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NEXT STEPS FOR THE GAS GRID

Future Gas Series: Part 1

“This report provides an extremely useful guide to the opportunities and challenges associated with low carbon gas and the gas grid. It will help inform the UK’s transition to a low carbon economy.”

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Inquiry Co-Chairs, September 2017

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Foreword

Gas currently plays a fundamental role within the UK's energy system. The overwhelming majority of buildings are heated through gas and it is used widely within industry for process heat. It is also a major source of electricity and even occasionally provides fuel for transport. Currently this is almost exclusively natural gas which releases greenhouse gas emissions when burnt. It will therefore almost certainly be necessary for the UK to undergo a dramatic shift away from unabated natural gas in order for it to meet its 2050 emissions reductions targets set out in the Climate Change Act and honour the Paris Agreement on Climate Change.

Across different areas of the energy system a number of different solutions are likely to replace natural gas. However, it may not be necessary or desirable to dispense with gas altogether. This is because there are forms of low carbon gases which release fewer greenhouse gas emissions when burnt than natural gas; in particular, gases produced from biological material (biogases) and hydrogen. It may therefore be possible to dramatically reduce emissions by replacing natural gas with low carbon gases.

One particularly challenging area for the UK to decarbonise is heat which accounts for almost half of final energy consumption in the UK. Around three-quarters of this is heat for domestic, commercial and public buildings and this alone accounts for 20% of UK greenhouse gas emissions. Currently most buildings (more than 80%) are heated by gas being transported in a system of pipes known as the gas grid which is then burnt in boilers. Much of the heat used in industrial processes also relies on gas delivered in a similar way. It is partly for this reason that there may be particularly exciting opportunities to use low carbon gases to provide heat.

It may be possible to continue to utilise parts of the existing gas transportation infrastructure (the pipes) but move from natural gas to low carbon forms of gas. This process is already underway through the injection of 'biomethane' into the gas grid, and there is ongoing research into 'bioSNG' (bio-synthetic natural gas). These gases could be used to make significant reductions in the emissions associated with heat and Government policy should support this. However, the limits on the potential sources of production of these gases mean they alone will not be sufficient to provide the widespread reduction in emissions which are required. In the long-term, bio-resources may also be more usefully deployed elsewhere; for example in hard-to-decarbonise sectors such as aviation or long-distance logistics.

Hydrogen is another form of low carbon gas which could be used in the gas grid. A safety programme is already underway to change most of the pipes in the gas grid to plastic (polyethylene), making them compatible with hydrogen. It is thought that hydrogen could be mixed or blended in with natural gas, possibly up to around 20% (volumetrically), equivalent to about 6% on an energy basis, and be safely used in most existing gas appliances. While this would provide only a minor reduction in emissions, it could help balance the wider electricity system.

A more radical proposal would be to repurpose parts of the gas grid to transport 100% hydrogen. This could deliver dramatic reductions in emissions and may be an effective way to decarbonise heat. Such an idea would be a large and complicated project and significant uncertainties remain about its feasibility and desirability. In recognition of the potential opportunities offered by hydrogen for heat, Government policy should focus on evidence gathering in this area and not closing off this option, with a view to making a longer-term decision at a later date.

We are delighted to have co-chaired Part 1 of Carbon Connect's *Future Gas Series* – a process which has brought together experts to consider the opportunities and challenges associated with a potential transition to a low carbon gas network, as well as the practical next steps and policy development associated with this. Parts 2 and 3 of the *Future Gas Series* will develop this process to consider in further detail the issues related to the production of low carbon gas and the issues related to consumers and the development of appliances.

We would like to extend a thank you to everyone who gave their time and expertise to this inquiry and we would like to especially thank the steering group for their valuable contributions. We are very grateful to IGEM for generously sponsoring the inquiry. We hope this report helps to advance thinking in this area and provide some ideas for next steps in the transition to a low carbon economy.

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Executive Summary

Natural gas, heat and decarbonisation

Heat represents roughly one-third of the UK's total greenhouse gas emissions. This will have to fall substantially for the UK to achieve its goal of reducing emissions by 80% by 2050 compared to 1990 levels, as set out in the Climate Change Act. 45% of energy consumption in the UK goes on heating buildings – where we live and work. Most of this comes from natural gas, with over 23 million customers and more than 80% of our homes heated by gas carried by the grid. Natural gas consists largely of methane (a greenhouse gas) which when burnt releases emissions of carbon dioxide (another greenhouse gas).

Decarbonising heat is viewed as a challenging task for a number of reasons. It is costly – all the low carbon heat solutions involve substantial up-front costs and/or higher operating costs than natural gas provided through the grid. It is also difficult to find non-gas sources of low carbon heat that can both deliver similarly large volumes of energy and match the dramatic swings in consumer demand for heat.

It has traditionally been assumed that gas could be replaced by electricity. In recent years, however, there has been a growing discussion of the technical challenges and costs of near complete electrification of heat.

Previous work by Carbon Connect supports an 'all-of-the-above' approach to heat decarbonisation – there is no silver bullet to this challenge.

The opportunity of low carbon gas

Increasing attention has begun to focus on the opportunities offered by low carbon gas. The low carbon gases of greatest interest are biogas, biomethane, bioSNG (bio-synthetic natural gas), biopropane and hydrogen. These gases, if used in the gas grid, could substantially reduce emissions from heat. They could also play a large role in decarbonising other sectors such as transport.

Options for low carbon gas range from the continued use of the gas grid with low carbon gases to the full decommissioning of the gas grid. This report reviews each of the potential future scenarios for the gas grid in turn:

> **Biomethane** from anaerobic digestion (AD) is already injected into the gas grid and could be used to a greater extent. However, there are limited quantities of sustainable feedstocks, so it can only replace a low proportion of heat demand – perhaps around 5% of current gas consumption. Bio-resources might also be better used in hard-to-decarbonise sectors such as aviation, shipping and heavy goods vehicles.
>
> **BioSNG** from waste gasification injected into the grid is feasible, and has greater potential to meet heat demand than biomethane from AD. However, the potential of bioSNG from waste feedstocks is still limited, and it is not yet at a commercial scale.

Blending a small amount of hydrogen with natural gas in the grid is expected to have few adverse impacts on gas customers, but would give a small reduction in greenhouse gas emissions. A more radical option is to convert some natural gas distribution networks to **100% hydrogen**. Consumer gas appliances (e.g. boilers and hobs) would need to be replaced with hydrogen-compatible ones, and low carbon hydrogen production facilities would need to be built. Repurposing significant amounts of the gas grid to transport 100% hydrogen could achieve extensive decarbonisation of heat. However, the idea needs to be proven and a proper assessment made of all the many issues involved.

A **hybrid gas/electric option** could be flexible enough to cope with seasonal heat demand and reduce the burden on the electrical system. Work is needed on the technologies and the commercial viability of this option, as well as to determine the greenhouse gas savings. Initial work is being done on this and on how to best integrate it with other scenarios for the gas grid.

Ultimately, the full or partial **decommissioning of the gas grid** could be necessary if low carbon gas cannot be deployed at scale. This would involve significant cost, and the capacity to transport large volumes of energy through the gas grid would need to be replaced. Work is needed to reduce uncertainties around the costs and implications of decommissioning.

Key policy issues for the future of the gas grid

All these scenarios involve common policy issues. This report explores three thematic policy areas – safety and demonstrations; legislation, regulation and governance; and costs, funding and billing. It recommends key steps for Government to address some of the challenges of greening the gas grid.

1. Safety and demonstrations

Testing and demonstration are needed to deliver necessary levels of safety for gas consumers, workers and the wider public. They will also be necessary for a proper understanding of the costs and implications of wider use of low carbon gas.

Since **biomethane** is already being injected into the grid, its safety has already been demonstrated. It poses no greater risk than natural gas, and the gas grid does not need modification.

Given that **bioSNG** is, like biomethane, a biologically-derived gas mainly composed of methane, it is widely expected to be safe to inject into the gas grid. More work is needed to demonstrate the production of bioSNG on a commercial basis.

Blending hydrogen has been done before – when the UK used town gas there was as much as 50% hydrogen by volume in the grid. Work is needed to confirm the safe upper limit of hydrogen that is compatible with the gas grid and, importantly, gas appliances. Some initial work is being done in the HyDeploy project at Keele University.

Introducing **100% hydrogen** to the gas grid is unprecedented: its safety needs thoroughly proving. Initial testing and desk-based research suggests it would be safe once the gas grid has been replaced with polyethylene pipes (due to be completed by 2032). This assumption needs to be proven through comprehensive testing of 100% hydrogen in the grid and 'downstream of the meter' (e.g. in pipes, in buildings and in appliances), and then by live trials.

Demonstrations and a live trial programme will be a prerequisite to any possible widespread repurposing of the gas grid to 100% hydrogen. Formal coordination in this area could be very helpful in supporting the development of such projects.

2. Legislation, regulation and governance

The regulatory framework for the gas grid today is tailored to natural gas and restricts the fullest use of low carbon gas. The Gas Safety (Management) Regulations (GS(M)R) will need to be reviewed to address barriers to the use of low carbon gas.

For the **biogases**, GS(M)R imposes restrictions on quality which limit the range of biogases permissible in the grid, although exemptions can and have been granted. More radical solutions would be to widen the limits in GS(M)R and/or transfer the GS(M)R gas quality standard to an industry standard.

GS(M)R limits the amount of **hydrogen** that can be blended into the grid to 0.1% by volume. There are two ways in which **hydrogen blends** in the grid could be regulated once blending has been proven: (i) through modification of the gas quality specifications in GS(M)R to permit greater than 0.1% hydrogen by volume; or (ii) through the issue of a class exemption by HSE.

GS(M)R does not cover **100% hydrogen** and HSE has stated initial demonstration work would be regulated through existing health and safety regulations. If bespoke regulation for hydrogen were needed, Government should ensure that a new regulatory framework for hydrogen could be delivered in a timely fashion.

3. Costs, funding and billing

There are barriers to investment in low carbon gas and challenges for how customers are billed for their energy.

The Renewable Heat Incentive (RHI) has been successful at encouraging the **biomethane** market but ends for new schemes in 2021. Extension or replacement schemes to encourage the commercialisation of biomethane beyond 2021 – albeit with a clear end to subsidies in the long term – could support further deployment of biomethane.

The RHI (or its replacement) could also be used to support **bioSNG** provided that there is convincing evidence that bioSNG technologies will become sufficiently low-cost to deliver affordable decarbonisation. As this is far from clear, the Government could instead explore new ways to encourage bioSNG in a cost-effective manner. This may include a role for local authorities or cross-sectoral funding.

How gas bills are currently determined acts as a barrier to increasing sources of low carbon gas in the grid, requiring propane to be added to biogases to increase their calorific value (CV). Billing methodologies should be modified to accommodate a range of gases with different CVs such as biomethane and bioSNG.

Many of the issues that apply to biogases would also apply to **blending hydrogen** since both are 'low CV' gases. Reforming billing methodologies to better accommodate varying CVs from gases such as biomethane and bioSNG could help with hydrogen blending.

A transition to **100% hydrogen** would require large up-front costs, estimated to be at least £200bn for a national conversion programme assuming carbon capture and storage (CCS) can be deployed to support large-scale hydrogen production. Of course, alternative investments in heat decarbonisation otherwise needed to meet national legal targets – widespread electrification and/or gas grid decommissioning – could be similarly or even more costly. Large political questions remain about how to spread costs of conversion across the country and different social groups; especially for those who are fuel-poor. Options include a levy on bills, providing funding through general taxation, or a combination of both.

Conclusions and next steps

The gas grid could play a vital role in transitioning to a low carbon energy system through the widespread use of low carbon gas. This report recommends the following next steps for policy in this area:

- **Focus on future-proof policy:** given the uncertainties around the best use of the gas grid in the long-term, policy decisions made in the short term should not shut off potential options prematurely
- **Ramping up energy efficiency measures** is critical to heat decarbonisation, regardless of the future of the gas grid. For example, improving the efficiency of the fabric of buildings can reduce the cost of transition to low carbon heating sources and improve our understanding of optimal choices in low carbon heat solutions
- **Keep reducing emissions with biomethane:** Government should work with industry to address its commercial and regulatory barriers
- **Explore bioSNG** as a technology with significant potential to support decarbonisation
- **Consider regulatory barriers** to safe transportation in the gas grid of more than 0.1% hydrogen by volume
- **Support the transition to a more flexible gas grid** that uses various forms of gas
- **Review and improve billing methodologies** to address the use of low carbon gas and deliver benefits to consumers
- **Coordinate evidence-gathering and demonstrations on converting the gas grid to 100% hydrogen**; this will allow for a proper understanding of the costs and implications of such a project
- **Ofgem should incorporate flexibility within its next round of price controls** (RIIO GD-2, running from 2021 to 2029) to allow for whatever decisions are taken for the long-term future of the gas grid
- **Consider the medium and long-term issues set out in this report** in areas such as regulation and investment in low carbon gas
- **Ensure the linkages and interactions between power, transport, heat** and other sectors are considered to ensure decarbonisation across the economy is cost-effective and timely

Introduction

In the years since the conclusion of Carbon Connect's *Future Heat Series* in 2015, there has been growing enthusiasm around the potential of low carbon gas to reduce emissions from heating.

Next Steps for the Gas Grid focuses on the future of the gas grid and the issues related to a potential transition to a low carbon gas network in the future. The second and third reports of the *Future Gas Series* will expand on two topics briefly touched on here: the issues related to the production of low carbon gas and the issues related to consumers and appliances, respectively.

In the first part of this report (Chapters 1 and 2) we have provided contextual and technical background and set out why low carbon gas and the future of the gas network are important topics for consideration. Because this report focuses on the role of the gas grid it predominantly examines low carbon gas in relation to heat, though it notes the opportunities associated with other sectors such as transport.

There are many uncertainties around the long-term future of the gas grid. For example, repurposing sections of the gas grid to transport 100% hydrogen could make a very useful contribution to efforts to decarbonise heating, but there are uncertainties around the costs, implications and desirability of such a move. In the second part of this report (Chapter 3), we explore different scenarios for the future of the gas grid in further detail, ranging from the widespread use of various low carbon gases to its decommissioning.

The final part of the report outlines the policy implications that arise from consideration of the future of the gas grid. We examine the practical next steps and policy development required to support a transition to a low carbon gas grid. To do this, we set out the issues related to safety testing and demonstration (Chapter 4); scrutinise the regulatory issues of using low carbon gases in the gas grid (Chapter 5); and give consideration to the economic and financial challenges of this technological transition (Chapter 6). This is divided into considerations related to biogases and considerations related to hydrogen. In the final chapter of our report, we summarise the key next steps for the gas grid, identifying recommendations which can be pursued in the short-term, and the longer-term considerations which will need attention in the future (Chapter 7).

This report examines low carbon gas and the future of the gas grid, so no detailed assessment of other heating technologies is provided. This is not a statement on their usefulness, but simply a reflection of the different focus of this report.

Part 1

AN INTRODUCTION TO THE FUTURE GAS SERIES

1. Natural gas, heat and decarbonisation

FINDINGS

1. There is a widespread consensus that significant policy development will be necessary in the area of heat in order for the UK to meet its emissions reductions targets. This will require the UK to shift dramatically away from its reliance on unabated natural gas for heating.

2. Heat system decarbonisation is particularly challenging because of the large volumes of energy associated with it, and the extreme and rapid swings in heat demand that can arise. In addition, all the low carbon heat solutions will likely involve substantial up-front costs to put in place and/or higher operating costs than the dominant incumbent of natural gas provided through the gas grid.

3. It seems likely that electrical heating solutions will play an important part in the decarbonisation of heat in the UK (alongside non-electric technologies and district heating). Nonetheless, there are technical challenges and significant costs with rolling out electrical heating technologies to the extent that has been conceived in recent years, which justifies the consideration of complementary or alternative solutions such as low carbon gases.

1.1 An introduction to natural gas

Gas plays a fundamental role within the UK's energy system. It is a major contributor to electricity generation; it is used widely within industry for process heat; and it even occasionally provides fuel for transport. Its most important role is in heating buildings: gas heats the overwhelming majority of homes and buildings across the country.

The gas used in the UK is almost exclusively natural gas, consisting largely of methane. Natural gas began widely substituting coal for heat in buildings and industry during the 1970s, and doing the same in power generation since the 1990s. Gas use, however, has a much longer history than this in the UK (Box 1).

Box 1 - A history of gas in the UK

Pre-1967: Town gas

Town gas, which was initially produced from coal and made up roughly of 50% hydrogen as well as methane and carbon monoxide, began to be used widely during the early 19th Century, primarily for lighting in factories and streets. By the 1930s there were over 1800 medium and large scale 'gasworks' (privately-owned local production sites) around the country[1]. At different rates of development, people began to use gas for cooking, heating, hot water and in industrial processes[2].

The market for town gas was generally controlled by local councils and small private firms until 1949 when the industry was nationalised into twelve regional gas boards and the national Gas Council[3].

1967 to 1977: The conversion to natural gas

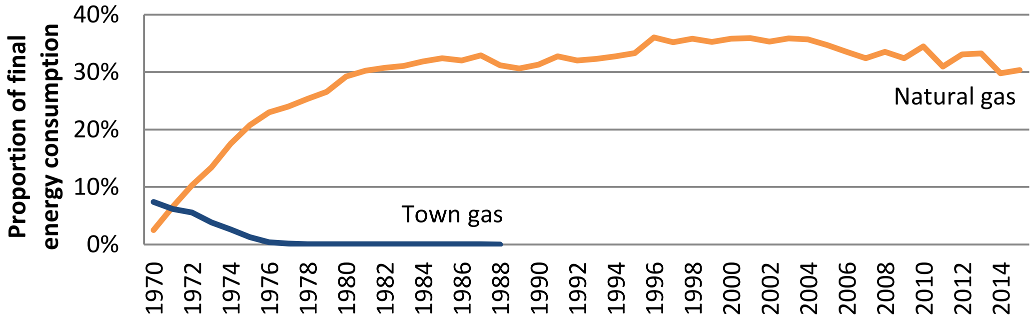
The era of town gas came to an end following the discovery of natural gas in the British part of the North Sea in the 1960s. Natural gas was affordable and abundant, and therefore the Government decided to undertake a large-scale programme to convert existing appliances to be compatible with it[4].

This began in 1967, and within ten years the programme to convert 14 million homes across Britain was completed at a cost of £600m (£2.9bn in 2010 prices), as well as the construction of a high-pressure national transmission network to deliver North Sea gas across the country and link all of the local distribution networks[5].

During the 1980s, the Government created a commodity market for sources of natural gas and private monopolies for its transportation, regulated by the newly created Office of Gas Supply (later becoming the Office of Gas and Electricity Markets or Ofgem)[6].

Since the conversion to natural gas, the UK's consumption of it has increased dramatically (Figure 1)[7]. The UK has been a net importer of natural gas since 2004 and its sources of natural gas are split between domestic production in the East Irish Sea and North Sea, pipelines from Europe and via tankers in the form of Liquefied Natural Gas (LNG)[8].

Figure 1: The conversion from town to natural gas

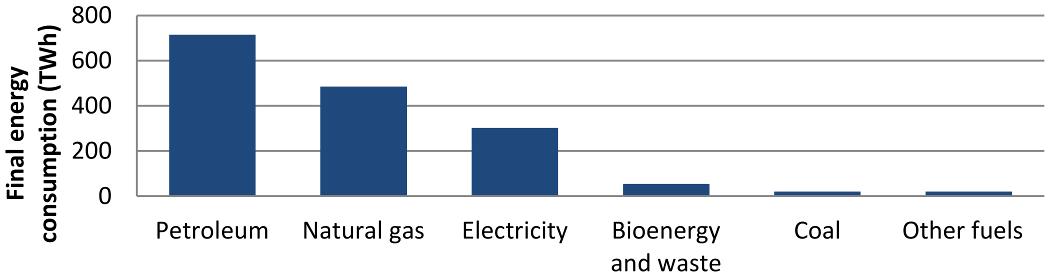


Source: BEIS (2016) Energy consumption in the UK (Table 1.02 Final energy consumption by fuel 1970 to 2015)

[1] MacLean, K. (2016) The historic role of hydrogen in town gas: the prospects for a hydrogen mix in green gas: sources of future hydrogen production: hydrogen injection into the system. In: *Green Gas Book* (Eds. Parliamentary Labour Party Energy and Climate Change Committee)
[2] Utoft, J. & Thomsen, H., The History of Gas. Available at: http://www.gashistory.org/Files/gashistoryWGC06.pdf
[3] Webber, C. (2006-2009) The Evolution of Gas Networks in the UK – A case study prepared for the International Gas Union's Gas Market Integration Task Force
[4] Sadler *et al.* (2016) H21 Leeds City Gate
[5] Dodds, P. & Demoullin, S. (2013) Conversion of the UK gas system to transport hydrogen. *International Journal of Hydrogen Energy* **38** (18) 7189 - 7200
[6] Webber, C. (2006-2009) The Evolution of Gas Networks in the UK – A case study prepared for the International Gas Union's Gas Market Integration Task Force
[7] Oxford Institute of Energy Studies (2015) The role of gas in UK energy policy
[8] British Gas (2017) Where does UK gas come from? Available at: https://www.britishgas.co.uk/the-source/our-world-of-energy/energys-grand-journey/where-does-uk-gas-come-from; BEIS (2016) DUKES: Chapter 4 Natural Gas

After petroleum, natural gas is the second most consumed fuel in the UK (Figure 2)[9]. Within the electricity system, around 30% is generated from gas power stations – ahead of electricity from renewable sources (24.6%)[10]. Around 700 vehicles are currently running on natural gas, as well as a number of light, gas-powered vehicles operating in urban areas and gas-powered buses[11].

Figure 2: Final energy consumption by fuel



Source: BEIS (2016) Energy consumption in the UK (Table 1.02 Final energy consumption by fuel 1970 to 2015)
Notes: Data for 2015 and converted from ktoe to TWh

1.2 An introduction to heat

Heating in the UK

Heat constitutes the single largest use of energy in the UK. 45% of the final energy consumed is used to provide heat, of which around three-quarters is used by domestic, commercial and public buildings, and the remainder for industrial processes[12].

In 2009, heat-related emissions accounted for around 32% of the total greenhouse gas emissions of the UK[13]. By combining the Committee on Climate Change's 2016 analysis of domestic heat policy and its 2016 Progress Report to Parliament, it is possible to estimate that total heat (and cooling) emissions in 2013 equated to approximately 38% of UK emissions[14].

Heating and hot water for domestic, commercial and industrial buildings make up around 40% of the UK's energy consumption and approximately 20% of its greenhouse gas emissions. The emissions associated with heating and hot water for buildings will need to be almost zero by 2050 if the UK is to meet its legally binding emissions reductions targets to reduce overall emissions by 80% by 2050 against 1990 levels, as set out in the Climate Change Act[15]; and will almost certainly need to reach zero if the UK is to achieve net-zero emissions post-2050 in accordance with its international obligations under the Paris Agreement.

The remainder of the energy consumption and emissions associated with heat are accounted for by industrial and commercial use, including both high temperature heat such as in refining processes and low temperature heat such as for drying[16]. Significant reductions in emissions associated with industry are also going to be necessary, as acknowledged in the Government's Industrial Strategy Green Paper[17]. This

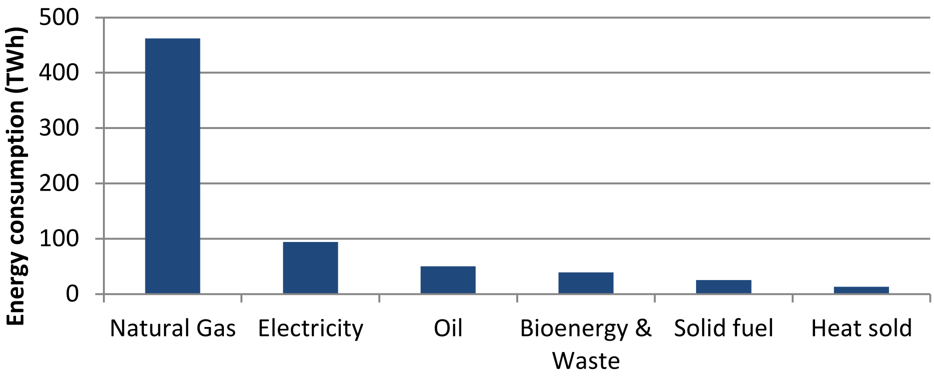
[9] BEIS (2016) Energy consumption in the UK
[10] BEIS (2016) Digest of United Kingdom Energy Statistics 2016, p. 120. Electricity generation by fuel in 2015: Gas 30%, renewables 24.6%, coal 22%, nuclear 21%, other fuels 2.8%
[11] Cadent (2016) The future of gas: transport
[12] BEIS (2016) Energy consumption in the UK; Chaudry *et al.* (2015) Uncertainties in decarbonising heat in the UK. *Energy Policy* **87**, 623–640
[13] Chaudry *et al.* (2015) Uncertainties in decarbonising heat in the UK. *Energy Policy* **87**, 623–640
[14] Committee on Climate Change (2016) Meeting carbon budgets: progress report to parliament; Committee on Climate Change (2016) Next steps for UK heat policy
[15] Committee on Climate Change (2016) Next steps for UK heat policy
[16] POST (2016) Carbon footprint of heat generation
[17] BEIS (2017) Building our industrial strategy

report focuses predominantly on energy use and emissions associated with buildings, but will at points refer to industrial process heat.

