



Programme Area: Carbon Capture and Storage

Project: Hydrogen Turbines

Title: Hydrogen Storage and Flexible Turbine Systems WP3 Report – Supporting Studies

Abstract:

The purpose and focus of the Hydrogen Turbines project is to improve the ETI's understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines, and to provide data on the potential economics and technical requirements of such technology to refine overall energy system modelling inputs. The final deliverable (D2) comprises eight separate components. This document is D2 WP3 Report – providing a series of supporting studies, including alternative methods of hydrogen production and hydrogen-based power generation, alternatives to salt cavern storage and broader issues around hydrogen use in the UK energy system.

Context:

This £300k project, led by global engineering and construction company Amec Foster Wheeler, in collaboration with the BGS, assessed the economics of a range of flexible power generation systems which involve the production of hydrogen (with CCS) from coal, biomass or natural gas, its intermediate storage (e.g. in salt caverns deep underground) and production of power in flexible turbines. The work included mapping of potentially suitable hydrogen storage salt cavern sites in and around the UK and provided the ETI with a flexible economic modelling tool to assess the range of possible options. The ETI's energy system modelling work suggests that systems such as these could provide a valuable contribution to the future energy mix, filling the gap between base load nuclear plant and low carbon power generation.

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Hydrogen Storage and Flexible Turbine Systems WP3 Report – Supporting Studies

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DISCLAIMER

The information contained herein is provided by Foster Wheeler Energy Limited (FWEL) to Energy Technologies Institute LLP (ETI), solely to assist ETI in improving its understanding of flexible power generation systems comprising of hydrogen production, storage and turbines, and to enable ETI to refine its Energy System Modelling Environment (ESME) model.

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1. EXECUTIVE SUMMARY

1.1 Introduction

Fossil fuel based power generation currently plays a key part in providing for the UK's energy demands. The development and implementation of Carbon Capture and Storage (CCS) technologies is an important option in reducing the associated CO₂ emissions, but adding CCS to conventional power systems impacts their ability to respond to power demand fluctuations, since the column systems required for solvent-based CO₂ removal work best at steady state conditions and may be less efficient in turndown operation.

Adding intermediate storage of hydrogen-rich fuel gas to a pre-combustion carbon capture scheme could be an attractive way of achieving flexible low-carbon power generation for the UK: the upstream carbon capture system would normally operate at a steady, base load capacity for maximum efficiency, while the hydrogen store would provide buffer capacity to allow the downstream hydrogen based power generation scheme to respond to demand fluctuations.

The purpose and focus of this project is:

- To improve the ETI's understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines; and
- To focus on the potential, economics and technical requirements for salt cavern storage and flexible turbines, and to enable refinement of the ETI Energy System Modelling Environment (ESME) model in order to confirm or adjust ESME findings.

1.2 Scope

This report covers the work undertaken in WP3 – Supporting Studies.

The aim of WP3 is to investigate the broader context of the study by considering alternative hydrogen production and hydrogen-based power generation technologies, the viability of adding hydrogen to the National Gas Grid, alternative forms of hydrogen storage and potential synergies achievable by combining different technologies. The scope of this work package will consist of research from existing literature.

The scope of WP3 consists of the following landscaping studies:

- Review of alternative hydrogen production options and their relative costs;
- Review of alternative hydrogen to power conversion options and their relative costs;
- Addition of hydrogen to National Gas Grid;
- Value of hydrogen for other uses;
- Review of availability and efficiency of hydrogen fired gas turbines;
- Consumer view of hydrogen as a natural gas substitute;
- Integrated solutions deploying hydrogen stores.

1.3 Key Findings of Work Package 3 – Supporting Studies

Key findings from the supporting studies element of the Hydrogen Storage and Flexible Turbine Systems Project are summarised below.

1.3.1 Alternative Hydrogen Production Options

The alternative hydrogen generation technologies considered include:

- Electrolysis (Low-Temperature and High Temperature);
- Biomass-Only Gasification;
- Thermo-Chemical Water Splitting;
- Photo-Catalytic Water Splitting;
- Biological Processes.

Table 1 below provides a summary of the estimated break-even prices for currently commercialised hydrogen production routes based on WP1 cost information and literature data.

Biomass gasification with CCS is a natural extension of the combined biomass and coal gasification option outlined in WP1. The capital cost curve for biomass gasification is not significantly steeper than for coal gasification, but the practical constraints on the consistent availability and sustainability of biomass feedstock limit the scale of biomass gasification and result in a higher specific cost. Biomass gasification is also negatively impacted by the feedstock cost relative to coal. Biomass gasification would be made more attractive by situations with local low cost feedstock (such as organic waste streams from local industries) or by government incentives which credit the CO₂ absorbed in sustainable production of the feedstock. Co-production of hydrogen using biomass and coal (WP1 Case 2) offers scale, feedstock flexibility and efficiency benefits over biomass only gasification.

Electrolysis is a clean technology that produces pure hydrogen and oxygen in a molar ratio of 2:1 with little waste and by-products. Specific capital costs are similar to the WP-1 conventional hydrogen generation technologies, but this technology is heavily impacted by the operating cost of electrical power. Electrolysis plants consist of numerous parallel modules of ~50 – 70 kg/h per module, so large scale plants would involve hundreds of parallel units and very little economy of scale. Although the large number of modules would make the hydrogen production rate highly scalable, it results in high maintenance costs. Given the limited capacity per module and the impact of electrical power cost, it is unlikely that this technology can compete with conventional technologies as a method of bulk hydrogen generation. However, this technology would be more attractive for small scale hydrogen production (such as local generation for hydrogen fuelled vehicle filling stations) to avoid the risk and cost of hydrogen transport, and for stranded power generation: wind or wave generation combined with electrolysis to hydrogen may become competitive where hydrogen can be stored and consumed locally and the system is isolated from the UK power grid.

Table 1 – Relative Cost of Hydrogen by Production Route

Technology	Assumed Plant Capacity (kg/h)	Hydrogen Cost (£/GJ)
SMR of Natural Gas with CCS	20,000	13.9
Coal Gasification with CCS	19,400	12.0
ATR of Natural Gas with CCS	19,100	12.0
Biomass Gasification with CCS	4300	18.5
Alkaline Electrolysis	2000	36.1

Although it is not possible to evaluate costs and break-even hydrogen prices for the remaining technologies at this time, a number of general observations can be made:

- Polymer Electrolyte Membrane (PEM) and high temperature electrolysis are also anticipated to fare better as small scale or stranded power generation schemes. Once fully developed, they offer efficiency and operability improvements over alkaline electrolysis. These technologies are already preferred over conventional electrolysis in niche applications, such as naval and aerospace uses, and they will inevitably diversify further as the technology matures.
- Photocatalytic water splitting is analogous to photovoltaic (PV) cells development and may be implemented as a progression of this technology. Due to the high surface area required for this technology, it is likely that this technology, once mature, will follow the same path as PV and become a distributed rather than a centralised hydrogen generation scheme, using residential or commercial roof area. For small producers, it is likely that this technology would be combined with fuel cells to avoid the requirement for transport of the hydrogen.
- Thermochemical water splitting is a means of converting heat into hydrogen. The feed temperatures for these processes require high grade heat in the range of 750°C to 1000°C where they compete with conventional steam turbine power generation. Use of this heat in steam cycle based power generation at approximately 50% efficiency, followed by electrolysis at approximately 70% efficiency results in an overall efficiency of 35%, which is comparable with the highest practicable thermochemical process efficiency. Moreover, use of steam cycle followed by electrolysis is a cleaner, safer technology and provides the option of direct production of power at 50% efficiency at periods of peak demand whereas the thermochemical process can only generate hydrogen, giving a maximum round trip power generation efficiency of only 20% (based on ~55% combined cycle efficiency for hydrogen based power generation).

The remaining technology options all rely on biological processes. Although modern biotechnology enables engineering of microbes to significantly increase selectivity and yields, biological processes generally have low reaction rates, require large reaction volumes, and require the processing of large flowrates of water. Due to the reaction volumes and water processing requirements, it is likely to be impractical to generate hydrogen on a large scale using a centralised biological process. It is more likely that economic implementation of these processes will rely on distributed generation: processes utilising plant waste would be best located close to the source of feed (whether a dedicated crop or an organic waste/by-product) and those relying upon light would be distributed in a similar manner to PV solar power generation - Grow Energy's modular Hydral bioreactors are intended to be applied on the face of industrial buildings to harvest sunlight for hydrogen generation.

1.3.2 Alternative Hydrogen to Power Conversion Options

The alternative technologies considered for power generation from hydrogen include:

- Reciprocating Engines;
- Hydrogen Fuel Cells:
 - Polymer Electrolyte Membrane (PEM);
 - Alkaline Fuel Cell (AFC);
 - Phosphoric Acid Fuel Cell (PAFC);
 - Molten Carbonate Fuel Cell (MCFC);
 - Solid Oxide Fuel Cell (SOFC)

Table 2 below provides an overview of the typical installed costs for different hydrogen to power options.

Reciprocating engines are a mature technology with efficiencies of up to nearly 50% which is higher than for comparable small open cycle gas turbines. Gas engines have high fuel flexibility, though use of hydrogen poses a number of technical challenges due to its wide flammable range and low ignition energy. Moreover, gas engines have traditionally proven practical and cost effective in the 10kW to 10MW distributed power sector. While these may be cost effective solution for distributed hydrogen generation, storage and power production, it is unlikely that they will compete with gas turbines for centralised production at up to 250MW capacity.

Fuel cells are a commercially proven means of converting hydrogen into electrical power. with operating efficiencies of up to 60%. Although cost data is inconsistent, it is clear that the cost of power generation using fuel cells is several times more expensive than conventional gas turbines. Moreover, current fuel cell installations are limited to capacities of 1MW or less, so installation of 50-250MW of fuel cells would be one or two orders of magnitude beyond current experience. For illustrative purposes, the largest modular units commercialised by Bloom Energy ⁽¹⁾ have a base load capacity of 200kW. 1250 of these units would be required to generate 250MW.

Fuel cells offer a selection of technologies ranging from mature alkaline fuel cells (AFC) to relatively recent innovations in the form of solid oxide fuel cells (SOFC). Most of the technologies have been extensively studied and, while implementation improvements continue to reduce cost and increase efficiency, it is unlikely that the cost of these technologies will drop dramatically and make them competitive against large gas turbines in the medium (20 year) term.

SOFC fuel cells are a relatively new development. Although these operate at around 1000°C, they require no precious metal catalysts, no corrosive chemicals and no liquid electrolyte, they only require fuel and air as feed, and are not as susceptible to CO₂, CO or sulphur poisoning as other technologies. Moreover, as all parts of a SOFC cell are solid, they can be formed into tubular cells to reduce space and promote fuel and air transfer. This should increase current density and reduce cost. The capital cost of SOFC technology has been reported at ~£3000/kW for scales up to 250kW, but the relative youth of this technology combined with the ability to shape the cells for optimal performance means that costs may drop more significantly than for other fuel cell technologies as the technology develops, making this potentially the most cost effective technology for medium scale stationary applications.

Table 2 – Comparative Costs for Hydrogen Based Power Generation

Technology	Typical System Capacity (kW)	Typical Specific Capital Cost (£/kW)
Combined Cycle GT/ST	Up to 300 MW	~500
Gas Engine	Up to 10 MW	500 - 1000
Alkaline Fuel Cells	Up to 1000 kW	1500 - 3000
Phosphoric Acid Fuel Cell	Up to 400 kW	1500 - 3000
Molten Carbonate Fuel Cell	250 – 500 kW	2000 - 4000
Polymer Electrolyte Fuel Cell	Up to 200 kW	5000 - 8000
Solid Oxide Fuel Cell	Up to 250 kW	~3000?

1.3.3 Addition of Hydrogen to National Gas Grid

The greatest hurdles to introduction of hydrogen into the UK natural gas distribution network arise from the differences in transport properties and combustion properties between the two fuels.

- The key transport property is diffusion, which is much greater in hydrogen and requires review of materials of construction. Higher diffusion rates for hydrogen can lead to embrittlement and cracking of metal pipes and can lead to development of flammable atmospheres around plastic pipes laid in channels.
- The key combustion property issues are Wobbe Index, which is 15% lower for hydrogen and is likely to require burner replacement; flame velocity, which is almost ten times faster for hydrogen and requires different types of burner in some applications; and energy density, which is three to four times lower for hydrogen and therefore requires three to four times as much fuel volumetric flow for the same heat output.

Many parts of the UK high pressure National Transmission System (NTS) can only function on natural gas, so the ideal location for hydrogen addition is in the downstream Local Distribution Zones (LDZ). This approach requires a dedicated hydrogen distribution system to collect hydrogen from producers/hydrogen stores and supply it to injection points within the LDZs.

Three options were considered in this investigation: complete replacement of natural gas with hydrogen for all consumers, blending of hydrogen into natural gas for all consumers, and replacement of natural gas with hydrogen for selected consumers.

Complete replacement of natural gas with hydrogen for all consumers

This option has the highest potential for carbon footprint reduction, but is subject to the following issues:

- A new hydrogen distribution network would need to be laid, linking hydrogen producers with all the LDZ addition points
- All LDZ pipework materials of construction and capacities would need to be reviewed for safety and operability. Inadequate pipework would need to be replaced or duplicated.
- End user flowmeters would need to be replaced or recalibrated for hydrogen.
- All domestic and small industrial appliances would need to be inspected and most burner assemblies/appliances modified or replaced to suit the new fuel.

The main concerns with this approach relate to safety, practicality and cost:

- Key safety concerns are the use of pipework designed for natural gas in hydrogen service. Hydrogen embrittlement can cause or propagate cracks in metal piping, flammable atmospheres may be formed in voids around plastic pipes, and existing leaks will leak more with hydrogen. Inspection and replacement of meters and burners in all domestic appliances is also a major safety risk, since any appliances missed during the process then present a fire or explosion hazard once fuels are changed.
- Key practicality concerns are the extent of pipework and appliance modifications required. A new hydrogen distribution network and modifications to the LDZ network would require extensive roadworks and disruption in parts of the country. Replacement of meters and appliance burners will also be highly disruptive, particularly as many appliances are likely to be uneconomic or not possible to repair and require complete replacement.

- The cost of this option is difficult to quantify as it depends on many factors, but inspection and modification of domestic consumer appliances alone is likely to cost several billion pounds.

Blending of hydrogen into the existing natural gas supply

This option has less potential for overall carbon footprint reduction, but is flexible (in terms of the level of addition) and offers a safer, less disruptive and less costly alternative to replacement of natural gas with hydrogen.

Fairly low levels (~3%v/v) of hydrogen could be added to natural gas with hardly any modification of end user appliances, whereas 15-20% v/v of hydrogen could potentially be added with some modification to industrial appliances (particularly gas turbines), but little modification to domestic appliances.

Use of natural gas enriched with up to 20%v/v hydrogen would only increase pipe velocities by up to 40%, metal pipes would be less prone to pipework embrittlement, and all pipework would exhibit lower leakage rates than for pure hydrogen. These factors should significantly reduce the quantity of LDZ pipework needing replacement, reducing disruption and cost, and make the remaining sections safer to operate.

If modification of domestic consumer meters and appliances is rendered unnecessary, this will significantly reduce the safety risk, level of disruption and cost.

It would be important to maintain the % hydrogen content of the blended gas constant, since gas is sold on the basis of a declared calorific value.

Replacement of natural gas with hydrogen for selected consumers.

Selection of individual, high volume consumers for fuel changeover is likely to give the greatest benefit in terms of carbon footprint reduction per unit implementation cost.

Selection of a small number of relatively large industrial users would limit the extent of pipework and reduce transmission costs, and this strategy would also allow the transmission system and consumer base for hydrogen fuel to grow in parallel with the growth in hydrogen production.

Dedicated hydrogen pipework direct to the consumer will eliminate safety risks associated with use of pipework designed for natural gas. Furthermore, as large industrial users are more likely than domestic consumers to be rigorous in the identification and modification of appliances, avoidance of domestic consumers will result in a significant reduction in the risk of fire and explosion after changeover.

1.3.4 Value of Hydrogen for Other Uses

Using a variety of methods, the value of hydrogen in various domestic markets was assessed and compared against the cost for the production methods evaluated in WP1. The results of this assessment are shown in Table 3.

Table 3 - Summary of the value of hydrogen across various end-uses

	Value of Hydrogen (£/GJ)
Domestic Fuel Gas	4
Transportation Fuel	17 – 37 (depending on fuel duty applied)
Chemical Feedstock	15
WP1 Cost	12 – 14 (excluding cost of further hydrogen purification)

Table 3 shows that hydrogen has the highest potential value as a transportation fuel, with the magnitude of this value highly dependent upon the level of fuel duty applied (range is based on zero duty through to same percentage duty as for petrol). Development of this market requires provision of hydrogen “pumps” at filling stations and consumer adoption of hydrogen fuelled vehicles. The latter is reliant upon reduction of the lifecycle cost of fuel cell and battery technology, and upon improvement in the distance these vehicles can travel between fuel stops. The safety issues associated with frequent transfers of pressurised hydrogen at 350-700 barg also need to be considered.

Hydrogen is already widely used as a chemical feedstock, so this evaluation considered the opportunity to replace high carbon footprint onsite hydrogen production with lower carbon footprint hydrogen import. Small hydrogen consumers are likely to already import hydrogen by tanker and large industrial hydrogen consumers are likely to achieve process and heat integrations that make onsite generation more efficient and more economic than import. Consequently, the largest potential market for supply of bulk hydrogen as chemical feedstock is likely to be small to medium scale consumers with hydrogen consumption of 5000kg/h or less, where loss of economies of scale versus world-scale facilities leads to a higher cost per unit production. Creation of an industrial hydrogen generation network consisting of a relatively small number of large producers will also lead to economies of scale for CCS and increase the likelihood of its adoption when motivated by carbon tariffs.

Use of hydrogen as an alternative to natural gas for domestic fuel use is an option with a very high carbon footprint reduction potential, but is the option with the least potential hydrogen value. As the natural gas being replaced is one of the most likely sources of fuel for hydrogen generation, hydrogen generated by this route cannot be cost competitive unless carbon footprint penalties are applied to natural gas fuel use: a strategy that would be highly unpopular as domestic heating bills would rise dramatically.

