Available online at www.sciencedirect.com

SciVerse ScienceDirect

journal homepage: www.elsevier.com/locate/he

Conversion of the UK gas system to transport hydrogen☆

Paul E. Dodds [a,*], *Stéphanie Demoullin* [b]

[a] UCL Energy Institute, 14 Upper Woburn Place, London WC1H 0NN, UK
[b] Department of Civil, Environmental and Geomatic Engineering, University College London, London, UK

ARTICLE INFO

Article history:
Received 16 January 2013
Received in revised form
2 March 2013
Accepted 6 March 2013
Available online 9 May 2013

Keywords:
Natural gas conversion
UK MARKAL
Energy system model
Hydrogen networks
Gas decarbonisation

ABSTRACT

One option to decarbonise residential heat in the UK is to convert the existing natural gas networks to deliver hydrogen. We review the technical feasibility of this option using semi-structured interviews underpinned by a literature review and we assess the potential economic benefits using the UK MARKAL energy systems model. We conclude that hydrogen can be transported safely in the low-pressure pipes but we identify concerns over the reduced capacity of the system and the much lower linepack storage compared to natural gas. New hydrogen meters and sensors would have to be fitted to every building in a hydrogen conversion program and appliances would have to be converted unless the government was to legislate to make them hydrogen-ready in advance.

Converting the gas networks to hydrogen is a lower-cost residential decarbonisation pathway for the UK than those identified previously. The cost-optimal share of hydrogen is sensitive to the conversion cost and to variations in the capital costs of heat pumps and micro-CHP fuel cells. With such small cost differentials between technologies, the decision to convert the networks will also depend on non-economic factors including the relative performance of technologies and the willingness of the government to organise a conversion program.

Copyright © 2013, The Authors. Published by Elsevier Ltd. All rights reserved.

1. Introduction

Most UK buildings are currently heated by boilers using natural gas transported by extensive transmission and distribution networks that service 84% of UK households. In 2010, UK households emitted 85 $MtCO_2$ by direct combustion of natural gas for heat and another 0.2 Mt of methane escaped from the gas networks [1]. Several studies [2,3] have concluded that these emissions must reduce in the future if the UK is to reduce greenhouse gas emissions in 2050 by 80% relative to 1990 levels, as mandated by the UK parliament [4].

Electric heating, particularly using heat pumps, is increasingly identified as a low-carbon alternative to natural gas [5–7]. This has provoked a number of studies funding by the gas industry to identify scenarios in which the gas networks continue to have a role in a low-carbon economy [8–10]. Yet one option not considered by these studies is to decarbonise the gas supply by delivering hydrogen rather than natural gas to homes through the existing gas networks. The UK government mentions this option in the heat strategy framework that it published in March 2012 [11] but notes that there are many uncertainties about this strategy.

Dodds and McDowall [12] take a first step towards assessing the potential benefits of hydrogen conversion by showing that it would be part of the cost-optimal decarbonisation pathway for the UK if conversion could be achieved at zero cost. In this paper, we greatly expand on this exploratory work by assessing the costs of a conversion program and

☆ This is an open-access article distributed under the terms of the Creative Commons Attribution License, which permits unrestricted use, distribution, and reproduction in any medium, provided the original author and source are credited.

* *Corresponding author*. Tel.: +44 (0)203 108 9071.
E-mail addresses: p.dodds@ucl.ac.uk, pedodds@hotmail.com (P.E. Dodds).

0360-3199/$ – see front matter Copyright © 2013, The Authors. Published by Elsevier Ltd. All rights reserved.
http://dx.doi.org/10.1016/j.ijhydene.2013.03.070

identifying technical issues surrounding conversion. We make a first assessment of the technical feasibility of transporting hydrogen in the gas networks in Section 2 and we make a first estimate of the costs of conversion in Section 3. This enables us to make a much more authoritative assessment of the economic benefits to the UK in Section 4.

2. Technical feasibility of transporting hydrogen using the gas networks

Transporting hydrogen using the gas networks is not a novel activity. Until around 1970, 'town' gas rather than natural gas was delivered by the gas networks. Town gas was manufactured from coal and contained a mix of hydrogen, carbon monoxide, methane and other gases [13]. In the 1960s, large deposits of natural gas were discovered under the North Sea and the UK Gas Council decided to switch the entire country from manufactured town gas to natural gas in a national program over a 10 year period [14]. New high-pressure transmission and distribution pipeline networks were built but the low-pressure pipes were mostly unchanged. In this section, we consider the technical feasibility and issues of a second national conversion program to transport 100% hydrogen in the gas networks.

2.1. Methodology

We assessed the technical feasibility of transporting hydrogen in the gas network through semi-structured interviews with 14 experts from industry, academia and government, underpinned by a literature review. These experts were chosen to examine both the feasibility of transporting hydrogen and the costs and complexity of converting the network. Table 1 summarises the interviewees; since some requested anonymity, we have grouped our findings by sector throughout this paper. We were particularly interested in experts who understood hydrogen behaviour, safety systems and other technological challenges, those with knowledge of the specifications and operational requirements of the natural gas network, and those with experience of using hydrogen for energy purposes (whether for existing industrial plants or demonstration projects for new technologies).

Our aim was to address the following broad questions:

Table 1 – Summary of interviewee backgrounds and expertise.

Sector	Number	Backgrounds
Government	3	Hydrogen policy, experience of deployment and safety
Industry	7	Directors, managers and engineers in companies producing and supplying natural gas, industrial chemicals and infrastructure products
Academia	4	Safety, gas pipes, fuel cells and the economics of hydrogen

- Will hydrogen transportation adversely affects pipeline integrity?
- Is hydrogen a safe energy carrier for use in homes?
- Can the existing gas networks deliver sufficient energy in the form of hydrogen to meet demand?
- Can end-user appliances perform correctly and safely using hydrogen?
- Would the conversion process be similar to the previous conversion from town gas to natural gas or are there additional factors that must be considered?

2.2. Pipeline integrity

Natural gas is transported to customers throughout the UK by numerous interconnected pipeline networks. A national transmission network supplies high-pressure gas from import terminals to 13 regional distribution networks [15,16]. The gas pressure is gradually lowered in each of these networks by pressure reduction stations until delivery from the low-pressure distribution network to buildings via millions of short service pipes. Pipes in different parts of the networks are constructed of different materials, with the variations mainly reflecting the operating pressure and age of the pipes. Table 2 summarises the characteristics of each part of the network. The suitability of pipes for transporting hydrogen depends on a number of factors including the material, operating pressure, age and overall condition [17].

2.2.1. High-pressure transmission and distribution pipes

At ambient temperature and pressures below 100 bar, the principal integrity concern for high-strength steel is hydrogen embrittlement. Hydrogen will diffuse into any surface flaws that occur due to material defects, construction defects or corrosion, resulting in a loss of ductility, increased crack growth or initiation of new cracks. These will ultimately lead to material failure [20–23]. Higher pressures are thought to increase the likelihood of material failure although no threshold value has been defined independently of other factors [24–26]. Hydrogen can be transported at high pressures using pipes constructed of softer steels that reduce the rate of embrittlement, and there is much industrial experience in this area spanning many decades [27]. This means that existing high-pressure natural gas pipelines are not suitable for hydrogen transport, but that a new national network of high-pressure pipelines could be constructed to transport hydrogen around the UK.