The dominance of natural gas for heat

Natural gas dominates heat in the UK (Figure 3). 67.5% of total heat demand across the economy is met by natural gas in the UK[18]. This is especially true for the domestic sector, where 75% of energy consumption for heat (space heating, water heating and cooking) is met by natural gas[19].

Figure 3: Overall energy consumption for heat by fuel



Source: BEIS (2016) Energy consumption in the UK (Table 1.04 Overall energy consumption for heat and other end uses by fuel 2010 to 2015)
Notes: Data for 2015 and converted from ktoe to TWh

More than 80% of homes in the UK are connected to the gas grid, meaning gas is transported via pipes directly to their house where it is combusted in a boiler which provides space heating and hot water[20]. Around 30% of households use gas ovens and roughly 60% of households have gas hobs, and the overwhelming majority of these homes are connected to the gas grid[21].

The remainder of domestic properties are off the gas grid; their heating and hot water comes from other sources such as heating oil, liquefied petroleum gas (LPG), solid fuels, mains electricity, and, to a limited degree, microgeneration (e.g. solar thermal); generally, these are more expensive than natural gas transported through the gas grid[22].

Around half of the energy consumed in non-residential buildings is for some form of heating or cooling. Within this, the majority of space heating, space cooling, hot water and catering are all provided by gas[23]. Around 60% of heat used for industrial processes comes from natural gas[24]. There are also examples of industrial processes where it will be difficult to replace gas as the source of heat due to the extremely high temperatures required.

The need to move away from unabated natural gas

The emissions associated with using natural gas to provide heat, combined with the requirements set out in the Climate Change Act and the Paris Agreement – as well as the science underlying these – means a dramatic shift away from the current system is required. Ultimately, to meet the Paris Agreement targets of net-zero emissions in the second half of this century, there is a need to move towards energy being delivered via zero-carbon vectors such as electricity, hot water and hydrogen. Furthermore, as methane is a potent greenhouse gas (regardless of its sources) then even small leakages rates are incompatible with

[18] BEIS (2016) Energy consumption in the UK. Overall energy consumption for heat in 2015 was 684TWh of which 462TWh was from natural gas
[19] BEIS (2016) Energy consumption in the UK. Domestic energy consumption for heat in 2015 was 388TWh of which 292TWh was from natural gas
[20] Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating
[21] DECC (2013) Energy Follow-Up Survey 2011, Report 9: Domestic appliances, cooking and cooling equipment
[22] House of Commons Library (2013) Heating oil and other off-gas grid heating. N.B. This can vary based on fluctuations in the price of oil and gas
[23] Committee on Climate Change (2016) Next steps for UK heat policy: Annex 2 – Heat in UK Buildings Today
[24] UKERC (2013) The future role of thermal energy storage in the UK energy system (data for 2012)

the stringent emissions goals of the Paris Agreement – a further reason not to use methane as an energy carrier in the longer term.

A previous report by Carbon Connect analysed energy pathway models for heat decarbonisation to 2050, and showed that the amount of natural gas used to heat buildings will need to fall by at least three-quarters by 2050 in order to meet carbon targets, and perhaps by as much as 95%[25]. More recently, the Committee on Climate Change has confirmed that the 2050 targets mean there is a need to "*prepare for a widespread shift away from natural gas for heating*"[26].

Indeed, without a near complete decarbonisation of heat for buildings, the Committee on Climate Change has concluded that meeting the 2050 target would be "*much more expensive*" and potentially "*impossible*". This is because under the central fifth carbon budget scenario to 2050, reducing emissions from sectors such as industry, agriculture and international aviation will be particularly challenging[27].

1.3 Heat decarbonisation

Progress to date

The Committee on Climate Change has reported that emissions associated with heating fell by a tenth from 2005 to 2012, largely due to rising energy efficiency in buildings and the roll-out of more efficient condensing boilers[28]. However, since 2013 heating emissions have plateaued, attributable to a slowing down in deploying insulation in buildings, which has led to an 80% fall in energy efficiency measures[29].

It is, however, difficult to assess the UK's progress to date in reducing emissions related to heating since there are no Government data which track this specifically. In the absence of official statistics, Policy Exchange combined a number of datasets to show that there has been a 20% reduction in the total emissions related to domestic heating (including cooking) between 1990 and 2015[30].

The EU's 2009 Renewable Energy Directive requires the UK to meet 15% of its energy needs from renewable sources by 2020 – broken down by the UK Government to 30% of its electricity, 12% of its heat, and 10% of its transport fuel. According to the House of Commons Energy and Climate Change Committee, the UK is on course to surpass its targets for electricity, but miss its targets for heat and transport. In 2015, just 5.64% of heat came from renewable sources[31], and according to the Committee on Climate Change, just 4% of heat demand in buildings and industry is from low-carbon sources[32].

The Committee on Climate Change have suggested that the UK has so far kept in line with its required overall emissions reductions, principally because of weaker than anticipated economic performance following the financial crisis and reductions in emissions related to electricity[33]. However, there is a widespread consensus that significant policy development will be necessary in the area of heat in order for the UK to meet its emissions reductions targets and carbon budgets in the future. In its most recent progress report, the Committee on Climate Change has stated that a "*clear, combined strategy for energy*

[25] Carbon Connect (2014) Future Heat Series Part 1 – Pathways for Heat: Low Carbon Heat for Buildings
[26] Committee on Climate Change (2017) Meeting Carbon Budgets: closing the policy gap
[27] Committee on Climate Change (2016) Next steps for UK heat policy
[28] Committee on Climate Change (2016) Next steps for UK heat policy
[29] Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating
[30] Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating
[31] Energy and Climate Change Select Committee (2016) 2020 renewable heat and transport targets; renewable sources defined as "wind, solar and hydro energy, bioenergy (energy from combustion of plant and animal matter; waste energy, such as landfill gas; and aerothermal, geothermal and hydrothermal energy (heat from the air, ground and water, respectively)."
[32] Committee on Climate Change (2017) Meeting Carbon Budgets: Closing the policy gap. N.B. Not all renewable energy is low-carbon, and not all low-carbon energy is renewable. For example. nuclear electricity is low-carbon but not renewable, whilst bioenergy is renewable but not necessarily low-carbon
[33] Committee on Climate Change (2016) Meeting Carbon Budgets – 2016 Progress Report to Parliament: Executive Summary

efficiency and low-carbon heat is needed" in order for the UK to meet its legally-binding fourth and fifth carbon budgets, as part of wider strategies which can deliver economy-wide decarbonisation through to 2050 and beyond[34].

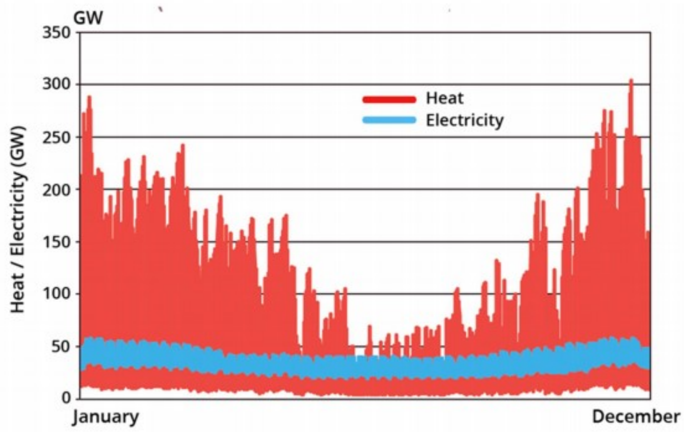
Finding 1

There is a widespread consensus that significant policy development will be necessary in the area of heat in order for the UK to meet its emissions reductions targets. This will require the UK to shift dramatically away from its reliance on unabated natural gas for heating.

The challenges of heat decarbonisation

Figure 4 is an oft-reproduced graphic in discussions of heat as it underlines why the challenges in relation to heat decarbonisation are so difficult to tackle. Firstly, the sheer amount of energy used to provide heat for buildings dwarfs that of electricity.

Figure 4: A comparison of electricity and (non-industrial) heat demand



Source: Sansom, R. (2015) Decarbonising low grade heat for a low carbon future, PhD thesis

Secondly, there is dramatic variation in demand which is characteristic of heating for buildings but not of electricity. Around 30-40% of heat use is fairly constant throughout the year, such as hot water, cooking and industrial processes. However, the remainder – in particular space heating in buildings – varies enormously throughout the course of the year and between relatively warmer and colder years[35] (exacerbated by the UK's generally poor efficiency building stock). The gas grid is capable of regularly meeting such large swings in demand. It can even handle acute peaks in heat demand during so-called '1 in 20' events – occasions where there is a short (either 6 minute or 1 hour) peak in demand that theoretically occurs just once every twenty years[36]. Low-carbon technologies must therefore match this performance and reliability.

Thirdly, heat decarbonisation will require significant additional operational costs and investments, totalling a sum in the order of hundreds of billions of pounds – and even higher if there is little progress on extensive, high-quality energy efficiency measures which could significantly reduce the overall costs of low carbon heat.

Finally, gas can be stored on a short-term basis in the pipes used to transport it, and for longer periods in salt caverns and other facilities[37]. Access to gas markets through interconnectors and LNG imports also assists with the management of inter-seasonal swings. The system of pipes used to transport gas as well as

[34] Committee on Climate Change (2017) Meeting Carbon Budgets: Closing the policy gap
[35] UKERC (2013) The future role of thermal energy storage in the UK energy system
[36] Sadler *et al.* (2016) H21 Leeds City Gate
[37] MacLean, K. *et al.* (2016) Managing heat system decarbonisation: comparing the impacts and costs of transitions in heat infrastructure

facilities connected to this are able to store vast amounts of energy for long periods – an estimated 50TWh of natural gas storage which would last 900 hours[38]. This is particularly significant because of its implications for energy security: while increased reliance on gas imports is problematic, the storage potential of gas means it is possible to build up reserves and allows for significant flexibility in when and how this is used.

Finding 2

Heat system decarbonisation is particularly challenging because of the large volumes of energy associated with it, and the extreme and rapid swings in heat demand that can arise. In addition, all the low carbon heat solutions will likely involve substantial up-front costs to put in place and/or higher operating costs than the dominant incumbent of natural gas provided through the gas grid.

Options for heat decarbonisation

The challenge for Government, therefore, is to manage a transition from the current heat supply to a low carbon alternative while best preserving the affordability and security of the UK's energy system. Table 1 provides a short outline of the main technologies which provide low carbon heat in buildings. Carbon Connect conducted analyses of heat decarbonisation in 2014 and 2015 and concluded that an 'all of the above' approach, entailing the implementation of a number of different low carbon heat solutions by 2050, is likely to be the most useful[39].

The importance of demand reduction

In addition to rolling out low carbon heat technologies, there is an urgent need to increase the efficiency of heating use in the UK and reducing heat demand[40]. This includes improving the fabric of buildings, increasing the efficiency of heating systems and reducing energy use through behaviour change. There has been progress made in energy efficiency but in recent years this has stalled and a policy vacuum has developed in this area[41].

Problems with electrification

The strategy documents released by the Government on heat decarbonisation have placed a strong emphasis on electric heating technologies. Most recently, *The Future of Heating: Meeting the Challenge* (published in 2013) suggested that by 2050 around 85% of total domestic heat demand would be met by heat pumps, 10% by heat networks and the remaining 5% by gas[42]. Recent research has questioned the affordability and practicality of a strategy for heat which is so heavily dominated by electrical heating technologies[43].

Figure 4 underlines why trying to meet the overwhelming majority of UK heat demand through electrical heat sources would be so challenging. The seasonal fluctuations in demand for heat mean that the UK would have to design an electricity system capable of meeting demand in the winter, which is on average seven times that of the summer[44]. It could be even higher than this on a particularly cold day, and the system would have to be capable of guaranteeing it could meet this.

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[38] MacLean, K. *et al.* (2016) Managing heat system decarbonisation: comparing the impacts and costs of transitions in heat infrastructure; Le Fevre, C. (2013) Gas storage in Great Britain, NG 72 Oxford Institute for Energy Studies
[39] Carbon Connect (2014) Future Heat Series – Part 1; Carbon Connect (2015) Future Heat Series – Part 2
[40] Committee on Climate Change (2017) Meeting Carbon Budgets: Closing the policy gap, p. 74
[41] Westminster Sustainable Business Forum (2016) Warmer & Greener: A guide to the future of domestic energy efficiency policy
[42] DECC (2013) The future of heating: meeting the challenge; Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating
[43] MacLean, K. *et al.* (2016) Managing Heat System Decarbonisation: comparing the impacts and costs of transitions in heat infrastructure; Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating; KPMG (2016) 2050 Energy Scenarios: The UK Gas Network's Role in a 2050 Whole Energy System; WWU (2016) Heat, Light and Power Model – Future of Energy and Investments in Energy Networks
[44] Dodds, P. *et al.* (2015) Hydrogen and fuel cell technologies for heating: a review. *International Journal of Hydrogen Energy*, **40**(5): 2065-2083

To do this will require the establishment of significantly more low carbon electricity generation capacity. Crudely speaking, in a scenario where natural gas for heat is entirely replaced with electricity, this would require plugging a gap of roughly 500TWh of energy with electricity[45] – more than doubling the total amount of electricity generation in the UK[46], and all of which would have to be low carbon. Moreover, in order for the electricity networks to support the extra capacity involved in electrifying heat, there will be a need to reinforce and upgrade the electricity to grid to handle the higher loads of energy in the system.

As has been mentioned, it is possible to store gas easily and the gas system can deliver energy flexibly across both short and long timescales. In contrast, electricity can only be stored in small quantities delivering energy for short durations, and is incredibly expensive when compared to storing gas[47]. This may even mean that to cope with extra demands on the electricity system created by changes in heating technologies, the UK might have to construct sources of power and storage which lay dormant for most of the year.

The principal focus of this report is around heat; however, it is impossible to consider sectors in isolation. The widespread rollout of heat pumps relies on sufficient affordable, secure and low carbon power being readily available, but widespread transitions to electric vehicles could make this challenge more acute.

Finding 3

It seems likely that electrical heating solutions will play an important part in the decarbonisation of heat in the UK (alongside non-electric technologies and district heating). Nonetheless, there are technical challenges and significant costs with rolling out electrical heating technologies to the extent that has been conceived in recent years, which justifies the consideration of complementary or alternative solutions such as low carbon gases.

[45] BEIS (2017) Energy consumption in the UK, Table 1.04. Overall energy consumption for heat with natural gas across all sectors in 2016 was equivalent to 500TWh.
[46] In 2015, electricity generation was 339 TWh (BEIS (2016) DUKES Chapter 5)
[47] MacLean, K. *et al.* (2016) Managing Heat System Decarbonisation: comparing the impacts and costs of transitions in heat infrastructure.

Table 1: Low carbon heat solutions for buildings

Solution	Outline
Electrical heating technologies	These can be broadly grouped into two types: resistive or storage heaters, and heat pumps. The former convert electricity directly to heat and are cheap to buy but expensive to run. The latter technology draws on ambient heat in the air, water or ground – they are expensive to buy, but cheaper to run. It is important to emphasise that electrical heating is not *per se* low carbon and depends on the carbon intensity of the electricity system. The extent to which electrical heating can decarbonise heat therefore depends on the extent to which the power system is decarbonised in the future.
Low carbon gases	This broadly involves using gases with much lower greenhouse gas emissions than natural gas to provide heat. This would most likely be in the same way as natural gas: combusted in boilers. Gas could also be used in Micro Combined Heat and Power (Micro-CHP) systems or fuel cell-based appliances which burn or utilise gas to provide heat and power either for an individual building or communally as part of a district heating network. Low carbon gases are summarised in more detail in Chapter 2.
District heating	District heat networks distribute heat (via hot water) from a centralised heat source directly to buildings. This is generally a very efficient way of providing heat and thereby reduces emissions. However, district heating is not in and of itself low carbon: it is dependent on the heat source chosen and whether it is low carbon or not. District heating today often runs on natural gas, but less greenhouse gas intensive sources of heat will be needed to deliver decarbonisation in the future.
Solar and geothermal technologies	Geothermal heating uses heat extracted from water or rock deep underground and solar takes it from the sun. There are very limited sources of geothermal heat in the UK and its climate heavily restricts the use of solar for heat, where there is a poor correlation between peak/seasonal demand and peak/seasonal production for space heating requirements.
Biomass	Biomass heating sources burn solid organic material to generate heat and include basic stoves, boilers and micro-CHP systems. The finite supply and competing sectors for the use of sustainable, low carbon biomass in the UK limits the potential role for heat[48].

Source: **Parliamentary Office of Science and Technology (2016) Carbon footprint of heat generation**
Carbon Connect (2014) Future Heat Series Part 1 – Pathways for Heat
Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating

[48] Committee on Climate Change (2011) Bioenergy review

2. Low carbon gas

FINDINGS

4. There are diverse sources of low carbon gas which could, to varying extents, make substantial contributions to the UK's efforts to reduce greenhouse gas emissions. Increasing attention has begun to focus on the opportunities offered by low carbon gases such as hydrogen, biomethane and bioSNG. This is in part because they are seen to provide significant opportunities in the area of heat decarbonisation, but low carbon gases could also play a large role in efforts to decarbonise other sectors such as transport.

2.1 Why focus on low carbon gases?

The potential of low carbon gas for heat

There is increasing attention on the significant opportunities offered by low carbon gases, which can be used with low or almost no greenhouse gas emissions. Particular interest lies in the area of heat decarbonisation: the UK could dramatically reduce the emissions associated with heat while maintaining a similar system to the one currently in place by changing the form of gas in the grid.

Much of the existing infrastructure used to transport gas could remain in place, consumers could keep similar, or in some cases, the same heating appliances, and the storage challenges of heat could be met in broadly the same way as they are by natural gas. Industrial processes which rely on heat generated by burning gas could also be supplied in a similar way by a low carbon form of gas.

In addition to these practical considerations, a number of recent studies have not only highlighted the potentially high costs associated with the electrification of heat, but suggested that the most affordable plan for reducing emissions from heat may include a significant contribution from low carbon gas (though estimates vary on the optimum size and nature of this)[49].

The potential of low carbon gas in other sectors

Low carbon gas could also make a substantial contribution to efforts to reduce transport emissions. Low carbon gases can be used as an alternative to electric vehicles, especially for heavy goods vehicles which are more challenging to power by electricity. There are already examples of this in practice such as forklift trucks, hydrogen-fuelled buses and biomethane CNG-fuelled trucks[50].

In addition, low carbon gas can help reduce emissions in the power sector through small on-site electricity generators, gas-fuelled combined heat and power (CHP) plants, and by replacing natural gas in power plants. There are more low carbon options available in the power sector than in heat or transport, however, so the need for low carbon gas is less pressing in this area.

2.2 What is low carbon gas?

There is no official definition of what makes a gas low carbon. It is probably best seen as a gas which, across its lifecycle, releases fewer greenhouse gas emissions when used than natural gas, on a per unit of

[49] MacLean, K. *et al.* (2016) Managing heat system decarbonisation: comparing the impacts and costs of transitions in heat infrastructure; Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating; KPMG (2016) 2050 Energy Scenarios: The UK Gas Network's Role in a 2050 Whole Energy System; Sadler *et al.* (2016) H21 Leeds City Gate
[50] Cadent (2016) The future of gas: transport

energy basis[51]. However, the emissions created by natural gas can vary depending on its source and different low carbon gases emit different levels of greenhouse gases. The following section outlines the main forms of low carbon gas.

2.3 Biogases

There are a number of gases – biogas, biomethane, bioSNG and biopropane – which can be grouped together as 'biogases' because they are produced from forms of organic matter such as organic waste, sewage, municipal solid waste (MSW) and wood[52].

Biogas

What is biogas?

Although biogas can be used as a catch-all term to describe all gases derived from biological sources, biogas technically refers to the raw gas which is produced from organic matter through a process known as anaerobic digestion (AD). It is broadly made up of 60% methane, 29% carbon dioxide and other constituent gases such as hydrogen sulphide, oxygen, hydrogen and nitrogen[53].

How is biogas produced?

The process of AD can be used to produce gas from certain forms of 'wet' organic matter such as food waste and agricultural residues. The organic matter needs to be processed in the absence of oxygen. AD is a well-established process and in December 2016 there were 540 AD plants running in the UK[54].

Why is biogas a low carbon gas?

Biogas releases greenhouse gas emissions when burnt, but is considered low carbon as it is derived from biological sources. Some sources are low carbon because they are derived from plants which captured carbon while they were alive and can also be replaced by the planting of new plants which will then capture carbon. Some sources, such as food waste, are low carbon because, if they were not processed to release energy, would release emissions by naturally degrading or through landfill emissions, often in the form of methane – a potent greenhouse gas that traps 25 times as much heat in the atmosphere per tonne than carbon dioxide. Some sources of biogas are low carbon for both reasons.

The extent to which biogases are 'low carbon' depends upon the nature of the feedstock used; for example, energy crops deliver far less of a greenhouse gas reduction than do organic wastes[55]. It is complicated to accurately calculate the exact greenhouse gas emissions coming from individual sources of bioenergy; however, in principle, all biogases can be accurately considered a lower carbon alternative to natural gas[56]. Biogas-associated greenhouse gas emissions are thought to be about 90% less than for fossil sources[57].

How can biogas be used?

Biogas is low quality and some of the elements within it make it incompatible with most gas-using appliances. Its predominant use is therefore not for the gas grid, but for heat and power generation. In December 2016 the UK had over 700 MWe of biogas capacity, enough to power the equivalent of 850,000

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[51] Foster, M. (2016) Green gas for an affordable, secure and sustainable future. In: *Green Gas Book* (Eds. Parliamentary Labour Party Energy and Climate Change Committee)
[52] Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating, p.38
[53] IGEM (2012) Biofuels: analysis of the various biofuel types including biomass, bioliquids, biogas and bioSNG, p. 23
[54] ADBA (2016) AD Market Report: December 2016
[55] DECC (2016) Consultation Stage Impact Assessment (IA): The Renewable Heat Incentive: A reformed and refocused scheme, p.99
[56] Welfle, A. *et al.* (2017) Generating low-carbon heat from biomass: life cycle assessment of bioenergy scenarios, *Journal of Cleaner Production* **149**: 448-460
[57] Parliamentary Office of Science and Technology (2015) Future of natural gas in the UK

homes[58]. However, most biogas plants produce biogas that is upgraded to biomethane with the addition of the requisite processing equipment.

Biomethane

What is biomethane?

Biomethane is largely made up of methane (approx. 95% by volume). It is produced from biological sources, and has a very similar composition and properties to natural gas.

How is biomethane produced?

The production of biomethane essentially entails an additional stage in the process to that of producing raw biogas through AD whereby the gas is 'upgraded' or 'scrubbed'. This process increases its methane content, removes impurities and CO2, and renders it of suitable quality to inject into the gas grid.

Why is biomethane a low carbon gas?

Biomethane is low carbon for the same reasons as biogas. It is important to emphasise that some feedstocks for biomethane (such as wastes) are less carbon intensive than others (such as energy crops), and biomethane from food waste delivers considerably more cost-effective greenhouse gas mitigation than does biomethane from crops, manures or slurries[59].

How can biomethane be used?

Because of its similar composition, biomethane can be directly substituted for natural gas in the existing transportation networks and used in existing appliances, as well as for transport. It therefore offers a relatively simple option to reduce emissions associated with heat and there is a growing industry of small-scale plants producing biomethane and injecting it into the gas grid.

BioSNG

What is bioSNG?

BioSNG (Bio Synthetic or Substitute Natural Gas) is produced through a different process to biomethane but is still made from biological sources. It also has a very similar composition and properties to natural gas.

How is bioSNG produced?

As opposed to biogas and biomethane, which are produced through anaerobic digestion (AD), the gasification process used to produce bioSNG can use any form of biomass, including both 'wet' sources such as sewage and 'dry' sources such as wood. Of greatest current interest is bioSNG from residual 'black bag waste' – shredded and dried waste after recycling which would otherwise go to landfill.