In conclusion, hydrogen has potential as a transportation fuel and as a low carbon footprint centralised source of chemical feedstock for small and medium scale industrial consumers. While it also has potential as a replacement for natural gas as a domestic fuel, this is unlikely to be cost effective. All of the options considered are highly dependent upon the development of infrastructure to supply the hydrogen to consumers. Furthermore, transportation and domestic fuel uses of hydrogen cannot be accommodated by existing vehicles and appliances: developing the market for hydrogen fuelled cars and replacing/modifying natural gas fuelled appliances with hydrogen fuelled appliances are both challenging prospects.

1.3.5 Availability and Efficiency of Hydrogen Fired Gas Turbines

High-hydrogen syngas fired gas turbine operation is a feasible alternative to natural gas fired variants, including for machines in the 300+MW_e class. Currently, reduced firing temperatures result in combined cycle efficiencies 4 – 5% below those of equivalent natural gas fired machines, but this gap could be closed if firing temperatures similar to natural gas firing become possible through advances in gas turbine technology, particularly in burner design.

Turndown operation with hydrogen-rich fuel firing presents different challenges compared with natural gas firing: carbon monoxide formation is less of an issue, but NO_x formation and flame velocity are more of a concern. While turndown performance for high hydrogen fuel fired turbines is anticipated to be similar to natural gas fired machines, flame velocity issues may create operability constraints or require a relatively higher diluent gas flow, which will further reduce exhaust temperature and negatively impact efficiency.

If efficient turndown operation is a requirement, a greater number of smaller turbines could be installed. However, smaller turbines suffer from loss of economies of scale, generally have slightly lower design load efficiencies, and may not be available in syngas variant designs suitable for high hydrogen fuel.

Syngas variant turbines are generally started up on natural gas and switched to high hydrogen fuel when online. As such, these machines are capable of operation on natural gas or a hydrogen rich natural gas fuel, though operating efficiency may be reduced since the turbines are not optimised for these fuels.

1.3.6 Consumer View of Hydrogen as a Natural Gas Substitute

While substitution of hydrogen for natural gas in the UK national gas grid could yield a huge reduction in the national carbon footprint, there are a number of substantial technical and HSE challenges associated with this changeover, as outlined in section 1.3.3.

Although industry and the general public may be supportive of initiatives associated with climate change, the level of inconvenience associated with installation or replacement of distribution pipework, together with the inconvenience and cost of modification or replacement of appliances incompatible with the new fuel will be a strong disincentive. Moreover, to achieve the same energy bills with hydrogen as with natural gas, the value of hydrogen fuel must equate to that of natural gas on an energy basis. The current value of natural gas is approximately £4/GJ, whereas the approximate value of hydrogen to achieve production economic break-even based on WP1 data is £12-£14/GJ. Increasing gas prices to this level would be unprecedented, highly unpopular, and would dramatically increase the number of UK households in what the UK government recognises as 'fuel poverty'.

1.3.7 Integrated Solutions Deploying Hydrogen Stores

Provision of a hydrogen hub consisting of storage caverns and a widespread collection and distribution system has the potential to transform the UK hydrogen economy as it will cause hydrogen to have a market value and will decouple producers and consumers.

By providing hydrogen with a market value, conventional chemical processes with a net excess of by-product hydrogen will have an incentive to become thermally efficient and export this hydrogen rather than burn it as fuel.

By decoupling producers and consumers, producers can be sized for efficiency and economies of scale and sited for integration opportunities in terms of cheap feedstock, potential process integration or potential utility integration. Size, integration and the ability to operate at a constant design point rather than vary with consumer demand will result in greater efficiency.

Creation of a hydrogen market will stimulate investment in small to medium sized enterprises utilising unconventional hydrogen production technologies. This in turn will stimulate further research and development into hydrogen technologies, which will reduce costs, increase efficiency and lead to the creation of new technologies.

A positive consumer image of hydrogen is vital in developing and expanding the UK hydrogen economy, so development of the hydrogen hub would require research and development of safeguards and safe practices for handling and storage of hydrogen to reduce the risk of accidental release causing fire or explosion.

2. INTRODUCTION

The Energy Technologies Institute (ETI) is a public private partnership between global industry members - BP, Caterpillar, EDF, E.ON, Rolls-Royce and Shell with the UK government. The ETI brings together projects that accelerate the development of affordable, clean, secure technologies needed to help the UK meet its legally binding 2050 targets. The ETI's mission is to accelerate the development, demonstration and eventual commercial deployment of a focused portfolio of energy technologies, which will increase energy efficiency, reduce greenhouse gas emissions and help achieve energy and climate change goals.

The ETI's modelling, using its Energy System Modelling Environment ("ESME") shows that flexible power generation systems comprising hydrogen generation with Carbon Capture and Storage ("CCS"), intermediate storage (particularly using salt caverns) and flexible turbines are attractive components in a future UK Energy system. In such a system, hydrogen is supplied from coal and biomass fired gasifiers and steam methane reformers, with carbon dioxide ("CO₂") captured for storage. This permits the use at high load of capital intensive and relatively inflexible conversion and CCS equipment, filling hydrogen storage when power is not needed, and releasing hydrogen at short notice through turbines when power is at a premium. Superficially there are no barriers to using salt caverns as stores: such stores are in use in the USA. However, these are for high value added applications and not for use in power where loss of efficiency is a more serious drawback. The ETI currently lacks sufficient data and knowledge to build a good representation of costs or efficiency (particularly relating to hydrogen storage) in ESME.

The purpose and focus of this project is:

- To improve the ETI's understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines; and
- To focus on the potential, economics and technical requirements for salt cavern storage and flexible turbines, and to enable refinement of the ETI Energy System Modelling Environment (ESME) model in order to confirm or adjust ESME findings.

2.1 Scope of Study

The Hydrogen Storage and Flexible Turbine Systems Project is split into five work packages. The first three work packages (WP1, WP2 & WP3) are focused on data collection and research in order to derive a basis for techno-economic analysis in WP4. Using the output from the WP4 modelling, a representative system will be selected. In WP5, this representative system will be compared against a post combustion CCGT case:

- WP1 – Hydrogen Power Production;
- WP2 – Hydrogen Storage;
- WP3 – Supporting Studies;
- WP4 – Development of a Flexible Modelling Tool;
- WP5 – Identification of a Representative System and Comparison of CCGT with CO₂ Buffer Storage.

This report covers the work undertaken in the execution of WP3 – Supporting Studies.

2.2 Scope of WP3 – Supporting Studies

The aim of WP3 is to investigate the broader context of the project by considering alternative hydrogen production and hydrogen-based power generation technologies, the viability of adding hydrogen to the National Gas Grid, alternative forms of hydrogen storage and potential synergies achievable by combining different technologies. The scope of this work package will consist of research from existing literature.

Specifically, the scope of WP3 consists of the following landscaping studies:

- Review of alternative hydrogen production options and their relative costs;
- Review of alternative hydrogen to power conversion options and their relative costs;
- Addition of hydrogen to National Gas Grid;
- Value of hydrogen for other uses;
- Review of availability and efficiency of hydrogen fired gas turbines;
- Consumer view of hydrogen as a natural gas substitute;
- Integrated solutions deploying hydrogen stores.

The WP3 report forms a part of the Final Report deliverables for the Hydrogen Storage and Flexible Turbine Systems Project.

3. ALTERNATIVE HYDROGEN PRODUCTION OPTIONS

3.1 Objective

The objective of this section is to provide a techno-economic review of alternative hydrogen production options, using both in-house experience and publicly available literature, so that their suitability for hydrogen generation can be compared.

3.2 Technology Overview

The conventional method of hydrogen generation is via gasification or reforming of fossil fuels. However, many alternative hydrogen generation technologies exist. The alternative technology options considered in this study are as follows:

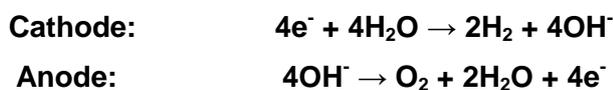
- Electrolysis (Low-Temperature and High-Temperature);
- Biomass-Only Gasification;
- Thermo-Chemical Water Splitting;
- Photo-Catalytic Water Splitting;
- Biological Processes.

This evaluation is undertaken in the context of competitiveness versus gasification/reforming based hydrogen production to support 50-250MW_e of power generation. Assuming ~55% combined cycle efficiency, the hydrogen flowrate required to generate this electrical power is 2700 - 14,000kg/h (30,000 - 152,000Nm³/h).

Electrolysis efficiencies are measured as a ratio of the heating value of hydrogen obtained to the electrical power expended to generate this hydrogen. 100% LHV efficiency is equivalent to 2.95kWh/Nm³.

3.2.1 Low-Temperature Electrolysis

Electrolysis is the process of applying a direct electric current across an electrolyte, normally consisting of a molten liquid or liquid solution, to cause a chemical reaction at the electrodes that separates the liquid into its constituent elements. When water is used as the electrolyte, it splits to generate elemental hydrogen and oxygen. The key electrolysis reactions are:



The most widespread low temperature electrolyser types are alkaline electrolysers and Proton Exchange Membrane/Polymer Electrolyte Membrane (PEM) electrolysers:

- As pure water has a low level of dissociation, it performs poorly as an electrolyte. For this reason, an alkali can be added to significantly increase the concentration of OH⁻ ions present in the solution.

Alkaline electrolysis uses an aqueous 20-40% KOH solution as an electrolyte, which is circulated through the electrolytic cells. Alkaline electrolysers are available at operating pressures of up to 25 barg⁽⁴⁾. Operating efficiencies are currently in the range of 65-75% for larger plants (4.6 to 3.9kWh/Nm³)⁽⁵⁾. Based on the source electrical power being produced by a combined cycle conventional power plant with 60% efficiency, the overall fuel to hydrogen efficiency for a large plant could be 40-45%. This is somewhat lower than the overall fuel to hydrogen efficiency calculated for gasification (68%), ATR (77%) or SMR (66%) processes in WP1.

Alkaline electrolysis is a mature technology with many existing modular industrial designs. The largest hydrogen production electrolysis module currently available is believed to be the Industrie Haute Technologie (IHT) S-556 (a sandwich of 556 cells combined into a single module), with a capacity

760Nm³/h (67kg/h) ⁽⁶⁾. According to IHT, the Sable Chemical Industries plant in Zimbabwe is the largest such plant in the world, having 28 S-556 electrolysis modules with an overall capacity of approximately 1850kg/h. Approximately 200 S-556 modules would be required to supply the hydrogen for 250MW_e of power generation.

Alkaline electrolysis has poor turndown performance ⁽⁴⁾, so is poorly suited to operation using power directly from renewable sources with variable supply current.

- PEM electrolysis uses an acidic polymer membrane electrolyte rather than a liquid electrolyte. Advantages of PEM over alkaline electrolysis are higher operating pressures (which can reduce or eliminate hydrogen compression) and better turndown performance ⁽⁴⁾.

PEM electrolysis is a less mature technology than alkaline electrolysis and this, combined with the technical complexity of the composite materials used in their manufacture mean that they currently have higher costs than alkaline electrolysis cells. Although operating efficiencies as high as 95% are reported in the literature (3.1kWh/Nm³), this figure drops at high current densities and falls with time as a result of membrane deterioration ⁽⁴⁾, leading to limited cell lifetimes.

3.2.2 High-Temperature Electrolysis

High-temperature electrolyzers typically use solid oxide electrolyser cells (SOEC). These cells operate at between 700°C and 1000°C and water is present in the form of steam. SOEC operation is the reverse of the more common solid oxide fuel cell (SOFC) operation described in section 4.2.2. SOECs can be operated in two different modes, differing in how the steam in the electrolyser is heated:

- **Allothermal Operation**
Allothermal operation is where an external source provides heat for the high-temperature electrolyser (for example, an upstream conventional or nuclear power plant could provide heat as well as power).
- **Autothermal Operation**
Autothermal operation is where heat for the high-temperature electrolyser unit is provided by electrical heating in the electrolyser core.

Allothermal operation is more energy efficient, but transfer of heat at such high temperatures is challenging in terms of selection of suitable transfer media and materials of construction. In common with PEM, SOEC is not a mature technology, and while SOEC offers greater current density and greater efficiency than alkaline electrolysis, it has yet to be implemented at a significant industrial scale.

3.2.3 Biomass Gasification

The principles of biomass gasification are similar to gasification of coal or petcoke and as such the technology is mature. However, specific challenges for biomass gasification include:

- **Feed composition**
High temperature gasification is recommended for biomass gasifiers to destroy acidic tars that would otherwise cause corrosion of the gasifier shell. Additional syngas clean-up is also required to remove sulphur and chlorine compounds.
- **Feedstock availability, seasonal variability, sustainability and supply security**
Although biomass gasifier technology is sufficiently developed to accommodate seasonal variations in feedstock, the challenges of obtaining a secure and sustainable supply of biomass fuel, and the cost of transporting this fuel, limit the practical size of biomass gasification plants. Delivering 250MW_e fuel

equivalent of hydrogen from one biomass gasification plant in the UK is unlikely to be practical: approximately 1.5 million tonnes/annum of wood pellets would be required; total EU production in 2006 is reported as 5 million tonnes.

As biomass is a more challenging gasifier feed than coal, combined coal and biomass gasification is often considered instead (as in WP1 Case 2). Co-firing of biomass yields greater economies of scale, reduces the dependency upon biomass availability and slightly increases the efficiency of biomass to syngas conversion.

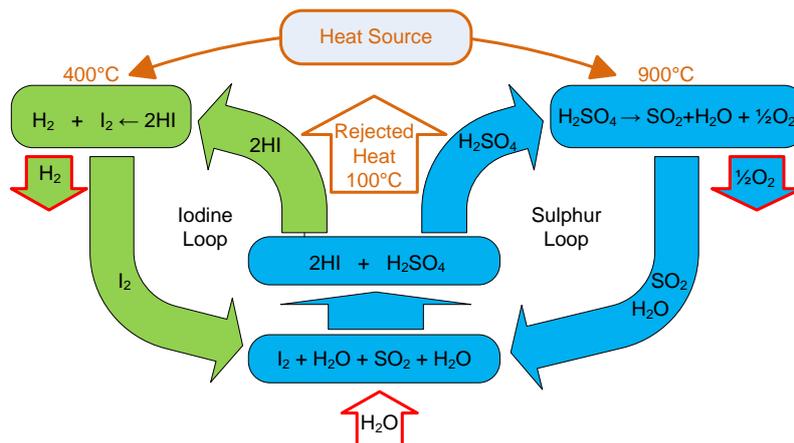
3.2.4 Thermo-Chemical Water Splitting

Thermo-chemical water splitting involves the conversion of water into elemental hydrogen and oxygen using a series of thermally driven chemical reactions.

There are several well established thermo-chemical cycles including the iodine-sulphur cycle (shown in Figure 1), the Westinghouse hybrid cycle (a variation of the iodine-sulphur cycle substituting the iodine thermo-chemical loop with SO₂ electrolysis) and the UT-3 cycle (a set of thermo-chemical reactions involving Calcium, Bromine and Iron).

Although thermo-chemical reactions have the potential for efficiencies of 35-40% (theoretical adiabatic efficiency for UT-3 cycle), development has not moved from pilot to commercial scale and there has been little recent development. The key challenges for thermo-chemical cycles are the corrosive nature of many of the reagents and the separation of reactants and products. Moreover, the high grade heat used to power these cycles could be used for steam cycle based power generation followed by electrolysis. These are cleaner, more mature technologies and offer a similar combined efficiency. Moreover, the steam cycle route offers the opportunity to deliver power rather than hydrogen at times of peak demand.

Figure 1 – Schematic of Iodine/Sulphur Thermo-chemical Process⁽⁴⁾



3.2.5 Photo-catalytic Water Splitting

Photo-catalytic water splitting is the conversion of water into oxygen and hydrogen through the action of light (usually ultraviolet) in the presence of a semiconductor catalyst. Light photons excite the semiconductor material to create electrons and holes. The holes oxidise water to oxygen; the electrons reduce water to hydrogen.

Figure 2 – Simplified Schematic of Photo-catalytic Water Splitting

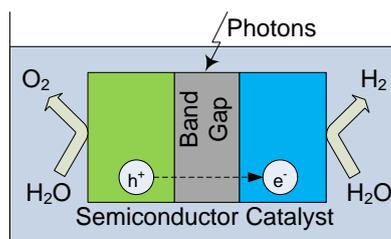


Photo-catalytic water splitting is an attractive technology because it is a clean and potentially renewable source of hydrogen: it consumes only water and sunlight and produces only hydrogen and oxygen ⁽⁸⁾.

Although photo-catalytic water splitting is simple in principle, key challenges include development of a semiconductor capable of operating in the more prevalent visible light spectrum that is stable under constant sunlight and has sufficient active sites to achieve a good reaction rate. Co-catalysts such as platinum are often needed to assist with the reduction of water to hydrogen and reagents are often added to act as electron scavengers or electron acceptors to promote the reaction. Moreover, as the anode and cathode must be separated if the oxygen and hydrogen are to be collected separately, application of a bias voltage is often needed to overcome the resistance of the electrolyte and semiconductor.

Photo-electrolysis is a variation of photo-catalytic water splitting in which photo-voltaic (PV) cells generate a current that is used for electrolysis. The two processes can be combined into a single module.

Whilst photo-catalytic water splitting is a promising area of research, the highly variable day lengths and sunlight intensity do not make the UK an ideal location and a number of technical challenges remain unresolved. It is therefore unlikely that the technology will be sufficiently mature in the medium (20 year) term for commercial implementation in the UK at an industrial hydrogen production scale.

3.2.6 Biological Processes

Several biological methods of hydrogen generation exist, utilizing a wide range of micro-organisms and organic catalysts. The following technologies are described in this section:

- Photo-biological water splitting
- Anaerobic bacterial fermentation
- Enzymatic hydrogen generation
- Biocatalysed electrolysis

Photo-biological Water Splitting

In this process, hydrogen is produced from water using sunlight and specialized microorganisms such as green algae in a bio-reactor.

