Industrial Fuel Switching Market Engagement Study

Final report

for

Business, Energy & Industrial Strategy Department

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A list of all the contributing organisations is included in the Appendix.

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1 Executive summary

1.1 The need for industrial fuel-switching

Over the next 20-30 years, the need for deep decarbonisation at a national level will drive significant changes to the gas grid. By 2050, national efforts to meet emissions reduction targets could potentially result in conversion to a high blend (or 100%) hydrogen grid, or alternatively could see localised decommissioning of the gas grid and a move towards electrification and decentralised energy supply[1].

Many UK industrial sites rely on energy supply from the gas grid. To remain competitive in UK and international markets, these industries will need to adapt to these possible changes to national infrastructure and fuel supply, and even industries not reliant on the gas grid (i.e. those that currently meet their energy requirements through use of coal or oil) will need to meet decarbonisation requirements.

Although some industrial sectors are already beginning to shift towards alternative fuels, some of the technology options for switching energy-intensive processes away from current fossil fuel energy sources are not yet commercially available, and some require further optimisation to become technically feasible. The Department for Business, Energy and Industrial Strategy (BEIS) has launched an Industrial Fuel Switching Innovation Competition to bring these technologies closer to commercial application. For the first phase of this Competition, BEIS have commissioned Element Energy and Jacobs to explore the potential for industries to switch to biomass, hydrogen and electric technologies and identify the constraints and opportunities to realise this potential.

1.2 Overall potential for industrial fuel switching

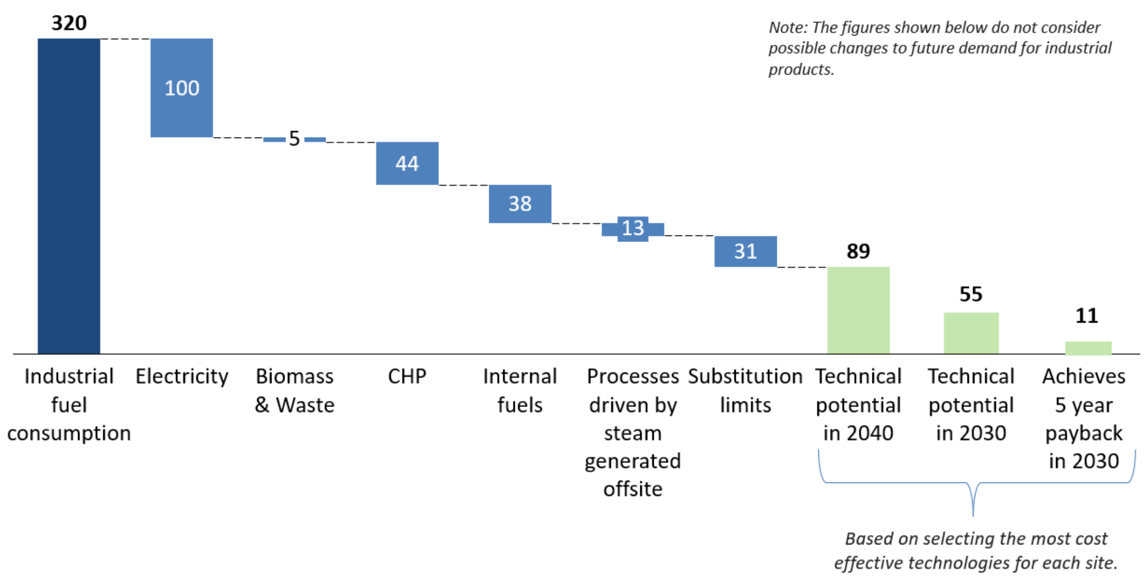


Figure 1: Annual industrial fuel consumption (TWh) and potential for fuel switching (based on selection of the most cost-effective technologies for each site)

Out of 320 TWh of fuel consumption across energy intensive industries[2] in the UK, the technical potential for fuel switching is found to be 89 TWh in 2040 (saving up to 16 Mt CO_2 per year), based on selecting the

[1] See, for example: Cost analysis of future heat infrastructure options for the National Infrastructure Commission (Element Energy & E4Tech, 2018); A future framework for heat in buildings: a call for evidence (BEIS, 2018).
[2] Excluding energy demand from “unclassified” industries.

most cost-effective technology for each site (or up to 96 TWh and 18 Mt CO_2 based on selecting technologies with the highest potential for each site[3]). Figure 1 shows the filtering process to determine the share of current fuel consumption that is suitable for switching. Some processes are not considered for fuel-switching, as shown in Figure 1:

- Existing processes fuelled by electricity, waste and biomass do not require fuel-switching;
- CHP-driven processes are not in scope and the potential for use of alternative fuels is not assessed here;
- Processes fuelled by internal fuels (i.e. those produced from process feedstock such as crude oil in refining), or steam produced at an external site, are not suitable for switching.

Although the remaining fuel consumption is relevant for fuel-switching, only processes which have compatible alternative technologies can be switched; for some processes, only a limited percentage of the demand can be met by an alternative fuel. Certain technologies may not be available before 2040; hence the technical potential for 2030 is lower (at 56 TWh) than in 2040. In addition, in order to implement these technologies, commercial barriers must be addressed; the commercial potential in 2030 (based on a 5-year discounted payback period, with central cost assumptions) is estimated at 11 TWh.

1.3 Industrial processes

Fuel consumption relevant for fuel-switching can be broken down into high-level processes according to heat requirements, as shown in Figure 2. Note that this shows the breakdown of relevant fuel consumption before the suitability or substitution limits of specific fuel switching technologies is taken into account.

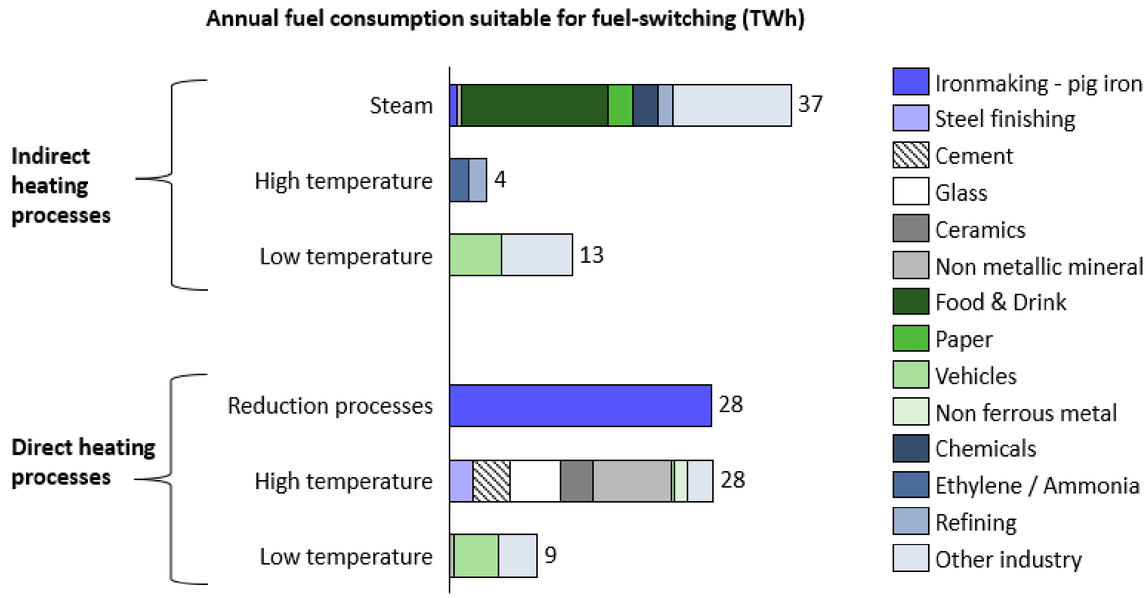


Figure 2: Annual fuel consumption relevant for fuel-switching, by industrial process

Reduction processes (i.e. in blast furnaces), processes requiring high temperature direct heating (e.g. in furnaces and kilns for cement and other non-metallic mineral production) and processes driven by indirect heating via steam (in a wide range of sectors) together account for 86% of the suitable demand. As such,

[3] For example, hydrogen or biomass boilers in place of heat pumps (which are highly efficient and therefore cost-effective, but can only meet 25% of process demand).

understanding which technologies are suitable for such processes, and when they are likely to become feasible, is central to assessments of the potential for fuel-switching.

1.4 Technology suitability

The proposed suitability of fuel-switching technologies for different types of industrial processes is summarised in Table 1, which includes a high-level categorisation of the fuel switching options. Some fuel-switching technologies can only replace a limited share of the fossil fuel demand for a given process, for instance due to limitations on output temperatures compared to required temperatures[4]. For such cases, the maximum estimated fossil fuel substitution rates for implementation in 2040 (at each site) are shown in the table in brackets.

Table 1: Suitability of fuel switching options available by 2040 for key industrial processes

Processes driven by	Process type[5]	Suitable fuel-switching options	Key sectors relying on these processes
Indirect heating	**Low temperature**	Solid biomass boilers, hydrogen boilers, electric boilers, electric heaters, heat pumps (up to 25% substitution), microwave heaters	Vehicles, other industry
	High temperature	Electric heaters, hydrogen heaters (hydrogen replacing gas in burners)	Refining, Ethylene & Ammonia
	Steam	Solid biomass boilers, hydrogen boilers, electric boilers, heat pumps in limited applications (up to 25% substitution)	Food & Drink, Paper, Chemicals, other industry
Direct heating	**Low temperature**	Electric heaters[6], hydrogen heaters	Vehicles, other industry
	High temperature	Solid biomass and waste combustion (cement sector – up to 80% substitution), hydrogen heaters, electric kilns / furnaces, radio frequency heating, electric plasma gas heaters (up to 25% substitution)	Glass, Ceramics, Cement, other non-metallic minerals
	Reduction processes	Direct reduction of solid biomass/waste materials (up to 25% substitution) or hydrogen (up to 25% substitution)[7], electric plasma gas heaters (up to 25% substitution)	Iron production

Based on interviews and workshops with industrial stakeholders and technology suppliers, the use of hydrogen (either as 100% fuel, or used in combination with gas or other fuels) could potentially be feasible for most applications, and the estimated overall technical potential for hydrogen is the highest of the three fuel types, followed by biomass and waste and finally electricity. The relative similarity between hydrogen and natural gas means that hydrogen is likely to be suitable for many processes currently fuelled by gas,

[4] For example, in the case of heat pumps and electric plasma gas heaters, where these are applicable, the electric technologies perform a pre-heating function to replace some of the fossil fuel demand, but some fossil fuel would still be required to achieve the required temperature. In the case of using hydrogen or biomass and waste in primary iron production, it is assumed that replacement of coke on a like-for-like basis will be limited due to the different weight-bearing abilities of other fuels, and the corresponding suitability for large existing blast furnaces.

[5] "Low temperature" corresponds to processes requiring temperatures of 30-80°C for indirect heating, and 80-240°C for direct heating. High temperature corresponds to processes requiring temperatures of up to 600°C for indirect heating, and up to 2,000°C for direct heating. Steam at different pressures can meet indirect heating requirements in the 80-240°C range.

[6] These are process heaters (furnaces) that use H_2 instead of natural gas or oil. These would be mainly for indirect heating other than steam/water. "Heater" and "furnace" are used rather interchangeably in the process industries.

[7] Note that this does not refer to DRI (direct reduced iron) but to substitution of alternative fuels within the baseline UK primary iron production route (either blast furnace or, in the future, HISarna)

including direct heating at high temperatures where the process gases interact with the end product (where biomass and electricity are unlikely to be suitable). However, practical and economic considerations are likely to limit the feasibility of any one technology or fuel type; industry technology choices will depend on the relative availability and cost of the technologies and their respective fuels.

1.5 Timescales for development and demonstration

Several fuel-switching technologies are already commercially available and ready for implementation at certain scales or in certain industries. However, in most cases, there are various technical and commercial challenges to be addressed before certain technologies could be considered as realistic options to drive processes across the full range of UK industries. Even some technologies that are already available would require significant design work to be applied in industries where they have not previously been used.

For many fuel-switching technologies (including hydrogen options, given the absence of experience of hydrogen in most sectors), implementation will only be feasible if further evidence on the suitability and reliability of the technologies in specific sectors is provided.

Figure 3 shows the possible timescales for when certain technologies could be available for commercial application across UK industries, based on when development and demonstration activities could be feasible according to industry and technology suppliers, and how this could enable progression to commercial applications within different sectors. This informs the estimated technical potential in different years, but the rate of adoption of these technologies within each industry would depend on the particular needs and decision factors for specific sites and as such the diagram does not show the rate of roll-out. In addition, technology implementation would require biomass and hydrogen to be available, and the estimated progression of the technology availability assumes that this is the case. In reality, the availability of all fuel types (and therefore the application of the technologies) will be linked to a range of wider energy sector decisions relating to the development of infrastructure to meet future UK energy needs. Energy and Industrial policy that signals the future availability of different fuels will have an impact on the technologies which are pursued by industries.

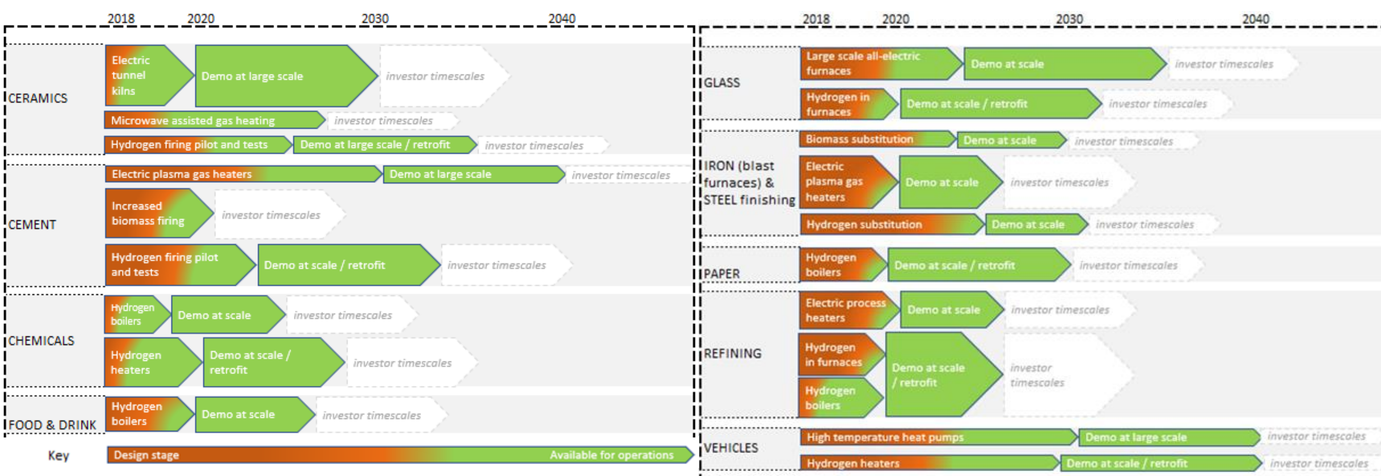


Figure 3: Timelines for development and demonstration

Investment decision timescales will also factor into the possible implementation roadmap: industrial investments for some industries may require up to five years between demonstration and commercial implementation, even for choices such as switching from one fuel to another within an existing furnace or kiln. Timescales for full equipment replacement could be longer, as they will depend on the age of the existing infrastructure and will be dependent on a positive business forecast for UK operations.

1.6 Impact of fuel costs on technology choice

Once technologies are proven, relative fuel costs and the provision of a long term, low carbon supply of fuel are likely to be the major drivers of fuel-switching, and will inform technology choices. Many fuel switching technologies will come at a capital cost premium compared to the incumbent technologies, and as such (in the absence of some form of subsidy), investment in these technologies would only be commercially justifiable if costs could be recovered through operational cost savings, mainly consisting of fuel costs. There are several types of processes where more than one alternative fuel could be suitable. Due to the uncertainty around future costs of hydrogen, biomass and electricity, it is not possible to definitively predict which options will be most attractive. However, based on comparing the estimated capex premiums and central fuel cost estimates, the following broad conclusions can be drawn regarding the fuel bill savings needed to make fuel switching technologies commercially feasible:

- In the absence of a carbon price for industrial fuel combustion, biomass boilers and hydrogen boilers for low temperature indirect heating would both need to offer a small fuel saving (less than 1p per kWh) relative to gas in order for these fuel switching technologies to achieve a five year payback period. Best-available assumptions suggest that solid biomass is likely to be significantly cheaper than either hydrogen or electricity and as a result is much more likely to achieve a five year payback in industrial scale boiler applications, despite higher capex.
- Heat pumps (which could be applicable for low temperature processes with thermal demand up to hundreds of kW) are likely to achieve a five year payback even with an estimated electricity price premium of 9p/kWh compared to gas, due to their very high efficiencies (with fuel consumption around one quarter that of equivalent boilers)
- Other electric technologies tend to have similar capex to fossil fuel equivalents, and offer a small efficiency saving compared to fossil fuel alternatives, indicating that technologies could achieve a five year payback even with a small premium for electricity over gas. However, the electricity price premium is likely to be much higher than the small margin required. Therefore, for direct heating applications where biomass is unsuitable, hydrogen technologies are more likely to achieve payback than electric options.
- A sufficiently high carbon price (£77/t by 2030 is assumed in this study) would make it possible for some fuel switching technologies to achieve payback without requiring a fuel saving relative to gas, given the low carbon factors for these alternative fuels.

1.7 Assessing the cost-effectiveness of fuel switching

To assess the overall potential emissions savings from fuel switching, for each industrial site, the cost-effectiveness of emissions reduction from all the suitable technologies is calculated from the perspective of industrial stakeholders[8] and the most cost-effective technology is selected for each site. When all fuel types are assumed to be available, the resulting mix of selected technologies across industry sectors consists largely of biomass and waste technologies where these are suitable, and hydrogen technologies where biomass and waste are not suitable, with electrification only from heat pumps (mainly due to the high price of electricity). Total emissions savings (relative to counterfactual technologies) are estimated at 15.9 Mt CO_2/year and the fuel switching potential in terms of replaced fuel demand is 89 TWh. If we consider only the technologies that are likely to be available by 2030, the technical potential in terms of emissions savings

[8] Cost effectiveness is calculated from a private perspective based on lifetime costs relative to the counterfactual, discounted at 10% (reflecting a private perspective), and including carbon costs (as these costs are expected to be incurred as part of the operating costs); and lifetime CO_2 emissions savings relative to the counterfactual.

is 9.7 Mt CO_2/year; hydrogen heaters and kilns are assumed to become widely applicable only in 2035, outside of Refining and Ethylene and Ammonia production sectors which are experienced in operating with hydrogen rich gases.

The table below shows the technical potential for fuel switching in 2030 and 2040 when only one alternative fuel type is considered across all applications. The results indicate that hydrogen has the highest potential overall (at 96 TWh by 2040, 78% of the total fuel consumption in scope), although around half of this only becomes available after 2030. In addition, under central fuel cost assumptions, the total cost of fuel switching to hydrogen technologies alone is a more costly approach to reducing emissions than switching to biomass technologies alone, due to the much higher cost of hydrogen (compared to biomass) assumed to apply in 2030 and 2040. Electrification is the most costly option overall (due to the high price of electricity), and also has the lowest potential.

Although switching to biomass is more cost-effective than other options (on average), if all available opportunities for switching to biomass and waste were realised in 2030, the total additional industrial biomass demand would be around 53 TWh per annum (compared to an estimated 5 TWh for industrial energy in 2016). According to Ricardo's bioenergy resource model, the total UK supply of solid biomass in 2030 could be in the region of 57 TWh so it is clear that it would not be possible to meet such a drastic increase in demand. Even meeting the potential demand from the steel sector alone (in the region of 10 TWh per annum) could prove to be disruptive to the biomass market and could drive up prices considering the potential demand for biomass in other energy sectors[9]. For each site, the choice to switch to biomass or waste would also depend on a reliable supply of a fuel that is suitable for that specific application (in terms of its chemical content and physical properties.

Table 2: Technical potential and cost-effectiveness of fuel switching (private perspective) when only one fuel type is available

	Technologies available in 2030			Technologies available in 2040		
Fuel type	**Potential emissions savings**	**Replaced fuel consumption**	**Weighted average private cost**	**Potential emissions savings**	**Replaced fuel consumption**	**Weighted average private cost**
Biomass/waste	9.4 Mt CO_2/year	52.7 TWh/year	£ 24.0 /tCO_2	10.3 Mt CO_2/year	55.6 TWh/year	£ 20.3 /tCO_2
Hydrogen	7.8 Mt CO_2/year	47.9 TWh/year	£ 79.6 /tCO_2	17.7 Mt CO_2/year	95.7 TWh/year	£ 66.6 £/tCO_2
Electricity	5.8 Mt CO_2/year	43.9 TWh/year	£ 308.5 /tCO_2	7.3 Mt CO_2/year	45.9 TWh/year	£ 259.1 £/tCO_2

1.8 Key fuel switching opportunities and potential synergies

Considerations of the potential for fuel-switching may be most valuable when other routes for industrial decarbonisation are taken into account, as this enables the most cost-effective opportunities and potential synergies between different options to be identified. In particular, carbon capture, utilisation and storage (CCUS) is likely to be required in some industries in order to meet emissions reduction targets, particularly

[9] Including residential and commercial heat, power generation, and bio-energy with carbon capture and storage (BECCS).

for sectors with high process emissions. In some cases, the use of CCUS in combination with fuel-switching in these sectors could be a cost-effective way to achieve negative emissions.

Table 3 sets out the most cost-effective fuel-switching options for each key group of industrial processes, highlights the potential for other decarbonisation routes including CCUS, and provides a summary of possible synergies with fuel switching. In summary:

- Use of biomass in industrial processes (where possible) provides a cost-effective opportunity to achieve negative emissions when combined with carbon capture.
- If industrial processes are switched to hydrogen, centralised hydrogen production with CCUS could be collocated with hydrogen demand.
- Synergies between electrification and CCUS are expected to be limited.
- Options for off-grid sites could include bio-LNG and bio-LPG, as well as onsite renewable generation combined with electric technologies.

To identify the best opportunities for industrial decarbonisation (and the role of fuel switching within this) the total system costs of the different decarbonisation options outlined above should be compared in detail for each key industry group, as well as by drawing high-level comparisons for industrial consumption as a whole. In such comparisons, technology costs and decisions may be influenced by geographic factors as well as site size. For example, industrial sites which are close or accessible to potential carbon storage sites, and which have high process emissions, are likely to be more attractive for CCUS. If sites with potential hydrogen demand are located close to these CCUS clusters, facilities for hydrogen production via methane reformation with CCUS could also be sited locally and use the same carbon transport and storage systems, which could help reduce the overall cost of low carbon hydrogen production for the relevant industries. This in turn could increase the total potential for cost-effective emissions savings via fuel-switching.

Next steps to inform the direction of industrial decarbonisation could include feasibility studies for the following options (which would be complementary parts of a fuel-switching decarbonisation route):

- Biomass + CCUS at large industrial sites with high process emissions (e.g. iron and cement production)
- Hydrogen production + CCUS + hydrogen in furnaces and kilns in key clusters of potential hydrogen demand

Such studies would be valuable in understanding the relative merits of fuel-switching and CCUS, and any additional benefits gained from the combination of the two.

In addition, there is a need to compare the potential costs to industry (and the energy system as a whole) of decarbonisation via use of “green gas” (i.e. biomethane and syngas), versus the fuel switching options presented in this study. Just as hydrogen and electricity costs could be prohibitive to industrial fuel-switching, increased injection of green gas (which could directly replace natural gas in a range of industrial applications, and could be supplied via the grid) could also expose industries to higher operating costs. Most industries operate with low margins, and increased costs associated with decarbonisation could negatively impact the feasibility of continued operation in the UK.

Therefore, if UK industry is to continue to thrive whilst contributing to the transition to a low carbon economy, it will be essential to identify the most cost-effective combination of decarbonisation technologies for the system as a whole. Switching to biomass, hydrogen, and electrification are likely to be part of this combination, and there is a clear need for further development and demonstration to determine the timescales and applications where they will be most effective.

Table 3: Potential decarbonisation routes for groups of industrial processes

Type of demand	Most cost-effective fuel switching options	Synergies with CCUS	Alternative decarbonisation routes
Primary iron production (24% of total relevant fuel consumption)	• Biomass (25% substitution in blast furnace or even higher after conversion to HISarna process) • Negative costs in 2030 and 2040 (including avoided carbon cost)	• Lower cost of CCUS after conversion to HISarna • Good opportunity to demonstrate biomass + CCUS (negative emissions)	• Replace existing blast-furnaces with direct iron reduction with hydrogen / gas • Electric arc furnace (secondary production only)
Cement kilns (3% of total relevant fuel consumption)	• Biomass + O2 enrichment • Negative costs in 2030 and 2040 (including avoided carbon cost)	• Cost of CCUS > cost of switching to biomass • Good opportunity to demonstrate biomass + CCUS (negative emissions)	
Steam and indirect low temperature heating for processes above 100 kW capacity (including Food & drink, Paper) (33% of total relevant fuel consumption)	• Biomass boilers • Low or negative costs in 2030 and 2040 (including avoided carbon cost)	• Higher cost for CCUS compared to cement or iron production	• Limited decarbonisation (through energy efficiency gains) from switching to CHP (unless combined with fuel switching) and/or waste heat recovery
High temperature heating + biomass unsuitable (Glass, other non-metallic minerals, steel finishing) (28% of total relevant fuel consumption)	• Hydrogen heaters & hydrogen kilns • Cost-effectiveness of around £70/t in 2040 (including avoided carbon cost)	• Possible for a few sites in potential CCUS clusters • >100 EU-ETS sites • 100s of smaller sites • Centralised hydrogen production with CCUS could be collocated with hydrogen demand	• Biogas / syngas (Depends on supply routes and the future of the gas network: total potential in region of 100 TWh vs current UK gas demand of 300 TWh[10])
Steam and indirect low temperature heating for processes below 100kW capacity (Food & drink, non-metallic minerals, chemicals, other industry) (1% of total relevant fuel consumption)	• Biomass boilers, hydrogen boilers *(Economics favour hydrogen for smaller sites due to higher impact of capex vs opex)* • Costs in 2040 less than £90/t for biomass; £90-140/t for hydrogen (at smallest sites) (including avoided carbon cost)	• Not suitable (highly dispersed & varied sites) • Centralised hydrogen production with CCUS could be collocated with hydrogen demand	• Biogas / syngas (Depends on supply routes and the future of the gas network: total potential in region of 100 TWh vs current UK gas demand of 300 TWh) • Bio-LPG / BioLNG (for off-grid sites) • Limited decarbonisation from CHP (unless combined with fuel switching) and/or waste heat recovery
Steam and low temperature indirect heating (<30 GWh per site) (11% of total relevant fuel consumption)	• Heat pumps	• Not suitable (sites too small and dispersed)	• Waste heat recovery

[10]This would include gas generated from energy crops and forest residues as well as from waste feedstocks (see Review of Bioenergy Potential: Summary Report, June 2017, Anthesis and E4Tech for Cadent Gas Ltd)

2 Introduction

2.1 Background

The need for deep decarbonisation at a national level will drive significant changes to the gas grid over the coming decades. By 2050, various possible scenarios could have been put into effect as part of national efforts to meet emissions reduction targets[11]:

- High blend / 100% hydrogen grid (supplied with low carbon hydrogen) in place of natural gas;
- Gas grid decommissioned in some locations and replaced with electrification and decentralised energy supply technologies;
- High blend of biomethane and/or syngas in the gas grid.