The production of bioSNG from waste is a multi-step process. Firstly, waste materials (in the form of refuse derived fuel or RDF) are converted to 'syngas' by a process called 'gasification', in which waste is heated at very high temperatures in low oxygen conditions. Syngas is then reacted with steam in a process known as the 'water gas shift' reaction in order to boost the level of hydrogen within the syngas. This high-hydrogen syngas then undergoes a 'methanation' reaction to transform it into methane. This methane is further refined, releasing carbon dioxide as a by-product and is then suitable for injection into the gas grid[60].

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[58] ADBA (2016) AD Market Report: December 2016
[59] DECC (2016) The Renewable Heat Incentive: A reformed and refocused scheme (Impact Assessment)
[60] Go Green Gas (2016) BioSNG Pilot Demonstration: Fuelling a green gas future

Why is bioSNG a low carbon gas?

BioSNG is a low carbon gas for similar reasons to biomethane and biogas. BioSNG from residual black bag waste will deliver greater mitigation than bioSNG from feedstocks such as imported wood pellets because of the avoided methane emissions that would have otherwise occurred if black bag waste had been sent to landfill instead of used to produce energy. However, the level of mitigation achieved compared to natural gas will also depend on the extent to which black bag waste is composed of organic matter (e.g. food waste) rather than wastes such as fossil-derived plastics (e.g. packaging). Moreover, gasification is an energy-intensive process requiring high energy input, negating some of the carbon savings.

How can bioSNG be used?

Like biomethane, bioSNG has the potential to directly replace natural gas in the energy system, including being injected into the gas network and used in existing heating appliances, as well as for transport. Additionally, the process of producing bioSNG could also be simplified to produce hydrogen instead.

Biopropane

What is biopropane?

Propane is a naturally occurring gas which is most commonly used in a liquefied form (generally referred to as Liquefied Petroleum Gas or LPG)[61]. Biopropane is a form of LPG derived from biological materials[62].

How is biopropane produced?

Biopropane can be produced in many different ways, using different types of thermal and chemical processes from a number of different biological sources including plant material, vegetable oil and animal fats[63]. Biopropane is available to buy in the UK as of 2017 and production facilities are being developed across Europe.

Why is biopropane a low carbon gas?

Biopropane is a low carbon gas for the same reasons as the other biogases, although as with all bioenergy, its carbon footprint will depend on the feedstock used.

How can biopropane be used?

Biopropane is compatible with existing heating appliances and could therefore be used as a direct replacement for LPG. Through this it could make a contribution to the decarbonisation of heat, primarily for buildings which are off the gas grid and run on LPG (about 171,000 homes in the UK)[64]. Additionally, propane is added to both biomethane and bioSNG to increase the quality of the gas before it is injected into the gas grid; biopropane could be used as a low carbon substitute.

2.4 Hydrogen

What is hydrogen?

Hydrogen gas is a colourless, odourless, tasteless and non-toxic element. When burnt it reacts with oxygen in the air to create water and heat.

[61] EUA (2016) Biopropane for the off-grid sector
[62] EUA (2016) Biopropane for the off-grid sector
[63] DECC (2014) RHI evidence report – biopropane for grid injection; EUA (2016) Biopropane for the off-grid sector
[64] Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating, p.39; EUA (2016) Biopropane for the off-grid sector

How is hydrogen produced?

Hydrogen can be produced in around twenty different ways, but there are two principal modes of bulk production: steam methane reformation (SMR) and electrolysis. SMR is a well-established industrial activity which chemically converts methane to hydrogen[65], and is considered the most economical way to produce bulk hydrogen[66]. Electrolysis involves using electricity to split water into hydrogen and oxygen[67].

Why is hydrogen a low carbon gas?

When hydrogen is combusted in a boiler it emits zero carbon dioxide emissions – so the determinant of how low carbon it can be is in how it is produced[68].

SMR results in emissions of carbon dioxide, so carbon capture and storage (CCS) infrastructure is required at SMR plants[69]. This is necessary to produce hydrogen that delivers emissions reductions compared to natural gas. The extent to which it reduces greenhouse gas emissions is determined by the efficiency of the SMR process and the rate at which carbon dioxide emissions are captured by CCS[70]. Currently, CCS technology is capturing over 90% of the carbon dioxide emissions from a SMR plant in Texas[71].

Electrolysis could produce hydrogen with extremely low greenhouse gas emissions provided electricity is generated from low carbon sources such as wind, solar or nuclear[72]. Electrolysers can play an energy system management role by balancing surplus generation from renewables in the electricity grid, thereby enabling the integration of more renewables whilst producing very low carbon hydrogen. However, the volumes of hydrogen available from 'surplus' renewable generation are likely to be fairly limited and would not be sufficient to meet a high proportion of UK heat demand.

How can hydrogen be used?

Although a large component of town gas, hydrogen is not used in the UK gas grid anymore[73]. It is most commonly used within the chemicals and oil industry (e.g. desulphurisation of fuels), and is usually produced on-site or distributed by vehicles as a liquid (typically imported from Holland) or as a compressed gas in cylinders rather than in pipelines. Where hydrogen is conveyed by pipeline in the UK (in Teesside and Merseyside), it is only carried short distances and in low quantities[74]. However, hydrogen could be transported long distances via pipes and there are large hydrogen pipelines in Europe and Texas.

Hydrogen could be used in the same way that natural gas is currently, in order to provide heat for use in residential buildings (with hydrogen boilers, ovens and hobs rather than natural gas equivalents)[75]. It can also play a role in providing heat for commerce and industry, and could be used in other areas such as for power and transport.

Finding 4

There are diverse sources of low carbon gas which could, to varying extents, make substantial contributions to the UK's efforts to reduce greenhouse gas emissions. Increasing attention has begun to focus on the opportunities offered by low carbon gases such as hydrogen, biomethane and bioSNG. This is in part because they are seen to provide significant opportunities in the area of heat decarbonisation, but low carbon gases could also play a large role in efforts to decarbonise other sectors such as transport.

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[65] Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System
[66] Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System
[67] IGEM (2012) Hydrogen: untapped energy?
[68] Dodds, P. *et al.* (2015) Hydrogen and fuel cell technologies for heating: a review. *International Journal of Hydrogen Energy*, **40**(5): 2065-2083
[69] Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System
[70] Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System, p.36
[71] IEA GHG (2015) Understanding the potential of CCS in hydrogen production. Presentation by Santos S to Joint IEA GHG and IETS workshop, March 2015; cited in ERP (2016) Potential role of hydrogen in the UK energy system
[72] E4tech and Element Energy (2016) Hydrogen and fuel cells: opportunities for growth – a roadmap for the UK
[73] Town gas was as much as 50% hydrogen by volume
[74] Energy Technologies Institute (2016) UK networks transition challenges – hydrogen
[75] Though the appliances need further testing and development and the hobs, in particular, are unproven.

Part 2

THE FUTURE OF THE GAS GRID

The gas grid is an extensive piece of energy infrastructure which permeates many aspects of our lives, often without us realising. This section offers an explanation of how the gas grid works and who owns and operates it. It then explores how this system might evolve over time, and describes some of the potential future scenarios for the gas grid – spanning from its continued use as a decarbonised energy network with the introduction of low carbon gas, through to its disuse and total decommissioning.

3. Future scenarios for the gas grid

FINDINGS

5. Biomethane is already injected into the gas grid and could be deployed more widely in order to reduce emissions associated with heat. However, there are limited quantities of sustainable feedstocks, so it can only meet a low proportion of heat demand (thought to be in the region of 5% of current gas consumption in the UK). In the long term, there are likely to be more effective uses of bio-resources in decarbonising other sectors with few alternative low carbon options (e.g. aviation, shipping and heavy goods vehicles) rather than injection into the gas grid to provide heat.

6. BioSNG production from residual 'black bag waste' has been demonstrated but requires further work for it to be rolled out commercially. BioSNG from the gasification of waste has greater potential to meet heat demand than biomethane from AD. However, bioSNG from waste feedstocks could still only meet a limited fraction of heat demand in the UK and there are likely to be more effective uses of the energy in black bag waste in decarbonising other sectors (such as road transport, shipping and aviation) rather than injection into the gas grid to provide heat.

7. Blending a small amount of hydrogen with natural gas in the grid is expected to have few adverse impacts on end-users and could play a useful role in electricity grid management. However, it only achieves very limited reductions in greenhouse gas emissions and there may be more effective uses of hydrogen from electrolysis in decarbonising sectors such as transport, which could also help tackle air quality issues.

8. Repurposing significant amounts of the gas grid to transport 100% hydrogen could be a practical route to deliver extensive heart decarbonisation. However, this idea remains to be proven and there is a need to reduce uncertainties surrounding this option before a proper assessment of its desirability can be made.

9. A hybrid gas/electric option could be flexible enough to cope with seasonal heat demand and reduce the burden on the electrical system. However, work is still needed to bring these technologies to maturity. There are uncertainties around the commercial viability of this option, the associated greenhouse gas savings, and how this best integrates with other scenarios for the gas grid. Initial work is being undertaken to address these issues.

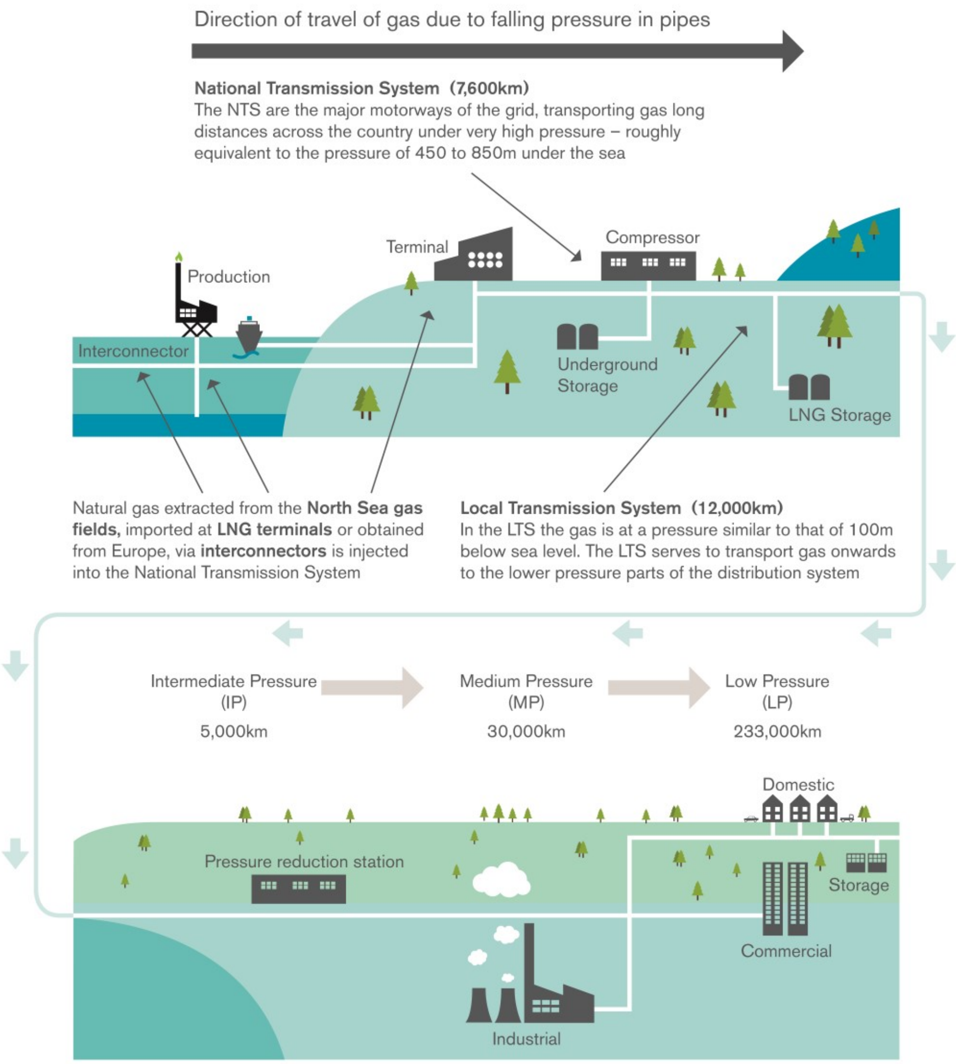
10. In the long term, the full or partial decommissioning of the gas grid could be necessary if low carbon gas cannot be deployed at scale, or if it is not pursued as an option. This is more likely to be required should carbon capture and storage not be developed in the UK. However, there would be significant costs associated with this. Moreover, the substantial capacity to transport and store large volumes of energy in the gas system would need to be replaced by another source. Work is needed to reduce uncertainties around the costs and implications of decommissioning.

3.1 What does the gas grid look like today?

What is the gas grid?

The UK's gas grid is the transportation network for natural gas, consisting of pipelines of more than 280,000km in length. The gas grid is composed of three systems: the National Transmission System (NTS); the Local Transmission System (LTS); and the Distribution Networks. The gas pressure in each of these successive tiers, from the NTS through to the lowest reaches of the Distribution Networks, is gradually reduced, allowing gas to 'cascade' down the system from high to low pressure (Figure 5).

Figure 5: The UK gas grid



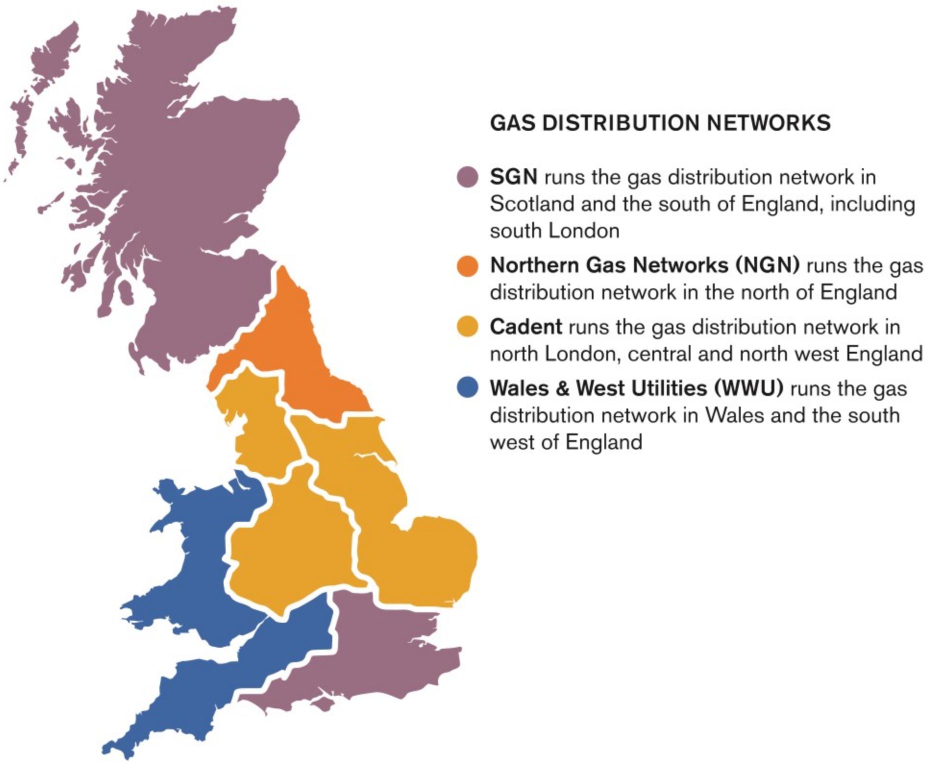
Source: Data taken from: Dodds, P.E. & Demoullin, S. (2013) Conversion of the UK gas system to transport hydrogen. *International Journal of Hydrogen Energy* 38, 7189-7200; Sadler *et al.* (2016) H21 Leeds City Gate. Adapted from: National Grid (2012) Annual report and accounts, p. 17

Who runs the gas grid?

The National Transmission System (NTS) is entirely owned and operated by National Grid Gas Transmission. In contrast, the eight regional distribution systems are owned and operated by four Gas Distribution Networks or GDNs (Figure 6).

In addition to the GDNs, there are Independent Gas Transporters (IGTs) which connect to the distribution system via the GDNs and serve their own downstream customers. IGTs have around 1 million customers, particularly in new residential and commercial developments. IGTs are therefore an increasingly important player in the gas industry.

Figure 6: The Distribution Networks, and their ownership by the GDNs



Source: **Adapted from Ofgem. Available at: https://www.ofgem.gov.uk/key-term-explained/map-who-operates-gas-distribution-network**

3.2 What could the gas grid look like in the future? Scenarios for the gas grid

This section outlines the various potential future scenarios for the gas grid, ranging between the continued use of the gas grid with low carbon gases and the full decommissioning of the gas grid. This section details what these possible future scenarios for the gas grid look like, and outlines the advantages and challenges of each.

The continued use of the gas grid

Despite being the source of the majority of the emissions from heating today, by transporting low carbon gases (instead of natural gas) the gas grid could still play a critical role in a decarbonised future.

Biomethane

Biomethane produced from anaerobic digestion (AD) is already injected into the gas grid, but in the future this could be expanded.

What are the advantages of biomethane?

Established technology

Biomethane production from AD and injection into the gas grid is an established process, and it is permitted under existing regulations and legislation. Accordingly, it has the potential to deliver greenhouse gas savings immediately. The deployment of biomethane from the anaerobic digestion of *waste* – rather than energy crops which currently produce the majority of biomethane – for heat is a 'low-regrets' measure, as it can deliver reductions in emissions through to the 2030s without requiring investment in new network infrastructure[76].

Consumer acceptance

Biomethane also provides an identical experience for the user as natural gas when used in appliances. This affords it a very high level of consumer acceptability, as it has no visible impact on downstream customers.

What are the disadvantages of biomethane?

Limited contribution

According to the Committee on Climate Change the potential of biomethane is limited to around 5% of gas consumption[77], primarily due to land-use limitations and the availability of suitable and sustainable feedstocks. While it may be possible to increase this through imports, this, in turn, raises concerns over the sustainability and security of importing biomethane. As a consequence of its limited ability to meet demand, biomethane extends the lifetime of natural gas use in the grid, which further limits its ability to deliver decarbonisation.

Better end-uses

Given the limited contribution that they can play within the energy mix, scarce bioresources should be deployed to their best utility. In models of bioenergy deployment by the ETI, taking into account the available biomass resources, the geography of the UK, time, technology options and logistics networks, bio-hydrogen and bio-electricity are produced in preference to biofuels and biomethane through to 2050[78]. Similarly, the Committee on Climate Change notes that, assuming there is CCS, only a relatively

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[76] Committee on Climate Change (2016) Next steps for UK heat policy
[77] Committee on Climate Change (2016) Next steps for UK heat policy
[78] ETI (2015) Insights into the future UK Bioenergy Sector, gained using the ETI's Bioenergy Value Chain Model (BVCM)

minor proportion of bioresources would be best deployed in heat, instead favouring its use to make hydrogen for use in transport[79]. Even if bioresources are deployed as bioenergy fuels, there are particularly few other low-carbon options beyond biofuels in the aviation, shipping and heavy goods vehicles sectors[80], favouring their use to decarbonise transport rather for heat.

Finding 5

Biomethane is already injected into the gas grid and could be deployed more widely in order to reduce emissions associated with heat. However, there are limited quantities of sustainable feedstocks, so it can only meet a low proportion of heat demand (thought to be in the region of 5% of current gas consumption in the UK). In the long term, there are likely to be more effective uses of bio-resources in decarbonising other sectors with few alternative low carbon options (e.g. aviation, shipping and heavy goods vehicles) rather than injection into the gas grid to provide heat.

BioSNG

Although not yet a mature technology, Cadent has launched a demonstration project producing bioSNG from residual 'black bag waste'. Expansion of this technology could enable bioSNG to play a major role in heating the UK.

What are the advantages of bioSNG?

High levels of decarbonisation

Cadent estimates that its waste-to-bioSNG plant has a carbon footprint 80% below that of fossil gas; and combined with CCS technology, its emissions savings could be as great as around 190% compared to natural gas – delivering 'negative emissions' (i.e. net emission reductions)[81].

However, whether these levels can be reached in practice has been contested. They may largely depend upon the extent to which bioSNG feedstock is waste-derived rather than from sources such as energy crops, and will also depend upon how much of the black bag waste is biologically-derived.

Hydrogen compatible

During the production of bioSNG from waste, a hydrogen rich 'syngas' is produced as an intermediary product prior to creating methane. In the future, this hydrogen rich gas could be purified to create a grid-injectable hydrogen gas instead of being used to create bioSNG, with the carbon instead being captured and sequestered via CCS[82]. This means that developing bioSNG plants in the short-term does not risk their disuse in the medium to long-term if Government were to pursue a hydrogen rollout, as they can flexibly adapt to a hydrogen future.

Reaches waste feedstocks that AD cannot

Compared with biomethane from AD, bioSNG is able to process more abundant sources of biogenic feedstock such as residual black bag and commercial wastes. BioSNG production is therefore capable of unlocking the value of waste feedstocks which AD is not able to do. This allows the potential for bio-derived methane to be expanded beyond the wet waste feedstocks suited to biomethane production, without competing with food production, which is beneficial as there are limits to the volumes of biomethane from crops that can be produced by AD sustainably. This wider range of feedstocks means

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79 Committee on Climate Change (2011) Bioenergy review
80 Royal Academy of Engineering (2017) Sustainability of liquid biofuels
81 GoGreenGas (2017) BioSNG Demonstration Plant - Project Close-Down Report
82 Cadent (2017) Biohydrogen: Production of hydrogen by gasification of waste. An NIA assessment of biohydrogen production and opportunities for implementation on the gas network

that bioSNG has far greater potential to produce higher quantities of renewable gas than biomethane from AD[83].

What are the disadvantages of bioSNG?

<u>Relies on waste</u>

Using waste as a feedstock conflicts with policies for sustainable resource use, which serve to minimise waste and, in doing so, act to deplete bioSNG of potential feedstocks for its production. A reduction of waste in the future is likely given concerns about resource depletion and future policy for waste minimisation, which is problematic for the supply of bioSNG.

This might also jeopardise the business models underpinning bioSNG, which rely on 'gate fees'. Gate fees are the charge levied upon a given quantity of waste received at a waste processing facility. BioSNG plants using waste as a feedstock receive income through gate fees, but as waste declines so too might the income from gate fees. If bioSNG business models are overly reliant on gate fees to be viable, future changes in waste policy could undermine heat decarbonisation policy. This will be discussed further in the second *Future Gas Series* report.

<u>Limited feedstocks</u>

As with biomethane, the feedstocks for bioSNG are too limited to be able to provide a significant amount of low carbon gas in the grid. Recent research by Anthesis and E4tech, commissioned by Cadent, estimates that the potential of gas from bioenergy (*both* bioSNG and biomethane) could be around 100TWh in 2050, or around a third of current domestic gas consumption[84]. However, this would involve diverting the majority of the UK's waste resources to bioSNG instead of other end uses.

<u>Needs development</u>

At present rates of development, potential bioSNG production from residual black bag waste in 2030 could be expected to be in the region of 25TWh per year[85], equivalent to around 8% of current domestic heat consumption met by natural gas[86]. However, at present there is only one demonstration plant converting black bag waste to bioSNG in the UK and a commercial-scale plant is only in development.

Finding 6

BioSNG production from residual 'black bag waste' has been demonstrated but requires further work for it to be rolled out commercially. BioSNG from the gasification of waste has greater potential to meet heat demand than biomethane from AD. However, bioSNG from waste feedstocks could still only meet a limited fraction of heat demand in the UK and there are likely to be more effective uses of the energy in black bag waste in decarbonising other sectors (such as road transport, shipping and aviation) rather than injection into the gas grid to provide heat.

[83] Anthesis Consulting Group and E4tech (2017) Review of Bioenergy Potential (forthcoming)
[84] Anthesis Consulting Group and E4tech (2017) Review of Bioenergy Potential (forthcoming)
[85] Go Green Gas (2016) Commercial BioSNG Demonstration Plant: First Project Progress Report
[86] BEIS (2017) Energy consumption in the UK, Table 1.04: Energy consumption for domestic heat in 2016 was 480TWh of which 311TWh was from natural gas

Blending hydrogen

Hydrogen could be partially used in the gas grid through blending it with other gases such as natural gas or biogases. In this scenario, surplus electricity from curtailed renewables production would be captured by electrolysis to generate hydrogen for injection into the grid (so-called "power-to-gas")[87]. This avoids wasting renewable energy and instead enables the existing gas grid to be used to absorb and utilise this.

It is unlikely, however, that hydrogen would be blended to more than 20% by volume (6% by energy): a study by the Health and Safety Executive (HSE) found that this level would most likely be the highest possible percentage hydrogen compatible with existing heating appliances[88]. Moreover, the HSE also identified concerns over the extent to which hydrogen blending is compatible with gas turbines. Gas turbines are particularly intolerant to hydrogen blending, with one major manufacturer setting a limit of 8.5% hydrogen by volume[89], and accordingly gas turbines may require modifications at very low blends in order to tolerate it[90]. Similar concerns are held with regards to the tolerance of industrial gas use with hydrogen blends.