2.2.2. Lower-pressure distribution and service pipes

Steel and iron pipes, which were used prior to 1970, are susceptible to embrittlement if the hydrogen gas pressure is high enough. There is uncertainty about the threshold pressure below which the pipes can be safely used with hydrogen [21,26]; it will almost certainly vary according to the type of steel or iron, as well as the pipeline microstructure, stress history and the type of welding used [24]. Conversely, the integrity of polyethylene pipelines, which have been used since 1970, should not be affected by the use of hydrogen [28,29]. An "Iron Mains Replacement Programme" is currently underway which aims to replace all of the low-pressure iron distribution pipes near buildings with polyethylene pipes for

Table 2 – Characteristics of the UK natural gas networks. High-density (HD) and medium-density (MD) polyethylene pipes are used in the distribution networks. The lengths of each type of pipeline in 2010 are estimated from Transco [18] in Dodds and McDowall [12], Dodds and McDowall [19].

Network/pipe	Network component	Pressure (bar)	Material		Length (km)
			Pre-1970	Post-1970	
Transmission	Transmission	70–94	High-strength steel		7600
Distribution	High pressure	7–30	High-strength steel		12,000
	Intermediate pressure	2–7	Steel	HD polyethylene	5000
	Medium pressure	0.075–2	Iron	MD polyethylene	30,000
	Low pressure	<0.075	Iron	MD polyethylene	233,000
Service	Building connections	<0.075	Copper	MD polyethylene	255,000

safety reasons by the mid-2030s [30]. Once this is completed, few iron pipes will remain within the distribution networks [19]. The UK government might be able to prepare at least part of the network to transport hydrogen if were to make subtle adjustments to this program.

Polyethylene pipes are more porous to hydrogen than natural gas so the quantity of gas escaping through the pipeline walls would be higher following conversion [29,31,32]. Although leak-tight pipes transporting nitrogen have been found to leak profusely when transporting hydrogen, some EU-focused studies conclude that leakage from gas networks with hydrogen is likely to be small enough to not present a safety hazard [22,33]. Calculations have suggested volumetric hydrogen leakage of less than 0.001% of the total annual transported volume [17], although this figure would have to be assessed for the UK gas network. Such small leakage rates would have negligible economic consequences, particularly because hydrogen energetic losses are generally smaller than natural gas energetic losses.

Hydrogen leakage from the connections between polyethylene pipes is another potential safety hazard if the hydrogen can accumulate to flammable concentrations [21,26]. New sources of escaped hydrogen could arise from seals proven tight for natural gas [32,34,35] but the importance of this phenomenon for the UK gas network is uncertain.

2.2.3. *Compressor and pressure reduction stations*

Compressors are generally only used on the high-pressure networks. Pressure reduction stations are used on all types of network.

Piston and centrifugal compressors are most commonly used in the gas networks. The type of gas does not affect piston compressors but centrifugal compressor operation depends on the gas volume and the higher volumetric flow rate of hydrogen would be an issue: either the rotational velocity would have to be increased, potentially raising material integrity concerns, or a higher number of compression stages would be required [17,21]. Since a new hydrogen transmission network would need to be built, further examination of compressors is not necessary.

Pressure-reduction stations are used extensively in the distribution networks. Natural gas cools upon expansion (the Joule–Thomson effect) but opposite occurs for hydrogen, so there is some uncertainty about whether intermediate cooling would be necessary following conversion [17]. The temperature rise is likely to be negligible, however, given the small pressure differences within the distribution networks. A small amount of remedial work might be required to transmit hydrogen using existing pressure-reduction stations; for example, one of our interviewees identified leakage from old compressor reduction stations as a potential issue.

2.2.4. *Hydrogen meters*

Natural gas consumption in the UK is measured in each property using a flow meter. Hydrogen has different flow properties and a different volumetric energy content to natural gas so the existing flow meters are not considered suitable for measuring hydrogen consumption [17,21,36]. A number of hydrogen-specific meters are available but our interviewees' highlighted reliability and accuracy issues from demonstration projects. They believe that further development is required to produce hydrogen meters that operate sufficiently well for households.

2.3. *Safety of hydrogen use in buildings*

The physical and chemical properties of hydrogen are well understood and safety standards are in place for industrial processes. Yet there is very limited knowledge of the risks associated with hydrogen as a consumer fuel in residential and service sector buildings [37,38].

Three main factors determine the hazardous potential of hydrogen leakage into a building:

1. the level of confinement and consequently the risk of gaseous accumulation;
2. the ability to detect hydrogen, both prior to ignition to initiate dispersion and once ignited to avoid injuries; and,
3. the tolerability of hydrogen ignition and explosion relative to the safety record of natural gas.

2.3.1. *Level of confinement*

Rooms within a building or wall partitions enclosing pipes represent confined spaces, but confined spaces can also be created by air currents, open doors and obstructions that enable hydrogen build-up to ignition concentrations.

The duration over which a flammable concentration of hydrogen is present in a confined domestic room is longer than for natural gas, as the higher volumetric release rate of hydrogen relative to natural gas tends to be larger than the increased dissipation rate due to the higher buoyancy of hydrogen in air [34,39]. It is therefore likely that the overall risk of gas ignition is higher for hydrogen than for natural gas in domestic and service buildings [39]. Existing hydrogen safety precautions largely bypass confinement issues by recommending outdoor installation of hydrogen technologies or requiring “preventive” detection and ventilation for indoor applications [35]. Outdoor installation is possible for fuel cells, but other potential uses of hydrogen (e.g. boilers or cooking) require indoor piping and use, and hence an understanding of hydrogen build-up and its diffusion properties in an unpredictable non-controlled environment.

2.3.2. *Ability to detect hydrogen*

As hydrogen is odourless, colourless and burns with an invisible flame, it is necessary to add impurities for humans to detect hydrogen leakages [32,34,40]. Mercaptans are added as odorants to natural gas but would cause sulphur poisoning in fuel cells if used with hydrogen. It might be possible to develop alternative odorants for hydrogen, although it would be necessary to show that no odorant separation would occur under any conditions [41,42]. No widely-used odorant currently exists for hydrogen but there is active research into this issue.

Of greater concern is the detection of ignited hydrogen by human senses, as there is no soot or smoke emissions [32,34,40]. There is little research in this area at present and it will be necessary for the UK Health and Safety Executive to examine the feasibility, desirability and obligation for flame detection at the end-user interface.

2.3.3. *Tolerability of hydrogen ignition*

The likelihood of a hydrogen explosion and the severity of deflagration or detonation (including the damage caused to humans and property, the duration of the hazard, the likelihood of transitioning a detonation and the ease of extinction) vary according to the level of confinement and subsequent risk of accumulation. As with natural gas, the ignition conditions necessary to ignite a flammable mixture are easily met in a household environment, for example from electrical sparks [32,40]. Hydrogen has lower heat emissivity and burns more rapidly than natural gas. The overall level and tolerability of this risk is determined by the combined effect of these factors [34,40,43].

2.3.4. *Public acceptance of hydrogen safety*

As well as understanding and minimising the risk of hydrogen ignition, it would be necessary to communicate and demonstrate the safety of hydrogen use (relative to natural gas) to the general population. During the transition from town gas to natural gas, there was scepticism from some members of the public about the safety of natural gas, despite the conversion achieving a large reduction in the number of gas poisoning incidents [14]. Hydrogen similarly offers some advantages over natural gas, notably that carbon monoxide poisoning is no longer an issue. Some academic work has laid the groundwork for engaging the public on hydrogen-related issues through surveys and small-scale communication events [38,44]. Public perception was highlighted as a key concern by gas industry interviewees but was not considered important by other interviewees with practical experience of using hydrogen for consumer applications (e.g. transport).

