Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target

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Executive Summary

The CCC develops scenarios for the UK's future energy system to assess routes to decarbonisation and to advise UK Government on policy options. Uncertainty to 2050 is large, and so different scenarios are needed to assess different trajectories, targets and technology combinations. Some of these scenarios assess specific technologies or fuels which have the potential to make a significant contribution to future decarbonisation.

Hydrogen is one such fuel. It has been included in limited quantities in some CCC scenarios, but not extensively examined, in part due to perceived or anticipated higher costs than some other options. But as hydrogen technology is developed and deployed, the cost projections and other performance indicators have become more favourable.

Two scenarios for hydrogen in energy were developed and modelled

The work presented here examines the potential role of hydrogen in two scenarios: *Critical Path* and *Full Contribution.* In the former, hydrogen makes a significant contribution to decarbonisation in 2050 but is not dominant, while in the latter hydrogen makes a central contribution to meeting 2050 targets. Both scenarios examine hydrogen in the transport sector and the Full Contribution scenario also considers its use as a more general low-carbon replacement for natural gas across the economy. Hydrogen is a flexible energy carrier and scenarios with many alternative transitions could be formulated, but were outside of the scope of this study.

Both scenarios are constructs, based on desired emissions reduction trajectories with specific 2050 targets for hydrogen use and are designed to test what could be achieved and how, not to endorse a specific course of action. They are modified according to plausible (though often aggressive) progress in technology performance, manufacturing capability, roll-out and commercial uptake. They are not forecasts and the *Full Contribution* scenario, in particular, would require strong support in the form of clear policy direction, development of industrial capability, cross-sectoral cooperation and broader international advances in order to be realised.

Each scenario is based on a suite of technologies, deployed in different applications across the UK energy system over the period to 2050. The maturity of each technology is characterised, along with its current and anticipated future costs. While many hydrogen technologies are currently too expensive to be directly competitive without support or some form of mandate, others are beginning to find commercial markets. Future costs for most hydrogen technologies are low enough to enable them to be deployed in both scenarios in large enough quantities to make a meaningful contribution.

The scenario development was informed by a model of the UK energy system, the UK TIMES energy system model (UKTM), which can show how the desired roll-out could take place. The model is designed to optimise the speed and timing of the deployment of technologies to meet the emissions constraints provided at the lowest cost. In some cases the model was forced to choose a hydrogen technology, in order to test the potential speed of roll-out, and validate the real emissions reduction contribution it could make. The model is not used to design the scenarios but to set the boundary conditions for the development of a narrative storyline describing the evolution of each scenario. Importantly, it also considers the entire UK energy system and its interactions, enabling potentially unexpected consequences of deployment in different areas to be identified and considered.

The 'Critical Path' scenario keeps hydrogen options open

In the *Critical Path* scenario the focus is on keeping hydrogen options open, should they be needed for decarbonisation in a later period. The focus is on strategically important applications – those hard to decarbonise in other ways. These include HGVs and buses, some cars, and a small amount of industrial and power generation use. The period from 2015-2020 is mainly devoted to pre-commercial activities such as demonstrations, but non-trivial deployment is required even from 2020 to allow hydrogen to make any significant contribution in 2050. Fleets of buses, cars, some LGVs and even HGVs require support and coordinated roll-out. Much activity is focused on what we term 'Pioneer regions'. These have favourable characteristics for early hydrogen introduction, such as large and coherent areas of demand, or proximity to potential Carbon Capture and Storage (CCS) sites allowing the production of hydrogen from natural gas while meeting emissions constraints. Co-ordinated fuelling infrastructure roll-out helps enable vehicle uptake, and tight emissions regulations are an important driver for hydrogen vehicle purchase. Small amounts of hydrogen are used in industry and in peaking power generation by around 2030.

Until the 2030s hydrogen is largely produced by electrolysis, and some by small-scale steam reforming plant in geographical hub regions that act as nodes for both transport fuelling and other uses. After that point, steam reforming plant using natural gas and CCS are increasingly used. At large scale this is a low-cost option, even with the CCS equipment and transmission pipelines required. It does assume however that CCS is technologically mature and cost-competitive and that CO_2 infrastructure is available. Should this not be the case then a considerably different set of production technologies would be needed, probably including large-scale electrolysis.

From 2030 to 2040 deployment continues, with hydrogen buses and HGVs increasingly prevalent. We consider it plausible that suitable HGV technology will be developed by 2030 and then become dominant due to very strong emissions drivers coupled with superior performance. By 2050 some 70% of the UK bus fleet and 90% of HGVs are hydrogen-fuelled, and 40% of vehicle kilometres in cars are fuelled by hydrogen. A modest amount of hydrogen is used in some sectors of industry, but none in buildings.

In the 'Full Contribution' scenario, hydrogen makes a central contribution to meeting 2050 targets

The *Full Contribution* scenario sees more rapid uptake of more hydrogen technologies in more sectors. Buses and HGVs are deployed even faster than in *Critical Path*, and cars are much more widely used. Bus fleet pilots have led to significant fleets by the mid-2030s, along with vehicles in every other category. Around 3,000 cars are operating in the UK by 2020, and 1.5m in 2030.

The natural gas grid is progressively converted to hydrogen, town by town, to supply vehicles and buildings. To facilitate this, the existing Iron Mains Replacement Programme is continued, so the majority of gas pipelines in the medium- and low-pressure networks are hydrogen-compatible. The best-suited urban areas in the Pioneer Regions are chosen for conversion to hydrogen. Gas appliances within these areas are modified in a tightly managed process and by 2025 hydrogen is widely available and used. Much domestic use is in boilers to provide heat, as micro-CHP technologies remain expensive. Industry use of hydrogen begins to develop and dedicated hydrogen transmission pipelines begin to be built in the mid-2020s.

From 2030 onwards the conversion of the gas supply to towns and cities is progressing rapidly, and 2035 sees 40% of domestic heat from hydrogen. By 2040 hydrogen is fuelling 20% of cars and 50% of buses, and even 20% of domestic shipping. Long-distance transmission pipelines link Humberside to the South-East and Merseyside to the South-West, and hydrogen is used in both peaking and large-scale combined heat and power plant. By 2050 hydrogen vehicles dominate in road transport, accounting for around 95% of every fleet type, with hydrogen supplied to the majority of refuelling stations and homes by bulk pipeline. Almost all comes from natural gas with CCS, though electrolysis fulfils some needs, particularly in more remote areas.

Strong policy support is crucial to achieving either scenario

Solid and coherent policy support is required to achieve even the *Critical Path* scenario, though the majority is not required before 2020. Demonstrations and pilots are however essential before then to ensure the option is retained. From 2020 a combination of strong emissions legislation, hydrogen-specific policy measures and ongoing international engagement should keep the UK in a position to accelerate hydrogen roll-out later on. Some actions are no-regrets, such as developing the right standards and training safety and support technicians.

To enable the *Full Contribution* scenario, much stronger support is required. Coherent and targeted policy measures to develop pioneer regions, ensure major bus fleet roll-out and provide supporting infrastructure for vehicles are essential. Vehicle grants will be needed to support the first cars and other vehicles, along with support for the development of hydrogen supply options. Conversion of the gas grid would require local authorities to need to decarbonise heat, and for them and gas distribution network operators to be supported in a coordinated way to manage the transition. Defining and supporting 'green' hydrogen will help ensure decarbonisation, and supportive policies and measures for hydrogen in industry and in heat must be aligned with those for vehicles.

Hydrogen* **could** *help the UK decarbonise dramatically by 2050, but would require strong support, starting now

The modelling also highlights areas for consideration in developing strategies for hydrogen roll-out. Perhaps counter-intuitively, the use of hydrogen to meet only part of the decarbonisation requirement in *Critical Path*, notably in transport, may be more difficult to achieve effectively than its predominant use in *Full Contribution.* Its partial use results in a co-existing mix of competing technologies and infrastructures and may eventually be sub-optimal, both in cost and location. Conversely, achieving the *Full Contribution* numbers requires an almost single-minded focus on supporting hydrogen from early on – not easy to achieve, nor necessarily desirable. Meeting a single overall target for the UK also means that emissions cuts – and the technologies used – in different sectors can vary dramatically. If all domestic heat is zero carbon for example, fewer cuts are needed elsewhere, with implications for technology roll-out.

Uncertainties about future fuel cost and availability, market mechanisms and technology development mean that the future energy system could diverge dramatically from the scenarios developed here. If CCS cannot be made to work cost-effectively then other options may be essential to provide low-carbon hydrogen, with almost no use of fossil fuels. Such options include electrolysis using renewable power and biomass-based routes. A failure to replace the iron gas mains could result in a massively distributed hydrogen system with local production and use.

Many individual actions are required to support the scenarios laid out in this document. While some are quite specific, several are overarching and will be required to frame the more specific ones. Some actions are required in the next five years:

- Government needs to set out a clear policy position supporting hydrogen as soon as possible, at a general level and ideally also at a level relevant to individual sectors. This will enable the multiple actors who need to invest to manage their risk, and will keep hydrogen open as a decarbonisation option.
- Specific support will be required for refuelling station rollout until at least 2020, to ensure that enough of a network exists to allow for subsequent growth and to keep the relevant actors (both station suppliers and OEMs) engaged in the sector. The difficulty of decarbonising transport massively in the long term means it is valuable to keep this option open. Further support may be required subsequently, but this will become clear before 2020.
- The policy trajectory for reducing vehicle carbon emissions and improving air quality needs to be at least maintained, to give confidence that investment in cleaner options will pay back. Supporting either infrastructure or vehicles alone would not give the relevant actors enough confidence to invest. For both vehicles and infrastructure, deployment needs to be self-supporting by around 2025, otherwise it is unlikely that FCEVs can take the proportion of the fleet they envisaged by 2050. A decision on further support will be needed between 2020 and 2025.
- Hydrogen supply also requires support, primarily in ensuring that no unfair obstacles are raised to its rollout, but also in better defining and rewarding the benefits it brings. Regulations, codes and standards have often not been designed with hydrogen in mind, and may restrict hydrogen deployment unnecessarily. Clear and fair definitions for 'green' hydrogen, coupled with support mechanisms, will enable it to be deployed more rapidly and cost-effectively.

In the early 2020s, specific support for other sectors will become important. While its exact nature will depend on the state of technology and deployment at that time, it is expected to include:

- Continued support for reduced emissions from other transport sectors, including long-distance trucking and shipping. These sectors are more conservative and support is likely to be required to ensure continued progress is made on decarbonisation and to bring other benefits. If support does not come early in the 2020s then these sectors are unlikely to be able to convert fast enough to meet future targets using hydrogen.
- Support to allow or require gas grids to accept hydrogen, and to convert local gas grids to operate using 100% hydrogen. This larger-scale network is needed to feed not only the range of transport options but also to provide heat for houses, a hard sector to decarbonise.
- CCS at large scale is required under these scenarios and a review in the 2020s will be essential to ensure performance and deployments are appropriate. Meanwhile indigenous renewable hydrogen or import options may have arisen and should be compared with CCS costs and performance. Should very large amounts of 'green' hydrogen be required then a decision on how best to achieve that would be required, with electrolysis of renewable electricity or biomass pathways possible options.
- Decarbonisation of heat must also be supported in and of itself, allowing the market to decide on options, but enabling hydrogen to be one of them.

Broad actions are required throughout the period to support all activities in the area. The UK will not develop all technologies alone, nor should it try. Instead we must engage internationally both strongly and proactively:

- Training for safety and service personnel must be developed, either through existing institutions or new ones. It should link to international activities wherever appropriate.
- Standards are already under development, but are lacking in some areas. An existing or new body should be appointed to ensure appropriate standards are put in place at the right time.
- Financing of some aspects of a widespread hydrogen rollout may be difficult, and flexibility should be allowed as far as possible to allow market actors to develop innovative financing proposals. It will be particularly important to ensure that markets are not unnecessarily compartmentalised (for example electricity provision, energy storage through hydrogen, and the provision of hydrogen fuel will almost certainly need to be linked).
- International engagement is essential. Not only are some technologies developed outside of the UK (though frequently with at least one UK supply chain component), but activities and innovations also depend on the interaction of an international community.

Supporting analysis – for example through energy systems modelling – will help ensure a good direction is maintained. Clear communication about the benefits and rationale for hydrogen deployment will also aid developments.

The analysis conducted in this project suggests that it is possible for hydrogen use to help the UK match very demanding future decarbonisation targets. For any significant deployment of hydrogen to occur support needs to begin – and be sustained – from now. For the most significant deployment that support needs to be highly co-ordinated, clear, and long-term.

1 Overview of hydrogen technologies – summary

This section provides a summary of the technologies that could be used to produce, store, transport and use hydrogen in the period to 2050, showing which are included in the scenario development. A full overview for each technology, covering the status, prospects, costs, interactions with infrastructure and international activities, and barriers to deployment are given in Section 6, along with references.

1.1 Transport

- Fuel cell electric vehicles (FCEVs) of several types are an important component of the scenarios:
  - FCEV light duty vehicles (cars) are hybrid vehicles combining a hydrogen fuel cell with a battery. They are commercially available today from two manufacturers, with around 120 vehicles deployed globally in 2014 and close to 1000 more expected by the end of 2015. Other manufacturers are expected to launch further FCEVs in the coming years, with sales expected to ramp up substantially in the 2020s, providing infrastructure is available and high capital costs are reduced.
  - FCEV Light Goods Vehicles (LGV) use similar technology to FCEV cars, though a larger proportion of current LGVs are range extender vehicles, where the fuel cell system is smaller, and augments a battery. They are at an earlier stage of development, and are not expected to be available in commercial volumes before the mid-2020s
  - FCEV buses have been used in demonstration projects since the mid-1990s in Europe, Asia and North America, and early commercial fleets are now gradually being introduced, with 83 buses in operation or about to be in operation in Europe, and 300 ordered for China. Further increase in bus manufacturing is needed to bring down capital costs.
  - Fuel cells for heavy goods vehicles (HGV) have attracted less interest to date than for buses or passenger cars, but in the longer term, fuel cells are considered to be one of the limited options to decarbonise long haul trucks.
  - Hydrogen could potentially play an important role as a propulsion fuel in shipping in the long term (after 2030), and for auxiliary power much earlier, albeit limited to routes with hydrogen supply infrastructure at ports.
- Fuel cells can be used in a number of other transport-related applications that are not included in detail in the scenarios, such as Auxiliary Power Units for HGVs, in motorbikes and scooters, and in trains. Significant use in aviation is unlikely in the timescale considered in this study (to 2050).

1.2 Electricity generation

Hydrogen can be used to generate electricity in a hydrogen turbine or in a stationary fuel cell.

- Hydrogen turbines are conventional gas turbines designed to burn hydrogen, which could be used in a capacity range from 1 to 500 MW. Although not currently deployed, they are relatively mature, and are used in the scenarios as peaking power plants to balance the electricity grid.
- Stationary power-only fuel cells are technologically mature, and are used as back-up or prime power for buildings and data centres, and for grid-scale electricity generation at the MW scale.

1.3 Industry

The predominant demand for hydrogen today is as an industrial feedstock, mainly for ammonia production for fertiliser and in oil refineries and chemical industries. Around 95% of global hydrogen production is produced and consumed at the same location, as part of a larger industrial process. Hydrogen is produced as a by-product of several large scale chemical production processes. In the future, hydrogen could be used to supply low-temperature heat in boilers and significant quantities of high-temperature heat for industrial processes, such as in the iron and steel sector and cement sector, although the latter would require plant redesign. Industrial use of hydrogen is modelled in the scenarios, with uptake depending on relative competitiveness with other industry decarbonisation options, and the availability of hydrogen.

1.4 Heat in buildings

Hydrogen could be distributed to buildings via the gas grid for use in heating and potentially CHP.

- Use of the existing natural gas low- and medium-pressure networks to feed 100% hydrogen to domestic, commercial, industrial and vehicle refuelling sites is considered in one of the scenarios. Use of 100% hydrogen would require boilers, appliances and meters in buildings to be converted. Hydrogen boilers have been produced and sold in small numbers, with other appliances in development. If hydrogen use becomes widespread, a range of boilers, cookers and fires is expected to become available relatively quickly.
- Fuel cell micro-CHP systems could deliver heat for hot water and space heating to homes, along with power that may be used in the building or fed into the grid. Two types of fuel cell technologies are commercially available today, with systems deployed so far using natural gas with a reformer. Future systems could use hydrogen directly if hydrogen were available.
- Fuel cell CHP could also be used at district heating scale, with a district heating network or directly co-located with a large heat demand. Current systems use natural gas, and are commercially viable with support schemes in South Korea and parts of the US. The technology should be cost competitive in many markets in the next 5 to 10 years.

There has been little published work on the safety of hydrogen in buildings, however the fire and explosion safety record of town gas, which contained 45 to 60% hydrogen by volume, is very good. Recent tests have shown that if hydrogen leaked inside a building, the concentration of hydrogen in the building would be higher than that for natural gas. However, it is likely that damage from a hydrogen explosion would be comparable to that from a natural gas explosion, as hydrogen has a lower energy content. Further testing work is needed on hydrogen's behaviour in buildings in different situations. Overall, hydrogen can be treated as another in the group of flammable gases, including natural gas & LPG, which are already supplied to buildings, with similar levels of risk.

1.5 Hydrogen production

Although hydrogen can be produced in many ways, three main processes are considered here:

- Steam Methane Reforming (SMR) is the most widely-used process for producing hydrogen and has been utilised globally for many decades in the oil refinery and chemical industries. Carbon capture and storage (CCS) can be added to a standard reformer to separate out carbon dioxide

(CO_2), with >90% CO_2 capture demonstrated. SMR plants with CCS are under development or in operation in several countries. Small-scale reformers suitable for refuelling stations can also be used, but these systems are too small for CCS to be used and they are proportionally more expensive than large-scale systems.

- Water electrolysis involves splitting water is into hydrogen and oxygen using electricity. Electrolysis has been used industrially to produce hydrogen for more than a century, and is mature at a range of scales, providing around 4% of global hydrogen production.
- Biomass is gasified by heating it to high temperatures with controlled amounts of oxygen, to produce a syngas containing hydrogen. Biomass gasification can be combined with CCS, to capture the CO_2 produced, which offers an atmospheric CO_2 sequestration route that could reduce the need for CO_2 emission cuts elsewhere in the economy. Biomass gasification with CCS is at the demonstration stage.

Other hydrogen production options are coal gasification with CCS, oil reforming and gasification with CCS and a range of less developed emerging methods.

1.6 Distribution infrastructure

- A network of hydrogen refuelling stations is needed to support the roll-out of FCEVs, as well as dedicated depots for heavy-duty vehicles and buses. Demonstration refuelling stations have been constructed and tested in several countries, including the UK. These stations use hydrogen from onsite electrolysers, or hydrogen brought in via compressed hydrogen tube trailers, liquid hydrogen tankers, and in one case via a pipeline.
- FCEV manufacturers have chosen to use hydrogen compressed to 700 bar to maximise the range of the vehicles while minimising the fuel cost. This means that compressors are an important component of hydrogen refuelling stations, as well as being used on a larger scale with high-pressure hydrogen pipelines. Hydrogen compressors are similar to natural gas compressors and are a mature technology. Compressed hydrogen can be transported in tube trailers, used commercially today by industrial gas companies, as well as in pipelines (see below).
- Hydrogen can also be stored and transported as a liquid. Liquefaction greatly increases the energy density of hydrogen, allowing it to be transported by road tanker or ship. It is particularly economic for transporting relatively small amounts of hydrogen over long distances, for which a pipeline cannot be justified. The principal disadvantages of liquid hydrogen are the substantial amount of energy that is consumed in liquefaction, difficulties in handling and losses due to boil-off.
- Use of the existing natural gas low- and medium pressure networks to feed 100% hydrogen to domestic, commercial, industrial and vehicle refuelling sites is considered in one of the scenarios. This would be facilitated by the ongoing Iron Mains Replacement Programme, which is replacing most existing iron pipes with polyethylene pipes, which can carry hydrogen. Although hydrogen has a lower energy content than natural gas, its lower density means the same pipeline with the same pressure drop across it could carry 80% of the energy when carrying hydrogen compared to when carrying natural gas. Use of 100% hydrogen in the gas grid is at the demonstration stage, in a limited number of trials. Conversion of the low and medium-pressure gas network to hydrogen would probably be done on a town-by-town basis, with coordinated conversion of the network

and appliances. The natural gas transmission network would not be converted and new high-pressure transmission and distribution systems for hydrogen would have to be constructed.

- Hydrogen could also be injected into existing natural gas streams at a relatively low concentration. In the UK, hydrogen in the gas grid is currently limited to 0.1% by volume, but in Germany, higher levels of 10% by volume are allowed, or 3% by volume where the grid gas may be fed to CHP engines and/or compressed natural gas (CNG) refuelling stations. However, this approach was not considered in the scenarios, for two reasons: firstly, 10% hydrogen by volume is only equivalent to 3% by energy, meaning that this level of low carbon hydrogen in the gas grid could only make a small contribution to gas grid decarbonisation. Secondly, newer gas appliances' control systems are based on using natural gas. Using natural gas with a small, and potentially variable proportion of hydrogen could lead to suboptimal operation, including risks of emissions increases.
- Dedicated hydrogen pipelines are the most efficient method of transporting large quantities of hydrogen, particularly over short distances. They are a mature technology used for industrial purposes in several countries, with almost 3,000 km of high-pressure hydrogen pipelines in use in Europe and North America.
- Other options for bulk hydrogen distribution are in development, such as metal hydrides and liquid organic hydrogen carriers, which can also serve for storage.

1.7 Bulk hydrogen storage

- Bulk compressed hydrogen storage is commercially used at industrial sites with significant hydrogen demands. Hydrogen is compressed in large stationary vessels at low pressures, or multi cylinder pallets and pressure tubes for medium and high pressures
- Hydrogen can also be stored in underground caverns, to provide large-scale storage over long timescales, including inter-seasonal storage. Hydrogen storage in salt caverns is well proven in the UK with substantial caverns in Teesside operational since the 1960s.
- Liquid hydrogen storage is also an established technology which is used industrially. Liquid hydrogen tanks can store more hydrogen in a given volume than compressed gas tanks. Bulk liquid hydrogen tanks are proposed for hydrogen refuelling stations with high demand and are used at some hydrogen refuelling stations.
- Metal hydrides and liquid organic hydrogen carriers can also be used for storage.

2 Critical Path Scenario

This chapter and the following one present two alternative pathways for hydrogen to contribute to emissions savings to 2050. The 'Critical Path' scenario is based on keeping open the option to use hydrogen in end-uses that are seen to be strategically important, and is designed to be consistent with the CCC's Central scenario analysis. Relatively little hydrogen deployment occurs before 2035. In the 'Full Contribution' scenario, significant deployment of hydrogen technologies takes place to 2035 and 2050.

Both scenarios were developed by defining a set of hydrogen end-uses for the 2050 end-point. This end-point then became the starting point for a qualitative 'backcasting' scenario development process. It was also used to provide input constraints for the UK TIMES energy system model (UKTM), which showed the full impacts of hydrogen use in each sector, and the interactions between sectors. The qualitative and quantitative insights from each of these processes were brought together to produce the narrative of each scenario.

Several other studies by the authors and others have considered the potential for hydrogen as a whole, or in particular sectors (e.g. Dodds and Demoullin, 2013, Dodds and Ekins, 2014, LCICG, 2014, Dodds *et al.*, 2015b, Element Energy, 2015, IEA, 2015). These were used as an input to this work, in terms of comparison of technology uptake rates and barriers.

2.1 Principles and definitions

The Critical Path scenario is based on keeping open the option to use hydrogen in end-uses that are seen to be 'strategically important'. Specifically, 'strategically important' end-use demands are defined here as demands that are hard to decarbonise by means other than hydrogen, or for which low-carbon options other than hydrogen are less obviously available.

In this scenario, there is no wholesale and technologically-specific commitment to an extensive roll-out of hydrogen technologies, in preference to other options. The Critical Path scenario would therefore tend to avoid large anticipatory investment commitments, ahead of an absolutely clear evidence of demand – e.g. building hydrogen delivery infrastructure ahead of need. The policy makers' strategy in this scenario is to "buy" some optionality to allow a contribution from hydrogen in some key sectors, at some point in the future – but without a wholesale commitment to it, and with a view to not paying too much for the "option".

In end uses such as heat and power provision in buildings, and private road vehicle transport over short distances, hydrogen could be envisaged to play an important role in a 'Full Contribution' scenario. But there are also strong alternative options, such as electric, bioenergy or district heating technologies. Therefore, these end uses were not judged to be strategically important, and hydrogen was not envisaged to play a strong role in delivering them in this scenario.

This leaves a number of end uses in which for different reasons, greater uncertainty remains around the availability of viable low carbon options. The most strategically-important end use demands were judged to be heavy goods vehicles (HGVs), buses, cars and light goods vehicles (LGVs) required to undertake journeys greater than 100-200 km, heavy industry, and flexible back-up generation in the power sector. It was in particular for these end uses that it was judged that policy makers would value keeping open the hydrogen option.

If the hydrogen option were called on and the technology successfully developed in each of these end use areas, the use of hydrogen in the energy system in 2050 could be summarised as follows:

- 90% of HGVs run on hydrogen – corresponding to the proportion of HGVs that operate within the UK only
- 70% of buses and coaches (long distance and urban), operating within the UK, run on hydrogen. This is an estimate of the proportion of buses that operate on routes outside of dense urban areas where electric buses may be viable
- 40% of private car vehicle kilometres are fuelled by hydrogen. This portion corresponds to the portion of total vehicle-kms that are travelled on journeys longer than 100 km. This is considered a strategically-important portion of this end-use demand because while cost-effective electric vehicles may operate comfortably over ranges of 100-200 km, there is uncertainty that their range will be able to extend much beyond this at reasonable cost.
- Hydrogen is used in power generation for flexible peaking plant, to help balance a system with high penetrations of variable renewables and less-flexible nuclear.
- Hydrogen may have a limited role in decarbonising fuel supply for heat demand in industry, especially for end uses where electrification is not suitable. Recent reports on the prospects for decarbonisation in industry have suggested that hydrogen is the most marginal abatement technology. Industrial decarbonisation roadmaps carried out for DECC mention using hydrogen as a low carbon fuel for heat supply in industry – however the option is not used in any of the abatement scenarios developed in the roadmaps (Parsons Brinckerhoff and DNV GL, 2015). Ricardo AEA (2012) reviewed industry decarbonisation, considering hydrogen fuel for heating a marginal option, after electrification, and suggest a usage of hydrogen in the order of 30 PJ.[1]

More detail on the assumptions behind the end point conditions, definition of modelling parameters, and the scenario development process is in Appendix A.

2.2 Narrative

2.2.1 2015 – 2020

In 2015 hydrogen technologies are limited to pre-commercial demonstration activities in the UK. These activities nevertheless provide an important starting point from which the deployment in this scenario builds.

[1] For the Critical Path scenario, this quantity of hydrogen was forced into industrial fuel demand for use in boilers and CHPs, and the model was given flexibility about which sectors to deploy this in. Note however that due to the structure of UKTM, hydrogen used for ammonia production and refining is not counted as a separate fuel input – rather these processes are packaged into a single process with the input fuel being natural gas. DECC roadmaps mention the decarbonisation of hydrogen in existing feedstock uses such as these; however, due to the complexities of the model, data availability and the limited time available on this project, it was not possible to split out these hydrogen-related processes within the model, hence it has not been possible to model them directly.

2.2.2 2020 - 2030

Although the 2050 end point for the Critical Path scenario has a more limited deployment of hydrogen than in the Full Contribution scenario, deployment is nonetheless significant enough by 2050 to mean that scale-up activities required to reach that level are required from the 2020s onwards. Critical Path begins to scale up hydrogen deployment in this decade, with a particular focus on urban bus fleets. There are a number of reasons for this focus. Buses are a significant end use amongst the strategically important end uses of Critical Path's 2050 end-point; there are already important hydrogen bus demonstrations in London and Aberdeen; the predictable 'back-to-base' journey and refuelling patterns of buses also make them an ideal technology to scale-up hydrogen infrastructure and production facilities whilst avoiding the 'chicken-and-egg' problems associated with supporting infrastructure for more dispersed and less predictable transport demands.

If hydrogen is ever to scale-up to an appreciable contribution within the energy system, whether in limited strategically-important end-uses, or more extensively, at some point a coordinated programme to deploy hydrogen technologies simultaneously in a variety of locations must be undertaken. This would generate critical learning about the technologies in different contexts, and would also generate more favourable economies of scale for technology manufacturers than hitherto available from relatively small demonstration programmes. At the same time, with relatively modest roll-out numbers, there remains a strong driver for deliberate clustering of hydrogen roll-out in regions which seem, in different ways, to be favourable 'seed-beds' for hydrogen technologies.

This leads to the suggestion in this scenario that 'Pioneer' cities or regions are identified, which for possibly different reasons have favourable characteristics for the early roll-out of hydrogen technologies. The suggested pioneer cities and regions are listed in Table 1. Reasons for inclusion in the list cover favourable supply-side as well as demand-side characteristics.

List of "Pioneer" hydrogen regions	
Region (NUTS Level 2 boundaries)	**Reasons for selection**
Tees Valley and Durham	Proximity of hydrogen related industries; metropolitan areas
Cheshire	Proximity of industry; metropolitan areas
Greater Manchester	Proximity of industry; metropolitan areas
Merseyside	Proximity of industry and potential CCS sites; metropolitan areas
West Yorkshire	Proximity of industry; metropolitan areas
West Midlands	Proximity of industry; metropolitan areas
East Yorkshire and North Lincolnshire	Proximity of industry and potential CCS sites; metropolitan areas
Gloucestershire, Wiltshire and Bristol / Bath area	Proximity of industry; metropolitan areas
Essex	Proximity to London and possible LH_2 import terminals
Kent	Proximity to London and possible LH_2 import terminals
Greater London	Large demand potential demand centre
Eastern Scotland	Proximity of industry and potential CCS sites; metropolitan areas
North Eastern Scotland	Proximity of industry and potential CCS sites; metropolitan areas

Table 1: List of 'Pioneer' hydrogen regions

The first important task of the pioneer regions will be to develop demonstrations of, and quite quickly scale-up, operational fleets of hydrogen buses within their metropolitan areas. The Critical Path scenario envisages that the total number of hydrogen buses in the UK by the late 2020s should be around 8 to 9 thousand. Equally divided between the 13 pioneer regions listed in Table 1, this would imply fleets of around 700 within each one. These hydrogen bus fleets would need to be supported by a small number of return-to-base refuelling depots, located conveniently for the routes of the buses. Most of these would supply hydrogen through their own forecourt decentralised hydrogen production methods, as will be discussed further below. As far as possible they will also be accessible to and suitable for private vehicles, to support the nascent publicly accessible infrastructure.

The 2020s sees other important developments for the transport sector. The UK and EU-wide commitment to decarbonisation begins to affect the transport sector even more strongly, and emissions standards set a clear trajectory towards a long-term requirement for a full-transition towards ultra-low emission vehicles (ULEVs). This applies to cars, light goods vehicles (LGVs) and heavy goods vehicles (HGVs).

HGVs benefit from some synergies with buses due to the fact that Local Authorities (LAs) often run public transport fleets as well as delivering services that require HGVs, such as waste collection. Encouraged by tightening air quality and CO_2 emissions regulations, LAs begin to convert their HGV fleets, such as waste collection vehicles, to hydrogen. They principally run and refuel them using similar ‘return to base’ logistics to those used for buses, and in some cases share the pre-existing bus depots. These early activities of LAs are critical in setting up HGV refuelling depots and hubs, which have the potential to begin to attract commercial fleets. By 2030 there are around 13,000 hydrogen HGVs in operation across the UK, or about 1,000 vehicles in each of the pioneer regions.

For cars and LGVs, until the mid-2020s, the ratcheting emissions standards can be met by relatively incremental improvements in vehicle efficiencies and clean-up technologies – the period sees sales of hybrid electric vehicles (HEVs) growing strongly in both car and LGV markets. However, from the mid- to late-2020s, the continued commitment of policy makers to tightening vehicle emissions standards makes it clear to manufacturers that vehicles with not incremental but step-change improvements in emissions are required. Manufacturers with existing models of battery electric vehicles focus more strongly on rolling these out, reducing cost and improving the space and comfort of the vehicle rather than significantly extending the range. As a result, around 700,000 BEV cars and 60,000 LGVs are on the roads by 2030.

However, the lack of focus on range creates an opportunity for developers of hydrogen fuel cell vehicles, who now focus their efforts on developing cost-effective cars and LGVs with sufficient hydrogen storage capacity to provide for longer-distance journeys. The existence of the hydrogen ‘pioneer’ regions provides these vehicle manufacturers with another important opportunity. Each pioneer region contains a small number of dedicated refuelling facilities designed to meet the needs of the hydrogen buses which by the late 2020s run within the bus networks of the major metropolitan areas. These are supported by a national network of decentralised refuelling stations, to support longer-distance journeys. The car and LGV vehicle manufacturers work with the LAs and bus companies to expand these refuelling facilities further for the smaller vehicles. The car and LGV manufacturers target vehicles at early adopters in both the private and LGV fleet sectors, the latter including fleet-owners of high-duty cycle vehicle fleets such as postal vehicles and fleets where zero emissions or low noise are an advantage – such as for urban deliveries. In some cases, vehicles are offered on a leasing basis to overcome perceived risk and high cost of the emergent technology.

In short, a combination of strong policy drivers on low-emission vehicles, innovative approaches to vehicle ownership and leasing, and the existence of a limited but nonetheless well-established and appropriate network of hydrogen bus and HGV refuelling depots within pioneer regions enables hydrogen vehicle developers to start filling the niche of longer-distance, low-carbon road transport left available by the focus of EV developers on short-distance urban vehicles. Whilst the total numbers of refuelling stations is small, with several around the perimeters of urban areas within each of the 13 pioneer regions and some 'connector stations' on main routes, this number would be greater than 65, the minimum believed to be required by UK H2Mobility to enable the first steps to a significant vehicle roll-out in the UK (UK H2Mobility, 2013). In the Critical Path scenario, numbers of hydrogen cars and LGVs on the roads in 2030 reach around 700,000 and 60,000 respectively.

By 2030 a very small amount of hydrogen is also used as a low carbon fuel for high- and low-temperature heat in industry, primarily in chemicals and non-ferrous metals. These demonstrations are in two of the pioneer regions with suitable industrial bases, Teesside and Merseyside, as part of a broader programme to explore options for decarbonising industry, also including efficiency measures, and the use of natural gas and electricity in preference to oil based and synthetic fuels.

As described, and despite quite considerable roll-out of vehicle technologies, the Critical Path scenario avoids serious commitments in terms of hydrogen delivery (transmission and distribution) technologies and infrastructure during this period. It achieves this through an approach based on building up demand and supply around self-sufficient hubs. These hubs begin as bus depots, are expanded by LAs to include HGVs, and then co-opted by manufacturers of smaller vehicles looking for bases from which to offer cars and LGVs. Other smaller refuelling stations or mobile refuellers may also begin to spring up in between these larger refuelling hubs.

At this stage each of these hubs and smaller refuelling points has access to its own decentralised production plant. A small proportion of these decentralised production units use natural gas SMR, in areas where electrolysis for some reason is hard to implement. Although this reduces the carbon-abatement potential of the hydrogen and has some small local emissions, zero exhaust emissions from vehicles mean that the option is still worthwhile, particularly in replacing diesel buses and HGVs. However, the majority of decentralised hydrogen production is from electrolysis, which, in the context of a strongly decarbonising electricity system, enables the hydrogen vehicles to run with lower GHG emissions than conventional vehicles.

2.2.3 2030 - 2040

By 2030, hydrogen vehicles are far from dominant – cars, LGVs and HGVs have penetrations of 2-3% of the total number of vehicles in their respective fleets, and buses less than 5%. But whilst small in relative terms, in absolute terms the deployment of hydrogen vehicles across vehicle types is substantial and representative of a very significant scale up from the situation in 2015.

In the Critical Path scenario, the decade of 2030-2040 sees the established hydrogen fleets expand from marginal roles to account for significant portions of transport demand. The policy context is of course central to this transformation. In this scenario, it is assumed that the direction set by emissions standards trajectories in the 2020s continues to be followed, with now a clear objective that by 2040 all new vehicles must be ULEVs.

From 2035 onwards, hydrogen buses rapidly expand their market penetration from their successful start in metropolitan areas to cover the whole of the pioneer regions, including their less-densely populated areas.

The successful deployment of hydrogen HGVs by local authorities in primarily urban situations now enables a market for HGVs in wider applications to develop, and, pushed by increasingly-tough emissions regulations and by the lack of alternative low-carbon technology, HGV fleet companies begin to convert to hydrogen. Initially the spread of hydrogen refuelling 'hubs', which have emerged since the early 2020s throughout the pioneer regions, is sufficient to allow commercial HGV fleets to traverse between pioneer regions and their existing HGV hydrogen hubs. However, the rapid growth in hydrogen HGVs begins to stretch the capacity of even these now large hubs, and demand for refuelling points for cross-country HGVs emerges. These points naturally spring up along the main motorway routes which connect the pioneer regions, further reinforcing the emergence of 'hydrogen corridors'.

These hydrogen corridors create greater confidence on the part of hydrogen car and LGV drivers to use the full range of their vehicle and to travel longer and longer distances, rather than being limited to their own pioneer region or a neighbouring one.

The combination of all of these factors results in a very rapid increase in the number of hydrogen vehicles on the roads during this period. From 2030 to 2040, numbers of FC buses increase from around 9,000 to almost 50,000; HGVs from 13,000 to around 190,000; cars from around 700,000 to around 5.3 million; and LGV numbers rise from 60,000 to 500,000.

Hydrogen use in industry continues to expand modestly, in conjunction with other low carbon technological solutions. By 2040, hydrogen use in industry has reached 3 TWh, about 1% by energy of the total industry fuel demand. Its use remains focused on a few applications in chemicals and non-ferrous metals, with some additional take-up in the food and drink sector.

By the late 2030s, a low-carbon electricity system with high intermittency begins to use hydrogen in OCGT plants to provide peak power, whilst still driving down the carbon emissions of the electricity sector. Some hydrogen-fuelled CCGT plants are also built at this time; these are flexible enough to support the decarbonisation of the power sector by providing mid-merit or peak power generation.

In this period in the Critical Path scenario, a substantial change in approach on hydrogen production and delivery infrastructure is required. As noted, in the previous decade the approach was dominated by hubs which, though growing substantially from their origins as bus depots, continued to produce hydrogen onsite, primarily using electrolysis. However, in the early 2030s, the continuing demand for hydrogen transport fuel begins to outstrip the capacity of the hubs, and the growing demand for refuelling points along hydrogen corridors creates the demand for hydrogen supply further away from the established production points within the pioneer zones. This brings a growing rationale for an expanded hydrogen delivery infrastructure and increases the viability of large-scale dedicated hydrogen production plants. The early 2030s sees the emergence of some hydrogen energy-dedicated large scale SMR production plants, and by 2035 around half of the hydrogen produced in the UK is from a large-scale production plant. The majority of these are SMR with CCS, and hence are clustered in regions of the UK with geographical proximity to CCS storage sites. Decentralised electrolysis also continues to expand rapidly during the 2030s, but large scale SMR CCS quickly overtakes it to become the dominant supplier of hydrogen by 2040, with a 55% share. This changing supply mix, for the first time in this scenario, creates serious questions about the need for and deployment of large-scale hydrogen delivery and distribution infrastructure. These spatial infrastructure issues are explored in greater depth in Section 2.4.