Whereas plants normally produce oxygen during photosynthesis, some algae consume water and produce hydrogen instead of oxygen when deprived of sulphur under anaerobic conditions.

Although many advances have been made to increase the yield of hydrogen, there remain a number of key challenges for this technology:

- Production is inhibited at high light levels but light intensity drops significantly away from the surface of the bioreactor due to absorption by the algae. This requires a compromise in reactor design.
- Volumetric yields are currently low, requiring large bioreactor volumes. Operating and maintaining large volume and large surface area systems involving live algae is a practical challenge.

Research efforts continue to find new ways to modify existing micro-organisms (most commonly *Chlamydomonas reinhardtii*) and to identify other naturally occurring microbes to achieve higher production rates⁽²⁾.

At this time, photo-biological water splitting is some way from commercial implementation and it is unlikely to be a viable option for large scale hydrogen production in the medium (20 year) term.

Anaerobic Bacterial Fermentation

This group of biological processes can be generally grouped into photo fermentation and dark fermentation.

- Photo fermentation is the production of hydrogen as a metabolic by-product in the presence of sunlight. Photo-fermentation is similar in practical application to photo-biological water splitting as described earlier.
- Dark fermentation differs from photo-fermentation and photo-biological water splitting in that the process is not reliant upon the presence of sunlight. Although a prototype hydrogen bioreactor using waste as a feedstock is in operation at Welch's grape juice factory in North East, Pennsylvania (U.S.)⁽¹⁰⁾, dark fermentation is an inefficient means of energy conversion, only partially converting the organics present in the feed stream. The feed organics tend to be converted into volatile fatty acids that reduce pH, suppress hydrogen formation and require subsequent biological treatment.

Enzymatic Hydrogen Generation

Enzymes are organic catalysts. Use of enzymes can potentially offer several advantages over conventional catalysts, including higher substrate specificity, higher product yield and faster reaction rate.

The key technology for enzyme based hydrogen production bioreactors is Cell-Free Synthetic Enzymatic Pathway Biotransformation (SyPaB)⁽¹¹⁾. SyPaB is the process of extraction of the enzymes necessary for a particular biotransformation from the organisms in which they occur. Extraction of these enzymes has two key benefits:

1. Extracted enzymes do not have to compete with other cellular processes so the reaction yields are higher and there are fewer by-products
2. Enzymes can be combined in combinations not present within a single known organism, resulting in an engineered pathway not found in nature. In terms of hydrogen, the postulated "Thauer Limit" for natural conversion of glucose to hydrogen is 4 moles of hydrogen per mole of glucose. A theoretical SyPaB pathway consisting of thirteen enzymes can generate twelve moles of hydrogen per mole of glucose: a three-fold improvement over anything found in nature.

Although commercial processes involving enzyme extraction are well proven in specific pharmaceutical and biotechnology applications, SyPaB is largely an academic concept

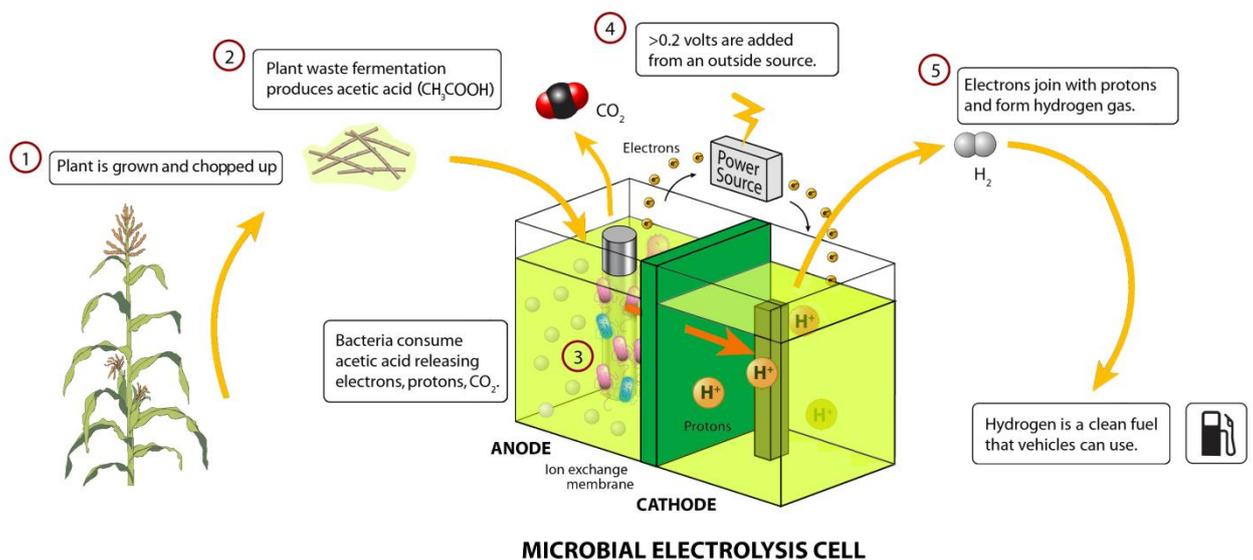
to date and is only likely to find application in high value pharmaceutical and specialty chemical processing in the medium (20 year) term.

Biocatalysed Electrolysis

Biocatalysed electrolysis or electrohydrogenesis is the process of hydrogen generation by microbial decomposition of organic matter enhanced with conventional electrolysis.

Figure 3 details the inner workings of a Microbial Electrolysis Cell (MEC). An organic waste solution (such as acetic acid from plant waste fermentation) is loaded into the anode chamber, where electrochemically active microbes metabolise it. The microbial electrochemical potential is not sufficient to reduce protons to hydrogen gas, but this reduction can be achieved when the electrochemical potential is enhanced by an externally applied power source. Because the externally applied potential is only supplementing the natural potential of the microbial activity, the apparent electrical efficiency of the electrolysis can exceed 200% (<1.5kWh/Nm³).

Figure 3 – The Microbial Electrolysis Cell⁽¹²⁾



Biocatalysed electrolysis combined two well proven technologies: fermentation and electrolysis. However, fermentation is usually a batch process and volumetric reaction rates are low. Consequently, the reactor volume that would be required for “on-purpose” bulk hydrogen generation using plant waste fermentation and MECs make this impractical. It is far more likely that MECs would be a practical option for distributed small scale hydrogen production from by-product waste streams.

3.3 Economic Overview

Table 4 presents a summary of estimated capital costs, operating costs, levelised hydrogen prices and product purities for different hydrogen production technologies.

Cost data is only provided for those technologies that have been commercialised for bulk hydrogen generation; other technologies require significant development before they become technically feasible and economically competitive at commercial scale.

Table 4 – Comparative Costs for Hydrogen Generation

Technology and Fuel	Capacity kg/h H ₂	Online Factor	Capital Cost		Operating Cost x10 ⁶ £/annum	Operating Cost £/kg H ₂	Product Cost (£/GJ) ⁽⁵⁾	Hydrogen Purity ⁽⁶⁾	Notes
			x10 ⁶ £	£/kg/h H ₂					
SMR of natural gas with CCS	20000	92%	623	34000	183	9145	13.93	Product syngas requires membrane or PSA purification	1
Coal gasification with CCS	19400	85%	700	42000	133	6866	11.97	Product syngas requires washing, acid gas removal and membrane or PSA purification	1
ATR of natural gas with CCS	19100	92%	669	38000	150	7874	11.98	Product syngas requires membrane or PSA purification	1
Alkaline electrolysis	2000	90%	86	48000	58	29190	36.12	Product is wet hydrogen stream	2
PEM electrolysis	Not commercial	N/A	Not commercial	N/A	N/A	N/A	N/A	Product is pure hydrogen stream	3
High temp electrolysis	Not commercial	N/A	Not commercial	N/A	N/A	N/A	N/A	Product is wet hydrogen stream	3
Biomass gasification with CCS	4300	85%	214	58000	53	12215	18.49	Product syngas requires washing, acid gas removal and membrane or PSA purification	4
Thermochemical water splitting	Not commercial	N/A	Not commercial	N/A	N/A	N/A	N/A	Depending upon process, hydrogen may require washing to remove acid gases	3
Photocatalytic water splitting	Not commercial	N/A	Not commercial	N/A	N/A	N/A	N/A	Product is wet hydrogen stream	3
Photo-biological water splitting	Not commercial	N/A	Not commercial	N/A	N/A	N/A	N/A	Product may contain other volatile metabolic products including CO ₂ , H ₂ S, CH ₄	3
Anaerobic bacterial fermentation	Not commercial	N/A	Not commercial	N/A	N/A	N/A	N/A	Product may contain other volatile metabolic products including CO ₂ , H ₂ S, CH ₄	3
Enzymatic hydrogen generation	Not commercial	N/A	Not commercial	N/A	N/A	N/A	N/A	Product may contain by-products including CO ₂ , H ₂ S, CH ₄	3
Biocatalysed electrolysis	Not commercial	N/A	Not commercial	N/A	N/A	N/A	N/A	Product is wet hydrogen stream	3

Notes

- 1 Data is extracted from WP-1 information
- 2 Data is taken from publicly available information and escalated
Plant capacity is based on largest known plant constructed to date
Product from electrolysis is hydrogen and oxygen. Value of oxygen is estimated as £40/tonne, which equates to £2.70/GJ (H₂ LHV).
Availability of public domain cost information for commercial hydrogen electrolysis is limited and inconsistent, so data has poor reliability
- 3 Commercial hydrogen production using these technologies at the scale required for this study is highly unlikely to be viable within the medium term. Moreover, as significant technical development is required to commercialise these technologies, prediction of the the cost of such a plant following these technology developments is impractical.
- 4 Data is developed from scaling of WP-1 information. Capacity is based on biomass feed rate to WP-1 mixed biomass/coal case: higher biomass flows are unlikely to be sustainable on a continuous basis.
- 5 Levelised price is the price of hydrogen (LHV basis) giving zero NPV, based on 30 year operation, 10% discount rate and cost neutral CO₂
- 6 Cost data for syngas based production routes does not account for yield losses or additional cost associated with further hydrogen purification.

3.4 Section Summary

Biomass gasification with CCS is a natural extension of the combined biomass and coal gasification option outlined in WP-1. The capital cost curve for biomass gasification is not significantly steeper than for coal gasification, but the practical constraints on the consistent availability and sustainability of biomass feedstock limit the scale of biomass gasification and result in a higher specific cost. Biomass feedstock is also more expensive than coal. Biomass gasification would be made more attractive by situations with local low cost feedstock (such as organic waste streams from local industries) or by government incentives which credit the CO₂ absorbed in sustainable production of the feedstock. Co-production of hydrogen using biomass and coal (WP1 Case 2) offers scale, feedstock flexibility and efficiency benefits over biomass only gasification.

Electrolysis is a clean technology that produces pure hydrogen and oxygen in a molar ratio of 2:1 with little waste and by-products. Specific capital costs are similar to the WP-1 conventional hydrogen generation technologies, but this technology is heavily impacted by the operating cost of electrical power. Electrolysis plants consist of numerous parallel modules of ~50 – 70 kg/h per module, so large scale plants would involve hundreds of parallel units with associated high maintenance costs. Given the limited capacity per module and the impact of electrical power cost, it is unlikely that this technology can compete with conventional technologies as a method of bulk hydrogen generation. However, this technology would be more attractive for small

scale hydrogen production (such as local generation for hydrogen fuelled vehicle filling stations) to avoid the risk and cost of hydrogen transport, and for stranded power generation: wind or wave generation combined with electrolysis to hydrogen may become competitive where hydrogen can be stored and consumed locally and the system is isolated from the UK power grid.

Although it is not possible to evaluate costs and break-even hydrogen prices for the remaining technologies at this time, a number of general observations can be made:

- PEM and high temperature electrolysis are also anticipated to fare better as small scale or stranded power generation schemes. Once fully developed, they offer efficiency and operability improvements over alkaline electrolysis. These technologies are already preferred over conventional electrolysis in niche applications, such as naval and aerospace uses, and they will inevitably diversify further as the technology matures.
- Photocatalytic water splitting is analogous to photovoltaic (PV) cells development and may be implemented as a progression of this technology. Due to the high surface area required for this technology, it is likely that this technology, once mature, will follow the same path as PV and become a distributed rather than a centralised hydrogen generation scheme, using residential or commercial roof area. For small producers, it is likely that this technology would be combined with fuel cells to avoid the requirement for transport of the hydrogen.
- Thermochemical water splitting is a means of converting heat into hydrogen. The feed temperatures for these processes require high grade heat in the range of 750°C to 1000°C where they compete with conventional steam turbine power generation. Use of this heat in steam-cycle based power generation at approximately 50% efficiency, followed by electrolysis at approximately 70% efficiency results in an overall efficiency of 35%, which is comparable with the highest achievable thermochemical process efficiency. Moreover, use of a steam cycle followed by electrolysis is a cleaner, safer technology and provides the option of direct production of power at 50% efficiency at periods of peak demand whereas the thermochemical process can only generate hydrogen, giving a maximum round trip power generation efficiency of only 20% (based on ~55% combined cycle efficiency for hydrogen based power generation).

The remaining technology options all rely on biological processes. Although modern biotechnology enables engineering of microbes to significantly increase selectivity and yields, biological processes generally have low reaction rates, require large reaction volumes, and require the processing of large flowrates of water. Due to the reaction volumes and water processing requirements, it is likely to be impractical to generate hydrogen on a large scale using a centralised biological process. It is more likely that economic implementation of these processes will rely on distributed generation: processes utilising plant waste would be best located close to the source of feed (whether a dedicated crop or an organic waste/by-product) and those relying upon light would be distributed in a similar manner to PV solar power generation - Grow Energy's modular Hydral bioreactors are intended to be applied on the face of industrial buildings to harvest sunlight for hydrogen generation.

4. ALTERNATIVE HYDROGEN TO POWER CONVERSION OPTIONS

4.1 Objective

The objective of this section is to provide a techno-economic review of alternative hydrogen to power conversion options, using both in-house experience and publicly available literature.

4.2 Technology Overview

Combined cycle gas turbines (with associated steam turbines for combined cycle systems) are the conventional means of converting gaseous fuels such as hydrogen into electrical power. A number of alternative hydrogen to power technologies exist and the following technology options are considered in this section:

- Reciprocating Engines;
- Hydrogen Fuel Cells:
 - Polymer Electrolyte Membrane (PEM);
 - Alkaline Fuel Cell (AFC);
 - Phosphoric Acid Fuel Cell (PAFC);
 - Molten Carbonate Fuel Cell (MCFC);
 - Solid Oxide Fuel Cell (SOFC)

4.2.1 Reciprocating Engines

Reciprocating engines operate on the same principle as gas turbines, in that combustion of fuel is converted into shaft power which is then converted into electrical power in a generator. Whereas gas turbines generate shaft power by means of a number of rotors with angled blades in the flow path of the hot combustion gases, reciprocating engines operate by combustion of fuel in a number of piston chambers, similar to a conventional car engine.

Reciprocating engine generators normally operate on fuels ranging from natural gas to diesel, have a typical size range of 10kW to 10MW, (though low speed diesel engines of over 50MW have been constructed) and have efficiencies ranging from 20-30% for small units up to nearly 50 % for large units (LHV basis). These efficiencies are comparable or higher than with equivalent open cycle gas turbines, and the efficiencies of reciprocating engines do not drop significantly when operated at reduced load.

Reciprocating engines are a mature technology and significant research has been undertaken into development of engines capable of operating with hydrogen fuel (particularly for the automotive market). One of the main challenges for hydrogen fired reciprocating engines is to ensure that fuel and air can be mixed and ignite at the correct point in the piston cycle: hydrogen has a relatively low ignition energy and wide flammable range, making it highly susceptible to premature ignition.

Two key disadvantages of reciprocating engines are their size, which limits the capacity per unit to around 20MW for gas engines, and the large number of moving parts, which may result in relatively lower availability and higher maintenance costs.

4.2.2 Hydrogen Fuel Cells

The hydrogen fuel cell is a type of electrochemical device which converts hydrogen and oxygen into water and energy without combustion. Each cell typically consists of an electrolyte material sandwiched between two catalyst-coated electrodes. Cell sizes can be adjusted to suit the required output current, but irrespective of size the output from a single fuel cell is usually approximately 1V DC. Multiple cells must be connected

in series to achieve a practical output voltage, and an inverter is required to convert the DC output into AC for voltage stepping and grid transmission. Overall, the basic elements necessary for a hydrogen fuel cell based power generation scheme are a pure hydrogen source, an oxygen source (or a source of air with scrubbing to remove process poisons) and electrical switchgear for DC-AC inversion and transmission. Depending on the type of cell (see later in this section) additional elements are necessary for some cell types for heating, heat recovery and/or CO₂ recovery.

Major challenges to the commercialization of fuel cell technology are cost, durability and size. Cost is linked to the complexity of the electrode, electrolyte and membrane systems, and the requirement for precious metal catalysts such as platinum within electrodes. Durability relates to the deterioration of membranes, electrolytes and electrodes with age, as well as the physical durability in terms of cells within vehicles or consumer electronic devices. Size is an issue in terms of the material cost associated with low energy density for stationary applications, but is a more significant issue in terms of size and weight when applied to vehicles and consumer electronics⁽²⁾. All these issues are currently being addressed by extensive research and development.

