary ATEX rating. Furthermore, this site's natural gas system contains multiple threaded fixtures not suitable for hydrogen service which would need replaced; this might not be applicable to other sites. The capital cost of hydrogen conversion for other sites may be reduced if the modifications required are not as extensive as they are for this site.

It is recommended that future studies on switching to hydrogen at similar sites involve additionally engagement with end user OEMs as well as SCR, hydrogen booster/compressor and infrared oven OEMs, further refinement of cost estimate basis and further work on compatibility of booster compressor seals with hydrogen service.

be reduced if the modifications required are not as extensive as they are for this site. However, the majority of the pipework for this site is either buried underground or located outdoors providing adequate ventilation, which may not be the case for other sites. Ventilation requirements should be assessed on a site-by-site basis.

Appendix H Case Study: Site 7 (Food and Drink 2)

H.1 Project Introduction

The Department for Business, Energy and Industrial Strategy (BEIS) is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. As part of this work, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. BEIS has appointed AECOM to undertake this study to assess the impact to industrial end users of switching from natural gas to 100% hydrogen.

The objectives of the project were to undertake initial site surveys of seven volunteer industrial sites. These surveys characterise the current site infrastructure, identify and assess the site-specific technical, safety, cost, environmental and implementation considerations of switching from natural gas to 100% hydrogen and provide initial safety evidence and prioritisation that support HSE's considerations on the safety of hydrogen.

H.2 Site Information

The site produces malts for the brewing sector. The site consumes between 35,000 and 45,000 MWh of natural gas per year and around 10,000 MWh of electricity.

Natural gas end users at the site include direct fired burners, fluid heaters, roasters, dryers and space and water heaters.

Natural gas is supplied to the site at an operating pressure of 2 barg. The on-site infrastructure consists of:

- 2 barg supply header from the site boundary to the metering shed.
- 2 barg let-down station, consisting of two parallel let-downs, a lead and a lag. Each consist of a particulate filter and a single diaphragm type regulator with associated slam shut valve to let the natural gas down to a set pressure, 165 mbarg for the lead stream and 148 mbarg for the lag stream.
- Several low-pressure let-downs reducing the 165 mbarg stream to lower pressures, and.
- Multiple 100 mbarg and 120 mbarg supply lines to different end users.

The existing pipework is a made of a mixture of materials: visual identification indicates that the older lines are made of carbon steel operated at low pressures (up to 165 mbarg) and new lines made of EN1.4401 (stainless steel equivalent to AISI 316) operated at low pressures (less than 140 mbarg).

H.3 Business Case Evaluation

The two business cases analysed are outlined in Table 19 . These options have been evaluated based on capital cost, operating cost and lifecycle cost. The costs are the differential cost between the decarbonisation case and the existing baseline plant and are based on the assumption of converting the existing infrastructure where possible and avoiding new build.

Table 19. Definition of cases for evaluation- Site 7 (Food & Drink 2)

	Option 1	Option 2
Description of option:	**100% Hydrogen Solution:** End user converted for hydrogen service	**Best Alternative (non-hydrogen) Solution:** All users replaced with electric alternatives

The capital cost, operating cost and lifecycle cost estimates are presented in Figure 27, Figure 28, and Figure 29, respectively.

Figure 27. Capital cost estimate for the business cases evaluated- Site 7 (Food & Drink 2)

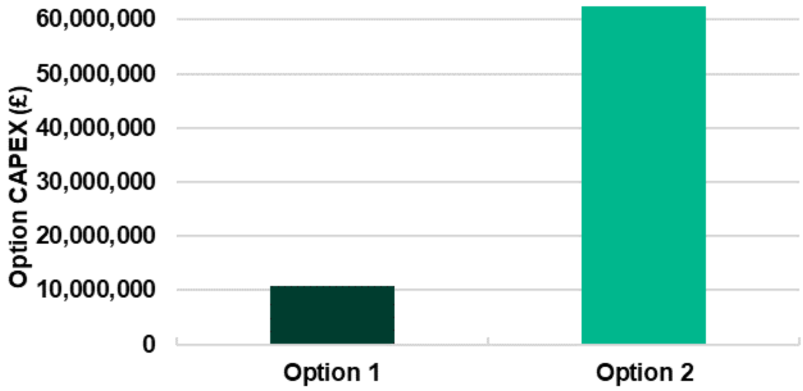


Figure 28. Operating cost estimate for the business cases evaluated- Site 7 (Food & Drink 2)