2.2.4 2040 - 2050

By 2040, hydrogen technologies are operating at scale in what is now an extremely low-carbon transport sector. Hydrogen vehicles in 2040 make up 10% of LGVs, 13% of cars, 25% of buses and 45% of HGVs. HEVs still contribute substantially in car and LGV fleets, and battery electric vehicles are popular for short-distance trips. Some battery electric buses are in use, whereas in HGVs the non-hydrogen fleet is split between HEVs and CNG vehicles. Reflecting this mix, hydrogen refuelling infrastructure is not ubiquitous – in particular it has not spread particularly extensively in urban areas, where electric re-charging infrastructure is more common, or outside of major motorway corridors. However, hydrogen corridors suitable for the long distance transit of coaches, LGVs, HGVs and cars extend on motorways and major roads spanning the whole of the UK.

Hydrogen buses are now close to ubiquitous within the pioneer regions, and the increasing availability of large scale hydrogen production and delivery infrastructure enable them to be taken up outside of the pioneer regions. By 2050, around 70% of the bus fleet across the UK uses hydrogen buses. With the HGV sector forced to drastically decarbonise, hydrogen emerged as the key enabling technology, and fuels 90% of the fleets.

Hydrogen cars and LGVs are favoured for long distance journeys, assisted by a sufficiently spread network of hydrogen refuelling stations on bulk routes. The result is that by 2050, hydrogen accounts for 40% of the vehicle kilometres travelled in cars and LGVs – this equates to about 17 million hydrogen cars and 2.6 million LGVs. Most of the remaining 60% of car and LGV vehicle kilometres are pure electric, with a few remaining hybrids.

Industrial hydrogen use has expanded modestly to 8 TWh in 2050 in high- and low-temperature heat in non-ferrous metals, chemicals and food and drink – however hydrogen has remained a marginal decarbonisation option, with other options proving more cost-effective. The majority of industry decarbonisation is achieved through an almost complete phasing out of oil products and carbon-intensive synthetic fuels as input fuels, combined with significant energy efficiency uptake. The majority of remaining industry fuel demand is met through natural gas and electricity. Industry, along with agriculture and land use, remains one of the higher emitting sectors in 2050, aligning with the sectoral emissions quoted in CCC (2012).

Hydrogen plays a significant role in adding low-carbon flexible capacity to the power system, providing 15 PJ of electricity in 2050, but perhaps more significantly 30 GW of capacity. The total capacity of the electricity sector is 120 GW.

In 2050, around 20% of hydrogen production for the transport sector is still decentralised, mostly using electrolysis. The rest is produced by SMR with CCS.

2.3 Discussion of outputs from UKTM for Critical Path scenario

The narrative of the Critical Path scenario was informed by energy system modelling conducted within the UK TIMES energy system model (UKTM).

Baseline GHG emission projections were taken from the CCC central scenario and the impacts of previously-identified abatement measures were assessed to derive emissions profiles for each sector to 2050, shown in Figure 1. These emission profiles were imposed on UKTM so that the model would be broadly consistent with the CCC central scenario. This meant that abatement measures using hydrogen technologies in the Critical Path scenario could be compared with alternative abatement measures from previous CCC studies.

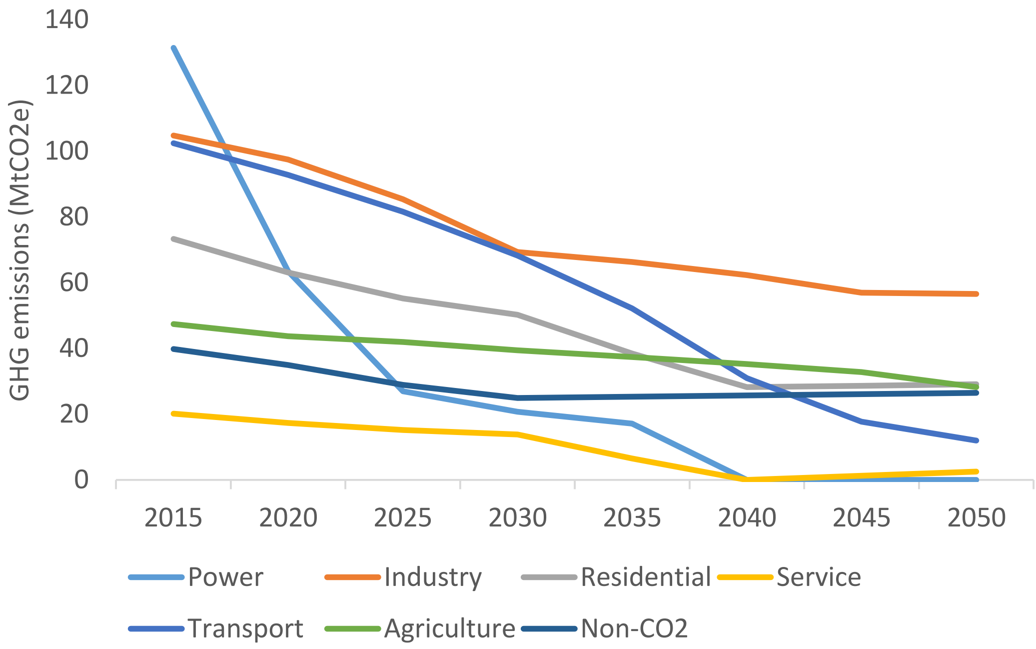

Figure 1: Sectoral GHG emissions in the Critical Path scenarios. 'Industry' includes energy industries such as oil refineries.

Additional constraints were imposed on UKTM so that hydrogen consumption would be consistent with the backcast scenario described in Section 2.2, particularly in the transport sector. On the supply side, constraints forced the model to use decentralised production for the transport sector exclusively until 2035 and then for at least 20% of the supply subsequently. On the demand side, the penetration of hydrogen-fuelled vehicles for each transport mode was specified for each 5-year period, and total industrial take-up of hydrogen (in addition to existing consumption) was also specified. The narrative and UKTM results were developed iteratively to reach a plausible scenario, and the UKTM results could then be used to calculate the abatement measures. More detail on the methodological interactions between modelling outputs and scenario storyline development is in Appendix A.

The hydrogen-related UKTM outputs give rise to a number of energy-system insights and challenges, discussed below.

2.3.1 Overall transitions within the transport sector

Figures 2–5 show UKTM outputs for the fulfilment of transport energy service demand by vehicle type in buses, HGVs, cars and LGVs, measured in billion vehicle kilometres. The transitions exhibited in these figures are driven in large part by two scenario-related modelling constraints. First, an emissions constraint on the transport sector forces a linear reduction in overall transport emissions between the Fourth Carbon Budget levels and the 2050 sectoral target, as defined in CCC (2012). Second, hydrogen-specific end-use constraints are applied to ensure the model replicates the scenario's description of hydrogen being used in strategically-important end uses in 2050. In addition to these major constraints, the model also operates within a number of other technological constraints, relating to the earliest dates of technology availability and maximum roll-out growth rates (more details are in Appendix A).

Figures 2 and 3 illustrate the technological transition in the bus and HGV sectors, respectively. They show that conventional diesel engines continue to dominate in these sectors throughout the 2020s. However from 2030 onwards a rapid and quite substantial shift begins in both sectors. A large part of this shift involves the growth of hydrogen technologies, as the model needs to ramp up to meet its 2050 targets for these technologies, and must start deploying them through the 2030s due to its growth constraints. However, other alternative lower carbon technologies are brought in from the mid-2020s onwards, and also contribute to eroding the share of diesel technologies. These other technologies – battery electric buses, and hybrid electric HGVs – are not forced in by technology-specific constraints, but are required by the model in order to meet its steadily declining sectoral emissions constraint.

While hydrogen buses are being rolled-out, other low carbon bus technologies are deployed, including electric and perhaps CNG buses. As UKTM does not include segmentation of the bus market, and this project has not focused in detail on the characteristics of non-hydrogen low-carbon bus options, it cannot be definitive on the relative share of the different options. Hydrogen buses will need to outcompete whichever other options are used, through benefits such as lower emissions, longer range, or higher reliability.

Figures 4 and 5 show a similar transition process in cars and LGVs, respectively.

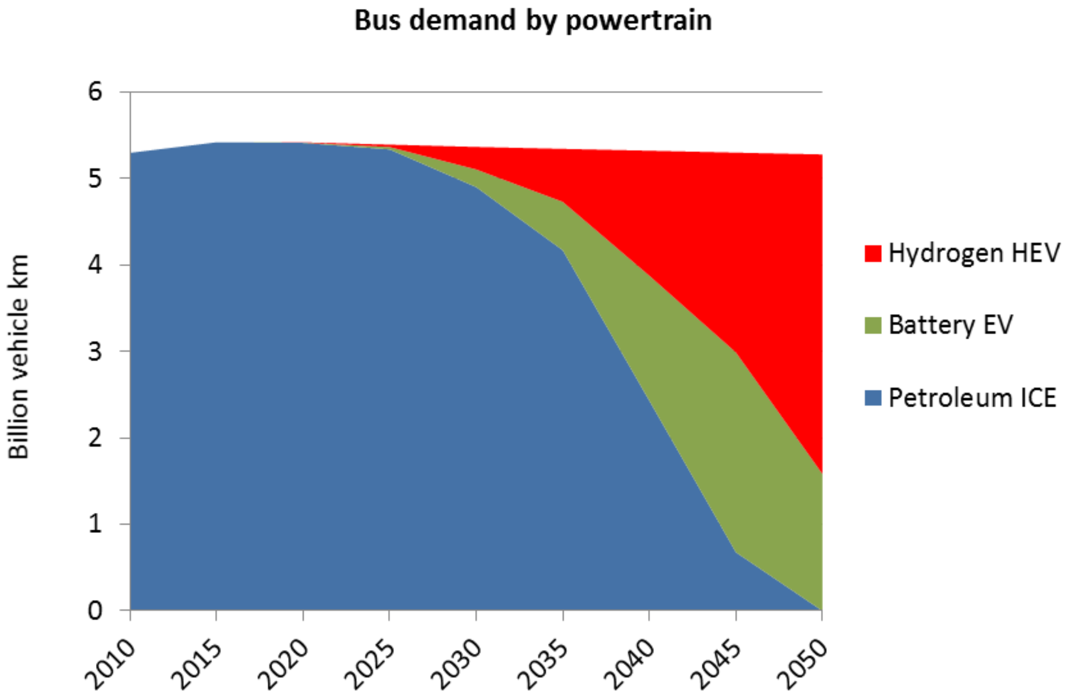

Figure 2: Critical Path scenario – bus vehicle kilometre demand

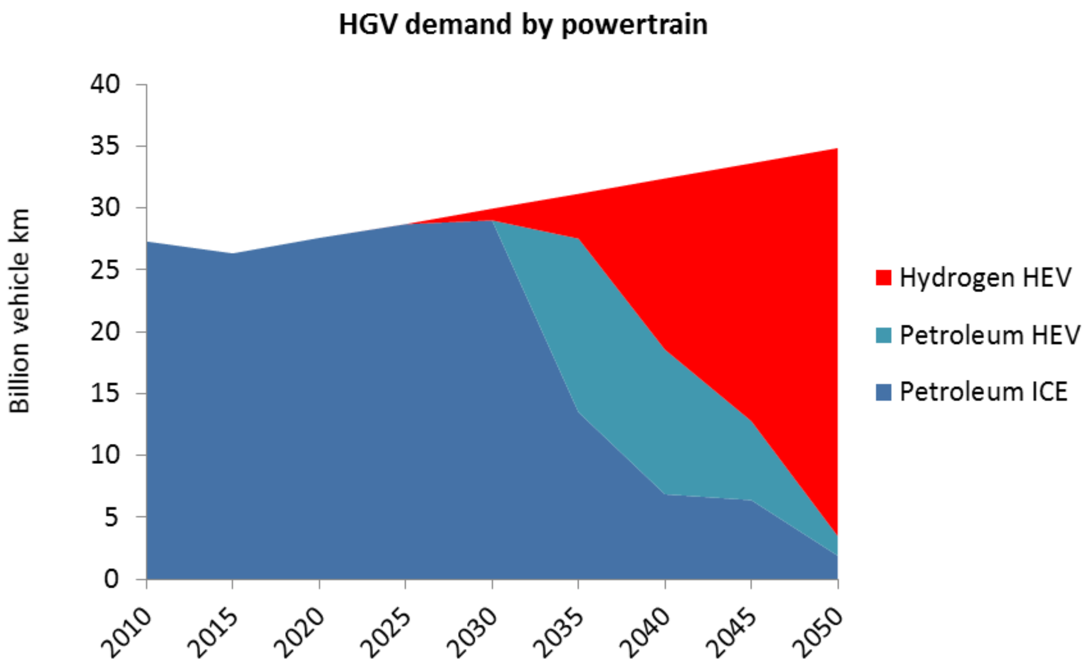

Figure 3: Critical Path scenario – HGV vehicle kilometre demand

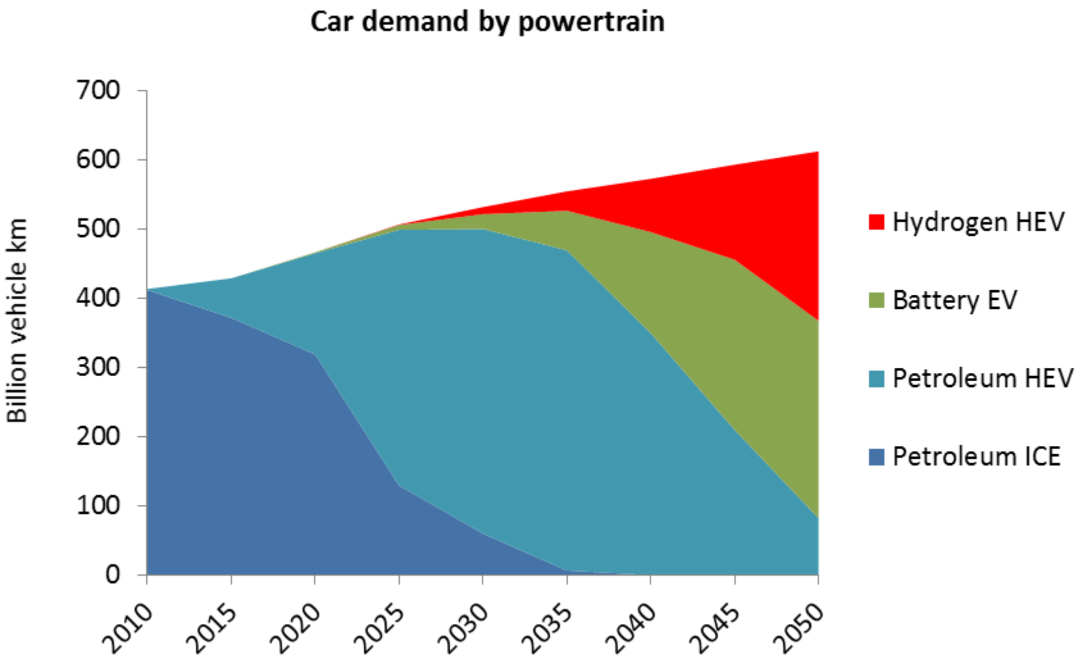

Figure 4: Critical Path scenario – car vehicle kilometre demand

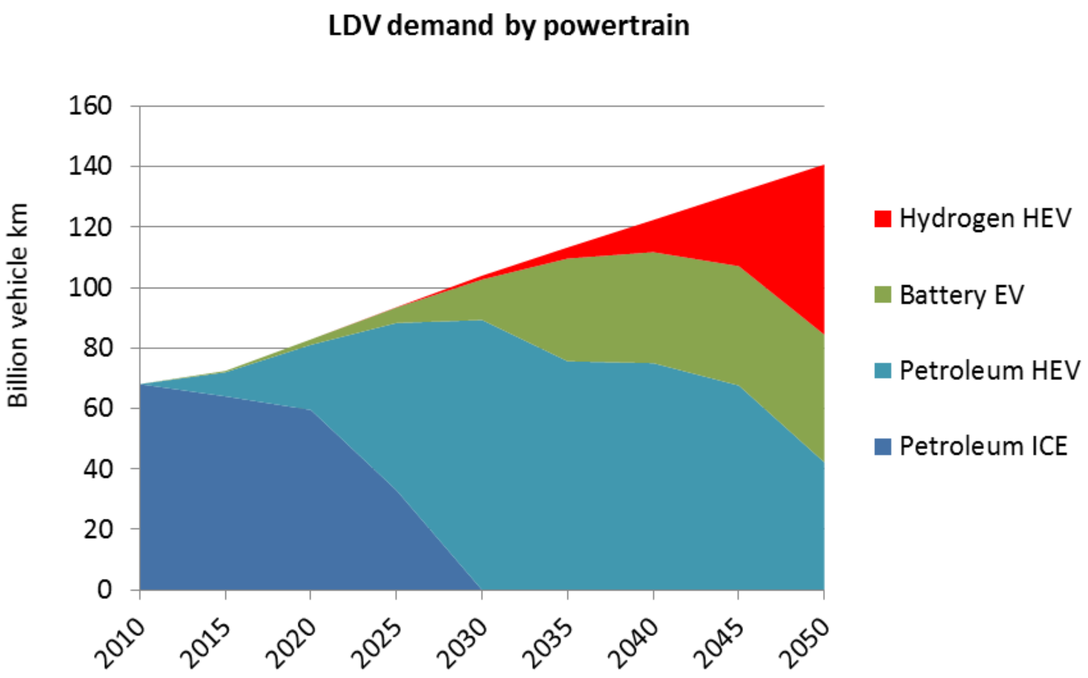

Figure 5: Critical Path scenario – LGV vehicle kilometre demand

As shown in Figures 4 and 5, the first major substitution in cars and LGVs is the very substantial growth until around 2030 of hybrid vehicles, which largely displace conventional petrol and diesel cars due to their greater efficiency and lower emissions. From 2030, hydrogen vehicle numbers grow steadily in both sectors, to meet 2050 targets within the constraints of annual growth rate limits. However, both sectors also simultaneously see a similar growth from 2030 onwards in pure electric vehicles. Again, these electric vehicles are not forced in the model by technology-specific targets, but are low-carbon alternatives chosen by the model in addition to the hydrogen vehicles, in order to fulfil each energy service demand whilst remaining within the overall sectoral emissions constraint.

The high-level story illustrated by these figures is about the timing of technological availability, and how this coincides with the timing and requirements of sector-specific emission reduction trajectories. The Critical Path scenario assumes hydrogen plays a significant role by 2050, but with its large-scale adoption somewhat delayed – due to late technology availability and a lack of technology-specific policy commitment and anticipatory infrastructure investment. At the same time, the scenario still has a linear emissions reduction constraint on the transport sector. This combination of factors sees the model selecting transitional low-carbon transport technologies during the middle period, as the emissions constraint forces it to displace conventional petrol and diesel engines at a time before the hydrogen technologies it must deploy by 2050 are sufficiently available. Battery-electric bus numbers thus grow strongly to 2045 but then reduce their contribution slightly in 2050 as they are replaced by hydrogen. For HGVs, a similar HEV trajectory is shown. In cars and LGVs, HEVs are a key transitional technology, dominating car sales in 2030, before being almost completely displaced by rapid growth in both hydrogen and pure electric vehicles. The fate of these transitional technologies in the modelling results raises questions about sunk investments and path dependency, especially in cases where the transitional technologies would involve some supporting infrastructure to make them viable. For policy makers this model dynamic highlights an important choice. If you wish to take a purely technologically neutral approach on decarbonisation, are you willing to accept the possibility of lock-in to the first technology that is available to meet your medium-term requirements, and accept the risk that it may not be the best technology for your long-term requirements? Alternatively, if you prefer to focus on achieving a more radical technological shift in the longer term, are you willing to accept a less linear decarbonisation pathway, as the success of the longer-term technology requires holding on to the conventional incumbent technology for longer, in order to avoid lock-in to what is only an incrementally-improved medium-term technology?

2.3.2 Hydrogen vehicle deployment rates

Figures 6 and 7 show the increasing market share of hydrogen FCEVs, and the average annual additions to the fleet, for the main road transport modes. The model was given technology availability and growth constraints to reflect the core assumptions that a major hydrogen commitment is delayed until late in the period to 2050, and even then focused only on strategically important end uses. Hydrogen buses are assumed to be available throughout the modelling time horizon, and their share of vehicle kilometres rises steadily throughout the time period. Cars begin to be available in commercial numbers from the mid-2020s onwards and ramp up rapidly in order to meet their 2050 targets within their growth constraints. HGVs and LGVs become widely available from 2035 but require lower average additions to their fleets each year due to their lower overall numbers.

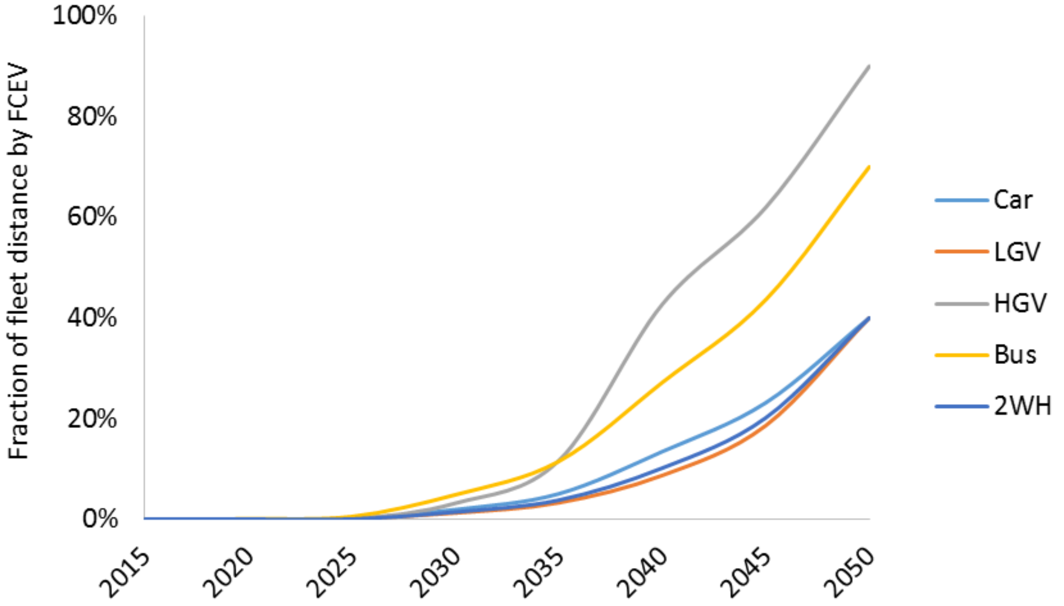

Figure 6: Critical Path scenario – fraction of fleet distance by hydrogen FCEVs

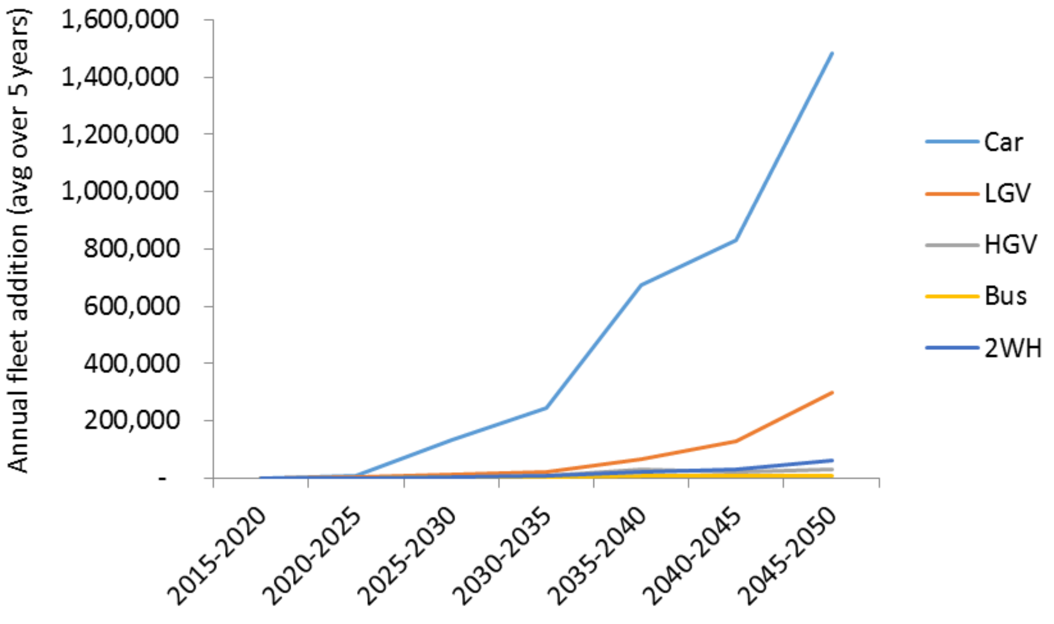

Figure 7: Critical Path scenario – annual hydrogen FCEV fleet additions (average over 5 years)

2.3.3 Hydrogen production

Hydrogen production for transport was constrained in the model to decentralised options until the early 2030s. This reflects the Critical Path scenario storyline element that commitment to hydrogen delivery infrastructure would be avoided for as long as possible, so the vast majority of hydrogen would have to be produced without delivery infrastructure at low levels of hydrogen demand, in practice meaning onsite electrolysers or small-scale SMR at refuelling depots and stations. Since many locations would not have a suitable nearby gas connection, electrolysis would likely dominate decentralised capacity. From the early-2030s, centralised production becomes viable and most of the rapid growth in hydrogen demand is met by large-scale SMR with CCS – this is a preferred option as its scale offers greater cost efficiencies than decentralised technologies, and the ability to add CCS to large-scale SMR means that it can still be a low-carbon production route. If a hydrogen national transmission network were constructed, then large coal or biomass gasification plants with CCS could be built instead of regional SMR plants. Production from large-scale electrolysis would be less likely due to the high cost of electricity, unless high deployment of intermittent renewables were to cause lengthy periods with excess electricity generation that would otherwise be wasted, and regulatory structures allowed suitable business models to be developed for these markets. Nevertheless, production from decentralised electrolysis (and to a small extent SMR) still accounts for 20% of transport sector hydrogen in 2050, reflecting a scenario-based modelling constraint that some hydrogen demand is in areas that cannot sensibly be accessed by hydrogen networks.

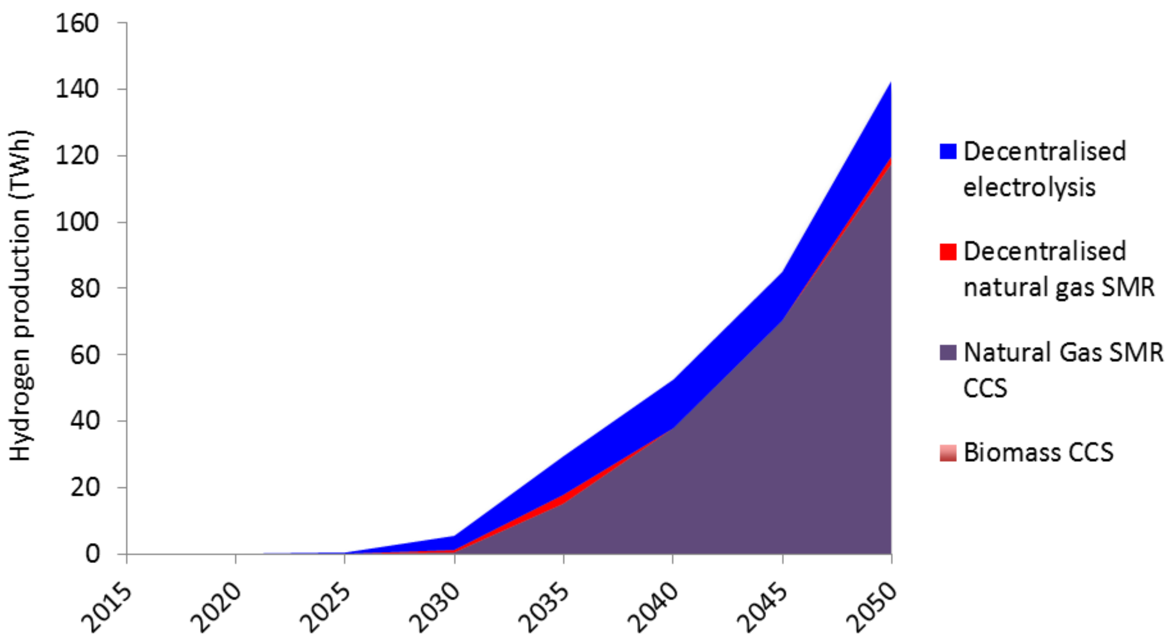

Figure 8: Critical Path scenario – hydrogen production methods

2.4 Spatial and infrastructure issues

Issues of spatial distribution and infrastructure are critical for energy systems, and can be particularly challenging for new technologies that require the development of new infrastructure to support them. A key consideration in a hydrogen transition involving transport is the number and distribution of refuelling stations that would need to be available to allow hydrogen vehicles to travel medium to long distances. As noted in the scenario description, the construction of commercial refuelling stations for cars begins in the late-2020s at locations on the edge of urban areas within each of the 13 pioneer regions, with more than 65 stations deployed as suggested in UK H2Mobility to enable a significant vehicle roll-out in the UK (UK H2Mobility, 2013). The distribution of these refuelling stations would be spread fairly widely across the UK, as the pioneer regions cover many areas of the country.

With a reasonable range (several hundred km) on the vehicle, aided by on-board GPS and telematics systems that help to plan routes via refuelling points as is done today with some battery EVs, the use of a hydrogen vehicle to travel between any two of the pioneer regions would already be viable. The subsequent growth of hydrogen refuelling stations along obvious routes between pioneer regions (such as the M6 between Liverpool and the West Midlands, and the M1 between Yorkshire and London) would then emerge in line with demand.

However, the particular nature of the Critical Path scenario poses an additional question in relation to infrastructure and use of hydrogen cars. In the Critical Path scenario, hydrogen cars are primarily used for medium to long distance trips, and less for short-distance and urban commuting trips. This is partly due to the success, in this scenario, of electric vehicles in capturing the niche of the short-range, ultra-low emission vehicle, but also due to the lack of commitment to creating hydrogen distribution infrastructure, which means that hydrogen is not widely available within high-density residential areas. This creates the question of whether users of hydrogen vehicles for long-distance inter-regional travel would still be able to drive them into cities and residential areas to park them in their own drives and garages; and if so whether the lack of refuelling facilities within their immediate vicinity would be a concern.

This issue could be resolved in a number of ways. The information provided by on-board systems may mean that having refuelling stations on the peripheries of towns, on motorways and A-roads would in fact be sufficient, and that drivers become accustomed to refuelling in these locations along the journey, without the need for a refuelling station within the vicinity of their final destination. Another option would be for such customers to use plug-in hybrid hydrogen vehicles, which would enable them to be electrically charged at the home or at their destination, with the powertrain switching from battery to hydrogen mode only on long-distance journeys. A further possibility is to consider a more radical reconfiguration of the way transportation is undertaken, possibly enhanced by the kinds of automated or driverless technologies considered by Begg (2014). The long-term potential of such technologies may be to create a more seamless mass transit system, which blurs the boundary between public and private transport. Rather than exclusively owning a single vehicle for all purposes, users may be part of a shared system which enables them to summon on demand the type of vehicle, or sequence of vehicles, that is optimal for the trip they desire to make. In our current paradigm the idea of taking one type of vehicle (e.g. a short-range electric vehicle) from the centre to the edge of a city, to exchange it for a different type of vehicle (e.g. a long-distance hydrogen vehicle) to travel a few hundred miles on a motorway before changing again to a short range vehicle at the outskirts of the destination city, seems unfeasibly complex. In a much more fluid system enabled by IT and alternative ownership models, it could be entirely straightforward.

As well as the location and distribution of refuelling stations, another key infrastructure question relates to the transmission of hydrogen from the production site to the demand location. As discussed through Section 2.2, the Critical Path scenario aims to delay till as late as possible the physical commitment of building infrastructure for the large-scale transmission and distribution of hydrogen between geographically-separated production and demand centres. This delay is enabled by the fact that production until 2035 is from decentralised SMR or electrolysis, which use existing gas and electricity networks to produce hydrogen onsite without the need for hydrogen delivery infrastructure. Yet from the mid-2030s, the quantities of hydrogen produced in the Critical Path scenario begin to test the plausibility of continuing to use only decentralised production methods. The cost-optimal option in the UKTM model is centralised SMR with CCS as the dominant method of hydrogen production – in fact, the decentralised options that do appear have been forced in as part of the Critical Path scenario constraints, reflecting the scenario storyline element that a lack of commitment to infrastructure means that decentralised forecourt production is the only possibility until the mid-2030s. From this point on, however, as shown in Figure 8, large-scale SMR CCS grows rapidly and questions of hydrogen delivery infrastructure become important.

Figure 9 shows the locations of saline aquifers which have potential as CCS storage sites around the UK and UK territorial waters, and the locations of major CO_2 point sources from electricity generation. Figure 10 represents the geographical distribution of the total 2050 hydrogen demand in the Critical Path scenario, assuming that hydrogen demands are in proportion to the relative population sizes of the regions.

If the objective were to minimise the lengths of CO_2 pipelines installed, SMR CCS would have to be as near as possible to the storage sites indicated on the map, and hydrogen pipelines would be required to deliver hydrogen from these sites to points of demand. Conversely, if the objective were to minimise the hydrogen delivery infrastructure, then SMR CCS would be built following the geographical patterns of hydrogen demand – this would minimise the lengths of hydrogen pipelines to be built, but very likely extend the lengths of CO_2 pipelines required to carry CO_2 to the offshore aquifers. In this project we have made the assumption that a hydrogen pipeline network would likely be required to support a national network of refuelling stations, whether production sites were centralised or decentralised. Centralised production enables economies-of-scale and also minimises the size of the CO_2 network, so is assumed for this scenario.

As shown in Figure 9, substantial clusters of offshore saline aquifers can be found in the North Sea off the east coast of Scotland, off the coast of East Anglia and Lincolnshire, in the Irish Sea off the coast of Merseyside and Lancashire, and a small site off the southern coast of Hampshire and Dorset.

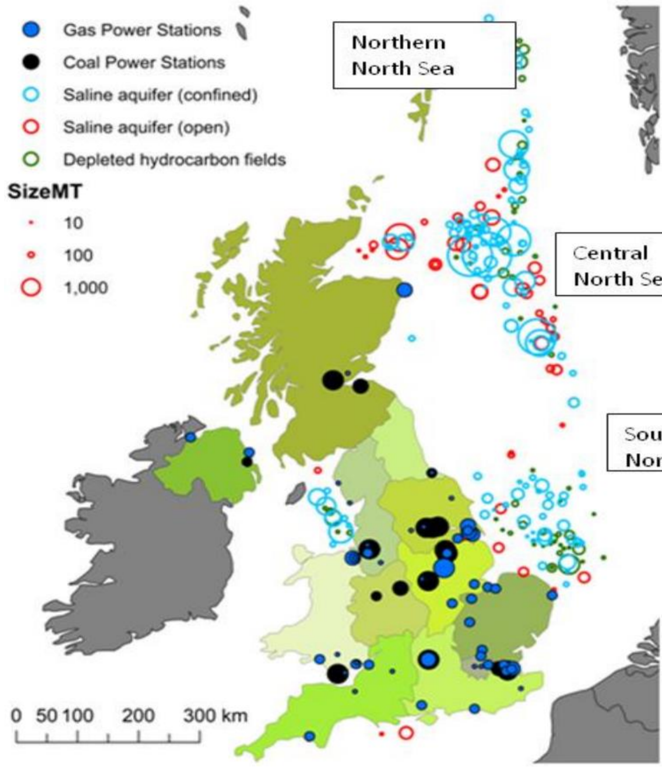

Figure 9: Locations of CO_2 point sources and saline aquifers, UK. Map provided by ETI. Source: DECC (2012).

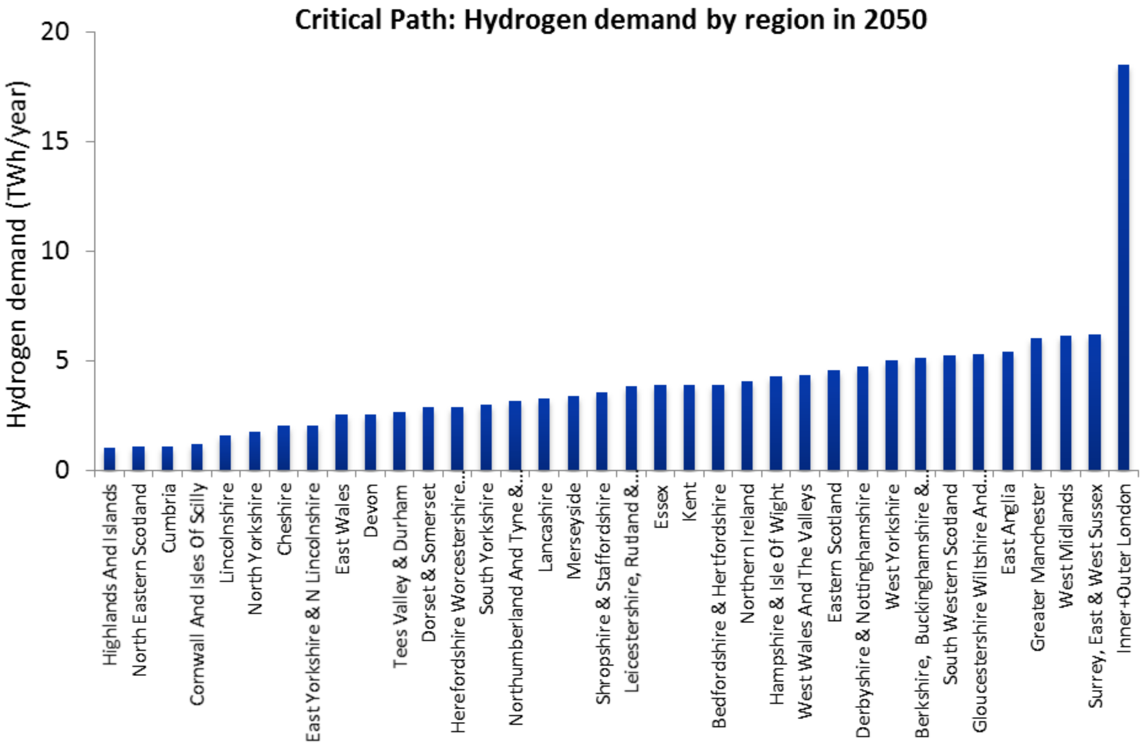

Figure 10: Geographical distribution of hydrogen demand in the Critical Path scenario in 2050, by NUTS level 2 region, assuming demand in proportion to population.