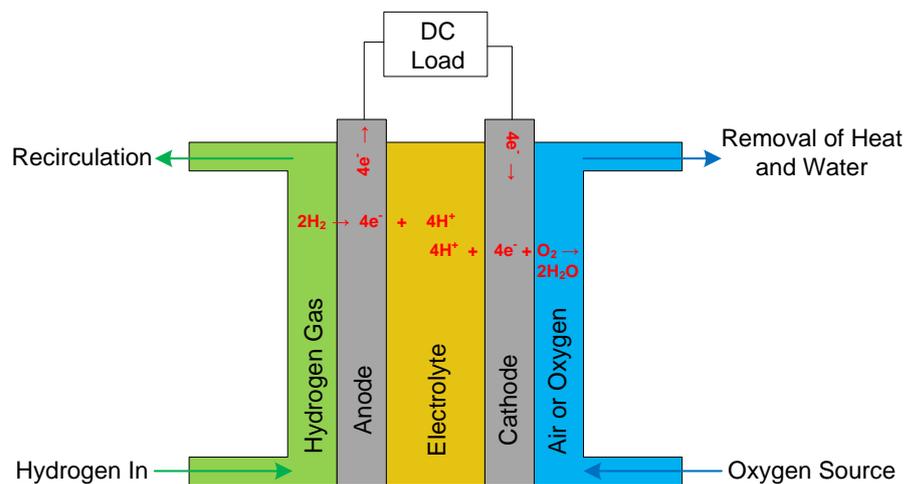
Whereas power generation efficiency from combined cycle power plants is limited by carnot efficiency and practical design considerations to around 60%, fuel cells have a theoretical efficiency of over 70%. Practical efficiencies in excess of 60% have been achieved in some fuel cell types, but efficiency drops as power output increases and the efficiency of fuel cells at design load is generally a design decision. Higher design load efficiency results in more expensive cells, so although high efficiencies are targeted for transport applications where distance per tank of fuel is a major consideration, fuel consumption may be a secondary consideration to fuel cell cost for many stationary fuel cell applications.

The following subsections provide an overview of the different types of hydrogen fuel cell available.

Polymer Electrolyte Membrane (or Proton Exchange Membrane) Fuel Cell

In a PEM fuel cell, hydrogen (or a hydrogen-rich fuel) is supplied to the anode and is electrochemically oxidised (by means of a catalyst) into its constituent protons (H⁺) and electrons (e⁻). The protons can flow through the porous anode and the PEM (electrolyte) to the cathode. The electrons flow around an external circuit to the cathode, where oxygen is electrochemically reduced and combines with the protons to form water and heat, which are expelled from the system.

Figure 4 – Working Mechanism of a PEM Fuel Cell⁽²⁾



The porous electrodes are generally carbon containing a platinum catalyst while the polymer electrolyte is a solid (usually a sulfonic acid polymer such as Nafion^{TM(14)})

Key advantages of PEM over other energy sources including other fuel cell types are as follows:

- PEM fuel cells can deliver higher power density than batteries and other types of fuel cell. This is a significant advantage for vehicles and mobile electronic devices.
- Commercial PEM fuel cells have achieved hydrogen to power conversion efficiencies of up to 50-60% in automotive applications, though efficiencies in stationary applications are often 35-40%.
- A solid electrolyte makes these cells insensitive to orientation and therefore well suited for mobile devices.
- Emissions from PEM cells are very clean so they can be used in situations where emission control is critical
- Relatively low temperature operation (around 80°C) allows for minimal start-up time, limited temperature hazards, and better durability due to less temperature cycling.

Key issues with PEM fuel cells are the requirement for costly platinum catalyst in the electrodes to achieve the high power density and their susceptibility to poisoning by CO⁽²⁾ – a potentially serious drawback for hydrogen generated via gasification or reforming routes.

Phosphoric Acid Fuel Cells

Phosphoric acid fuel cells (PAFC) operate in a similar manner to PEM fuel cells, but the polymer electrolyte is replaced with a silicon carbide matrix saturated with phosphoric acid.

PAFCs operate at a higher temperature than PEM fuel cells (around 150°C). They typically have a similar operating efficiency (35-40%), but have a lower power density than PEM cells resulting in larger, heavier units. The greater operating temperature of these units gives the potential for overall efficiency improvement through effective use of waste heat.

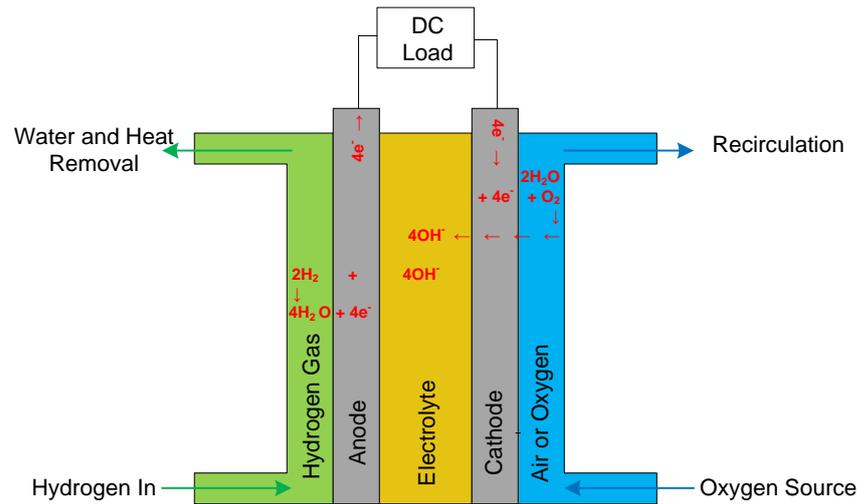
The PAFC is the forerunner of modern fuel cells: it is one of the most mature cell types and the first to be used commercially. This type of fuel cell is used to power commercial premises in the 100-400kW range, and has been used in some large commercial vehicles, but the better power density and lack of a corrosive electrolyte in PEM cells has led these to dominate in smaller mobile applications⁽²⁾.

Alkaline Fuel Cells

Alkaline fuel cells (AFCs) differ from PAFC and PEM fuel cells in that the electrolyte is an alkaline solution (usually KOH) and the ion transported is OH⁻ rather than H⁺. This means that water and heat are produced at the anode.

AFCs were one of the first fuel cell technologies to be developed and were used in the early U.S. space program to produce electrical power and water on-board spacecraft. AFCs use an aqueous potassium hydroxide (KOH) electrolyte, modern designs can operate at low temperatures (~70°C) and the electrodes can contain a non-precious metal catalyst (such as nickel) rather than platinum or palladium. In low specific power applications, efficiencies of up to 60% can be achieved.

Figure 5 – Working Mechanism of an Alkaline Fuel Cell



The alkaline fuel cell is the earliest and least complex fuel cell. Due to its simplicity and use of non-precious metal catalysts, it is the most robust and cheapest type of fuel cell. One major weakness is its susceptibility to poisoning by CO₂ (leading to creation of potassium carbonate, K₂CO₃, in the electrolyte medium) which results in a short lifespan if the hydrogen is impure or air is used as the oxygen carrier.

Molten Carbonate Fuel Cells

Molten carbonate fuel cells (MCFCs) operate in an analogous manner to alkaline fuel cells, but instead of OH⁻ ions as the electrolyte charge carrier, carbonate ions (CO₃²⁻) are used. As the electrolyte is a molten carbonate within an alumina matrix, MCFCs operate at high temperatures: in excess of 600°C. Furthermore, the carbonate charge carrier requires CO₂ to be present in the oxygen source and CO₂ appears along with water and heat at the anode.

The main advantages of MCFC fuel cells over PEM, PAFC and AFC are their efficiency (>50% efficiency can be achieved with non-precious metal catalysts at high power densities due to the fast kinetics at operating temperature), and their resistance to CO₂ and CO poisoning (meaning that air can be used as the oxygen carrier)⁽²⁾.

The primary disadvantages of current MCFC technology are high temperature operation, reduced lifecycle due to corrosion by the high temperature electrolyte (though this is being addressed with material selection improvements), use of a liquid electrolyte (making the cells sensitive to orientation), and the requirement to inject CO₂ at the cathode for carbonate ion formation⁽²⁾.

The operating temperature, sensitivity to orientation and requirement for CO₂ injection make MCFC unsuitable for mobile applications, but it remains the current technology of choice for large scale (MW scale) stationary fuel cell power generation, particularly in applications where waste heat can be usefully employed to increase overall efficiency, such as CHP plants. The requirement for high operating temperature means that MCFC technology does not have fast response for on-demand applications unless a constant parasitic load is applied to keep the cells at or close to operating temperature when idle.

Solid Oxide Fuel Cells

Solid oxide fuel cells (SOFCs) are a relatively recent innovation in fuel cell design. They operate in an analogous manner to alkaline fuel cells, but instead of OH⁻ ions as the electrolyte charge carrier, oxygen ions (O²⁻) ions are used instead. More recently, other SOFC designs have been developed that transport protons (H⁺) instead of oxygen ions, making these cells analogous to PEM cells.

SOFCs use a hard, non-porous, ceramic compound as the electrolyte. Because the electrolyte is a hard solid, the cells do not have to be constructed in the plate-like configuration typical of other fuel cell types.

SOFCs operate at very high temperatures (700-1,000°C). At this temperature, kinetics are sufficient to use non-precious metal catalysts and the cells are resistant to CO, CO₂ and sulphur poisoning. Moreover, SOFCs may be used with a light hydrocarbon fuels as well as hydrogen since reforming of the fuel occurs within the cell itself ⁽²⁾. In common with MCFC cells, efficiencies of up to 60% can be achieved, with greater overall efficiencies possible through effective use of waste heat.

Disadvantages of SOFCs mostly relate to the operating temperature. These include slow start-up, significant thermal insulation to retain heat and protect personnel, challenging material selection and material durability (due to temperature cycling).

Advantages of SOFCs include high efficiency, relatively low material cost, flexible geometry, simplicity of operation, fuel flexibility, low maintenance and resistance to chemical poisons.

The challenging operating conditions for SOFCs and brittle nature of the ceramic electrolyte may render them unsuitable for many mobile applications, but the technology is rapidly being commercialised for stationary applications: commercial distributed power generation units of 100-200kW are already available and domestic CHP boilers utilising SOFC co-generation are being developed. In time, the advantages of SOFC are likely to make this technology replace PAFC and MCFC as the technology of choice for medium to large scale stationary distributed power generation, and for small scale cogeneration applications. Like MCFC, SOFC high operating temperatures can cause a delay in on-demand power generation unless a constant parasitic load is applied to keep the cells at or close to operating temperature when idle.

It is understood that Mitsubishi are evaluating a combination of SOFC fuel cells with gas turbines, in which the natural gas feed goes to the SOFC cells, generating electric power directly, and the combustible off-gas from the cells is burned in the gas turbine. Overall gas-to-power efficiency of 70% is expected over time.

4.3 Economic Overview

4.3.1 Reciprocating Engines

Reciprocating gas engine costs are typically in the range of £500-£1000 per kilowatt based on conventional fuels. By comparison, the installed cost of a 300MW combined cycle GT/ST plant is approximately £500 per kilowatt.

4.3.2 Hydrogen Fuel Cells

The specific cost of hydrogen fuel cells vary significantly between types, as indicated in Table 5 ⁽¹⁸⁾ ⁽¹⁹⁾. It is important to note that quoted specific costs for different fuel cells vary widely between references. As such, the data is of questionable reliability.

Table 5 – Comparative Costs for Hydrogen Based Power Generation

Fuel Cell Type	Typical System Capacity (multiple cells) (kW)	Typical Specific Capital Cost (£/kW)
Alkaline Fuel Cells	Up to 1000 kW	1500 - 3000
Phosphoric Acid Fuel Cell	Up to 400 kW	1500 - 3000
Molten Carbonate Fuel Cell	250 – 500 kW	2000 - 4000
Polymer Electrolyte Fuel Cell	Up to 200 kW	5000 - 8000
Solid Oxide Fuel Cell	Up to 250 kW	~3000?

Alkaline fuel cells are the simplest and most mature fuel cell technology. The simple construction, low temperature operation and lack of precious metal in the electrodes results in the lowest specific cost of all the available types. For cost and speed of response reasons, alkaline fuel cells remain a popular choice for many applications. Although cost competitive versus other technologies, alkaline fuel cells have a number of disadvantages including use of a corrosive reagent, susceptibility to de-activation by CO₂ and a low current density, resulting in large cells.

Phosphoric acid fuel cells offer a cost effective option for small to medium capacity stationary applications. Molten carbonate fuel cells are less cost effective at small to medium scale applications due to the overhead associated with high temperature operation and CO₂ dosing. However, the lower cell cost means that this technology is one of the most cost effective at high system capacities.

Polymer electrolyte fuel cells have the highest specific cost and cannot compete with phosphoric acid or molten carbonate fuel cells in most stationary applications. However, the high power density, low maintenance, low operating temperature and lack of aggressive chemicals make this the technology of choice for small mobile applications and emission sensitive environments.

Solid oxide fuel cells are relatively new to the market. For this reason, cost data is limited and quickly outdated as the technology develops.

4.4 Section Summary

Reciprocating engines are a mature technology with efficiencies of up to 50%, which is higher than for comparable open cycle gas turbines. Gas engines have high fuel flexibility, though use of hydrogen poses a number of technical challenges due to its wide flammable range and low ignition energy. Moreover, gas engines have traditionally proven practical and cost effective in the 10kW to 10MW distributed power sector. While these may be cost effective solution for distributed hydrogen generation, storage and power production, it is unlikely that they will compete with gas turbines for centralised production at up to 250MW capacity.

Fuel cells are a commercially proven means of converting hydrogen into electrical power, with operating efficiencies of up to 60%. Although cost data is inconsistent, it is clear that the cost of power generation using fuel cells is several times more expensive than conventional gas turbines. Moreover, current fuel cell installations are limited to capacities of 1MW or less, so installation of 50-250MW of fuel cells would be one or two orders of magnitude beyond current experience. For illustrative purposes, the largest modular units commercialised by Bloom Energy ⁽¹⁾ have a base load capacity of 200kW. 1250 of these units would be required to generate 250MW.

Fuel cells offer a selection of technologies ranging from mature alkaline fuel cells (AFC) to relatively recent innovations in the form of solid oxide fuel cells (SOFC). Most of the technologies have been extensively studied and, while implementation improvements continue to reduce cost and increase efficiency, it is unlikely that the cost of these technologies will drop dramatically and make them competitive against large gas turbines in the medium (20 year) term.

SOFC fuel cells are a relatively new development. Although these operate at around 1000°C, they require no precious metal catalysts, no corrosive chemicals and no liquid electrolyte, they only require fuel and air as feed, and are not as susceptible to CO₂, CO or sulphur poisoning as other technologies. Moreover, as all parts of a SOFC cell are solid, they can be formed into tubular cells to reduce space and promote fuel and air transfer. This should increase current density and reduce cost. The capital cost of SOFC technology has been reported at ~£3000/kW for scales up to 250kW, but the relative youth of this technology combined with the ability to shape the cells for optimal

performance means that costs may drop more significantly than for other fuel cell technologies as the technology develops, making this the most cost effective technology for medium scale stationary applications.

5. ADDITION OF HYDROGEN TO NATIONAL GAS GRID

5.1 Objective

The objective of this section is to explore the technical and HSE challenges associated with adding hydrogen to the existing UK national gas grid, and the likely cost of addressing these challenges.

5.2 Overview

One means of reducing overall UK CO₂ emissions is to generate low CO₂ footprint hydrogen (either from low footprint energy sources or from conventional sources with CCS) and consume this hydrogen instead of natural gas.

Two options exist for the move from natural gas to hydrogen rich fuel consumption:

1. Replacement of natural gas with a fuel richer in hydrogen
This option essentially consists of adding hydrogen to the existing national gas grid. This will present some technical and HSE challenges, both in terms of the distribution system, metering and the behaviour of fuel burning appliances, but has the potential for the least overall impact on consumers.
2. Supply of a second fuel to consumers
This option would only be practical for large industrial users, since the cost and disruption associated with a new gas supply to every domestic consumer would be prohibitive.

The scope of this section of the report is to consider the practicality of the first option: replacement of natural gas with hydrogen rich fuel within the existing UK gas distribution network.

When considering replacement of natural gas with a hydrogen rich fuel, three main options exist:

1. Converting the entire natural gas distribution network to run on hydrogen instead of natural gas.
This is the extreme case which has the greatest benefits in terms of CO₂ emissions reduction, but also has the greatest impact on the operability and safety of the distribution network and connected fuel burning appliances.
2. Introducing a proportion of hydrogen into the entire natural gas distribution network to form a hydrogen rich fuel.
This option would not achieve the same level of CO₂ emissions reduction, but it has the advantage that the hydrogen addition can be set to a level that mitigates or eliminates operability and safety concerns related to the distribution network and connected fuel burning appliances.
3. Introducing a proportion of hydrogen into part of the natural gas distribution network to deliver hydrogen rich fuel to a subset of consumers.
Delivery of hydrogen fuel to only part of the distribution network would limit the potential carbon footprint reduction, but would also limit the level of disruption, the cost and the HSE risks associated with the change.

The remainder of this section of the report considers the technical and HSE challenges associated with each of these options.

5.3 Technological Challenges

5.3.1 Overview of the UK Natural Gas Network

The UK natural gas network is composed of high-pressure, medium-pressure and low-pressure distribution grids as outlined in Figure 6 and Table 6.

