



Progressive energy

Biohydrogen: Production of hydrogen by gasification of waste

An NIA assessment of Biohydrogen production and opportunities for implementation on the gas network

July 2017

Report for Andy Lewis, Cadent Gas Ltd

Prepared by Progressive Energy Ltd and Advanced Plasma Power Limited

Approved by



Chris Manson-Whitton
(Project Director)

Progressive Energy Ltd
Swan House,
Bonds Mill,
Stonehouse GL10 3RF
United Kingdom

Tel: +44 (0)1453 822444

Web: www.progressive-energy.com

Acknowledgements

Our thanks to University College London, Johnson Matthey, Catal, Carbotech and Clariant who all provided valuable advice on the production of Biohydrogen.

Disclaimer

This document is issued for the party which commissioned it and for specific purposes connected with the above-captioned project only. The judgements drawn in the report are offered as informed opinion. Accordingly Progressive Energy Ltd. and Advanced Plasma Power Limited give no undertaking or warrantee with respect to any losses or liabilities incurred by the use of information contained therein.

Version Control Table

Version	Date	Author	Description
v0.1	08/06/17	Mike Cairns-Terry	First draft for internal review
V0.2	21/06/17	Mike Cairns-Terry	Second draft for Cadent review
V1.0	30/06/17	Mike Cairns-Terry	Final report issued to Cadent
V1.1	07/07/17	Mike Cairns-Terry	Minor updates following internal feedback.

CONTENTS

1.0	EXECUTIVE SUMMARY.....	6
1.1	Markets for Biohydrogen and functional specification	7
1.2	Producing Biohydrogen.....	9
1.3	Commercial plant design	10
1.4	Economic and environmental performance against alternatives	12
1.5	Deployment.....	16
2.0	Introduction and objectives	18
3.0	Functional specification	20
3.1	Uses of hydrogen and existing production technologies	20
3.2	Biohydrogen production rate	25
3.3	Specification of hydrogen and CO ₂ streams	29
3.4	Summary plant specification	37
4.0	Demonstration of hydrogen production.....	40
4.1	Laboratory scale testing.....	41
4.2	Demonstration of hydrogen production at pilot scale	55
5.0	Commercial plant definition	60
5.1	Design discussion	60
5.2	Process description	67
6.0	Economic and greenhouse gas analysis	79
6.1	Greenhouse gas analysis.....	79
6.2	Economic model.....	83
6.3	Comparison of Biohydrogen to BioSNG.....	92
6.4	Comparison of Biohydrogen to alternative hydrogen pathways	94
7.0	Pathway to deployment	98
7.1	Barriers to deployment.....	98
7.2	The Role for a demonstration project	99
7.3	Commercial basis for a demonstration project	108
7.4	Demonstration project options	110
7.5	Reference demonstration project development.....	113

A.1.0	Offline rig	117
A.2.0	Pilot-scale plant.....	119
A.3.0	Future developments	123
A.4.0	Mass-basis Sankey diagram	128
A.5.0	Financial information	129

1.0 EXECUTIVE SUMMARY

Hydrogen is seen by many as a key element of the UK's future energy mix because it generates no greenhouse gas emissions at the point of use. The Climate Change Committee's (CCC) most recent recommendations on heat identify hydrogen as one of two candidate technologies for decarbonisation and the Low Carbon Vehicle Partnership, E4Tech and UCL Energy Institute all forecast significant demand for transport hydrogen by 2030. Understanding the technologies that can generate this hydrogen is essential in planning the future gas network.

One promising approach is hydrogen production by gasification of waste, referred to as Biohydrogen. The process steps for Biohydrogen can be summarised as follows:

- Production of biosyngas, an approximately equimolar mixture of carbon monoxide and hydrogen, through gasification of wastes or biomass.
- Increasing the hydrogen content by reacting the biosyngas with steam to produce further hydrogen and carbon dioxide.
- Refining the hydrogen by removing carbon dioxide.
- Removal of residual traces of carbon monoxide by conversion to methane.

In this project, the partners (Progressive Energy, Advanced Plasma Power and Cadent) sought to lay much of the groundwork necessary to understand how Biohydrogen may be deployed. This work built on the development of BioSNG, a similar process where methane is produced by waste gasification. The project involved:

- Considering the commercial applications of Biohydrogen and defining the appropriate scale and specifications for a commercial Biohydrogen plant.
- Demonstrating production of Biohydrogen from waste at pilot scale.
- Designing a facility to produce Biohydrogen at commercial scale.
- Analysing the cost and environmental impact of the technology.
- Assessing routes to deployment.

The project has shown that:

- It is technically feasible to produce Biohydrogen using established technologies.
- On a like-for-like basis Biohydrogen has similar costs to hydrogen produced by steam methane reforming (SMR) of natural gas combined with carbon capture and storage and lower costs than electrolytic hydrogen.
- Carbon savings for Biohydrogen are more than four times greater than alternative technologies.
- The cost per tonne of carbon dioxide saved is 75% lower than SMR hydrogen.
- A most attractive route for developing Biohydrogen technology is through a plant focussed on BioSNG production with some demonstration of hydrogen production.

This summary highlights key conclusions from the project and compares Biohydrogen to alternative options for low-carbon gas.

1.1 Markets for Biohydrogen and functional specification

1.1.1 Markets and plant scale

There are two main categories of hydrogen use:

- Transport
- Heat

The Committee on Climate Change (CCC)¹ predicts that by 2050 hydrogen use in transport could be as high as 140TWh/year. However, although there are ongoing projects to develop the hydrogen market for buses, the Low Carbon Vehicle Partnership (LowCVP) forecasts² that, in 2020, hydrogen consumption will be only 0.1GWh. Therefore, whilst this is an important future market, early commercialisation of Biohydrogen at volume is unlikely to come via the transport sector.

Both the CCC³ and the Government's heat strategy⁴ recognise the role that hydrogen can take in decarbonising heat. Total gas consumption on the distribution system is currently around 540TWh per annum with domestic consumption at around 320TWh per annum and this offers significant market potential for Biohydrogen deployment.

Given the negative emissions delivered by Biohydrogen, domestic gas demand could be fully decarbonised with a combination of around one third natural gas, one third SMR hydrogen and one third Biohydrogen.

One approach is wholesale conversion of part of the gas grid, as envisioned in the NGN's H21 Leeds Citygate project⁵. Another option is to blend hydrogen into the existing gas distribution grid as is being established in the HyDeploy project⁶, which considers blending levels of up to 20%. A third option is direct delivery to industry, which is examined in the Hydrogen Clusters study⁷.

A plant converting 100,000 tonnes per annum of refuse derived fuel into around 375GWh of hydrogen was considered because this represents a good compromise between the need to avoid excessive transport of waste and the improved economies achieved by larger scales.

¹ <https://www.theccc.org.uk/wp-content/uploads/2015/11/E4tech-for-CCC-Scenarios-for-deployment-of-hydrogen-in-contributing-to-meeting-carbon-budgets.pdf>

² [http://www.lowcvp.org.uk/assets/reports/20150307_LowCVP%20Infrastructure%20Roadmap_HYDROGEN_Final%20\(with%20graphics\).pdf](http://www.lowcvp.org.uk/assets/reports/20150307_LowCVP%20Infrastructure%20Roadmap_HYDROGEN_Final%20(with%20graphics).pdf)

³ <https://www.theccc.org.uk/wp-content/uploads/2016/10/Next-steps-for-UK-heat-policy-Committee-on-Climate-Change-October-2016.pdf>

⁴ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/190149/16_04-DECC-The_Future_of_Heating_Accessible-10.pdf

⁵ <http://www.northerngasnetworks.co.uk/archives/document/h21-leeds-city-gate>

⁶ <http://www.smarternetworks.org/Project.aspx?ProjectID=2081>

⁷ 'The Merseyside Hydrogen Cluster: A Low Cost, Deliverable Project, TECHNICAL REPORT to Cadent Gas Ltd', 2017

This size of plant would meet around 6% of the demand of a city the size of Leeds. It is also a reasonable size to meet industrial demand; there are five industrial facilities around Manchester that would consume the entire output of a single Biohydrogen plant.

Whilst on average over a year, the hydrogen produced by a single 48MW Biohydrogen could be blended with the natural gas consumed by a city such as Leeds at levels around 20% by volume, the seasonal and daily variations in demand present a challenge. Typical demand profiles for gas are shown in the following diagram.

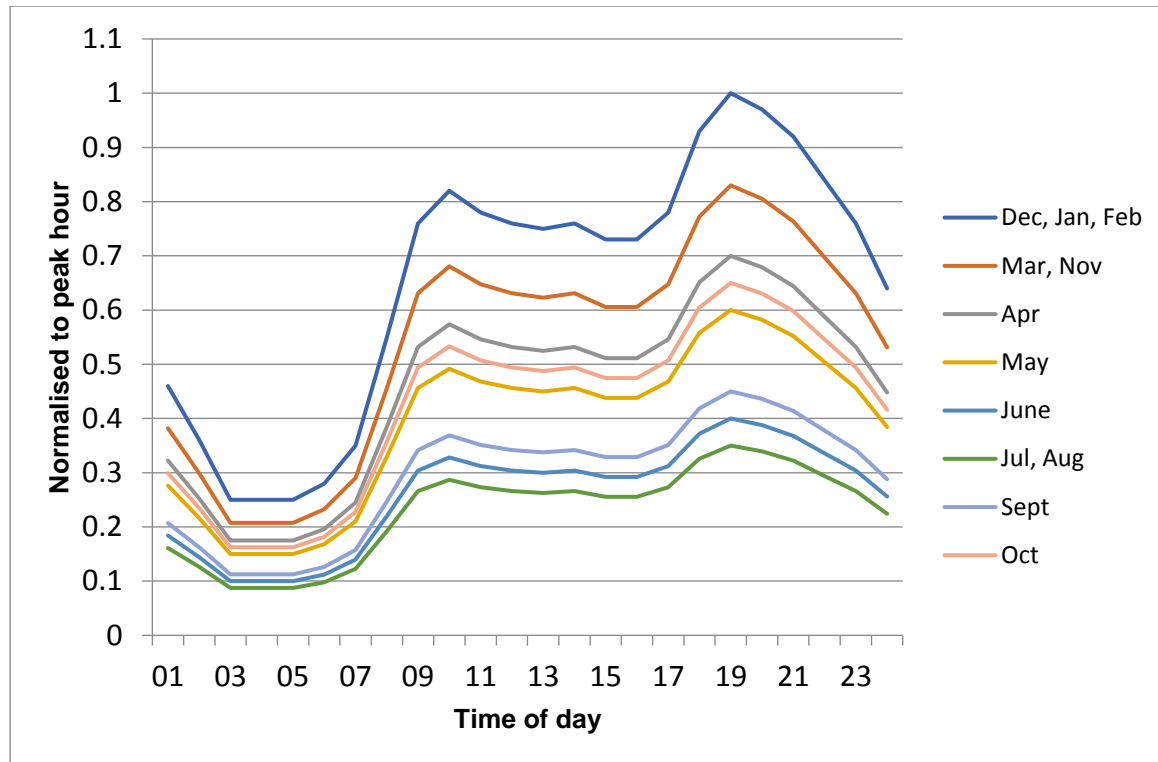


Figure 1: Seasonal and diurnal variations in gas demand

If a plant is dimensioned to blend to 20% by volume when demand is at average levels, it will be operating below capacity for significant periods of time. This is very difficult for a plant processing waste, which should not be stored for a long period, and leads to high costs because of low utilisation of equipment.

Four points in the Cadent network that could accommodate 48MW of hydrogen input at 20% blend levels all year round have been identified. This shows limited potential for deployment of technology through blending without additional measures. The problem can be addressed through a number of solutions such as:

- gas storage;
- smaller plants – albeit at higher hydrogen production costs;
- plants producing hydrogen for both network blending and direct industrial use; and
- hybrid plants able to swing between hydrogen and BioSNG production as demand varies.

1.1.2 Gas specifications

The specification for use of hydrogen in transport is set out in ISO 14687-2:2012. However, no specification exists for hydrogen distributed via the gas grid, and this is an important area for future work which should focus on meeting the functional requirements of consumers whilst optimising environmental and economic performance.

For the purposes of this project, a hydrogen specification was developed on the basis of blending at 20% by volume with gas in the grid whilst meeting GS(M)R Wobbe number requirements. It was assumed that this specification would be acceptable for industrial users and networks completely converted to hydrogen.

Analysis showed that with a 2% limit on non-combustible content, hydrogen blended at 20% with natural gas in the grid could meet the Wobbe number restrictions from the GS(M)R. Carbon monoxide levels are not specified in the GS(M)R, but a limit of 100ppm was set as a conservative figure based on the 15-minute Workplace Exposure Limit of 200ppm. Other limits on contaminants were taken from the GS(M)R.

No limits were placed on levels of methane within the hydrogen. This is important because the design developed for full scale plants relies on controlling carbon monoxide level by converting it to methane. The gas produced by Biohydrogen plants using the design developed in this project had methane levels of 4% by volume.

The specification for carbon dioxide for storage is set out in ISO 27913:2016.

1.2 Producing Biohydrogen

The development and optimisation of a commercial plant design capable of meeting the product specification requires process modelling. In order to inform and validate the process models, laboratory-scale experiments were conducted. These assessed and characterised potential high and low temperature shift catalysts for bulk Biohydrogen production, and a high-activity methanation catalyst to remove residual carbon monoxide.

The laboratory experiments successfully demonstrated conversion of waste derived syngas to hydrogen and removal of carbon monoxide to very low levels, with experimental results validating the kinetic modelling as shown in Figure 2. Through the experimental programme optimum conditions were identified for Biohydrogen production using low temperature shift and high temperature shift reactions, and the impact of diluents on the reaction was understood.

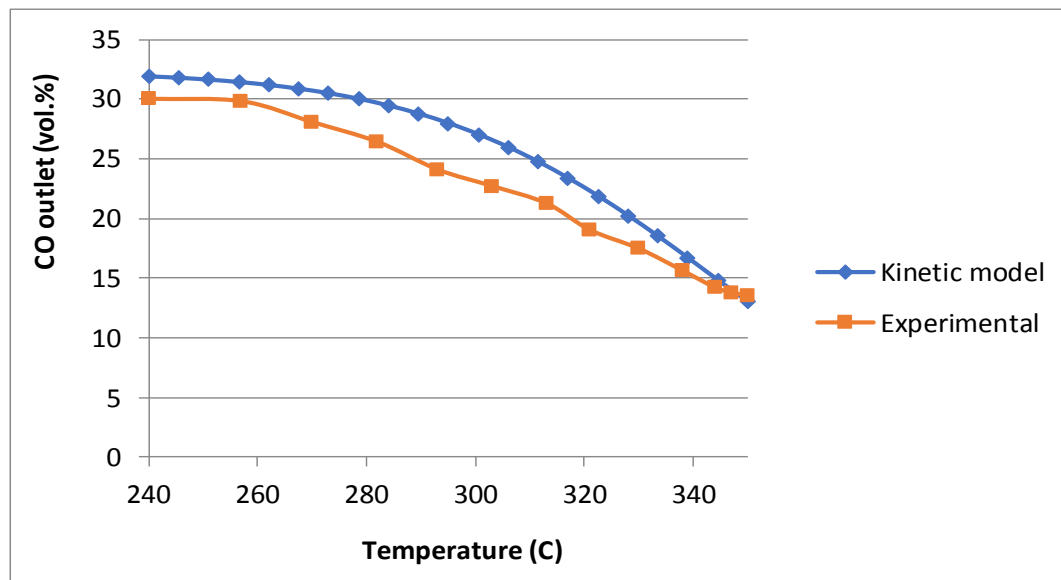


Figure 2: Comparison of derived rate equation with experimental data for the water-gas shift

The results of the laboratory tests were validated at larger scale in the 50kW pilot plant. This plant was originally developed for the BioSNG demonstration project and was reconfigured to produce Biohydrogen. The pilot plant tests successfully demonstrated production of hydrogen from waste derived syngas, with results which were in line with the models developed from the laboratory scale tests; Figure 3 shows how the carbon monoxide concentration was consistently reduced to 2-4% by the low temperature shift reactor.

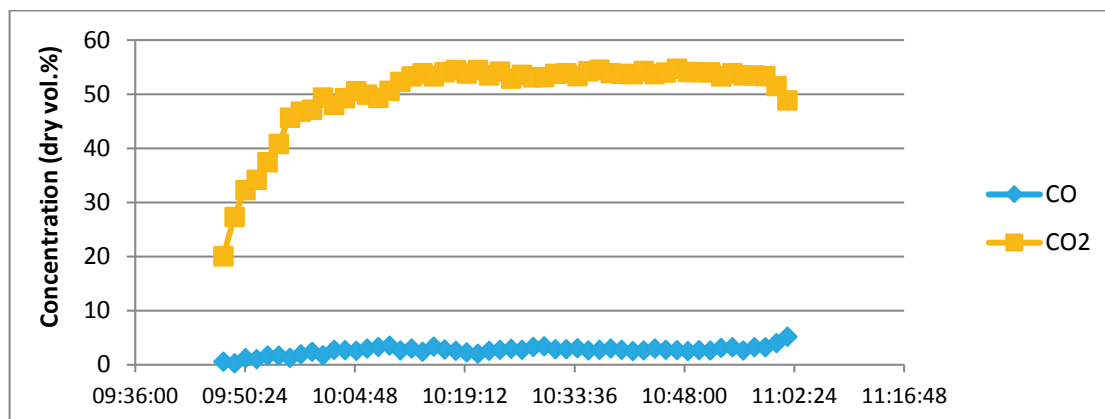


Figure 3: Carbon monoxide and dioxide concentrations at the outlet of the low temperature shift

1.3 Commercial plant design

The commercial plant design is based on the results of the experimental programme. The facility is designed to convert 100,000 tonnes per annum of refuse derived fuel into 45MW

of grid-quality hydrogen, enough to heat more than 25,000 homes, and 3MW of transport-quality hydrogen, sufficient for a fleet of 100 buses.

First, waste is gasified in a two-stage process to produce a low tar syngas at atmospheric pressure. The syngas is cleaned of contaminants and cooled, before being compressed for introduction to an isothermal low temperature shift reactor, which converts 95% of the carbon monoxide in the syngas to Biohydrogen. The shifted syngas passes to a chemical absorption process to separate storage-quality carbon dioxide. A slipstream passes to a pressure swing adsorption unit to produce transport-quality hydrogen, with the remainder passing to a methanator to remove residual carbon monoxide before being injected into the gas grid.

A key to the overall efficiency of the plant is the heat recovery and steam system; a major driver behind the decision to use an isothermal low temperature shift was its lower heat requirements compared to the high temperature shift reaction.

Table 1 summarises the key technical parameters associated with the commercial plant, demonstrating that this provides a highly efficient means of converting waste into a zero-carbon fuel for heat and transport.

Figure 4 shows a Sankey diagram mapping the energy flows in the process.

Inputs	Energy basis (HHV)	Mass basis
RDF feedstock	61.84MW	13.4te/h
Power	7.2MW	
Outputs		
High-purity hydrogen output	3.1MW	0.08te/h
'Grid-quality' hydrogen output	45.3MW	1.55te/h
CO₂ output		18.0te/h
Efficiency		
Overall plant efficiency	70%	
Feedstock to Biohydrogen efficiency	78%	

Table 1: Biohydrogen process summary

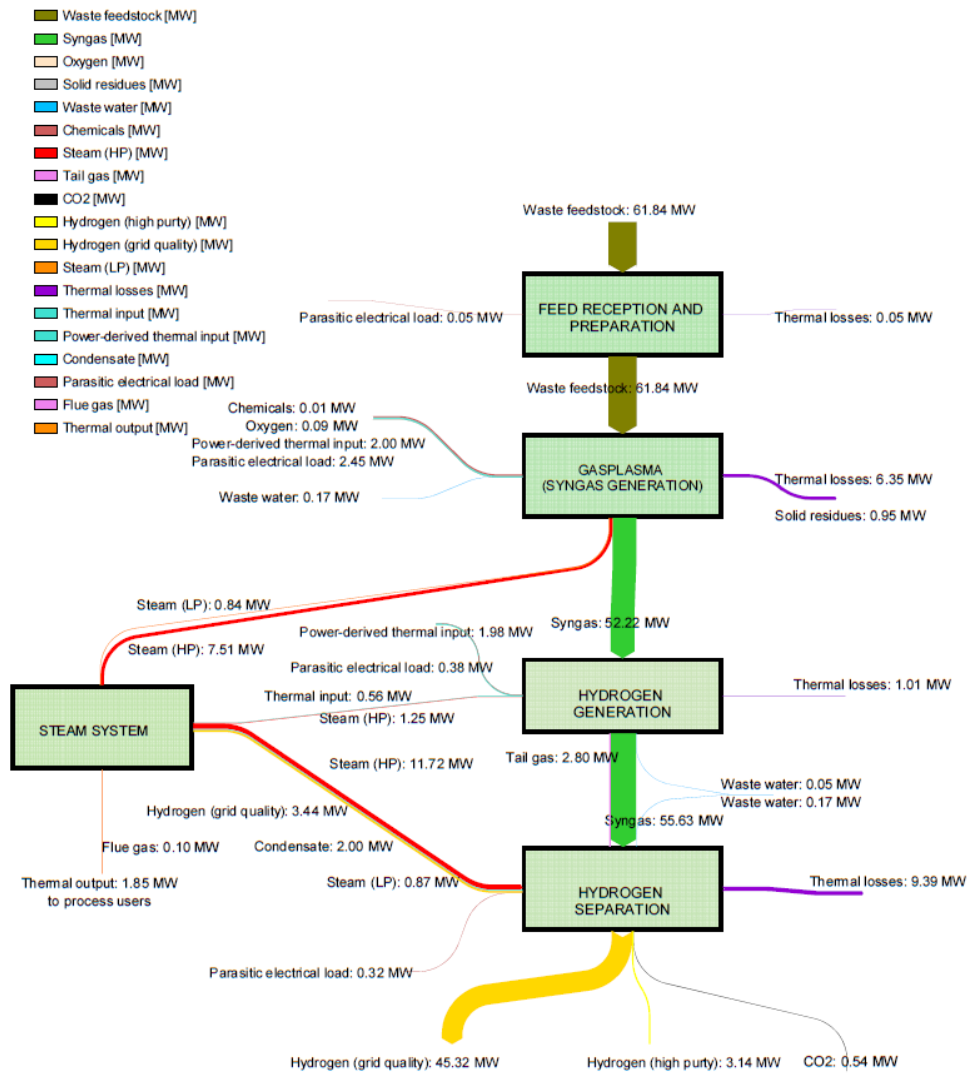


Figure 4: Energy-basis Sankey diagram for Biohydrogen production

1.4 Economic and environmental performance against alternatives

The case for deployment of Biohydrogen rests on its environmental and economic performance against other options.

A detailed greenhouse gas analysis was carried out for the baseline plant. This considered emissions from product and feedstock transport and the electricity and chemicals, including oxygen, consumed by the plant. The analysis showed that Biohydrogen offers an 81% reduction in emissions without CCS and that this increased to 232% if carbon dioxide is sequestered. Electricity and oxygen production are the key contributors to Biohydrogen emissions; as the UK's electricity carbon intensity reduces, Biohydrogen's emissions performance will improve.

The GHG savings from this route are nearly four times greater than those from hydrogen produced using SMR with CCS. The negative emissions from Biohydrogen with CCS, mean that an overall network using a combination of around a third Biohydrogen and one third hydrogen from SMR with CCS could still continue to use one third natural gas and achieve zero carbon heat overall. On this basis, there is sufficient UK feedstock to deliver Biohydrogen at a level which would result in zero carbon emissions for the entire UK domestic gas demand.

The capital and operating costs of a first of a kind Biohydrogen facility were estimated using data from the costs of commercial BioSNG plants and engagement with equipment suppliers. The results of the economic analysis are set out in the following table.

	£/MWh
Capital cost	39.5
Operating cost	52.4
Gate fee	(20.6)
Levelised cost	71.3
Market price of gas	(20.0)
Additional cost	51.3
GHG Savings (tonne CO₂eq/MWh)	0.57
Cost of carbon savings (£/tonne)	91

Table 2: Biohydrogen levelised costs summary (first of a kind)

This shows that for a first of a kind plant, the levelised cost of Biohydrogen is £71/MWh with a cost of £91 per tonne of carbon dioxide savings.

As the Biohydrogen technology develops, costs will fall as confidence in the technology increases. This is illustrated in the following graph.

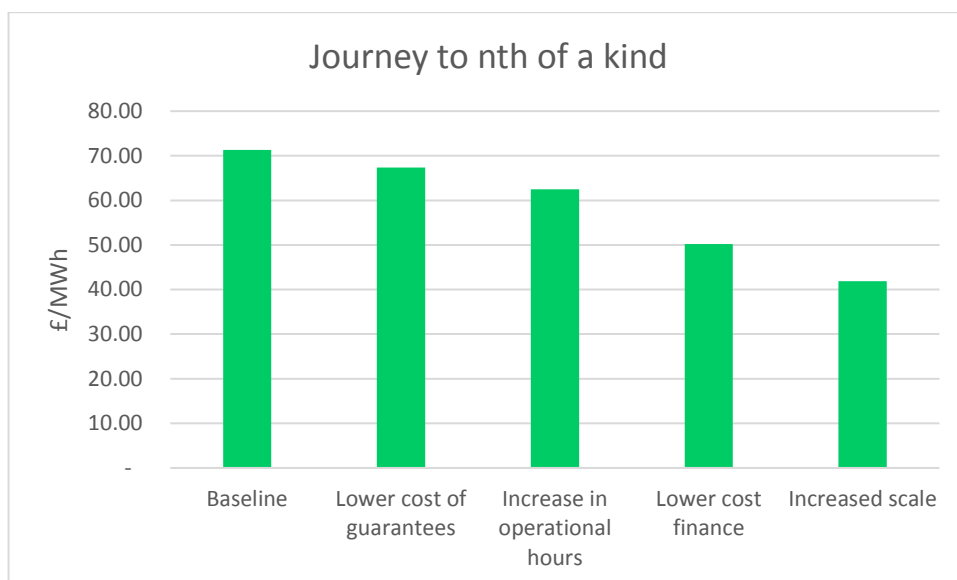


Figure 5: Biohydrogen levelised cost as technology matures

The eventual cost of £42/MWh is similar to SMR hydrogen, even though Biohydrogen offers far greater GHG savings.

BioSNG is a substitute natural gas produced from waste feedstocks⁸. It uses the same feedstocks and addresses the same markets as Biohydrogen and is a complementary technology. The technologies are compared in the following table.

	Biohydrogen – nth of a kind	BioSNG – nth of a kind
Technical maturity	Pilot plant	Demonstration plant under construction
Gross efficiency⁹	78%	64%
Cost with CCS	£42/MWh	£32/MWh
Carbon savings with CCS	565kg/MWh	462kg/MWh
Cost of carbon savings with CCS	£39/te	£26/te

Table 3: Comparison of Biohydrogen to BioSNG (nth of a kind)

This shows that both technologies offer good GHG performance and low costs. The key advantage of Biohydrogen is its high conversion efficiency. This means that its overall potential is greater than BioSNG – a given amount of feedstock will produce 23% more Biohydrogen than BioSNG. It also means that Biohydrogen will be more cost effective to produce from feedstocks that do not have a gate fee such as straw or energy crops.

SMR with CCS and electrolysis are both technologies capable of delivering low carbon hydrogen. Table 4 provides a comparison of Biohydrogen with these sources.

⁸ <http://gogreengas.com/>

⁹ The energy content of gas injected into the grid divided by the energy content in the feedstock used to produce it both measured using higher heating values. This ignores electricity and any other energy inputs or heat and any other energy outputs.

	SMR with CCS¹⁰	Biohydrogen – nth of a kind	Electrolysis¹¹
Maturity	Mature once CCS is established.	No plants currently in operation.	Mature.
Typical scale	Large scale. Around 1,900GWh/a	Medium scale Around 350GWh/a	Small scale – sized to match available low-cost electricity. Up to around 75GWh/a
Cost of heat grade hydrogen	£40/MWh	£42/MWh with CCS £25/MWh without CCS	£134/MWh from off peak electricity
Cost of transport grade hydrogen	Around £1.73/kg ¹²	£1.70/kg with CCS. £1.00/kg without CCS	£5.36/kg
Carbon savings	59% (H21 report)	232% with CCS 81% without CCS	Around 12% based on forecast 2020 grid intensity of 174kgCO _{2eq} /MWh _e
Cost of carbon savings	£163/tonne	£25/tonne without CCS £39/tonne with CCS	£3,909/tonne for grid power but more cost effective if low carbon source used.

Table 4: Comparison of Biohydrogen to alternative pathways

This shows that nth of a kind Biohydrogen has comparable or lower costs and far better environmental performance than SMR or electrolytic hydrogen. Even a first of a kind Biohydrogen plant has a lower cost of carbon abatement at £91/tonne.

¹⁰ <http://www.northerngasnetworks.co.uk/wp-content/uploads/2016/07/H21-Report-Interactive-PDF-July-2016.pdf>, cost figures include hydrogen generation and CCS but exclude the costs of inter-seasonal storage and upgrades to the network. That report uses a carbon intensity of 209kgCO_{2eq}/MWh for natural gas instead of the 243kgCO_{2eq}/MWh used in this report but for simplicity their numbers have not been adjusted.

¹¹ Horizon 2020 European work on Fuel Cells.

¹² Assumes the 99.9% hydrogen considered in the H21 report can be upgraded for transport use with 10% losses.

Compared with hydrogen from natural gas, the potential for Biohydrogen is limited by the availability of sustainable feedstocks such as wastes and biomass residues. Work by Cadent has shown that there are more than 155TWh of sustainable UK feedstocks which could be converted into 123TWh of Biohydrogen. As noted above, this would be sufficient when used alongside hydrogen from SMR with CCS to fully decarbonise domestic gas consumption.

1.5 Deployment

First of a kind Biohydrogen facilities have levelised costs at least £50/MWh higher than current natural gas prices and even nth of a kind CCS Biohydrogen facilities produce gas that is £22/MWh more expensive than fossil gas. The technology will only start to be deployed if there is Government action to encourage the adoption of low carbon solutions for heat or transport.

Transport demand for hydrogen is not forecast to reach significant scale until 2030. Therefore, heat is the only suitable market for hydrogen in the medium term.

The pre-requisites for widespread deployment of hydrogen for heat are:

- The implementation of a scheme that provides support to Biohydrogen such as the Contracts for Difference or Renewable Heat Incentive.
- Changes to the grid gas specifications and development of standards for hydrogen networks.

If appropriate support is put in place there are two scenarios for Biohydrogen development. If CCS infrastructure is developed and parts of the gas network convert to hydrogen then a large market for Biohydrogen will develop and its cost and decarbonisation advantages over SMR should allow it to secure a significant market share. If CCS is not adopted then it is less likely that there will be wholesale conversion of gas networks to hydrogen. In this case Biohydrogen may be blended into the network and complement BioSNG, biomethane and possible electrolytic hydrogen. Opportunities for blending hydrogen at the Biohydrogen plant scale could be limited and this could constrain total demand. This could be addressed by incorporating direct supply to industry, or alternatively constructing plants capable of delivering both BioSNG and Biohydrogen.

Commercialisation of Biohydrogen will involve several steps. Success of the technology is closely linked to the success of BioSNG because successful BioSNG operation will provide good evidence for the feasibility of Biohydrogen production and because commercial BioSNG plants could provide a low-cost route to Biohydrogen demonstration.

A demonstration project will be required to provide a market reference to encourage commercialisation. Several potential configurations of demonstration projects are possible, including construction of a dedicated plant and repurposing of the first small commercial BioSNG plant. The most prospective route to demonstration is through use of a slipstream of syngas from a commercial BioSNG plant. Key attributes of such as project are given in Table 10.

Element	Attribute	Units	Scale
BioSNG Host Project	RDF input (as rec'd)	tonne pa	100,000
	Thermal output rating	MWth	42
	Footprint	Ha	3.1
	Cost	£M	£108m
Biohydrogen Demonstration Stream	Hydrogen production rating	MWth	4
	Quality		Grid/heat quality unless specific transport opportunity
	Estimated additional cost	£M	£5-£8M

Table 5: Key attributes of Biohydrogen demonstration by slipstream from BioSNG plant

Demonstrating Biohydrogen production in this way is more cost effective than a dedicated project, making it more attractive for funders. Given appropriate support from the Government and industry, a large scale BioSNG facility is likely to start operation in 2021, which fits well with the development timescales for Biohydrogen. At this scale it is possible that some of the Biohydrogen could be used for transport demonstration opportunities.

The operation of a BioSNG facility producing significant quantities of Biohydrogen would provide a high quality reference for the Biohydrogen technology, enabling the roll out of large scale plants once the appropriate policy and regulatory support is in place.

2.0 INTRODUCTION AND OBJECTIVES

Hydrogen is seen by many as a key element of the UK's future green energy mix because it generates no greenhouse gas emissions at the point of use. Hydrogen is being promoted as an ideal energy vector for heating and transport but an outstanding question is how to produce low carbon hydrogen cost-effectively.

In this project the partners (Progressive Energy, Advanced Plasma Power and Cadent) sought to increase understanding of the production of hydrogen by gasification of waste, a process referred to as Biohydrogen. This builds on work to develop BioSNG technology¹³, where methane is produced by waste gasification, because hydrogen production represents a simplification of that process. Biohydrogen offers the prospect of low carbon hydrogen production from low-grade fuels at parity with the cost of natural gas, and with the potential of negative carbon emissions if the separated CO₂ is sequestered.

Biohydrogen production can be summarised as follows:

- Production of high-quality biosyngas, (an approximately equimolar mixture of CO and H₂) from a low-grade fuel such as RDF or recovered waste wood
- Increasing the hydrogen content by means of the water-gas shift reaction, accompanied by the conversion of the CO to CO₂
- Removal of residual traces of CO via a methanation reaction
- Separation of CO₂ and water vapour to give a clean product gas with high hydrogen content, suitable for bulk injection into the gas network or upgrading for use in fuel cells

Before Biohydrogen can be deployed commercially several barriers must be overcome. Firstly, the commercial applications must be sufficiently well understood that a functional specification for hydrogen production can be produced. Secondly, the technical feasibility of hydrogen production from waste derived feedstock must be demonstrated to show that the concept is credible. Thirdly, the process must be optimised for commercial deployment, with designs produced, environmental impact understood and costs modelled. Fourthly, the chosen designs must be deployed at larger scale, with hydrogen supplied to end users.

This project seeks to push forward commercial deployment of hydrogen production from waste by systematically working to address each barrier.

Chapter 3.0 summarises work undertaken to define a functional specification for commercial Biohydrogen plants, which included an assessment of future markets for hydrogen, analysis to establish an appropriate scale for the plants, and development of specifications for output streams.

Chapter 4.0 describes the experimental programme, which demonstrated Biohydrogen production from waste and provided experimental data to underpin commercial designs.

¹³ <http://gogreengas.com/>

Chapter 5.0 summarises the reference design developed for commercial Biohydrogen production and discusses the drivers behind design choices. Future process improvements are also identified.

Chapter 6.0 contains assessments of the greenhouse gas emissions and costs associated with Biohydrogen production, and uses the results to compare Biohydrogen to alternative sources of low carbon gas.