2.4. *Energy delivery and energy storage capacity of the network*

The energy carrying capacity of hydrogen is about 20–30% less for a pipeline of the same pipe diameter and pressure drop than for natural gas [17,45], despite the much lower volumetric energy density of hydrogen being offset by a much higher flow rate. This means that the hydrogen energy transmission capacity at an unchanged pressure is approximately 20% lower than the UK annual average calorific value of 39.5 MJ/m^3 for natural gas [46]. Gas demand per household is likely to change in the future; households choosing fuel cell micro-CHP rather than hydrogen boilers would increase their energy consumption by 25% (for electricity generation) compared to present, but this could be offset by fitting energy conservation measures. An engineering appraisal is required to understand the extent to which the networks would require reinforcement in order to transport sufficient hydrogen to meet demand.

Peak gas demands are currently met by using the current pipe network as a short-term storage reservoir. The volume of gas maintained in a pipeline network during normal operation is commonly called the linepack. The linepack capacity of the network for hydrogen is more than four times smaller than for natural gas as it depends only on the relative volumetric energy densities of the two fuels [17]. There is uncertainty about whether the network operators would be able to follow current natural gas operating practices for hydrogen, or whether additional storage would be required.

One option to increase hydrogen linepack capacity would be to use higher operating pressures than at present [21]. As well as increasing pipeline integrity safety concerns, there might be insufficient existing compressor capacity for this option and customers might not be able to use the hydrogen at the higher pressure. Additional (and costly) changes to the networks would likely be incurred and additional safety precautions would be required.

2.5. *Hydrogen end-use appliances*

Natural gas currently fuels boilers and cooking stoves in homes. Hydrogen could replace natural gas in all of these appliances. Furthermore, fuel cell-based micro-CHP boilers fuelled by hydrogen could also generate substantial amounts of decentralised electricity during peak demand periods [12].

Hydrogen can be combusted directly. One measure of the performance and safe operation of natural gas and hydrogen burners is the Wobbe Index, a measure for interchangeability of gases in burners to ensure efficient and safe operation [17,47,48]. Burners deployed in the UK are designed for a Wobbe band ranging from 47.2 to 51.4 MJ Sm^{-3} (where 1 MJ Nm^{-3} = 0.9476 MJ Sm^{-3} [49]) and these might be compatible with pure hydrogen [17], although more work is required to verify this hypothesis.

Gas seals, flame detection and the higher flame velocity of hydrogen pose problems for hydrogen combustion [17]. The small quenching gap of hydrogen requires tighter tolerances at the sealing of the burner head while the higher flame speed of hydrogen creates a risk for flashback (i.e. flame lift-off) [32,34]. A grid conversion would therefore require burner heads and seals to be adjusted/replaced [17], even if the current burner Wobbe Indices were proven suitable for hydrogen. Hydrogen appliances have been demonstrated but have not been used on a large scale [50,51]. Alternatively, given that conversion to hydrogen would not realistically occur until after 2030 (see Section 4), the government could produce new regulations requiring all new natural gas appliances to be compatible with both fuels.

2.6. *Conversion process*

In the conversion from town gas to natural gas, houses lost their gas supply only for a day or two. Streets were systematically isolated from the town gas system and connected to the natural gas system by large teams working street by street. A comprehensive survey of the local pipes and all properties and appliances requiring conversion preceded and guided conversion.

Our gas industry interviewees' noted that converting from natural gas to hydrogen would be more difficult because natural gas is supplied by complex networks with many more interconnections, linked to a central transmission system, so it would be much harder to isolate parts of the network. In contrast, town gas was largely manufactured locally. If it were necessary to convert much larger areas than previously then there could be much longer supply disruptions. Yet it might be possible to minimise the disruption through temporary measures. For example, the conversion of Cornwall to natural gas was uniquely difficult because the county was supplied by a single trunk gas main that could transport either town gas or natural gas but not both at the same time. The solution was to provide a temporary supply of substitute natural gas (composed of propane mixed with air) by road until all of the buildings had been converted [14]. Similar strategies could be designed for hydrogen.

It would be necessary to have hydrogen 'on tap' and ready to feed into converted networks during the conversion process, either through pre-built transmission and distribution networks or using local storage as a temporary measure. Much hydrogen production and delivery infrastructure would have to be built prior to the start of the conversion program and these would be underutilised in the early years.

Prior to the natural gas conversion program, a pilot conversion was performed on Canvey Island near London. Canvey Island had the advantages of having few gas network links with the mainland and having a new LNG import terminal that had just been constructed. For the conversion to hydrogen, one option would be a pilot conversion of one of the four Scottish Independent Networks (towns in Scotland that are not connected to the national transmission network and are instead supplied by liquid LNG delivered by road tankers).

2.6.1. *Socioeconomic issues surrounding a conversion program*

The conversion to natural gas took place at a time when gas was a nationalised industry. The decision was made by the national Gas Council and implemented by the Regional Boards, working together when necessary [14]. Financing was organised centrally. The industry was privatised in the 1980s and the gas networks and household connections are now owned by numerous private companies. Any decision to convert would have to be driven by the government in conjunction with these companies. New hydrogen infrastructure would most likely be built privately using funding from commercial markets rather than the government debt. Several interviewees identified government action to create the necessary market conditions as a key requirement to underpin investment in hydrogen infrastructure.

The UK population has evolved since the last conversion program. Married women are more likely to be employed outside the home than in the 1960s and 1970s so a greater proportion of households are empty during the day. Households tend to move more frequently and a greater proportion of the housing stock is rented from private landlords. There is also greater social diversity within the population. The conversion program would have to cope with logistical issues created by these changes.

2.7. *Interviewee opinions of hydrogen conversion*

The interviewees from the gas industry were strongly sceptical about the likelihood of converting the gas networks to transport hydrogen. They expressed concerns about the older pipes in the UK gas networks having loose joints and thought that the poor quality records and maps of some parts of the distribution networks would be an impediment to conversion. An engineering study would be needed to understand whether the joints issue is limited to iron pipes or also affects polyethylene pipes. Poor quality records were an issue during the conversion from town gas to natural gas and emergency conversion teams were on standby throughout to convert properties that were supplied by unexpected routes. An investigation would be required by the gas industry to assess the quality of their records; the uncertainty over the total length of iron pipes in the network, with an original estimate of 91,000 km in 2001 updated to 101,800 km in 2004 [52], does not inspire confidence.

Other key concerns raised by gas industry interviewees were public perception and the economic viability, with hydrogen production in particular viewed as an inefficient and expensive process compared to natural gas. One might argue that this viewpoint reflects a short-term planning horizon within the gas industry that does not yet envisage the full economic consequences of decarbonising the UK energy system, yet several other interviewees who were more positive about the role of hydrogen also questioned the economic viability and believed that political action would be necessary to support the deployment of hydrogen technologies at competitive prices. We examine the costs and the potential economic benefits of conversion in the next two sections.

3. Gas system conversion costs

In this section we estimate the cost of converting the UK gas system to hydrogen. "Gas system" here refers to the gas pipeline networks and the end-use appliances that consume natural gas. All costs are UK pounds in the year 2010 unless otherwise stated.

In the conversion from town gas to natural gas, the national program to convert or replace every gas appliance in 12 million homes cost £600m in 1977, which is equivalent to £2.9bn in 2010 prices [14]. Only minor work was required to existing gas pipes, for example to fit new valves to assist the purging of town gas or to fix faults that were inadvertently found during the appliance conversion program, but new high-pressure transmission and distribution networks were constructed to deliver natural gas as described in Section 2.6.