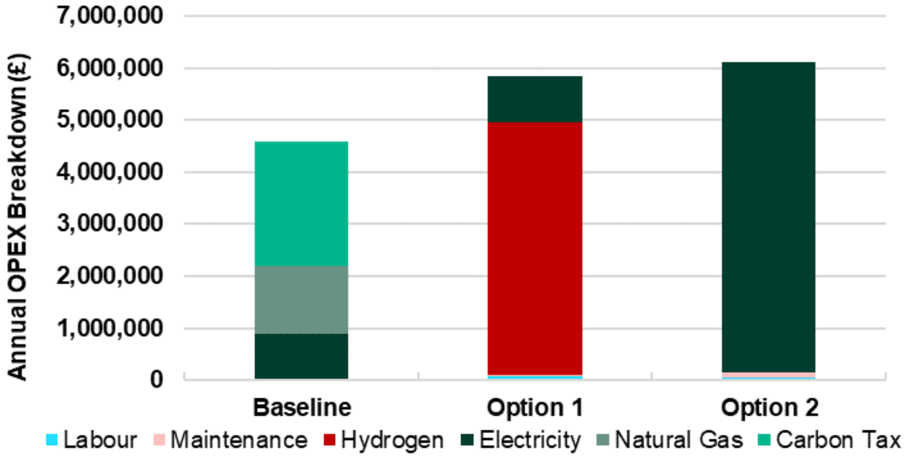
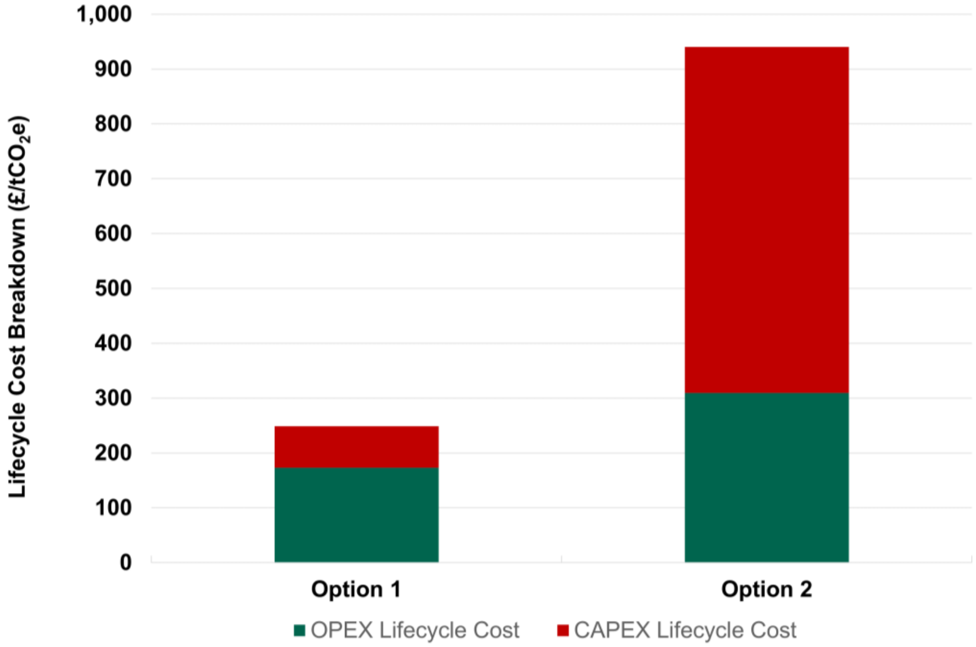


Figure 29. Lifecycle cost estimate for the business cases evaluated- Site 7 (Food & Drink 2)



H.4 Technical Challenges of Conversion

The site's existing natural gas infrastructure, including grid connection, fiscal metering and pipework, would require major modifications to enable the switch from natural gas to hydrogen. Re-routing of pipework and relocation of pressure let-downs externally would be required to limit impact from increased severity of hydrogen leaks.