Finally, Chapter 7.0 looks at the pathway to deployment of Biohydrogen technology and assesses the near-term potential of different hydrogen markets to provide end users. The questions that must be addressed by a demonstration project are discussed and a route forward is proposed.

Note: unless otherwise specified, heating values are quoted as higher heating values (HHV)

3.0 FUNCTIONAL SPECIFICATION

In order to develop and assess a plant design for commercial Biohydrogen production, it is necessary to produce a functional specification detailing the required compositions of product streams and the preferred scale of Biohydrogen production. Both of these depend on the potential uses of Biohydrogen and this chapter begins with an assessment of those uses, which underpins the subsequent analysis. Existing production technologies are also considered.

The appropriate scale of Biohydrogen production is then assessed, looking at each use in turn, followed by consideration of the likely quality specification in each case. This work is then used to produce a functional specification for commercial plants.

It was concluded that the commercial design should be for a plant taking in 100,000 tonnes per annum of RDF and producing around 50MW of Biohydrogen. Specifications for the plant's output streams were defined, for transport and grid-quality hydrogen as well as carbon dioxide.

3.1 Uses of hydrogen and existing production technologies

In determining the specification for the Biohydrogen it is important to understand the markets that a commercial plant could supply. There are two key sectors where hydrogen is expected to be used: transport and heat. Heat could take the form of hydrogen delivered through the grid, or heat for industry through either onsite hydrogen generation or delivery of hydrogen as part of a local specialised grid. These markets and the medium-term potential for supply into them are discussed below; short term issues such as timescales for market evolution are looked at when a demonstration project is considered in Chapter 7.0.

Future Biohydrogen facilities will form one part of the solution for future provision of low carbon hydrogen. It is important alternative production methods are also considered when assessing the future use of Biohydrogen.

3.1.1 Transport

Hydrogen has been viewed as a potential vector to decarbonise transport for the last two decades. Currently electrification is seen by Government as the prime pathway for decarbonisation of the passenger vehicle sector and is likely to see larger growth in the short term than adoption of hydrogen. However, low carbon liquid and gaseous fuels still have an important role, as expressed in the Government's recent consultation on renewable transport fuels, where the transport minister states that:

“As we transition to electric cars, we will continue to need low carbon liquid and gaseous fuels for decades to come, particularly to decarbonise transport sectors that are not as easy to electrify, such as planes and lorries.”

The electrification objective is supported by grants for research and development, charging infrastructure and vehicle purchase. Hydrogen fuels cell cars complement the advantages of electric vehicles by offering extended ranges and faster refuelling, and benefit from development of electric drivetrains, which are common to both. Vehicles such as the Toyota Mirai are supported under the low carbon vehicle grant scheme.

While electrification looks set for a large role in decarbonising cars, there are fewer low carbon solutions for heavy goods vehicles (HGVs) and buses. Electrification of HGVs is not feasible with current battery technology and the charging time for electric buses is a substantial constraint on utilisation. Conversion to biomethane is one solution, but hydrogen is an alternative.

Hydrogen offers zero tailpipe emissions, particularly advantageous for urban environments and buses, which typically operate as back-to-base enabling gradual roll out of hydrogen refuelling infrastructure. Early hydrogen bus trials have already been undertaken in London¹⁴ and Aberdeen and the 5-year JIVE¹⁵ programme, which will operate fleets of 10-30 buses, commenced in January 2017. This could then lead to wider bus roll out and subsequent early HGV activities in urban environments such as refuse vehicles.

LowCVP are forecasting that there will be 8,000 hydrogen trucks and buses by 2030. The CCC commissioned a report¹⁶ from E4Tech and UCL Energy institute on likely levels of hydrogen deployment to 2050. This forecasts some adoption by 2030, around 50TWh of hydrogen use in 2040 and 140TWh of consumption by 2050.

One of the challenges with this sector is counterparty risk for the offtaker, particularly during the nascent period of adoption with few potential customers. LowCVP forecasts that total transport hydrogen consumption in 2020 will be only 3,000 kilograms (0.1GWh), which is far lower than the minimum production volumes for a commercial Biohydrogen facility. While a specification should be developed for transport, it is unlikely to be the primary offtaker for early commercial plants.

3.1.2 Heat

The Government's heat strategy¹⁷ recognised hydrogen's potential as a gas for direct heating use. The Committee for Climate Change's (CCC) most recent recommendations on heat policy¹⁸ states that hydrogen can play an important role in decarbonisation of heat and calls on the Government to clearly set out the role that hydrogen will play in heating buildings. The CCC states that:

¹⁴ See, for example, the Clean Hydrogen in European Cities (CHIC) project

¹⁵ <http://www.fch.europa.eu/news/launch-project-jive-large-scale-deployment-fuel-cell-buses-europe>

¹⁶ <https://www.theccc.org.uk/wp-content/uploads/2015/11/E4tech-for-CCC-Scenarios-for-deployment-of-hydrogen-in-contributing-to-meeting-carbon-budgets.pdf>

¹⁷ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/190149/16_04-DECC-The_Future_of_Heating_Accessible-10.pdf

¹⁸ <https://www.theccc.org.uk/wp-content/uploads/2016/10/Next-steps-for-UK-heat-policy-Committee-on-Climate-Change-October-2016.pdf>

“Both heat pumps and hydrogen bring significant challenges, but in order to reduce heating emissions close to zero in the long term, extensive use of at least one of these options will be required. It may require a combination of the two solutions, with each dominating in different regions, interspersed with heat networks. It is not possible at this stage to identify either heat pumps or hydrogen as the dominant solution, nor should either be ruled out.”

The wholesale conversion of part of or the entire domestic gas network to hydrogen would require around 300TWh per annum of hydrogen. This could be met by a combination of SMR and electrolysis (reviewed in Section 3.1.3) together with Biohydrogen. It is extremely unlikely that the required volumes could be supplied unless the UK develops the CCS infrastructure necessary for SMRs to produce low-carbon hydrogen, and so CCS should be seen as a prerequisite to wholesale conversion of all or part of the gas network to hydrogen.

Heat users and distribution options are considered below.

3.1.2.1 Delivery through the gas distribution system to existing gas customers

Currently the gas grid does not accept more than 0.1% hydrogen by volume. However, there are a number of programmes underway to establish the feasibility of using the grid to transport hydrogen through the distribution network. This takes two forms, as a blend with natural gas, or through conversion of the distribution system to accommodate 100% hydrogen. From a hydrogen producer perspective, grid injection offers the potential of a wide customer base and therefore much lower counterparty risk once injection *per se* has been adopted.

As a blend of hydrogen and natural gas

Blending hydrogen and natural gas is already undertaken across Europe, and the HyDeploy NIC project is seeking to establish it in the UK. In parts of Germany a blend of up to 10% by volume hydrogen in natural gas is permitted. In Holland, injection of hydrogen up to 20% by volume was trialled at Ameland¹⁹. In the UK, a review by the HSE considered blending up to 15% by volume²⁰. Through the work of HyDeploy it is anticipated that the regulatory and technical constraints associated with hydrogen blending will be addressed; preliminary work on safe blending levels has already been performed by the Hystart NIA project²¹. In addition there are billing issues, due to the lower calorific value of such blends and the current Flow Weighted Average CV (FWACV) billing regime. This is being addressed through another Network Innovation Project, ‘Future Billing Methodology’. Through both these projects it is anticipated that blending of hydrogen from a variety of sources into the gas distribution could be feasible as early as 2020.

¹⁹ ‘Pilot Project On Hydrogen Injection In Natural Gas On Island Of Ameland In The Netherlands’, M.J. Kippers et al, International Gas Union Research Conference, 2011

²⁰ ‘Injecting Hydrogen into the gas network – a literature search’ Hodges et al HSE, 2015

²¹ ‘Hydrogen Addition to Natural Gas Feasibility Study’, NGN and NG, 2016

Injecting hydrogen into the network to create a blend for use by consumers provides an opportunity for the early roll out of Biohydrogen production, since there is significant demand for low carbon replacements for natural gas that are compatible with existing appliances. A specification should therefore be produced for this use. The potential scale of deployment in this mode is explored in Section 3.2.2.3.

Conversion of sections of the distribution system to 100% hydrogen

Even deeper decarbonisation of the gas distribution system is being considered through the conversion of the network to 100% hydrogen. NGN's Leeds Citygate H21 Project²² is a case study in conversion of an exemplar city to hydrogen, taking a broad consideration of all the relevant factors: conversion of domestic appliances, suitability of the network, and production, delivery and storage of the hydrogen, assumed to be produced primarily from steam methane reformation (SMR) of natural gas with associated carbon capture and storage (CCS) infrastructure. The focus of this project was the domestic sector and the hydrogen was presumed to be injected into the 7 barg system for distribution to all tiers below. This work concluded that there was no substantive reason why such a transformation should not be possible and laid out the activities necessary to take this forward. The timeframe for conversion of an exemplar city is given as the late 2020s, with further roll out during the early 2030s. Further work is also being undertaken by Cadent into the role and needs of industrial consumers in developing hydrogen infrastructure clusters for such zones of conversion. Such customers typically require baseload hydrogen consumption throughout the year.

Complete hydrogen conversion of existing networks offers a longer-term opportunity for Biohydrogen because Biohydrogen offers far greater carbon savings than SMR hydrogen. However, it is unlikely that any conversions will take place soon enough to offer an early route for demonstration and commercialisation. Development of a specification for hydrogen for this use is discussed in Section 3.3.3.

Whilst the National Transmission System is capable of carrying much larger volumes of gas than the distribution networks, there are a number of constraints relating to both the materials of construction and the nature of the gas consumers connected to it, which mean that there are barriers to accommodating hydrogen except in a blend, and at relatively low blending levels. This is currently being assessed by National Grid Gas Transmission.

3.1.2.2 Direct delivery to industrial customers

Many large industrial facilities use natural gas to generate process heat (sometimes from the National Transmission System) and could convert to using hydrogen. These users could ultimately take hydrogen through existing natural gas networks, but could also have hydrogen produced on-site or nearby and distributed through a new local network. Using new local networks of production and distribution would address materials-of-construction issues with existing high pressure natural gas pipelines that may not be

²²<http://www.northerngasnetworks.co.uk/wp-content/uploads/2016/07/H21-Report-Interactive-PDF-July-2016.pdf>

suitable for conversion to hydrogen and would provide Biohydrogen plants with large baseload volumes of hydrogen offtake. However, counterparty risk for the hydrogen provider does increase as the individual customer base is reduced.

Large industrial customers may offer an early opportunity to demonstrate Biohydrogen production, particularly if a large, financially stable customer can be found to partner in a project, or if a network encompassing several users can be established.

Industrial heat use in the UK in 2015 was almost 100TWh²³; this market therefore holds significant potential for deployment of commercial Biohydrogen plants and could receive hydrogen as early as 2024. It should therefore be considered in the functional specification.

3.1.3 Alternative production methods

There are two other prominent pathways for the production of low carbon hydrogen:

- Steam methane reforming (SMR) combined with carbon capture and storage (CCS).
- Electrolysis of water using low carbon or surplus electricity.

SMR production with CCS is considered in detail in the NGN H21 report and is compared to production by electrolysis and Biohydrogen in Table 30 (Section 6.4).

The table shows that SMR with CCS is suitable for large scale production of hydrogen and can provide very high volumes of gas for a cost double the current market price for gas. The technology is mature with little room for future cost savings and is best suited for deployment in coastal regions close to carbon storage infrastructure. The capital cost of production is low (£0.58m/MW) but operating costs are high (£0.36m/MW per year) because of the cost of purchasing natural gas for conversion. The cost of per tonne of carbon saved is in the middle of a range of technologies considered by the Government in their impact assessment²⁴ of the fifth carbon budget.

Electrolysis offers a small-scale solution that can be cost effective for some applications such as filling stations for hydrogen vehicles. However, currently the cost of hydrogen produced by electrolysis is far more expensive than SMR hydrogen (£6.20/kg versus £1.90/kg for transport-grade) and it does not offer significant GHG benefits unless low carbon electricity is used.

3.1.4 Proposed focus

The largest market in the short to medium term is expected to be the heat sector, both through the distribution of hydrogen as a blend through the gas grid and through delivery of unblended hydrogen to local industrial customers. There is a strong European track

²³ BEIS (2016) Historical gas data: gas production and consumption and fuel input 1920 to 2015, August 2016 <https://www.gov.uk/government/statistical-data-sets/historical-gas-data-gas-production-and-consumption-and-fuel-input-1882-to-2011>

²⁴ http://www.legislation.gov.uk/ukia/2016/152/pdfs/ukia_20160152_en.pdf

record for hydrogen blending and, whilst there are currently UK regulatory barriers, significant activities are already underway to address these. There is a strong prospect of blending being in place by the early 2020s and potential for wider use over the decade. Demonstration of low carbon hydrogen from alternative sources than electricity (which is costly) and steam methane reformation (which is dependent on CCS) could be important in facilitating earlier adoption.

Transport applications, whilst holding the prospect of demonstration projects around 2020, are unlikely to require significant volumes of hydrogen consumption until towards 2030.

Therefore, typical hydrogen project scale and specification should be dictated primarily by heat applications, albeit with potential side streams of smaller volumes of transport quality production. Such a side stream could be enlarged for an early transport demonstration project.

3.2 Biohydrogen production rate

There are a number of important factors in determining the appropriate production rate. Some of these are common to the BioSNG project while others are dictated by the hydrogen application and how it is delivered to the consumer.

Economic performance of the facility itself generally improves with scale, delivering lower levelised cost per unit of hydrogen. However, this is constrained by feedstock availability and the size of the feasible offtake; setting a plant scale which is too large will limit the number of feasible plant locations. These factors are discussed in more detail below.

3.2.1 Feedstock availability

Feedstock arisings were considered carefully in the BioSNG Demonstration Plant project. The reference plant size, consuming around 100,000 tonnes per annum of dry refuse derived fuel, can be supplied from a reasonably sized town, accounting for residual domestic, commercial and industrial waste arisings.

It is also similar in scale to small conventional energy from waste facilities which have a good track record of securing finance. This confirms that it is feasible to contract for such waste volumes with sufficient certainty, typically with a measure of cover ratio such that funders can be satisfied.

Some locations may be able to support larger facilities, modelled as double line plants, i.e. taking around 200,000 tonnes per annum. This scale is still smaller than the larger energy from waste facilities, demonstrating that such plants are feasible, although the number of locations which could accommodate such plants would be limited.

3.2.2 Offtake constraints

Although the markets identified above show potential for consumption of many terawatt hours of Biohydrogen in the UK, deployment is only possible if the product of commercial plants can be distributed to users economically. In practice, unless the entire gas grid is

converted to hydrogen, this means that there must be sufficient local demand to consume the output of a plant.

A plant consuming 100,000 tonnes per annum of RDF equates to around 60MWth (HHV) of input feedstock. Initial commercial plant simulations predicted an approximate output of around 50MWth of hydrogen on an HHV basis, which is around 1.25 tonne/hour, 15,000m³/hr or 375GWh/annum, assuming 7500hrs per annum operation.

These volumes were compared with potential routes for offtake to assess whether 100,000 tonnes per annum of RDF was an appropriate scale for commercial plants, so to define the scale for which a commercial plant should be designed.

3.2.2.1 Transport

Bus fleets have been identified as the earliest likely adopters of hydrogen for transport. A typical bus will consume around 5 tonnes per annum of hydrogen. A large depot will operate around 100 buses, i.e. 500 tonnes per annum or 20GWh. This equates to around 5% of the standard 100,000 RDF plant identified. This suggests that transport applications in the medium term are likely to be serviced by slip streams from larger plants designed to service grid or industrial customer applications.

3.2.2.2 Grid Injection: 100%

The Leeds H21 Citygate project identified that Leeds has an average annual demand of around 6000GWh, equivalent to an average 678MWth hourly demand, with a one-in-twenty peak hour of around 3180MWth.

This suggests capacity for around 10-15 Biohydrogen plants of 50MWth scale in a conurbation such as Leeds, some of which could potentially be larger scale plants. It would be challenging to source sufficient quantities of waste or biomass from the local area to fuel these plants; in total, Leeds produces sufficient waste to meet around a quarter to a third of this demand.

However, full conversion to hydrogen would only realistically take place on the basis of the availability of large scale hydrogen production from natural gas with CCS. Therefore the scope for Biohydrogen would be somewhat reduced but it could nonetheless sustain, for example, three plants at the 100ktpa RDF scale which would meet 15-20% of demand, even accounting for the demand profiles explored in 3.2.2.3.

This model could be replicated across conurbations as they are converted to hydrogen.

3.2.2.3 Grid Injection: blending

As considered above, blending of hydrogen into the gas network offers a near-term opportunity for hydrogen utilisation.

Total gas consumption on the distribution system is currently around 540TWh per annum. On the basis of 20% blending by volume, which equates to around 7% by energy, this suggests a hydrogen demand of 38TWh pa, or the equivalent of around 100 plants of the

100ktpa RDF proposed which would consume almost one-third of the UK's sustainable biomass resource²⁵.

However, it is important to consider where the gas could be injected into the system on a more local geographic basis. Using the Leeds data as an example, this suggests that on an average annual basis Leeds would consume around 450GWh of hydrogen at 20% blending, enough capacity to support one 100,000 RDF te pa plant.

However, understanding utilisation is also important, recognising the seasonal and diurnal fluctuation in gas demand. Standard curves are used in the gas industry to predict typical peak demand at different times of the day and year; these can be used to approximate gas demand throughout the year. These curves are shown in the figure below, based on a normalisation against the peak hour.

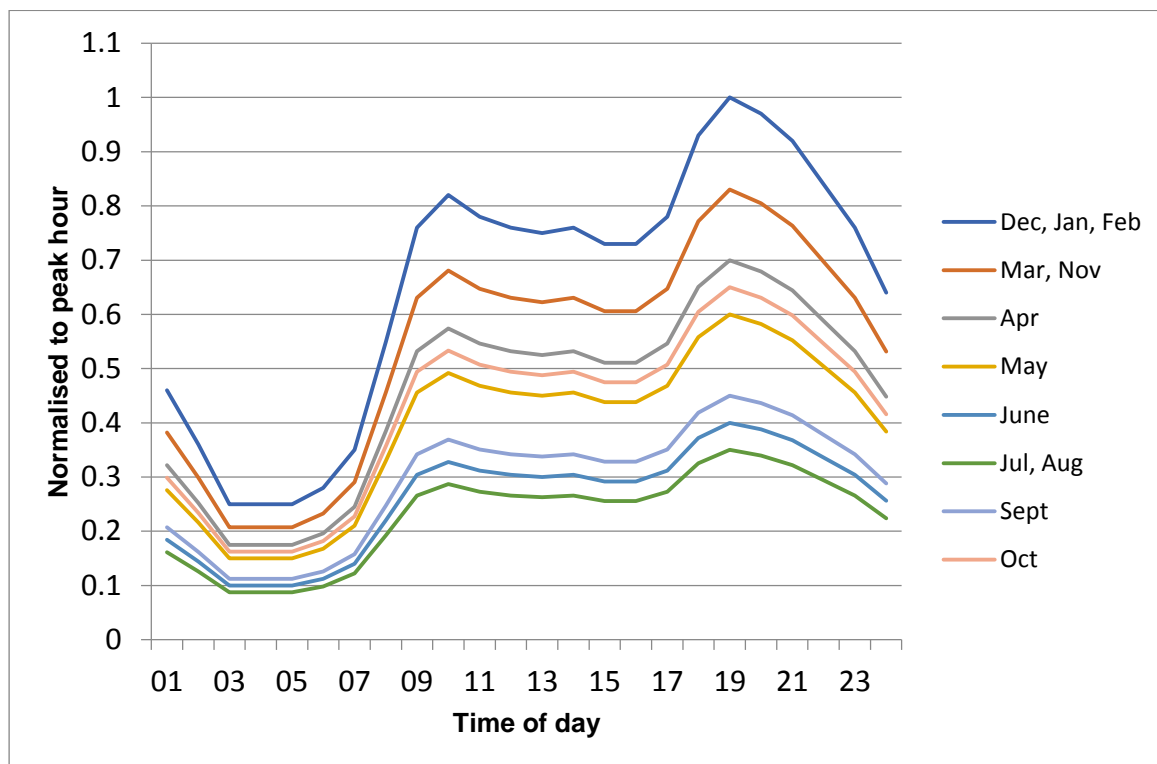


Figure 6: Diurnal gas demand throughout the year

On the basis of a total annual demand of 6000GWh, the average Leeds hourly gas flow is 678MW, which equates to 0.44 on the normalised scale, meaning that the average flow is 0.44 of the peak hourly flow.

As demand varies the flow of hydrogen that can be accommodated on the network also changes. At times of low demand a 50MW plant will not be able to inject all the hydrogen it can produce; at high demand the hydrogen content of the blended stream will be lower. Table 6 illustrates some of the key scenarios for a plant in Leeds.

²⁵ 'Review of Bioenergy Potential: Technical Report for Cadent Gas Ltd', Anthesis & E4Tech, 2017

	Network gas flow		Hydrogen injected	Blend level	
	Normalised	MW	MW	% by vol	% by energy
Average flow	0.44	678	48	20	7
Peak flow	1.00	1530	50	10	3
Summer minima	0.09	138	10	20	7

Table 6: Hydrogen blending at various gas flows

Without storage, a 50MW hydrogen plant would be operating at 100% whenever the normalised gas flow exceeded 0.46 which would lead to a potential utilisation over the year of below 60%, assuming that the plant were capable of operating at a turndown of around 30%. Clearly this is insufficient for a commercial case to be made. However, there are ways of increasing plant utilisation, explored below.

Another way to assess the feasibility of deployment at 50MW scale is to look for points in the distribution network where flows are sufficiently high to accommodate a hydrogen volume blend of 20%. For a 50MW hydrogen plant, approximately 15,000m³/hr of hydrogen are produced. To accommodate this the local network flow must be around 64,000m³/h.

Data from Cadent on gas flows in the Local Transmission System (LTS) in their networks shows four points in the system where these quantities of gas could be introduced, even at summer minimum flows. This shows some potential for deployment, although limited.

Daily and annual minima flows clearly present a barrier to large-scale deployment by blending but four ways to overcome the issue have been identified.

The first of these is the inclusion of storage. According to the Leeds analysis, inclusion of 250MWh storage (enough for 5 hours' production at full capacity) could increase utilisation to more than 80%, although it would come with increased capital and operating costs.

Another option is to blend only a portion of the plant's output, sending the rest to industrial users as below. Looking again at the Leeds analysis, but for 25MW of hydrogen, utilisation increases to almost 90%, even without storage.

A third solution would be to construct a plant that was capable of switching to a high-methane (90%) product gas at times of low grid demand. This would dramatically increase the number of points in the gas network where the output from a facility could be accommodated; initial analysis suggests that there are 250 suitable pipes in the Cadent Local Distribution Zones with sufficient flows for this scenario. A conceptual design for this type of plant is presented in Section 5.1.7.3.

The fourth solution is to operate a hydrogen network in parallel to the natural gas network to carry hydrogen to a number of blending points around the network. This has not been analysed in detail.

Overall, blending has a good potential to provide the offtake for initial Biohydrogen plants. Variation in demand may limit the widespread deployment of blending technology but there are a number of solutions to address this.

3.2.2.4 Individual industrial customers

Large scale industrial facilities could have a role to play in providing additional demand to increase plant utilisation throughout the year and reduce storage and/or pipeline infrastructure. Emerging work from the Hydrogen Clusters project suggests that in the North-West region (~1200 square miles around Manchester) there are five industrial facilities that would consume at least 375GWh pa (full output from a 50MW hydrogen plant). This would double to around ten if facilities were included that could take 185GWh (250MW flow) of gas. These plants, and smaller ones, could be linked together in local networks to provide sufficient offtake for further Biohydrogen plants, or be used in conjunction with grid blending.

Some industrial processes specifically require hydrogen (such as ammonia or peroxide production); in these cases there may also be the potential for increased value to be attributed to the product compared with natural gas.

3.2.3 Economic factors for plant scale

Ultimately the Biohydrogen facility must be commercially viable. Analysis from the BioSNG project suggests that although at 200,000 tonnes per annum dry RDF scale SNG could be produced at cost parity with natural gas, halving the scale increases the levelised cost of gas by approximately 70%. Due to the similarity of the Biohydrogen process with the BioSNG process, the variation of cost with scale is expected to be similar.

There is a prospect of certain markets (transport and industrial consumers) attributing greater value to hydrogen compared with BioSNG which may facilitate smaller scale projects.

3.2.4 Summary of proposed scale

The foregoing has considered the prospects for deployment of Biohydrogen plants converting 100ktpa of RDF into 50MW (1.25te/hr) of Biohydrogen. Potential has been shown for multiple plants to be deployed to directly supply industry and the existing gas grid, and so this scale will be the reference. Plants at smaller scale would have significantly greater prospects of deployment but at significantly greater levelised cost of gas.

3.3 Specification of hydrogen and CO₂ streams

The above arguments have shown that the most prospective uses of hydrogen in the near future are in grid blending, transport and industry applications. The specifications presented below focus on grid blending, grid conversion and transport, with the assumption that industrial users will use 'grid-quality' hydrogen.

The environmental benefits of Biohydrogen production from waste rather than BioSNG production are greatest if the CO₂ produced during the process is captured and stored. For this reason, the required quality of such CO₂ is also considered.

3.3.1 Transport

The specification of hydrogen for use in Proton Exchange Membrane fuel cells (which are expected to dominate use of hydrogen in transport) is given by ISO 14687-2:2012, and presented in Table 7.

The standard is currently under review, with a revised standard expected to be produced in 2018²⁶; however, at present it offers the best indication of the required specification.

Component	Specification (ppmv)
Water	5
Total hydrocarbons	2
Oxygen	5
Helium	300
Total nitrogen and argon	100
Carbon dioxide	2
Carbon monoxide	0.2
Total sulphur compounds	0.004
Formaldehyde	0.01
Formic acid	0.2
Ammonia	0.1
Total halogenated compounds	0.05
Particulates	1 mg kg ⁻¹

Table 7: Hydrogen specification for PEM fuel cells, ISO 14687-2

As discussed in 3.2.2.1, if Biohydrogen is used in transport in the medium term it will be taken as a slipstream from a grid blending or industrial use plant and upgraded to fuel cell quality. For this reason, most of the hydrogen produced by Biohydrogen plants does not need to meet the Table 7 specification; conventional pressure swing adsorption technology can be used to refine high purity hydrogen.

Fuel cell vehicles store hydrogen at pressures of the order of 700bar. While the Biohydrogen process operating pressure will not approach this, the eventual need to compress hydrogen provides a driver for operation at higher pressures than may otherwise be chosen.

²⁶ 'Measurement of 'total halogenated compounds' in hydrogen: Is the ISO 14687 specification achievable?', Brown et al., 2015

3.3.2 Grid conversion and industrial heat

There has only been limited discussion of the standards for a hydrogen network. In the H21 report NGN proposes to use hydrogen with 99.9% purity but does not discuss why this purity was selected or what limits should be placed on contaminants such as carbon monoxide. In contrast to the GS(M)R specification, which was driven by the characteristics of the available gas, the hydrogen network specification should be driven by the needs of hydrogen consumers as well as hydrogen suppliers.

As described above, transport users will require very high purity hydrogen. It is generally thought that a hydrogen network will not be able to deliver hydrogen at the purities required, so transport users will always need a degree of on-site upgrading. Heat consumers will generally be combusting hydrogen and should not require high purities. However, catalytic hydrogen heaters and domestic fuel cells are under development that may require certain purities. A detailed analysis of likely sources and uses of hydrogen will be required before a hydrogen purity specification can be determined but methane content up to 10% is likely to be acceptable.

It is important that the purity specified is not unnecessarily onerous; Biohydrogen costs are lower if it is permitted to contain higher quantities of methane, nitrogen and carbon dioxide and this should be allowed unless it has a detrimental impact on customer safety or equipment. Low purity hydrogen will frequently have better greenhouse gas emissions performance because producing high purity hydrogen results in lower overall yields.

Acceptable levels of contaminants will also be driven by the sources and uses of hydrogen and by gas safety. In this report it is assumed that hydrogen gas will have the same limits on contaminants that are currently required for grid natural gas. However, these do not limit carbon monoxide which will be an issue for Biohydrogen and hydrogen produced using SMR. The 15-minute workplace exposure limit for carbon monoxide is 200ppm²⁷; this project conservatively assumes a carbon monoxide limit of 100ppm. It is likely that it will be possible to make a case for higher levels than this in future.

Determining the specification for hydrogen in a dedicated network is a very large project requiring co-ordination across a significant number of stakeholders. The results of this project will explain the impacts of choices made on hydrogen purity on the costs and environmental impact of Biohydrogen which should help inform the standardisation process.

Until such a specification is produced, designs will be based on the specification for grid-blended hydrogen as detailed below.

3.3.3 Grid blending

Natural gas injected to the UK grid must meet the criteria set out in the Gas Safety (Management) Regulations (GS(M)R) 1996. In addition, the gas will be subject to the Network Entry Agreement (NEA) made with the local Gas Distribution Network. The

²⁷ www.hse.gov.uk/pubns/priced/eh40.pdf

GS(M)R specification is given in Table 8. The specification from a typical NEA from Northern Gas Networks (NGN) is given in Table 9²⁸.

The specification for Biohydrogen will be chosen so as to ensure that the blended gas is consistent with the GS(M)R specification as far as possible and will be informed by the NEA requirements.

Property	GS(M)R Range or Limit
Hydrogen Sulphide (H ₂ S)	< 5 mg/m ³
Total sulphur (S)	< 50 mg/m ³
Hydrogen (H ₂)	< 0.1 mol%
Oxygen (O ₂)	< 0.2 mol%
Impurities and water and hydrocarbon dew temperatures	The gas shall not contain solids or liquids that may interfere with the integrity or operation of the network or appliances
Wobbe number (WN)	Between 47.20 and 51.41 MJ/m ³ - normal limits Between 46.50 and 52.85 MJ/m ³ - emergency limits
Incomplete Combustion Factor (ICF)	< 0.48 - normal conditions < 1.49 - emergency conditions
Sooting Index (SI)	< 0.60
Odour	Gas below 7 bar (g) will have a stenching agent added to give a distinctive odour

Table 8: Natural gas specification from GS(M)R

Property	Unit	Range	Comment
Hydrogen sulphide (H ₂ S)	mg/m ³	< 5	3.3 ppm by volume
Total sulphur (S)	mg/m ³	< 50	Typically <15 ppm by volume
Hydrogen (H ₂)	mol%	< 0.1	
Oxygen (O ₂)	mol%	< 1.0--	
Hydrocarbon dew point	°C	< -2	At any pressure up to delivery pressure
Water dew point	°C	< -10	At the delivery pressure
Wobbe index	MJ/m ³	47.20 – 51.41	Real, gross, dry
Incomplete combustion factor (ICF)		< 0.48	As defined in GS(M)R
Soot index (SI)		< 0.6	
Gross calorific value	MJ/m ³	37 – 44	In compliance with the Wobbe Index, ICF and SI limits and below the Target CV cap
Carbon dioxide (CO ₂)	mol%	< 2.5	

²⁸ The specification is taken from 'Hydrogen Addition to Natural Gas Feasibility Study', NGN and NG, 2016

Nitrogen (N₂)	mol%	< 10.0	
Total inerts	mol%	< 10.0	
Contaminants	Shall not contain solid or liquid material that may interfere with the integrity or operation of pipes or gas appliance		
Organo halides	mg/m ³	< 1.5	
Radioactivity	Becquerel/g	< 5	
Odour	Gas delivered shall have no odour that might contravene the Northern Gas Networks' statutory obligation not to transmit or distribute any gas at a pressure below 7bar(g), which does not possess a distinctive and characteristic odour.		
Pressure	Shall be that required to deliver gas into the System taking account of the back pressure as the same shall vary from time to time. The delivery pressure shall not exceed seven bar gauge (7 barg).		
Delivery temperature	°C	1 - 20	

Table 9: Natural gas specification from a typical NEA

Blending levels

The Hystart project, conducted under the NIA programme, considered in detail the impact of hydrogen blending on UK gas networks. The project considered a range of issues, including Wobbe number, dewpoints, odorant, calorific value and impact on domestic appliances, and concluded that hydrogen blending at up to 20% could be feasible. The analysis recognised the variable characteristics of gas around the UK and highlighted the need for live information on gas quality so that blending ratios could be reduced if necessary.

In Figure 7, the Wobbe number of a gas stream comprised of pure hydrogen blended to various levels with UK average natural gas²⁹ is shown. As found in Hystart, gas blended at up to 20% hydrogen meets the Wobbe number specification. In seeking to establish the appropriate levels of other contaminants, effect on the Wobbe number at 20% blending will be a key consideration; limits derived from 20% blending will be conservative for lower blends.

²⁹ Taken from 'Hydrogen Addition to Natural Gas Feasibility Study', NGN and NG, 2016

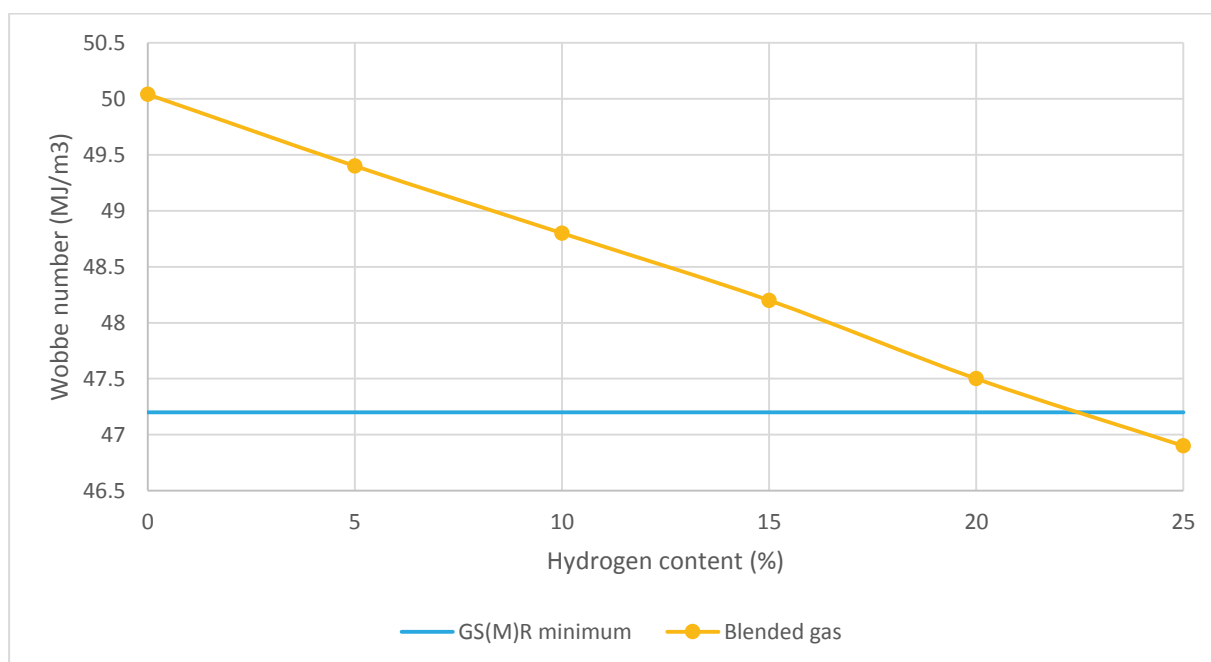


Figure 7: Graph of Wobbe number of blended gas as blending level of pure hydrogen increases

Contaminants

The GS(M)R and NEA specifications place limits on certain chemical contaminants, specifically sulphur species and organohalides. The most straightforward approach when specifying hydrogen for blending is to place the same concentration limits on such species in the hydrogen as are in place for the natural gas, ensuring that the mixed stream will be within the natural gas specification.