Many UK industrial sites rely on energy supply from the gas grid, with at least 45% of overall industrial fuel consumption being met by natural gas in 2016[12]. To remain competitive in the UK, these industries will need to adapt to changes to national infrastructure and fuel supply that will come with the possible scenarios above, and even industries not reliant on the gas grid (i.e. those that currently meet their energy requirements through use of coal or oil) will need to meet decarbonisation requirements in their own right.

Options for switching energy-intensive processes away from current fossil fuel energy sources will include electrification, hydrogen and biomass technologies, many of which are not yet commercially available or require further optimisation to become technically feasible.

In line with the Clean Growth Strategy, BEIS funding has been allocated for fully funded projects to bring these technologies closer to commercial application. BEIS will be seeking applications from industrial emitters, technology vendors and other industrial stakeholders with ideas for potential projects.

This study is the first phase of a three Phase **Industrial Fuel Switching Competition** which forms part of BEIS's wider programme to accelerate the commercialisation of innovative, clean, cheap and reliable energy technologies by the mid-2020s. Up to £20m has been allocated for all three phases of the Competition.

The aim of this study, an initial market engagement and assessment phase, is to understand the technical and economic potential for industry to switch to a low carbon fuel (including electrification, hydrogen and bioenergy/waste), with current and future technologies, and the key challenges and opportunities.

2.2 Scope

The focus of this study is on switching of fuel consumption related to combustion of fossil fuels (rather than process feedstocks); as such, potential emissions savings will be limited to the energy-related share of industrial emissions and will not cover process emissions.

The total relevant annual fuel consumption and the breakdown by industry is set out in Figure 4. Only the fossil fuel demand (shown on the right) is considered for fuel switching; the total fuel consumption (shown on the left) also includes existing consumption of biomass and waste, and electricity. Demand from "unclassified" industries is not included in the detailed analysis of the potential, as data on the type of

[11] See, for example: Cost analysis of future heat infrastructure options for the National Infrastructure Commission (Element Energy & E4Tech, 2018); A future framework for heat in buildings: a call for evidence (BEIS, 2018).
[12] DUKES Energy Consumption Table 4.04: Industrial final energy consumption by end use (different processes)

processes and the scale of industrial sites included in this demand is not available, and therefore it is not possible to identify which fuel switching technologies would be applicable.

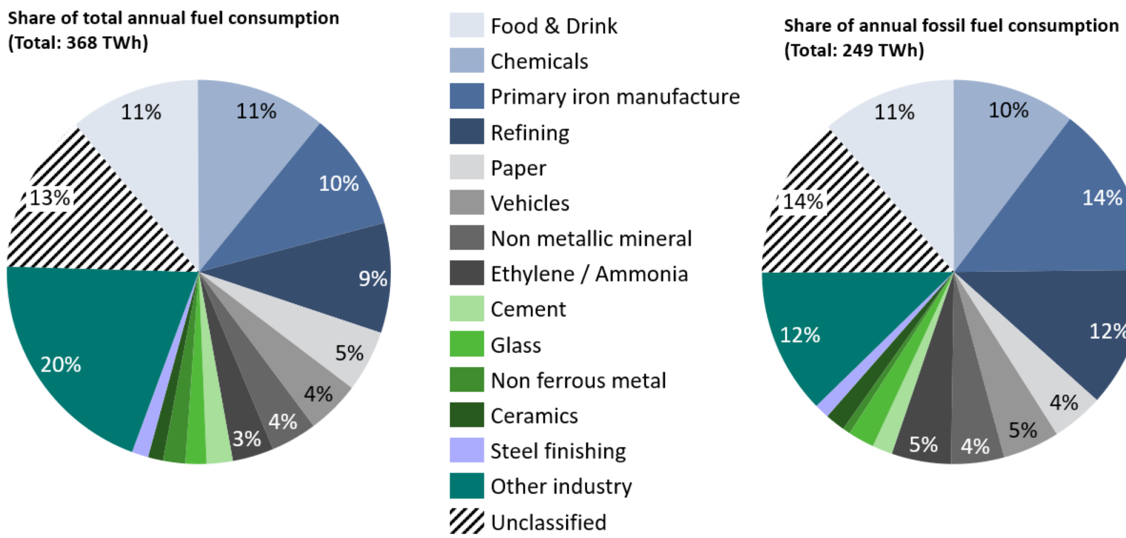


Figure 4: Breakdown of total annual fuel consumption and fossil fuel consumption by industry[13]

Table 4 shows the technologies included in the scope of this study, which aims to focus on identifying alternative, low carbon fuel options which could avoid drastic changes to process design, but which could be viable options under gas grid decarbonisation scenarios whereby any gas available in the grid (where it is not decommissioned) significantly differs in chemical properties compared to natural gas. The potential industrial applications for the technologies not in scope are either already well understood, or are being addressed as part of wider BEIS workstreams.

Table 4: Technologies in scope for this study

Technologies in scope	Not in scope for this study
Biomass	CHP
Hydrogen	Biomethane
Electrification	Synthetic methane
	CCUS
	Energy efficiency

[13] Based on DUKES 2017 and Industry Pathway Models data. “Other industry” includes various industries where demand can be classified by process: wood, rubber and plastic, furniture, water collection, treatment and supply, waste collection and treatment, mechanical and electrical engineering, textiles, construction, other mining and quarrying, pharmaceuticals, printing and publishing

2.3 Study approach

The study builds on previous industrial decarbonisation work within BEIS and has involved close engagement with relevant stakeholders. The key stages of the study have been as follows:

- Literature review and stakeholder engagement with industrial organisations, trade bodies and technology vendors to identify industrial fuel-switching options (including detailed data on each potential technology) and their suitability to various industrial processes.
- Characterisation of detailed processes in each UK industry and development of cross-sectoral process types to identify cross-sectoral fuel switching options.
- Development of a bottom-up model of industrial processes and fuel switching options at site level.
- Assessment of technical and economic potential of fuel switching using marginal abatement cost curves.
- Development of innovation timelines to identify requirements for demonstration of particular technologies.
- Industry workshop to disseminate study results and seek feedback from stakeholders on the implications for possible feasibility studies and innovation and demonstration activities funded through the Industrial Fuel Switching Competition.

The next chapter of this report sets out the industrial fuel consumption in scope, and shows how this can be broken down by industry and into different processes. Chapter 4 then describes the biomass & waste, hydrogen and electric fuel switching technologies, their suitability for different processes, timescales for commercialisation and the metrics used to determine which technologies are most cost-effective for each industrial site. Chapter 5 shows the resulting technology selection that makes up the total technical potential, explores the impact of variations in fuel cost, and considers the commercial potential for each fuel type under different cost scenarios. Finally, the key challenges and opportunities for fuel switching are set out in Chapter 6.

3 Industrial fuel consumption and processes

3.1 Industrial fuel consumption by sector

Consideration of the current industrial fuel consumption provides initial insight into the potential for fuel-switching in each sector. Figure 5 shows the estimated energy-related industrial fuel consumption for the main energy intensive industries, based on data from UK TIMES[14] and DUKES 2017[15], separated into consumption of fossil fuels (mainly coal, oil, and gas) and non-fossil fuels (electricity, biomass and waste).

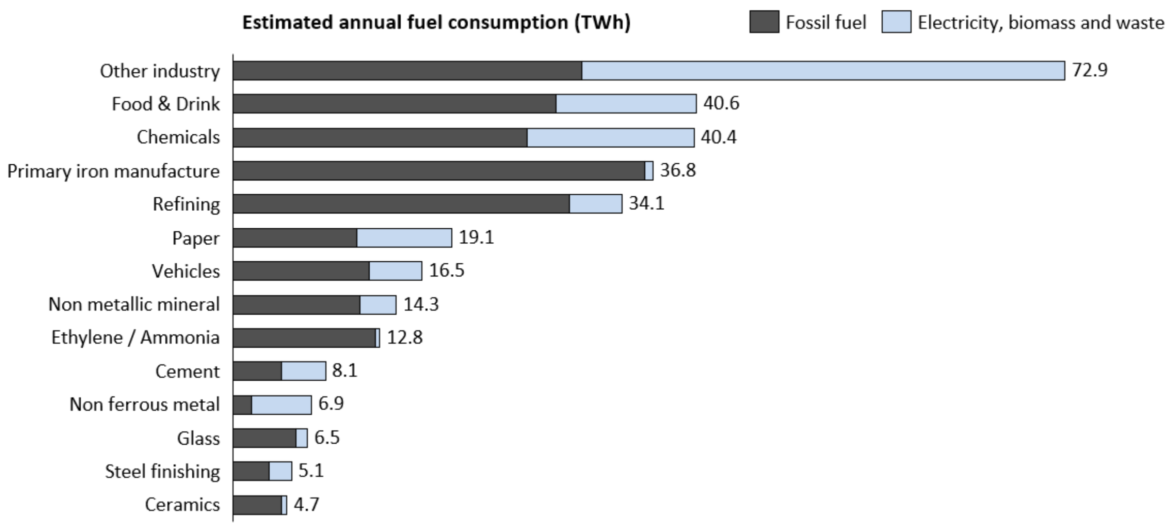


Figure 5: Baseline annual fuel consumption for energy intensive industries

As shown in Figure 5, electricity, biomass and waste already meet a significant share of industrial energy demand in many industries, accounting for 33% of the fuel consumption for the industries listed above. The remaining 67% is fossil fuel consumption, which currently accounts for an estimated 65% of energy-related emissions for these industries. This study explores the opportunities for switching this fossil fuel demand to alternative, low carbon fuels: specifically, biomass and waste, electricity and hydrogen.

Figure 6 provides a further breakdown of the fuel consumption into specific fuels and identifies which types of fuel consumption are not included in the detailed analysis:

- Several industries (most notably Chemicals, Food & Drink, and Paper) use CHP to supply heat and electricity to drive industrial processes, accounting for 19% of industrial fossil fuel consumption in total. Although CHP could be switched to alternative fuels, this is being considered in a parallel study and the potential and challenges are not assessed here.
- A further 17% of fossil fuel is internal fuel generated from process feedstock, such as crude oil in refining, and then combusted to drive processes; this is not also not considered in the detailed analysis as switching this for an alternative fuel would rely on a reliable alternative market for the internal fuels (this may also require separation of the constituent products for re-sale).

[14]Data extracted from BEIS Industrial Pathway Models, based on the UK TIMES model which uses DUKES 2010
[15]DUKES ECUK Table 4.04: Industrial final energy consumption by end use (different processes) 2009 to 2016

- 6% of fossil fuel demand comes from undefined processes for which the suitability for fuel-switching cannot be determined.

The fuel demand in scope for consideration in this study is the remaining 57% of fossil fuel demand for these industries (which translates to 39% of the overall fuel demand, and 123 TWh).

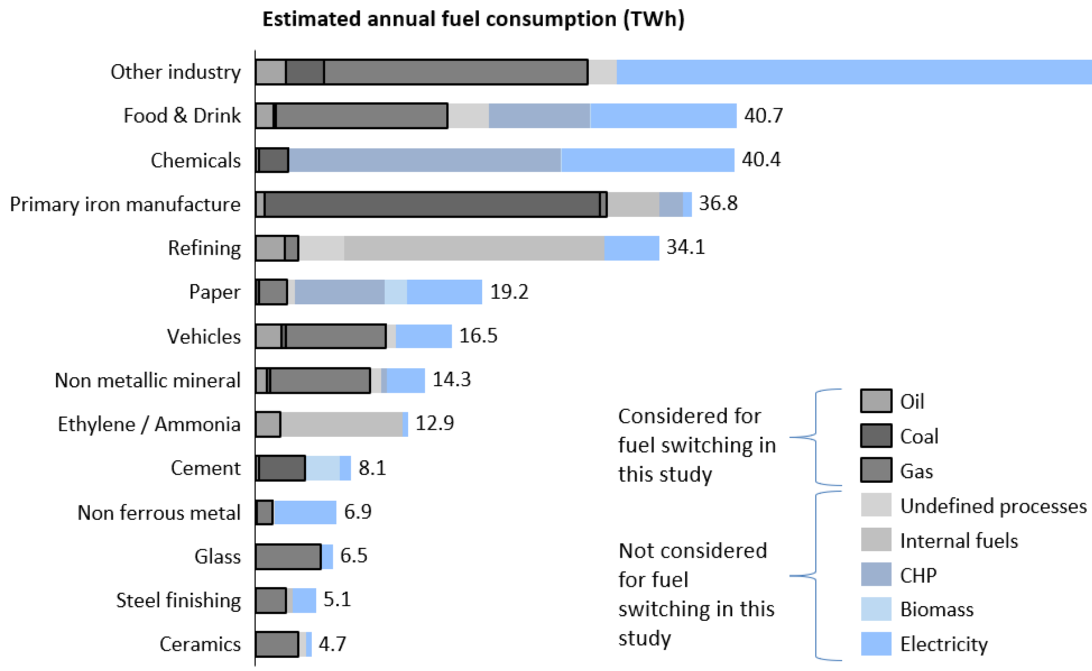


Figure 6: Baseline annual fuel consumption and suitable demand for fuel switching

As shown in Figure 6, suitable demand for fuel switching varies across the energy intensive industries: primary iron production and food and drink production both account for a large share of the suitable demand (at 24% and 13% respectively). Natural gas is the main fossil fuel for most industries (including food & drink production), whereas primary iron production relies heavily on coke (from coal) to drive blast furnace processes. Cement and chemicals production also use coal, as do other industries not specified above[16]. Due to the higher carbon content of coal compared to natural gas, the potential emissions savings for fuel switching in these industries will be higher per unit of fuel replaced, than for industries relying on gas.

3.2 Cross-sectoral industrial processes

Some industry sectors have distinctive processes where the heat or fuel driving these processes must be provided in a way that is specific to that sector. However, many industrial processes can be mapped to common "cross-sectoral processes" according to similar energy and heat requirements shared by processes across multiple sectors.

[16] "Other industry" here includes various industries where demand can be classified by process: wood, rubber and plastic, furniture, water collection, treatment and supply, waste collection and treatment, mechanical and electrical engineering, textiles, construction, other mining and quarrying, pharmaceuticals, printing and publishing

Mapping industrial processes in this way facilitates the assessment of the fuel-switching potential: the potential for a particular technology can be assessed by identifying its capabilities (e.g. in terms of output temperatures) and comparing them with the requirements of each high-level process.

3.2.1 Processes driven by direct heating

In processes which involve heating a solid material (e.g. melting, kiln firing or metal shaping processes), combustion gases typically come into direct contact with the material. Many such **direct heating processes** have very high temperature requirements (ranging from 240°C up to 2,000°C), which are met by combustion of fuels in a furnace or heater. Drying and separation processes for some industries also involve direct heating, typically with temperatures below 200°C. The nature of product interactions with combustion gases varies for different direct heating processes. Multiple cross-sectoral processes have been defined to capture this, as shown in Table 5.

Table 5: Mapping and process requirements of direct heating processes

Sector	Process[17]	Cross-sectoral process	Process requirements
Steel finishing	Rolling	Direct - High Temperature	240-2,000°C
Primary iron production	Melting	Direct - High Temperature (Blast furnace)	240-2,000°C
Primary iron production	Sintering	Direct - High Temperature (Sinter plant)	240-2,000°C
Cement	Kiln firing	Direct - High Temperature (Mixed kiln)	240-2,000°C
Vehicles	“High temperature process”	Direct - High temperature	240-2,000°C
Vehicles	“Low temperature process”	Direct - Low temperature	80-240°C
Glass	Melting	Direct - High Temperature	240-2,000°C
Ceramics	Kiln firing	Direct - High Temperature (kiln)	240-2,000°C
Non-ferrous metal	Melting and other high temperature processes	Direct - High Temperature	240-2,000°C
Non-metallic mineral	Kiln firing and other high temperature processes	Direct - High Temperature	240-2,000°C
Non-metallic mineral	Drying	Direct - Low temperature	80-240°C
Other industry	“High temperature process”	Direct - High Temperature	240-2,000°C
Other industry	Drying / Separation	Direct - Low temperature	80-240°C

[17] “High temperature process” and “low temperature process” refer to the fuel consumption categories defined in DUKES ECUK Table 4.04: Industrial final energy consumption by end use (different processes) 2009 to 2016

3.2.2 Processes driven by indirect heating

For processes which involve heating gases or liquids, the process fluid can be passed through a furnace tube, which is heated on the outside by combustion gases. This type of indirect heating is largely applicable to the Refining and Petrochemicals industries, at temperatures of 240-600°C. High pressure steam generated on many industrial sites can be used to provide indirect heating, to drive processes with heat requirements up to 240°C. Heat demand for lower temperature processes can either be met by low pressure steam (80-240°C) or by hot water heating for space heating up to 80°C (where this is not met by waste heat recovered from other onsite processes). These processes and their requirements are summarised in Table 6.

Table 6: Mapping of indirect heating processes (sector specific to cross-sectoral process)

Sector	Process	Cross-sectoral process	Process requirements
Primary iron production	Steam generation	Indirect - Low Pressure Steam	80-140°C
Ethylene	Cracking	Indirect - High temperature	240-600°C
Ammonia	Steam reforming	Indirect - High temperature	240-600°C
Chemicals	High temperature	Indirect - High Pressure Steam	190-240°C
Chemicals	Turbine	Indirect - High Pressure Steam	190-240°C
Food & Drink	"Low temperature process"	Indirect - Low Pressure Steam	80-140°C
Food & Drink	Drying	Indirect - Low Pressure Steam	80-140°C
Paper	"Low temperature process"	Indirect - Low Pressure Steam	80-140°C
Vehicles	Space heating	Indirect - Low temperature	30-80°C
Refining	"Low temperature process"	Indirect - High temperature	240-600°C
Refining	Drying / separation	Indirect - High pressure Steam	190-240°C
Refining	Space heating	Indirect - Low Pressure Steam	80-140°C
Non-metallic mineral	"Low temperature process"	Indirect - Low Pressure Steam	80-140°C
Other industry	"Low temperature process"	Indirect - Low Pressure Steam	80-140°C
Other industry	Space heating	Indirect - Low temperature	30-80°C

3.2.3 Fuel consumption by cross-sectoral process

Figure 7 shows the split of suitable demand into cross-sectoral processes by sector, based on demand for each process (as defined in DUKES and the BEIS Industrial Pathways model) and feedback from industry stakeholders. Suitable fuel consumption can broadly be separated into the following categories:

- Steam driven processes: 37 TWh
- Primary iron production melting processes: 28 TWh

- Direct high temperature heating processes: 28 TWh
- Indirect low temperature heating processes: 13 TWh
- Direct low temperature heating processes: 9 TWh
- Indirect high temperature heating processes: 4 TWh

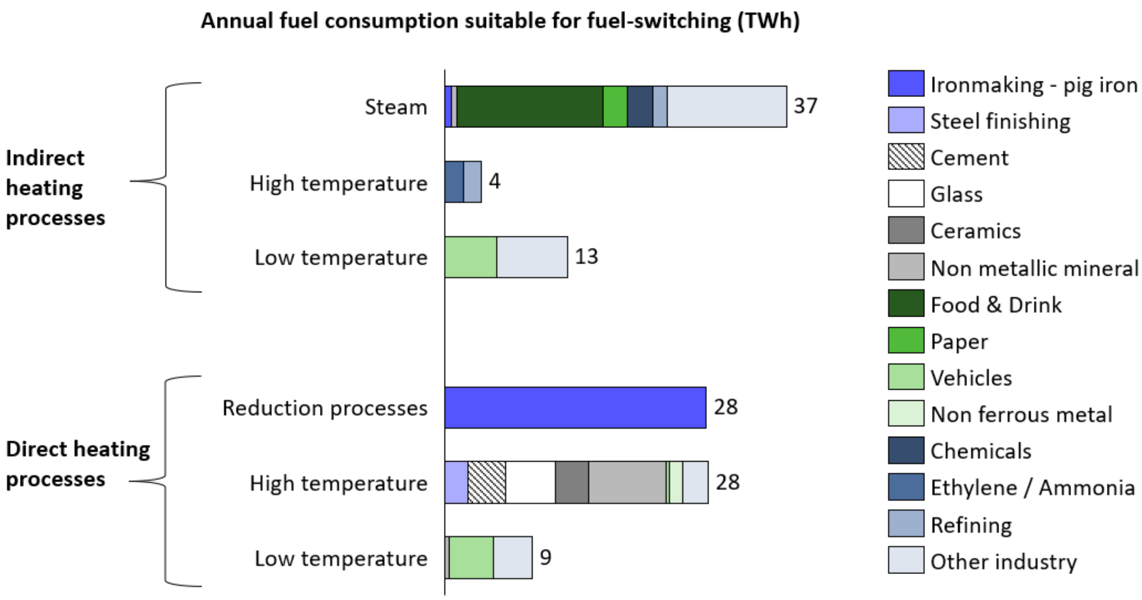


Figure 7: Breakdown of fuel consumption suitable for fuel switching by cross-sectoral process

There is some variation in temperature requirements and product interactions with combustion gases for specific processes within each of the categories defined in Figure 7, which will impact feasibility and implementation timescales for different fuel switching technologies in accordance with their capabilities. However, the high-level potential for fuel switching can be assessed by defining the broad suitability of the various technologies for these cross-sectoral processes. These technologies, their characteristics and their suitability for different processes are explored in the next chapter.

4 Fuel switching technologies

4.1 Technologies and suitability

The fuel switching technologies considered in this study are shown in Table 7, alongside the processes for which they are likely to be applicable to.

Table 7: Potential fuel switching technologies

Alternative fuel	Potential fuel switching technologies	Applicable processes or sectors
Electricity	Immersion Steam Boiler	Steam-driven processes
	Electrode Steam Boiler	Steam-driven processes
	Electric Process Heater	Indirect heating
	Electric Kiln	Ceramics firing
	Electric Infra-Red Heaters	Low temperature direct heating
	Electric Plasma Gas Heaters	High temperature direct heating
	Microwave Heaters	Drying solid materials
	Open Loop Heat Pump	Low pressure steam, low temperature indirect heat
	Closed Loop Heat Pump	Low temperature indirect heat
	Electric furnace	Glass melting
Hydrogen	H_2 as an ironmaking reductant	Primary iron production
	H_2 Boilers	Steam-driven processes
	H_2 Heaters	High temperature direct heat
Biomass/ waste[18]	Biomass Boiler	Steam-driven processes
	Direct Biomass Combustion	Cement kilns
	Biomass Combustion + O2 enrichment	Cement kilns
	Biomass as an ironmaking reductant	Primary iron production

Some technologies which provide direct high temperature heating are likely to be suitable only for specific sectors, due to the different tolerances or requirements for combustion gas interactions with the products. However, most other technologies could be applied to a range of different sectors. In particular, indirect heating and / or steam technologies (including boilers, electric process heaters and heat pumps) would be technically suitable in any industry where these forms of heat are required.

[18] Technically, biomethane (or green coke, for use in iron production) produced via biomass gasification could replace natural gas (or coke) in any relevant sector, as an equivalent fuel with no technical constraints on the process side. However, gasification is a fuel preparation/conversion technology, as opposed to a fuel switching technology. Biomethane supplied via centralised production and grid injection would not pose any technical challenges for industry. For on-site production, and the feasibility and costs would be specific to each site (depending on local supply of biomass and on the ability to accommodate production facilities onsite). In the long term, the potential for biomethane as an alternative to natural gas for industrial applications would depend largely on the level of supply compared to demand for renewable gas (and various biomass feedstocks) across the energy sector, including wider renewable heat demand as well as potential road transport applications. Beyond this, this technology is not considered in detail in this study.

Table 8 summarises the suitability of fuel-switching options for the main cross-sectoral processes and identifies the sectors for which these are most relevant. Some fuel-switching technologies can only replace a limited share of the fossil fuel demand for a given process, e.g. due to limitations on output temperatures vs required temperatures. For example, in the case of heat pumps and electric plasma gas heaters, where these are applicable, the electric technologies perform a pre-heating function to replace some of the fossil fuel demand, but some fossil fuel would still be required to achieve the required temperature. In the case of using hydrogen or biomass and waste in primary iron production, it is assumed that replacement of coke on a like-for-like basis will be limited due to the different weight-bearing abilities of other fuels, and the corresponding suitability for large existing blast furnaces.

Table 8: Suitability of fuel switching options for key industrial processes

Processes driven by:	Process type	Sectors relying on these processes	Suitable technologies		
			Biomass & waste	Hydrogen	Electricity
Indirect heating	Steam	Food & Drink, Paper, Chemicals, other industry	Biomass boilers	Hydrogen boilers	Electric boilers Heat pumps (MVR) in limited applications (25% substitution)
	High temperature	Refining, Ethylene & Ammonia		Hydrogen heaters	Electric heaters
	Low temperature	Vehicles, other industry	Biomass boilers	Hydrogen boilers	Electric boilers Heat pumps (25% substitution) Microwave heaters
Direct heating	Reduction processes	Iron production	Direct reduction of biomass (up to 25% substitution)	Direct reduction of hydrogen (up to 25% substitution)	
	High temperature	Glass, Ceramics, Cement, other non-metallic minerals	Biomass / waste combustion (cement only – up to 80% substitution)	Hydrogen heaters / furnaces / kilns	Electric kilns / furnaces Electric plasma gas heaters (25% substitution)
	Low temperature	Vehicles, other industry		Hydrogen heaters	Electric heaters

			Microwave heaters

Based on discussions with industrial stakeholders and technology suppliers, as shown in Figure 7, switching existing processes to hydrogen (either as 100% fuel, or used in combination with gas or other fuels) could potentially be feasible in the full range of cross-sectoral processes, in most sectors. This reflects the relative similarity between hydrogen and natural gas (compared to electricity and biomass). However, only a few industries have experience of combusting hydrogen-rich gases. Engineering design and testing work is required to understand the technical and cost implications for each sector, especially in high temperature processes; management of NO_x emissions could be costly relative to the measures required for natural gas combustion. The feasibility of substitution of hydrogen in iron production is particularly uncertain, and would depend on the counterfactual method of production. Currently, UK primary iron production is blast furnace based, and substitution of hydrogen would be limited to very low percentage of demand. However, in the future, alternative coal-based processes such as HISarna could be compatible with a higher share of fuel substitution. For the purposes of the analysis in this study, it is assumed (based on initial industry feedback) that up to 25% of coal consumption could be replaced.

Biomass & waste could provide opportunities for fuel switching in many sectors, but with the exception of biomethane or synthetic methane from biomass (see discussion on p17), it is not suitable to replace gas in high temperature direct heating applications due to the different chemical and physical properties. However, biomass (or biocoke) could be substituted for coal or coke in cement and iron production. In the case of cement production, the rate of substitution could be increased from 40% to 60%, and ultimately to 80% by using oxygen enrichment. In iron production, the substitution rate is more uncertain, but it has been assumed to be up to 25% for the purposes of this study (reflecting industry feedback).

Various electrification technologies are likely to be suitable for application across the majority of cross-sectoral processes. However, in the case of heat pumps and electric plasma gas heaters, where these are applicable, the electric technologies perform a pre-heating function to replace some of the fossil fuel demand, but some fossil fuel would still be required to achieve the required temperature. Substitution rates are estimated to be 25% for both technologies, based on feedback from industry and technology suppliers. In addition, electrification is not an option for primary iron production due to the reliance on reduction processes alongside combustion (note that electric arc furnaces in the UK already produce steel via secondary production, but this type of steel is not suitable for all the markets served by the UK production).

4.2 Timescales for commercialisation

Although some of the technologies are already commercially available and ready for implementation at certain scales, for most of the options described previously there are various challenges to be addressed before they could be considered by industrial stakeholders as realistic options to drive processes at UK sites. Table 9 summarises the key challenges for implementation, for each fuel type.