For the conversion from natural gas to hydrogen, we do not account for the loss of capital in existing facilities as previous studies have shown that natural gas can still have an important long-term role in hydrogen and electricity production if carbon capture and storage (CCS) facilities are used [19]. We estimate the cost of replacing appliances below. Since the amount of work that would be required to convert the gas networks is uncertain, we do not attempt to produce a single representative cost. We assume that no investment in the low-pressure gas networks is required in our base conversion case but we examine the consequences of requiring additional investment in sensitivity studies in Section 4. New high-pressure hydrogen transmission and distribution pipeline networks would have to be built to transport hydrogen around the country.

3.1. *Labour*

Using information from our interviews with two gas industry experts combined with data from the town gas conversion program [14], we estimate that two gas engineers would require 6 h each on average to convert a single property. This includes a preliminary visit, delivery of components, disconnection from the gas mains, placement of isolation valves, replacement of burners on household appliances and replacement of gas meters. A pilot conversion program could produce a more accurate estimate of time requirements.

We estimate a labour cost of £25 per hour (assuming 80% of the conversion is performed by gas technicians at £15 per hour [53] and the remainder requires skilled gas engineers at £43 per hour [54]). This includes a 20% mark-up to account for administration costs. The average labour cost per house is then £300.

3.2. *Meters and detectors*

All houses would require new hydrogen meters and leak detectors. Assuming meters are similar to existing natural gas meters, a typical meter costs £66 and the box, fittings and gas regulator cost £50 [55]. The labour for fitting the meter is included in the 12 h above so the total meter cost per house is around £120.

We assume that two detectors are fitted on ceilings in each home, probably in the kitchen and near the boiler. If each detector costs £20 then the total sensor cost per house is £40.

3.3. *Appliances*

One of our interviewees estimated the cost of new burner heads, including sealing, for existing boilers and cookers at only around £7.50. We assume that each boiler and each oven will require one burner head and that each hob will require four heads. While virtually all houses connected to the gas network have boilers, only around 60% use gas hobs and around 50% use gas ovens. Taking these statistics into account, the total cost of appliance parts per house averages £30.

3.4. *Total cost of converting households to hydrogen*

The cost of converting each household is summarised in Table 3. It is necessary to apportion the labour cost between appliances and this is also shown in Table 3, using the assumption that each of the four categories requires the same amount of labour. The appliance conversion costs are dominated by labour costs and these could be mostly avoided if the government legislated to make appliances hydrogen-ready in advance of the switchover. We therefore identify two household conversion scenarios. In the first scenario, the government legislates for conversion in advance and the principal cost of conversion is to fit new meters and sensors at a cost of £230 per house. In the second scenario, there is little forward planning prior to conversion and cost is £490 per house.

Currently around 22.6 million households use gas in the UK. The total cost of conversion would be £5bn for the first scenario and £11bn for the second scenario if all households were converted. It is conceivable that some households would switch from gas to electricity for heating and cooking in the future [2,56] so these figures are likely to be upper estimates.

4. Economic benefits of converting the gas system

We assess the economic benefits of converting the gas system to transport hydrogen using the UK MARKAL energy systems model. MARKAL is a widely-applied partial equilibrium, bottom-up, dynamic, linear programming optimisation model [57]. UK MARKAL portrays the entire UK energy system from imports and domestic production of fuel resources, through fuel processing and supply, explicit representation of infrastructures, conversion of fuels to secondary energy carriers (including electricity and heat), end-use technologies and energy service demands of the entire economy [58,59]. It includes a full representation of hydrogen pathways from production (from electrolysis, fossil fuels and biomass) and transportation to end-use. It is calibrated to the UK energy consumption in the year 2000. UK MARKAL studies underpin UK government decarbonisation strategies [3,60] and the

Table 3 – Cost of converting each household to use hydrogen. The cost per appliance splits the labour cost between each appliance.

Item	Cost per household (£)	Cost per appliance (£)
Labour	300	
Meters and detectors	160	230
Boiler parts	8	80
Hob parts	18	90
Oven parts	4	90
Total	490	490

model has also recently been used to examine decarbonisation pathways for residential heat provision [12,56]. MARKAL allows us to draw insights about the relative importance of different technologies, costs and policies within the whole UK energy system, including the use of different fuels to satisfy energy demands across the economy.

4.1. Methodology

We use a research version of UK MARKAL that is based on v3.26, which was used and documented by [3]. The research version has a new representation of the natural gas networks [12] and a residential sector disaggregated by house type. Past and future investments in the gas networks related to the UK Iron Mains Replacement Programme [30] are treated as sunk costs but pipe renewal costs are included in the model [19], with substantial investments required from 2050 to maintain capacity. The same investments are required whether the networks are transporting hydrocarbon gases or have been converted to supply hydrogen.

We have revised the hydrogen sector to update the production and transport technologies and to add the option to convert the gas networks to deliver hydrogen instead of hydrocarbon gases [61,62]. The model must invest in new national transmission and regional high-pressure distribution networks in order to deliver hydrogen to the existing low-pressure gas pipelines. These networks are assumed to operate at pressures of up to 100 bar, similar to existing high-pressure industrial hydrogen pipelines [63], and 1% of the hydrogen energy is assumed to be used for compression. In practice, different combinations of pipe sizes, operating pressures and compression energies can be used to supply the same quantity of hydrogen.

The MARKAL platform is not able to represent inter-seasonal storage of hydrogen (e.g. using salt caverns) so UK MARKAL hydrogen production costs do not take account of peak demands in the same way as for electricity generation. This means that a single annual hydrogen price is calculated by the model.[1]

We extend the representation of district heating in the model to add small hydrogen-fuelled combined-cycle turbines (for CHP) and boilers, with fuel delivered from the high-pressure hydrogen distribution pipes; these can co-exist with natural gas heating in buildings.

All of these changes to the model, and the resulting impacts on heat provision, are fully described in [56].

4.1.1. Conversion cost assumptions

For this study, we added the conversion costs from Section 3 to the model. It was necessary to add a number of constraints to ensure that the model accounted for all of the costs of the conversion program in a realistic way.[2] Our implementation enables UK MARKAL to convert any proportion of the gas networks to hydrogen at any time, to continue using the networks to deliver gas or to abandon the networks altogether, with the choice depending solely on the cost-optimal strategy. Our base conversion case assumes:

1. The government develops a long-term strategy to convert the network to hydrogen and legislates to require all gas appliances to be hydrogen-ready well in advance of conversion. New meters and sensors must still be fitted to every property during conversion.
2. No changes are required to the low-pressure gas networks for them to transport hydrogen.
3. The high-pressure gas networks cannot safely transport hydrogen so it is necessary to construct new national hydrogen transmission and high-pressure distribution networks.

We test the first assumption with a case where no proactive action is taken by the government so the full household conversion costs in Section 3 are incurred. We test the second assumption by examining four cases in which low-pressure network conversion costs 25%, 50%, 75% and 100% of the cost of building a new hydrogen low-pressure network.

4.1.2. UK climate change policy

We implement UK climate policy in UK MARKAL by constraining CO_2 emissions to reduce in linear steps between 2000 and 2050. In some previous studies [3,60], the 80% emissions reduction target in 2050 (relative to the 592.4 $MtCO_2$ emissions in 1990) is interpreted as a 90% reduction in CO_2 in the model, in recognition that only a 70% cut in non-CO_2 GHG emissions might be realistically achievable [34] and that there is uncertainty whether emissions from land-use change and from international transport fuels should be included. In this study, we use an 80% target for consistency with UK policy and we do not include the UK share of international aviation and shipping emissions in any scenarios. Since the reduction in CO_2 emissions might need to be higher than 80%, we have tested the robustness of our results for emission cuts of up to 90% relative to 1990.

