Hy-Impact Series
Study 2: Net-zero hydrogen

Hydrogen production with CCS and bioenergy

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A report for

equinor

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This report has been prepared by Element Energy.

Element Energy is a strategic energy consultancy, specialising in the intelligent analysis of low carbon energy. Since its inception in 2003, Element Energy provides consultancy services across a wide range of sectors, including carbon capture and storage and industrial decarbonisation, smart electricity and gas networks, energy storage, renewable energy systems and low carbon vehicles. With a team of over 50 specialists, Element Energy provides consultancy on both technical and strategic issues, believing that the technical and engineering understanding of the real-world challenges support the strategic work and vice versa.

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Executive Summary

Motivation and project overview

The UK is committed to reaching net zero emissions across the economy by 2050. The Committee on Climate Change's (CCC) recent report supporting this goal states that hydrogen has a critical role to play in achieving decarbonisation levels above the previous 80% target.[1] While hydrogen deployment is a key option for decarbonising the most challenging sectors, broader development of the hydrogen economy has the potential to benefit the wider energy system. As a low carbon and flexible energy carrier, hydrogen can support both the heat and electricity sectors in accommodating peak demands and enabling high penetration of renewable technologies.

Achieving net zero emissions nationally will very likely require the use of bioenergy with carbon capture and storage to offset emissions from sectors that will not reach zero emissions by 2050. Bioenergy is expected to provide up to 15% of the UK's primary energy demand in 2050 and should be leveraged to sequester between 20 and 65 $MtCO_2$ in negative emissions.[1] Displacing natural gas with sustainable biogas for hydrogen production via autothermal reforming (ATR) may provide a viable route towards the negative emissions required to reach the UK's net zero target.

This report investigates the potential for net zero and net negative hydrogen produced from natural gas and biogas to cost effectively contribute to a decarbonised UK economy in 2050. The analysis presented includes the following steps:

- Assessment of UK biogas availability to determine the volumes likely to be available for hydrogen production in the UK to 2050, considering the demand for bioenergy from competing uses and the share of the available bioenergy that is suitable for large-scale biogas production.
- Development of plausible options for natural gas, biogas, and hydrogen transport and delivery before, during, and after the conversion of the natural gas distribution grid to hydrogen.
- Analysis of the cost and carbon intensity of hydrogen production from natural gas and biogas under a range of assumptions for the availability of bioenergy and the level of hydrogen deployment. The potential for net zero and net negative emissions and the cost of carbon abatement are also calculated.
- Assessment of the natural gas demand under the scenarios considered and the likely impact on the level of UK gas imports.

1 Net Zero: The UK's contribution to stopping global warming, Committee on Climate Change, 2019.

Biogas availability for hydrogen production

Bioenergy availability in the UK is likely to be between 130 and 350 TWh/year in 2050. The CCC's recent report quantifies the potential availability of bioenergy resource in the UK and notes that bioenergy may contribute between 5% and 15% of the UK's total primary energy supply in 2050.[2] The present study develops three bioenergy scenarios based on the availability of i) domestic biomass, ii) biomass imports, and iii) biogenic wastes. The volume of each source will depend on the level of ambition in agricultural innovation, domestic afforestation, and waste reduction and utilisation, and on the strength of international sustainability governance. In the Low scenario (business-as-usual), 132 TWh/year of bioenergy is available in 2050, rising to 226 TWh/year in the Central (medium ambition) case and to 345 TWh/year in the High (most ambitious) scenario.

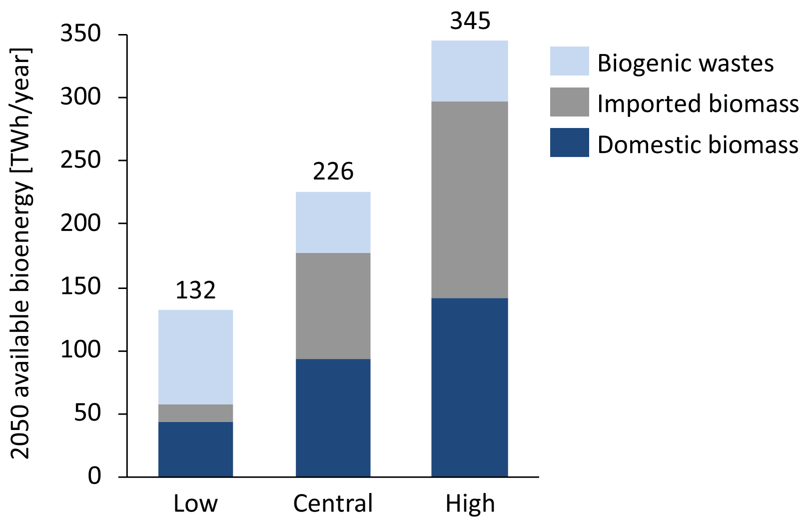


Figure 0.1 Scenarios for bioenergy availability in 2050

Bioenergy availability is expected to be sufficient to allow production of net negative emissions hydrogen in all hydrogen demand scenarios considered. Three hydrogen deployment scenarios at varying levels of ambition are analysed and key results for each are shown in Table 0.1.

- **CCC Further ambition[1]:** Hydrogen is used in industry and for long-haul HGVs and shipping, but has a smaller role in the decarbonisation of buildings and private vehicles.The hydrogen demand is 272 TWh/year.

- **H21 XL[3]:** Hydrogen provides 56% of heat demand currently fulfilled by natural gas on the local distribution network, including significant use in industry, as well as 31% of the UK's power demand. The hydrogen demand is 505 TWh/year.

- **World-leading deployment[4]:** This scenario assumes hydrogen production capacity increases continually at a high but realistic rate. By 2050, hydrogen replaces virtually all natural gas demand, provides 31% of the UK's power demand, and is used significantly in road and rail transport. Hydrogen is also produced for export via pipelines to mainland Europe and for the generation of electricity for export via interconnectors. The hydrogen demand is 1,040 TWh/year.

2 Biomass in a low-carbon economy, CCC, 2018.

3 H21 North of England Report, NGN and Cadent, 2018.

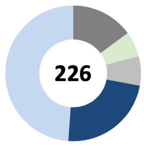
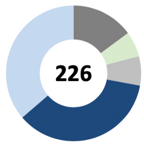
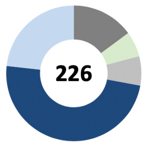
4 This scenario is based on H21 Max in the H21 North of England report.

Net negative emissions can be achieved at all hydrogen deployment levels in the Central bioenergy scenario. The amount of bioenergy resource dedicated to hydrogen will depend on the demand from competing uses and the size of the hydrogen economy. Three hard-to-decarbonise sectors (industry, aviation, and off-gas grid homes) are expected to consume a total of 60 TWh/year bioenergy. The remaining resource will likely be allocated to hydrogen and electricity production, depending on the relative levels of electrification of heat and transport and of hydrogen deployment as shown in Table 0.1. Out of 226 TWh/year assumed bioenergy availability in the UK in 2050 in the Central scenario, we estimate that between 50 and 105 TWh/year may be available for hydrogen production.

Production of biogas via gasification is a critical enabling technology for net zero hydrogen which should be supported to enable development at a commercially-viable scale. Gasification plants have been successfully demonstrated at sizes up to 20 MW, but an increase in scale to around 200 MW is required for gasification to be commercially viable. The technology required at this scale is already available, but no systems of this size are currently under development, and support from government is needed to de-risk the investment needed to reach commercial scale. Such support would also demonstrate commitment to development of the UK's bioeconomy and increase the likelihood of realising the Central or High bioenergy scenarios described above.

Improvements in gasification efficiency may also be achieved with deployment at commercial scale. With the efficiency improvements anticipated by 2050 from large-scale deployment, the bioenergy resource available for hydrogen will produce between 36 and 76 TWh/year biogas and enable net negative emissions to be achieved in each of the hydrogen deployment scenarios. Use of the available biogas in hydrogen production could abate over 50 $MtCO_2$/year in the least ambitious hydrogen scenario, CCC Further ambition, rising to nearly 200 $MtCO_2$/year under the World-leading deployment scenario.

Table 0.1 Bioenergy availability and potential for carbon reduction in the Central bioenergy scenario

Central Bioenergy Scenario	CCC Further ambition	H21 XL	World leading deployment
Hydrogen demand (TWh/year) (= 80 TWh/year)	272	505	1040
Uses of bioenergy (TWh/year) Aviation, Hydrogen, Industry, Power, Off-gas homes			
Bioenergy for hydrogen (TWh/year)	50	77	105
Biogas for hydrogen (TWh/year) (= 10 TWh/year)	36	56	76
Maximum savings over natural gas use ($MtCO_2$/year)	-54	-98	-196
Net emissions ($MtCO_2$/year)	-3.6	-4.9	-3.4
Hydrogen cost (£/MWh) (= £10/MWh)	£49.62	£48.14	£45.56
Abatement cost (£/tCO_2) (= £25/tCO_2)	£142	£137	£128

Cost of hydrogen and carbon abatement

The estimated cost of hydrogen varies between £41/MWh and £48/MWh depending on the level of biogas usage. Blue hydrogen produced via ATR using 100% natural gas is at the low end of this range, and the hydrogen price increases as more natural gas is displaced with biogas. As shown in Table 0.2, replacing 4.4% of the natural gas with biogas is sufficient to produce net zero hydrogen. If all 56 TWh/year available for hydrogen production in the H21 XL scenario are utilised, the biogas fraction is 9.3% and nearly 5 $MtCO_2$/year negative emissions are achieved.

The cost of carbon abatement via hydrogen production varies between £109/tCO_2 for blue hydrogen (100% natural gas) to £137/tCO_2 for hydrogen with negative emissions of -10 $kgCO_2/MWh_{H2}$ under the Central bioenergy scenario. In the context of the CCC's expectation that technologies needed to abate the final 20%

of the UK's emissions will cost up to £200/tCO_2, these figures indicate that negative emissions hydrogen could be a cost-effective approach.[1] For example, these values are competitive with the CCC's cost estimate for bioenergy with CCS (BECCS) in the power sector of £158/tCO_2. With negative emissions of -10 kgCO_2/MWh_{H2} the H21 XL scenario may reach up to 5 MtCO_2/year negative emissions by 2050. The potential for negative emissions rises to around 20 MtCO_2/year under the more ambitious High bioenergy scenario. The CCC's Further ambition scenario includes negative emissions of 50 MtCO_2/year in 2050**.** The negative emissions from hydrogen production could make a significant contribution towards reaching this target and enabling economy-wide net zero emissions.

Table 0.2 Key results on the cost of hydrogen and carbon abatement in the H21 XL scenario

H21 XL Scenario	Blue Hydrogen	Net zero Hydrogen	Max CO_2 abatement
Biogas fraction	**0%**	**4.4%**	**9.3%**
= 2% biogas			
Biogas consumed (TWh/year)	**0**	**26**	**56**
Hydrogen cost (£/MWh)	**£40.60**	**£44.20**	**£48.10**
= £10/MWh			
Emissions savings over natural gas use (MtCO_2/year)	-89	-93	-98
Net emissions (MtCO_2/year)	**4.5**	**0**	**-4.9**
Cost of abatement (£/tCO_2)	**£109**	**£123**	**£137**
= £25/tCO_2			

Feasibility of large-scale biogas and hydrogen delivery

There are a range of feasible network configurations for the large-scale production and delivery of biogas in the short and long term. In addition to the option of production of biogas at dedicated sites collocated with the ATR plant, a green gas net balancing scheme could be used to achieve an equivalent outcome through the distributed injection of biogas into the natural gas network. This approach would allow biogas to be injected at all levels of the gas network in the shorter term prior to conversion of the natural gas grid. As the natural gas distribution system is converted to hydrogen, biogas production can continue at sites near to the ATR plant or at remote sites via injection into the gas national transmission system (NTS). These options enable net zero hydrogen production to be realised through a variety of technical approaches relevant from the development of initial demonstration facilities through to nationwide hydrogen deployment and to form a valuable part of the UK's roadmap to a net zero energy system.

Implications for the gas sector

With Central bioenergy availability, the UK's natural gas imports in 2050 are likely to be comparable or lower than today, despite reductions in domestic production. As domestic offshore natural gas production reduces in the coming years, increased natural gas usage has the potential to impact the security of UK energy supply. Our analysis indicates that total gas demand (natural gas and biogas) will reduce by at least 150 TWh/year in two of the three hydrogen deployment scenarios considered. This reduction is due to energy efficiency and the increased electrification of sectors which currently use natural gas, such as domestic and industrial heat, despite hydrogen production causing increasing gas demand. The use of biogas in hydrogen production further reduces the demand for natural gas by between 50 and 150 TWh/year.

Although gas demand increases relative to today's usage in the World leading deployment scenario, this is driven by the UK's export of hydrogen and electricity produced from hydrogen, rather than a rise in domestic demand. It should be noted that domestic natural gas consumption is not necessarily reduced in scenarios featuring lower hydrogen deployment. In the CCC's Further ambition scenario, there is considerable usage of natural gas with CCS in the power sector for peaking and mid-merit electricity generation, resulting in a comparable gas demand to the H21 XL deployment scenario.

