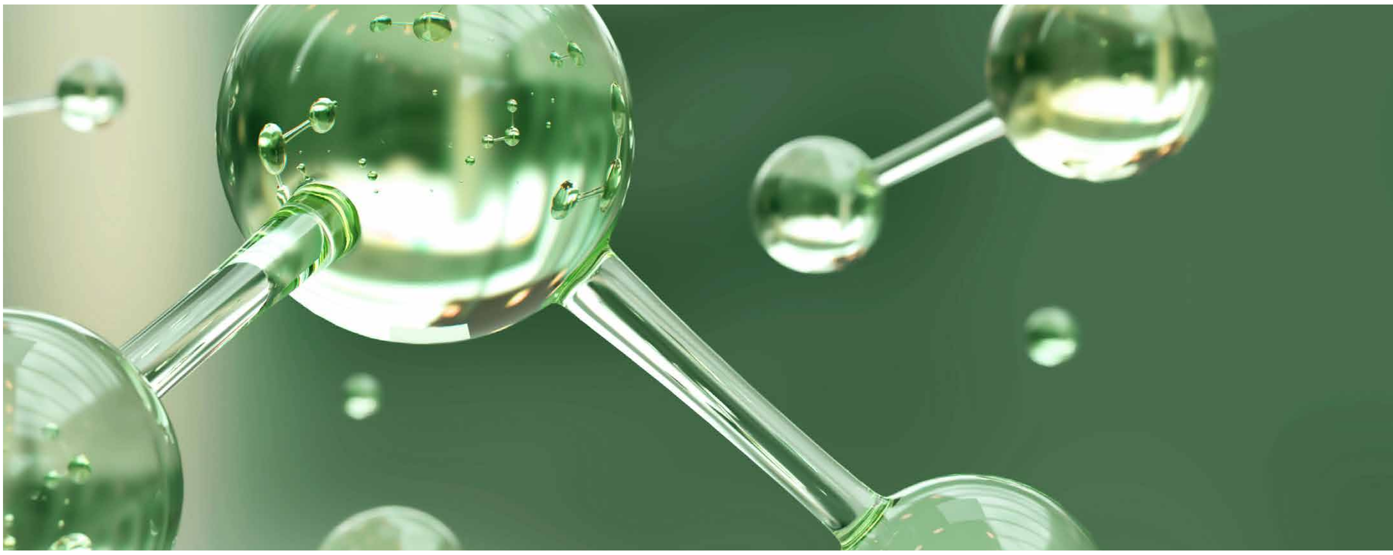
The Institution of Engineering and Technology

Transitioning to hydrogen

Assessing the engineering risks and uncertainties



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About this report

This report is a cross-professional engineering institution (PEI) collaboration between the Institution of Chemical Engineers (IChemE), Institution of Engineering and Technology (IET), Institution of Mechanical Engineers (IMechE), Health and Safety Executives Laboratory (HSL) and Institution of Gas Engineers and Managers (IGEM).

A workshop was organised by the IET to identify and agree the key questions that need to be addressed to repurpose the gas grid to hydrogen for large-scale deployment to industry, homes and businesses. There were participants from industry, academia and government and it resulted in the identification of 300 issues across several categories. In order to take this forward, a professional engineering institution (PEI) Group was established by the IET in partnership with the IChemE, IMechE, IGEM and HSL.

The Group reviewed the results of the workshop and the key questions identified. These were subsequently revised and rationalised to 15 core questions. This report provides a summary of the Group's work.

The PEI Group would welcome any comments or suggestions.
Please send these to **sep@theiet.org**.

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Foreword

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The Committee on Climate Change's (CCC) report *Net Zero – the UK's Contribution to Stopping Global Warming* sets out in clear terms the case for the UK to have net-zero greenhouse gas emissions by 2050, and the need to tackle at pace the decarbonisation of hard-to-reach areas of energy use.

Space heating, currently dominated by natural gas boilers, still represents a major obstacle. Various options are possible in engineering terms but all have their challenges. Given the scale of the challenge, effort is needed on all fronts. Electrical solutions such as heat pumps will require a large expansion of the electricity system, in particular its peaking capacity, and modifications to buildings themselves. District heating has considerable appeal but comes with substantial infrastructure challenges. Biofuels and geothermal heating potentially have their places, but hydrogen through the existing gas system can be a credible solution at scale that has received limited attention until recently.

This report is thus timely. It presents an assessment of the engineering deliverability of hydrogen through the gas system and into homes and businesses. The authors are engineers – experts in the field – and by working through their professional engineering institutions the work has an assurance of independence. They conclude that following completion of the iron mains replacement programme already underway for other reasons, the gas system will be able to carry hydrogen safely, but they also identify a range of engineering questions that require resolution before a commitment to hydrogen at scale can be made with full confidence. Fortunately, a number of development and pilot projects are already underway that will answer many of these questions, and the authors draw these together to identify where gaps remain and where further work is still needed to confirm engineering feasibility. Getting this work done is now urgent if we are to achieve net-zero by 2050.

The group that has come together for this work is keen to remain engaged in helping to drive outcomes that facilitate large-scale deployment – making sure policy thinking in hydrogen is informed by impartial engineering advice, assessing the outcomes of the various projects and pilot deployments, and supporting any further work commissioned to fill the gaps in our engineering understanding. We stand ready to do that.

I hope very much that this report helps its intended audience: policymakers, who will soon need to make choices regarding how heat will be decarbonised. I would note also that the work has been a model of collaboration between engineering professionals from different institutions, from which all involved have learned. I commend it to you.

1. Executive summary

Over the last few years serious consideration has been given to the repurposing of the gas network to pure hydrogen so that it can be used by industry, in homes and businesses, and to contribute to the decarbonisation of the UK's energy sector. Unlike other energy vectors such as electricity, district heating and carbon-based gases, high-purity hydrogen has not been deployed at scale anywhere in the world. This puts hydrogen at a distinct disadvantage and so any case to deploy hydrogen will need to be sufficiently compelling to compensate for this lack of experience.

This report begins by exploring the importance of natural gas to the UK's energy system and the reasons for considering hydrogen, which could contribute significantly to the decarbonisation of the UK and reducing the current dependency on natural gas. These include:

Hydrogen allows much of our existing gas infrastructure to be used

Hydrogen can be used by industry, businesses and homes

Hydrogen can be produced in large volumes

Hydrogen compares well with other low-carbon heat technologies

It presents 15 core questions that would need to be addressed to enable the large-scale retrofit deployment of hydrogen to homes and businesses. Each of these core questions are reviewed and their importance explained. There have been a growing number of projects exploring hydrogen and these are briefly summarised with a subjective assessment made in terms of their contribution to the core questions and gaps identified.

Finally, there are five key messages that require urgent attention:

- **Progress CCuS infrastructure** - Without the simultaneous deployment of a carbon capture, utilisation and storage (CCuS) infrastructure hydrogen does not have a future for large-scale retrofit deployment to industry, homes and businesses.
- **Deploy critical new technology** - The large-scale deployment of hydrogen to homes and businesses will involve the introduction of new technologies for which there is limited experience.
- **Prepare a transition programme** - This needs to include sufficient enough detail to ensure the identification of critical path items and their associated uncertainties.
- **Develop skills and plan resources** - Transitioning to hydrogen will require resources ranging from craft skills, technicians, planning and designer engineers, academic and industrial researchers though to project management and customer-facing skills.
- **Fund the programme** - The transition programme will require substantial investment over many years.

The paper does not pass judgement on whether hydrogen is desirable in terms of the economy, society or the environment. It has come to the view that from an engineering perspective there is no reason why large-scale deployment of hydrogen cannot be achieved safely. However, it is important that the engineering risks and uncertainties are comprehensively addressed before a programme of large-scale deployment is commenced.

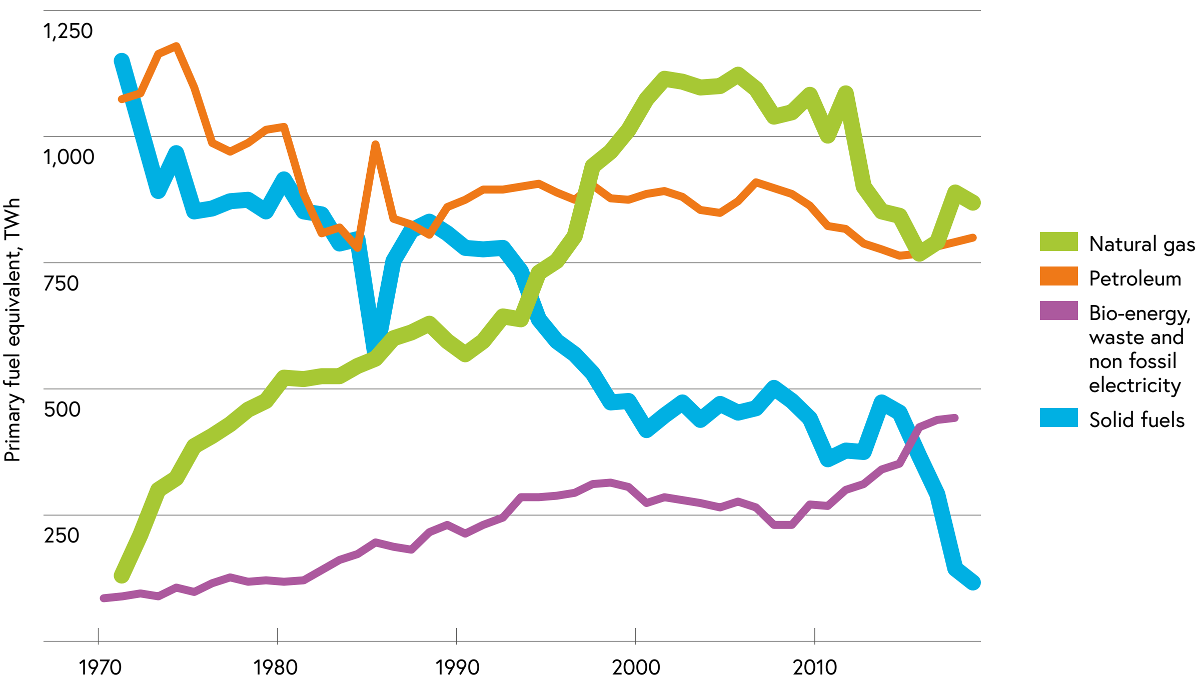
2. Introduction

The UK's changing energy landscape

The energy landscape of the UK is evolving from one based on fossil fuels to one based increasingly on low-carbon sources such as nuclear and renewables. Until the 1970s the UK was dependent on coal for most of its energy needs. Town gas manufactured from coal was introduced over 200 years[1] ago and comprised 50% hydrogen, ~25% methane with the remainder a mixture of carbon monoxide and impurities. The discovery of natural gas[2] in the North Sea transformed the UK's dependency on coal to one that became increasingly dependent on natural gas (Figure 1). This was facilitated by a major gas appliance conversion programme which was mostly completed within ten years and resulted in over 40 million appliances converted from Town gas to natural gas throughout the UK.

Natural gas offered many advantages over solid fuels. Not only was it clean and convenient, it improved the economics of central heating, which has resulted in over 85% of UK households heated by gas central heating in 2017 (Figure 2), leading to higher levels of comfort and wellbeing. Both the industrial and services sectors also saw a substantial increase in gas consumption as a proportion of total energy demand, with ~50% now met by gas (Figure 3). Excluding transport, natural gas provided more than 50% of total UK energy consumption in 2017 (Figure 4)[4].

Figure 1 – Final energy consumption by fuel, by sector, in primary energy equivalents 1970 to 2017[3]



[1] Williams, T.I. (1981) A history of the British Ga Industry. Oxford University Press, Oxford. UK.
[2] Typical hydrocarbon content of natural gas is methane (up to 90%) with the remainder ethane, propane and butane. "Natural gas" and "gas" are used interchangeably throughout this report.
[3] ECUK (2018) Table 1.1. See www.gov.uk/ government/statistics/energy-consumption-in-the-uk
[4] ECUK (2018) Table 1.04. See www.gov.uk government/statistics/energy-consumption-in-the-uk

Figure 2 – UK households with natural gas central heating[5]

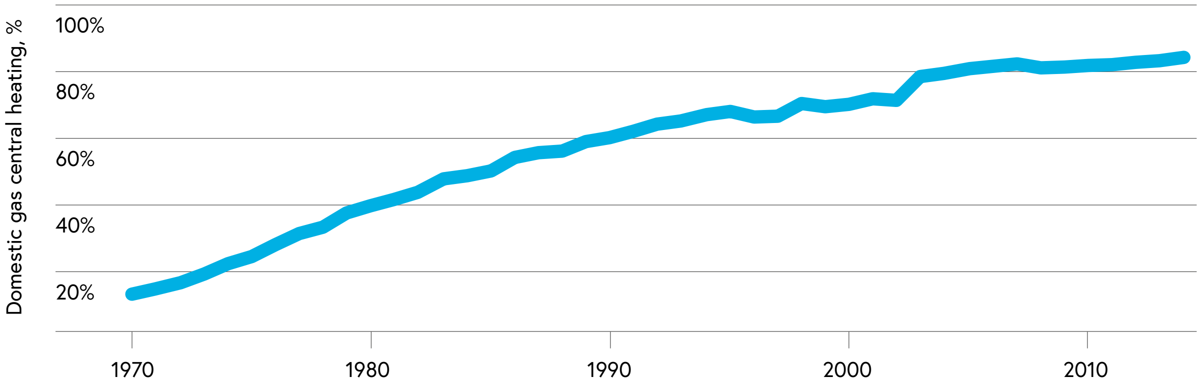


Figure 3 – UK industrial and services energy demand for gas, in primary energy equivalents[6]

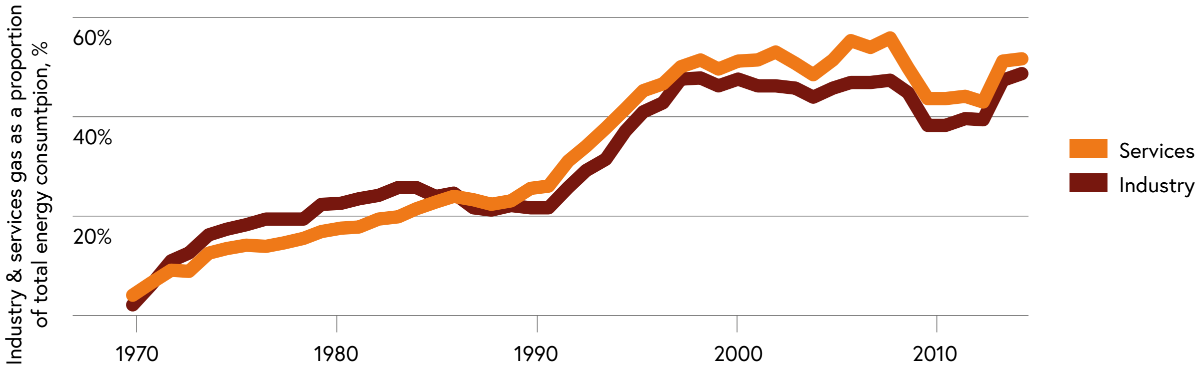
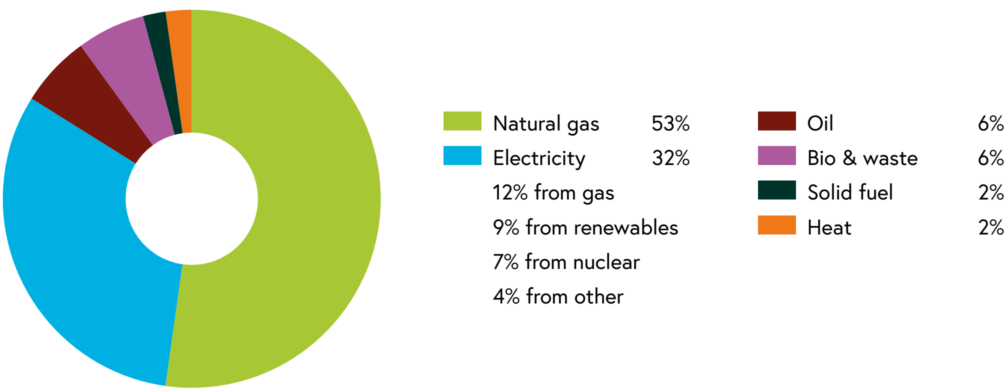