Table 9: Key challenges to be addressed for various fuel switching technologies

Fuel type	Main challenges to be addressed for implementation
Electricity	• Reliability • Impact on product quality for direct heating applications
Hydrogen	• Technology availability • Flame temperature & control • Impact on product quality for direct heating applications • Supply of hydrogen • Management of NOx emissions
Biomass/waste	• Reliability of supply • Impact on product quality for direct heating applications

For many fuel-switching technologies (including hydrogen options for most industries), implementation will only be feasible if further evidence on the suitability and reliability of the technologies in certain sectors is provided. Figure 8

Figure 3 shows the possible timescales for when certain technologies could be available for commercial application across UK industry, based on when development and demonstration activities could be feasible according to industry and technology suppliers, and how this could enable progression to commercial applications within different sectors. This informs the estimated technical potential in different years, but the rate of adoption of these technologies within each industry would depend on the particular needs and decision factors for specific sites and as such the diagram does not show the rate of roll-out. In addition, technology implementation would require biomass and hydrogen to be available, and the estimated progression of the technology availability assumes that this is the case. In reality, the availability of all fuel types (and therefore the application of the technologies) will be linked to a range of government and wider energy sector decisions, as well as infrastructure development in sectors affecting the whole of the UK, such as decarbonisation of heat and transport. For example, the roll-out of hydrogen availability in different parts of the UK will impact the timescales for implementation of hydrogen technologies.

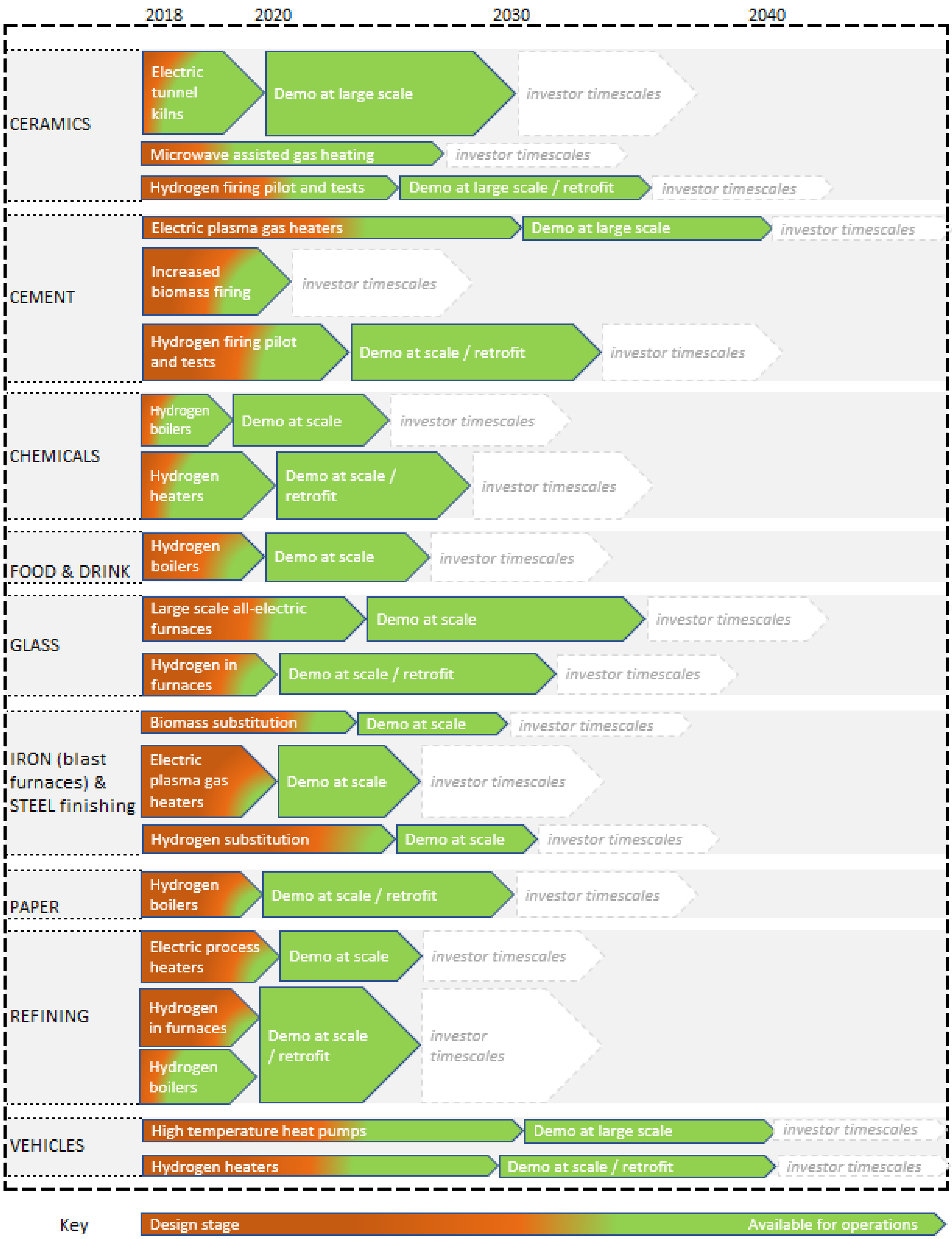


Figure 8: Overview of timelines for technology availability, from the design stage to validation for application beyond demonstration activities (assumes that fuels are available)

Biomass boilers and some electric technologies are already commercially available and in use in some sectors, and are not shown in Figure 8. In contrast, outside of chemicals production and refining (sectors which are experienced in combustion of hydrogen-rich gases), hydrogen heaters and kilns may not be suitable for widespread industrial implementation until around 2035. Investment decision timescales will also factor into the possible implementation roadmap: industrial investments are likely to require a minimum of 5 years between demonstration and commercial implementation, even for choices such as switching from one fuel to another within an existing furnace or kiln. Timescales for full equipment replacement could be longer, as they will depend on the age of the existing infrastructure and will be dependent on a positive business forecast for UK operations.

4.3 Comparison of fuel switching technologies

If there are multiple technologies available for fuel-switching, the most attractive choice from the industry perspective will be determined by the relative economics of the different options. This will depend on fuel costs as well as technology replacement costs. In addition, the emissions savings of the different options relative to the counterfactual will vary. Lifetime costs and emissions relative to the counterfactual technologies can be compared to determine which technologies could be cost-effective to reduce industrial emissions. Although the fuels currently used within specific industrial processes vary from site to site (e.g. depending on whether the site has access to the gas grid), for the purposes of this analysis, the counterfactual technologies (and fuels) are assumed to be the same for any given cross-sectoral process, as set out in Figure 5. On the basis of national fuel consumption data, this is accurate for most industrial sites.

Table 10: Counterfactual technologies for cross-sectoral processes

Processes driven by:	Process type	Counterfactual technology
Indirect heating	**Steam**	Gas boiler
	High temperature	Gas boiler
	Low temperature	Gas boiler
Direct heating	**Primary iron production**	Blast furnace, basic oxygen furnace and sinter plant
	High temperature	Gas fired furnace or kiln Mixed kiln (40% alternative fuels, 60% coal / pet coke) for cement kilns
	Low temperature	Gas fired furnace

4.3.1 Relative emissions savings

Estimated emissions savings from the different technologies can be calculated by considering the fuel consumption over the technology lifetime (a factor of the baseline heat demand and the technology efficiency), and the carbon content of the relevant fuel, compared to that of the counterfactual technologies. As lifetimes vary (e.g. electric technologies typically have shorter lifetimes than gas technologies), emissions savings can be calculated in terms of the difference in average annual emissions.

Table 11 shows the estimated annual emissions savings from different technologies, for technologies installed in 2030, with illustrative site-level process capacities. Assumed technology efficiencies and fuel substitution rates can be found in the Appendix. The carbon content of the various fuel types in 2030 are assumed to be as follows:

- 0.2 kg/kWh for gas[19]
- 0.4 kg/kWh for coal
- 0.03 kg/kWh for biomass and waste (based on domestic solid biomass)
- 0.02 kg/kWh for hydrogen (based on BEIS estimates for centralised production via steam reformation with CCUS)
- 0.11 kg/kWh for electricity (based on BEIS assumptions for decarbonisation of grid electricity)

As shown in Table 11, when the substitution rate is 100%, emissions savings are highest for hydrogen, followed by biomass and electric technologies, reflecting their different carbon factors. However, the substitution rate that can be achieved is the main factor influencing emissions savings for each process. As such, the technologies with the highest potential for emissions savings are those which can completely replace fossil fuel demand in a particular process.

[19] Emissions factors for gas and coal taken from the Treasury Green Book guidance tables (published by BEIS)

Table 11: Annual emissions savings for technologies installed in 2030

Process	Counterfactual (illustrative process capacity)	Fuel switching technology	Estimated average annual emissions savings
Low pressure steam	Gas boiler (7 MW)	Biomass boiler	7.4 tCO_2
		Hydrogen boiler	7.9 tCO_2
		Electric boiler	6.1 tCO_2
		Open loop heat pump (25% substitution rate)	1.6 tCO_2
High pressure steam	Gas boiler (10 MW)	Biomass boiler	11.1 tCO_2
		Hydrogen boiler	11.9 tCO_2
		Electric boiler	9.2 tCO_2
Indirect low temperature	Gas boiler (2 MW)	Biomass boiler	2.6 tCO_2
		Hydrogen boiler	2.8 tCO_2
		Electric boiler	2.2 tCO_2
		Electric process heater	2.2 tCO_2
		Open loop heat pump (25% substitution rate)	0.6 tCO_2
Indirect high temperature	Gas fired furnace (35 MW)	Hydrogen heater (50% substitution rate)	19.1 tCO_2
Direct high temperature	Gas fired kiln (16 MW)	H2 fired kiln (50% substitution rate)	9.3 tCO_2
		Electric tunnel kiln	17.0 tCO_2
Direct high temperature (cement kiln)	Mixed fuel kiln, 40:60 biomass: coal / pet coke (80 MW)	Biomass / waste combustion with oxygen enrichment (increase to up to 80% biomass / waste)	98.5 tCO_2
		Hydrogen combustion (50% substitution of coal / pet coke)	75.6 tCO_2
		Electric plasma gas heaters (25% coal / pet coke substitution)	18.5 tCO_2
Direct high temperature (primary iron production)	Blast furnace or equivalent process (650 MW)	Biomass as a reductant (15% substitution rate)	127.2 tCO_2
		Hydrogen as a reductant (15% substitution rate)	181.4 tCO_2
Direct low temperature	Gas fired furnace (3 MW)	Hydrogen heater (50% substitution rate)	1.7 tCO_2
		Electric tunnel kiln (in ceramics)	3.0 tCO_2

4.3.2 Relative costs

The costs associated with fuel switching technologies and their counterfactual technologies can be compared on a lifetime basis, accounting for the lifetime fuel costs and other operating costs as well as the capital cost. The relative fuel costs associated with biomass and waste, hydrogen and electricity compared to counterfactual fuels (i.e. gas or coal) depend on carbon prices as well as on the price of the fuels.

Most fuel switching technologies will come at a capital cost premium compared to the counterfactual, with the exception of some electric technologies which could have a comparable or lower cost (though in most cases they will have a lower technology lifetime). For most technologies, the capital cost is estimated for replacement (e.g. the cost of a new gas boiler is compared to the cost of a new biomass boiler), as opposed to for the costs of switching to an alternative fuel by making incremental changes to existing equipment. Estimated costs of ancillary items such as onsite biomass storage and emissions clean-up technology are also included in the capital cost for each technology.

Figure 9 shows the present costs over the technology lifetime, for different technology options for provision of low pressure steam for a process with a demand of around 45 GWh per year (approximately 6 MW capacity).

Costs and other technical assumptions for the different technologies are based on industry expertise within Jacobs, supported by information from technology suppliers and other industry experts. Assumptions for each of the technologies are provided in the Appendix. Annual costs are discounted at an annual discount rate of 10% to give the total lifetime cost in terms of "present costs" (in practice, some investors may require a payback period of 5-7 years for new technologies, so the lifetime present costs are not necessarily an indicator of which technologies would be most commercially attractive in the absence of financial incentives).

Fuel price assumptions (based on various assumptions for 2030 onwards) are as follows:

- Gas: 3.5 p/kWh
- Biomass: 2.2p/kWh
- Hydrogen: 6.3p/kWh
- Electricity: 12.9p/kWh (including carbon price)
- Carbon: £77/t (included in electricity price, additional for other fuels depending on emissions)

These central cost scenarios are based on Treasury Green Book central assumptions and best-available estimates for hydrogen, biomass and carbon price (based on Element Energy assumptions agreed in consultation with BEIS).)

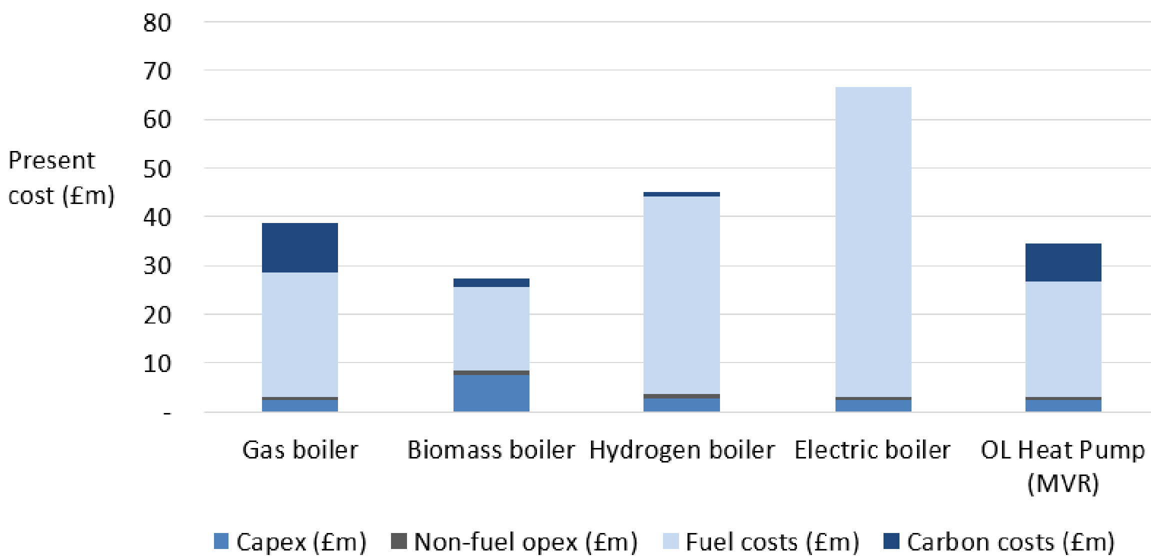


Figure 9: Net present costs[20] for technologies to provide low pressure steam (45 GWh per year, 6 MW capacity)

For the low pressure steam case shown in Figure 9, the biomass boiler is the lowest cost technology on a lifetime present value basis, despite the higher capex: at £7.5 million, it is around three times the price of a gas boiler, compared to a 20% premium for the hydrogen boiler. The electric boiler has a similar capex to the gas boiler. However, for a process of this capacity, fuel costs dominate the lifetime costs, and the low cost of biomass compared to the other fuels makes this the lowest cost technology overall, even compared to the gas boiler.

Heat pumps (mechanical vapour recompression) also have relatively low fuel costs compared to other electric alternatives, due to their high efficiency, and have a lower capex premium than biomass boilers on a thermal output basis. However, heat pumps are assumed to be suitable for displacement of only 25% of low pressure steam demand (due to the heating capabilities of the technology), and as such, part of the counterfactual gas boiler capex and operating costs are also included in the lifetime costs for this technology (including the associated cost of carbon, which make it significantly more costly). Carbon prices around this level could be a major driver for fuel switching, improving the commercial case for the low carbon alternatives to fossil fuels.

Process capacity (i.e. the scale of annual demand on a given site and for its specific processes) has a significant impact on relative technology costs: sites and processes with higher levels of demand benefit from economies of scale (in terms of technology capacity) compared to lower capacity processes, and therefore fuel costs represent a higher share of the total lifetime cost, relative to the capex. To illustrate this, Figure 10 shows the present costs for low pressure steam technologies for a process with a demand of around 2 GWh per year (approximately 300 kW capacity).

[20] Net present cost: capex + discounted annual costs over lifetime (fuel costs, non-fuel opex, and carbon costs). Discounted to 2030 (real) at a discount rate of 10%.

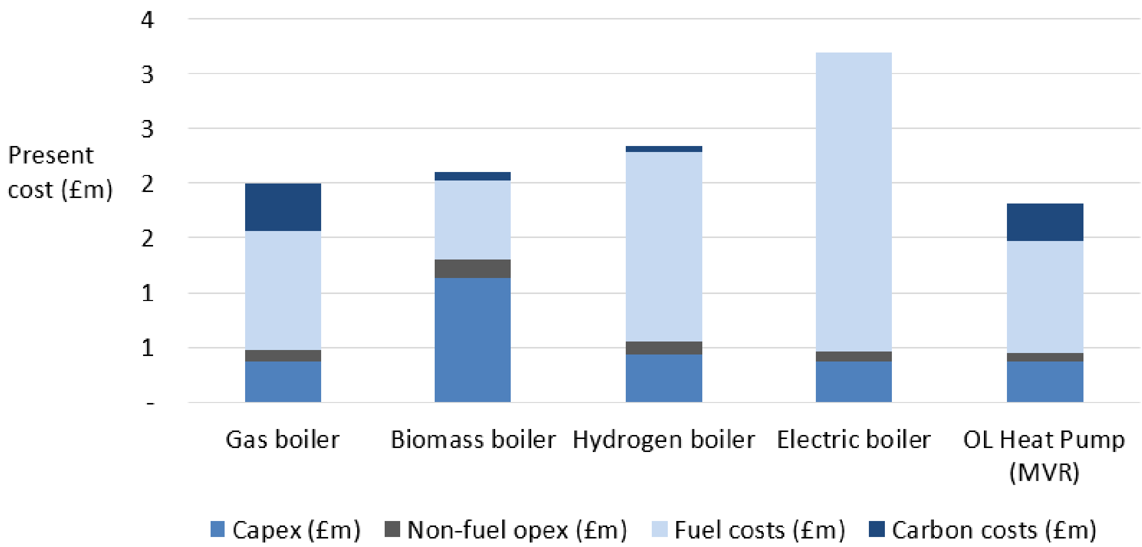


Figure 10: Net present costs[21] for technologies to provide low pressure steam (2 GWh per year, 300 kW capacity)

The resulting trend for this lower demand differs from that shown in Figure 9. Due to the higher ratio of capex to fuel costs for the smaller site, the biomass boiler is more costly than the heat pump over the technology lifetime, despite the higher price of electricity. The hydrogen boiler costs are also closer to the gas and biomass cases here, suggesting that for even lower levels of demand, hydrogen would be more cost-effective solution than biomass, even at the fuel prices assumed here.

Figure 11 compares the lifetime costs for ceramics kiln technologies, for a kiln with a demand of 113 GWh per year (approximately 16 MW capacity).

[21] Net present cost: capex + discounted annual costs over lifetime (fuel costs, non-fuel opex, and carbon costs).

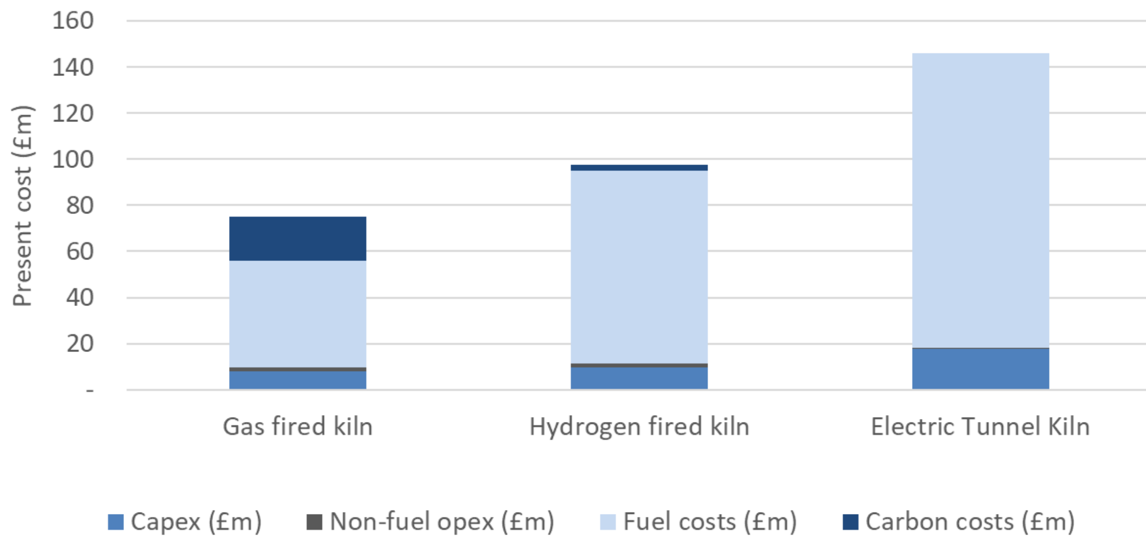


Figure 11: Net present costs[22] for kiln technologies for the ceramics sector (113 GWh per year, 16MW capacity)

In the case of ceramics kilns, biomass is not suitable and therefore under these assumptions, hydrogen kiln would be the lowest cost alternative.

Although the lifetime cost comparisons in Figure 9-Figure 11 only show two different cross-sectoral processes, the trends they demonstrate are reflected across the range of industrial processes. One important takeaway is that if fuel prices in 2030 and beyond are similar to these central assumptions (see p26), many fuel switching technologies will significantly increase industrial operating costs and will not be commercially feasible, even after accounting for carbon costs.

The next chapter sets out the potential for industrial fuel switching and explores the commercial attractiveness of fuel switching technologies under different cost scenarios.

[22] Net present cost: capex + discounted annual costs over lifetime (fuel costs, non-fuel opex, and carbon costs).

5 Potential for industrial fuel switching

5.1 Technical potential

For the purposes of this analysis, it is assumed that each process at a given site can select one fuel-switching technology at a time (even if that technology has a limited substitution rate). In addition to the technical suitability parameters explored in Section 4.1 (p17), technologies which are unlikely to be suitable at a large scale have been assigned a maximum capacity, which means that they will not be applied for large industrial sites[23].

It is assumed that for each process at a given industrial site, the technology with the **lowest cost per tonne of carbon saved** is selected[24]. As cost-effectiveness depends on process capacity, to assess the most cost-effective technology on a site by site basis, the data on suitable fuel consumption within each industry is split to a site level based on the relative emissions of EU-ETS sites (this assumes that the ratio of process emissions to energy-related emissions is equivalent at all sites within a given industry). The remaining energy consumption is split between the estimated number of non-EU-ETS sites. Where possible, sites relying on CHP have been excluded (to reflect CHP fuel consumption not being considered for fuel switching in this study).

The technical potential from the full mix of fuel switching technologies available in 2040 and 2030 is shown in Figure 12 and Figure 13 respectively.

The charts show the technologies selected for each site in order of **cost-effectiveness**. For each site, the cost-effectiveness of all the suitable technologies is calculated on the following basis, from a private perspective:

- Lifetime costs relative to the counterfactual, discounted at 10% (reflecting a private perspective), and including carbon costs (as these costs are expected to be incurred as part of the operating costs)
- Lifetime CO_2 emissions savings relative to the counterfactual
- Fuel costs and emissions assumptions follow a central scenario, similar to the assumptions set out in Section 4.3[25].

The overall technical potential on this basis is estimated to be 89 TWh/year for technologies available in 2040, and 55 TWh for technologies available in 2030 (or in terms of total emissions savings, 15.9 and 9.7 Mt CO_2/year respectively).

[23] Assumed sizing constraints are shown in the Appendix.
[24] Note that due to the variation in technology lifetimes, this is determined based on an annualised version of the lifetime costs
[25] Note the main difference between 2030 (as defined on p27 and p29) and 2040 is the 0.11 kg/kWh for electricity (based on BEIS assumptions for decarbonisation of grid electricity) in 2030; 0.05 kg/kWh in 2040.

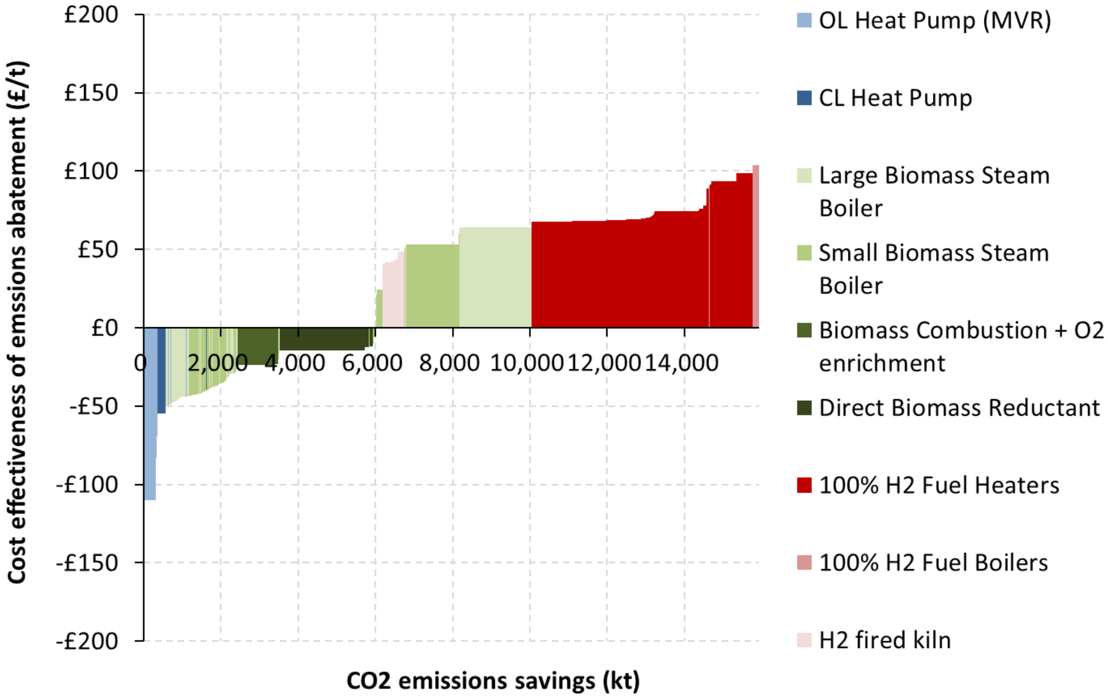


Figure 12: Cost curve for fuel switching technologies available in 2040 (central cost scenario) based on lifetime emissions savings and costs relative to the counterfactual (including carbon costs) discounted at 10% to reflect industry technology choices

The following conclusions can be drawn based on the selection of technologies shown in Figure 12:

- Heat pumps could be highly cost-effective in provision of low temperature heat at sites with low levels of demand
- Under central cost assumptions, biomass technologies are the most cost-effective technology across a range of applications (including steam-driven processes, reduction in blast furnaces and substitution of solid fossil fuels in cement firing)[26]
- Hydrogen technologies are likely to be suitable for many direct heating applications where biomass is not suitable, accounting for 45% of the total potential for fuel-switching (despite the maximum assumed substitution rate of 50% for most direct heating applications)

Figure 13 shows the technical potential based on technologies available in 2030.

[26] Note that this assumes sufficient availability of UK solid biomass; the total biomass demand for industrial energy was estimated at 5 TWh in 2016, so the scenario shown represents a drastic increase in demand. Even meeting the potential demand from the steel sector alone (in the region of 10 TWh per annum) could prove to be disruptive to the biomass market and could drive up prices considering the potential demand for biomass in other energy sectors.