The shift catalysts used in Biohydrogen production are extremely sensitive to these contaminants requiring ppb levels of sulphur. In order to ensure catalyst longevity, it is already necessary to achieve these ppb levels of contaminants in the biosyngas, and so Biohydrogen will meet the contaminant limits specified.

As discussed in Section 3.3.2, carbon monoxide content is not specified in the GS(M)R, despite its safety implications. The 15-minute Workplace Exposure limit for carbon monoxide is 200ppm, and this project will use a conservative limit of 100ppm. It is likely that a safety case can be made for a higher limit in future.

Non-combustible content

The GS(M)R specification places no restrictions on the non-combustible content of natural gas; limits on inert content are effected by the Wobbe number specification. The NEA specification from NGN limits carbon dioxide content to 2.5% and total inerts to 10% (including nitrogen content, which is itself limited to 10%).

To gain an idea of the appropriate limit for non-combustible content in hydrogen at 20% blending, the Wobbe number of the mixed gas is plotted as CO₂ content in the hydrogen stream is increased (Figure 8). The plot shows that, for average UK gas mixed with hydrogen at 20%, CO₂ content in the hydrogen stream can be as high as 2% before the

Wobbe number lower limit of 47.2MJ/m^3 is breached. Nitrogen and oxygen contents in the stream have a lower effect on Wobbe number than CO_2 ; therefore a limit of 2% on total non-combustible content would ensure that Wobbe number conditions are met for the majority of UK locations for all blending levels up to 20%.

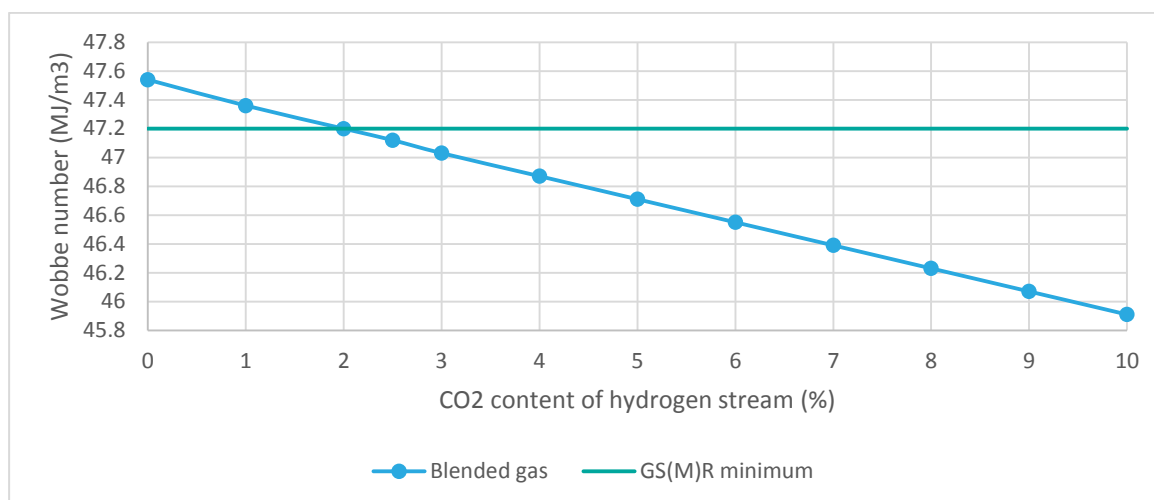


Figure 8: Graph of Wobbe number of gas mixed with 20% hydrogen stream as CO_2 content in hydrogen stream is varied

By definition, there are many locations in the UK where the natural gas delivered through pipelines will have Wobbe numbers lower than the average and so the blended Wobbe will be lower. It is instructive to see whether this can be managed by reducing the blending level.

Figure 9 shows the Wobbe number of the blended gas at various levels of hydrogen blending, with 2% CO_2 in the hydrogen. This clearly illustrates that changing the level of hydrogen blending is an effective way to control the Wobbe number, and so 2% CO_2 can be accommodated in the hydrogen even in areas where the unblended natural gas has a low Wobbe number. Restricting the levels of hydrogen blending will have the consequence of either reducing revenue from hydrogen sales, or restricting deployment to areas of high gas flow. Whether non-combustible content should be reduced further is then a matter for techno-economic optimisation.

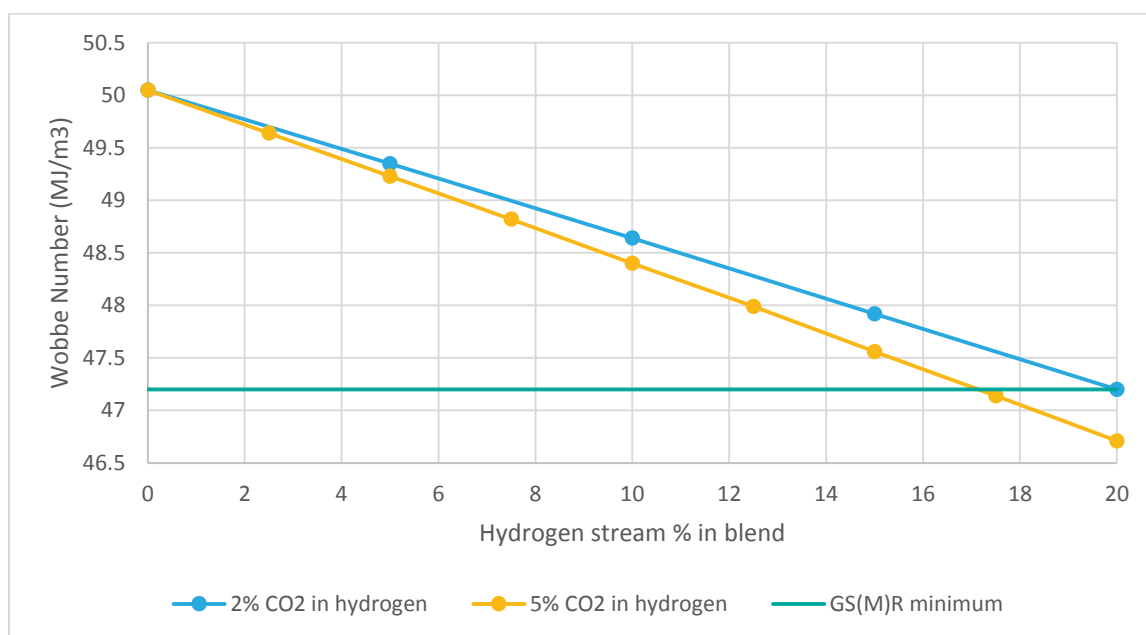


Figure 9: Graph of Wobbe number of mixed gas as the level of hydrogen stream in the blend increases

It is worth investigating whether reducing the level of blending could be used to accommodate higher levels of non-combustibles. Figure 9 also shows the Wobbe number of the blended gas at 5% CO₂ content. Again, it is clear that lower levels of blending can be used to accommodate higher non-combustible content; in fact, blending level has a far greater effect than non-combustible content. As before, this is a question for techno-economic optimisation.

In conclusion, a 2% limit on non-combustibles is an appropriate reference for design purposes. Based on UK average gas, this allows 20% hydrogen blending while meeting GS(M)R Wobbe number limits; lower blending levels can be used in areas where the Wobbe number of the initial gas is low.

Pressure and temperature

The pressure at which the hydrogen stream is blended with the gas will be dictated by the pressure in the network at the point of injection. The LTS includes pipes operating at pressures well in excess of normal plant operating pressures; plant operating pressures should be optimised based on other factors, but there is a clear advantage to higher pressures for blending purposes.

Natural gas injected to the grid must be delivered at 1-20°C. The hydrogen stream should also be introduced at 1-20°C, to ensure consistency with gas in the grid.

3.3.4 CO₂ for storage

At present, producers of biomethane can sell co-produced CO₂ for use in industry. The total market for this exceeds 500ktpa. A typical BioSNG plant will produce 65ktpa of CO₂; therefore it is assumed that by the time Biohydrogen is deployed in the early 2020s, the

market for CO₂ reuse will be saturated. If not sold for reuse, CO₂ will be either emitted or stored.

Storage of CO₂ greatly enhances the environmental benefits of Biohydrogen. The specification for stored CO₂ is covered by ISO 27913:2016. The specification was chosen both to preserve pipeline integrity and to prevent damage to CO₂ stores, and took into account thermodynamic properties, corrosion, and consequences of leakage, among others. Several of the relevant areas are the subject of ongoing research and so the standard presented represents the current best understanding. Table 10 shows the ISO specification.

Species	Specification	
	Level	Notes
CO ₂	>95%	Compliant with OSPAR and London Convention, 2007
H ₂ O	≤50ppmv	Minimises potential for inter-species reactions
H ₂	<1%	Total non-condensable content to be <4%
N ₂	<2%	
Ar	Not specified	
CH ₄	Not specified	
CO	≤0.2%	
O ₂	≤10ppmv	
H ₂ S	<200ppmv	
SO ₂	≤50ppmv	
NO ₂	≤50ppmv	
C ₂ +	<2.5%	

Table 10: CO₂ specification for storage from ISO27913, Annexe A, Table A1

Looking at the specification, items such as hydrogen and nitrogen may be challenging to meet with certain CO₂ separation technologies, which necessarily informs technology choice; some technologies would require an additional upgrading step for captured CO₂, giving rise to a further outlet stream.

Transport of CO₂ takes place at high pressures (>85 bar); therefore capture processes that produce pressurised CO₂ may be advantageous.

3.4 Summary plant specification

This chapter has set out the case for hydrogen use in transport, industry and the gas grid, and concluded that commercial Biohydrogen plants should be designed based on grid blending of hydrogen at levels up to 20%. The specification for such a plant is summarised below.

3.4.1 Scale and feedstock

The reference plant will produce 1.25 te/hr hydrogen, approximately equivalent to 50MW on an HHV basis. The plant will be fuelled by RDF; approximately 100,000 tonnes per annum will be required for the scale of plant considered. A hybrid plant that can produce various blends of BioSNG and hydrogen has also been considered.

3.4.2 Gas specifications

3.4.2.1 Hydrogen stream

The specification for the hydrogen stream is driven by the requirements of blending with natural gas in the grid. For the remainder of this report this specification is referred to as “grid-quality”, and is expected to be suitable for grid blending, grid conversion and supply to industry. Table 11 summarises the specification.

Property	Unit	Range	Comment
Hydrogen sulphide (H ₂ S)	mg/m ³	< 5	3.3 ppm by volume
Total sulphur (S)	mg/m ³	< 50	Typically <15 ppm by volume
Non-combustibles (including CO ₂ , N ₂ , O ₂)	mol%	< 2.0	
Total oxygen (O ₂)	mol%	<1.0	
Contaminants	Shall not contain solid or liquid material that may interfere with the integrity or operation of pipes or gas appliance		
Organo halides	mg/m ³	<1.5	
Carbon monoxide	ppmv	<100	
Radioactivity	Becquerel/g	< 5	
Odour	Gas shall be odorised as required when injected into grids below 7barg		
Pressure	Up to 7 barg		
Delivery temperature	°C	1-20	

Table 11: Summary specification for the hydrogen stream

The specification does not place a limit on methane content.

The reference plant will also be capable of producing small quantities of hydrogen (80kg/h) at transport quality (following the specification in Section 3.3.1).

3.4.2.2 CO₂ stream

The quality of the CO₂ stream should be as detailed in Table 10 of Section 3.3.4. This will ensure that it can be introduced to existing storage networks.

4.0 DEMONSTRATION OF HYDROGEN PRODUCTION

This chapter reports the results of experimental work and of demonstration of Biohydrogen production at pilot scale.

The specific objectives of the work were:

- To characterise potential catalysts for the process, understanding performance and optimal operating conditions for conversion of waste-derived syngas,
- To show that residual CO levels in the product can be reduced to near zero in order to eliminate the possibility of injecting CO into the gas network on account of its known toxic potential,
- To demonstrate production of Biohydrogen at scale, including the processing required to utilise such a low-grade fuel with sensitive catalysts,
- To provide from the foregoing an analytical basis for the definition of a full-scale process.

In pursuit of these objectives practical investigations and demonstrations were undertaken utilising existing assets from the earlier small-scale BioSNG plant developed by the project partners at Swindon. These comprise a laboratory-scale “offline test rig” and a 50kW³⁰ process facility which replicates all of the system elements that would constitute the production train in a commercial-scale plant. During the course of the test programme it became clear that shift reactions alone would not be sufficient to remove CO to the levels required and so the programme was expanded to investigate methanation as a solution to this problem.

The first element of the work used the offline rig to establish the performance and optimal operating conditions of HTS, LTS and high-activity methanation catalysts. The work investigated adiabatic and isothermal operation, and showed that the proposed reaction scheme was capable of producing Biohydrogen with very low residual CO contents. Results enabled models to be developed for use in designing a full-scale plant.

The work then progressed to running experiments on the 50kW facility. This work validated the results of the offline programme, achieving CO contents after the LTS stage that were in line with offline results and modelling, and showcased the ability of the technology to produce Biohydrogen from waste. These experiments also provided confidence that the models developed during the offline work were able to predict results at larger scale.

Overall, the experimental programme provided the necessary confidence in the technology to underpin design of a commercial plant.

³⁰ All calorific values are given on a gross basis unless otherwise noted

4.1 Laboratory scale testing

Focussed testing of catalysts on smaller scale experimental facilities has formed a key part of the Biohydrogen experimental programme. Key advantages of working at smaller scale are the tight control over experimental conditions, allowing flux rates, gas compositions, pressures and temperatures to be trialled, and the ability to easily and quickly trial a range of different catalysts and configurations. A suitable offline rig was developed during the BioSNG project and this was reused in the Biohydrogen programme. A full description of the rig is given in Appendix A.1.0.

The catalyst types investigated are given in Table 12 below.

High temperature shift (CT-118HTS)	Fe_2O_3 78-80 wt.%, Cr_2O_3 > 7 wt.%
Low temperature shift	CuO > 36 wt.%, ZnO > 38 wt.%, Al_2O_3 6-10 wt.%
Methanation	Ni 22% wt.%

Table 12: Catalysts used in laboratory-scale testing

The catalysts were chosen as a result of cost saving and universalisation considerations. Furthermore, Fe-Cr and Cu-Zn catalysts are currently the most widely used, not only in the production of hydrogen but also in synthetic ammonia, where various types of syngas from natural gas, coke-oven gas, and refinery gas, etc. are adopted as raw fuel. Consequently, Fe-Cr and Cu-Zn catalysts are expected to be suitable for hydrogen production from cleaned biosyngas.

The water-gas shift reaction (WGS) depends strongly on operational conditions including catalyst type, feeding gas composition, space velocity, temperature, and $\text{H}_2\text{O}/\text{CO}$ ratio; therefore, a proper selection of parameters for achieving efficient WGSR is the most important. To this end, the effects of these parameters and influence of CO_2 content on H_2 production from model and real bio-syngas were evaluated and discussed.

Experimental work established CO conversions and selectivities to hydrogen across the range of conditions and facilitated further development of the kinetics of the process and validation of models. Optimal conditions for Biohydrogen production were established and the results of the work, when combined with Demonstration Plant data, provide confidence in up-scaling from demonstration to commercial scale.

It became clear that residual CO levels following the shift reactors would be too high for a commercial plant to safely export and so the work also verified the ability of a final methanation step to remove CO down to levels below 100ppm.

4.1.1 High temperature shift

4.1.1.1 Objectives

A number of trials involved the preparation and operation of the Offline Rig to examine the characteristics of the high temperature water-gas shift reaction with the aim of

producing a shifted product gas with a carbon monoxide content of below 10% by volume, so as to fit with onward low temperature water-gas shift reaction where low residual carbon monoxide is desired (mainly for the reason of avoiding excessive exotherms).

The system was fed with high purity gas bottles for kinetics determination and, subsequently, with biosyngas taken from the BioSNG gas store.

The work undertaken to deliver on trial objectives is specifically to:

- Identify reaction kinetics and confirm 'fit' with theoretical/published information, and thermodynamic equilibrium,
- Confirm the ability to the high temperature water-gas shift reaction to produce a < 10% by volume carbon monoxide product gas,
- Ascertain optimal performance conditions of the high temperature water-gas shift reaction in terms of temperature, gas composition, gas space hourly velocity (GSHV), etc.

4.1.1.2 Testing performed

The lab-scale rig was operated in the first instance to investigate commercial fixed bed catalysts for high temperature water-gas shift (Run 298). One Fe₂O₃ based catalyst (CT-118HTS) was tested successfully in an undiluted bed. The configuration was chosen to simulate the active band in the HTS-11 vessel of the pilot plant. The experiments were initially carried out under same operation conditions that would be encountered in the pilot plant.

4.1.1.3 Key results

Kinetic assessment

One of the objectives of the run was to confirm the kinetics of the water-gas shift reaction for this system using a high temperature iron oxide (Fe₃O₄) shift catalyst. This was achieved with a suite of tests using various concentrations of carbon monoxide and steam to establish the order of the reaction. Combined with literature data, the final rate equation was established as shown below.

$$r_{CO} = 10^{1.16} \exp\left(\frac{-94 \pm 2}{RT}\right) * p_{CO}^{0.91} * p_{H_2O}^{0.2} * p_{CO_2}^{-0.16} * p_{H_2}^{0.05} \left(1 - \frac{1}{K} \frac{p_{CO_2} p_{H_2}}{p_{CO} p_{H_2O}}\right) \quad (1)$$

Where r is the reaction rate (mol gcat⁻¹ s⁻¹); R is the universal gas constant (kJ mol⁻¹ K⁻¹); T is the reaction temperature (K); K is the equilibrium constant for WGS reaction; and P is the partial pressure of the gas component.

The derived rate equation was compared to experimental data, showing good agreement, with both curves approaching the equilibrium conversion for outlet temperatures above 350°C.

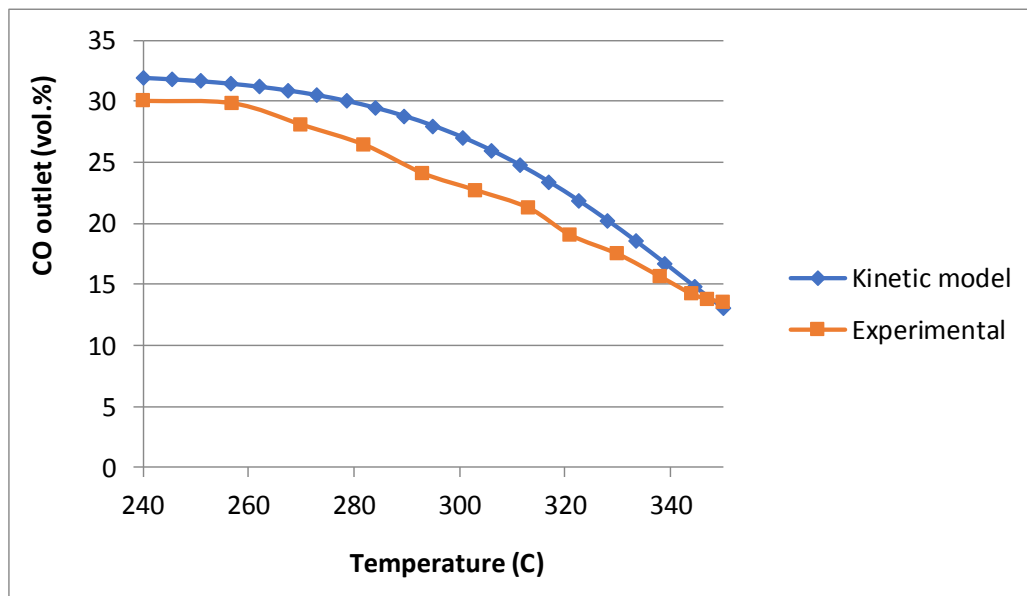


Figure 10: Comparison of derived rate equation with experimental data for the water-gas shift

Optimised conditions

Figure 11 presents thermodynamic and experimental CO conversion between 240 and 350°C for a mixture of syngas and steam ($\text{CO}:\text{CO}_2 = 1.9$, $\text{CO}:\text{steam} = 1$). From the figure, it can be observed that increasing the reaction temperature resulted in decreasing thermodynamic CO conversion and, therefore, H_2 yield. The reason is that the WGS reaction is a mild exothermic reaction and, therefore, is thermodynamically favoured at low temperature. However, experimental evidence shows that the reaction is kinetically limited on this catalyst for temperatures below 350°C. In order to achieve high CO conversion is then preferable to operate the reactor at a temperature between 300 and 350°C.

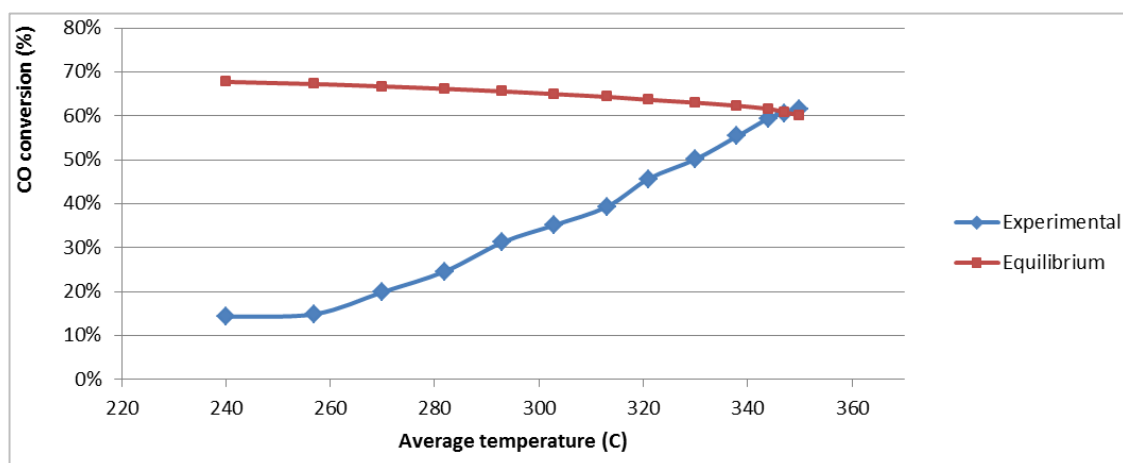


Figure 11: Equilibrium and experimental CO conversion of the WGS reaction at atmospheric pressure, at temperatures of 240-370°C, and at CO/steam molar ratios of 1:1.

Tests on syngas

A series of tests have been conducted at fixed flows of syngas and nitrogen diluent. To this mixture a variable water flow was added.

A broad range of conditions were tried using syngas as the source gas, but the lowest product gas CO content achieved was around 8% by volume, with conversions of CO of 50-60% at 340°C. Such performance was found even with great excesses of water vapour present.

Such conversion figures are consistent with equilibrium considerations (see Figure 11) and model predictions (see Figure 10) for this catalyst type.

As such, it appears that attainment of <8% CO in the HT-WGS product gas may be unachievable with this catalyst type-reactor configuration.

4.1.1.4 Conclusions

At 350°C and a CO/Steam ratio of 1:1, the catalyst was very active, with CO conversion of 62% (v/v), and H₂ selectivity > 99% (i.e. very little methane being produced). At the same conditions the equilibrium CO conversion is 64%.

The kinetics of the high temperature water-gas shift (WGS) reaction over CT-118HTS are described well by a power-law rate equation with six parameters (i.e., pre-exponential factor, activation energy, and reaction orders with respect to both products and reactants). The role of the reverse WGS reaction is expressed by the presence of the equilibrium constant in the reaction rate formula. The kinetic data showed that increasing H₂O concentration had a slight positive effect on the WGS reaction rate.

The experiments have shown carbon monoxide conversions being in line with thermodynamic equilibrium at steady-state conditions.

From the experimental results and modelled predictions it is possible to define the conditions for achieving low carbon monoxide concentrations in the HT-WGS product gas. These conditions should be:

- Carbon monoxide inlet concentrations of between 15-20% by volume (wet),
- High steam addition rates of greater than 0.75x the syngas flow (dry),
- Inlet temperatures of 320-330°C, outlet temperature lower than 360°C,
- GSHV <10000h⁻¹.

4.1.2 Low temperature shift

4.1.2.1 Objectives

Subsequently, the offline rig was operated to investigate commercial fixed bed catalysts for low temperature water-gas shift. Two CuO/ZnO based catalysts were tested successfully in two undiluted beds of different dimensions. The configuration was chosen to simulate the active band in the LTS reactors of the pilot plant. The experiments were initially carried out under same operation conditions that would be encountered in the pilot plant.

Similarly to the high temperature shift, the low temperature shift (LTS) section increases the hydrogen yield of the process by driving the water-gas shift reaction to almost completion. The most recent literature reports that the LTS reactor is better operated at about 200°C inlet temperature and would reduce the CO level from typical inlet levels of 10-12% (dry) to 1-4% (dry) by volume.

The specific objectives of the work were to:

- Identify reaction kinetics and confirm 'fit' with theoretical/published information, and thermodynamic equilibrium,
- Confirm the ability of the low temperature water-gas shift reaction to produce a < 4% by volume carbon monoxide product gas,
- Ascertain optimal performance conditions of the low temperature water-gas shift reaction in terms of temperature, gas composition, GSHV, etc.,
- Investigate operation of the reaction in isothermal configuration.

4.1.2.2 Testing performed

LTS tests were performed in Run 297 with two similar catalysts. CT-4180 and CT-4188 are Alumina modified Copper-Zinc Oxide pelleted catalysts used in the removal of low levels of CO in H₂ and synthesis gas streams by the low temperature (170-250°C) reaction of CO with steam.

These types of catalyst require careful reduction in sulphide and chloride free H₂ to activate. Since the reduction reaction is exothermic the catalyst should be exposed to the process stream at temperatures of 180-230°C; higher temperatures will lead to sintering of the catalyst. The control of the reduction process will affect the LTS activity of the fully reduced catalyst as the objective is to maximise the Cu dispersion and minimise the Cu crystallite size; this can be difficult in a small-scale test reactor cell as the control is not as good as in a large reactor charge.

	CT-4180	CT-4188
Surface area, m ² /g	> 120	> 100
Pore volume, ml/g	0.3	0.33
Bulk density, kg/l	1.3-1.6	1.2-1.5
Nominal size, mm	3	5 x 3
Promoters	Zn/Cu/Al	Zn/Cu/Al
CuO:ZnO	1:1.2	1:1.4

Table 13: LTS catalysts characterization

4.1.2.3 Key results

Kinetic assessment

To find the most accurate rate expression for the water-gas shift reaction at lower temperatures a simplified form of E.1 was used, where both orders of reaction for CO and H₂O were considered equal to 1. The equation was selected to fit the experimental data of the data sets shown in Figure 12 and Figure 13.

The best fitting was provided by the following equation:

$$r_{CO} = 3.01 \times 10^5 \exp \frac{-52.125}{RT} * p_{CO} * p_{H_2O} * \left(1 - \frac{1}{K} \frac{p_{CO_2} p_{H_2}}{p_{CO} p_{H_2O}}\right) \quad (2)$$

where the reaction rate of CO is expressed in (mol vol.cat⁻¹ h⁻¹), R gas constant (J/mol K), T temperature (K), and pressure in atmospheres.

Optimised conditions

Figure 12 shows experimental measurements of carbon monoxide conversion versus H₂O/CO ratio over the temperature range of 170–230°C. As expected, the conversion of CO increases with increasing H₂O/CO ratio at constant temperature. For example, a 1:1 molar feed ratio and 220°C, the conversion reaches 70%. The equilibrium conversion for these conditions is calculated as 87%. For approximately an equal-molar H₂O and CO mixture, the effect of space velocity was investigated (Figure 13). The isotherm in this figure shows that as expected the conversion of the WGS reaction decreases slowly with increasing space velocity.

Further insights were gained during testing of the larger rig (below).

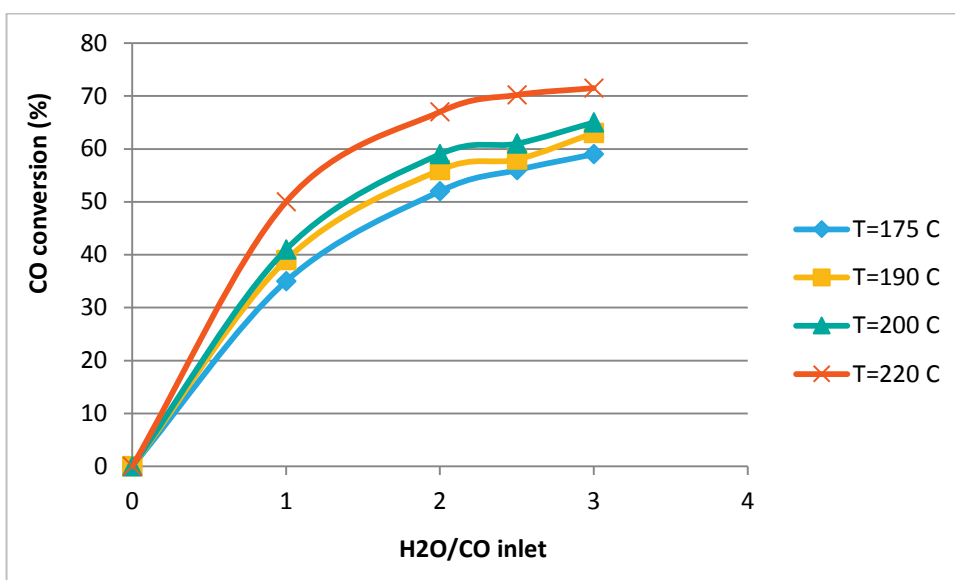


Figure 12: CO conversion vs. H₂O/CO ratio (reaction temperature: 175–220°C; pressure: 1 barg; GHSV: 8100 h⁻¹)

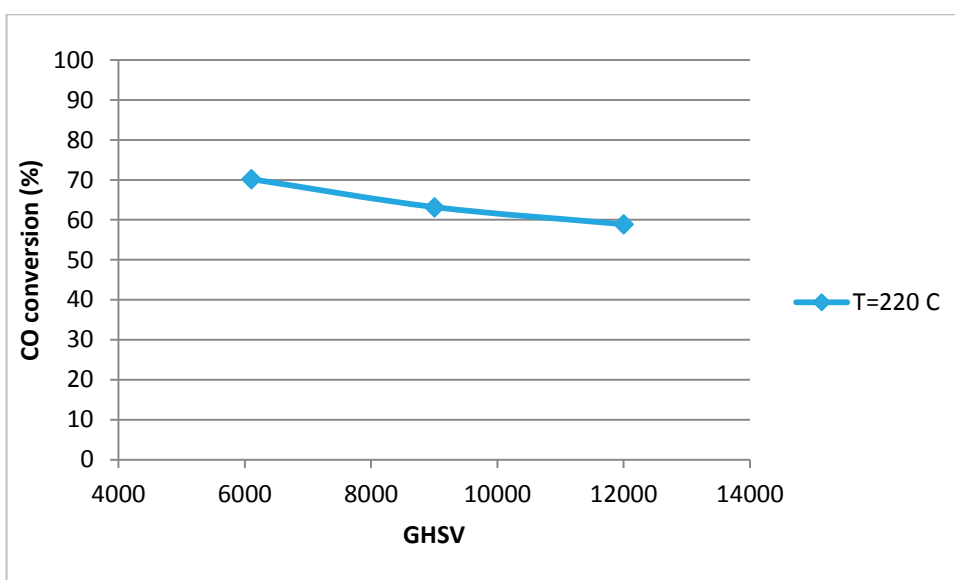


Figure 13: CO conversion as a function of space velocity (reaction temperature: 220 °C;

Larger rig (isothermal) operation

In order to validate the model obtained on the small rig, a further test was undertaken on a larger rig using twice the amount of catalyst. This included both catalyst samples and was arranged in a ~ 4cm thick layer located at the centre of the reactor. The rest of the volume was filled with inert material, as shown in Figure 14.

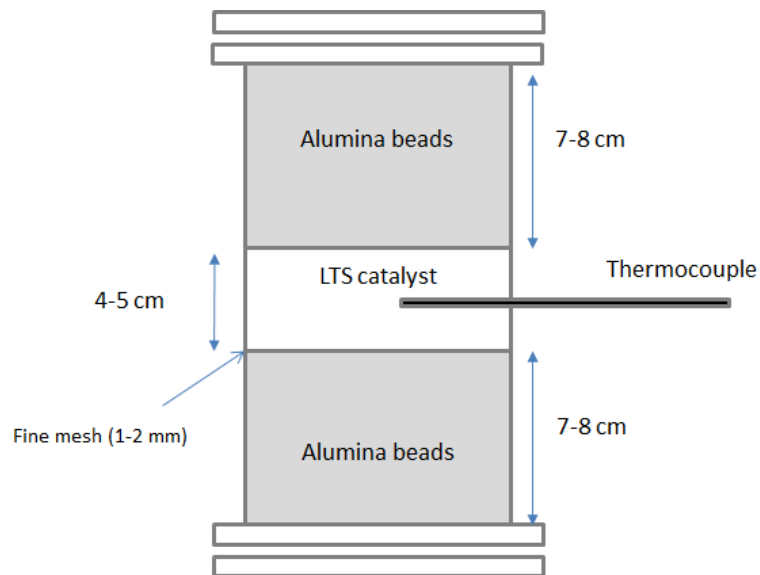


Figure 14: Large vessel and catalyst configuration schematic

The whole vessel was surrounded by tracing heaters which allowed an independent control of temperature.

Figure 15 shows the comparison between experimental data obtained in the large rig utilising real syngas and model results. The agreement between experimental and model results is fairly good, with the model underestimating CO conversion by approximately 10% at higher temperatures. This might be due to slightly different composition of the catalytic bed which includes two different Cu based catalysts. However, a good prediction at high temperature could be provided by an equilibrium model.