4.2. Gas system conversion in the base conversion case

The amount of hydrogen delivered by the low-pressure gas networks in 2050 following conversion is shown in Fig. 1 as a function of the gas distribution network conversion costs. In the base conversion case (denoted “0%”), 499 PJ hydrogen are consumed in the residential sector with an 80% reduction in CO_2 emissions. For comparison, UK residential natural gas consumption in the years 2005–2010 averaged 1310 PJ. Hydrogen consumption reduces steadily to 317 PJ as the conversion costs for the gas distribution networks are increased. Interestingly, if CO_2 emissions are not constrained then converting a small part of the network to hydrogen is still the cost-optimal strategy; this is viable because the hydrogen is produced by coal gasification and coal is a much cheaper (although more polluting) fuel than natural gas.

[1] We plan to evaluate the importance of interseasonal variations in hydrogen demand in the future using a new model based on the TIMES platform.

[2] If the model is allowed to convert the network over a long time period then it will build new hydrogen appliances to replace obsolete gas appliances and thus avoid conversion costs, but such a strategy is not possible in practice. Such difficulties are occasionally encountered with energy system models and great care is required to avoid creating implausible scenarios.

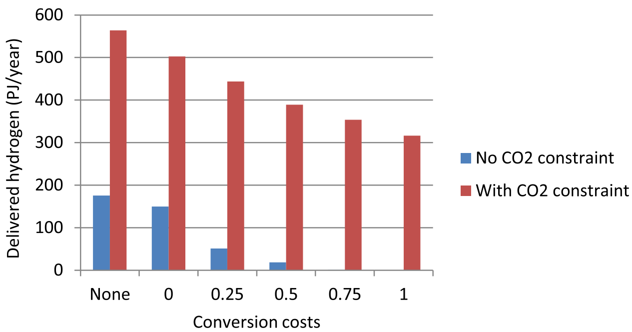

Fig. 1 – Hydrogen delivered by the low-pressure gas networks to the residential sector in 2050 as a function of the conversion cost. In the "No cost" case, there are no costs to convert the networks to deliver hydrogen. In the other cases, household conversion costs are incurred to fit hydrogen meters and sensors, and the % refers to the pipeline conversion costs which are expressed as a fraction of the cost of building a new low-pressure hydrogen pipeline network. See Section 3 for a full breakdown of the costs.

The transition from natural gas to hydrogen delivery in the gas system is shown in Fig. 2. Natural gas consumption falls steeply after 2030 as parts of the network are converted to deliver hydrogen and many customers also switch to electric heating using heat pumps. Fig. 2 also shows that if the government were to take no long-term proactive action to prepare for hydrogen conversion (i.e. no pre-organised switching) then this would little impact the cost-optimal decarbonisation strategy (although it would increase the total cost of the energy system to the UK).

MARKAL-type models tend to poorly represent pipeline infrastructure because the capital costs are specified as a function of the energy throughput while the actual pipeline costs are more dependent on the geography of the country and the design of the network. In UK MARKAL, the pipeline network investment costs are calculated as a function of the maximum delivered energy in the last decade (2000–2010). Using these costs throughout the model time horizon implicitly assumes that the pipeline length per customer and the energy demand per customer will not change in the future. This assumption has been tested elsewhere by iterating model runs with an external spreadsheet that recalculates the pipeline costs and network size according to consumption in each time period [12]. We use the same approach here. Fig. 3 compares the base conversion case with the iterated conversion case. Hydrogen consumption in 2050 reduces by 26 PJ when this assumption is removed, which is not negligible but not large enough to change the overall energy system trends.

If CO_2 emissions are reduced by 90% rather than 80% in 2050, relative to 1990 emissions, then residential hydrogen consumption in the base conversion case reduces in 2050 by 11% to 446 PJ. Although hydrogen is a zero-carbon energy carrier, it is produced from fossil fuels with CCS and these are assumed to capture only 85% of the CO_2. The fugitive emissions from these plants become more important for a 90% target and the model chooses to replace some hydrogen consumption with renewable electricity.

4.2.1. *Heat technology portfolio*

The heat technologies used for residential heat provision in the base conversion case are shown in Fig. 4. Between 2020 and 2040, the primary heating fuel changes from gas to electricity as heat pumps are installed where possible. Hydrogen is used exclusively in fuel cell micro-CHP boilers. Although hydrogen is only used in 20% of buildings, the consumption per building is higher than at present because substantial amounts of zero-carbon electricity are also generated. Micro-CHP generation coincides with periods of high heat demand, and hence high electricity demand, and therefore tends to depress peak electricity prices and enable the use of electric boilers in some homes (natural gas boilers are not used after 2040).

Fig. 5 demonstrates the impact of hydrogen-fuelled micro-CHP by comparing residential heat provision in 2050 for the base conversion case and no-conversion case (the equivalent case but with conversion prohibited). Only electricity and hydrogen are used in the conversion case. In the no-conversion case, micro-CHP is not deployed but natural gas boilers are still in operation in houses that cannot use heat pumps. Heat pump utilisation is unchanged and some district heating is used to replace micro-CHP and electric boilers in smaller houses and flats.

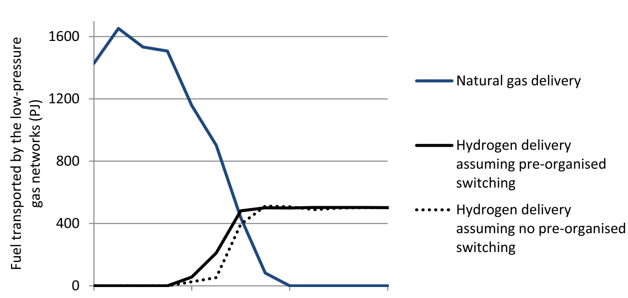

Fig. 2 – Transition from natural gas to hydrogen in the base conversion case. The impacts of cost reductions achieved by pre-organising the transition through proactive government policies, as described in Section 3.4, are highlighted for the hydrogen curve.

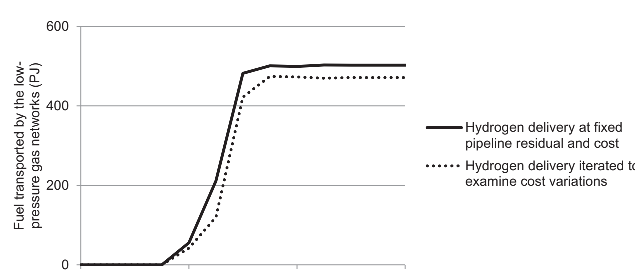

Fig. 3 – Impact of assuming fixed pipeline residual and capital costs in the model on the transition to hydrogen transport in the low-pressure gas networks in the base conversion case.

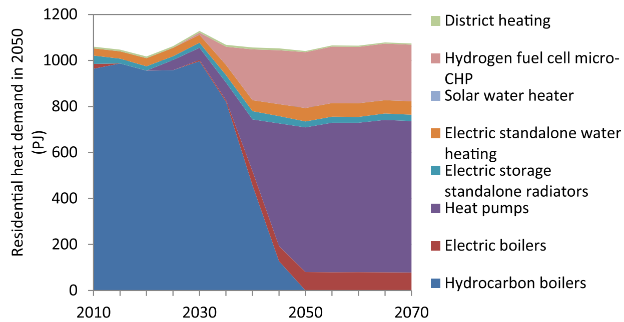

Fig. 4 – Residential end-use heat appliances in the base conversion case, for an 80% reduction in CO_2 emissions in the year 2050.