Figure 4 – UK energy consumption for heat and other end uses by fuel 2017 (excluding transport)



[5] ECUK (2018) Table 3.18. See www.gov.ukgovernment/statistics/energy-consumption-in-the-uk

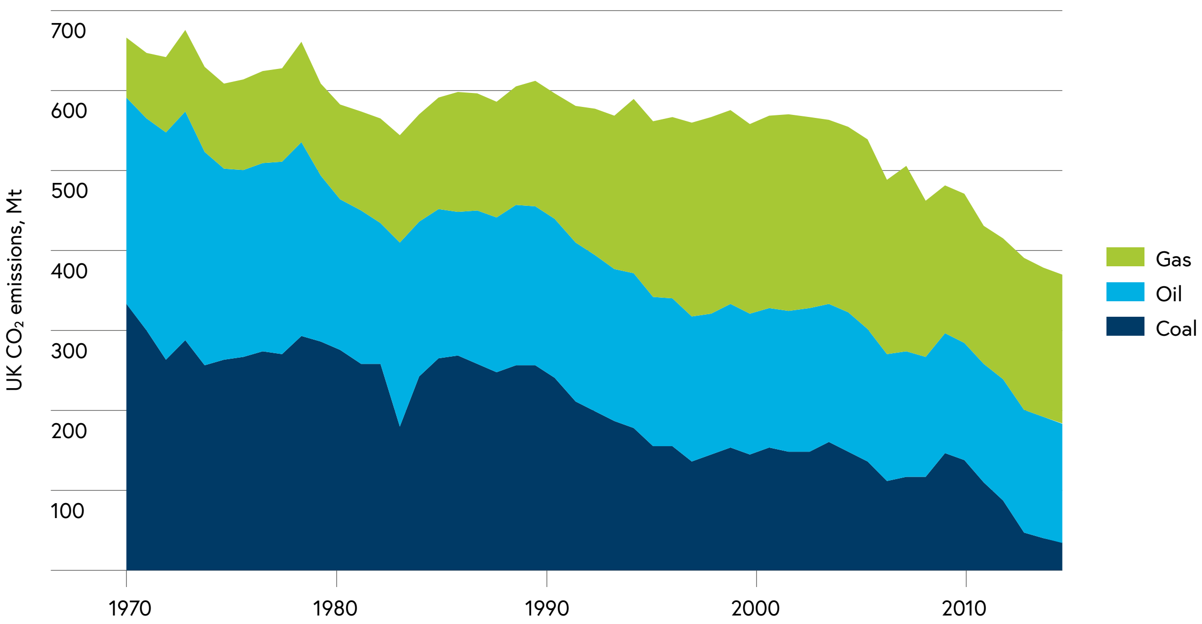
[6] ECUK (2018) Tables 4.09 and 5.07. See www.gov.uk/government/statistics/energy-consumption-in-the-uk

The main problem with natural gas, as with all fossil fuels, is that when combusted it produces CO_2 and in order to achieve the UK's 2050 GHG (greenhouse gas) target very substantial reductions are required. Even though natural gas has helped reduce UK CO_2 emissions by displacing coal and oil (which have double the CO_2 emissions of natural gas), it has now become a major contributor to UK CO_2 emissions (Figure 5). Hence, natural gas consumption has to either be significantly reduced or the CO_2 captured and sequestered to ensure the UK is able to deliver the reductions required.

Capturing CO_2 is possible for large installations such as power generation and heavy industry but it is unlikely to be economically viable for smaller installations, i.e. domestic, services and light industry. This is because:

- there are a multitude of small point sources which would need to be connected to an infrastructure to allow the CO_2 emissions to be captured and sequestered
- the combustion products are at low concentration (low partial pressure), which would make achieving a high CO_2 capture rate difficult
- the emissions are intermittent and highly variable, which would make transport and sequestration technically challenging.

Figure 5 - UK CO_2 emissions by fuel 1970 to 2017[7]



[7] BEIS (2018) Table 2. See www.gov.uk/government/statistics/provisional-uk-greenhouse-gas-emissions-national-statistics-2017 and Carbon rief analysis for 1970 to 1989

Can we use low-carbon gas?

The alternative is to supply these installations with a low-carbon gas. In the UK Government's 2019 Spring Statement[8] it announced proposals to increase the proportion of green gas such as biomethane in the grid and reduce dependence on burning natural gas to heat homes. Green gases such as biomethane are manufactured from waste feedstocks such as food and sewage which would otherwise go to landfill. However, the projected volumes are limited with estimates ranging from 20TWh[9] to 100TWh[10], which is substantially less than current domestic demand.

Over the last few years numerous investigations have been undertaken to identify other low-carbon alternatives to natural gas for heating. BEIS' report published in December 2018 provides a comprehensive overview of the current evidence[11]. The options initially identified as suitable for large-scale retrofit deployment included electric heating using heat pumps, hybrid heat pumps, resistive heating and district heating. More recently hydrogen has been identified as a potential viable option but it would require repurposing of the existing gas network and associated infrastructure. Gas appliances and industrial burners would also need to be replaced or converted for use with hydrogen and there may be some applications where it is not suited.

Hydrogen has been produced in large quantities for the chemical industry from natural gas as well as other fossil fuels[12]. But as the process involves CO_2 emissions, carbon capture and sequestration technologies would be needed for the hydrogen to be classified as low carbon[13]. Hydrogen can also be produced in bulk from electrolysis but the power source would need to be from renewable electricity[14] or low-carbon sources.

The following sections of this report discuss the potential benefits and drawbacks of hydrogen. It then lists several core engineering questions that need to be addressed before hydrogen can be deployed to industries, homes and businesses with confidence. Some of these questions have been or are in the process of being addressed and the report identifies and summarises the principal projects and investigations either recently completed or currently underway.

It is important to emphasise that this report is focused on engineering issues and makes no judgement on the economics, social and environmental implications of hydrogen.

Green gases such as biomethane are another proposed solution, but projected volumes are limited.

8 Spring Statement 2019: Written Ministerial Statement. See www.gov.uk/government/publications/spring-statement-2019-written-ministerial-statement
9 Imperial College London (2018) Analysis of alternative UK heat decarbonisation pathways. See www.theccc.org.uk/publication/analysis-of-alternative-uk-heat-decarbonisation-pathways
10 Anthesis and E4Tech (2017) Renewable gas potential to 2050. See www.cadentgas.com/about-us/the-future-role-of-gas/renewable-gas-potential
11 BEIS (2018) Clean Growth - Transforming Heating Overview of Current Evidence. See www.gov.uk/government/publications/heat-decarbonisation-overview-of-current-evidence-base
12 Commonly referred to as "brown" hydrogen
13 Commonly referred to as "blue" hydrogen
14 Commonly referred to as "green" hydrogen

3. Why hydrogen?

The gas network can be repurposed for use with hydrogen

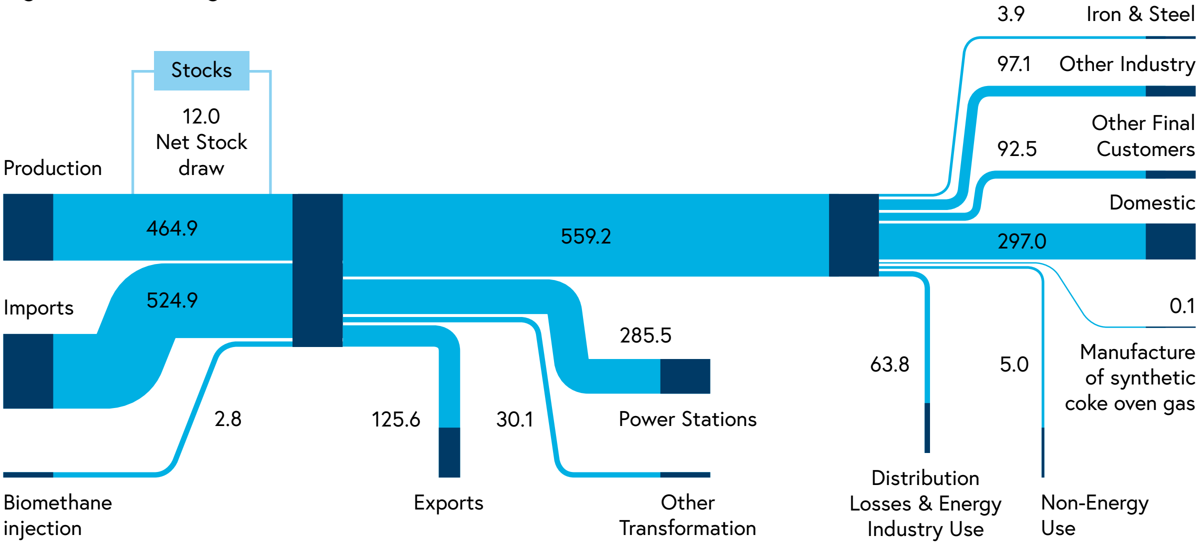
Prior to 1970 the low and medium-pressure (<7bar) gas network comprised of "iron mains" pipework. Polyethylene pipe was introduced in the 1970s for new connections and repairs to the existing iron mains as it offered advantages in terms of cost, lower losses, etc. Iron mains has a higher risk of failure causing injury and damage and since 1977 there has been a targeted programme of replacing these 'at-risk' mains[15]. The Iron Mains Replacement Programme (IMRP) was introduced in 2002 "to address 'societal concern' regarding the potential for failure of cast iron gas mains and the consequent risk of injuries, fatalities and damage to buildings (defined as incidents)".

The programme is scheduled to complete in 2031 and would mean that most of the iron mains pipework will have been replaced with polyethylene, which can be used with hydrogen, whereas iron mains are less suitable for repurposing, particularly in populated areas[16]. Therefore, by the early 2030s, the gas industry would largely have a "hydrogen-ready"[17] network.

The existing gas infrastructure can be used to support a hydrogen system

Over the last 40 years the UK has made substantial investments in its natural gas infrastructure. These include gas production, national transmission, storage, interconnectors as well as import terminals using liquid natural gas (LNG). The total gas supply in 2017 was nearly 1,000TWh with imports contributing more than 50% (Figure 6). The expectation is that as UK conventional production declines, import dependency could increase by up to 90%[18] by 2050. This gas infrastructure supports a market that includes supplies to power generation plants, industry, commerce and domestic householders. Additionally, the UK trades via the interconnectors with continental Europe to Belgium, the Netherlands as well as the Republic of Ireland and Norway. The UK gas system has proved to be highly resilient and has brought substantial economic and social benefits.

Figure 6 – Natural gas flow chart 2017 (TWh)[19]



[15] HSE's Enforcement policy for the replacement of iron gas mains. See www.hse.gov.uk/gas/domestic/gasmain.pdf

[16] This is mainly due to leaks from joints and so would not be used in the vicinity of buildings and population. Hence there might be some retained iron mains deemed to be low risk for use with hydrogen.

[17] The IMRP adopts a risk-based approach to determining the replacement of irons mains and hence it is difficult to be determine with precision how much of <7bar would be hydrogen but an estimate is ~90%.

[18] See www.fes.nationalgrid.com

[19] BEIS (2017) "Digest of United Kingdom Energy Statistics 2018". See www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes#2018

In 2017 power generation was the largest gas consumption sector (34%) closely followed by domestic (32%), with the remainder (34%) shared between industry, services and exports (Figure 7). Natural gas is predominantly used for low-temperature heat applications such as space and water heating (43% of total UK consumption) and industrial processes (6% of total UK consumption). However, it is also used for high temperature processes (2% of total UK consumption) such as the manufacture of chemicals, metals, glass and ceramics. Figure 8 shows gas consumption by application as a percentage of total UK consumption.

A feature of the UK's gas infrastructure is that it provides considerable system flexibility. This is important in terms of meeting the substantial variations in gas demand for space heating due to weather changes and from variations in electricity demand from flexible mid-merit and peaking gas plants. The infrastructure supporting this flexibility comprises 1.44 billion m^3 or ~15TWh of storage, eight interconnectors, four liquified natural gas (LNG) terminals, as well as the inherent flexibility provided from line-pack (the ability to store gas within the distribution system itself)[21]. Much of this infrastructure would also be available to support hydrogen infrastructure.

Figure 7 – UK gas consumption 2017

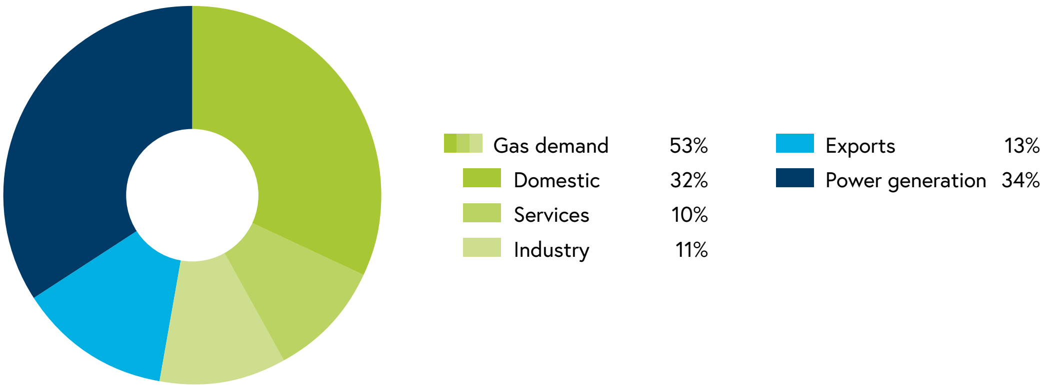
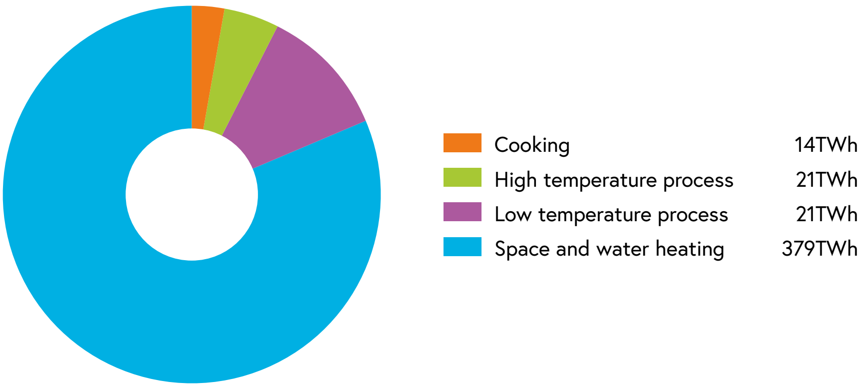


Figure 8 – UK gas demand by application 2017 (TWh)[20]



[20] Low temperature process" corresponds to 30-80°C for indirect heating, and 80-240°C for direct heating. "High temperature process" corresponds to temperatures up to 600°C for indirect heating and up to 2,000°C for direct heating.