Recommendations for further work

This study demonstrates the feasibility of net negative emissions hydrogen production and the potential environmental benefits. Hydrogen production with biogas is cost competitive with other negative emissions technologies and can make a significant contribution to the UK's 2050 net zero target. Additional research is needed to further quantify the system-level benefits of negative emissions hydrogen deployment and to identify actions needed in the near term. This further work may include:

- A detailed study on a **future Humber CCS cluster** and the regional potential for biogas production in the medium and near term.
- Consultation with farmers, forestry experts, DEFRA, and local authorities to **identify risks and barriers that may limit the UK's production of bioenergy feedstocks** and to develop recommendations for their mitigation.
- **Integrated analysis of the costs and benefits of using bioenergy feedstocks for hydrogen and power production** to allow a robust comparison of the financial, environmental, and energy-system implications of each route.

Contents

Acronyms

AD	Anaerobic Digestion
ATR	Autothermal Reforming
BECCS	Bioenergy with carbon capture and storage
BEIS	Department for Business, Energy & Industrial Strategy
Blue Hydrogen	Hydrogen produced using natural gas or biogas reforming coupled with CCS
Capex	Capital expenditure
CCC	Committee on Climate Change
CC(U)S	Carbon capture (utilization) and storage
CO_2	Carbon Dioxide
DEFRA	Department for Environment, Food and Rural Affairs
GW	Gigawatt (unit of power)
H_2	Hydrogen
H21	H21 project – a collaborative gas industry programme investigating 100% hydrogen gas networks.
HHV	Higher Heating Value
kW	Kilowatt (unit of power)
kWh	Kilowatt hour (unit of energy)
LDS	Local distribution system
LPG	Liquefied petroleum gas
LTS	Local transmission system
MSW	Municipal solid waste
Mt	Million tonnes
MW	Megawatt (unit of power)
MWh	Megawatt hour (unit of energy)
NTS	National transmission system
Opex	Operational expenditure
Scope 1 emissions	Direct emissions of greenhouse gases
Scope 2 emissions	Indirect emissions of greenhouse gases from energy production
SNG	Synthetic natural gas
TRL	Technology readiness level
TWh	Terrawatt hour (unit of energy)
UCO	Used cooking oil

Introduction

Introduction

1.1 Background

The UK is committed to reaching net zero emissions across the economy by 2050. The Committee on Climate Change's (CCC) recent report supporting this goal states that hydrogen has a critical role to play in achieving levels of decarbonisation above the previous 80% target.[1] Hydrogen deployment is a key enabler for eliminating carbon emissions from energy intensive sectors, including heavy industry, long-haul transport, and peak demands for heating and electricity.

Development of the hydrogen economy beyond the most hard-to-decarbonise sectors has the potential to provide several benefits to the wider energy system. Decarbonisation of heat via conversion of the natural gas grid to hydrogen may be less costly than electrification of heat.[5] Hydrogen is a flexible energy carrier and can be stored for daily and interseasonal usage as natural gas is today. It may also provide cost effective and low carbon electricity generation, contributing to grid flexibility as the share of intermittent renewables increases.[6]

Achieving net zero emissions nationally will also require the use of biomass with carbon capture and storage (CCS) to offset emissions from agriculture, aviation, and other areas that will not reach zero emissions by 2050. Bioenergy is expected to provide between 5% and 15% of the UK's primary energy demand in 2050 and should be leveraged to sequester between 20 and 65 $MtCO_2$/year in negative emissions, according to the CCC.[2] Low carbon hydrogen is most cost-effectively produced at large scales from natural gas via autothermal reforming (ATR) with CCS.[7] Displacing natural gas with sustainable biogas in this process may provide a viable route towards the negative emissions required to reach the UK's net zero target.

1.2 Objectives and scope

This report investigates the potential for net zero and net negative hydrogen produced from natural gas and biogas to cost effectively contribute to a decarbonised UK economy in 2050. Specific objectives include:

- Estimation of the **level of bioenergy resource that may be available for hydrogen production** in 2050 given the possible production volumes and competing uses
- Assessment of the **feasibility and cost of biogas production at the needed scales**, and the impact of biogas usage on the **cost and carbon intensity** of hydrogen produced using large-scale ATR
- Development of **plausible scenarios** for the deployment of the **infrastructure required to enable production and delivery** of biogas and hydrogen at national scales
- Analysis of the **potential for net zero and net negative hydrogen production** using biogas at several scales of hydrogen deployment given the available bioenergy resource
- Assessment of the possible impacts of **widespread hydrogen deployment on UK natural gas imports**.

5 Cost analysis of future heat infrastructure, Element Energy for the National Infrastructure Commission, 2018
6 Hydrogen and Fuel Cells: Opportunities for Growth, A Roadmap for the UK, E4Tech and Element Energy for Innovate UK and BEIS, 2016
7 Hydrogen in a low carbon economy, CCC, 2018

1.3 Project methodology and report structure

The project methodology is summarised below and in Figure 1.1.

1. **Assessment of UK biogas availability** – Sections 2.1 to 2.3 discuss the potential availability of biogas for hydrogen production in the UK to 2050.[8] Three scenarios for the UK's total bioenergy feedstocks are developed based on the set of scenarios presented by the CCC for domestic biomass, imported biomass, and biogenic wastes in their report on Biomass in a low-carbon economy (Nov 2018). The amount of bioenergy (and resulting biogas) likely to be available for hydrogen production is estimated based on these scenarios, accounting for (i) the share of the bioenergy that is unsuitable for large-scale biogas production and (ii) the share of the bioenergy likely to be diverted for other uses. The potential biogas production methods are considered and the resulting cost and carbon intensity of biogas is assessed.

2. **Options for infrastructure deployment** – Section 2.5 develops plausible scenarios for natural gas, biogas, and hydrogen transport and delivery before, during, and after the natural gas distribution grid is converted to hydrogen.

3. **Hydrogen deployment scenarios** – Section 3.1 considers three levels of hydrogen deployment covering a range of ambition levels for the hydrogen economy: the CCC's Further ambition scenario,[1] the H21 XL scenario developed in the H21 North of England report,[3] and a World leading deployment scenario that additionally includes use of hydrogen in transport and for export.[4]

4. **Cost and carbon analysis of hydrogen production** – Sections 3.2 to 3.4 present details of Equinor's ATR production concept and analyse the implications of the three bioenergy availability scenarios developed in Section 2 on the amount of carbon neutral and carbon negative hydrogen that could be produced in the UK in 2050. The resulting cost and carbon intensity of hydrogen is determined in each case.

5. **Implications for the gas sector** – Section 3.5 compares the demand for natural gas in the three hydrogen deployment scenarios with current demand, and discusses the likely impact on the level of UK gas imports.

The study's key findings are presented in Section 4.

8 We have used 'biogas' as a general term to refer to bio-derived methane produced via both gasification and AD.

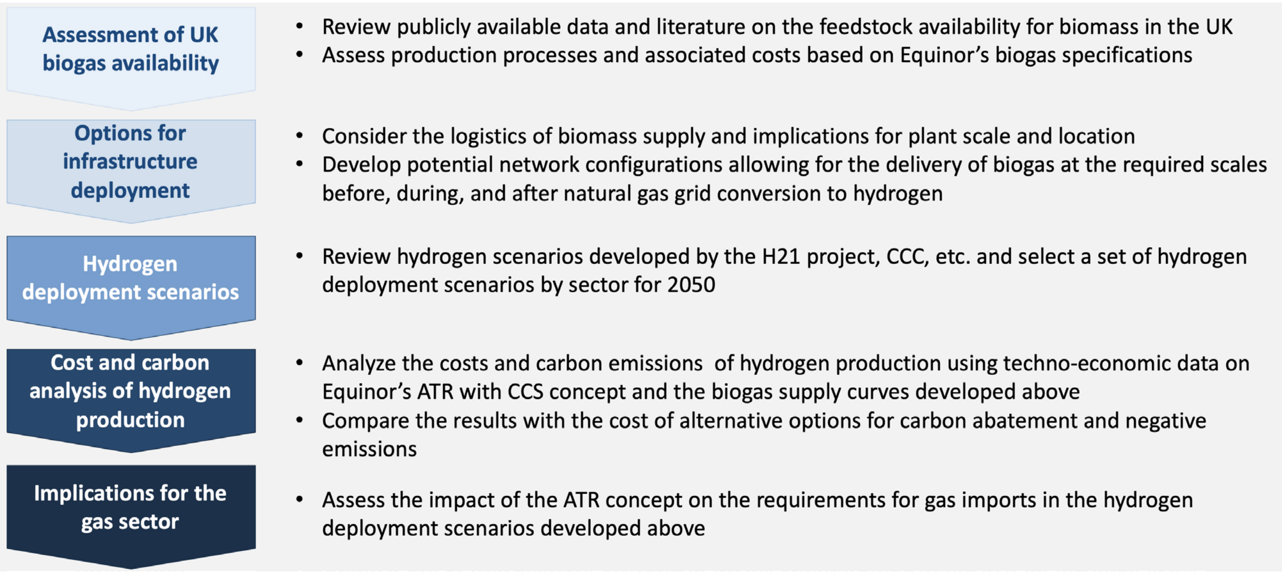


Figure 1.1 Summary of project methodology

Potential UK biogas availability

2 Potential UK biogas availability

2.1 Scenarios for feedstock availability

This section develops three scenarios for the availability of bioenergy in the UK in 2050: Low, Central, and High. These cover the range of bioenergy resource described in the CCC's report Biomass in a low-carbon economy (Nov 2018). Limitations on the resource usable for hydrogen, including feedstock suitability and competing uses, are discussed in the following sections.

The CCC's recent report quantifies the potential availability of bioenergy resource in the UK and suggests how it can best be directed towards reaching the UK's carbon reduction targets. The study notes that bioenergy could supply between 100 and 300 TWh/year in 2050, making up between 5% and 15% of the UK's total primary energy supply of about 2000 TWh/year. This compares with a bioenergy contribution of 150 TWh/year, or 7% of total supply, in 2018.[2,9]

The scenarios developed by the CCC are broadly consistent with other recently published work on the availability of bioenergy.[5,10] Three categories of resource are considered:

(i) domestic biomass (forestry, energy crops, and agricultural residues),

(ii) biomass imports, and

(iii) biogenic wastes.

For the present study, the scenarios developed by the CCC in each of the above categories are combined into three overall bioenergy resource availability scenarios: Low, Central, and High. These are shown in Table 2.1. The CCC assumes that CCS will be available in 2050 in all scenarios, and notes the importance of using CCS technology with the available bioenergy resource to maximise negative emissions.

Table 2.1 Bioenergy resource scenarios used in the present study

Bioenergy Scenarios	Biomass	Biomass imports	Biogenic waste	Total resource before considering suitability and competing uses
Low	Business as usual	Middle road	High	132 TWh/year
Central	Multi-functional land use	Average of Middle road and GGI	Low	226 TWh/year
High	High biomass	Global governance & innovation (GGI)	Low	346 TWh/year

9 Digest of UK Energy Statistics, BEIS, 2018.

10 Review of Bioenergy potential: Technical report, Anthesis and E4Tech for Cadent, 2017.

Biomass scenarios

- **Business as usual:** Existing trends in land use, agricultural productivity, and innovation continue to 2050. There is little change in diets and food waste.
- **Multi-functional land use:** Medium levels of ambition in innovation and behaviour change to allow agricultural land to be released for other uses. More farmland dedicated to hedgerows and increased afforestation lead to a more diverse agricultural landscape.
- **High biomass:** Agricultural land released through higher agricultural productivity and some changes in diets and food waste. High rates of tree and bioenergy crop planting and productivity.

Biomass import scenarios

- **Poor global governance:** Imports to decline to zero by 2050 reflecting poor sustainability governance internationally, and the fact that domestic production exceeds the UK's 'equal share' of all globally-produced biomass.
- **Middle road:** Continuation of current trends globally. While more biomass is available internationally, imports remain low to match the UK's 'equal share' given increased domestic production.
- **Global governance and innovation:** A favourable global context for sustainable biomass production and supply is accompanied by strong sustainability governance, allowing imports to increase more than three-fold.

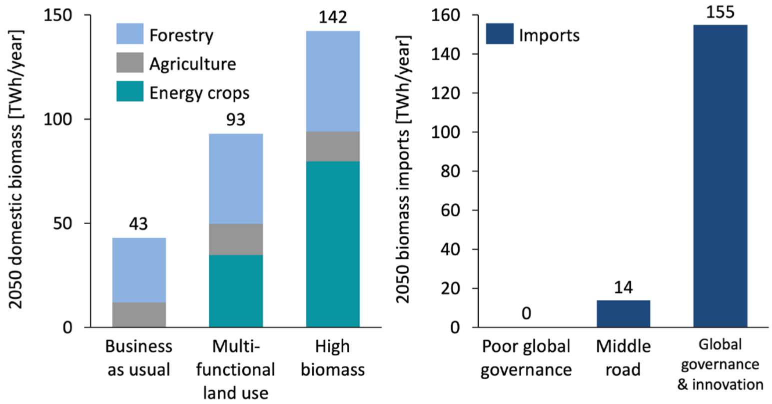


Figure 2.1 Scenarios for the domestic production (left) and import (right) of biomass in 2050

Biogenic waste scenarios

- **Low waste:** Preferred scenario. Waste is minimised at source and most barriers to waste separation and use are overcome, allowing residual waste to be almost fully exploited. The available biogenic waste resource is less than that exploited today.