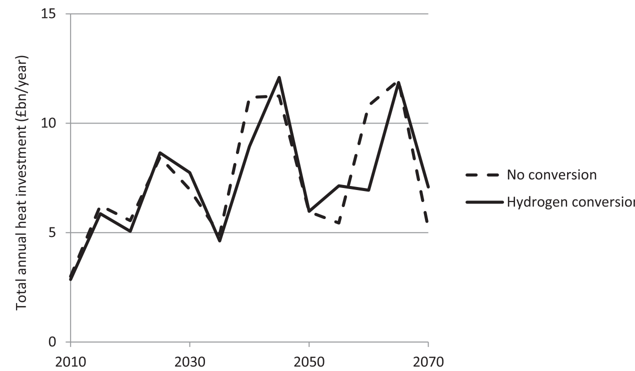

Fig. 6 – Annual investment in residential heat technologies in homes in the base conversion and no-conversion cases for an 80% reduction in CO_2 emissions in 2050. Each point represents the average annual investment over a 5-year period. Costs are £bn in the year 2010.

4.2.2. Hydrogen production

The most economical strategy for producing hydrogen is consistently a combination of coal gasification and natural gas steam-methane reforming (SMR), both with carbon capture and storage (CCS). In 2050, around 50% of hydrogen is produced by each method but any large increases in hydrogen demand (for example, due to high heat pump capital costs in Section 4.5) are met by building only extra SMR plants. No electrolysis is used for hydrogen production for heat, and production from biomass with CCS (i.e. atmospheric carbon sequestration) is not available to the model.

4.3. *Investment in heat provision*

The annual investment in heat provision in the base conversion case is compared with the no-conversion case in Fig. 6. The costs are similar until 2030. After 2030, the long-term average costs are still similar but investment in the base conversion case is much more stable than in the no-conversion case. Investment stability does not generally affect the choice of decarbonisation pathway in MARKAL because all investment costs are annualised over the lifetime of the technology in the objective function (although all investments are discounted using a social discount rate of 3.5% per year [64] so delaying investment reduces the net present value of the costs).

In the base conversion case, £2.3bn is invested in fitting hydrogen meters and sensors to houses in the conversion program. In the absence of a long-term proactive government strategy for conversion, the cost of converting appliances is a further £4.3bn. The total cost of converting households, £6.6bn, is substantially lower than the £11bn mentioned in Section 3.4 because some houses switch to electric heating rather than being converted to hydrogen so do not incur the conversion costs. Building high-pressure transmission and distribution pipeline networks for hydrogen costs a further £8.2bn. The low-pressure gas pipes are assumed to incur no conversion costs.

The annual investment in natural gas and hydrogen technologies (boilers, micro-CHP, conversion costs and hydrogen pipelines) is shown in Fig. 7. Investment in the early years is dominated by natural gas. The new hydrogen high-pressure networks are constructed from 2030 and expenditure from 2035 represents the conversion program and new hydrogen appliances. Hydrogen pipeline costs are a small part of the total expenditure, which is dominated by investment in heat technologies. After 2040, investment reduces to a much lower level as hydrogen provides a much smaller fraction of residential heat than natural gas at present. The model instead invests in heat pumps, which are not shown on this graph.

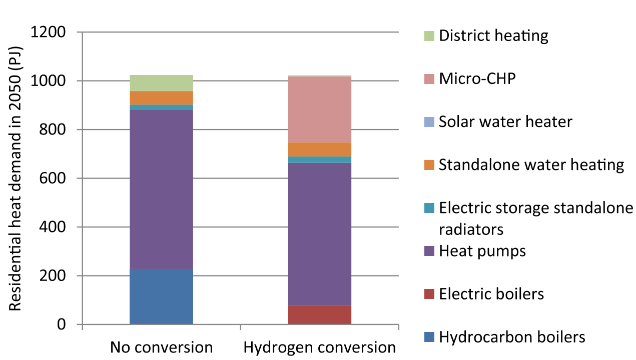

Fig. 5 – Residential heat technologies in 2050 for the cases with and without hydrogen conversion.

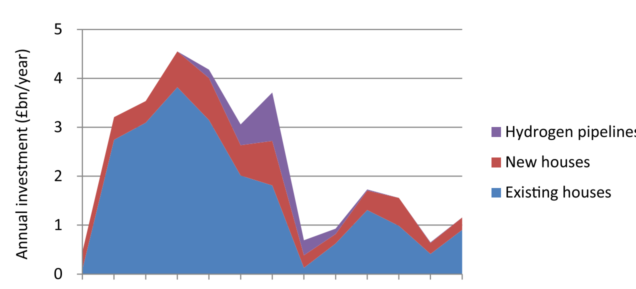

Fig. 7 – Annual investment in natural gas and hydrogen residential heat technologies in the base conversion case for an 80% reduction in CO_2 emissions in 2050. Each point represents the average annual investment over a 5-year period. Costs are £bn in the year 2010.

Table 4 – Hydrogen consumption for district heating and within homes in 2050, for cases with and without conversion of the natural gas networks. The hydrogen consumption figures exclude hydrogen used for cooking and for electricity production in CHP technologies.

	Without conversion	With conversion
Fraction of heat supplied by district heating	10.1%	0.5%
Hydrogen consumption for residential district heat (PJ)	54	4
Hydrogen consumption within homes for heat (PJ)	0	271

The investment peak after 2050 occurs due to the model replacing the first generation of fuel cell micro-CHP devices, which have lifetimes of 18 years.

4.4. *Hydrogen-fuelled district heating*

All of the scenarios presented above allow hydrogen to be used for to supply district heat as well as in homes. In Table 4, we examine how gas network conversion affects the deployment of residential district heating. The district heating share of heat production falls from 10.1% in the case with no conversion to 0.5% in the base conversion case. A substantial amount of hydrogen is used for district heat with no conversion but only a negligible amount is used in the base conversion case as fuel cell micro-CHP becomes more competitive than district heating. If a lack of public acceptability were to prevent the use of hydrogen in homes (Section 2.3.4), then these results show that there would be an alternative role for hydrogen in generating district heat and that district heating could then have a much greater role in UK heat provision in the future, as an alternative to piped natural gas.

4.5. *Sensitivity of the results to end-use technology cost assumptions*

We showed in a previous study that the cost-optimal provision of UK residential heat is sensitive to assumptions about technology learning rates of heat pumps in the future [56]. In this section we examine the impacts of (i) heat pump capital costs remaining unchanged from the present instead of reducing by 25% by 2025 through technology learning; and, (ii) micro-CHP capital costs per kW reduce by 25% rather than by 50% in 2030.

Residential sector hydrogen consumption in 2050 for the conversion case and the two sensitivity cases is shown in Fig. 8. Residential heat is provided using only electricity and hydrogen in all cases. With no heat pump learning, residential micro-CHP fuel cells are more competitive than heat pumps at low conversion costs and heat provision in 2050 is dominated by micro-CHP and electric boilers, leading to hydrogen consumption at levels similar to natural gas today. The cost advantage of hydrogen erodes as the conversion costs increase until there is little difference between the three cases when the low-pressure network conversion cost reaches 75% of the cost of building new networks. The difference between the high micro-CHP case and the base case is much less pronounced; hydrogen consumption reduces by 53 PJ in the 0% conversion cost case and is unchanged at high conversion costs. Given the small differences in costs between technologies, it is likely that a range of economic factors (e.g. market structure, government subsidies and taxes) and non-economic factors (e.g. the size, safety and operating characteristics of each technology) will determine the most suitable choice of heat technology for each home.