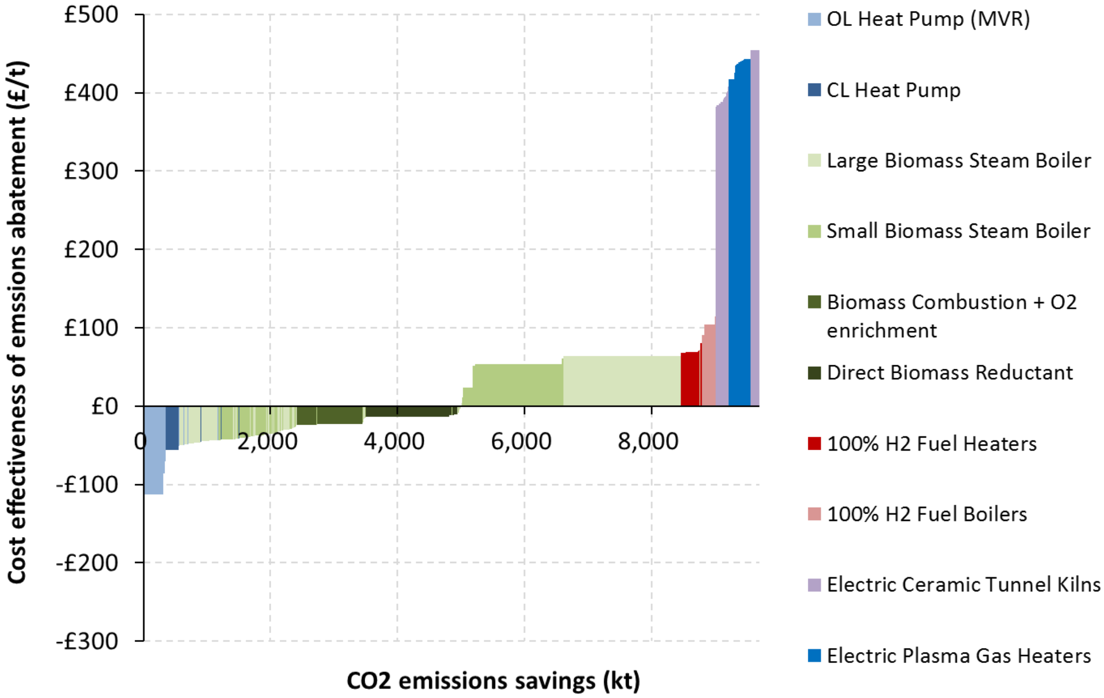


Figure 13: Cost curve for fuel switching technologies available in 2030 (central cost scenario) based on lifetime emissions savings and costs relative to the counterfactual (including carbon costs) discounted at 10% to reflect industry technology choices

Most of the biomass applications and electric technologies selected as part of the 2040 potential are already commercially available and widely used in some sectors today (and thus are still part of the 2030 potential). However, hydrogen heaters and kilns are at lower TRL levels and may not be suitable for widespread industrial implementation outside chemicals production and refining until around 2030-2035, meaning that the only options for the corresponding direct heating applications in 2030 would be electrification (where this is available). This is largely due to the lack of supply of hydrogen as a fuel (for industry and for the wider energy sector). Rapid development and testing of hydrogen solutions could be essential for realisation of the full potential for fuel switching, but this would also depend on timescales for making hydrogen widely available (e.g. via the gas grid). It is possible that technologies could be implemented earlier, if demonstrated and proven quickly.

Table 12 shows the technical potential for fuel switching in 2030 and 2040 when only one alternative fuel type is considered across all applications, and also for the scenarios where there is a) no hydrogen availability, b) no biomass availability and c) all fuels are available. The weighted average cost is calculated based on the total annual costs and emissions savings achieved by the selected technologies across all sites.

Table 12: Technical potential for fuel switching, by fuel type

Fuel type	Technologies available in 2030 Potential emissions savings	Replaced fuel consumption	Weighted average cost	Technologies available in 2040 Potential emissions savings	Replaced fuel consumption	Weighted average cost
Biomass/waste[27]	9.4 Mt CO_2/year	52.7 TWh/year	£ 24.0 /tCO_2	10.3 Mt CO_2/year	55.6 TWh/year	£ 20.3 /tCO_2
Hydrogen	7.8 Mt CO_2/year	47.9 TWh/year	£ 79.6 /tCO_2	17.7 Mt CO_2/year	95.7 TWh/year	£ 66.6 £/tCO_2
Electricity	5.8 Mt CO_2/year	43.9 TWh/year	£ 308.5 /tCO_2	7.3 Mt CO_2/year	45.9 TWh/year	£ 259.1 £/tCO_2
Biomass/waste and electricity (no hydrogen)	9.4 Mt CO_2/year	53.9 TWh/year	£ 41.7 /tCO_2	10.7 Mt CO_2/year	57.9 TWh/year	£ 41.5 /tCO_2
Hydrogen and electricity (no biomass /waste)	7.8 Mt CO_2/year	48.7 TWh/year	£ 99.2 /tCO_2	16.9 Mt CO_2/year	90.5 TWh/year	£ 59.3 /tCO_2
All fuels available	9.7 Mt CO_2/year	55.3 TWh/year	£ 38.6 /tCO_2	15.9 Mt CO_2/year	89.4 TWh/year	£ 30.8 /tCO_2

The results in Table 12 indicate that hydrogen has the highest potential overall (at 95.7 TWh by 2040, 78% of the total fuel consumption in scope), although around half of this only becomes available after 2030. In addition, under central fuel cost assumptions, the total cost of fuel switching to hydrogen technologies alone is a much more costly approach to reducing emissions than switching to biomass technologies alone, due to the much higher cost of hydrogen (compared to biomass) assumed to apply in 2030 and 2040. Electrification is the most costly option overall (due to the high price of electricity), and also has the lowest potential.

In the no hydrogen scenario, the potential emissions savings in 2040 are slightly higher than in the biomass only scenario, as electric technologies can be applied for a few of the direct high temperature applications that biomass is not suitable for (see Table 8 on p18). However, these technologies are very costly, due to the high electricity price, and they are not suitable for all the processes that can be covered by hydrogen, so the total potential is lower than for the scenario shown in Figure 12 (all fuel types), and comes at a higher average cost to industry. The selected technologies in this scenario are shown in Figure 14 (see also Figure 12 for comparison).

[27] Note that meeting the increased demand for biomass from industry under these fuel-switching scenarios could prove to be disruptive to the biomass market and could drive up prices considering the potential demand for biomass in other energy sectors.

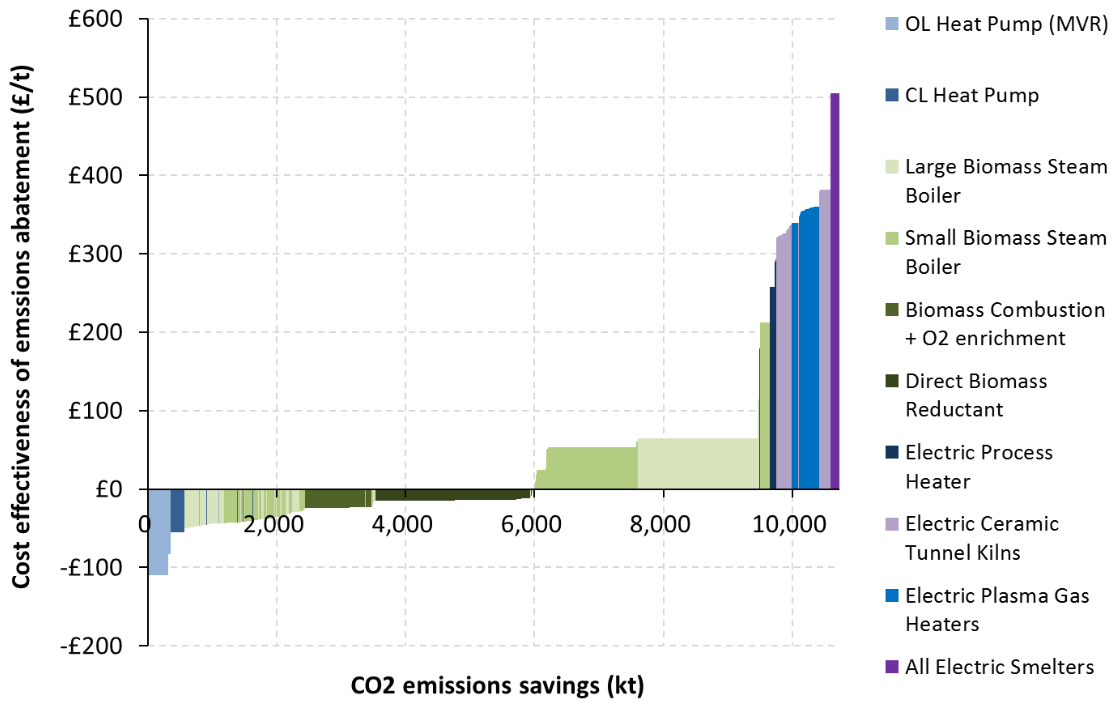


Figure 14: Cost curve for fuel switching technologies available in 2040 (central cost scenario, no hydrogen) based on lifetime emissions savings and costs relative to the counterfactual (including carbon costs) discounted at 10% to reflect industry technology choices

The "no biomass" scenario (shown in Figure 15) can also be compared with the "all fuels" scenario (Figure 12); the overall potential in 2040 is very similar to the case where only hydrogen and electricity are available, as hydrogen technologies are assumed to be suitable for most of the same processes as biomass. However, for technologies available in 2030, the potential is lower in the case where no biomass is applied, due to the additional time that is expected to be required for hydrogen technologies to become widely applicable. As relative costs depend on fuel prices to a large extent, under central cost assumptions[28], the "no biomass" scenario is more costly than the "all fuels" scenario. In terms of technology choices for specific applications, this is mainly due to the replacement of biomass boilers with hydrogen boilers, and the use of hydrogen instead of biomass in cement and iron production. A version of the cost curve for "all fuels" (Figure 12) which considers a higher price for biomass is shown in Figure 16; the key difference is that when the biomass cost is increased from 2.2p/kWh to 3.1p/kWh (all other costs being constant), biomass technologies become more expensive and as a result, 38% of the demand for biomass boilers switches to hydrogen boilers (on the basis that they become more cost-effective on a lifetime basis).

[28] In the central fuel cost scenario, fuel prices in 2040 are assumed to be 3.5p/kWh for gas, 1.5p/kWh for coal, 6.3p/kWh for hydrogen, 2.2p/kWh for biomass and 12.9p/kWh for electricity

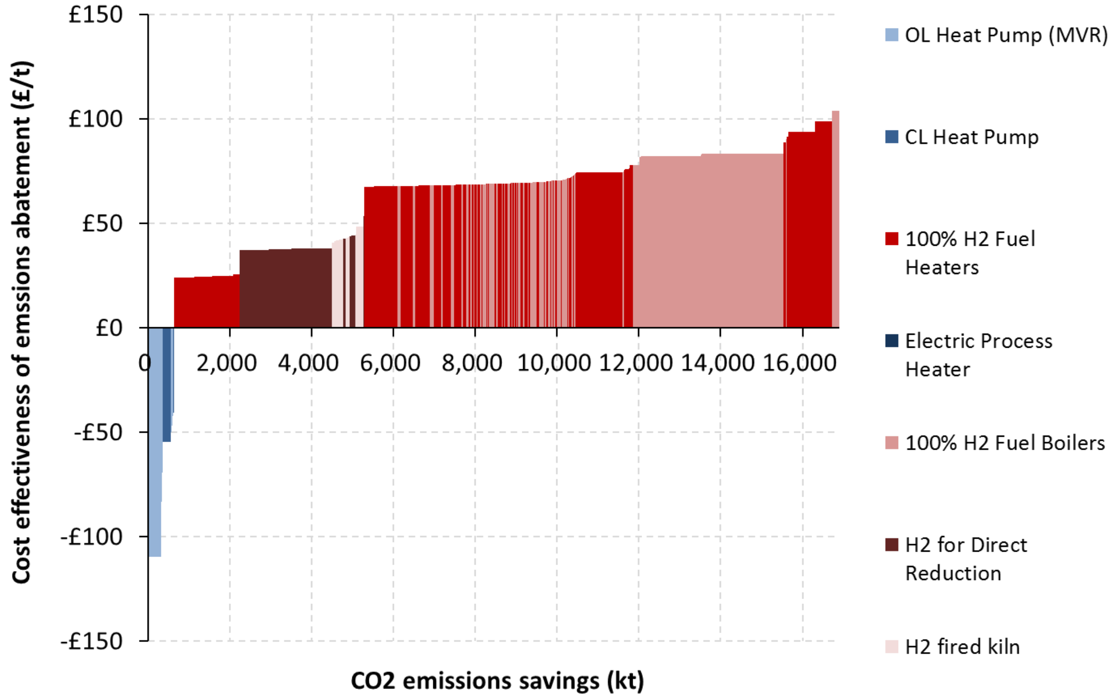


Figure 15: Cost curve for fuel switching technologies available in 2040 (central cost scenario, no biomass) based on lifetime emissions savings and costs relative to the counterfactual (including carbon costs) discounted at 10% to reflect industry technology choices

A table of various sensitivities on the results shown in this section of the report (including different discount rates and fuel price scenarios) and their impact on the selected technologies can be found in the Appendix.

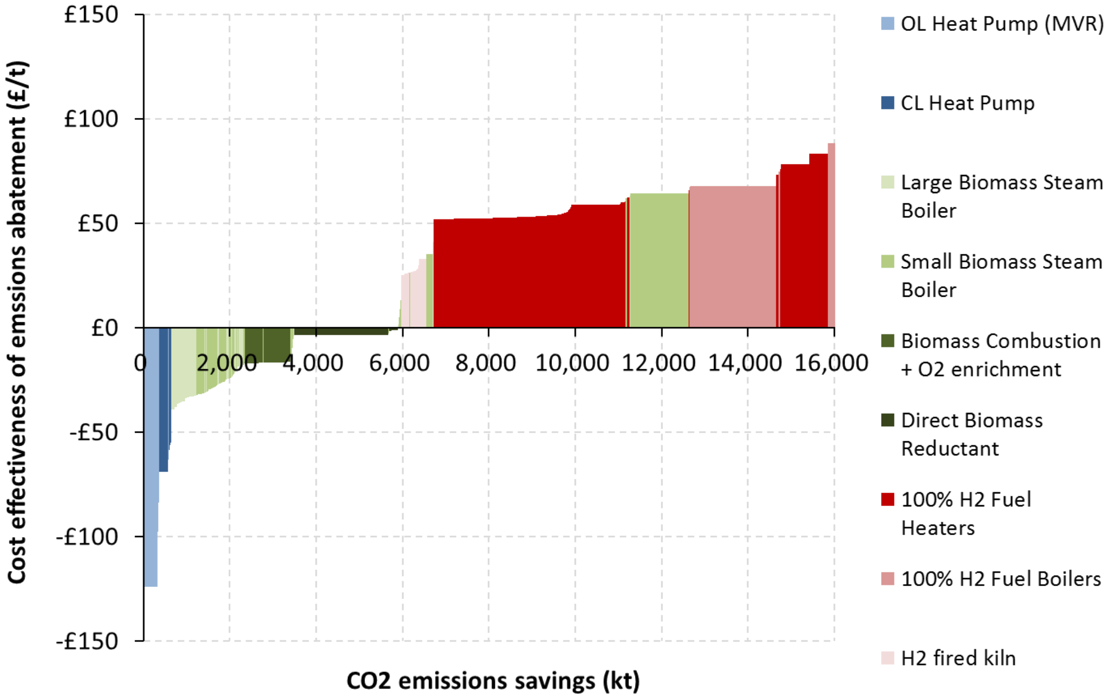


Figure 16: Cost curve for fuel switching technologies available in 2040 (high biomass cost scenario) based on lifetime emissions savings and costs relative to the counterfactual (including carbon costs) discounted at 10% to reflect industry technology choices

5.2 Cost requirements for commercial application

As explored in Section 4.3.2 (see p25), many fuel switching technologies have higher capex than the counterfactual technologies. Although some form of fuel switching could be technically feasible for all processes, in the absence of subsidies investment in these technologies would only be commercially justifiable if capex premiums could be recovered through savings in the operational costs.

Operational costs are dominated by fuel costs. The relative fuel costs associated with biomass and waste, hydrogen and electricity compared to counterfactual fuels (i.e. gas or coal) depend on carbon prices as well as on the price of the fuels.[29] Due to the significance of operational costs in industry, fuel and carbon prices will be a major driver of fuel switching technology choices. However, the fuel price at which fuel-switching technologies would become commercially viable also depends on the future cost premiums for these technologies, which are by no means certain (especially for those technologies which have yet to be implemented at scale).

Table 13 provides some examples of capex premiums for alternatives to gas boilers and furnaces, and the estimated fired fuel price differentials that would be required to recover these costs over a five year period (reflecting the assumed investment criteria for a new technology). Results are shown for two different boiler capacities, to illustrate the fact that larger sites benefit from economies of scale and therefore require

[29] In the case of electricity, electricity price projections already account for the projected carbon price and the equivalent industrial price for the overall grid electricity generation mix (Green Book Guidance Tables 4-8, central scenario).

marginally lower fuel price savings per kWh, compared to smaller sites (see 6 MW boiler and 300 kW boiler comparisons).

Table 13: Fuel price differentials (compared to counterfactual fuels) required for undiscounted 5 year payback of fuel switching technologies

Counterfactual	Fuel switching technology	Technology capex premium	Fuel price for break even (with no carbon price)	Fuel price for break even (assuming carbon price of £77/t)	Fuel price in central cost assumptions (in 2040)[30]
Gas boiler (6 MW)	Biomass boiler	£4.8m	0.2 p/kWh lower than gas	**Up to 1.0 p/kWh more expensive than gas**	**1.4 p/kWh cheaper than gas**
	Hydrogen boiler	£0.5m	0.02 p/kWh lower than gas	Up to 1.2 p/kWh more expensive than gas	2.8 p/kWh more expensive than gas
	Electric boiler	-£0.6m	Electricity price must be equivalent to fired gas cost	Up to 1.4 p/kWh more expensive than gas	9.3 p/kWh more expensive than gas (grid electricity)
Gas boiler (300 kW)	Biomass boiler	£0.8m	0.7 p/kWh lower than gas	**Up to 0.5 p/kWh more expensive than gas**	**1.4 p/kWh cheaper than gas**
	Hydrogen boiler	£0.08m	0.07 p/kWh lower than gas	Up to 1.2 p/kWh more expensive than gas	1.6 p/kWh more expensive than gas
	Electric boiler	No premium	Electricity price must be equivalent to fired gas cost	Up to 1.4 p/kWh more expensive than gas	8 p/kWh more expensive than gas (grid electricity)
Gas furnace (22 MW)	Hydrogen burners	£1m	0.01 p/kWh lower than gas	Up to 1.2 p/kWh more expensive than gas	2.8 p/kWh more expensive than gas
	Electric furnace	No premium	Electricity price must be equivalent to fired gas cost	Up to 1.4 p/kWh more expensive than gas	8 p/kWh more expensive than gas (grid electricity)

Based on estimated capex premiums, in the absence of a carbon price for industrial fuel consumption, biomass needs to be at least 0.2 p/kWh cheaper than gas in order for biomass boilers to achieve a 5 year undiscounted payback period. Under the central assumptions of this study, it is assumed to be 1.4p/kWh cheaper than gas in 2030, and as such is deemed to be a cost-effective fuel switching option. Furthermore,

[30] In the central fuel cost scenario, fuel prices in 2040 are assumed to be 3.5p/kWh for gas, 1.5p/kWh for coal, 6.3p/kWh for hydrogen, 2.2p/kWh for biomass and 12.9p/kWh for electricity, and a carbon price of £77/t. This translates to a carbon cost saving (relative to gas) of 1.19 p/kWh for biomass, 1.25 p/kWh for hydrogen, and 1.42 p/kWh for electricity. Electricity is assumed to come from the grid.

with a carbon price of £77/t and a biomass carbon content of 0.03 kg/kWh (including life cycle emissions) in line with the central assumptions for this study, the biomass price could be up to 1 p/kWh higher than the price of gas for technologies to achieve undiscounted payback.

Hydrogen would need to be less than 0.1 p/kWh cheaper than gas to achieve a five year undiscounted payback period for boilers and furnaces (in the absence of a carbon price). Even with a carbon price of £77/t, the hydrogen price for undiscounted payback could only be up to 1.2p higher than the price of gas, whereas under central assumptions it is estimated to have a premium of 2.8 p/kWh (based on central cost estimates for hydrogen produced centrally via reformation of methane, combined with CCUS, and distributed via the existing gas grid).

For electric technologies such as electric boilers, kilns and furnaces, capital costs could be lower or equivalent to their fossil fuel counterparts. However, for fuel switching to be considered, operating costs would also need to be equivalent, meaning that after accounting for the higher efficiency of electric heating options, the cost of electricity would need to be within 4%-7% of the price of gas. With no carbon price imposed on industrial gas combustion, this translates to a maximum margin of 0.1-0.2 p/kWh (for a gas price of 3p/kWh), or up to 1.6 p/kWh with a carbon price of £77/t. However, central assumptions have grid electricity at a premium of 9 p/kWh compared to the price of gas in 2030, meaning that the operating costs for these technologies far exceed their gas equivalents. However, heat pumps (which could be applicable for low temperature processes with thermal demand in the hundreds of kW) are likely to achieve payback, due to their very high efficiencies (with fuel consumption around one quarter that of equivalent boilers). Furthermore, some industrial sites could have the option to generate their own renewable electricity onsite, which could make electricity more affordable, depending on the cost of storage.

The impact of lower alternative fuel prices on the commercial potential of fuel switching technologies within each fuel type is shown in Table 15. As with the technical potential, the commercial potential is based on selecting the most cost-effective technology for each site, but it only includes technologies that achieve a 5 year discounted payback period[31] compared to the counterfactual technology. This means that the only technologies included are those where the total operational costs (i.e. mainly fired fuel costs) are equivalent or lower than those of the counterfactual. The assumed fuel and carbon prices behind these estimates are shown in Table 14. The central cost scenarios are based on Treasury Green Book central assumptions and best-available estimates for hydrogen and biomass from recent BEIS studies. The low costs for each of the alternative fuels have been selected to show the scenario under which each of these fuels could begin to be a commercially feasible option for fuel switching.

Table 14: Fuel price assumptions (price in 2040)

Fuel type	Low cost scenario	Central cost scenario	High biomass cost scenario
Coal / coke[32]	1.5 p/kWh	1.5 p/kWh	1.5 p/kWh
Gas	3.5 p/kWh	3.5 p/kWh	3.5 p/kWh
Biomass/waste [33]	**1.4 p/kWh** (36% decrease vs central cost scenario)	2.2 p/kWh	**3.1 p/kWh** (41% increase vs central cost scenario)

[31] Assuming a 10% discount rate, to reflect the case for an industrial investor
[32] Fuel costs for coal & coke, gas and electricity come from Treasury Green Book Guidance Tables, central scenario)
[33] High biomass costs in line with ESME upper bounds for UK biomass in 2050; central and low costs in line with scenarios for UK solid biomass in AEA's UK and Global Bioenergy Resource report for DECC (note that these are also closely aligned to Ricardo (2017) central estimates for UK pellets and ESME lower bound for UK biomass)

Hydrogen	**4.0 p/kWh** (36% decrease vs central cost scenario)	6.3 p/kWh	6.3 p/kWh
Electricity	**4.0 p/kWh** (69% decrease vs central cost scenario)	12.9 p/kWh	12.9 p/kWh
Carbon	£77/t	£77/t	£77/t

Table 15: Estimated commercial potential (based on 5 year discounted payback) for fuel switching in 2040, under different scenarios

	Low fuel cost scenario		Central fuel cost scenario		High biomass fuel cost scenario	
Fuel type	**Potential emissions savings**	**Replaced fuel consumption**	**Potential emissions savings**	**Replaced fuel consumption**	**Potential emissions savings**	**Replaced fuel consumption**
Biomass/waste	3.8 Mt CO_2/year	12.3 TWh/year	3.5 Mt CO_2/year	10.9 TWh/year	1.7 CO_2/year	4.9 TWh/year
Hydrogen	0.3 Mt CO_2/year	1.7 TWh/year	None	None	-	-
Electricity	0.6 Mt CO_2/year	3.7 TWh/year	0.6 Mt CO_2/year	3.7 TWh/year	-	-
Biomass/waste and electricity (no hydrogen)	4.4 CO_2/year	16.0 TWh/year	4.2 CO_2/year	14.5 TWh/year	2.4 CO_2/year	8.5 TWh/year
Hydrogen and electricity (no biomass /waste)	0.9 CO_2/year	5.3 TWh/year	0.6 CO_2/year	3.7 TWh/year	-	-
All fuels	4.7 CO_2/year	17.7 TWh/year	4.2 CO_2/year	14.5 TWh/year	2.4 CO_2/year	8.5 TWh/year

Figure 17 illustrates which technologies are included in the commercial potential in each fuel cost scenario and their relative emissions savings potential, providing an indication of which technologies are most likely to be attractive to investors. However, there are various site-specific factors which may influence technology costs and choices (such as the availability of renewable electricity generated onsite, or limited access to the gas grid which could be used to supply hydrogen in the future).

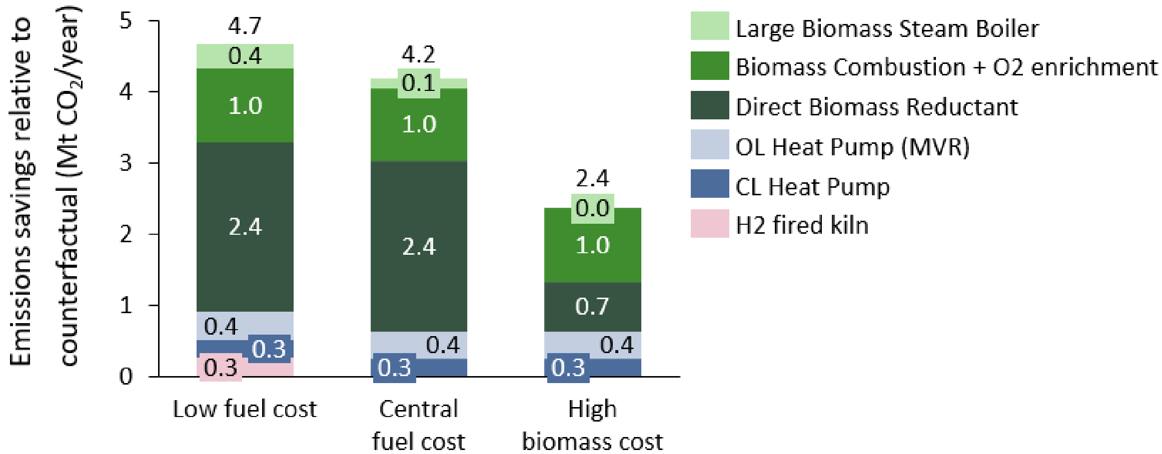


Figure 17: Breakdown of commercial potential by emissions savings per technology under different fuel cost scenarios (all fuel types considered)

5.3 Opportunities for specific industrial sectors

The following pages summarise the key fuel-switching options for the main energy intensive industries in the UK, exploring the costs, possible timescales and innovation opportunities for each technology.

Iron & Steel

Sector background

41 TWh/yr fuel consumption

12.8 $MtCO_2$/yr EU ETS emissions

7 Major sites

Economic contribution: As of 2016, the UK steel industry employed 32,000 people, with an economic output of £1.6 billion, 0.1% of the UK economy.