Major modifications would need to be made to the natural gas end users to convert to hydrogen, in most instances further work is required to understand the full extent of modifications required.

The operation of the major natural gas users is critical to the operation of the site and requires a high degree of reliability and availability. The abrupt loss of fuel to the burners will result in a shutdown of production. Extended outages of more than a couple of hours will result in a loss of product batches with high associated costs for removal and disposal of the spoilt product and cleaning of equipment. There is a perceived risk that there will be increased risk of loss of fuel to the burners when using hydrogen service interrupting plant operation which would have a commercial impact.

There are currently hydrogen boilers being developed and prototyped by several boiler OEMs that could replace the current water space and water heaters at the site.

Discussions with OEMs found that burners capable of firing up to 100 vol% hydrogen are in development. To be able to achieve flexibility sufficient to be facilitate operation from 0 vol% to 100 vol% hydrogen as well as liquid fuels, multiple burner heads may be required.

Hydrogen ready oil heaters and dryers of the size and duty required at the site are currently not available. It may be feasible to retrofit a hydrogen burner to the existing Hot Oil Boiler or dryer as hydrogen burners of the required duty are available; however, the requirements will be unit specific and likely extensive and expensive.

Hydrogen ready roasters of the size and duty of those installed are not currently commercially available. However, contact has been made with the roasters OEM who have indicated that they are developing a hydrogen roaster.

The site has raised concerns regarding increased NOx emissions in the roasters' burner's combustion gases. NOx can react with compounds within the malt to form the highly hepatotoxic and carcinogenic compound N-Nitrosodimethylamine (NDMA). There is a perceived risk that there could be an increased chance of contamination of the malt product with NDMA from leakage of combustion gases via seals and cracks in equipment. However, the roasters OEM were confident that partial combustion of natural gas posed greater risk than the gases from hydrogen firing. Further work is required to establish if NOx level changes from switching to hydrogen lead to changes in the amount of NDMA formation in the malt product under realistic operational conditions.

H.5 Summary of Conclusions

The following key findings were identified from the initial site survey and safety assessment:

- Existing natural gas lines are sized for natural gas volumetric flows and will be undersized for the hydrogen service and necessitate replacement.
- Existing natural gas routing is not generally suitable or best practice for hydrogen. Lines should be re-routed to minimise internal pipe runs and let-down stations relocated externally and set to 100 mbarg or lower where possible to minimise hydrogen pressure and leak sources within buildings.
- There are no or very limited electrical equipment on the site with ATEX rating of IIC-T1 or better.
- Ventilation in terms of DSEAR and SR25 is inadequate in a number of locations for hydrogen service but can be addressed with relatively minor modifications to increase ventilation.
- The implementation of hydrogen fuel switching will require some modifications to systems and personnel training. Standard Operating Practices and Risk Assessments and Method Statements will need to be updated and staff will need to be trained for hydrogen hazards.
- Economics of conversion to hydrogen including initial capital expenditure and the uncertainty in hydrogen pricing could be a barrier to implementation.

H.6 Further Considerations

Most of this site's natural gas pipework does not have sufficient capacity for hydrogen service and there are no or very limited equipment items on the site with the necessary ATEX rating. The capital cost of hydrogen conversion for other sites may be reduced if the modifications required are not as extensive as they are for this site.

It is recommended that future studies on switching to hydrogen at similar sites involve additionally engagement with roaster and burner OEMs, further refinement of cost estimate basis, further analysis on explosion relief on combustion equipment and investigation of efficiency impacts to drying processes from additional water vapour present from hydrogen combustion.

Appendix I Safety Considerations

I.1 Consequence Modelling

The consequence modelling performed is high level and was designed to provide a scoping assessment of consequences for credible scenarios onsite involving hydrogen. Applying these results for other site configurations in a generic way without due regard to the limitations and modelling assumption listed below could result in an incorrect interpretation of the magnitude of a hazard. Specific consequence modelling for a site would be required to determine if additional risk controls are required to reduce risks to ALARP.