The Critical Path scenario includes about 25 TWh of hydrogen per year produced from decentralised methods. The most likely candidate regions to use this decentralised hydrogen would mainly be those with the lowest demand, as lower throughputs would make the economics of hydrogen pipelines less viable. It is assumed that, despite its relatively low demand, Tees Valley and Durham would be connected to centralised production, as the region already has strong industrial hydrogen production experience. Excluding Tees Valley and Durham, the remaining 14 lowest demand regions (from Highlands and Islands to South Yorkshire, reading along the x axis) each have an annual demand less than 3 PJ, and in total the demands of these 13 regions sum to around 29 TWh per year, a similar level to that produced from decentralised sources in Critical Path. It could therefore be assumed that these 13 regions would have hydrogen supplied from local decentralised SMR or electrolysis, without the need to connect to a hydrogen network.

It is then possible to group the remaining higher demand regions into clusters in relation to potential sites for large scale SMR CCS, based on the map in Figure 9. Production facilities in the Merseyside region could feed one pipeline that ran to Greater Manchester, Lancashire and West Yorkshire, and another that ran south to Shropshire, the West Midlands and into South Wales. Production facilities in Teesside could feed a pipeline running to Northumberland, Tyne and Wear. Production facilities on the east coast of Scotland, perhaps near Grangemouth, could supply a pipeline to eastern and southern Scotland; production facilities on the East Anglian coast could supply a pipeline running to London and the south-east; production facilities on the Humber could supply a pipeline to the East Midlands; and production facilities on the southern Hampshire coast could supply a pipelines to Oxfordshire and the Bristol/Bath area.

3 Full Contribution Scenario

3.1 Principles and definitions

The Full Contribution scenario is an aggressive hydrogen uptake scenario characterised by early, consistent and long-term commitment to the extensive use of hydrogen across the economy. This commitment is equally strong throughout the timeframe of the scenario, allowing strategic, anticipatory investments in hydrogen-enabling infrastructure in advance of the materialisation of hydrogen demand, which the model shows is more cost-effective. It is driven by an early decision to decarbonise heat provision across the UK by delivering hydrogen using existing infrastructures, and this subsequently provides some of the infrastructure for FCEV adoption in the transport sector. Around 85% of UK homes are heated using natural gas and these households are accustomed to a small, quiet, reliable, responsive, low-cost, high-power heating system on demand. For these reasons, gas heating is very popular (Ipsos MORI and Energy Saving Trust, 2013). This scenario builds on their popularity by continuing the status quo for heating in on-gas areas, but with a national conversion programme replacing natural gas with hydrogen across the country to greatly reduce CO_2 emissions.

The use of hydrogen in the Full Contribution scenario in 2050 can be described as follows:

- Hydrogen fuel cell vehicles are the dominant technology for all private road transport, buses and light and heavy goods vehicles (HGVs).
- Hydrogen is piped into many buildings (residential, public sector and commercial) where it is used to generate heat in hydrogen boilers (with similar operational characteristics to existing gas boilers) and possibly also in micro-CHP fuel cells in larger homes with higher heat demands. Where district heating infrastructure is developed, hydrogen may also be used as a zero-carbon energy carrier for small CHP units and for district heat boilers.
- All residential, public and commercial buildings would have piped hydrogen except:
    - Rural (off gas grid) and high rise (termed 'off gas on grid') homes – about 5 million properties.
    - Areas where district heating is already installed.
- Hydrogen is used as a storage medium for excess renewable electricity generation, primarily at a large scale (salt caverns and other large scale storage).
- Hydrogen is also used in power generation for peak generation and also for some mid-merit generation in CCGTs.
- Hydrogen is used extensively as a clean fuel in some industry sectors – it provides low-carbon high-temperature and low-temperature heat for iron and steel production, non-metallic minerals, non-ferrous metals, paper, chemicals and food and drink.
- Hydrogen is also widely used as a propulsion fuel for vessels on inland waterways and for passenger ferries on routes within the islands of the United Kingdom.
- Key to the supply of hydrogen in this scenario in 2050 are the existing gas distribution networks, which have been repurposed to carry hydrogen to domestic users and to local refuelling stations. The high-pressure gas network cannot be repurposed to carry hydrogen and has been replaced; any bulk transportation of hydrogen that is required must be achieved via dedicated hydrogen transmission pipelines, or other delivery methods.

Once again, a qualitative 'backcasting' process was used to develop the evolution of the Full Contribution scenario from this combination of 2050 hydrogen end-uses, as well as providing input constraints for the UKTM energy systems model. The qualitative and quantitative insights from each of these processes were brought together to produce the narrative of the Full Contribution scenario, laid out in the following sections.

For more detail on the assumptions behind the end point conditions, definition of modelling parameters, and the scenario development process, see Appendix A.

3.2 Narrative

3.2.1 2015 – 2020

In order to facilitate the later extensive roll-out of hydrogen, a key action in the first five years of this scenario is the continuation of the ongoing Iron Mains Replacement Programme (IMRP) to a planned conclusion in the mid-2030s. This programme is replacing legacy iron pipes within 30 m of buildings with polyethylene pipes for safety reasons. Although already underway for two decades, uncertainty over the future of the gas networks in a low-carbon energy system has encouraged policy makers to slow down the programme and target the pipes at highest risk of causing accidents, in order to reduce expenditure. In the Full Contribution scenario, these uncertainties are resolved by a clear decision to continue to invest in the IMRP for the medium- and low-pressure gas network. In addition to the safety benefit, this decision is further justified by the potential future benefit of making the network 'hydrogen ready', thus facilitating an extensive future use of hydrogen.

Due to this long-term commitment, this period also sees the start of an expansion in training of hydrogen gas-safe workers. The high rate of roll-out achieved in subsequent phases of the scenario, in both gas mains and building appliances, is dependent on a growing cadre of skilled workers.

This phase also sees the beginnings of an early roll-out of hydrogen vehicles. Bus demonstrations are expanded with 100 buses operating across the UK by 2020. There are also around 3,000 cars: a handful of private vehicles as well as fleet vehicles and taxis and about 500 light delivery vehicles. Around 20 HGVs are in operation, mainly trialled by local authorities for waste collection vehicles. Each of these activities is not rolled-out uniformly across the country, but strategically targeted on cities and metropolitan areas within the pioneer regions listed in Table 2. As noted in the discussion of pioneer regions within the Critical Path narrative, the reasons for inclusion in the list include favourable supply-side as well as demand-side characteristics.

List of "Pioneer" hydrogen regions	
Region (NUTS Level 2 boundaries)	**Reasons for selection**
Tees Valley and Durham	Proximity of hydrogen related industries; metropolitan areas
Cheshire	Proximity of industry; metropolitan areas
Greater Manchester	Proximity of industry; metropolitan areas
Merseyside	Proximity of industry and potential CCS sites; metropolitan areas
West Yorkshire	Proximity of industry; metropolitan areas
West Midlands	Proximity of industry; metropolitan areas
East Yorkshire and North Lincolnshire	Proximity of industry and potential CCS sites; metropolitan areas
Gloucestershire, Wiltshire and Bristol / Bath area	Proximity of industry; metropolitan areas
Essex	Proximity to London and possible LH_2 import terminals
Kent	Proximity to London and possible LH_2 import terminals
Greater London	Large demand potential demand centre
Eastern Scotland	Proximity of industry and potential CCS sites; metropolitan areas
North Eastern Scotland	Proximity of industry and potential CCS sites; metropolitan areas

Table 2: List of 'Pioneer' hydrogen regions

In this early period, hydrogen production is decentralised, with the majority from electrolysis, supported by some decentralised SMR. The use of the existing gas and electricity networks allows refuelling stations with forecourt hydrogen production to be located optimally according to the needs of the various users, with some planning and co-ordination between various fleet owners.

3.2.2 2020 - 2030

From 2020, all pioneer regions aim to scale-up the operational fleets of hydrogen buses within their metropolitan areas. The Full Contribution scenario envisages that the total number of hydrogen buses in the UK rises from just 100 in 2020, to 1,200 in 2025 and 15,000 in 2030. Buses are deployed evenly across all pioneer regions. Similarly, LGV and HGV numbers rise across the pioneer regions, reaching 150,000 and 30,000 by 2030. These include LA-owned HGVs and delivery vehicles, and privately-owned fleets including postal and delivery vehicles. These hydrogen vehicle fleets have largely return-to-base refuelling patterns, and thus continue to be supported by a network of carefully-planned refuelling depots. Refuelling demands for these fleet vehicles continues to be met through forecourt decentralised hydrogen production methods, mainly decentralised electrolysis, with a handful of decentralised natural gas SMRs.

Three urban/metropolitan areas within pioneer regions are targeted for the early roll-out of hydrogen for heating and buildings. These are chosen from Liverpool (Merseyside pioneer region), Teesside (Tees Valley and Durham pioneer region), Fife (the Eastern Scotland pioneer region) and

Leeds[2] (West Yorkshire pioneer region). These towns have strong industrial heritage, and proximity to potential CCS sites, making them good contenders for large-scale hydrogen production. The IMRP is accelerated in these towns and completed in the 5 years to 2025.

Conversion of each town is planned according to the design of the gas distribution network. Towns are divided into zones of around 50 adjacent streets that can be supplied by both natural gas and hydrogen. This means there might be around 100 zones in total for a large town. Each building in each zone is then converted from natural gas to hydrogen over a period of a few days. Conversion is limited to spring, summer and autumn, and special provision made for disabled and elderly residents. The overall process is similar to the successful conversion of the UK gas networks from town gas to natural gas in the 1970s in Great Britain and in the last decade in the Isle of Man. At the peak, 10,000 appliances are converted each day. Since it is necessary to convert the whole network in each town, the only exceptions to conversion are those organisations that stop using gas or large industrial sites connected directly to the gas transmission system.

From 2025 hydrogen is increasingly available within the pioneer towns. Small-scale hydrogen refuelling points, connected to the hydrogen gas network, spring up to supply vehicles and complement the established decentralised forecourt production depots. The increasing refuelling station coverage in these urban regions opens up the potential for hydrogen FCEVs as private vehicles for urban use. Demand for these is driven by falling costs and improving performance, tightening air quality and emissions legislation, as well as purchasing incentives and ownership models that enable consumers to de-risk their capital investment. Thus hydrogen vehicles become fairly commonplace within these city centres by 2030. Uptake and use are also underpinned by a national network of decentralised refuelling stations, to support longer-distance journeys.

From 2025 onwards, the same buildings programme begins to be rolled out in the remaining pioneer regions, with the increasing availability of hydrogen in the re-purposed gas networks allowing for the same knock-on effect in the use of hydrogen for private urban vehicle transport. Overall, the hydrogen car fleet increases from 3,000 in 2020 to 200,000 in 2025 and 1.5 million in 2030. The growth in hydrogen use in buildings is also substantial, accounting by 2030 for about 20% of residential and service sector heat demand, either in hydrogen boilers or via hydrogen-fuelled district heating.

By 2030, there is also a significant use of hydrogen as a low-carbon fuel for high- and low-temperature heat in industry, notably in food and drink, non-ferrous metals and non-metallic minerals, as a replacement for natural gas when it is no longer available. These applications have arisen following demonstrations from the early 2020s onwards, in two of the pioneer regions with suitable industrial bases, Teesside and Merseyside, and this hydrogen consumption sums to around 3% of total national industrial fuel demand in 2030. These measures fit within a broader programme

[2] Northern Gas Networks has commissioned a feasibility study, the H21 project, to examine how Leeds could be converted to use hydrogen. Leeds is located on the corner of a triangle of the Humber (with the proposed National Grid White rose CCS line) and Teesside with its history of hydrogen production and existing hydrogen storage caverns. The Leeds gas distribution network already has a large percentage plastic (PE) pipe and has several gas feeder points into the city, which would facilitate a transition. Leeds has a good mixture of domestic, commercial and industrial users so is a good location to understand the consequences of conversion.

to explore options for decarbonising industry, also including efficiency measures, and the use of natural gas and electricity in preference to oil based and synthetic fuels.

Hydrogen transmission infrastructure to connect pioneer regions is not required in the early decades in the Full Contribution scenario. The main hydrogen production options are large-scale SMR with CCS, and decentralised electrolysis and SMR. Through a combination of these technologies and cavern storage, each of the pioneer regions produces sufficient hydrogen to meet demand within the regional boundaries. For the majority of the hydrogen pioneer regions, this hydrogen demand comes from buses, LGVs, HGVs and a relatively small number of cars. These vehicles are largely fuelled at depots with decentralised SMR or electrolysis, as part of a larger national network of decentralised fuelling stations required to support FCEV roll-out. In the pioneer towns, however, with the rapid roll-out of hydrogen in buildings based on the complete re-purposing of the gas distribution network, hydrogen demand is driven by heat rather than transport, and nearby large-scale SMR CCS facilities are the primary source of production. The first dedicated bulk hydrogen transmission lines are built in the mid-2020s to transport hydrogen over relatively short distances from SMR CCS facilities close to the coast in Merseyside, Teesside and Humberside, to the pioneer towns, where it enters the re-purposed low- and medium-pressure gas networks. As the rest of the pioneer regions follow suit in the second half of the 2020s, SMR CCS becomes increasingly viable. As its cost advantage (through scale economies) over decentralised approaches grows, it makes increasing sense to meet the growing demand for hydrogen by expanding production in large-scale facilities connected to CCS storage sites. Some use of gaseous trucks and tube trailers may also be appropriate.

By 2030, a low-carbon electricity system with high intermittency begins to use hydrogen in OCGT plants to provide peak power, as part of government efforts to completely decarbonise the electricity supply by this date. Hydrogen plants provide 1 GW of flexible capacity.

3.2.3 2030 - 2040

By 2030, hydrogen cars and LGVs account for 3%–5% of their respective fleets, and buses for 9% on a national basis. However, their use is heavily concentrated in the pioneer regions, most of which now have the majority of their buses running on hydrogen and also large proportions of the other fleets. From 2030 onwards, hydrogen vehicles begin to be rolled out in bus fleets across the remainder of the UK.

By 2030, the pioneer towns have been converted to hydrogen. The national IMRP is completed across the whole country in the early 2030s, and the same roll-out of hydrogen in distribution networks and buildings is expanded to towns across the country. By 2035, 40% of residential and 35% of service sector building heat is provided by hydrogen; by 2040, hydrogen penetration reaches 60% and 50%, respectively.

In the context of tightening emissions standards for all classes of vehicles, as well as the increasing availability of hydrogen within pioneer regions, hydrogen vehicles show strong sales growth including HGVs, LGVs and other vehicles such as taxis. Hydrogen cars are increasingly chosen by commuters within the pioneer regions, and have sufficient range to allow travel between pioneer regions. Road connections between such nearby pioneer regions present the obvious routes for emerging hydrogen corridors, with regular refuelling stations incorporating decentralised hydrogen production from electrolysis. By 2040, 20% of cars and LGVs, 45% of HGVs and 50% of buses run on hydrogen.

During the 2030s, strict emissions constraints start to be applied to shipping, producing a growth in demand for hydrogen in domestic shipping routes. By 2040 hydrogen supplies about 20% of domestic shipping demand.

Hydrogen is now being used in substantial quantities across the country. While much of the hydrogen demand can be met by relatively decentralised options, especially electrolysis, or by large-scale production which is also close to large demand, such as SMR with CCS in the pioneer regions, it is increasingly the case that the locations of the most economic production methods do not fit exactly the spread of demand around the country. This provides an increasingly strong justification for bulk transmission of hydrogen over long distances, connecting large-scale production centres to demand centres. Two key transmission corridors emerge: from Humberside to London and the South-East; and from Merseyside through the West Midlands to Bristol and the South-West. These corridors follow the routes of the M1 and M6/M5 respectively.

By 2040, hydrogen is being used by large OCGT electricity generation plants and also by decentralised CCGT CHP plants in heat network schemes. These provide 3 GW of flexible OCGT capacity to the electricity system and have a total electrical output of 90 PJ.

3.2.4 2040 - 2050

By 2040, 75% of UK urban on-gas areas have been converted to hydrogen. The widespread hydrogen distribution infrastructure also provides the regional infrastructure to support a comprehensive network of hydrogen refuelling stations with fuel at competitive cost. These include new refuelling stations built on the emerging hydrogen corridors between pioneer regions, which facilitate national travel.

Hydrogen vehicles now dominate sales of new cars, HGVs, LGVs and buses. In 2040 they account for 20%, 45%, 20% and 50% of their respective fleets. By 2050, this has risen to around 95% for all modes. Hydrogen in domestic shipping continues to grow, and by 2050 accounts for around 50% of domestic shipping fuel demand.

By 2050, hydrogen is used substantially as a low-carbon fuel for high- and low-temperature heat in industry, and accounts for about 50% of industrial fuel use. Hydrogen further plays a significant role in adding low-carbon flexible capacity to the power system, providing 10 GW of centralised generation capacity and 15 GW CHP capacity in 2050, and generating 130 PJ electricity.

Hydrogen production in 2050 is dominated by natural gas SMR CCS, with very small amounts of decentralised electrolysis remaining to serve 10% of the transport sector. The dominance of this large-scale and geographically-restricted form of production means a substantial hydrogen bulk delivery infrastructure from the large CCS production sites at Merseyside, Teesside, Humberside and eastern Scotland, to demand centres. The major bulk transmission lines described in the previous phase could by 2050 be augmented with major lines from eastern to central Scotland; from Teesside to Lancashire and from Merseyside to Lancashire and Cumbria; the existing line from Merseyside to Bristol could extend into south Wales; and a new line could be built from Humberside to the east Midlands.

3.3 Discussion of outputs from UKTM for Full Contribution scenario

The narrative of the Full Contribution scenario was informed by energy system modelling conducted using UKTM, following a similar process to the Critical Path scenario. On the supply side, constraints forced the model to use decentralised production for the transport sector exclusively until the start of the gas network conversion programme in around 2025, but this was then set to reduce to a minimum of 10% of transport consumption by 2035. On the demand side, the penetration of hydrogen-fuelled vehicles for each transport mode was specified for each 5-year period. The market shares of hydrogen for heating in the residential, service and industry sectors were specified, with the model identifying the cost-optimal technologies to adopt within these constraints. The rate of gas network conversion was matched to the market share of hydrogen and the maximum share of natural gas was reduced accordingly. A minimum contribution of hydrogen CCGTs was also specified for 2050. More details on the methodological interactions between modelling outputs and the scenario storyline development are provided in Appendix A.

For the Critical Path scenario, emission profiles were imposed on UKTM to produce a scenario broadly consistent with the CCC's existing central scenario. The assumptions in these profiles about the portfolio of low-carbon technologies deployed in each sector are incompatible with the Full Contribution scenario, because a hydrogen-centred economy has a quite different balance of emissions, with a higher level of decarbonisation of end uses and hence a lower level of upstream decarbonisation. The residential sector, for example, might be virtually completely decarbonised by 2050 in a hydrogen scenario but is a source of 30 $MtCO_2e$ emissions in the CCC central scenario. For this reason, sectoral emission profiles were not imposed on UKTM for the Full Contribution scenario. Only an economy-wide emissions constraint was applied in each period to 2050, forcing a linear reduction in each sector's overall emissions between the Fourth Carbon Budget levels and the 2050 sectoral target, as defined in CCC (2012).

This section considers the energy-system insights and challenges suggest by the outputs of UKTM. As for the Critical Path scenario, the transitions exhibited in these figures are driven in large part by constraints that force UKTM to transition to hydrogen-powered end-use technologies by the year 2050, in this case to ensure the model replicates the scenario's description of hydrogen being used extensively across the transport, residential, service, industry and power sectors. In addition to these major constraints, the model also operates within a number of other technological constraints, relating to the earliest dates of technology availability and maximum rates of roll-out (more details are available in Appendix A).

3.3.1 Overall transitions within the transport sector

Figures 11–14 show UKTM outputs for the provision of transport energy service demands by vehicle type in buses, HGVs, cars and LGVs, measured in billion vehicle kilometres.

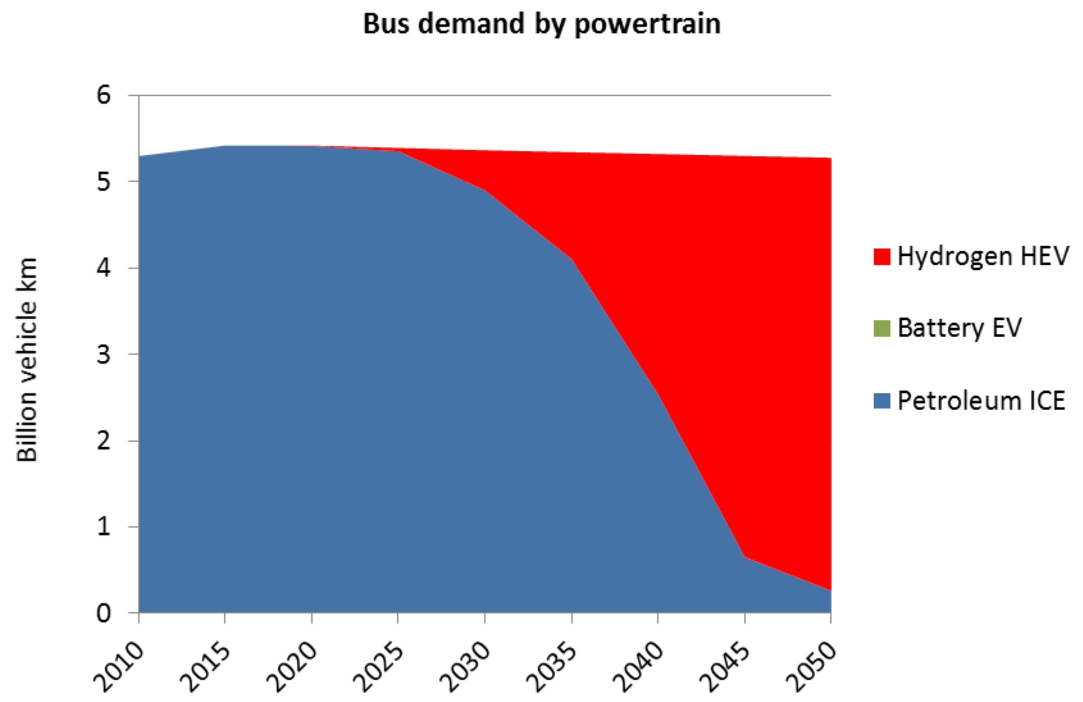

Figure 11: Full Contribution scenario – bus vehicle kilometre demand.

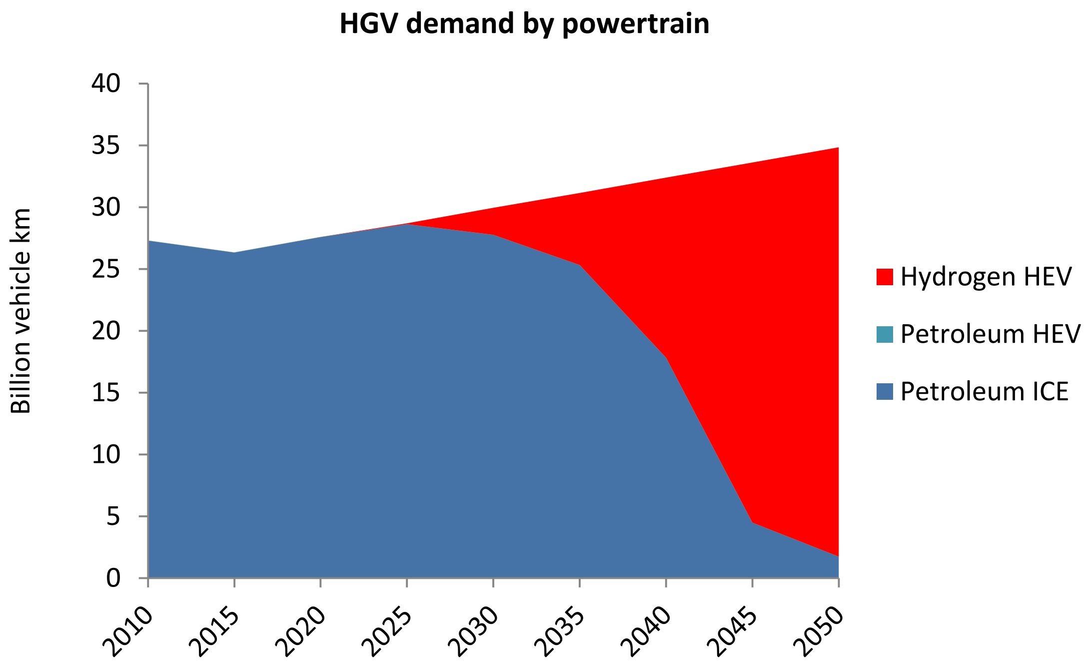

Figure 12: Full Contribution scenario – HGV vehicle kilometre demand

Figures 11 and 12 illustrate the technological transition in the bus and HGV sectors, respectively. They show that conventional diesel engines continue to dominate in these sectors throughout the 2020s. However from 2030 onwards a steady shift occurs in both sectors towards the dominant use of hydrogen technologies by 2050. Unlike in Critical Path however, the figures illustrate that in Full Contribution other alternative lower carbon technologies are not deployed in the middle period, with a later phasing out of diesel and a direct transition to hydrogen without any interim roles for CNG, pure electric, or hybrid electric vehicles.

Figures 13 and 14 show a similar transition process in cars and LGVs, respectively.

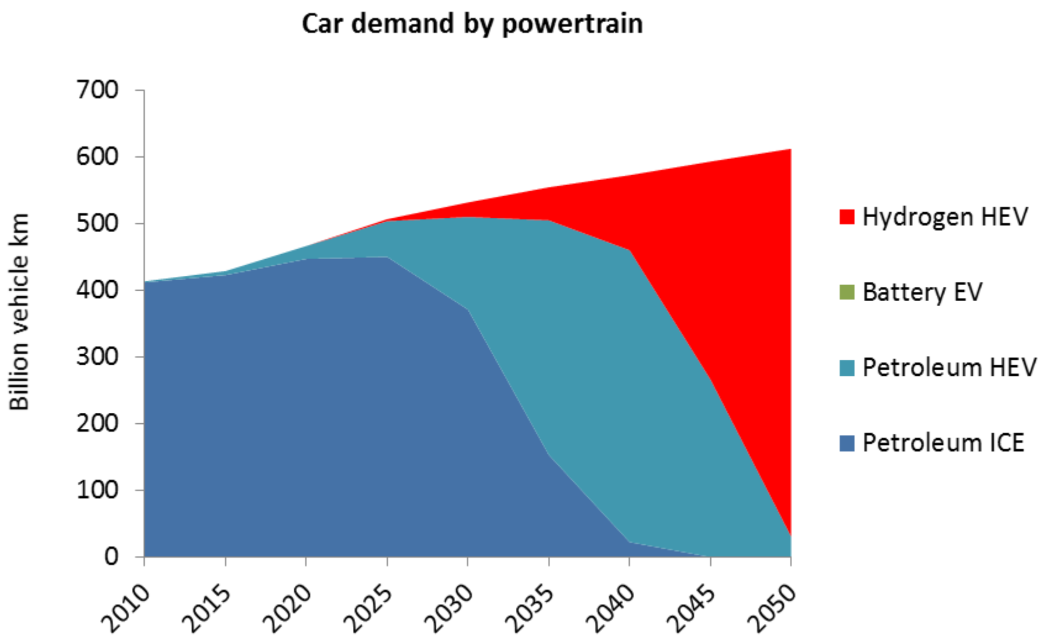

Figure 13: Full Contribution scenario – car vehicle kilometre demand

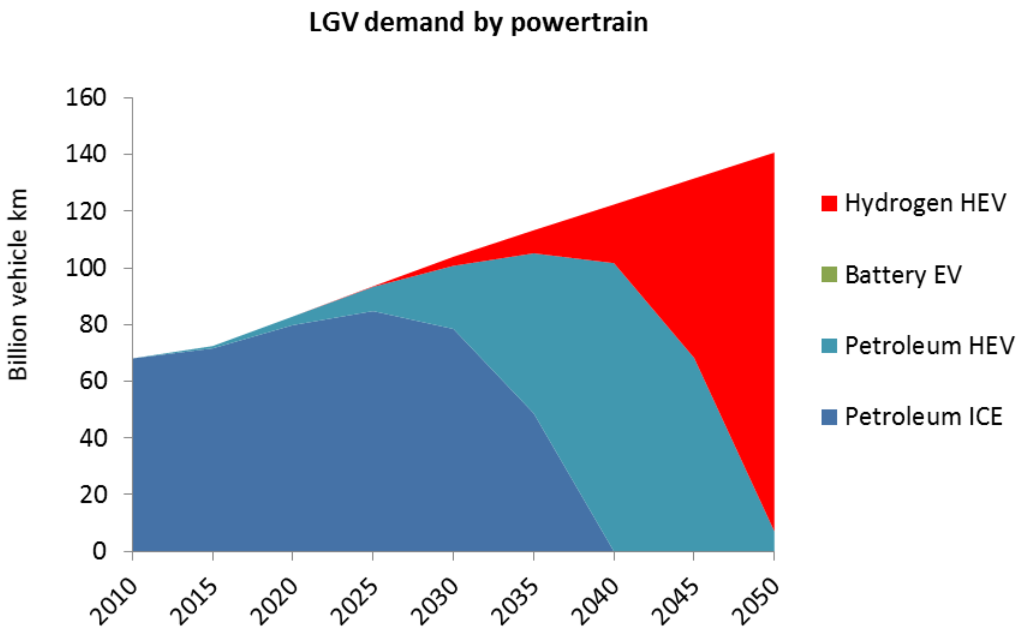

Figure 14: Full Contribution scenario – LGV vehicle kilometre demand

As shown in Figures 13 and 14, hybrid electric vehicle numbers grow strongly in the middle period, peaking around 2035 for LGVs and around 2040 for cars. These act as a transition technology: from petroleum hybrid to fuel cell hybrid vehicles, which account for almost all new sales after 2040. In contrast to the Critical Path scenario, there is no medium-term role for battery electric vehicles.

So for all vehicle types, a key difference compared to Critical Path is the absence of a transitional low-carbon technology such as CNG or battery electric vehicles. Rather a later and more direct transition from conventional (or relatively conventional, including hybrid electric) vehicles to hydrogen occurs. In Critical Path, these medium-term transitional technologies were required due to the linearly declining sectoral emissions constraint applied to transport. In Full Contribution, however, higher emission reductions in residential and service sectors as a result of starting the gas network conversion programme in 2025 mean that the transport is required to make less extensive emissions reductions in the same period to meet carbon budgets. Indeed, as is suggested by the technology transitions depicted in the above figures, the transport sector emissions in the Full Contribution scenario around 2030 to 2040 are significantly higher than in the Critical Path scenario. Total emissions could be lower in the transport sector if other non-hydrogen technologies were brought in during this period.

In the Critical Path scenario, the role of such transitional technologies raised questions about the potential problems of sunk investments in medium-term technologies under a linear decarbonisation pathway. The above graphs may be seen as representing an alternative option in which delayed emission cuts in the transport sector enable fuel cell technology innovation to reduce vehicles costs and hydrogen supply infrastructure to be built up, avoiding the possible risk of sunk-investments in medium-term solutions. There are, of course, other significant risks in such a strategy: maintaining the overall emissions trajectory would depend on the success of deep reductions in other sectors, and the strategy is also dependent on the ultimate success of hydrogen-powered fuel cell vehicles – both of which are uncertain.

3.3.2 Hydrogen vehicle deployment rates

Figures 15 and Figure 16 show the increasing share of vehicle kilometres provided by hydrogen vehicles, and the average annual additions to the fleet, for the main transport modes. The Full Contribution scenario assumes a heat-led strategy for the hydrogen transition, with the hydrogen infrastructure provided to enable conversion of buildings to hydrogen-fuelled heat, and this has the knock-on effect of enabling the infrastructure to support widespread ownership and use of hydrogen vehicles. This means that hydrogen growth in transport occurs more slowly than for heat. All technologies show relatively slow growth until 2035, after which time they ramp up quite rapidly. The roll-out of cars is especially dramatic. Net average annual additions to fleet are around 400,000 in the early 2030s, but this doubles in the second half of that decade, and then quickly rises to 3 million in the 2040s, and 3.5 million by the last five years of the time horizon. This is very rapid, but plausible in the context of the size of the vehicle fleet at that point and the expected total annual sales.

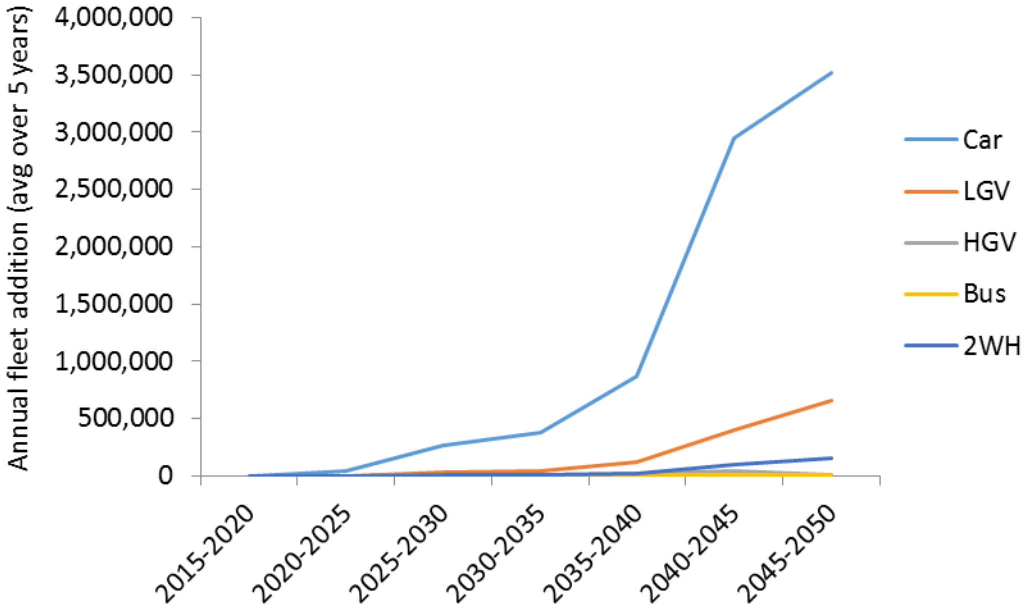

Figure 15: Full Contribution scenario – average annual additions to fleet

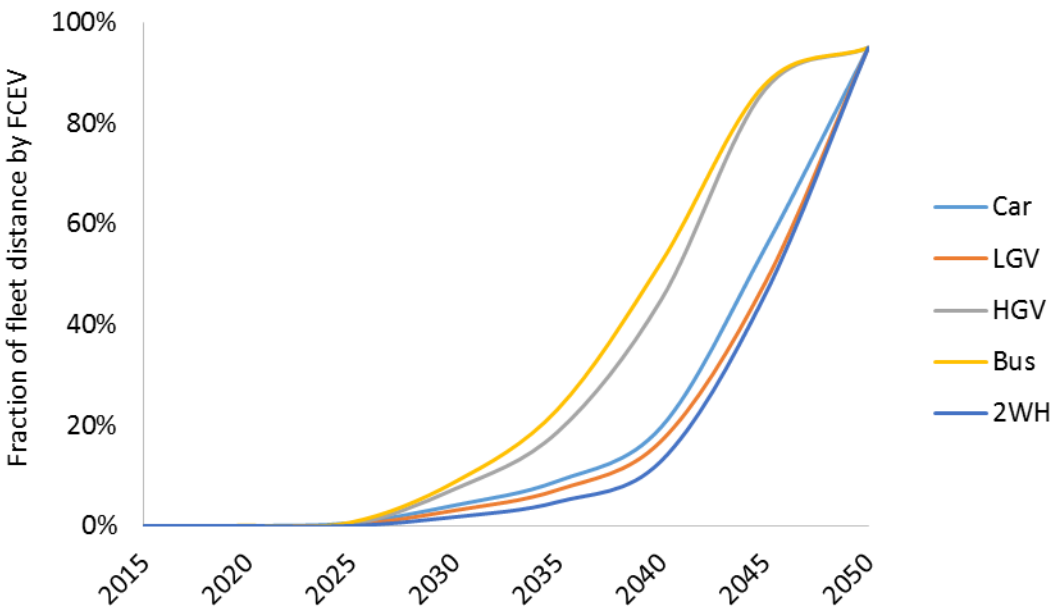

Figure 16: Full Contribution scenario – share of fleet distance by FCEVs

3.3.3 Hydrogen use in residential buildings

Figure 17 shows the Full Contribution residential heat provision. In most houses, natural gas boilers are directly replaced by hydrogen boilers. In some solid-wall houses, hybrid heat pumps with integrated hydrogen boilers for peak heat demands are deployed instead, and a small number of houses deploy standard heat pumps. Heat networks, with hydrogen technologies used in both CHP and boilers, are constructed to supply some flats. Perhaps surprisingly, no fuel cell micro-CHP devices are deployed as price projections suggest they will be too expensive, although this could change if innovation were to lead to greater cost reductions than currently forecast or if the peak winter electricity price were higher than that calculated by UKTM. This rapid roll-out of a low carbon heating fuel within the residential sector ensures that residential emissions are significantly lower in the middle-period of Full Contribution than in the equivalent period of Critical Path.

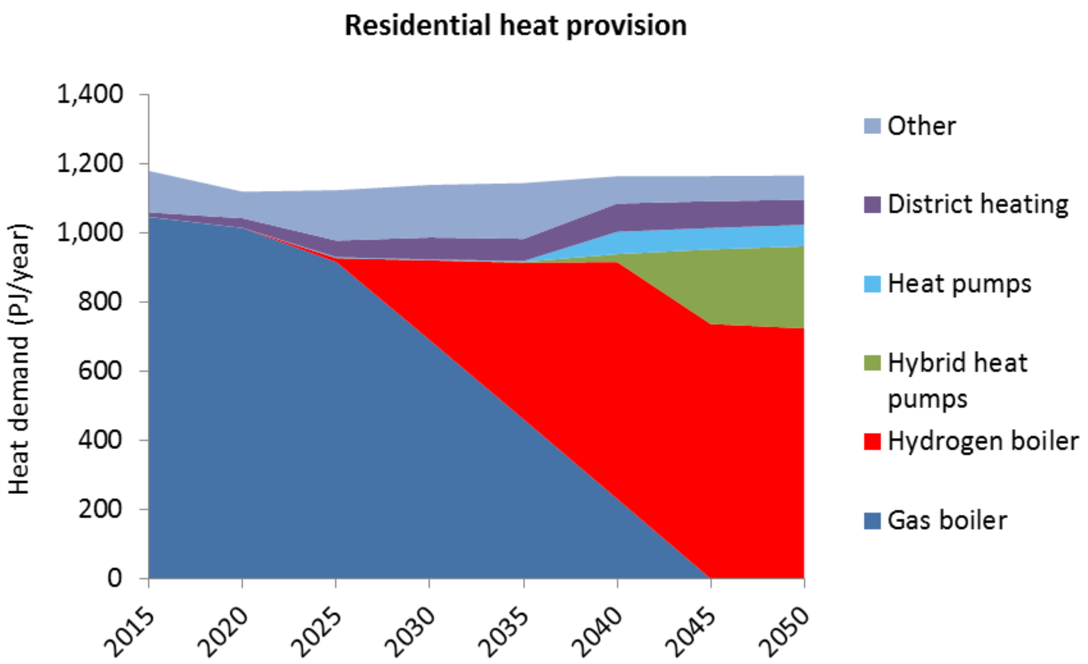

Figure 17: Full Contribution scenario – residential heat provision

3.3.4 Hydrogen use in service sector buildings

Figure 18 shows the provision of heat in the service sector. As with the residential sector, the trajectory shows a relatively early-action replacement of natural gas with hydrogen boilers, causing services emissions in Full Contribution to be lower during the middle period than in Critical Path, which helps allow the correspondingly later action in the transport sector. Hydrogen demand continues to increase to 2050 with service sector demand growth.