Figure 6 - Schematic view of the different parts of a natural gas delivery system⁽³⁾

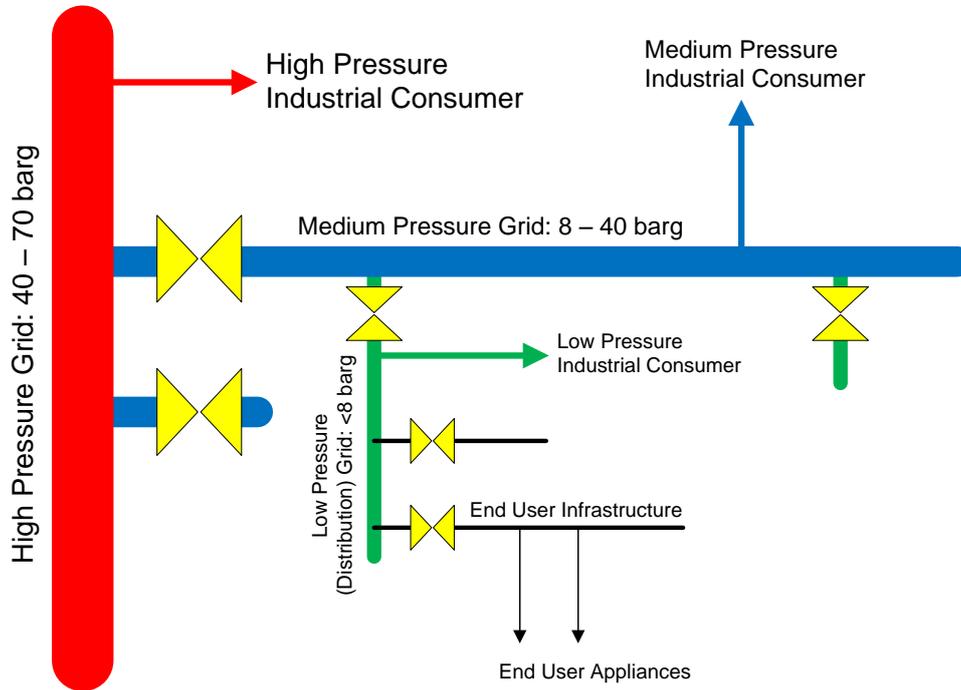


Table 6 - Summary of the different parts of the UK natural gas delivery system⁽³⁾

Grid Element	Pressure (barg)	Infrastructure Elements	Material of Construction	End Users
Gas Production and Treatment	>65	Various Plant	Carbon Steel or Alloy	High Pressure Grid
High Pressure Grid	40 – 70	Compression stations, LNG storage terminals, underground stores, blending stations	Carbon steel	Power plants, foundries, NG reformers, Medium Pressure Grid
Medium Pressure Grid	8 – 40	Valves and pressure regulators	Carbon steel	Small power plants, industrial kilns Distribution Grid
Distribution Grid	<8	Gas holders, valves and pressure regulators	Carbon steel, cast iron, polyethylene, PVC	Offices, domestic users
Domestic Consumer Infrastructure	<8	Valve and pressure regulators	Copper, polyethylene	Appliances

Natural gas enters the system at one of the UK's coastal gas terminals or LNG storage facilities and is then transported through the pipelines that constitute the High Pressure Grid. Compressor stations and underground stores serve to maintain gas pressure throughout the network. The overall high pressure system consisting of terminals, pipelines, compressors and storage facilities is called the National Transmission System (NTS)

Throughout the NTS, connections with pressure regulators feed a number of large industrial users and a number of regional domestic transmission systems called Local Distribution Zones (LDZ). Each LDZ consists of medium pressure pipelines and low pressure distribution grids that serve domestic and smaller industrial users⁽²¹⁾.

In principle, hydrogen can be added to the distribution network at any point, though the further into the distribution system the hydrogen is added, the more addition points are needed. This gives increased scope for phased implementation of hydrogen addition/replacement or targeting of particular consumers, but requires more new hydrogen distribution network piping to connect the addition points.

5.3.2 Technical Challenges of Hydrogen Addition

The UK natural gas distribution network was designed to deliver natural gas, and end user appliances are designed for the flame characteristics of natural gas. To understand the impact of fully or partially replacing this natural gas with hydrogen, it is necessary to compare the properties of natural gas (largely methane, CH₄) with hydrogen. Key transport and combustion parameters of hydrogen, methane and natural gas are tabulated in Table 7.

Table 7 - Comparison of Hydrogen and Natural Gas Properties

Property	Unit	Hydrogen	Methane	Natural Gas
Lower Heating Value By Mass	MJ/kg	120	50	52 - 60
Lower Heating Value By Volume	MJ/Nm ³	10.8	33.9	37.5 - 43
Density	kg/m ³	0.090	0.72	0.72
Wobbe Index	MJ/Nm ³	41	48	48 - 49
Air to Gas Ratio for Combustion	Nm ³ /Nm ³	2.5	10	~9.5
Ignition energy	mJ	0.01 – 0.02	0.3	~0.3
Autoignition Temperature	°C	500	580	~580
Lower Flammable Limit	%	4	5	4.4 - 5
Upper Flammable Limit	%	75	15	15 - 17
Adiabatic Flame Temperature (in 25°C Air)	K	2473	2223	~2223
Viscosity (1 barg, 15°C)	cP	0.01	0.01	0.01
Flame Velocity	m/s	350	40	~40
Diffusion Coefficient (Polyethylene) (20 barg, 40°C)	cm ² /s	3.6x10 ⁻⁶	1.7x10 ⁻⁷	~1.7x10 ⁻⁷

A system designed for natural gas cannot be used with hydrogen, or a mixture of natural gas and hydrogen, without proper review of the impact of the transport and combustion property changes on the safety and operability of the transmission system and all conceivable consumer appliances.

5.3.3 Local Distribution Zone Addition

One of the potential options for hydrogen addition points within the natural gas transmission network is just upstream of each of the local distribution zones (LDZ). This is the strategy adopted for the previous transition in the UK from town gas to natural gas, a process that occurred between 1967 and 1977.

To enable hydrogen injection upstream of each LDZ, a hydrogen transmission system (HTS) analogous to the NTS would be required to maintain the hydrogen supply to the LDZs. The overall geography of the HTS may differ significantly from the NTS, since the sources of hydrogen and natural gas may be completely different. The pipe diameter for the HTS will depend on how much hydrogen is injected into the fuel:

- A very large HTS flow will be required if hydrogen replaces all natural gas in the LDZ, since the volumetric heat content in hydrogen is approximately one third to one quarter that of natural gas (LHV basis). As pipeline pressure drop

is roughly proportional to density and the square of velocity, the velocity increase is partially offset by the eight-fold reduction in density to give a pressure drop increase of roughly 1.2 to 1.5 times that of natural gas. Provided that there are no velocity constraints, the HTS pipelines should then be the same or only slightly larger than NTS pipelines.

Re-compression of hydrogen will require larger compressors, since its low molecular weight makes it more challenging to centrifugally compress.

The NTS flow for this option will drop considerably, only supplying large industrial users (some of these cannot accept hydrogen, since the natural gas is used as a chemical feedstock rather than as a fuel). Sections of the NTS not supplying industrial users will become redundant.

- If hydrogen is blended into the LDZ natural gas, the hydrogen flow will be considerably lower than for the replacement case, resulting in smaller HTS pipework.

The NTS flow in this case will drop somewhat, but although pipework may be oversized for the new flows, none of the NTS will become redundant.

The size of the HTS pipework and the reduction in NTS flow will be dependent upon the hydrogen to natural gas blend ratio.

The level of hydrogen to be dosed into natural gas depends on what is taken as the limiting factor: to avoid adverse impacts on gas turbines, limits as low as 3%v/v are suggested. For the majority of domestic appliances, levels of 15-20%v/v may be possible without modification (though with some reduction in power output due to the lower hydrogen Wobbe index).

Being largely constructed out of steel, cast iron, polyethylene (PE), PVC and copper⁽³⁾, existing LDZ pipework should generally be suitable for hydrogen rich fuel delivery⁽²⁰⁾. However, the 1.2 to 1.5 fold increase in pressure drop through the network may result in low end user supply pressures. Where these become unacceptably low and existing pipeline operating pressures cannot be increased to compensate, pipelines would have to be replaced or duplicated to reduce the pressure drop. Replacement pipework would either require a larger diameter or a higher operating pressure to achieve minimum end user delivery pressures.

A full survey would also be required to verify the safety of all sections of the LDZ and end user distribution systems (as part of a survey of end user appliances).

5.3.4 National Distribution System Addition

A second option for hydrogen addition points is within the NTS, upstream of all the LDZ systems. However, this option is subject to a number of major issues that render it impractical:

- The NTS supplies major chemical plants that require natural gas as a feedstock. These plants cannot accept hydrogen or hydrogen rich fuel, so would require separate high pressure natural gas supplies
- Existing LNG storage systems cannot liquefy hydrogen or hydrogen rich fuel, These systems would also require separate natural gas supplies if still required
- Underground storage caverns designed for natural gas may not be practical or safe to operate with hydrogen: the higher diffusivity of hydrogen may lead to significant leakage from the geological storage structures (salt caverns are ideal because fractures self-heal through creep, but fractures in other geological structures can lead to routes for hydrogen to migrate away - refer to section 9 of the WP2 report), and the well pipework and topside equipment may be susceptible to embrittlement.

- The NTS pipeline compressors are designed for compression of natural gas, which is eight times denser than hydrogen. Even if the seals on these compressors are modified for hydrogen service, they will not achieve design pressure ratios with hydrogen or hydrogen rich fuel.
- The NTS is designed to carry natural gas from a number of specific coastal receiving terminals. The sources of hydrogen are unlikely to coincide with the natural gas sources, so the current NTS and required HTS may differ significantly in geography.

5.3.5 Selective Addition

While replacement of all natural gas fuel with hydrogen can deliver the greatest carbon footprint reduction benefits, domestic customers are all relatively small users and the logistics, cost and risk of switching every domestic distribution system and appliance from natural gas to hydrogen present a formidable challenge.

An alternative to replacement of all natural gas fuel with hydrogen is to selectively supply hydrogen to individual consumers. To achieve the greatest quantity of natural gas replaced with hydrogen per unit cost, it is likely that large, industrial consumers, particularly those relatively close to hydrogen producers/hydrogen storage caverns are the best targets. Since the hydrogen supply infrastructure also needs to grow, this strategy will allow the supply, distribution system and customer base to develop in parallel. This strategy could potentially be combined with hydrogen dosing into local LDZ systems at levels where the supply infrastructure and end user appliances do not require modification.

5.3.6 Gas Quality Management and Supply Metering

Maintenance of a consistent gas composition is vital: it ensures reliable combustion performance in end user appliances and is a contractual obligation for metering and pricing purposes.

Blending for control of gas composition and calorific value is already used with the natural gas distribution system. Blending of hydrogen with natural gas (if required) would be undertaken in a similar manner to existing systems.

UK gas supplies are metered and charged on the basis of calorific value. Addition of hydrogen to the LDZs would impact this metering in two ways:

1. The calorific value of the gas would change. This change in calorific value would have to be declared, the new value maintained, and charges per unit volume adjusted to reflect the new value.
2. Gas is metered upstream of each consumer using flowmeters that report total volumetric flow in cubic metres (or cubic feet). These flowmeters often rely on the physical properties of the gas to calculate flow and changes in these physical properties due to hydrogen addition would require affected meters to be recalibrated or replaced.

5.3.7 Pipeline Integrity

In the event that an LDZ pipeline cracks or ruptures, gas will be released. Addition of hydrogen to the gas composition will have several impacts on such a situation:

- Hydrogen is a smaller molecule than methane and has a much higher diffusion coefficient.
 - In the event of a cracked pipe, hydrogen will diffuse out of the pipe at a faster rate than natural gas. In the event of a rupture, both methane and natural gas will leave the pipe rapidly, but as the majority of distribution

pipes are buried, hydrogen will diffuse through the ground and into the air at a faster rate than natural gas.

- In the event of a faulty appliance block valve, hydrogen will leak through the valve at a higher rate. Because of its buoyancy, it can then accumulate at high points in buildings.
- Diffusion rates through intact pipe are very small and should not be an issue. A possible exception may occur in the case of polymer pipes located in ducting: in this case, hydrogen diffusion may result in a build up of hydrogen gas in the ducting void, eventually leading to a flammable atmosphere that may ignite in the event of inspection or maintenance work.
- The presence of hydrogen in metal/alloy pipework can lead to hydrogen embrittlement, which in turn can cause creation and propagation of cracks, particularly at points of high stress such as joints and welds. The likelihood of cracking depends on the temperature, hydrogen partial pressure, the grade of metal/alloy and its treatment.
Prior to introduction of hydrogen, the potential for hydrogen embrittlement of metal pipework needs to be assessed and mitigation measures taken. Mitigation measures may include monitoring, treatment/lining of pipe or replacement of pipe.
- Hydrogen has a much wider flammable range than natural gas and a much lower ignition energy. This means that hydrogen rich gas leaks are more likely to achieve a composition where they can ignite and they are more likely to achieve ignition when this occurs. A further issue with pure hydrogen fires is that the resulting flames can be invisible during daylight.

5.3.8 Energy Capacity

As noted previously, pure hydrogen has approximately one third to one quarter of the heat capacity of natural gas on a volumetric basis. For the LDZ distribution pipework system, design velocities will then be three to four times higher. Although this effect will be mitigated by lower hydrogen density, hydrogen fuel replacement would result in a 1.2 to 1.5 fold increase in line pressure drop, which may result in unacceptable end user pressures. Increasing the operating pressure of the pipelines would reduce pressure drop and increase end user pressures, but where pressures are constrained by design limitations, pipelines replacement or duplication (installation of a second pipeline in parallel to share flow) would be necessary.

For domestic end user installations, pressure drop between the meter and consumers is restricted to 1mbar under BS 6891. This restriction, together with the small pipe sizes used in domestic installations, results in flow that is not fully turbulent. In these conditions, pressure drop is no longer proportional to density and square of velocity; instead, pressure drop is proportional to velocity. Hence, for domestic installations, it is likely that a change to pure hydrogen fuel will result the BS 6891 pressure drop criterion being exceeded.

Although exceeding the BS 6891 pressure drop criterion could potentially require the replacement of distribution pipework in many domestic installations with a larger bore, a key reason for the pressure drop limit is to prevent incomplete combustion and the associated production of carbon monoxide. Hydrogen fuel does not create carbon monoxide, so the main purpose of the pressure drop restriction may no longer be valid. On this basis, and to avoid significant cost and disruption associated with extensive pipework replacement, it is likely that BS 6891 would need to be updated with pressure drop restrictions relaxed slightly for hydrogen fuel.

5.3.9 End User Appliance Modifications

The impact on end user appliances of replacing natural gas with hydrogen rich fuel is covered in section 8 of this report.

5.4 HSE Challenges

5.4.1 Safety Issues

The increased risk of ignition following an accidental release of hydrogen or hydrogen rich gas is described in section 5.3.7.

Other key health and safety issues relating to use of hydrogen rich fuel include:

- Hydrogen impurities
Hydrogen generated by gasification or reforming routes is extracted from a synthesis gas stream that is high in carbon monoxide (CO). Any hydrogen intended for use as a domestic fuel would have to achieve low levels of residual CO, since this is a poisonous gas normally resulting from incomplete combustion of carbonaceous fuels and strict measures are normally taken to prevent its generation.
- Pure hydrogen burns with a flame that is invisible during daylight, so when using pure hydrogen on gas appliances, there may be no visible indication of whether the burner is on or off.
- Hydrogen's wide flammability limits and high flame velocity mean that gas mixtures with a high hydrogen content (>30%) have a higher risk of achieving detonation rather than deflagration (a much more destructive mode of combustion) in confined areas, though in unconfined spaces hydrogen's low density relative to air means that it rises rapidly away from any leak.
- Switchover of appliances between natural gas and hydrogen fuel presents a significant safety risk: any appliances not inspected and modified present a potential fire or explosion hazard when used after the switch. Furthermore, as it will be necessary to change burners before or after the switch, there is a window of opportunity for the accidental operation of hydrogen burners on natural gas or natural gas burners on hydrogen. It is likely that burner changeover would occur before fuel changeover, since whereas it may not be possible to design replacement burners that are fully operable with both fuels, it should be possible to design them to be fully operable with hydrogen and safely operable with natural gas.

5.4.2 Health and Environmental Concerns

Hydrogen generally compares well with natural gas from a health and environmental perspective:

- Hydrogen is non-toxic.
- Unlike methane, is not a greenhouse gas.
- Unlike methane, incomplete combustion of hydrogen does not generate poisonous carbon monoxide

The main potential adverse impact of hydrogen use is that hydrogen burns with a higher temperature flame than natural gas, and higher flame temperature generally results in higher NO_x generation.

5.5 Economic Assessment

Assessment of the likely cost of hydrogen addition to the natural gas network is extremely difficult, as there are many options and several key unknowns which would have major cost implications:

- Complete replacement of natural gas with hydrogen would require development of a new hydrogen transmission system analogous to the natural gas transmission system. The geography of this system will depend on the location and number of hydrogen feeds into this system, and the number and location of the necessary hydrogen storage caverns to provide buffer capacity
- Complete replacement of natural gas with hydrogen would require a full review of the LDZ distribution systems, both in terms of their suitability for transport of hydrogen, and of their capacity to accommodate the increased flow required for hydrogen fuel.
- ALL industrial and domestic gas appliances subject to the change from natural gas to hydrogen fuel would need to be examined and modified for hydrogen only fuel. Considering this exercise for domestic consumers alone:
 - Approximately 15 million households have gas central heating and an average of at least one other appliance
 - Assume a Gas Safe engineer charges £50 for assessment of the appliances in each home, giving a sub-total of £750 million
 - Assume 90% of boilers can have burners replaced at £100 for supply and fitting, 10% are unable to be modified and must be replaced at a cost of £750. This gives a sub-total of £2.5 billion
 - Other appliances include ovens, hobs, fridges and fires. Assume 90% can have burners replaced at £100 for supply and fitting, 10% are unable to be modified and must be replaced at an average cost of £200. This gives a sub-total of £1.65 billion
 - The overall cost is therefore estimated at around £5 billion, though who would pay these costs is a moot point
- It is worth noting that the previous gas composition change – from town gas to natural gas – took place over a period of ten years from 1967 to 1977 at an estimated cost of £100 million. The extent of gas distribution, the number of customers and the number of customer appliances has expanded significantly since this time, and the cost of labour and materials have risen with inflation.
- If hydrogen were added to natural gas as a blend instead of a replacement, costs could be significantly lower, but this depends on what level of hydrogen is added. In principle, there must be a small level of addition at which burners will not be adversely affected and require replacement, existing LDZ infrastructure is adequate and gas charges could possibly be adjusted to take account of the flowrate calibration error rather than having all meters replaced. In this case, the cost of the change would be infrastructure for hydrogen delivery to LDZ injection points and blending control, together with social impact costs such as updated training of gas engineers and a public awareness campaign.

5.6 Section Summary

The greatest hurdles to introduction of hydrogen into the UK natural gas distribution network arise from the differences in transport properties and combustion properties between the two fuels.