Generic consequence modelling has been performed for a range of system pressures and indicative hole sizes. Hazard ranges for each hazardous outcome (e.g., jet fire, flash fire and explosion) have been calculated within Phast 8.61. Version 8.61 of Phast specifically includes a number of model improvements to better represent the consequences of hydrogen releases, these improvements include:

- Miller Jet Fire Model: A specific jet fire model developed for hydrogen. The model provides a better fit the experimental findings of large-scale hydrogen jet fires versus the existing correlations used by hydrocarbon (e.g., natural gas) jet fires (e.g., cone models developed by Chamberlain or Johnson).
- Unified Dispersion Model (UDM): A number of improvements have been made to the Phast UDM model to better account for the buoyancy effects of hydrogen releases, in particular for initially dense releases.

The following key assumptions have been made in the consequence modelling:

1. Releases are modelled at a nominal 1m elevation in typical ambient conditions of D5 and F2 weather with an UK average air temperature of ~10°C.
2. Jet fire modelling for natural gas cases uses the “Cone Model” within Phast and for hydrogen cases uses the “Miller Model” which was specifically developed for hydrogen fires.
3. Outdoor dispersion modelling is based on un-impinged momentum dominated dispersion. This is considered the most appropriate for pressurised gaseous releases from gas distribution systems which tend to have highly directional jet releases.
4. For explosion modelling it has been cautiously assumed that the entire flammable volume contributes to an explosion event. For hydrogen, a cautious assignment of TNO multi-energy model (MEM). Curve 8 (peak overpressure of 2 bar) has been selected to represent the upper range of explosion overpressures observed experimentally, for hydrogen deflagrations in congested regions. At concentrations >18% H_2 in air there is an increased risk of Deflagration to Detonation Transition (DDT) with can result in peak overpressures >10 bar (TNO curve 10). Hydrogen detonations can occur outside of equipment or enclosures and are more likely to occur than for natural gas due to a much lower initiation energy for detonation. The conditions under which a DDT would occur are complex and therefore excluded from this high level modelling. Using TNO curve 8 is considered sufficiently cautious to represent the consequences of a DDT as TNO curves 10 and 8 converge to give the same overpressure levels within a short distance of the source explosion and a 2 bar source explosion is sufficient to cause catastrophic damage of all structures considered in the study. For Natural Gas a TNO MEM Curve 6 (peak overpressure of 0.5 bar) has been selected to represent a Natural Gas explosions within a congested region.
5. For enclosures and buildings, a cautious assumption of stoichiometric concentration within the volume is taken as a worst case consequence for both hydrogen and NG releases respectively. To account for buoyancy driven stratification of gas, the enclosed volume is assumed to be 66% filled for hydrogen and 80% filled for methane as recommended in the Hy4Heat WP7 Consequence Modelling report.

Jet Fire Results

The results of the consequence modelling for jet fires are shown in Table 20 .