- **High waste:** Government, households, and businesses take less action causing less waste to be avoided in 2050. Higher collection rates for this residual waste are achieved and most barriers to waste separation and use are overcome. The available resource therefore increases relative to today.

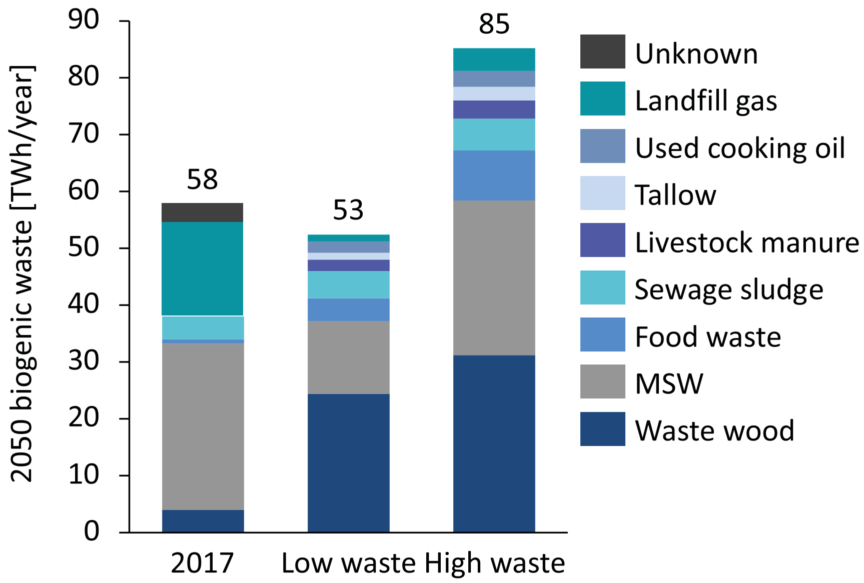


Figure 2.2 Scenarios for biogenic waste in 2050[11]

2.2 Biogas production routes and feedstock suitability

This section presents the methods for converting raw bioenergy feedstocks into biogas. The following biogas production routes are considered:

- Gasification

- Anaerobic digestion (AD)

The suitability of the feedstocks discussed in Section 2.1 above for gasification and AD are shown in Table 2.2. The majority of the feedstock types and around 90% of the bioenergy are appropriate for use with gasification, which is therefore considered the biogas production route of primary interest. However, these feedstocks are also those likely to be diverted for competing uses as discussed in the next section, 2.3.

11 2017 values taken from Digest of UK Energy Statistics, BEIS, 2018.

Table 2.2 Feedstocks suitable for biogas production via gasification and anaerobic digestion (AD) Gasification

Bioenergy Scenarios	Suitable for gasification?	Suitable for AD?	Scenario availability (TWh/year)		
			Low	Central	High
Energy crops – miscanthus	✔	✔	0	18	40
Energy crops – Short rotation coppice willow	✔	✘	0	18	40
Agriculture	✔	✔	12	15	14
Forestry	✔	✘	31	43	48
Imported wood chips	✔	✘	14	85	155
Waste wood	✔	✘	31	24	24
Municipal Solid Waste (MSW)	✔	✔	27	13	13
Food waste	✘	✔	9	4	4
Sewage sludge	✘	✔	5	5	5
Livestock manures	✘	✔	3	2	2
Tallow	✘	✘	3	1	1
UCO	✘	✘	3	2	2
Landfill gas	✘	✘	4	1	1
Total bioenergy feedstock (TWh/year)			132	226	346
Total feedstock suitable for gasification (TWh/year)			115	215	335
Total feedstock suitable for AD (TWh/year)			56	57	78
Feedstock only suitable for AD (TWh/year)			17	11	11

Gasification

Gasification of woody and dry bioenergy feedstocks produces a fuel known as bio-substitute natural gas, or bioSNG. A diagram of the gasification process is shown in Figure 2 3. Depending on the feedstock type, some pretreatment may be required. This may include shredding or drying woody feedstocks, and depackaging and sorting waste feedstocks where needed. The feedstocks are then partially combusted in the presence of steam to produce a mixture of hydrogen, carbon monoxide, methane, as well as inert gases and impurities which depend on the type of feedstock used. The resulting gas is cleaned to remove the impurities and a water gas shift reaction is used to remove carbon monoxide. The gas mixture is then methanated to convert the hydrogen to methane and finally excess carbon dioxide is removed. The resulting bioSNG is chemically identical to natural gas and can be injected into the natural gas grid.

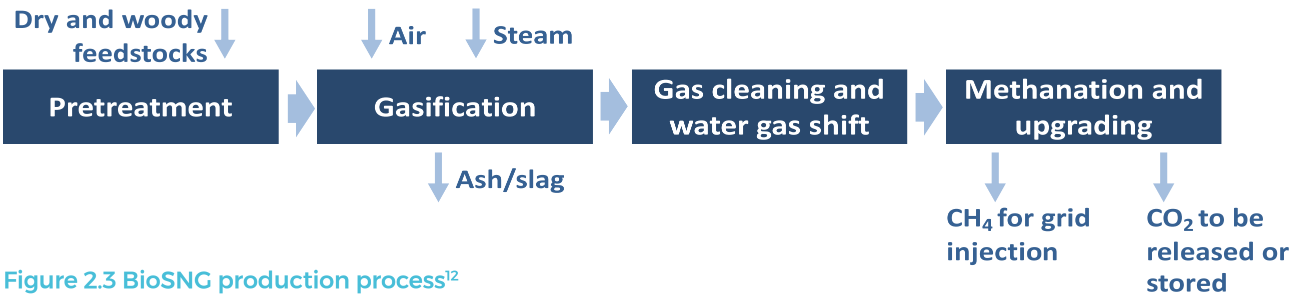


Figure 2.3 BioSNG production process[12]

Biomass gasification is currently at Technology Readiness Level (TRL) 8 to 9; demonstration plants are operating successfully but the technology still requires external funding support and is not fully commercialised. Table 2.3 lists several existing and in-progress gasification plants. The largest plant developed to date is the 20 MW GoBiGas facility in Sweden which operated between 2014 and 2018. The plant demonstration was technically successful, although it was ultimately not economically viable. Further size increases are anticipated to reduce costs, with commercial scale facilities anticipated to be between 200 and 400 MW. The technology required for systems at this size is technically available, and with government support for deployment gasification could play a significant role in decarbonisation efforts.

As noted in Table 2.2 above, a wide range of feedstocks are suitable for gasification, most of which are easily transportable. Forestry, waste wood, and municipal waste are used most commonly today (see Table 2.3). Gasification plants currently operating are designed to use either woody feedstocks or waste feedstocks, but improved pre-treatment processes may allow facilities to flexibly use a range of feedstocks in future.[13] Nevertheless, size increases above the commercial scale may be limited due to local bioresource availability and the costs of feedstock transport.[14]

Table 2.3 Existing and planned bioSNG production facilities

Project	Location	Size (MW biomethane	Feedstock	Status
GoBiGas Phase 1[14]	Gothenburg, Sweden	20	Forestry	Completed 2014, shut down 2018
GoBiGas Phase 2[16]	Gothenburg, Sweden	100	Forestry	Cancelled 2018
Gaya[15]	Saint-Fons, France	3	Forestry and agriculture	Completed 2016
GoGreenGas Pilot[16]	Swindon, UK	0.05	Municipal waste and waste wood	Completed 2015
GoGreenGas Commercial[18]	Swindon, UK	2.5	Municipal waste and waste wood	In progress
Ambigo[17]	Alkmaar, Netherlands	4	Waste wood	In progress

12 BioSNG Demonstration Plant: Project Close-Down Report, Cadent, 2018.
13 Innovation Needs Assessment for Biomass Heat, Ecofys and E4tech for BEIS, 2018.
14 http://www.ieabioenergy.com/wp-content/uploads/2018/06/GoBiGas_Webinar_20_june_final.pdf
15 http://www.projetgaya.com/en/
16 https://gogreengas.com/
17 https://www.modernpowersystems.com/features/featurefocus-shifts-from-power-to-chemicals-6151882/
18 AD Information Portal, NNFCC for DEFRA and DECC, accessed May 2019, http://www.biogas-info.co.uk/

Anaerobic digestion

Anaerobic digestion (AD) is used primarily for wet feedstocks including food waste, sewage sludge, livestock manures and some agricultural residues, although up to 40% dry content may also be used.[18] The resulting fuel is known as biomethane.

Figure 2.4 resents a diagram of the AD process. The feedstocks are first depackaged and pretreated, which may include de-bagging and shredding the material. The feedstocks enter the AD chamber where they are broken down by bacteria and archaea to produce methane, carbon dioxide, water, and digestate. This process takes between 14 and 40 days and may occur in a single stage batch reactor or in a continuous flow system.[19] The digestate is a nutrient-rich substance which may be used as fertiliser or in low-grade building materials. The resulting gas is a mixture of methane and carbon dioxide (typically between 30 and 50% by volume).[20] This mixture must be cleaned from impurities and the carbon dioxide removed before being compressed and injected into the gas grid. The technical characteristics of AD plants are presented in Section 5.2, Appendix B.

Figure 2.4 AD production process

Anaerobic digestion is currently at TRL 9. Nearly 100 AD plants are receiving support from the GB Renewable Heat Incentive (RHI) to inject biomethane into the gas grid, while over 750 are producing biomethane for on-site heating.[20] The average capacity of sites injecting into the grid is about 3 MW and those using the energy on site have an average capacity of 0.4 MW. The capacity of AD plants is limited by local feedstock availability as wet feedstocks are more costly to transport given their high water content and low energy density.

AD plants typically inject biomethane into the gas network local distribution system (LDS) due to their small size. We therefore assume that biomethane from AD is not available for hydrogen production in 2050 as the LDS has been converted to carry hydrogen (rather than natural gas). Novel methods to allow direct production of hydrogen via AD are currently under investigation and may allow existing AD plants to continue operating, injecting hydrogen into the LDS after grid conversion.[13] This assumption eliminates between 10 and 20 TWh/year of bioenergy resource from the scenarios based on the Low, Central and High estimations of feedstock availability for AD purpose only in Table 2.2.

19 Meegoda et al, A Review of the processes, parameters, and optimisation of anaerobic digestion, International Journal of Environmental Research and Public Health, 2018.

20 RHI Monthly Statistics Data, BEIS, Jan 2019.

2.3 Bioenergy for hydrogen production and competing uses

In 2050, 'acceptable' uses of bioenergy, as recommended by the CCC, will be limited to those where carbon abatement is maximised and where at least partial carbon capture is possible. This section assesses the bioenergy demand from other sectors, and the resulting limitation on the availability of bioenergy for hydrogen production. The use of bioenergy for electricity production will depend to a large extent on the UK's decarbonisation strategy, including whether electrification of heat and transport, or use of hydrogen, is more widespread. Three potential levels of demand for bioenergy for electricity production are therefore considered, corresponding to the hydrogen deployment scenarios discussed further in Section 3. In addition, other hard-to-decarbonise sectors (industry, aviation, and off-gas grid homes) are expected to consume 60 TWh/year (of the 100 to 300 TWh/year of bioenergy projected by the CCC by 2050) of bioenergy.[1]

The CCC's recent bioenergy report and Net Zero report list the acceptable uses of bioenergy and anticipate that the cost, achievable capture rates, and the value of each energy service will determine the optimal split between them, as all have similar tCO_2e savings per tonne of biomass.[1,7] These applications and the expected bioenergy demand are described further below. The CCC also recommends that distributed uses of bioenergy that are not compatible with carbon capture are phased out by 2050. These uses include:

- Liquid biofuels for road transport
- Solid biomass for heat in buildings
- Biomethane for use in the power sector, which can be decarbonised in other ways
- Biomethane as a long-term strategy for gas grid decarbonisation[21]

The CCC has estimated the demand for several competing uses of bioenergy in hard-to-decarbonise sectors.[1] These include:

- **Industry** – Cement, iron, steel, and chemicals plants may consume 13 TWh/year of bioenergy in 2050, according to the CCC's Further ambition scenario.
- **Aviation** – Bioenergy should be used to produce 5 to 10% of the UK's aviation fuel demand, consuming 32 TWh/year in CCC's Further ambition scenario. CCS should be deployed at the fuel production facilities; carbon capture at the point of fuel usage is not feasible.
- **Off-gas grid home**s – 15 TWh/year bioenergy are dedicated to producing bioLPG for off-gas grid homes to use with hybrid heat pumps in CCC's Further ambition scenario. CCS should be deployed at the fuel production facilities; carbon capture at the point of fuel usage is not feasible.

These three sectors are expected to consume a total of 60 TWh/year bioenergy.