What are the advantages of blending?

<u>No consumer impact</u>

Given that blending up to 20% hydrogen with methane by volume (6% by energy) should be achievable with no deleterious effects on end users and the grid, there is no need for new grid infrastructure or appliances. The only infrastructure requirements are aspects such as hydrogen production facilities.

<u>Prepares for a potential transition to 100% hydrogen</u>

By demonstrating the use of hydrogen in the gas grid to the general public, customers may be more willing to accept a later potential transition to 100% hydrogen.

What are the disadvantages of blending?

<u>Low emissions reductions</u>

A 20% hydrogen blend by volume would only equate to roughly a 6% carbon reduction relative to the natural gas it displaced. There is also an ongoing debate as to the extent to which surplus renewables would be available, both practically and economically, to be used by electrolysers. Whilst they could certainly play a useful role in managing the electricity grid, a number of contributors to this inquiry have expressed uncertainty around whether or not surplus renewables could deliver enough hydrogen to allow a blend of 20% hydrogen in the *entire* GB gas grid. Hydrogen blending would therefore most likely be injected locally in a number of places across the distribution system, but this would limit its overall decarbonisation impact.

<u>Better uses of hydrogen</u>

Whilst there is still some time until there would ever be a substantial fleet of hydrogen vehicles with a high demand for hydrogen gas, it is worth emphasising the idea that given the limited amounts of hydrogen that can be produced from electrolysis running on surplus renewables, there are questions about the suitability of putting hydrogen into the grid for heat if it could be better deployed in other areas of the energy system such as decarbonising HGVs and buses, which are hard to electrify and which are sources of considerable air pollution. The UK Government has committed a £23m package including

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[87] Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System
[88] Health and Safety Executive (2015) Injecting hydrogen into the gas network – a literature search
[89] Health and Safety Executive (2015) Injecting hydrogen into the gas network – a literature search
[90] Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System

developing power-to-gas technology as critical infrastructure for hydrogen fuel cell vehicles in order to mitigate road emissions and reduce air pollution[91].

Finding 7

Blending a small amount of hydrogen with natural gas in the grid is expected to have few adverse impacts on end-users and could play a useful role in electricity grid management. However, it only achieves very limited reductions in greenhouse gas emissions and there may be more effective uses of hydrogen from electrolysis in decarbonising sectors such as transport, which could also help tackle air quality issues.

100% hydrogen

Previous studies have explored what a conversion from natural gas to hydrogen might look like. The Leeds City Gate project outlines a vision to convert the city of Leeds and its surrounding area to 100% hydrogen in 2026-29, followed by conversions sweeping across cities in the north of England in the early 2030s, and by the mid-2040s reaching cities as far apart as Bristol and Aberdeen. Other gas users in this scenario would remain on a natural gas/biogas mix, whilst the high pressure natural gas National Transportation System would remain in place for large industrial users such as CHP power stations, as well as supplying natural gas as a feedstock for hydrogen production from SMR[92].

A study by KPMG outlined a comparable scenario in which there is a successive city-by-city shift to 100% hydrogen so that by 2050 most residential and commercial gas customers use hydrogen as their source of heating. Their scenario forecasts that hydrogen gas contributes to 47% of the UK energy mix in residential and commercial settings. Their scenario also sees a role for biomethane to contribute to a third of UK energy in these sectors, largely filling gaps for parts of the gas grid which have not converted to hydrogen[93].

What are the advantages of converting to 100% hydrogen?

<u>Deep decarbonisation</u>

It has been suggested that replacing natural gas with hydrogen produced via SMR with CCS in the distribution network of Leeds could reduce greenhouse gas emissions from heating by an estimated 73% compared to natural gas, assuming functional CCS capturing 90% of carbon dioxide and assuming that electricity has the same carbon intensity as that in 2015[94] (though this is expected to be able rise to greater than 80% with improvements to CCS, SMR and the ongoing decarbonisation of electricity)[95].

Hydrogen can be produced in a range of ways that have the potential to be zero-carbon in the longer term, and potentially even accommodate negative-emissions routes (e.g. through the gasification of biomass with CCS).

<u>Makes use of existing grid</u>

One reason for interest in 100% hydrogen conversion is a project called the Iron Mains Replacement Programme (IMRP), also known as the Iron Mains Risk Reduction Programme (IMRRP). This is already underway and is due to complete in 2032, meaning that for safety reasons all metal gas pipes within 30m

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[91] Department for Transport and the Office for Low Emission Vehicles (2017) £23 million boost for hydrogen-powered vehicles and infrastructure. Available at: https://www.gov.uk/government/news/23-million-boost-for-hydrogen-powered-vehicles-and-infrastructure
[92] Sadler *et al.* (2016) H21 Leeds City Gate
[93] KPMG (2016) 2050 Energy Scenarios: The UK Gas Network's Role in a 2050 Whole Energy System
[94] This also assumes that there is no rise in the embodied carbon associated with the upstream emission of natural gas extraction compared to current levels.
[95] Sadler *et al.* (2016) H21 Leeds City Gate

of a property will be replaced with polyethylene (plastic) ones[96]. The IMRP will make the pipes compatible with the transportation of 100% hydrogen, meaning there would be limited upgrades required to facilitate a conversion from natural gas. If 100% hydrogen is found to be possible, there are significant potential cost savings and practical benefits associated with utilising the existing network infrastructure rather than constructing the new networks required for other low carbon heat sources such electrical heat pumps or district heat networks.

Familiarity

Millions of UK customers are familiar with gas boilers, hobs, ovens and fires. Hydrogen-fired appliances would most likely broadly resemble these. Other heating technologies, such as heat pumps (which are low carbon provided that the electricity supply is low carbon), are unfamiliar and have faced barriers to their commercial uptake to date, not least due to their high cost and space requirements.

Relatively low disruption during switchover

Converting to hydrogen also causes relatively low disruption to areas of conversion. In buildings, conversion would require access to properties for a few days (in the summer, when heat demand is lowest) to exchange natural gas-fired appliances for hydrogen-fired equivalents (although it may also be necessary to fit ceiling vents in buildings changing over to hydrogen[97]) – during which time there is an opportunity to assess appliances for gas safety. There is minimal disruption at the street level – unlike installing heat networks or reinforcing the electricity grid to support more heat pumps, both of which are highly disruptive at the street-level due to their high requirements for new and upgraded infrastructure[98].

No carbon monoxide (CO) poisoning

Hydrogen combustion does not emit carbon monoxide (CO), and therefore would eliminate the risk of harm due to CO poisoning, which in 2015 caused 24 accidental deaths in England and Wales[99].

Air quality benefits

The combustion of hydrogen in gas boilers is expected to reduce emissions of particulate matter (PM), small micro-particles in the air which are a leading cause of air quality problems in the UK. Burning natural gas leads to PM emissions and sooting of the boiler, but hydrogen does not contain carbon and therefore does not soot.

It should be emphasised, however, that hydrogen could worsen some air pollutants. The combustion of hydrogen gas in boilers will be a higher temperature process that could generate more nitrogen oxides (NOx) than natural gas, a potentially damaging group of pollutants that are known to be damaging to human health, so it is important for research into hydrogen appliances to focus on finding ways that hydrogen combustion can avoid adverse impacts on air quality. It is also worth noting, however, that the use of hydrogen in fuel cells would produce very low air pollutant emissions, about one-tenth that of gas-burning technologies[100].

Synergies

Conversion of the gas grid to transport hydrogen could be coordinated with its use in other sectors; for example, fuelling stations for hydrogen vehicles.

96 HSE/Ofgem (2011) 10 year review of the Iron Mains Replacement Programme
97 Kiwa Ltd. (2015) Energy Storage Component Research & Feasibility Study Scheme: HyHouse - Safety Issues Surrounding Hydrogen as an Energy Storage Vector
98 MacLean, K. *et al.* (2016) Managing heat system decarbonisation: comparing the impacts and costs of transitions in heat infrastructure
99 Office for National Statistics (2016) Number of deaths from accidental poisoning by carbon monoxide, England and Wales, deaths registered in 2015
100 H2FC Supergen (2014) The role of hydrogen and fuel cells in providing affordable, secure low-carbon heat, p.25

What are the disadvantages of converting to 100% hydrogen?

Costs

The cost of hydrogen fuel will almost certainly be higher than that of natural gas. There are also high costs imposed due to the need to switch over appliances to run on hydrogen, although this could be minimised since all boilers would have to be changed on a natural cycle of replacement anyway.

It is important, however, to compare these costs to alternative decarbonisation options in order to be making like-for-like comparisons since heat decarbonisation is, by its nature, an expensive process. A fuller exploration of the costs of 100% hydrogen is given in Chapter 6.

CCS requirement

The most cost-effective method of producing hydrogen at scale is likely to be steam methane reformation (SMR) but this will require the development of carbon capture and storage (CCS) infrastructure for it to be low carbon.

Safety

Although hydrogen is expected to be as safe as natural gas, this must be thoroughly demonstrated (see Chapter 4).

Consumer acceptance

While the similarities between a natural gas-based system and a potential 100% hydrogen solution may help its consumer acceptance, the extent to which consumers are willing to accept hydrogen is still not clear. Separate from the actual safety evidence, there may be a widespread perception that it is unsafe which could impede its deployment.

Long-term sustainability

Since heat emissions will need to fall close to zero, a long-term issue with hydrogen is whether producing it from SMR with CCS would be decarbonising *enough*. This may require alternative sources of hydrogen production but there are significant uncertainties around these. These issues related to the production of hydrogen will be covered in detail in the next report in the *Future Gas Series*

Finding 8

Repurposing significant amounts of the gas grid to transport 100% hydrogen could be a practical route to deliver extensive heat decarbonisation. However, this idea remains to be proven and there is a need to reduce uncertainties surrounding this option before a proper assessment of its desirability can be made.

Hybrid scenarios

Outside of scenarios in which low carbon gas plays a dominant role in UK heat, it is conceivable that the gas grid could still play a key role. The usefulness of gas lies in its ability to meet extreme peaks in demand for energy and its inherent storage capacity, as well as its ability to work across the entire energy system.

A hybrid heating system could use both electricity and gas to provide heating and hot water. A typical hybrid heating system in the domestic setting would be a small heat pump with a gas boiler. The electric heat pump could be used when electricity supply is affordable and low carbon (i.e. in times when supply of electricity is greater than demand). Conversely, heating could be provided by gas during times where electricity prices would be high and gas would be capable of meeting extreme peaks in energy demand more easily and cheaply. By optimising the energy vector it uses based on the balance of the electricity grid, hybrid heat pumps could be an automated solution which could reactively and dynamically respond to changes in the energy system and thereby provide affordable heat to customers.

Project FREEDOM, a research activity led by Western Power Distribution and Wales and Western Utilities, is currently underway in order to understand if hybrid heating systems are technically capable, affordable and attractive to customers as a way of heating homes, and to investigate the feasibility of using heat pumps on their electricity/gas networks[101]. Similar research into hybrid systems will be undertaken by NGN at the Integrated Electricity and Gas Research Laboratory (IntEGReL) at Gateshead which will specialise in demonstrations of coupled gas, electricity and heat systems[102].

Advantages

Optimises benefits of gas

A hybrid system could play to the strengths of the gas grid when it is appropriate to do so. Using gas for heat is ideal for meeting rapid swings in heat demand and extreme situations where there is prolonged need for heat.

Minimises reliance on electricity at peak times

Supplying natural gas to hybrid heat pumps for heating during peak periods would support the electricity network by reducing the need to reinforce the electricity distribution networks for peak needs, while still allowing high-efficiency heat pumps to provide the bulk of heating needs across the year.

Disadvantages

Costs

There is uncertainty around the total operational and capital costs of this option. Early estimates suggest a hybrid system would cost less than an all-electric solution to heat decarbonisation[103]. However, there are concerns as to whether the system could make economic sense for energy customers. For example, whether electricity prices would be low enough or gas prices high enough in order to make a hybrid system as affordable as a gas boiler remains unknown and hard to predict in the long-run.

Customer acceptability

There are questions around its consumer acceptability, as it would involve owning two heating appliances and there are concerns that its complexity would be perceived negatively. Whether gas customers would be willing to or can afford to purchase an additional heating technology is doubtful. Moreover, the majority of heat for hot water will be provided by gas (not electric); at present, hot water sets the peak capacity of boilers, and so there would be no reduction in associated size or cost of boilers in homes with hybrid systems.

Emissions reductions

The emissions reductions this would deliver are also uncertain. Initial work has suggested that a hybrid heating system could reduce gas use by around 50%[104]. However, the level of emissions reductions that can be delivered will depend on the extent to which the electricity system can be decarbonised, as well as how much low carbon gas there is in the grid.

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101 WWU (2016) NIA Project Registration: FREEDOM - Flexible Residential Energy Efficiency Demand Optimisation and Management
102 NGN (2017) Northern Gas Networks and CESI launch unique gas and whole systems research laboratory – IntEGReL. Available at: http://www.northerngasnetworks.co.uk/archives/11220
103 WWU (2016) NIA Project Registration: FREEDOM - Flexible Residential Energy Efficiency Demand Optimisation and Management
104 WWU (2016) NIA Project Registration: FREEDOM - Flexible Residential Energy Efficiency Demand Optimisation and Management

Economics

If the number of customers on the grid falls due to the uptake of heat electrification, GDNs would likely have to increase unit network costs in order to remain profitable; or charge exit fees to customers who switch away from using the gas grid. Progressively rising network charges for each customer with gradually fewer customers could eventually result in the grid becoming an uneconomic asset, which could drive customers to switch away from gas, leaving GDNs potentially unable to recover their investments.

Finding 9

A hybrid gas/electric option could be flexible enough to cope with seasonal heat demand and reduce the burden on the electrical system. However, work is still needed to bring these technologies to maturity. There are uncertainties around the commercial viability of this option, the associated greenhouse gas savings, and how this best integrates with other scenarios for the gas grid. Initial work is being undertaken to address these issues.

A decommissioned gas grid

In a future where low carbon gas does not play a role in decarbonising heat, the gas grid faces significant uncertainty. If the heat demand of gas customers currently connected to the grid is met through technologies such as heat networks or electrical heating technology, then the gas grid may serve no useful purpose. In this scenario, the gas network could not be left idle: for safety reasons it would have to undergo a process of decommissioning[105].

What are the advantages of this option?

A decision to partially or fully decommission the gas grid may simply be the only option available to policymakers in order to facilitate a transition to a low carbon economy in line with the UK's commitments to emissions reductions, particularly if CCS does not develop in the UK.

What are the challenges of this option?

Costs unknown but significant

The costs of decommissioning the gas grid are unknown. This inquiry has heard estimates in the range of £4bn to £20bn, but the five-fold difference in these figures indicates the extent of the uncertainty surrounding decommissioning, and work is needed to clarify these costs.

Further uncertainties

Decommissioning the grid involves more than simply shutting down pipelines. For example, it remains debatable as to whether or not it would be necessary for the government to compensate network owners for the enforced loss of their assets. What is more certain is that it would affect thousands of jobs in a highly-skilled workforce across the gas sector. There also concerns around how the decommissioning of the gas grid could affect bills – at present the assets of the gas grid are paid off over 45 years under Ofgem's current regulatory regime but if this were to be shortened this could lead to immediate increases in bills.

Alternative

The end of the gas grid would, as a corollary, require the mass electrification of heat or widespread rollout of other heating technologies. However, it would be imprudent to commit to the decommissioning of the

[105] Frontier Economics (2016) Future regulation of the UK gas grid: Impacts and institutional implications of UK gas grid future scenarios – a report for the CCC

gas grid without certainty that other energy systems could fill the vacuum created in the absence of the gas grid as an energy transportation network. Committing to gas decommissioning would require reinforcing the UK electricity network to be capable of carrying this extra energy load – equivalent to more than doubling the carrying capacity of the UK electricity system[106], as well as associated storage needs[107]. This could be particularly challenging if electricity generation from gas transmission would need to be replaced too. These represent unavoidable additional costs on top of the costs of gas grid decommissioning.

Finding 10

In the long term, the full or partial decommissioning of the gas grid could be necessary if low carbon gas cannot be deployed at scale, or if it is not pursued as an option. This is more likely to be required should carbon capture and storage not be developed in the UK. However, there would be significant costs associated with this. Moreover, the substantial capacity to transport and store large volumes of energy in the gas system would need to be replaced by another source. Work is needed to reduce uncertainties around the costs and implications of decommissioning.

[106] BEIS (2016) DUKES July 2016
[107] WWU (2016) Heat, Light and Power Model – Future of Energy and Investments in Energy Networks

Part 3

KEY POLICY ISSUES FOR LOW CARBON GAS

The previous chapter outlined several future scenarios for the gas grid, ranging from an extensive hydrogen network to a fully decommissioned gas grid. Across all of these scenarios, there are issues that are common to all potential futures of the gas grid which demand policy attention. This chapter reviews three thematic policy issues in turn – safety and demonstrations; legislation, regulation and governance; and costs, funding and billing – and recommends key steps for Government to take in order to address some of the challenges that arise when considering the future of the gas grid.

The following chapters are not an attempt to systematically review each of the scenarios examined above. Rather, they examine the policy and practical considerations associated with the increased use of low carbon gases in the gas grid to provide heat, divided between biogases and hydrogen. In the area of biogases it is possible to look at relatively immediate policy development. The increased use of hydrogen in the gas grid, however, is a much more long term project which is subject to more contingencies. Much of the discussion related to hydrogen therefore examines the future considerations which would need to be addressed if it were rolled out as a low carbon heating source. The developments which need to be implemented in the near future in order to potentially facilitate the use of hydrogen in the gas grid are also set out.

4. Safety and demonstrations

FINDINGS

11. Biomethane and bioSNG pose no greater risk than natural gas, and the gas grid does not need modification to transport them. However, there are safety regulations and gas quality standards which must be met before biogases can be injected into the grid. Biomethane is a mature technology so it is beyond demonstration project stage. BioSNG production from black bag waste is already being demonstrated at a plant in the UK.

12. Unlike biomethane and bioSNG which are forms of methane, hydrogen would be a complete departure from the natural gas which is currently transported in the gas grid. Therefore further research is required in terms of safety testing and demonstration before hydrogen could be used in the gas grid.

13. The safety case for blending hydrogen needs to be fully demonstrated and this work is ongoing at a project in a private gas network in the UK. This and other research will also need to examine practical questions such as how to reflect blending in billing and where to locate it.

14. Comprehensively testing the safety implications of using 100% hydrogen in gas grid and 100% hydrogen in buildings (i.e. downstream of the meter) are necessary prerequisites of a live trial of converting occupied buildings to 100% hydrogen.

15. A substantial live trial (or trials) of existing, occupied homes would be a necessary prerequisite to the widespread rollout of 100% hydrogen in the gas grid. It remains unclear precisely what a comprehensive live trial(s) for 100% hydrogen might look like and what components would be necessary. Consensus is needed around this in order to ensure the live trial(s) could adequately provide sufficient information to enable Government to make a decision on 100% hydrogen in the early 2020s.

16. There is a need for a group to be established which can coordinate action around hydrogen testing and demonstration projects. This is important in order to ensure their timely and cost-effective delivery in order to keep the UK’s options on heat decarbonisation open.

A potential transition from natural to low carbon gas must be done in a way that maintains necessary levels of safety. Alongside safety considerations, there is also a need to address public perception and acceptability issues (which are of course closely correlated with safety), as well as public willingness to engage in an appliance conversion programme. For these reasons, it is important that both technical safety tests and small-scale demonstrations of concepts are undertaken; especially for hydrogen, a radical departure from natural gas/biogases which is as of yet unproven. Hydrogen demonstration projects are also vital to fully understand the costs and practical implications of its use in the gas grid, which are currently highly uncertain.

4.1 Biogases

Are biomethane and bioSNG safe in the gas grid?

There are three aspects to the safety of biomethane and bioSNG in the gas grid:

- **Transporting in pipelines** Biomethane and bioSNG are, like natural gas, predominantly methane – meaning the safety risk and practical implications of using these gases in the gas grid is broadly the same as that of natural gas. The existing pipelines are technically able to carry biogases. However, safety regulations which apply to the transportation of gases mean that any biogases injected into the gas grid must be of the correct composition to satisfy gas quality standards; this regulatory issue will be explored further in Chapter 5
- **Leak detection** Biomethane and bioSNG can be combined with odorants such as mercaptan to give them the same smell as natural gas, reducing the risk of harmful outcomes in the event of a leak
- **Carbon monoxide poisoning** Biomethane and bioSNG can be a source of carbon monoxide (CO) poisoning, but represent no greater risk in this regard than natural gas

Do biogases need demonstration before they can be deployed?

Biomethane

There is no need to run demonstration projects for the injection of biomethane into the gas grid as it has been demonstrated both as a concept and commercially. In December 2016, there were almost 90 plants injecting biomethane into the gas grid meaning this is an established process in the UK[108]. There is, however, scope for research and development to make the use of biomethane more efficient (a topic which BEIS has sought research into[109]), as well as support its commercial development to reduce or remove the need for subsidies.

BioSNG

BioSNG is much less developed, but the concept of producing it from residual black bag waste has been shown. Cadent has developed a pilot bioSNG production plant[110] and is currently involved in the construction of a commercial-scale bioSNG demonstration plant[111]. BioSNG needs to be tested in practice by the development of further plants and, in particular, its commercial viability established. As this relates to the production of bioSNG rather than issues with the gas grid, this will be covered in the second report in the *Future Gas Series*.

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[108] ADBA (2016) AD Market Report: December 2016

[109] BEIS (2016) Developing a Methodology to Assess Biomethane Leakage from AD plants; awarded to Ricardo Energy & Environment. Available at: https://www.contractsfinder.service.gov.uk/Notice/27bdbbe4-d1fb-4126-b18b-f8d3486d3be8?p=@NT08=UFQxUlRRPT0=NjJ

[110] Cadent (2013) Gas Network Innovation Competition Full Submission Pro-forma: BioSNG Demonstration Plant

[111] Cadent (2016) Gas Network Innovation Competition Full Submission Pro-forma: Commercial BioSNG Demonstration Plant

Finding 11

Biomethane and bioSNG pose no greater risk than natural gas, and the gas grid does not need modification to transport them. However, there are safety regulations and gas quality standards which must be met before biogases can be injected into the grid. Biomethane is a mature technology so it is beyond demonstration project stage. BioSNG production from black bag waste is already being demonstrated at a plant in the UK.

4.2 Hydrogen

Unlike biomethane and bioSNG which are forms of methane, hydrogen is a radical departure from the natural gas which is currently transported in the gas grid. Therefore, much more is required in terms of safety testing and demonstration before hydrogen could be used in the gas grid. There are three general aspects to the safety of hydrogen:

- **Transporting in pipelines** The ongoing Iron Mains Replacement Programme (IMRP) is converting the existing local distribution networks pipes from iron to plastic and is due to complete in 2032. This is intended to replace all pipes within 30 metres of property, covering 90% of the distribution network. These plastic pipes would be technically able to transport hydrogen in a way that the existing metal pipes are not. The remaining 10% of the network would need to be converted to allow the use of hydrogen but these would be the lowest-risk areas (far away from buildings) so it is believed that this could be achieved at reasonably low cost and with low levels of disruption[112]
- **Flame visibility** Hydrogen burns hotter than natural gas with an almost invisible flame. The near invisible flame presents challenges for its use in cookers, gas fires and similar appliances; chemical compounds would therefore need to be developed to make the flame more visible[113]
- **Leak detection** Like methane, hydrogen is odourless. To detect hydrogen leaks odorant chemicals must be added to it. For potential blends of up to 20% hydrogen by volume (6% by energy) current odorant chemicals are thought to be acceptable for use[114]. However, they are incompatible with 100% hydrogen gas, as they do not stay mixed with the hydrogen, and they are also not tolerated by fuel cells. Accordingly, there would be a need to develop new odorant chemicals that remain mixed with hydrogen and are compatible with fuel cells whilst still being a smell that is recognisable to the public in the event of a gas leak[115]

There are well-established methods of producing hydrogen (such as SMR and electrolysis), but there is scope for research to improve these methods (e.g. bring down costs) as well as enhance understanding on their deployment (e.g. where production sites could be located and how they interact with networks for carbon capture and storage).

There are also early prototypes of hydrogen appliances such as cookers and boilers, but there is still a substantial need for research and development in this area in order to, *inter alia*, significantly reduce the costs of production and improve performance.