[21] ECUK (2018). See www.gov.uk/government/statistics/energy-consumption-in-the-uk

Hydrogen compares well with other low-carbon heat technologies

Over 24 million[22] (~85%) UK households use natural gas for space and water heating. These households have heating systems which generally comprise a gas boiler supplying heated water via pipework to radiators for space heating and hot water for washing. A key feature of gas heating is the capability to deliverc large quantities of heat on demand over prolonged periods. This is possible because gas boilers are typically rated between $20kW_{th}$ to $30kW_{th}$ which is substantially above normal household demand. Due to this high capacity, they can be very responsive to consumers' heat requirements. This also means that boilers can provide hot water on demand as well as space heating, using combination boiler technology, thereby avoiding the need for hot water storage. At present there are over 24 million gas boilers installed in UK households, of which 14 million are combination boilers. Condensing technology is used by 16.5 million boilers[23], which can achieve efficiencies of ~90% and potentially higher with exhaust heat recovery.

In the domestic sector the conversion of existing natural gas appliances to operate on 100% hydrogen is not viable and so their replacement would be required. Initial investigations have shown that hydrogen boilers can deliver comparable levels of performance to natural gas for a similar cost. Boilers and appliances can be designed to be "hydrogen-ready", i.e. operating initially on natural gas with conversion to hydrogen at some later date.

In the industrial sector, some applications (e.g. steam-raising and hot water boilers and indirect heaters used in the food processing industry) can be converted to 100% hydrogen using existing technology. In other applications (e.g. glassmaking kilns) it is less clear the extent to which hydrogen can be substituted for natural gas because of the different combustion characteristics and potential impact on surrounding materials.

In the power and combined heat and power (CHP) sectors, much work is taking place to develop gas turbine combustion systems suitable for 100% hydrogen fuel. Some models are currently available following combustion system modifications. Other gas turbine models are available now for mixed gas operation, some with and some without combustion system modifications. Reciprocating engines (spark ignition) can take up to about 20% hydrogen by volume, but may need control system modifications; above this figure engine replacement will be necessary.

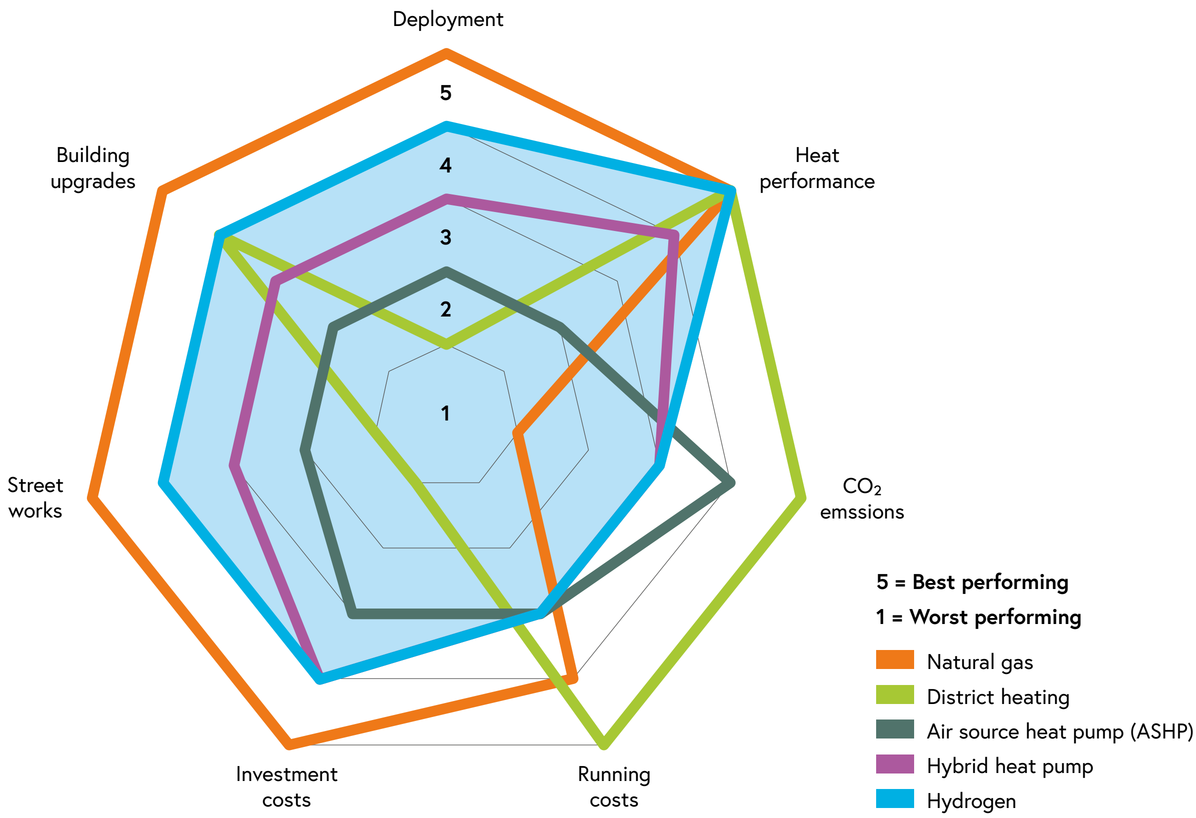
Hence at an infrastructure level, hydrogen offers the potential benefit of using much of the existing gas infrastructure. At a building level it offers similar benefits as it can use the existing building gas pipework (subject to inspection) and heating system (radiators, water pipework, controls), although today's gas appliances will need replacing. Industrial applications need to be investigated further for 100% hydrogen, but there would still be potential for blended operation, possibly with biomethane[24].

To illustrate the potential benefits of hydrogen, Figure 9 compares the primary heating technologies suitable for large-scale retrofit deployment to domestic buildings (referred to earlier) against several criteria (see page 14). The comparison is subjective and generalised. It is not meant to indicate that one form of heat technology is "better" overall another but solely to illustrate the different features of each technology and to highlight the potential benefits of hydrogen.

Natural gas is shown as a benchmark comparator and it performs the best against most criteria but, as expected, not against CO_2 emissions. Air source heat pumps (ASHP) perform poorly against most criteria but well against running costs and CO_2 emissions. District heating ranks well against heat performance, CO_2 emissions and running costs but badly against investment cost, street works, building upgrades and deployment. Overall, hydrogen performs comparatively well against several criteria and this is explained in Table 1 on page 16.

[22] ECUK (2018) Table 3.18. See www.gov.uk/government/statistics/energy-consumption-in-the-uk
[23] ECUK (2018). See www.gov.uk/government/statistics/energy-consumption-in-the-uk
[24] Element Energy and Jacobs (2018) Industrial Fuel Switching Market Engagement Study. See www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/764058/industrial-fuel-switching.pdf

Figure 9 – Comparison of natural gas and low-carbon heating technologies for large-scale retrofit deployment to domestic buildings



The criteria used are:

1. **CO_2 emissions**

   These are dependent on both the technology and the energy source. Hence for electric heat technology the CO_2 emissions associated with electricity production must beattributed. Heat pumps will have lower CO_2 emissions than resistive heating because of their higher efficiency, e.g. 270%[25] versus 100%.

2. **Heat performance**

   Gas heating is highly responsive to consumer and building needs as the technology and network infrastructure permits comparatively high capacity heat sources, e.g. domestic gas boilers rated at 20kWth to 30kWth, whereas for electricity heat output is limited to <15kWth using single-phase electricity heat pumps. The lower heat output may mean it takes longer for space heating to reach the occupants' desired temperature. Additionally, the heat output of air source heat pumps deteriorates with lower ambient temperatures, which is when more heat is demanded by the building. This may require supplementary heating or using hybrid heat pumps, which combine an electric heat pump with a natural gas boiler for "peaking" duty.

3. **Deployment**

   A programme of large-scale retrofits will need to cover ~30 million homes and businesses and be completed over the next 30 years. Depending on the technology the programme will require upstream investment in production assets, network assets and building upgrades. The challenge for deployment will be to mobilise the skills, resources, and manage a highly complex programme which can schedule the many activities required to be undertaken over the next 20 to 30 years, whilst minimising the disruption and cost to the public and businesses.

4. **Building upgrades**

   Replacing one form of heat technology with another, e.g. heat pump, hydrogen boiler, will inevitably require other associated work. This may include replacing gas hobs and gas fires with the equivalent electric versions, upgrading radiators to ensure effective operation with heat pumps, building energy efficiency improvements and replacement of existing gas pipework. Metering changes may also be required, i.e. heat metering for district heating, conversion metering from natural gas to lower CV hydrogen.

5. **Street works**

   These are associated with the infrastructure installed in streets with connections to homes and businesses. If this infrastructure needs to be reinforced to meet higher electricity demand or installed in the case of district or community heating, then the cost and disruption can be substantial, mainly as a result of the large number of buildings affected.

6. **Investment costs**

   These include the cost of the heat technology, building upgrades, and associated upstream infrastructure. For example, a heat pump is more expensive than resistive heating but there will be less associated infrastructure as the equivalent electricity capacity will be less.

7. **Running costs**

   These mainly comprise the fuel although there will other running costs, e.g. maintenance.

[25] A heat pump can achieve efficiencies above 100% as it absorbs low temperature heat from an external source such as air, ground, water (lakes, river, sea) and then upgrades the heat to a higher temperature so that it can be used for space heating. The process is similar to a fridge but in reverse.

Table 1 – Explanation for comparative performance of hydrogen with other technologies

Criteria	Performance	Explanation
CO_2 emissions	3	Production of hydrogen can either involve chemical processes which permit CO_2 to be sequestered – potentially achieving ~95% capture rates – or electrolysis powered by low-carbon technologies. However, even with high capture rates associated with chemical process there will also be greenhouse gas emissions from natural gas supply chains[26] (exploration, extraction, transport, storage) that need to be considered. Additionally, the efficiency of the chemical process will require more natural gas feedstock, thereby increasing CO_2 emissions. This also applies to electricity where hydrogen is used for power generation.
Heat performance	=5	Boilers can be engineered to operate on hydrogen with similar levels of heat output and thereby delivering comparable levels of heat performance to natural gas.
Deployment	4	Most of the existing "iron mains" gas network will have been replaced for safety reasons by 2030 with polyethylene pipework, which is deemed to be suitable for hydrogen. Hence much of the preparatory work that would be required for repurposing will have been completed. There remains a substantial programme of activity involving building and network upgrades as well as the construction of hydrogen with production and carbon capture, utilisation and storage (CCuS) facilities, but this should still be less than for electricity or district heating.
Building upgrades	4	Natural gas domestic boilers will need to be replaced but otherwise the existing hot water pipework, radiators and hot water storage can continue to be used. There is some uncertainty whether open-flame devices such as gas hobs and gas fires could be used, in which case these would also need to be replaced for other low-carbon heating technologies. All gas pipework would need to be tested and possibly replaced to ensure it can be safely used with hydrogen.
Street works	4	Much of the work associated with hydrogen would have been completed as part of the iron mains replacement programme[27] (IMRP), although there would still be investment required and works to be completed for local gas infrastructure.
Investment costs	4	The iron mains replacement programme would have funded a significant portion of the costs associated with hydrogen. There is scope to share in other infrastructure such as CCuS with power generation and other large industrial facilities, which will reduce the investment cost.
Running costs	=4	These will be higher than natural gas due to the losses associated with the chemical production of hydrogen from gas or from electrolysis powered by low-carbon technologies.

[26] Balcombe et al. (2018) The carbon credentials of hydrogen gas networks and supply chains. See www.sciencedirect.com/science/article/pii/S1364032118302983
[27] See www.hse.gov.uk/gas/supply/mainsreplacement/index.htm

Hydrogen production is a mature technology

Three main methods of hydrogen production are proven at scale: electrolysis, reformation of methane (gas) and partial oxidation of oil refinery residues. Electrolysers are commercially available up to 10MW and can be easily "stacked", plus there is a programme to design at scale, e.g. up to 100MW[28]. Steam methane reforming (SMR) is a well-proven technology and used throughout the world[29] but only one SMR plant has been fitted with CO_2 capture[30], which is essential for the technology to be described as low-carbon. However, autothermal reforming would permit higher levels of CO_2 capture with unit sizes of up to 1,250 t/day but there are no operating examples of this size and none with CCuS. There are several (smaller) autothermal reforming plants operating today but none which manufacture hydrogen for export. The final product is usually methanol or ammonium nitrate. Hydrogen production by partial oxidation of oil residues is also well proven but there is no experience with waste and biomass at commercial scale.

Although hydrogen production is a mature technology, the capacity required to meet current UK natural gas demand would necessitate a very substantial increase from present day levels of 29.3TWh pa[31] (~740kt pa), which is for industrial applications. The H21 North of England study[32] has a hydrogen demand projection of ~300TWh by 2050 which is equivalent to ~8Mt pa of hydrogen production. (Note: global hydrogen production in 2016 was ~55 Mt[33]).

The box on the right illustrates the amount of production plant required.

The scale of the investment required and the associated cost[40] of electrolysis including electricity production is likely to mean that hydrogen production will initially come from gas reforming. There is scope for this to change with improvements in electrolyser efficiency, developments in other methods of producing hydrogen[41] and imports. Electrolysers with hydrogen storage do have the potential to offer system flexibility[42] and could assist in reducing "spill" electricity from intermittent energy sources such as offshore wind turbines. This may help with reducing production costs, although it is likely to be no more than marginal.

Estimate of production infrastructure required to meet ~300TWh of hydrogen demand[34]

Electrolysis

Typical sizes for electrolysers are 10MW, although ITM Power has plans for a 100 MW "HGAS" unit[35], which would have a peak production 40,000kg/day with an electricity consumption of 60kWh/kg_{H2}. To produce 8Mt of "green" hydrogen, ~480TWh of low-carbon electricity production would be required. Assuming this was from wind (with a 40% load factor) would mean an installed electrolyser capacity of 140GW, i.e. 1,400 100MW electrolysers and supplied by wind capacity equivalent to 23 times that of Hornsea 1, 2, 3, and 4 (6GW)[36]. The electrolysers would have an estimated footprint of 1000ha (~1,500 football pitches) and a water consumption of 0.5litres/kWh, which would be equivalent to the annual consumption of ~1.2 million households[37].

Autothermal reforming

The largest single ATR plant currently operating converts a total of 165MMSCFD of natural gas to synthesis gas for onward processing at the Oryx plant owned by Qatar Petroleum and Sasol[38]. If such a plant were used for hydrogen production then it would produce ~360t/day, which is about ~5TWh pa. Hence ~60 units would be required to produce 300TWh of hydrogen. However, there is no fundamental issue with increasing the capacity with new larger designs to 1250t/day which would reduce the number required to ~20 units. The ATRs would have an estimated footprint of 220ha (~300 football pitches) and a water consumption of 0.12litres/kWh, which would be equivalent to the annual consumption of ~0.3 million households[39].