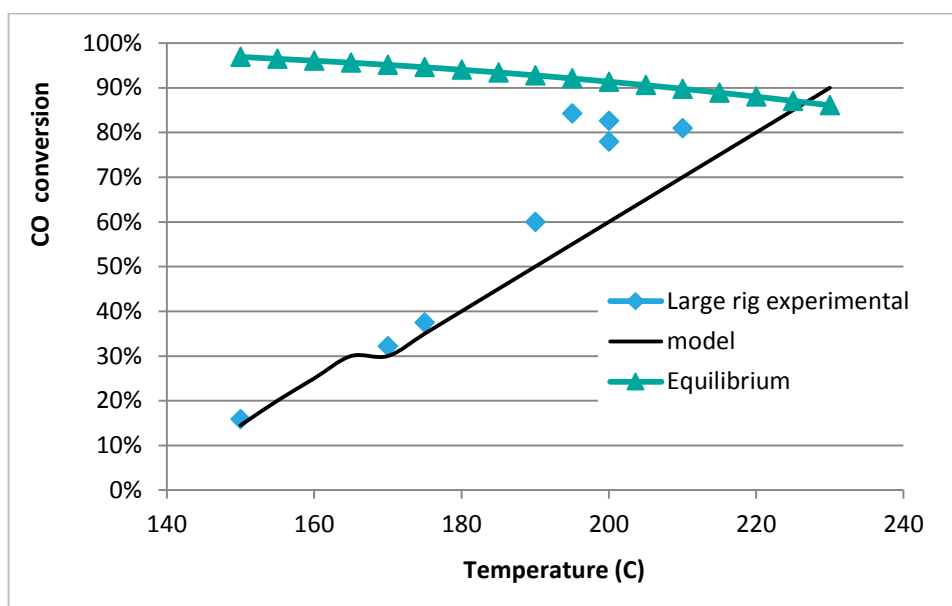


Figure 15: Large vessel experimental, kinetic model and equilibrium data comparison

Different steam to CO ratios were also tested with results in line with equilibrium predictions (Figure 16). When $\text{H}_2\text{O}/\text{CO}$ was increased from 1.4 to 2.2 a decrease in residual CO was observed, indicating that a slight excess amount of water helps in pushing the reaction towards the final products. However the performance of WGS reaction is insensitive to variations in ratio if $\text{H}_2\text{O}:\text{CO}$ is greater than 3, as this would cause pore saturation.

Excessive steam feeding the WGS reaction has two beneficial effects: it increases equilibrium conversion and disfavours coke formation. It is concluded, therefore, that for the examined catalysts the most appropriate reaction condition is a $\text{H}_2\text{O}:\text{CO}$ molar ratio of approximately 2.

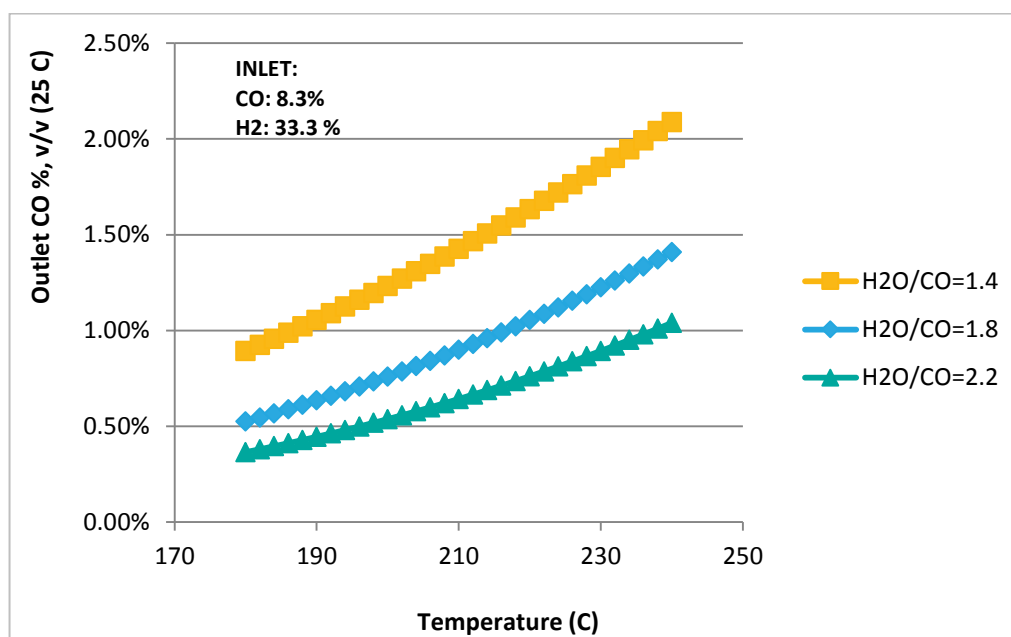


Figure 16: CO outlet concentration (wet at 25°C) for different H₂O/CO ratio

4.1.2.4 Test on syngas

Figure 17 shows the concentration of the reactive WGS species (CO and CO₂) in the large vessel during operation on waste-derived syngas.

Inlet composition was adjusted to replicate the conditions that would be observed in the real plant after the high temperature shift on a Fe₂O₃ based catalyst (Table 14: Inlet gas properties). In particular, CO₂ and H₂ fractions were enhanced to achieve a residual CO concentration of approximately 9-10% by volume, in line with previous tests with the HTS catalysts.

	Syngas (vol.%)	Bottles (Nlph)	Inlet concentration (vol.% dry)
H ₂	33.1	200	45.9
CO	33.0		9.3
CO ₂	30.2	200	44.5
Others (N ₂ , CH ₄ ...)	3.7		-
TOTAL	100.00	-	100
TOTAL flowrate (Nlph)	150	400	

Table 14: Inlet gas properties

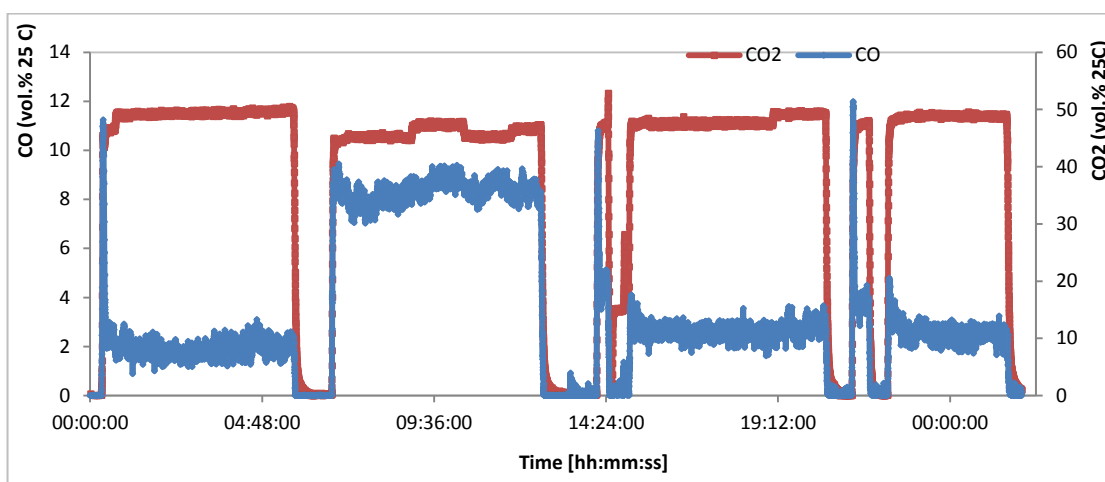


Figure 17: Overall trend of CO/CO₂ reacting during the run on the large rig operated on syngas

Except for the second day, when a water pump failure led to an insufficient water supply, the catalytic bed showed a consistent activity during the days of operation, with an average of 72% CO conversion. The average bed temperature throughout was maintained consistently between 230 and 240°C. At this temperature a good agreement between experimental and model predicted data was found, with both curves approaching the equilibrium value of 2.1 % of residual CO. When excess steam was added to the system (steam:CO = 2), lower peaks of CO at 1-1.5% could be observed.

No catalyst deactivation could be observed during the four days of continuous operation.

4.1.2.5 Conclusions

The dedicated experiments on the offline rig have shown that CuO-ZnO catalysts are very active for water-gas shift. This is better conducted at rather low temperatures to preserve the integrity of the catalyst and favour reaction towards completion.

The experiments showed carbon monoxide conversions being in line with thermodynamic equilibrium at steady-state conditions if temperature is maintained above 230°C.

Similarly to the high temperature shift, the low temperature shift (LTS) section increases the hydrogen yield of the process by driving the water-gas shift reaction almost to completion. The LTS reactor is better operated at about 200°C inlet temperature and would reduce the CO level from typical inlet levels of 9-10% (dry) to 1-3% (dry) by volume. Higher conversion could be potentially achieved for lower inlet CO levels.

4.1.3 CO methanation

4.1.3.1 Objectives

A further test (Run 303) was performed to confirm the ability to achieve ppm levels CO on the offline rig at steady state for a prolonged period of time using a very active methanation catalyst in the small vessel. A 22% Ni Catalyst inside the vessel was configured in stratified fashion to aid temperature control. A similar configuration would

be used in the pilot plant (third methanation reactor) when operated for the large-scale demonstration (Section 4.2).

The work undertaken to deliver on trial objectives was specifically:

- Operation of the offline rig vessel (small) on bottled gas (N_2 , CH_4 , CO , CO_2 , H_2) and steam on high-Ni (22%) catalyst.
- Establishment of ideal conditions for total and selective CO conversion.

4.1.3.2 Testing performed

In this test a multi-layer configuration (Figure 18) for the catalyst inside the bed was chosen.

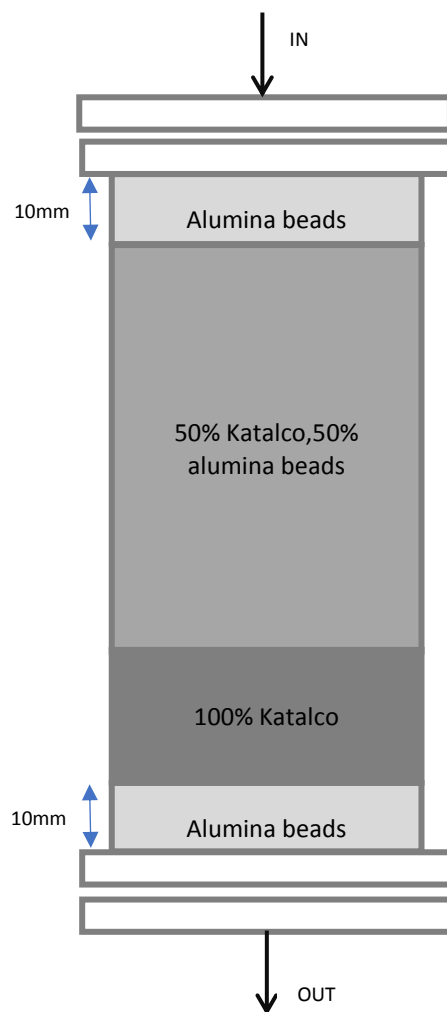


Figure 18: Layout of methanation reactor with sequential axial flow stages

The feed gas enters the top of the reactor and is dispersed homogeneously across the entire bed surface, made initially of inert beads. It then enters a 50% diluted catalytic bed from the top. In this way, the produced gas is not constantly in contact with fresh catalyst, protecting the catalyst from overheating. The final section is a pure catalytic layer for final conversion. This design is particularly suitable for the final methanation stage in which an

isothermal operation at low temperature and full CO conversion are required.

	T _{inlet}	CO ₂	N ₂	H ₂	CO	H ₂ O	CH ₄	Total flow*	Pressure
	°C	Nlph	Nlph	Nlph	Nlph	mlph	Nlph	Nlph	barg
Reduction	350	0	MAX	200	-	-	-		1
	400	0	MAX	200	20	-	-		1
Methanation test	280	200	40	100	35	60	-	375	1
CO polishing test	250	180	200	200	35	60-100		615	1
Reducing T	240	200	40	100	35	60	100	475	1
Calibration	100	200	40	100	35	-	100	475	1

Table 15: Operating conditions

4.1.3.3 Key results

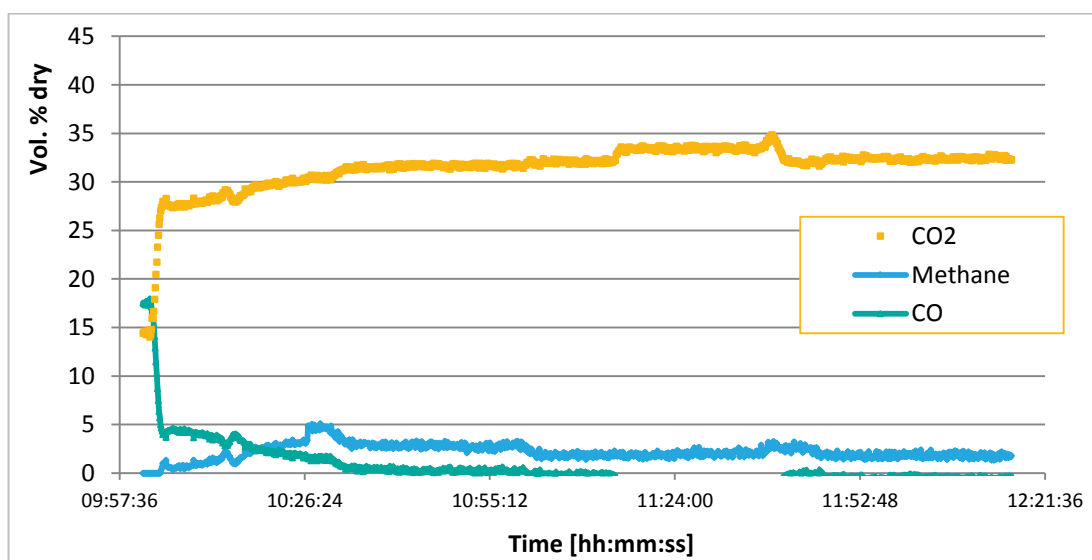


Figure 19: Overall trend of CO/CO₂ reacting during the run

Figure 19 shows the result of a methanation test on a steam containing simulated HTS-LTS shifted syngas (residual CO: 5.2%) under programmed reaction temperatures in the integral-flow reactor. The shifted gas, free of steam at this stage, was fed into the reactor at time 10:05. In about 20 minutes (temperature being 250°C) the outlet CO concentration quickly reached the outlet concentration value of 1.08% by volume, indicating that methanation was taking place.

The symmetrical trends of CO and CH₄ reflected the occurrence of CO methanation as the dominating reaction from 250°C. Notably, CO₂ concentration also increased from 20% to above 34%, indicating that some water-gas shift was still taking place.

At the same time, the change in the temperature profile with time-on-stream in the reactor was stable and in line with expected trends. Temperature profile gradually spread out across the reactor, along with an increase in CO conversion, until reaching equilibrium conditions at ~ 280°C (temperature averaged throughout the reactor) after two hours of operation; very low concentrations of CO were observed in the outlet. At this temperature, the CO methanation selectivity estimated as the molar ratio of removed CO over produced CH₄, is lower, due to the lower residual CO.

If a feed gas with a lower CO was tested, then even lower values of residual CO could be potentially achieved. Such results would be in line with recent publications in the field.

4.1.3.4 Conclusions

Over a 22.5%Ni/Al₂O₃ catalyst it was found that the complete selective CO methanation without CO₂ methanation is possible for hydrogen-rich gases containing CO of up to 5.6% by volume, provided the reaction temperature is controlled at or lower than 250°C. This critical temperature decreased with a decrease in the initial CO content of the gas.

The main conclusions are:

- (a) in any CO–CO₂ coexisting hydrogenous gas the complete methanation of CO is possible provided a low reaction temperature is maintained;
- (b) under a given reaction temperature the CO methanation selectivity (measured as the molar ratio of produced CH₄ over removed CO) is higher at higher inlet CO concentration;
- (c) as CO methanation proceeds, produced steam reacts with residual CO producing more CO₂, possibly due to water-gas shift;
- (d) the desired outlet CO levels below 100 ppm would be achievable under 100% selective CO methanation given that the inlet CO content is appropriately low.

4.1.4 Summary of laboratory scale work

Three reactions were investigated in the course of the experimental work:

- High temperature shift
- Low temperature shift
- CO methanation

For each of these the performance and appropriate reaction conditions for the catalysts were established, and the catalysts were confirmed to be suitable for Biohydrogen production. Kinetic models were developed to assist in future process design.

High temperature shift work showed that close-to-equilibrium CO conversion could be achieved, with 62% observed. CO contents in the outlet stream reached as low as 8%, in line with predictions from modelling.

Experiments on the low temperature shift catalyst obtained conversions in line with thermodynamic equilibrium and achieved CO contents of 1-3% (dry) by volume in the outlet stream. Operating temperatures of around 200°C were found to be suitable.

In order to achieve ppm levels of CO in the product stream, a highly active methanation catalyst was investigated. Very low CO contents were achieved and it was established that the catalyst would be capable of removing residual CO to the levels required.

Work then progressed to demonstration of Biohydrogen production and validation of models on the pilot plant.

4.2 Demonstration of hydrogen production at pilot scale

The next stage of the programme was to demonstrate production of Biohydrogen at larger scale using a repurposed BioSNG pilot plant.

The BioSNG Demonstration Plant Project was a £5M project to demonstrate production of BioSNG from waste and included the construction of a 50kW-scale plant. That plant was capable of gasifying waste, shifting syngas, producing methane and removing CO₂. As an experimental facility the plant was built with sufficient flexibility to allow it to be repurposed for Biohydrogen production, allowing the Biohydrogen technology to be demonstrated at low cost. The use of the existing plant did preclude testing of the low temperature shift catalyst in the isothermal configuration.

A full description of the plant is given in Appendix A.2.0; the plant tests the key process elements of waste gasification, biosyngas clean-up, high and low temperature shift and methanation of residual CO. It was originally intended to also test removal of CO₂ using the existing PSA system. However, through process flow scheme optimisation and detailed discussions with the PSA supplier it became clear that a commercial plant flow scheme would use a different separation technology. In light of this, and exacerbated by scheduling challenges with the supplier, this element of the test was not undertaken.

Experiments on this plant successfully validated the results of the offline testing programme, achieving CO concentrations after the LTS that were in line with those tests, providing confidence that the models are suitable for larger-scale operation, and demonstrating that Biohydrogen can be produced from waste at scale.

4.2.1 Objectives

The objective of this work was to demonstrate full-chain operation of the Demonstration Plant, specifically:

- Verify conclusions of offline testing at larger scale,
- Demonstrate Biohydrogen production from waste,
- Confirm operation of multi-stage water-gas shift and methanation on syngas taken from the Biohydrogen gas store for full CO conversion.

4.2.2 Testing performed

The work was performed during Run 301 using syngas generated during Run 274.

Figure 20 shows the gas flow through the plant during operation; stored, waste-derived syngas was polished and sent through two high temperature shift reactors followed by two low temperature shift reactors and a final methanator. This allowed the kinetic models for both the HTS and LTS reactions to be validated.

Because of the small-scale of the plant and the way it was constructed, heat losses necessitated the use of electric blankets to ensure components were at sufficient temperature. This will not be necessary on commercial plants.

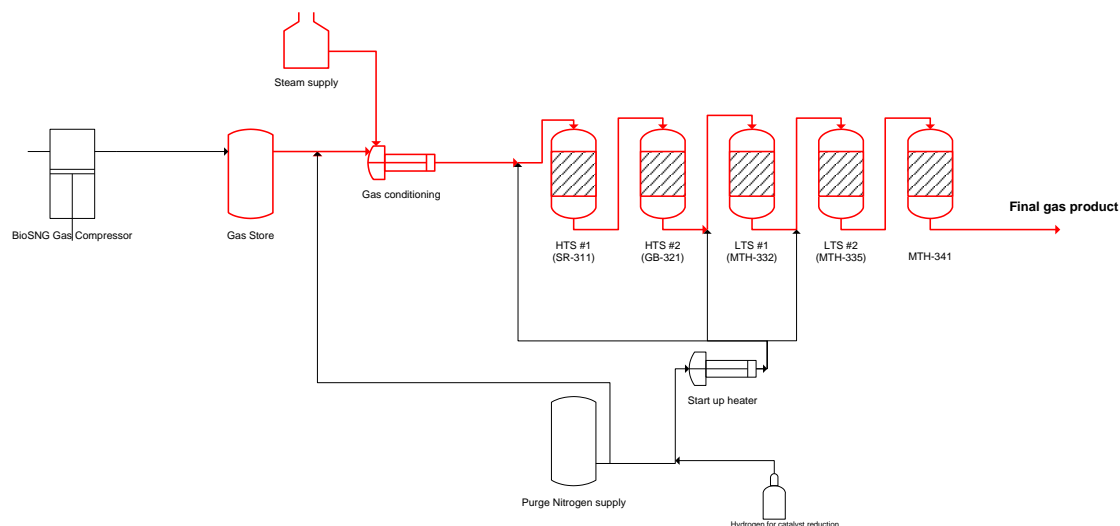


Figure 20: Plant configuration for operations (gas path shown in red)

4.2.3 Key results

4.2.3.1 Operation of high temperature water-gas shift

During the trial syngas was taken from the gas store and was fed to the reaction train. Prior to entry to the high temperature water-gas shift reactor controlled flows of steam (generated from an auxiliary boiler) were added to the gas. This combined syngas-steam mixture was then heated and passed to the reaction train. The steam flow was varied to maximise CO conversion.

Average inlet and outlet streams for the high temperature shift are given in Table 16. The inlet stream is given prior to steam addition.

Component	H ₂	CO	CO ₂	CH ₄	N ₂	H ₂ O ³¹
Units	vol%	vol%	vol%	vol%	vol%	vol%
Inlet from gas store	32.0%	31.9%	29.2%	3.2%	3.6%	0.0%
Outlet	37.8%	13.5%	35.6%	2.3%	3.3%	7.5%

Table 16: Average gas compositions into and out of HTS

Temperatures across the reactor are shown below in Figure 21, and show the mildly exothermic reaction across the reactor, with the outlet temperature slightly higher than the inlet condition. There is no evidence of change in system temperature throughout the trial. The measured exotherm across the reactor was -40.3 kJ/mol, very close to the published figure of -41.1 kJ/mol.

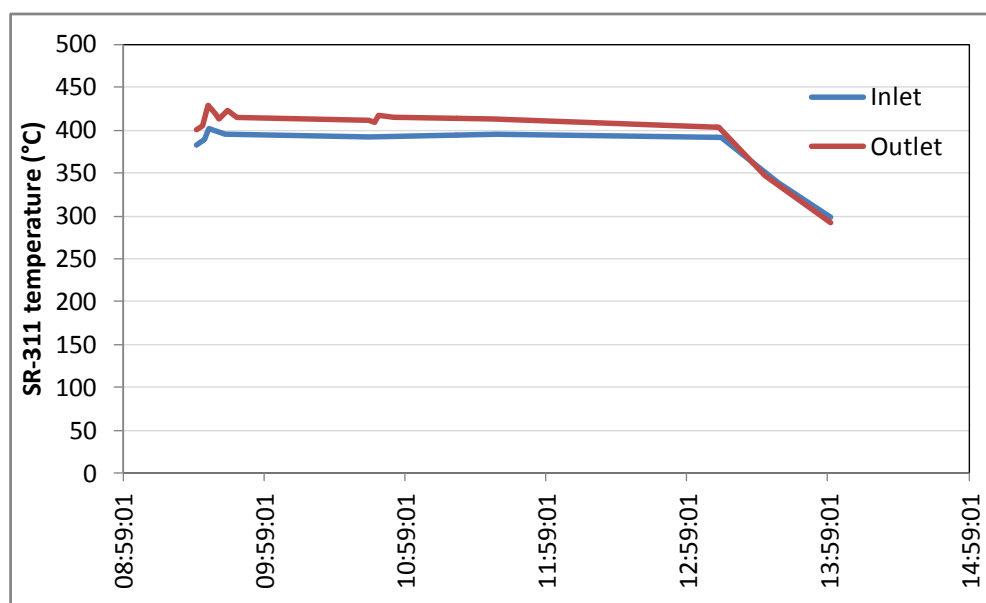


Figure 21: Temperatures in the high temperature water-gas shift reactor (SR-311)

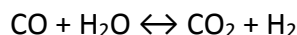
While the inlet syngas condition is approximately 1:1, the outlet condition was strongly influenced by steam availability and syngas flow. Higher steam flows were seen to promote higher hydrogen production. The syngas flow rate had a lesser influence but, nevertheless, high flows reduced hydrogen production.

CO conversion across the reactor was 25-50%. This was some 20% lower than expected, mainly due the higher temperature regime at which the reactors were operated.

³¹ H₂O values in this section are estimated only.

4.2.3.2 Operation of low temperature water-gas shift

The low temperature water-gas shift is governed by the same exothermic reaction pathway as the HTS:



During the trial, partially shifted syngas from the outlet of the HTS reactor entered the LTS reactor. Inlet and outlet compositions are given in Table 17.

Component	H ₂	CO	CO ₂	CH ₄	N ₂	H ₂ O
Units	vol%	vol%	vol%	vol%	vol%	vol%
Inlet	37.8%	13.5%	35.6%	2.3%	3.3%	7.5%
Outlet	41.3%	2.6%	50.1%	2.3%	3.2%	0.5%

Table 17: Average gas compositions into and out of LTS

Temperature rises of as much as 40°C were observed in the reactor, directly in line with published literature and models. In steady-state operation CO concentrations of between 2-4% were achieved, as shown in Figure 22. This value is well in line with predictions and offline rig works.

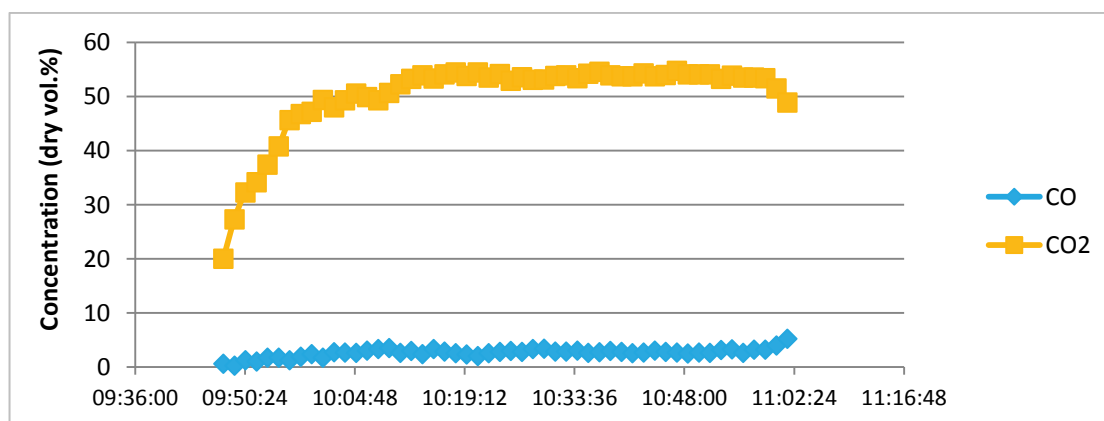


Figure 22: CO and CO₂ concentration in the low temperature water-gas shift reactor (MTH-332)

4.2.3.3 Operation of post-low temperature shift methanation

At the time of testing only 12% Ni w/w catalyst was available in sufficient quantities for use on the pilot plant. This catalyst required an operating temperature of ~330°C to light off the methanation reaction pathway, which was not achieved. The outlet temperature of the methanation reactor peaked at 250°C which would have been sufficient for the more active catalyst identified during laboratory scale testing. Methanation at significantly higher temperatures risks the reverse water-gas shift reaction.

4.2.4 Conclusions

Table 18 contains a summary of the gas compositions generated throughout the process.

Total CO conversion was 92.1% through both HTS and LTS reactors, with the HTS achieving, on occasions, 59%. H₂/CO molar ratio increased from 1:1 in the syngas from the gas store, to 2.8:1 in the HTS to a final 15.9:1 in LTS product gas.

The LTS reactor achieved CO concentrations of 2.6%, a value in line with predictions and offline rig works. To achieve lower CO concentrations a more active methanation catalyst that is active at low temperatures (~250°C) would be needed, as demonstrated in laboratory scale testing (Section 4.1.3).

The work confirms that the sensitive LTS catalyst is operating as expected on waste-derived syngas in the pilot plant and provides confidence that the proposed production configuration is viable.

Component	H ₂	CO	CO ₂	CH ₄	N ₂	H ₂ O
Units	vol%	vol%	vol%	vol%	vol%	vol%
Gas store	32.0%	31.9%	29.2%	3.2%	3.6%	0.0%
HTS product gas	37.8%	13.5%	35.6%	2.3%	3.3%	7.5%
LTS product gas	41.3%	2.6%	50.1%	2.3%	3.2%	0.5%
Methanator product gas	41.3%	2.6%	50.1%	2.3%	3.2%	0.5%

Table 18: Syngas composition throughout the reactor train

5.0 COMMERCIAL PLANT DEFINITION

This chapter summarises the process design for commercial Biohydrogen plants, developed to meet the Functional Specification described in Chapter 3.0.

A discussion of the key design choices is given, followed by a summary of the proposed Biohydrogen production process for a commercial plant. Possible enhancements of the process are also considered.

The design described here builds on experimental work detailed in the previous chapter and on engagement with technology providers.

Throughout the chapter heating values are given on a gross calorific value unless otherwise specified and “LTS” is used as an abbreviation for “low temperature water-gas shift”.

5.1 Design discussion

The baseline design is for a commercial-scale Biohydrogen plant, producing 360GWh per annum of hydrogen from refuse derived fuel (RDF) or similar biomass-rich feedstock, 23GWh of which would be high-purity hydrogen for use in transport applications.

Production of an optimised design needs to address a number of key design challenges. This discussion details the provisions taken to address these challenges and the reasoning behind them. In doing so it draws out some of the common challenges faced by the industry and the way in which the proposed approach, in particular how the syngas is produced, confers certain advantages when it comes to use of a syngas in a catalytic conversion process.

5.1.1 Syngas generation

The Biohydrogen production approach proposed is a development of the partners’ BioSNG technology, which produces substitute natural gas from RDF. This has been piloted at Swindon and a small scale commercial plant is under construction³². The requirements of the two processes in terms of syngas quality are very similar, being primarily driven by the need to produce a gas low in volatile organic compounds (VOCs), tars, nitrogen and organic sulphur contaminants. Therefore the same technological arguments apply, as set out below.

Indirect gasification

The focus of other work on BioSNG³³ production has focused on utilising indirect gasification technologies. In principle, these offer a significant thermochemical efficiency advantage for BioSNG production, providing a syngas with as much as 15% methane. For Biohydrogen production this is not an advantage. Furthermore the technical challenges relating to syngas quality for catalytic conversion remain. Effectively, these are anaerobic

³²<http://gogreengas.com>

³³ Repotec’s designs for Gobigas, Gussing, ECN’s Milena system, among others

pyrolysis systems, with the methane content simply the gaseous end of a spectrum of complex and condensable hydrocarbons produced, including VOC, sulphur-containing organic species and tars. All of these additional species must be removed.

Removal of the VOCs and tars down to levels suitable for an engine has been demonstrated with gas scrubbing technologies such as Dahlman's Olga system (although there is an efficiency loss inherent in removing combustible carbon species). Achieving levels suitable for sensitive catalysts such as those used for the low temperature shift is, however, a more difficult undertaking.

The organic sulphur species are even more problematic; because these compounds are chemically very unreactive, conventional scrubbing will not remove them. Current experience and published papers show that the organo-sulphur compounds derived from indirect gasification of biomass does indeed present a challenge.

The issues associated with complex organics and organo-sulphur compounds suggest that indirect gasification has significant drawbacks as a technology for producing syngas to be used in Biohydrogen production.

Gasplasma®

The partners sought a gasification technology that produced a syngas free of complex organics and organic sulphur compounds, and settled on APP's Gasplasma® process; APP is now a central member of the development consortium. This process is a combination of two distinct steps.

The first is a true gasification process in which steam and oxygen are used as oxidants in the partial oxidation of the fuel, rather than the anaerobic pyrolysis conditions that characterise indirect gasification processes; accordingly, lower levels of methane and higher hydrocarbons are produced by the fluidised bed gasifier in the Gasplasma® system. The gasifier used is a commercial Outotec fluidised bed gasifier which was selected through extensive due diligence and testing by APP at its pilot plant.

In the second step, the crude syngas produced by the bubbling bed gasifier is exposed to extreme conditions in the separate plasma converter (based on the Tetronics plasma system - operating in more than 80 plasma furnaces internationally). The plasma converter breaks down complex hydrocarbons, including organo-sulphur compounds³⁴, which are reduced to simple chemicals. The syngas stream is then made up of oxides of carbon, hydrogen and simple inorganic contaminants such as hydrogen sulphide and hydrogen chloride which are readily removed with conventional gas scrubbing techniques. In this way the Gasplasma® process addresses the drawbacks of indirect gasification technologies and produces a syngas suitable for use in catalytic processes.

³⁴ 'Reforming of tars and organic sulphur compounds in a plasma-assisted process for waste gasification', Materazzi, Lettieri, Taylor, Chapman, Fuel Processing Technology, 2015

Nitrogen content

The requirement for low levels of inerts such as nitrogen arises from their effect on the calorific value of the product and the expense of removing them later by physical adsorption processes. For the blending of hydrogen into the gas network the requirements differ slightly from those of the BioSNG process, in that higher levels of nitrogen can be tolerated in the syngas without concentrating in the product to the same extent. It is still necessary to use oxygen rather than air as the oxidant but it is possible to accommodate lower purities, potentially as low as 90%, based on the downstream process flow schemes discussed below.

5.1.2 Heat integration and steam system

High overall efficiency is key to the commercial feasibility of the Biohydrogen technology and so it is important that heat is recovered and reused where possible; minimising the heat inputs required is also important.

Two shift configurations were considered, as described in Section 5.1.5; the chosen configuration, isothermal LTS, reduces the levels and grade of steam input required.

The most significant opportunities for heat recovery in the Biohydrogen commercial plants are from the Gasplasma® system, the LTS reaction, and syngas compression. Recovered heat is used to raise steam for the gasifier, the LTS reaction and regeneration of the CO₂-absorption solution. The heat recovery and steam system operate at 200°C, with hydrogen used to produce higher grade steam as required.

A challenging element of the system is heat recovery from the hot syngas leaving the plasma converter, where ash fouling could be a particular concern. However, this element is common with BioSNG technology and so the challenge has already been faced and the effectiveness of the solution will have been well proven before commercial Biohydrogen plants are built.

5.1.3 Syngas contaminant removal

As previously discussed (Section 5.1.1) the Gasplasma® system ensures that VOCs and tars produced during gasification are broken down, as are organo-sulphur compounds. The result is that the remaining contaminants can be removed by a conventional COS hydrolysis unit coupled to acid and alkali scrubbing.

While this produces a gas of sufficient quality for use in a gas engine, with ppm levels of contaminants such as sulphur and chlorine, further treatment is required to reach the low ppb-levels required to ensure low temperature shift catalyst longevity in commercial Biohydrogen plants.

Advice from catalyst suppliers has resulted in the inclusion of a zinc oxide bed to further reduce sulphur levels and additional sacrificial copper-zinc protection which can be provided either in a separate vessel or by oversizing the catalyst bed to mitigate deactivation.

5.1.4 Operating pressure

A key process variable is the operating pressure of the system.

Gasifiers in the relevant size range for waste or biomass fuels operate at near atmospheric pressure. It would be an advantage if pressurised waste or biomass gasifiers could be employed as it would significantly reduce gas compression loads. However, such RDF / biomass gasifiers are not currently commercially available and so receipt of syngas near 1 bar pressure has to be adopted as a given condition for the Biohydrogen process design.

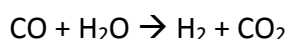
The shift reaction is equimolar, and so, according to Le Chatelier's principle, higher pressure does not affect the reaction equilibrium. Operating pressure is therefore driven by other considerations.