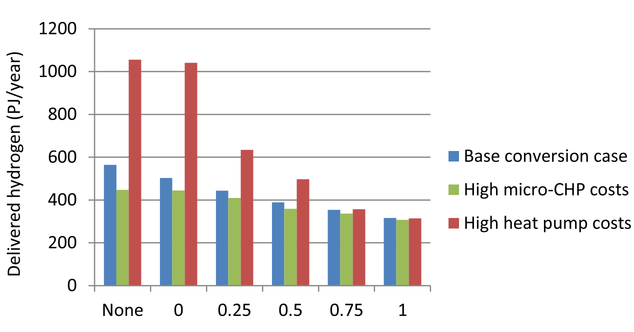

Fig. 8 – Hydrogen delivered by the low-pressure gas networks to the residential sector in 2050 under different assumptions about the future capital costs of key technologies, for an 80% reduction in CO_2 emissions in 2050. See Fig. 1 for an explanation of the conversion costs.

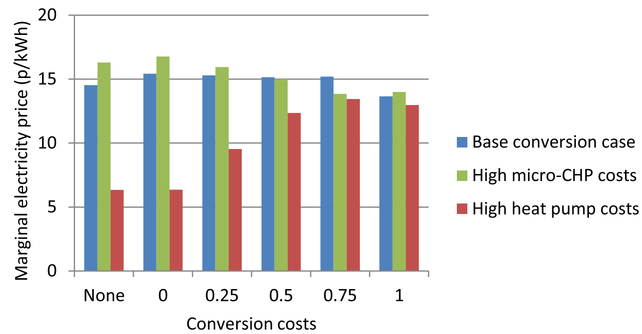

Fig. 9 – Residential marginal electricity prices on winter days in 2050 under different assumptions about the future capital costs of key technologies. See Fig. 1 for an explanation of the conversion costs.

Converting the gas network to transport hydrogen has little impact on fuel commodity prices in all of the cases. The only exception is the winter daytime electricity price, when demand for heat peaks, which is shown in Fig. 9. Using a high proportion of micro-CHP in the residential sector tends to depress this price because much less backup generation capacity is required in the electricity sector as peak micro-CHP generation occurs at the same time as peak demand. The electricity price rises as heat pumps replace micro-CHP at higher conversion costs. Electricity prices in other seasons are not influenced by the choice of heat technology in the residential heat sector.

5. Conclusions

Existing steel pipes designed to transport natural gas at high pressures cannot be used to transport hydrogen because the high-strength steel is susceptible to embrittlement. It would be necessary to construct a new hydrogen transmission network using a softer steel to transport hydrogen around the country. Polyethylene pipes are suitable for transporting hydrogen at low pressures, although there is uncertainty as to whether the seals between pipes or the pressure reduction stations would require remedial work to operate safely. Iron pipes might be suitable for transporting hydrogen as well but most should be replaced with polyethylene pipes by the mid-2030s; it might be possible to prepare at least part of the network to transport hydrogen if the UK government were to make subtle adjustments to the Iron Mains Replacement Programme. There is uncertainty whether the distribution networks could supply sufficient hydrogen to meet demand since the capacity would be 20% lower at the same operating pressures, the total linepack buffer storage would be only a quarter of the current natural gas storage and since households with micro-CHP fuel cells would consume substantially more hydrogen than those producing only heat. A full engineering appraisal would be required to examine these concerns in sufficient detail.

There are a number of safety concerns surrounding the use of hydrogen in buildings as hydrogen has quite different properties to natural gas. The overall risk of hydrogen ignition within a building is higher than for natural gas. Moreover, hydrogen has no smell and suitable odorants have not yet been developed, and hydrogen flames are invisible. It would be necessary to fit hydrogen sensors and new meters in each home as part of a hydrogen conversion program. It would also be necessary to convert heating and cooking appliances to use hydrogen, but this could be avoided if the government were to legislate well in advance to make new appliances hydrogen-ready; only minor, low-cost changes would then be required. There is a precedent for such a program in the national conversion from town gas to natural gas in the 1970s, but such a program would be more complex today due to two factors: (i) because the current gas network is much more interconnected than the gas networks of the 1960s so it would be more difficult to limit the length of supply disruptions during conversion; and, (ii) the difficulty of organising and financing a national program when the networks are owned by several private companies (gas supply was organised centrally in the 1970s).

Converting the networks to hydrogen provides a lower-cost residential decarbonisation pathway for the UK than identified in previous studies, despite heat pumps still dominating in the base decarbonisation case. At least 300 PJ of hydrogen is delivered to homes in all decarbonisation scenarios, where it is used exclusively in micro-CHP fuel cells in all types of building. The cost differentials between different heat technologies are small and uncertainties in the capital costs of key technologies can greatly affect the cost-optimal pathway. Given the small differences in costs between technologies, it is likely that a range of economic and non-economic factors will determine the most suitable choice of heat technology for each home. While hydrogen conversion has the potential to contribute to providing the lowest-cost decarbonised heat supply to UK homes, the feasibility of this option in the future is likely to depend on the willingness of the UK government and the network owners to invest resources over the next 20 years to prepare for and minimise the costs of a national conversion program.

Acknowledgements

The long-term development of the UK MARKAL model has been supported by the UK Energy Research Centre, while the analysis reported in this paper was supported by the Hydrogen and Fuel Cells Supergen Hub. Both of these initiatives are funded by the RCUK Energy Programme. We are indebted to the insightful and detailed comments of an anonymous reviewer that helped us to improve the paper.

REFERENCES

[1] DEFRA. National atmospheric emissions inventory 2012.

[2] Skea J. Research and evidence needs for decarbonisation in the built environment: a UK case study. Building Research and Information 2012;40:432–45.

[3] Hawkes A, Narkeviciute R, Morris S, Solano-Rodriguez B. Pathways to 2050 – detailed analyses. London, UK: AEA Technology plc; 2011.

[4] HM Parliament. The climate change act 2008. London, UK 2008.

[5] Dolman M, Abu-Ebid M, Stambaugh J. Decarbonising heat in buildings: 2030–2050. Cambridge, UK: Element Energy and AEA; 2012.

[6] Hawkes A, Munuera L, Strbac G. Low carbon residential heating. Imperial College London; 2011.

[7] Rhodes A. Low carbon heat: commercial opportunities and challenges for the UK energy generation and supply KTN 2011.

[8] Arran J, Slowe J. 2050 pathways for domestic heat. Edinburgh, UK: Delta-ee; 2012.

[9] Greenleaf J, Sinclair J. Pathways for decarbonising heat: a report for National Grid. Redpoint Energy; 2012.

[10] National Grid. The potential for renewable gas in the UK. National Grid; 2009.

[11] DECC. London, UK. DECC, editor. The future of heating: a strategic framework for low carbon heat in the UK 2012.

[12] Dodds PE, McDowall W. The future of the UK gas network. Energy Policy, submitted for publication.

[13] Chandler D, Lacey AD. The rise of the gas industry in Britain. London, UK: British Gas Council; 1949.

[14] Williams TI. A history of the British gas industry. Oxford, UK: Oxford University Press; 1981.

[15] National Grid. Annual report and accounts 2010/11. London, UK: National Grid plc.; 2011.

[16] Simmonds G. The UK gas industry 2000/2001. Industry Brief: CRI, University of Bath; 2000.

[17] Haeseldonckx D, D'haeseleer W. The use of the natural-gas pipeline infrastructure for hydrogen transport in a changing market structure. International Journal of Hydrogen Energy 2007;32:1381–6.

[18] Transco. Transportation ten year statement 1999. Reading, UK 1999.