28 See www.itm-power.com/product/hgas
29 See www.h2tools.org/hyarc/hydrogen-production?f%5B0%5D=hydrogen_production_keywords%3A250
30 IEAGHG (2018) The Carbon Capture Project at Air Products' Port Arthur Hydrogen Production Facility. Available from www.ieaghg.org
31 Royal Society (2018) Options for producing low-carbon hydrogen at scale. See royalsociety.org/~/media/policy/projects/hydrogen-production/energy-briefing-green-hydrogen.pdf

Hydrogen experience is limited

Hydrogen experience is limited to industrial applications as there are no examples of networks supplying 100% hydrogen to homes and businesses in the UK or elsewhere. There is extensive experience in the UK and overseas of Town gas, which comprises up to 50% hydrogen, and this might be helpful in providing some reassurance to the public when explaining the conversion roll-out and programme. But in order to make a significant contribution to meeting the UK's greenhouse gas targets a programme of hydrogen infrastructure deployment would need to be implemented over the next 30 years and be of "sizeable" scale. This timescale is ambitious and contrasts with electricity and gas infrastructures, which have evolved incrementally over ~150 years. Any proposal to deploy hydrogen at scale will need to be sufficiently compelling to compensate for the lack of experience and the accelerated timescale. Hence it is important that the engineering risks and uncertainties are identified and comprehensively addressed before a programme of large-scale deployment is commenced.

[32] See www.northerngasnetworks.co.uk/event/h21-launches-national/
[33] Brown, Daryl. (2016). Hydrogen Supply and Demand: Past, Present, and Future. Gasworld.
[34] The estimate is solely to illustrate the scale of the production infrastructure required. Detailed engineering would need to take account of many other factors, e.g. storage, demand variability, spatial factors,
[35] See www.itm-power.com/product/hgas
[36] See www.orsted.co.uk/en/Generating-energy/Offshore-wind/Our-wind-farms
[37] Department for Business, Energy and Industrial Strategy (2018) Hydrogen supply chain evidence base.
[38] See www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base
See www.topsoe.com/sites/default/files/topsoe_synthesis_gas_technology.ashx__2.pdf
[39] Department for Business, Energy and Industrial Strategy (2018) Hydrogen supply chain evidence base.
See www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base
[40] Imperial College London (2018) Analysis of alternative UK heat decarbonisation pathways.
See www.theccc.org.uk/publication/analysis-of-alternative-uk-heat-decarbonisation-pathways
[41] The Royal Society (2018) Options for producing low-carbon hydrogen at scale. See www.royalsociety.org
[42] Imperial College London (2018) Analysis of alternative UK heat decarbonisation pathways.
See wwwtheccc.org.uk/publication/analysis-of-alternative-uk-heat-decarbonisation-pathways

4. What are the engineering risks and uncertainties?

Background and methodology

With the growing interest in hydrogen and in particular the repurposing of the existing low-pressure gas network from natural gas to pure hydrogen, a workshop was scheduled by the Institution of Engineering and Technology (IET). The objective was to identify and agree the key areas that would need to be addressed for the large-scale retrofit deployment of hydrogen to homes and businesses.

The format of the workshop was to have four sessions looking at the various aspects of hydrogen supply from production through to use. Attendance included representatives from industry, academia and government.

The workshop identified over 300 issues that covered:

- **Technical – includes planning, operations, engineering**
- **Greenhouse gas emissions – includes CO_2, methane, CCuS**
- **Security – includes energy security, dependency on imports, operational security**
- **Economics – includes all costs, pricing, volatility**
- **Regulation and policy**
- **Safety**
- **Time to deploy**
- **Public acceptability**
- **Skills**

A cross-professional engineering institution (PEI) group was subsequently established with membership from:

- **Institution of Chemical Engineers**
- **Institution of Mechanical Engineers**
- **Institution of Gas and Engineering Managers**
- **Institution of Engineering and Technology**
- **Health and Safety Laboratory**

The objectives of the Group were to:

- **provide independent engineering assurance to government (BEIS) and the public;**
- **review the 300 issues identified from the workshop and in particular the core questions that need to be addressed; and**
- **review proposals for addressing those core questions and identify any gaps.**

The Group reviewed the results of the workshop and core questions identified. These were subsequently revised and rationalised to 15 core questions. The revisions cover most of the same issues identified from the workshop but have been refined and updated because of subsequent developments[43].

[43] It should be noted that a number of these questions are already being addressed by some the activities currently underway and referred to above. However, the Group's view is that this does not negate the necessity of retaining the question.

Core questions

The following list the core questions which need to be addressed.

Question 1 – How do we ensure that the interdependencies of both hydrogen and CCuS infrastructures are recognised and each are developed in a coordinated manner?

In July 2018 the CCuS Cost Challenge Taskforce published its report[44]. It recognised the urgency of developing CCuS facilities to ensure that the technology can be deployed at scale during the 2030s. Also recognised is the potential to unlock the hydrogen economy, as well as greenhouse gas removal technologies such as bioenergy with carbon capture and storage (BECCS). If hydrogen is to be deployed at scale via the repurposing of the natural gas infrastructure then it is essential that hydrogen production is progressed in parallel with CCuS infrastructure. Ideally several smaller CCuS schemes would generate more "learning by doing" than a single large scheme and promote knowledge sharing between participants.

It is therefore vital that the development of both hydrogen and CCuS infrastructures are coordinated to support the deployment of hydrogen and the transition from natural gas.

Question 2 – Are there issues associated with hydrogen quality and safety that will prevent its use by specific technologies?

Hydrogen purity will need to be specified along with proposals for quality control and monitoring. This needs to take account of odorants and flame colourants required for safety reasons but also impurities that might arise from contamination after many years of operation with odorised natural gas. Limitations on the use of specific technologies should be identified, along with proposals for how they might be addressed, e.g. "point-of-use" scrubber to provide high-purity hydrogen for fuel cells.

Question 3 – What are the risks – perceived or otherwise – to public safety from a hydrogen energy system and how can these risks be managed to an acceptable level?

Hydrogen is different from natural gas but there are similarities with the risks associated with its use. It is important to understand how and why levels of risk may be different. These differences need to be evaluated and addressed, particularly in the context of repurposing the natural gas infrastructure for use with hydrogen within consumer premises. Risks may be categorised into those that are network related but within the public environment, and those that are beyond the meter and in consumer premises.
For example:

– **Network**

Pipework, fittings and other components and infrastructure that will be used to carry hydrogen and associated leak detection, including those for jointing, maintenance and repair. Amendments to emergency procedures, training for managers and operatives and on-site actions by first responders, etc. under emergency conditions.

– **Consumer premises**

Those associated with appliances, hydrogen ventilation requirements and hydrogen gas escapes within property and other confined spaces. The assessment needs to recognise that consumer premises present an uncontrolled environment where the risks associated with deliberate interference, poor maintenance or accidental damage are greater.

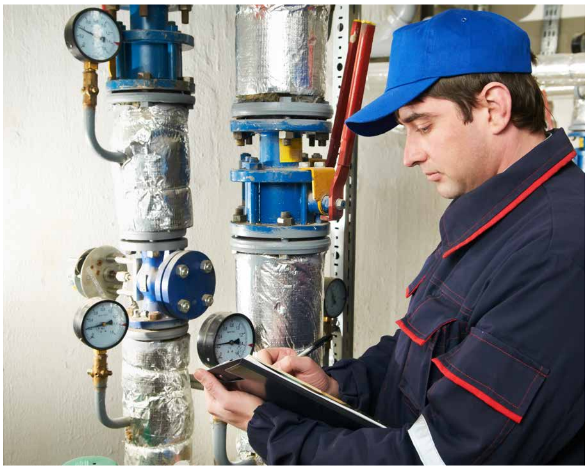
[44] See www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report

There are of course risks associated with hydrogen production, but this is within an industrial environment which is controlled and for which there is already considerable experience.

Question 4 – What needs to be done to convert a building's gas infrastructure (pipework, appliances, ventilation) for use with hydrogen?

Consumer premises present an uncontrolled environment which is largely undocumented with respect to gas infrastructure and appliances. For example, gas pipework in existing premises might comprise different materials (steel, copper) and not meet modern standards. Building ventilation requirements are also potentially different for hydrogen and other forms of detectors are needed for leakage. There are no standards for hydrogen infrastructure and its use within consumer premises and there is insufficient knowledge, resource and experience. If conversion to hydrogen requires replacement of all gas infrastructure and appliances the cost and transition consequences need to be identified and incorporated in any deployment programme.

However, the deployment of hydrogen also presents an opportunity to increase the safety of installations. For example, the removal of gas appliances deemed to be unsafe and the scope to upgrade pipework and other infrastructure thereby reducing the risk from carbon monoxide poisoning, i.e. the application of tamperproof devices and components.



Question 5 – What RD&D (research, development and demonstration) programmes are required to enable a decision to be made for the large-scale deployment of hydrogen?

Other than within industry there is no experience within the UK or elsewhere for the commercial or domestic use of hydrogen. Although there is considerable UK and global experience of hydrogen production and transmission, this is predominantly limited to oil refineries using partial oxidation of residues and other chemical industries using steam methane reforming processes. At present, most of the studies evaluating hydrogen systems are based on "desktop analyses" underpinned by cost, deployment and performance assumptions. The large-scale deployment of hydrogen will require the adoption of technologies for production, transmission, distribution, storage and consumption where there is either little or no experience. This will require a comprehensive research and development programme supplemented by deployment to evaluate the commercialisation of the various technologies.

Question 6 – What needs to be done to ensure that RD&D programmes are coordinated and made publicly available whilst respecting commercial interests? large-scale deployment of hydrogen?

A considerable programme of preparatory work is required before large-scale retrofit deployment of hydrogen can be initiated. These range from laboratory-based research through to pilot trials and will involve many organisations including academia, industry and government. Funding is essential to underpin this work and this needs to be properly co-ordinated and managed. In order to support the transition to hydrogen the timescales for these programmes will be very challenging and the risk of duplication or delays in publicising the results needs to be minimised. This may require a form of obligation on key participants to work and communicate cooperatively.

Question 7 – How might the public be affected by the transition to hydrogen? (Note: this should include deployment in and outside the home, technology, economics and performance).

Public support and acceptance will be critical to the deployment of hydrogen. Initial research[45] has identified that awareness of the need to reduce carbon emissions is relatively high but knowledge of hydrogen and other low-carbon heat technologies is low. Raising public awareness must be a priority for government and industry. A comprehensive assessment needs to be undertaken to understand the impact on domestic and commercial consumers arising from a transition to hydrogen. This needs to include:

- **the disruption arising from changes required within buildings, e.g. replacement of pipework and appliances, hydrogen leakage detection devices, ventilation**
- **changes within the home and customer acceptance/buy in**
- **disruption arising from local network changes, e.g. street works**
- **operational impact of changeover from natural gas to hydrogen**
- **performance of hydrogen heating relative to natural gas and other low-carbon options**
- **cost impact relative to natural gas and other low-carbon options.**

Question 8 – What are the core performance and cost assumptions associated with hydrogen infrastructure and what is the scope for future improvements?

The core performance and cost data associated with the deployment of a hydrogen system are largely based upon assumptions or based on data from industrial applications. Consequently, there are uncertainties associated with these assumptions which need to be identified and addressed. In particular, any that are critical to the deployment of hydrogen. For example, steam methane reforming with CCuS is limited to a single facility and there are presently no autothermal reforming (ATR) units with CCuS[46].

An example of the type of evidence that needs to be collected and reviewed regularly is included in BEIS' "Heat Technical Research" covering hydrogen for heat[47]. This can help identify key cost and performance uncertainties and where further research and investigation is required. Performance also includes the capability of hydrogen production plants to provide flexible support and the impact on other parameters such as efficiency. (Note: further R&D contracts are anticipated from BEIS under its Clean Growth initiative).

Partial substitution of hydrogen into the natural gas system (up to 20% hydrogen by volume) can provide a route to derive real-cost and performance data without incurring the costs associated with high-purity hydrogen, such as replacement of domestic appliances. This would still require a scalable commercial-sized hydrogen production facility along with CCuS infrastructure. Such an approach has been recommended by IGEM and IMechE already and is consistent with the UK Government's 2019 Spring Statement[48] to accelerate "the decarbonisation of our gas supplies by increasing the proportion of green gas in the grid".

[45] See www.theccc.org.uk/publication/public-acceptability-of-hydrogen-in-the-home-madano-and-element-energy
[46] It should be noted that the capture of CO_2 has no impact on the fundamental operation of the ATR plant.
[47] See www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base
[48] Spring Statement 2019: Written Ministerial Statement. See www.gov.uk/government/publications/spring-statement-2019-written-ministerial-statement

Question 9 – What is the environmental impact from the large-scale deployment of hydrogen to homes and businesses?

An environmental assessment needs to be undertaken to assess the impact arising from the large-scale deployment of hydrogen. Initial research[49,50] has been undertaken and further work identified, particularly with respect to upstream emissions. This needs to cover all aspects of the transition to hydrogen, from production through to consumption and include feedstock and waste streams. It also needs to include emissions from combustion such as NOx as well as water vapour and any risk to the environment from "unintended consequences" and, in particular, the carbon capture levels achievable from autothermal reforming and gas heated reforming technologies (ATR and GHR). The assessment should compare the impact from the large-scale deployment of hydrogen against the counterfactual scenarios, e.g. electric heating. (Note: even in the counterfactual scenarios hydrogen-powered generation is likely to have a prominent role[51]).

Question 10 – How would a transition to hydrogen be delivered?

The large-scale retrofit deployment of hydrogen has not been undertaken anywhere before and there are many uncertainties. Although comparisons with the deployment of natural gas in the 1970s are made, the dependence on Town gas was substantially less than today at 10% of total UK final energy consumption[52] compared to over 50% in 2017 (see Figure 4). The transition to hydrogen will present enormous challenges which may mean constraints on scheduling, e.g. outside the space heating season, in order to minimise the impact of a gas supply disruption to consumers.

A detailed programme of delivery needs to be developed that includes all the various activities that must be completed before a decision is made to commence the large-scale deployment (e.g. >10,000 households) of hydrogen. These must include:

- **research activities that need to be completed**
- **skills development and resource planning**
- **pilot trials within a controlled environment prior to small-scale deployment (<1,000 households) ramping up to medium-scale deployment (<10,000 households).**

The programme should then identify large towns and cities suitable for large-scale retrofit deployment. It will need to include planning, engineering design, liaising with local organisations, training, mobilisation of resources, public engagement, etc. as well as identifying the risks and mitigating action.

It is important that the programme can demonstrate that hydrogen is able to make a significant contribution to delivering the UK's 2050 greenhouse gas targets as well as the ongoing contribution that hydrogen can make on a longer time scale, e.g. 2080.

In the meantime, the potential for industry to switch to hydrogen needs to be investigated. Some industrial applications (e.g. steam raising and hot water boilers) appear suitable for conversion to 100% hydrogen using existing technology; other applications have challenges implicit in the process (e.g. brick kilns). There are also industries where a partial conversion to hydrogen may transpire to be the final solution (e.g. glassmaking) because of the different combustion characteristics of hydrogen from natural gas.