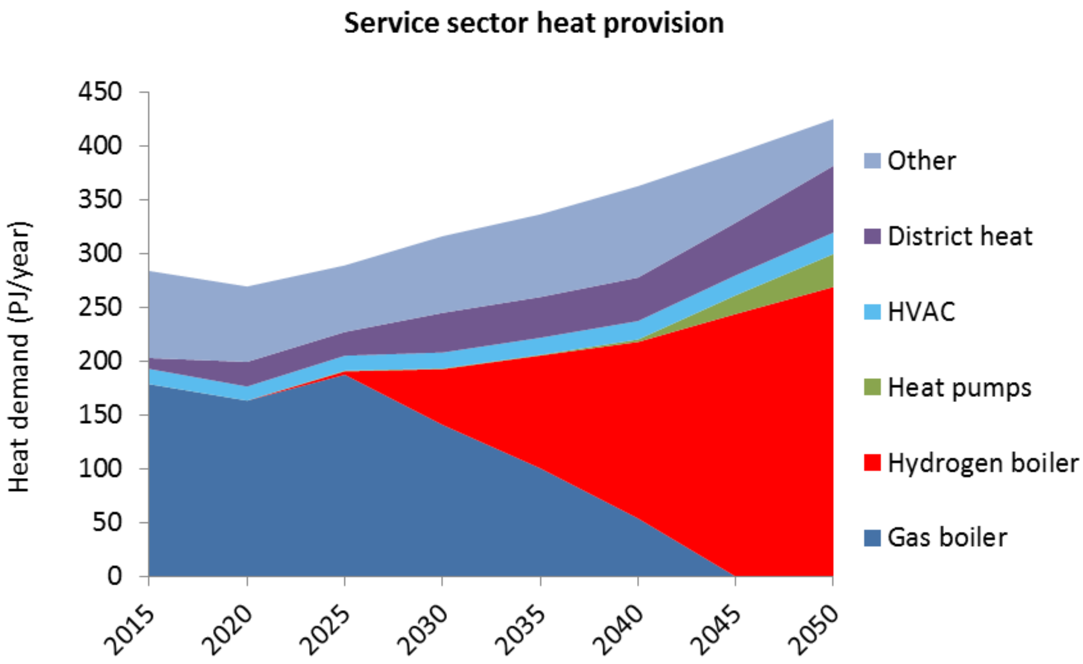

Figure 18: Full contribution scenario – heat provision for service sector buildings

3.3.5 Hydrogen use in industry

Figure 19 shows fuel consumption in industry for the Full Contribution scenario. In this sector, hydrogen is largely displacing oil and natural gas in boilers for high and low temperature heat. A small amount of additional decarbonisation is offered by biomass-based fuel sources.

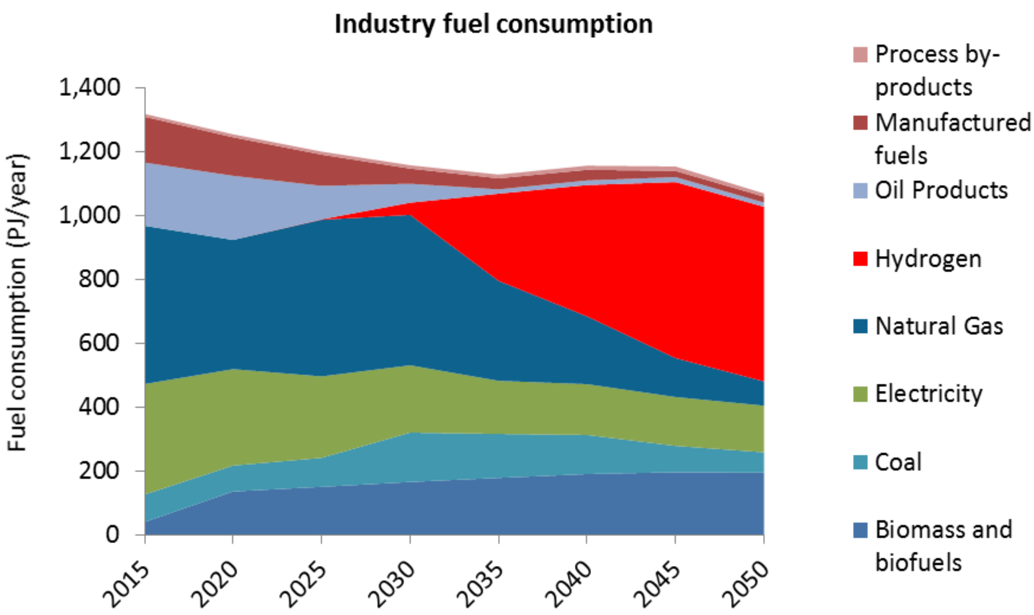

Figure 19: Full contribution scenario – industry total fuel consumption

3.3.6 Hydrogen production

The initial deployment of FCEVs in the transport sector is supported by decentralised hydrogen production at depots, in a similar way to the Critical Path scenario. However, Figure 20 shows that centralised hydrogen production using large SMR plants with CCS commences much earlier, as the pioneer towns have already been converted by 2025. The conversion programme enables new urban hydrogen refuelling stations to be widely deployed in these towns and these can provide lower-cost hydrogen than the decentralised stations in the Critical Path scenario. This means there is less need for decentralised stations, and these provide only 10% of hydrogen for the transport sector in 2050. Total annual hydrogen production in 2050 is around 6 times higher in the Full Contribution scenario than in the Critical Path scenario, as a consequence of the wide adoption of hydrogen for heat provision. Centralised hydrogen is produced exclusively by SMR plants with CCS.

In contrast to the transport sector, hydrogen demand for heat provision would vary substantially throughout the year and there would be a requirement for buffer and possibly inter-seasonal storage. In order to meet peak heat demands, the UKTM model assumes that the SMR design capacity is 30% higher than the average annual output, and that salt cavern storage with a capacity of 25 days of average annual hydrogen consumption is required in each converted gas network.

If a hydrogen national transmission network were constructed, then large coal or biomass gasification plants with CCS could be built instead of regional SMR plants. Production from large-scale electrolysis would be less likely due to the high cost of electricity, unless high deployment of intermittent renewables were to cause lengthy periods with excess electricity generation that would otherwise be wasted.

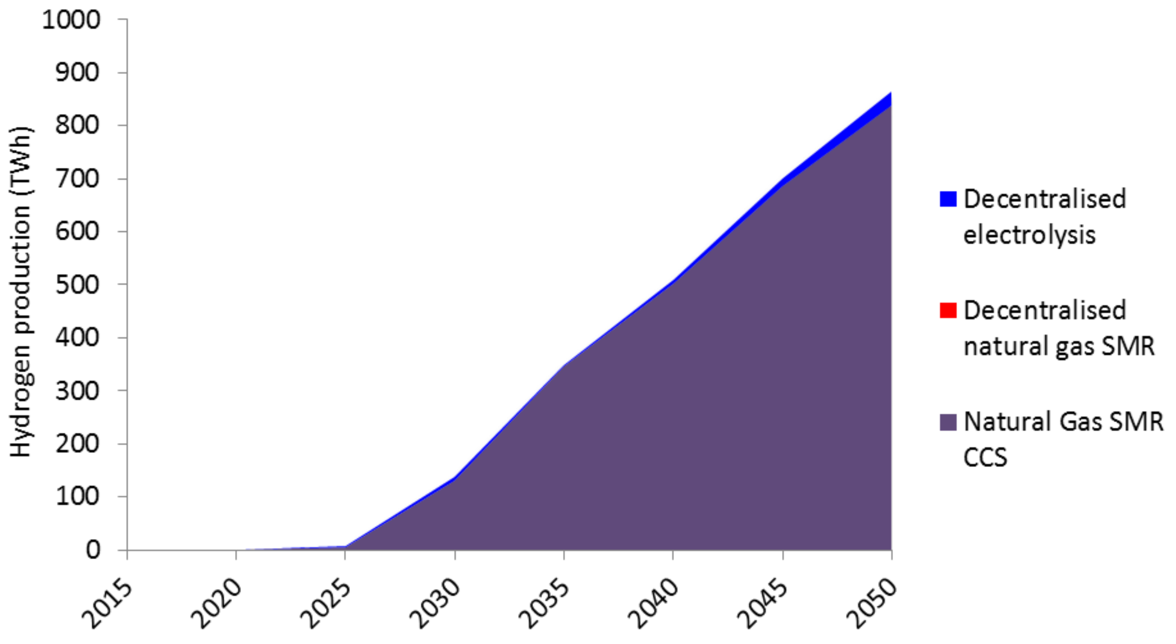

Figure 20: Full Contribution scenario – hydrogen production methods

3.4 Wider energy system impacts of the Full Contribution scenario

In the CCC Central Scenario, the UK's 2050 emission targets are achieved through a wide range of measures. Electrification of heat and transport, coupled with a great reduction in the emissions intensity of supplied electricity, has an important role. The scenario is highly detailed to 2030 and a number of potential end-points are identified for 2050. In most of these, biomass technologies with CCS make an important contribution by sequestering around 45 Mt of atmospheric CO_2.

The Full Contribution scenario takes a different approach and results in a different balance of emissions between sectors in 2050, as shown in Table 3. Since hydrogen replaces natural gas for heating across the building stock, the residential sector is virtually decarbonised in the Full contribution scenario, in addition to the service and transport sectors. This means that there is less need for expensive atmospheric CO_2 sequestration through biomass with CCS, and electricity emissions are much less negative. Overall, the balance of emission reductions moves from the supply to the demand sectors.

	CCC Central	Critical Path	Full Contribution
Services	2	3	4
Electricity (excluding biomass with CCS saving)	6	5	0
Biomass with CCS	-46	-44	-8
CCC Industry	57	57	48
Residential	29	30	3
Transport	12	13	9

Table 3: Comparison of GHG emissions in 2050 in Critical Path and Full Contribution scenarios with notional emissions from the CCC Central Scenario ($MtCO2_e$).

Widespread adoption of hydrogen means that there is little electrification of heat and transport, so electricity generation in 2050 is 38% lower in Full Contribution than in Critical Path, at 340 TWh. However, there is a much greater 50 TWh contribution from hydrogen-fuelled CHP plants supplying heat networks, compared to 5 TWh in Critical Path in which decarbonisation of the heat network supply is more expensive without hydrogen as an option.

The Full Contribution scenario technologies are much less diverse than for the Critical Path scenario. Hydrogen comes to dominate most end-use sectors and the transition is generally from existing high-carbon technologies to hydrogen-fuelled technologies, with little electrification of end-uses even as a stop-gap measure. The early and widespread conversion of the gas networks to hydrogen is sufficient to meet stepped emission targets to 2050, so there is little incentive to adopt other low-carbon technologies such as battery-electric vehicles at the same time.

3.5 Spatial and infrastructure issues

The considerable challenge faced in the Full Contribution scenario, which is not faced in the Critical Path scenario, is the early roll-out of a hydrogen supply to buildings. This is predicated on a commitment to complete the IMRP and a rapidly-scaling, highly co-ordinated, planned and mandated switchover programme from natural gas supply to hydrogen supply, street-by-street in each city. Figure 21 shows an example of a conversion plan for the UK. An outcome of this major strategic programme would be the almost ubiquitous availability of hydrogen within residential areas once they have been converted. In the narrative of the scenario, this street-level availability of hydrogen makes it much easier to build refuelling stations and enable the roll-out of hydrogen vehicles.

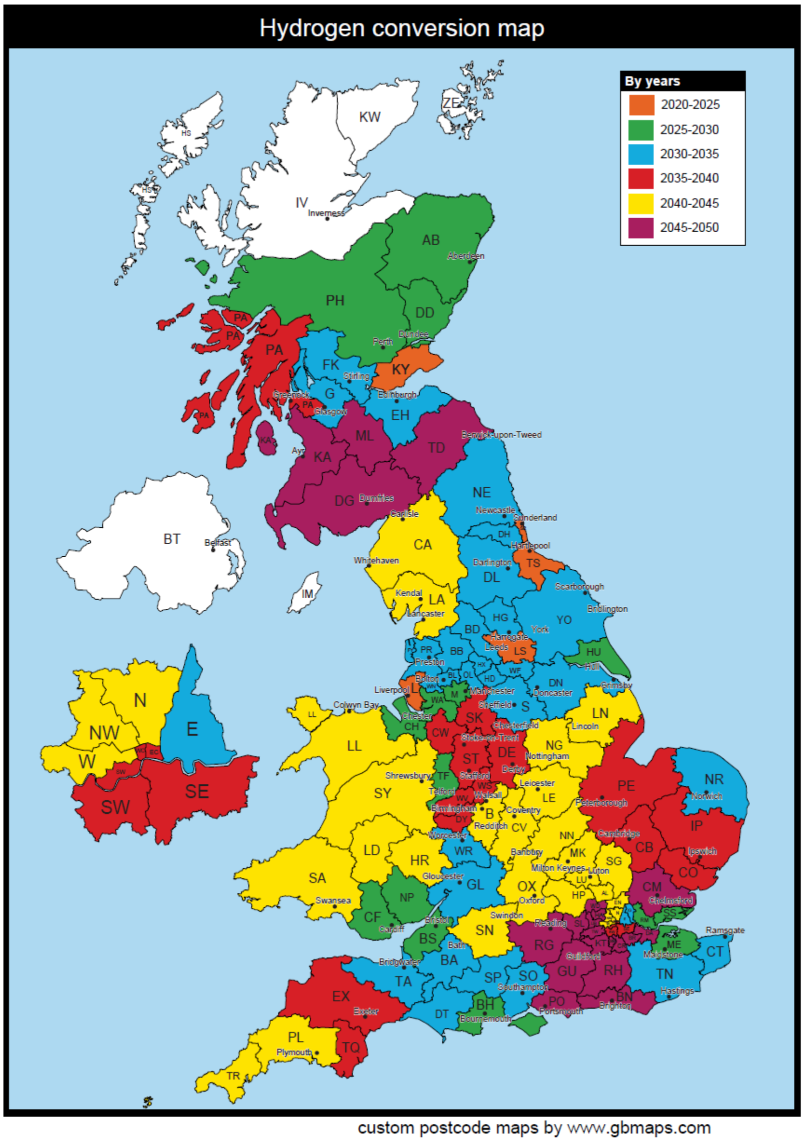

Figure 21: Potential regional conversion plan to transition the UK gas networks to deliver hydrogen. Copyright and Intellectual property of Kiwa Ltd 2015.

Thus the Full Contribution scenario to some extent avoids the challenging questions addressed by the Critical Path scenario around both the limited availability of hydrogen refuelling stations nationally at the start of the roll-out of hydrogen cars, and the particularly limited availability of refuelling stations within urban and residential areas. The mandated programme to plumb entire residential areas into hydrogen described in Full Contribution overcomes these issues. In some respects, it is perhaps simpler to imagine how the scale-up of vehicles occurs in the Full Contribution than in the Critical Path scenario, which leaves a number of questions open about how a partial contribution of hydrogen works in relation to the required co-existence of other, potentially competing technologies, and their supporting infrastructures. On the other hand, of course, the very significant level of centralised decision making and prescription passed from national down to regional policy making levels, and the significant consensus required to back a particular technology and fuel, which is a striking requirement for the success of Full Contribution, is much less evident in Critical Path.

As discussed in Section 3.3.6, the Full Contribution scenario is even more reliant on centralised SMR with CCS than the Critical Path scenario. In absolute terms, the contribution from decentralised sources in Full Contribution is similar to Critical Path, at around 35 TWh/year. However, the total quantities of hydrogen required are much larger – 860 TWh/year in 2050, compared to Critical Path's 143 TWh/year.

As in Critical Path, our assumption remains that the preference would be to minimise the lengths of CO_2 pipelines by locating SMR CCS plants as close as possible to potential storage sites, as concentrated CO_2 leakage is more hazardous than hydrogen leakage. As shown in Figure 9, substantial clusters of offshore saline aquifers exist in the North Sea off the east coast of Scotland, and off the coast of East Anglia and Lincolnshire; in the Irish Sea off the coast of Merseyside and Lancashire; and a small site off the southern coast of Hampshire and Dorset. It would also be important to locate the plants in areas suitable for salt caverns, to provide sufficient energy storage to meet peak periods. This constrains the location of the SMRs, requiring hydrogen pipelines to transport the hydrogen from these large-scale generation points to the demand regions. Figure 22 indicates how the total hydrogen demand in Full Contribution in 2050 would be allocated across the UK, assuming regional hydrogen demands were in proportion to population.

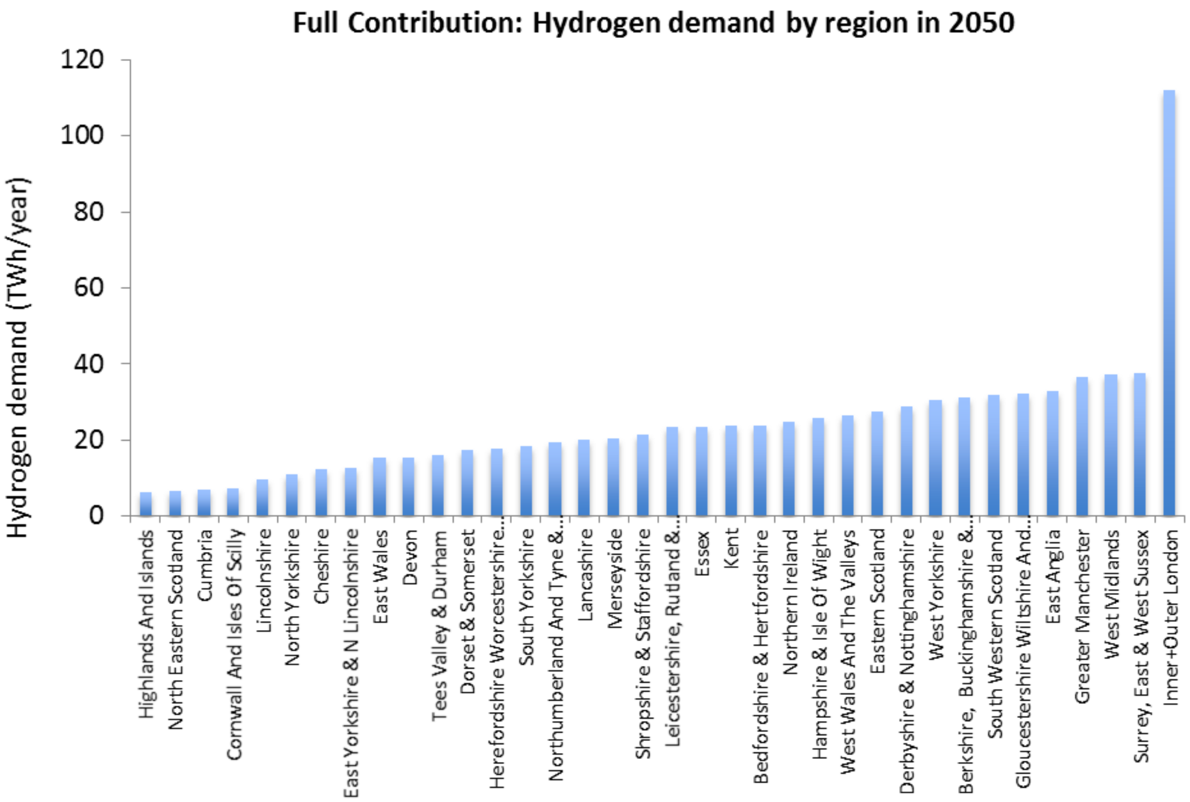

Figure 22: Geographical distribution of hydrogen demand in the Full Contribution scenario in 2050, by NUTS level 2 region, assuming demand in proportion to population.

The Full Contribution scenario in 2050 includes about 25 TWh of hydrogen per year produced from decentralised methods. It could be assumed that the most likely candidate regions to use this decentralised hydrogen will be those with the lowest demand, as lower throughputs would make the economics of hydrogen pipelines less viable. As shown in Figure 22, even the areas with the very lowest demand in this scenario have a demand of around 7 TWh/year – a demand level that is higher than that of any other single region in Critical Path, with the exception of Inner and Outer London. Only the three lowest demand regions – Highlands and Islands, North Eastern Scotland, and Cumbria – can be supplied by the decentralised capacity available in this scenario. The remainder of the regions must be supplied by large scale SMR CCS. As with Critical Path, it is possible to group the remaining higher demand regions into clusters in relation to potential sites for large scale SMR CCS, based on the map in Figure 9. However, in this scenario the pipeline infrastructure would probably need to be more extensive and more networked, due to the greater number of regions requiring piped hydrogen, and the significantly larger quantities overall.

Production facilities in the Merseyside region could feed one pipeline that ran to Greater Manchester, Lancashire and West Yorkshire, another that ran south to Shropshire, the West Midlands and into South Wales, and another directly into North Wales. Production facilities in Teesside could feed a pipeline running to Northumberland, Tyne and Wear. Production facilities on the east coast of Scotland, perhaps near Grangemouth, could supply pipelines to eastern and southern Scotland; production facilities on the East Anglian coast could supply pipelines running to London and the south-east; production facilities on the Humber could supply a pipelines to north and east Yorkshire, south Yorkshire, Lincolnshire and the East Midlands; and production facilities on the southern Hampshire coast could supply a pipeline to Oxfordshire, and one running to the Bristol / Bath area, before continuing to Devon and Cornwall.

4 Strategic consideration of hydrogen pathways

4.1 Summary

Under each scenario, many actions – both specific and overarching – will be required to guide the development of hydrogen and ensure the UK can profit best from the opportunities that arise or that can be created. Here we suggest when and what support may be required in the Critical Path and Full Contribution scenarios to achieve their respective levels of deployment in 2035. These actions will require ongoing review in the light of progress against the targets, and we have not attempted to hypothesise what may be required for the post-2035 period.

Other reports (LCICG, 2014, Element Energy, 2015, IEA, 2015) have also examined possible hydrogen futures in the UK and internationally, and suggested support measures. We have tried to align with these documents where relevant, though the different scenarios and uptake rates considered in the different cases renders perfect alignment both difficult and of limited relevance. In some cases they contain more detail than is laid out below, and in some cases the suggestions are at a considerably higher level, but they should certainly be considered in conjunction with our suggestions.

Tables 4 and 5 summarise the actions required in each five year period to 2035 for the Critical Path and Full Contribution scenarios, respectively. The actions are colour coded to show:

- actions needed in both scenarios at the same time. While these are generally *required* for the scenario, they also include low regrets actions in the Critical Path scenario to keep the option open for greater hydrogen deployment
- actions needed in both scenarios but at different times
- actions needed in that scenario alone

The actions are then explained in more detail in the rest of this chapter, where the main decision points are also indicated.

We only list actions required by the UK. Many developments are taking place elsewhere and so hydrogen technology, for example, will continue to evolve even without UK engagement. For the UK to have the best chance to benefit, however, it must actively engage.

Table 4: Actions required to achieve the Critical Path scenario

	Policy	Technology development & engineering	UK supply chain and servicing	Standards and safety	Financing	International developments	Energy system developments	Information
2015-2020	• Support for early HRSs • Local and national bus policy • Support for pioneer cities and demos • Fuel duty reduction for H2 • Definitions for green H_2 • Continuation of the IMRP • Support for gas grid conversion trials • Policy for H_2 decarbonisation	• Continue to support UK R&D and monitor international progress • Watching brief on HRSs • Continued R&D on novel storage • Vehicle/HRS coordination programme	• Training of skilled technicians	• Testing and demos to revise H_2 standards • Revision of HRS siting regulations • Appliance modifications for UK requirements		• UK participation in international coordination activities • Engagement with global OEMs for vehicles • Monitoring UK vs ROW HRSs	• Regulatory and technical support for energy storage • Progressive grid decarbonisation	• Information sharing on infrastructure development • Publication of modelling and analysis
2020-2025	• Overall/sector hydrogen policy direction • Support for FCEV cars, LGVs and fleets • HGV policy	• Guidance on H_2 heat appliances in the UK	• UK supply chains for components from 2020		• Financing models for HRSs		• Review of CCS development	• Information on HRSs • Comms on safety and availability of technologies
2025-2030	• Industry decarbonisation programmes • Planning support for H2 transmission pipelines							
2030 and beyond					• Financing models for trans-mission pipelines			

Table 5: Actions required to achieve the Full Contribution scenario

	Policy	Technology development and engineering	UK supply chain and servicing	Standards and safety	Financing	International developments	Energy system developments	Information
2015-2020	• Overall/sector hydrogen policy direction • Support for FCEV cars, LGVs and fleets • Support for early HRSs • Support for pioneer cities and demos • Local and national bus policy • Fuel duty reduction for H_2 • Definitions for green H_2 • Continuation of the IMRP • Support for gas grid conversion trials • Policy for H_2 decarbonisation • Heat decarbonisation policy	• Continue to support UK R&D and monitor international progress • Watching brief on HRSs • R&D on novel storage • Vehicle/HRS coordination programme • Guidance on H_2 heat appliances • Responsive mode funding for HRSs	• UK supply chains for components from 2015 • Training of skilled technicians including gas fitters	• Testing and demos to revise H_2 standards • Revision of HRS siting regulations • Appliance modifications for UK requirements • Standards for gas grid conversion	• Financing models for HRSs	• UK participation in international coordination activities • Engagement with global OEMs for vehicles • Monitoring UK vs ROW HRSs	• Regulatory and technical support for energy storage • Progressive grid decarbonisation	• Information sharing on infrastructure development • Publication of modelling and analysis • Comms on safety and availability of technologies • Information on HRSs
2020-2025	• HGV policy • Support for H2 production and storage for local gas grids • Planning support for H2 transmission pipelines • Industry decarbonisation programmes • Coordination to support local gas grid conversion						• Review of CCS development	
2025-2030				• Inclusion of H_2 in the GS(M)R	• Financing models for trans-mission pipelines			
2030 and beyond	• Shipping policy • Demonstration support for H2 turbines							

4.2 Actions required by the UK to support scenario achievement

4.2.1 Policy

- **Overall and/or sectoral hydrogen policy direction – from 2020 in Critical Path and 2015 in Full Contribution**. All of the hydrogen supply and use pathways involve multiple stages and interaction with several other sectors. These include electricity supply and distribution, an emerging CCS network, other end use technologies in each sector, and (in the Full Contribution scenario) domestic energy use. This complexity, together with uncertainty about the role of hydrogen in each of these areas, causes a barrier to innovation and compounds the risks of deployment. A clear government position on the role of hydrogen in general, and ideally in each sector, is needed to underpin the other policies described in this section. For example, the LCICG concluded that this clarity would remove or reduce many barriers to innovation, and reduce the cost of innovation support, as well as improving the UK's ability to attract technologies from global developers (LCICG, 2014). In the FC scenario a strong national commitment to hydrogen is needed to enable regional decision making and bring hydrogen in to the gas network.
- **Support for early refuelling stations – from 2015 in both scenarios.** Support is needed for refuelling stations in the early years of deployment to support demonstrations, ensure enough provision to attract vehicle sales to the UK, and ensure that the early network develops in such a way to encourage infrastructure sharing. The UK H2Mobility programme, involving government, technology providers and users developed a coordinated plan for vehicle and refuelling station roll-out, but is not currently pursuing it. Several public funding sources are available for the first stations up to 2020 (Element Energy, 2015, HRSIGS, 2015), and UK Government is providing funding for an initial network, overseen by OLEV. However, in the period 2020-2030 in the CP scenario and 2020-2025 in the FC scenario there will still be relatively few refuelling stations, each with low utilisation, and so further support may be required to ensure geographical coverage and encourage access for several vehicle types. However, UKH2Mobility suggests that refuelling stations can be profitable from the 2020s as part of a continuous roll-out of vehicles at a similar level to that seen in the FC scenario (Hayter, 2014). In the CP scenario, continued support may be needed for the first ten years of vehicle roll-out, though the German H2Mobility model is for risk and reward to be managed through a joint venture of stakeholder organisations such as fuel providers, OEMs and Government. Wherever possible, fuelling stations for fleets such as buses should be publicly accessible. AC Transit's Oakland, California site provides one model for this, with a fuelling station that has an external-facing aspect for public access, and a section accessible only to qualified personnel on the inside of the bus depot.
- **Support for FCEV cars – from 2020 in Critical Path, 2015 in Full Contribution**. In addition to a clear HRS roll-out strategy and commitment, a range of policies at national and local level will be needed to support FCEV car roll-out, particularly in the early years. These are needed to overcome the initial higher total cost of ownership versus conventional vehicles, plus additional consumer reluctance related to uncertainty over a new technology and limited refuelling station availability.
  - **A clear policy trajectory towards lower carbon cars** is essential to giving industry confidence that there will be a market for FCEVs and refuelling infrastructure. This could be in the form

of continued targets for reduction in tailpipe CO_2 emissions from passenger cars beyond 2021, which are due to be agreed by the end of 2015 (EC, 2015). This policy alone may not drive early FCEV introduction, as it is unlikely to be set sufficiently stringently to require significant uptake of FCEVs in the 2020s. However, achieving ever-lower CO_2 targets is very likely to require fuel switching, rendering FCEVs an important offering for the OEMs, and one which they will need to deploy well before it becomes essential to their strategy.

- **Air quality policy.** A continued focus on improved air quality and commensurately tightening standards is assumed for both scenarios.
- **Purchase grants.** Currently, grants for FCEVs are available through the Plug-In Car Grant scheme, which also covers electric and plug in vehicles. £200 million has been made available to continue the plug-in car grant from 2015 to 2020. FCEVs would currently receive a grant of up to 35% off the cost of the car, capped at £5000, however, the grant level is due to be reviewed in November 2015, and additional criteria for FCEV eligibility added (OLEV, 2015b). It is hard to estimate the success of such grants in encouraging FCEV cars, given that the price of FCEVs will be set by the OEMs on the basis of expected consumer demand rather than purely on cost, until they truly become mass-produced. However, such grants are effective means of supporting an early market, and we estimate that grants or other purchase support may be needed in the UK while the first 10,000 vehicles are deployed, as a signal to consumers and vehicle manufacturers[3]. Purchase grants will need to be combined with the other policy measures suggested here to achieve early deployment, with all of these measures used in the **FC scenario from 2015**. In the CP scenario the uptake is much slower, and while sufficient support is required for OEMs to continue to bring cars to the UK, **the majority of it will be required from 2020.** After these first vehicles are supported, further deployment should be primarily driven by ongoing cost reduction and strong overarching vehicle CO_2 policy.
- **Other national car policies.** Favourable treatment for FCEV cars and for hydrogen under other national policies for example vehicle excise duty and company car tax.
- **Local policy incentives.** Local authorities in pioneer regions, or in regions focused on air quality improvement could incentivise use of FCEV cars through policies such as congestion charging exemption, use of additional lanes, and preferential access to or reduced costs of parking, which have proved highly successful in encouraging the uptake of hybrid and electric vehicles.
- **Public procurement.** Procurement of FCEV cars for fleets such as local authority vehicles, which could be supported by national guidance on procurement, and national funding, as is currently done through the ULEV readiness programme.

- **Support for FCEV LGV purchase – from 2020 in Critical Path, 2015 in Full Contribution.** There is strong interest in FCEVs in the LGV sector in the UK, but reluctance to pay higher total cost of ownership (Hayter, 2014). Many of the policies proposed above for cars already cover or could also be extended to LGVs, as well as the fleet policies below. However, there is the potential for

[3] The IEA roadmap modelling includes very high direct subsidies for FCEVs in the early years of deployment, falling to $5k in around 2025, plus exemption of hydrogen from fuel taxation until cost competitiveness is achieved, in around 2035 (IEA 2015).

additional policy measure for commercial LGVs, such as allowing night time deliveries – because noise would be low – or designating certain areas only accessible to ZEVs as part of a broader drive to improve urban air quality.

- **Support for fleets other than buses – from 2020 in Critical Path, 2018 in Full Contribution**. Fleet deployment is an important component of early stage roll out in both scenarios, and allows increased refuelling station utilisation. Possible support measures range from provision of information and advice for fleets, as is currently provided via EST, to support for vehicle leasing and refuelling infrastructure. This could also help to ensure that fleets are refuelled at public refuelling stations rather than using depot sites where feasible (Element Energy, 2015).
- **Local and national bus policy – from 2015 in both scenarios**. Buses are the first vehicles to be rolled out in both scenarios. Roll-out is likely to be driven most effectively by local policies, with the urban air quality likely to be as important to local authorities as greenhouse gas savings. Local policy support could include specific tender requirements, public procurement, and support for infrastructure provision, and would be aided by cooperation between cities e.g. in bus purchasing The FCH JU is supporting the development of a set of connected bus 'clusters' and a joint procurement strategy with the aim of achieving lower prices of buses for all regions involved (FCH JU, 2015b). National policy can further support this transition, for example through grants for vehicles and infrastructure such as the Low Emission Bus Scheme (OLEV, 2015a), and through information provision to local authorities, such as through the LowCVP's *Low Carbon Emission Buses* activities. However, both scenarios require fast ramp up of bus numbers, which will mean activity at a scale greater than that seen to date, most probably focused through regional purchasing strategies and zero emission bus mandates rather than direct grants after the first tens of buses. For example, in the CP scenario, each of the pioneer cities identified would need programmes similar to those in Aberdeen and London, with fleets of around FC 700 buses in each pioneer city required by the late 2020s.
- **HGV policy – from 2020 in Critical Path, 2023 in Full Contribution**. The scenarios both require uptake of hydrogen HGVs, with the Critical Path scenario also requiring relocation of some HGV fleet depots to locations of hydrogen production. HGVs are likely to be one of the more difficult hydrogen technologies to introduce, as discussed in the technology section. However, uptake should be driven through strong CO_2 and air quality emissions policies in the sector, as early as 2020 in FC, and 2023 in CP. Early uptake in certain, shorter-distance, sectors could be supported by public procurement, for example in local authority vehicles, backed up by information provision. Fuel-based support, such as support for refuelling infrastructure and fuel duty differentials could also be used, as has been done for natural gas HGVs. Use of hydrogen HGVs could also be strongly influenced by preferential access policies such as night time deliveries, low emission zones and toll exemptions. Moving HGV depots will require significant planning, co-ordination and support, for example from Local Authorities who are converting their own short-range fleets such as waste collection. It may be possible, as with bus fleets, to make refuelling depots also accessible to longer-distance HGVs that come into the urban area.
- **Domestic shipping policy – from 2030 in Full Contribution.** Emissions constraints on local pollutants around ports and sulphur more widely, already being applied in this sector, will be sufficiently strict by the 2030s to support the introduction of hydrogen into this sector.

- **Support for pioneer cities and coordinated demonstrations – from 2015 in both scenarios**. A coordination programme would be needed to identify and support pioneer cities or regions, to facilitate their uptake of buses, HGVs and refuelling infrastructure. In this way, a coordinated programme to deploy hydrogen technologies simultaneously in a variety of different locations could be undertaken. This would generate critical learning about the technologies in different contexts, and would also generate more favourable economies of scale for technology manufacturers than from relatively small demonstration programmes. This is needed from 2015, but would need to expand significantly from 2020 in the FC scenario.
- **Policy to support hydrogen supply** – this would not force the uptake of hydrogen over other low-carbon technologies, but ensure as far as possible that hydrogen was not disadvantaged by exclusion or omission. Examples of sectoral policy would include the inclusion of hydrogen in broader low carbon targets, carbon pricing, and market based mechanisms to support hydrogen use.
    - **Fuel duty reduction/exemption for hydrogen from 2015 in both scenarios, until HRS become economic.** This could help to reduce impacts of low utilisation in early refuelling stations. Whilst the IEA includes exemption of hydrogen from fuel duty until 2035 in their roadmap, UK H2Mobility suggested that with high deployment there may be the potential for taxation after 2025 once the infrastructure and vehicle case is established (Hayter, 2014). The IEA expects that this favourable policy treatment might be necessary for a period of 10 to 15 years after FCEV market introduction, to reduce a continued gap in TCO with conventional cars (IEA, 2015), with close monitoring to prevent over or underspending as costs of vehicle and refuelling technologies change.
    - **Policy to support hydrogen production and storage for local gas grids - from 2020 in the Full Contribution scenario only.** Hydrogen for heating will have higher costs than natural gas, given the higher costs of production and storage. Public support to reduce the cost of hydrogen for local grids would be justified on the grounds of lower GHG emissions than natural gas. This could be done by policy support for low-carbon hydrogen production, for example in a similar manner to support for biogas under the Renewable Heat Incentive. This support could be varied according to the lifecycle GHG emissions of the hydrogen production, as is currently being discussed in DECC's Green Hydrogen Policy group. By the standards of current FIT and RHI payments current industry thinking is that this support need not be large, but would need to recognise the value of hydrogen in providing inter-seasonal heat storage capacity as well as the differential costs between natural gas and hydrogen.
- **Policy for hydrogen decarbonisation – from 2015 in both scenarios.** Policy is needed to drive the decarbonisation of hydrogen used in each of the sectors identified, for example through renewable content obligations or differential taxation at a sector level. In the transport sector, the Renewable Transport Fuels Obligation (RTFO) supports hydrogen from biomass, but not hydrogen from renewable electricity or other low carbon routes. The RTFO supports the UK's renewable transport fuel targets to 2020, but beyond 2020 there are as yet no EU or UK level targets for carbon reduction or renewable energy use in the transport sector specifically. Unlike electric vehicles, where electricity supplied to transport can be expected to be decarbonised

through policies directed at the electricity sector, there is no other current policy that would specifically lead to hydrogen decarbonisation.