As with all process plants, operation at higher pressures offers advantages in terms of equipment sizes up to a point, but these advantages diminish once pressures are sufficiently high to require thick-walled reactor vessels and significant power consumption in gas compression. For the production of Biohydrogen, a pressure of 10 bar(g) has been selected for the water-gas shift processing train. This is sufficient to achieve a reasonably compact design and also provides gas to the high-purity hydrogen PSA system at an appropriate pressure.

The syngas compressor is placed after the wet scrubbing systems. This ensures that the compression process provides the heating necessary for the syngas prior to the LTS.

5.1.5 Shift reaction

Hydrogen is produced by conversion of the CO in syngas through the water-gas shift reaction:



This is an exothermic equilibrium reaction with hydrogen production favoured by low temperature.

Standard shift catalysts (high temperature shift catalysts, or "HTS" catalysts) operate at temperatures in excess of 300°C, limiting CO conversion and resulting in high CO levels in the product. In order to achieve high levels of CO conversion it is necessary to operate at lower temperatures, using low temperature shift ("LTS") catalysts. This enables shift reaction operation at close to 200°C, improving hydrogen yield.

LTS operation was considered in two configurations: adiabatically following an HTS, or isothermally without a prior HTS. The isothermal configuration has been chosen, both because it achieves better CO conversion and because of the steam system implications; HTS operation would require steam levels significantly in excess of stoichiometric in order to attenuate temperature increase in the HTS and LTS reactors, and at temperatures exceeding 300°C. This would entail use of large quantities of high-grade heat from natural gas or hydrogen, whereas in the isothermal configuration, near-stoichiometric steam levels can be used at 200°C, and the majority of heat loads can be serviced by recovered heat (Section 5.1.2).

5.1.6 CO₂ removal and gas upgrading

There are many commercially deployed techniques for separating CO₂ from process streams with the optimal solution depending on factors such as the required specification of the product stream, required CO₂ purity, and the temperature and pressure conditions of the inlet and outlet streams.

There are two relevant specifications for hydrogen produced by Biohydrogen plants, as explored in detail in Chapter 3.0. These are:

- Hydrogen for use in fuel cells
 - 99.95% purity, with additional restrictions on certain contaminants
- Hydrogen for use in the gas network (after complete switchover to hydrogen), in industry, or blended into the natural gas network (“grid-quality”)
 - < 2% inerts.
 - CO content below 100ppm.
 - Some methane can be accommodated.

Commercial plants anticipated in the context of this investigation would produce both but, owing to the limited market for transport-grade hydrogen, less than 10% of the output would be at transport quality at this stage.

A PSA system is proposed in order to achieve the 99.95% purity required for use in fuel cells. However, this system results in significant slip of Biohydrogen into the tail gas, reducing both product yield and purity of the CO₂ stream. The tail gas can be recirculated back into the main process train when upgrading a small slip stream of high purity hydrogen, but this cannot be done for the whole process stream because the CO₂ must ultimately be removed from the system. SMRs use the tail gas to provide process heat but this quantity of heat is not required for Biohydrogen. For this reason and because the CO₂ is not of sufficient quality for sequestration, PSAs are inappropriate.

Several other separation technologies were considered, including membrane separation, physical solvents and amine systems. However, the optimal solution in this application was found to be a Benfield-type potassium carbonate system because it offers the following advantages:

- High CO₂ recovery
- High CO₂ selectivity
- Low absorption solution regeneration temperatures allowing good heat integration
- Low electrical loads
- Low pressure drop for product stream

As a result, the slip of product into the CO₂ stream is very low, giving good Biohydrogen yields and a captured CO₂ stream at a purity suitable for sequestration.

Following CO₂ removal there will be residual CO in the Biohydrogen stream. At this point a slipstream is taken for high-purity hydrogen production in a PSA (the tail gas is reintroduced to the Biohydrogen plant) with the bulk of the gas proceeding to a methanator with a high-nickel catalyst, where residual CO is converted to methane.

In this way two streams of Biohydrogen are produced, meeting both the fuel cell and grid-quality specifications.

5.1.7 Future developments

During the design work several technology developments were identified that, while not yet available, could improve performance of future plants. These are summarised below, with full details given in Appendix A.3.0.

5.1.7.1 Pressurised gasification

The system operating pressure is a key process variable and, as described in Section 5.1.4, will be 10barg.

Gasifiers in the relevant size range for waste or biomass fuels operate at near atmospheric pressure. Therefore, the syngas produced must be compressed before entering downstream processing, incurring significant electrical load.

If pressurised gasification were employed, only the steam and oxygen would need to be compressed, greatly reducing compression loads. However, such RDF / biomass gasifiers are not currently commercially available and so receipt of syngas near 1 bar pressure has to be adopted as a given condition for the Biohydrogen process design.

5.1.7.2 Selective removal of reaction products (Appendix A.3.0)

The shift reaction is an equilibrium reaction, and so Le Chatelier's Principle applies. According to the principle, such reactions can be affected by temperature and pressure of operation, or by reactant concentrations. Conventional approaches, discussed above, seek to minimise the temperature of operation and therefore increase hydrogen production. An alternative approach is to selectively remove reaction products, thereby promoting the forward reaction. This can be accomplished using absorbents or membranes.

Sorbent enhanced water-gas shift (SEWGS)

The SEWGS process uses a solid absorbent such as calcium oxide to react with CO₂ produced in the shift reaction, continuously removing it from the gas stream as it passes through the vessel. This allows the conversion of carbon monoxide to hydrogen to proceed much further than would normally be the case, even at higher temperatures (350-700°C); hydrogen contents of 99% are reported in the literature, with CO₂ of sufficient purity for sequestration. It has also been suggested that some level of sulphur could be tolerated.

The ability to operate at higher temperatures presents the opportunity to recover high-grade steam for use in power generation or elsewhere in the process and may even remove the need for a catalyst. It also allows near-stoichiometric levels of steam to be used but does present challenges for other system components. The absorption process is itself strongly exothermic (and regeneration therefore endothermic), so effective heat recovery and reuse is key.

While SEWGS offers clear potential advantages in terms of process intensification and efficiency, the technology is at a pre-commercial stage of development. Development work should be monitored closely with a view to considering SEWGS for future Biohydrogen plants.

Membrane reactors

Membrane reactors use a membrane to selectively remove hydrogen from the gas stream, making it possible to achieve high conversion of carbon monoxide even up to 500°C and reducing the requirement for cooling.

Various microporous, dense metallic and dense ceramic membranes are suitable for operation at these temperatures, and techniques such as use of a sweep gas can further improve yield. Conventional Cu- and Fe-based catalysts are not well suited for operation in membrane reactors, and so alternative catalysts are under development.

Water-gas shift membrane reactor research is presently at lab scale but is ready for transition to pilot scale.

As with SEWGS, development of the technology should be monitored closely.

5.1.7.3 Hydrogen-methane hybrid plants

In developing the Functional Specification for commercial Biohydrogen plants a key consideration was the plant scale, which was strongly influenced by the capacity of the local gas grid to blend Biohydrogen. It was determined that, were plants to be capable of switching to production of 90% methane at times of low gas demand, the number of locations at which they could be deployed would greatly increase.

While such plants are not the focus of this project, a conceptual design has been produced. Key characteristics of the hybrid design are:

- Inclusion of a second LTS reactor, allowing some syngas to be diverted for methanation with a CO:H₂ ratio of slightly above 3:1 (i.e. before the second LTS).
- Routing of that stream to two methanation reactors in series (because 10% hydrogen can be accommodated in the product, fewer reactors are required than for BioSNG).
- The methanated stream is routed to the existing Biohydrogen final methanation reactor to remove residual carbon monoxide.
- Some syngas is always routed through both LTS reactors;
 - This can then be sent to the existing high-purity hydrogen PSA so that transport hydrogen is always available.
 - A portion of this gas can be introduced prior to the second methanation reactor to aid process control.

Further details of the design are given in Appendix A.3.2, together with a process flow scheme.

5.2 Process description

This section provides a description of the reference design of a commercial Biohydrogen plant. The plant described produces 3.1MW high-purity Biohydrogen for use in transport and 45.3MW 'grid-quality' hydrogen for use in industry or grid blending. This second stream contains 4% methane by volume.

The plant described here uses an isothermal low temperature shift (LTS). An energy and mass balance has also been produced for a plant that uses an adiabatic high temperature shift (HTS) followed by an adiabatic low temperature shift but the isothermal LTS configuration was preferred.

5.2.1 Facility overview

Biohydrogen facilities can be viewed as comprising three distinct processes:

1. **Fuel Preparation** which is based on reception dried RDF as feedstock for the Gasplasma® process.
2. **Syngas Production** which converts the RDF into a syngas through the Gasplasma® process which includes cooling, cleaning and conditioning of the syngas to be suitable for the LTS catalyst. During the syngas cooling stage, steam is produced from recovered heat for use elsewhere in the process.
3. **Hydrogen production** which processes the cool clean syngas from the Gasplasma® process to synthesise high-purity and 'grid-quality' Biohydrogen. This is achieved by compression and polishing of the syngas to remove catalyst poisons, an isothermal water-gas shift reaction to convert CO in the syngas to Biohydrogen, and a CO₂-removal stage, after which a slip stream enters a pressure-swing adsorber (PSA) and is upgraded to high-purity hydrogen, with the remainder entering a methanation stage to remove residual CO and produce grid-quality hydrogen.

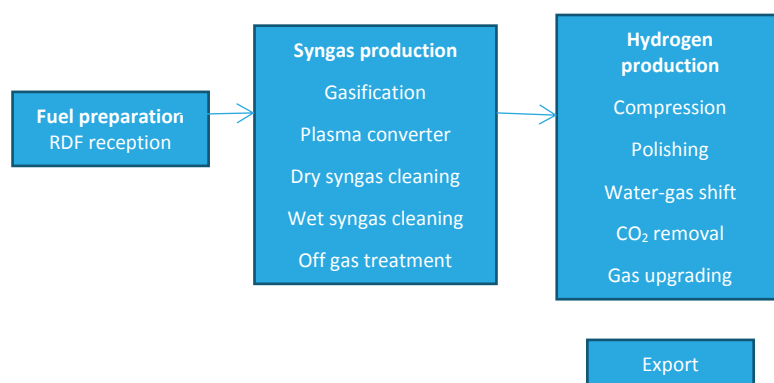


Figure 23: Summary of main Biohydrogen process steps

The first two processes are largely common to the BioSNG technology, and have previously been described in detail elsewhere. However, in order to fully describe the Biohydrogen process, all three steps are detailed below.

Biohydrogen plants will be capable of utilising a range of feedstocks. The most challenging of these is RDF, which is the reference for this commercial plant design.

A detailed set of Sankey diagrams for the process is provided in Appendix A.4.0, and a process flow scheme is given below.

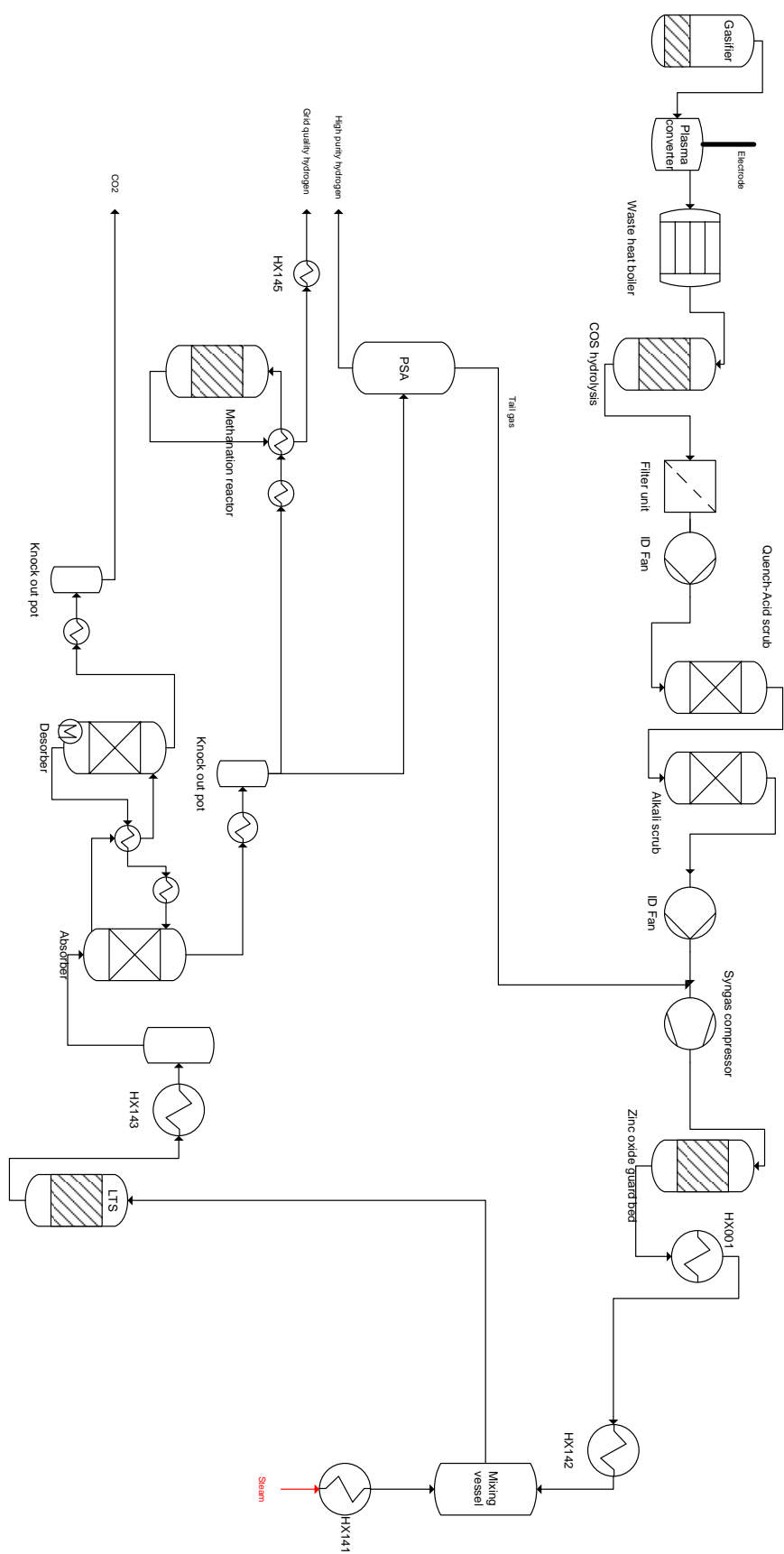


Figure 24: Flow scheme for a commercial Biohydrogen plant

5.2.2 Fuel preparation

RDF reception

The RDF reception area receives deliveries of dry RDF during the agreed operating hours for the facility. The reception area is sized to allow for fluctuations in delivery volumes and will be capable of holding sufficient RDF to feed the gasifier for several days. The RDF is loaded onto a conveyer and delivered to a shredder which ensures that agglomerates are degraded and blended prior to feeding into the process.

5.2.3 Syngas production

The syngas production system operates for 24 hours a day, 7 days per week.

At the heart of the facility is the advanced Gasplasma[®] thermal process that produces a syngas. This is a crude but low-tar syngas which is cooled and refined to remove particulate matter, acid gases and volatile metal vapours. Within the syngas production section of the facility there are six main process groups:

- Fluid bed gasifier
- Plasma converter
- Gas cooling system
- Dry gas cleaning system
- COS hydrolysis
- Wet gas cleaning system

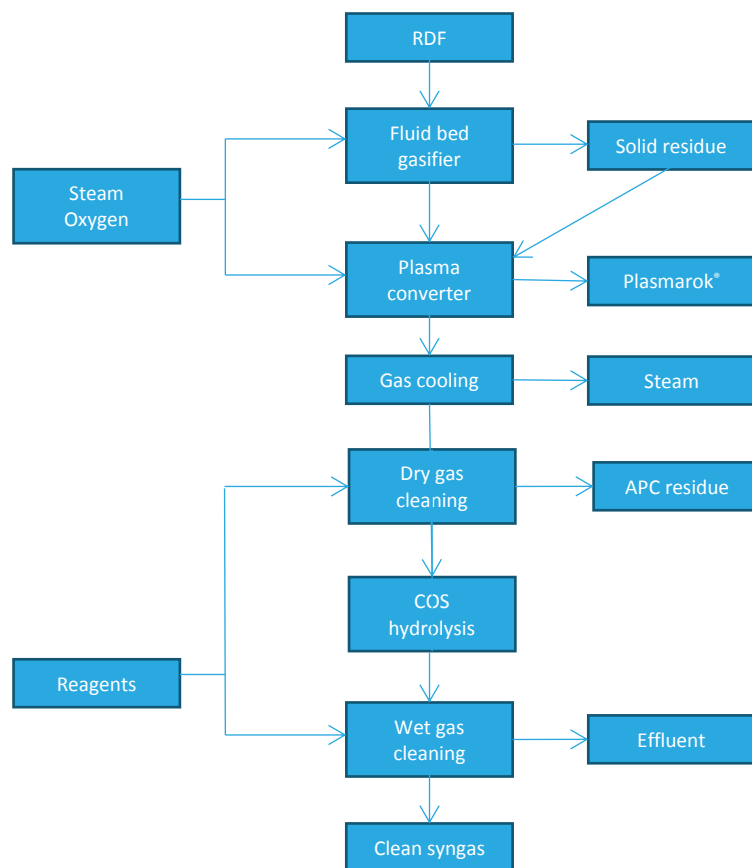


Figure 25: High-level summary of syngas generation process

5.2.3.1 Gasplasma®

Gasification of RDF

RDF is fed into the bubbling fluidised bed gasifier along with steam and oxygen to convert the mixed materials into raw gases. The process conditions are maintained by control of oxygen, steam and RDF feed rate. This process provides sufficient heat to maintain the fluidised bed temperature and produce a “crude syngas”. The syngas contains significant quantities of long chain and cyclic hydrocarbons which would condense as tars and residues if it was allowed to cool.

The ash component of the RDF is automatically removed from the base of the gasifier through the bed screening process and conveyed to a hopper where it is stored before disposal to inert landfill. There are no other residues; chars or ash removed at this stage of the process.

The oxygen used to fluidise the gasifier bed material is produced cryogenically offsite, and is at 99.5% purity in the reference case (future value engineering could reduce this to closer to 90%). The steam used to fluidise the gasifier bed material is generated with heat recovered from cooling the syngas. Both the steam and the oxygen oxidise the fuel.

Plasma conversion of gas

The crude syngas is transferred from the gasifier to the plasma converter via a refractory lined duct in which additional oxygen is injected to raise the gas temperature. In the centre of the plasma converter is a graphite electrode from which a thermal plasma arc is generated. The syngas is exposed to elevated temperatures and intense ultra violet light. The effect is to “crack” and reform the tars and chars contained in the syngas into simpler compounds: hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), and water (H_2O). The Gasplasma® also breaks down sulphur-containing organic compounds, important in this system because the syngas will ultimately pass over catalysts that would be poisoned by such substances if they were present even in ppb quantities in the gas.

The syngas is then drawn via a refractory lined duct to the inlet of the gas cooling system. At all times the gasifier and plasma converter operate at a negative pressure of -5 to -10 mbarg.

The design of the plasma converter is optimised by computerised fluid dynamics (CFD) modelling to obtain maximum residence time for the syngas within the converter whilst allowing time for ash and dust particles to drop out of the gas stream. These particles are incorporated into a molten slag pool which builds up in the base of the converter. This molten material is removed from the plasma converter via an overflow weir and cooled for use as a vitrified and stable material. This material has been approved by the UK Environment Agency as a product and is trademarked under the name Plasmarok®.

5.2.3.2 Gas cooling system

The gas cooling system comprises a water-tube heat recovery boiler designed to reduce syngas temperatures from circa 1,100°C to 160°C and generate saturated steam at 10 bar(g) pressure. This steam joins the medium pressure steam system, steam from which is used in hydrogen generation and CO_2 separation.

5.2.3.3 Dry gas cleaning system

The dry gas cleaning system, operating at 150 to 160°C, removes fine particulate materials from the syngas stream, neutralises acid gases, and removes heavy metal vapours.

The syngas passes to the ceramic particulate filter via an insulated duct into which the reagents sodium bicarbonate and activated carbon are injected. The duct provides sufficient residence time and turbulence to allow good reaction and collection, providing high capture rates for acidic components and volatile metals. Particulate matter, including the by-products from the reagent reactions, is trapped on the ceramic candle filter elements and periodically removed using a carbon dioxide reverse pulse system.

5.2.3.4 COS hydrolysis

From the dry gas cleaning system, the gas flows through an alumina bed at around 160°C, in order to hydrolyse any COS present in the gas to form H_2S . This ensures that the sulphur can be removed by the wet gas cleaning system and does not contaminate downstream catalysts.

5.2.3.5 Wet gas cleaning system

From the dry gas cleaning phase, the syngas is cooled by direct contact with scrubbing liquor in a condenser scrubber. The unit is used to reduce the gas temperature to approximately 45°C. The condenser operates as an acid scrubber, absorbing ammonia. To ensure complete absorption and neutralising of the ammonia the pH is maintained as acidic; sulphuric or nitric acid can be dosed into the scrubber to ensure this.

The gases are passed through a second, alkaline oxidative scrubber to remove acid gases (for example sulphur dioxide and hydrogen chloride) and readily oxidisable gas species (in particular hydrogen sulphide). The hydrogen sulphide is chemically oxidised to produce a stable effluent. The effluent from this scrubber and the condensate from the condenser scrubber are discharged from the system for neutralisation, treatment and discharge to sewer.

5.2.3.6 Hydrogen production from syngas

The hydrogen production process is designed to operate continuously. A flare system allows diversion of gas away from the process when necessary, for example, while syngas is brought up to the required specification during start-up.

The hydrogen production process takes the cool, low-pressure syngas and processes it to produce two Biohydrogen streams: one high-purity and one at 'grid-quality' (see Section 5.1.6).

Hydrogen production from syngas incorporates the following steps:

- Compression
- Syngas polishing
- Low temperature isothermal water-gas shift reaction ("LTS")
- CO₂ removal
- Gas upgrading (by PSA or methanation)
- Export

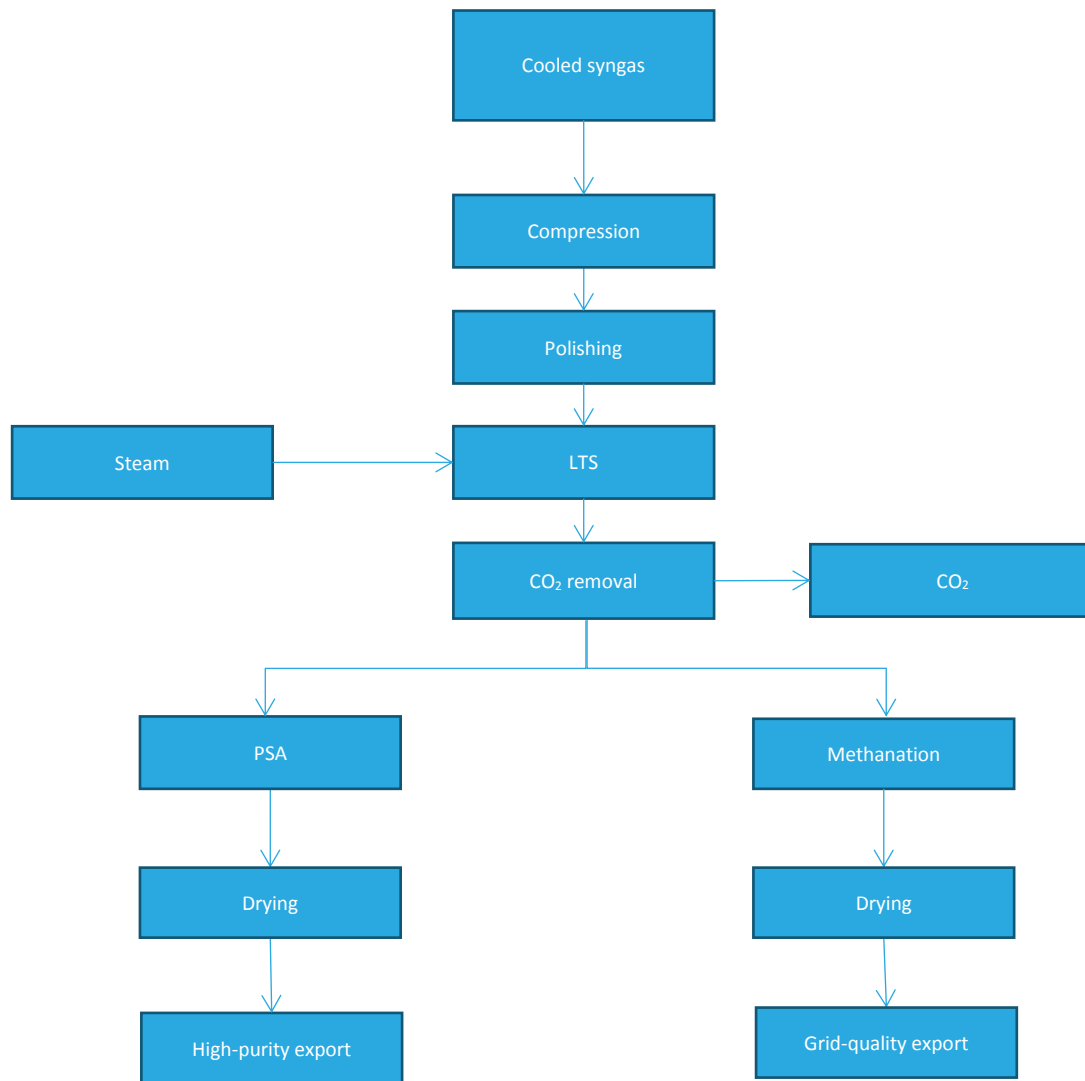


Figure 26: High-level summary of Biohydrogen generation process

5.2.3.7 Compression

First, the syngas is compressed to around 10 bar(g) using a reciprocating compressor. The compression is performed in multiple stages with intercooling, and the gas exits at 300°C.

5.2.3.8 Syngas polishing

Syngas from the compressor is cooled to 120°C and passes through a zinc oxide guard bed which reacts with any remaining H₂S to produce zinc sulphide and water. Residual COS will be hydrolysed in this reactor to form H₂S and removed. The guard bed reduces total sulphur content in the gas stream down to ppb levels in order to meet the LTS catalyst specifications.

5.2.3.9 Water-gas shift reaction

The cleaned syngas is reheated to 200°C and mixed with steam from the medium-pressure steam system at 200°C prior to entering the LTS. As discussed in Section 5.1.5, steam levels are close to stoichiometric and the vessel is operated isothermally.

In the reactor CO and steam are converted into Biohydrogen and CO₂, with the temperature of operation ensuring that high CO conversion is achieved. Heat given off by the reaction is used to raise low pressure steam.

The high hydrogen gas mixture exiting the LTS reactor is cooled and the heat recovered.

5.2.3.10 CO₂ removal

Cooled gas from the LTS reactor passes into a chemical absorption system, using activated potassium carbonate solution as the solvent. The CO₂ in the hydrogen-rich gas reacts with the potassium carbonate in an absorber column to form potassium bicarbonate. The potassium bicarbonate solution then enters a stripper column where heat from the steam system is used to release the CO₂, regenerating the solvent.

This technology achieves high removal efficiency and the captured CO₂ is at a high purity. This captured CO₂ can then be used instead of fossil CO₂ in industry, or sequestered long-term in a carbon capture and storage scheme, resulting in strongly negative overall CO₂ emissions for the process (Section 6.1.3).

5.2.3.11 Gas upgrading and export

The Biohydrogen plant produces two specifications of hydrogen. Following bulk CO₂ removal, the gas passes through a condensate separator and a slipstream of gas is sent to a PSA unit to produce high-quality hydrogen, with the remainder proceeding to a methanator in order to convert residual CO. The size of the slipstream will depend on demand for high-purity hydrogen but is anticipated to be less than 10% of the stream.

High-purity hydrogen

The gas slipstream passes into a PSA unit at 20°C. The pressure in the gas stream is sufficient for the high-pressure stage of the PSA cycle, so no further compression is required. The PSA unit produces two gas streams: a transport-grade hydrogen stream and a tail gas stream consisting primarily of hydrogen but with some species such as carbon monoxide and methane. The tail gas stream is at close to atmospheric pressure and is reintroduced into the process prior to the syngas compressor to ensure that overall yield is not reduced.

The high-purity hydrogen stream experiences a pressure drop of around 1 bar across the PSA. It is not necessary to dry the gas from the PSA in order to meet specifications for export.

The hydrogen is then compressed and stored ready for use in vehicles.

‘Grid-quality’ hydrogen

The bulk of the process gas flows from the condensate separator to a methanator. The methanator contains a high-activity catalyst which requires the process gas to be at around 160-180°C; the gas is heated via a feed/effluent exchanger using heat from the methanator’s outlet stream.

The purpose of the methanator is to react residual CO with hydrogen to produce methane. The high-activity catalyst ensures that CO levels are reduced to below 100ppm. Methane

levels in the hydrogen stream can reach 7%; for grid blending and industrial use this methane content is operationally beneficial.

The gas exits the reactor and is cooled by the inlet stream. It is then necessary to dry the gas from the final methanator in order to meet specifications for export and a standard molecular sieve dehydration unit is used. The unit will have two beds so that one bed can be regenerated while the other adsorbs water, enabling continuous operation. The dried gas flows through a filter to remove any dust that may have been picked up from the desiccant bed.

The gas exits the drier at 35°C, and is suitable for blending with natural gas in the gas grid or for industrial use. The reference case is that the gas is injected into the grid.

5.2.3.12 Water and steam system

There are several points in the process where steam is used, the largest being the steam input to the LTS and the regeneration of the CO₂ solvent. Large quantities of heat can be recovered at various points, particularly from the syngas as it exits the plasma converter and the LTS reactor.

Consumption and production of steam are almost in balance and so careful design of the water and steam system results in around 80% of the required heat being provided by the process. The remainder is provided through firing of Biohydrogen, which also provides superheat where required.

Process condensate is recycled via the deaerator and chemical treatment to be reused in the process, minimising overall water input to the process.

5.2.4 Process model

Full mass and energy balances were produced for both plant configurations, incorporating process models produced during the experimental work described in Chapter 4.0.

The models are most easily understood through the use of Sankey diagrams. The energy-basis Sankey diagram is given as Figure 27, and the mass-basis Sankey diagram is given in Appendix A.4.0.

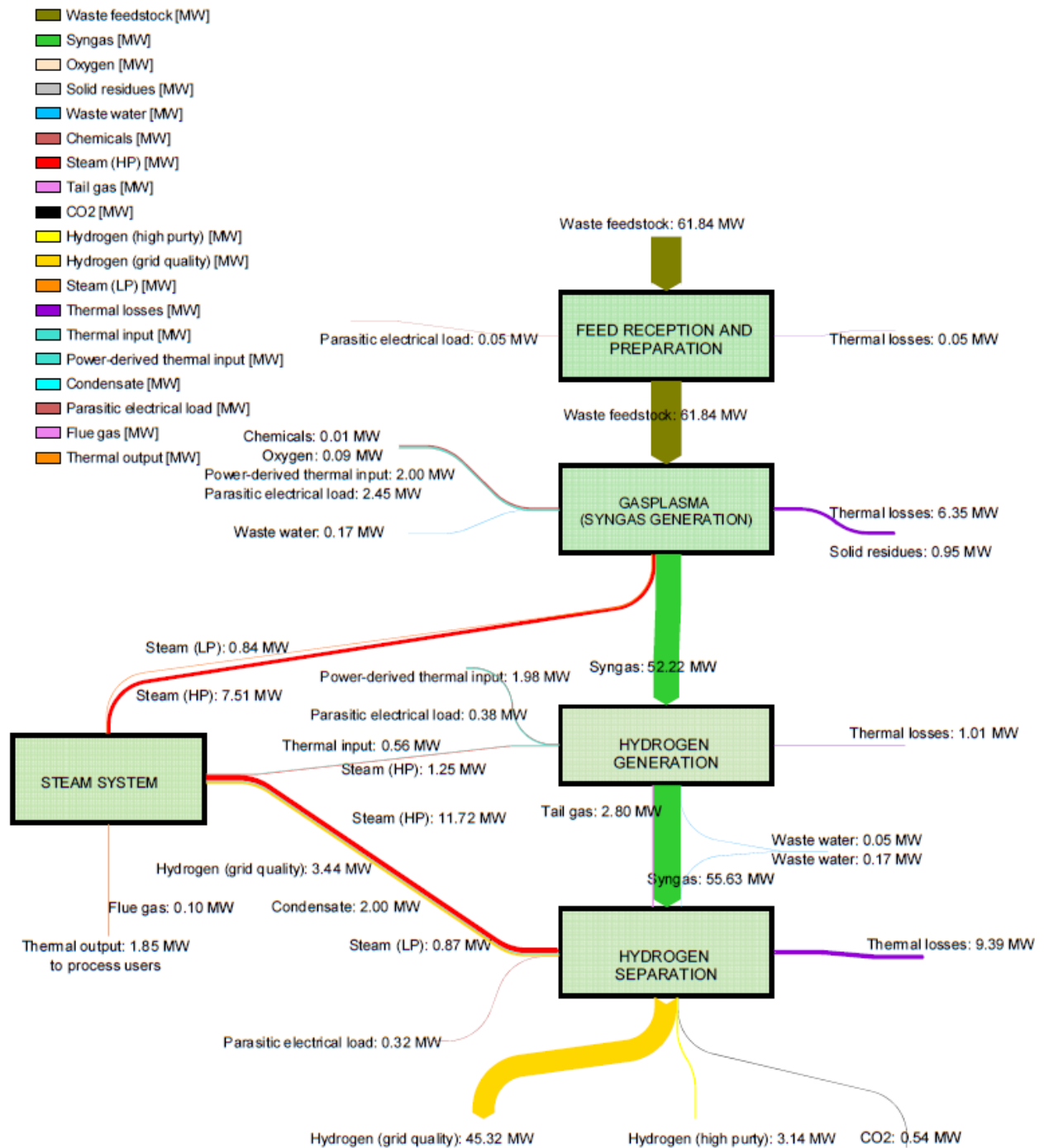


Figure 27: Energy-basis Sankey diagram for Biohydrogen production

The key parameters for the process model are summarised below:

Inputs	Energy basis (HHV)	Mass basis
RDF feedstock	61.84MW	13.4te/h
Power	7.2MW	
External heat	0.0MW	
Outputs		
High-purity hydrogen output	3.1MW	0.08te/h
'Grid-quality' hydrogen output	45.3MW	1.55te/h
CO ₂ output		18.0te/h
Efficiency		
Plant efficiency	70%	
Feedstock to Biohydrogen	78%	

Table 19: Biohydrogen process summary

The efficiency of the process compares well with BioSNG production, where plant efficiencies are closer to 60% and with a feedstock to BioSNG efficiency of 64%. This means that, for a given quantity of available feedstock, materially more Biohydrogen could be produced; the UK could supply sufficient feedstock to produce 100TWh per year of BioSNG, which rises to 123TWh of Biohydrogen.

The quantity of CO₂ captured is significantly higher than from BioSNG, meaning that the environmental benefit of Biohydrogen production is significantly greater where CCS is available. This is explored further in Section 6.1.

The process modelling confirmed the ability of the plant to produce CO₂, high-purity hydrogen and grid-quality hydrogen streams that meet the specifications defined in the Functional Specification.