49 See www.gov.uk/government/publications/atmospheric-impacts-of-hydrogen-literature-review
50 See www.gov.uk/government/publications/hydrogen-for-heating-emissions-potential-literature-review
51 See www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy/
52 DECC (2009) "Digest of UK energy statistics (DUKES): 60th anniversary". See www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-60th-anniversary

Question 11 – What are the options for the bulk production of hydrogen?

The economic bulk production of low-carbon hydrogen is critical to the viability of a hydrogen-based energy system. Steam methane reforming (SMR)[53] has been used for nearly 100 years in industry. However, the extent to which carbon can be captured is limited to <90% and there is currently only one SMR plant globally with CCuS. The alternative thermochemical process for hydrogen production is autothermal reforming (ATR) but experience to export hydrogen is limited. ATR (possibly combined with Gas Heated Reforming - GHR) offers advantages over SMR and the technology should permit much higher levels of carbon capture, e.g. >95%. However, there are no operating ATR plants with CCuS and if this technology is to underpin the deployment of hydrogen then it needs to be proven and commercialised.

Other forms of hydrogen production include electrolytic, biological and solar, all of which are at various stages of development. At present none of these technologies can compete with natural gas for the commercialised bulk production of hydrogen. The potential for future development for these technologies and others needs further investigation.

The viability of importing hydrogen from countries with lower production costs also warrants investigation. For example, solar photo-voltaic generation costs are considerably lower when installed in locations with higher solar irradiation than the UK, e.g. the Middle East and Australia have solar irradiation levels two to three times that of the UK. However, hydrogen will need to be transported and there may be other additional costs such as water required for electrolysis.

An exercise to evaluate the range of options for the bulk production of hydrogen is required. These should include existing through to those at an early experimental stage but with a focus on the suitability for bulk production and economic viability.

Question 12 – Are there any actions that could be taken in advance of a decision on hydrogen that could expedite the transition?

The detailed programme for the deployment of hydrogen (see Question 10) will be helpful to identify "critical path" transition issues. From these the cost of pre-emptive action can be assessed. For example, the manufacture of gas appliances which are hydrogen-ready would reduce the need for replacement and ease the transition. Other action might include surveying buildings to assess the readiness for conversion to hydrogen and accelerating the replacement of "at-risk" iron mains pipework with polyethylene.

Surveys prior to conversion and post-conversion assessments are essential for a safe, reliable process. All of this must be underpinned by a series of increasing trials, from four small community trials to two larger community trials at, say, 5,000 people, then a small town. To gain learnings, an evidence base should be provided along with the development of any underpinning regulatory processes.

Consideration could be given to the partial replacement of natural gas with hydrogen as this would allow early experience to be gained without requiring many users to modify their appliances, e.g. with hydrogen production, CCuS, development of hydrogen infrastructure, industrial use of hydrogen/natural gas mixtures.

[53] "Options for producing low-carbon hydrogen at scale" RSC January 2018. See www.royalsociety.org/~/media/policy/projects/hydrogen-production/energy-briefing-greenhydrogen.pdf

Question 13 – Are there any implications for the role of bio-hydrogen particularly with respect to access to hydrogen and CCuS infrastructure?

Biomass and waste resources offer the prospects of a significant hydrogen production including the scope for negative carbon emissions. The location of production facilities is constrained by the access to feedstock, which would also require connections to hydrogen and CCuS infrastructures. This may limit the role for bio-hydrogen unless alternative arrangements can be considered to overcome these constraints. Waste is a limited resource and care should be taken not to "double account", as there are assumptions about the use of waste to provide "negative emissions" by producing electricity from waste. A similar argument may be applied to biomass.

Some industrial processes do not lend themselves readily to conversion to 100% hydrogen, but high-hydrogen mixtures are likely to prove viable. Ideally, the methane to which the hydrogen is added would be "carbon-neutral", and a holistic solution may well prove to be to convert bio-hydrogen to methane and utilise it in these processes. This would represent a more beneficial use of bio-hydrogen than simply to add it to the bulk supply.

Question 14 – In what industrial processes could hydrogen be used cost-effectively?

In 2017, 11% of total UK natural gas consumption was used by industry (see Figure 7), of which 6% was used for space and water heating, 3% for low temperature and 2% for high-temperature process applications (Figure 8). There are some applications where conversion to 100% hydrogen is not possible, e.g. brick kilns which may require a bio-SNG mix as a low-carbon solution. Hence, industrial processes which currently use natural gas or other fossil fuels need to be reviewed and the technical and economic viability of converting to hydrogen needs to be reviewed. (Note: the use of hydrogen for industrial processes is referred to extensively in the Energy Transitions Commission report[54]).

Two issues are perceived as being important to industry. One is how any increased cost in hydrogen production (compared to natural gas) or the effect of its implementation on the efficiency of the processes might affect the international competitiveness of the company vis-a-vis others who continue to burn natural gas. The other issue perceived by industry as being important is that of reliability. Because in all cases the hydrogen must be 'manufactured', it will need to be supplied with the same resilience as that offered by natural gas.

Question 15 – Can salt cavern storage of hydrogen meet the operational and economic requirements of a hydrogen network?

Bulk storage of hydrogen using salt caverns is likely to be essential for the economic production of hydrogen and to support system resilience. This will be particularly important to support seasonal variations in demand. The UK has many years' experience of hydrogen salt cavern storage but no experience of the duty cycle that would be associated with supporting hydrogen networks, e.g. fast cycle versus seasonal. Hence the prospective technical requirements and the duty cycle associated requirements of a hydrogen storage need to be evaluated and the technical capability of salt cavern storage assessed. The geographic dispersion of geological strata suitable for dissolution mining to produce salt caverns will not permit even coverage of this facility over the whole of the UK and this needs to be evaluated.

[54] "Mission possible - Reaching net-zero carbon emissions from harder-to-abate sectors by mid-century" Energy Transitions Commission November 2018. See www.energy-transitions.org/sites/default/files/ETC_MissionPossible_FullReport.pdf

5. What is the UK doing to investigate hydrogen?

In 2011 the Department of Energy and Climate Change published the UK's carbon plan[55] which set out how the UK will achieve decarbonisation and make the transition to a low-carbon economy. The plan reviewed current greenhouse gas emissions and presented proposals for reductions. It also identified that decisions would need to be made regarding the gas grid while acknowledging the benefits of using a gas grid that is already built. This subsequently triggered several reports (examples of which may be found here[56,57,58]) which discuss in detail future options for the gas grid. Additionally, there have also been a number of projects and investigations exploring repurposing the gas grid to hydrogen. The following lists and summarises the main projects undertaken in the UK. (Note: this is based on the descriptions provided by the projects themselves.)

1) HyDeploy and $HyDeploy_2$[59]

The HyDeploy project is the UK's first practical project to demonstrate if hydrogen can be safely blended into the natural gas distribution system at concentrations of up to 20% hydrogen by volume without requiring changes to the network components or downstream appliances, and so avoiding any associated disruption. The project has a number of objectives which include:

- **Evidence gathering (e.g. laboratory work, safety assessments, network appliance testing) in order to create the evidence base and demonstrate that, for the purpose of the proposed trial, hydrogen can be blended into the Keele university network at concentrations up to 20% by volume without disruption to customers and without prejudicing the safety of end users.**

- **Obtaining an exemption from the Health and Safety Executive to the current hydrogen limit within Gas Safety Management Regulations (GS(M)R)[60] in order to allow a ten-month trial to take place on a private gas distribution network at Keele University. The Exemption was granted in October 2018.**

Whilst stable combustion at above 20% hydrogen by volume has been demonstrated to be possible (an example is shown in Figure 10), the trial will limit blending to 20 vol%. It should be noted that all gas appliances sold in the UK are certified with reference gas G222[61] which contains 23% by volume of hydrogen.

The HyDeploy scientific work has considered appliances, gas detection, network procedures and the impact that the presence of hydrogen might have on the materials from which the Keele gas distribution network is constructed. The trial itself is due to start in the summer of 2019 and provide blended gas to 101 homes plus commercial buildings for ten months.

The £7.6m project is funded under Ofgem's[62] Network Innovation Competition and is a collaboration between Cadent Gas Ltd, Northern Gas Networks Ltd (NGN), Progressive Energy Ltd, Keele University, the Health & Safety Laboratory (HSL) and ITM Power. Cadent and NGN are the Gas Distribution Network co-funders and sponsors of the project.

55 HM Government (2011) "The Carbon Plan: Delivering our low carbon future" www.gov.uk/government/publications/the-carbon-plan-reducing-greenhouse-gas-emissions--2
56 Ofgem (2016) The Decarbonisation of Heat. See www.ofgem.gov.uk/system/files/docs/2016/11/ofgem_future_insights_programme_-_the_decarbonisation_of_heat.pdf
57 Houses of Parliament (2017) Decarbonising the Gas Network. See researchbriefings.parliament.uk/ResearchBriefing/Summary/POST-PN-0565
58 Policy Connect (2017) Next steps for the Gas Grid. See www.policyconnect.org.uk
59 hydeploy.co.uk
60 Gas Safety (Management) Regulations 1996
61 EN437 "Test Gasses – Test Pressures – Appliance Categories" 3 December 2002
62 Office of Gas and Electricity Markets

Figure 10 – Gas ring at 100 vol% methane (top) and 71.6 vol% methane and 28.4 vol% H_2 (bottom)

HyDeploy$_2$ is a £14m Network Innovation Competition-funded follow-on project to HyDeploy, starting in 2019, also co-funded by Cadent and NGN. The project seeks to extend the HyDeploy evidence base to demonstrate safe operation of a blended network containing 20 vol% in a non-disruptive manner to consumers on public networks, to support the pathway to national deployment of hydrogen blending.

2) HyNET NW[63]

The HyNET NW project will investigate two areas of the UK broadly described as the Mersey and Humber estuaries. It will consider their potential for blending hydrogen into the low-pressure gas network up to the point at which wholesale replacement of appliances could be avoided, which is likely to be around 20% hydrogen by volume (from the HyDeploy project). This level of blending maximises CO_2 reduction[64] with minimum inconvenience or cost to the customer. The work includes an examination of some of the major industries in the area and the scope for a higher level of blending with hydrogen with a modest investment.

Merseyside was identified as having the greater initial potential as there was a good level of industrial engagement, the industries were less scattered geographically, and the declining production from the Liverpool Bay oil and gas fields offered the potential for storing CO_2 (an inevitable by-product of hydrogen production using natural gas as a feedstock) on the right sort of timescale.

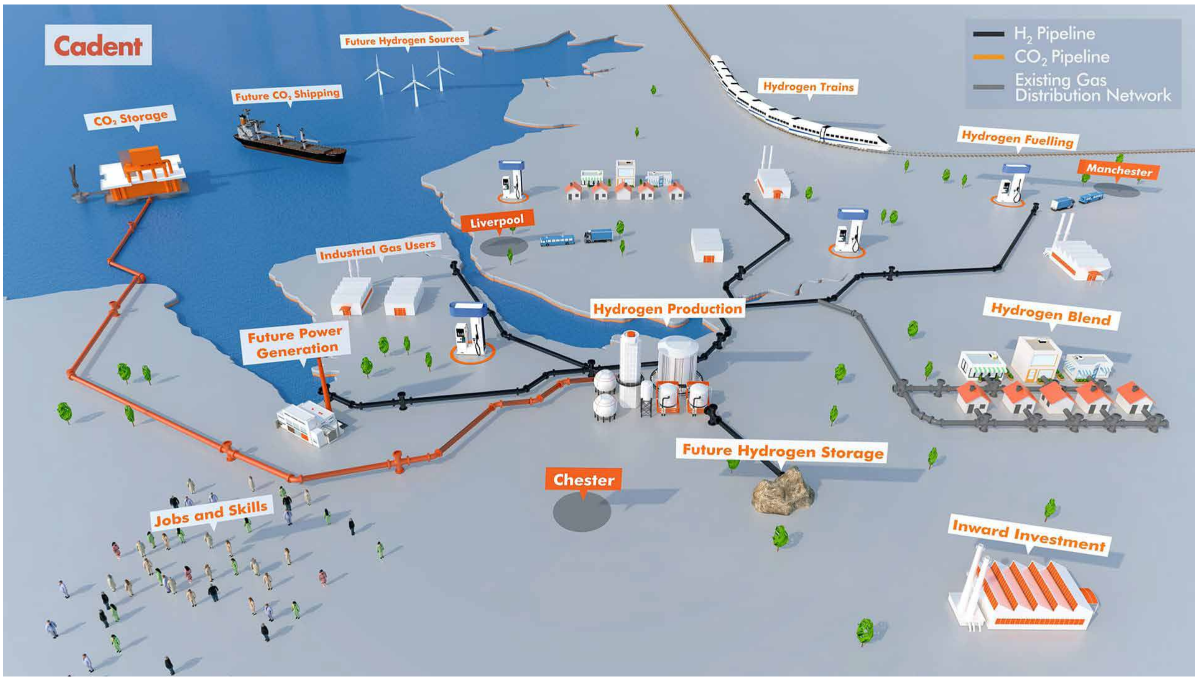
An important feature of the location was the level of industrial demand, which means that highly variable space heat demand can be managed by line pack within the blended hydrogen pipeline. This avoids expensive salt cavern storage which would otherwise be required.

Figure 11 shows the conceptual design. The presence of a hydrogen supply in the area opens up possibilities beyond the original concept, to include transport and power production. Additional synergies are also available from the presence of CO_2 storage infrastructure, with costs reduced by employing existing repurposed gas pipelines, offshore structures, wellheads etc.

HyNet NW identified autothermal reformation (ATR) of natural gas as the preferred hydrogen production method with several advantages compared to the more traditional Steam methane reforming (SMR). These include a higher carbon capture rate, better efficiency and smaller plant footprint.

63 Hynet.co.uk
64 Estimated at ~6% based on the ratio of the GCV of H2 to natural gas of 0.3

Figure 11 – HyNet NW project



Cadent subsequently commissioned the next phase of the work, which has now been completed. This went into further detail and identified a route forward, in terms of R&D, to develop burners or applications, pipeline design, hydrogen production technology and business case development. Some of these, such as setting a standard for the composition (quality) of the hydrogen, are to be covered by the Hy4Heat series. The attraction of blending hydrogen with natural gas is that it can be implemented almost immediately, requires no changes to appliances and could deliver a reduction in CO_2 emissions before 2026. It is also low risk because, if necessary, both domestic and industrial customers could revert to 100% natural gas operation at any time.

The project has been funded under several NIAs[65] and is a joint development between Cadent Gas Ltd and Progressive Energy Ltd, who are developing the project with further phases of work, e.g. type testing, further design work.

Both the HyNET NW and Aberdeen projects include a route to "kick start" the simultaneous development of both hydrogen and CCuS infrastructure at low cost because no changes are required to domestic appliances.

3) South Wales Hydrogen Study

Following the launch of the HyNet NW project, the Welsh Government, in consortium with others, including National Grid commissioned a study to investigate the feasibility of a similar project for South Wales comprising Port Talbot steelworks and the gas and oil industry cluster around the Milford Haven Waterway. This commenced by identifying the main CO_2 emitters in the area and examining the potential of each source for either conversion to hydrogen (in whole or in part) and/or coupling to a CCuS infrastructure, were one to be in place.