- The key transport property is diffusion, which is much greater in hydrogen and requires review of materials of construction. Higher diffusion rates for hydrogen can lead to embrittlement and cracking of metal pipes and can lead to development of flammable atmospheres around plastic pipes laid in channels.
- The key combustion property issues are Wobbe Index, which is 15% lower for hydrogen and is likely to require burner replacement; flame velocity, which is almost ten times faster for hydrogen and requires different types of burner in some applications; and energy density, which is three to four times lower for hydrogen and therefore requires three to four times as much fuel volumetric flow for the same heat output.

Many parts of the UK high pressure National Transmission System (NTS) can only function on natural gas, so the ideal location for hydrogen addition is in the downstream Local Distribution Zones (LDZ). This approach requires a dedicated hydrogen distribution system to collect hydrogen from producers/hydrogen stores and supply it to injection points within the LDZs.

Three options were considered in this investigation: complete replacement of natural gas with hydrogen for all consumers, blending of hydrogen into natural gas for all consumers, and replacement of natural gas with hydrogen for selected consumers.

Complete replacement of natural gas with hydrogen for all consumers

This option has the highest potential for carbon footprint reduction, but is subject to the following issues:

- A new hydrogen distribution network would need to be laid, linking hydrogen producers with all the LDZ addition points
- All LDZ pipework materials of construction and capacities would need to be reviewed for safety and operability. Inadequate pipework would need to be replaced or duplicated.
- End user flowmeters would need to be replaced or recalibrated for hydrogen.
- All domestic and small industrial appliances would need to be inspected and most burner assemblies/appliances modified or replaced to suit the new fuel.

The main concerns with this approach relate to safety, practicality and cost:

- Key safety concerns are the use of pipework designed for natural gas in hydrogen service. Hydrogen embrittlement can cause or propagate cracks in metal piping, flammable atmospheres may be formed in voids around plastic pipes, and existing leaks will leak more with hydrogen. Inspection and replacement of meters and burners in all domestic appliances is also a major safety risk, since any appliances missed during the process then present a fire or explosion hazard once fuels are changed.
- Key practicality concerns are the extent of pipework and appliance modifications required. A new hydrogen distribution network and modifications to the LDZ network would require extensive roadworks and disruption in parts of the country. Replacement of meters and appliance burners will also be highly disruptive, particularly as many appliances are likely to be uneconomic or not possible to repair and require complete replacement.

- The cost of this option is difficult to quantify as it depends on many factors, but inspection and modification of domestic consumer appliances alone is likely to cost several billion pounds.

Blending of hydrogen into the existing natural gas supply

This option has less potential for overall carbon footprint reduction, but is flexible (in terms of the level of addition) and offers a safer, less disruptive and less costly alternative to replacement of natural gas with hydrogen.

Fairly low levels (~3%v/v) of hydrogen could be added to natural gas with hardly any modification of end user appliances, whereas 15-20%v/v of hydrogen could potentially be added with some modification to industrial appliances (particularly gas turbines), but little modification to domestic appliances.

Use of natural gas enriched with up to 20%v/v hydrogen would only increase pipe velocities by up to 40%, metal pipes would be less prone to pipework embrittlement, and all pipework would exhibit lower leakage rates than for pure hydrogen. These factors should significantly reduce the quantity of LDZ pipework needing replacement, reducing disruption and cost, and make the remaining sections safer to operate.

If modification of domestic consumer meters and appliances is rendered unnecessary, this will significantly reduce the safety risk, level of disruption and cost.

It would be important to maintain the % hydrogen content of the blended gas constant, since gas is sold on the basis of a declared calorific value.

Replacement of natural gas with hydrogen for selected consumers.

Selection of individual, high volume consumers for fuel changeover is likely to give the greatest benefit in terms of carbon footprint reduction per unit implementation cost.

Selection of a small number of relatively large industrial users would limit the extent of pipework and reduce transmission costs, and this strategy would also allow the transmission system and consumer base for hydrogen fuel to grow in parallel with the growth in hydrogen production. Zones of high industrial natural gas fuel usage, particularly those close to major hydrogen producers or potential hydrogen storage caverns, would be ideal candidates for early switching from natural gas to hydrogen.

Dedicated hydrogen pipework direct to the consumer will eliminate safety risks associated with use of pipework designed for natural gas. Furthermore, as large industrial users are more likely than domestic consumers to be rigorous in the identification and modification of appliances, avoidance of domestic consumers will result in a significant reduction in the risk of fire and explosion after changeover.

6. VALUE OF HYDROGEN FOR OTHER USES

6.1 Objective

The objective of this section is to determine the relative value of hydrogen for uses other than electric power generation. The following uses are considered: domestic fuel, transport fuel and chemical feedstock.

A brief discussion of hydrogen purity and how it affects the end-user applications described below can be found in WP1 and is relevant to this section.

6.2 Value as a Domestic Fuel

Through the addition of hydrogen gas to the national gas grid system, hydrogen or a hydrogen-rich natural gas has the potential to replace natural gas as the fuel gas supplied to homes (see section 5).

End-user appliances including boilers, grills, ovens, hobs, fires, tumble dryers and fridges could be operated on hydrogen following changes to their fuel delivery systems, though such changes would be costly and any omissions would lead to fire and explosion risk (see section 5 and 8).

Based on the ETI assumed natural gas market value of \$6.60/MMBtu and an exchange rate of \$1.52 = £1, the energy value of natural gas in UK currency and SI units is £4.12/GJ. As gas is traded based on energy value, hydrogen substituted for natural gas would have to trade at a similar level to avoid price rises.

Comparing the value of hydrogen as a natural gas substitute (~£4/GJ) with the break-even costs established for produced hydrogen in WP1 (~£12-14/GJ), it is clearly uneconomic to generate hydrogen by these methods for sale into the national gas grid. As natural gas is the feedstock for the ATR and SMR technology options in WP1, this result is not surprising.

6.3 Value as a Transport Fuel

The use of hydrogen as a transport fuel is well established and many hydrogen powered modes of transport have been developed. Early hydrogen vehicles include rockets and planes (using energy derived from internal combustion). More recently, hydrogen has been used for road vehicles including cars, buses and motorcycles. As well as H2ICE (hydrogen internal combustion engine) vehicles, FCV (fuel cell vehicles) are appearing which use an electric motor driven by power generated from reacting hydrogen and oxygen in a fuel cell.

Road vehicles are a key potential market for use of hydrogen as a transport fuel. Most road transport fuels are currently sold in an extensive network of filling stations, each offering a variety of fuel options including petrol, diesel and liquid petroleum gas (LPG). To be competitive with existing transport fuels, hydrogen must become available at filling stations, must be comparable with other fuels in terms of fill time, and must be competitive with other fuels in terms of cost per mile travelled.

The price of hydrocarbon based fuels in the UK varies with the price of crude oil and also with the level of tax and duty imposed by the government. Considering petrol and diesel, which currently supply the lion's share of motor vehicles, the current pump price of approximately £1.40 is made up as indicated below.

Table 8 – Composition of Current Petrol and Diesel Pump Price

Fuel cost:	£0.53/litre	38%
Delivery and profit:	£0.05/litre	4%
Duty:	£0.59/litre	42%
VAT:	£0.23/litre	16%
TOTAL:	£1.40/litre	100%

Two methods were used to develop a hydrogen price to give a cost per mile equivalent to a modern petrol engine vehicle:

- Fuel efficiency for a modern UK family car on a ‘combined cycle’ is generally around 9-10 miles per litre (34-38mpg). This results in a cost of £0.14-£0.16/mile.
Fuel consumption data for hydrogen vehicles is less available than for conventional vehicles, but marketing data for the Audi A2H2 reports a range of 137 miles from 1.8kg of compressed hydrogen. For a fuel cost of £0.15 per mile, this equates to a pump price £11.4/kg. Based on a hydrogen energy density of 120MJ/kg, this equates to an energy cost of £95/GJ.
- The reported fuel to motion efficiency of a typical petrol vehicle is 20%, whereas the same figure for fuel cell vehicles is 24%. Given a petrol energy density of approximately 36 MJ/L, the cost per MJ of delivered power from a petrol engine at 20% overall efficiency works out as £0.19/MJ. Ignoring potential weight differences, the same delivered power to the same car should deliver the same distance travelled under similar speed and road conditions. If the fuel cell car is to achieve £0.19/MJ of delivered power, the cost of power delivered to the fuel cell at 24% overall efficiency is £0.046/MJ, or £46/GJ.

As marketing data is notoriously optimistic, the slightly lower value of £46/GJ will be used. This is the pump price for hydrogen that gives approximately the same cost per mile as petrol.

Converting the hydrogen pump price into a hydrogen value is difficult because duty is specified on a volume basis for other fuels. Working on the assumption that the same percentage duty might apply as for petrol, two cases are proposed: one case has duty applied at the same percentage rate as petrol, the other considers the case where no duty is applied as a “green incentive”.

Table 9 – Predicted Hydrogen Transport Fuel Price Compositions

	Duty Case		No Duty Case	
Fuel cost:	£17.48/GJ	38%	£36.80/GJ	80%
Delivery and profit:	£1.84/GJ	4%	£1.84/GJ	4%
Duty:	£19.32/GJ	42%	£0	0%
VAT:	£7.66/GJ	16%	£7.66/GJ	16%
TOTAL:	£46/GJ	100%	£46/GJ	100%

On the basis above, the value of hydrogen is estimated as somewhere in the range of £17/GJ to £37/GJ depending on duty. At this value, production of hydrogen from fossil fuels as investigated in WP1 could become economic.

It should be noted however that the approach above is a very simplistic one: the capital cost of the vehicle, depreciation rate and other operating costs in terms of maintenance and fuel cell/battery life will impact the economics of hydrogen cars. Moreover, in addition to economics, the availability of fuel and the range achievable between fuel stops will need to improve to increase the attractiveness of these cars for the general market.

6.4 Value as a Chemical Feedstock

Hydrogen is used extensively as a feedstock in the production of chemicals. A few examples of established, large scale applications include:

- Hydrocracking – conversion of heavy petroleum fractions to lighter ones;
- Hydrotreating – conversion of olefins into paraffins
- Hydrodesulfurisation – the conversion of mercaptans into hydrogen sulphide and removal of hydrogen sulphide to sweeten gas;
- Hydrodealkylation – reacting an aromatic hydrocarbon, such as toluene, in the presence of hydrogen gas to form a simpler aromatic hydrocarbon devoid of functional groups;
- Hydrogenation – removal of C=C double bonds for the saturation of unsaturated compounds such as fats and oils;
- Reduction of metallic ores;
- Production of many chemicals including ammonia, hydrogen peroxide and methanol

When considering hydrogen as a chemical feedstock, it is important to note that whereas use of hydrogen as a domestic or transport fuel replaces use of alternative fuels with higher carbon footprints, most processes that can use hydrogen as a chemical feedstock already do so. In this sense, the opportunity for carbon footprint reduction arises from replacement of a high carbon footprint production process with a lower carbon footprint process.

When hydrogen is required as a chemical feedstock, it can either be produced on site or imported. For small users, import of hydrogen by road tanker is often the most convenient and economic method (companies such as Air Products offer build, own, operate (BOO) hydrogen production plants for industrial customers and may include extra capacity to enable tanker export). For larger users, road tanker import becomes uneconomic and impractical, and currently there are few situations where there is an opportunity for import of hydrogen by pipeline, so hydrogen is generally produced on site, either by extraction from existing streams or by reforming/gasification in dedicated hydrogen production plants (currently without CCS).

If hydrogen becomes available as part of a national distribution system, it would provide industrial users with an alternative option to meet their hydrogen demands. In this case, the choice of on-site production or import would be based on the following factors:

- Purity – industrial hydrogen users often have high purity requirements. Such requirement may not apply to hydrogen distributed primarily as a fuel and it may not be economic to apply tighter production specifications for a subset of non-fuel uses. Additional on-site purification could be applied, but this would reduce the value of the imported stream.
- Feedstock – if industrial processes contain hydrogen rich process streams, it may be more economic to recover hydrogen from these streams than to import it.
- Chemistry – if on-site processes generate other reactants as well as hydrogen, import of hydrogen will not be economic. An example is methanol production: in this process, hydrogen is generated by reforming or gasification of fuels into syngas. As the methanol process requires both the hydrogen and

carbon monoxide in the syngas, import of hydrogen alone would not make economic sense.

- Integration – on-site hydrogen generation provides opportunities for process and heat integration that improve the economics of this option versus hydrogen import.
- Scale – The cost of hydrogen production by traditional reforming and gasification routes is sensitive to scale. A single SMR based hydrogen production train can achieve 10,000kg/h hydrogen production. At capacities below this, much of the equipment becomes smaller rather than reducing in number, and typically the capital cost (C) varies with capacity (Q) according to the formula $C = C_0(Q/Q_0)^{0.65}$. This means that a 50% reduction in scale results in roughly a 30% increase in cost per unit of production
- CO₂ Tariffs – Tariffs may be imposed on CO₂ emissions to achieve carbon footprint reduction targets. This will provide an incentive to apply CCS to CO₂ intensive technology such as reforming. Adoption of CCS requires routing of captured CO₂ to a suitable sequestration location, which may be impractical or uneconomic for many UK locations. This will favour import rather than on-site hydrogen generation.

Existing plants will either already import hydrogen or have invested in on-site hydrogen production plants. In the latter case, it is unlikely that these plants will cease operating their on-site production facilities unless they are motivated to do so (for example by carbon taxes). For new plants however, an off-site hydrogen supply that is accessible, low CO₂ footprint, reliable and of suitable quality would be attractive provided that the hydrogen is available at a competitive price.

For the reasons outlined above, hydrogen import for chemical feedstock use is likely to compete with sub-world scale on-site generation by dedicated hydrogen production plants. Based on WP1 work, the break-even price of product hydrogen from a world scale facility with CCS is in the region of £12 - £14/GJ. Using the scaling method outlined above, the approximate break-even price of product hydrogen from a facility with CCS at 50% of world scale is £15 - £18/GJ. On this basis, the approximate value of hydrogen targeted for supply as a chemical feedstock to new industrial users is estimated as £15/GJ.

For the reasons outlined above, the availability of a hydrogen network is likely to result in a relatively small number of large capacity production plants running at relatively constant rates. This will lead to economies of scale and ideal operating conditions for CCS, increasing the likelihood of its adoption when motivated by carbon tariffs.

6.5 Section Summary

The assessments above outline the extent to which hydrogen gas could compete with conventional carbon based fuels for applications other than power generation.

Table 10 - Summary of the value of hydrogen across various end-uses

	Value of Hydrogen (£/GJ)
Domestic Fuel Gas	4
Transportation Fuel	17 – 37 (depending on fuel duty applied)
Chemical Feedstock	15
WP1 Cost	12 – 14 (excluding cost of further hydrogen purification)

Table 10 shows that hydrogen has the highest potential value as a transportation fuel, with the magnitude of this value highly dependent upon the level of fuel duty applied (range is based on zero duty through to same percentage duty as for petrol). Development of this market requires provision of hydrogen “pumps” at filling stations and consumer adoption of hydrogen fuelled vehicles. The latter is reliant upon reduction of the lifecycle cost of fuel cell and battery technology, and upon improvement in the distance these vehicles can travel between fuel stops. The safety issues associated with frequent transfers of pressurised hydrogen at 350-700 barg also need to be considered.

Hydrogen is already widely used as a chemical feedstock, so this evaluation considered the opportunity to replace high carbon footprint onsite hydrogen production with lower carbon footprint hydrogen import. Small hydrogen consumers are likely to already import hydrogen by tanker and large industrial hydrogen consumers are likely to achieve process and heat integrations that make onsite generation more efficient and more economic than import. Consequently, the largest potential market for supply of bulk hydrogen as chemical feedstock is likely to be small to medium scale consumers with hydrogen consumption of 5000kg/h or less, where loss of economies of scale versus world-scale facilities leads to a higher cost per unit production. Creation of an industrial hydrogen generation network consisting of a relatively small number of large producers will also lead to economies of scale for CCS and increase the likelihood of its adoption when motivated by carbon tariffs.

Use of hydrogen as an alternative to natural gas for domestic fuel use is an option with a very high carbon footprint reduction potential, but is the option with the least potential hydrogen value. As the natural gas being replaced is one of the most likely sources of fuel for hydrogen generation, hydrogen generated by this route cannot be cost competitive unless carbon footprint penalties are applied to natural gas fuel use: a strategy that would be highly unpopular as domestic heating bills would rise dramatically.

In conclusion, hydrogen has potential as a transportation fuel and as a low carbon footprint centralised source of chemical feedstock for small and medium scale industrial consumers. While it also has potential as a replacement for natural gas as a domestic fuel, this is unlikely to be cost effective. All of the options considered are highly dependent upon the development of infrastructure to supply the hydrogen to consumers. Furthermore, transportation and domestic fuel uses of hydrogen cannot be accommodated by existing vehicles and appliances: developing the market for hydrogen fuelled cars and replacing/modifying natural gas fuelled appliances with hydrogen fuelled appliances are both challenging prospects.

7. HYDROGEN FIRED GAS TURBINES

7.1 Objective

The objective of this section is to review the availability and efficiency of hydrogen fired gas turbines.

The information gathered in WP1 regarding power generation gas turbines suitable for firing on a high-hydrogen syngas at the 300+MWe scale is expanded upon to include a comparison of the efficiency of hydrogen versus natural gas firing, based on existing experience.

7.2 Available H₂ –Fired Gas Turbines

There is extensive historical experience with firing of hydrogen and CO/hydrogen mixtures such as blast furnace gas in gas turbines, mostly accumulated in small, older turbine types with rather low efficiencies.

In WP1, two potential suppliers of large power generation gas turbines (300+MWe class) capable of firing high-hydrogen fuel gas meeting the requirements of the current project were identified. These are General Electric, who offered the Frame 9F Syngas Version, and Mitsubishi Heavy Industries, who offered a version of their 701F. Both require addition of a fuel gas diluent (nitrogen or perhaps steam), primarily to limit NO_x formation.

Although the Siemens 8000H is currently available only for natural gas fired applications, Siemens advised that they are expending considerable investment to develop a variant able to operate on high-hydrogen syngas.

By the time of order placement for any of the options outlined in WP1, it is likely that other manufacturers, particularly Alstom, will also be able to provide large hydrogen-fuelled gas turbines to compete with the models already discussed.