6.0 ECONOMIC AND GREENHOUSE GAS ANALYSIS

This chapter analyses the economic and greenhouse gas performance of commercial Biohydrogen plants and compares the technology with BioSNG and alternative methods of hydrogen production.

The BioSNG technology³⁵ already offers a route to a low-carbon, fully fungible alternative to natural gas, with sufficient feedstock available for it to make a meaningful contribution to low carbon heat and transport. Meanwhile, steam methane reformation (SMR) provides a route to hydrogen production at scale.

The case for Biohydrogen rests on it offering improvements on these options; if Biohydrogen can offer carbon savings in excess of those possible from BioSNG and a levelised cost of hydrogen that is comparable to or lower than SMR-derived hydrogen, a compelling case for adoption of the technology can be made. Key metrics are the cost per megawatt hour of hydrogen and the cost per tonne of carbon saved.

To this end, an assessment of the carbon emissions associated with the Biohydrogen process has been undertaken. The aim of the modelling was to establish the environmental benefits of Biohydrogen production from waste. The economic analysis then uses the plant design described in Section 5.2 (but with no transport-grade stream) as the basis for an economic model, which generates a levelised cost for Biohydrogen production from a first of a kind plant.

Taking these together, the costs of carbon savings from Biohydrogen production can be quantified and the technology can be evaluated against BioSNG and alternative technologies for hydrogen production.

The assessment shows that Biohydrogen with CCS has a GHG intensity more than 230% lower than fossil gas. Even without CCS, Biohydrogen offers an 82% reduction in emissions. Importantly, it offers the potential for substantially lower emissions than both BioSNG and SMR-derived hydrogen at comparable costs.

6.1 Greenhouse gas analysis

6.1.1 Methodology

The baseline analysis considered a commercial plant producing 360GWh/annum of 'grid-quality' Biohydrogen from dry RDF. This is similar to the facility described in Section 5.2, the only difference being that no transport-grade hydrogen is produced (the impact on greenhouse gas performance of this change is minimal). The plant was considered with and without carbon capture and storage.

³⁵See <http://gogreengas.com/wp-content/uploads/2015/11/BioSNG-170223-1-Project-Close-Out-Report.pdf> for the BioSNG Demonstration Plant project close-down report, or <http://gogreengas.com> for more general information

Any analysis of carbon emissions must be clear about the boundary of the system considered. Three different boundaries are commonly considered, described as Scope 1, 2 and 3:

- Scope 1: Direct emissions produced at the facility, e.g. from burning fuel
- Scope 2: Carbon emissions associated with electricity and heat produced offsite but imported to the facility
- Scope 3: Emissions associated with production and transport of material inputs and product use

Of these, a Scope 3 analysis offers the most comprehensive view of the emissions associated with a process and so that basis has been used as the reference case.

One approach in the renewables industry is to consider emissions derived from biogenic carbon to be zero and fossil-derived carbon emissions to have the GWP of CO₂³⁶. This approach ignores the particular issues associated with a waste feedstock. The key question is what should be taken as the counterfactual. For waste, there is no option to 'do nothing'; it must be disposed of, generally either by incineration or landfill. Therefore, these should be the counterfactuals against which waste-fuelled processes are evaluated.

Incinerators convert the vast majority of fossil and biogenic carbon in the feedstock to CO₂. Taking this as a counterfactual, CO₂ emissions associated with fossil carbon in the feedstock should be discounted because they would have been emitted anyway. When waste is landfilled the biogenic content decomposes and produces methane, a greenhouse gas 23-25 times as damaging as carbon dioxide. Emissions associated with landfill are therefore far greater than those associated with incineration. A conservative approach is to take incineration as the counterfactual and discount all CO₂ emissions arising from carbon in the feedstock; that is the basis for this analysis.

For clarity, the full assessment considered emissions associated with:

- Transport of municipal waste and RDF,
- Production of dry RDF from municipal waste,
- Production of Biohydrogen from RDF (electricity, oxygen, chemicals),
- Separation and capture of CO₂.

The carbon intensity of electricity used in the process is an important factor and is rapidly reducing in the UK (Figure 28). For this analysis, operation in 2020 was assumed and an average taken of the carbon intensities from all four scenarios given in National Grid's 2016 Future Energy Scenarios (FES). The intensity used was therefore 174gCO₂/kWh.

³⁶ See for example the methodology outlined in Annex V.C of the Renewable Energy Directive (Directive 2009/28/EC)

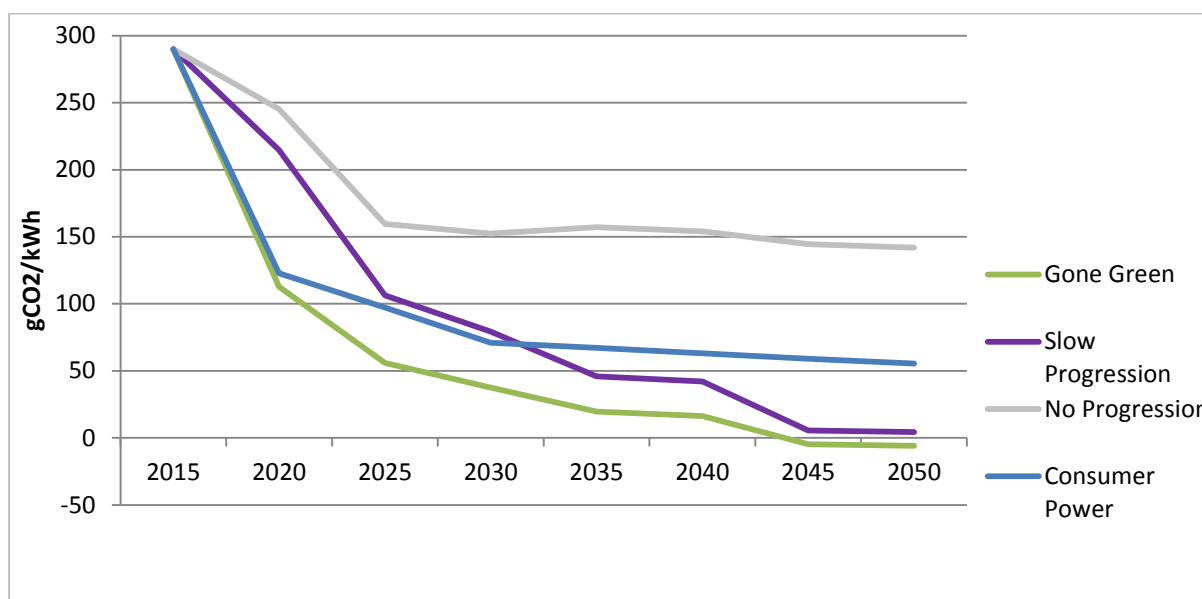


Figure 28: Carbon intensity of grid electricity according to FES 2016 (Figure 5.2.5)

6.1.2 Emissions

Emissions from each process step are given below, per megawatt hour of Biohydrogen on a higher heating value basis.

Feedstock transport

The waste used in these plants will be collected locally, typically from sites within a 10km radius of the refuse derived fuel processing plant which will in turn be a short distance from the Biohydrogen facility. Due to the short distances involved, analysis has shown the impact of this feedstock transport to be very small, resulting in emissions of 0.9kgCO_{2eq}/MWh.

RDF production

Ofgem's UK Solid and Gaseous Biomass Carbon Calculator gives electricity, diesel and sulphuric acid use figures for a range of RDF production configurations. Figures for an aerobic digestion-type facility have been used, resulting in emissions of 8kgCO_{2eq}/MWh.

Biohydrogen plant

The main emissions associated with the Biohydrogen plant itself derive from imported electricity (0.148MWh_e/MWh with carbon capture, 0.122MWh_e/MWh otherwise) and oxygen (103kg/MWh). Together with other chemical inputs, the total emissions are 41kgCO_{2eq}/MWh with carbon capture, or 36kgCO_{2eq}/MWh without.

CO₂ capture

The Biohydrogen process captures carbon dioxide at sufficient quality for long-term sequestration. 369kgCO_{2eq}/MWh are captured.

Product distribution and use

The product is injected into the national gas grid, with exact pressures depending on plant location, potentially but not necessarily requiring some further compression. This is excluded from the calculation.

Emissions at the point of use are taken to be zero; emissions arising from small quantities of methane combustion are ignored because of the incineration counterfactual, as discussed above.

6.1.3 Results

The table below summarises the emissions from the process for the capture and non-capture cases. Savings against natural gas are given using the EU grid mix value of 243kgCO_{2eq}/MWh³⁷.

Process step	Emissions (kgCO _{2eq} /MWh hydrogen)	
	Biohydrogen (CCS)	Biohydrogen (no CCS)
Feedstock transport	0.9	0.9
RDF production	8.1	8.1
Hydrogen facility: Electricity	25.8	21.2
Hydrogen facility: Oxygen	12.0	12.0
Hydrogen facility: Chemicals	3.4	3.4
Hydrogen facility: CO ₂ capture	(372)	0.0
Total	(322)	46
Total saving vs natural gas	565	198
% saving vs natural gas	232%	81%

Table 20: Consumption and carbon emissions, per MWh BioSNG produced

³⁷ JEC Well-to-Wheel study, WTT Appendix 1, available at <http://iet.jrc.ec.europa.eu/about-jec/>

These compare with figures for BioSNG of a 462kgCO_{2eq}/MWh saving with carbon capture (211%) or 207kgCO_{2eq}/MWh (85%) without. SMR-derived hydrogen results in a 59% saving, according to the H21 Leeds City Gate study; using the same emissions factors as in this assessment would give 51% savings³⁸ (saving 123 kgCO_{2eq}/MWh).

6.1.4 Conclusion

The analysis clearly shows the advantage of Biohydrogen production.

When compared with SMR hydrogen with CCS, a Biohydrogen plant *without* access to sequestration has significantly lower emissions (by 75kgCO_{2eq}/MWh). Where a Biohydrogen plant can access CO₂ sequestration it achieves substantial negative emissions of 322kgCO_{2eq}/MWh, which is 442kgCO_{2eq}/MWh lower than SMR with CCS and 566kgCO_{2eq}/MWh lower than natural gas. Therefore, Biohydrogen can take an important role in offsetting emissions in the wider network.

It is also clear that, once CCS infrastructure is in place, there is a significant advantage (101kgCO_{2eq}/MWh) in using Biohydrogen rather than BioSNG, as illustrated in Figure 29.

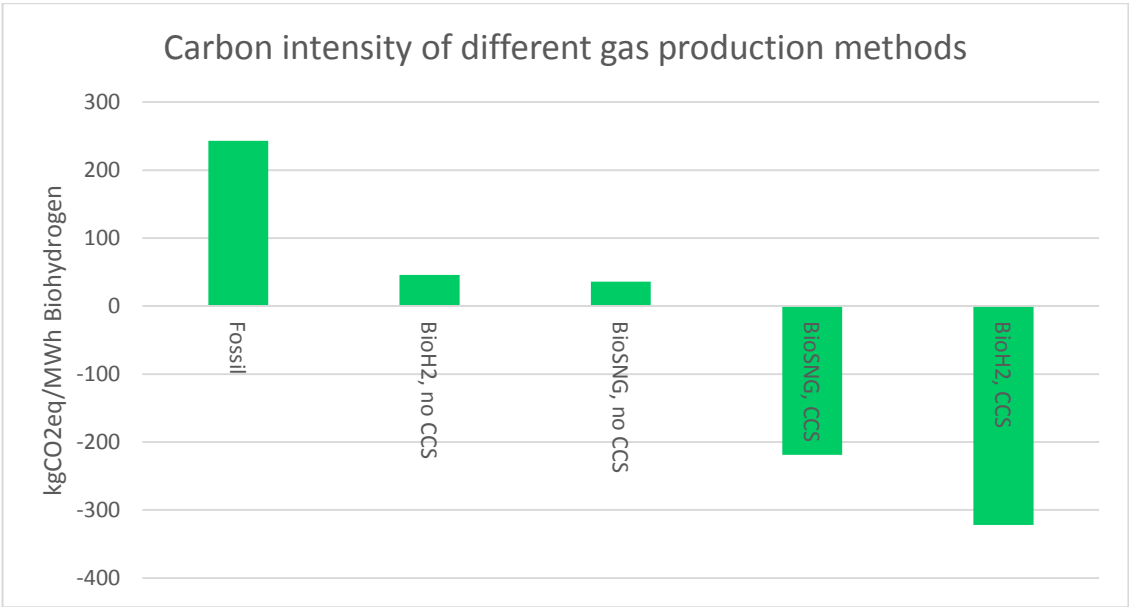


Figure 29: Carbon intensity of different gas production methods

6.2 Economic model

The base case economic model is for a first of a kind Biohydrogen plant, configured as described in Section 5.2 but producing no transport-grade hydrogen. Once developed, the model was used to trial a range of different plant configurations.

³⁸ This figure also assumes no compression of hydrogen for storage, for consistency with Biohydrogen analysis.

6.2.1 Delivery structure

A typical delivery structure for a commercial Biohydrogen facility will involve the proposed Owner of the facility putting in place arrangements for the delivery, operation and funding of the project, often in a project specific vehicle (SPV) dedicated to the development, construction and operation of the plant.

The structure used to deliver a facility has a significant impact on overall project costs. Costs will also depend upon the level of risk transfer the Owner wishes to achieve as contractors will expect their margin to reflect the guarantees they are providing.

The economic model assumes that the Owner will adopt a delivery structure with an engineering, procurement and construction contractor (EPC) providing a turnkey delivery of the facility and with funding being arranged on the basis of this transfer of risk.

A typical structure is summarised in Figure 30.

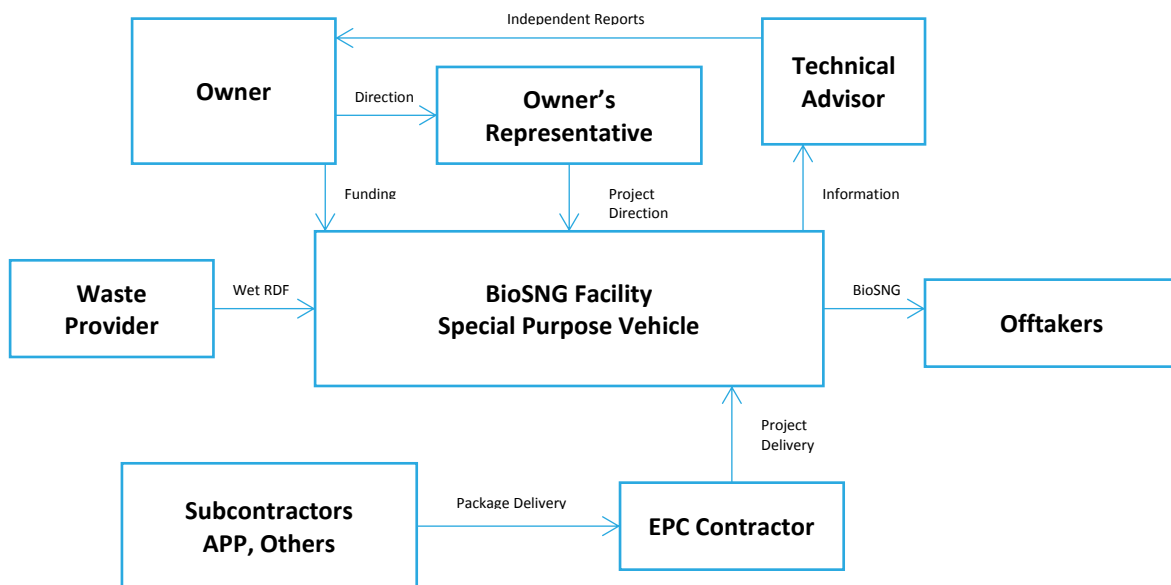


Figure 30: Typical Biohydrogen project delivery structure

The Owner will provide equity funds supported by senior and junior providers of finance. The Owner will engage an Owner's Representative to ensure their interests are protected and that delivery partners perform as required by their contracts. The Owner and funders may also engage a technical advisor to provide independent reports on project progress.

The EPC contractor will deliver the facility for a fixed price contract with guarantees on plant performance and delivery timescales. The EPC will place subcontracts with a number of package providers such as APP, who will deliver the gasification package.

In order to underpin the business case and support long term funding the Owner will enter into long-term contracts (with guaranteed prices) with waste providers and Biohydrogen offtakers.

This structure apportions risk between Owner, funders, the EPC contractor and subcontractors on the basis that risk is apportioned to where it is best managed, with the costs associated with the EPC guarantees offset by the lower cost finance. Over time risks

and technology deployment will become better understood and the cost of delivery and finance will fall.

6.2.2 Capital costs

The capital cost of the facility was assessed by breaking the facility into a set of discrete packages and then estimating the cost of each of these. The packages for a Biohydrogen plant are listed in Table 21.

Detailed cost estimates for many of the packages were obtained during BioSNG development work; where equipment differed, vendors were approached and asked to provide budgetary quotes. If necessary the quotes were then scaled or adjusted to reflect difference in scope between the quote and the final design.

Package	Outline Specification	Potential Suppliers
Feedstock handling	Delivery and shredding of waste to the dryer	Saxlund
Gasplasma® package	Gasification of dried RDF using fluidised bed gasifier and plasma converter	Tetronics
Waste Heat Boiler	Cooling of syngas and generation of steams	Greens Power, TIBS, Thyssen Krupp
Dry gas cleaning	Syngas cleaning to remove particulate and vapours	Glosume, Megtec
APC discharge / collection	Conveyance of solids to storage for offsite removal	Saxlund
Wet Syngas cleaning	Syngas cooling and acid scrubbing	ERG
Flare	Oxidisation of gases during start-up/shutdown	Flare Products, Uniflare
Oxygen plant	Oxygen supply for gasifier and convertor consumption	Linde, Air Products, Air Liquide
Civils	Ground works and construction of buildings	Local contractor
Syngas compressor, enclosure and storage	Compression of clean syngas and storage	Mayekawa, SAID
Water-gas shift and CO₂ removal	Production of hydrogen product stream from syngas	Amec Foster Wheeler, Technip, Johnson Matthey
Pressure swing adsorber	Purification of product stream to produce transport-grade hydrogen	Carbotech
Power and controls	Supply of plant control system	Siemens, Valmet

Mechanical and Electrical installation	Installation of procured plant and equipment together with interconnections	Local contractor
Construction Management	Management of onsite works	Amec Foster Wheeler, Technip, Valmet

Table 21: Equipment packages and potential vendors for Biohydrogen production

Outline layouts for the facility have been prepared using CAD modelling software. Summary information from this layout is presented in the following table.

	hectares
Overall site area including roads	3.14
Waste reception and preparation building area	0.55
Other buildings	0.29
External area	2.30

Table 22: Biohydrogen layout areas

The layout has been used in the estimate of the cost of the civils work and buildings.

The quotes from suppliers for the packages set out in the table above have been combined with estimates of other costs such as fees for obtaining planning permission to produce the cost model set out in the following table.

	£M
Fuel preparation	1.20
Gasification, cooling, bulk cleaning	27.60
Syngas compression	5.00
Water-gas shift	14.00
Building and civils	10.20
CO2 compression	1.50
Other equipment	1.00
Mechanical installation, power, controls	8.00
Grid connection and project development	3.50
Engineering, procurement, construction and guarantees	18.00
Contingency	9.00
	99.00

Table 23: Biohydrogen capital costs summary

This shows that the cost of a first of a kind facility that produces 48MW of hydrogen is £99m or £2.0m per megawatt. This is considerably cheaper than the average cost of

£5.5m per megawatt for a waste to power plant³⁹ or the £2.5m per megawatt for a BioSNG plant. This is predominately due to the far higher conversion efficiency of Biohydrogen (71%) compared to electricity (25%) or BioSNG (64%) generated from waste.

6.2.3 Operating costs

The key operating costs of a Biohydrogen facility are set out in the following table.

Type	Description
Parasitic load	The cost of power used for plant equipment, mainly plasma converter and oxygen plant power. This report assumes that power is sourced from the grid at a market price.
Waste disposal	The cost of disposing of APCr waste generated from gas cleaning.
Chemical consumables	Consumables derived from the mass and energy balance. Chemicals used in gas cleaning.
Catalysts	The cost of catalyst replacement.
Maintenance	Annual and lifecycle costs of maintaining equipment.
Staff costs	Salaries, benefits, social security costs, IT and other costs associated with employees.
Other consumables	Consumables not derived from the mass and energy balance such as lubricants, personal protection equipment or electrodes.
Other	Permit compliance, royalties and rent.

Table 24: Biohydrogen operating cost elements

The annual costs of chemical consumables, parasitic load and waste disposal are simple calculations based on the quantities taken from the mass balance and the unit rates for each item. The rates, based on recent quotes or discussions with suppliers, are summarised in the following table.

³⁹https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66176/Renewables_Obligation_consultation_-_review_of_generation_costs_and_deployment_potential.pdf

	Rates
Power	£95/MWh(e)
Natural gas	£25/MWh
Oxygen	£35/tonne
Waste disposal	£140/tonne
Sodium Bicarbonate	£166/tonne
Sulphuric Acid	£175/tonne
Sodium Hydroxide	£67/tonne
Sodium Hypochlorite	£418/tonne

Table 25: Biohydrogen operating costs assumed rates

Suppliers of capital equipment have provided estimates of the annual and lifecycle maintenance costs. An average cost of 2% of capital cost is used in the models.

Staff costs are driven by the number of staff required and their salaries. A staffing model has been developed building on experience of operating similar facilities. Required staff numbers and salaries are set out in the following table.

Position	Number		Salary (£)
Plant manager	1		60,000
Shift supervisor	5		40,000
Plant operators	15		25,000
Maintenance engineers	10		30,000
General labour	5		15,000

Table 26: Biohydrogen salary assumptions

An allowance of 20% covers social security costs such as pensions and national insurance, and an additional 15% allowance covers other employee costs such as IT, human resources and recruitment costs.

The model uses a cost of £40/tonne for sequestration of the compressed carbon dioxide. This is taken from the North Gas Networks H21 report⁴⁰ and assumes disposal in

⁴⁰<http://www.northerngasnetworks.co.uk/wp-content/uploads/2016/07/H21-Report-Interactive-PDF-July-2016.pdf>

abandoned North Sea oil fields. It is likely that lower storage costs could be achieved in other areas such as Merseyside.

Overall, operating costs are summarised in the following table:

Costs	(£M/an)
Labour	1.60
Power	4.95
CO₂ sequestration	5.36
Oxygen	1.30
Consumables	1.80
Maintenance	1.98
APC disposal	0.35
Insurance rent and rates	1.20
Other costs	0.50
	19.04

Table 27: Biohydrogen operating costs summary

6.2.4 Levelised costs

Levelised costs are estimates of the revenue per MWh_{th} of Biohydrogen that a plant would need to achieve in order to cover its capital and operating costs whilst delivering an adequate return to funders.

The key inputs to the levelised cost calculations are the capital costs set out in Section 6.2.2, the operating cost set out in Section 6.2.3.

The facility will receive income, known as the gate fee, for accepting waste. Current market rates for refuse derive fuel can be found on the Lets Recycle website⁴¹, which shows spot price gate fees with a mid-range value of £85 per tonne. A gate fee of £75/tonne is assumed in the modelling, which equates to £21/MWh of hydrogen.

Hurdle rates are assumed to be 12% for first of a kind plants, which is the assumption used in the DECC's calculation of appropriate levels of support under the Renewable Heat Incentive⁴². The hurdle rate is used to calculate the levelisation factor used to discount capital cost. This calculation results in a factor of 6.9 for first of a kind plants.

For simplicity, the baseline model only considers the production of hydrogen for heating and doesn't assume any production of transport grade hydrogen. The impact of producing small quantities of premium Biohydrogen is examined in the next Section.

The detailed calculations of the levelised costs of Biohydrogen are set out in Appendix A.5.0 and are summarised in the following table.

⁴¹<http://www.letsrecycle.com/prices/efw-landfill-rdf-2/efw-landfill-rdf-2017-gate-fees/>

⁴²https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/505132/Consultation_Stage_Impact_Assessment_-_The_RHI_-_a_reformed_and_refocussed_scheme.pdf

	£/MWh
Capital cost	39.5
Operating cost	52.4
Gate fee	(20.6)
Levelised cost	71.3
Market price of gas	(20.0)
Additional cost	51.3
GHG savings (tonne CO₂eq/MWh)	0.57
Cost of carbon savings (£/tonne)	91

Table 28: Biohydrogen levelised cost summary

6.2.5 Sensitivity analysis

A number of variations to the baseline design were modelled to explore their impact on levelised costs and the cost of carbon savings. The sensitivities are:

- An nth of a kind facility that is built and operated after the technology has matured. This is twice the scale of the baseline (98MW), operates for 90% of the year rather than 85%, has an allowance of 15% for EPC costs rather than 25%, and has a cost of capital of 8% rather than 12%.
- A first of a kind facility operating without any carbon capture or storage, with carbon dioxide vented directly to atmosphere.
- A first of a kind facility that produces 100% high purity hydrogen that meets the transport specification at low pressures.
- A first of a kind facility producing its own power from the combustion of syngas in gas engines.

The levelised costs of these are shown in Figure 31.

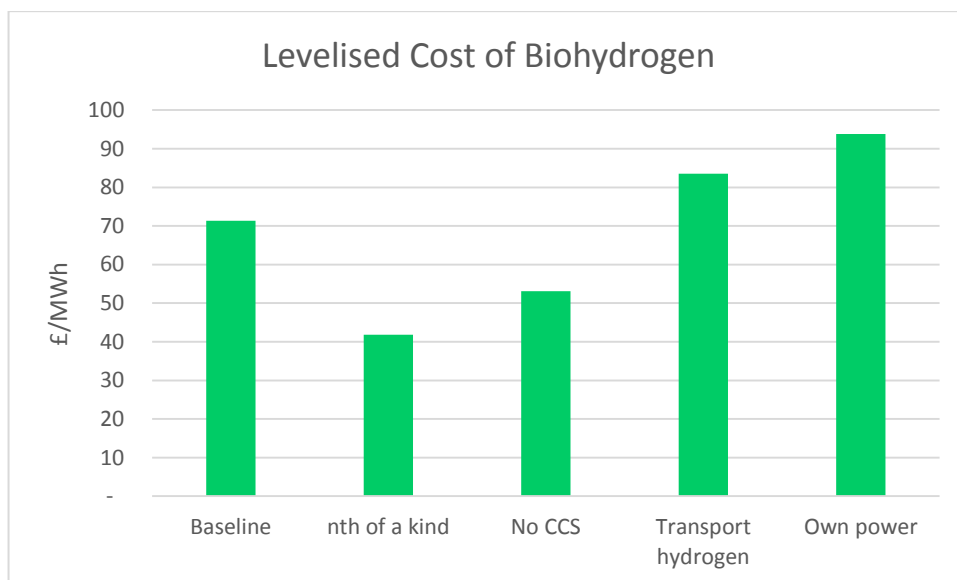


Figure 31: Levelised cost of Biohydrogen for different plant configurations

The costs compare to an expected price for natural gas of around £20/MWh.

The fall in expected cost from the first of a kind to nth of a kind is very significant and reflects the cost of guaranteeing and funding a new technology. The nth of the kind assumptions do not include any technical innovations. They are purely based on:

- A reduction in the premium charges by contractors for providing performance guarantees.
- An increase in plant operating hours because of operational learning from previous plants.
- A fall in the cost of capital from 12% to 8% as funders gain experience of the technology.
- A doubling in plant scale because of a general increase in the confidence of all stakeholders.

The cumulative impact of these changes is shown in the Figure 32.

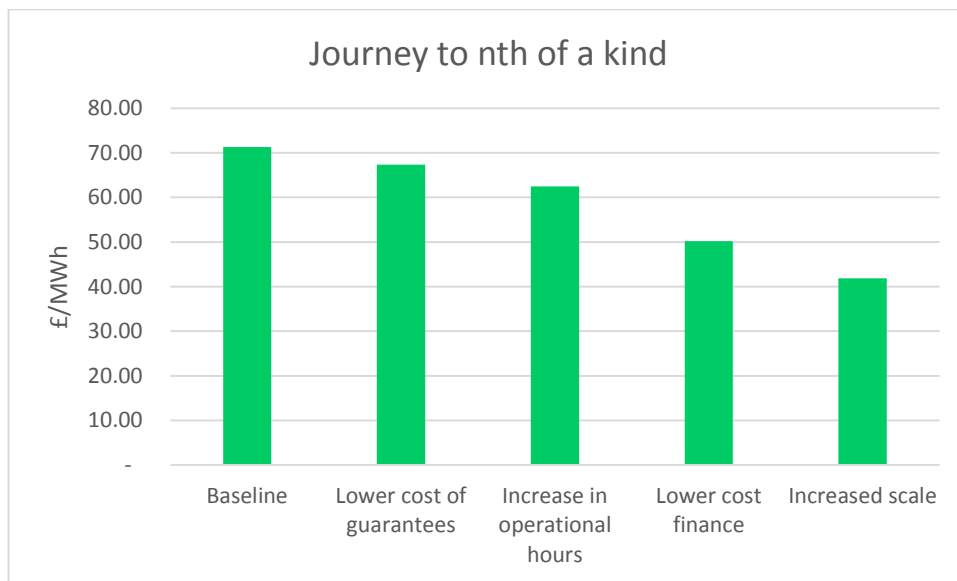


Figure 32: Levelised cost of Biohydrogen as technology matures

The following chart (Figure 33) shows the cost of carbon saved by each option, assuming a reference of natural gas both for carbon emissions and gas price.

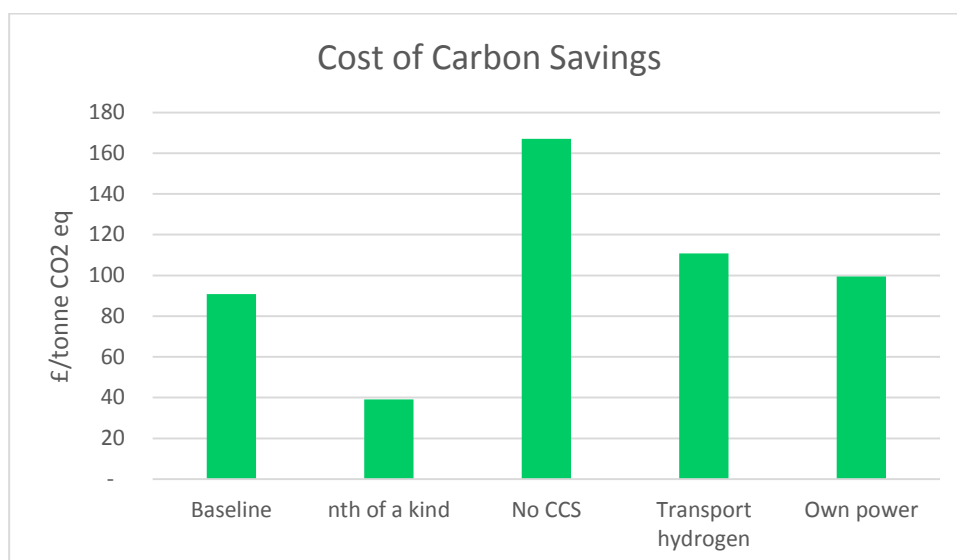


Figure 33: Cost of carbon savings for a range of Biohydrogen plant configurations

These costs show that Biohydrogen offers very good value for money compared to other low carbon technologies; using similar assumptions hydrogen produced by an SMR with CCS has a cost of £40 per MWh or £163 tonne of carbon dioxide saved.

6.3 Comparison of Biohydrogen to BioSNG

Producing Biohydrogen, rather than BioSNG, results in a product that has no emissions at the point of use. All of the carbon in the feedstock can be captured at the point of production and, if this is done, Biohydrogen has a clear environmental advantage. Furthermore, Biohydrogen production is more efficient than BioSNG production which means that it offers advantages even when CCS is not used. This is demonstrated by the comparison of Biohydrogen and BioSNG in Table 29.

	Biohydrogen – nth of a kind	BioSNG – nth of a kind
Technical Maturity	Pilot plant.	Demonstration plant under construction.
Heat applications	Some replacement of current appliances required.	Compatible with current appliances.
Transport applications	New vehicles required, technology under development.	New vehicles required. Technology is mature.

Gross efficiency⁴³	78%	64%
Cost without CCS	£25/MWh	£21/MWh
Cost with CCS	£42/MWh	£32/MWh
Carbon savings without CCS	198kg/MWh (81%)	207kg/MWh (85%)
Carbon savings with CCS	565kg/MWh (232%)	462kg/MWh (190%)
Cost of carbon savings with CCS	£39/te	£26/te

Table 29: Comparison of Biohydrogen to BioSNG

This shows that mature Biohydrogen has roughly the same cost and GHG impact as mature BioSNG when CCS is not used. Production of Biohydrogen is more efficient than BioSNG but BioSNG production generates significant amounts of excess heat that can be used to generate electricity and reduce power costs.

For waste feedstocks, which attract a gate fee rather than incur a cost, higher efficiencies do not result in better economics. For feedstocks with a cost, such as most biomass residues, the higher efficiencies of Biohydrogen production would result in lower costs than BioSNG. BioSNG produced from wood residues without any CCS would cost around £90/MWh while Biohydrogen from the same feedstock would cost £60/MWh because of the higher production efficiencies.

Another benefit of higher efficiency is that Biohydrogen could make more of a contribution to energy demand from a limited amount of biomass feedstock than BioSNG. Work for Cadent shows that sustainable UK feedstocks could generate more than 100TWh of BioSNG⁴⁴. The higher conversion efficiencies for Biohydrogen mean that it could produce 123TWh of Biohydrogen from the same feedstocks.

However, complete conversion to Biohydrogen will require some changes in heating infrastructure and appliances. Therefore, there would need to be a wider driver for hydrogen conversion such as adoption of hydrogen production by steam methane reforming combined with CCS.

As discussed in Section 3.3.3, hydrogen can be blended in the gas network, potentially to levels of 20%, while maintaining compatibility with most existing infrastructure. This would allow the benefits of higher conversion efficiencies to be realised. However, there

⁴³ The energy content of gas injected into the grid divided by the energy content in the feedstock used to produce it, both measured using higher heating values. This ignores electricity and any other energy inputs or heat and any other energy outputs.

⁴⁴ 'Review of Bioenergy Potential: Technical Report for Cadent Gas Ltd', Anthesis & E4Tech, 2017

are only a limited number of points within the network with sufficient gas flows all year round to allow Biohydrogen to be blended economically (Section 3.2.2).

When CCS is used hydrogen will offer significantly better GHG performance than BioSNG because more carbon can be captured. The figures in the table obscure the real benefits of Biohydrogen. On a per megawatt basis Biohydrogen offers 22% better GHG savings than BioSNG (565kg/MWh savings against natural gas versus 462kg/MWh). However, the high conversion efficiencies depress the Biohydrogen performance. For a given amount of biomass, Biohydrogen will generate 50% greater GHG savings than BioSNG. Looked at another way, the negative emissions from Biohydrogen for a given quantity of feedstock will be 80% greater than from BioSNG.

If CCS infrastructure is developed it seems likely that some parts of the gas network will switch completely to hydrogen and Biohydrogen will be able to contribute gas into those networks. Even if hydrogen produced by SMR with CCS is not adopted the availability of CCS infrastructure would allow production of very low carbon hydrogen for blending into the network and direct supply to industry.