The two centres are expected to be the natural gas import terminals and oil refinery at Pembroke and the Port Talbot Steelworks, where processing of the blast furnace gas (BFG) and the off-gasses from the Basic Oxygen Steelmaking (BOS gas) could produce hydrogen and CO_2 for export and reduce the amount of gas that is currently being flared. This gas processing requires the transfer of technology from the petrochemical industry to steelmaking and offers the potential for lowest-cost hydrogen. There is no obvious and convenient location for CO_2 storage in South Wales and options for the disposal of the CO_2 are under consideration.

[65] Network Innovation Allowance

Having established hydrogen and CCuS infrastructure around these centres, there is potential to reduce South Wales' CO_2 emissions further by linking in to one or the other.

4) Hy4Heat[66]

The scope of Hy4Heat may include demonstrations on domestic, commercial and industrial appliances (including certification), hydrogen gas meters, as well as extending the safety assessments carried out for HyDeploy, and is scheduled until spring of 2021. The work will inform decisions on whether to proceed to a community trial, similar to that proposed in $HyDeploy_2$.

The Department for Business, Energy & Industrial Strategy appointed Arup as the named programme manager, with technical and industry specialists: Kiwa Gastec, Progressive Energy, Embers and Yo Energy. Contractors are being appointed to deliver a number of work packages aimed at establishing if it is technically possible, safe, and convenient to convert the existing low-pressure (<7bar) gas network to 100% hydrogen.

5) H21 Leeds City Gate Project[67]

The H21 Leeds City Gate project examined the technical and economic feasibility of converting the existing gas network in Leeds to 100% hydrogen. Hydrogen would be produced in Teesside and piped to a new ring main encircling Leeds, and included conversion of infrastructure and appliances in homes and businesses as well as the logistics of conversion from gas to hydrogen.

The study showed that the capacity of the gas network was adequate, that incremental conversion was possible with comparisons drawn with the transition of town gas to natural gas when over 40 million appliances were converted from 1967 to 1977 at a cost of £563 million[68]. A number of important conclusions were reached including:

- **Both the Medium Pressure (MP) and Low Pressure (LP) gas distribution networks have sufficient capacity to convert to 100% hydrogen with relatively minor upgrades.**
- **Hydrogen storage to manage diurnal demand swings is possible using existing (or repurposed) salt cavern storage on Teesside.**
- **Inter-seasonal storage would be in salt caverns on the East Humber coast (Figure 12).**
- **It is possible for the existing gas network to be segmented and converted from natural gas to hydrogen incrementally through the summer months over a three-year period with minimal disruption for customers during the conversion.**

The £266k project was funded under Ofgem's Network National Innovation Allowance and was a collaboration between Northern Gas Networks Ltd (NGN), Wales and West Utilities Ltd, Kiwa Ltd and Amec Foster Wheeler Ltd.

Figure 12 – H21 Leeds Citygate project

[66] www.hy4heat.info
[67] www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf
[68] "Why Hydrogen? The solution for real problems", Mark Crowther, Director, GASTEC at CRE, 29th Feb 2012

6) H21 NIC[69]

The aim of the H21 is to provide critical evidence to support the viability of converting the UK gas distribution networks to 100% hydrogen. It builds on the work of the 2016 H21 Leeds City Gate project, which established hydrogen conversion is technically possible and economically viable. The H21 NIC project will provide essential evidence to partner the Government's £25 million 'Downstream of the meter' hydrogen programme (Hy4Heat), which examines using hydrogen as a potential heat source in the home. Phase 1 comprises controlled testing and includes:

- **Hydrogen testing of key gas (mostly metallic) network components by the Health and Safety Laboratory in Buxton, Derbyshire.**
- **Hydrogen hazard testing under specified accident conditions by DNVGL Spadeadam's site in Cumbria.**

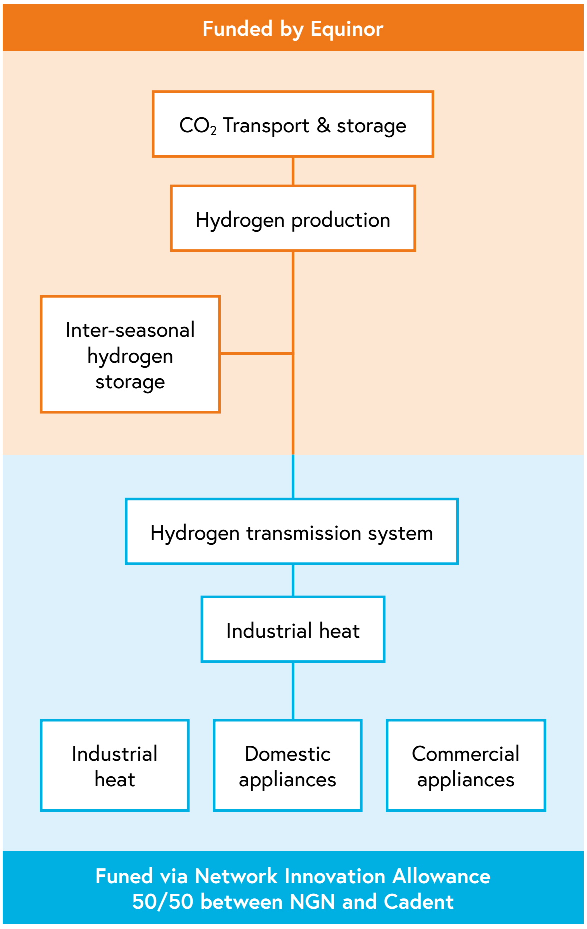
The £10.3 million three-year project started in April 2018 and is funded by Ofgem's National Innovation Competition. It is led by Northern Gas Networks Ltd in partnership with all gas distributors to deliver the evidence required to underpin a safety case for hydrogen.

7) H21 North of England[70]

The H21 North of England extends the H21 Leeds Citygate concept to cover an area north of a line between the Humber and the Mersey that includes Tyneside (Newcastle Gateshead), Teesside, York, Hull, West Yorkshire (Leeds, Bradford, Halifax, Huddersfield, Wakefield), Manchester, Liverpool and lays a foundation to roll out the concept to rest of the UK. It is a development of the H21 Leeds City Gate project into a detailed engineering solution for converting 3.7 million UK homes and businesses from gas to hydrogen.

Project development is by Cadent Gas Ltd and led by Northern Gas Networks Ltd in partnership with global energy company Equinor (Figure 13). The preferred hydrogen production technology is autothermal reforming (ATR) of gas, which would be based at Easington with Teesside as an alternative location. Salt cavern storage to manage inter-seasonal fluctuations in demand would be at Aldbrough and diurnal storage provided by line pack within the transmission pipelines.

Figure 13 – H21 North of England project

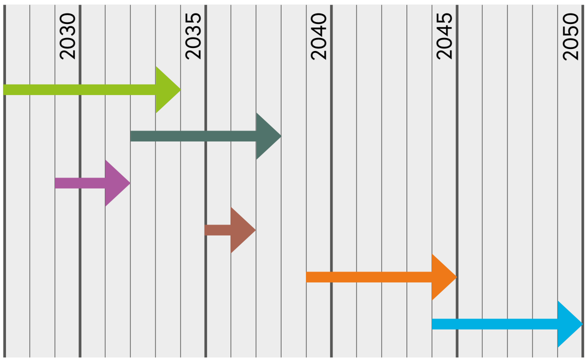


The project proposes conversion commencing in 2028, with expansion across 3.7 million properties in Leeds, Bradford, Wakefield, York, Huddersfield, Hull, Liverpool, Manchester, Teesside and Newcastle over the following seven years. A six-phase further rollout could see 12 million more homes across the rest of Great Britain converted to hydrogen by 2050 (Figure 14).

[69] See www.northerngasnetworks.co.uk/2017/11/30/ofgem-awards-9-million-innovation-funding-northern-gas-networks-pioneering-clean-energy-project-h21/
[70] See www.northerngasnetworks.co.uk/event/h21-launches-national/

The project is funded by Ofgem's Network Innovation Allowance for the gas network element, with Equinor funding the remaining work.

Figure 14 – Proposed rollout for hydrogen conversion for the majority of Great Britain



Area covered

- H21 North of England
- South Yorkshire, East/West Midlands
- Scotland
- South Wales and South West England
- East Anglia and the Home Counties
- London

8) Generating Hydrogen in Orkney[71]

The Generating Hydrogen in Orkney initiative (also called 'Surf 'n' Turf') is a project that utilises some of the renewable electricity in the area which is either surplus to demand, or greater than the ability of the transmission infrastructure to distribute it, i.e. 'spill energy'.

Electricity is generated on the nearby islands of Eday and Shapinsay by wind and tidal energy. When the generation exceeds local demand and/or the capacity to export it the 'spill energy' is used in electrolysers to produce hydrogen. This hydrogen is then stored as a high-pressure gas in tube trailers for transport to mainland Orkney, or elsewhere if the market justifies the transport costs. The electrolysers are of the proton exchange membrane (PEM) type and have a capacity of 1MW (Shapinsay) and 0.5MW (Eday), producing ~50 tonnes of hydrogen pa.

Located in Kirkwall there is a 75kW hydrogen fuel cell, which supplies a CHP scheme to several of the harbour buildings, a marina and three ferries (when docked) in Kirkwall. There is also a hydrogen refuelling station in Kirkwall, which services the five hydrogen fuel cell road vehicles operated by the Orkney Islands Council.

9) H100[72]

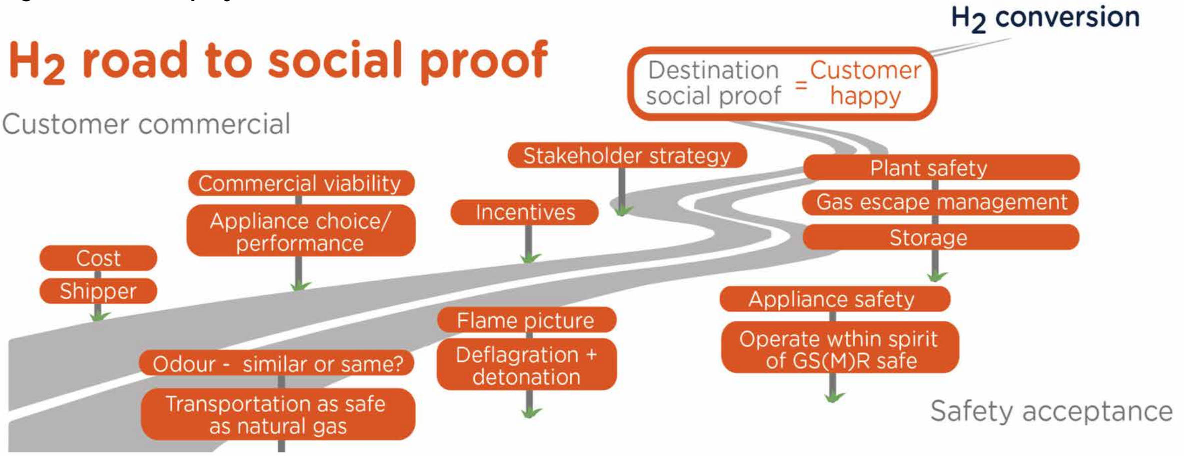
The objective of the Hydrogen 100 (H100) project is to demonstrate the safe, secure and reliable distribution of hydrogen. Described as the "H2 road to social proof" the project seeks to identify socio-economic and technical issues associated with a Southern Gas Networks (SGN) hydrogen feasibility study by developing and building an evidence base to satisfy customers and stakeholders. H100 covers all aspects of gas distribution that may be affected by the switch from gas to hydrogen (Figure 15).

The following activities are also taking place in support of the SGN feasibility programme:

- Technical assurance and programme overview for the safety case and compliance elements of H100.
- Stakeholder and customer strategy to enable seamless project delivery and to keep stakeholders fully informed.
- Safety case and operational procedures covering all relevant sections of GS(M)R and SGN procedures and standards for constructing and operating a hydrogen distribution network, as well as building a safety case and compliance framework to enable safe construction and operation.
- Testing polyethylene materials and jointing techniques to evaluate the effects of hydrogen on polyethylene pipe and fittings.
- Analysing the characteristics hydrogen when it escapes and tracks into properties, which will then be used to develop quantified risk assessments and procedures to support the emergency process.
- Examining the consequences of hydrogen ingress into property in terms of gas concentrations, movement, accumulation, ignition sources, energy required for ignition and the likelihood of ignition from common electrical appliances to the point of and including detonation.
- Assessing hydrogen logistics to give insight into the complexities of construction and the operational requirements for each site. H100 will also develop an estimation tool that can be used to baseline the hydrogen volumes required in terms of production,

[71] www.surfnturf.org.uk
[72] www.sgn.co.uk/Hydrogen-100/road-to-social-proof/

Figure 15 – H100 project



transportation, distribution and storage, and to estimate plant footprint before the feasibility and FEED (Front End Engineering Design) studies are commenced.

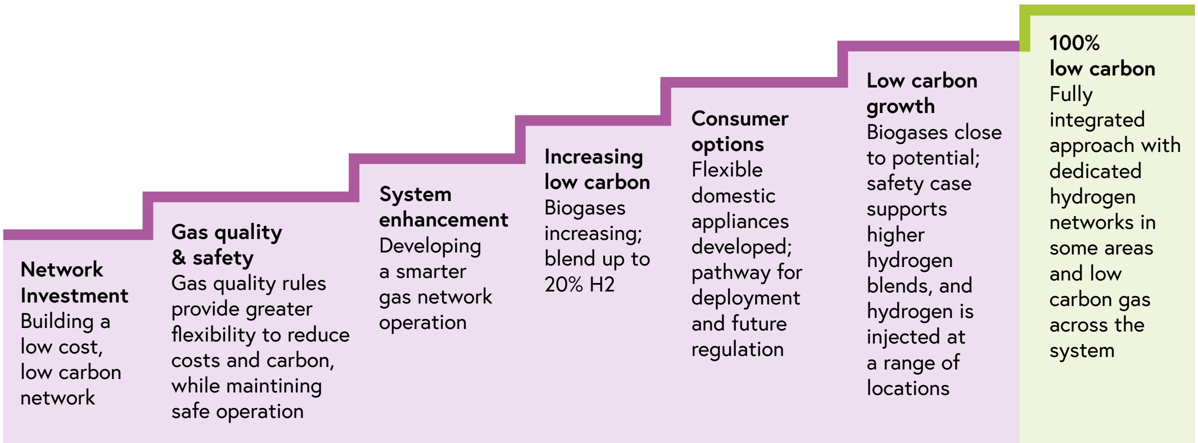
- Hydrogen metering to determine the suitability of existing UK natural gas meters for use with hydrogen.
- Odorant and gas detection will be tested and evaluated against SGN and industry standards for use with hydrogen gas. It will also choose gas instruments that will detect hydrogen and then test them against the current industry standards but for use with hydrogen.
- Appliance testing will comprise a long-term field trial and testing of 100% hydrogen appliances installed in buildings to ensure they remain safe and operate efficiently.