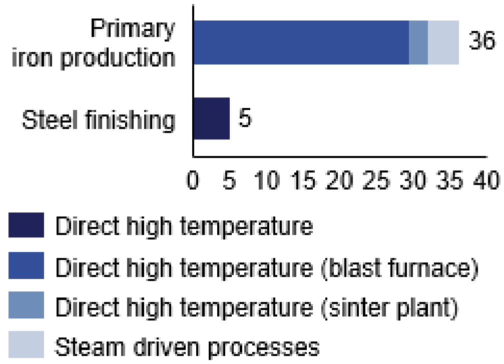
Typical characteristics: sites are often large scale, with many high temperature processes over 1000°C and emissions from a single iron & steel plant may be over 5 $MtCO_2$/yr.

Key processes: Primary extraction of iron in the blast furnace using coal, secondary electric production and steel rolling and finishing.

Fuel consumption

- Consumption of coal to make coke for use in the blast furnace (heating and reductant) dominates the fossil fuel consumption. Blast furnace heating accounts for over 85% demand. Some substitution or replacement with HISarna process may be possible.
- In secondary production via Electric Arc Furnace, nearly all of the current energy use is in the form of electricity.

Annual fuel consumption (TWh)



Suitable processes & technologies for fuel switching

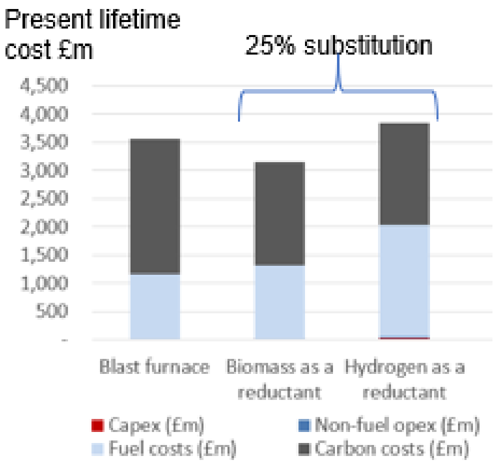
Sector	Process	High level process	Counterfactual technology	Suitable technologies
Steel finishing	Rolling	Direct - High Temperature	Natural gas fired furnace	Electric Plasma Gas Heaters, 100% H_2 Fuel Heaters
Primary iron production	Melting	Direct - High Temperature (Basic oxygen furnace and Blast furnace)	Blast furnace Efficiency improvements of 10% beyond 2030 (not including coking plant)	Direct Biomass Reductant, Electric Plasma Gas Heaters, H_2 for Direct Reduction

- Some UK sites are considering replacing traditional blast furnaces with the more efficient HISarna process, which uses coal directly rather than producing coke. This may accommodate some fuel switching towards biomass or hydrogen.
- Biomass gasification to produce syngas fuel is also an option to directly replace natural gas.

Key references: UK Steel industry: statistics and policy, briefing paper 2018

Iron & Steel

Fuel switching options



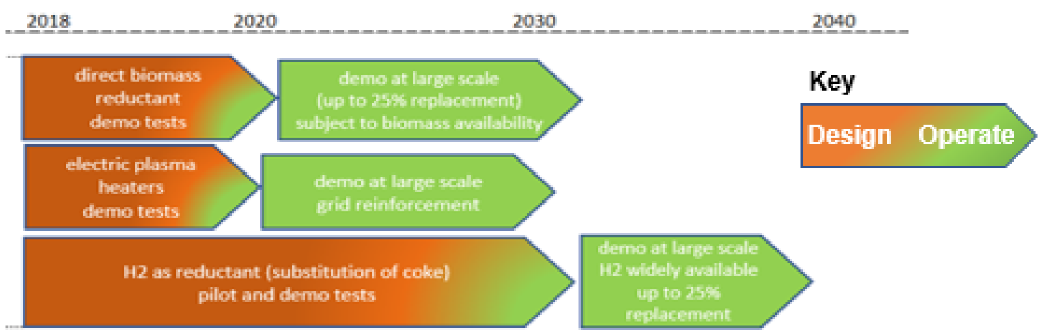
Biomass is low cost, very low emissions & suitable for off-grid. However supply capacity is uncertain. Can be used as feedstock to blast furnace or syngas for steel furnaces.

Electricity has high fuel cost, but can be highly efficient with no onsite emissions. Increasing EAF and electric plasma heaters.

Hydrogen is not cost effective for most processes, but has potential for direct switch with natural gas. Can be used directly as reductant, for combustion or in HYBRIT process.

Technology demonstration timelines

- Partial substitution of coal for biomass, electricity or hydrogen could be feasible by 2020, but implementation is likely to depend on other long term plans for decarbonisation.
- Iron production: small number of trials globally which are exploring substitution of coke with other fuels such as biomass and hydrogen. Evidence from these projects required before implementation.
- Use of hydrogen heaters for steel finishing: initial UK trials could be possible in the relatively near term.



Alternative decarbonisation options

- **HYBRIT process** is a disruptive technology allowing a **100% shift to hydrogen** for liquid steel production in the pilot plant trialling stage. UK steelmakers more likely to shift to a BF/BOF derivative like HiSarna.
- ULCOWIN and ULCOLYSIS are **emerging electric technologies** for replacing BF/BOF route
- **Recycle plastic** is already being used as a feedstock to the blast furnace in Austria with waste plastics pulverization and Blast Furnace injection used in Japan since 1996.
- **Biocoal from woodchip** is being research for use directly in blast furnaces.

Food & Drink

Sector Background

28 TWh/yr fuel consumption

2.3 $MtCO_2$/yr EU ETS emissions

Thousands of sites

Economic contribution: Accounts for 17% of UK manufacturing GVA, with a contribution of £28 billion to the economy, and employs 400,000 people.

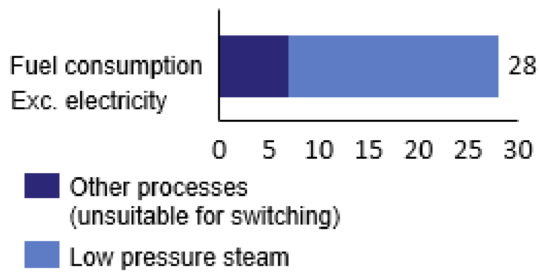
Typical characteristics: 96% of the manufacturing businesses are SMEs. Plants are highly diverse, often of small scale and distributed widely across the UK.

Key processes: Processes are diverse, including drying, baking, chilling, pasteurisation and distillation.

Fuel consumption

- The fuel consuming processes are diverse.
- Many of these processes can be categorised as "Low temperature heat" or "Drying" both of which can be driven by low pressure steam.
- Energy use is primarily natural gas (66%), with boilers and direct heating representing 54% and 27% of energy consumption in the sector respectively.

Annual fuel consumption (TWh)



Suitable processes & technologies for fuel switching

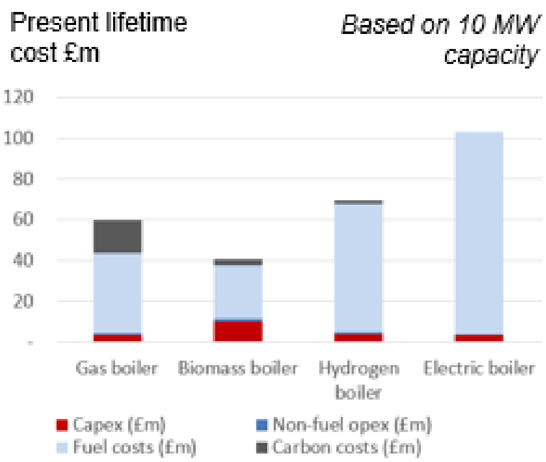
Process	Cross-sectoral process	Counterfactual technology	Suitable fuel switching technologies
Low temp heat	Indirect - Low Pressure Steam	Natural gas boiler	Large Biomass Steam Boiler, Small Biomass Steam Boiler, Electrode steam boiler, Immersion Steam Boiler, 100% H2 Fuel Boilers
Drying	Indirect - Low Pressure Steam	Natural gas boiler	Large Biomass Steam Boiler, Small Biomass Steam Boiler, Electrode steam boiler, Immersion Steam Boiler, 100% H2 Fuel Boilers

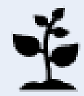
- The primary options focus on **replacing natural gas in boilers** with biomass, hydrogen or electric boilers, for use in steam generation.
- **Electrification of heat** is one of the most important options for decarbonizing. Low temperature processes may utilise heat pumps to reduce fuel consumption.
- 8% of the energy demand from the food & drink sector currently comes from off-grid sites, using oil and solid fuels. Biomass, bioLNG and bioLPG could be alternative options here.

Key references: https://www.fdf.org.uk/publicgeneral/FDF-GT-Exec-Summary.pdf

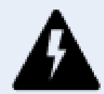
Food & Drink

Fuel switching options





Biomass is low cost, very low emissions & suitable for off-grid. However supply capacity is uncertain. Biomass use is already widespread.

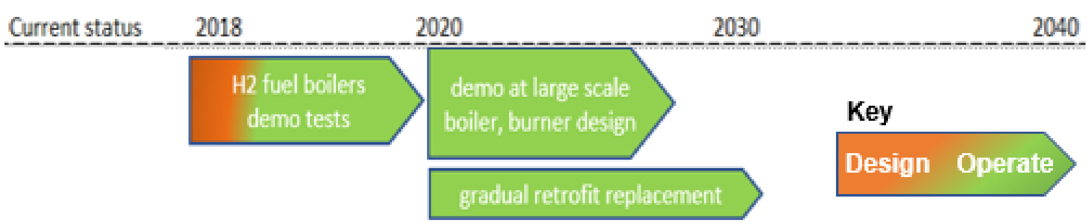


Electricity has high fuel cost, but can be highly efficient with no onsite emissions. Low temperature processes can utilise heat pumps. Electric boilers can also contribute.

Hydrogen can be directly switched for natural gas in boilers, but is not currently cost effective in the key food & drink processes, such as low pressure steam generation.

Technology demonstration timelines

- Biomass boilers are already commercially available. Their use in the food & drink sector will depend on the long term biomass strategy and availability of sustainable sources of biomass.
- Other indirect heating technologies (hydrogen heaters/boilers) are likely to be suitable for gradual fuel-switching approach, where e.g. one burner at a time is replaced, or a blend of fuels is used. These could potentially be implemented in the relatively near term, by 2020, subject to shared learnings from e.g. trials by the first industrial adopters.



Alternative decarbonisation options

- Heat pumps using heat recovered from waste streams, for use in processes such as drying, boiling, distillation.
- Electric ovens for drying, boiling and baking.
- Increased use of microwave technologies for niche applications, including continuous drying.
- Mechanical vapour recompression to generate heat using vapour from an evaporator.
- UV pasteurisation or sterilisation and infrared for heating.
- Anaerobic digestion utilising waste food for biogas as a fuel for boilers or CHP.
- Biological hydrogen produced from food waste via fermentation

Cement

Sector background

8.1 TWh/yr fuel consumption

6.8 $MtCO_2$/yr EU ETS emissions

11 Major sites

Economic contribution: UK cement production revenue was around £0.95 billion in 2017, employing around 4000 people.

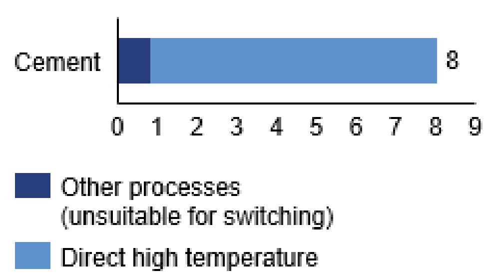
Typical characteristics: Clinker production capacity is ~11 Mt/yr, with site CO_2 emissions typically 0.2 – 1 $MtCO_2$/yr; some are direct process emissions. Plants are of reasonable size and are often in isolated locations.

Key processes: Heating raw materials, such as limestone to produce clinker. Pre-calcining and clinker production in the rotary kiln (1450°C), as well as crushing and grinding.

Fuel consumption

- The most energy-intensive steps in the production of cement are driven by 'Direct High temperature' heat. Alternative technologies are available, but suitability is limited.
- In 2015, 42% of fuel in the UK cement industry came from waste material, typically waste incineration or mixed biomass.

Annual fuel consumption (TWh)



Suitable processes & technologies for fuel switching

Sector	Process	High level process	Counterfactual technology	Suitable technologies
Cement	Kiln firing	Direct - High Temperature	Mixed kiln – 40% biomass, 60% coal	Biomass combustion (+ O2 enrichment), Electric Plasma Gas Heaters, H_2 Fuel Heaters

- Increased substitution of coal with biomass in cement production is likely to be the most cost-effective technology by far, largely due to the lower fuel costs compared to hydrogen and electricity. Even after accounting for the carbon price, hydrogen and electricity costs are too high for these fuels to be cost-effective.
- Suitability of alternative technologies will depend on the format in which this heat must be applied for a particular product, and the level of sensitivity of the products to different fuels and temperatures.

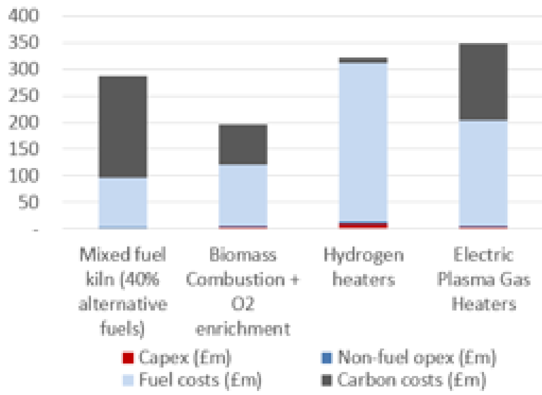
Key references: IBISWorld cement manufacturing UK market research report 2018

Cement

Fuel switching options

Present lifetime cost £m

c.80 MW capacity



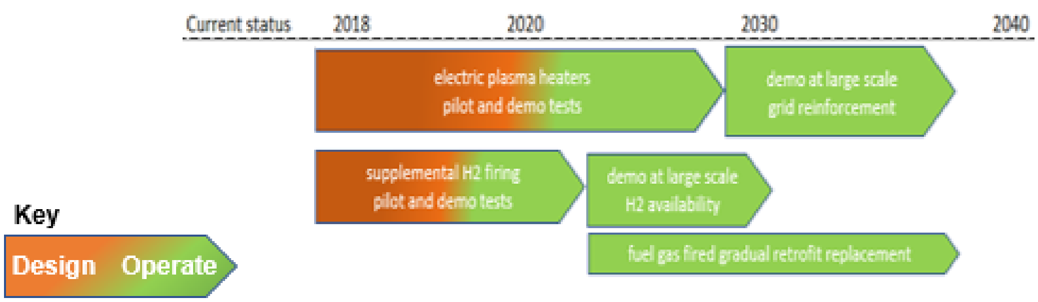
Biomass & waste is low cost, very low emissions & suitable for off-grid. However supply capacity is uncertain. Already widely used for combustion.

Electricity has no onsite emissions but the high fuel cost makes it uneconomic. Waste heat recovery generation and electrically heated kilns are being researched.

Hydrogen performs reasonably on cost but hydrogen firing does not present an attractive option due to kiln off-gases. Also, isolated location difficult for new pipelines.

Technology demonstration timelines

- Biomass technologies are already commercially available. However, the extent of their use will be dependent on the long term strategy and availability of sustainable sources of biomass.
- Electric and hydrogen technologies would need to be proven at scale before being adopted beyond trials or demonstrations, to determine the specific technical design requirements and associated costs. The potential for electric plasma heaters is being looked at under the CemZero program, which considers penetration rates up to 25% (in 2040), due to the high level of uncertainty given the low TRL of the technology.



Alternative decarbonisation options

- There has been some work on **alternative cement formulations** with lower energy of production, although not yet widely adopted yet. Replacing energy-intensive clinker production through blending in other materials (**Cementitious substitution**) such as pulverised fuel ash or blast furnace slag is technically feasible and already implemented.
- **Oxygen enrichment** also can be used to enhance stable and consistent combustion of low-quality alternative fuels with low heating value and larger particle size.
- **Electrification** of kiln thermal heats loads by, for example, use of plasma technology to produce hot gas using electricity. Limestone deposition by electrolysis, replacing kilns. TRL is low and disruption is high.

Glass, Ceramics & non-metallic minerals

Sector background

26 TWh/yr fuel consumption

4.0 $MtCO_2$/yr EU ETS emissions

Hundreds of sites

Economic contribution: Glass, ceramic and other non-metallic minerals sectors combined employ over 30,000 people, with a revenue of over £8 bn. (Ceramics 20,000 and £2 bn).

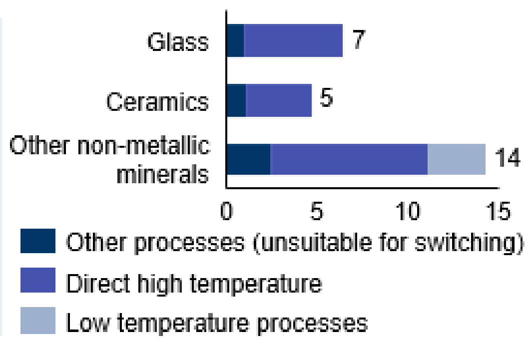
Typical characteristics: A large proportion of firms are SME's with diverse products & much of the fuel-switching demand is concentrated in the Midlands, based around kilns and furnaces.

Key processes: Processes include melting raw materials in a furnace, extrusion, moulding forming, pressing and annealing.

Fuel consumption

- The most energy-intensive processes are driven by 'Direct High temperature' heat. Use of alternative technologies depends on the format in which this heat must be applied for a particular product, and the level of sensitivity of the products to different fuels and temperatures.
- The majority of energy consumption is currently natural gas for heating.

Annual fuel consumption (TWh)



Suitable processes & technologies for fuel switching

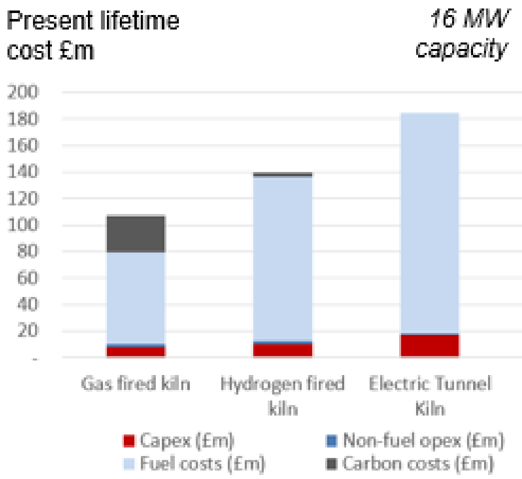
Sector	Process	Cross-sectoral process	Counterfactual technology	Suitable fuel switching technologies
Glass	Melting and annealing	Direct - High Temperature	Natural gas fired furnace	All Electric Smelters, H_2 Fuel Heaters
Ceramics	Kiln firing	Direct - High Temperature (kiln)	Natural gas fired kiln	Electric Kilns, H_2 fired kiln
Non metallic minerals	High temperature processes	Direct - High Temperature	Natural gas fired furnace	H_2 Fuel Heaters
Non metallic mineral	Low temperature processes	Indirect - Low pressure steam	Gas boiler	H_2 Fuel Boilers, Biomass boilers, Electric boilers
Non metallic mineral	Low temperature processes	Direct – Low temperature	Gas furnace	H_2 Fuel Heaters, Electric tunnel kilns, Electric Infra-red heaters

In 2020, no fuel-switching technologies for this sector would be commercial, even after accounting for the carbon price, For technologies to achieve payback, the gap between the price of gas and electricity and hydrogen prices would have to significantly reduce.

Key references: http://www.eumerci-portal.eu/documents/20182/38527/5+-+UK.pdf

Glass, Ceramics & non-metallic minerals

Fuel switching options



Biomass is low cost, very low emissions & suitable for off-grid. However supply capacity is uncertain. Opportunities for syngas and in ceramics solid biomass.

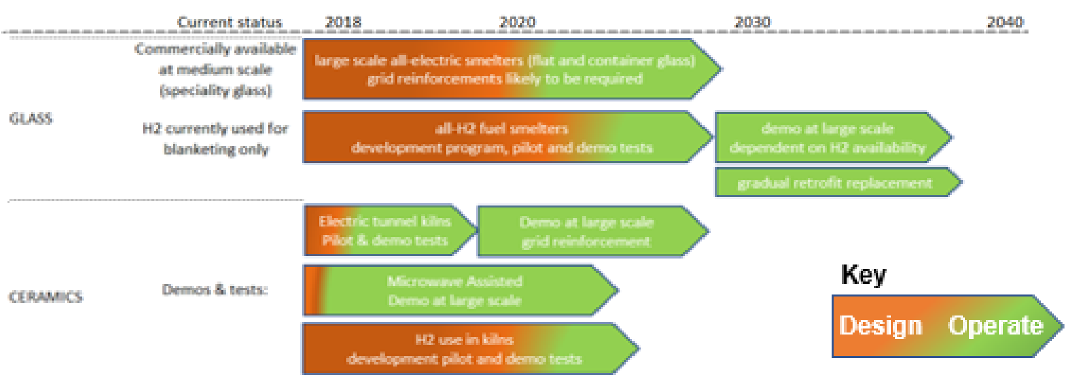
Electricity has high fuel cost, but can be highly efficient with no onsite emissions. Electric or microwave assisted kilns & resistive heating.

H_2

Hydrogen performs reasonably on cost, but still requires reductions, and could be utilised as a replacement to natural gas in burners in ceramics, but less attractive option for glass.

Technology demonstration timelines

- Tests in specific applications will be required for hydrogen technologies to be implemented; initial industrial implementation could be feasible by 2020.
- Electric and hydrogen technologies would need to be proven at scale before being adopted beyond trials or demonstrations, to determine the specific technical requirements (in terms of equipment design and operational changes) and associated costs.
- Electric technologies are already available but uptake may be limited by the relatively high cost of electricity.



Alternative decarbonisation options

- Many alternative electrification options, including microwave assisted drying, field enhanced sintering and heat pumps to assist drying heat load.
- For glass, all electric melters could replace furnaces. Hydrogen can be used as a fuel for melting furnaces, forehearths and lehrs.

Chemicals

Sector Background

38 TWh/yr fuel consumption

7.2 $MtCO_2$/yr EU ETS emissions

Thousands of sites

Economic contribution: The UK chemicals sector accounted for £12.1 billion of the UK economy's GVA and 99,000 direct jobs in 2016

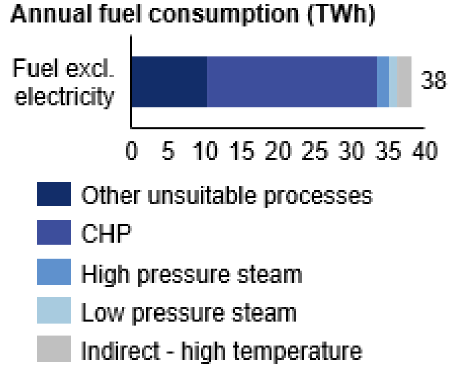
Typical characteristics: Highly diverse, primarily 2500 SMEs and microbusinesses (97% of sector). Plants concentrated in four main clusters (Hull, Teesside, Runcorn & Grangemouth) connected by ethylene pipeline.

Key processes: Processes include compression, pumping, cracking and heat for reactions. Chemicals include ammonia, chlorine, TiO_2, olefins and aromatics.

Fuel consumption

- Energy use is primarily natural gas (47%) and electricity (26%). 40% consumption is CHP, not considered here and byproduct fuels are considered unsuitable for switching, leaving only 4.8 TWh demand.
- This demand can be characterised as "indirect high temperature heat" within Ethylene and Ammonia production, and "indirect heating via steam" in production of other chemicals.

Annual fuel consumption (TWh)



Suitable processes & technologies for fuel switching

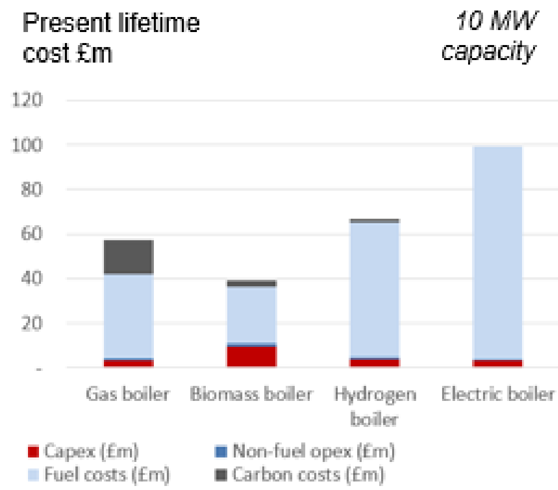
Process	Cross-sectoral process	Counterfactual technology	Suitable fuel switching technologies
Turbines (High pressure steam expanded in turbines & also used at lower pressure levels)	Indirect - High Pressure Steam (60%)	Gas boiler	Biomass boiler, Electrode steam boiler, Immersion Steam Boiler, 100% H_2 Fuel Boilers
	Indirect – Low Pressure Steam (40%)	Gas boiler	Biomass boiler, Electrode steam boiler, Immersion Steam Boiler, 100% H_2 Fuel Boilers, Open Loop Heat pump (MVR)
Cracking / Steam reforming	Indirect – High temperature	Gas furnace	Hydrogen heaters • Requires net H_2 demand on site • option to use onsite SMR + CCS to produce hydrogen from fuel gas

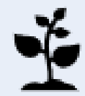
- Whilst biomass boilers and heat pumps are currently the only cost-effective technologies for steam-driven processes, there is significant opportunity for low carbon hydrogen.

Key references: https://www.parliament.uk/documents/commons-committees/Exiting-the-European-Union/17-19/Sectoral%20Analyses/7-Sectoral-Analyses-Chemicals-Report.pdf

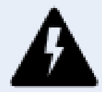
Chemicals

Fuel switching options





Biomass is low cost, very low emissions & suitable for off-grid. However supply capacity is uncertain. Cost effective opportunity in boilers (outside of ethylene and ammonia).

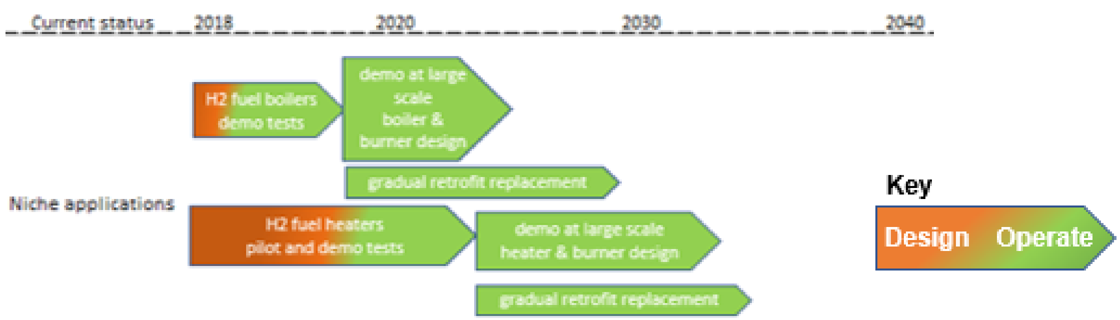


Electricity has high fuel cost, but can be highly efficient with no onsite emissions. Only heat pumps cost-effective eg for low pressure steam. Electric boilers may also contribute.

Hydrogen produced as a byproduct is already used, but otherwise is not currently cost-effective. Has potential for direct switch with natural gas in boilers and heaters.

Technology demonstration timelines

- Biomass boilers are already commercially available, with use dependent on supply and national strategy. MVR open loop heat pumps have also already been employed in some applications.
- Other indirect heating technologies e.g. hydrogen boilers and heaters are likely to be suitable for gradual fuel-switching approach, and may be implemented in the relatively near term subject to shared learnings from trials. Trial funding and fuel cost reductions are required.