From the analysis it is clear that, with or without CCS, Biohydrogen offers benefits over BioSNG, providing greater quantities of low-carbon gas at comparable cost. With CCS the environmental benefits are even more compelling.

6.4 Comparison of Biohydrogen to alternative hydrogen pathways

SMR with CCS and electrolysis are both mature technologies capable of delivering low carbon hydrogen and it is instructive to compare them with Biohydrogen. This is done in Table 23.

	SMR with CCS ⁴⁵	Biohydrogen – nth of a kind	Electrolysis ⁴⁶
Potential production	Limited by demand – very large quantities of natural gas	Limited by available biomass resource – around 123TWh using sustainable UK resources.	Limited by demand – available supply of electricity is likely to exceed demand

⁴⁵ <http://www.northerngasnetworks.co.uk/wp-content/uploads/2016/07/H21-Report-Interactive-PDF-July-2016.pdf>, cost figures include hydrogen generation only

⁴⁶ Horizon 2020 European work on Fuel Cells (Fuel Cell & H2 joint undertaking (FCH JU), Multi - Annual Work Plan (2014 – 2020), http://www.fch.europa.eu/sites/default/files/documents/FCH2%20JU%20-%20Multi%20Annual%20Work%20Plan%20-%20MAWP_en_0.pdf), and recent work by Element Energy projecting developments into the future (http://www.fch.europa.eu/sites/default/files/study%20electrolyser_0-Logos_0.pdf).

	available for conversion.		because of relatively high hydrogen costs.
Technology maturity	Mature once CCS is established.	No plants currently in operation.	Mature.
Preferred location	Production is best located near oil and gas fields for carbon storage.	On outskirts of towns and cities – close to waste production.	Close to intermittent electricity supplies and transport demand.
Typical scale	Large scale. Around 1,900GWh/a	Medium scale Around 350GWh/a	Small scale – sized to match available low-cost electricity. Up to around 75GWh/a
Capital cost	£0.58m/MW	£1.41m/MW	£0.99m/MW
Operating costs	£0.36m/MW/a	£0.18m/MW/a net of gate fee	£0.03m/MW/a plus cost of electricity
Cost of grid-quality hydrogen	£40/MWh	£42/MWh with CCS £25/MWh without CCS	£134/MWh from off peak electricity ⁴⁷
Cost of transport-grade hydrogen	Around £1.73/kg	£1.70/kg with CCS. £1.00/kg without CCS.	£5.36/kg
Carbon savings compared to fossil methane	59% (H21 report approach ⁴⁸) 51% (Section 6.1.3 approach)	232% with CCS 81% without CCS	Around 12% based on forecast 2020 grid intensity of 174kgCO _{2eq} /MWh _e
Cost of carbon savings	£163/tonne (H21 report approach) £158/tonne (Section 6.1.3 report approach)	£25/tonne without CCS £39/tonne with CCS	£3,909/tonne for grid power but more cost effective if low carbon source used.

⁴⁷Assuming £95/MWh electricity and 7500 hours per year operation for consistency with Biohydrogen

⁴⁸ The H21 report uses a carbon intensity for natural gas of 209kgCO_{2eq}/MWh compared to the 243kgCO_{2eq}/MWh used in this report. The carbon savings used and costs of carbon savings using both values are quoted in this table.

Table 30: Comparison of Biohydrogen to alternative pathways

A mature, nth of a kind waste Biohydrogen plant will produce a gas with a similar levelised cost to hydrogen produced by SMR with CCS and significantly lower than the cost of hydrogen produced by electrolysis using off peak electricity. As explained in Section 6.2.5 the cost of Biohydrogen produced by first of a kind plants will be higher but should fall quickly at the technology matures.

The key advantage of Biohydrogen is the depth of decarbonisation it offers when combined with CCS. It provides more than four times the GHG savings of hydrogen produced by SMR with CCS and far higher savings than electrolytic hydrogen produced from grid electricity.

This high GHG saving results in very low costs for each tonne of carbon dioxide saved. The low figures are driven by the gate fees for using feedstock. However, even if wood residues with a cost of £60/tonne were used in the process, the cost per tonne of carbon dioxide saved for a Biohydrogen CCS plant would be £97/tonne, a third of the cost of carbon savings for hydrogen produced by SMR with CCS.

The economics of the three processes are quite different. Biohydrogen production has relatively high capital costs but operating costs are subsidised by the waste gate fees. Capital costs for SMR are lower but the cost of the natural gas feedstock makes operating costs high. Capital costs for electrolysis are relatively high at present but may fall due to innovation. The operating costs for electrolysis are driven by the costs of electricity.

The key disadvantage for Biohydrogen is that its potential is limited by the availability of sustainable feedstocks such as wastes and biomass residues. Work by Cadent has shown that there are more than 155TWh of sustainable UK feedstocks which could be converted into 123TWh of Biohydrogen⁴⁹. This could be supplemented by imported biomass but the imported volumes are hard to forecast.

There are limitations to widespread adoption of electrolysis using conventional electricity supplies. It is effective at producing small quantities of transport grade hydrogen but is expensive and does not offer significant GHG benefits. Electrolysis may be used at larger scales using stranded electricity when generation exceeds demand. However, there are competing technologies for utilising excess electricity and the amount available and its cost are difficult to forecast.

If CCS infrastructure is developed then wholesale conversion of parts of the gas network may take place as described in the NGN H21 report. If this is the case, then Biohydrogen should be able to compete with SMR on cost while offering significantly increased CO₂ savings. A combination of SMR and Biohydrogen with CCS would be able to meet the UK's entire gas demand with zero net emissions: the emissions from SMR with CCS would be balanced by the negative Biohydrogen emissions.

⁴⁹ 'Review of Bioenergy Potential: Technical Report for Cadent Gas Ltd', Anthesis & E4Tech, 2017

In terms of blending of hydrogen into the grid, Biohydrogen is at a more appropriate scale than SMR facilities. However, even Biohydrogen would need storage, co-users, or the ability to produce hydrogen-methane mixtures to deliver its potential.

From the comparison it is clear that Biohydrogen has the potential to produce hydrogen at costs comparable to SMRs and significantly below electrolyzers, while greatly exceeding the environmental benefits of both.

7.0 PATHWAY TO DEPLOYMENT

The primary object of this chapter is to consider the steps required to commercialise Biohydrogen. As is discussed below, success is closely linked to deployment of the BioSNG because:

- BioSNG is a fungible product with fewer market barriers at present; and
- Successful BioSNG operation will provide good evidence for the feasibility of Biohydrogen production.

Catalytic production of hydrogen is a relatively established process, given a high-quality syngas. Therefore, a plan for commercialisation builds on the existing roadmap for BioSNG deployment.

As defined in Section 3.4.1, the reference commercial Biohydrogen facility will produce around 48MWth of gas. It is expected to predominately produce grid quality Biohydrogen, with the opportunity to provide a slip stream of fuel cell quality Biohydrogen. A future design, outlined in 5.1.7.3, may allow the plant to swing between Biohydrogen and BioSNG production in order to maximise utilisation. To deliver benefits over BioSNG production beneficial use or sequestration of CO₂ is likely to be important. However, the higher efficiencies of Biohydrogen production means that it offers advantages over BioSNG even without sequestration.

This chapter considers the barriers to deployment of such commercial facilities and evaluates the role of a demonstration plant in addressing these barriers. The near-term evolution of markets for Biohydrogen use and the commercial basis for a demonstration plant were considered, and a variety of demonstration plant configurations proposed. The work established that the most prospective route for demonstration is by taking a slipstream of biosyngas from a commercial BioSNG plant.

7.1 Barriers to deployment

In order to take a new conversion process through to commercialisation, there are a number of potential risks which need to be addressed:

Market: Is there a market for the product and are the revenues expected to be sufficient for commercial success? What are the risks attached to this market and revenue now and in the future? How does the product reach the end customer and are there constraints to project location or the overall market size? Viewed from the other perspective, does this process become a market enabler? The prospect of a new source of product, particularly at lower cost, can unlock new markets that might otherwise not develop.

Feedstock: Is sufficient feedstock available that matches the process requirements at an acceptable price (or, for waste, a 'gate fee' revenue)? Feedstock availability, quality and price needs to be acceptable at both a project specific level and at a national scale. Both are required for incoming investors to enter the market.

Technology: Is the technology capable of converting the available feedstock to a product of sufficient quality with the reliability and resilience necessary to operate for the

commercial life of a project? Is the evidence base for this sufficiently robust for an incoming investor and are there contractors able to accept the necessary risk transfer from investor?

Funding: Are there investors willing to fund the first commercial project at the scale required with its risk profile? This will be contingent on the key project attributes above.

Some of these barriers are entirely external. These are addressed by marshalling the evidence and engaging with policymakers and market participants. However, a number of barriers are internal and closely dependent on the specifics of the process itself.

7.2 The Role for a demonstration project

Demonstration projects are a tool for addressing some barriers. They primarily provide confidence in the technology and its risk profile. However, demonstration projects also provide evidence of:

- the appetite for participants such as contractors and suppliers to deliver into the market;
- the ability to contract for feedstock of acceptable quality and terms;
- the ability to contract for the product on acceptable terms for both offtaker and producer; and
- a tool for establishing an emerging market, which requires evidence of a viable route for the product before the market can develop.

Except in very unusual circumstances, investors are unlikely to fund projects without evidence of successful operation under commercial conditions.

If a new product source has the prospect of enabling development of a new market, evidence of successful operation is invaluable in providing the confidence for other actors. Biohydrogen production has the potential to help establish a new market because unlike electrolysis it offers a high-volume, low-cost and low-emission source of hydrogen and unlike hydrogen from fossil sources it is not contingent upon establishment of carbon capture and storage (CCS).

As acknowledged above, deployment of Biohydrogen is likely to be strongly linked to the development of BioSNG. Because it is a fungible product with an existing market, the first commercial BioSNG plant is already under construction, and it is anticipated that the first larger scale plant would also produce BioSNG. That is the basis of the discussion below.

It is important to establish the purpose for a hydrogen demonstration project, based on the parameters discussed above.

7.2.1 Technical demonstration

At its highest level the process has three stages: conversion of feedstock to high quality syngas, conversion of syngas to hydrogen, and upgrading, primarily through the removal of carbon dioxide.

The main technical risk for conversion of waste and biomass to hydrogen is the production of high-quality syngas. The water-gas shift process is mature and used in the chemical industry and refineries around the world. Similarly, removal of carbon dioxide from hydrogen gas streams is well established.

Demonstration and commercial production of BioSNG firmly addresses the risk associated with production of a high-quality syngas. The main risks are reliability, the production of long chain hydrocarbons (tars), ability to cool reliably, successful ash removal, and the contamination of syngas with impurities that may damage catalysts. All these factors are common to Biohydrogen and BioSNG. In general, methanation catalysts are more sensitive than those associated with water-gas shift so the risks for BioSNG production are greater than for Biohydrogen.

Therefore, operation of a commercial BioSNG facility is expected to provide a high level of confidence of the technical feasibility of Biohydrogen production.

The evidence of high-quality syngas production from a BioSNG plant is expected to persuade suppliers to offer commercial guarantees for the hydrogen conversion and upgrading step. If this is the case, demonstration of these stages may not be required.

However, it is recognised that investors may still require operational evidence of these processes operating:

- on the syngas produced from biomass;
- at the small scales of biomass plant compared with the chemical facilities;
- with the conversion performance stipulated; and
- at the required output gas quality.

Chemically, the conversion performance is well understood. However, both the shift process, as well as the downstream CO₂ stripping does rely on extensive heat integration. The performance of this will impact on process efficiencies and economic and environmental performance.

In terms of hydrogen quality, the requirements for gas grid injection are not particularly onerous compared with most existing hydrogen offtake requirements. Therefore, this is not expected to be a major risk, although good evidence will be required that carbon monoxide levels can be met. For transport or fuel cell applications, the specification is substantially tighter as discussed in Section 3.3.1. Therefore, an investor may require demonstrated evidence that this higher gas quality could be met.

In summary, the most significant technical risks for Biohydrogen production would be addressed through operation of BioSNG facilities, particularly since this has to deal with the most variable element, the waste. However, demonstration of the syngas to hydrogen stage may also be necessary for investor confidence but this would not necessarily require a new integrated gasification and conversion facility.

7.2.2 Contractors and suppliers of equipment

Construction of a BioSNG plant substantially reduces the risks associated with the ability to secure contractors and suppliers of equipment for Biohydrogen facilities. Construction

of a Biohydrogen plant requires the same suite of participants. The main technical difference relates to the catalysis stage but in both cases potential suppliers are broadly similar.

There is a wider base of experience in delivering shift catalysis than methanation because it is a standard processing element in the chemical industry. It is therefore expected that an individual catalysis stage supplier would be able to provide performance guarantees, subject to the quality of the incoming syngas.

There is also substantial international experience in the removal of CO₂ from hydrogen rich streams and, compared with other hydrogen applications, the product specification for grid injection (Section 3.4.2.1) is not particularly onerous. The purity of hydrogen for fuel cells is necessarily higher, although it is expected that a supplier of upgrading equipment would be able to offer performance guarantees subject to the grid gas specifications from which a slip stream would be taken.

The primary risk relates to the ability to secure appropriate performance guarantees for the integrated facility, with the main interface issue being the quality of the syngas. Securing guarantees for a BioSNG plant is therefore expected to demonstrate that an appropriate guarantee could be obtained for a Biohydrogen plant.

7.2.3 Feedstock

For the foregoing reasons, the securing of waste contracts and operating a BioSNG plant on that waste should provide sufficient evidence that it is possible to contract for feedstock of acceptable quality and on acceptable terms for hydrogen applications.

7.2.4 Hydrogen offtake

Hydrogen offtake represents one of the most significant uncertainties in funding a plant to deliver Biohydrogen. This is due to the immature market for hydrogen.

In an immature market, there is a paucity of both suppliers and offtakers for a product. Potential offtakers have reservations about developing equipment without a proven supply and investors in production facilities will be concerned about limited offtakers, particularly if the nature of the offtake is less proven technically and in terms of customer acceptance. Furthermore, product value can be less well defined.

In order for a market to develop, suppliers need visibility and confidence that a consumer base will develop, and offtakers need to be confident that product will be available. Biohydrogen is an important element in facilitating the development of this market. As shown in Chapter 6.0 this route for hydrogen production has the potential to offer hydrogen at lower prices than alternative sources, such as electrolysis, and at material volumes up to 123TWh. The carbon savings are substantial and do not rely on establishment of CO₂ transport and storage infrastructure, unlike fossil-based sources. However, as such infrastructure develops, it will be one of very few opportunities for negative emissions. In this regard, Biohydrogen demonstration is not simply about de-risking it as a production route, but plays a crucial role in developing hydrogen as a solution by providing confidence in a low-carbon, low-cost source. It is a market maker.

As discussed in Section 3.1 there are a number of potential hydrogen markets. These have different characteristics in risk, timescales and value terms as described below. These markets are not mutually exclusive; a Biohydrogen facility could deliver to a combination of markets.

7.2.4.1 Hydrogen blend in the gas distribution system

This is potentially an emergent market for hydrogen. Across Europe, up to 12% hydrogen is permitted into the gas grid⁵⁰. Here in the UK, the HyDeploy Project is seeking to establish the level of hydrogen-natural gas blend (anticipated to be between 10-20% by volume) which the HSE considers can be safely delivered and used by customers without modification to the network and appliances. This is a three-year project in three phases. During the first phase, the evidence base will be developed to present to the HSE to secure the appropriate exemption from GS(M)R, followed by construction of hydrogen production/injection equipment and then trialling the blend on a private closed network. If successful, this project will be followed by a trial on a public network before being able to be rolled out.

Market timescales:

- Mid 2018 establishment in principle with the HSE and anticipated blend level confirmed.
- Mid 2020 completion of closed network trial; demonstrated evidence of operation.
- Mid 2022 completion of public network trial and therefore ability to start roll out.

Offtake risk: This application does not require changes to the gas network or downstream appliances, so once the regulatory principle has been established (similar to the exemption secured for oxygen level for biomethane plants) roll out is then governed by the hydrogen production facilities. Similarly, because hydrogen would be delivered as a blend, any issues of hydrogen supply reliability would not be an issue for offtakers, because in the event of a shortfall they could continue using natural gas. The variation in hydrogen supply would be smaller than the diurnal and seasonal variation in gas offtake.

At a macro-level there would be a large and instantaneous market for the hydrogen, between 15-30TWh across the UK distribution grid as a whole. If the outturn blend is limited to 15% by volume, Biohydrogen would make up 5% of energy in the gas network. Therefore, a single hydrogen production facility would need to connect to the network at a location which transports a minimum of around 20 times the facility's capacity in energy terms, significantly limiting the number of potential sites. This may be mitigated through strategies such as the use of some hydrogen storage.

Value: For this application, the market value for the hydrogen is equivalent to natural gas. In addition, a support structure for low carbon heat would need to be in place, certainly for early plants. This is assumed to be similar to the RHI. As shown in Section 6.4,

⁵⁰ CEN/TC 234 Date: 2011-03, FprCEN/TR N 54:2011 CEN/TC 234 Secretariat: DIN "Gases from non-conventional sources — Injection into natural gas grids — Requirements and recommendations"

Biohydrogen offers a low-cost production route compared with alternatives, and so would be well placed to compete in this market. The detailed nature of such a support structure would need to be factored into design and funding of any demonstration type project, particularly if grant funding were involved.

Market maker role: The main barrier to blending of hydrogen into the gas grid is regulatory. This barrier is already being actively addressed, without further evidence of the feasibility of alternative hydrogen production routes beyond electrolysis. Once the regulatory barrier is addressed, offtake is limited only by available hydrogen production at acceptable cost, rather than requiring substantial changes by users. In that regard, there is less need for a ‘market maker’ compared with other applications.

7.2.4.2 Hydrogen supply to dedicated industrial users

It is increasingly recognised that there are few options for certain industries to reduce their carbon intensity; many industries use gas as a source of high grade heat for which there are few low carbon alternatives. Therefore, another potential market is the provision of hydrogen for industrial users. In conjunction with considering the feasibility of blending hydrogen into the gas grid, work is being undertaken into the feasibility of using hydrogen in an industrial cluster. This is expected to require conversion for the specific offtakers. However, compared with conversion of domestic users to 100% conversion, substantial quantities of natural gas could be displaced with hydrogen at lower cost and with fewer regulatory hurdles. This is shown from the table taken from the work on hydrogen clusters showing the scale of industrial sites in the North West⁵¹. A commercial scale facility will produce around 350GWh of hydrogen per annum, so just a few industrial sites would need to convert to take the output.

Sector ^{1 2}	Number of Sites	Natural Gas Use (GWh)	Average Natural Gas Use (GWh) Per Site
Chemicals	25	2,568	103
Glass	8	1,506	188
Food and drink	36	1,835	51
Oil and gas	5	1,691	338
Ceramics	2	171	85
Cement	1	16	16
Pulp and paper	5	890	178
Metals	2	271	135
Other	81	2,091	26
TOTAL	165	11,039	67
Notes:			
1. Includes only sites with > 5.9 GWh/annum natural gas consumption, which are connected to the LTS			
2. Excludes sites such as Runcorn (Inovyn) and Ince (CF Industries) which are connected to the NTS			

Table 31: Scale of industrial gas use in North-West England

⁵¹ ‘The Merseyside Hydrogen Cluster: A Low Cost, Deliverable Project, TECHNICAL REPORT to Cadent Gas Ltd’, 2017

Timescales: Feasibility work is being undertaken in 2017-2018 with the expectation that a demonstration phase, including trialling hydrogen at specific industrial users, could take place between mid-2019 and mid-2022. This would be a similar programme to the HyDeploy project. Subject to successful trialling, development of dedicated hydrogen production and distribution infrastructure could take place from 2022, with offtake commencing between 2024-2025. A Biohydrogen demonstration project could be integrated into the trial phase, or the subsequent dedicated infrastructure phase, although the volumes and offtake certainty would be very different and dictate the nature of the Biohydrogen production facility as discussed below.

Offtake Risk: The smaller the number of offtakers, the higher the offtake risk. Linking into industrial offtakers means that the hydrogen production facility would be subject to counterparty risk. The magnitude of this risk would depend on the number of offtakers and the scale of production relative to their demand.

If Biohydrogen production were integrated with the trial phase discussed above, then the offtake volumes would be smaller, subject to greater risk as the offtakers themselves would be trialling their ability to use hydrogen, and the trial phase would be finite in timescale. This would mean that a Biohydrogen demonstration project integrated into this phase would have to be small.

If Biohydrogen production were integrated with the subsequent dedicated infrastructure phase, then the volumes would be higher, be more resilient due to diversity of offtake, and proven utilisation, and would necessarily be for long-term operation.

Industrial offtakers would not change to hydrogen without confidence in continued energy supply. It is expected that early users would need to be able to continue to operate on natural gas or hydrogen for resilience. This would mean that failure to supply hydrogen could be accommodated, subject to appropriate commercial arrangements for natural gas.

Value: The market value for the hydrogen would be equivalent to natural gas. It would rely on an appropriate support structure for low carbon heat in industry, to enable both conversion of industrial sites, and development of necessary infrastructure. Whilst there is an appetite to enable industry to lower its carbon impact such a support structure does not yet exist.

Market maker role: The volumes required in this sector means that only Biohydrogen or fossil with CCS offer the prospect of cost-effective sources. Biohydrogen is not dependent on addressing barriers to CCS (although it could benefit further once CCS is established). Therefore, it is an important 'market maker' in this sector. It is noted that BioSNG can deliver a low carbon solution for industry with much lower barriers for individual users. However, the combined industrial and domestic demand for gas will exceed that available from indigenous bio-resources. Therefore, for gas to play a low carbon role in this sector, hydrogen will be important and so Biohydrogen has strategic value beyond BioSNG as a route to, and part of, widespread hydrogen use.

7.2.4.3 Dedicated hydrogen supply to the grid

Consideration is being given to the conversion of substantial sections of the grid to 100% hydrogen. This is one route to achieving high levels of decarbonisation of the gas grid. This is unlikely to be a short-term market for Biohydrogen facilities. However, as policymakers and commercial entities evaluate the feasibility of this approach for decarbonising heat, evidence of practical and viable sources of low carbon is crucial.

Timescales: The timescales are beyond that relevant for considering a demonstration facility. Realistically this is unlikely before the late 2020s at the earliest. However, evidence of Biohydrogen production based on other offtakers is an important aspect of enabling grid conversion to hydrogen.

Offtake risk: Once fully developed, this provides a market size which exceeds the realistic Biohydrogen production capacity. Furthermore, the offtake is via an interconnected grid with many offtakers. Volumes of offtake at specific locations are likely to match production facility scale, offering the prospect of many potential connection points. If grid conversion is adopted as a strategy, then this offers a low offtake risk to suppliers of hydrogen, similar to biomethane today.

Value: The market value for the hydrogen would be equivalent to natural gas. In addition, it would rely on an appropriate support structure for low carbon heat, enabling both appliance and network conversion as well as hydrogen production costs. As Biohydrogen from waste feedstock is likely to be cost competitive with alternative sources, it would be well placed in this market.

Market maker role: The volumes required in this sector means that only Biohydrogen or fossil with CCS offer the prospect of cost-effective sources. In reality, conversion of the grid to operate on hydrogen would only proceed with very high confidence in CCS, probably entailing operational projects. Therefore, whilst Biohydrogen is extremely helpful, offering lower carbon emissions and lower costs, it is not of itself a market maker for this opportunity.

7.2.4.4 Hydrogen supply for transport

An alternative market is use of the hydrogen as a transport fuel. This is not a mature market and so this application would require the parallel demonstration of end users.

Timescales: The primary focus for this market is buses. The 5-year JIVE⁵² programme, coordinated by Element Energy in the UK, formally commenced on 1st January 2017 and is designed to pave the way to commercialisation through the deployment of 142 fuel cell buses across 9 locations, more than doubling the number of FC buses operating in Europe. They will operate in large fleets of 10-30 buses, reducing costs compared to previous deployments. JIVE will also test new hydrogen refuelling stations with the required capacity to serve fleets in excess of 20 buses. This programme is expected to provide the platform for subsequent, larger bus fleet trials.

⁵² <http://www.fch.europa.eu/news/launch-project-jive-large-scale-deployment-fuel-cell-buses-europe>

Offtake risk: For early projects, the offtake risk for this application would be relatively high, because the number of customers will be limited, and likely to be part of demonstration projects themselves. A depot servicing a fleet of 100 buses would need the equivalent installed hydrogen production capacity of around 2.5MWth. This would be a large end use demonstration project, yet less than a tenth of commercially operating hydrogen production facility.

Resilience of supply would be important for this application as the users would be dedicated to hydrogen. Such a trial would need to integrate alternative sources of hydrogen, although they would not necessarily need to be low carbon. For example, existing industrial sources of hydrogen could be used, such as hydrogen upgraded from chlor-alkali plants or refineries.

As this market grows, even early deployment would be unlikely to achieve a match between commercial Biohydrogen offtake and local users. Therefore, this market is most likely to be accessed by hydrogen plants servicing both transport and other users, so both offtakers would be required for an individual project.

Value: This market is likely to provide the highest value for the hydrogen. The reference market value would be displacement of liquid fuels, at around £90/MWh including fuel duty. Hydrogen is expected to be valued as a development fuel under the RTFO, further enhancing its value. This is a mature support regime and also one which is compatible with grant funding schemes. Given that this application would entail additional costs for the end users, a portion of the subsidy may need to cascade to the user to offset some of these costs.

The current reference source of hydrogen is by electrolysis which has a predicted 2020 cost of £6.20/kg, equivalent to around £157/MWh. Therefore, Biohydrogen has the opportunity to compete very favourably, particularly from nth of a kind facilities.

Market maker role: The reference production route considered by many for this market is electrolysis. This is a demonstrated route offering very high levels of purity. However, the difference in cost between the two routes is substantial. Therefore Biohydrogen could unlock this market by transforming the economics, potentially offering hydrogen at a cost not dissimilar to liquid fuels even from relatively early commercial projects. Furthermore, the potential bio-resources would be more than sufficient to satisfy this market for a long time into the future and would not be contingent on CCS, although that technology would improve the greenhouse gas savings.

7.2.5 Carbon dioxide offtake

As shown in Chapter 6.0, whilst Biohydrogen delivers carbon saving without sequestration of CO₂, the benefits are substantially increased where CO₂ is stored. Furthermore, as CCS infrastructure becomes established, Biohydrogen plants become an important element for delivering Bio-CCS, also known as BECCS. The negative emissions from BECCs are increasingly seen as important in meeting our climate obligations, although have yet to be properly accounted for under carbon trading regimes. Whilst the establishment of CCS infrastructure will be based on fossil sources, individual Biohydrogen production plants are of sufficient scale to be material. Where there is the opportunity to locate close to

potential CCS infrastructure, this provides a no-regrets opportunity for future carbon savings.

There is a potential intermediary role for CO₂ usage. For example, the Swindon BioSNG project will sell approximately 5,000 tonnes per annum of CO₂ into the industrial market. However, given the volumes of CO₂ from a commercial plant compared with the overall UK market for CO₂, this will rapidly become saturated.

7.2.6 Summary of aspects requiring demonstration

Table 32 is a summary of the different markets and their attributes in terms of timescale, offtake risk, value and the role of bio hydrogen as a ‘market maker’ as well as summarising the CO₂, technical, supplier and feedstock risk issues, particularly in light of BioSNG demonstration.

Market	H2 Blend	H2 Industrial	100% H2 Conv	Transport
Timescale for offtake demo	2020	2022	-	2020?
Timescale for market development	2022+	2024+	2027+	2023?
Offtake risk	Low as many offtakers through grid. However, individual connection point capacity will limit number of projects unless integrated with other markets.	High for direct delivery but reducing with number of users and particularly if linked to grid blending.	Low once established.	High for the foreseeable future due to limited individual users.
Value	£20 + RHI equiv.	£20 + RHI equiv.	£20 + RHI equiv.	£90 + RTFO
BioH2 role as “market enabler”	Helpful	Important	Important	Important
CO2 offtake	Similar for all markets. BioSNG facilities delivery will establish confidence but market expected to saturate for CO ₂ sales and will move to CCS as carbon savings become important and infrastructure is established.			
Technical risk	Similar risk for all markets, primarily relating to the production of high quality syngas. BioSNG operation will reduce risk for this element. Demonstration of conversion to hydrogen may be necessary for investor confidence			

Equipment Supply & Contractor	Similar for all markets. BioSNG facilities delivery will substantially reduce risk.
Feedstock contracting risk	Similar for all markets. BioSNG facilities delivery will substantially remove risk.

Table 32: Summary of market attributes relevant to Biohydrogen

7.3 Commercial basis for a demonstration project

Typically, a demonstration project will require a funding stream which can accommodate a risk profile which is greater than commercial projects and also typically not make a return on funds invested. Therefore, a project will require a source of funds that values the long-term potential of the technology.

Compared with a pilot type facility, however, it is expected that such a project will operate 'commercially' inasmuch as it will sell product under contract. Operational costs will need to be funded for the project life, ideally through project revenues.

7.3.1 Project funding

Given that a demonstration project will not deliver a commercial return and has a high risk profile, sources of funds are required where the funder has a wider interest in deployment of the process. Such stakeholders or funders include:

Government: The UK has made decarbonisation commitments under its own Climate Change Act and more recently under the Paris Agreement. These will not be achieved without substantially decarbonising heat and transport, and therefore establishing pathways to decarbonise these sectors is critically important. This means that the Government has an interest in establishing and evidencing practical routes. It has a number of UK and some international grant funding programmes available (Innovation UK, Department specific schemes, NER, ERA-NET, H2020 programmes, noting that access to some of these tranches may be impacted by Brexit) that could be used to provide support. However, the overall cost of a demonstration (tens of millions of pounds) is higher than would normally be allocated to a single project.

Gas Distribution Networks: The GDNs have an interest in establishing the basis for continued use of the network to deliver low carbon heat. These are regulated businesses and so there are limits to their internal funds, although they may provide access to wider innovation funds, or may have parent companies with wider strategic interests. The use of innovation funding relies on the support of Ofgem.

Technology providers: Typically, technology providers have the biggest interest in seeing a new process demonstrated. However, a transition from lab scale investigations to full demonstration is beyond the reach of most technology providers. Furthermore, a project such as this integrates a number of technical elements, so the full project cost is greater than the contribution of any individual technology provider. The two primary elements here are the upstream gasification, where the participants have already taken forward a

demonstration project, and the downstream, hydrogen conversion, where technology providers are unlikely to consider investment in a full process chain, or even self-funding their own element.

Contractors: Whilst contractors have an interest in seeing new technologies reach the market such that they can then deliver projects commercially, it is highly unlikely that such participants would have the desire or ability to fund demonstration projects.

Feedstock owners: Waste is the primary source of feedstock. Only the large waste contractors would have the scale to contemplate a project of this size. Their focus is on reliable routes for handling and “utilisation” of their waste resources. Whilst there are merits associated with production of hydrogen, compared with conventional power generation, their focus is likely to remain on well-established routes for waste valorisation, without other substantial policy drivers. Even if they were to consider this route, access to internal funds for demonstration is likely to be limited.

Energy Companies: There are examples of energy companies being involved in demonstration projects, for example the Engie BioSNG demonstration project in Lyon, as well as Gobigas in Sweden. However, in general, the large energy companies are not well capitalised and their resources are likely to be focused on nearer term market investments.

Hydrogen Offtakers: These actors have one of the strongest interests in seeing low-carbon, low-cost sources of hydrogen reach the market. However, in general, the end users either need to develop or demonstrate new technologies, or at least have to make modifications to their own facilities. Therefore, it would require a particularly well-capitalised entity to be able to contemplate substantial funding upstream, as well as downstream development.

Financial investors: Financial investors have a substantial interest in seeing new markets and opportunities develop such that they are able to invest capital in new projects. However, in general, their appetite is investing in the second and subsequent projects, rather than demonstration projects or even the first commercial project. The exception would be an investor with an even greater strategic interest, such as development to the wider hydrogen economy, where this would be just one small element.

In reality, whilst there are a number of interested parties, very few have the appetite or ability to invest their own resources in a demonstration project itself. Therefore, in reality, any demonstration project is likely to rely on grant funding of some form. Furthermore, approaches which limit the total capital involved are likely to be most achievable. The willingness of funders to invest in the project will also be driven by the signals from Government on the strategic future for hydrogen. For example, a clear decision to convert the gas network to hydrogen would increase the probability of securing private sector investment in a demonstration project.

7.3.2 Revenues

7.3.2.1 Hydrogen market

As discussed above, there are a number of routes to market for hydrogen. Use for heat applications will have a lower market value compared with transport but the market size and lower quality present a lower barrier. Some form of revenue-based incentive is expected to be important; otherwise, upfront funding would not only have to cover capital investment but may also need to cover some operational costs. The nature of such funding, and its compatibility with grant funding, will be important; for example, incentives such as the Renewable Heat Incentive cannot be received in conjunction with a grant but obligations such as the Road Transport Fuel Obligation can.

7.3.2.2 Gate fee

This is one of the most substantial revenue streams for a project. The demonstration project should be located where there is good access to appropriate waste as significant transport requirements will reduce revenues. Limiting onsite preparation will lower capital cost. As a demonstration project, alternative disposal routes without punitive implications will be important.

7.4 Demonstration project options

There are a number of potential demonstration project options. These are laid out below and evaluated based on the opportunities and risks associated with each.

7.4.1 Dedicated Biohydrogen demonstrator

A Biohydrogen demonstrator could simply replicate the BioSNG facility, as a full chain waste to hydrogen project at an appropriate scale. The scale of the BioSNG plant was chosen to be approximately one-tenth that of a standard commercial plant, on the grounds that this was the smallest scale that could operate on a full-time basis and fully replicate the functionality of a larger facility. Increasing scale further than this necessarily increases capital cost.

By analogy, this would suggest a plant size of around 4MWth capacity, with a cost of around £25M. This would provide a comprehensive evidence base for an integrated Biohydrogen production facility. However, a key question is whether it provides sufficient added value to secure investment, given the BioSNG demonstration facility.

The situation where this might be feasible would be in the context of a wider hydrogen demonstrator, for example as part of a bus fleet trial, where the relatively low cost of hydrogen compared with the potential value might make a project at this scale attractive.

7.4.2 Slip stream from commercial biomethane plant

The BioSNG roadmap to deployment anticipates construction of a commercial scale facility commencing in early 2019 for operation in 2021, although this depends on changes in Government support for low carbon heat or transport. This enables an approach to

demonstrate Biohydrogen production through provision of a slipstream of high-quality syngas from this facility for a Biohydrogen demonstrator.

This has the advantage that the commercial rationale for the wider plant construction comes from commercial scale production of BioSNG. This is a fungible product with a mature market, operating at a scale with the prospect of commercial returns with appropriate subsidies and based on an integrated operating demonstration facility.

A reference case would be provision of around 10% of production directed towards hydrogen; e.g. 4MWth from a 40MWth underlying BioSNG plant. This would mean that the opportunity for hydrogen blending into the network would be well managed and could fuel an appropriately sized industrial user, or be used in transport for a substantial fleet demonstration, backed up by the heat markets.