7.3 Thermal Efficiency Comparison

The information received from GE for the Frame 9F Syngas gas turbine and from Mitsubishi for the 701F when firing high-hydrogen syngas is compared with the corresponding natural gas fired equivalents in Table 11 below.

Table 11 - Gas turbine performance comparison

Turbine Variant	Firing Fuel	Nominal Output (MW _e)	Exhaust Temp (°C)	Heat Rate (kJ/kWh)	Thermal Efficiency (%)
GE 9FB	Natural Gas	339.4	627	8995	40.0
GE 9F	Hydrogen-Rich	304.2	555	8735	41.2
Mitsubishi 701F4	Natural Gas	324.3	592	9027	39.9
Mitsubishi 701F	Hydrogen-Rich	331.3	502	8203	43.9

Notes

- 1 The values for natural gas firing are taken from published data for operation under ISO conditions.
- 2 The values for high-hydrogen syngas firing are project-specific and include allowances for inlet and exhaust pressure losses, but they provide a general indication of expected performance with hydrogen-rich fuel.

Two key points emerge from examination of Table 11:

- The thermal efficiencies derived from the heat rates for the gas turbines firing hydrogen fuel appear higher than those of the natural gas variants. However,

these figures are deceptive as this is not a like-for-like comparison: the efficiency calculation measures the electrical energy generated compared with the fuel energy consumed in the turbine, but does not take account of the energy imparted to separately compress gases entering the turbine. As diluent nitrogen is introduced with the fuel in the syngas variant turbines, a higher mass flow of compressed gas is fed to the expander part of those machines, relative to natural gas firing. Table 12 provides a breakdown of the WP1 Case 1 combined cycle power plant efficiency (based on the GE Frame 9F machine). The apparent GT efficiency is 40.4%, but this drops to 36.3% when diluent nitrogen compression is taken into account.

- Table 11 shows that the hydrogen fuelled gas turbines operate with exhaust temperatures 70 – 90°C lower than their natural gas-fired counterparts. While there will be differences in pressure ratio, exhaust composition and exhaust pressure to be taken into account, lower exhaust temperatures generally indicate significantly reduced bulk mean gas temperatures at the inlet to the expansion section of the gas turbine. Lower firing temperatures result in reduced gas turbine efficiencies (net of diluent compression). Moreover, the reduced turbine exhaust temperature will reduce the pressure and temperature of the steam that can be generated in the downstream heat recovery steam generator, which will in turn reduce the steam cycle efficiency and the overall combined cycle efficiency.

Table 12 – WP1 Combined Cycle Efficiency Breakdown

Parameter	Unit	WP1 Case 1 Data
Feed To GT	kg/h	355518
GT Heat Input (LHV basis)	MW _{th}	666.3
GT Power Output	MW _e	269.5
Apparent GT Efficiency	MW _e /MW _{th}	40.4%
Diluent Compression	MW _e	27.5
Adjusted GT Efficiency	MW _e /MW	36.3%
ST Power Output	MW _e	128.0
ST Ancillary Parasitic Loads	MW _e	2.30
Net Output	MW _e	367.7
Net LHV Efficiency	MW_e/MW_{th}	55.2%

Natural gas fired 300+MW combined cycle plant designs with LHV efficiency over 60% are available from all the main gas turbine suppliers. It is estimated that if the firing temperature of the syngas variants when firing hydrogen-rich fuel gas could be increased to that of the natural gas variants (through design development and/or alternative NO_x suppression measures), the efficiency of the hydrogen-rich fuel fired combined cycle and of the overall IGCC plant could be increased 4 - 5% points over current values.

In general, the turndown performance of gas turbines with hydrogen-rich fuel should be similar to that of natural gas fired machines. However, the operability and efficiency of gas turbines at reduced load will require detailed study by the steam turbine suppliers, as it is affected by a number of factors, including:

- Carbon monoxide formation – reduced combustion performance at turndown results in higher exhaust carbon monoxide emissions with natural gas fuel. Carbon monoxide is less of an issue with hydrogen-rich fuels, particularly fuels with virtually no carbon content.

- Flame speed – hydrogen has a very high flame speed and this can cause issues in burner design. Reduced turbine output load results in reduced burner gas velocities, which can compound these issues. Relatively higher diluent flow rates may be required to counter the reduced burner flow, which will reduce combustion temperature and negatively impact efficiency.

Historically, power suppliers have installed progressively larger and more efficient gas turbines in central power networks to benefit from their lower specific cost and higher efficiency. It is expected that the same trend will be followed with hydrogen firing. However, if hydrogen storage schemes may be required to operate for prolonged periods at reduced load, installation of a larger number of smaller gas turbines should be considered. Although smaller machines may allow higher efficiency operation at reduced loads, typically machine costs follow a cost exponent of 0.65 to 0.7, meaning two machines of half capacity would cost roughly 30% more than a single machine. Furthermore, smaller machines tend to have slightly lower full load efficiencies and sourcing smaller machines designed for high hydrogen fuel firing may prove more difficult.

Gas turbines designed for hydrogen-rich fuel firing will generally be started up on natural gas fuel, with switch over to hydrogen-rich firing taking place after the turbine is on line. Individual suppliers may have developed the capacity for an earlier transition to hydrogen-rich firing, but this has not been explored. Since start-up generally occurs on natural gas, long term operation of the hydrogen-adapted gas turbines on natural gas or a mixture of natural gas and hydrogen mixtures will be possible, although power output and thermal efficiency are likely to be reduced since the turbines are not optimised for these fuels. Although unplanned fuel switching may not be possible, the ability to switch from hydrogen rich fuel back to natural gas provides the flexibility to bring generation capacity back on line with a secondary fuel in the event of a loss of hydrogen availability.

7.4 Section Summary

High-hydrogen syngas fired gas turbine operation is a feasible alternative to natural gas fired variants, including large for machines in the 300+MW_e class. Currently, reduced firing temperatures result in combined cycle efficiencies 4 – 5% below those of equivalent natural gas fired machines, but this gap could be closed if firing temperatures similar to natural gas firing become possible through advances in gas turbine technology, particularly in burner design.

Turndown operation with hydrogen-rich fuel firing presents different challenges compared with natural gas firing: carbon monoxide formation is less of an issue, but NO_x formation and flame velocity are more of a concern. While turndown performance for high hydrogen fuel fired turbines is anticipated to be similar to natural gas fired machines, flame velocity issues may create operability constraints or require a relatively higher diluent gas flow, which will further reduce exhaust temperature and negatively impact efficiency.

If efficient turndown operation is a requirement, a greater number of smaller turbines could be installed. However, smaller turbines suffer from loss of economies of scale, generally have slightly lower design load efficiencies, and may not be available in syngas variant designs suitable for high hydrogen fuel.

Syngas variant turbines are generally started up on natural gas and switched to high hydrogen fuel when online. As such, these machines are capable of operation on natural gas or a hydrogen rich natural gas fuel, though operating efficiency may be reduced since the turbines are not optimised for these fuels.

All representations from gas turbine suppliers mentioned in this chapter are state-of-the-art in early 2013, but in line with machine availability (discussed in WP1), advances in power output and thermal efficiency may be expected by the time at which orders could be placed (assumed to be around 2020).

8. CONSUMER VIEW OF HYDROGEN AS A NATURAL GAS SUBSTITUTE

8.1 Objective

The objective of this section is to establish the likely consumer view of hydrogen as a natural gas substitute. Based on a study of the technical and HSE challenges associated with adding hydrogen to the natural gas network, the likely industrial and domestic consumer response to such a proposal is assessed.

8.2 Technology Challenges

Section 5 of this report provides an assessment of the options and technical challenges associated with addition or substitution of hydrogen for natural gas in the National Gas Grid. The discussion in Section 5 touches upon the end-user issues associated with a change from natural gas to hydrogen rich gas or hydrogen. This section of the report expands upon those issues.

Technical challenges when moving from natural gas to hydrogen fuel relate to the differences in physical properties between the two gases. Table 7 summarises these differences. The key property differences that create technical challenges are: physical density, energy density, air to gas ratio, flame temperature and flame speed. The technical challenges associated with each of these property differences are outlined below. HSE challenges are considered separately in the next section.

8.2.1 Physical Density

Hydrogen has one eighth of the density of natural gas. This means that hydrogen is extremely buoyant and rises rapidly, affecting the shape of horizontal flames. The lower density of hydrogen also impacts pressure drop and Wobbe Index, each of which is covered in the next section.

8.2.2 Energy Density

The volumetric energy density is a key characteristic of fuel gases, as it determines the volume of gas that needs to be carried in a pipe to transfer a particular heat duty.

The volumetric energy density of hydrogen is one quarter to one third of the natural gas energy density, meaning that three to four times greater volumetric flow of hydrogen is required to achieve the same heat output.

For large pipelines operating at medium to high pressure, flow is turbulent and the combination of increased velocity and reduced density results in a 1.2 to 1.5 fold increase in line pressure drop for the same heat duty. If pipeline operating pressures cannot be increased, greater pressure drop may result in unacceptably low end user delivery pressures and require replacement or duplication of supply pipelines.

Within domestic installations, the low pressures and small diameters result in flow that is not fully turbulent. In this case, the higher hydrogen flow results in a three to four fold increase in pressure drop. BS 6891 limits the pressure drop in domestic installations to 1 mbar. This limit is believed to be at least partly to avoid low burner pressures causing incomplete combustion leading to formation of carbon monoxide – a toxic gas that cannot be formed by combustion of hydrogen – so the BS 6891 pressure drop restriction might be relaxed for hydrogen fuel. In the event that it is not, almost all domestic installations would require replacement of existing pipework with a larger bore.

Energy density and physical density also affect the design duty of fuel appliances: Wobbe Index is defined as the ratio of the energy density to the square root of the physical density and is a measure of fuel equivalence. At a particular regulator valve setting, a fuel appliance fed with two different fuels will give a heat output in ratio to

their Wobbe indices. As the Wobbe Index for hydrogen is only 85% that of natural gas, unmodified burners would typically have a maximum output of 85% of their natural gas design values.

8.2.3 Air to Gas Ratio

Air to gas ratio is the volume of air required for full combustion of a unit volume of fuel. The air to gas ratio for hydrogen is one quarter of that for natural gas. While this does not represent an issue in most domestic burners, some industrial burners provide a controlled ratio of air to fuel and replacement of natural gas with hydrogen in these appliances may result in poor performance.

8.2.4 Flame Temperature

When hydrogen burns in air, the resulting flame is hotter than a natural gas flame. While this may be advantageous for cooking purposes, it may result in higher than expected skin temperatures in heaters and turbines designed for natural gas, leading to potential trips or damage.

8.2.5 Flame Speed

Flame velocity is the inherent speed at which a flame front moves through a mixture of fuel and air. The flame velocity for hydrogen is extremely fast: almost nine times faster than natural gas. The higher hydrogen flame speed, combined with its higher nozzle velocity (for the same duty) will result in a different flame shape. In appliances designed for natural gas, the hydrogen flame may not occur in the intended position.

Some designs of burners premix air and fuel and inject this through a nozzle into the combustion chamber. This type of burner is not appropriate for hydrogen fuel, as the hydrogen flame velocity exceeds reasonable jet velocities and the flame is likely to blow back into the fuel/air mixing chamber.

8.3 HSE Challenges

As the modern UK gas distribution network and consumer base was never intended to transport or process hydrogen fuel, none of its elements can be assumed as safe to transport or fire hydrogen instead of natural gas.

The gas distribution network has its roots in 1807, when gas street lighting was first installed in Pall Mall. Over the past two centuries, the network of distribution pipework, storage systems and consumer appliances has gradually been expanded and upgraded. The result of over two hundred years of development is an enormous length of distribution pipework of different sizes, materials, ages and condition, and an extensive customer base consisting of a largely undocumented number of appliances of different type, manufacture, age and condition.

Changeover from town gas to natural gas took place over a ten year period from 1967 to 1977 and one of the major drivers was safety issues: town gas had a high carbon monoxide content, so even small leaks or flame-outs could lead to fatalities due to carbon monoxide poisoning.

Changeover from natural gas to hydrogen is driven by carbon footprint issues rather than immediate safety issues. Since safety must be the top priority, it is important that the changeover is undertaken in a safe manner and long term use of hydrogen as a domestic fuel is at least as safe as use of natural gas.

The key HSE challenges associated with transport and firing of hydrogen can be grouped into two types: challenges during the changeover and long terms operating challenges. The key property differences that create HSE challenges are an extension of those that cause technical challenges and consist of: diffusivity, energy density,

composition, flame temperature, flammable range and flame speed. The HSE challenges associated with each of these property differences are outlined below.

8.3.1 Diffusivity

Being such a small molecule, the diffusivity coefficient of hydrogen is much greater than that of natural gas. There are three issues associated with hydrogen's high diffusion rate that could influence the safety of hydrogen storage and transport:

- While the diffusion rate through metal pipe is negligible, diffusion of hydrogen into metal pipe walls causes an effect known as hydrogen embrittlement. While this effects some metals more than others, hydrogen embrittlement can lead to crack generation in areas of high stress such as welds, connections or bends and can cause existing cracks to grow. This can eventually lead to significant leaks or pipe failure.
- The diffusion rate through plastic (polyethylene and PVC) pipes is small and would not present a significant source of network losses, but hydrogen diffusing through the pipe walls may accumulate in adjacent voids (such as channels or ducts) if there is no air flow, creating a flammable atmosphere over time that could ignite and cause damage or injury in the event that the pipe is disturbed during inspection or maintenance.
- Gas distribution pipework does crack from time to time and cause leaks. In the event of a spontaneous leak in a buried pipe, diffusion of gas to the surface often limits the leakage rate. In the case of hydrogen, the greater diffusion rate can lead to a greater rate of leakage to the surface. Combined with hydrogen's lower flammable limit and low ignition energy, there is a greater risk of this gas causing a fire or explosion in a confined space. In open space, risk of fire and explosion from cracks in buried pipes is reduced, since hydrogen's high buoyancy means that it will quickly rise into the atmosphere rather than form a cloud.

8.3.2 Physical and Energy Density

As described in section 8.2.2, burners designed for natural gas can typically deliver 85% of their design duty with hydrogen, since the lower heating value is offset by greater flow through the fuel control valve. However, this means that the fuel nozzle velocity with hydrogen is almost three times that of natural gas which, combined with greater buoyancy and higher flame velocity, gives rise to different flame shapes. Different flame shapes at best will give reduced performance, but in the worst case the new flame shape can cause overheating of the combustion chamber walls, melting of these walls, rupture of pipework in boilers and external fires.

Small leaks through valves and joints, which are more prevalent with hydrogen because of its high diffusivity, will tend to rise do to hydrogen's buoyancy and accumulate at high points in buildings, potentially creating a flammable atmosphere.

8.3.3 Composition

The composition of hydrogen give some HSE advantages: unlike methane, it is not a greenhouse gas so any leaks do not adversely impact global warming. Pure hydrogen does not contain carbon, so there is no risk of incomplete combustion forming carbon monoxide: a poisonous gas which causes about fifty deaths per year in the UK and can be fatal through cumulative exposure to low levels. However, as one of the principle sources of hydrogen is from gasification or reforming of carbonaceous fuels into syngas, it is possible that hydrogen may contain carbon monoxide as an impurity. While it is likely that hydrogen fuel would be odorised in the same way as natural gas to allow leak detection, there is a risk that leaks of hydrogen containing some level of carbon monoxide could cause poisoning.

Pure hydrogen burns with a flame that is invisible during daylight. This may cause aesthetic issues in gas fires, but more importantly it may make it difficult to determine when an appliance is lit. This can lead to burns, fire and explosion risks due to undetected flame-outs or loss of a visible reminder to turn off heating or cooking appliances.

8.3.4 Flame Temperature

Hydrogen burns with a higher adiabatic flame temperature than natural gas. This has two potential adverse effects:

1. NO_x formation increases with temperature, so hydrogen fired equipment will tend to generate higher levels of NO_x than natural gas fired equipment
2. Higher temperature flames will cause higher combustion chamber operating temperatures in some appliances. This, particularly when combined with the different flame shape described in section 8.3.2 above, can lead to equipment damage and fire or explosion risk in equipment designed for natural gas.

8.3.5 Flammable Range and Flame Speed

Hydrogen has a wider flammable range than natural gas: the lower flammable limits are similar, but the upper limit for hydrogen is much higher. Moreover, hydrogen has a very high flame speed.

As described in section 8.2.5, hydrogen's high flame speed means that burner designs that pre-mix fuel and air prior to the burner nozzle become impractical and unsafe. Use of hydrogen in such burners will result in blow back of the flame into the mixing chamber. In the best case, the appliance will trip and fail to work; in the worst case the mixing chamber may explode on blow back or the chamber walls may heat and melt, losing containment and causing uncontained fire.

In the event of a hydrogen leak, its high buoyancy tends to lift the gas into the atmosphere and out of harm's way in an unconfined situation. In a confined situation however, hydrogen's flame characteristics lead to a higher risk of detonation rather than deflagration if the mixture does ignite (and the wider flammable range and low ignition energy mean it is more likely to ignite). Detonation results in a pressure wave with considerably more destructive power.

As mentioned previously, hydrogen is likely to be odourised with a mercaptan in the same way as natural gas to enable detection of leaks. However, the sulphur present in mercaptans is a poison for the precious metals in some fuel cells, so a separate supply or mercaptan removal systems would be required for hydrogen destined for such fuel cells.

8.4 Implementation Strategies

In order to change over from natural gas to hydrogen fuel, two options exist:

- One option is to dose hydrogen into natural gas instead of replacing it entirely. For blends of natural gas and hydrogen containing 15-20 vol% hydrogen, it is anticipated that nearly all existing domestic appliances can be operated safely and little change to existing distribution pipework will be required. At levels above 3-5% however, modification or replacement of some industrial appliances such as gas turbines may be required.
- The second option is for complete replacement of natural gas with hydrogen. For this option, a phased changeover would need to occur, with different sections of the gas distribution grid switching from natural gas to hydrogen at different times. In advance of changeover for each section, hydrogen pipelines would need to be laid between the producers/storage caverns and gas grid

addition point; existing gas grid pipework would need to be carefully surveyed to ensure suitability in terms of material of construction, condition and capacity; unsuitable or undersized grid pipework would need to be replaced or duplicated; every gas consumer would need to be visited by a qualified hydrogen gas installer (which would require extensive retraining and requalification of gas safe installers) and the condition of the distribution system and make and model of all appliances established; undersized end user distribution pipework and unsafe/inoperable appliances would need to be modified, replaced or disconnected.