Finding 12

Unlike biomethane and bioSNG which are forms of methane, hydrogen would be a complete departure from the natural gas which is currently transported in the gas grid. Therefore further research is required in terms of safety testing and demonstration before hydrogen could be used in the gas grid.

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[112] Health and Safety Executive & Ofgem (2011) 10 year review of the Iron Mains Replacement Programme
[113] Energy Research Partnership (2016) Potential role of hydrogen in the UK energy system, p. 17
[114] DNV GL (2016) Hydrogen Addition to Natural Gas Feasibility Study, p. 49
[115] Energy Research Partnership (2016) Potential role of hydrogen in the UK energy system, p. 17

4.3 Blending hydrogen

Is blending hydrogen in the gas grid safe?

It is widely suggested that blending hydrogen in the gas distribution system would probably be possible without a need to change the overwhelming majority of appliances currently in homes today[116] and would likely be safe in the pipes[117]. However, the level of blending (which could range from as low as 2-3% to as high as 20% by volume) and its safety with both existing gas appliances and gas pipelines would still have to be confirmed in practice in the UK before it could be allowed. At present, the permissible level of hydrogen in the grid is only 0.1% by volume[118].

Does hydrogen blending need to be demonstrated?

If this limit were to be changed, the safety of blending hydrogen would have to be convincingly demonstrated in the UK – a certain percentage of hydrogen (which would have to be determined, and is expected to be no more than 20% by volume, equivalent to 6% by energy) must be proven to be safe to use in gas pipelines and existing gas appliances.

An important work in this area so far is the HyDeploy project, which aims to demonstrate that natural gas containing levels of hydrogen beyond those permitted by current regulations can be distributed and used safely. The project is using Keele University's private gas network to test blending, and trials will run from 2017 to 2020. By testing the safety of blending hydrogen in the current natural gas network and its compatibility with end-use appliances, this study could pave the way for changes to the gas regulations to permit the injection of more concentrated hydrogen blends into the grid[119].

However, there are other areas of research needed in this space, such as fully understanding how to bill for having gases with different calorific values (energy content per unit volume) than natural gas in the grid. This is currently being considered as part of the Future Billing Methodology research project and its associated industry consultation[120], and is covered in more detail in Chapter 6.

Other research is needed to see how much hydrogen would be available for blending and where. Additionally, some gas appliances such as many of those used in industrial processes can only tolerate much lower levels of hydrogen than conventional ones used in buildings to provide heat. Work to understand how industry connected to gas distribution networks might be impacted by hydrogen blending, and what could be done about it, is therefore needed.

The most recent development in this space has been initial work to explore the potential of establishing a public gas network in northwest England transporting hydrogen blends[121]. The Liverpool-Manchester Hydrogen Cluster project is conceptually envisaged to carry blends of hydrogen and natural gas (up to 20% by volume, equivalent to 6% by energy) to customers in the region, while also supplying high hydrogen blends (up to 100%) to selected industrial sites[122]. Hydrogen would be produced in bulk by SMR, with carbon emissions captured and stored in offshore gas fields[123]. Cadent are currently undertaking initial

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[116] Health and Safety Executive (2015) Injecting hydrogen into the gas network – a literature search. This report concluded that only a small minority of gas appliances would likely be incompatible with hydrogen blends as high as 20% by volume (gas appliances built before the introduction of the Gas Appliances Directive (GAD)) – but by 2020 this would only be 2% of all domestic gas appliances and less than 0.5% of all commercial gas appliances, and falling. These appliances will require identifying and then either be converted or withdrawn from service.
[117] Health and Safety Executive (2015) Injecting hydrogen into the gas network – a literature search
[118] Gas Safety (Management) Regulations 1996 (SI 1996/551)
[119] Cadent (2016) Gas Network Innovation Competition Screening Submission Pro-forma: HyDeploy
[120] Cadent (2016) Gas Network Innovation Competition Screening Submission Pro-forma: Future Billing Methodology
[121] Cadent (2017) Gas Network Innovation Allowance Project Registration – Industry and Network Blends: Delivering reduced carbon intensity on the network
[122] Cadent (2017) The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project – Summary Report
[123] Cadent (2017) The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project – Summary Report

work to explore the feasibility of this project. Later work could include a demonstration of hydrogen blending on a public network[124], prior to any potential final investment decision on such a project – which could be made as early as 2022[125].

Finding 13

The safety case for blending hydrogen needs to be fully demonstrated and this work is ongoing at a project in a private gas network in the UK. This and other research will also need to examine practical questions such as how to reflect blending in billing and where to locate it.

4.4 100% hydrogen

Is 100% hydrogen in the gas grid safe?

The evidence heard during the compilation of this inquiry suggested that there are two aspects to the tests which are needed in relation to ensuring the safety of using 100% hydrogen in the gas grid to provide heat:

- Comprehensive testing of 100% hydrogen *in the gas grid* (i.e. 'upstream of the meter', or the pipelines that are part of the distribution systems which are owned and operated by GDNs), and
- Comprehensive testing of the use of 100% hydrogen *downstream of the meter* (i.e. the pipes that connect to buildings and appliances within buildings; these are not owned and operated by GDNs)[126]

Proving the safety of hydrogen in the gas grid

This work programme would need to provide a full outline of the safety implications of using 100% hydrogen in the gas distribution system. This work would include physical tests quantifying the risk of hydrogen compared to natural gas in the distribution network, including controlled tests in laboratory conditions, tests to quantify the risks emanating from gas leaks, as well as field testing of pipelines. The estimates heard in compilation of this report for the timescale for such an undertaking varied between 2 and 4 years. The estimates heard also varied on the overall cost of such a project between £15-£20m[127].

The testing of hydrogen in the gas grid could potentially be financed through Ofgem funding. There are two ways in which Ofgem can help fund innovation in the gas grid – the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC):

- The NIA aims to encourage GDNs to innovate in order to develop solutions that can enhance the development of their networks. It is a set annual allowance that each GDN receives in order to run small-scale innovation projects[128]
- In contrast, the NIC is "*an annual competition to fund selected flagship innovative projects that would deliver low carbon and environmental benefits to customers*". The NIC represents additional funding to the NIA and is focussed on funding larger scale, more complex projects. GDNs submit bids to Ofgem to compete for an annual pot of £18m to fund their programmes of work[129]

Whether to fund this work with the NIC would ultimately be a decision for Ofgem based on the criteria of the NIC and the nature of any future bids from GDNs. At time of writing, NGN have submitted an NIC

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[124] Cadent (2017) Gas Network Innovation Allowance Project Registration – Industry and Network Blends: Delivering reduced carbon intensity on the network
[125] Cadent (2017) The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project – Summary Report
[126] H21 Leeds City Gate (2017) Executing the H21 Roadmap
[127] H21 Leeds City Gate (2017) Executing the H21 Roadmap
[128] Ofgem (2015) Gas Network Innovation Allowance Governance Document
[129] Ofgem (2015) Gas Network Innovation Competition Governance Document

application for £13.5m to carry out comprehensive testing, measurement and quantified risk assessment of 100% hydrogen in the low pressure distribution system[130]. This work would provide quantified evidence on the safety of transporting 100% hydrogen in polyethylene pipelines, and is planned to complete by 2020. This project would also include field testing *in situ* on specific streets and derelict council sites.

Proving the safety of hydrogen 'downstream of the meter'

There is also a need to prove the safety of hydrogen 'downstream of the meter' – in the piping in people's homes and in appliances. This would include furthering understanding of the needs around odourisation of hydrogen, the use of hydrogen in pipes in people's homes and the general safety implications of hydrogen in buildings.

Initial work has been done in this area. In 2015, DECC commissioned the HyHouse project which aimed to understand the risks that hydrogen poses during a gas leak in a domestic setting. This involved flooding a remote unoccupied property with both hydrogen and natural gas. Their tests on an unoccupied home showed that "*the risks of a significant fire and explosion and the subsequent impact on the health of a householder following a significant leak of either hydrogen, natural gas or a natural gas and hydrogen mixture are similar*"[131].

Future work would need to develop the HyHouse project to look at hydrogen in different types of buildings. Such a project would also need to support the development of hydrogen appliances, developing understanding of their work in practice and how to test their safety. Additionally, it would be important to convert unoccupied buildings to run on hydrogen and simulate heat use of customers over an extended period of time.

Unlike the networks, the 'downstream' testing does not have one clear group to conduct the tests – the appliance market alone is fragmented and funds such as Ofgem's NIC are not designed for research downstream of the meter. There is therefore a strong case for BEIS to coordinate testing of this kind and for it to be funded through the BEIS innovation budget.

BEIS appears to have shown an initial interest in taking up this role, developing work streams within the BEIS Hydrogen Innovation Programme that seek to explore themes such as assessing the safety of hydrogen within existing buildings, trialling hydrogen appliances in unoccupied buildings, and preparing for an occupied consumer trial[132]. The Government has dedicated £25m until 2020 which will define a hydrogen quality standard, and develop and trial domestic and commercial hydrogen appliances, including trialling hydrogen appliances in unoccupied buildings[133]. BEIS has also recently announced that it is seeking to appraise three different variations in approach to switching from natural gas to hydrogen appliances (a full replacement, a component adaption, or dual-fuel appliances) and their proposed project, valued at £40,000-60,000, would commission a study *"to improve the evidence base on the cost, performance and practicality of each approach and the trade-offs between them"*[134]. Government has therefore committed to undertaking multi-million pound work programmes related to the safety of hydrogen downstream of the meter.

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[130] NGN (2017) Gas Network Innovation Competition Screening Submission Pro-forma: H21
[131] Kiwa Ltd. (2015) Energy Storage Component Research & Feasibility Study Scheme: HyHouse - Safety Issues Surrounding Hydrogen as an Energy Storage Vector
[132] Saltmarsh, J. (2017) Presentation at IGEM's 2017 Conference, 4 July 2017
[133] BEIS (2017) Funding for innovative approaches to using hydrogen gas for heating. Available at: https://www.gov.uk/government/publications/funding-for-innovative-approaches-to-using-hydrogen-gas-for-heating
[134] BEIS (2017) Appraising different types of hydrogen appliance. Available at: https://www.contractsfinder.service.gov.uk/Notice/7cd97c81-2e27-4319-90d3-65c8df7d6cb5?p=@NT08=UFQxUlRRPT0=NjJ

Finding 14

Comprehensively testing the safety implications of using 100% hydrogen in gas grid and 100% hydrogen in buildings (i.e. downstream of the meter) are necessary prerequisites of a live trial of converting occupied buildings to 100% hydrogen.

Demonstrations of 100% hydrogen

The Leeds City Gate H21 report argues that a prerequisite for any potential widespread conversion of the gas grid to 100% hydrogen is a full 'live' trial of occupied buildings being converted to run on hydrogen. It cites the large trial of around 8,000 customers in Canvey Island which was conducted during the conversion from town to natural gas[135].

The evidence heard during the compilation of this report concurred that – provided 100% hydrogen had first passed the required safety testing in the gas grid and downstream of the meter – a substantial trial (or trials) which demonstrates the transportation of hydrogen in the existing gas grid and its use to provide heat in occupied buildings would be a necessary precursor to any potential widespread rollout of 100% hydrogen. Such a live trial(s) would be needed in order to demonstrate beyond any doubt the end-to-end logistics and safety of hydrogen conversion. It would also enhance understanding of the real costs associated with hydrogen conversion which are highly uncertain and provide 'learning-by-doing' on how to practically manage a potential widespread rollout. Additionally, a live trial(s) would test customers' attitudes to hydrogen, assess the level of disruption consumers would be willing to accept during a conversion, and help to assure householders about the safety of hydrogen.

There are, of course, limits to what a hydrogen demonstration can show – it would not provide extensive insight into the production and storage of hydrogen at scale, nor would it necessarily shed light on the costs and operation of a hydrogen transmission system – but nevertheless, a demonstration project is an essential part of a potential move to 100% hydrogen. The need to demonstrate 100% hydrogen has been re-iterated most recently by the Committee on Climate Change, which has stated that a new strategy is required for "*developing active preparations for strategic decisions in the early 2020s on the role for hydrogen for heat and the future of the gas grid, including pilots, demonstrations, and research on the challenges of a wider-scale hydrogen switchover*"[136].

There are no projects in place to demonstrate the practical use of 100% hydrogen in the gas grid to provide heat. The recently opened H21 Project Office, set up by Leeds City Council and NGN[137], has been tasked with overseeing NGN's future NIC bid on hydrogen[138], modelling the rollout of hydrogen in urban centres across the UK[139], researching alternative production and storage technologies[140], and exploring the impacts of 100% hydrogen on metering[141]. SGN are planning to fund a project which will test the transportation of 100% hydrogen in a new purpose-built hydrogen network[142]. The planned programme of work will carry out a feasibility study of the construction and demonstration of a 100% hydrogen distribution network, assessing the technical and practical viability of doing so as well as carrying out a quantitative and qualitative risk assessment for a 100% hydrogen network. The research would provide evidence to select a practical and cost-effective site for a larger demonstration project of 100% hydrogen. However, these projects in themselves will not provide the evidence base which will be required to inform a potential conversion of the natural gas grid to using 100% hydrogen to provide heat.

135 Sadler *et al.* (2016) H21 Leeds City Gate
136 Committee on Climate Change (2017) Progress report to Parliament
137 NGN (2017) Northern Gas Networks Hydrogen project takes step forward as £25 million fund announced for hydrogen in homes
138 NGN (2017) Gas Network Innovation Competition Screening Submission Pro-forma: H21
139 NGN (2017) NIA Project Registration: H21 – Strategic Modelling, Major Urban Centers
140 NGN (2017) NIA Project Registration: H21 – Alternative hydrogen production and Network storage technologies
141 NGN (2017) NIA Project Registration: H21 –Domestic and Commercial Metering
142 SGN (2017) NIA Project Registration: 100% Hydrogen

What would a live trial(s) look like?

There is a broad consensus on the need for a trial (or trials) of conversion of existing, occupied buildings as a prerequisite to any potential widespread repurposing of the gas grid to transport 100% hydrogen – and, as the Committee on Climate Change confirms, there is a need for any hydrogen demonstrations to be of "*sufficient diversity and scale*" so that Government is well placed to make strategic decisions on hydrogen in the 2020s[143]. However, there is not the same level of agreement on the exact nature of such a project. A live trial(s) would need to be designed based on a balance between providing sufficient evidence in areas such as consumer reaction, logistics and final confirmation of the safety case, and practical considerations such as the level of funding available, suitable locations, and time and labour constraints.

Key aspects of a live trial (or trials) which must be considered include:

Size

This inquiry heard varying suggestions for such a project ranging from one large demonstration project approximately mirroring the Canvey Island conversion of around 8,000 customers from town to natural gas; to a series of smaller demonstration projects, potentially 3-4 sites converting around 200-500 customers in each area[144]; or a combination of smaller and larger pilot projects.

A series of smaller demonstrations could provide benefits including allowing learning from across numerous different environments and wider engagement of the public as demonstration sites would be spread across the country. On the other hand, a certain scale of project may be necessary to provide meaningful lessons for a future wider conversion – this may not need to be as large 8,000 but perhaps somewhere between this and 500 customers. A number of contributors suggested that a minimum size of 1,000-2,000 customers would be necessary to provide useful learning. The exact size and nature of a demonstration project which would provide sufficient learning is not clear at this stage.

Production and CCS

During (a) live trial(s) there would have to be a sustainable and continuous source of hydrogen to avoid intermittency in supply. There are various options to source hydrogen for trials.

- **Bulk hydrogen with/without CCS** One option would be to use surplus hydrogen which is generated as a by-product of industrial processes or from existing SMR plants. It might be possible to combine such a project with the demonstration of CCS; but this may not be necessary or desirable, especially since CCS has already been demonstrated in a hydrogen context[145]. Accordingly, it might be more sensible to run a demonstration of 100% with hydrogen produced without CCS. Prior to any transition to the widespread use of 100% hydrogen in the gas grid, however, there would need to be clear evidence that sufficient secure, affordable and low carbon hydrogen is available to make it a viable plan (i.e. 100% hydrogen from SMR cannot proceed without functional CCS); this is a wider issue, though, which will be considered in detail in the next report in *the Future Gas Series*
- **Electrolysis** This would open up the possibility of situating live trials in a number of locations, as well as linking electricity demand management to hydrogen generation. However, it would be a more expensive way of sourcing hydrogen compared to SMR, and it is unclear whether sufficient cost-effective hydrogen could be produced in this way to feed all the demonstration homes

[143] Committee on Climate Change (2017) Progress report to Parliament
[144] Sadler *et al.* (2016) H21 Leeds City Gate
[145] Energy Research Partnership (2016) Potential role of hydrogen in the UK energy system; see Section 2.4

Transportation

A further consideration is how the hydrogen is transported to people's homes:

- **Pipelines** It would be important to use this as an opportunity to demonstrate the safety of transporting hydrogen in plastic pipes, but it raises questions over how production sites might be connected to pipelines, and would require the total isolation of one part of the distribution system
- **Tanker** An alternative idea is to tanker hydrogen in on roads, but at large scale this would likely become hugely impractical requiring multiple tankers of hydrogen delivered a day, depending on the scale of the project. It is also risky to use tankers during winter – road transportation would be particularly difficult during extended periods of high gas demand (e.g. when it is snowing, or when roads are icy), and this would risk leaving trial homes without heat when they need it most

Storage and transmission

A trial of hydrogen conversion would need to include a certain level of hydrogen storage (dependent upon the scale of a trial) to cope with changes in demand. The security of supply of hydrogen will be enhanced by deploying suitable storage solutions. A major consideration for the scope of such a demonstration project would be whether it includes large salt cavern storage (which would most likely be part of a longer term conversion), or a less ambitious solution such as smaller tankers of hydrogen. A related consideration is whether such a trial includes a hydrogen transmission system.

Hydrogen appliances and customer engagement

The final aspect of a live trial is the availability of suitable hydrogen appliances to use in converted buildings. Worcester Bosch is aiming to have a prototype of a hydrogen boiler by the end of 2017[146] but there would be a need for further development of sufficient, appropriate appliances for a demonstration project.

In addition, converting hundreds or thousands of gas consumers' buildings would require excellent customer engagement, including a proactive media campaign to dispel potentially damaging negative publicity. SGN's Oban project trialled more than twenty customer engagement methods which resulted in a greater than 90% access rate amongst customers[147]. Work such as this can provide valuable lessons regarding accessing homes and collecting data with willing customers.

Regulation and standards

The Health and Safety Executive (HSE) states that, whilst some existing regulations are both applicable and sufficient, there are currently no bespoke hydrogen safety regulations. As such, the regulation of hydrogen demonstrations will be kept under review as the safety evidence emerges. The current regulations on the gas in the grid are the Gas Safety (Management) Regulations (GS(M)R). However, since it applies only to natural gas, not hydrogen, there would be a need to regulate any 100% hydrogen demonstrations using other existing health and safety legislation in the near term[148].

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[146] Evidence submitted to this inquiry
[147] SGN (2016) Opening up the Gas Market
[148] For example, the Health and Safety at Work etc. Act 1974 (HSWA) and the various regulations made under it; in particular, the combined application of the Management of Health and Safety at Work Regulations 1999, the Pressure Systems Safety Regulations 2000 (PSSR) and the Pipelines Safety Regulations 1996 (PSR) will require the duty holder to put in place a safety management system not dissimilar in scope to a safety case (although without the requirement for HSE to approve it before the gas is conveyed). Importantly, unlike GS(M)R, the Gas Safety (Installation and Use) Regulations 1998 (GSIUR) apply to hydrogen in the domestic supply context. HSE also recognise that these demonstration hydrogen networks are unlikely to be networks in the GS(M)R sense. For example, they will be fed from local storage rather than dedicated transmission and distribution pipes conveying gas from a terminal, storage or production facility. This local storage will also be regulated using existing legislation, such as PSSR and, if relevant quantities are stored, the Control of Major Accident Hazards Regulations 2015 (COMAH).

A final consideration is that any potential widespread rollout of hydrogen in the gas grid would need to use hydrogen which is of comparable quality to the hydrogen which has been used in safety tests and demonstrations.

Timelines

The Committee on Climate Change identifies the need for government clarification on the long term plan for heat decarbonisation, the role of the gas grid and the potential use of hydrogen in the next Parliament (anticipated to run between 2022 and 2027)[149]. This is because an extensive conversion of the gas grid to 100% hydrogen would most likely need to begin during the 2020s in order for it to be completed by 2050s.

It will be necessary to have a sufficient evidence base in place before a long-term decision on hydrogen and the gas grid can be made, including findings from a live trial of conversion. If such a live trial has not been demonstrated by the time a decision needs to be made (in the early to mid-2020s) then the opportunity to use hydrogen for heat may be closed, not necessarily because of its merits as an idea but because it has not been fully tested and demonstrated in time.

The extensive nature of a live trial means that work needs to begin soon in order for it to be in place during the early to mid-2020s and to keep the UK's options open on heat decarbonisation. This is likely to need to take the form of safety testing followed by a live trial as set out in Figure 7. Doing so would allow all required information to be ready for a Government decision on 100% hydrogen in the early 2020s, which would be needed if conversion were to be completed by the 2050s.

Safety testing and live trials are needed to keep options open and understand more fully the implications of repurposing the gas grid to run on 100% hydrogen. It should not necessarily tie the UK into rolling out hydrogen more widely.

Finding 15

A substantial live trial (or trials) of existing, occupied homes would be a necessary prerequisite to the widespread rollout of 100% hydrogen in the gas grid. It remains unclear precisely what a comprehensive live trial(s) for 100% hydrogen might look like and what components would be necessary. Consensus is needed around this in order to ensure the live trial(s) could adequately provide sufficient information to enable Government to make a decision on 100% hydrogen in the early 2020s.

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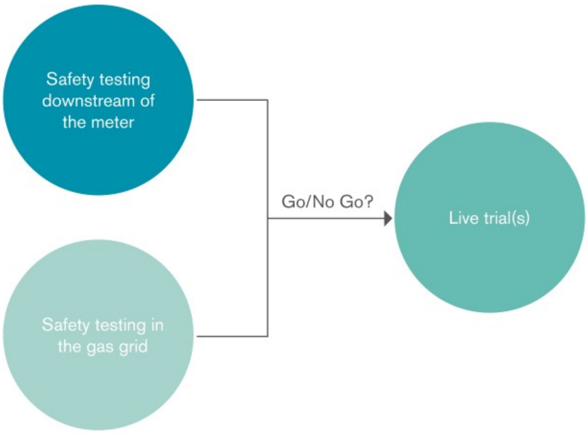
[149] Committee on Climate Change (2016) Next steps for UK heat policy, p. 7

Figure 7: Potential steps for a live trial



Source: Adapted from H21 Leeds City Gate (2017) Executing the H21 Roadmap

4.5 Funding 100% hydrogen demonstration projects

Costs

It is difficult to estimate the potential costs associated with a live trial(s) of 100% hydrogen conversion without a clear consensus as to what they might look like. The costs depend on a number of factors including its size and scope, so until such issues are decided it remains too early to provide a proper estimation of the costs. For a ball-park figure, the Leeds City Gate H21 team has suggested an additional £30m would be needed to fund a live trial before a decision to proceed with a hydrogen rollout can be taken[150].

Sources of funding

There are many potential sources of funding for a live trial(s) (Table 2). The particular challenge associated with funding a live trial(s) is coordinating the available funding. This is because the sums involved are likely to be larger than individual safety tests and purely relying on a source such as the BEIS innovation budget may not be sufficient. Additionally, some funding streams are only set up to fund specific areas; for example, it is unlikely that the network-related Ofgem NIA/NIC would be appropriate to fully fund a demonstration that includes extensive development of hydrogen appliances.

4.6 Coordinating 100% hydrogen demonstration projects

Currently there is considerable discussion of the idea of hydrogen demonstration projects but developments in this area have been somewhat fragmented. In order to deliver the safety testing and live trials which would form an evidence base for a decision on the potential conversion of the gas grid, substantial coordination would be required. This may be best delivered through a formal coordination body.

[150] Sadler *et al.* (2016) H21 Leeds City Gate; H21 Leeds City Gate (2017) Executing the H21 Roadmap

Why establish a coordination body?

Other reports have noted the importance of coordination in the low carbon gas space:

- The Leeds H21 Project suggested setting up a Programme Team to coordinate the whole hydrogen conversion process which would mirror the Conversion Executive that was setup to oversee the conversion from town to natural gas[151]
- The Parliamentary Advisory Group on CCS has also suggested the establishment of a Heat Transformation Group which would "*assess the least cost route to the decarbonisation of heat in the UK (comparing electricity and hydrogen) and complete the work needed to assess the chosen approach in detail*"[152]
- The H2FC Supergen has also called for the establishment of a government agency tasked with coordinating support for a hydrogen and fuel cell sector in the UK, following a similar model in Germany[153]
- The Sustainable Gas Institute has stated that it will be necessary to conduct a "*coordinated programme of work*" on demonstrations and safety testing of low carbon gas to ensure a comprehensive evidence base[154]

If the Government are going to fund multi-million pound research in this area, projects should be coordinated to ensure that taxpayer money is being spent in a cost-effective manner. Given that the Government has already announced its intention to invest £25m in testing the safety of hydrogen downstream of the meter, it is important that this and any other investments are efficiently spent to ensure maximum research output.