Table 20. Jet fire hazard ranges for hydrogen vs natural gas releases

Scenario		Jet Fires								
Pressure	Hole size (mm)	Flame Length (m)		Change from NG	Distance to Thermal Flux - 37.5 kW/m² (m)		Change from NG	Distance to Thermal Flux - 6.3 kW/m² (m)		Change from NG
		H_2	NG	%	H_2	NG	%	H_2	NG	%
25 mbarg	0.561	0.1	0.1	-2%	0.1	0.1	-2%	0.1	0.1	-2%
25 mbarg	5	0.7	0.9	-17%	0.7	0.9	-17%	0.7	0.9	-17%
25 mbarg	25	3.3	3.5	-6%	3.3	3.5	-6%	3.5	3.9	-10%
50 mbarg	0.561	0.1	0.1	-6%	0.1	0.1	-6%	0.1	0.1	-6%
50 mbarg	5	1	0.9	8%	1	0.9	8%	1.2	0.9	33%
50 mbarg	25	3.2	3.9	-17%	3.2	3.9	-17%	3.7	4.2	-12%
150 mbarg	0.561	0.1	0.1	-9%	0.1	0.1	-9%	0.1	0.1	-9%
150 mbarg	5	0.9	0.9	0%	0.9	0.9	0%	1.1	0.9	27%
150 mbarg	25	3.7	4.4	-16%	3.7	4.4	-16%	4.6	4.7	0%
300 mbarg	0.561	0.2	0.1	79%	0.2	0.1	79%	0.2	0.1	79%
300 mbarg	5	0.9	1	-3%	0.9	1	-3%	1.2	1	22%
300 mbarg	25	4.1	4.5	-9%	4.1	4.5	-9%	5.4	4.5	20%
300 mbarg	100	14.1	15.6	-10%	14.1	15.6	-10%	20	19.5	2%
300 mbarg	250	31.6	30.7	3%	31.6	33.4	-5%	45.9	43.8	5%
1.5 barg	0.561	0.2	0.2	-14%	0.2	0.2	-14%	0.2	0.2	-14%
1.5 barg	5	1.3	1.3	-7%	1.5	1.3	11%	1.7	1.3	24%
1.5 barg	25	5.5	5.5	1%	5.7	5.5	4%	8	6.2	28%
1.5 barg	100	19.3	19.9	-3%	20.5	20.6	-1%	30.3	26.8	13%
1.5 barg	250	43.6	44.2	-1%	46.2	48.5	-5%	70.6	66.9	6%
3.0 barg	0.561	0.2	0.2	-15%	0.2	0.2	-15%	0.2	0.2	-15%
3.0 barg	5	1.5	1.6	-7%	1.7	1.6	7%	2.1	1.6	25%
3.0 barg	25	6.7	6.7	0%	7	6.7	5%	10	7.8	28%
3.0 barg	100	23.4	23.9	-2%	25.2	25.7	-2%	37.6	33.4	13%
3.0 barg	250	53	53.3	-1%	57.2	59.8	-4%	87.6	83.3	5%
6.0 barg	0.561	0.2	0.3	-15%	0.2	0.3	-15%	0.2	0.3	-15%
6.0 barg	5	1.9	2.1	-7%	2.2	2.1	6%	2.6	2.1	26%
6.0 barg	25	8.5	8.5	0%	9.1	8.5	7%	13	10.2	27%
6.0 barg	100	29.7	30.1	-1%	32.2	33.3	-3%	48.2	44	10%
6.0 barg	250	67.2	66.9	0%	73	76.4	-5%	112.1	108.4	3%

Hazard ranges to lower flux levels, such as 6.3 kW/m² are predicted to be larger for hydrogen than an equivalent natural gas scenario. Conversely, for higher flux levels, such as 37.5 kW/m² the differences in hazard range are reduced for natural gas. This contrary conclusion is understood to be a direct effect of the different jet fire modelling approaches using Phast 8.61.

Flash Fire Results

The results of the consequence modelling for flash fires are shown in Table 21 .

Table 21. Flash fire hazard ranges for hydrogen vs natural gas releases

Scenario		Flash Fires					
Pressure (barg)	Hole size (mm)	Downwind Distance to Half–LFL (m)		Change from NG	Max Cloud width to Half–LFL (m)		Change from NG
		H_2	NG	%	H_2	NG	%
25 mbarg	0.561	N/A	N/A	N/A	N/A	N/A	N/A
25 mbarg	5	1.4	0.7	92%	0.21	0.08	170%
25 mbarg	25	4.2	2.7	55%	0.71	0.34	107%
50 mbarg	0.561	0.2	<0.1	N/A	0.03	0.01	N/A
50 mbarg	5	1.5	1	48%	0.23	0.08	186%
50 mbarg	25	5	3	66%	0.82	0.36	127%
150 mbarg	0.561	0.3	<0.1	N/A	0.03	0.01	N/A
150 mbarg	5	1.8	1.1	62%	0.25	0.09	185%
150 mbarg	25	6.7	3.6	86%	1.01	0.39	157%
300 mbarg	0.561	0.3	<0.1	N/A	0.03	0.01	N/A
300 mbarg	5	2	1.2	74%	0.26	0.09	184%
300 mbarg	25	8	4	100%	1.15	0.42	174%
300 mbarg	100	27.9	18.2	53%	3.91	1.88	108%
300 mbarg	250	54.6	53.3	2%	7.34	4.98	48%
1.5 barg	0.561	0.4	<0.1	0%	0.04	0.01	N/A
1.5 barg	5	2.9	1.4	114%	0.34	0.11	199%
1.5 barg	25	13.4	5.4	148%	1.67	0.53	214%
1.5 barg	100	51.7	28.5	81%	5.66	2.69	111%
1.5 barg	250	98.2	90.9	8%	10.93	7.68	42%
3.0 barg	0.561	0.5	<0.1	N/A	0.05	0.01	N/A
3.0 barg	5	3.6	1.5	136%	0.41	0.13	203%
3.0 barg	25	18.2	6.7	172%	2.12	0.64	231%
3.0 barg	100	68.4	37.3	83%	6.98	3.47	101%
3.0 barg	250	127.2	120.7	5%	13.51	9.92	36%
6.0 barg	0.561	0.7	<0.1	N/A	0.07	0.01	N/A
6.0 barg	5	4.7	1.8	154%	0.52	0.17	211%
6.0 barg	25	25.1	8.8	186%	2.8	0.83	239%
6.0 barg	100	89.5	52.7	70%	8.83	4.8	84%
6.0 barg	250	164.8	168.7	-2%[37]	16.98	13.41	27%