21 As noted in the previous section, existing AD plants may be converted to produce biohydrogen for injection into the converted hydrogen grid.

The CCC recommends in the same studies that any remaining bioenergy resource is dedicated to hydrogen and electricity production.[1,7] The volume directed towards each sector is not yet known, and will depend on the level of electrification of heat, transport, and other sectors, the size of the hydrogen economy, and the costs and benefits of using bioenergy in each case. National decarbonisation policy and the level of investment and innovation in bioenergy use in electricity and hydrogen production will be strong factors in determining the preferred use of bioenergy.

To identify upper and lower bounds for the potential availability of bioenergy for hydrogen, we have made assumptions on the level of bioenergy used for electricity production in each of the three hydrogen scenarios presented in more detail in Section 3, with the implications of these for natural gas demand detailed in Section 3.5. These demands are additional to those from the hard-to-decarbonise sectors discussed above.

- **CCC Further ambition**: This scenario relies primarily on electrification to decarbonise heat (via heat pumps and hybrid heat pumps) and the majority of road transport (excluding long haul HGVs). Hydrogen use is therefore relatively limited (see Section 3.1) and the use of bioenergy in electricity production is prioritised. The CCC estimates that 105 TWh/year of bioenergy will be dedicated to electricity production in new and existing power plants with CCS. Combined with the 60 TWh/year demand from the hard-to-decarbonise sectors (Industry 13 TWh/year, Aviation 32 TWh/year, off-grid homes 15 TWh/year), a total of **165 TWh/year** are diverted for uses other than hydrogen.

- **H21 XL**: This scenario features a partial conversion of the natural gas distribution grid and significant use of hydrogen for flexible power generation. Electricity consumption of bioenergy is assumed to be the average of the CCC further ambition (105 TWh/year) and World Leading deployment (50 TWh/year) scenarios, therefore 78 TWh/year are consumed for electricity. Combined with the 60 TWh/year used in hard-to-decarbonise sectors, this gives a total of **138 TWh/year** of bioenergy dedicated to competing uses.

- **World leading deployment**: Hydrogen is the preferred decarbonisation route in this scenario, with complete conversion of the natural gas distribution grid to hydrogen and significant contributions to decarbonising transport and the power sector. We therefore assume that no new bioenergy power stations are constructed, although major power producers using bioenergy today will continue to operate. Bioenergy power stations too small to justify CCS installation are phased out by 2050.
  50 TWh/year bioenergy, the same volume consumed today,[9] is therefore dedicated to electricity in addition to the 60 TWh/year for the hard-to-decarbonise sectors, resulting in **110 TWh/year** unavailable for hydrogen production i.e. dedicated to competing uses.

Figure 2.5 allows a comparison between the supply available in the bioenergy scenarios developed in 2.1 (see Table 2.2) and the demand for other uses in the hydrogen deployment scenarios discussed above. Only feedstocks suitable for gasification are shown as these feedstocks are also of primary interest for the competing sectors. 10 to 20 TWh/year of potential AD produced biogas are not considered.

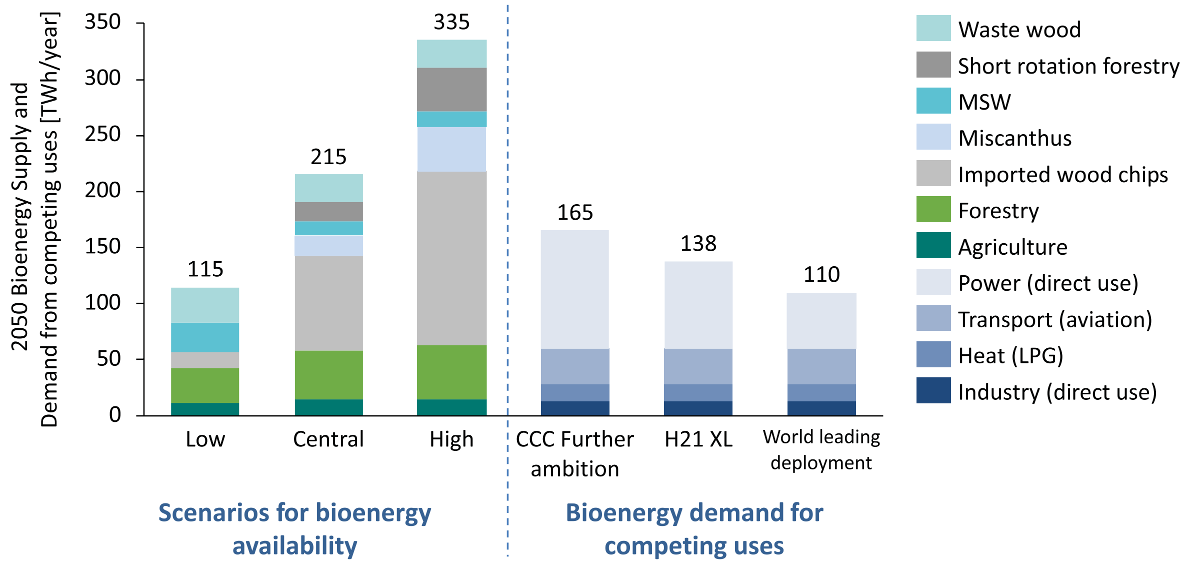


Figure 2.5 Supply of bioenergy suitable for gasification and demand from competing sectors in 2050

Table 2.4 presents the range of bioenergy resource that may be available for hydrogen production. This depends on both the total available bioenergy and on the amount diverted for other uses, which varies with the hydrogen deployment scenario. For example, the potential resource available for hydrogen in the Central bioenergy scenario (215 TWh/year total bioenergy) is likely to be between 50 TWh/year for the CCC Further ambition scenario (when 165 of the total 215 TWh/year are diverted to other uses) and 105 TWh/year, corresponding to the widespread deployment of hydrogen in the World leading deployment scenario (110 TWh/year diverted out of total 215 TWh/year).

Table 2.4 Bioenergy resource available for hydrogen production in 2050 in each bioenergy scenario and in each hydrogen deployment scenario, considering efficiency losses during conversion from raw feedstock

			CCC Further ambition	H21 XL	World leading deployment
Bioenergy scenarios	**Total bioenergy resource (TWh/year)**	**Gasification-suitable resource (TWh/year)**	**Bioenergy resource available for hydrogen (TWh/year)**		
Low	132	115	0	0	5
Central	226	215	50	77	105
High	346	335	170	197	225

The values shown in Table 2.4 are for the 'raw' bioenergy resource; losses in the gasification process will further reduce the amount of biogas available for hydrogen production. The efficiency of biogas production via gasification varies by feedstock but is expected to average about 72% in 2050.[15] The 77 TWh/year of bioenergy available in H21 XL under the Central bioenergy scenario therefore correspond to 56 TWh/year of biogas. The levels of biogas available for hydrogen in 2050 are shown in Table 2.5.

Table 2.5 Biogas available for hydrogen production in 2050 in each bioenergy scenario and in each hydrogen deployment scenario

	CCC Further ambition	H21 XL	World leading deployment
Bioenergy scenarios	**Biogas available for hydrogen (TWh/year)**		
Low	0	0	3.6
Central	36	56	76
High	123	143	163

2.4 Cost and carbon intensity of biogas

Table 2.6 presents the assumed cost and carbon intensity of bioenergy feedstock production in 2050.[12,22] The carbon intensity shown includes only emissions involved in producing and delivering the feedstocks and in producing the biogas and does not include the biocarbon embodied in the biogas itself, which is 185 kgCO_2/MWh, identical to the carbon intensity of natural gas.

Both the cost and carbon intensity of the biogas vary with feedstock type. Each feedstock is divided into quintiles to represent the variation of carbon intensity within the total available stock. Emissions from agricultural and forestry feedstocks vary with the quality of land and amount of fertiliser required, while waste feedstock emissions vary as the content changes. The carbon intensity of imported wood chips depends on the land used for production as well as the transport distance and method. As the economy is decarbonised towards 2050, emissions from feedstock transport and pre-processing are expected to reduce substantially. However, emissions from fertilisers, land use and land use change, and feedstock decay during transport and processing will continue. The emissions from each feedstock have been reduced by 65% to account for the expected change by 2050. The feedstock cost is the average across the total available stock and does not vary across the quintiles.

22 Biomass Feedstock Availability, Ricardo for BEIS, 2017.

Table 2.6 Cost and carbon intensity of bioenergy feedstocks. Feedstocks only suitable for AD are shaded darker blue[5,22]

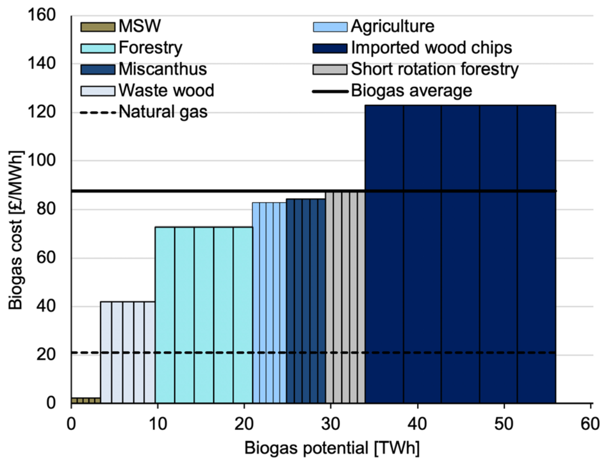
Feedstock	Cost (£/MWh)	Quintile 1 ($kgCO_2/MWh$)	Quintile 2 ($kgCO_2/MWh$)	Quintile 3 ($kgCO_2/MWh$)	Quintile 4 ($kgCO_2/MWh$)	Quintile 5 ($kgCO_2/MWh$)
Agriculture	£19	7.1	7.4	7.7	8.0	8.3
Food waste	-£17	6.0	9.0	12.0	15.0	18.0
Forestry	£14	2.5	3.4	4.4	5.4	6.3
Imported wood chips	£40	3.1	9.8	16.6	23.3	30.0
Miscanthus	£20	9.3	11.6	13.9	16.2	18.5
Municipal Solid Waste (MSW)	-£23	9.2	10.2	11.3	12.3	13.4
Sewage sludge	£30	14.8	18.0	21.1	24.2	27.3
Short rotation forestry	£21	2.7	3.1	3.4	3.7	4.1
Waste wood	-£2	0.8	0.9	1.0	1.1	1.2
Wet manure	£16	14.8	18.0	21.1	24.2	27.3

The technical characteristics assumed for gasification plants are shown in Table 2.7. The efficiency improvements and reduction in the capital and operating costs shown are possible if the economies of scale necessary for commercialisation are realised.

Table 2.7 Technical characteristics of gasification systems in 2020 and in 2050

Technical characteristic	Value – 2020	Estimated Value - 2050
Overall process efficiency[12,15]	55%	68%
Electricity consumption[12]	0.09 kWh/kWh bioSNG	0.09 kWh/kWh bioSNG
Feedstock consumption (HHV)[12,13]	1.73 kWh/kWh bioSNG	1.38 kWh/kWh bioSNG
Load factor[12]	90%	90%
Plant lifetime[12]	30 years	30 years
Required rate of return	10%	10%
Capital cost[5,12]	£1,800/kW bioSNG	£1,575/kW bioSNG
Operating cost[5,12]	£100/kW bioSNG	£88/kW bioSNG
Commercial scale[12]	200 MW	200 MW

The cost and carbon intensity of the biogas available in 2050 in the Central bioenergy scenario with the H21 XL hydrogen deployment scenario are shown in Figure 2.6. Table 2.8 presents the average carbon intensity and cost of biogas produced from all feedstocks. A worked example calculation is presented in Section 5.1, Appendix A.



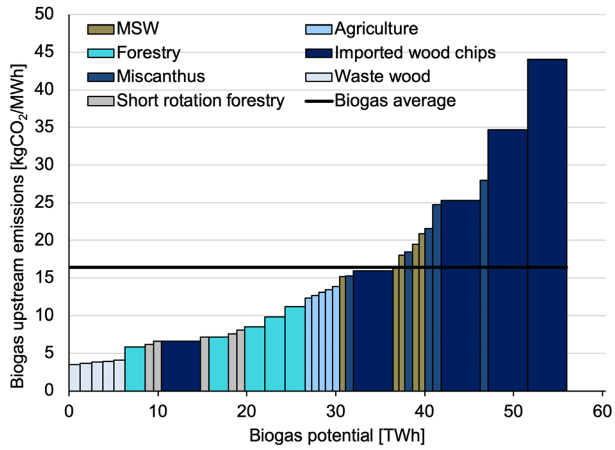


Figure 2.6 Cost (left) and carbon intensity (right) in the Central bioenergy scenario with the H21 XL hydrogen deployment scenario

Table 2.8 Average biogas cost and carbon intensity

Wholesale cost	Carbon intensity
£87.50	16.4 $kgCO_2$/MWh

2.5 Network configurations and biogas delivery

The development of appropriate infrastructure is critical to enable the production and distribution of biogas and hydrogen at the scales considered here. This section outlines potential configurations of the natural gas and hydrogen networks, and options for biogas supply, before, during, and after the gas distribution grid is fully converted to hydrogen. The arrangements presented here are intended to illustrate one feasible method of biogas and hydrogen delivery; other configurations are also possible.