- **Agreed definitions for green hydrogen - from 2018 in Critical Path, 2015 in Full Contribution.** These would be needed at the pump in both scenarios, and also for domestic use in the FC scenario. For example, they would include agreement on when terms such as 'green hydrogen' can be used, a term which has been defined in Germany (McDowall, 2014). Rules regarding the chain of custody for hydrogen produced from renewable electricity via the grid, or from renewable hydrogen via the gas grid would also be needed. DECC has set up a Green Hydrogen Standard Working Group with the aim of defining the emission thresholds for hydrogen production to be defined as green hydrogen, and to recommend how the emissions from hydrogen should be calculated. It is possible that renewable hydrogen and low-carbon hydrogen could be separately defined by this standard.
- **Continuation of the Iron Mains Replacement Programme (IMRP) – from 2015 in both scenarios** – the existing low pressure and medium pressure gas network is currently being converted to polyethylene pipe suitable for hydrogen via the iron mains replacement programme. This is required for the FC scenario, but is also a low regrets move in the CP scenario, as it is in any case required to ensure safety and keeps the option open for conversion of parts of the gas network. Because the purpose of the programme is to reduce accidents it is expected to continue in the future, but there have been moves to slow the programme while targeting pipes at most risk of failure.
- **Planning support for hydrogen transmission pipelines - from 2028 in Critical Path, 2020 in Full Contribution.** While pipelines should only be built where a clear (long-term) economic case can be made, government can play a useful role in supporting planning consents and ensuring these are not withheld or held up unreasonably.
- **Industry decarbonisation programmes - from 2025 in Critical Path, 2020 in Full Contribution.** In the CP scenario, industrial use in 2030-2050 is as part of broader industry decarbonisation programmes, alongside other technologies and measures required to maintain competitiveness. Hydrogen would need to be included in policy to support decarbonisation, such as innovation funding, capital allowances or reduction targets, but not necessarily favoured. Hydrogen would most likely be adopted at larger industrial plants outside urban areas and near hydrogen pipeline infrastructure. Large industrial clusters with onsite CCS facilities could be a particularly important market, as dedicated onsite hydrogen production plants would centralise CO_2 capture and avoid the need for constructing a CO_2 pipeline network across the site to the turbines, boilers and furnaces used by different processes. Specific support for hydrogen in industrial trials in relevant pioneer areas such as Teesside and Merseyside could begin in the early 2020s for the FC scenario, to seed the wider roll-out.
- **Support for gas grid conversion trials – from 2019 in both scenarios (as a no regrets option in CP).** Initial trials of gas grid conversion will need financial support. Capital costs (network and first fix user costs) could be supported through the Ofgem Gas Network Innovation Competition, which allows gas network companies to compete for funding for development and demonstration of new technologies, operating and commercial arrangements. However, this would not support the future operating costs of the network, which would be higher for hydrogen than for natural gas, and would require further support.

- **Heat decarbonisation policy – from 2019 in FC.** Conversion of the gas grid to hydrogen will not occur without policy support, as the lower carbon hydrogen option is more expensive than natural gas in operation, and additionally there are the costs and disruption of the conversion of the grid and appliances. Policy aimed at reducing the cost of hydrogen used in the heat sector or increasing the cost of alternatives, would be unlikely to drive conversion alone in most regions, unless there is local hydrogen production in industry. It is likely that a higher level policy would be needed, such as government requiring local authorities to make plans for heat sector decarbonisation, in which they would identify which options (hydrogen, heat pumps, district heating etc.) would be used and then plan for their roll-out.
- **Coordination to support local gas grid conversion - from 2020 in the Full Contribution** scenario only, starting in the Pioneer regions. Even with a policy driver for gas grid conversion, the ability to change may be limited by the fragmented nature of the gas industry. Only the local gas distribution network operator (DNO) has necessary skills to manage the transition, but as a regulated business their remit may be limited by Ofgem. The local authority might like to make the transition but would have neither the expertise nor funds, while the hydrogen shippers and suppliers need local cooperation. Coordination support from a national body or other areas that have already managed the transition would help to overcome this, and also ensure that roll out in different areas was phased such that skilled engineers were available. Conversion of the local network and provision of the first fix of new appliances needs to be delivered by the gas DNO, albeit supported by information provision via the local authority. Costs of conversion could be met by government support, or alternatively the gas DNO could be allowed to treat this as part of its regulated activity, and so spread the cost across all network users. The change could be coordinated with other changes, such as roll-out of smart meters or improved insulation.
- **Demonstration support for hydrogen turbines from 2030 in Full Contribution only.** H_2 turbines are likely to be developed and demonstrated internationally well before 2030 (Japan already has a programme in place (NEDO, 2015). If this has not occurred then support should be put in place to allow their demonstration in the early 2030s at the latest, to allow their use as peaking plant in the late 2030s.

4.2.2 Technology development and engineering

Continue to support UK R&D and monitor international progress - from 2015 in both scenarios. This is needed for many technologies in three separate technology families here: production, use in heat and use in transport. Additional specific actions for the UK are highlighted.

Production: The large-scale production, storage and pipeline transportation of hydrogen from natural gas using **large-scale SMR** is an extremely well established and low cost technology, widely used in the UK. Large tonnages are produced, stored and used in Teesside and on the Wirral. There is no requirement for strategic intervention for technology development in SMR.

Smaller-scale production technologies do require further development. Reducing the cost of **electrolysers** will be important, and this depends largely on more standardisation of parts, the wider employment of mass-production techniques, a general scaling up of the whole electrolyser industry, and rationalisation of supply chains. The industry is global and these developments will be driven by all possible electrolyser applications internationally, not simply hydrogen refuelling stations (HRS).

‘Power-to-gas’ and localised production and use of hydrogen, for example on islands, will be important components of this demand. Breakthrough technology development is not required (E4tech, 2014). **Small-scale SMR** plants will also provide some hydrogen in the early phases of roll-out, and while commercial examples exist they require further cost reduction and component development to make them fully robust and competitive. Again, this move to series production and a better qualified supply chain will be driven by global industrial markets for hydrogen as much as by HRS or other UK efforts.

Heat: Hydrogen usage for heat production is also well proven, with a range of industrial burners available. Projects for DECC and Northern Gas Networks (Leeds H21) are investigating the real costs and practicalities of converting the low pressure natural gas networks within towns to hydrogen (H21, 2015). On completion these should be evaluated, and could potentially be extended through pilots in the Pioneer Regions, to provide evidence and a knowledge base for future roll-out. Most hydrogen domestic products have been built, at least in prototype fashion, and a suitable regulatory framework exists, although the UK will require more installation-specific documentation, to be developed from **2015 in FC but only from 2020 in CP** as a no-regrets move.

Transport: The cost of infrastructure to provide hydrogen to transportation uses generally needs to come down, which depends primarily on developing a larger (global) market, with more competition and a more mature supply chain. Some technologies such as hydrogen sensors or contaminant measurement devices may require specific development; this is addressed later. The cost and supply of some HRS components is currently restricted – few companies are able to provide **high pressure (700 bar) dispensing hoses or nozzles**, and suitably accurate yet cost-effective **metering and contaminant control**, and low-cost but accurate **pre-cooling techniques** are also problematic. Major programmes to support developments in these technologies have been funded or are still under way internationally and good progress is being made. A **watching brief for the UK from 2015 in both scenarios**, and possibly **a responsive mode funding mechanism for new developments here could nevertheless be appropriate in FC should this slow progress in the period to 2018**. Although most likely to be widely deployed in HRS, small scale **hydrogen storage** technology is much more broadly applicable and remains expensive, as do **compressors**. While both of these areas are mature in an industrial sense, the new requirements of infrastructure and potential opportunities for large-scale and long-distance transportation of hydrogen are driving novel solutions, which may eventually win out over current technologies. Solid state and chemical hydride storage is not easily adapted to vehicles themselves, but is looking promising for bulk storage and delivery, with metal hydrides and organic chemical hydrides being developed for industrial and other uses. Continued support of UK expertise in these areas through **R&D funding will help to keep the UK well positioned. This should continue in both scenarios from 2015**, monitored and adjusted for relevance.

In the initial stages of roll-out **(from 2015 for both scenarios, but with a lighter touch for CP) it will be essential to ensure careful co-ordination between vehicle and HRS deployment**, as has been extensively discussed for example in the different H2Mobility studies (UK H2Mobility, 2013, Hayter, 2014) and is now being implemented at a minimum necessary scale through OLEV’s Hydrogen Refuelling Infrastructure Grant Scheme (HRSIGS, 2015). Coordination between refuelling infrastructure and vehicle actors, particularly with regard to early vehicle deployments and early refuelling stations. OEM transparency on their initial rollout locations and vehicle numbers will help give confidence to HRS developers and investors. This entails not only ensuring that stations are close enough together to act as backup should one not be working, but that mobile stations are also available as a further backup option, and perhaps even that secondary delivery methods have been secured. In the early stages of rollout, redundancy is needed to develop consumer confidence. More specific HRS-related issues such as metering and billing will also require co-ordination.

For vehicles, costs of many components and systems need to come down, and some level of performance increase – especially in terms of fuel cell and hydrogen system weight reduction and improved on-board storage – will be required to make **cars** competitive across the board and increase the viability of fuel cell **LGVs**. The majority of this will take place as part of the OEMs' existing R&D programmes, and major cost reductions will come as mass-production is implemented globally. Typical analyses, for example James *et al.* (2014), suggest that even with cumulative production of only around 30,000 vehicles, fuel cell system costs will come down by around 80%, and demand for this number of cars will depend significantly on countries other than the UK, in the initial roll-out period to 2020. Japan, the USA, Germany, Korea and one or two other areas such as Scandinavia will be the important early markets.

The use of plug-in hybrid FCEVs may help to overcome part of the initial infrastructure challenge, when HRS coverage is insufficient. Although this may require slightly more expensive vehicles as the batteries may need to be larger to allow for all-electric range, this is partly balanced by a smaller fuel cell. It also reduces the need for ubiquitous HRS infrastructure. Again, this development is occurring naturally within the OEMs and it is unlikely that any specific support is required in this area.

For **HGVs** the picture is more complex. Current ICE technologies are highly efficient and very reliable and hydrogen technologies will need to meet these benchmarks. Fuel cell lifetimes, which are currently approaching 5,000hrs in cars and sometimes reach 20,000hrs in buses, will need to be at least 50,000hrs for HGVs. Japan's NEDO has an R&D project in place targeted at achieving 50,000hrs and 600,000 cycles for exactly this purpose (Shinka, 2014). Improvements in car systems and in buses will have important carryover effects into HGVs, in particular in understanding failure mechanisms and avoiding them. UK support for ongoing R&D and for HGV integration may be important, but the majority of this development is likely to be elsewhere, so **the UK should retain close involvement and ties to international work in the area in both scenarios, from 2015 onwards**.

On-board storage of hydrogen will need to improve, as it will be important to be able to drive HGVs for several hundred miles between refuelling stations. Ground-up redesign of commercial vehicles incorporating bespoke hydrogen storage is likely to occur and will also help, and liquid hydrogen may also be used for some period of time to allow for greater range. These complex technologies would benefit from further research and development to reduce different storage tank costs and enhance safety, but much of this work is international and so while the UK should play a role through both the Health and Safety Laboratory (HSL) and other bodies, including academics, it cannot lead nor act alone. Early and continued participation in standards developments will be essential, however. Also, while liquefaction today 'consumes' around 35% of the energy in the hydrogen, good engineering design and optimisation could halve this (Seeman *et al.*, 2013), reducing what is sometimes a major cost and emissions penalty. Novel technologies such as magnetic liquefiers could allow smaller-scale plants but are some way in the future. Technology development is being pursued and we do not see this as a high priority for the UK.

Both scenarios include large scale SMR with CCS, which is still unproven at the small scale and has limited deployment at large scale. Support for trials is discussed elsewhere, but ongoing technical development and especially cost reduction is necessary to make SMR with CCS a viable option, in addition to more detailed assessment and characterisation of available secure CO_2 sinks. Work funded through the ETI has supported some technical aspects of CCS development, but several demonstration projects have not gone ahead through lack of funds. Clear policy support and incentives are required to drive demonstrations of the technology and especially of its integration, though much of the technology is mature enough to be demonstrated and does not require specific development. Strong international collaboration is likely to be required, including that through bodies such as the IEA and IPHE[4], to share cost, benefit and learning.

4.2.3 UK supply chain and servicing development

- **UK supply chains and other support for technology roll-out and maintenance will be required from 2015 in FC and 2020 in CP.** The supply chains for major equipment such as vehicles will be international and the component supply chains will develop accordingly as part of this demand. However, replacement part availability, local subsystem or system manufacturing and local skilled labour to service and support hydrogen technologies will be essential in keeping the technology working and engendering confidence in users and in the wider community. While global OEMs will choose their Tier 1 suppliers based on competence, many other areas in the supply chain can be claimed by new entrants, such as Tier 2 component development for Tier 1, and any parts of the value chain around hydrogen delivery. Regional and national government support can help establish a supply base or even a small cluster of mutually reinforcing industrial competencies.
- **Training of skilled technicians** such as gas fitters, garage mechanics and roadside support will be required. Emergency responders must also be suitably equipped to deal with the different hazards associated with hydrogen technologies, primarily in the transport sector. This will be needed in **both scenarios from 2015**, apart from the **gas fitters, required for the FC scenario only**. Some of the early servicing requirements will be handled exclusively by vehicle suppliers who are likely to want to carefully watch and manage their early vehicles, but this is not sustainable beyond the first few thousand. Additional work is ongoing internationally, such as the European HySafe project (IEA, 2015), and these programmes can be built upon locally. Wider international collaboration will also be important, for example with North America and Asia, partly because of the international nature of components and complete technologies, and partly because of the important learning and skills transfers possible. Some of this can be achieved at a political level (e.g. through the IPHE), but in part it also requires co-ordination between relevant government and official registration bodies such as Gas Safe in the UK. While large numbers of installers and other trained experts will not be required initially, it will be essential to have appropriate geographic coverage that matches the specific technologies as they are rolled out.

[4] International Partnership for Hydrogen and Fuel Cells in the Economy

4.2.4 Standards and safety

- **Testing and demonstration to revise hydrogen standards - both scenarios from 2015.** Many standards for hydrogen production, storage, transport and refuelling exist at UK, other national, European, and international levels. As installation numbers increase, further work testing real systems should underpin the further development and evolution of these standards and the relationship between them. For example, the Hyhouse[5] project has investigated quantitatively the concentrations of hydrogen that occur with different sizes of leak in a two storey property to guide refinements to existing standards before widespread deployment. Other areas for examination would include hydrogen transported in tankers, hydrogen vehicle use in underground car parks and tunnels as well as a variety of aspects of pipeline delivery and local storage. A new body – or a larger mandate for an existing one such as the Institute of Gas Engineers and Managers (IGEM) – to consider hydrogen energy standards holistically and ensure appropriate implementation or revision of existing industrial and other regulations could help to streamline and rationalise the process and the standards themselves.
- **Inclusion of hydrogen in the GS(M)R[6] – FC scenario from 2025.** Hydrogen pipelines currently fall outside GS(M)Regulations though are covered by pipelines regulations. Including hydrogen pipelines in the GS(M)R would improve access to rights of way for hydrogen infrastructure.
- **Standards for gas grid conversion – FC scenario from 2015.** The Institute of Gas Engineers and Managers (IGEM) should be encouraged to sponsor appropriate research and then write the necessary standards. The impact of such a change of gas quality has not been considered since privatisation and its implications need careful consideration.
- **Regulations for siting hydrogen refuelling stations should be revised from 2015 in both CP and FC.** For HRS the main specifications are ISO/TS 20100 (Gaseous H2 refuelling), ISO 14687-2 (purity) and ISO 17268 (connectors). All public HRS must comply with these by 2017. However, current regulations such as COMAH[7] restrict the amount of hydrogen that can be stored onsite, limiting the size and ultimately the economic case for HRS. Work to include hydrogen in the 'Blue Book' used for safety acceptance of forecourt installations is underway (Element Energy, 2015).
- **Technology modification and harmonisation may be required from 2015 in both scenarios.** Depending on the source of the appliance or product, modifications may be required to ensure compatibility with European or UK requirements. For example, Japanese fuel cell systems have required the gas processing unit for PEM systems to be re-engineered to meet local gas specifications (IEA, 2015).

4.2.5 Financing

- **Financing models for refuelling stations - from 2020 in Critical Path, 2018 in Full Contribution.** Innovative financing models or other risk-reduction techniques are needed for all early refuelling

[5] Hyhouse: A project to compare the concentrations of hydrogen and natural gas in a property arising from simulated leaks from the domestic gas pipework, a leak in the gas main outside and from a hydrogen car in the integral garage.
[6] Gas safety (management) regulations
[7] Control of Major Accident Hazards

stations, particularly those with distributed hydrogen production, which will be high capital cost and underutilised for a significant period. Significant first mover disadvantage in investments in these first refuelling stations must therefore be overcome. Options could include joint ventures, tradable station permits, public-private partnerships and encouraging involvement of industrial asset financers and entrepreneurs with mixed debt/equity models. For example, under the German H2mobility initiative, vehicle manufacturers, fuel suppliers and industrial gas suppliers have formed a joint venture to plan and finance refuelling station network expansion – taking a mutual initial risk in order to build the network and the revenue base. In UKH2mobility, investment by individual organisations, with coordination to avoid duplication, is envisaged to avoid the complexities of joint ventures (Hayter, 2014). Other options could include:

- Technical modification, such as mobile refuelling stations, where availability is valued much as capacity payments are used for grid electricity reserves;
- Joint ventures between different fleet operators or between fleet users and public providers;
- Payment for fuel in advance, with an infrastructure premium paid per vehicle, or cross-subsidy from the vehicle manufacturers bundling fuel with a leased vehicle[8] and paying infrastructure providers for availability of that fuel;
- Cross-financing of high and low throughput stations in agreed strategic locations;
- Insurance for infrastructure costs, where lower than predicted utilisation triggers a payment.

- **Financing for transmission pipelines - from 2030 in Critical Path, 2025 in Full Contribution** - these are major projects with high capex, and likely underutilisation in early years. Pipelines will not be built until there is a degree of certainty over demand and locations of large supplies, which could lead to use of alternative sub-optimal supply routes even when a pipeline would be lower cost (LCICG, 2014).

4.2.6 International developments

- **Specific international co-ordination in both scenarios from 2015.** All hydrogen energy-related work is international. For either scenario to be realised it will be important both to benefit from learning elsewhere, and also to understand the competitive position for initially scarce hydrogen technologies. Ongoing international engagement is therefore essential from the very beginning. As described in the scenarios, hydrogen energy touches not only transport or energy but many other areas, potentially extending as far as the marine and agriculture jurisdictions. UK Government has participated in the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) since its inception, mainly through DECC. In order to ensure that the UK benefits as much as possible from hydrogen energy developments, suitable cross-governmental engagement and liaison nationally and internationally is required. A specific governmental or other office or organisation could be set up with responsibility for coordination (and potentially management) of the various inter-related areas.
- **Engagement with global OEMs for vehicles in both scenarios from 2015**. Of particular importance will be to ensure that the UK is deploying vehicles (such as buses) that have been partially or fully developed in the UK into suitable local markets, as well as continuing to make a

[8] As Hyundai has chosen to do with its early release FECVs

case for larger-scale deployment of cars developed elsewhere by the major OEMs. Many countries have stated their wish to be early adopters of FCEVs but limited numbers of cars will be delivered globally until at least 2020, and so success in either scenario will depend on some of the earliest vehicles coming to the UK to bring confidence and experience to users and developers.

- **Monitoring UK refuelling infrastructure versus ROW activity from 2015 in both scenarios.** The UK refuelling infrastructure available in the early years of FCEV car roll out will need to be comparable with competing regions for early FCEV car deployment in other countries, in order to attract OEMs to sell into the UK. If deployment is much faster elsewhere it may be more difficult for the UK to compete.

4.2.7 Energy system developments

- **Review of the development of CCS by 2025 in both scenarios.** This is needed to determine whether SMR with CCS is likely to be a viable pathway for hydrogen in the long term. It has been suggested that hydrogen production should be included in one of the first CCS demonstrations before 2025, using pre-combustion decarbonisation, to inform this decision (LCICG, 2014). Lack of success with CCS would imply a need to move to other low carbon hydrogen production options, such as large scale electrolysis, or biomass gasification and reforming, which would be have higher costs, and have impacts on the wider energy system. It is likely that hydrogen will not be an economic option beyond niches, in comparison with electrification of heat and transport, unless CCS technologies are available in the future.
- **Progressive grid decarbonisation from 2015 in both scenarios**. Both scenarios include the use of electrolysis, despite this being non-zero emissions in the early years when supplied from the grid. Progressive decarbonisation of the grid is needed to allow this use to continue in the later years of the scenarios. This is needed for all ULEVs and as such is a no-regrets move for low carbon transport as well as electricity generation.
- **Regulatory and possibly technical support for business models for energy storage in both scenarios from 2015**. Policy changes may be needed to enable aspects of grid energy storage and services which will enable successful business models for distributed electrolysis and hydrogen in power generation. These could include allowing operators of small storage to bid into certain markets from which they are currently excluded, and from which they can derive additional revenue. The ability to produce and sell hydrogen into different markets – transport and heat, for example – could also benefit producers. Timing for any such changes would require relatively frequent reassessment in the early period of either scenario, as business models will evolve rapidly in response to technology and market changes.

4.2.8 Information

- **Communication activities on safety and availability of technologies are needed from 2020 in CP and from 2015 in FC.** Information and education will be essential to smooth the path of any hydrogen technology rollout, with all types of audience from expert users to the general public. The former will react well to clarity and certainty of government objectives and support, while the latter will want and expect to understand the benefits, costs and any issues (e.g. safety) associated with new technology. For example, public confidence in FCEV safety could be improved by information campaigns including the results of FCEV crash tests required for the NCAP safety rating) (IEA, 2015). Communicating the safety of domestic hydrogen is at least as important, and will require co-ordinated efforts by companies and industry bodies, backed up by evidence gained through the testing programmes mentioned earlier.

- **Refuelling infrastructure information provision from 2015 in FC, 2020 in CP.** Freely and widely available information on the status and location of refuelling stations will be required, to ensure early adopters are able to refuel easily.
- **Information-sharing and co-ordination between stationary and transport infrastructure development and across other areas is required in both scenarios from the outset in 2015.** Information regarding planned developments in infrastructure – for example – may have important implications in terms of planning for other areas of deployment in the early years of each scenario. Likewise, cross-cutting issues such as green hydrogen definitions and availability should be co-ordinated across sectors. Again, a central coordination office within Government, perhaps supplemented by a central information repository of information – such as granted planning applications or similar documents – could help to ensure that the greatest utilisation of equipment was achieved and reduce duplication of effort.
- **Modelling, analysis and publication should be ongoing from 2015 in both scenarios.** Government, academia and other research- and analysis-oriented actors will need to support the ongoing development and roll-out of the different technologies through timely evaluation and modelling of both the wider energy system and its components, plus their interactions.

4.3 Conclusions

Many individual actions are required to support the scenarios laid out in this document. While some are quite specific, several are overarching and will be required to frame the more specific ones. Some actions are required in the next five years:

- Government needs to set out a clear policy position supporting hydrogen as soon as possible, at a general level and ideally also at a level relevant to individual sectors. This will enable the multiple actors who need to invest to manage their risk, and will keep hydrogen open as a decarbonisation option.
- Specific support will be required for refuelling station rollout until at least 2020, to ensure that enough of a network exists to allow for subsequent growth and to keep the relevant actors (both station suppliers and OEMs) engaged in the sector. The difficulty of decarbonising transport massively in the long term means this option is a valuable one to keep open. Further support may be required subsequently, but this will become clear before 2020.
- The policy trajectory on reducing vehicle carbon emissions and improving air quality needs to be at least maintained, to give confidence that investment in cleaner options will pay back. Supporting either infrastructure or vehicles alone would not give the relevant actors enough confidence to invest. For both vehicles and infrastructure, deployment needs to be self-supporting by around 2025, otherwise it is unlikely that FCEVs can take the proportion of the fleet they envisaged by 2050. A decision on further support will be needed between 2020 and 2025.

- Hydrogen supply also requires support, primarily in ensuring that no unfair obstacles are raised to its rollout, but also in better defining and rewarding the benefits it brings. Regulations, codes and standards have often not been designed with hydrogen in mind, and may restrict hydrogen deployment unnecessarily. Clear and fair definitions for 'green' hydrogen, coupled with support mechanisms, will enable it to be deployed more rapidly and cost-effectively.

In the early 2020s, specific support for other sectors will become important. While its exact nature will depend on the state of technology and deployment at that time, it is expected to include:

- Continued support for reduced emissions from other transport sectors, including long-distance trucking and shipping. These sectors are more conservative and support is likely to be required to ensure continued progress is made on decarbonisation and to bring other benefits. If support is not put in place early in the 2020s then these sectors are unlikely to be able to convert fast enough to meet future targets using hydrogen.
- Support to allow or require gas grids to accept hydrogen, and to convert local gas grids to operate using 100% hydrogen. This larger-scale network is needed to feed not only the range of transport options but also to provide heat for houses, a hard sector to decarbonise.
- CCS at large scale is required under these scenarios and a review in the 2020s will be essential to ensure performance and deployments are appropriate. Meanwhile indigenous renewable hydrogen or import options may have arisen and should be compared with CCS costs and performance. Should very large amounts of low carbon hydrogen be required without CCS then a decision on how best to achieve that would be required, with electrolysis of renewable electricity or biomass pathways possible options.
- Decarbonisation of heat must also be supported in and of itself, allowing the market to decide on options, but enabling hydrogen to be one of them.

Broad actions are required throughout the period to support all activities in the area. The UK will not develop all technologies alone, nor should it try. Instead we must engage internationally both strongly and proactively:

- Training for safety and service personnel must be developed, either through existing institutions or new ones. It should link to international activities wherever appropriate.
- Standards are already under development, but are lacking in some areas. An existing or new body should be appointed to ensure appropriate standards are put in place at the right time.
- Financing of some aspects of a widespread hydrogen rollout may be difficult, and flexibility should be allowed as far as possible to allow market actors to develop innovative financing proposals. It will be particularly important to ensure that markets are not unnecessarily compartmentalised (for example electricity provision, energy storage through hydrogen, and the provision of hydrogen fuel will almost certainly need to be linked).
- International engagement is essential. Not only are some technologies developed outside of the UK (though frequently with at least one UK supply chain component), but activities and innovations also depend on the interaction of an international community.
- Supporting analysis – for example through energy systems modelling – will help ensure a good direction is maintained. Clear communication about the benefits and rationale for hydrogen deployment will also aid developments.

5 Scenario costing

Technology specific cost information is included in chapter 1 (Overview of hydrogen technologies). These cost data have been combined with deployment data to form Task 5 of this study, which has been delivered as a separate costing tool in excel. The tool calculates overall scenario cost as well as levelised cost (e.g. £/kWh, £ per vehicle km) and emissions savings versus a counterfactual technology provided by the CCC. As desired by the CCC, input data (such as commodity prices) can be changed in the costing tool by the CCC.

6 Overview of hydrogen technologies - detail

This section provides an overview of the status, prospects and costs of technologies that could be used to produce, store, transport and use hydrogen in the period to 2050. Technologies are characterised in terms of their status, prospects, interactions with infrastructure and international activities, and barriers to their deployment are summarised. Technical development for the fuel cell stacks and systems used is well advanced, and much future cost reduction depends on mass manufacture. Figure 23 below shows the results of detailed engineering cost modelling (US DOE, 2014b) and indicates that the initial production of 20-30,000 systems has by far the largest incremental impact. This underpins the more rapid cost reductions anticipated in cars and LDVs where numbers ramp more quickly, than in HDVs and buses.

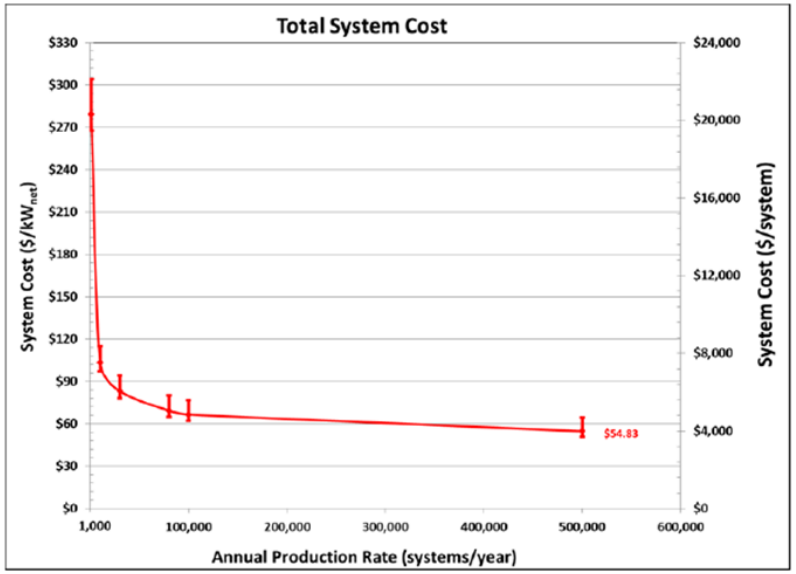

Figure 3. Projected cost of 2013 80-kW$_{net}$ transportation fuel cell systems at 1,000, 10,000, 30,000, 80,000, 100,000, and 500,000 units/year.

Figure 23: Cost reduction curve for fuel cell systems. Source: (US DOE, 2014b).

6.1 Transport

6.1.1 FCEV – Light Duty Vehicles (LDV)

Technology description	Most 2015 fuel cell cars, and those proposed for the coming years, use a series-parallel hybrid electric powertrain combining a hydrogen fuel cell with a (typically small) battery. For 'plug-in hybrid' or 'range extender' hybrid FCEVs, the fuel cell system is smaller and the battery larger, but all solutions are based on similar electric drive trains and include some battery or other storage. Unlike hydrocarbon-fuelled vehicles, FCEVs emit only water vapour, so do not contribute to local air pollution. They have a longer range and refuel faster than comparable battery electric vehicles. Proton Exchange Membrane (PEM) fuel cells are the dominant technology for FCEV due to their high power density, low operating temperature and ability to rapidly and deeply vary their electrical output in response to drive cycle needs (Fuel Cell Today, 2013).
Status	**Level of technical and commercial maturity:** Most active FCEV manufacturers have reached Technology Readiness Level (TRL[9]) 7 and above, though the different automotive companies are at different stages of internal development. FCEVs are commercially available in small numbers in selected regions (e.g. Toyota Mirai and Hyundai ix35 (Tucson) FCEVs in Japan, California, Scandinavia, the UK and Germany). **Deployment:** About 120 vehicles were deployed globally in 2014; Toyota and Hyundai, the two only manufacturers building significant numbers of passenger FCEVs, are each planning to produce 700-1000 FCEVs in 2015.
Infrastructure required to support deployment	Deployment of FCEVs requires the deployment of hydrogen refuelling infrastructure. This deployment needs to occur in a coordinated way, to ensure that FCEV drivers have sufficient infrastructure at their disposal and that hydrogen refuelling stations (HRS) can be economically viable despite low station utilisation during the vehicle introduction phase. In practice, until the number of vehicles reaches a certain density in an area, HRS must be 'subsidised' in some way, using either public or private money. The UK H_2Mobility project has developed a roadmap to roll out about 1150 HRS by 2030, which would provide all of the UK's population with access to an HRS. In a first phase, 65 HRS would be deployed in major cities and on important connecting roads (UK H2Mobility, 2013). These HRS would provide hydrogen at 70MPa (700 bar), which is the agreed standard for vehicle tanks in passenger cars (buses and other vehicles may use 35MPa). However, the hydrogen distribution infrastructure to the HRS and the form of hydrogen storage at the HRS will vary, and could for example be at lower or higher pressure, or in another form such as a liquid or a metal hydride.

[9] The definition of Technology Readiness Levels in this report is based on those used in the Horizon 2020 Work Programme.

Prospects for commercialisation	The first commercial passenger FCEVs are already available from Toyota and Hyundai. Other manufacturers such as Honda, Daimler, Ford and Nissan are expected to launch FCEVs in the coming years. While uptake in the UK is projected to be initially slow (e.g. UKH2Mobility projects a total of 13,000 vehicles in the first 5 years), FCEV sales could ramp up substantially in the 2020s. UKH2Mobility projects a cumulative FCEV fleet of 1.6 million vehicles and annual sales exceeding 300,000 vehicles by 2030 (UK H2Mobility, 2013).
Fundamental barriers to deployment	Refuelling infrastructure needs to be rolled out for FCEV to be attractive to customers. As mentioned above, the business model for this requires support in the early years. Although FCEVs are expected to become cost competitive with other vehicle types on a total cost of ownership (TCO) basis, the upfront capex is likely to remain higher than for ICE vehicles and this may affect consumer choice, unless appropriate financing options are available. A lack of user acceptance would limit uptake even if the technology is economically superior. Negative public perception of hydrogen safety would be a barrier to end user acceptance. This has not yet proven to be an issue, with established proven technology and safety standards in place, but could rapidly change if a newsworthy accident were to occur early in the deployment phase.
International linkages	The UK has a significant skills base, and companies involved in the supply chain globally. However, UK vehicle development is through niche players, not mass-market OEMs and so vehicles are expected to be imported. The UK so far has good links with those supplying vehicles though is viewed as a 'fast follower' secondary market. To benefit from the CO_2 reduction potential of FCEVs the UK will need to maintain strategic links with the countries and companies manufacturing the vehicles. The Zero Emissions Vehicle mandate plus significant infrastructure support makes California a leading region for FCEV passenger cars. Japan and Korea also have strong support programmes and are actively targeting strategic overseas markets. European level coordinated efforts for FCEV promotion also exist, with UK organisations actively participating.

Performance and cost

In a standard FCEV configuration, the fuel cell typically supplies the required power to the electric machine, with a battery boost when required. A commonly cited power range for the fuel cell is 70 kW (JRC, 2013) to over 110 kW (Toyota, 2015). The currently available Hyundai ix35 fuel cell car has a tank to wheel energy use (efficiency) of approximately 0.70 km/MJ (Hyundai, 2015a), compared to 0.56 km/MJ for the equivalent diesel ICE version (Hyundai, 2015b). About 1 km/MJ appears to be realistic in the longer term for FCEVs (IEA, 2015).

Currently available passenger FCEVs are sold at a price of £66,000 (Toyota Mirai, before subsidy (Toyota, 2015b)) to £67,985 (Hyundai ix35, before subsidy (Taylor, 2015)). Actual vehicle manufacturing costs are significantly higher, as the vehicles are produced in low volumes, but this is typical of any new vehicle introduction. The additional costs are largely borne by the automotive companies in order to facilitate FCEV market entry.

Future cost range: By 2030, an 'average' FCEV could be less than £3,000 more expensive than a comparable car with a conventional ICE drive train (E4tech based on the Coalition study, 2010).

FCEV (non plug-in hybrid)		2014 (est)	2030	2050
CAPEX	k£/vehicle	118	21	20
Fixed OPEX	k£/vehicle/yr	5.2	1.7	1.6
Efficiency	vkm/MJ	0.7	0.9	1.0
Lifetime	years	12	12	12
Mileage	km/vehicle/yr	13,500	13,500	13,500

FCEV (plug-in hybrid)		2014 (est)	2030	2050
CAPEX	k£/vehicle	124	25	23
Fixed OPEX	k£/vehicle/yr	4.7	1.7	1.6
Efficiency	vkm/MJ	0.9	1.2	1.4
Lifetime	years	12	12	12
Mileage	km/vehicle/yr	13,500	13,500	13,500

6.1.2 FCEV - Light Goods Vehicles (LGV)

Technology description	The drivetrain and fuel cell capacity of FCEV Light Goods Vehicles (LGV) is generally very similar to those of passenger FCEVs. Their mileage is usually higher and so are the annual fixed operational and maintenance costs. Compared to passenger cars, a larger proportion of current LGVs are range extender vehicles, where the fuel cell system augments a battery and is smaller than for standard FCEVs. Existing fuel cell range extender LGVs have been equipped with fuel cells of 5–10 kW (Intelligent Energy, 2012, Symbio FCell, 2013). The overall vehicle 'tank to wheel' efficiency of these vehicles is higher than for standard FCEVs, as the roundtrip efficiency (electricity in – electricity out) of a battery within a constrained set of limits is typically higher than that of a fuel cell (hydrogen in – electricity out).
Status	**Level of technical and commercial maturity:** The base technology is the same as for passenger FCEVs, though frequently these range extenders have been provided by specialist fuel cell companies rather than OEMs to date, and so are not as advanced or manufacturing-ready. This is because fuel cell LGV projects currently tend to be more focused on retrofits of commercially available battery electric vehicles, and on fuel cell range extenders for PHEV, rather than new ground-up designs (Intelligent Energy, 2012, Symbio FCell, 2015, US Hybrid, 2015). **Deployment:** Fuel cell range extenders have been retrofitted into battery electric LGVs and undergone successful trial runs in Europe and the US.
Infrastructure required to support deployment	Requires hydrogen filling stations. Commercial vehicles operated on a back-to-base basis may be able to use non-public HRS at the base, but a more widely available refuelling infrastructure is beneficial. Plug-in hybrids / fuel cell range extender BEVs would usually be charged at base, with the fuel cell obviating or reducing the need for EV charging infrastructure. Typical LGV retrofit projects use 350 bar tanks rather than the LDV standard of 700 bar. As soon as LGVs become available from OEMs, however, it is likely that 700 bar will be used.
Prospects for commercialisation	The first demonstration projects for fuel cell range extender BEVs are strongly subsidised (e.g. in France). Limitations of battery vehicles in terms of range and recharge time are providing the incentive for further projects to be examined. The drive towards increased shares of zero emission vehicles in cities (e.g. the planned Ultra Low Emission zone in London) is likely to be an important driver of zero emissions delivery vehicles such as fuel cell (range extender) LGVs. However, fuel cell vans are not expected to be available in commercial volumes before the mid-2020s (UK H2Mobility, 2013).

Fundamental barriers to deployment	Need for hydrogen refuelling infrastructure. Currently high added capital cost for fuel cell drive train. Fuel cell system and hydrogen tank may add weight and volume to the drivetrain, which may lower the usable space for freight. However, for LGVs volume is typically more of a constraint than weight, and so if the (more compact) fuel cell system actually displaces batteries this may result in greater overall delivery capacity.
International linkages	France is very active in promoting fuel cell range extender LGVs. However, these projects tend to be country-specific so while it is important for fuel cell companies to have access to global markets, it is less important for the UK as a whole to be linked into international initiatives.

Performance and cost

A fuel cell system for an LGV does not fundamentally differ from that for a passenger car, other than in size, for a range-extender. Performance requirements for the fuel cell system are likely to be lower than for passenger cars, as driveability is comparatively less important in the LGV market.

In plug-in LGVs FCEVs the fuel cell acts typically as a battery range extender, and hence the fuel cell is smaller, approx. 30 kW (JRC, 2013), which can also result in an overall lower cost compared to non-plug versions.

Future cost range: For full fuel cell electric LGVs the additional cost compared to conventional ICE LGVs is expected to be comparable to that of passenger FCEVs: By 2030, an 'average' FCEV could be less than £3,000 more expensive than a comparable car with a conventional ICE drive train (E4tech based on McKinsey, 2010).