Alternative decarbonisation options

- Due to the wide range of processes, there are a number of alternative options for each fuel.
- **Membrane separation**: Energy intensive separation processes, such as distillation, may be replaced by membrane technologies, often pressure driven. This reduces energy consumption and switches it to electricity.
- Niche applications of **direct electric** heating e.g. air and process gas heating.
- **Third Party supply of steam** produced in biomass boilers eg from power plants nearby.
- **Direct motion use**: Larger sites are characterised by multi-level steam systems, and power generation through turbines. Often these turbines can be used to directly drive process pumps and compressors, as opposed stand-alone power generation, which is more efficient.

Paper & Pulp

Sector Background

13
TWh/yr fuel consumption

0.9
$MtCO_2$/yr EU ETS emissions

~36
major sites

Economic contribution: In 2016, the UK produced 3.7 Mt of paper and board, with an annual turnover of £6.5 bn and 25,000 direct jobs.

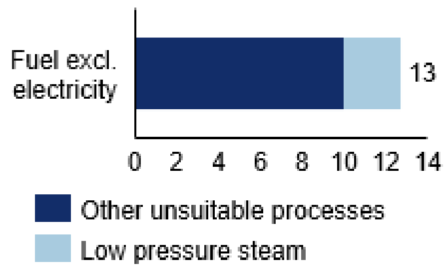
Typical characteristics: Around 36 working paper mills of reasonable size and most production uses recovered waste paper (73%) or imported pulp.

Key processes: Processes include pulping, drying, bleaching, refining and finishing. Pulping and drying use the most energy. 50% CO_2 reduction already realised by sector.

Fuel consumption

- Natural gas is the dominant but use has decreased significantly, with >25% of energy from biomass in 2017
- Sector already makes significant use of electricity and alternative fuels & the majority of energy demand is met by CHP (not considered).
- The remaining fossil fuel driven processes can be categorized as "Low temperature heat" or "Drying", both of which can be driven by low pressure steam.

Annual fuel consumption (TWh)



Suitable processes & technologies for fuel switching

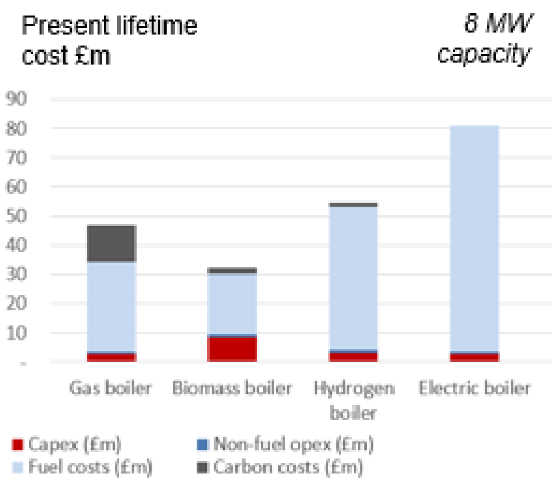
Process	Cross-sectoral process	Counterfactual technology	Suitable fuel switching technologies
Low temperature heat	Indirect - Low Pressure Steam	Natural gas boiler	Biomass boiler, Electrode steam boiler, Immersion Steam Boiler, 100% H2 Fuel Boilers
Drying	Indirect - Low Pressure Steam	Natural gas boiler	Biomass boiler, Electrode steam boiler, Immersion Steam Boiler, 100% H2 Fuel Boilers

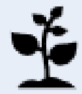
- Low pressure steam has considerable potential for switching; Biomass boilers are likely to be the most cost-effective technology, based on current cost estimates.
- There is a potential fuel switching cluster around Manchester.

Key references:
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/652141/pulp-paper-decarbonisation-action-plan.pdf; http://www.paper.org.uk/information/positionpapers/cpi/5KeyAsksMay2017.pdf

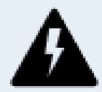
Paper & Pulp

Fuel switching options





Biomass is low cost, very low emissions & suitable for off-grid. However supply capacity is uncertain. Use is already widespread and there is still cost effective opportunity in boilers.

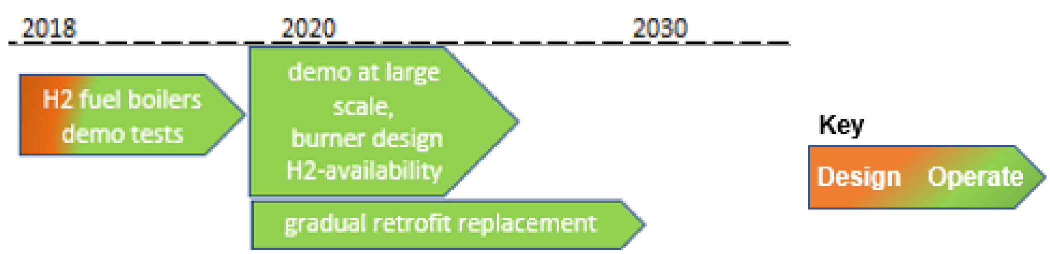


Electricity has no onsite emissions but has high fuel cost and few cost effective opportunities. Electric boilers or infrared drying may contribute.

Hydrogen is not currently used or cost effective, but has potential for direct switch with natural gas in steam generation.

Technology demonstration timelines

- Biomass boilers are already commercially available, with use dependent on supply and national strategy. MVR open loop heat pumps have also already been employed in some applications.
- Other indirect heating technologies, such as hydrogen boilers are likely to be suitable for gradual fuel-switching approach. They could potentially be implemented in the relatively near term subject to the availability of hydrogen and shared learning from trials. Trial funding and fuel cost reductions are required.



Alternative decarbonisation options

- Alternative electrification options include infra-red drying and microwave drying to replace steam drying process.
- Incineration of residues from onsite processes
- Partnership with energy from waste (EfW) operators has promise. Options include utilising heat from CHP as steam, selling by-products to the EfW plant or utilising biogas from recycled paper. An example includes the DS Smith Paper Mill in Kent.
- Innovative technologies include Deep Eutectic Solvents for pulp production, supercritical CO_2 for drying and superheated steam drying.

Vehicles

Sector background

8.1 TWh/yr fuel consumption

0.4 $MtCO_2$/yr EU ETS emissions

16 major sites

Economic contribution: 1.7 m cars were produced in the UK in 2017, contributing £202 bn GVA and £20 bn to the Treasury, as well as employing 186,000 people.

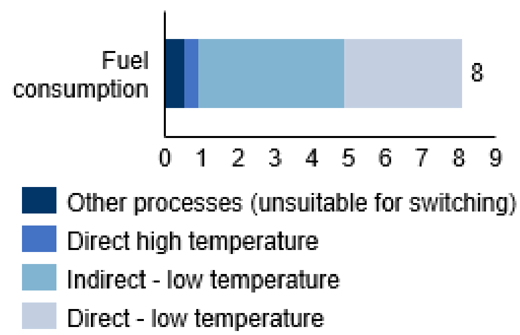
Typical characteristics: 16 large, high volume, sites, many near Birmingham. Diverse processes and global competition.

Key processes: Processes include pressing, welding, die casting, machining, paintwork, plastic operations and assembly. The paint shop is the largest thermal energy consumer.

Fuel consumption

- Vehicle production processes are used to reach a range of temperatures, although primarily low temperature heat, which could be provided by a number of alternative technologies.
- The majority of fuel use currently is natural gas, with some electricity (partly renewable).
- Heat is used both directly (e.g. heating components in furnaces) and indirectly (e.g. space heating via pipes in paint shops).

Annual fuel consumption (TWh)



Suitable processes & technologies for fuel switching

Process	Cross-sectoral process	Counterfactual technology	Suitable fuel switching technologies
High temperature process	Direct high temperature heat	Natural gas fired furnace	100% H_2 Fuel Heaters
Low Temperature Process	Direct low temperature heat	Natural gas fired furnace	Electric Infra-Red Heaters, 100% H_2 Fuel Heaters
Drying / Separation	Direct low temperature heat	Natural gas fired furnace	Electric Infra-Red Heaters, 100% H_2 Fuel Heaters
Space Heating (e.g. paint shop)	Indirect low temperature heat	Natural gas boiler	Immersion Steam Boiler, Electric Process Heater, closed loop heat pump, 100% H_2 Fuel Boilers

Biomass technologies are unlikely to be suitable due to space constraints at the majority of sites. Similarly, hydrogen would need to be delivered via pipeline so is dependent on location and national progress on hydrogen production.

Key references: https://www.smmt.co.uk/industry-topics/economy/uk-automotive-and-the-uk-economy/

6 Key challenges and opportunities for fuel switching

This chapter summarises the key challenges and opportunities for fuel switching for biomass & waste, hydrogen and electrification, including innovation and demonstration activities to support future implementation of these technologies, and developments within the wider energy system that could facilitate fuel switching.

6.1 Challenges and opportunities for biomass & waste

The main advantages and disadvantages of pursuing biomass & waste for fuel switching are summarised in Table 16.

Table 16: Advantages and disadvantages of pursuing biomass & waste fuel switching

Advantages	Disadvantages
Technologies such as biomass boilers and combustion of biomass & waste already available for many applications	High level of uncertainty around scale and cost of sustainable supply; industrial fuel-switching applications will be in competition with domestic heating and CHP, and potentially with production of green gas
Currently a relatively low cost fuel which could be competitive with gas	Sites may be constrained by onsite storage footprint requirements or fuel delivery logistics
Low emissions (and potential for negative emissions if used in combination with carbon capture, utilisation and storage)	Most biomass & waste (not including green gas) is unlikely to be suitable for most direct heating applications (Glass, Ceramics, other non-metallic minerals) due to the impacts on product quality
High potential for application in iron & steel and cement	High technology cost premium compared to gas equivalents (including the cost of emissions scrubbing equipment to ensure that air quality impacts are within regulated levels)
Suitable for off-grid sites	

Biomass boilers providing steam or low temperature heat to industrial processes are already available today, and are likely to be cost-effective, especially for processes of 1 MW capacity and above. The following biomass technologies could also provide good solutions for cost-effective decarbonisation of industry, but would require **further development and demonstration** to ensure that implementation is possible by 2040:

- High biomass & waste substitution rates with oxygen enrichment (70% and above) in cement production
- Substitution of biomass for coal and/or coke in iron production

Alongside this, further use of biomass & waste technologies for fuel switching will depend on rigorous assessment of the UK biomass and waste availability, analysis of the best use of these resources to meet possible demand across the energy sector, and clear policy that supports these priorities. Where biomass & waste can be used for fuel switching, long-term certainty around their availability and price will be required to enable industry to make investment decisions.

Figure 18 shows the relative fuel switching potential (in terms of fuel demand replaced) for biomass technologies at identified industrial sites, showing the distribution of demand for key sectors. Note that only identified non-CHP EU-ETS sites are shown; as such, a significant share of fuel switching potential from the following sectors is excluded from the map: Food & Drink; Paper; Chemicals; Vehicles; Non-ferrous metals; Other industry.

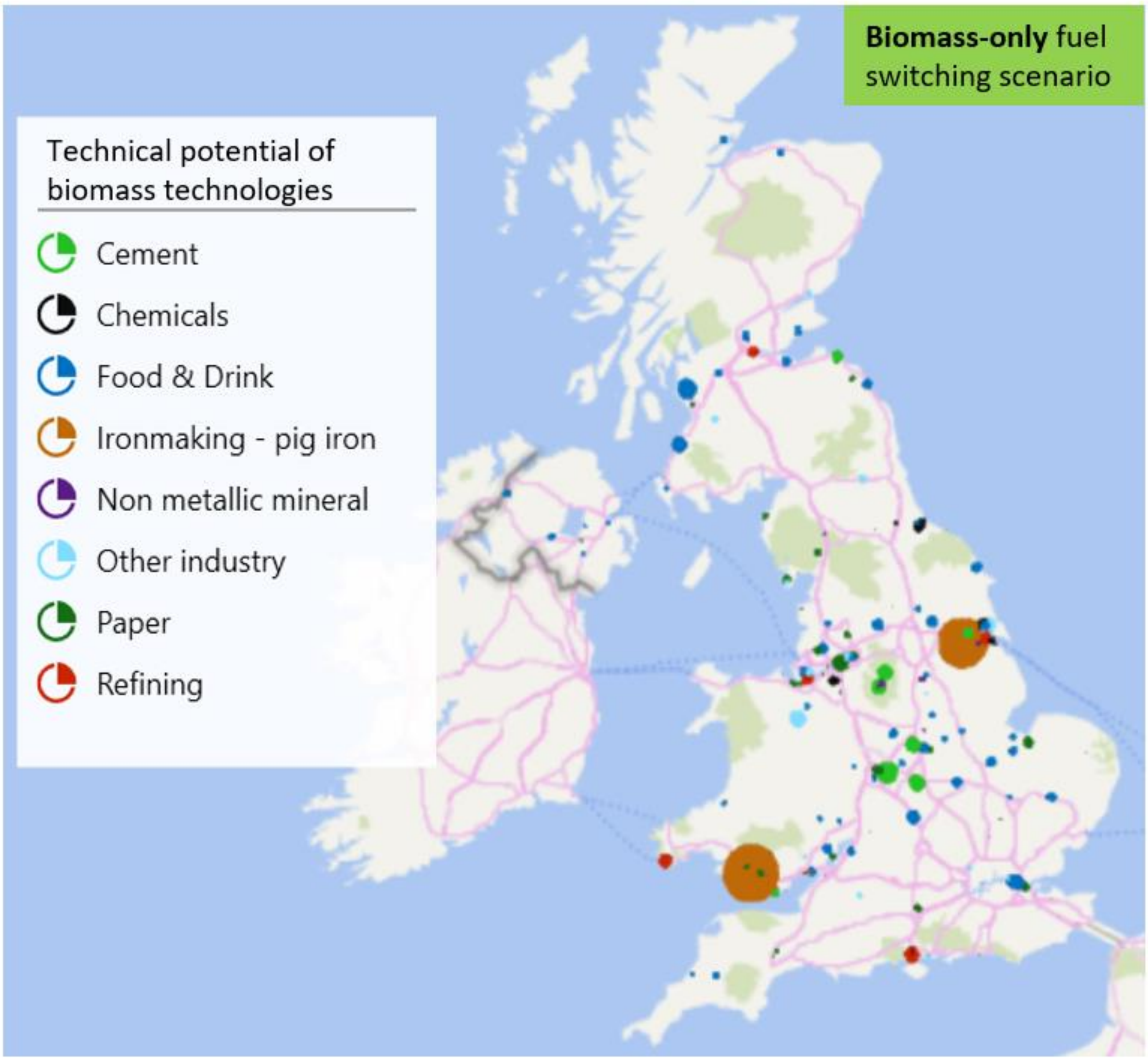


Figure 18: Fuel switching potential (relative heat demand replaced) for biomass technologies at identified industrial sites

6.2 Challenges and opportunities for hydrogen

The main advantages and disadvantages of pursuing biomass & waste for fuel switching are summarised in Table 17.

Table 17: Advantages and disadvantages of pursuing hydrogen fuel switching

Advantages	Disadvantages
High overall potential (could be used in most sectors, likely including high temperature direct heating applications)	Uncertainty around capex associated with of abatement of NOx emissions, especially for high temperature processes
Possible that hydrogen will be supplied via the gas grid in future	Additional safety processes required for most industries
Retrofit of existing gas infrastructure could be feasible for many	Hydrogen boilers and burners are not yet widely available at scale
Technology costs are likely to be similar to gas equivalents in the long term, although initially they will have a cost premium (see Figure 9-Figure 11 on p26-28)	Fuel cost premium compared to natural gas is likely
	Unlikely to be suitable for off-grid sites as the most cost-effective hydrogen supply in most cases will be via the grid
	Possible security of supply risk of switching mainly to hydrogen, if produced from natural gas

The cost-effectiveness of hydrogen applications will be highly dependent on the fuel price relative to natural gas (as explored in Section 4.3 and Section 5.2), and a low cost, low carbon national hydrogen supply would be essential to enable switching to hydrogen. However, even if the future fired cost of hydrogen relative to natural gas becomes low enough for a commercial case to be achieved, the current lack of understanding of some of the technical requirements would need to be addressed if the potential is to be realised. This means that there are several opportunities for innovation and demonstration to ensure that fuel-switching to hydrogen could be feasible:

- Hydrogen boilers to be tested at various scales
- Assessment of product quality impacts for hydrogen furnaces and kilns
- Understanding of NO_x emission management requirements for different high temperature direct heating processes
- Retrofit of existing furnaces and kilns to operate with hydrogen and gas
- Safety implications for different industries

Figure 19 shows the relative fuel switching potential (in terms of fuel demand replaced) for hydrogen technologies at identified industrial sites, showing the distribution of demand for key sectors. Note that only identified non-CHP EU-ETS sites are shown; as such, a significant share of fuel switching potential from the following sectors is excluded from the map: Food & Drink; Paper; Chemicals; Vehicles; Non-ferrous metals; Other industry.

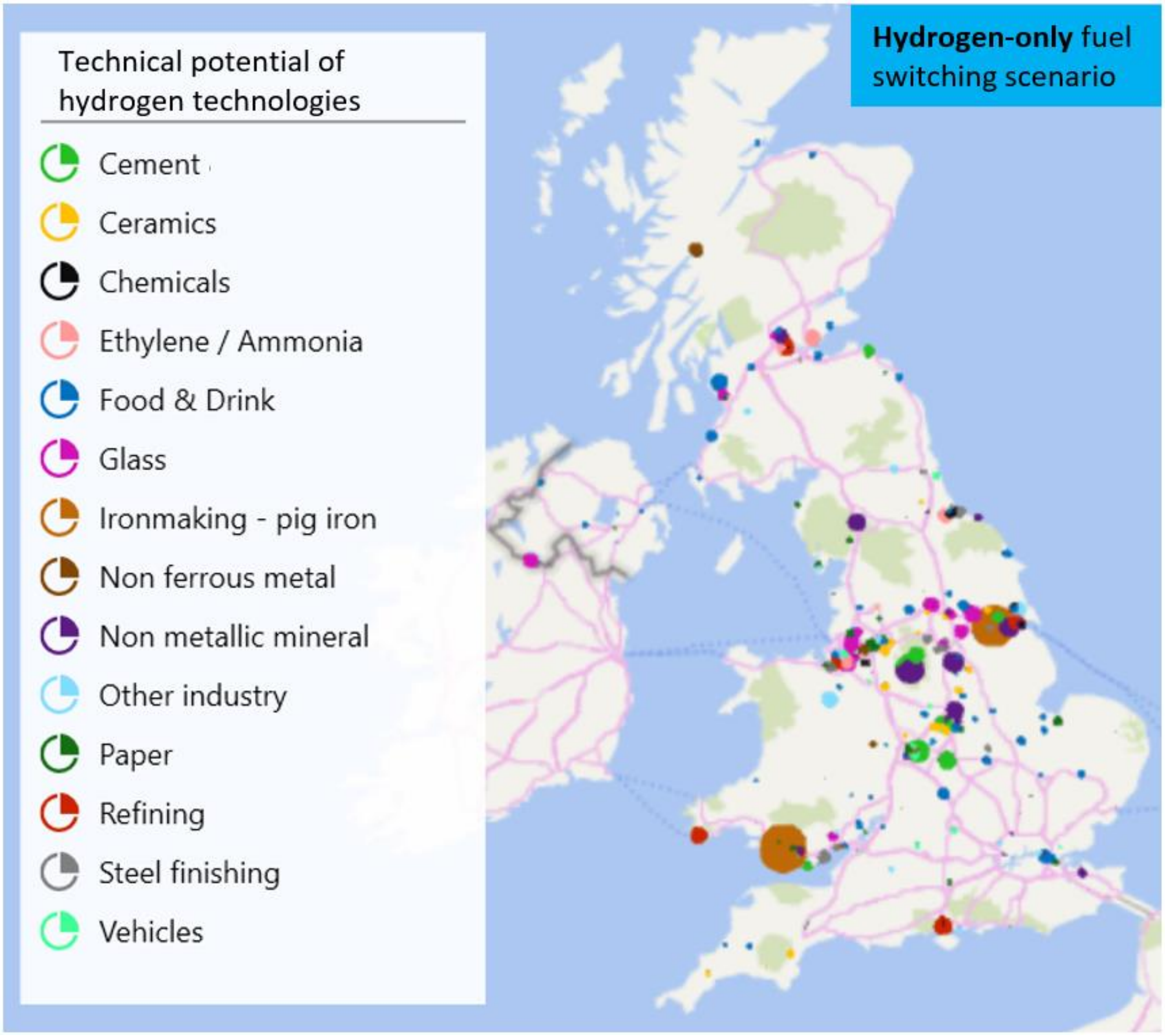


Figure 19: Fuel switching potential (relative heat demand replaced) for hydrogen technologies at identified industrial sites

Industrial sites which are close or accessible to potential carbon storage sites, and which have high process emissions, are likely to be attractive for CCUS. The first opportunities for hydrogen production via methane reformation with CCUS are likely to be located close to these CCUS clusters in order to use the same carbon transport and storage systems, which could help reduce the overall cost of low carbon hydrogen production. As such, sites with potential hydrogen demand which are located close to initial CCUS clusters (in coastal areas) could provide the early opportunities for switching to hydrogen.

6.3 Challenges and opportunities for electrification

The main advantages and disadvantages of pursuing electrification for fuel switching are summarised in Table 18.

Table 18: Advantages and disadvantages of pursuing fuel switching to electrification

Advantages	Disadvantages
Technologies (such as electric heaters and boilers and heat pumps) already available at some scales	Lower reliability of supply compared to gas – critical for some sectors
No on-site emissions	Product quality impacts for direct heating applications
Can be highly efficient (especially heat pumps in low temperature applications)	Uncertain (and possibly very high) grid reinforcement or connection costs
Potential opportunity to use surplus renewable generation (only for highly flexible industries)	Current high fuel cost compared to natural gas and other fuel switching options

Applications of heat pumps for low pressure steam and low temperature heat driven processes with capacities in the region of 100s of kW could be cost-effective even with the current differential between gas and electricity prices, due to the high efficiency of heat pumps, whereas the commercial case for many other electric technologies is likely to be challenging due to the high price of electricity. While onsite renewable generation combined with storage could potentially reduce costs for the industrial site, there may be a need to review of the role of electricity price in facilitating industrial decarbonisation.

In addition, a key area of uncertainty is the additional costs associated with grid reinforcements that may be required for electrification of industrial sites; costs could be highly site specific, as they will depend on the spare capacity in existing local electricity infrastructure.

Opportunities to explore the practical potential fuel-switching to electric technologies include:

- Assessment of the potential fossil fuel displacement by heat pumps at specific sites (or sites that are typical for particular industrial sub-sectors) and comparison with heat recovery technologies
- Demonstration of large-scale electric kilns and furnaces for application in glass and ceramics
- Development of lower TRL technologies such as microwave heaters, to better understand the maximum scale and the potential for application for efficiency savings in processes that are more difficult to switch, e.g. those heavily reliant on internal fuels

Figure 20 shows the relative fuel switching potential (in terms of fuel demand replaced) for electric technologies at identified industrial sites, showing the distribution of demand for key sectors. Note that only identified non-CHP EU-ETS sites are shown; as such, a significant share of fuel switching potential from the following sectors is excluded from the map: Food & Drink; Paper; Chemicals; Vehicles; Non-ferrous metals; Other industry.

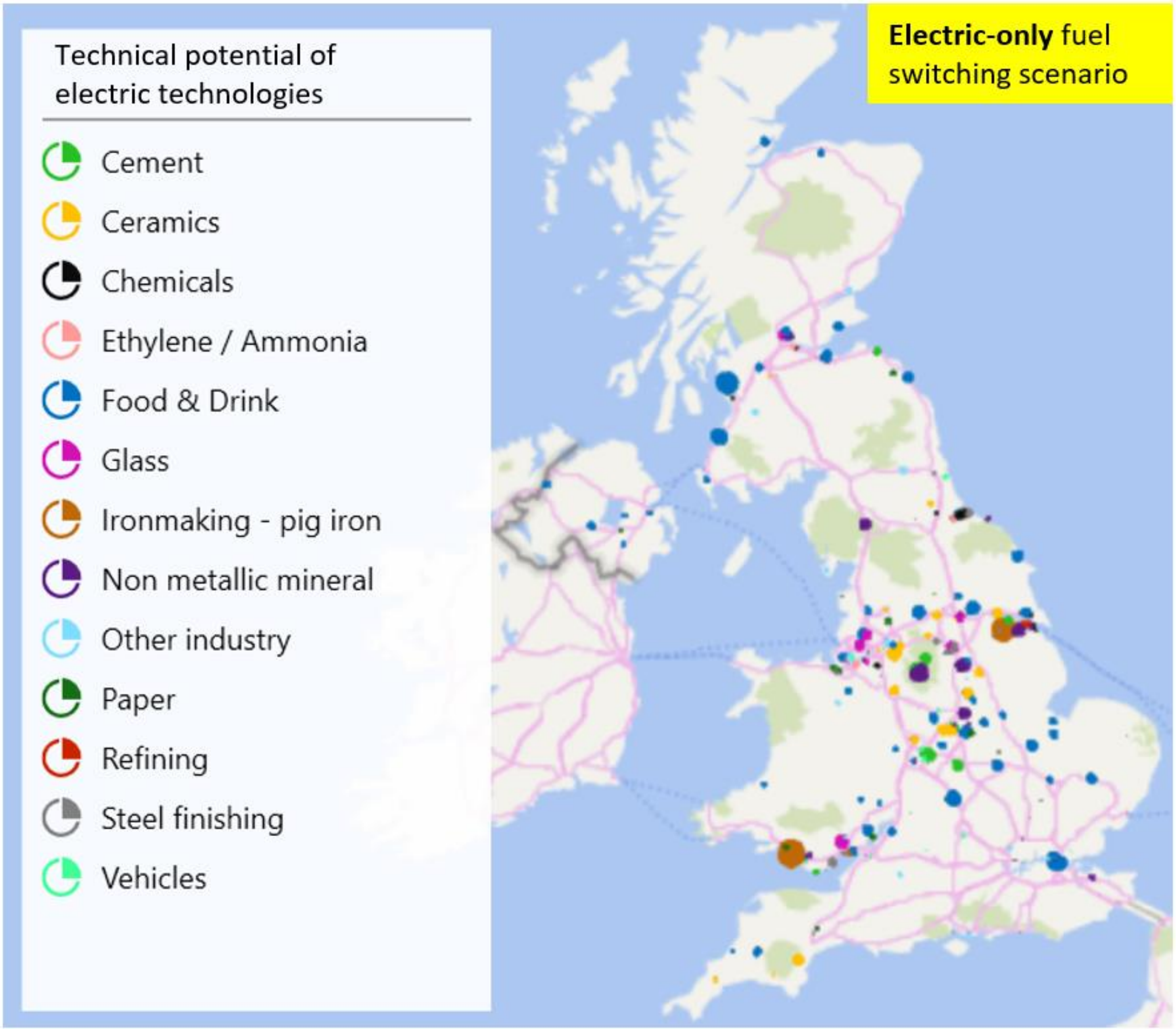


Figure 20: Fuel switching potential (relative heat demand replaced) for electric technologies at identified industrial sites

6.4 Comparing decarbonisation pathways

Considerations of the potential for fuel-switching may be most valuable when other routes for industrial decarbonisation are taken into account, as this enables the most cost-effective opportunities and potential synergies between different options to be identified. In particular, carbon capture, utilisation and storage (CCUS) is likely to be required in some industries in order to meet emissions reduction targets, particularly for sectors with high process emissions. In some cases, the use of CCUS in combination with fuel-switching in these sectors could be a cost-effective way to achieve negative emissions.