Figure 2.7 shows a possible approach **prior to conversion** of the natural gas grid. As bioenergy is inherently a widely distributed resource, the production of biogas will also be distributed. While some production may be co-located with ATR facilities, it is likely that the majority of the required volume will be injected into the local transmission system (LTS). BioSNG plants at commercial scale (at or above 100 MW) must be connected to the gas grid at locations with sufficient capacity to absorb the volumes produced. This will likely require siting near to the gas national transmission system (NTS) or local transmission system (LTS). The local distribution system (LDS) will be suitable only near to urban regions where flow rates and demand are sufficient to accommodate the baseload requirements of the bioSNG plant.[23]

23 The potential for bioSNG production in the UK, E4Tech and NNFCC for DECC, 2010.

ATR facilities will draw the bulk (or all) of their gas requirements from the natural gas grid and achieve net zero or net negative emissions via a carbon offsetting scheme. This 'green gas net balancing system' will allow hydrogen and biogas production facilities to be developed in the most suitable locations while ensuring that the carbon footprint of the gas system is continually reduced.

As the hydrogen and bioenergy capacities are first established (prior to conversion of the gas distribution grid), there are three options for biogas production and gas grid delivery:

- Production of bioSNG at a plant near to the ATR
- Production of bioSNG at a plant remote to the ATR. The bioSNG is injected into the LTS making use of the green gas net balancing system.
- Production of biomethane at an AD plant remote to the ATR. The biomethane is injected into the gas network making use of the green gas net balancing system. As discussed in Section 2.2, only small volumes of biogas are expected to be available from AD due to the low feedstock volumes and location of many AD sites off of the gas grid.

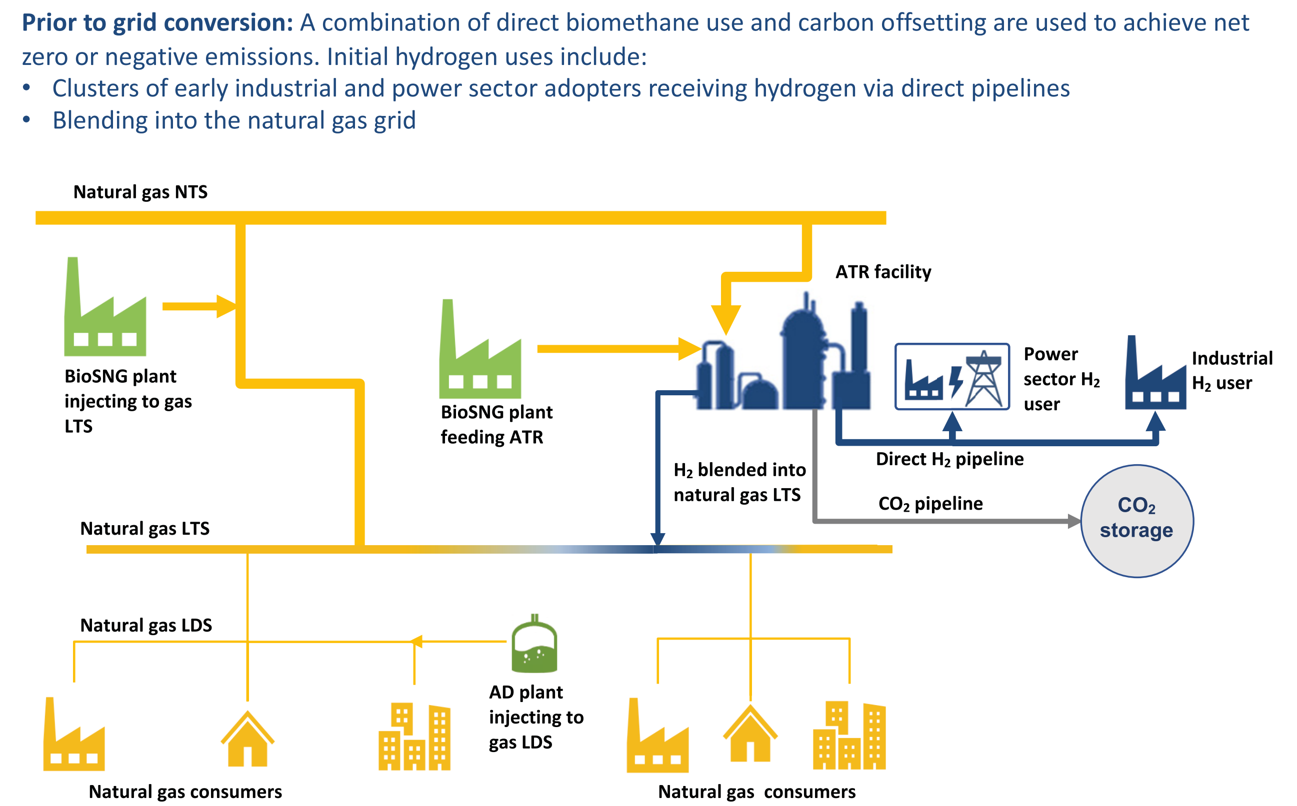


Figure 2.7 Options for biogas production and delivery prior to conversion of the natural gas grid

Figure 2.8 shows a possible approach when the grid has been partially converted to hydrogen. At this point, the pipelines constructed for hydrogen delivery to early adopters in Figure 2.7 are extended and connected to form the beginning of the hydrogen national transmission system (NTS). The hydrogen NTS is connected to the LTS and local distribution system (LDS) as parts of the natural gas grid are converted to hydrogen. Early large-scale adopters will continue to use hydrogen drawn directly from the hydrogen NTS, while later adopters in industry and the power sector may also draw from the hydrogen LTS.

As in Figure 2.7, a green gas net balancing system is used to verify the carbon footprint of the UK gas system and ensure that it continues to reduce towards net zero.

Partial grid conversion: A combination of direct biomethane use and carbon offsetting are used to achieve net zero or negative emissions. Biogas may be produced:

- In a bioSNG plant local to the ATR facility for direct use in hydrogen production
- In bioSNG plants injecting to the gas LTS, making use of a net balancing scheme
- In AD plants injecting to the gas LDS, making use of a net balancing scheme

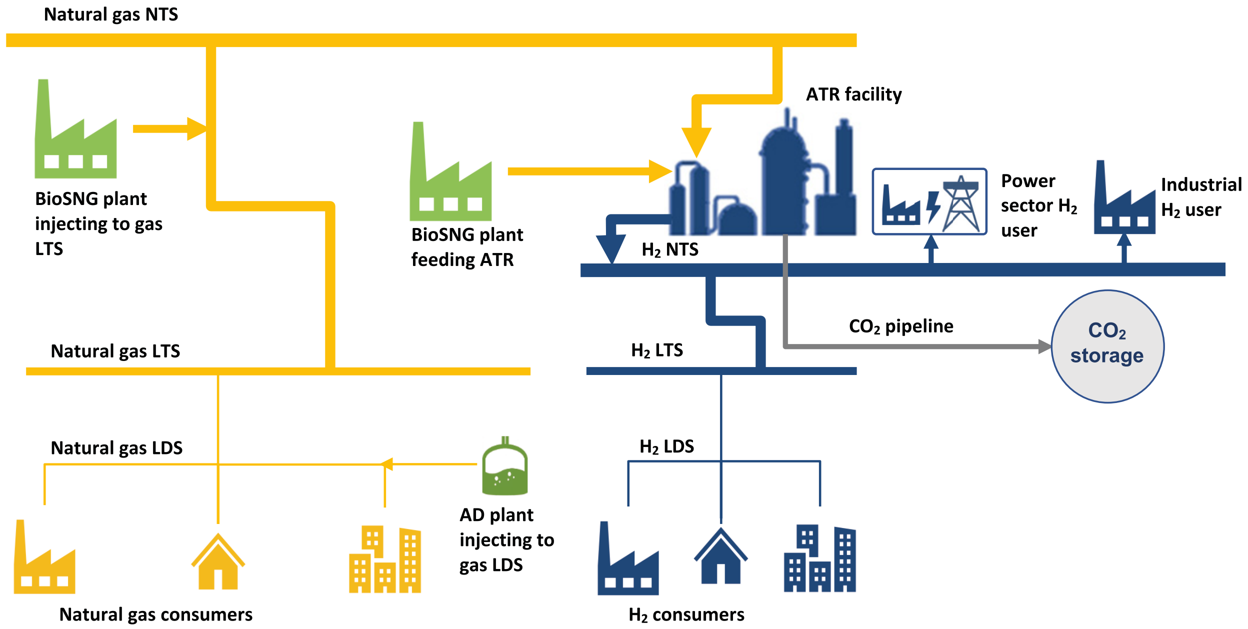


Figure 2.8 Options for biogas production and delivery when the grid has been partially converted to hydrogen

Figure 2.9 shows a possible approach in the case **after** full grid conversion to hydrogen, perhaps in 2050. At this point, conversion of the natural gas grid to hydrogen will preclude injection of biogas into the distribution grid. Two options for biogas production and delivery remain:

- Production of bioSNG at a plant local to the ATR
- Production of bioSNG at a plant remote to the ATR. The bioSNG is injected into the NTS making use of the green gas net balancing system.

At this time, small scale AD facilities could either generate biogas to use on-site for heat or electricity production, or use advanced methods to produce hydrogen directly and inject this into the hydrogen LDS.

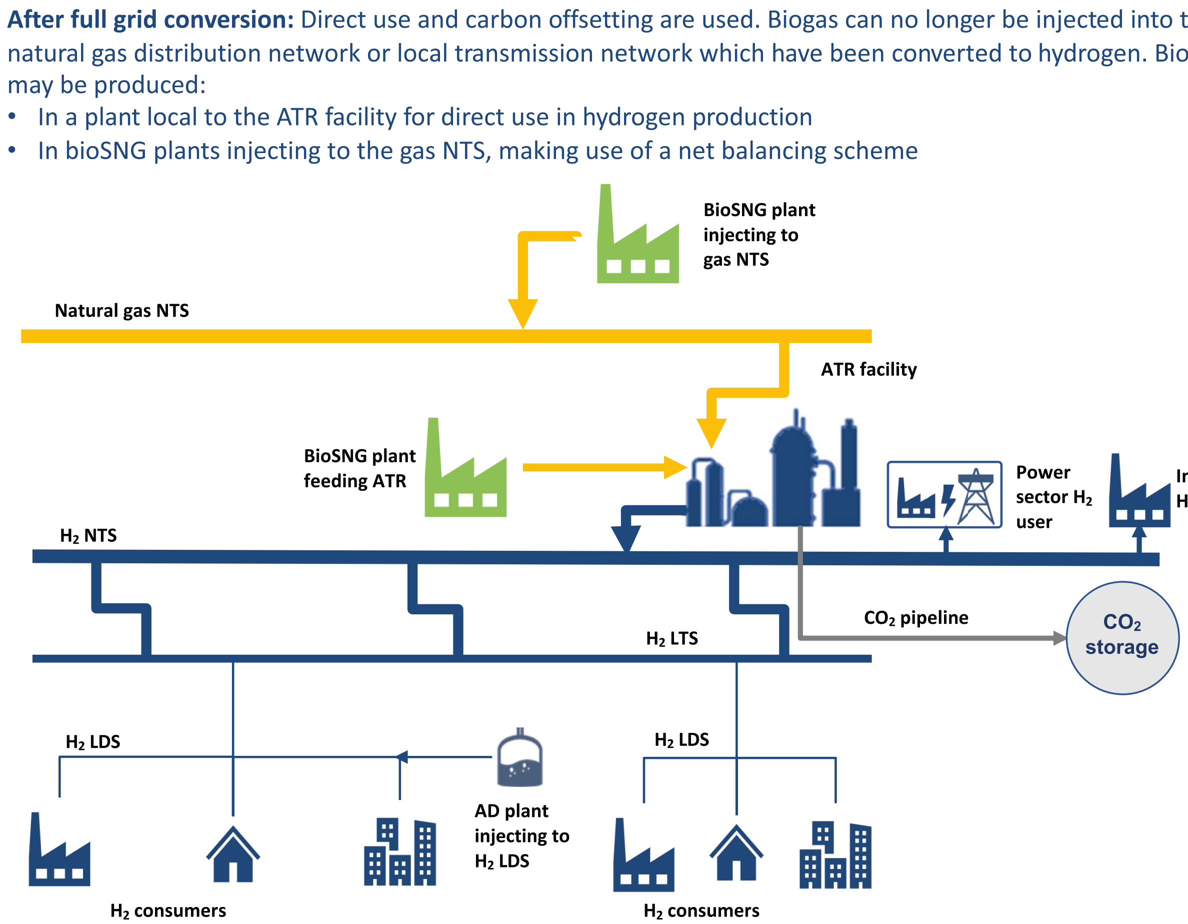


Figure 2.9 Options for biogas production and delivery after full hydrogen conversion

Hydrogen deployment scenarios

3 Hydrogen deployment scenarios

3.1 Selected deployment scenarios

Three hydrogen scenarios have been selected to cover a plausible range of deployment levels. These were discussed briefly in Section 2.3 above; further details are provided here. The scale of hydrogen use will depend on the preferred strategy for large scale decarbonisation. Hydrogen is expected to play a role in energy intensive applications in all scenarios, but some usage may be displaced if electrification is preferred for the decarbonisation of heat and transport. As discussed in Section 2.3, the amount of bioenergy available for hydrogen production varies between these scenarios as different volumes are dedicated to other uses in each. Where hydrogen is more widely deployed, a higher portion of the UK's total bioenergy resource is available, as shown in Table 2.4. The hydrogen deployment scenarios are described below.