[37] For larger hole sizes the difference between maximum flash fire extents is reduced but the footprint (i.e., total affected area) of the hydrogen cloud remains greater than the equivalent Natural Gas scenario due to an increased cloud width, reflecting the increased volumetric flow of hydrogen.

Explosions Results

The results of the consequence modelling for explosions in external congested regions and enclosures and buildings are shown in Table 22 and Table 23 , respectively.

Table 22. Explosion overpressure hazard ranges for H2 vs NG releases – external congested region

Scenario		Explosions								
Pressure (barg)	Hole size (mm)	Explosion diameter to 0.5 barg overpressure (m)		Change from NG	Explosion diameter to 0.35 barg overpressure		Change from NG	Explosion diameter to 0.17 barg overpressure		Change from NG
		H_2	NG	%	H_2	NG	%	H_2	NG	%
25 mbarg	0.561	N/A[38]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
25 mbarg	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
25 mbarg	25	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50 mbarg	0.561	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50 mbarg	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50 mbarg	25	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
150 mbarg	0.561	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
150 mbarg	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
150 mbarg	25	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
300 mbarg	0.561	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
300 mbarg	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
300 mbarg	25	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
300 mbarg	100	16.0	4.4	266%	19.5	8.4	131%	31.1	16.2	131%
300 mbarg	250	39.3	13.0	202%	47.9	25.2	91%	76.4	48.1	91%
1.5 barg	0.561	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1.5 barg	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1.5 barg	25	5.7	N/A	N/A	7.0	N/A	N/A	11.1	N/A	N/A
1.5 barg	100	24.9	5.7	341%	30.4	10.9	178%	48.5	20.9	178%
1.5 barg	250	59.1	17.2	244%	72.2	33.2	117%	115.0	63.6	117%
3.0 barg	0.561	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
3.0 barg	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
3.0 barg	25	7.0	N/A	N/A	8.6	N/A	N/A	13.6	N/A	N/A
3.0 barg	100	31.1	7.0	344%	38.0	13.6	180%	60.5	26.0	180%
3.0 barg	250	73.9	21.3	248%	90.2	41.1	119%	143.8	78.7	119%
6.0 barg	0.561	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6.0 barg	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6.0 barg	25	9.4	N/A	N/A	11.5	N/A	N/A	18.3	N/A	N/A
6.0 barg	100	42.0	9.5	340%	51.2	18.4	178%	81.6	35.3	178%
6.0 barg	250	94.7	28.0	238%	115.7	54.2	114%	184.3	103.7	114%

[38] N/A indicates where an explosion overpressure was not predicted due to a very small vapour cloud size.

Table 23. Explosion overpressure hazard ranges for H2 vs NG releases – enclosures and buildings

Scenario	Explosions								
Pressure (barg)	Explosion diameter to 0.5 barg overpressure (m)		Change from NG	Explosion diameter to 0.35 barg overpressure		% Change from NG	Explosion diameter to 0.17 barg overpressure		% Change from NG
	H_2	NG	%	H_2	NG	%	H_2	NG	%
Small Enclosure ($1\ m^3$)	2.8	1.4	100%	3.4	2.7	126%	5.4	5.2	5%
Medium Enclosure ($10\ m^3$)	5.8	3.0	92%	7.0	5.8	63%	11.2	11.1	1%
Large Enclosure ($100\ m^3$)	12.4	6.5	92%	15.2	12.5	63%	24.2	24.0	1%
Small Building ($1,000\ m^3$)	26.8	13.9	92%	32.7	27.0	63%	52.1	51.6	1%
Medium Building ($5,000\ m^3$)	45.8	23.8	92%	55.9	46.1	63%	89.1	88.3	1%
Large Building ($10,000\ m^3$)	57.7	30.0	92%	70.4	58.1	63%	112.2	111.3	1%

I.2 DSEAR Assessment

The results for the DSEAR assessment for each site are presented in Table 24 to Table 29Table 29 .