Table 19 sets out the most cost-effective fuel-switching options for each key group of industrial processes, highlights the potential for other decarbonisation routes including CCUS, and provides a summary of possible synergies with fuel switching. In summary:

- Use of biomass in industrial processes (where possible) provides a cost-effective opportunity to achieve negative emissions when combined with carbon capture.
- If industrial processes are switched to hydrogen, centralised hydrogen production with CCUS could be collocated with hydrogen demand.

- Synergies between electrification and CCUS are expected to be limited.

Table 19: Potential decarbonisation routes for groups of industrial processes

Type of demand	Most cost-effective fuel switching options	Synergies with CCUS	Alternative decarbonisation routes
Primary iron production	• Biomass (25% substitution in blast furnace or even higher after conversion to HISarna process) • Negative costs in 2030 and 2040 (including avoided carbon cost)	• Lower cost of CCUS after conversion to HISarna • Good opportunity to demonstrate biomass + CCUS (negative emissions)	• Direct reduction (DRI) with hydrogen / gas (unlikely for UK sites) • Electric arc furnace (secondary production only)
Cement kilns	• Biomass + O2 enrichment • Negative costs in 2030 and 2040 (including avoided carbon cost)	• Cost of CCUS > cost of switching to biomass • Good opportunity to demonstrate biomass + CCUS (negative emissions)	
Steam and indirect heating at large sites (Food & drink, Paper)	• Biomass boilers • Low or negative costs in 2030 and 2040 (including avoided carbon cost)	• Higher cost for CCUS compared to cement or iron production	• Limited decarbonisation from CHP (unless combined with fuel switching) and/or waste heat recovery
High temperature direct heat + biomass unsuitable (Glass, other non-metallic minerals, steel finishing)	• Hydrogen heaters & hydrogen kilns • Cost-effectiveness of around £70/t in 2040 (including avoided carbon cost)	• Possible for a few sites in existing CCUS clusters • >100 EU-ETS sites • 100s of smaller sites • Centralised hydrogen production with CCUS could be collocated with hydrogen demand	• Biogas / syngas (Depends on supply routes and the future of the gas network: total potential in region of 100 TWh vs current UK gas demand of 300 TWh[34])
Steam and indirect heating at smaller sites (Food & drink, non-metallic minerals, chemicals, other industry)	• Biomass boilers and hydrogen boilers *(Economics favour hydrogen for smaller sites due to higher impact of capex vs opex)* • Costs in 2040 less than £90/t for biomass; £90-140/t for hydrogen (at smallest sites) (including avoided carbon cost)	• Not suitable (highly dispersed & varied sites) • Centralised hydrogen production with CCUS could be collocated with hydrogen demand	• Biogas / syngas (Depends on supply routes and the future of the gas network: total potential in region of 100 TWh vs current UK gas demand of 300 TWh) • Bio-LPG / BioLNG (for off-grid sites) • Limited decarbonisation from CHP (unless combined with fuel switching) and/or waste heat recovery
Steam and low temperature indirect heating (<30 GWh demand per site)	• Heat pumps	• Not suitable (sites too small and dispersed)	• Waste heat recovery

[34]This would include gas generated from energy crops and forest residues as well as from waste feedstocks (see Review of Bioenergy Potential: Summary Report, June 2017, Antithesis and E4Tech for Cadent Gas Ltd)

To identify the best opportunities for industrial decarbonisation (and the role of fuel switching within this) the total system costs of the different decarbonisation options outlined above should be compared in detail for each key industry group, as well as by drawing high-level comparisons for industrial consumption as a whole. In such comparisons, technology costs and decisions may be influenced by geographic factors as well as site size. For example, industrial sites which are close or accessible to potential carbon storage sites, and which have high process emissions, are likely to be more attractive for CCUS. If sites with potential hydrogen demand are located close to these CCUS clusters, facilities for hydrogen production via methane reformation with CCUS could also be sited locally and use the same carbon transport and storage systems, which could help reduce the overall cost of low carbon hydrogen production for the relevant industries. This in turn could increase the total potential for cost-effective emissions savings via fuel-switching.

Next steps to inform the direction of industrial decarbonisation could include feasibility studies for the following options (which would be complementary parts of a fuel-switching decarbonisation route):

- Biomass + CCUS at large industrial sites with high process emissions (e.g. iron and cement production)
- Hydrogen production + CCUS + hydrogen in furnaces and kilns in key clusters of potential hydrogen demand

Such studies would be valuable in understanding the relative merits of fuel-switching and CCUS, and any additional benefits gained from the combination of the two.

In addition, there is a need to compare the potential costs to industry (and the energy system as a whole) of decarbonisation via use of “green gas” (i.e. biomethane and syngas which could directly replace natural gas in a range of industrial application, and could be supplied via the grid), versus the fuel switching options presented in this study. While hydrogen and electricity costs could be prohibitive to industrial fuel-switching, increased injection of green gas to the grid could potentially also expose industries to higher fuel costs if the costs of decarbonisation are passed on to network customers. Most industries operate with low margins, and increased costs could negatively impact the feasibility of continued operation in the UK.

If UK industry is to continue to thrive whilst contributing to the transition to a low carbon economy, it will be essential to identify the most cost-effective combination of decarbonisation technologies for the system as a whole. Switching to biomass, hydrogen, and electrification are likely to be part of this combination, and there is a clear need for further development and demonstration to determine the timescales and applications where they will be most effective.

6.5 Recommendations for the Industrial Fuel Switching Competition

The findings of this study were shared with stakeholders across industry, technology suppliers, and wider energy sector stakeholders, with a view to raising awareness of different technology options and encouraging these stakeholders to engage with the subsequent phases of the Industrial Fuel Switching Competition (Phase 1 being this Market Engagement study). BEIS will provide funding for innovation and demonstration activities to be completed by 2021 to address some of the remaining challenges for industrial fuel switching, in order to ensure that technologies will be available for UK industries under various decarbonisation scenarios (including decommissioning the gas grid, or converting it to hydrogen). Phase 2 of the competition will fund feasibility studies for Phase 3 projects (also to be fully funded), which will aim to develop or demonstrate fuel switching technologies.

Recommendations for Phases 2 and 3 of the Competition are summarised in Table 20, based on the findings of this study and feedback from industry stakeholders.

Table 20: Recommendations for Phase 2 and 3 of the Industrial Fuel Switching Competition

Topic	Stakeholder feedback & recommendations
Technical issues to be addressed to allow fuel switching to be feasible	Need to understand design and cost implications of NO_x emissions management for direct heating applications of hydrogen Oxygen enrichment and increased biomass/waste substitution in cement production needs research and demonstration (product quality, burner design) before being implemented Possible impacts of each fuel type on products for specific sub-sectors need to be understood (this also particularly impacts direct heating applications) Technical requirements for large-scale electrification need to be explored via a pilot facility Some sectors are interested in onsite production of syngas from biomass to replace natural gas; the practical implications of this need to be explored, as well as the question of biomass supply
Scale of demonstration activities required and implications for funding and timescales	For direct high temperature applications with large sites (including glass, ceramics, cement, and other minerals), a dedicated pilot facility would be required to address the technical questions and demonstrate feasibility. £15m funding could easily be used to cover the costs for a single demonstration site or pilot facility for any of these industries. The glass sector is prepared to match any funding (on a 1:1 basis) and already has plans for a pilot facility to test alternatives to gas, subject to sufficient funding availability. Preference would be to shift the balance of funds to maximise funding available for Phase 3; in general, if the funding is split across multiple projects then only smaller scale projects (e.g. 10 MW capacity or less) would be feasible. Benchtop studies to test explore technical aspects such as emissions, combustion characteristics or efficiency could also be feasible, where onsite testing would be out of budget. The Competition should be clear about the outputs required from Phases 2 and 3 and be open to projects of different scales to accommodate this within the budget available. Brexit could have a huge impact on supply chains for demonstration facilities and could therefore affect timescales
Role of feasibility studies	Design and assess costs for a Phase 3 demonstration / pilot project to address the technical issues or uncertainties for technologies that could be applicable by 2030 or before (businesses do not generally seriously consider investment decisions beyond a 10 year timeframe) Opportunities for commonality and use of waste products between industries should be explored within feasibility studies
Potential links to other projects and sources of funding	Initial projects could potentially feed into demonstration activities under gas and electricity network operator “Regulatory price controls” to identify future business plans Links to existing cluster-based projects (e.g. for hydrogen, H21 or HyNet) could reduce costs and help to make projects useful for a number of industries. In addition, projects on this timescale will be more attractive if there is a clear plan for provision of the relevant fuel type in the early 2020s.

7 Appendix

7.1 List of contributing stakeholders

British Ceramics Confederation
British Glass
British Steel
Cadent
Cerney
Chemicals Industry Association
Collins Walker
Confederation of Paper industries
DryEff Program
DS Smith
Dynamic Boost
EXHEAT
Food & Drink Federation
Glass Futures
H2FC Supergen
HSL
Huntsman
Hydrogen Technologies Inc
Lafarge cement
Marble Power
Mineral Products Association
N&P
Northern Gas Networks
Parat Halvorsen AS
PetroIneos (Grangemouth)
Process Technologies
Progressive Energy
SABIC
ScanArc Plasma Technologies AB
SIMEC
SMMT
Tata
Teeside Collective
The Committee on Climate Change
UK PIA
Velde Boilers and Plants
Viking Heat Engines AS

7.2 Technology assumption tables

Technology	Technology readiness level in 2018 (TRL)	Lifetime (years)	Input (kWh fuel in / kWh thermal output)	Substitution rate (fossil fuel replacement per site)		
				2020	2030	2040
Large Biomass Steam Boiler	9	25	1.18	100%	100%	100%
Small Biomass Steam Boiler	9	25	1.18	100%	100%	100%
Direct Biomass Combustion	9	25	1.25	33%	33%	33%
Biomass Combustion + O2 enrichment	9	25	1.19	66%	66%	66%
Direct Biomass Reductant	3	20	1.19	5%	15%	25%
Electric Steam Boiler (small)	9	15	1.01	100%	100%	100%
Electrode Steam Boiler (large)	9	15	1.01	100%	100%	100%
Electric Process Heater	9	15	1.01	100%	100%	100%
Electric Ceramic Tunnel Kilns	6	15	1.05	100%	100%	100%
Electric Infra-Red Heaters	8	15	1.05	100%	100%	100%
Electric Plasma Gas Heaters	9	15	1.11	15%	25%	25%
Microwave Heaters	7	15	1.01	100%	100%	100%
OL Heat Pump (MVR)	9	20	0.25	25%	25%	25%
CL Heat Pump	9	20	0.25	25%	25%	25%
Electric glass furnace	6	8	1.05	100%	100%	100%
H2 for Direct Reduction	3	20	1.09	5%	15%	25%
100% H2 Fuel Boilers	8	20	1.09	100%	100%	100%
100% H2 Fuel Heaters	8	20	1.09	15%	50%	100%
H2 fired kiln	9	25	1.18	15%	50%	100%
Natural gas fired furnace	9	25	1.09	100%	100%	100%
Natural gas boiler	9	25	1.09	100%	100%	100%
Blast furnace	9	25	1.18	100%	100%	100%
Basic Oxygen Furnace	9	25	1.18	100%	100%	100%
Sinter Plant	9	25	1.18	100%	100%	100%
40 alternative, 60 coal/petcoke fired kiln	9	25	1.25	100%	100%	100%
Natural gas fired kiln	9	25	1.18	100%	100%	100%

Technology	Reference size (kW)	Maximum size (kW)	Marginal capex (£/kW)	Marginal opex (£/kW/y)	Variable opex (£/kWh)
Large Biomass Steam Boiler	50,000	300,000	£ 515.00	£ 5.20	£ 0.001
Small Biomass Steam Boiler	50,000	20,000	£ 515.00	£ 4.90	£ 0.001
Direct Biomass Combustion	120,000	200,000	£ 62.50	£ 1.25	£ 0.000
Biomass Combustion + O2 enrichment	120,000	200,000	£ 67.00	£ 1.33	£ 0.000
Direct Biomass Reductant	120,000	-	£ 83.00	£ 1.25	£ 0.000
Electric Steam Boiler (small)	50,000	10,000	£ 120.00	£ 4.00	£ 0.000
Electrode Steam Boiler (large)	50,000	100,000	£ 120.00	£ 2.40	£ 0.000
Electric Process Heater	4,000	10,000	£ 120.00	£ 2.40	£ 0.000
Electric Ceramic Tunnel Kilns	20,000	20,000	£ 1,000.00	£ 3.34	£ 0.000
Electric Infra-Red Heaters	6	13	£ 233.00	£ 4.66	£ 0.000
Electric Plasma Gas Heaters	7,000	100,000	£ 262.00	£ 2.98	£ 0.000
Microwave Heaters	100	1,000	£ 8,000.00	£ 160.00	£ 0.010
OL Heat Pump (MVR)	1,600	10,000	£ 300.00	£ 6.00	£ 0.000
CL Heat Pump	1,000	10,000	£ 450.00	£ 9.00	£ 0.001
Electric glass furnace	35,000	22,500	£ 193.00	£ 3.34	£ 0.000
H2 for Direct Reduction	120,000	-	£ 232.00	£ 4.64	£ 0.000
100% H2 Fuel Boilers	50,000	200,000	£ 199.00	£ 3.98	£ 0.000
100% H2 Fuel Heaters	35,000	200,000	£ 232.00	£ 4.64	£ 0.000
H2 fired kiln	10,000	-	£ 732.00	£ 13.30	£ 0.001
Natural gas fired furnace	35,000	-	£ 193.00	£ 3.86	£ 0.000
Natural gas boiler	50,000	-	£ 166.00	£ 3.32	£ 0.000
Blast furnace	120,000	-	£ -	£ -	£ -
Basic Oxygen Furnace	120,000	-	£ -	£ -	£ -
Sinter Plant	120,000	-	£ -	£ -	£ -
40 alternative, 60 coal/petcoke fired kiln	120,000	-	£ -	£ 2.50	£ 0.000
Natural gas fired kiln	8,000	-	£ 665.00	£ 13.30	£ 0.001

Technology capex for specific sites is calculated on the following basis, using the standard engineering practice of **0.6** as a sizing coefficient:

Technology capex = (Marginal capex * Size (kW)) * (Size / Reference size)^(0.6)

Technology capacity for a site with a certain estimated annual demand was estimated by assuming an annual load factor of **80%**.

7.3 Technology summary

1	Technology name	**Large Biomass Boiler**
2	Current TRL / Target Date for TRL 9	9 / -
3	Maximum size currently available (LHV basis)	264 MW (power sector)
4	Maximum size that can be achieved over time	Unlikely to be required above 100 MW
5	CAPEX estimate	**Basis: 50 MWth**
	Range of applicability	20 – 100 MWth (SF = 2/3)
	Boiler equipment cost (Boiler, biomass handling, flue gas cleaning system)	£175/kWth (fired; LHV basis)
	Total boiler installed cost (TIC)	£515/kWth (fired; LHV basis)
6	OPEX estimate	
	OPEX Fuel (LHV basis)	Heat duty / 0.85
	O&M fixed costs	5.2 £/kW/y
	O&M variable costs	0.7 £/MWh
7	Counterfactual case	Steam boiler firing natural gas
	CAPEX (TIC)	£166/kWth (fired; LHV basis)
	Fuel cost LHV basis	Heat duty / 0.92
	O&M costs	3.9 £/kW/y
8	Efficiencies (current / future) LHV basis	85% / 92%
9	Fuel inputs	Wood / waste wood / straw / stover
10	Technology lifetime	25 years
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	All processes where steam, at different pressures, is used for heating

12	Technology providers that have responded to our enquiries	Byworthy boilers (UK)
13	Known industry examples	• GSK Dungarvan, Ireland • Sleaford Straw-Fired Renewable Energy Plant, Lincolnshire, UK • Ironbridge, Severn Gorge, UK • Drax Power Limited, Drax, UK • Templeborough Waste Wood-Fired Plant Rotherham, South Yorkshire • Skaerbaek Power Plant, Fredericia, Denmark • Alholmens Kraft, Alholmen, Jakobstad, Finland • Hurst Biomass Boiler at Wagner Lumber, Cayuta, NY + many others

References:

Biomass heating; a practical guide for potential users; May 2013
IEA ETSAP Technology Brief 101; May 2010
Babcock & Wilcox
Doosan Babcock
BURMEISTER & WAIN SCANDINAVIAN CONTRACTOR
Premium wood pellets at 18 MMBTU/tonne and 250 $/t

1	Technology name	**Small Biomass Boiler**
2	Current TRL / Target Date for TRL 9	9 / -
3	Maximum size currently available (LHV basis)	20 MW (by definition)
4	Maximum size that can be achieved over time	20 MW (by definition)
5	CAPEX estimate	**Basis: 10 MWth**
	Range of applicability	20 – 100 MWth (SF = 2/3)
	Boiler equipment cost	
	Total installed boiler cost	
	Total installed biomass preparation yard	
	Total steam plant installed cost (TIC)	£515/kWth (fired; LHV basis)
6	OPEX estimate	
	OPEX Fuel (LHV basis)	Heat duty / 0.85
	O&M fixed costs	£4.9 /kW/y
	O&M variable costs	£0.6/MWh
7	Counterfactual case	Steam boiler firing natural gas
	CAPEX (TIC)	£166/kWth (fired; LHV basis)
	Fuel cost LHV basis	Heat duty / 0.92
	O&M costs	3.3 £/kW/y
8	Efficiencies (current / future) LHV basis	85% / 92%
9	Fuel inputs	Wood / waste wood / straw / stover
10	Technology lifetime	25 years
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	All processes where steam, at different pressures, is used for heating
12	Technology providers that have responded to our enquiries	Byworthy Boilers (UK)
13	Known industry examples	

References:

Biomass heating; a practical guide for potential users; May 2013
IEA ETSAP Technology Brief 101; May 2010
Babcock & Wilcox
Doosan Babcock
BURMEISTER & WAIN SCANDINAVIAN CONTRACTOR

1	Technology name	**Direct Biomass Combustion**
2	Current TRL / Target Date for TRL 9	9 / -
3	Maximum size currently available (LHV basis)	1 million TPA cement plant has thermal fired load of around 120 MW.
4	Maximum size that can be achieved over time	Assume maximum 60% of site thermal load from renewable fuels
5	CAPEX estimate	**Basis: 1 kiln at 120 MW**
	Range of applicability	Fixed fee per site
	Kiln conversion cost to fire more biomass	£63/kWth (fired; LHV basis) (£7.5 million (Ricardo AEA, 2013))
	Pyro-processing system replacement cost (assume not required)	£150 million (1000 KTPA) (Actual equipment cost of kiln ~ £15 million)
6	OPEX estimate	
	OPEX Fuel (LHV basis)	Assume same fired duty as counterfactual case
	O&M fixed costs	£0.6 /kW/y
	O&M variable costs	£0.1/MWh
7	Counterfactual case	Coal or petcoke firing (with 42% biomass – UK cement average)
	CAPEX	£15 million for rotary kiln replacement
	Efficiency	3.3 GJ/tonne clinker
	O&M costs	£2.5/kW/y
8	Efficiencies (current / future) LHV basis	3.3 GJ/tonne clinker
9	Fuel inputs	Various biomass and waste streams
10	Technology lifetime	25 years
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Cement industry only

12	Technology providers that have responded to our enquiries	N+P (manufacturers of “subcoal”)
13	Known industry examples	All UK cement plants are using some degree of alternative fuels.

References:
Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050 – Cement (PB and DNV GL, Report to DECC, March 2015)
Sustainable Development Report 2016 = MPA Cement

Assume 800 kcal/kg (3.3 GJ/tonne) thermal energy consumption, per tonne of clinker production (2006 world average for preheater-precalciner kilns)

1	Technology name	**Direct Biomass Combustion with O2 Enrichment**
2	Current TRL / Target Date for TRL 9	9 / -
3	Maximum size currently available (LHV basis)	1 million TPA cement plant has a thermal fired load of around 120 MW.
4	Maximum size that can be achieved over time	Assume maximum 80% of site thermal load from renewable fuels
5	CAPEX estimate	**Basis: 1000 KTPA plant**
	Range of applicability	O2 enrichment only – assume only applied once a site reaches 60% biomass firing
	Incremental new design cost (primarily air separation unit, excluding kiln cost)	£67/kWth (fired; LHV basis) (£8 million (IFC, 2017) – assumes O2 produced on site)
	Kiln retrofit cost (includes air separation unit). Kiln only conversion costs assumed minor, mainly installation of the O2 buffer tank system.	£83/kWth (fired; LHV basis) (£10 million (IFC, 2017) – assumes O2 produced on site)
6	OPEX estimate	Incremental increase due to electricity demand for O2 production
	OPEX Fuel (LHV basis)	3.15 GJ/tonne clinker (fired duty) 25 kWh/tonne clinker (electricity for O_2 production) – estimated as £0.5/tonne clinker (IFC, 2017)
	O&M fixed costs	£0.7 /kW/y
	O&M variable costs	£0.1/MWh
7	Counterfactual case	Coal or petcoke firing (with 42% biomass – UK cement average)
	CAPEX	£15 million for rotary kiln replacement
	Fuel cost LHV basis	3.3 GJ/tonne clinker
	O&M costs	2.5 £/kW/y
8	Efficiencies (current / future) LHV basis	3.15 GJ/tonne clinker

9	Fuel inputs	Various biomass and waste streams
10	Technology lifetime	25 years
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Cement industry only
12	Technology providers that have responded to our enquiries	
13	Known industry examples	• Steetley Dolomite (now Lhoist) Thrislington, closed in 2015. • Lafarge's Karsdorf plant, Germany • Implemented in many other EU plants

References:

IFC / SNIC / Associacao Brasileira de Cimento Portland; 2017

Steetley Dolomite Case Study "Oxygen-enhanced combustion for optimised kiln performance" Air Products brochure. 2009

	Technology name	**Biomass Gasification to Renewable Gas and Green Coke**
2	Current TRL / Target Date for TRL 9	8 /2025
3	Maximum size currently available (LHV basis)	6 MW thermal
4	Maximum size that can be achieved over time	Next development step will be 20 MW single train. Anticipated that 50 MW could be achieved by 2 x 25 MW trains.
5	CAPEX estimate	**Basis: 20 MW**
	Range of applicability	
	Gasification cost	Vendor estimates "ball park" TIC of €20 million for 20 MW plant, based on current economics. Target is to halve CAPEX per MW for 50 MW plant.
6	OPEX estimate	
	OPEX Fuel (LHV basis)	
	O&M fixed costs	£1.7 /kW/y
	O&M variable costs	£0.2/MWh

7	Counterfactual case	This is a fuel preparation/conversion technology.
	CAPEX	
	Fuel cost LHV basis	
	O&M costs	
8	Efficiencies (current / future) LHV basis	
9	Fuel inputs	
10	Technology lifetime	
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	“Renewable gas” can replace natural gas in any sector. Green coke to replace coke in ironmaking.
12	Technology providers that have responded to our enquiries	Cortus Energy (Sweden)
13	Known industry examples	Höganäs (Sweden) plant trial. This new plant will use forestry-based fuels

1	Technology name	**Biomass as Ironmaking Reductant (Bio-coal / Green Coke / Subcoal)**
2	Current TRL / Target Date for TRL 9	3
3	Maximum size currently available (LHV basis)	Unknown
4	Maximum size that can be achieved over time	Too early in development cycle to estimate.
5	CAPEX estimate	**Basis:** CAPEX is the cost of fuel preparation. Cost of blast furnace feed conversion unknown.
	Range of applicability	
6	OPEX estimate	Too early in development cycle to estimate.
	OPEX Fuel (LHV basis)	Too early in development cycle to estimate.
	O&M fixed costs	Too early in development cycle to estimate.
	O&M variable costs	Too early in development cycle to estimate.
7	Counterfactual case	Coke plant
	CAPEX	£100/tonne
	Fuel cost LHV basis	0.8 GJ/tonne
	O&M costs	2.0 £/kW/y
8	Efficiencies (current / future) LHV basis	Too early in development cycle to estimate.
9	Fuel inputs	(Bio-coal / Green Coke / Subcoal)
10	Technology lifetime	25
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Ironmaking - pig iron only
12	Technology providers that have responded to our enquiries	Cortus Energy (Sweden), N+P (UK & The Netherlands), Antaco (UK)
13	Known industry examples	Höganäs (Sweden) plant trial

1	Technology name	**Electric Steam Boiler (small)**
2	Current TRL / Target Date for TRL 9	9 / -
3	Maximum size currently available	4 MWe
4	Maximum size that can be achieved over time	10MWe (2 x 5)
5	CAPEX estimate	**Basis: 4 MWth**
	Range of applicability	2 - 4 MWth (SF = 0.6)
	Boiler equipment cost (incl. Instrumentation/control)	50 £/kWe
	Control panel	50 £/kWe
	Reinforcement/expansion of the grid connection	Assume not required for this capacity
	Total steam plant installed cost (TIC)	200 £/kWe
6	OPEX estimate	
	OPEX electricity	Heat duty / 0.99
	O&M fixed costs	2.0 £/kW/y
	O&M variable costs	0.3 £/MWh
7	Counterfactual case	Steam boiler firing natural gas
	CAPEX (TIC)	£166/kWe
	Fuel cost (LHV basis)	Heat duty / 0.92
	O&M costs	3.9 £/kW/y
8	Efficiencies (current and future)	99.9%
9	Fuel inputs	Electricity
10	Technology lifetime	15 years
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	All processes where steam, at different pressures, is used for heating
12	Technology providers that have responded to our questions	• EXHEAT (UK) • Cerney (Spain) • Vapec AG (Switzerland)
13	Known industry examples	• 5 t/h boiler Kuwait (EXHEAT)

References:
Electrification in the Dutch process industry, February 2017; Exheat; Cerney; Vapec

1	Technology name	**Electrode Steam Boiler (large)**
2	TRL	9 / -
3	Maximum size currently available	90 MWe
4	Maximum size that can be achieved over time	Unlikely to be required above 100 MW
5	CAPEX estimate	**Basis: 50 MWth**
	Boiler equipment cost (incl. Instrumentation/control)	15 £/kW
	Electrical connection costs	
	Reinforcement/expansion of the grid connection	
	Installation factor	8
	Total boiler installed cost (TIC)	120 £/kW2
6	OPEX estimate	
	OPEX electricity	Heat duty / 0.99
	O&M fixed costs	1.2 £/kW/y
	O&M variable costs	0.2 £/MWh
7	Counterfactual case	Steam boiler firing natural gas
	CAPEX (TIC)	£166/kW
	Fuel cost (LHV basis)	Heat duty / 0.92
	O&M costs	3.3 £/kW/y
8	Efficiencies (current and future)	99.9%
9	Fuel inputs	Electricity
10	Technology lifetime	15 years
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	All processes where steam, at different pressures, is used for heating
12	Technology providers that have responded to our questions	• Collins Walker (UK) • Parat (Norway) • Cerney (Spain) • Vapec AG (Switzerland)
13	Known industry examples	• Infraserv, Denmark (Parat) • UPM, Nordland Papier, Denmark (Parat) • Bonduelle, France (Vapec)

		• Kernkraftwerk Leibstadt, Switzerland (Vapec)

References:

Electrification in the Dutch process industry, February 2017
Parat
Vapec AG

1	Technology name	**Electric Heaters**
2	Current TRL / Target Date for TRL 9	9
3	Maximum size currently available	4 MW
4	Maximum size that can be achieved over time	Unknown
5	CAPEX estimate	
	Range of applicability	1-5 MW
	Equipment cost	50 £/kW (EXHEAT)
	Control panel	50 £/kW (EXHEAT)
	Reinforcement of grid connection	Assume not required at this size
	Total installed cost (TIC)	120 £/kWe
6	OPEX estimate	
	OPEX	Duty/0.995
	O&M fixed costs	1.2£/kW/y
	O&M variable costs	0.2 £/MWh
7	Counterfactual case	Furnace firing natural gas
	CAPEX (TIC)	£193/kW
	Fuel cost	Heat duty / 0.92
	O&M costs	3.9 £/kW/y
8	Efficiencies	99.5%
9	Energy inputs	Electricity
10	Technology lifetime	15
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	• Combustion air and fuel gases • Thermal oils • Process gases • Water streams • Liquid vaporizers • Tank heating • Ammonia • Steam superheating • Dryers

12	Technology providers that have responded to our questions	• EXHEAT (UK)
13	Known industry examples	• Reactor regeneration systems in olefins and propane dehydrogenation units • Methanation reactor feed heating • Hot oil for amine regeneration and glycol reboilers

References:

Exheat

Sigma Thermal

1	Technology name	**Large-Scale Electric Ceramic Tunnel Kiln**
2	Current TRL / Target Date for TRL 9	5-6 / 2030
3	Maximum size currently available	1 MW
4	Maximum size that can be achieved over time	20 MW (2030)
5	CAPEX estimate	**Basis: Per Site**
	Range of applicability	
	Equipment cost (incl. Instrumentation/control)	
	Control panel	
	Reinforcement/expansion of the grid connection	
	Total installed cost	£1000/kW fired (LHV basis) (£20 million per site)
6	OPEX estimate	
	OPEX electricity	Heat duty / 0.95 (LHV)
	O&M fixed costs	1.7£/kW/y
	O&M variable costs	0.2 £/MWh
7	Counterfactual case	Natural gas-fired kiln
	CAPEX	£665/kW fired (LHV basis)
	Fuel cost (LHV basis)	2.1 GJ/tonne brick
	O&M costs	Heat duty / 0.85 (LHV)
8	Efficiencies (current and future)	0.95
9	Fuel inputs	Electricity
10	Technology lifetime	20
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Ceramics only
12	Technology providers that have responded to our questions	Keller HCW GMBH (Germany)

13	Known industry examples	

References:

Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050 – Ceramics (PB and DNV GL, Report to DECC, March 2015)
Paving the way to 2050 – The Ceramic Industry Roadmap, Cerame-Unie
Keller HCW GMBH

1	Technology name	**Electric Infra-Red Heater**
2	Current TRL / Target Date for TRL 9	7-8
3	Maximum size currently available	6 kW
4	Maximum size that can be achieved over time	12-13 kW
5	CAPEX estimate	**Basis: MWth**
	Range of applicability	
	Equipment cost (incl. Instrumentation/control)	
	Control panel	
	Reinforcement/expansion of the grid connection	
	Total installed cost	£233/kWe
6	OPEX estimate	
	O&M fixed costs	2.3£/kW/y
	O&M variable costs	0.3 £/MWh
7	Counterfactual case	Natural gas fired ovens
	CAPEX	£193/kWth fired, LHV basis
	Fuel cost (LHV basis)	Heat duty / 0.92
	O&M costs	3.9 £/kW/y
8	Efficiencies (current and future)	0.95
9	Fuel inputs	Electricity
10	Technology lifetime	15
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Process side temperatures up to 240°C; automotive, plastics, textile, composite and metals
12	Technology providers that have responded to our questions	Heraeus Noblelight Ltd UK)
13	Known industry examples	Car hoods pre-treatment; cutting laminated glass; contact-free welding,

		laminating, and embossing of plastics; drying of wood

References:
Eisenmann
Heraeus Noblelight Ltd

1	Technology name	**Plasma Gas Technology**
2	Current TRL / Target Date for TRL 9	9 (metals processing)
3	Maximum size currently available	8 MWe per burner. 72 MW (8 x 7 MWe) has been deployed.
4	Maximum size that can be achieved over time	Assume unlimited by increasing number of burners
5	CAPEX estimate	**Basis: 50 MWe**
	Range of applicability	40 – 80 MWe (SF = 0.6)
	Burner equipment cost	200 £/kWe
	Electrical connection costs	100 £/kWe
	Reinforcement/expansion of the grid connection	
	Overall system installed cost	750 £/kWe
6	OPEX estimate	
	OPEX electricity	Heat duty / 0.90
	O&M fixed costs	1.5£/kW/y
	O&M variable costs	0.2 £/MWh
7	Counterfactual case	Natural gas furnace
	CAPEX (TIC)	£193/kW
	Fuel cost (LHV basis)	Heat duty / 0.92
	O&M costs	3.9 £/kW/y
8	Efficiencies (current and future)	90%
9	Fuel inputs	Electricity
10	Technology lifetime	15 years
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Provides heat to smelting processes. Technology development also looking to target cement and pulp industries.
12	Technology providers that have responded to our questions	• ScanArc Plasma Technologies AB (Sweden)
13	Known industry examples	• BEFESA ScanDust AB, Sweden (ScanArc)

		•

References:

ScanArc brochure and email exchange

CemZero is a new project launched by cement manufacturer Cementa and the energy company Vattenfall. CemZero will investigate the possibility of using electricity to heat kilns and thereby reduce carbon dioxide emissions. One technique that can contribute to successful results is plasma technology, which makes it possible to convert electrical energy into hot gas in an energy efficient way with very low carbon dioxide emissions.

1	Technology name	**Microwave Heater**
2	Current TRL / Target Date for TRL 9	4 to 5
3	Maximum size currently available	24 kW demo plant
4	Maximum size that can be achieved over time	
5	CAPEX estimate	**Basis: MWth**
	Range of applicability	
	Equipment cost (incl. Instrumentation/control)	Continuous process microwave ovens from £600,000+.
	Control panel	
	Reinforcement/expansion of the grid connection	Assumed not required
	Total installed cost	£8,000/kW installed.
6	OPEX estimate	
	OPEX electricity	
	O&M fixed costs	80£/kW/y
	O&M variable costs	10.1 £/MWh
7	Counterfactual case	Natural gas fired ovens
	CAPEX	£193/kW
	Fuel cost (LHV basis)	Heat duty / 0.92
	O&M costs	3.9 £/kW/y
8	Efficiencies (current and future)	40% of natural gas duty
9	Fuel inputs	Electricity
10	Technology lifetime	15
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Wood drying, solids drying
12	Technology providers that have responded to our questions	Process Technologies UK), C-Tech Innovation (UK)
13	Known industry examples	

References:

C-Tech Innovation

1	Technology name	**Microwave Assisted Gas Fired (MAGF)**
2	Current TRL / Target Date for TRL 9	5 to 7
3	Maximum size currently available	120 kW
4	Maximum size that can be achieved over time	10% of conventional firing load
5	CAPEX estimate	
	Range of applicability	
	Equipment cost (incl. Instrumentation/control)	
	Control panel	
	Reinforcement/expansion of the grid connection	
	Total installed cost	£732/kWe
6	OPEX estimate	
	OPEX electricity	
	O&M fixed costs	7.3 £/kW/y
	O&M variable costs	0.9 £/MWh
7	Counterfactual case	Natural gas fired kiln
	CAPEX	£665/kWth fired (LHV basis)
	Fuel cost (LHV basis)	Heat duty / 0.92
	O&M costs	13.3 £/kW/y
8	Efficiencies (current and future)	90% of original total heat requirements by fuel gas and 10% by electricity. On a per tonne(brick)/unit time basis however, total heat requirement reduces by 40% as the heating can be achieved in much less time. Hence for an original counterfactual firing duty of 100 MW, with MAGF the heat supply would be 10 MW electricity, 50 MW natural gas.
9	Fuel inputs	Electricity and natural gas
10	Technology lifetime	15

11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Ceramics
12	Technology providers that have responded to our questions	C-Tech Innovation UK)
13	Known industry examples	Drayton kilns

References:
C-Tech Innovation
EA Technology Ltd

1	Technology name	**OL HTHP (MVR) Heat Pump**
2	Current TRL / Target Date for TRL 9	7-9 / 2023 for emerging technologies at >1MWe scale
3	Maximum size currently available	660 kW_{th} (165°C) Kobelco´s SGH 165 5.1 MW_{th} (156°C) Spilling Technologies
4	Maximum size that can be achieved over time	Size of demo projects is rather small at lower temperatures
5	CAPEX estimate	
	Range of applicability	1-5 MWth
	Compressor cost (incl. motor, VSD, instrumentation and control)	206 £/kW_{th} (as per Spilling Technologies)
	Total installed compressor cost	300 £/kW_{th} (at an installation factor of 1.5 as per Emerson)
6	OPEX estimate	
	OPEX electricity	Duty/COP
	O&M fixed costs	3 £/kW/y
	O&M variable costs	0.4 £/MWh
7	Counterfactual case	Steam boiler firing natural gas
	CAPEX	£166/kWth fired (LHV basis)
	Fuel cost	Heat duty / 0.92
	O&M costs	3.3 £/kW/y
8	Efficiencies (Coefficient of Performance)	4 (depends on temperature lift)
9	Energy inputs	Electricity
10	Technology lifetime	20
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	• Any low grade waste heat source; • All processes where steam, at pressures of 5.5 bar or lower, is used for heating.
12	Technology providers that have responded to our questions	• Spilling Technologies GmbH (Germany)

		• AIT Austrian Institute of Technology GmbH
13	Known industry examples	• Huntsman, UK (nitro-benzene to aniline process) • DryF demonstration – Mars pet food – 500 kW thermal • Kobe Steel, Japan • Propane/propylene splitters in Petrochemicals plants.

References:

IEA HPP
FME HighEFF
European Heat Pump Summit, Nuremberg, 24-25 October 2017
Hybrid Energy
DryF
AIT Austrian Institute of Technology GmbH
Emerson Climate Technologies GmbH
Spilling Technologies GmbH
Australian Alliance for Energy Productivity, 2017

1	Technology name	**CL HTHP Heat Pump**
2	Current TRL / Target Date for TRL 9	7-9 / 2023 for emerging technologies at>1MWe scale
3	Maximum size currently available	200 kW (150°C); 1.6 MW (130°C)
4	Maximum size that can be achieved over time	Size of demo projects is rather small and at lower supply temperatures
5	CAPEX estimate	
	Equipment cost	300 £/kW$_{th}$ (Emerson´s paper)
	Total installed cost (TIC)	450 £/kW$_{th}$ (at an installation factor of 1.5 as per Emerson)
6	OPEX estimate	
	OPEX	Duty/COP
	O&M fixed costs	4.5 £/kW/y
	O&M variable costs	0.6 £/MWh
7	Counterfactual case (TIC)	Steam boiler firing natural gas
	CAPEX	£166/kWth fired (LHV basis)
	Fuel cost	Heat duty / 0.92
	O&M costs	3.3 £/kW/y
8	Efficiencies (Coefficient of Performance)	4 (depends on temperature lift)
9	Energy inputs	Electricity
10	Technology lifetime	20
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	• Any low grade waste heat source; • All processes where heating below 130 -150°C is required (subject to operability, safety, etc).
12	Technology providers that have responded to our questions	• AIT Austrian Institute of Technology GmbH
13	Known industry examples	• Nestlé Halifax, UK • DryF demonstration – Wienberger brick – 600-100 kW thermal • DryF demonstration – Agrana starch – 600 kW thermal • Tofu plant, Australia

References:
IEA HPP
FME HighEFF
European Heat Pump Summit, Nuremberg, 24-25 October 2017
Hybrid Energy
AIT Austrian Institute of Technology GmbH
Emerson Climate Technologies GmbH
Viking Heat Booster
Australian Alliance for Energy Productivity, 2017

1	Technology name	**All-Electric Glass Furnaces**
2	Current TRL / Target Date for TRL 9	6 (assumed, because of economics, see below)
3	Maximum size currently available	300 tpd (TECOGLASS)
4	Maximum size that can be achieved over time	*"There is no technical limitation to furnace capacity"*. (Quote from Fives Glass).
5	CAPEX estimate	Tecoglass referred us to the comparison study done for British Glass and BEIS
	Range of applicability	Equivalent to counterfactual smelters firing natural gas.
	Equipment cost	
	Electrical connection costs	
	Reinforcement/expansion of the grid connection	
	Total installed cost	"*Electric furnace systems require capital investment comparable or less then fuel fired alternative technologies and normally cheaper rebuild costs" (*quote from Fives Glass).
6	OPEX estimate	
	O&M fixed costs	
	O&M variable costs	
7	Counterfactual case	Glass smelters firing natural gas
	CAPEX (TIC)	"*Electric furnace systems require capital investment comparable or less then fuel fired alternative technologies and normally cheaper rebuild costs" (*quote from Fives Glass).
	Efficiency	1.4 MWh/tonne melting (British Glass; Container glass)
	O&M costs	
	Technology lifetime	15 to 20 years

8	Efficiencies	0.9 MWhr/tonne (Fives Glass)
9	Energy inputs	Electricity
10	Technology lifetime	5 to 8 years (BAT) (Reduced campaign length)
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Glass sector
12	Technology providers that have responded to our questions	Tecoglass (UK)
13	Known industry examples	• Luigi Bormioli, Parma, Italy • Hite Industries, Korea

References

Fives Glass
British Glass
Tecoglass
Schneider Electric White Paper 14th International Seminar on Furnace Design Vsetin, Czech Republic

1	Technology name	**100% Hydrogen Boiler**
2	Current TRL / Target Date for TRL 9	7-8
3	Maximum size currently available	Assume 100 MWth (adapting a standard design for a natural gas boiler)
4	Maximum size that can be achieved over time	Equivalent to counterfactual natural gas boiler
5	CAPEX estimate	
	Range of applicability	Equivalent to counterfactual natural gas boiler
	New CAPEX (TIC)	199 £/kWth fired
	Conversion cost (boilers)	50 £/kW gas capacity
	Connection cost to be added to above (piping + control valve)	350 £/m (assume 35000 £)
6	OPEX estimate	
	O&M fixed costs	2.0 £/kW/y
	O&M variable costs	0.3 £/MWh
7	Counterfactual case (steam boilers on natural gas)	
	CAPEX	166 £/kWth fired
	O&M costs	3.3 £/kW/y
8	Efficiencies (current and future) (LHV basis)	92%
9	Fuel inputs	H2
10	Technology lifetime	20 years
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	All processes where steam, at different pressures, is used for heating
12	Technology providers that have responded to our questions	
13	Known industry examples	• Propane dehydrogenation plants • Chlor-alkali industry (INOVYN UK, Austria, Canada) • Ethylene (steam) crackers • Velde´s Boiler plant for process steam generation (reference)

References:

H21 report
Velde
INEOS Runcorn (now INOVYN)
http://processengineering.co.uk/article/2001409/ineos-project-reduce

1	Technology name	**100% Hydrogen Heater**
2	Current TRL / Target Date for TRL 9	7-8
3	Maximum size currently available	Assume 100 MWth (adapting a standard design for a natural gas-fired furnace)
4	Maximum size that can be achieved over time	
5	CAPEX estimate	
	Range of applicability	Equivalent to counterfactual natural gas furnace
	New CAPEX (TIC)	232 £/kWth fired
	Conversion cost (furnaces)	50 £/kWth gas capacity
	Connection cost to be added to above (piping + control valve)	350 £/m (assume 35000 £)
6	OPEX estimate	
	OPEX (LHV basis)	Heat duty / 0.92
	O&M fixed costs	2.3 £/kW/y
	O&M variable costs	0.3 £/MWh
7	Counterfactual case (steam boilers on natural gas)	
	CAPEX	193 £/kWth fired
	Fuel cost (LHV basis)	Heat duty / 0.92
	O&M costs	3.1 £/kW/y
8	Efficiencies (current and future) (LHV basis)	92%
9	Fuel inputs	H2
10	Technology lifetime	20
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Most processes where heat at high temperature is used for heating
12	Technology providers that have responded to our questions	
13	Known industry examples	

1	Technology name	**H2 as Ironmaking Reductant**
2	Current TRL / Target Date for TRL 9	3 / 2035
3	Maximum size currently available	Too early in development cycle to estimate.
4	Maximum size that can be achieved over time	Too early in development cycle to estimate.
5	CAPEX estimate	Outside of hydrogen generation, could be relatively minor.
	Range of applicability	
	Equipment cost	
	Total installed cost	
6	OPEX estimate	
	OPEX	
	O&M fixed costs	
	O&M variable costs	
7	Counterfactual case	Coal use in blast furnace
	Efficiencies	12.0 GJ/tonne
	CAPEX	130 £/tonne
	O&M costs	2.6 £/kW/y
8	Efficiencies	
9	Energy inputs	H2
10	Technology lifetime	20
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Ironmaking - pig iron
12	Technology providers that have responded to our questions	
13	Known industry examples	Austrian steelmaker Voestalpine is building an experimental facility at Linz to look at the potential to replace coking coal with hydrogen in the production of crude steel from pig iron.

1	Technology name	**HYBRIT (direct reduction of pig iron using hydrogen instead of natural gas)**
2	Current TRL / Target Date for TRL 9	3 / 2035
3	Maximum size currently available	Too early in development cycle to estimate. Pilot plan trials in 2018-2024. Demonstration trials 2025-2035.
4	Maximum size that can be achieved over time	Assume commercial scale iron production from pig iron.
5	CAPEX estimate	A pre-feasibility study (2016-2017) indicated that HYBRIT´s capex is about 30 to 50% higher than that of BF´s
	Range of applicability	
	Equipment cost	
	Total installed cost	
6	OPEX estimate	
	OPEX	
	O&M fixed costs	
	O&M variable costs	
7	Counterfactual case	BF / BOF route from pig iron (Note: no direct reduction in UK currently)
	CAPEX	387 £/tonne
	Efficiency	12.0 GJ/tonne
	O&M costs	7.7 £/kW/y
8	Efficiencies	The pre-feasibility study estimated a 25% overall energy savings (H2 production plant included)
9	Energy inputs	
10	Technology lifetime	
11	Suitability for the high-level cross sectoral process types considering temperature, pressure, safety, etc.	Ironmaking - pig iron

12	Technology providers that have responded to our questions	
13	Known industry examples	SSAB / LKAB / Vattenfall

References: /
SSAB / LKAB / Vattenfall

7.4 Key results and sensitivity analysis for technical and commercial potential

Sensitivities and key results:

ID	Fuel type	Fuel cost scenario	Year	Filter	Discount rate	Carbon costs	Replaced fuel consumption (TWh)	Potential emissions savings (Mt CO2 / year)	Weighted average cost (£/t)
S1	All	Central	2040	Technology availability in 2040	10%	Yes	89.4	15.9	30.8
S2	All	Central	2030	Technology availability in 2030	10%	Yes	55.3	9.7	38.6
S3	Biomass	Central	2040	Technology availability in 2040	10%	Yes	55.6	10.3	20.3
S4	Electrification	Central	2040	Technology availability in 2040	10%	Yes	45.9	7.3	259.1
S5	Hydrogen	Central	2040	Technology availability in 2040	10%	Yes	95.7	17.7	66.6
S6	No hydrogen	Central	2040	Technology availability in 2040	10%	Yes	57.9	10.7	41.5
S7	No biomass	Central	2040	Technology availability in 2040	10%	Yes	90.5	16.9	59.3
S8	Biomass	Central	2030	Technology availability in 2030	10%	Yes	52.7	9.4	24.0
S9	Electrification	Central	2030	Technology availability in 2030	10%	Yes	43.9	5.8	308.5
S10	Hydrogen	Central	2030	Technology availability in 2030	10%	Yes	47.6	7.7	79.6
S11	No hydrogen	Central	2030	Technology availability in 2030	10%	Yes	53.9	9.4	41.7

ID	Fuel type	Fuel cost scenario	Year	Filter	Discount rate	Carbon costs	Replaced fuel consumption (TWh)	Potential emissions savings (Mt CO2 / year)	Weighted average cost (£/t)
S12	No biomass	Central	2030	Technology availability in 2030	10%	Yes	48.7	7.8	99.2
S13	All	Central	2040	Technology availability in 2040	3.5%	Yes	89.7	16.0	20.6
S14	All	Central	2030	Technology availability in 2030	3.5%	Yes	55.7	9.8	18.5
S15	Biomass	Central	2040	Commercial potential (5 year payback)	10%	Yes	10.9	3.5	- 18.2
S16	Electrification	Central	2040	Commercial potential (5 year payback)	10%	Yes	3.7	0.6	- 82.4
S17	Hydrogen	Central	2040	Commercial potential (5 year payback)	10%	Yes	-	-	-
S18	No hydrogen	Central	2040	Commercial potential (5 year payback)	10%	Yes	14.5	4.2	- 28.1
S19	No biomass	Central	2040	Commercial potential (5 year payback)	10%	Yes	3.7	0.6	- 82.4
S20	All	Central	2040	Commercial potential (5 year payback)	10%	Yes	14.5	4.2	- 28.1
S21	All	Low	2040	Commercial potential (5 year payback)	10%	Yes	17.7	4.7	- 44.1
S22	All	High	2040	Commercial potential (5 year payback)	10%	Yes	8.5	2.4	- 34.5
S23	No hydrogen	Low	2040	Commercial potential (5 year payback)	10%	Yes	16.0	4.4	- 45.9

ID	Fuel type	Fuel cost scenario	Year	Filter	Discount rate	Carbon costs	Replaced fuel consumption (TWh)	Potential emissions savings (Mt CO2 / year)	Weighted average cost (£/t)
S24	No biomass	Low	2040	Commercial potential (5 year payback)	10%	Yes	5.3	0.9	- 100.6
S25	No hydrogen	High	2040	Commercial potential (5 year payback)	10%	Yes	8.5	2.4	- 34.5
S26	All	Low	2040	Technology availability in 2040	10%	Yes	86.8	15.5	- 20.2
S27	No hydrogen	Low	2040	Technology availability in 2040	10%	Yes	57.6	10.7	- 28.9
S28	No biomass	Low	2040	Technology availability in 2040	10%	Yes	88.2	16.2	- 5.4
S29	All	High	2040	Technology availability in 2040	10%	Yes	89.1	16.0	29.3
S30	No hydrogen	High	2040	Technology availability in 2040	10%	Yes	57.6	10.7	48.2
S31	Hydrogen	Low	2040	Commercial potential (5 year payback)	10%	Yes	1.7	0.3	- 15.5
S32	Biomass	Low	2040	Commercial potential (5 year payback)	10%	Yes	12.3	3.8	- 30.4
S33	Electrification	Low	2040	Commercial potential (5 year payback)	10%	Yes	3.7	0.6	- 136.6
S34	Biomass	High	2040	Commercial potential (5 year payback)	10%	Yes	4.9	1.7	- 11.4
S35	No biomass	Low	2040	Commercial potential (5 year payback)	10%	Yes	5.3	0.9	- 100.6

Breakdown of emissions saving potential by technology, for each scenario:

ID	Large Biomass Steam Boiler	Small Biomass Steam Boiler	Direct Biomass Combustion	Biomass Combustion + O2 enrichment	Direct Biomass Reductant	Electric Steam Boiler (small)	Electrode Steam Boiler (large)	Electric Process Heater	Electric Ceramic Tunnel Kilns	Electric Infra-Red Heaters	Electric Plasma Gas Heaters	Microwave Heaters	OL Heat Pump (MVR)	CL Heat Pump	Electric glass furnace	H2 for Direct Reduction	100% H2 Fuel Boilers	100% H2 Fuel Heaters	H2 fired kiln
S1	18%	16%	0%	6%	15%	0%	0%	0%	0%	0%	0%	0%	2%	2%	0%	0%	1%	36%	4%
S2	29%	26%	0%	11%	15%	0%	0%	0%	4%	0%	3%	0%	4%	2%	0%	0%	2%	3%	0%
S3	28%	39%	0%	10%	23%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
S4	0%	0%	0%	0%	0%	34%	35%	1%	6%	0%	14%	0%	5%	3%	2%	0%	0%	0%	0%
S5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	14%	42%	41%	3%
S6	27%	26%	0%	10%	22%	0%	0%	1%	4%	0%	4%	0%	4%	2%	1%	0%	0%	0%	0%
S7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	0%	15%	35%	43%	3%
S8	31%	43%	0%	11%	15%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
S9	0%	0%	0%	0%	0%	35%	37%	1%	6%	0%	9%	0%	7%	4%	0%	0%	0%	0%	0%
S10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	96%	4%	0%
S11	30%	29%	0%	11%	15%	0%	0%	1%	4%	0%	4%	0%	4%	2%	0%	0%	0%	0%	0%
S12	0%	0%	0%	0%	0%	0%	0%	0%	5%	0%	7%	0%	5%	3%	0%	0%	76%	4%	0%
S13	18%	17%	0%	6%	15%	0%	0%	0%	0%	0%	0%	0%	2%	1%	0%	0%	1%	36%	4%
S14	29%	27%	0%	10%	15%	0%	0%	0%	4%	0%	3%	0%	4%	2%	0%	0%	2%	3%	0%
S15	4%	0%	0%	29%	67%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
S16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	61%	39%	0%	0%	0%	0%	0%
S18	3%	0%	0%	24%	57%	0%	0%	0%	0%	0%	0%	0%	9%	6%	0%	0%	0%	0%	0%
S19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	61%	39%	0%	0%	0%	0%	0%
S20	3%	0%	0%	24%	57%	0%	0%	0%	0%	0%	0%	0%	9%	6%	0%	0%	0%	0%	0%
S21	8%	0%	0%	22%	51%	0%	0%	0%	0%	0%	0%	0%	8%	5%	0%	0%	0%	0%	6%
S22	0%	0%	0%	43%	30%	0%	0%	0%	0%	0%	0%	0%	17%	11%	0%	0%	0%	0%	0%
S23	8%	0%	0%	23%	54%	0%	0%	0%	0%	0%	0%	0%	9%	6%	0%	0%	0%	0%	0%

ID	Large Biomass Steam Boiler	Small Biomass Steam Boiler	Direct Biomass Combustion	Biomass Combustion + O2 enrichment	Direct Biomass Reductant	Electric Steam Boiler (small)	Electrode Steam Boiler (large)	Electric Process Heater	Electric Ceramic Tunnel Kilns	Electric Infra-Red Heaters	Electric Plasma Gas Heaters	Microwave Heaters	OL Heat Pump (MVR)	CL Heat Pump	Electric glass furnace	H2 for Direct Reduction	100% H2 Fuel Boilers	100% H2 Fuel Heaters	H2 fired kiln
S24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	43%	28%	0%	0%	0%	0%	30%
S25	0%	0%	0%	43%	30%	0%	0%	0%	0%	0%	0%	0%	17%	11%	0%	0%	0%	0%	0%
S26	6%	6%	0%	7%	16%	14%	10%	1%	0%	0%	1%	0%	3%	2%	0%	0%	0%	33%	4%
S27	9%	9%	0%	10%	23%	20%	14%	1%	4%	0%	4%	0%	4%	2%	1%	0%	0%	0%	0%
S28	0%	0%	0%	0%	0%	15%	12%	1%	0%	0%	1%	0%	2%	2%	0%	15%	8%	41%	4%
S29	6%	16%	0%	6%	15%	0%	0%	0%	0%	0%	0%	0%	2%	2%	0%	0%	14%	35%	4%
S30	27%	25%	0%	10%	22%	0%	0%	1%	4%	0%	4%	0%	4%	2%	1%	0%	0%	0%	0%
S31	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%
S32	9%	0%	0%	27%	64%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
S33	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	61%	39%	0%	0%	0%	0%	0%
S34	0%	0%	0%	59%	41%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
S35	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	43%	28%	0%	0%	0%	0%	30%