- **CCC Further ambition**: This scenario is described in the CCC's recent Net Zero report, and includes measures to reduce the UK's carbon emission by 96% relative to 1990.[1] Heat pumps and hybrid heat pumps are deployed in most homes and businesses and all cars and vans are electric in 2050. Hydrogen is used in industry, to support hybrid heat pumps during peak winter heating demand, and to decarbonise long-haul HGVs and shipping, however is used minimally in power. Given energy efficiency measures and the high levels of electrification in this scenario, hydrogen demand is modelled to be ~30% of current natural gas demand.[24] 105 TWh/year bioenergy resource are modelled as dedicated to electricity production with CCS and a total of 165 TWh/year bioenergy are absorbed by end-uses other than hydrogen.

- **H21 XL**: In this scenario, hydrogen plays a significant role in the decarbonisation of both the heat and power sectors, though there is still significant electrification of heat and transport. As developed in the H21 North of England report,[3] hydrogen provides ~31% of the UK's power demand and ~56% of the heat demand currently provided by natural gas on the local distribution network, including significant use in industry.[24] In this scenario, gas demand on the local distribution network is decreased by ~44% from current levels due to a combination of electrification and energy efficiency. The seasonal demand for hydrogen in the power sector complements that in the heat sector, reducing the required interseasonal storage capacity without compromising the load factor of hydrogen production facilities. As significant electrification of heat occurs in this scenario, hydrogen demand is modelled to be ~60% of current natural gas demand. A total of 138 TWh/year bioenergy are diverted for end-uses other than hydrogen.

- **World-leading deployment**: This scenario explores the potential deployment of hydrogen when production capacity increases continually at a high but realistic rate (similar to that set out in the H21 Max scenario presented in the H21 North of England report). By 2050, hydrogen replaces a large majority of natural gas demand, provides 31% of the UK's power demand, and is used significantly in road and rail transport. Hydrogen is also produced for export via pipelines to mainland Europe and for the generation of electricity for export via interconnectors. Some electrification of heat and transport occurs in this scenario, however hydrogen demand is modelled to be ~120% of current natural gas demand due to the large quantity of hydrogen and electricity exported. 110 TWh/year bioenergy are dedicated to end-uses other than hydrogen.

The hydrogen demand in each of the three scenarios are compared in Figure 3.1.

24 This is consistent with the High H_2 scenario developed in Hydrogen for Power Generation: Opportunities for hydrogen and CCS in the UK power mix, Element Energy for Equinor, 2019, assuming ambitious further deployment of hydrogen in the power sector between 2035 and 2050. Reaching 31% penetration requires full replacement of the natural gas fleet, moderate growth in RES, and reduced use of electricity imports.

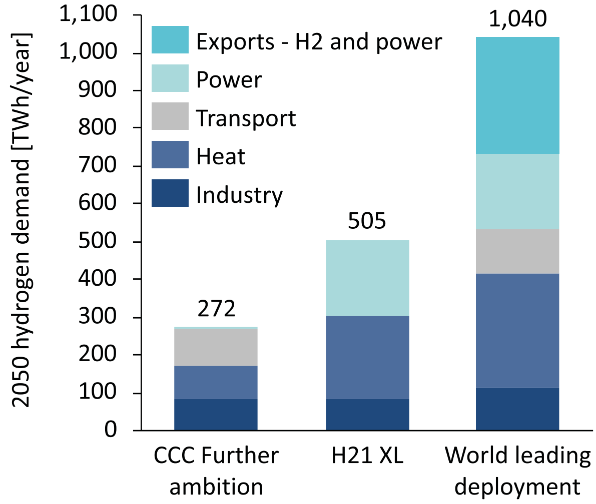


Figure 3.1 Hydrogen demand by sector in the selected deployment scenarios

3.2 Hydrogen production via ATR

Autothermal reformation (ATR) produces hydrogen from natural gas (and/or biogas), oxygen, and steam, following the process shown in Figure 3.2. The fuel inputs and steam are heated before entering the ATR chamber where the fuel is partially oxidized. A gas heated reformer is installed in series with the ATR to recover the waste heat, increasing the system efficiency. The resulting synthesis gas (or syngas) contains a mixture of hydrogen and carbon monoxide. A water gas shift reaction is used to convert the carbon monoxide to carbon dioxide and to further increase the hydrogen content. The carbon dioxide is then separated and captured, leaving the hydrogen ready for export.

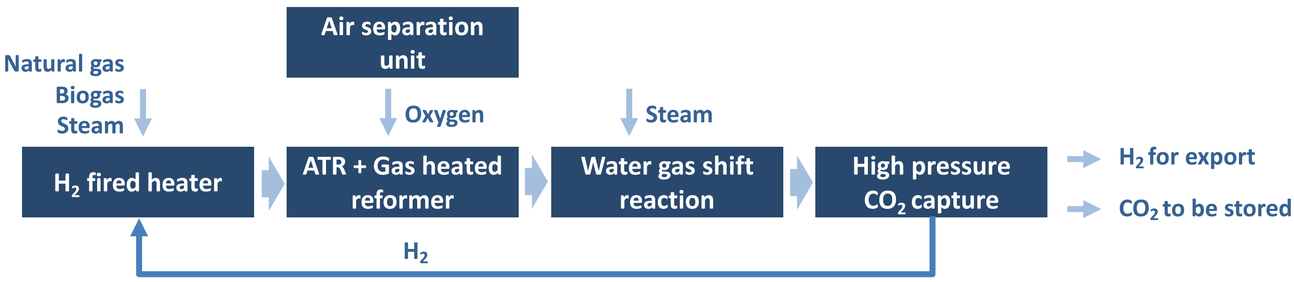


Figure 3.2 ATR process diagram

Further details of the ATR system are provided in Table 3.1 and cost data is shown in Table 3.2. ATR design exercises have considered biogas contributions of up to 20% of the fuel input, with the remainder provided by natural gas.[25] The achievable biogas fraction will depend on the volume of hydrogen production and biogas availability; a 20% biogas fraction may not be realised in all scenarios. As noted in Section 2.5, the biogas fraction may be achieved via a green gas net balancing scheme or direct biogas usage. The assumed costs and carbon intensity of the input fuels are shown in Table 3.3.

25 CO_2 capture from alternative ATR based hydrogen processes – 1.5 GW hydrogen production, Equinor internal document, 20/03/2019.

Table 3.1 Technical characteristics of the ATR system[25]

Technical characteristic	Value
Overall process efficiency	80%
Electricity consumption	0.05 kWh/kWh$_{H2}$
Natural gas or biogas consumption (HHV)	1.2 kWh/kWh$_{H2}$
Biogas fractions considered	0% to 20%
Carbon capture efficiency	96.8%
Load factor	95%
Plant lifetime	30 years
Hydrogen purity	98.2%
CO_2 from hydrogen combustion	0.5 gCO_2/kWh$_{H2}$

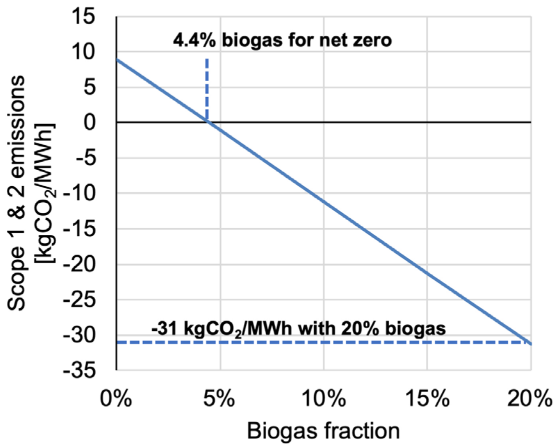
Table 3.2 Capital and operating costs of the ATR, hydrogen storage, and carbon transport and storage

ATR[3]	Cost (£ million/TWh annual capacity)
Capex	£78.5 million / (TWh/year capacity)
Catalyst replacement	£0.2 million /year / (TWh/year capacity)
Maintenance and labour	£2.4 million /year / (TWh/year capacity)
Hydrogen storage[3]	**Cost (£ million/TWh storage capacity)**
Storage capacity required	1.5% of annual hydrogen demand (~2.2 TWh)
Capex	£230 million /TWh storage capacity
Cushion gas	£27.3 million /TWh storage capacity
Opex	£59.3 million /year /TWh storage capacity
CO_2 transport and storage[3]	**Cost**
Capex	£54 million / (MtCO_2/year)
CO_2 storage opex	£1.0 million /year / (MtCO_2/year)

Table 3.3 Cost and carbon intensity of ATR fuel inputs in 2050

	Natural gas	Biogas	Electricity
Wholesale cost[26]	£21/MWh	£87.50/MWh	£60/MWh
Carbon intensity[3]	185 kgCO_2/MWh	16.4 kgCO_2/MWh	26.6 kgCO_2/MWh

26 Natural gas and electricity properties from BEIS Fossil fuel price assumptions, BEIS, 2018 and Green Book Supplementary Guidance, HM Treasury, 2019.



As shown in Figure 3.3, net hydrogen emissions are reduced as a greater fraction of biogas is used in the ATR process described above. A 4% biogas fraction results in net zero emissions when Scope 1 (direct) and Scope 2 (indirect) emissions are considered. Scope 3 (upstream) emissions are expected to be very low by 2050 and are discussed further in Section 5.3, Appendix C. If 20% of the required natural gas is replaced with biogas (either directly or via the 'green gas net balancing system,' net emissions of -31 $kgCO_2/MWh_{H2}$ can be achieved. Figure 3.3 assumes biogas upstream emissions equal to the average of the values shown previously in Figure 2.6, i.e. that all available biogas is used for hydrogen production.

Figure 3.3 Carbon emissions (Scope 1 and 2) for hydrogen production with biogas

3.3 Potential for negative emissions hydrogen production

This section compares the biogas available for hydrogen production discussed in Section 2.3 with the demand for hydrogen in the three deployment scenarios presented above in Section 3.1. The carbon intensity of the hydrogen produced in each scenario depends on these two quantities, as shown in Table 3.4. The upper portion of the table presents the volume of biogas available for hydrogen production in each of the nine scenario combinations and is taken directly from Table 2.5.

For example, with Low bioenergy availability, no biogas is available for hydrogen production in either CCC Further ambition or H21 XL, and only a small volume is available in the World leading deployment scenario. Between 36 and 76 TWh/year biogas may be used for hydrogen under the Central bioenergy scenario, depending on the level of hydrogen deployment and corresponding diversion of bioenergy feedstocks for other uses. This rises to between 123 and 163 TWh/year in the High bioenergy scenario.

The central portion of Table 3.4 presents the carbon intensity of the resulting hydrogen. In the Low bioenergy scenario, the carbon emissions are positive in all hydrogen deployment scenarios. Negative emissions are achieved in all hydrogen deployment scenarios under the Central and High bioenergy scenarios. The lower part of the table presents the yearly nationwide emissions from hydrogen production. These are again positive in the Low bioenergy case, while up to 5 $MtCO_2$ net negative emissions are possible in the Central bioenergy scenario and up nearly 20 $MtCO_2$ net negative emissions can be reached in the High bioenergy scenario. A worked example of these calculations is presented in Section 5.4, Appendix D.

These results indicate that bioenergy and biogas availability will not limit the production of net zero hydrogen in the UK in the Central bioenergy scenario. An 80% reduction in emissions relative to 1990 levels would result in UK emissions just below 200 $MtCO_2$ in 2050. The negative emissions from hydrogen production with biogas could make a significant contribution towards bridging the gap between this level of decarbonisation and economy-wide net zero emissions.

Table 3.4 Net emissions per MWh hydrogen and total hydrogen production emissions under each scenario for bioenergy availability and each hydrogen deployment scenario. Net negative emissions are indicated by green shading; net positive emissions by yellow shading.

	Hydrogen scenarios	CCC Further ambition	H21 XL	World leading deployment
	Hydrogen demand (TWh/year)	**272**	**505**	**1040**
Available biogas for hydrogen production (TWh/year)	**Low** bioenergy scenario	0	0	3.6
	Central bioenergy scenario	36	56	76
	High bioenergy scenario	123	143	163
CO_2 emissions intensity of hydrogen if all available biogas consumed ($kgCO_2/MWh_{H2}$)	**Low** bioenergy scenario	9	9	8
	Central bioenergy scenario	-13	-10	-3
	High bioenergy scenario	-66	-38	-17
Total CO_2 emissions from hydrogen production ($MtCO_2$/year)	**Low** bioenergy scenario	2.4	4.5	8.7
	Central bioenergy scenario	-3.6	-4.9	-3.4
	High bioenergy scenario	-18.1	-19.3	-17.8

3.4 Hydrogen and carbon abatement cost

The results presented in this section focus on the Central bioenergy scenario using the H21 XL deployment scenario for the projected hydrogen deployment. In this case, 56 TWh/year of biogas is available for hydrogen production and there is a national demand for 505 TWh/year hydrogen.