There are other reasons why such a group would be useful. A coordinating group could help clarify the following uncertainties related to the topic:

- The exact components of safety testing of hydrogen *in the gas grid* which are necessary to be completed before HSE/BEIS can sanction the small-scale conversion process involved in a live trial or trials of occupied homes
- The exact components of safety testing of hydrogen *downstream from the meter* which are necessary to be completed before HSE can sanction the small-scale conversion process involved in a live trial(s) of occupied homes
- The projected costs and timelines for both of the above live trial(s) as well as the most appropriate sources of funding
- The most appropriate size and scope of a live trial(s)
- The projected cost and timeline of a live trial(s) as well as the most appropriate sources of funding and how to coordinate these

This would help to prevent wasted resources on safety testing and demonstration projects which do not add to the current evidence base, avoid duplication of effort, and develop a clear roadmap for how live trials will be developed in line with the required timelines which have been set out above. Additionally, it could scope all the potential sources of funding outlined in Table 2 (as well as identify additional sources) in order to evaluate how best to coordinate them and fully fund the necessary evidence gathering.

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151 Sadler *et al.* (2016) H21 Leeds City Gate
152 Parliamentary Advisory Group on CCS (2016) Least-cost decarbonisation for the UK: the critical role of CCS
153 H2FC (2017) The economic impact of hydrogen and fuel cells in the UK
154 Speirs *et al.* (2017) A greener gas grid: what are the options? Sustainable Gas Institute, Imperial College London

What would the coordination body look like?

Given the importance of BEIS, Ofgem and HSE to testing and demonstration in the area of hydrogen, it is important that there is at least some coordination in this area between these organisations.

It would be useful, however, to develop a more ambitious coordinating group which could utilise additional expertise and look in detail at a number of the points outlined above. This group would need to include experts from across relevant industries, such as producers of hydrogen gas, appliance manufacturers, the GDNs, as well as academics, independent experts, consultancies and consumer groups. This does not necessarily need to be formally endorsed by Government; however, it would need to be in consultation with the relevant bodies including BEIS, Ofgem and HSE.

This body could be a standalone coordination mechanism for testing and demonstrations, or it could have a larger remit, such as oversight for a potential future conversion to 100% hydrogen or for research into heat decarbonisation more broadly.

Finding 16

There is a need for a group to be established which can coordinate action around hydrogen testing and demonstration projects. This is important in order to ensure their timely and cost-effective delivery in order to keep the UK’s options on heat decarbonisation open.

Table 2: Sources of funding for 100% hydrogen demonstrations

Source of Funding	Outline
Government (BEIS)	Central government funding allocated to low carbon research, as well as the Industrial Strategy Challenge Fund. Funding from the devolved administrations would also fall in this category.
Ofgem NIA/NIC	Ofgem's innovation funding. Up to £18 million per annum is available through the NIC.
Local Authorities (LAs) **Local Enterprise Partnerships (LEPs)**	Local Authorities are well positioned between local businesses, universities and other institutions all of which have access to funding streams. Whist LAs themselves will lack the financial resources to fund this work, many are part of Local Enterprise Partnerships (LEPs) between LAs and businesses. LEPs decide what the priorities should be for investment in roads, buildings and facilities in the area. There are 39 in England. LEPs receive funding from Government's Regional Growth Fund, Growing Places Fund, the EU Structural and Investment Funds (2014-2020) and the Local Growth Fund. Their counterparts in Wales, Scotland and Northern Ireland are also potential sources of funding.
Innovate UK	Innovate UK is the UK's innovation agency and can fund research into energy infrastructure and low carbon innovation. It also funds the Energy Systems Catapult Smart Systems and Heat programme which will after 2017 seek to undertake a large demonstration of designs and technologies in this work.
University Research Funding	Primarily from the Research Councils (e.g. Engineering and Physical Sciences Research Council (EPSRC)). EPSRC has previously funded research on hydrogen incorporation into the gas grid. This stream may be appropriate for research related to lower technology readiness levels.
UK Research & Innovation (UKRI)	From April 2018, a new body – UK Research & Innovation (UKRI) – will incorporate the seven Research Councils, Innovate UK and the research funding parts of the Higher Education Funding Council for England.
Gas Distribution Networks (GDNs)	GDNs have their own funding which they can contribute to projects. This currently happens when GDNs apply to Ofgem's NIC, which require a 10% contribution. Shareholders of GDNs could further back investment in this work.
Commercial Sources of Funding	A commitment to hydrogen by Government would almost certainly attract private sources of funding by providing investors with good certainty of continued investment in this area.
Hydrogen Council **Oil and Gas Climate Initiative** **Mission Innovation**	A global initiative of 13 CEOs and Chairpersons from various industries and energy companies committed to advancing the hydrogen economy. International companies currently involved are: Air Liquide, Alstom, Anglo American, BMW GROUP, Daimler, ENGIE, Honda, Hyundai Motor, Kawasaki, Royal Dutch Shell, The Linde Group, Total and Toyota. Hydrogen Council members plan to invest at least €1.9 billion/year in hydrogen technology for the coming 5 years. A CEO-led initiative which aims to show sector leadership in the response to climate change, made up of ten oil and gas companies that collaborate on action to reduce greenhouse gas emissions. OGCI Climate Investments is a partnership that will invest $1 billion over the coming years to support start-ups and help develop and demonstrate innovative technologies that have the potential to reduce greenhouse gas emissions significantly. A global initiative of 22 countries and the European Union to dramatically accelerate global clean energy innovation.

5. Legislation, regulation and governance

FINDINGS

17. While primary legislation is supportive of low carbon gas in principle, secondary legislation, such as the Gas Safety (Management) Regulations (GS(M)R), may need to be reviewed to address barriers to the use of low carbon gas.

18. At present the GS(M)R limits on the quality of gas which can be injected into the grid are seen by many in industry as a regulatory barrier to the deployment of biogases. Currently these barriers are reduced by exemptions to the GS(M)R granted by the Health and Safety Executive (HSE). Two more radical proposals to reduce barriers in the long term are widening the limits in GS(M)R and/or transferring the GS(M)R gas quality standard to an industry standard.

19. There are two ways in which hydrogen blends in the grid could be regulated: (i) through modification of the gas quality specifications in GS(M)R in order to permit greater than 0.1% hydrogen by volume; (ii) through the issuance of a class exemption by HSE permitting derogation from this limit in the distribution system. Whichever path is chosen, the safety of blending hydrogen must be thoroughly proven and demonstrated before either regulatory option is taken.

20. HSE has stated that potential work on demonstrating hydrogen would be regulated through existing health and safety regulations other than GS(M)R. This 'toolbox-approach' is appropriate to allow initial work in the hydrogen space without excessive regulatory burden. This approach could prove suitable in the long-term for regulation of a potential conversion to 100% hydrogen, but if it were to become apparent that bespoke regulation for hydrogen were needed, Government should ensure that a new regulatory framework for hydrogen could be delivered in a timely fashion to prevent delay of a potential rollout of hydrogen.

This section investigates the legislative and regulatory challenges associated with a potential increase in the use of low carbon gas in the grid. It also explores potential problems related to the governance arrangements of the grid.

5.1 What gas legislation is there, and does it apply to low carbon gas?

The Gas Act 1986

The Gas Act 1986 is the primary legislative instrument of relevance to the gas grid. Section 48 of the Gas Act 1986 defines "gas" as:

> *"any substance in a gaseous state which consists wholly or mainly of **methane**, ethane, propane, butane, **hydrogen** or carbon monoxide; a **mixture** of two or more of these gases; or a combustible mixture of one or more of those gases and air".*

Accordingly, biomethane, bioSNG and hydrogen (including blending hydrogen with natural gas) all fall within the scope of existing gas legislation[155].

Whilst primary legislation can accommodate low carbon gas, there are more difficulties for low carbon gas in terms of secondary legislation (also known as 'regulations' or 'statutory instruments').

The Gas Safety (Management) Regulations 1996 (GS(M)R)

The main regulation in this area is GS(M)R, which stipulates gas quality requirements which must be met for gas to be permissible in the gas grid. This provides consistency in the quality of gas supplied to customers and ensures its safety[156]. GS(M)R is owned and enforced by the Health and Safety Executive (HSE).

Finding 17

While primary legislation is supportive of low carbon gas in principle, secondary legislation, such as the Gas Safety (Management) Regulations (GS(M)R), may need to be reviewed to address barriers to the use of low carbon gas.

5.2 Is the regulation of the gas grid suitable for low carbon gas?

Biogases

Once upgraded from biogas, some biomethane is still not compliant with GS(M)R. This is because the range of gases permitted by GS(M)R is narrow: currently, regulations are based on the composition of North Sea gas, which fails to reflect the diversity of gases that the future gas grid could be transporting. These regulations often mean that some sources of biogases are excluded from the gas grid, and must be expensively processed in order to ensure that they meet these requirements.

What can be done to overcome this problem?

Exemptions from GS(M)R

At present, the primary way in which regulatory barriers can be overcome is through exemptions. HSE is allowed to issue exemptions from the regulations, provided that *"the health and safety of persons likely to be affected by the exemption are not prejudiced as a consequence"*[157]. GDNs can apply to HSE for an exemption, which would allow them to operate outside of a defined part of the GS(M)R.

HSE is also able to grant 'class' exemptions where sound evidence demonstrates that safety is preserved across an industry or sector. For example, by granting a class exemption, HSE has allowed gas conveyors to transport biomethane with an oxygen content of up to 1% rather than 0.2% as specified in GS(M)R. This has been widely praised by the gas industry for supporting the deployment of biomethane injection into the grid in the UK.

Beyond this mechanism, there are two more novel ways in which regulatory barriers could be further reduced in the future:

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155 Gas Act (1986), c. 44
156 Gas Safety (Management) Regulations 1996 (SI 1996/551)
157 Gas Safety (Management) Regulations 1996 (SI 1996/551)

Widening the limits of GS(M)R

There is an ongoing conversation within the gas industry about whether there is a need to widen the limits of the gas quality permitted in the gas grid. Widening the limits of GS(M)R could eliminate a hurdle for biomethane developers by removing unnecessarily restrictive gas quality requirements imposed on them[158].

A recent project by SGN explored this issue, examining whether gas of quality outside the permissible range could be distributed and utilised safely and efficiently in Great Britain. It found that widening certain limits on the energy content of gas in GS(M)R would be possible[159]. Such work points towards ways in which the regulations could be amended in order to better accommodate biomethane and bioSNG.

However, whilst amending GS(M)R could encourage more biogases, it is also important to acknowledge that there are potential downsides of doing this. Relaxing gas quality standards is expected to have adverse impacts upon the efficiency of boilers. A trade-off between greater low carbon gas in the grid and reduced appliance efficiency must therefore be resolved prior to any move to widen gas regulations. Overall, positive developments in this area will need to seek an appropriate regulatory balance between encouraging low carbon gas and protecting the safety and consumer rights of gas customers.

Transferring GS(M)R to an industry standard

A more radical solution to the restrictions imposed by the gas standards is currently under consideration: transferring the gas quality specification within GS(M)R from the remit of HSE to industry[160]. This would involve moving the gas quality specifications of GS(M)R to a standard overseen by the Institution of Gas Engineers and Managers (IGEM). The industry is currently gathering evidence to support a change, without reducing safety standards, to the specification.

IGEM is currently responsible for numerous gas safety standards already and the gas industry is where the expertise on technical issues lies. The argument for doing this would be that an industry standard can respond to changes in the needs of industry in a more agile manner than Government can. There would be no need for parliamentary scrutiny of technical gas quality standards, thereby avoiding the burdensome and time-consuming process of gaining parliamentary approval over technical gas issues.

Moving to an industry standard could be construed as a move to 'water down' regulations in order to allow GDNs to more freely act without scrutiny and reduce regulatory costs. Accordingly, the safety of such a move would need to be fully demonstrated to Government and HSE before this is sanctioned. Under such a system GDNs and domestic providers of gas would still need to have an HSE-approved safety case and would still have a duty to convey gas safely.

Finding 18

At present the GS(M)R limits on the quality of gas which can be injected into the grid are seen by many in industry as a regulatory barrier to the deployment of biogases. Currently these barriers are reduced by exemptions to the GS(M)R granted by the Health and Safety Executive (HSE). Two more radical proposals to reduce barriers in the long term are widening the limits in GS(M)R and/or transferring the GS(M)R gas quality standard to an industry standard.

Blending hydrogen

The amount of hydrogen allowed in the grid under GS(M)R is just 0.1% by volume. This prevents injecting hydrogen blends into the gas distribution system. Desk-based research by HSE concluded that concentrations of hydrogen in methane of up to 20% by volume (equivalent to 6% on an energy basis)

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158 SGN (2013) Gas Network Innovation Competition Full Submission Pro-forma: Opening up the Gas Market
159 SGN (2016) Opening up the Gas Market
160 Specifically, Schedule 3 of GS(M)R, which stipulates the technical requirements for gas quality

would be unlikely to increase risk from within the low pressure part of the gas network. The report notes that there is "*little evidence*" to suggest that materials used for the low pressure distribution networks will degrade due to the injection of hydrogen/gas blends into the natural gas network[161].

GS(M)R could therefore likely be modified to incorporate more hydrogen in the gas grid, as it is in many other European countries[162], but an adequate safety case would, of course, still have to be presented to HSE to do this. Moving the gas quality specifications of GS(M)R to an IGEM standard could be beneficial in this regard as it would expedite any process to change these regulations.

It could also be possible to regulate blends of hydrogen through issuing a class exemption, as was done for biomethane. The ongoing HyDeploy project from Cadent is anticipated to be regulated through a bespoke exemption. If sufficient evidence is provided to demonstrate the safety of blending hydrogen, it could be possible that HSE issues a class exemption to regulate for hydrogen blending.

Finding 19

There are two ways in which hydrogen blends in the grid could be regulated: (i) through modification of the gas quality specifications in GS(M)R in order to permit greater than 0.1% hydrogen by volume; (ii) through the issuance of a class exemption by HSE permitting derogation from this limit in the distribution system. Whichever path is chosen, the safety of blending hydrogen must be thoroughly proven and demonstrated before either regulatory option is taken.

100% hydrogen

GS(M)R defines the gas which it regulates as "*any substance in a gaseous state which consists wholly or mainly of methane*"[163]. Accordingly, hydrogen is not included within the existing gas regulations. If 100% hydrogen in the gas grid were to be sanctioned this would most likely be part of a wider political decision in favour of a conversion process, but there would be two options for regulating such a move:

Use existing HSE regulation

HSE have indicated that initial regulation of hydrogen would be through existing health and safety regulations (as discussed in the previous chapter). It is conceivable that this approach of using existing instruments from the 'toolbox' of HSE regulation may be perfectly adequate. This is because this toolbox-approach could be used to form a 'safety management system' which would functionally mirror a safety case for 100% hydrogen, including the associated criminal penalties in the event of a breach of the relevant regulations.

Develop new regulation

However, it may emerge over time and as 100% hydrogen matures as a system that this toolbox-approach would be inadequate for its safe regulation, particularly if the geographical extent of a future hydrogen network becomes significant. It is currently too early to tell whether this will be the case or not, but if it becomes more apparent that there is a need to develop new, bespoke regulation for 100% hydrogen then this would be a course of action for HSE and industry.

In this event, there would be a need to produce a new set of gas quality regulations for hydrogen which would mirror the regulations set for natural gas today under GS(M)R. It would be essential for these

[161] Health and Safety Executive (2015) Injecting hydrogen into the gas network – a literature search
[162] Staffell, I. & Dodds, P.E. (Eds.) (2017) The role of hydrogen and fuel cells in future energy systems. H2FC SUPERGEN, London, UK; ITM Power, National Grid, Shell, SSE, et al., (2013) Power-To-Gas: A UK Feasibility Study. Sheffield: ITM Power
[163] Gas Safety (Management) Regulations 1996 (GS(M)R) (SI 1996/551)

hydrogen regulations to refer to an appropriately developed standard which can accommodate hydrogen. This hydrogen standard would specify the gas quality requirements of hydrogen in the grid[164].

Estimates from HSE and Leeds City Gate indicate that compiling evidence and the technical work for developing hydrogen regulations would take 5 to 10 years to complete[165], but it is important to note that all work on the demonstration of hydrogen would actively contribute towards the development of a sufficient body of evidence to understand what regulation would look like. Accordingly, it is expected that the timescales of developing new hydrogen regulation would fit within the timescales needed for hydrogen deployment (2030s onward). The final 18 to 30 months of this process would be needed to take the evidence base and turn it into a regulation for Ministerial approval.

Finding 20

HSE has stated that potential work on demonstrating hydrogen would be regulated through existing health and safety regulations other than GS(M)R. This 'toolbox-approach' is appropriate to allow initial work in the hydrogen space without excessive regulatory burden. This approach could prove suitable in the long-term for regulation of a potential conversion to 100% hydrogen, but if it were to become apparent that bespoke regulation for hydrogen were needed, Government should ensure that a new regulatory framework for hydrogen could be delivered in a timely fashion to prevent delay of a potential rollout of hydrogen.

5.3 Are present governance frameworks suitable for low carbon gas?

Low carbon gas poses challenges for the governance arrangements of the energy sector.

Local government

Local governments are taking up an increasingly significant role within heat decarbonisation, primarily through their involvement with heat networks. The low carbon gas agenda poses unique questions about the role that local governments play within the energy sector.

Biogases

Local authorities are responsible for waste management, and therefore play a major role in dictating how feedstocks for biogases are used. For example, a shortage of separate food waste collections is limiting the development of the AD industry[166]. Local authority waste policy therefore has implications for biogases; this will be explored further in the second report in the *Future Gas Series.*

Hydrogen

Local authorities could play a key role in supporting 100% hydrogen in the UK. As trusted figures, local authorities are ideally placed to communicate positive media tackling concerns around the perceived risk of hydrogen. Local authority buy-in will be helpful to ensuring that conversions could proceed on schedule especially given their role in housing, planning and building standards. Local authorities are also landlords of social housing, which enables them to install hydrogen appliances in many customers' homes. For this reason, local authorities may also be well placed to provide homes for a live trial programme of hydrogen.

Governance of hydrogen

How a conversion to 100% hydrogen would be governed is unknown. The transition from town gas took place in a non-privatised energy system, led by a centralised Conversion Executive with full oversight of the process. However, the governance of the gas industry is different today. There are no national monopolies in which coordination of the conversion process would naturally lie. Instead, a new system of

[164] Mirroring Schedule 3 of GS(M)R
[165] Sadler *et al.* (2016) H21 Leeds City Gate, p. 302; HSE pers. comm.
[166] ADBA (2016) AD Market Report: December 2016

coordinating the rollout of hydrogen would likely need to be established. Such a coordination mechanism would interlink the Government, the GDNs, HSE, Ofgem, as well as local authorities and other industry actors.

How new infrastructure requirements such as hydrogen production, transmission, and appliances fit within the oversight of Ofgem and a liberalised energy market is unclear[167] (and is explored further in Chapter 6). CCS also presents a challenge, since at present there are no regulatory frameworks in which the capture, transportation and storage of carbon dioxide are covered[168]. This will be explored in detail in the second report in the *Future Gas Series.*

[167] Ofgem (2016) Future Insights Series: The Decarbonisation of Heat
[168] Parliamentary Advisory Group on Carbon Capture and Storage (2016) Lowest Cost Decarbonisation for the UK: the critical role of CCS

6. Costs, funding and billing

FINDINGS

21. The Renewable Heat Incentive (RHI) has been successful at encouraging the biomethane market in the UK. However, it is not due to provide support for new schemes after 2021. Government should work with industry to ensure they are supporting biomethane injection into the gas grid to become commercially viable without subsidy beyond the lifetime of the RHI policy.

22. The RHI (or its replacement) could be used to support bioSNG – but it is important to emphasise that this should only be done if there is convincing evidence in the future to suggest that sufficient cost reductions in bioSNG technologies will occur to ensure that this policy instrument delivers affordable decarbonisation. There is ongoing debate as to whether this is likely or not. Given these concerns, it would be appropriate for Government to explore new ways in which it could help encourage bioSNG in a cost-effective manner, which may include a role for local authorities or cross-sectoral funding.

23. The need to add propane to biogases prior to injection to the grid is, in part, imposed due to how gas bills are currently determined. This is an avoidable barrier to their deployment. Billing methodologies should be modified to accommodate sources of gas with lower energy densities, such as biomethane and bioSNG, in order to avoid the significant costs associated with adding propane.

24. Although not yet occurring in the gas distribution system, many of the issues that apply to biogases would also apply to blending hydrogen. Reforming billing methodologies to better accommodate low CV gases such as biomethane and bioSNG would facilitate any potential introduction of hydrogen blending.

25. The costs of an extensive transition to 100% hydrogen would be expensive – estimated to be in the region of £200bn. Whilst substantial, however, they would be of comparable size to other investments in heat decarbonisation which would have to be made if hydrogen were to not be a viable option, and some studies have suggested they would be less expensive than the widespread electrification of heat.

26. If parts of the existing gas system were to switch from natural gas to 100% hydrogen one of the biggest challenges in this area will be a political decision on a fair and effective way to fund this. This would likely mean a decision between a levy on bills, providing funding through general taxation or a combination of both.

Low carbon gases could form part of the most cost-effective mix of solutions to heat decarbonisation – but, depending on the level of the transition to using low carbon gases for heat, there may be significant costs involved. However, all options for heat decarbonisation involve additional costs, not just low carbon gas. In order to understand the costs of low carbon gas properly, therefore, it is necessary to contextualise them against their alternatives, establishing whether they are 'costly' in comparison to other options rather than as standalone solutions.

Low carbon gases pose potential challenges for how investments in the energy system are financed and how customers are billed for their energy. Increasing the use of biogases will require doing more to remove economic barriers and incentivise their use. Blending hydrogen in the grid would raise questions about how a new gas mix could be billed. A transition to 100% hydrogen would be particularly challenging when it comes to finance – what would be the best or fairest way to fund such a large scale national infrastructure programme?

6.1 Biogases

What are the costs of biogases?

In total, it has been suggested that around £25bn of investment might be needed for biogases to reach their 'full potential'[169].

Biomethane

A literature review of cost estimates for biomethane has shown that the retail price of biomethane might be, on average, around 8.1 pence per kWh (within the range of 4.4 pence to 13.6 pence per kWh). In contrast, the average retail price of a unit of gas supplied to domestic customers by the six main suppliers in 2015 was 4.44 pence per kWh. The higher retail price of biomethane reflects its production costs, which makes up roughly two-thirds of the average retail price. AD plants are expensive, incurring capital costs of between £1800 and £4500 per kW[170].

By combining estimates of the capital infrastructure costs of deploying biomethane at scale[171] with estimates of realistic levels of biomethane deployment[172], it is possible to estimate that the rollout of biomethane to meet 5% of gas consumption (a foreseeable level of deployment according to the Committee on Climate Change) would likely incur capital costs in the region of £2.7bn, excluding the significant 'sunk' capital costs of around £20bn incurred though the upgrading and installation of waste infrastructure which would be required regardless of biomethane. The cost of £2.7bn to deliver 5% of gas consumption (24.25TWh of gas[173]) equates to a capital cost of £111 per MWh.

BioSNG

Little data exists on the costs of bioSNG from waste[174] since it has only just reached demonstration stage in the UK. The costs of bioSNG will likely become clear following further demonstration and commercial development, but a systematic review of the costs of low carbon gas suggests that the costs of bioSNG production "*appear to be competitive with the range of cost estimates for biomethane production with AD*"[175].

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[169] Cadent (2016) The Future of Gas: Supply of Renewable Gas
[170] Speirs *et al.* (2017) A greener gas grid: what are the options? Sustainable Gas Institute, Imperial College London, p. 53
[171] National Grid (2009) The Potential for Renewable Gas in the UK (£30bn to deploy biomethane to meet 18% of gas demand, of which £20bn are sunk waste infrastructure costs)
[172] Committee on Climate Change (2016) Next Steps for UK Heat Policy
[173] On a capital cost basis, assuming final consumption by gas as 485TWh (from BEIS (2016) DUKES Table 1.02)
[174] Speirs *et al.* (2017) A greener gas grid: what are the options? Sustainable Gas Institute, Imperial College London
[175] Speirs *et al.* (2017) A greener gas grid: what are the options? Sustainable Gas Institute, Imperial College London, p. 54

The cost of the first demonstration plant of producing bioSNG from black bag waste in the UK was £4.25m[176], with the subsequent commercial plant expected to cost £23m[177]. Progress on the commercial plant to date has derived the following cost estimates laid out in Table 3.