[19] Dodds PE, McDowall W. The future of the natural gas pipeline system in the UK. In: International energy workshop 2012. Cape Town: 2012.

[20] Florisson O, Alliat I, Lowesmith B, Hankinson G. The value of the existing natural gas system for hydrogen, the sustainable future energy carrier (progress obtained in the NaturalHy project). In: 23rd world gas conference. Amsterdam: NaturalHy; 2006.
[21] Castello P, Tzimas E, Moretto P, Peteves SD. Techno-economic assessment of hydrogen transmission & distribution systems in Europe in the medium and long term. Petten, Netherlands: The Instiute for Energy; 2005.
[22] NaturalHy. Preparing for the hydrogen economy by using the existing natural gas system as catalyst. In: European commission's sixth framework programme; 2009.
[23] Gillette JL, Kolpa RL. Overview of interstate hydrogen pipeline systems. Argonne National Labouratory, U.S. Department of Energy; 2007.
[24] EIGA. Hydrogen transportation pipelines. European Industrial Gases Association; 2004.
[25] Barnoush A. Hydrogen embrittlement. Saarland University; 2011.
[26] Roads2HyCom. Effects of hydrogen on materials 2008.
[27] van der Zwaan BCC, Schoots K, Rivera-Tinoco R, Verbong GPJ. The cost of pipelining climate change mitigation: an overview of the economics of CH_4, CO_2 and H_2 transportation. Applied Energy 2011;88:3821–31.
[28] Castagnet S, Grandidier J-C, Comyn M, Benoît G. Effect of long-term hydrogen exposure on the mechanical properties of polymers used for pipes and tested in pressurized hydrogen. International Journal of Pressure Vessels and Piping 2012;89:203–9.
[29] Klopffer M-H, Berne P, Castagnet S, Weber M, Hochstetter G, Espuche E. Polymer pipes for distributing mixtures of hydrogen and natural gas: evolution of their transport and mechanical properties after an ageing under an hydrogen environment. In: 18th World Hydrogen Energy Conference 2010-WHEC 2010, vol. 78-1. Essen: Schriften des Forschungszentrums Jülich/Energy & Environment; 2012. p. 352–9.
[30] HSE. The health and safety executive's enforcement policy for the replacement of iron gas mains. London, UK: HSE; 2001.
[31] Foulc M-P, Nony F, Mazabraud P, Berne P, Klopffer M-H, Flaconneche B, et al. Durability and transport properties of polyethylene pipes for distributing mixtures of hydrogen and natural gas. Lyon. In: 16th world hydrogen energy conference 2006.
[32] Ricci M. Experts' assessments and representations of risks associated with hydrogen. UKSHEC: University of Salford; 2005.
[33] Iskov H, Backman M, Nielsen HP. Field test of hydrogen in the natural gas grid. In: 18th world hydrogen energy conference 2010-WHEC 2010. Essen: Institute of Energy Research - Fuel Cells (IEF-3), Forschungszentrum Jülich GmbH; 2010. p. 389–92.
[34] Alcock JL. Compilation of existing safety data on hydrogen and comparative fuels. European Integrated Hydrogen Project Phase 2 (EIHP2); 2001.
[35] Pritchard DK, Royle M, Willoughby D. Installation permitting guidance for hydrogen and fuel cell stationary applications: UK version. Health and Safety Executive; 2009.
[36] Guo X. Personal communication to S Demoullin; 13 March 2012.
[37] Guthrie DE. Personal communication to S Demoullin; 15 June 2012.
[38] Ekins P. Hydrogen energy: economic and social challenges. Earthscan; 2010.
[39] Lowesmith BJ, Hankinson G, Spataru C, Stobbart M. Gas build-up in a domestic property following releases of methane/hydrogen mixtures. International Journal of Hydrogen Energy 2009;34:5932–9.
[40] Abdel-Aal HK, Sadik M, Bassyouni M, Shalabi M. A new approach to utilize hydrogen as a safe fuel. International Journal of Hydrogen Energy 2005;30:1511–4.
[41] Sprague MJ, Flynn PJ, Boehman AL, Lvov SN, Kirby S, Lee J. Odorization of hydrogen for fuel leak detection. Columbia, South Carolina, USA: The National Hydrogen Association Conference & Hydrogen Expo; 2009.
[42] Puri PS. Novel methods of leak detection. In: 16th hydrogen energy conference. Lyon: 2006.
[43] Lowesmith BJ, Hankinson G, Spataru C, Stobbart M. Gas build-up in a domestic property following releases of methane/hydrogen mixtures. NaturalHy: Loughborough University; 2009.
[44] Bellaby P, Flynn R, Ricci M. The mirage of citizen engagement in uncertain science: public attitudes towards hydrogen energy. International Journal of Science Education, Part B 2011;1:97–114.
[45] Spataru C. Hazards and risks associated with hydrogen and natural gas mixtures. Hydrocarbon World; 2012.
[46] National Grid. Historic actual NTS demands, actual CWV and SNT (January 1998 to December 2011). Seasonal and annual data. http://www.nationalgrid.com/uk/Gas/Data/misc [accessed 25.07.2].
[47] Domnick A. LNG quality – background and outlook. In: Report of the IGU working group PGCD 1. IGU; 2006.
[48] Zachariah-Wolff JL, Egyedi TM, Hemmes K. From natural gas to hydrogen via the Wobbe index: the role of standardized gateways in sustainable infrastructure transitions. International Journal of Hydrogen Energy 2007;32:1235–45.
[49] Environment Agency. Guidance to operators for the conversion of natural gas data to standard conditions 2008.
[50] Ilbas M, Yılmaz İ, Veziroglu TN, Kaplan Y. Hydrogen as burner fuel: modelling of hydrogen–hydrocarbon composite fuel combustion and NOx formation in a small burner. International Journal of Energy Research 2005;29:973–90.
[51] SWB. Solar hydrogen project at Neunburg vorm Wald, Germany 2004.
[52] CEPA. 10 year review of the iron mains replacement programme. Cambridge, UK: HSE/Ofgem; 2011.
[53] Joint Industry Board. Notice of promulgation to the industry in Scotland & Northern Ireland 2012.
[54] National Grid Gas Plc. Gas distribution connection and service charges 2012.
[55] Phoenix Natural Gas Ltd. Connection policy 2012.
[56] Dodds PE. Review and disaggregation of the UK MARKAL residential sector heat provision to assess the prospects for using hydrogen in the built environment. H2FC Working Paper No 1. London, UK: UCL Energy Institute; 2013.
[57] Loulou R, Goldstein G, Noble K. Documentation for the MARKAL family of models. ETSAP, IEA; 2004.
[58] Kannan R, Strachan N, Pye S, Anandarajah G, Balta-Ozkan N. UK MARKAL model documentation 2007.
[59] Anandarajah G, Strachan N. Interactions and implications of renewable and climate change policy on UK energy scenarios. Energy Policy 2010;38:6724–35.
[60] Usher W, Strachan N. UK MARKAL modelling – examining decarbonisation pathways in the 2020s on the way to meeting the 2050 emissions target. London, UK: Committee on Climate Change; 2010.
[61] Dodds PE, McDowall W. A review of hydrogen production technologies for energy system models. UKSHEC Working Paper No 6. London, UK: UCL; 2012.
[62] Dodds PE, McDowall W. A review of hydrogen delivery technologies for energy system models. UKSHEC Working Paper No 7. London, UK: UCL; 2012.
[63] Schmid SA. Reference case for hydrogen distribution. Stuttgart, Germany: DLR Institute of Vehicle Concepts; 2006.
[64] HM Treasury. The green book. London, UK 2011.