FCEV (non plug-in hybrid)		2014 (est)	2030	2050
CAPEX	k£/vehicle	159	26	24
Fixed OPEX	k£/vehicle/yr	16	5	5
Efficiency	vkm/MJ	0.4	0.6	0.6
Lifetime	years	10	10	10
Mileage	km/vehicle/yr	21,000	21,000	21,000

FCEV (plug-in hybrid)		2014 (est)	2030	2050
CAPEX	k£/Vehicle	142	25	24
Fixed OPEX	k£/vehicle/yr	17	6	6
Efficiency	vkm/MJ	0.5	0.6	0.7
Lifetime	years	10	10	10
Mileage	km/vehicle/yr	21,000	21,000	21,000

6.1.3 FCEV - Buses

Technology description	Fuel cell buses use an electric drive train powered by a hydrogen fuel cell. Like passenger FCEVs, the drive train is usually hybridised with a battery and/or supercapacitor. Hydrogen buses have been used in demonstration projects since the mid-1990s in Europe, Asia and North America, and early commercial fleets are now gradually being introduced.
Status	**Level of technical and commercial maturity:** Most buses are at TRL 7 (NREL, 2014). In US field trials the stack lifetime currently ranges from 5,500 – 17,200 hrs, with a vehicle driving range (between refuelling stops) varying from 145 to 294 miles (NREL, 2014). **Deployment:** Currently 27 demonstration projects are active worldwide (International Fuel Cell Bus Collaborative, 2015), with 83 buses in operation or about to be in operation (FCH JU, 2015b). Over 20 buses were delivered in 2014 in Europe alone (E4tech et al., 2014), and larger initiatives are underway.
Infrastructure required to support deployment	Given the back-to-base nature of bus operation, infrastructure does not need to be widely available in the same way as for passenger FCEV. However, dedicated and highly reliable hydrogen refuelling infrastructure needs to be set up at the bus depot, which represents additional logistical complexity and cost if a hydrogen bus fleet is being operated alongside conventional diesel buses. Fuel cell buses typically use 350 bar compressed hydrogen for on-board storage (the cylinders are accommodated on the bus roof), so refuelling station requirements for buses are also for 350 bar delivery.
Prospects for commercialisation	Studies show that fuel cell buses can have a lower TCO than conventional diesel buses if deployed at scale (McKinsey, 2012). However, reaching this state will require a considerable increase in fuel cell bus manufacturing, to bring down fuel cell bus capital costs. Fuel cell buses also compete within the low-carbon vehicle sector with battery electric buses, deployed predominantly in China to date.
Fundamental barriers to deployment	The cost gap to conventional buses remains high at low volumes, especially on a CAPEX basis (McKinsey, 2012). This causes particular problems as public transit authorities have limited budgets and need to clearly justify additional expenditures. To overcome this, joint procurement clusters are being set up enabling many commonly specified buses to be bought by a group of transit authorities, at an individually lower cost than when only a few are ordered. Regulatory uncertainty, especially on alternative fuel taxation, carbon taxes, air quality legislation and other issues in order to sustain stable, long-term investments (McKinsey, 2012). Supply chains for fuel cell buses need to be built up. Fuel cell buses are currently manufactured in very low numbers, as OEMs are not ready to pay for the upfront investment in production capacities before demand is certain. Activities such as joint procurement will help to overcome this (FCH JU, 2015b).

International linkages	Deployment in the UK is currently strongly linked to EU projects such as HyTransit, High V.LO City and CHIC programmes. Technology leadership for stacks and fuel cell systems is mainly with North American companies (Ballard, Hydrogenics), and in Japan, though bus integration know-how is also strong in Europe and some European manufacturers have supplied FC bus stacks (e.g. NedStack, Proton Motor).

Performance and cost

As with passenger FCEV, PEM fuel cells dominate the market and will continue to do so. Fuel cell bus power ranges from 32-180 kW (International Fuel Cell Bus Collaborative, 2015). Estimates for current, 2030 and 2050 costs are based on McKinsey (2012), Dodds and McDowall (2014b) and US DOE (2014b). For comparison, the CAPEX for a conventional diesel bus is around £134,000 (Dodds and McDowall, 2014b).

FCEV Buses		2014 (est)	2030	2050
CAPEX	k£/vehicle	803	364	154
Fixed OPEX	k£/vehicle/yr	13	12	11
Efficiency	vkm/MJ	0.16	0.21	0.24
Lifetime	years	15	15	15
Mileage	km/vehicle/yr	31,000	31,000	31,000

6.1.4 FCEV - Heavy Goods Vehicle (HGV)

Technology description	Fuel cells for heavy goods vehicles (HGV) have thus far attracted less interest than for buses or passenger cars, as they will need to have much longer demonstrated lifetimes than for cars, and competing with the range of a conventional HGV requires large amounts of hydrogen to be stored, which may necessitate liquid hydrogen or dedicated ground-up designs. However, fuel cells are already being demonstrated as range extenders for electric powertrains in HGV used for local delivery or in tasks such as refuse collection. Fuel cells also represent an option to significantly increase the range of zero emission HGVs, which are increasingly sought in urban areas. Research and development is also being carried out on full fuel cell drivetrains for HGVs, but fuel cell and hydrogen storage technology is unlikely to meet the cost, durability and range requirements of this market in the short term. In the longer term, fuel cell trucks are considered to be one of the limited options to decarbonise long haul trucks. It is, however, estimated to be relatively more difficult to displace incumbent ICE technology in this sector, given diesel engines already reach efficiencies of up to 40% during constant highway operation (IEA, 2015).
Status	**Level of technical and commercial maturity:** Fuel cell range extenders are being trialled in large duty vehicles for local delivery (Renault, 2015). Very few efforts are currently being made to develop long haul full size fuel cell powered HGV in the US (US DOE, 2014a). Japan has a technology programme dedicated to this area (Shinka, 2014). **Deployment:** The deployment is currently limited to a small number of demonstration projects (CTE, 2015, Renault, 2015, TTSI, 2015).
Infrastructure required to support deployment	Hydrogen refuelling infrastructure is needed for fuel cell HGVs to be viable. For long range HGV, it is vital to have a sufficiently dense network of HRS spread over very large areas. For local delivery with daily back to base operation, wide scale deployment of such infrastructure is less critical.
Prospects for commercialisa tion	The first demonstration projects rely on strong subsidies. Given the less favourable market conditions for fuel cell technology in HGVs, it is likely that they will only become available on a commercial scale after fuel cells have penetrated the market in other vehicle categories (LGVs, buses, passenger cars). Strong mandated emissions reductions will help drive change.

Fundamental barriers to deployment	Need for widespread availability of hydrogen fuelling infrastructure, potentially with some liquid hydrogen. The long haul HGV market is very cost sensitive. Capex of fuel cell systems needs to reduce. Hydrogen storage technologies need to become more compact to enable the driving ranges needed for HGVs. Liquid on board hydrogen storage may be part of future solutions. To achieve the same range, current technology 700 bar tanks take up four times more volume than a diesel tank (IEA, 2012). The durability of the fuel cell systems is currently not sufficient for an application in long haul trucks, but this is likely to change in the medium term (2020-2030) as a dedicated Japanese programme is targeting stack lifetimes of 50,000 hours (Shinka, 2014).
International linkages	Especially across Europe, refuelling infrastructure needs to be developed in a coordinated way across borders for the technology to become a serious option for long haul trucks. Markets like Japan and the US could possibly be developed more quickly as single national legislation would cover a sufficiently large area for HGVs.

Performance and cost

Given the very limited number of demonstration projects, current cost and performance for fuel cell HGV is difficult to estimate. Although the duty cycles will be very different, the status of fuel cell buses is probably the closest to fuel cell HGVs.
Fuel cell HGVs are estimated to reach an efficiency of 0.2 km/MJ and their cost is estimated to reach below £80,000 (Dodds and McDowall, 2014b), however this is rather speculative given fuel cell HGV are still very early stage. For comparison, current costs are around £69,000 for a comparable diesel HGV and £183,000 for a hybrid HGV (Dodds and McDowall, 2014b). For the fuel cell system, a similar cost evolution to fuel cell buses can be assumed, but on-board hydrogen storage is likely to remain more costly than for buses given the need for a longer range.

Fuel Cell Heavy Goods Vehicle		2014 (est)	2030	2050
CAPEX	k£/vehicle	406	118	78
Fixed OPEX	k£/vehicle/yr	16	14	13
Efficiency	vkm/MJ	0.2	0.2	0.2
Lifetime	years	7	7	7
Mileage	km/vehicle/yr	58,000	58,000	58,000

6.1.5 Fuel Cell Auxiliary Power Units for HGVs

Fuel Cells are also being developed as Auxiliary Power Units for HGVs, be it for 'hotel' loads (energy use when HGVs are stationary such as for cabin heating, cooling, lighting, and electrical devices) or for cargo cooling while the main engine of the truck is not running. Some developments in this area use Solid Oxide Fuel Cells (SOFC) that may be adapted to run on diesel, given that this fuel is readily available on board of the truck. However, PEM fuel cells coupled with diesel reformers are also prevalent. Were hydrogen refuelling stations to be widely deployed in the future, such APUs could be designed as lower cost PEMFC running on hydrogen.

6.1.6 Fuel cell motorbikes (and scooters)

Motorbikes as a vehicle category are overall not expected to have a significant impact on greenhouse gas savings, but it is worth noting that fuel cells are also being implemented here. As with other mobility applications, PEM fuel cells are favoured. In the UK, fuel cell company Intelligent Energy has developed a 4 kW fuel cell system for 2 and 4 wheel vehicles in cooperation with Suzuki Motor Corporation of Japan.

6.1.7 Vehicles with internal combustion engines (ICE) using hydrogen as fuel

Pure hydrogen ICEs

With relatively little modification, hydrogen can also be used in conventional internal combustion engines. The most prominent demo project involved the "BMW Hydrogen 7", a car designed to use hydrogen (as well as petrol) and field trialled around 2005, but the project terminated in 2009. The main disadvantage is the much lower fuel efficiency in an ICE compared to fuel cells, resulting in several times higher on-board storage requirements compared to FCEVs. In all likelihood, ICE cars running on pure hydrogen will not play a significant role in future transport. This is underpinned by the fact that no major car OEMs is looking into developing or commercialising this technology.

Hydrogen blended fuels in ICEs

Hydrogen blending into natural gas/methane/diesel can enhance the efficiency and environmental performance of conventional ICEs. Institutes such as the Idaho National Engineering and Environmental Laboratory (INEL) in the US and the Swiss Federal Laboratories for Materials Science and Technology (EMPA) are investigating the option of blending hydrogen in CNG for ICE engines, as is the UK-based company ULEMCo. If this concept finds acceptance among vehicle OEMs, hydrogen could become a widely used additive and could be incorporated in existing refuelling infrastructure. If FCEVs succeed, however, at some point they will displace this option.

6.1.8 Fuel Cell Trains

To substitute diesel trains in the future, hydrogen powered trains have been proposed in several countries and prototypes have been tested in several markets in the last 10-15 years, including Japan, USA, Denmark, Spain, China, South Africa (in mining operations) and the UK. Most of these projects use a PEM fuel cell to convert hydrogen into electricity, but internal combustion engines are also proposed (e.g. Denmark). Most recently Alstom has announced the development of regional commuter trains that will be demonstrated in regular operation in Germany after 2018.

Current technology and commercial data for future hydrogen trains are highly speculative. Moreover, rail fuel consumption and emissions are much lower in absolute terms than for road transport, so although hydrogen-fuelled trains are included in the UKTM model, rail is not examined in detail in this report. Although track-electrification is viewed as the obvious solution to reduce the share of diesel trains and hence emissions, plans in many European states have been slowed (e.g. UK, Germany). Hydrogen trains may possibly profit from establishment of hydrogen in road transport and one day become a viable alternative to track electrification.

6.1.9 Fuel Cells for Ships

Hydrogen fuel cells have already been used for propulsion of ferries or boats in a few projects (e.g. Lake Constance, Hamburg, Scotland, Bristol and Norway). The growing adoption of LNG on ships, mainly due to emission controlled zones (e.g. Baltic Sea region), could become an incentive to consider fuel cells (better efficiency with an expensive fuel). Hydrogen could play an important role as a propulsion fuel in shipping in the long term (i.e. after 2030), but is highly speculative. Fuel cells for auxiliary power may be adopted much earlier (Fuel Cell Today, 2012) but would also be limited for routes where hydrogen supply infrastructure at ports is secured.

6.1.10 Fuel Cells for Airports and Aircraft

Hydrogen fuel cells are seen as a viable approach to reducing aviation emissions through the use in ground vehicles and buses. Several demonstrations projects at airports have been carried out or are currently in operation. In view of announcements by airlines, airports and aviation associations to limit both carbon emissions and air pollutants, ground operations are an area of focus. Therefore fuel cells could play an important role at airports in the coming 10 to 20 years. Besides ground operations, fuel cells have also been tested for operation on aircraft to supply auxiliary power. Hydrogen for aircraft propulsion has been discussed and demonstrated in some tests, but the greenhouse benefits are negligible for high altitude flights (above 11km) due to the high forcing effect of water vapour at this altitude. A complete redesign of aircraft and therefore turnover of the aircraft fleet would be required. The complexity and cost of installing liquid hydrogen fuelling infrastructure for aircraft is also high, particularly if it is low-carbon, and it would require widespread availability of hydrogen in different countries if used on international flights. Hydrogen for propulsion is therefore unlikely to be relevant in the period to 2050 other than in smaller and lower-flying aircraft. An exception could be unmanned aerial vehicles, which may use hydrogen much earlier. Companies already offer fuel cell solutions in this area.

6.2 Electricity generation

6.2.1 Hydrogen turbines

Technology description	Hydrogen turbines are conventional gas turbines designed to burn hydrogen as fuel. Both open cycle and combined cycle gas turbines can be used. Similar to conventional gas turbines they could be used in a broad capacity range from about 1 to 500 MW.
Status	**Level of technical and commercial maturity:** Although hydrogen is currently not used as a fuel for gas turbines, turbine manufacturers such as Siemens have developed hydrogen gas turbines using hydrogen and air, though sometimes nitrogen is added to the hydrogen stream as a diluent to reduce flame temperatures and speeds and enable conventional materials sets to be used. TRL level is estimated at 7-9. Development activities are concentrated around optimising the combustion of hydrogen with air to minimize the formation of nitrogen oxide, a pollutant. Future developments may include hydrogen plus oxygen turbines to offer emission free combustion, though the very high flame temperatures and other characteristics make the materials issues challenging. **Deployment:** To the best of the authors' knowledge, hydrogen turbines are currently not used, other than in R&D, though they could be deployed given a short lead time.
Infrastructure required to support deployment	No specific infrastructure is required, but a hydrogen gas network would be most supportive for deployment of this technology. Otherwise, hydrogen gas turbines may be located at any suitable hydrogen source (e.g. an industrial site with hydrogen off-gases, a hydrogen production facility, or a hydrogen storage facility, such as underground caverns).
Prospects for commercialisation	If hydrogen is established as a major energy carrier, hydrogen turbines may substitute for natural gas turbines and act as peaking power plants to balance the electricity grid. This may be challenged by future stationary fuel cells, given substantial enough cost reductions, if they can offer the same or better efficiency and emission performance.
Fundamental barriers to deployment	• Availability of hydrogen as a fuel

International linkages	• Research and development activities in hydrogen turbines is reported from Germany (Siemens), US (GE) and Japan (Toshiba, Hitachi), and typically conducted by developers or manufacturers of conventional gas turbines.

Performance and cost

Cost and performance of hydrogen CCGT based on US DOE (2009). OCGT capex based on E4tech personal communication with Siemens in 2013. For OCGT lifetime of CCGT was assumed and a similar Opex to Capex ratio as for CCGT was assumed, to derive OCGT Opex.

Hydrogen gas turbines (OCGT)		2014 (est)	2030	2050
CAPEX	£/kW	555	555	555
Fixed OPEX	£/kW/yr	0.0043	0.0043	0.0043
Efficiency	% (HHV)	48%	48%	48%
Lifetime	years	20	20	20

Hydrogen gas turbines (CCGT)		2014 (est)	2030	2050
CAPEX	£/kW	389	389	389
Fixed OPEX	£/kW/yr	0.0030	0.0030	0.0030
Efficiency	% (HHV)	32%	32%	32%
Lifetime	years	20	20	20

6.2.2 Fuel cells for stationary power-only applications

Technology description	Stationary power-only fuel cells are used as back-up or prime power (e.g. telecom towers, offices buildings, hospitals, data centres) and even for grid scale electricity generation at the MW scale or for large onsite power demands, e.g. in large data centres.
Status	**Level of technical and commercial maturity:** Stationary fuel cells are available as technologically mature systems. While MCFC are available in building block sizes up to and above 1MW, PAFC and SOFC systems are available in 100–400kW block sizes but can be combined in a modular way to reach the MW scale. MCFC in stationary applications reach several MW, but cannot use pure hydrogen directly because to function they require carbonate ions. Carbon-containing fuels, such as natural gas or biogas, are used. AFC demonstrations of tens of kW are in development, and plans for MW of deployment have been announced. PEMFC are mainly used in sub 50kW systems for back-up power (e.g. at telecom towers) and less common in larger systems, but PEMFC could use industrial hydrogen off-gases to generate power. 1MW PEM plants have been built and a 2MW one is in build. AFC may offer a lower-cost but large footprint option also. Costs for all these technologies have reduced substantially over the last few years but economic viability still hinges on favourable regulatory environment or subsidies. **Deployment:** More than 300 MW of large stationary fuel cells have been deployed globally to date, dominated by MCFC[10] from FuelCell Energy, SOFC from Bloom Energy and PAFC from Doosan Fuel Cells America (previously UTC).
Infrastructure required to support deployment	Hydrogen infrastructure is not necessarily required, but with the exception of MCFC, all currently available technologies could run on hydrogen (PEMFC, SOFC, PAFC, AFC). Most large scale fuel cells used today run on natural gas and in some cases biogas, requiring a connection to the gas grid or a local source of biogas, respectively. A few operate on pure hydrogen, usually a waste stream from a chlor-alkali or similar plant. Use of other gaseous hydro-carbon fuels may be possible through technology adaptation. Methanol is often used as fuel in smaller back-up power systems, either in a direct methanol PEMFC or in a standard PEMFC combined with a reformer. For the small amounts of methanol or hydrogen in back-up power systems no dedicated infrastructure is required, as supply is small enough to rely on road transport. In addition, a lack of infrastructure is often the reason for needing a back-up system.

[10] Molten Carbonate Fuel Cell

Prospects for commercialisation	As further cost reductions are achieved, stationary fuel cells will compete with any other distributed generation technology (natural gas generator sets, diesel gensets, but also distributed solar and wind).
Fundamental barriers to deployment	Cost competitiveness with conventional generation technology. Decision makers often not aware of the technological maturity of stationary fuel cells – hence may not consider this alternative.
International linkages	• Deployments of large stationary fuel cells have so far been concentrated in two (subsidised) markets: South Korea and the US. Technology leadership is based in the US (Fuel Cell Energy, Bloom Energy and Doosan Fuel Cells America), but international linkages play an increasing role (FuelCell Energy Solutions in Germany, Posco and Doosan in South Korea). The UK retains a place through LG/Rolls-Royce Fuel Cell Systems (SOFC hybridised with a microturbine) and AFC Energy (AFC technology). • Technology leadership of small PEMFC onsite power generation is concentrated in North America (Ballard in Canada, Relion/PlugPower in the USA), but many smaller players in Europe and Asia are also developing or commercialising stationary prime power fuel cells (NedStack in the Netherlands).

Performance and cost

Cost and performance characteristics listed below are from a recent European study (FCH JU, 2015a) and refer to an archetype natural gas fuel cell system of 1 MW electric output that represents a blend of different fuel cell technologies. Fuel cells for CHP are discussed under section 0).

NB: The capex cited includes three stack replacements during the lifetime of the system.

Large prime power fuel cell		2014 (est)	2030	2050
CAPEX	£/kW	4,337	2,846	2,467
Fixed OPEX	£/kW/yr	40	40	40
Efficiency electric	% (HHV) el	44%	47%	47%
Lifetime	years	11	13	13

6.3 Industry

The predominant demand for hydrogen today is as an industrial feedstock. The highest demands are for ammonia production for fertiliser (50%) and in oil refineries and chemical industries (40%) (Wawrzineck and Keller, 2007, Ball and Weeda, 2015), where hydrogen is mostly used as feedstock in hydrogenation processes, and as a reducing agent to remove impurities at different scales. It is also used industrially as a gas carrier in several manufacturing operations. Some by-product hydrogen is used for onsite fuel and heating. At present, about 50 million tons of hydrogen are produced globally every year for these purposes (Air Products, 2015). Around 95% of global hydrogen production is thought to be produced and consumed at the same location, as part of a larger industrial process. Statistics of hydrogen production capacities and consumption for the UK consider only merchant plants and not hydrogen produced at plants for own use, so are not comprehensive. The UK has two hydrogen pipelines:

- a 35 km pipeline (up to 50 bar) that links the BOC Linde production plant at Teesside with Huntsman chemical refining plants at Wilton and North Tees; and,
- a substantial line between Ellesmere Port and Runcorn.

Hydrogen is produced as a by-product of several large scale chemical production processes. Ethylene crackers and chlor-alkali production plants are the largest sources of by-product hydrogen in the UK, followed by refining operations.

In the future, hydrogen could be used to supply low-temperature heat and significant quantities of high-temperature heat for industrial processes. In the iron and steel sector, coal/coke could almost completely be substituted by hydrogen, which can be an alternative reductant, but this would require the construction of new furnaces. In the cement (non-metallic minerals) kilns, coal is often used as a fuel and hydrogen burns at a similar temperature so is potentially a better alternative than the lower-temperature natural gas. However, clinker is heated primarily by radiant heat transfer and the very low luminosity of a hydrogen flame could be an issue. Moreover, using hydrogen could require the kiln to be redesigned and replaced.

During the switch from town gas to natural gas in the 1970s, many industries invested in new plant to take advantage of the new fuel. Yet the Industry Roadmaps to 2050 (DECC, 2015) identify only a small future strategic role for hydrogen in UK industry. This probably reflects the current investment climate, as most UK industrial plants are foreign-owned and substantial new investments in new plant have mostly targeted growing markets. These factors make it unlikely that substantial long-term investments to redesign existing plants to use hydrogen would be considered in the near future, even if these appeared to be cost-optimal from a whole-economy perspective.

6.3.1 Industry – Low temperature heat processes

Technology description	Low-temperature heat is widely-used across many industries for process heating and drying applications (DECC, 2014). Iron and steel, chemicals, non-metallic minerals, non-ferrous metals, pulp and paper and food and drink plants in the UK produce low-temperature heat using natural gas, which could be switched to hydrogen. Heat can be supplied either by generic or process-specific furnaces that heat the material directly or indirectly by heating a fluid in boilers. Hydrogen combustion characteristics such as velocity and flame heating properties are different from natural gas, and whilst there is likely to be limited potential to use it directly in existing process-specific furnaces (Häussinger *et al.*, 2000) the use of hydrogen in more generic industrial boilers has been proven feasible and only requires burner retrofit to accommodate hydrogen gas properties (Scaria and Thariyath, 2014). Hydrogen could be combusted in boilers in a mix with natural gas, coke oven gas and blast furnace gases to reduce their environmental impacts. For 100% hydrogen applications, oxyfuel burners could combust pure hydrogen with pure oxygen rather than air to avoid nitrous oxide formation and increase the combustion efficiency by 15% compared to conventional natural gas boilers (Ricardo AEA, 2012).
Status	Hydrogen burners are commercially available and sometimes used at sites with available by-product hydrogen (TRL 9).
Infrastructure required to support deployment	Hydrogen supply (onsite production or a link to a transmission/distribution network).
Prospects for commercialisation	Already used commercially in some industrial niches. A high level of hydrogen purity is not required. The main barrier is the availability of hydrogen and its cost relative to natural gas.
Fundamental barriers to deployment	• Lack of infrastructure (e.g. to link sites with by-product hydrogen to sites that could use hydrogen) • Hydrogen costs compared to other fuels

International linkages	A hydrogen pipeline network connects various industrial complexes in Belgium, The Netherlands and France.

Performance and cost

The CAPEX for hydrogen oxyfuel burners could be 30% higher than those shown below to pay for condensation and flue gas recycling (Ricardo AEA, 2012).

Low temperature heat and drying Hydrogen 100% boiler		2014 (est)	2030	2050
CAPEX	£/kW	98.3	98.3	98.3
Fixed OPEX	£/kW/year	3.2	3.5	3.5
Efficiency	kWh/kWh	90%	90%	90%
Lifetime	Years	25	25	25
Availability factor	%	90%	90%	90%

6.3.2 Industry – High-temperature heat for iron and steel production

Technology description	Around 90% of global iron production comes from blast furnaces, with the remainder from directly-reduced iron ore (DRI). Blast furnaces use coke to reduce iron ore into molten iron, subsequently refined to steel in an oxygen furnace. DRI is produced from reformed natural gas converted into a carbon monoxide and hydrogen mix, used to reduce the iron ore. The DRI is then further refined to steel in an electric arc furnace. The most energy intensive step is the reduction of iron ore to a metallic state. A novel gas-solid suspension ironmaking technology is being developed at the University of Utah (Sohn, 2007). The technology reduces iron ore concentrates in a gas solid suspension using hydrogen gas, avoiding the coking and pelletisation processes used in conventional steelworks (Pinegar *et al.*, 2011). Another novel route uses hydrogen to reduce fine ore and produce hot bracketed iron, which is then melted with scrap and introduced into an electric arc furnace. This route potentially has high emissions saving potential, but market entry is not expected until 2030 (Fischedick *et al.*, 2014).
Status	These technologies have not been constructed at commercial scale (TRL 4).
Infrastructure required to support deployment	Hydrogen supply (onsite production or a link to a transmission/distribution network).
Prospects for commercialisation	Public or private funding is needed to deploy commercial scale pilots. Some R&D is being invested abroad and a pilot plant was under development in Utah (Sohn, 2007). Current status is not known.
Fundamental barriers to deployment	• Lack of infrastructure (e.g. to link sites with by-product hydrogen to sites that could use hydrogen) • Lack of economic viability for retrofitting existing plants • UK iron and steel production is mostly based on blast furnace and basic oxygen furnace routes. DRI facilities and electric arc furnace plants would need to be deployed.
International linkages	Technology mainly being researched abroad, in the USA and China in particular.

<u>Performance and cost</u>

These technologies are currently at an early stage of development and it is difficult to estimate credible costs. Techno-economic analyses of novel iron and steel processes using hydrogen are required.

6.3.3 Hydrogen in refining operations

Technology description	Hydrogen is produced in refining operations via the catalytic reforming unit, where linear and cyclic paraffins are dehydrogenated to produce aromatic chains and raise the octane number of the virgin naphtha. Hydrogen is used mainly in two refinery process: Hydrocracking and hydrodesulphurisation. • Hydrocracking breaks long chain ("heavy") hydrocarbons into shorter chains ("light"). The heavier the crude oil, the more hydrogen is needed. • Hydrodesulphurisation (sweetening) removes sulphur from refinery products. When a good-quality crude oil blend is used and the constraints on product quality are not too stringent, hydrogen demand from the purifying processes can be met by the hydrogen produced by catalytic reforming. In recent decades, however, crude oil quality has decreased and the need for cleaner and lighter petroleum products has increased the demand for hydrogen beyond the by-product production, leading refineries to gradually construct onsite hydrogen production capacity. While most refineries have built SMR plants, some have instead used partial oxidation of heavy residues to produce syngas and then convert it to hydrogen and CO_2 via a CO shift reaction (DECC, 2015). Refineries therefore represent a net demand for hydrogen. Consumption ranges from 5–10 kg per tonne oil throughput (Holmes, 2015), depending on the refinery configuration (Ramachandran and Menon, 1998). The seven major UK refineries had a throughput of 69.2 million tonnes in 2013, corresponding to a demand for around 500 kt hydrogen. While hydrogen demand per unit throughput might be expected to continue rising in the future, total demand for petroleum is expected to fall if climate change emission targets are to be met. Bio-oil, from biomass pyrolysis, might be refined in a similar way to petroleum in the future, and this could present a new market for hydrogen. Little information is available about biorefinery designs at present.
Status	Hydrogen production and use in refineries dates from the start of petroleum refining, and is common around the world (TRL 9). Different types of biorefineries are at different development stages (TRL 5-9).
Infrastructure required to support deployment	Hydrogen supply (dedicated onsite production or a link to a transmission/distribution network) where by-product hydrogen from catalytic reforming is not sufficient to cover hydrogen demand.

Prospects for commercialisation	Petroleum refineries are already operational. Biorefineries will depend on the optimum uses for the limited available bioresource.
Fundamental barriers to deployment	None
International linkages	In Western Europe, hydrogen supply can generally be considered sufficient, as strict sulphur requirements have been in place for a long time and there is an overcapacity of refineries. Some refinery hydrogen plant projects have taken place in recent years in countries such as Bulgaria, Greece, Turkey, Israel and Italy (e.g. Eni's biorefinery project in Venice require more hydrogen than conventional refineries) In the rest of the world, hydrogen plants are typically added or enlarged when fuel quality standards are lifted (e.g. China, Russia, and the Middle East).
Performance and cost Refinery use of hydrogen as a feedstock is best represented as a large point-source demand. Hydrogen plants at refineries are comparatively small contributors to overall capex. The cost of hydrogen at a refinery is largely driven by the opex (i.e. cost of feedstock natural gas, LPG).	

6.3.4 Chemicals – Hydrogen use in ammonia production

Technology description	The ammonia production process has two main parts: (i) hydrogen production, usually via steam methane reforming, but also from large electrolysers in some places; and, (ii) the Haber-Bosch process. The latter combines nitrogen from the air with hydrogen to produce ammonia. The reaction is reversible and the production of ammonia is exothermic. 3 tonnes of hydrogen are consumed for every 17 tonnes of ammonia produced. The UK has three ammonia plants in operation with a total capacity of 1,200 kt/year, and hence a hydrogen demand of around 200 kt/year.
Status	Mature technology (TRL 9).
Infrastructure required to support deployment	Hydrogen supply (onsite production or a link to a transmission/distribution network).
Prospects for commercialisation	Already used throughout the world.
Fundamental barriers to deployment	None
International linkages	Ammonia, or fertiliser production in more general is often tied to the local availability of energy carriers for hydrogen production. Examples are Qatar (natural gas steam reforming), China (coal gasification), and in Canada, Norway and Egypt (hydropower and electrolysis).

<u>Performance and cost</u>

Use of hydrogen as a feedstock for ammonia production is best represented as a large point-source demand. Hydrogen costs are very different dependent on the local energy source, feedstock and hence process used.

6.4 Heat in Buildings

6.4.1 Hydrogen distribution and use in buildings (100% hydrogen)

Technology description	Use of the existing natural gas low- and medium pressure network to feed 100% hydrogen to domestic, commercial, industrial and vehicle refuelling sites. To use 100% hydrogen, boilers, appliances and meters in buildings need to be converted.
Status	Hydrogen has been used in buildings in the UK for close to 200 years in the form of town gas, which is 45–60% hydrogen by volume. However, use of 100% hydrogen is at the demonstration stage. Domestic and commercial hydrogen burning appliances are rare due to the absence of demand. Current products are restricted to boilers (see below). If hydrogen use becomes widespread, a whole range of boilers, cookers and fires should become available although the design of flame and flicker fires is expected to be quite difficult.
Infrastructure required to support deployment	• Medium and low pressure hydrogen network is required (see section 6.6.7) • A system to fully odorise hydrogen will need to be in place.[11] • On conversion of dwellings to hydrogen, the gas carcass (pipework) should be pressure tested and an excess flow valve should be fitted. Some additional ventilation may be appropriate.
Prospects for commercialisation	Despite few real world examples, hydrogen use in buildings could be a competitive alternative in view of the costs and complexities of other low carbon options such as air source heat pumps and district heating. If hydrogen is established as a major energy carrier, a wide range of hydrogen consuming appliances could be designed and marketed over a period of three to five years. The conversion of the low pressure gas network in the UK could be carried out at a million properties per year from the early 2020s to about 2050. This could be achieved with a small increase to the current 150,000 Gas-safe registered engineers.[12]
Fundamental barriers to deployment	• Public perception of hydrogen safety – an information programme on the safety of hydrogen would be required. • Conversion of the network from natural gas to hydrogen (see section 6.6.7) • Conversion of the connected appliances to hydrogen.

[11] There is currently a debate whether this should be stench (probably containing sulphur and/or nitrogen hetero atoms) or whether (for example) cyclohexene might be acceptable (a more sweet-apple smell). Certain odorants poison fuel cells and so would need to be removed for some uses.

[12] Currently all natural gas systems in domestic and commercial property can only be installed and serviced by Gas-safe registered engineers. Currently hydrogen lies outside this scheme, but in the event of its widespread use legislation would likely be brought forward to include hydrogen in either this or a similar scheme.

	• Organisation of conversion process (see section 6.6.7). Conversion has to be essentially compulsory although consumers could change to electricity instead. • A suitable funding mechanism. • The appliance market needs reassurance that hydrogen will be rolled out. • Hydrogen purity standards: Since distribution of gas through a widespread gas distribution network inevitably causes contamination of the delivered gas from water, cutting oils, and plastic debris, and the hydrogen will also have to be odorised, the purity of hydrogen that can realistically be delivered though the network is still to be assessed and agreed.
International linkages	Trials with 100% conversion to hydrogen in the residential sector are very rare. A small area of Denmark at Vestenskov installed a wind-farm generated hydrogen distribution[13] network and about 40 mCHP units. At the end of the trial the project closed and no in-depth references are available. The project used purpose-laid pipes and hydrogen storage in steel vessels. A 'hydrogen town' in Kyushu, Japan, is also trialling pure hydrogen in houses[14].

<u>Cost of conversion to hydrogen:</u>

Kiwa Gastec estimates the conversion cost of a house to £3,500, based upon recent costs of the Isle of Man conversion from Town gas to Natural gas. This includes:

- New condensing boiler (installed) £2000
- New gas fire (installed) £750
- New cooker £250 and
- Miscellaneous (incl. meter) £500

Economies of scale should reduce this in large towns. Fixed operational costs should be the same as natural gas (e.g. inspections, maintenance).

[13] http://www.dac.dk/en/dac-cities/sustainable-cities/all-cases/energy/vestenskov-the-worlds-first-hydrogen-community/
[14] http://www.iwatani-europe.de/kitakyushu-hydrogen-town.html

Hydrogen safety in buildings

There has been little published work on the safety of hydrogen in buildings. However, the fire and explosion safety record of town gas (45 to 60% hydrogen by volume) was and is very good. The poor overall safety record of town gas was due to its high CO content, which would be absent if 100% hydrogen was supplied.

It is as a result of this lack of previous published work that SSE and DECC funded the Hyhouse project to measure absolute and relative concentrations of natural gas and hydrogen within a two-storey Scottish farmhouse. This determined that if hydrogen leaked inside a building as a result of corrosion or a failed fitting, the concentration of hydrogen in the building would be about 120% to 160% volume for volume (v/v) of that for natural gas[15]. This arises from the relatively lower density and higher dispersion rate of hydrogen. For example, leakage tests with a leak of 64kW (equivalent to the fuel supply of two typical combi boilers) into a well-sealed property resulted in concentrations of natural gas of ~8%v/v and hydrogen ~12%v/v. In both cases the atmosphere was potentially explosive. However, it is likely that damage from each explosion would be comparable, as although there would be more hydrogen in the house by volume, the amount of energy in the atmosphere would be less (due to its lower energy content). Further work is needed on the very complex interactions between the size and location of either a natural gas or hydrogen leak or the severity of any explosion.

Overall it is appropriate to treat hydrogen as another in the group of flammable gases (natural gas & LPG) already supplied to domestic and commercial buildings, with similar levels of risk.

[15] Hyhouse experimental programme funded by SSE and DECC, and carried out by Kiwa Gastec.

6.4.2 Use of 100% hydrogen in gas boilers (individual and district scales)

Technology description	The combustion of hydrogen is relatively straightforward. This can either be a conventional high temperature flame or as low temperature catalytic combustion. The absence of carbon in the fuel means that CO_2 emissions are zero at the point of use. The only other product of the reaction is steam that can be released to the atmosphere without risks. Hydrogen has about 20% of its energy content (HHV) bound up in the heat of condensation of the water vapour produced during combustion, compared to only 10% for natural gas. Therefore it will be desirable to try to maximise condensation of this water as in the case of a condensing boiler. **High temperature systems:** These appliances are straight replacements for exiting natural gas appliances feeding traditional, high temperature, wet central heating systems. The different flame speed and density of hydrogen means that burners need to be changed, but so long as the burner is designed for the fuel being used, the appliance performance should be similar. **Low temperature systems:** For its operation, H2ydroGEM® (the Catalytic Combustor from Giacomini of Italy) uses a catalytic reaction so it is a thermal generator without flame. A catalyser allows hydrogen and oxygen to combine to form water, simultaneously releasing heat. Heat produced by the reaction is removed by a heat exchanger embedded in the burner. The water temperature is between 35 and 40 °C. This temperature is ideal to feed low temperature heating systems such as underfloor systems. The low combustion temperature (300-350 °C) avoids the formation of NOx.
Status	Several boiler makers have already produced hydrogen boilers at a variety of scales and some hydrogen burning boilers are already on the market ranging from a few kW to those burning surplus hydrogen in industry at several MW. The actual numbers sold are extremely small, probably less than 100 (Kiwa Gastec estimate).
Infrastructure required to support deployment	Medium and low pressure hydrogen network is required (see section 6.6.7).
Prospects for commercialisation	Once hydrogen is established as a major energy carrier, further hydrogen boilers could be designed and marketed over a period of three to five years.

Fundamental barriers to deployment	As above (section 6.4.1)
International linkages	• Italy, Germany and Sweden all have several small manufacturers of hydrogen appliances. The US has a large number of enthusiastic amateurs who have converted natural gas appliances to hydrogen. However if the UK were first to roll out whole areas to hydrogen there is no reason why the UK should not lead the world. Gas appliance manufacturing in the UK is highly automated and labour productivity is high, and imports from Asia have been extremely limited so far (Source: Kiwa Gastec).
Cost of conversion to hydrogen at individual house level: See section 6.4.1 Cost of conversion to hydrogen at district boiler level: Conversion cost is dependent upon size and environmental performance of the boiler. For a reasonable average across the spectrum Kiwa Gastec estimates a conversion cost of £100 per kW. Small mass-produced burners and very large burners may be an order of magnitude less. Fixed operational costs are expected to be the same as in case of natural gas (e.g. inspections, maintenance).	