By 2030, there could be in the region of 25TWh of bioSNG produced a year, equivalent to roughly 38 large scale plants (each approx. 665GWh). Although no proper model of the costs of rollout exists, simple arithmetic (ignoring any economies of scale or other assumptions) suggests that this would cost in the region of £5.75bn, or equivalent to a capital cost of approximately £230 per MWh.

Table 3: Costs of bioSNG

	First of a kind plant (315GWh per year)	Commercial plant (665GWh per year)
Capital cost	£108m	£151m
Operating cost	£10.2m per year	£16.5m per year

Source: Go Green Gas (2016) First Project Progress Report: June 2016

What more can be done to improve the economics of biogases?

Financing biogases

More could be done to encourage the deployment of biomethane and bioSNG through improving its economics, and this will be explored further in the second report in the *Future Gas Series*. There are many ways in which policy could improve the favourability of the economics of biogases. Potential options include:

Pricing

Biogases are expensive in comparison to natural gas, but the full cost of natural gas is not reflected in its price since there is no carbon price and it benefits from a low VAT rate of 5%. Without pricing reflective of the carbon impact of natural gas, biogases will continue to be disadvantaged. A major disadvantage of any higher fuel prices, however, would be the adverse distributional impacts, since additional costs such as VAT rises and carbon prices affect fuel poor households the worst.

Renewable Heat Incentive (RHI)

BioSNG is financed in the same way as biomethane – through the non-domestic renewable heat incentive (RHI), a tax-payer funded subsidy scheme[178]. The level of subsidies available to biomethane producers falls over time as biomethane costs fall, from 7.90 pence per kWh before January 2013 to 3.20 pence per kWh as of July 2017[179]. This level of subsidy, however, is far too low for bioSNG producers.

One potential solution to this issue could be a dedicated RHI tariff for bioSNG which would acknowledge the different status of market maturity between biomethane from AD and bioSNG from gasification of waste. This tariff would also include consideration of both black-bag waste gate fees and bioSNG payments. Gate fees can considerably affect the effective subsidy bioSNG receives, as bioSNG producers would receive payments in the region of £33 per MWh by collecting and managing waste material[180].

[176] Cadent (2013) Gas Network Innovation Competition Screening Submission Pro-forma: BioSNG Demonstration Plant
[177] Cadent (2015) Gas Network Innovation Competition Screening Submission Pro-forma: Commercial BioSNG Demonstration Plant
[178] DECC (2014) RHI Biomethane Injection to Grid Tariff Review
[179] Ofgem (2017) Tariffs and payments: Non-Domestic RHI. Available at: https://www.ofgem.gov.uk/environmental-programmes/non-domestic-rhi/contacts-guidance-and-resources/tariffs-and-payments-non-domestic-rhi
[180] Go Green Gas (2017) BioSNG Demonstration Plant: project close-down report

However, Government would only ever be able to support such a policy decision if there were strong evidence to suggest that there will be cost reductions in bioSNG technologies to ensure that this policy instrument would deliver cost-effective decarbonisation. There is some scepticism as to whether these cost reductions could be achievable in timespans short enough to merit RHI support. Industry would have to convincingly prove the case that bioSNG costs will fall over time before Government could deliver new financial support to bioSNG in the RHI.

Other financing mechanisms

However, issues with the RHI have prompted calls for a new funding mechanism for bioSNG. Government reviews of the RHI have delayed investment in low carbon heat, and fiscal risks stemming from changes in government policy can undermine investor confidence. Critics of the RHI have argued that this prevents the longer-term certainty over the profitability of bioSNG technology which would be needed to ensure investment. Instead, some critics of the RHI have suggested to this inquiry that financing deployment through consumer bills might be able to provide the long-term revenues required for investor confidence. Whether or not this is in the long-term interest of customers remains debatable, however, and would depend on the prospects of bioSNG becoming a cost-effective technology and how long support would be required for. Accordingly, financing bioSNG deployment through bills is not without concerns, but it does illustrate a potential model which could be explored.

Other options should be explored, too, though. For example, bioSNG is linked to waste feedstock policy, and financing models could explore ways in which these policy areas can be integrated. In this vein, regional funding could be possible: local authorities could be paid to generate renewable gas from their waste, for example. An alternative possibility is to explore how bioSNG could be used in early HGV transport and subsidised through transport decarbonisation initiatives. It is clear, therefore, that more work needs to be undertaken to investigate innovative models for financing bioSNG and their desirability.

Above all, it is important that there is a future for biogases after the RHI scheme concludes in 2021. Signalling an intention to encourage the commercialisation of biomethane beyond 2021, with a view to making biomethane subsidy-free in the long run, and ideally clarifying what form this would take could support further deployment of biomethane.

Finding 21

The Renewable Heat Incentive (RHI) has been successful at encouraging the biomethane market in the UK. However, it is not due to provide support for new schemes after 2021. Government should work with industry to ensure they are supporting biomethane injection into the gas grid to become commercially viable without subsidy beyond the lifetime of the RHI policy.

Finding 22

The RHI (or its replacement) could be used to support bioSNG – but it is important to emphasise that this should only be done if there is convincing evidence in the future to suggest that sufficient cost reductions in bioSNG technologies will occur to ensure that this policy instrument delivers affordable decarbonisation. There is ongoing debate as to whether this is likely or not. Given these concerns, it would be appropriate for Government to explore new ways in which it could help encourage bioSNG in a cost-effective manner, which may include a role for local authorities or cross-sectoral funding.

Processing costs

As previously mentioned, biogas contains a high percentage of carbon dioxide which must be removed to produce biomethane which is suitable for injection into the grid. However, this alone is not enough to inject biomethane into the grid. Usually, propane is added to biomethane prior to injection in order to 'enrich' it (boost its energy content).

This is done to ensure fair billing. Gas customers are billed for the amount of energy they use, which is the product of the volume of gas used and the amount of energy per unit volume of gas (the calorific value or CV). Customers are billed on an 'average CV' of gas for all customers within their local area[181] (rather than, for example, the actual CV of the gas they use in their boilers). This 'average CV' that is used applies across a relatively large area (known as a local distribution zone or LDZ), and a different CV is used for billing in each of the 13 LDZs that cover Great Britain.

This is a problem for biomethane and bioSNG[182], which – even if their CV and other characteristics are compliant with GS(M)R – typically have a CV that is lower than the 'average CV' used to bill customers. With more biogases being injected, the CV could vary significantly within an LDZ. Therefore current billing regimes mean that biogases entering the grid are enriched with propane to boost their CV to levels similar to that in the rest of the LDZ.

Propane enrichment is costly and seen as a barrier to entry[183]. The cost of propanation nationally is over £2m a year, which will rise in the future – if 5% of the gas in the grid were biomethane, propanation costs would total £40m a year. Blending with propane, a fossil fuel, also increases the greenhouse gas emissions of biogases. This issue would also affect any bioSNG which is injected into the gas grid.

Changing billing methodologies to avoid the need for propanation could eliminate these high extra unnecessary costs and encourage more biogases. Presently, with the 'average CV' used in billing calculated for such large areas, limits are placed on the range of CV of gas that can be injected into the grid in order to prevent the CV varying too much.

This could be avoided if the measurements were made at a more local level (potentially even down to individual homes). New ways of charging (such as tracking energy consumption rather than gas flows, or by measuring the CV of gas at the meter) could solve these issues. By measuring the calorific value of gas at more places along the distribution network, more accurate measurement of the CV being delivered to gas customers could be ascertained which would in turn allow for more accurate billing, thereby removing the need to enrich biogases with propane.

In this vein, Cadent is researching ways to develop and implement a more specific billing methodology that can ensure that customers are accurately billed for the CV of the gas they use[184]. Its Future Billing Methodology project[185], and associated consultation[186], aims to provide a "*proof-of-concept*" for maximising the use of "*alternative GS(M)R compliant gases*" such as biomethane, bioSNG and hydrogen blending by exploring ways gas energy can be attributed to gas flows in the LDZ network at a more specific level. Its proposed models include billing for meters that receive biomethane separately to the rest of an LDZ; dividing each LDZ into separate charging zones billed with a CV representative of their gas inputs; and

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181 Technically known as the flow-weighted average calorific value (FWACV)
182 E4tech (2010) The Potential for bioSNG Production in the UK
183 SGN (2015) Gas Network Innovation Competition Full Submission Pro-forma: Real-Time Networks; Cadent (2016) Gas Network Innovation Competition Screening Submission Pro-forma: Future Billing Methodology
184 Cadent (2016) Gas Network Innovation Competition Screening Submission Pro-forma: Future Billing Methodology
185 Cadent (2016) Gas Network Innovation Competition Screening Submission Pro-forma: Future Billing Methodology
186 Cadent (2017) Future Billing Methodology – Unlocking a low carbon gas future: consultation document

transmitting real-time CVs to smart meters which could pave the way to CV measurements at the smart meter itself[187].

The difficulty of this task should not be underestimated. Given the ongoing difficulties of rolling out smart meters, there are practical challenges associated with linking CV measurement to smart meters; and reforming the billing methodology would require investments in network modifications in addition to further research and demonstration of these models. But, the benefits to both greenhouse gas emissions and gas customer bills arguably justify tackling this problem.

SGN is also researching ways to determine the CV received by consumers more locally, allowing customers to be billed closer to the point of use[188]. Its Real-Time Networks project aims to develop a real-time energy demand model of the gas networks, and explores how a combination of CV measurement nearer to consumers and network analysis methods for determining the energy received by consumers can achieve this.

A related issue which could be addressed is the need for expensive monitoring equipment to measure the CV of biomethane injected into the grid. Whilst some have called for the use of cheaper (but less accurate) monitoring devices, there are understandable concerns surrounding the protection of customer rights in terms of correct billing[189]. An appropriate regulatory balance which both protects consumer interests and removes barriers to the growth of the biomethane industry is needed.

Finding 23

The need to add propane to biogases prior to injection to the grid is, in part, imposed due to how gas bills are currently determined. This is an avoidable barrier to their deployment. Billing methodologies should be modified to accommodate sources of gas with lower energy densities, such as biomethane and bioSNG, in order to avoid the significant costs associated with adding propane.

Connecting to the gas grid

Connections are another way that propane enrichment can be avoided. Some biomethane plants are able to connect to the grid at the local transmission system level, which has saved producers around £350,000 in avoided expenditure on propane spiking equipment because the low CV biomethane is sufficiently ‘diluted’ by the natural gas[190].

Connecting to the transmission system is particularly useful since it is not always possible to connect AD plants to the distribution system. Some sites for biomethane injection are too far from distribution pipelines, but close to transmission. Other sites cannot connect to distribution networks because the grid in that area is not able to support the level of flow required by the AD plant: they continuously produce biomethane for injection to the grid, but the gas distribution network does not have enough demand for this gas during certain times of day or during summer (i.e. when demand is low).

However, work could be done to improve the speed and reduce the costs associated with connecting to transmission – in particular with the high pressure national transmission system, which costs in the region of £2m per plant and takes up to three years to complete[191]. These barriers mean that some AD plants burn biogas for power instead of injecting into the grid.

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[187] Cadent (2017) Future Billing Methodology – Unlocking a low carbon gas future: consultation document
[188] SGN (2015) Gas Network Innovation Competition Full Submission Pro-forma: Real-Time Networks
[189] Ofgem (2016) Open letter: Consultation on relaxing the accuracy requirements of Calorific Value Determining Devices
[190] National Grid Gas Transmission (2016) Network Innovation Competition Submission: Project CLoCC (Customer Low Cost Connections)
[191] National Grid Gas Transmission (2016) Network Innovation Competition Submission: Project CLoCC (Customer Low Cost Connections)

To tackle these issues, it is important to develop ways to connect AD plants to the transmission system in a cheaper and timelier fashion (where appropriate). Initial work is being undertaken to reduce these time and cost barriers, such as National Grid Gas Transmission's Project CLoCC (Customer Low Cost Connections).

Another proposed solution is a 'common pool' injection system whereby AD plants could tanker their biomethane to a common site for injection. This would allow more immediate connections to grid for plants that cannot connect directly to it, and could be a less expensive way of getting biomethane to the grid.

Feedstocks and food waste

A final area in which Government could do more to encourage biomethane is in terms of feedstock policy. There is significant potential to increase, for example, the production of biomethane from food waste – but a key barrier to doing so is household collection systems, which are not harmonised across the county. There is a need for local and national government to explore ways in which more food waste could be diverted away from landfill and towards productive end-uses such as biomethane production. It is important, however, that due attention be given to debate over whether tying energy production to waste management is a sustainable environmental policy, and the waste hierarchy – which states that it is better to prioritise the prevention and minimisation of waste, reuse and recycling above energy recovery and disposal – should be front and centre within such policy.

Final end use of biogas

At present, most AD plants produce biogas rather than biomethane for injection into the grid. Whether it is sensible for the vast majority of biogas to be used in the power sector is questionable as the power system decarbonises. In the near to medium term, it might make more sense to inject biomethane than dedicate significant amounts of biogas to power. Accordingly, Government should be aware of the ways in which biogas can be used across sectors and should be aware of a potential need to, in the future, align financial incentives to support the best use of bioresources in the energy system as a whole.

6.2 Hydrogen

Blending hydrogen

How much does blending hydrogen into the gas grid cost?

Since low levels of hydrogen would be compatible with grid infrastructure, there would be no significant additional costs imposed in terms of repurposing the networks. There would, of course, be costs related to demonstrating hydrogen blending and establishing its safety case to permit blending. However, if blending is permitted the primary costs incurred would relate to the production of hydrogen.

Electrolysers would be an expensive form of hydrogen production – they generally incur higher hydrogen production costs than technologies such as SMR (with or without CCS) and biomass gasification (with or without CCS)[192], and are estimated to generate hydrogen at a wholesale cost of roughly 10 pence per kWh[193]. However, given that any blending of hydrogen in the grid would be powered by surplus electricity, it follows that the price of blending hydrogen in the grid would be highly dependent upon the price of primary energy powering the electrolysers[194]. The greatest potential for low-cost hydrogen from electricity would be from surplus renewable power which could be very cheap, and which if tied to grid management could provide further revenue.

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192 Speirs *et al.* (2017) A greener gas grid: what are the options? Sustainable Gas Institute, Imperial College London
193 Sadler *et al.* (2016) H21 Leeds City Gate, p.50; Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System
194 Speirs *et al.* (2017) A greener gas grid: what are the options? Sustainable Gas Institute, Imperial College London

However, some contributors to this inquiry disagree with this assertion, particularly given that surplus renewables are often beneficiaries of constraint or curtailment payments whereby generators are paid not to generate due to insufficient transmission capacity for this electricity, which calls into question the economics of 'cheap' surplus renewables. Others believe that despite an ever-growing role for renewables in decarbonising the power sector there is still some debate around the availability and affordability of surplus renewables, especially during winter when demand for energy from the gas grid is highest[195].

There are no known estimates costing a scenario for extensive hydrogen blending from electrolysis (up to 20% by volume or 6% by energy) in the UK gas grid. However, a recent study by Cadent has explored the costs of blending using hydrogen produced from SMR with CCS: the Liverpool-Manchester Hydrogen Cluster project has estimated that the capital costs of converting gas networks in the area to hydrogen blends (with some industrial sites converted to 100% hydrogen) could be in the region of £600m with annual operational costs of around £57m[196].

What more could be done to improve the economics of hydrogen blending?

Similarly to biogases, blends of hydrogen and natural gas that would be injected into the grid might have low CVs[197]. Injecting these blends of hydrogen might not be allowed – even if the GS(M)R limit of 0.1% of hydrogen by volume had been raised or exemptions issued – if these blends were to have too low a CV. Current billing regimes would not accept them as they would be sufficiently low to distort the 'average CV' which is used to bill gas customers[198]. Previous work has suggested that a blend of greater than 3.5% hydrogen by volume would be enough to achieve this[199]. Blends of greater than 3.5% hydrogen by volume (equivalent to 1% by energy) would therefore need to have their CV raised through the addition of propane. As previously discussed, reforming billing regimes would address this issue and avoid the need for propane[200].

Although hydrogen blending is not yet occurring in the gas grid, many of the issues described for biogases above would also apply to blending hydrogen. Reducing the cost of connecting natural gas/hydrogen blend injection sites and identifying business models that can support long-term investment in hydrogen blending infrastructure are all important ways in which the economics of hydrogen blending could be improved if it were permitted for deployment in the gas grid in the future.

Finding 24

Although not yet occurring in the gas distribution system, many of the issues that apply to biogases would also apply to blending hydrogen. Reforming billing methodologies to better accommodate low CV gases such as biomethane and bioSNG would facilitate any potential introduction of hydrogen blending.

100% hydrogen

What are the costs of 100% hydrogen?

Today, natural gas is cheap: the average retail price of a unit of gas supplied to domestic customers by the six main suppliers in 2015 was just 4.44 pence per kWh[201]. In comparison, hydrogen gas in the Leeds H21

[195] Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System
[196] Cadent (2017) The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project – Technical Report, p.106-107
[197] SGN (2013) Gas Network Innovation Competition Screening Submission Pro-forma: Widening the Gas Market
[198] Cadent (2017) Future Billing Methodology – Unlocking a low carbon gas future: consultation document
[199] DNV GL (2016) Hydrogen Addition to Natural Gas Feasibility Study, p.4
[200] Cadent (2016) Gas Network Innovation Competition Screening Submission Pro-forma: Future Billing Methodology
[201] Ofgem (2016) Retail Energy Markets in 2016

project was estimated at 7.3 pence per kWh[202], while the Sustainable Gas Institute has suggested an achievable retail price of hydrogen could be around an average of 9.3 pence per kWh[203] (both assuming SMR with CCS).

Ostensibly these retail prices make hydrogen seem expensive, but this price should be considered in the context of other low carbon heating technologies. Electrification is not cheap either: the average price of off-peak electricity is around 10p per kWh, and a unit of electricity supplied to domestic customers by the six main suppliers in 2015 was 14.26 pence per kWh[204] – almost twice as expensive as hydrogen is thought to be, and almost three times as costly as natural gas is today.

Whilst it is unclear how the price of hydrogen would feed into energy bills, the largest component of energy bills is the cost of the fuel itself. Variation in the wholesale price of gas can feed through to bring about changes in the price of customers' bills, which suggests that a higher price for hydrogen fuel would in turn raise energy bills[205].

Initial estimates of the costs of conversion suggest it would require significant investment (Table 4). A national conversion to 100% hydrogen is estimated to cost just over £200bn to 2050 in a scenario where hydrogen meets 75% of total heat demand[206]. The greatest share of this – roughly £75bn – would be incurred in converting appliances. By 2050, the annual operating cost for the hydrogen infrastructure would be £5.5bn; for comparison, total expenditure on the gas grid today is around £2bn a year[207].

These estimates are broadly similar with other work. KPMG has estimated that a scenario where hydrogen contributes to 47% of UK residential and commercial energy would total costs in the range of £104-122bn[208]. Whilst it is important to emphasise that these early costings of 100% hydrogen could not be seen to represent definitive estimates (in part because these estimates have at times used the same source data), what they do illustrate is that hydrogen will demand significant investment to realise.

Table 4: Estimates of the costs of converting to 100% hydrogen

Area of conversion:	Leeds	Major UK cities	UK-wide
Customer size	660,000	22m (17 cities)	253 cities
Total capital costs	£2bn	£50bn	£127bn
Total annual operational costs	£140m	£2.8bn	£5.5bn (by 2050)

Notes: Estimates rounded
Sources: Sadler *et al.* (2016) H21 Leeds City Gate; Frontier Economics (2016) Future regulation of the gas grid

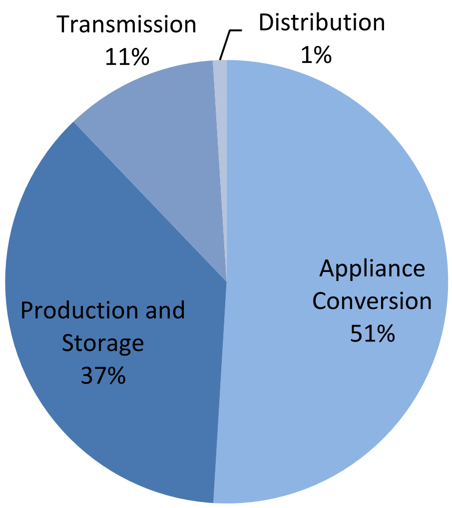
As illustrated by Figure 8, the greatest costs of conversion are expected to fall in terms of installing appliances, representing just over half of the total costs of the programme. In contrast, upgrading the distribution networks would cost just 1% of the total cost of the work programme, and creating a new hydrogen transmission system would cost just over a tenth of the total cost[209].

Finally, it is important to note that although the costs of the IMRP are estimated to be around £21bn to 2032, these are 'sunk costs' which are planned to happen regardless of a decision to convert to hydrogen,

[202] Sadler *et al.* (2016) H21 Leeds City Gate. Estimate on a standalone project basis, excluding the costs of appliances
[203] Speirs *et al.* (2017) A greener gas grid: what are the options? Sustainable Gas Institute, Imperial College London
[204] Ofgem (2016) Retail Energy Markets in 2016
[205] House of Commons Library (2016) Energy Prices: Briefing Paper Number 04153
[206] Frontier Economics (2016) Future Regulation of the Gas Grid; both capital and operational costs totalled
[207] Sadler *et al.* (2016) H21 Leeds City Gate
[208] KPMG (2016) 2050 Energy Scenarios: The UK Gas Network's Role in a 2050 Whole Energy System
[209] Sadler *et al.* (2016) H21 Leeds City Gate

and therefore are not additional costs of converting to hydrogen[210]. It is worth, however, expressing that the requirement for investment would most likely be revisited if Ofgem felt that the gas network was going to be stranded.

Figure 8: Percentage share of capital costs of converting Leeds to hydrogen



Source: Sadler *et al.* (2016) H21 Leeds City Gate; adapted from P. Dodds (pers. comm.)

Uncertainties

It is also important to emphasise throughout this section there are, of course, uncertainties surrounding these estimates. For example, the potential effects of energy efficiency upon the costs that consumers pay has not been fully understood, but for hydrogen boilers it is likely to be impactful given that they entail high operating (fuel) costs.

The total cost of the hydrogen option would also depend on its end use. Whilst the Leeds H21 City Gate study envisions the widespread use of hydrogen boilers, this is not necessarily inevitable. Energy model runs with the UK TIMES model show that by 2050 a portfolio of technologies could be adopted under a least-cost hydrogen scenario, including fuel-cell microCHPs and hybrid heat pumps to support the electricity system[211].

This suggests that the level of hydrogen used in 2050 varies substantially between scenarios. The higher fuel requirements of microCHP would increase hydrogen demand considerably, whereas the widespread deployment of hybrid heat pumps would reduce hydrogen demand since it would only need hydrogen intermittently to meet peak demands on a daily or seasonal basis. Further uncertainty is introduced when considering the potential roles that hydrogen might play for transport and electricity[212].
This wide range of potential outcomes generates an uncertainty about future demand for hydrogen. Ultimately, very little is known about the true costs that low carbon gases would impose, and it is likely that these would only fully materialise if live trials for hydrogen take place, further reinforcing the urgency of demonstrations. Not only would these refine cost estimates, but they would help identify where costs can be reduced.

[210] MacLean, K. *et al.* (2016) Managing heat system decarbonisation: comparing the impacts and costs of transitions in heat infrastructure. Annexes and Literature Review.
[211] Dodds, P. (pers. comm.)
[212] Staffell, I. & Dodds., P.E. (Eds.) (2017) The role of hydrogen and fuel cells in future energy systems. H2FC SUPERGEN, London, UK

Finally, it is worth mentioning that the costs given here stand independently of any policy introduced in the interim which could reduce them. For example, boiler regulations introduced today could help reduce costs associated with appliance change-over, through policies such as the standardisation of boiler backplates which could reduce the time it takes to change from a natural gas to hydrogen boiler, as well as through policies to support the remanufacturing of natural gas boilers to make them hydrogen compatible (instead of building boiler parts entirely from scratch)[213]. These ideas will be explored in the final report in the *Future Gas Series.*

Comparisons to other heat decarbonisation technologies

Although 100% hydrogen appears to be costly, it is important to contextualise these costs against alternative decarbonisation pathways for heat.

Electrification

Electrifying heat broadly incurs three costs: the costs of the appliances, the costs of installing extra electricity generation capacity, and the costs of upgrading the networks (including storage) to cope with the extra load.