10) ENA hydrogen gas quality decarbonisation pathway[73]

This project will build on existing knowledge to set out and appraise the pathway for gas network decarbonisation, and build knowledge and understanding in several important areas (Figure 16). The project forms part of the key strategic objective to push the frontiers of the decarbonisation through a whole systems approach. It will also:

- support the development of policy and regulatory change around decarbonisation of gas networks to give a shared view of the pathways

Figure 16 – ENA hydrogen gas quality decarbonisation pathway

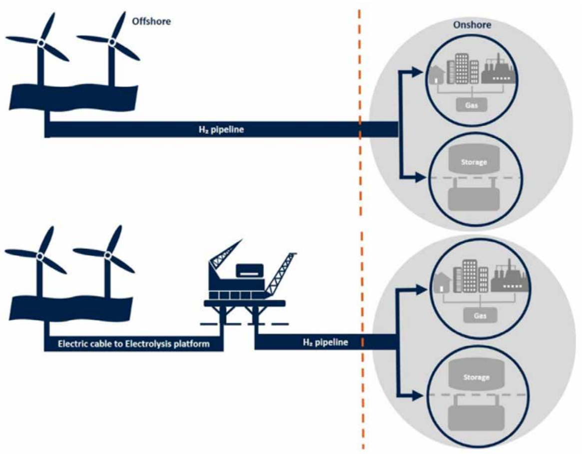


[73] See www.energynetworks.org/news/press-releases/2019/march/industry-experts-gather-to-kick-off-major-new-gas-grid-decarbonisation-project.html

– identify decision points for changes to the networks, and their operation in order to support decarbonised gas among the GB gas network licensees
– ensure that innovation and other activity to support decarbonisation is coordinated and that real options analysis is independently evaluated for policy and decision makers.

Stakeholders across the industry and governments will be engaged in the process to develop pathways and options for decarbonising gas, complementing existing and planned activity.

Figure 17 – HyGen



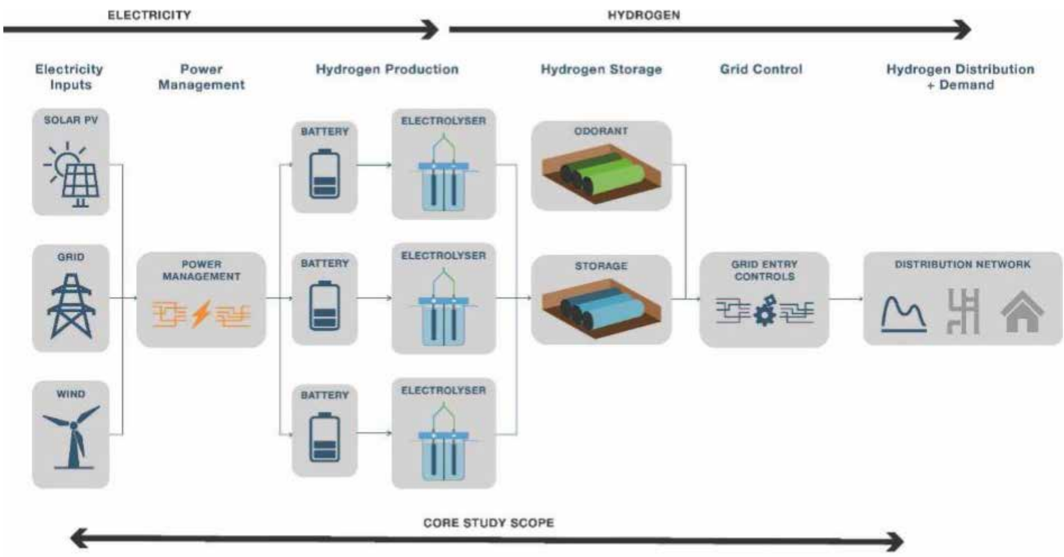
11) HyGen

HyGen is a feasibility study examining the local production and storage of hydrogen at three possible sites: Levenmouth in Fife, Aberdeen and Machrihanish in Campbelltown (Figure 17). This project will consider each site for the development of a 100% hydrogen infrastructure in the three locations and contemplate the scalability to the wider area. The study will examine the use of existing and or new facilities, the selection of the most likely suitable technology and a commercial evaluation of each site. All the sites are unique and the potential of each shall be ascertained in the project. The future scale up for use in transport and heat for each site will also be considered.

12) Methilltoune

Methilltoune is a feasibility study looking to deliver a first-of-its-kind hydrogen production demonstrator in Levenmouth, Fife. This includes a distribution network with storage to supply hydrogen to domestic properties for heating and cooking (Figure 18). The project aims to complete the construction and operation of a hydrogen energy system demonstrator in 2021, marrying this project with H100[74] to construct the entire end-to-end supply, distribution and end-use system. The demonstration will see public trialling of hydrogen for heating – the final step in proving hydrogen as a safe and acceptable method for the decarbonisation of heat.

Figure 18 – Methilltoune core study scope



[74] www.sgn.co.uk/Hydrogen-100/Road-to-Social-Proof

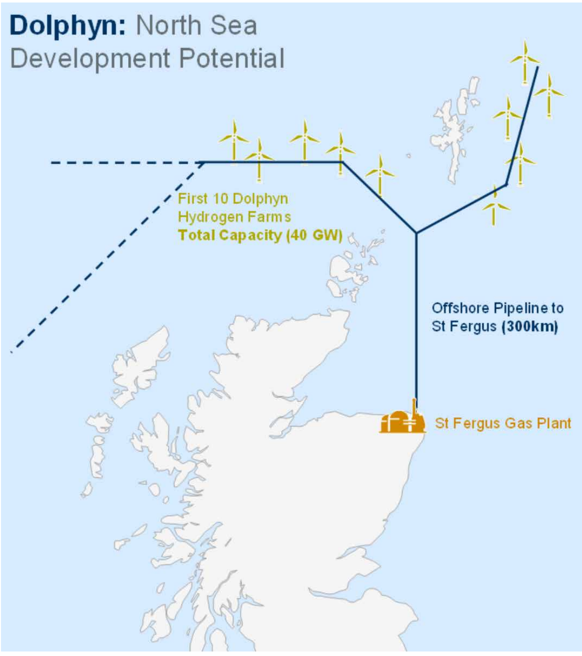
13) Dolphyn ERM Project

The Deepwater Offshore Local Production of Hydrogen (Dolphyn) project will consider large-scale retrofit hydrogen production from offshore floating wind turbines in deep water locations (Figure 19).

This is a partnership project led by ERM with Engie, Tractebel Engie and ODE. The project looks to utilise the vast UK offshore wind potential to power electrolysers to produce hydrogen from the water the turbines float on. Large 10MW turbines consisting of desalinisation technology and PEM electrolysers will feed hydrogen at pressure via a single flexible riser to a sub-sea manifold with other turbines' lines. The gas is then exported back to shore via a single trunkline. A 20-by-20 array array would have a 4GW capacity, producing sufficient hydrogen to heat more then 1.5 million homes.

This project may include the offshore wind supply of hydrogen supported with hydrogen from steam methane reformation with carbon capture technology. This project is well aligned to work the ACORN[75] project at St Fergus.

Figure 19 – Dolphyn ERM project



14) Aberdeen Vision and Cavendish

Pale Blue Dot Energy has received the first ever storage licence to capture and store carbon dioxide at the ACORN CO_2 storage facility. The vast quantity of vacant gas wells in the North Sea present the ideal opportunity to permanently store CO_2. This aligns with the UK Government's target to deploy carbon capture technology by the mid 2020s. The storage facility is likely to be used to CO_2 emissions from a SMR facility at St Fergus to produce low-carbon hydrogen (Figure 20).

Project Cavendish is a collaborative feasibility project between SGN, National Grid and Cadent, working with ARUP and Uniper Energy. The project will look at the production, storage and distribution of hydrogen from the Isle of Grain (Figure 21).

This project will consider SMR hydrogen production, CCuS storage in LNG tankers for transport to the carbon capture facility at ACORN. The project will look at blending up to 2% hydrogen by volume in the NTS, to be used with the Real-Time Networks Project[76]. The project will consider hydrogen use for Transport for London (TfL), and power generation in South London via retrofitting Greenwich power station for hydrogen combustion.

[75] See www.pale-blu.com/acorn/
[76] See www.sgn.co.uk/real-time-networks/

Figure 20 – Aberdeen Vision and ACORN facility

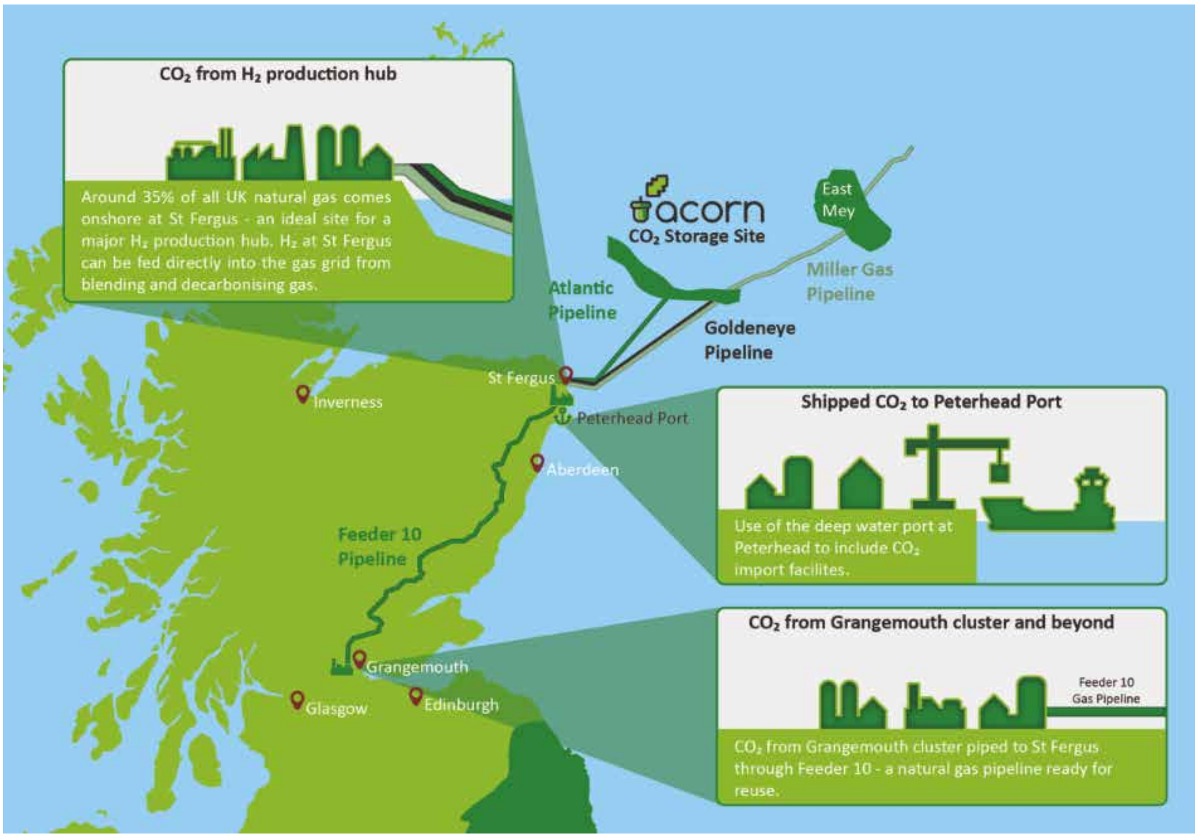


Figure 21 – Cavendish feasibility project

15) InTEGReL[77]

InTEGRel (Integrated Transport Electricity Gas Research Laboratory) is a fully integrated whole energy systems development and demonstration facility. This provides a space for industry, academia, SMEs and government to come together to explore and test new energy technologies, strategies and processes which bring transport, electricity and gas together in one place.

The £20m Centre for Energy Systems Integration (CESI) project aims to develop wide-scale, probabilistic modelling and simulation of integrated energy systems in sufficient detail and sophistication to meet the needs of the energy trilemma. The collaboration includes Northern Gas Networks, Newcastle University, Northern Powergrid, Northumbrian Water and Siemens. A key enabler for InTEGReL has been the EPSRC National Centre for Energy Systems Integration (CESI), which brings together the expertise of leading academics from the Universities of Newcastle, Heriot-Watt, Sussex, Edinburgh and Durham with a wide spectrum of industrial and governmental energy experts in a highly collaborative five-year research programme.

16) Feasibility for hydrogen in the NTS

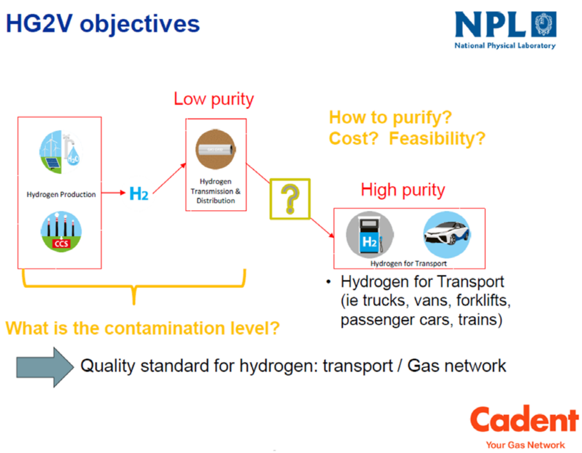
This is a technical feasibility study which is being delivered by the materials team at the Health & Safety Executive. The six-month study is evaluating the assets and materials on the National Transmission System (NTS) and highlighting any key concerns for hydrogen introduction at concentrations of 2, 20 and 100%. The study will cover aspects such as welding, coatings, leakage, hydrogen embrittlement mechanisms, hazardous areas and priority areas for further work. This study will be the foundation of the Health & Safety Executive's work exploring the capability of the NTS to transport hydrogen.

17) Hydrogen Grid to Vehicle Project

Hydrogen-powered vehicles use fuel cells that must be supplied by high-purity hydrogen (Figure 22). Grid-supplied hydrogen is likely to collect contaminants which will need to be removed prior to use in fuel cells and so the objective of this three-year project is to identify what needs to be done. The project is funded by Ofgem's National Innovation Award through Cadent and led by the National Physics Laboratory and comprises:

- Identification of impurities in the hydrogen supply
- Technology and landscape study
- Economic impact study
- National trial/Gas Network Simulator

Figure 22 – Hydrogen grid to vehicle project



[77] See www.ncl.ac.uk/cesi/research/demo/integrel/

18) Pre-normative Research into Safety of Liquid Hydrogen (PRESLHY)[78]

In its cryogenic liquid state hydrogen (LH2) has a much higher energy density than as a gas, and is the method of choice to store and transport large quantities in applications such as shipping and export of bulk renewable energy. Hence it offers advantages as an energy carrier with some intrinsic safety advantages for fuel cell-driven transport, e.g. trains, ships or car or truck fleets.

There is considerable industry experience in the safe handling of LH2 but little experience in the transport sector, which means new conditions and with untrained users. This European Commission-funded collaborative project, which started in January 2018, will investigate the respective knowledge gaps with a large experimental programme providing new validated models and engineering correlations for efficiently safe design and operation of innovative hydrogen solutions.