The location descriptions have been simplified and the tables reordered to not match the same order as the case studies in order for the sites to remain anonymous.

The tables should be read noting the following assumptions that were made as part of the calculations:

- The site is designed, built and maintained in accordance with good industry practice.
- The site is not located in a coastal location or close to other sources that may trigger consideration of adverse conditions as defined in IGEM 25.
- It is noted that the IGEM 25 hydrogen supplement is marked as “Draft for comment”. It is assumed that there will be no major revisions to this document.
- All sources of Natural Gas on the site will be replaced with pure Hydrogen at similar operating conditions (i.e., pressure and temperature).
- Calculated values are based on hydrogen at the same temperatures and pressures as current natural gas lines.
- All current classifications are calculated according to IGEM 25.
- Calculated extent is from each flange, valve & fitting etc. only. It does not apply to welded pipework.

Table 24. Summary of Classifications and Extents A

Location	Current Classification	Current Extent	Calculated (H_2) Classification	Calculated (H_2) Extent
Enclosures / Buildings				
Meter House	Zone 1	Entire enclosure	Zone 0	Entire enclosure
Confined regions (e.g., behind transformers)	Zone 2	0.5 m	Zone 2	1.5 m
Unconfined regions	Zone 2	NE	Zone 2	NE
Gas regulator enclosure	Zone 0	Entire enclosure	Zone 0	Entire enclosure
Confined regions (e.g., flexible hose)	Zone 2	0.5 m	Zone 2	1.5 m
Unconfined regions	Zone 2	NE	Zone 2	NE
Workshop	Zone 2	0.75 m (>100 mbarg) NE (< 100mbarg	Zone 0	Entire enclosure
Pressure Relief Vents				
Metering pressure relief vent (creep relief)	Zone 1 Zone 2	X_S = 0.5 m X_C = 1.37m X_R = 2.5m X_H = 2m Downwash = 0.85m	Zone 1 Zone 2	X_S = 1 m X_C = 1.41m X_R = 3.5m X_H = 2m Downwash = 0.85m
Pressure relief vent (creep relief)	Zone 1 Zone 2	X_S = 0.5 m X_C = 0.83 m X = 2 m	Zone 1 Zone 2	X_S = 1 m X_C = 0.85 m X = 2.5 m

Table 25. Summary of Classifications and Extents B

Location	Current Classification	Current Extent	Calculated (H_2) Classification	Calculated (H_2) Extent
Enclosures / Buildings				
Metering Station – Unregulated	Zone 2	Entire enclosure	Zone 2	Entire enclosure
Metering Station – Regulated	Zone 2	NE	Zone 2	NE
Boiler House	Zone 2	NE	Zone 2	NE
Burner Enclosure	Zone 2	NE	Zone 2	NE
Burner Enclosure	Zone 2	NE	Zone 1	Entire enclosure
AHUs	Zone 2	NE	Zone 2	NE
Ovens	Zone 2	NE	Zone 2	NE
Gas supply	Zone 2	NE	Zone 2	NE
Pressure Relief Vents				
Meter shed - vent	Zone 1 Zone 2	X_s = 0.5 m X_r = 3 X_h = 7m Downwash = 1.60m	Zone 1 Zone 2	X_s = 1 m X_r = 7.5 X_h = 6m Downwash = 3.23m
Outdoors				
Gas inlet	Zone 2	0.5	Zone 2	1.5
Gas inlet	Zone 2	NE	Zone 2	NE
RTO	Zone 2	NE	Zone 2	NE
RTO	Zone 2	NE	Zone 2	NE