Investors in the hydrogen demonstration project would need to fund the downstream equipment upgrading to hydrogen and pay for the syngas diverted from BioSNG production. In its simplest configuration, the two plant elements could be separate without heat integration or sharing of auxiliary equipment, and the timing of investment in the hydrogen production element could be independent of the primary plant, managing risks for both parties.

An alternative strategy is a more integrated approach, with closer heat integration and shared use of auxiliary equipment. This would increase efficiency, reduce costs and demonstrate operation more closely representative of commercial operation. However, it would require closer co-operation between investors and could jeopardise the ability to reach financial close on the commercial project. A common investor would make this more deliverable.

The most integrated option would be the development of a commercial plant with the capability of 'swinging' between BioSNG and hydrogen production as proposed in Section 5.1.7.3. This would entail increased cost and risk compared with a BioSNG-only plant. However, if the plant could be designed such that the risk profile for BioSNG production could be managed, support for a hydrogen demonstrator would provide maximum potential output and a reference model for a flexible plant.

The cost of the 'demonstration' element of these configurations would be expected to range between around £5-15M.

7.4.3 Modification/slip stream from the small commercial BioSNG plant

An alternative demonstration approach would be to modify or take a slip stream from the small commercial BioSNG plant being constructed in Swindon.

In scale terms, full modification would be a hydrogen processing train of around 4MWth, not dissimilar to the slip stream model considered above. Full conversion would not be substantially different in cost from a slip stream from a large commercial plant, with a smaller plant being lower cost, although economies of scale would limit the savings. That suggests a demonstration of hydrogen production could be feasible for under £5M, and so has the potential to be a low-cost option.

However, there are a number of disadvantages of this approach. The primary role of the BioSNG plant is to deliver long term stable operation of the facility. This benefits the roll-out of both BioSNG and Biohydrogen. Intervention in this plant would risk the opportunity for such operation. It would also potentially divert BioSNG sales away from existing offtakers such as Howard Tenens.

The other major issue is that production of Biohydrogen requires a hydrogen offtake. The other demonstration approaches have the opportunity to locate strategically with a potential hydrogen market. Whilst there is a hydrogen filling station in Swindon, it is a very small scale, and the gas connection would not have capacity to take more than a small fraction of BioSNG thermal capacity as hydrogen. This would mean that the hydrogen production element would realistically be at little more than a pilot scale and so its value as a stepping stone to commercialisation would be limited.

7.4.4 No demonstrator at all

It could be argued that it is possible to enter this market without a demonstrator at all. This would depend on downstream technology providers being prepared to give process guarantees based on syngas quality. This in turn would depend on exemplary operation of the upstream process in the BioSNG facility, providing the necessary confidence for the downstream processors, the overall contractor and potential investors. This may be feasible but securing investment for a large project without a good integrated reference is expected to be challenging. Furthermore, it is recognised that development of the hydrogen market opportunity more widely does depend on confidence in reliable, low cost, low carbon sources of hydrogen and so a demonstrator fulfils a wider function than confidence for the production technology investors and participants.

7.4.5 Comparison of demonstration options

Table 33 below summarises the demonstration options.

Approach	Dedicated Demonstrator	Slip stream from large BioSNG facility	Modify Small Commercial BioSNG Plant	No Demonstrator
Scale	4MWth	4-36MWth	0.4MWth	N/A
Cost	£25M	£5-15M	£3M	£0M
Benefits	Good demonstration of integrated facility.	Substantial demonstrator at low cost. Meaningful demonstration.	Low cost.	No cost.
Risks	Substantial funding required.	Relies on commercial BioSNG plant build out (but all developments	Very small demonstrator, market offtake risks, limited value for scale	Significant risk of no investors in commercial plant.

	Value for money of replicating upstream gasification facility.	do). Relies on BioSNG investors prepared to engage.	up, jeopardising ability to operate BioSNG plant.	
--	--	---	---	--

Table 33: Options for demonstrating Biohydrogen

7.5 Reference demonstration project development

From the above analysis, the most compelling and feasible demonstration approach is expected to be via a slip stream from a commercial BioSNG facility. However, it is recognised that given the dependency of a demonstration project on the available sources of funding there is a need to remain flexible. The reference demonstration project definition is described in Table 34 below.

Element	Attribute	Units	Scale
BioSNG Host Project	RDF input (as rec'd)	tonne pa	100,000
	Thermal output rating	MWth	42
	Footprint	Ha	3.1
	Cost	£M	£108 (Foak)
Biohydrogen Demonstration Stream	Hydrogen production rating	MWth	4
	Quality		Grid/heat quality unless specific transport opportunity
	Estimated additional cost	£M	£5-£8M

Table 34: Reference demonstration project definition

In terms of practical delivery of such a project, there are two dependencies: the underlying host BioSNG project and the Biohydrogen demonstrator. The funding, partners and site requirements are therefore reviewed below accounting for both these aspects.

7.5.1 Funding

This has two foci: pursuing investors with an interest in commercial BioSNG facilities and considering potential funding sources for the Biohydrogen element.

With regard to the former, the project partners are engaged with the market. This includes strategic investors from the upstream waste sector (potentially including local councils), the process sector and downstream energy sector as well as financial institutions. All investors need to be convinced that such a project is capable of delivering returns that meet their hurdle rate and that the technical, delivery and commercial risks are acceptable. Strategic interest is also key, given that many have alternative investment opportunities. On the basis that successful sustained operation of the small scale

commercial plant provides the technical evidence required, the primary risk relates to revenue. The current uncertainties with the RTFO and the substantial degradation of the RHI, along with the lack of clarity relating to support for low carbon heat after the closure of the RHI, represent project risks to be addressed.

Following successful operation of the small-scale BioSNG commercial facility in Swindon there is the potential to attract some debt finance to a larger project, although it is recognised that the level of debt is likely to be relatively limited.

It will be important to ensure that the primary investors in the host site are not exposed to additional risk associated with Biohydrogen demonstrator. Reaching financial close with projects such as these is challenging without additional demonstrator project risk. At its simplest, commercial arrangements could be put in place for an offtake of syngas, such that the host BioSNG plant investor would be agnostic to sales of syngas or BioSNG. The commercial plant investor would only need to provide for a 'flange' at the appropriate point in the process. This approach would also be particularly suitable for the owner of the demonstration project where both the process and the offtake may not be as reliable. This hosting arrangement could therefore insulate the demonstration plant owner from the risks associated with inability to take waste.

With regard to funding the demonstration element of the project, as acknowledged in Section 7.3.1, this is expected to require an element of grant funding. Potential sources include Innovation UK, Department specific schemes, NER, ERA-NET and the H2020 programmes, noting that access to some of these tranches may be impacted by Brexit. The sum of funds required is at the larger end of some of the schemes and in most cases will also require private sector match funding. The co-funding for the demonstrator from the same investors as the host plant significantly reduces project delivery risk.

Another potential route to funding is as part of a wider demonstration project, for example, as part of an integrated transport project. In that regard, the project partners are also following developments in that field.

7.5.2 Potential suppliers

The primary focus for the host site is to establish suppliers and, in particular, EPC contractors able and prepared to provide the process guarantees and EPC wrap that funders will require. The Partners are engaged in the market with key contractors.

For the hydrogen demonstration aspect of the project, the requirement for full process guarantees is less onerous and the technical requirements are more narrowly focused. Here the main candidates are the catalyst suppliers and where appropriate their process plant delivery partners, such as Johnson Matthey and Clariant in partnership with Amec Foster Wheeler.

7.5.3 Sites

The site requirements are driven by the BioSNG host project requirements. Key criteria are proximity to gas grid with sufficient capacity, ability to consent for waste processing, proximity to appropriate feedstock arisings, and sufficient area.

An extensive screening process has been undertaken of over 100 currently consented, but not developed, waste processing sites across the UK, including those for conventional thermal treatment.

These have been assessed against proximity to the gas grid and, where possible, initial views taken on expected capacity on the local gas grid. This has reduced this to a short list of five to eight sites which are being reviewed in more detail for project suitability.

In parallel, key areas on the gas grid with good interconnectivity and high network capacity have been identified, identifying in particular parts of Birmingham, London and the North West which could have potential for a project, subject to specific sites being available.

For the demonstration project, the principle attribute is the identification of potential hydrogen offtakers. This is an iterative process, as the potential for hydrogen production itself may facilitate development of users, particularly where incorporated in wider demonstration projects. There is known hydrogen activities and interest the North West as well as London, with historic interest in hydrogen projects in Birmingham.

7.5.4 Next steps

The next steps will be driven by the need to develop the host BioSNG plant. This will require development funds to go through the project development cycle of finalising suitable site selection and securing appropriate option agreements, obtaining necessary consents, agreement of waste supply and gas offtake agreements, securing appropriate renewable/low carbon support, appointment of an EPC and O & M contractor, and securing bank and equity finance. Financial close will be contingent on demonstrated sustained operation of the plant in Swindon, so is unlikely to be before early-mid 2019, with initial operation in 2021.

In parallel, the key focus in terms of the Biohydrogen development cycle is focused on the grant funding opportunities which could enable development, on the same time frame as the commercial plant. This places earliest operation of a hydrogen demonstration project in 2021.

APPENDICES

A.1.0 OFFLINE RIG

The offline rig used in the Biohydrogen project was originally developed as part of the BioSNG Demonstration Project.

This plant is designed to be operated at a range of reactor space velocities up to $40,000\text{h}^{-1}$, taking feedstock derived from bottled gases, real waste-derived syngas from the Demonstration Plant store and steam, or mixtures of these. It enables accurate measurement and control of input flow and composition with inlet temperatures in the range 200°C to 450°C and operation up to 10barg into a range of reactor geometries, with detailed instrumentation for temperature and gas compositions. The equipment is spread across two mobile skids; a photograph and P&ID for the process is shown below.

The system includes four main units: feeding gas unit; steam generation/preheater unit; reaction unit; cooling and gas sampling for analysis. The bio-syngas can be taken from the syngas storage vessels in the pilot plant or simulated by CO , CO_2 , H_2 , CH_4 and N_2 stored in five cylinders separately. The flow rates of the reactants are controlled by five volume flow controllers. In the steam generation unit, deionised water is stored in a vessel and the flow rate of steam is controlled by a peristaltic pump feeding the desired amount of deionised water to the preheater. The real-time temperatures of preheater and catalyst bed are detected by J-type thermal couples.

All experiments described in this work were performed in a well-insulated fix-bed quartz micro reactor tube (ID 25 mm, 210 mm length). A larger unit (ID 83 mm, 210 mm length) with external heating was also used to test isothermal configuration and lower space velocities. A cooling coil and drier are equipped downstream of the reactor. Outlet gas composition is measured by an FTIR analyser.



Figure A-1: Offline rig photograph

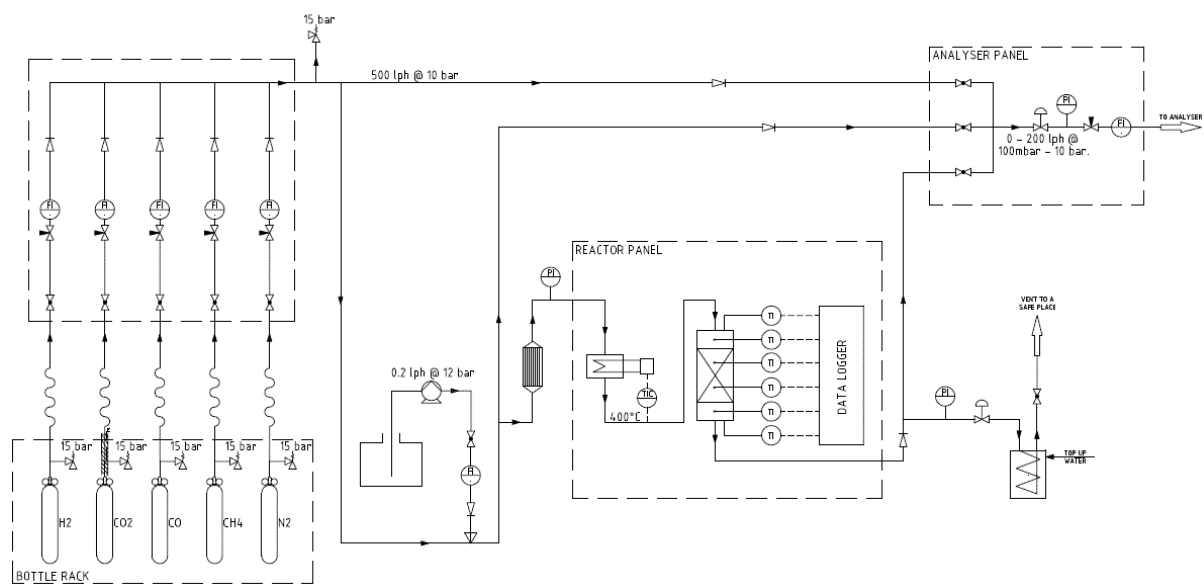


Figure A-2: Offline facility piping and instrumentation diagram

A.2.0 PILOT-SCALE PLANT

Biohydrogen production from waste was demonstrated by modifying the small-scale plant constructed in the BioSNG Demonstration Plant Project. The resulting plant is described below.

The syngas used in the project is a waste-derived syngas from Advanced Plasma Power's (APP) existing Gasplasma® pilot facility, located at Swindon, which is converted and refined in a dedicated conversion and conditioning plant.

Both components are shown in the photographs and process flow diagram below.



Figure A-3: The major components of the pilot plant: two-stage fluidised bed and plasma converter for syngas generation (left), syngas storage vessels and BioSNG facility (right)

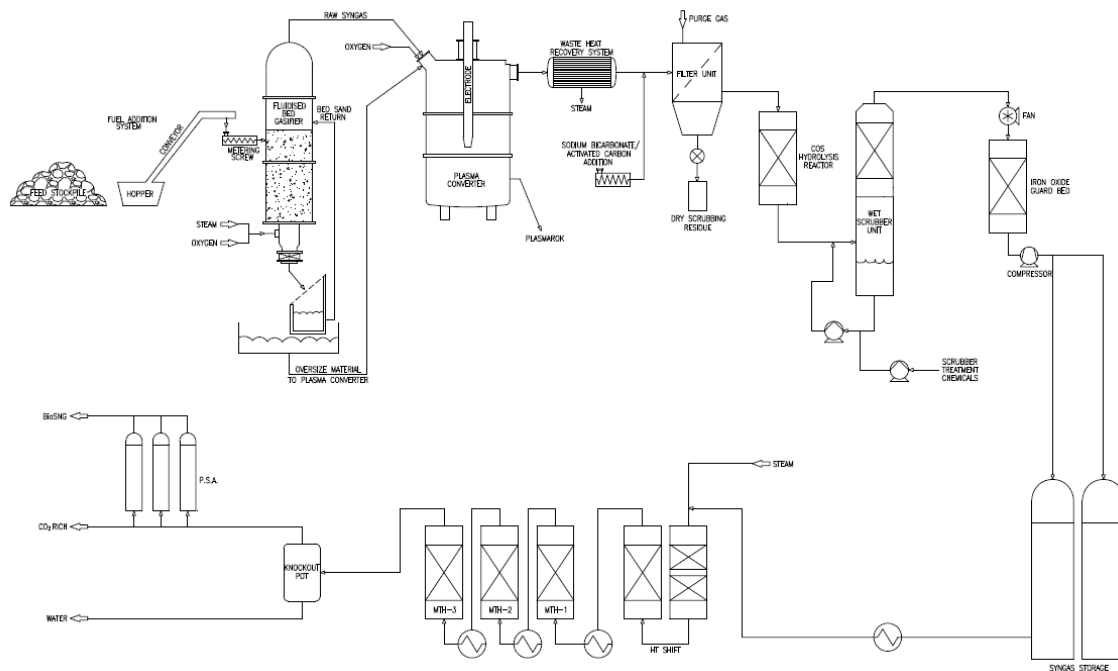


Figure A-4: Demonstration Gasplasma® and BioH2 schematic (to be modified)

The Gasplasma® process is a combination of two distinct thermal process steps. The first is a bubbling fluidised bed gasification process in which steam and oxygen are used to partially oxidise the waste-derived fuel. In the second step, the crude syngas produced by the gasifier is exposed to high temperatures (around 1200°C) in a separate plasma arc converter.

Downstream of the plasma arc converter, the syngas is cooled to below 200°C in a heat exchanger prior to treatment to remove any residual particulates and acid gas contaminants (mostly, chlorine and sulphur based components). This includes a dry filter (incorporating a ceramic filter unit with sodium bicarbonate and activated carbon dosing), an alumina hydrolysis reactor to convert any residual COS to H₂S, and then an oxidative alkaline wet scrubber. This provides bulk removal of nitrogenous compounds, chloride, fluoride, and sulphur gases present prior to demisting to reduce entrained water. An iron oxide pellet guard bed is used for any residual sulphur scavenging. Slightly negative pressure (5–10 mbar) is maintained using an induced draft (ID) fan located after the wet scrubber.

The outlet of the ID fan defines the system boundary between the original Gasplasma® pilot facility and the new Biohydrogen Demonstration Plant. In order to separate the operation of the Gasplasma® and the Biohydrogen Demonstration Plants, the syngas from the Gasplasma® process is compressed and stored. The syngas is generated at approximately 0.05 barg pressure and is compressed to 50 barg through a four-stage reciprocating compressor, featuring interstage cooling with condensate removal. The compressed syngas is then supplied to the Biosyngas store, which comprises four identical gas storage vessels. These vessels are capable of holding approximately 1.2 tonnes of

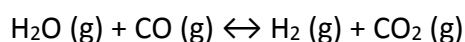
compressed syngas. Each vessel features inert gas purge, pressure relief and vent connections.

To produce Biohydrogen, the compressed syngas is fed from the store to the main Biohydrogen process plant where it is subject to a series of process operations designed to transform the syngas from a mixture of hydrogen, carbon monoxide, and carbon dioxide to a H₂-rich gas that can then be further purified to produce a H₂ gas of a quality suitable for injection into the grid. These process operations comprise:

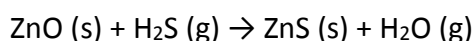
Pressure Letdown System. This section of the plant receives syngas from the high-pressure store and a heater electrically heats the syngas before releasing the pressure to the required plant operating pressure (in the range 2 to 20 barg). This initial heating is required to prevent the formation of solid, frozen carbon dioxide in the process pipework due to Joule-Thompson cooling during pressure reduction.

Gas Conditioning. The syngas is then electrically heated by further heaters to 400°C and controlled flows of either steam, or steam-forming deionised water, are added. The steam-laden syngas is then electrically heated to provide the feed gas to the water-gas shift reactor at a temperature sufficient to initiate the reaction.

High Temperature Water-Gas Shift Reaction. The high temperature water-gas shift reactor comprises a two-stage tubular reaction vessel with a suspended canister containing ferro-chrome catalyst beads. In this reactor, the syngas components are combined to enhance the hydrogen content via the moderately exothermic reversible water-gas shift reaction:



Each of the canisters is half filled with zinc oxide in which residual sulphur contaminants (principally hydrogen sulphide) are removed:



Low Temperature Shift Gas Preparation. Some or all of the cleaned, shifted syngas from the guard bed passes through a water-cooled heat exchanger to cool the gas to a temperature appropriate for that required for downstream LTS reactors.

Low Temperature Water-Gas Shift Reaction. The cooled partially shifted syngas is then fed to the LTS reactors. The low temperature water-gas shift reactors comprise two sequential tubular reaction vessels with a suspended canister containing CuO-ZnO catalyst beads. In this reactor, the CO is further reduced to 2-5% by volume, enhancing the quantity of H₂. The LTS catalyst in use during operation was Katalco 83-3M.

Methanation Reactor. The shifted syngas is then fed to one methanation reactor. The reactor contains a suspended canister containing diluted catalyst beads, comprising nickel-based catalysts of mild activity. As the gas passes through this bed the residual carbon monoxide within the shifted syngas is converted to methane, according to:



As the syngas passes through the series of water-gas shift and methanation reactors the concentrations of H₂ and CO₂ rise steadily to approximately 57% and 36% by volume

respectively (water free measurements) while the levels of carbon monoxide drop away to near zero.

Product Gas Conditioning. From the final methanation reactor the shifted product gas is cooled through a water-cooled heat exchange unit and thence passes to a knock-out pot where any condensed water droplets are removed from the gas stream.

The entire process has been designed to be automatically operated from the control system which monitors the process conditions and takes appropriate actions where necessary to ensure the process remains both safe and in control.

The gas composition was continuously monitored using an IR Xentra 4210 analyser in the Gasplasma® facility, a Gasmeter Fourier Transform Infrared (FTIR) Continuous Emissions Measuring System (CEMS) and Gas Data Click! gas analyser in the BioH₂ facility, and in the Pressure Swing Absorption (PSA) unit, a Siemens Ultramat 23 for CO/CO₂ and a Siemens Calormat for Hydrogen.

A.3.0 FUTURE DEVELOPMENTS

A.3.1 SELECTIVE REMOVAL OF REACTION PRODUCTS

Sorbent enhanced water-gas shift

The principal incentives for the development of the Sorbent Enhanced Water-Gas Shift (SEWGS) concept is the improvement of the overall energy efficiency associated with electricity production in pre-combustion carbon capture and storage schemes; entailing significant process intensification – reduced component count coupled with high temperatures and pressures (<700°C, and 40Bar).

SEWGS exploits the Le Chatelier's Principle by advantageously altering the equilibrium conditions of the water-gas shift reaction when used in the production of hydrogen from synthesis gas. To this end various embodiments of the SEWGS concept described in the literature utilise a solid adsorbent that progressively removes CO₂ from the reaction zone as it is being formed, thus promoting the forward reaction to the point where the conversion of CO to CO₂ can effectively be completed at high temperature (reportedly in the range of 350 to 700°C) in a single reactor stage.

The originating adsorbent used in SEWGS development is CaO, a “chemisorbent” with which CO₂ is chemically combined in the WGS reactor to form CaCO₃, which, upon regeneration releases CO₂ and returns the CaO to its original state as an adsorbent. Several alternative adsorbents have been proposed and trialled in pursuit of greater physical durability and resistance to chemical degradation such as potassium promoted hydrotalcite.

Two broad process concepts have been advanced for SEWGS:

1. A multi-vessel arrangement in which multiple reactors operate sequentially in adsorption and regeneration modes; similar in concept to the operation of pressure swing adsorption systems (this will be referred to as the Stepwise concept⁵³).
2. A twin vessel arrangement in which a solid adsorbent is continuously abstracted from the SEWGS reactor for regeneration in a parallel vessel, with regenerated sorbent being re-circulated to the reactor.⁵⁴

Adsorption of CO₂ onto a CaO adsorbent is a strongly exothermic process ($\Delta H = -183$ KJ/mol) and correspondingly the regeneration of the adsorbent is in equal measure

⁵³ <http://www.stepwise.eu/project/how/>

⁵⁴ ‘Sorbent enhanced water gas shift-rethinking carbon capture in IGCC’, William Steen,*a Carl Richardson,a Yongqi Lu,b Hong Lu,b and Massoud Rostam-Abadib, 2014

^aURS Group, Austin, TX USA

^bUniversity of Illinois Urbana-Champaign, Urbana, IL USA

endothermic. Hence the adsorption and regeneration processes will represent significant heat transfers within the system; however, in SEWGS both the adsorption and regeneration processes take place at high temperatures, which affords the possibility of efficient waste heat recovery for power generation to meet plant heating and electrical loads.⁵⁵ In the absence of such high-grade waste heat, primary energy (such as from natural gas or parasitic hydrogen consumption) would be required in any event to operate a syngas to hydrogen process, whereas these high temperature endogenous phenomena can be exploited to enhance overall system efficiency via the production of turbine quality steam.

Each of the two SEWGS concepts outlined above would entail its own particular sorbent regeneration procedure. In the Stepwise concept, reactor vessels are cycled sequentially from adsorption to desorption with the desorption process being effected by the combined effects of a steam purge and pressure let down. The use of steam as a stripping medium is reported in the literature to facilitate production of a hydrogen product stream of high (99%) purity coupled with a CO₂ stream that is of sufficient purity for geological storage.

In the second process configuration above, the continuous re-generation of the adsorbent would be effected by the combustion of hydrogen in the separate re-generation reactor (*op cit Footnote 54*).

In both SEWGS concepts outlined here the high temperature of the regeneration process coupled with the high temperature exotherm of the adsorption reaction afford the opportunity for beneficial use of reject heat. A further benefit of the high temperature process environment reported in the literature is that the use of a WGS catalyst may be significantly reduced or even eliminated altogether.

It has also been postulated in the literature that the SEWGS reactor could tolerate a level of H₂S and COS in the synthesis gas with these being adsorbed and desorbed as H₂S along with the CO₂ reject stream.

Conclusions

SEWGS offers conceptual benefits in comparison with the established process concepts adopted for this hydrogen project:

- Single stage reaction / process intensification
- Reduced process steam requirement (i.e. near stoichiometric)
- High purity product and reject streams
- Tolerance of sulphur in syngas
- Prospect of improved thermal efficiency via efficient utilisation of reject heat

⁵⁵ By comparison the energy rejected from the regeneration of (e.g.) amine or Selexol adsorbents is of little value in this respect on account of its moderate temperature.

However, the commercialisation of SEWGS presents a number of significant technical challenges amongst which the following appear to be the most prominent:

- Chemical and mechanical durability of the solid adsorbent
- Design for heat transfer within and between the process operations
- Realisation of system components (such as valves) that will tolerate the high temperature conditions
- Realisation of a design that would be commercially effective at the moderate scale implicit in a biomass or waste-fuelled facility

It is clear from a review of the literature that SEWGS is at a pre-commercial stage of development, so it is not a candidate process for the early production of bio-hydrogen. However, the elegance of the process concept coupled with the potential efficiency and intensification advantages suggest that it should be regarded as a technology with future potential in this sector. Accordingly, the outcome of ongoing SEWGS developments such as the H2020 Stepwise project (op cit) should be monitored closely with respect to future hydrogen and CCS project developments.

Membrane reactors

In membrane reactor (MR) hydrogen production, the chemical reactions take place in membrane reactors where hydrogen or CO₂ is selectively removed. This shifts the equilibrium-limited reaction towards the product side, giving increased conversion, and/or allowing the reactions to be carried out at milder thermal conditions.

This field has been subject to substantial research with more than 100 papers being published each year since 2008, as shown by Gallucci et al.⁵⁶.

Similarly to a SEWGS system, in a WGS-MR, the WGS reaction is combined with hydrogen membrane purification. The WGS reaction is exothermic and conversion is therefore favoured at low temperatures. However, when hydrogen is continuously removed, the equilibrium is shifted and it is possible with a higher conversion at higher temperatures. This reduces significantly the cooling demand. Operating temperatures of 300-500°C are suitable for the WGS-MR, and various microporous, dense metallic and dense ceramic membranes can be operated at these temperatures. Mass transport can also be increased by sweep gas on the permeate side that decreases the partial pressure of hydrogen. Sweeping is most effective for membranes with high hydrogen selectivity. In the case of high-purity hydrogen production, sweeping with steam is most relevant since it can be removed by condensation.

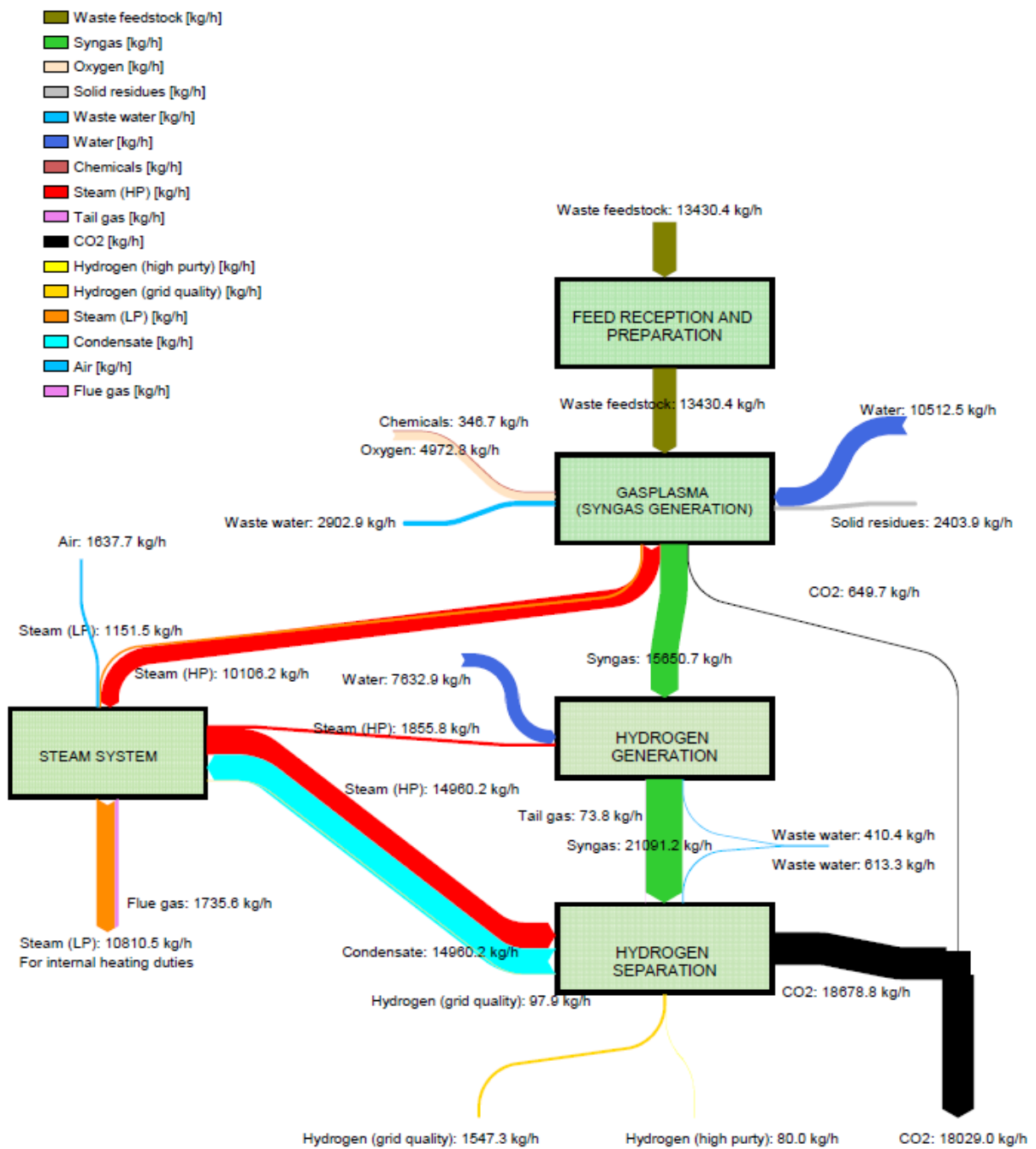
Conventional Cu- and Fe-based catalysts are not well suited for WGS-MRs due to a retardation effect of the reaction products that is more intense in membrane reactors. There is therefore focus on the development of alternative catalysts, such as Cu-ceria and

⁵⁶ 'Recent advances on membranes and membrane reactors for hydrogen production', Gallucci F, Fernandez E, Corengia P, van Sint Annaland M., Chem Eng Sci Apr. 2013;92:40e66.

⁵⁸ Note: Steam injection will be required into the two additional methanation reactors but this has not been shown – for simplicity.

- The two- stage reactor configuration could be embodied in a single reactor shell for simplicity, with a midpoint tap-off for the 3:1 H₂ / CO stream.
- The fully shifted gas from LTS#2 would be routed as per the base case scheme for purification via the PSA, the flow rates and input compositions to the PSA remaining unchanged from the base case.
- The 3:1 stream is routed via the existing CO₂ scrubbers to a methanation train comprising two additional methanator stages prior to polishing in the existing final methanator stage to remove residual oxides of carbon down to a compliant level (i.e. <100ppm). To this end it may be necessary to use a ruthenium-based catalyst in the polishing reactor in a similar manner to that incorporated into the final stage of the Vesta process.
- To balance more evenly the exotherms between the two additional reactors it may be possible to operate the first stage of the WGS to a figure below stoichiometry subject, of course, to being satisfied that this would not promote catalyst coking.
- The forward reaction in the methanators is favoured by an overall excess of H₂ to CO over the two stages. It is notable that there is little if any penalty in creating a product gas with, for example, 10% residual hydrogen; the principle objective in methanation being to ensure that the oxides of carbon had been effectively converted in the methanator reactors.
- Swinging the balance of H₂ to CH₄ within the limits postulated above gives a turndown on network-injected hydrogen of up to 9:1, whilst maintaining constant syngas generation and reducing any serious reduction in project income (depending, of course, on the relative sales prices of hydrogen and SNG).

A.4.0 MASS-BASIS SANKEY DIAGRAM



A.5.0 FINANCIAL INFORMATION

Levelised Costs

	Baseline £/MWh	No sequestration £/MWh	Transport quality to grid £/MWh	DIY Power £/MWh	Nth of a kind £/MWh
Capital cost	39.5	38.7	56.7	63.9	18.7
Operating cost	52.4	35.0	52.6	59.8	43.8
Gate fee	(20.6)	(20.6)	(25.8)	(29.8)	(20.6)
Levelised cost	71.3	53.1	83.6	93.8	41.9
Market price of gas	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)
Required support	51.3	33.1	63.6	73.8	21.9
Hydrogen price (£/kg)	2.11	1.57	3.28	2.78	1.24
CO ₂ savings (kgCO ₂ eq/MWh)	565	198	574	742	558.6
Cost of CO ₂ savings (£/tonne CO ₂ eq)	91	167	111	99	39.1
Opex	£m	£m	£m	£m	£m
Labour	1.6	1.6	1.6	1.6	1.6
Power	5.0	4.0	2.0	0.7	7.9
CO ₂ sequestration	5.4	-	4.3	5.4	11.4
Oxygen	1.3	1.3	1.3	1.3	2.8
Consumables	1.8	1.8	1.8	1.8	3.6
Maintenance	2.0	1.9	2.3	2.2	2.8
APC disposal	0.4	0.4	0.4	0.4	0.9
Insurance rent and rates	1.2	1.2	1.2	1.2	1.8
Other costs	0.5	0.5	0.5	0.5	1.0
	19.0	12.7	15.3	15.0	33.7

	Baseline £m	No sequestration £m	Transport quality to grid £m	DIY Power £m	Nth of a kind £m
Capex					
Fuel preparation	1.2	1.2	1.2	1.2	1.8
Gasification, cooling, bulk cleaning	27.6	27.6	27.6	27.6	41.8
Compression	5.0	5.0	5.0	5.0	7.6
Water-gas shift	14.0	14.0	14.0	14.0	21.2
PSA	-	-	4.7	-	-
Power generation	-	-	6.0	8.6	-
Building and civils	10.2	10.2	10.2	10.2	15.5
CO2 compression	1.5	-	1.5	1.5	2.3
Other equipment	1.0	1.0	1.0	1.0	1.5
Mechanical installation, power, controls	8.0	8.0	8.0	8.0	12.1
Grid connection and project development	3.5	3.5	3.5	3.5	5.3
Construction management	18.0	17.6	20.7	20.2	16.4
Contingency	9.0	8.8	10.3	10.1	12.6
	99.0	96.9	113.7	110.8	138.1