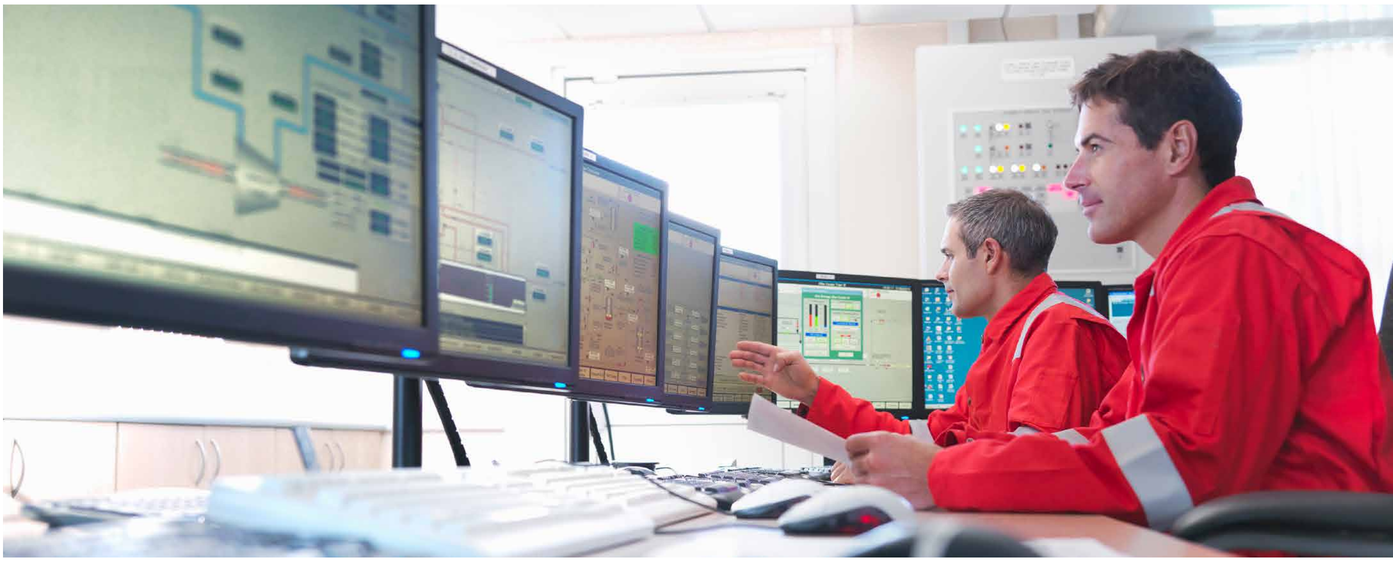
19) HyMotion

The HyMotion project is to develop a long-term strategy which sets out a pathway to deployment of hydrogen-related mobility infrastructure in the North West, and to identify technical solutions to enable network-delivered hydrogen for these applications. The focus is on road and rail, as these account for the vast majority of transport emissions in the area. The work also includes an analysis of opportunities in the marine transport sector.

Whilst the study area includes two major airports in Manchester and Liverpool, air travel is excluded from the analysis on the basis that hydrogen is unlikely to be a suitable aviation fuel.

The road transport aspect concentrates on buses and commercial (non-passenger) fleets, such as HGVs, LGVs and other smaller vehicles. The focus of the rail element is on lines which have not yet been electrified. The work is due for publication in June 2019.

Hydrogen supply is not covered; this is assumed to be available as a consequence of other initiatives, such as HyNET.



[78] See www.preslhy.eu
[79] SNG "Synthetic Natural Gas", is a of gas created from waste, bio- or fossil materials that serves as a substitute for natural gas and is suitable for inclusion in the natural gas infrastructure, e.g. having a composition and properties complying with GSMR.

20) Future Gas System Architecture (FGSA)

IGEM-funded FGSA project has been commissioned to comprehensively identify all the new and existing functions that the gas system will be required to perform between now and 2050 as it transitions to a low-carbon energy sector.

Evidence will be provided to justify the new functions that will be required, highlight the technical challenges associated with delivering those functions and consider necessary changes to the physical architecture of the gas system. It will also consider the impact of new and emerging technology and any risks that need to be managed in order to ensure the system continues to operate safely. The overarching goal is to provide a collective view of future functionality for the gas system, taking into consideration the system as it is today, current assumptions and working practices and the changing demands that are being placed upon it.

A consolidated vision of future functionality will be achieved by bringing together a wide range of stakeholders, including government, the regulator, academia, system operators, industry bodies and specialist experts. Representatives working with alternative systems such as electricity, waste and transport will also be engaged in order to understand the interactions between them and the gas system. In doing so, the project seeks to complement the Future Power System Architecture (FPSA) project delivered by BEIS, the Institution of Engineering and Technology (IET) and the Energy Systems Catapult (ESC), thereby moving to a more closely integrated GB energy system.

Taking a holistic approach, the project will consider the gas system from end to end. It will use systems engineering as core methodology, mirroring the FPSA project. This will enable insights gained through both projects to be compared and contrasted.

The outcomes of the project will describe robust, evidence-based conclusions and recommendations concerning the various transition pathways that could be adopted in order to achieve a low-carbon gas/energy system, along with guidance as to the timelines associated with successful delivery of each pathway.

Project contributions to core questions

The appendix lists the projects from Section 5 with a subjective judgement on the extent each core question is addressed by one or more of the projects. Those judged to be either partially or not addressed are shown in Table 2. It is recommended that action needs to be taken to ensure these questions are fully addressed.

Core question	Contribution to question from projects
1. How do we ensure that the interdependencies of both hydrogen and CCuS infrastructures are recognised and each are developed in a coordinated manner?	**Partial**
5. What RD&D programmes are required to enable a decision to be made for the large-scale deployment of hydrogen?	**Partial**
6. What needs to be done to ensure that RD&D programmes are coordinated and made publicly available whilst respecting commercial interests?	**None**
7. How might the public be affected by the transition to hydrogen?	**Partial**
8. What are the core performance and cost assumptions associated with hydrogen infrastructure and what is the scope for future improvements?	**Partial**
9. What is the environmental impact from the large-scale deployment of hydrogen to homes and businesses?	**None**
11. What are the options for the bulk production of hydrogen?	**Partial**
12. Are there any actions that could be taken in advance of a decision on hydrogen that could expedite the transition?	**Partial**
13. Are there any implications for the role of bio-hydrogen and the access to hydrogen and CCuS infrastructure?	**None**
14. In what industrial processes could hydrogen be used cost-effectively?	**Partial**
15. Can salt cavern storage of hydrogen meet the operational and economic requirements of a hydrogen network?	**Partial**

Table 2 – Core questions judged to be partially or not addressed by the projects summarised in Section 5.

6. Conclusions and recommendations

This report has focused on the engineering risks and uncertainties associated with the large-scale deployment of hydrogen to homes and businesses through the repurposing of the natural gas network. From an engineering perspective there is no reason why this cannot be achieved safely but there are several risks and uncertainties which need to be investigated. The industry is making good progress but there remain several areas yet to be addressed. It is important to emphasise that this report makes no judgement on whether or not hydrogen is desirable in terms of the economy, society and the environment.

However, it is recognised that any proposal to deploy hydrogen at scale will need to be sufficiently compelling to compensate for the lack of experience and the accelerated timescale. Hence it is important that the engineering risks and uncertainties identified are comprehensively addressed before a programme of large-scale deployment is commenced. In addition to the core questions listed in Section 4, the following key messages are made:

Progress CCuS infrastructure

Without the simultaneous deployment of a CCuS infrastructure hydrogen does not have a future for large-scale retrofit deployment to industry, homes and businesses. This is because in the immediate future the bulk production of hydrogen will require gas reforming technologies which produce large volumes of CO_2. Without a CCuS infrastructure hydrogen production will be dependent on electrolysis supplied from low-carbon sources such as renewable technologies with some production from biomass. This would constrain hydrogen to sectors of the transport market and specialist niche heat markets. In the longer term it may be possible for larger volumes of hydrogen to be produced from low-carbon sources but it is unlikely to be within a timescale to support a sizeable contribution to the UK meeting its 2050 greenhouse gas targets.

Deploy critical new technology

The large-scale deployment of hydrogen to homes and businesses will involve the introduction of new technologies for which there is limited experience. Projections of cost and performance are essential in the evaluation of such technologies but can never match actual deployment along with operational experience. Hence the concept of "learning by doing" is needed to ensure uncertainties can be evaluated and the risks minimised. Historical evidence for the time taken for energy supply and energy end use technologies to reach widespread deployment range from 20 to 70 years[80]. Compressing the deployment to 30 years will be challenging but can be helped through the identification and early deployment of critical new technologies. These would then need to be subjected to accelerated evaluation in terms of performance and costs prior to embarking on their next phase of development.

Prepare a transition programme

Fundamental to the deployment of hydrogen is a comprehensive and robust transition programme. This needs to include sufficient detail to ensure the identification of critical path items and their associated uncertainties. Assumptions will need to be underpinned by evidence and where evidence is not available then it will need to be sought. This will also be helpful in the identification of those assets or activities which need to be deployed early. Examples range from large assets such as reforming plants but might also include assets such as hydrogen-ready boiler appliances.

[80] Gross, R., Hanna, R., Gambhir, A., Heptonstall, P., & Speirs, J. (2018). How long does innovation and commercialisation in the energy sectors take? Historical case studies of the timescale from invention to widespread commercialisation in energy supply and end use technology. Energy Policy, 123(C), 682-699.

Domestic households present considerable uncertainties in terms of the work that needs to be done prior to conversion, particularly as they present an "uncontrolled" environment with the possibility of unsafe appliances and infrastructure that will need to be addressed. This was a feature of the more recent conversion on the Isle of Man from propane to natural gas[81], as well as the UK's conversion programme from Town gas to natural gas in the 1960s and 1970s[82]. There are lessons to be learnt from the UK's conversion programme in the 1960s. For example, a pilot scheme on Canvey Island was implemented with natural gas supplied from imported LNG to ~7,000 buildings prior to the main conversion programme. Public relations were a prominent and important feature of the programme and this is likely to be essential for the conversion to hydrogen. Hydrogen blending with natural gas may assist may assist in making consumers comfortable with the concept of hydrogen as a fuel gas and would provide some essential infrastructure on which to build a 100% hydrogen supply.

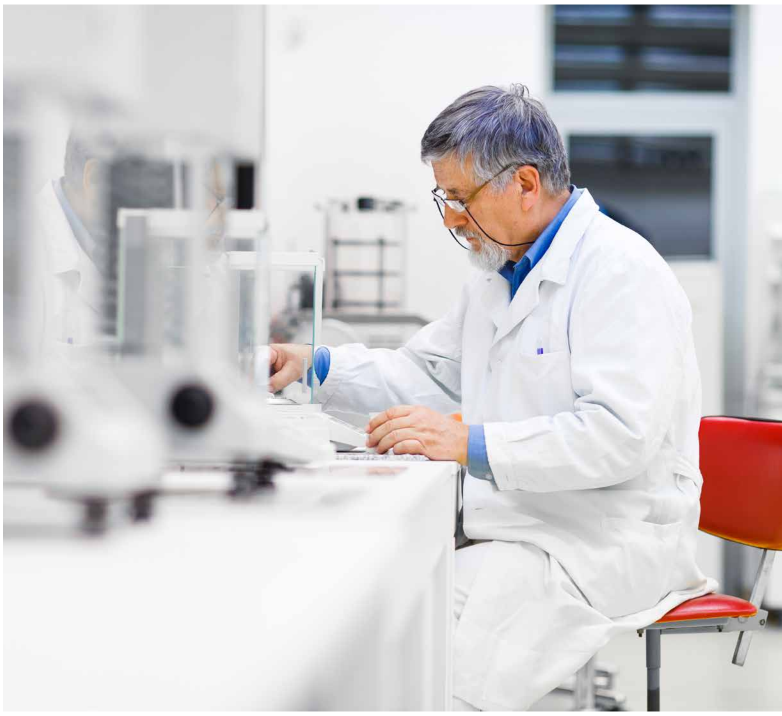
Develop skills and plan resources

Transitioning to hydrogen will require resources ranging from craft skills, technicians, planning and design engineers, academic and industrial researchers though to project management and customer-facing skills. Again this will require commitment from many different parties, e.g. gas industry, other industries, training organisations, academia, research establishments and engineering institutions.

Consideration should be given to creating a strategic partnership with industry to attract recruits from schools, colleges and universities. This may include specific incentives on regulated companies to implement a sustainable pipeline of skills required to meet the resource requirements of the energy transition.

Fund the programme

The transition programme will require substantial investment over many years. The H21 North of England study costed the capital investment at ~£23 billion with ~3.8million "meter points" (building) converted, i.e. ~£6k/building[83]. This will require commitment from many different parties and for such a commitment it is essential that a stable funding regime is assured and underpinned by central and local government policy in conjunction with Ofgem and other regulatory parties.



[81] Brookfield Infrastructure Partners L P. (2012). "Natural gas conversion in the 21st century." Available from www.igem.org.uk. Accessed in July 2015.
[82] Williams, T.I. (1981) A history of the British Gas Industry. Oxford University Press, Oxford. UK.
[83] See www.northerngasnetworks.co.uk/event/h21-launches-national/

7. Appendix – Project contributions to core questions

Full contribution
Partial contribution
No contribution

	HyDeploy and $HyDeploy_2$	HyNET NW	South Wales Hydrogen Study	Hy4Heat	H21 Leeds City Gate project
1. How do we ensure that the interdependencies of both hydrogen and CCuS infrastructures are recognised and each are developed in a coordinated manner?		Partial	Partial		Partial
2. Are there issues associated with hydrogen quality and safety that will prevent its use by specific technologies?				Full	
3. What are the risks – perceived or otherwise – to public safety from a hydrogen energy system and how can these risks be managed to an acceptable level?	Partial			Full	Partial
4. What needs to be done convert a building's gas infrastructure (pipework, appliances, ventilation) for use with hydrogen?				Full	Partial
5. What RD&D programmes are required to enable a decision to be made for the large-scale deployment of hydrogen?				Partial	
6. What needs to be done to ensure that RD&D programmes are coordinated and made publicly available whilst respecting commercial interests?					
7. How might the public be affected by the transition to hydrogen? (Note: this should include deployment in and outside the home, technology, economics and performance.)				Partial	Partial
8. What are the core performance and cost assumptions associated with hydrogen infrastructure and what is the scope for future improvements?					Partial
9. What is the environmental impact from the large-scale deployment of hydrogen to homes and businesses?					
10. How would a transition to hydrogen be delivered?				Partial	Partial
11. What are the options for the bulk production of hydrogen?		Partial			
12. Are there any actions that could be taken in advance of a decision on hydrogen that could expedite the transition?	Partial				
13. What are the implications for the role of bio-hydrogen and the access to hydrogen and CCuS infrastructure?					
14. In what industrial processes could hydrogen be used cost-effectively?			Partial	Full	
15. Can salt cavern storage of hydrogen meet the operational and economic requirements of a hydrogen network?					

H21 NIC	H21 North of England	Generating Hydrogen in Orkney	H100	ENA hydrogen gas quality decarbonisation pathway	HyGen	Methilltoune	Dolphyn ERM project	Aberdeen Vision and Cavendish	InTERGel	Feasibility for hydrogen in the NTS	Hydrogen Grid to Vehicle Project (HG2V)	Prenormative Research into the Saftey of Liquid Hyrdogen	HyMotion	Future Gas System Architecture (FGSA)

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