The carbon intensity of hydrogen varies as shown previously in Figure 3.3. Figure 3.4 presents the net carbon emissions resulting from hydrogen production and the carbon savings relative to natural gas consumption at the same level. 93 $MtCO_2$/year are emitted from the consumption of 505 TWh/year natural gas. “Blue” hydrogen produced from natural gas has positive net emissions of 4.5 $MtCO_2$/year, a saving of 89 $MtCO_2$/year over the natural gas case. The hydrogen net emissions can be reduced to zero if 4.4% of the natural gas used for production is replaced with biogas and 4.9 $MtCO_2$/year negative emissions can be achieved if the 56 TWh/year of biogas are fully utilised (9.3% biogas fraction), abating 98 $MtCO_2$/year.

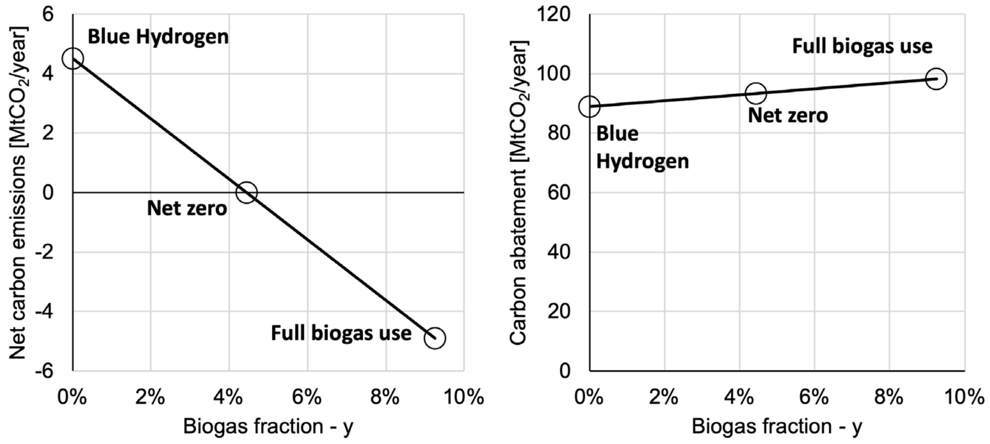


Figure 3.4 Variation of net carbon emissions (left) and carbon abatement relative to natural gas (right) with biogas fraction, y

The costs of hydrogen and of carbon abatement are presented in Figure 3.5 and in Table 3.5 for the different approaches to hydrogen production: blue hydrogen, net zero, and full biogas use. Blue hydrogen that does not use biogas has a cost of £41/MWh. The cost rises linearly with the fraction of biogas and would reach £122/MWh if hydrogen was produced using only biogas. The cost of hydrogen produced with biogas fraction y can be found via the following formula:

$$H_2 \text{ cost per MWh} = £41 \cdot (1–y) + £122 \cdot y.$$

The cost of net zero hydrogen (y = 4.4%) is £44/MWh while full usage of the available biogas (y = 9.3%) results in a hydrogen cost of £48/MWh. These costs include the cost of hydrogen storage and of carbon transmission and storage (see Table 3.2), but do not include the cost of grid conversion. These values are consistent with previous estimates of the cost of hydrogen production from fossil fuels and biomass with CCS.[27]

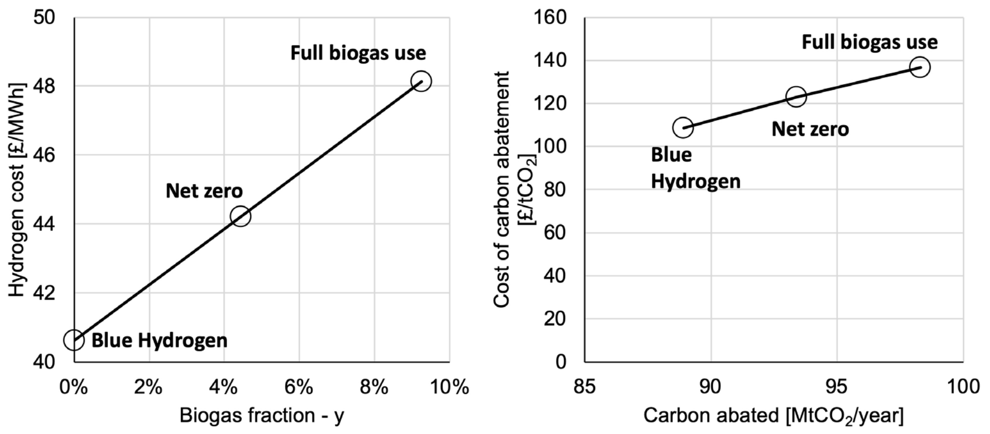


Figure 3.5 Variation of hydrogen cost (left) and the cost of carbon abatement (right)

27 A Greener Gas Grid: What are the options?, ICL Sustainable Gas Institute, 2017.

The carbon abatement cost also increases as the biogas fraction rises. Carbon abatement from blue hydrogen costs £109/tCO_2 while the cost of abatement from hydrogen made using only biogas would be £264/tCO_2. The cost of abatement at intermediate biogas fractions is:

$$\text{Abatement cost per tonne} = £109 \cdot (1\text{-}y) + £264 \cdot y.$$

The cost of carbon abatement rises to £123/tCO_2 for net zero and to £137/tCO_2 for the maximum carbon abatement achievable when the available bioenergy is fully utilised. These values compare favourably with the CCC's expectation that technologies needed to abate the final 20% of the UK's emissions will cost up to £200/tCO_2, as well as with their cost estimate for BECCS in the power sector of £158/tCO_2.[1]

Table 3.5 Emissions, costs of hydrogen and costs of CO_2 abatement associated with using blue, net zero, and net negative hydrogen. These values use the Central bioenergy scenario and the H21 XL deployment scenario.

	Natural gas (Counterfactual)	Blue hydrogen	Net zero	Full Biogas Use (Net negative)
Fuel demand (TWh/year)	505	505	505	505
Consumed biogas (TWh/year)	n/a	0	26	56
Biogas fraction	n/a	0%	4.4%	9.3%
Fuel cost (£/MWh)	21	41	43	48
Specific net emissions (kgCO_2/MWh)	185	9	0	-10
Emissions savings relative to natural gas (kgCO_2/MWh_{H2})	n/a	176	185	195
Total net emissions (MtCO_2/year)	93	4.5	0	-4.9
Total emissions savings relative to natural gas (MtCO_2/year)	n/a	89	93	98
Cost of abatement (£/tCO_2)	n/a	£109	£123	£137

3.5 Implications for the gas sector

In 2017, the UK consumed 865 TWh natural gas, of which 400 TWh were imported.[24] As domestic offshore natural gas production reduces in the coming years, increased dependence on natural gas imports may impact the security of UK energy supply. The CCC has recommended that the natural gas distribution grid is decommissioned or converted to hydrogen by 2050. Natural gas demand will therefore be limited to large scale users drawing from the national transmission system, which may include hydrogen production, industry, and the power sector.

Table 3.6 presents the demand for natural gas for hydrogen production across the three deployment scenarios and for varying levels of bioenergy availability.

Natural gas demand for hydrogen is about 45% above today's levels in the World leading deployment scenario, but in this case 30% of the produced hydrogen is ultimately exported via pipeline or via the export of electricity produced from hydrogen. This scenario implicitly relies upon high levels of international cooperation, including reliable international partnerships and global consensus on decarbonisation. Excluding the fuel inputs required to produce hydrogen for export, the natural gas demand is similar to current levels, as some electrification of current natural gas demand takes place.

If international energy trading is more volatile, a level of hydrogen deployment similar to the H21 XL scenario may be more likely as the maximum ambition. In this case, the demand for natural gas use for blue hydrogen is at about 260 TWh/year lower than today's demand. This decrease is due to significant electrification of the heat sector, which currently consumes significant quantities of natural gas.

The natural gas demand for hydrogen production is lowest in the CCC Further ambition scenario, but this does not result in a significant reduction in the nationwide demand for natural gas. In this case, 325 TWh/year natural gas are required for blue hydrogen, less than the level produced domestically today. However hydrogen is not used for power production in this case, and the power sector consumes around 270 TWh/year natural gas for gas turbines with CCS.[1] The total natural gas demand is 595 TWh/year, a similar amount to that of the H21 XL scenario, despite the lower level of hydrogen deployment.

At all hydrogen production levels, the use of biogas in hydrogen production reduces the UK's demand for natural gas imports. While the level of natural gas imports will depend on the scale of domestic production in 2050, overall demand in the H21 XL scenario may be reduced by between 10% and 25% depending on the volume of bioenergy available.

Table 3.6 Natural gas demand in each hydrogen deployment scenario

Hydrogen scenarios		CCC Further ambition	H21 XL	World leading deployment
Hydrogen demand (TWh/year)		**272**	**505**	**1040**
Natural gas demand for blue hydrogen (TWh/year)		325	605	1250
Natural gas demand for net zero hydrogen (TWh/year)	**Central** bioenergy scenario	310	580	1190
	High bioenergy scenario	310	580	1190
Natural gas demand if all available biogas consumed (TWh/year)	**Central** bioenergy scenario	290	550	1170
	High bioenergy scenario	200	460	1080

Conclusions and recommendations

4

4 Conclusions and recommendations

4.1 Key findings

We have demonstrated the feasibility of producing both net zero and net negative emissions hydrogen, at levels commensurate with the widespread deployment of hydrogen in 2050, using Equinor's ATR with CCS concept with a mixture of natural gas and biogas. Further conclusions are presented below.

Biogas availability for hydrogen production

We estimate that in a Central availability scenario between 50 and 100 TWh/year bioenergy will be available for hydrogen production in 2050. This conclusion is based on a review of the most up-to-date literature on bioenergy resource availability, and on the likely competing uses for bioenergy. Net negative emissions can be achieved for hydrogen deployment scenarios considered (up to 1040 TWh of hydrogen in 2050) in the Central bioenergy scenario, and up to 5 $MtCO_2$/year negative emissions can be achieved.

Cost of hydrogen and carbon abatement

The cost of carbon abatement via hydrogen production varies between £109/tCO_2 for blue hydrogen to £137/tCO_2 for negative emissions hydrogen under the Central bioenergy scenario. These values are consistent with the CCC's expectation that technologies needed to abate the final 20% of the UK's emissions will cost up to £200/tonne CO_2.

The cost of abatement is also competitive with the CCC's cost estimate for BECCS in the power sector of £158/tCO_2.[1] We note that our study has not included a detailed economic analysis on the use of bioenergy in the power sector on the same basis as we have done for hydrogen, so a robust comparison of the relative economics cannot be made with confidence. We suggest that a comparative assessment of the case for using the limited bioenergy resource to produce hydrogen versus using the resource in the power sector (or a combination) would be a useful piece of further work. This could include an assessment of how the co-location of facilities using bioenergy for hydrogen and power production, for example at Drax, could provide further economic benefit.

With the 505 TWh/year of hydrogen deployment anticipated in the H21 XL scenario, usage of the biogas available for hydrogen production would enable the net capture of 5 $MtCO_2$/year. The potential for negative emissions rises to around 20 $MtCO_2$/year under a more ambitious scenario for bioenergy availability. These negative emissions could make a significant contribution towards bridging the gap between this level of decarbonisation and economy-wide net zero emissions.

Table 4.1 Emissions, costs of hydrogen and costs of CO_2 abatement associated with using blue, net zero, and net negative hydrogen. These values use the Central bioenergy scenario and the H21 XL deployment scenario.

	Natural gas (Counterfactual)	Blue hydrogen	Net zero	Full Biogas Usage (Net negative)
Fuel demand (TWh/year)	505	505	505	505
Biogas fraction (%)	n/a	0%	4%	9%
Fuel cost (£/MWh)	21	41	43	48
Specific net emissions ($kgCO_2/MWh_{H2}$)	185	9	0	-10
Total emissions savings relative to natural gas ($MtCO_2$/year)	n/a	89	93	98
Cost of abatement (£/tCO_2)	n/a	109	123	137
Total net emissions ($MtCO_2$/year)	93	4.5	0	-4.9

Feasibility of large-scale biogas and hydrogen delivery

There are a range of feasible network configurations for the large-scale production and delivery of biogas in the short and long term. In addition to the option of production of biogas at dedicated sites collocated with the ATR plant, a green gas net balancing scheme could be used to achieve an equivalent outcome through the distributed injection of biogas into the natural gas network. In the shorter term prior to conversion of the natural gas grid, biogas may be injected at all levels of the gas network. As the natural gas distribution system is converted to hydrogen, biogas production can continue at sites near to the ATR plant or at remote sites via injection into the gas NTS. Upon full conversion of the grid to hydrogen, smaller scale AD plants may continue to operate by producing biohydrogen for grid injection. These options enable net zero hydrogen production to be realised through a variety of technical approaches relevant from the development of initial demonstration facilities through to nationwide hydrogen deployment and to form a valuable part of the UK's roadmap to a net zero energy system.