6.4.3 Fuel Cell mCHP

Technology description	Fuel cell micro-CHP systems are designed to deliver heat for hot water and space heating to homes, along with power that may be used in the building or fed into the grid. As with any other CHP, this should offer better fuel efficiency than separated solutions if both heat and power are used. Two types of fuel cell technologies are relevant today: PEMFC (low- and to some extent high-temperature) and SOFC. Commercial systems deployed so far use natural gas as fuel and therefore include a reformer unit to convert methane to a clean hydrogen-rich gas stream for PEMFC, and a pre-reformer to assist the oxidation of methane for SOFC.

Status	**Level of technical and commercial maturity:** PEMFC (low and high temperature) and SOFC are at TRL 9 for some applications, but are not yet fully commercial as subsidies are still required for their deployment. Development activities are focused on cost reduction and stack lifetime improvement. **Deployment:** By the end of 2014, more than 100,000 fuel cell mCHPs had been deployed globally, the vast majority in Japan, where a support scheme has been in place for several years (E4tech et al., 2014). These systems typically have electrical output of between 0.7 – 1.0 kW, are designed to run all year round and may be supported by conventional boilers to provide seasonally higher heat demand. Deployment in the UK to date is limited primarily to trials, with the total number of installed systems likely to be below 100 units (E4tech estimate).
Infrastructure required to support deployment	Fuel cell mCHPs installed today use natural gas and are connected to the gas grid or local storage like conventional gas boilers. Fuel cell mCHP *could* also run on hydrogen and be connected to a future hydrogen infrastructure. When running on hydrogen, PEMFCs may offer technical advantages over SOFC, hence would likely be favoured.
Prospects for commercialisa tion	If projected cost reductions are realised, the technology should become fully commercial (economically viable without incentives) prior to 2020, at least in mass markets such as Japan. Authoritative global deployment projections are not available. In the lead market, Japan, the government has stated a deployment goal of 1.4 million units (roughly 1 GW) by 2020 (E4tech et al., 2014).
Fundamental barriers to deployment	• Cost gap to conventional heating system remains high (both on capex and TCO basis), hence deployment requires incentives (FCH JU, 2015a). • Available technology requires natural gas or similar feed (e.g. LPG). May be adapted to other fuels in the future. • Limitations in stack lifetime require stack replacement during the useful life of the system for some applications – although manufacturers usually include stack replacement in a maintenance scheme, end-consumers may see stack replacements as a financial risk. • Different standards and different gas qualities mean that engineering and standardisation work is required to allow technology and product transfer between countries, such as from Japan to Europe.

International linkages	• Deployment in the UK is currently linked to the European ene.field programme. • Some technology development is taking place in the UK, mainly at a cell and stack level, with IE CHP one of the only activities on system integration. • Technology leadership in Japan. Several European boiler manufacturers (system integrators) have partnerships with Japanese suppliers, while some European players develop their own technology.

Performance and cost

Cost and performance characteristics listed below are from a recent European study (FCH JU, 2015a) and refer to an archetype mCHP of 1 kW electric that represents a blend of PEMFC and SOFC characteristics and costs. SOFC systems can achieve higher electrical efficiencies than PEMFC systems when both are fed on natural gas; efficiency running on hydrogen is comparable.

Current costs refer to 500 units produced per year, which is representative of where European boiler manufacturers are currently with their fuel cell mCHP products. 2030 cost refer to 100,000 units produced annually, which implies that boiler manufacturers have by then achieved mass-market roll-outs in several European markets. This seems plausible given plans in Germany for a market acceleration program to be launched in 2016 involving tens of thousands of units in the coming years, and in view of the Japanese Ene-farm program. 2050 costs refer to 1,000,000 units per year and bring only little additional cost reduction compared with 100,000 units per year in 2030.

NB: Cost for two stack replacements during the lifetime are included for today's systems. For future systems the cited study (FCH JU, 2015a) predicts stack lifetimes equal to the system lifetime, hence no stack replacements are required. Japanese companies already warranty their systems for up to ten years with no stack replacement. Systems running on hydrogen would be approximately 20% lower cost, due to savings from fuel reforming and clean-up. Cost cited below exclude an auxiliary gas burner (~£800, 10–15 kW_{th}), which is typically integrated in the fuel cell system to cover most of the space heating demand.

Operational strategies may change in future: High utilisation of the fuel is important to amortise the investment in the early introduction phase, hence mCHPs today cover typically the base heat demand of a building and use a gas boiler for winter heating loads. In the long term, cheaper fuel cell mCHP may be scaled for heat demands in winter, implying that the electrical capacity of the fuel cell will be underutilised in summer months.

Natural Gas Fuel Cell mCHP		2014 (est)	2030	2050
CAPEX	£/kW	17,380	3,320	3,129
Fixed OPEX	£/kW_yr	322	161	161
Efficiency combined	% (HHV) el+th	80%	87%	87%
Efficiency thermal	% (HHV) th	47%	48%	48%
Efficiency electric	% (HHV) el	33%	38%	38%
Heat-to-power ratio	th/el output	1.45	1.27	1.27
Lifetime	Years	10	15	15

6.4.4 Fuel cell district scale CHP

Technology description	Fuel cell district scale CHP systems are designed to generate electricity while at the same time deliver heat to residential, commercial or industrial clients, usually by means of a district heating network or sometimes directly co-located with a large heat demand. As with any other CHP, this improves fuel efficiency as both heat and power are used.
Status	While MW scale fuel cells deployed so far (>300 MW) are mainly used for power only generation, some are designed and operate as CHP plants. Two types of fuel cell technologies are commercially available today: Molten Carbonate Fuel Cells (MCFC) and Phosphoric Acid Fuel Cells (PAFC). SOFC is expected to become relevant in the future as well, while PEMFC is less suitable for this application due to its low temperature output.
Infrastructure required to support deployment	Hydrogen infrastructure is not necessarily required, but with the exception of MCFC, all currently available technologies could run on hydrogen (PEMFC, SOFC, PAFC). Large scale fuel cells used today run on natural gas and in some cases biogas, requiring a connection to the gas grid or a local source of biogas, respectively. Use of other gaseous hydro-carbon fuels may be possible through technology adaptation.
Prospects for commercialisa tion	Currently this technology is not yet commercially viable without support schemes, which have ensured deployment mainly in South Korea and parts of the US. The technology should be cost competitive with conventional alternatives in many markets in the coming 5 to 10 years. Authoritative global deployment projections are not available specifically for district scale CHP fuel cell systems.
Fundamental barriers to deployment	• The investment in district heat networks (regulatory aspects, risk of delays in permitting and construction) is a major barrier to deployment (this is less of a problem at sites owned and operated by one entity with high onsite heat and power demands). • Lack of cost competitiveness with conventional CHP technologies • Decision makers are often not aware of the technological maturity of stationary fuel cells – hence may not consider this alternative
International linkages	• Deployments of large stationary fuel cells for CHP applications have so far been concentrated in two markets: South Korea and the US. Technology leadership is based in the US (Fuel Cell Energy and Doosan Fuel Cells America), but international linkages play a growing role (FuelCell Energy Solutions in Germany, Posco and Doosan in South Korea). The UK has had limited interaction with these markets to date.

Performance and cost

Cost and performance characteristics listed below are from a recent European study (FCH JU, 2015a) and refer to an archetype natural gas CHP of 1.4MW electric output that represents a blend of different fuel cell technologies. Systems running on hydrogen would be approximately 20% lower cost, due to savings from fuel reforming and clean-up.

NB: The capex cited includes three stack replacements during the lifetime of the system.

Natural Gas Fuel Cell district scale CHP		2014 (est)	2030	2050
CAPEX	£/kW	5,574	4,027	3,718
Fixed OPEX	£/kW/yr	571	50	50
Efficiency combined	% (HHV) el+th	73%	76%	76%
Efficiency thermal	% (HHV) th	28%	28%	28%
Efficiency electric	% (HHV) el	45%	47%	47%
Heat-to-power ratio	th/el output	0.79	0.74	0.74
Lifetime	years	16	17	17
Stack replacement cost (over lifetime)	£/kW	5,200	4,353	4,136

6.5 Hydrogen production

Hydrogen has been produced commercially based on natural gas, coal, electricity and industrial processes for decades. Numerous novel production technologies are under development, for example thermocracking water or using algae, but these have not yet reached a level of development in which it is possible to plausibly estimate capital costs (other than noting that they would be very high).

Technoeconomic assessments of hydrogen production plants are available from several sources, notably the H2A Production Analysis programme of the USA Department of Energy. Several less mature technologies are being developed at the National Renewable Energy Laboratory (NREL) in the US. These assessments were compared in Dodds and McDowall (2012) and more recently in Dodds (2015).

None of the published technoeconomic studies focused on the UK, and translating these costs to the UK context is important but not straightforward. A comparison during UKTM energy system model development showed that the hydrogen production CAPEX from a range of studies that were analysed by Dodds and McDowall (2012) were substantially lower than the cost of equivalent electricity generation technologies from Mott MacDonald (2010)[16], which suggests that international technoeconomic studies substantially underestimate the costs of deployment of hydrogen production technologies in the UK. Since these studies are generally not based on actual plant costs, they should be treated with healthy scepticism. For this report, this comparison has been extended to DECC's electricity CAPEX assumptions as implemented in more recent versions of UKTM. UK-specific hydrogen production costs for all technologies have been derived from international studies on the basis of that comparison, using the approximate cost increases in Table 6.

CAPEX increases for UK hydrogen production plants		Study that is compared with Dodds and McDowall (2012)
Gasification plants	200%	Mott MacDonald (2010) – coal IGCC
Gasification plants with CCS	300%	Mott MacDonald (2010) – coal IGCC
SMR	100%	Leeds H21 project – UK SMR
SMR with CCS	200%	Port Arthur SMR CCS retrofit cost (Santos, 2015) – USA CCS retrofit
Nuclear	200%	Mott MacDonald (2010) – nuclear power

Table 6: CAPEX increases for hydrogen production plants in the UK, relative to an appraisal of international technoeconomic studies presented in Dodds and McDowall (2012).

The costs in this section therefore reflect studies from across the technoeconomic literature, as reported in Dodds (2015), but increased to reflect the UK context. An exception is electrolysis, for which data of a recent study at European level were used as reference. The costs of individual technologies are reported in the descriptions below.

[16] The coal gasification CAPEX was estimated by subtracting the CCGT CAPEX from the coal IGCC CAPEX. Other technologies were similarly examined.

6.5.1 Steam-methane reforming (with CCS)

Technology description	Natural gas reforming is currently the most widely-used process for producing hydrogen and has been utilised globally for many decades in the oil refinery and chemical industries. SMR (Steam Methane Reforming) produces around half of the global hydrogen production (García, 2015). SMR plants produce relatively pure streams of hydrogen and CO_2, using reformer, water gas shift and hydrogen purification stages. Waste CO_2 is ejected to the atmosphere in an air mix (~20% CO_2). Fluidised-bed membrane reforming has also been demonstrated in small-scale plants (Iaquaniello *et al.*, 2008), with the aim of increasing hydrogen purity and reducing the plant size, but the membranes can add significant cost and require replacement. Compact, small-scale reformers, suitable for refuelling stations, have been proposed as one option for a hydrogen economy (Ogden, 2001). While this option would remove the requirement for expensive delivery infrastructure in the early stages of a transition to hydrogen, the systems would be too small for CCS to be used so substantial CO_2 emission savings would be not be achieved. CCS can be added to a standard reformer by adding chemical or physical CO_2 absorption materials to the flue gas outlet or by adding an additional pressure swing absorption to separate out CO_2, with >90% CO_2 capture achieved at the Port Arthur Enhanced Oil Recovery project using the latter approach (Santos, 2015). Membranes could also be used to capture CO_2 and a sorption-enhanced reformer has been proposed that would produce a separate stream of CO_2 that would be much cheaper to capture (García, 2015). Peak SMR efficiencies are currently in the range 60%–75%, with larger plants being more efficient (Dodds, 2015). Efficiencies are expected to rise only slightly in the future but the gap between central and distributed plant efficiencies should reduce. Membrane plants are likely to only slightly increase the conversion efficiencies (Shirasaki *et al.*, 2009). Adding CCS facilities to existing plants would lower the efficiencies by around 5–10 percentage points.
Status	**Level of technical and commercial maturity:** SMRs are at TRL 9 and are fully commercial plants for industry. SMR plants with CCS are under development or in operation in several countries and are at TRL 8. Membrane reformers are at an earlier stage of development. Small-scale SMR is also in use, though is less commercially mature with few producers or installations. Costs do not scale linearly and so small SMR plants are proportionally more expensive than large ones **Deployment:** Used for around half of all existing hydrogen production.
Infrastructure required to support deployment	Gas clean-up to required level. Where the hydrogen is not consumed on-site one or more of the following: • pipelines • liquefaction plant • a suitably-sized compression and/or loading station for tube trailers

Prospects for commercialisation	SMR plants are already used commercially.
Fundamental barriers to deployment	With CCS: Cost of CCS facilities and availability of CO_2 pipelines. RD&D challenges for novel designs (membrane and sorption-enhanced reformers)
International linkages	Several industrial gas companies build and operate reformers, and are testing novel designs. Most development work is done outside of the UK, though UK expertise in catalysis plays an important role.

Performance and cost

Converted from numerous sources to GBP. CAPEX increases according to Table 6 are applied. Data from Dodds and McDowall (2012) and Santos (2015), and broadly verified against costs independently produced for the Leeds H21 project.

SMR		2014 (est)	2030	2050
CAPEX	£/kW(H2 out, HHV)	445	445	445
Fixed Opex	£/kW(H2 out, HHV)/year	18	18	18
Efficiency (System)	% (kWh(NG in)/kWh(H2 out, HHV)	73%	80%	80%
Lifetime	Years	30	30	30
Availability	%	90%	90%	90%

SMR with CCS		2014 (est)	2030	2050
CAPEX	£/kW(H2 out, HHV)	803	724	684
Fixed Opex	£/kW(H2 out, HHV)/year	32	29	27
Efficiency (System)	% (kWh(el in)/kWh(H2 out, HHV)	68%	75%	75%
Lifetime	Years	25	30	30
Availability	%	90%	90%	90%

6.5.2 Coal gasification (with CCS)

Technology description	Coal gasification is mature but is less-widely used than SMR outside of China, despite typically having lower feedstock costs, because the conversion efficiency is lower and the capital investment costs are higher and more variable. Only large-scale plants are envisaged. Coal gasification was been used commercially across the UK for 150 years to produce town gas, which contained around 50% hydrogen. The coal is gasified at high pressure and temperature to produce a syngas stream containing hydrogen, carbon monoxide, volatile compounds and various impurities. In a hydrogen production plant, the syngas is scrubbed and then follows a similar route to an SMR to separate the hydrogen. The effluent is much more polluted than for a natural gas plant so the scrubbing equipment is more expensive and it is necessary to remove and dispose of coal ash. Moreover, the additional pollution means that capturing the CO_2 in a CCS plant is likely to be more expensive than for natural gas, and with a larger efficiency penalty. However, the cost would likely be lower than for coal combustion plants as CO_2 capture can be integrated into the gas water shift and purification stages, rather than CO_2 being removed from the combustion effluent. Coal gasification efficiencies in the literature range from 50%–80%, which could represent both technological differences and the wide variations in the quality of different types of coal (Dodds, 2015). Any future conversion efficiency improvements will be reduced by the incorporation of CCS. Since a greater quantity of CO_2 is produced by coal gasification than by SMR for each unit of produced hydrogen, one might expect a greater conversion efficiency reduction to capture the CO_2, and a 20% loss of efficiency is assumed here. On the other hand, novel membrane technology could reduce the efficiency loss from CO_2 capture (Amelio *et al.*, 2007). CCS developments for coal electricity generation plants would be applicable to hydrogen production plants. For this study it was estimated that adding CCS facilities to existing plants would reduce efficiencies by around 10 percentage points.
Status	**Level of technical and commercial maturity:** Coal gasifiers are at TRL 9 and are used at industrial sites in several countries. Pilot coal plants with CCS for electricity generation have been demonstrated and are at TRL 7. Hydrogen production plants would use similar technology but are unproven so TRL 6 is suggested. Membrane technologies are at an earlier stage of development. **Deployment:** Used to produce around 20% of hydrogen globally.
Infrastructure required to support deployment	Gas clean-up to required level. Where the hydrogen is not consumed on-site, one or more of the following: • pipelines • liquefaction plant • a suitably-sized compression and/or loading station for tube trailers

Prospects for commercialisation	Coal gasification plants are already used commercially.
Fundamental barriers to deployment	With CCS: Cost of CCS facilities and availability of CO_2 pipelines. RD&D challenges for novel designs (membrane and sorption-enhanced reformers)
International linkages	Used globally.

Performance and cost

Data from Dodds and McDowall (2012), which converts costs from numerous sources to GBP. CAPEX increases according to 1 are applied.

Coal gasification		2014 (est)	2030	2050
CAPEX	£/kW(H2 out, HHV)	1,606	1,594	1,594
Fixed Opex	£/kW(H2 out, HHV)/year	80	80	80
Efficiency (System)	% (kWh(NG in)/kWh(H2 out, HHV)	65%	65%	65%
Lifetime	years	30	30	30
Availability	%	90%	90%	90%

Coal gasification with CCS		2014 (est)	2030	2050
CAPEX	£/kW(H2 out, HHV)	2,461	2,461	2,446
Fixed Opex	£/kW(H2 out, HHV)/year	123	123	122
Efficiency (System)	% (kWh(el in)/kWh(H2 out, HHV)	52%	52%	52%
Lifetime	years	25	30	30
Availability	%	90%	90%	90%

6.5.3 Oil reforming and gasification (with CCS)

At reformer operating temperatures, light oils evaporate and can be reformed in a similar way to natural gas, at similar cost and with similar operating characteristics, though with a lower hydrogen production efficiency due to the lower H:C ratio. Hydrogen produced from heavy oils using an oil gasification plant, results in similar cost and operation to a coal gasification plant. Bio-oils, for example produced from biomass pyrolysis, could be used in similar ways to petroleum oils.

Both oil reformers and oil gasification plants are already used commercially, but hydrogen from oil is not generally considered in the literature. SMR and coal gasification data can serve as a reference point, noting that oil reforming would have a lower efficiency than SMR, while oil gasification would have a higher efficiency than coal gasification.

CCS plants are not proven for oil reforming and gasification.

6.5.4 Biomass gasification (with CCS)

Technology description	Biomass gasification is similar but generally more complicated and expensive than coal gasification due to the need for pre-treatment and the different composition of the feedstock. Biomass gasification with CCS offers an atmospheric CO_2 sequestration route that would be an alternative to biomass electricity generation plants with CCS. Woody biomass has high water content, with only half the energy density of coal. This means that an additional drying step is required prior to gasification, and that there are much greater material handling challenges to produce the same quantity of hydrogen. The low hydrogen content of biomass (~6%) and high oxygen content (~40%) also lowers the plant efficiency compared to coal gasification. Saxena *et al.* (2008) identify three broad methods for producing hydrogen from biomass: thermochemical conversion (gasification or pyrolysis), biochemical/biological conversion and mechanical extraction. Technologies other than gasification are still at the laboratory stage of development. The principal gasification technologies under development are fixed-bed, fluidised-bed and entrained flow gasifiers (Hossain and Charpentier, 2015). Biomass-fuelled technologies are most strongly characterised by their diversity, in terms of both the types of technology and the range of different biomass fuels that are used. For example, waste would be an alternative feedstock to purpose-grown biomass, although it may be more difficult to handle meaning a different plant design would likely be required. There are no completed industrial-scale demonstrations of any biomass technology for producing hydrogen (Kalinci *et al.*, 2009), therefore cost and energy efficiency data must be considered speculative. Capital costs are higher than coal gasification costs because additional plant is required, and biomass plants are typically at smaller scale than coal. The conversion efficiency of woody biomass (without CCS) is estimated here at 50%, although several references have estimated potential efficiencies of 54 - 68% (Kinchin & Bain 2009; NREL, 2011; Hamelinck and Faaij, 2001). CO_2 removal is an essential step in bio-hydrogen production; hence Larson et al. (2005) estimate that the biggest difference between with and without CCS configurations is likely to be the additional electricity use in CO_2 compression. The major techno-economic studies of hydrogen production technologies (H2A, Techpol) do not consider biomass gasification with CCS, but this technology would be a derivative of coal gasification with CCS and offers the opportunity of negative lifecycle emissions (Hamelinck and Faaij, 2001). The biomass with CCS costs are estimated here from coal gasification with CCS estimates. The Energy Technologies Institute's work on BVCM and ESME includes a major role for bio-hydrogen with CCS (cost data not publically available), and the Low Carbon Innovation Coordination Group are updating the bioenergy Technology Innovation Needs Assessment to include bio-hydrogen with CCS (yet to be published).

Status	**Level of technical and commercial maturity:** Small gasification plants for hydrogen have been constructed at pilot scale, suggesting development to TRL 5. Biomass hydrogen + CCS systems are at TRL 4. However, coal gasification developments offer a clear development route for biomass gasification. **Deployment:** A small number of biomass gasification power plants have been built for power generation (up to 40 MW_{th} input), with a few larger plants (up to 135 MW_{th} input) built to use MSW, lignite and peat. The largest biomass gasification plant built for hydrogen production is at pilot scale (< 1MWth input).
Infrastructure required to support deployment	Gas clean-up to required level. Where the hydrogen is not consumed on-site one or more of the following: • pipelines • liquefaction plant a suitably-sized compression and/or loading station for tube trailers
Prospects for commercialisation	Biomass gasification plants without CCS do not seem to offer sufficient incentives to justify the additional costs compared to other hydrogen production technologies except in particular local conditions. In the long-term, biomass gasification with CCS to produce hydrogen could offer a cheaper route than biomass combustion for electricity generation to benefit from atmospheric CO_2 sequestration.
Fundamental barriers to deployment	• Cost of building test facilities. • With CCS: Availability of CO_2 pipelines. • Biomass handling challenges. • Feedstock availability and sustainability. • RD&D challenges for novel designs.
International linkages	All of the large-scale biomass gasification technology developers (suitable for hydrogen production) are outside of the UK

Performance and cost

Data from Dodds and McDowall (2012), which converts costs from numerous sources to GBP. CAPEX increases according to 1 are applied. The additional CCS costs are estimated from coal gasification with CCS costs.

Biomass gasification		2014 (est)	2030	2050
CAPEX	£/kW(H2 out, HHV)	3,708	2,422	2,009
Fixed Opex	£/kW(H2 out, HHV)/year	260	170	141
Efficiency (System)	% (kWh(NG in)/kWh(H2 out, HHV)	50%	50%	50%
Lifetime	years	30	30	30
Availability	%	90%	90%	90%

Biomass gasification with CCS		2014 (est)	2030	2050
CAPEX	£/kW(H2 out, HHV)	4,902	3,296	3,279
Fixed Opex	£/kW(H2 out, HHV)/year	343	231	230
Efficiency (System)	% (kWh(el in)/kWh(H2 out, HHV)	40%	40%	40%
Lifetime	years	25	30	30
Availability	%	90%	90%	90%

6.5.5 Water electrolysis

Technology description	Electrolysers are essentially an electrochemical cell in which water is split into hydrogen and oxygen using direct current electricity. In some cases a fraction of the energy is also supplied in form of heat. Three different types of electrolyser technology are currently available as commercial products, namely conventional alkaline electrolysers (liquid electrolyte), Proton Exchange Membrane (PEM) electrolysers and most recently also anion exchange membrane (AEM, also known as alkaline PEM) electrolysers. Historically, alkaline electrolysis has dominated the market and accounts for nearly all the installed water electrolysis capacity worldwide. PEM electrolysis has been commercial for close to 10 years, whereas AEM appeared on the market only very recently. Although no products based on solid oxide electrolysis cells (SOEC) technology are available, the concept has been proven by development and operation of test stacks.
Status	**Level of technical and commercial maturity:** Water electrolysis has been used industrially to produce hydrogen for more than a century. It can be considered fully technical and commercially mature. E4tech estimates some 30 SME manufacturers share a global market of 100–200 million USD revenue. **Deployment:** Water electrolysis accounts for about 4% of global hydrogen production (65 million tonnes) comes from electrolysis (E4tech, 2014). The largest electrolysis plants (over 30,000 Nm^3/h) have historically been deployed for the fertiliser industry (E4tech, 2014). Apart from this industry, hydrogen from electrolysis is used in making other chemicals, food processing, metallurgy, glass production, electronics manufacturing and power plant generator cooling.
Infrastructure required to support deployment	With grid electricity as the common source of power, grid connection and AC-DC conversion, often in the MW scale is required. Usually electrolysers serve an onsite hydrogen demand. If not, transport of hydrogen via tube trailers (or other transport means) is required. Demonstration projects are also under way in which electrolysers are connected also to gas grids, i.e. feed their hydrogen production onto the grid.
Prospects for commercialisation	Despite many historical multi-megawatt scale installations, the current electrolyser market is dominated by sub-MW scale industrial applications and hence the electrolyser industry is not ready to serve an “electrolysis for energy purposes” market immediately and at low cost. Roadmaps on how to establish water electrolysis as an energy technology in have been proposed, suggesting that hydrogen for transport from electrolysis could become cost competitive in the 2020ies in Europe (FCH JU, 2014).
Fundamental barriers to deployment	No fundamental barriers are known. Currently, a lack of cost competitiveness with other hydrogen production or supply routes is a hindrance to wider deployment.

International linkages	Several demonstration projects in Europe and North America look into electrolyser designs optimised for taking up intermittent and variable electricity and/or feeding hydrogen onto the natural gas grid. Manufacturers very active in this field are European players Hydrogenics, NEL Hydrogen, McPhy, ITM Power, Siemens, Areva H2 Gen and GP Joule, as well as US-based Proton OnSite.

Performance and cost

Converted from EUR to GBP. Data source: (FCH JU, 2014).

Values for current cost and 2030 cost are from a recent European FCH JU study. This assumes that by 2030 there is an increase in manufacturing volume of water electrolysis technology, mainly due to growth in Power-to-Gas and H2 mobility applications in Europe (and elsewhere). This would strengthen the supply chain and enable volume manufacturing in the water electrolysis industry, which currently is a niche market with many systems being built as bespoke designs. No major technology advances for the core technology are expected, and so the cost per kW after 2030 is not expected to fall further (i.e. after volume manufacturing has already been introduced). On a hydrogen output basis costs may fall slightly further, due to efficiency improvements.

Water electrolysis		2014 (est)	2030	2050
CAPEX	£/kW(el in)	887	468	468
	£/kW(H2 out, HHV)	1,215	576	558
Fixed Opex	£/kW(el in)/year	33	22	22
Efficiency (System)	% (kWh(el in)/kWh(H2 out, HHV)	73%	81%	84%
	kWh(el)/kg(H2)	54.0	48.5	47.0
Lifetime	Years	25	30	30
Availability	%	98%	98%	98%

6.5.6 Emerging methods for hydrogen production

A range of production methods are being developed: photobiological and photoelectrochemical methods, thermochemical water splitting, chemical and calcium looping, the Kvaerner process and plasma reforming are some examples (Ball *et al.*, 2009, Steward *et al.*, 2012). These are at various stages of development and their likely future costs and performance are very uncertain. Academic work is ongoing globally and the UK is well represented

Barriers to development and deployment of novel hydrogen production methods include

- Low level of technical maturity relative to existing production methods,
- Cost reduction required to enable competitiveness,
- Technical complexity and low yields also hamper many of these techniques.

The availability of a range of existing hydrogen production technologies means that developing these technologies is a low priority, though in principle they may aid low-CO_2 hydrogen production in the future.

6.6 Distribution infrastructure

Some existing small hydrogen fuelling stations dispense fuel from compressed gas in multi cylinder pallets (MCP) that are delivered to the station. Historically, this is the most economic system for locations with low fuel demand at 350 bar if the delivery distance is not too long (Yang and Ogden, 2007), and it might be the most suitable in the future in some locations. The modern move to 700 bar has rendered this approach much less viable as onsite compression is always required.

The principal advantage of tube trailer delivery is that it avoids the high liquefaction energy cost and high pipeline investment costs of alternative delivery systems. Tube trailer fuelling stations can be cheaper than other hydrogen fuelling stations because the hydrogen is dispensed directly from the tube trailer so little on-site storage is required. Fuelling stations tend to be small because a single tube trailer can store only 250–500 kg and it is impractical to replace the trailer several times each day.

High costs are the principal disadvantages of tube trailer delivery, particularly for long-distance deliveries. As well as having much higher fuel costs, long-distance delivery investment costs are also higher because a greater number of tube trailers are required to deliver the same amount of fuel.

The tube trailer capacity varies between 250 kg and 700 kg (for high pressure, i.e. ~500bar tubes) in the literature. This has an important influence on the energy efficiency of delivery, particularly over long delivery distances. Tube trailers are particularly inefficient for hydrogen delivery over long distances when compared to road tankers, primarily because the cost of transporting a single load is very similar but the tube trailer load capacity is much lower than the typical hydrogen road tanker capacity of 2,000–7,500 kg.

Tube trailers are competitive at short delivery distances, but if the demand is very high then pipelines are a more economic option. This leaves two principle roles for tube trailers in a hydrogen economy. Firstly, tube trailers can be the most economic technology during the transition to a low carbon economy when demand is low. Secondly, tube trailers can be the most economic technology for geographically-isolated fuelling stations in areas with low demand in a developed hydrogen economy.

The large physical size of tube trailers makes handling them on congested urban filling station sites challenging.

Alternative options such as metal hydrides are being developed by companies such as the Australia-based Hydrexia. Their high temperature magnesium hydride technology shows the potential to carry 3-4 times as much hydrogen as a conventional tube trailer and at zero pressure, avoiding many safety restrictions. However, the hydrogen supplied to the vehicles needs to be released from the hydride, which requires energy in the form of heat, and compressed to meet the vehicle requirements.

6.6.1 Hydrogen refuelling stations

Technology description	Road transport users would require a network of hydrogen refuelling stations to support the roll-out of FCEVs. Heavy-duty vehicles and buses would mostly refuel at dedicated depots, while the public would use refuelling stations. In contrast to existing stations, there are several different types of hydrogen refuelling station that could be deployed. The costs of different types vary but are all more expensive than existing refuelling stations. Hydrogen refuelling stations and depots can be split into two broad categories, according to whether the hydrogen is stored in liquid or gaseous form (Weinert, 2005). Numerous station configurations might be constructed: • Liquid – Liquid: liquid hydrogen supplied by road tankers for trucks and ICE cars with liquid tanks (note liquid tanks are currently not used in FCEVs, as 700 bar gaseous storage can provide sufficient range. However, hydrogen ICEs and/or heavy goods vehicles may require liquid storage for acceptable range). • Liquid – Gaseous: liquid hydrogen supplied by road tankers and gasified onsite for trucks and ICE cars with gas tanks. • Gaseous – Gaseous: gaseous hydrogen supplied by pipeline for trucks and ICE cars with gas tanks. • Onsite gaseous – Gaseous: gaseous hydrogen produced onsite by decentralised electrolysis or SMR for trucks and ICE cars with gas tanks. Requires more onsite storage than stations supplied by pipeline. • Tube trailer – Gaseous: Tube trailer filled centrally and driven to site to supply trucks and ICE cars with gas tanks. Liquid hydrogen and compressed gaseous hydrogen are three and six times less dense than petrol, respectively, so both types of station will require more physical space and more equipment than is deployed at current petrol stations to supply the equivalent amount of fuel. This difference will be partially reduced by the higher efficiency of fuel cell vehicles relative to ICEs. Little storage is required for continuous GH_2 pipeline deliveries but bi-weekly LH_2 tanker deliveries would require a large LH_2 storage tank. Space limitations are likely to be most acute for stations with on-site hydrogen production. Although site and hydrogen supply specific, it can be said that most current petrol fuelling stations are not suitable for hydrogen delivery and would have to be completely rebuilt. Sites with more than 5 t hydrogen storage are subject to Control of Major Accident Hazards (COMAH) regulations; while many industrial sites already operate within COMAH restrictions, this could be a particular issue for hydrogen refuelling stations with liquid storage, where the additional costs and restrictions of meeting COMAH are not well understood and could be prohibitively expensive. The safe day to day handling of liquid hydrogen may always require professional technicians, which could create a barrier to its widespread deployment.

Status	**Level of technical and commercial maturity:** A small number of gaseous refuelling stations have been constructed in the UK, using onsite electrolysers, tube trailers or liquid hydrogen imported from the Netherlands. A pipeline-fed refuelling station has been constructed in California and tanker-fed stations are in operation. Japan has close to 50 stations operational. Moreover, hydrogen refuelling is commercially used for fuel cell fork-lift trucks in warehouses in North America. These technologies are judged to be at TRL 8 for road transport. **Deployment:** Demonstration refuelling stations have been constructed and tested in several countries, some are publically accessible.
Infrastructure required to support deployment	Hydrogen production/import and delivery infrastructure.
Prospects for commercialisation	Relatively mature technology that is a prerequisite for the success of fuel cell vehicles.
Fundamental barriers to deployment	• Low capacity factors in the period following deployment. • Large upfront investment to build a basic network. • Government intervention required to coordinate deployment and regulation.
International linkages	Japan, California, Germany and the UK are currently deploying hydrogen refuelling station infrastructure for the initial roll out of vehicles.

<u>Performance and cost</u> Costs vary widely for refuelling stations, and are affected by four factors: (i) the design of the station (primarily the amount of on-site storage and the deployment of spare compressors to ensure high station availability); (ii) the cost of each station component; (iii) the size of the station; and, (iv) the assumed utilisation factor of the station (i.e. the ratio of actual delivery to potential throughput). The extent to which the costs of refuelling stations will be reduced in the future by innovation for the individual components (e.g. gaseous storage) and through economies of scale for larger stations (e.g. through cheaper compressors) is unclear. Indicative costs for public car refuelling stations currently built are in the order of one 1 million £. Station equipment suppliers expect to cut costs to one third of this, once hydrogen refuelling has become a mainstream technology (Source: E4tech communication with Linde).

6.6.2 Hydrogen compression

Technology description	Most FCEV manufacturers have chosen to use hydrogen storage tanks with 700 bar compression to maximise the range of the vehicles while minimising the fuel cost. This means that compressors are an important component of hydrogen refuelling stations. Compressors are also used on a larger scale with high-pressure hydrogen pipelines. Hydrogen compressors are similar to natural gas compressors. Designs include linear, rotor and centrifugal compressors. Piston and centrifugal compressors are most commonly used in the gas networks (Dodds and Demoullin, 2013). 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 (Haeseldonckx and D'haeseleer, 2007). Piston-metal diaphragm compressors are often used in hydrogen refuelling stations, and have an adiabatic efficiency of around 70%. More recent developments are the ionic liquid compressors developed by Linde for their hydrogen refuelling products and electrochemical compressors under development by HyET.
Status	**Level of technical and commercial maturity:** Hydrogen compressors are widely used in pipelines and have been developed for refuelling stations. They are similar to pumps for other gases and liquids. **Deployment:** Deployed around the world.

Infrastructure required	Hydrogen supply.
Prospects for commercialisation	Hydrogen compressors are already used commercially.
Fundamental barriers	Maintenance and servicing as well as size of conventional piston compressors are often considered a major barrier for distributed installations with low hydrogen throughput.
International linkages	Used globally.
Performance and cost Compressors are integrated into larger systems and the performance and cost of those systems incorporates compressor costs. Little information is available about large-scale compressors. For small-scale compressors at hydrogen refuelling stations, costs today are around 5000 £/(kg/hr) and could reduce to 2500 £/(kg/hr) in the future (Krewitt and Schmid, 2004, Mintz *et al.*, 2008).	

6.6.3 Compressed hydrogen tube trailers

Technology description	Hydrogen is compressed in cylinders ("tubes") made of metal or composite material. The higher the pressure to which hydrogen is compressed, the higher the storage density, but also material requirements (hence cost) and associated cost for compression.
Status	Tube trailers are commercially used by industrial gas companies. Pressures up to 200 bars are common. High pressure tube trailers of up to 500 bars (and hence higher transport capacities) have been introduced by industrial gas companies to supply hydrogen refuelling stations, but are rarely used outside this sector.
Infrastructure required to support deployment	Refilling terminals with compressor systems of suitable pressures are required. A station's onsite bulk or buffer storage requires a corresponding decanting/offloading system.

Prospects for commercialisation	Tube trailers up to 200 bars are used commercially by industrial gas companies for various gases. Today sites with large industrial hydrogen demands (e.g. refineries, chemical industry) are usually equipped with on-site or local dedicated hydrogen production, often using pipelines. Therefore, little demand exists for large hydrogen quantities and thus higher pressure tube trailers outside the hydrogen mobility sector. Tube trailers are expected to play an important part in distribution infrastructure for hydrogen mobility however. To compete with other forms of supply (pipelines, liquid hydrogen tankers, on-site production), there is a clear trend to higher tube pressures up to 500 bar, though this comes with additional safety requirements.
Fundamental barriers to deployment	• Space requirements at refuelling stations for dispensing ('unloading') periods • Negative public perception of safety in case of large numbers of pressure tube trailer trucks on roads, especially if pressures increase • Safety regulations restrict access of high pressure tube trailer trucks from sensitive locations in urban areas (and from underground access including tunnels in many areas)
International linkages	• High pressure tube trailers (up to 500 bar) are being introduced in Europe, North America and Japan. Most development work is outside the UK, as are many of the standards and regulations discussions

Performance and cost data are based on NREL (2010), adapted to 2014£.

CHG tube trailer		2014 (est)	2030	2050
Net H2 capacity	kgH2	280	672	672
Tube pressure	bar	180	490	490
Volumetric density (tube only)	kgH2/m³ (gross)	13.2	29.9	29.9
Gravimetric density (system)	kgH2/kgsystem	1.2%	2.4%	2.4%
CAPEX	k£/trailer (w/o truck)	152	236	236
CAPEX	£/kgH2 trailer capacity (w/o truck)	543	352	352
Lifetime	years	20	20	20
Availability	%	98%	98%	98%

6.6.4 Hydrogen liquefaction

Technology description	Liquefaction greatly increases the energy density of hydrogen, allowing it to be transported by road tanker or ship. It is particularly economic for transporting relatively small amounts of hydrogen over long distances, for which a pipeline cannot be justified (Yang and Ogden, 2007). Hydrogen undergoes liquefaction at a temperature of 20 K (–253 °C). Theoretically, only about 4 MJ kg^{-1} must be removed from the gas, but the cooling process has a very low Carnot cycle efficiency (Fichtner, 2009) so even large plants require 30 MJ kg^{-1} to liquefy hydrogen. The principal disadvantages of LH_2 are the substantial amount of potentially expensive electricity that is consumed and the difficulties handling such a volatile fuel. Larger liquefaction plants (250 tH_2/day) have lower investment costs and are more efficient than smaller plants (3 tH_2/day). The top end of the range shown below reflects actual costs for small plants during the 1990s (e.g. Syed *et al.*, 1998). The H2A project (Steward *et al.*, 2008) has similar costs but other studies forecast substantially lower investment costs that are consistent with the US Department of Energy target to dramatically reduce the cost of liquefaction (e.g. Mytelka, 2008). There is widespread belief that the costs of large-scale production in the future will be substantially lower than the costs of existing small-scale plants. The energy efficiency of liquefaction varies from 68% to 84%, with larger plants being more efficient. Since large, centralised liquefaction plants are most likely to be built in the future, it is appropriate to assume a liquefaction energy efficiency towards the top of this scale. Research in the European IdealHy project concurs with this (Seeman *et al.*, 2013).
Status	**Level of technical and commercial maturity:** Liquefiers are at TRL 9 and are used at industrial sites in several countries. **Deployment:** Used in several countries.
Infrastructure required to support deployment	Hydrogen production plant, road tanker fleet.
Prospects for commercialisation	Small plants already used commercially.