Table 26. Summary of Classifications and Extents C

Location	Current Hazardous Area Classification	Current Extent	Calculated (H_2) Hazardous Area Classification	Calculated (H_2) Extent
Enclosures				
Metering Shed - Indoor	Zone 1	Entire enclosure	Zone 0	Entire enclosure
Pressure Relief Vents				
Metering Shed – Vent	Zone 1 Zone 2	X_s = 0.5 m X_c = 2m X_r = 2.5m X_h = 2m Downwash = 0.85m	Zone 1 Zone 2	X_s = 1 m X_c = 1.65m X_r = 3.5m X_h = 2m Downwash = 0.85m
Gas Supply Systems				
Gas supply to Burner (outdoors)	Zone 2	NE	Zone 2	NE
Gas Bellows connected to Burner (adverse and congested conditions)	Zone 2	1.5m	Zone 2	4m

Table 27. Summary of Classifications and Extents D

Location	Current Hazardous Area Classification	Current Extent	Calculated (H_2) Hazardous Area Classification	Calculated (H_2) Extent
Gas Distribution Systems				
Metering station (outdoors)	Zone 2	2.5 m	Zone 2	1.5 m
Gas in below grade pipe-trenches	Zone 1	Entire pipe-trench	Zone 2	2.0 m
Gas in elevated pipe-racks	Zone 2	2.5 m around elevated pipe-rack	Zone 2	1.5 m
Let-down Station (outdoors)	Zone 2	2.5 m	Zone 2	1.5 m
Boiler house PCVs (outdoors)	Zone 2	1-3 m	Zone 2	2.0 m
Enclosures				
Boiler House (Indoors)	Zone 2	NE	Zone 2	NE
Boiler Room	Zone 2	NE	Zone 1	Entire room
Oven Room	Zone 2	NE	Zone 2	NE

Table 28. Summary of Classifications and Extents E

Location	Current Classification	Current Extent	Calculated (H_2) Classification	Calculated (H_2) Extent
Enclosures / Buildings				
Metering - Indoors	Zone 2	150mm	Zone 2	150mm
Main Process Area - Indoors	Zone 2	NE	Zone 2	NE
Gas Boosters	Zone 2	NE	Zone 2	2 m

Table 29. Summary of Classifications and Extents F

Location	Current (NG) Classification	Current Extent	Calculated (H_2) Classification	Calculated (H_2) Extent
Enclosures				
Meter shed	Zone 1	Entire enclosure	Zone 0	Entire enclosure
Process equipment house	Zone 2	0.5m	Zone 2	1.5m
Burners	Zone 2	NE	Zone 2	NE
Process equipment house	Zone 2	0.5m	Zone 2	1.5m
Process equipment house	Zone 2	NE	Zone 2	NE
Process equipment house	Zone 2	NE	Zone 2	NE
Process equipment house	Zone 2	NE	Zone 2	NE
Building	Zone 2	NE	Zone 2	NE
Engineering	Zone 2	NE	Zone 2	1.5m
Pressure Relief Vents				
Meter shed - vent	Zone 1 Zone 2	X_s = 0.5 m X_c = 1.37m X = 4.5m	Zone 1 Zone 2	X_s = 1 m X_c = 1.41m X = 3m
Outdoors				
Gas Main	Zone 2	NE	Zone 2	NE
Gas Supply	Zone 2	NE	Zone 2	NE

Summary of Classifications and Extents G

Location	Current Classification	Current Extent	Calculated (H_2) Classification	Calculated (H_2) Extent
Enclosures / Buildings				
Metering station - Indoor	Zone 1 Zone 2	Entire Enclosure 0.5m from upper ventilation	Zone 1 Zone 2	Entire Enclosure 1.5m from upper ventilation
Gas manifolds and boilers mezzanine	Zone 2	NE	Zone 2	NE
Main Process Area - Indoor	Zone 2	NE	Zone 2	NE
Acoustic enclosures	Zone 0 Zone 1	Entire Enclosure 0.5m from openings	Zone 0 Zone 1	Entire Enclosure 0.75m from openings
Gas supply cabinets	Zone 2	NE	Zone 2	NE
Pressure Relief Vents				
Metering station - vent	Zone 1 Zone 2	X_s = 0.5 m X = 3.5 m	Zone 1 Zone 2	X_s = 1 m X = 2.5 m

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