Implications for natural gas imports

With Central bioenergy availability, the UK's natural gas import dependence in 2050 is likely to be comparable or reduced relative to today, despite reductions in domestic gas production. Natural gas demand reduces by at least 150 TWh/year in two of the three hydrogen deployment scenarios considered. The use of biogas in hydrogen production further reduces the demand for natural gas by between 50 and 150 TWh/year, resulting in between 450 and 550 TWh/year gas demand in the H21 XL scenario. This is of similar order to the current volume of gas imports.[24] Where natural gas demand does increase over today's usage, this is driven by the UK's export of hydrogen and electricity produced from hydrogen, rather than a rise in domestic demand. Domestic natural gas consumption is not necessarily reduced in scenarios featuring lower hydrogen deployment. In the CCC's Further ambition scenario, there is considerable usage of natural gas with CCS in the power sector to produce peaking and mid-merit electricity,[1] resulting in a comparable gas demand to the H21 XL deployment scenario.

4.2 Recommendations for further work

This study has presented an analysis of the potential for net zero and net negative emissions hydrogen in 2050 and demonstrated the feasibility and the environmental benefits of this concept. Additional research is needed to further quantify the system-level benefits of negative emissions hydrogen deployment and to identify actions needed in the near term. This further work may include:

- A detailed study on a **future Humber CCS cluster** and the regional potential for biogas production in the medium and near term.
- Consultation with farmers, forestry experts, DEFRA, and local authorities to **identify risks and barriers that may limit the UK's production of bioenergy feedstocks** and to develop recommendations for their mitigation.
- **Integrated analysis of the costs and benefits of using bioenergy feedstocks for hydrogen production and in the power sector** to allow a robust comparison of the financial, environmental, and energy-system implications of each route.

Appendix

5

5 Appendix

5.1 Appendix A: Example biogas cost and carbon intensity calculation

This section presents an example calculation of the cost and carbon intensity of biogas produced from miscanthus via a commercial-scale gasification plant in 2050. The assumed technical and economic characteristics of the plant are repeated for reference in Table 5.1.

Table 5.1 Technical characteristics of gasification systems in 2020 and in 2050

Technical characteristic	Value - 2020	Estimated Value - 2050
Overall process efficiency[12,15]	55%	68%
Electricity consumption[12]	0.09 kWh/kWh bioSNG	0.09 kWh/kWh bioSNG
Feedstock consumption (HHV)[12,13]	1.73 kWh/kWh bioSNG	1.38 kWh/kWh bioSNG
Load factor[12]	90%	90%
Plant lifetime[12]	30 years	30 years
Required rate of return	10%	10%
Capital cost[5,12]	£1,800/kW bioSNG	£1,575/kW bioSNG
Operating cost[5,12]	£100/kW bioSNG	£88/kW bioSNG
Commercial scale[12]	200 MW	200 MW

The price of biogas is determined from the net present lifetime cost of production and the volume of biogas produced, as laid out in Table 5.2. The production cost is the sum of the capital, operation and maintenance, and fuel costs over the lifetime of the plant. The biogas price must be sufficient to cover these costs and provide the required rate of return to the plant owners and/or investors.

Table 5.2 Calculation of the price of biogas produced from miscanthus in a 200 MW biogas plant in 2050. Discount factors over the plant lifetime sum to 8.61.

200 MW plant	Cost (£ million)	Net present lifetime cost (£ million)
Capital cost	£315	£315
Operation and maintenance	£17.5/year	£151
Electricity cost - £130.19/MWh	£18.4/year	£159
Miscanthus cost - £27.68/MWh	£60.4/year	£521
Total production cost		£1,146
200 MW plant	**Annual Production (TWh/year)**	**Lifetime total (TWh)**
Biogas production	1.57	47.3
Biogas price (£/MWh)		£1,146 / 1.57 / 8.61 = **£84.31**

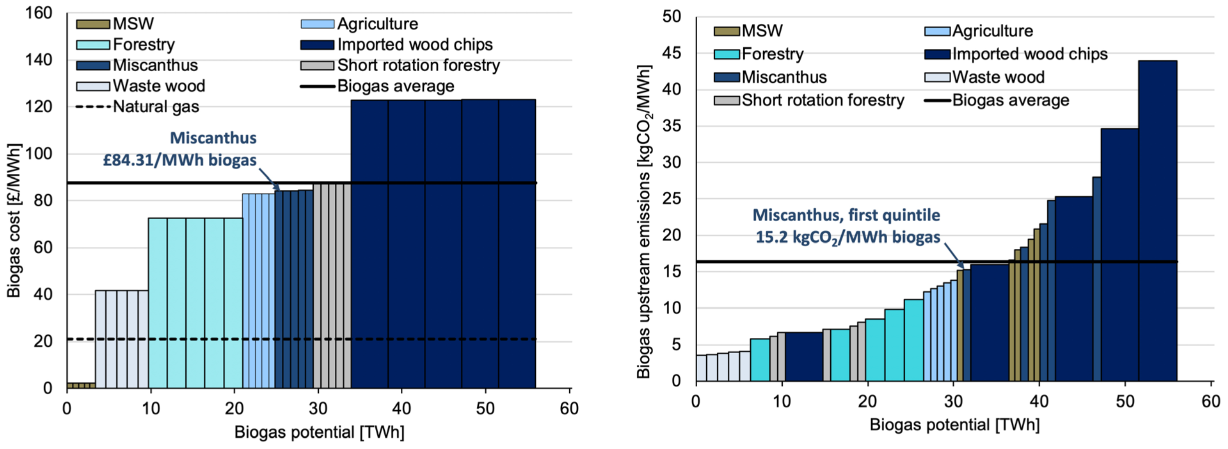
The carbon emissions associated with biogas from miscanthus are calculated in Table 5.3. The Scope 1 emissions are assumed to be zero as the carbon captured during growth of the miscanthus offsets the carbon present in the biogas and the carbon emitted during biogas production. Small but positive emissions arise from Scope 2 which includes carbon from the electricity used for the gasification process and from fertilisers, land-use, and pre-processing in the miscanthus production.

Table 5.3 Calculation of total Scope 1 and 2 emissions from biogas production from miscanthus in 2050

Scope 2	kWh electricity or miscanthus/kWh biogas produced	$kgCO_2/MWh$ electricity or miscanthus	$kgCO_2/MWh$ biogas
Electricity production	0.09	26.6	2.4
Miscanthus production	1.38	9.3	12.8
Scope 2 Total			**15.2**
Scope 1 Total			**0**
Scope 1 and 2 Total			**15.2**

The results calculated in Table 5.2 and Table 5.3 are highlighted in the cost and carbon intensity curves shown in Figure 5.1.

Figure 5.1 Cost (left) and carbon intensity (right) of biogas in the Central bioenergy scenario with the H21 XL hydrogen deployment scenario



5.2 Appendix B: Details of AD production facilities

Table 5.4 Technical characteristics of AD systems in 2020 and in 2050[5]

Technical characteristic	Value – 2020	Estimated Value - 2050
Overall process efficiency	81%	81%
Electricity consumption	0.12 kWh electricity /kWh biomethane	0.12 kWh electricity /kWh biomethane
Feedstock consumption (HHV)	1.11 kWh feedstock /kWh biomethane	1.11 kWh feedstock /kWh biomethane
Load factor	86%	86%
Plant lifetime	30 years	30 years
Required rate of return	10%	10%
Capital cost	£539/kW biomethane	£496/kW biomethane
Operating cost	£190/year/kW biomethane	£175/year/kW biomethane
Typical scale[20]	1 MW biomethane	1 MW biomethane

5.3 Appendix C: Inclusion of natural gas Scope 3 emissions

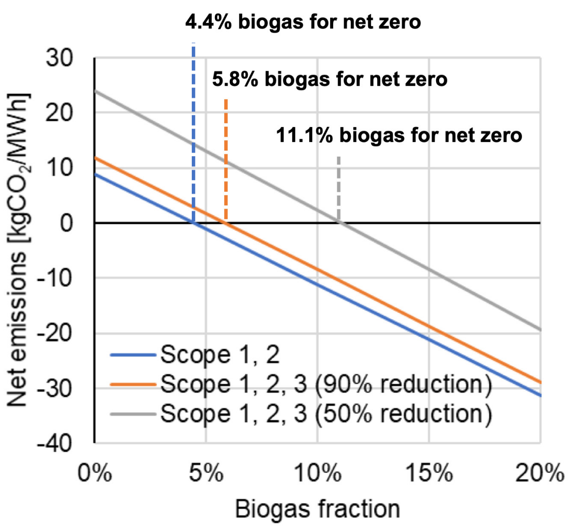


Figure 5.2 presents the variation in net emissions with biogas fraction. The Scope 1 and 2 emissions are shown, along with two cases including the Scope 3 emissions from natural gas. The first case (shown in orange) assumes a 90% reduction in natural gas upstream emissions relative to today's values,[28] while the second (shown in grey) assumes a 50% reduction. If Scope 1 and 2 emissions are considered, a 4.4% biogas percentage fraction in the overall gas composition is required to reach net zero emissions. This rises to 5.8% and 11.1% for the two cases including Scope 3 emissions. In the analysis presented in Section 3.4, a biogas fraction of 4.4% is assumed.

Figure 5.2 Net hydrogen emissions with varying biogas fraction

28 The 2018 natural gas Scope 3 emissions are from UK Government Greenhouse Gas Conversion Factors for Company Reporting, BEIS and DEFRA, 2018. Reductions exceeding 90% of this value have already been achieved in the Norwegian Troll field (H21 North of England Report, NGN and Cadent, 2018.)

5.4 Appendix D: Example hydrogen carbon intensity calculation

Table 5.5 and Table 5.6 present an example of the calculations performed to populate Table 3.4. The case shown is the H21 XL hydrogen demand scenario with Central bioenergy availability. The ATR process is 80% efficient and 631 TWh/year of fuel are required to supply the hydrogen demand of 505 TWh/year. 4% of the fuel required is electricity while the remainder is natural gas and biogas. With 56 TWh/year of biogas available for hydrogen production, 548 TWh/year natural gas are needed by the ATR. Biogas contributes 9.25% of the total gas demand.

Table 5.5 Calculation of fuel consumption and biogas fraction when all available biogas is consumed in the Central bioenergy scenario with H21 XL

	Value	Details
Hydrogen scenario	H21 XL	505 TWh/year demand
Bioenergy scenario	Central	56 TWh/year available
Process efficiency (HHV)	80%	
Total fuel input	505 / 80% = **631 TWh/year**	**kWh/kWh$_{H2}$**
Electricity input	27 TWh/year (4%)	0.054
Biogas input	56 TWh/year (9%)	0.111
Natural gas input	548 TWh/year (87%)	1.085
Biogas fraction	56 / 548 = **9.25%**	

The calculation of net emissions in the same case is shown in Table 6-6. The carbon capture rate at the ATR is 96.8%, resulting in the capture of 214.4 kgCO_2/MWh$_{H2}$ out of the 221.5 kgCO_2/MWh$_{H2}$ contained in the natural gas and biogas consumed by the ATR. A small amount of methane is present in the produced hydrogen which will be converted to CO_2 upon combustion. Scope 1 emissions of biogas are assumed to be zero as the carbon captured during growth of the miscanthus offsets the carbon present in the biogas and the carbon emitted during biogas production. Carbon captured from atmosphere during bioenergy feedstock production allows negative Scope 1 emissions of -12.9 kgCO_2/MWh$_{H2}$ to be achieved.

Scope 2 emissions include those generated during electricity and biogas production. These add a further 3.2 kgCO_2/MWh$_{H2}$ for a final hydrogen carbon intensity of -9.7 kgCO_2/MWh$_{H2}$. Over the 505 TWh produced annually, net negative emissions of -4.9 MtCO_2/year are realised.

Table 5.6 Calculation of Scope 1 and 2 emissions when all available biogas is consumed in the Central bioenergy scenario with H21 XL. Scope 1 emissions of biogas are assumed to be zero as the carbon captured during growth of the miscanthus offsets the carbon present in the biogas and the carbon emitted during biogas production.

Scope 1	kWh/kWh_{H2}	$kgCO_2/MWh$	$kgCO_2/MWh_{H2}$
Natural gas	1.085	185	201.0
Biogas	0.111	0	0
Residual carbon embodied in hydrogen	1	0.5	0.5
Carbon captured at ATR - 96.8% capture rate	n/a	n/a	-214.4
Scope 1 Total			**-12.9**
Scope 2	**kWh/kWh_{H2}**	**$kgCO_2/MWh$ electricity or biogas**	**kg/MWh_{H2}**
Electricity production	0.054	26.6	1.4
Biogas production	0.111	16.4	1.8
Scope 1 and 2 Total			**-9.7**
Net emissions			505 TWh x -9.7 $kgCO_2/MWh$ = **-4.9 Mt CO_2/year**

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