- **Appliances** Installing electricity-driven heating appliances such as heat pumps in 80% of homes would cost an estimated £200bn[214]
- **Generation** Meeting 80% of peak domestic heat demand in 2050 with heat pumps would require a 175% increase in current peak power demand levels. To meet this additional electricity generation demand with gas power stations has been estimated to cost over £60bn[215]
- **Network costs** Greater uptake of electricity-driven appliances would also require the reinforcement and upgrading of power distribution networks. The costs of reinforcing the low voltage electricity network in order to support the wide scale deployment of electric heat pumps have been projected to be in the range of £13 to £30 billion[216]
- **Storage** The costs of electricity storage could be significant, but investment in storage systems would likely be necessary for electricity to be able to meet highly variable demand for heat energy[217]

In total, therefore, decarbonising heat through total electrification could be expected to cost in the order of £300bn – potentially far greater than the costs of a national hydrogen conversion[218]. This comparison is, of course, simplistic given that these costs will be spread over decades of investment in the energy system, and many of the costs of new low carbon electricity generation capacity will be embedded within the prices of electricity bills. Moreover, this is not to say that electrification is too expensive to play a cost-effective role in the future of heat – it almost certainly will – but what it does illustrate is that although the costs of low carbon gas are expensive, they are of comparable size to other investments in low carbon heat which would have to be made if low carbon gas fails to materialise as a viable option.

In addition, all heating options which involve the end of gas would have to incur an additional cost of decommissioning the gas grid. The cost of doing this remains highly uncertain – estimates given in evidence to this inquiry have ranged from £4bn to £20bn. Cadent has loosely estimated the cost at £8bn[219].

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213 Kiwa Ltd. & E4tech (2016) Desk study on the development of a hydrogen-fired appliance supply chain
214 Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating
215 Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating
216 MacLean, K. *et al.* (2016) Managing heat system decarbonisation: comparing the impacts and costs of transitions in heat infrastructure - Annexes and Literature Review
217 WWU (2016) Heat, Light and Power Model – Future of Energy and Investments in Energy Networks
218 Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating
219 Cadent (2016) Gas Network Innovation Competition Full Submission Pro-forma: BioSNG Demonstration Plant

Finding 25

The costs of an extensive transition to 100% hydrogen would be expensive – estimated to be in the region of £200bn. Whilst substantial, however, they would be of comparable size to other investments in heat decarbonisation which would have to be made if hydrogen were to not be a viable option, and some studies have suggested they would be less expensive than the widespread electrification of heat.

How can this be paid for?

A generic problem for heat decarbonisation solutions is that they involve extra costs which need to be met and therefore raise distributional and equity questions. This is no different for low carbon gas and to one of the key questions around the potential repurposing of the gas grid to transport 100% hydrogen: how could it be funded? This debate does not need to be resolved now and may never need to be decided but in the event of a conversion a key political decision would be how to bear the costs.

In the absence of an alternative mechanism being devised, it is likely that if a conversion were to be undertaken the costs would have to be met through levies (whereby charges are spread across customers' bills), funding through general taxation or a mixture of both. Currently, the Renewable Heat Incentive (RHI) is paid for through general taxation, rather than energy customers' bills. However, it is standard practice for gas network upgrades to be funded through levies on customers' bills (such as the IMRP)[220].

Considerations for socialisation and taxation

Local, regional or national?

Both levies and taxes are useful in that they can distribute the costs of conversion across a wide base, and, importantly, across long timespans. Funding a conversion to 100% hydrogen through general taxation would spread the costs nationally. Currently, each GDN has different cost bases which are then passed onto gas customers' bills through levies in the area they operate in, while the costs of running the transmission system are spread across gas customers' bills nationally. It is likely that a hydrogen conversion would encompass only parts of the country if it went ahead. If the costs of hydrogen conversion were met through levies on bills there would be a question over whether these should be placed on the bills of only those customers experiencing a changeover to hydrogen, all gas customers in the region experiencing a changeover to hydrogen, or all gas customers in the country.

Interaction with other heating solutions

Spreading the costs of hydrogen conversion through a national levy on gas customers' bills rather than a regional one would reduce the impact the conversion has on an individual customer's bills. However, if a conversion to 100% hydrogen were undertaken in parts of the UK, payment for this would not take place in a vacuum. It is likely that it would be in conjunction with the rollout of other low carbon heating technologies such as heat networks and electrical heating solutions.

Unless all additional costs associated with the transition to low carbon heating are spread nationally through bills and taxation then some people could end up 'paying twice' for the decarbonisation of themselves and others. For example, if one region transitions to hydrogen and the cost of this is met by levies on all gas customers' bills, those individuals who are not on hydrogen and have to contribute to the cost of their transition to another form of low carbon heating will have paid for the cost of someone else's transition and their own.

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[220] Sadler *et al.* (2016) H21 Leeds City Gate, p.256

Private or public good?

One of the issues at stake here would be whether transition amounts to a private or public good. There are limited private gains for customers using natural gas to heat buildings moving to hydrogen and the driver of this would be the 'public good' of reducing greenhouse gas emissions, so although the spreading of costs could be justified this point would need to be communicated clearly.

The main complicating factor would be if the conversion process involved replacing existing appliances with new hydrogen appliances which would provide a private benefit to those experiencing the changeover[221]. This could potentially be addressed if customers involved in a transition, excluding fuel poor households, paid either the whole cost of new appliances or the difference between the residual value and the value of the new appliance.

This could also be dealt with through a second-hand/reconditioning market. Boilers from converted homes that were still usable could be used by households whose boiler broke down a year or so before their planned conversion. Boilers could also be converted off-site to be used with hydrogen allowing sufficient time to ensure function and safety are OK. These ideas will be explored further in the third report in the *Future Gas Series.*

Certainty of investment

Some contributors believe that a levy provides relative certainty of investment. Funding low carbon technologies through tax funds is seen by some as more likely to be impacted by changing political climates. A levy therefore could provide more long-term stability in the investment programme.

Alternatively, some have suggested that consideration should be given as to whether it could be possible to use contracts in order to provide certainty to investment – in much the same way that has been done by Government for projects such as HS2 and Hinkley Point C.

Social equity

A major downside of a levy is that, because those from lower wealth households pay more for their energy bills as a share of income than wealthier customers, adding levies to bills is socially regressive and paying for a hydrogen conversion through energy bills could exacerbate fuel poverty[222]. Renewed ambition to improve the energy efficiency of fuel poor homes would be particularly important to mitigate these effects if a hydrogen conversion was undertaken and paid fully or partially through a levy on bills.

A key benefit of using taxation to do this is that it would be less socially regressive because it can also take into account the circumstances of taxpayers in order to minimise adverse distributional outcomes. In doing so, funding low carbon gas through general taxation protects fuel poor homes from rising energy bills[223].

Energy bills

More broadly, there is significant political sensitivity around energy bills as well as a history of media criticism of environmental schemes which increase energy bills. The H21 Leeds City Gate report suggests that it would be possible to fund a widespread conversion to hydrogen using a levy without a significant increase in customers' bills, as the costs of conversion would effectively replace the costs of IMRP which is due to complete in 2032[224]. This would still mean, however, that bills would be higher than they would otherwise be without a conversion. There is also an issue around the fact that first movers to hydrogen would likely have to pay higher energy bills for hydrogen than natural gas, which would be, again, politically sensitive especially if the transition were mandated.

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[221] Sadler *et al.* (2016) H21 Leeds City Gate, p.306
[222] NEA, Frerk and MacLean September 2017
[223] NEA, Frerk and MacLean September 2017
[224] Sadler *et al.* (2016) H21 Leeds City Gate, p.306

Constituent parts of a changeover

As has been outlined, converting existing natural gas customers to hydrogen would involve a series of different component costs. There would be initial capital costs associated with developing facilities for the production and storage of hydrogen, network upgrades to support its transportation, and deploying appropriate appliances. It would be necessary to work out if these costs should be met through one single method such as a levy on bills or a more mixed approach.

Mandating a changeover

A number of contributors raised the idea that hydrogen conversion would be particularly difficult to manage because of a sense that customers undergoing a conversion to hydrogen would feel that they were being forced or mandated to change. This is because the nature of the gas grid means it would not be possible to allow people to choose to stay on natural gas or move to hydrogen (or switch between both). This mandation therefore denies them any choice over their heating solution, and forces them to pay (either through a local or national levy on bills or through taxation).

This argument is misleading, however, as those customers in an area subject to hydrogen conversion could choose to install an alternative solution such a heat pump if they wished, just as they could today choose to do so. Moreover, some contributors to this inquiry have argued that a hydrogen conversion would not *reduce* consumer choice, as it would still pose the same fundamental choice of using either gas, electricity or other technologies to provide heat. A hydrogen conversion would therefore be merely changing the nature of the choice rather than removing choice itself; mandating a changeover need not always reduce consumer choice.

Role of GDNs and established practices

As mentioned, the RHI is funded by general taxation. However, this is an incentive scheme rather than full upfront funding for heating measures; and while other national infrastructure such as roads, flood defences and waste facilities are paid for by taxpayers, energy infrastructure, is generally paid for by users through levies, not tax[225].

A fundamental issue is the extent to which upstream production costs and/or in-home conversions would be paid for on gas bills and therefore included within the financial remit of GDNs.

The H21 Leeds City Gate report discusses the option of spreading the costs associated with a conversion to 100% hydrogen via a levy on bills[226]. This would be an unprecedented expansion to the roles of GDNs and many would argue that it would be inappropriate to extend the remit of GDNs to infrastructure downstream of the meter. It would also have major impacts on the appliance market, whereby GDNs may be in charge of buying and installing boilers; in turn, raising questions about consumer choice within the appliance market.

In the H21 model the production of hydrogen is also included within the role of the GDNs. At present, low carbon gas production is distinct from the role of the GDNs. The emerging biomethane industry is a multi-player market, and accordingly there are arguments that the production and storage of hydrogen should also be free-market activities. Government would likely need to provide clarity on the responsibility and ownership of each part of the supply chain. This is particularly important for Ofgem which at present does not incorporate such assets into its regulatory framework, and which would therefore need revisiting in this context.

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[225] Infrastructure and Projects Authority (2016) National Infrastructure Delivery Plan Funding and Finance Supplement
[226] Sadler *et al.* (2016) H21 Leeds City Gate

Finding 26

If parts of the existing gas system were to switch from natural gas to 100% hydrogen one of the biggest challenges in this area will be a political decision on a fair and effective way to fund this. This would likely mean a decision between a levy on bills, providing funding through general taxation or a combination of both.

Additional considerations

Energy efficiency

As with all low carbon gas, energy efficiency will be hugely important in reducing the costs of hydrogen bills. Any rollout of hydrogen must be closely tied to a renewed effort to deploy cost-effective energy efficiency measures. Such work could proceed in advance of the timing of a conversion, and this should be considered as a priority by a future Government.

Carbon pricing

Carbon pricing is a simple way in which energy bills can reflect the impacts fuels have on the environment, and ensures all technologies are on a level playing field. To bring natural gas level with decarbonised solutions, a price in the region of £200-£300 per tonne of carbon might be needed[227]. A carbon price may help first movers to low carbon gas, since it would help reduce otherwise high energy bills. The absence of a carbon price is arguably unfair, since it would favour carbon intensive heating sources.

However, political support for carbon pricing is weak. If it raised bills it would be controversial and adversely impact the poorest in society the most, potentially exacerbating fuel poverty. Carbon pricing is too blunt an instrument to reflect these socioeconomic concerns. Some contributors to this inquiry have made arguments that, although carbon pricing is very good at rewarding the conversion of a single factory from (for example) coal to gas or promoting energy efficiency, it is too crude an instrument to drive upgrading or repurposing of whole energy systems. These concerns around carbon pricing do, to some extent, further justify the use of the RHI to fund low carbon gas, which serves to correct price signals for low carbon technologies.

Price controls

In terms of the current price control system, there would also be a need to include flexibility in RIIO-GD2 from 2021 to 2029, given that during this interval Government may make a decision on the future of hydrogen in the gas grid. Frontier Economics raise the idea that RIIO-GD2 price controls should contain trigger points to allow Ofgem or the networks to re-evaluate the price control allowances within the control period[228]. Triggers could include a Government decision on a mandated hydrogen switchover, or conversely a decision to commence extensive network decommissioning before 2029. It would also likely be necessary to include this flexibility in future price control periods after 2029 too, particularly to accommodate any decisions on decommissioning taken after this timeframe.

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[227] Dodds, P. (pers. comm.)
[228] Frontier Economics (2016) Future regulation of the gas grid

7. Next steps for the gas grid

The Committee on Climate Change identified a distinction in heat decarbonisation between 'low regrets' options which can be pursued today, and considerations which need attention in the longer term[229]. This is also useful in relation to the future of the gas grid, as some actions must be taken now whilst other decisions cannot yet be made. This chapter therefore summarises the 'Next steps' and 'Medium to long-term considerations' suggested by this report, which together outline a future for policy on the gas grid.

7.1 Next steps

Focus on future-proof policy

The best use of the gas grid in the future is still uncertain: scenarios range from the widespread repurposing of the existing gas grid to run on 100% hydrogen to the full-scale decommissioning of the grid. In general, policy decisions made in the short term should reflect this uncertainty about the long-term plan and as far as is practical and proportionate not shut off potential options prematurely.

Enhance efficiency gains

Increasing the efficiency of energy use is a priority which can bring immediate and long-term benefits in terms of decarbonisation, energy security and affordability. There are potential 'quick wins' in areas such as substituting the remaining non-condensing boilers for more fuel-efficient condensing boilers, and lower-cost insulation measures such as cavity wall insulation[230]. Measures which improve the efficiency of the fabric of buildings are particularly useful as they can make long-term transitions to low carbon heating sources cheaper, more practical and are important for understanding which low carbon heat solutions might be applicable.

Deploy biomethane

Injection of biomethane to the gas grid can provide immediate reductions in the emissions associated with heating. Government should continue to support this by ensuring regulatory barriers to deploying biomethane are as low as possible while at all times maintaining the safety of the gas system. Additionally, Government should work with industry to ensure they are supporting biomethane injection into the gas grid to become commercially viable without subsidy beyond the lifetime of the RHI which closes in 2021.

Widening the gas quality regulations could support the deployment of biomethane and other forms of low carbon gas. There are, however, potential associated trade-offs; for example, lower gas quality standards reduce the efficiency and lifetime of appliances. Where assessments show that there are no insurmountable associated safety, operational, and consumer issues, regulatory barriers to the deployment of biomethane and other low carbon gases should be reduced.

[229] Committee on Climate Change (2016) Next steps for UK heat policy
[230] Policy Exchange (2016) Too hot to handle? How to decarbonise domestic heating

Explore bioSNG

BioSNG is a technology with significant potential to support decarbonisation. Government should explore ways in which support for bioSNG could be provided. This is particularly challenging because of its immaturity relative to other low carbon heat technologies. Any support would need to be based on robust evidence on the viability of the technology and likely cost reductions of it in the future.

Support hydrogen blending

If injecting hydrogen/natural gas blends (ranging from 3-20% hydrogen by volume, equivalent to 1-6% by energy content) into the gas grid can be shown to be safe, relevant exemptions from GS(M)R should be issued by HSE and/or GS(M)R should be modified to allow more than 0.1% hydrogen by volume to be transported in the gas grid.

Develop a flexible gas grid

There is significant discussion in the power sector about the development of a more 'flexible' system. To a certain extent, this could be replicated in the gas grid whereby a system utilising almost exclusively natural gas could move to a more flexible system incorporating a number of different gas. Whilst the incorporation of new forms of gas into the gas grid bring their own challenges, a transition to a more flexible gas grid which utilises a number of forms of gas could bring significant benefits in terms of decarbonisation and energy system balancing. While always maintaining the safety of the system and protecting consumers' interests, Government should in general be supportive of such a transition.

Improve billing

Steps should be taken to improve billing methodologies in order to address issues arising from the use of low carbon gas. This offers benefits to natural gas customers by accurately billing for the energy they use, but it also removes barriers to the deployment of biogases and hydrogen blending by reducing the costs imposed due to propanation.

Demonstrate 100% hydrogen

Repurposing parts of the existing gas grid to transport 100% hydrogen could be an effective way to reduce emissions associated with heat. The costs, implications and desirability of such an option remain hugely uncertain, however, so policy in this area should focus on evidence gathering and keeping options open.

This requires action in the short term in the area of safety testing and demonstrations as these would be essential prerequisites to any potential widespread conversion of the gas grid to 100% hydrogen. There is significant scope to improve the coordination of work in this area. Safety testing and demonstration projects are required to allow the UK more choices on heat and should not tie the UK into rolling out hydrogen more widely.

Long term options on the gas grid

If a decision were taken during the next round of price control negotiations to decommission the gas grid, this would commit the UK to pursuing decarbonisation of heat without the full range of options available. Ofgem should, within its next round of price controls (RIIO-GD2 running from 2021 to 2029), make no firm commitment to the decommissioning of the gas grid, but should incorporate the required flexibility within price controls to allow for such an eventuality should it arise as the result of a Government decision on the future of gas. There is also a strong case for further work to be undertaken in order to establish the costs, impacts and implications of fully or partly decommissioning the gas grid.

A further development in this area could be to take steps now which potentially reduce the costs of a transition to 100% hydrogen in the future; for example, standardising boiler black plates to reduce costs of a potential changeover of appliances. Such changes would need to be proportionate, however, and reflect the fact that a 100% hydrogen conversion may never be pursued.

Continue the Iron Mains Replacement Programme (IMRP)

The Iron Mains Replacement Programme (also known as the Iron Mains Risk Reduction Programme) should continue in order to ensure the ongoing safety of the gas grid. This also prepares the network for future conversion to hydrogen, if this becomes desirable. Whilst these policies might have to be reviewed beyond the mid-2020s, Government should continue to support their aims until such a time as a clearer decision on the future of the gas grid is to be taken. Consideration may need to be given to the phasing of this work; for example, to ensure conversion is completed region by region, and potentially favouring areas that might be more likely to convert to 100% hydrogen such as in the north of England.

7.2 Medium to long-term considerations

Paying for a conversion to 100% hydrogen

If there were a conversion to 100% hydrogen, then major political decisions would have to be taken on whether the costs of converting to 100% hydrogen should be paid for by general taxation or through levies on energy bills or a combination of both.

Regulation of 100% hydrogen

If there were a conversion to 100% hydrogen, it may be possible to regulate 100% hydrogen with existing HSE regulations. However, if it were to become apparent that there is a need to create new regulations for 100% hydrogen, this is likely to take 5 to 10 years to complete.

Governance of low carbon gas

A potential transition to 100% hydrogen poses challenges for the governance of the gas grid. Today, there is no certainty as to the future ownership and operation of a hydrogen transmission network, hydrogen production sites and hydrogen storage. These roles do not need immediate clarity and may never need it, but consideration must be given to them in the event of a transition to 100% hydrogen.

The future role of biogases

In the long term, bioenergy is thought to be able to play useful roles in decarbonising sectors such as transport and aviation alongside playing a role in heat. There will need to be a long-term plan for the best uses or re-applications of these resources.

Whole system interactions with power and transport

Linkages and interactions between power, transport, heat and other energy sectors must be considered if decarbonisation across the economy is to be cost-effective and timely. Understanding that our heat system will evolve flexibly, responding to changes in the power and transport sectors, will be important to making sensible decisions around the future of the gas grid.

Production and consumer-end questions

Arguably the biggest uncertainties around the increased use of low carbon gas relate to the production of it (including carbon capture and storage) and the implications of low carbon gas for consumers, rather than the networks. These issues will be considered in detail in Parts 2 and 3 of the *Future Gas Series*.

Glossary

Anaerobic digestion (AD)	A series of biological processes in which microorganisms break down organic matter in the absence of oxygen to produce biogas.
Biogas	A term to describe gases derived from biological sources (e.g. biomethane, bioSNG), but technically refers to the raw gas which is produced by AD.
Biomethane	An 'upgraded' version of biogas which has enriched levels of methane and less carbon dioxide. It is suitable to inject into the gas grid. It is produced by AD.
Biopropane	A low carbon form of propane derived from biological instead of fossil sources.
Bio-Synthetic Natural Gas (BioSNG)	A form of biologically-derived methane, similar to biomethane, but which is produced by gasification rather than anaerobic digestion (AD). Also known as bio-substitute natural gas.
Calorific Value (CV)	The amount of energy in a given volume of gas.
Carbon Capture and Storage (CCS)	A technology that can capture and store carbon dioxide emissions from the use of carbon-based fuels preventing the emissions from entering the atmosphere.
Electrolysis	The use of electricity to split chemical compounds. Used to split water into hydrogen and oxygen, and therefore a way of producing hydrogen gas.
Gas Distribution Networks (GDNs)	A company which owns and operates the gas distribution networks of the UK. These are Cadent (formerly known as National Grid Gas Distribution (NGGD)), Northern Gas Networks (NGN), SGN and Wales and Western Utilities (WWU).
Gas Safety Management Regulations (GS(M)R)	A key regulation for gas safety; stipulates the acceptable composition and quality of gas permitted in the gas grid.
Gasification	A thermal decomposition process that converts organic materials into gases (primarily carbon monoxide, hydrogen and carbon dioxide). The gases produced can be converted into bioSNG or enriched to produce hydrogen.
Hydrogen	A colourless, odourless, tasteless and non-toxic gas. Its combustion does not produce any carbon dioxide, making it a low carbon gas.
kWh/TWh (kilowatt-hour/terawatt-hour)	Measures of energy. 1 kWh is approximately the energy used when to wash a full load of clothes in a washing machine. 1 TWh is equivalent to 1 billion kWh; for scale, Hinkley Point C is expected to produce 25TWh of electricity a year.
Low carbon gas	Any gas which can deliver significant greenhouse gas emissions reductions compared to natural gas. This inquiry focuses on biomethane, bioSNG, biopropane and hydrogen as low carbon gases.
NOx	A collective term for mixtures of nitrogen oxides, typically nitric oxide (NO) and nitrogen dioxide (NO2). Produced from the reaction of nitrogen and oxygen during the combustion of hydrocarbon fuels; they are harmful air pollutants.
Particulate Matter (PM)	A collective term for microscopic air pollutants. They are linked to respiratory disease and cardiovascular illness and are a major public health issue.
Steam Methane Reformation (SMR)	A method of bulk hydrogen production. Methane reacts with high-temperature steam under high pressure in the presence of a catalyst to produce hydrogen.
Syngas	The product of gasification, and an intermediary gas in the production of bioSNG. Syngas is a combination of hydrogen, carbon monoxide and carbon dioxide. This can then be chemically reacted through the water-gas shift and methanation to produce hydrogen.
Synthetic Natural Gas	A form of methane, similar to natural gas, which is produced by the gasification of fossil fuels (e.g. coal); it is synthetic but not produced from biological sources (unlike bioSNG).

Methodology and Steering Group

Carbon Connect carried out this inquiry between November 2016 and August 2017. Evidence was gathered by a series of evidence gathering sessions held between October 2016 and March 2017, interviews with those working in and around the sector, written submissions, desk-based research and input from our Steering Group of experts. The views in this report are those of the authors. Whilst they were informed by the Steering Group and listed contributors, they do not necessarily reflect the opinions of these individuals and organisations.

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About Carbon Connect

Carbon Connect is the independent, cross-party forum that seeks to inform and guide a low carbon transformation underpinned by sustainable energy.

In 2009 the Rt Hon Ed Miliband MP, then Secretary of State for Energy and Climate Change, delivered a keynote address at the Westminster launch of Carbon Connect. Since then Carbon Connect has been at the forefront of policy debate, parliamentary engagement and research related to sustainable energy.

Over a number of years, Carbon Connect has built up an unrivalled portfolio of parliamentary roundtables and conferences, detailed policy briefings and highly respected reports. This has been achieved by drawing on the expertise of Carbon Connect members and working with a wide range of parliamentarians, civil servants, business leaders and experts who give their time and expertise to support our work.

Carbon Connect's main activities comprise facilitating discussion between industry, academia and policymakers on low carbon energy and producing its own research and briefings in this area. We do this by:

- Holding regular events and seminars in Parliament
- Producing concise briefing papers on energy and climate change policy
- Publishing research reports with evidence-based recommendations for policymakers
- Disseminating updates to parliamentarians and our members, with summaries of relevant stories, industry news, and other political developments

About Policy Connect

Policy Connect is the go-to cross-party think tank, successfully delivering new policy ideas through research, evidence, political meetings and sector engagement.

With no set ideology, we recommend the best approach from facts and data, and help influence policy decisions and law-making. We find the common ground and build consensus to improve public policy. We do this by running forums, commissions and All-Party Parliamentary Groups. We have overseen the research and delivery of more than 50 key publications.

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