8.5 Likely Consumer Response

The domestic and industrial consumer response to a proposed change from natural gas to hydrogen fuel is likely to be driven by the following factors:

- Public perception of hydrogen in general
- Level of cost and inconvenience associated with the switch
- Risks during changeover
- Cost of hydrogen fuel relative to natural gas
- Advantages and disadvantages of hydrogen as a fuel

8.5.1 Public Perception of Hydrogen

Members of the general public will normally have little knowledge of hydrogen, as it is a substance with few uses outside of chemical industries until relatively recently. Although its use resulted in the Hindenburg airship disaster, memories of this event have faded over the past seventy years and it is generally remembered vaguely as a chemical which can be dangerous as it can catch fire or explode.

More recently, hydrogen has mainly been in the news as a potential road transport fuel, where it is portrayed as an environmentally friendly fuel of the future.

8.5.2 Level of Cost and Inconvenience Associated with Switching

One of the most likely influences on public perception of switching to hydrogen fuel is the level of inconvenience and cost during the switch.

Moving from natural gas to natural gas dosed with 5-20% hydrogen is likely to have a relatively small impact:

- New pipelines would need to be laid between hydrogen producers/storage caverns and the points of hydrogen injection into the gas grid. This would cause some disruption as these would generally be laid along roads in urban areas
- Surveys of all affected domestic and commercial gas appliances would need to be undertaken to check that these appliances are safe and effective for use with hydrogen rich fuel.
- It is anticipated that some industrial appliances would require modification or replacement, but nearly all existing grid pipeline infrastructure and domestic appliances would be unaffected

Moving from natural gas to hydrogen is likely to have a much larger impact:

- New pipelines would need to be laid between hydrogen producers and the points of hydrogen injection into the gas grid. This would cause some disruption as these would generally be laid along roads in urban areas. As the switchover would need to be phased in order to be practical, a different hydrogen addition

point would be required for each phase, resulting in more extensive dedicated hydrogen pipework.

- Surveys of all gas grid pipework would need to be undertaken to ensure that materials of construction, condition and capacity are suitable for hydrogen duty.
- It is anticipated that a significant proportion of the grid may prove unsuitable or undersized and need to be replaced, creating extensive roadworks in urban areas.
- Surveys of all affected domestic and commercial gas appliances would need to be undertaken to check that end user distribution pipework and appliances are safe and effective for use with hydrogen fuel.
- It is anticipated that most domestic and commercial gas appliances would need to be modified or replaced to operate safely and effectively. Modification or replacement of gas fired boilers, cookers, grills, ovens, hobs, fires, tumble dryers and fridges would result in significant disruption and cost.

8.5.3 Risks during Changeover

Awareness of potential risks during the fuel changeover will influence public perception. The survey of existing appliances and plan for modification or replacement will need to be perceived as robust and thorough, since failure by one household to identify and/or address an appliance unsuitable for use on hydrogen could, in a worst case scenario, result in an explosion affecting many neighbouring properties.

8.5.4 Cost of Hydrogen versus Natural Gas

While the public is generally supportive of measures to minimise global warming, it is unlikely to accept a significant increase in fuel bills (requiring an equivalent cost per unit heat content compared with natural gas), especially after bearing the cost of modification or replacement of appliances.

As described in section 6.2, the value of hydrogen giving parity with natural gas is £4/GJ, whereas the break-even value of hydrogen produced by gasification/reforming of fossil fuels, based on data from WP1, is £12-£14/GJ. This means that natural gas prices for fuel consumers would need to be increased three-fold before hydrogen becomes competitive, putting gas at an unprecedented price level, roughly equal in cost on an energy basis to electricity. In the UK, over 20% of households currently spend more than 10% of their income on fuel – a situation considered by the Government to constitute ‘fuel poverty’. A three-fold increase in gas prices would significantly increase this number.

8.5.5 Advantage and Disadvantages of Hydrogen as a Fuel

Improved public perception of hydrogen fuel can be obtained by highlighting its positive impact on global warming and its clean emissions.

8.6 Section Summary

While substitution of hydrogen for natural gas in the UK national gas grid could yield a huge reduction in the national carbon footprint, there are a number of substantial technical and HSE challenges associated with this changeover, as outlined in section 5.4.

Although industry and the general public may be supportive of initiatives associated with climate change, the level of inconvenience associated with installation or replacement of distribution pipework, together with the inconvenience and cost of modification or replacement of appliances incompatible with the new fuel will be a strong disincentive. Moreover, to achieve the same energy bills with hydrogen as with

natural gas, the value of hydrogen fuel must equate to that of natural gas on an energy basis. The current value of natural gas is approximately £4/GJ, whereas the approximate value of hydrogen to achieve production economic break-even based on WP1 data is £12-£14/GJ. Increasing gas prices to this level would be unprecedented, highly unpopular, and would dramatically increase the number of UK households in what the UK government recognises as 'fuel poverty'.

9. INTEGRATED SOLUTIONS DEPLOYING HYDROGEN STORES

9.1 Objective

The objective of this section is to review integrated solutions deploying hydrogen stores by studying the potential for synergies in terms of process and utility dependencies, efficiency, HSE impact or supply/demand profile, achievable through adoption of an integrated scheme involving hydrogen storage with two or more hydrogen production routes and/or two or more hydrogen consumers.

9.2 Potential Integrated Systems

As discussed previously in section 6.4, there is currently no centralised hydrogen distribution network. In the absence of such a network, the low density, low heating value and hazardous nature of compressed hydrogen gas mean that batch transfer by road tanker is expensive and only cost effective for small consumer. In the absence of potential synergies between neighbouring plants, excess hydrogen has little value except as a fuel, so medium or large scale industrial hydrogen demands are generally met by onsite production facilities.

In the event of the creation of hydrogen network with an associated store, the opportunity would be created for hydrogen to become a traded commodity. Conventional plants connected to such a network could benefit as follows:

- Plants with large hydrogen demands are likely to retain dedicated hydrogen production (HPU) capacity, since there are normally opportunities for utility or process integration with the balance of plant. However, these plants could be fitted with carbon reduction technologies where appropriate and operated at a design capacity slightly in excess of process demand, with the excess routed to the network. In the event of a trip of this plant, hydrogen could be imported from the network instead of exported, maintaining production in the balance of plant. Carbon footprint reduction may result from operation of the HPU at peak efficiency and such a facility will generate revenue for the network provider through receipt of relatively low value excess hydrogen and provision of the facility for provision of capacity on demand.
- Many chemical processes, such as steam crackers, aromatics and chlor-alkali plants, may operate with an excess of hydrogen rich fuel gas. In the absence of a market for this gas, overall plant efficiency is not a priority during design and excess energy is often dissipated or used for inefficient power generation. If a market for hydrogen exists however, there is an incentive to design an efficient plant, extract hydrogen for sale and use the remaining fuel gas to meet on site fuel needs.
- As discussed in section 6.4, where process industries have a small or medium scale demand for hydrogen, import of hydrogen from a centralised, world scale production facility with CCS may be a more cost effective solution than on-site generation, particularly where a centralised storage facility eliminates the risk of loss of hydrogen availability through trip of the hydrogen plant. Replacement of batch transfers by road tanker may also offer HSE benefits, as transport, storage and loading/unloading of very high pressure hydrogen cylinders is hazardous.

In terms of less conventional technologies, the availability of a centralised hydrogen store and hydrogen distribution network would allow the following:

- Taking the concept of this study in reverse, rather than generate hydrogen by conventional methods to allow low carbon footprint power generation at times of peak demand when the electricity price is highest, electrolysis could be used to

generate hydrogen at times of low demand when electricity prices are low. This hydrogen could then be supplied to the hydrogen hub and stored for use as a chemical feedstock or as fuel. In principle, electrochemical cells could be used to generate hydrogen and oxygen at times of low electricity price, then convert hydrogen into electricity at times of high electricity price. Oxygen co-product from electrolysis could be sold separately.

- Renewable power sources such as wind, wave and solar result in electrical power. Each of these energy sources is cyclical in nature and weather dependent, so they cannot be relied upon as a consistent contributor to the UK power grid. Combining these power generators with an energy storage system such as electrolysis and hydrogen storage would result in a more consistent power source, but power is more easily transported than hydrogen (and oxygen), and these are generally highly distributed generation systems so it would make more economic and logistical sense to supply the resulting power to a small number of centralised electrolysis plants connected to the hydrogen hub.
- Renewable technologies such as biomass or waste gasification and biological processes such as photo-chemical water splitting, photo-biological water splitting and anaerobic fermentation generate hydrogen or hydrogen rich syngas. The resulting hydrogen could be directly converted into electrical power via turbines or fuel cells to supply the UK power grid, or the hydrogen could be sent to the hydrogen hub and stored for use as a chemical feedstock or as fuel.

9.3 Benefits of a Hydrogen Hub

Key benefits of the provision of a UK hydrogen hub would include:

- Reduced wastage of hydrogen
- Improved efficiency
- Load balancing
- Greater opportunity for integration
- Greater opportunity for investment
- Greater platform for research and development

9.3.1 Reduces Wastage of Hydrogen

In the absence of a hydrogen hub, by-product hydrogen from chemical plants has value only as a fuel unless it can be sold to a neighbouring facility. Even if it can be sold, its value will be limited as the hydrogen supply is only as reliable as the upstream process without the buffering provided by a storage cavern.

In the event of a hydrogen hub, by-product hydrogen has value and there becomes a driver for plants to be designed for greater thermal efficiency so that excess hydrogen can be exported rather than consumed as fuel.

9.3.2 Improved Efficiency

In the absence of a hydrogen hub, chemical plants with a requirement for hydrogen either have to generate this hydrogen themselves, take a supply from a neighbouring facility or import by road tanker. Production of hydrogen at small to medium capacities is generally more expensive and less efficient than large scale generation; import from neighbouring facilities usually has no buffer capacity and is dependent upon the reliability of the upstream process; import by road tanker is expensive, highly inefficient, and the transfer and transport and storage of high pressure hydrogen are a source of significant safety risk.

In the event of a hydrogen hub, hydrogen plants can be built at world scale and operated at a consistent design point. World scale facilities offer economies of scale and efficiency benefits, particularly when operated at a consistent design point rather than modulating to accommodate varying demand.

9.3.3 Load Balancing

The principal purpose of the hydrogen storage cavern or caverns at the heart of the hydrogen hub is to provide buffer capacity: to balance short term imbalances between hydrogen supply and demand.

For hydrogen producers, the presence of the hydrogen store allows conventional hydrogen plants to operate at a consistent design point and unconventional producers to produce at a rate determined by external factors such as light level or electricity price. Short term production capacity is not constrained by consumer demand.

For hydrogen consumers, the hydrogen store provides a source of hydrogen that has a reliability greater than that of a hydrogen production plant, can be instantly available and can achieve very high turndown ratios. Short term consumption rate is not constrained by production capacity.

9.3.4 Greater Opportunity for Integration

Creation of a hydrogen supply and distribution network and storage hub allows the producers and consumers to be decoupled and located separately. This in turn allows the location of each plant to be optimised based on the proximity to feedstock (particularly feedstock arising from other process waste streams), proximity to other process integration opportunities (such as consumers of oxygen co-product from electrolysis) and proximity to potential heat integration opportunities (such as district heating using low grade waste heat – a common practice in many countries but seldom seen in the UK).

Conversely, where new industry is created to generate or consume hydrogen, this provides the opportunity for collaboration with other production or consumption technologies to co-locate and take advantage of process and utility integration potential and share infrastructure such as a CO₂ export pipeline.

Figure 7 below provides a schematic of the range of potential technologies that could be integrated through use of a hydrogen hub with an intermediate hydrogen store.

9.3.5 Greater Opportunities for Investment

Creation of a hydrogen hub and the associated creation of a market for hydrogen will create the opportunity for many small to medium sized enterprises to invest in relatively small scale plants for hydrogen generation or based on hydrogen consumption. While individually these plants would be small, together they could create a significant source of hydrogen generation, much of it potentially renewable, and consumption.

As well as potentially increasing the level of renewable energy and thereby reducing the UK carbon footprint, stimulated investment will have a social impact, creating jobs and increasing the hydrogen market, which in turn will spread the infrastructure costs.

9.3.6 Greater Platform for Research and Development

Greater opportunities for investment in hydrogen generation and consumption technologies will result in increases interest in these technologies which in turn will prompt greater research and development.

Increased R&D in hydrogen technologies, particularly combined with greater commercial application, will result in cost reduction, efficiency improvements, new technologies and better understanding.

A positive consumer image of hydrogen is vital in developing and expanding the UK hydrogen economy, so development of the hydrogen hub would require research and development of safeguards and safe practices for handling of hydrogen to reduce the risk of accidental release causing fire or explosion.

9.4 Section Summary

Provision of a hydrogen hub consisting of storage caverns and a widespread collection and distribution system has the potential to transform the UK hydrogen economy as it will cause hydrogen to have a market value and will decouple producers and consumers.

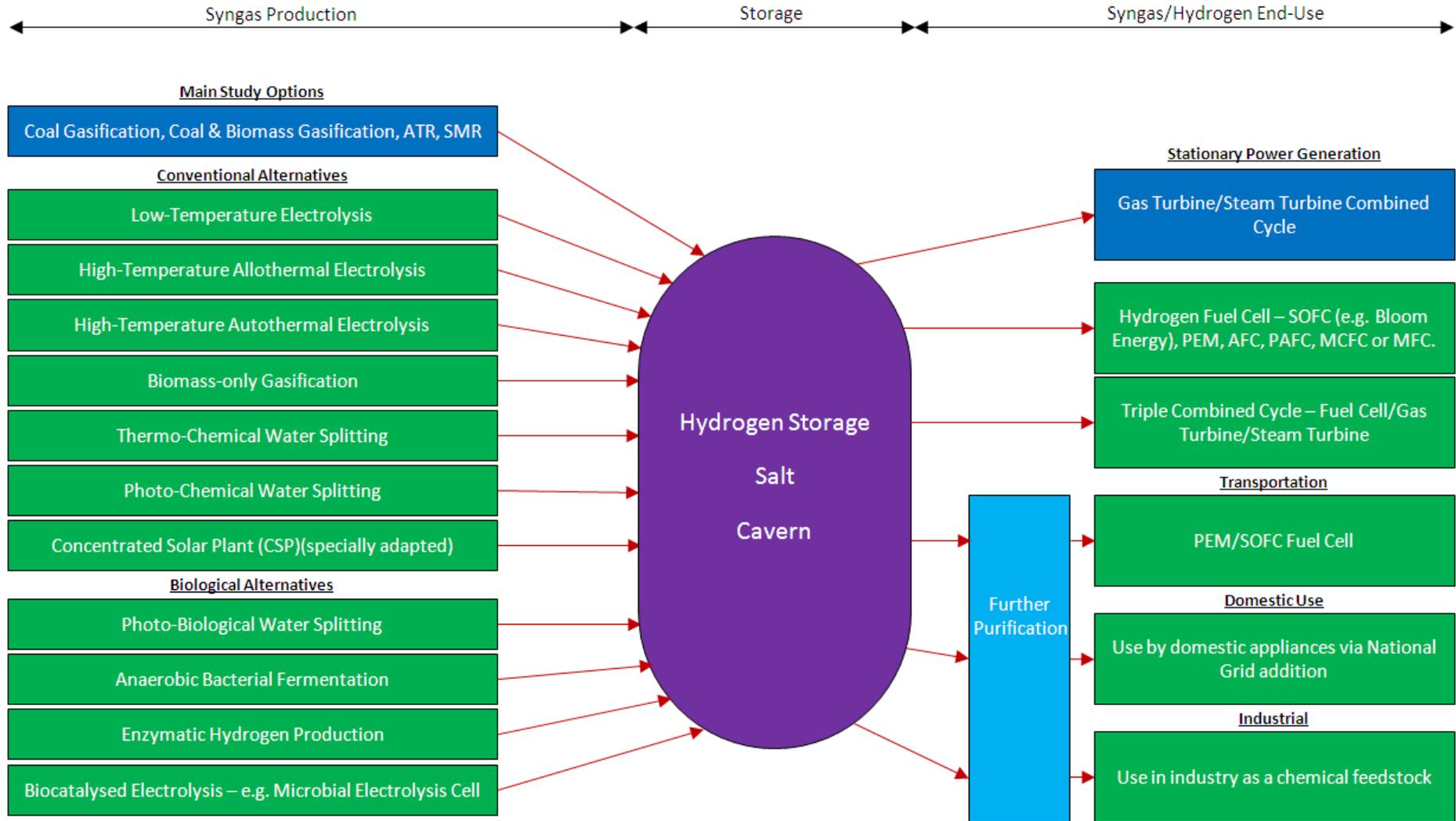
By providing hydrogen with a market value, conventional chemical processes with a net excess of by-product hydrogen will have an incentive to become thermally efficient and export this hydrogen rather than burn it as fuel.

By decoupling producers and consumers, producers can be sized for efficiency and economies of scale and sited for integration opportunities in terms of cheap feedstock, potential process integration or potential utility integration. Size, integration and the ability to operate at a constant design point rather than vary with consumer demand will result in greater efficiency.

Creation of a hydrogen market will stimulate investment in small to medium sized enterprises utilising unconventional hydrogen production technologies. This in turn will stimulate further research and development into hydrogen technologies, which will reduce costs, increase efficiency and lead to the creation of new technologies.

A positive consumer image of hydrogen is vital in developing and expanding the UK hydrogen economy, so development of the hydrogen hub would require research and development of safeguards and safe practices for handling and storage of hydrogen to reduce the risk of accidental release causing fire or explosion.

Figure 7 - Summary of syngas production, storage and end-use technologies covered in study



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