Fundamental barriers to deployment	• Scaling-up to larger plants • Improving process energy efficiency
International linkages	Used globally.

Performance and cost

Data from Dodds and McDowall (2014a), which synthesises technoeconomic data costs from several sources including Mintz *et al.* (2008) and Krewitt and Schmid (2004). Costs are forecast to reduce in the future primarily due to economies of scale. Today's costs are for medium plants (25 tH_2/day) and the small plants that are in operation today (around 3 tH_2/day) have capital costs of approximately 2000 £/kW.

Liquefaction		2014 (est)	2030	2050
CAPEX	£/kW(H2 out, HHV)	666	267	267
Fixed Opex	£/kW(H2 out, HHV)/year	47	19	19
Electricity input	kWh(elc in)/kWh(H2 out, HHV)	0.22	0.18	0.18
Lifetime	Years	20	20	20
Availability	%	96%	96%	96%

6.6.5 Liquid hydrogen tankers

Technology description	Liquid hydrogen road tankers are already used in the UK and abroad. They operate in a similar way to petroleum fuel tankers. The main challenges are dealing with boil-off and from hazards resulting caused by accidents, particularly as the number of tankers and the distance covered might have to be greatly increased compared to existing road tankers. Hydrogen is more likely to be imported in liquid than gaseous form in the future as demand increases and before pipelines are built, to combine the higher energy density and flexibility of source and destination, and an international trade using road tankers already exists. Petroleum fuels are transported around the UK using a national pipeline network and delivered to refuelling stations from regional hubs by road tankers. Since the energy density by volume of liquid hydrogen is one-third that of gasoline, a much greater number of tankers would be required to deliver the same quantity of fuel. Moreover, it is highly unlikely that a national pipeline network could be constructed for liquid hydrogen, due to the very low boiling point, so the road tanker journeys could be much longer. On the other hand, hydrogen production could be more decentralised than current oil refinery production, reducing the distance between production plants and refuelling stations and so enabling road tankers to perform a greater number of sorties per year. The relative fuel demand for hydrogen would also be lower as a result of the greater efficiency of hydrogen fuel cells compared to internal combustion engines. Road tankers in the UK have a volume limit of 34,000 litres and a load limit of 29 tonnes. For liquid hydrogen, the volume limit would be reached for a load of only 2 tonnes, which is equivalent to around 20% of the energy of an equivalent volume of diesel. Both the capital investment cost and the energy efficiency of road tankers are determined by the average trip distance. For 200 km round-trips, the energy loss during transit is very low. For 1,600 km round-trips, the efficiency drops to around 91%.
Status	**Level of technical and commercial maturity:** Road tankers are at TRL 9, in very highly skilled business-to-business environment. **Deployment:** Used in several countries, including the UK.
Infrastructure required to support deployment	Hydrogen liquefaction plant or imported liquid hydrogen.

Prospects for commercialisation	Already used commercially.
Fundamental barriers to deployment	None.
International linkages	Used globally.

Performance and cost

Current capital cost range from H2A and TECHPOL programmes for around 250 deliveries per year is 40–120 £/kW. For 72 deliveries per year, this could increase to 400 £/kW. Independent, UK-focused calculations for the UKTM model suggest a capital cost of 170 £/kW.

Driver salaries are a substantial variable cost for road tankers, which was estimated at around 9 £/TWh H_2 for 250 deliveries per year in the UKTM calculations.

Liquid hydrogen road tanker		2014 (est)	2030	2050
Net H2 capacity	kgH2	2,000	2,000	2,000
Volumetric energy density	kgH2/m³ (gross)	60	60	60
CAPEX	k£/truck and trailer	400	350	300
CAPEX	£/kgH2 trailer capacity	200	175	150
Lifetime (trailer)	years	15	15	15

6.6.6 Hydrogen injection into the natural gas grid at relatively low concentrations

Technology description	Hydrogen from a production plant could be injected into a natural gas pipeline, probably at medium pressure (i.e. around 7 bar). The hardware is relatively straightforward, consisting of a simple tee piece with valves, flow measurement and gas analysis. Upstream and downstream gas analysis would be required in case the feed gas already contained hydrogen. The difficulties surrounding adding low concentrations of hydrogen occur not during periods of high bulk flow and constant pressure, but at low bulk flow and varying pressure. It is then difficult to maintain hydrogen concentration at a constant level. **Older appliances (non-fully premixed):** Up to about 20% by volume hydrogen in natural gas (equivalent to about 7% on an energy basis), modest effects on the bulk combustion in simple appliances are observed. Hydrogen raises flame speed, lowers flame ionisation conductivity and increases the tendency of gas fired internal combustion engines to knock. This assessment is supported by a recent HSL report (HSE, 2015). **Newer appliances (fully premixed):** Hydrogen addition has a significant effect on modern combustion equipment, including condensing boilers. In consequence the German Government limits addition of hydrogen to 10% by volume (~3% energy basis) or to 3% by volume (1% energy) where the grid gas may be fed to CHP engines and/or CNG units. Whilst the HSL report is correct in assessing the overall risk of adding hydrogen is low, the report considerably underestimates the difficulties of managing hydrogen addition to the network especially if this value is ever to fall below that prescribed. Due to the nature of modern burners such a fall might lead to substantial increases in appliance CO levels with its ensuing risks. The effect of hydrogen addition on appliances using flame ionisation for control purposes is complex, and will need to be carefully assessed.
Status	Injection of hydrogen into a NG pipeline has been trialled on the Island of Ameland off the Netherland's coast. The exact level of injection was variable. On Ameland it was found difficult to control injection levels especially on hot summer nights when gas use was very small and hence flow levels are low. Photographs clearly showed burner plaques running hotter (at 15–20% by volume) than without hydrogen but this was not quantified. British Gas cautioned against operating with hydrogen content over 10% by volume back in 1979 due to increased burner temperatures causing carbon deposits within burners. One medium sized UK boiler maker has definitively stated that their product is unsuitable for use with natural gas to which hydrogen has been added. Modern condensing boilers often have very extended guarantees (up to 14 years) and anything which could increase burner plaque temperature and thus shorten appliance life will carry a burden of risk.

	Injection of hydrogen is also occurring in Germany, although to date absolute levels are low[17] (typically about 2% by volume i.e. 0.6% by energy) although higher levels may occur on specific lines delivering gas to known destinations, often industrial or commercial estates rather than domestic housing.
Infrastructure required to support deployment	The physical injection of the hydrogen is fairly straightforward. Much more complex is the instrumentation and gas analysis equipment needed to determine the required gas flow rates. As indicated above this is even more difficult during periods of line pack and line unpack, i.e. varying the pressure within a pipeline to store gas. Identifying co-locations where large hydrogen generators can be installed and points where hydrogen can be injected into gas lines is also a challenge.
Prospects for commercialisation	The concept of adding small percentages of hydrogen to natural gas well established, but there are several problems with implementation in practice. The concentration of hydrogen in the network would need to be defined and maintained to allow use in newer appliances, as above, with risks if hydrogen fell below these levels. This would also mean substantial seasonal variations in hydrogen addition rates (following gas demand), which do not fit readily with injecting hydrogen generated from surplus renewable electricity. It is possible to see a local future in grid balancing if a few MW of electrolysers were to be installed on industrial sites, for example, and feed hydrogen onto the natural gas grid. These could rapidly consume electricity that otherwise be curtailed. Such an approach whilst possibly commercially attractive (in terms of managing the electricity network) is unlikely to have a material effect on UK carbon savings.
Fundamental barriers to deployment	• Risk of claims for resulting damage from shortened boiler life due to higher burner operating temperatures. • The current Gas Safety (Management) regulations limit hydrogen to 0.1% by volume. This seems unnecessarily low[18].
International linkages	Currently Germany is most active with several sites that produce hydrogen and inject it into the natural gas grid (Eon project Falkenhagen, Thüga Project Frankfurt), especially where the feed is to a particular industrial site and hence hydrogen injection levels are not limited by CNG/CHP on the same grid section.

[17] Kiwa Gastec Personal communication.

[18] The limit in place in Germany is 10% v/v (about 3% by energy) falling to 3%v/v (about 1% by energy) when the natural gas may be used as a feedstock to CNG refuelling stations

Performance and cost

The maximum concentration likely to be allowable is 3% v/v, i.e. 1% by energy. Costs divide up into three areas:

- The cost of the electrolyser and gas injection equipment. The issues here arise from the difficulties of co-locating the electrolyser (probably on a sub-station) and injection equipment (along a suitable gas line) as traditionally these facilities have been kept separate. Costs will be site dependent and almost impossible to meaningfully estimate. Assuming £1m/km for the hydrogen line, £1,300/kW for the electrolyser and £2m for the injection point, this would give a cost of about £20m for a 2 MW electrolyser with about 15 km of line. It is worthy to note however that this equipment will need a 200 MW gas flow to maintain output at 3% by volume. This is a very large gas supply unlikely to occur in many lines except on the UK Natural Gas National Transmission System (NTS).
- Larger costs are likely to be primarily related to managing the process of injection e.g. educating Gas-safe engineers, issuing modified installation instructions etc. There will still be a finite risk of claims for resulting damage from shortened boiler life due to higher burner operating temperatures.
- Without extensive research it is exceedingly difficult to predict these. It is possible to envisage the necessary R&D costing £25m and training the Gas-safe work force another £75m (Kiwa Gastec estimate).

6.6.7 Repurposing of the natural gas MP and LP distribution networks to use only hydrogen

Technology description	The UK's existing LP and MP gas network is currently in reasonable repair and is being converted to polyethylene (PE) pipe via the Government-sponsored Iron Mains Replacement Programme. These PE pipes can carry hydrogen. Note that this does not include conversion of the intermediate and high pressure natural gas distribution network or natural gas transmission network. This is because: • Hydrogen is considered to impose a significant risk to the integrity of the welded joints of the existing NTS. • The UK power stations and large industrial users will still require access to natural gas for the foreseeable future. An important question regarding conversion of the gas network to hydrogen is the ability of the existing pipes to transport the same, or at least similar, quantities of energy. The energy-carrying capability of low pressure gas pipes is limited by pressure drop from the local pressure reduction station to the user. It is not limited by pressure rating of the pipe. The calorific value of hydrogen (energy per unit volume) is about a third that of natural gas. However, its density (mass per unit volume) is about an eighth that of natural gas. This means that hydrogen moves faster through a pipe for the same pressure drop[19]. As a result of this an existing low pressure or medium pressure gas pipeline could carry about 80% of the energy when carrying hydrogen as compared to when carrying natural gas, assuming the same pressure drop. However, the pressure drop across the low pressure network could be increased. The UK LP network is permitted to operate at between 25 and 75mbar. Many networks currently operate from about 40mbar at the inlet pressure (i.e. at the pressure reduction station) to 25mbar at the network extremity. If this inlet pressure were raised to 65mbar, the pressure drop could be increased from (40-25) = 15mbar to (65-25mbar) = 40mbar. This should be more than adequate to increase the energy capacity when hydrogen was used, and re-establish, or even increase, the existing network capacity. Recent calculations by a gas utility have shown capacity is more likely to be limited by excessive velocity.

[19] The pressure drop along a pipe is directly proportional to the density of the fluid and the square of its velocity, hence for the same pressure drop the energy carrying capacity of a pipe with hydrogen is about 80% that pipe with natural gas.

Status	Industrial hydrogen grids have existed for nearly 100 years, and town gas grids for nearly 200 years. Town gas was 50-60% hydrogen by volume and (given the relatively primitive technology) had a good fire and explosion safety record. Genuinely domestic and commercial hydrogen distribution is unusual. A project was carried in Denmark in a few dozen properties using (at least initially) stainless steel distribution pipework. The use of PE pipe for hydrogen has been fully validated in the EU with no *"adverse long-term effects on antioxidants, polymer structure or the mechanical performance of the polymer pipe"* (Iskov *et al.*, 2010).
Infrastructure required to support deployment	• Storage of hydrogen: Consideration of network demand by Kiwa GasTech (unpublished) indicates that the production potential for the hydrogen plants feeding a hydrogen network should be considerably larger than the average annual demand (possibly by a factor of 150%). This then means that inter-seasonal storage can be realistically sized (possibly 30 to 40 days). These values are very dependent upon the nature of annual demand, and in particular the coldest and longest foreseeable winter. Storage of hydrogen in salt caverns is well proven in the UK, US and Russia (see section 0). • Conversion of appliances in buildings, vehicle refuelling stations etc. • Continued existence of the natural gas transmission and high and intermediate pressure network will remain essential for the supply of SMR plants, power stations other large users and transnational shipping.
Prospects for commercialisation	The use of low carbon hydrogen as an energy vector unusually gives a convenient route to both a centrally co-ordinated and locally driven solution to the 2050 carbon problem. The concept would be conversion of about one million homes per year (and associated towns & cities) over the 30 years. This is expected to require between 25% and 50% of the UK current gas workforce. It would need to be accompanied by a proportionate construction of SMR plants. This would effectively decarbonise most of UK heat, transport and industry. This route can either be planned out in a nationwide coordinated plan (see conversion map in Figure 21), or local authorities and gas DNOs can be permitted to choose their own transition dates. It is convenient to draw parallels between these change overs and the digital switchover recently carried out by the broadcasting authorities. Unlike a conversion to district heat or heat pumps the process would be entirely controlled and the carbon savings are ensured.

Fundamental barriers to deployment	• Whilst conceptually the use of 100% hydrogen is accepted by many professional gas engineers some work is required in limited areas e.g. levels of noise and vibration, possible debris pick up and odorisation. Other currently unknown issues may also arise, but the wide experience with town gas indicates none are expected to fundamentally prohibit deployment.
	• The deployment of 100% hydrogen networks is extremely unlikely to occur without:
	  ○ Active leadership from DECC (or other body - a radical suggestion might be to place these authorities outside Government in an Office of Energy Infrastructure) and 'wider society'. This is because widespread discussions in the industry show the project has too high a regulatory risk and political rejection without such full socialisation of the decision process.
	  ○ Appropriate financial incentives. Costs and implications are regarded as too large by individual local authorities. Local authorities need the same technical support as they obtained from central government under the original clean air act. Only DECC can set the legal framework to which gas network operators and the gas train can operate.

International linkages	Repurposing the MP and LP natural gas grid to hydrogen is, to the authors' knowledge, currently not carried out anywhere in the world. The UK is unusual in its very highly developed low pressure natural gas infrastructure, which gives the UK a real global advantage if hydrogen technology was to be adopted.
<u>Cost estimate:</u> The current Iron Mains replacement plan of about £1,000million per year is effectively providing the necessary network upgrade. The other costs can be relatively simply evaluated, i.e. end user conversion, SMR and hydrogen storage construction and intermediate pipelines estimated at 20% additional to that of Iron Mains replacement, i.e. £200million (Source: Kiwa Gastec estimate).	

6.6.8 Dedicated hydrogen pipelines

Technology description	Pipelines are the most efficient method of transporting large quantities of hydrogen, particularly over short distances. Capital costs are slightly higher than for equivalent natural gas pipelines at high pressures. At low pressures, the polyethylene pipes that have been used in the UK gas networks since the 1970s can be used to safely transport hydrogen. Almost 3,000 km of high-pressure hydrogen pipelines have been constructed since 1938 in Europe and North America (van der Zwaan *et al.*, 2011). Transporting hydrogen through high-pressure steel pipelines requires the correct choice of steel and welding procedure as higher carbon steels can be prone to hydrogen embrittlement. The lower calorific value but much lower density of hydrogen with reference to methane means that at low and medium pressures the energy carrying potential of a hydrogen pipeline is about 80% of that with natural gas. Truly Low-pressure pipelines are currently little used for hydrogen but town gas, a mixture of hydrogen and carbon monoxide, was delivered at low pressure to buildings across the UK for 150 years. There is however much more flexibility over the choice of pipeline material at low pressures, and the polyethylene (PE) pipes being introduced as part of the Iron Mains Replacement Programme are suitable for transporting hydrogen. PE pipes normally have a pressure limit of 7 bar (PE 100) but larger plastic pipes with a limit of 17 bar have been proposed that would reduce the cost of medium-pressure hydrogen pipes. Pipeline costs are affected by the diameter but also crucially by the topography, land use and labour costs; A comprehensive estimate of the costs requires an understanding of the demand and supply points, and the transmission system design for any particular scenario. This could, for example, be derived from the existing national transmission network for natural gas. The lifetime of hydrogen pipes is very long but difficult to predict. It is determined by a slow reduction in pipeline thickness over time and the degree of hydrogen embrittlement. The capital costs are often annualised over a 30-year period for accounting purposes, but it is likely that pipelines would last for at least 50–100 years.
Status	**Level of technical and commercial maturity:** Hydrogen pipelines are at TRL 9 and are used for industrial purposes in several countries. **Deployment:** Used in several countries.
Infrastructure required to support deployment	None.

<table>
<tr><td>Current and future costs</td><td>Pipeline investment costs can be split into four main categories: materials, labour, right-of-way fees and miscellaneous. Only the material costs are likely to differ from pipelines used for natural gas. One method is to estimate the cost as the equivalent methane pipeline cost + 20% (van der Zwaan et al., 2011), although the H2A study (Steward et al., 2008) assumes only a 10% cost increase. Pipeline costs depend on the pipe diameter and length but also the topography and land use, with costs peaking in urban areas. The UK tends to have a higher cost of construction than most other countries. The costs presented below have units £/cm diameter/m length, and are for mixed low-urbanisation landscapes in the UK.
<table>
<tr><th></th><th>Cost range</th><th>Central cost</th></tr>
<tr><td>Transmission/high-pressure distribution</td><td>9–15</td><td>12</td></tr>
<tr><td>Medium-pressure distribution</td><td>17–31</td><td>24</td></tr>
<tr><td>Low-pressure distribution</td><td>28–42</td><td>35</td></tr>
<tr><td>Service pipes to buildings</td><td>49–78</td><td>67</td></tr>
</table>
These costs are unlikely to greatly reduce in the future; reductions in the material costs through innovation are likely to be balanced by increased labour and wayleave costs.</td></tr>
<tr><td>Prospects for commercialisation</td><td>High-pressure hydrogen pipelines have been in continuous use since 1938. Low-pressure polyethylene (PE) pipes have been used since the 1970s for natural gas and are also suitable for hydrogen transportation.</td></tr>
<tr><td>Fundamental barriers to deployment</td><td>Low capacity factors in the period following deployment.
Large upfront investment to build a basic network.
Government intervention required to coordinate deployment and regulation.
Need for wayleaves across private land.</td></tr>
<tr><td>International linkages</td><td>Used in several countries.</td></tr>
</table>

6.7 Bulk hydrogen storage

6.7.1 Bulk compressed hydrogen storage

Technology description	Hydrogen is compressed in large stationary vessels (low pressures ~45bar) or multi cylinder pallets (MCPs) and pressure tubes for medium and high pressures. The higher the storage pressure, the higher the storage density, but also material requirements (hence cost) in order to ensure vessel integrity.
Status	Bulk compressed hydrogen storage is commercially used at industrial sites with significant hydrogen demands.
Infrastructure required to support deployment	Bulk compressed hydrogen onsite storage requires onsite compressor capacity to fill the storage vessel. Without a need for onsite compression, bulk storage vessels of low pressures (e.g. 50 bars) can be filled by tube trailers with high pressures (e.g. 200 bars).
Prospects for commercialisation	Low (~45 bar) and medium pressure (typically 200–500 bar) pressure vessels are commonly used in industry and produced at scale. In contrast high pressure cylinders or tubes (700–1,000 bar) are rarely used outside the hydrogen refuelling sector and hence produced in low quantities today (e-mobil BW, 2013).
Fundamental barriers to deployment	• Regulatory frameworks for permitting high pressure bulk storage can be very different dependent on location • Public safety perception can be a substantial barrier to compressed hydrogen storage in densely populated places, e.g. at refuelling stations in residential areas.
International linkages	• Almost all development and suppliers are non-UK, and much of the standards development and testing also. Japan, Canada, Germany US all significantly involved

Performance and cost based on NREL (2010).

Compressed Hydrogen bulk storage		2014 (est)	2030	2050
Net H2 capacity	kgH2	366	366	366
Tube pressure	bar	301	301	301
Volumetric density (tubes only)	kgH2/m³	18	18	18
CAPEX (w/o installation)	k£/system	300	300	300
CAPEX (incl. Installation)	k£/system	390	390	390
CAPEX (incl. Installation)	£/kgH2	1077	1077	1077
Lifetime	years	20	20	20

6.7.2 Bulk liquid hydrogen storage

Technology description	Liquid hydrogen (LH_2) tanks can store more hydrogen in a given volume than compressed gas tanks. The volumetric capacity of liquid hydrogen is 70 kg/m³, compared to 30 kg/m³ for a 700 bar high pressure gas vessel (excluding peripheral system components and safety setbacks). Typically, 30% of the heating value of hydrogen is required for liquefaction (US DOE, 2015a), though research into better liquefaction cycles, including magnetic liquefaction, suggests this could be reduced by almost half (idealHy, 2013). In addition, if any hydrogen boil-off is not used but vented, storage efficiency is reduced (for bulk storage NREL estimates 0.25% of hydrogen would be lost per day (NREL, 2010).
Status	Liquid hydrogen storage is an established technology and used industrially. Bulk liquid hydrogen tanks are proposed for hydrogen refuelling stations with high demand (e.g. at motorways) and are used at some hydrogen refuelling stations.
Infrastructure required to support deployment	For liquid hydrogen storage at refuelling station, hydrogen is supplied by liquid hydrogen tankers (filled at large liquefaction terminals). Although work into smaller-scale liquefiers has been undertaken (BC Government, 2011), liquefaction at the scale of refuelling station demands is unlikely to become commercially viable.
Prospects for commercialisation	Bulk liquid hydrogen storage is often considered more suitable than compressed for hydrogen refuelling stations with high demands. During the early roll out of fuel cell vehicles (smaller stations size and low utilisation), compressed hydrogen storage is likely to be the predominant onsite storage technology. However, Iwatani of Japan is currently building or planning several stations with liquid onsite storage. In the UK none of the currently planned refuelling stations uses liquid hydrogen storage. Some concerns exist about the use of liquid hydrogen outside a highly skilled business to business environment.

Fundamental barriers to deployment	• Supply infrastructure with liquid hydrogen tankers is required
International linkages	• Iwatani ordered close to 30 refilling stations from The Linde Group for deployment in Japan. Iwatani plans to supply these stations with liquid hydrogen.

Performance and cost based on NREL (2010).

Liquid hydrogen bulk storage		2014 (est)	2030	2050
Net H2 capacity	kgH2	1,000,000	1,000,000	1,000,000
Tank volume	m³	16096	16096	16096
Volumetric density (tubes only)	kgH2/m³	62	62	62
CAPEX (w/o installation)	£/system	19,724,729	19,724,729	19,724,729
CAPEX (incl. Installation)	£/system	25,642,147	25,642,147	25,642,147
CAPEX (incl. Installation)	£/kgH2	26	26	26
Boil-off per day	%	0.25%	0.25%	0.25%
Efficiency (@10 days avg. storage time)	%	97.50%	97.50%	97.50%
Lifetime	years	20	20	20

6.7.3 Metal hydride bulk onsite storage

Metal hydrides are an established hydrogen storage technology for niche applications, such as submarines, and for small amounts of storage for portable power and scooters. Some companies (McPhy, Hydrexia) are looking into commercialisation of magnesium-based metal hydrides for bulk hydrogen storage onsite and/or on trailers. Metal hydrides have the advantage that they store hydrogen at atmospheric or very low (below 10 bar) pressures, hence having less stringent set-back requirements and other safety restrictions compared to compressed gas. Material level (the metal hydride itself) storage percentages can be up to 7% by weight, and system storage around 3%, comparable to compressed gas at 500 bar (E4tech calculations). Metal hydrides require a thermal energy input to release the hydrogen (“discharging”), while comparable thermal energy is released during the preceding hydrogenation (“charging”) step. Depending on the hydride type this energy can amount to about 30% of the hydrogen HHV.

Both charging and discharging can be time consuming, but the required system components (small compressor for charging, heater for discharging) can be relatively low cost compared to alternative hydrogen storage with similar or better space requirements (i.e. high pressure compressed hydrogen, liquefied hydrogen).

Due to the early stage of this technology, it is currently not foreseeable whether it will play a significant role in future hydrogen infrastructure.

6.7.4 Liquid Organic Hydrogen Carriers bulk storage (e.g. at refuelling station)

Liquid organic hydrogen carriers are a range of chemicals that can be 'charged' with hydrogen and then 'discharged' - hydrogenation and de-hydrogenation – and are therefore a carrier liquid for hydrogen. Chiyoda Corporation has a large-scale pilot facility converting between toluene and methylcyclohexane, while the start-up Hydrogenious uses Dibenzyltoluene as a carrier liquid and claims a hydrogen density of 60 kg per m^3 carrier liquid and 6wt% hydrogen per kg of carrier liquid (Hydrogenious, 2015). Thermal energy input of about 25% of the HHV of hydrogen is required for dehydrogenation (discharging), while the equivalent amount of energy would be released during the hydrogenation step, and a specialised catalyst is required to ensure the reactions are sufficiently rapid but manageable. While stored in the liquid carrier, infrastructure such as for conventional liquid fuels could be used, but additional infrastructure for charging and discharging (reactors) is required.

Due to the early stage of this technology, it is currently not foreseeable whether it will play a significant role in future hydrogen infrastructure.

6.7.5 Hydrogen storage in caverns

Technology description	Cavern storage is widely suggested as the only feasible method of providing zero carbon inter-seasonal storage. At 280 kWh/m^3 hydrogen in caverns offers about 100 times the energy density of compressed air storage.
Status	Many of the world's large chemical and refinery complexes already have very substantial cavern storage of hydrogen. Several caverns are operated in Texas (summing up to more than 500 GWh) to cover inter-seasonal swings in production and demand. There is more operational history of hydrogen caverns in Russia (Basniev *et al.*, 2010). Hydrogen storage in caverns is also very well proven in the UK with substantial caverns in Teesside fully operational since the 1960s (3 caverns at 70,000 m^3). Suitable areas for future cavern storage in the UK have been reported in literature (ETI, 2015). Most recently the FCH JU funded project HyUnder assessed this technology for several European countries, including the UK. Provided an established market for hydrogen storage, salt caverns of 500,000 m^3 volume could each store 4,000 tonnes of hydrogen (HyUnder, 2014). In contrast to liquefied hydrogen and compressed hydrogen, salt caverns could offer a large scale bulk storage option, able to balance seasonal variations of energy demand and supply, if hydrogen is established as a major energy carrier.
Infrastructure required to support deployment	Bulk compressed hydrogen onsite storage requires onsite compressor capacity to fill the storage vessel. This is well proven technology that can be seen working in Teesside with very high levels of reliability.
Prospects for commercialisation	The technology is commercially used in the chemicals and refinery sectors, with at least three large caverns that have been washed in Texas in the past 15 years that are cost effective at about £0.35/Nm^3 of gas (~£3.9/kgH_2), although this value is very dependent upon location, scale and operational regime (e.g. is the gas displaced with salt brine or by pressure cycling). Several projects have looked into the feasibility to store hydrogen in underground salt caverns for energy storage.
Fundamental barriers to deployment	Hazards and their public perception are an important barrier. The HSE have recently published a report on the hazards of cavern storage (BGS, 2008). Requirement for very large-scale storage is to be demonstrated before regulatory and investor (be it public or private) commitment to underground storage.
International linkages	Given the few worldwide examples of hydrogen storage in caverns, knowledge transfer between developers and operators of these sites should be sought if the UK decides to deploy this technology.

Cost and Performance:

A total capex of £250 million are reported for the Alborough site which stores about 2.3 TWh hydrogen at about 270 bar, roughly £4/kgH_2. Specific (i.e. per kWh or kg of hydrogen cycled through the storage cavern) cost data vary greatly among different review studies, as utilisation and compressor dimension can be very different. For this study, data from Redpoint (2013) were used:

- Specific capex of £790/kW H_2 output capacity (derived from £0.95/kWh H_2).
- Specific opex of £0.004/kWh H_2.

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8 List of Acronyms

Capex	Capital expenditure
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CNG	Compressed natural gas
CP	Critical Path Scenario
DNO	Distribution network operator
DRI	Directly-reduced iron ore
FC	Full contribution scenario
FCEV	Fuel cell electric vehicle
HGV	Heavy goods vehicle
HHV	Higher heating value
ICE	Internal combustion engine
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IMRP	Iron Mains Replacement Programme
LA	Local authority
LGV	Light goods vehicle
LH_2	Liquid hydrogen
LHV	Lower heating value
LP	Low pressure
LPG	Liquid petroleum gas
MCFC	Molten carbonate fuel cell
mCHP	Micro Combined heat and power
MCP	Multi cylinder pallets
MP	Medium pressure
NTS	National Transmission System
OCGT	Open cycle gas turbine
Opex	Operating expenditure
PAFC	Phosphoric acid fuel cell
PEMFC	Polymer electrolyte membrane fuel cell
SMR	Steam Methane Reforming
SOFC	Solid oxide fuel cell
TRL	Technology Readiness Level
UKTM	UK TIMES energy system model

9 Conversions

The conversion factors in Table 7 were used to convert to £2014 from other currencies and to correct for inflation. The UK GDP deflator was taken from UK national statistics[20] and the exchange rates from market averages.[21]

	$ in £	€ in £	£ in £
2010	1.10	1.19	0.73
2001	1.06	1.18	0.73
2002	1.13	1.20	0.75
2003	1.26	1.11	0.77
2004	1.45	1.17	0.79
2005	1.48	1.19	0.81
2006	1.54	1.23	0.84
2007	1.72	1.26	0.86
2008	1.62	1.11	0.88
2009	1.41	1.01	0.90
2010	1.44	1.08	0.93
2011	1.52	1.09	0.95
2012	1.53	1.19	0.97
2013	1.54	1.16	0.98
2014	1.65	1.24	1.00

Table 7: Currency conversion and inflation correction factors

[20] https://www.gov.uk/government/statistics/gdp-deflators-at-market-prices-and-money-gdp-december-2014-quarterly-national-accounts

[21] www.oanda.com

Appendix A - Underlying assumptions and methods for scenario development

Scenario definitions and assumptions

The scenarios are based on some key underlying assumptions.

Critical Path scenario

The Critical Path scenario is based on keeping open the option to use hydrogen in end-uses that are seen to be 'strategically important', as summarised in Table 8. Specifically, in this project 'strategically important' end-use demands are defined as demands that are hard to decarbonise by means other than hydrogen, or for which low-carbon options other than hydrogen are less obviously available.

	2035	2050
Fuel cell cars	5%	40%
Fuel cell motorcycles	4%	40%
Fuel cell LGVs	3%	40%
Fuel cell HGVs	12%	90%
Fuel cell buses	11%	70%
Hydrogen in domestic shipping	0%	0%
Residential heat from hydrogen	0%	0%
Service sector heat from hydrogen	0%	0%
Share of hydrogen in industrial energy consumption	1%	3%

Table 8: Market penetration of hydrogen-powered technologies in 2035 and 2050 in the Critical Path scenario

The following notes describe how this assumption was interpreted in order to define the parameters of the scenario.

Cars and LGVs

The Critical Path scenario includes an assumption that by 2050, hydrogen provides for the vehicle-kilometres travelled by cars and LGVs on long-distance journeys only. The accompanying implication of this is that battery electric vehicles succeed and are cost effective for short-distance journeys, but they do not achieve sufficient range to be used for long-distance journeys – this leaves an available niche for long-distance, low-carbon car and LGV transport, which hydrogen vehicles are able to occupy.

According to the IEA, the 'usable range' of the '24 kWh battery powered Nissan LEAF' is about 100 km (IEA, 2013, p25). Note that this usable range is not equal to the maximum technical capability of the battery, but includes some allowance for 'range anxiety', which prevents drivers in practice from using the maximum energy store of the battery before recharging. In a report for the CCC, Element Energy analysed statistics from the Department for Transport (DfT) travel database, and calculated that while a vehicle with a utilised range of 100 km would account for 90% of all journeys, it would account for only 60% of all vehicle kilometres (Element Energy, 2009, p3). Although evidence suggests that BEVs with longer range will become more prevalent, costs may not drop sufficiently to make them ubiquitous.

In combination, the references above provide the information for the assumption in the Critical Path scenario that FCEVs account for the portion of car and LGV vehicle-kilometre demand that takes place on journeys over 100 km, and that this amounts to 40% of car and LGV vehicle kilometres.

HGVs

The Critical Path scenario includes the assumption that all HGV journeys within the UK are provided by hydrogen vehicles. This implies that hydrogen FCEVs are found to be more suitable than other technologies for the transportation of heavy cargo, for example because electric batteries do not provide sufficient energy capacity without breaching acceptable limits on size and weight. Thus hydrogen FCEVs are the dominant HGV technology within the UK; the caveat that journeys that begin and end outside the UK are not provided by hydrogen reflects uncertainty about what refuelling infrastructure will be in place outside of the UK.

According to statistics from the Department for Transport (DfT), the vast majority of goods moved by UK HGVs – about 99% of the total tonnage – are moved on purely domestic journeys, within the UK (Department for Transport, 2015). On the basis of this very high percentage of tonnes with domestic origin as well as destination, the project has made an assumption that a similarly high percentage of HGVs will never need to leave the UK. The figure assumed is 90%.

Buses

While hydrogen buses are being rolled out, several other low-carbon bus technologies will be deployed, including hybrid and battery electric buses. As UKTM does not include segmentation of the bus market, and this project has not focused in detail on the characteristics of low-carbon bus options beyond hydrogen buses, it cannot be definitive on the relative share of the different options. Hydrogen buses will need to out-compete whichever options are used, through benefits such as lower emissions, longer range, or higher reliability. In Critical Path, the share of bus vehicle kilometres provided by hydrogen was set to 70% in 2050.

Full Contribution scenario

The Full Contribution scenario is characterised by a consistent and long-term commitment to the extensive use of hydrogen across a range of energy services, as summarised in Table 9. This commitment is equally strong throughout the timeframe of the scenario, which enables strategic, anticipatory investments in hydrogen-enabling infrastructure to occur in advance of the actual materialisation of hydrogen demand. It is driven by an early decision to decarbonise heat provision across the UK by delivering hydrogen using existing infrastructures – this subsequently provides some of the infrastructure for FCEV adoption in the transport sector.

	2035	2050
Fuel cell cars	9%	95%
Fuel cell motorcycles	5%	95%
Fuel cell LGVs	7%	95%
Fuel cell HGVs	19%	95%
Fuel cell buses	23%	95%
Hydrogen in domestic shipping	5%	50%
Residential heat from hydrogen	41%	83%
Service sector heat from hydrogen	33%	67%
Share of hydrogen in industrial energy consumption	24%	51%

Table 9: Market penetration of hydrogen-powered technologies in 2035 and 2050 in the Full Contribution scenario

Use of the UK TIMES Model (UKTM) in scenario development

Introduction to UKTM

UKTM is a multi-time period, bottom-up, technology-rich cost optimisation model of the UK energy system. It is the successor of the UK MARKAL model, which was originally developed to provide insights for the Energy White Paper 2003, and was under constant development until 2012 (Dodds *et al.*, 2015a).

The simplest formulation of UKTM is to minimise discounted energy systems cost, under a wide variety of physical and policy constraints. This minimisation takes into account evolving costs and characteristics of resources, infrastructures, technologies, taxes and conservation measures, to meet energy service demands.

General description of data sources and assumptions in UKTM

UKTM is a very large model, with 2000 technology types, 600 energy carriers plus constraints, taxes, emissions and other model parameters. The model has almost 300,000 data elements. Model data have been obtained from a wide range of sources and have undergone quality assurance checks. Model documentation will be available from the UKTM website.[22] The transport sector is broadly similar to that developed in Dodds and McDowall (2014a) and Dodds and Ekins (2014), while the residential sector is derived from Dodds (2014). Conversion of the gas networks to hydrogen is based on research in Dodds and McDowall (2013) and Dodds and Demoullin (2013).

[22] The UKTM website is at: https://www.ucl.ac.uk/energy-models/models/uktm-ucl.

Background constraints applied within UKTM for both scenarios

Emissions trajectory

Both scenarios assume that the UK remains committed to the low-carbon trajectory recommended by the CCC and enshrined in the Climate Change Act 2008. The Critical Path scenario follows a similar abatement pathway in end-use sectors to the CCC's central scenario that is described in the CCC's 2012 report, "The 2050 Target". The sectors whose abatement levels are matched to this CCC scenario are:

- Industry
- Residential
- Services
- Transport
- Agriculture
- Non-CO_2

Sectoral emissions in the Full Contribution scenario are not constrained to the CCC's central scenario.

Vehicle growth rates

FCEV deployments for each mode were set in each period, to reflect plausible growth rates and the time required for the technologies and supporting infrastructure to be appropriately developed.

Constraints specific to Critical Path scenario

Hydrogen use in buildings, except for very limited industrial consumption, was prevented, and conversion of any existing gas networks prohibited. Decentralised hydrogen production was assumed to produce all transport hydrogen until 2035, after which its contribution reduced linearly to 20% by 2050.

Constraints specific to Full Contribution scenario

A comprehensive, 20-year gas networks conversion plan was mandated in UKTM from 2025 to 2045. This was assumed to progress linearly over time, and to affect buildings in all end-use sectors. Natural gas use in distribution networks was prohibited after 2045. A district heat market for hydrogen was opened up by this option from 2030. A minimum capacity of hydrogen salt cavern storage, equal to 25 days of annual centralised hydrogen consumption, was required to be in operation in each period. A minimum contribution of 10 GW CCGTs with mid-merit capacity factors (minimum 40%) were also required to be in operation by 2050. Decentralised hydrogen production was assumed to service only the transport sector and to have only a 10% share of the market for this sector by 2050.

Relationship between scenario development and modelling

The scenarios were developed with some iteration between qualitative narrative development and quantitative modelling analysis.

Scenario end points and definitions were used to frame the qualitative development of a narrative that describes a sequence of events that could lead to the 2050 outcome defined in each scenario. This narrative was developed through numerous discussions within the project team, and involved extending plausible hypotheses into the future based upon intuitive interpretations of knowledge and data available in the present. These data included the current status, recent progress and anticipated potential of hydrogen technologies and demonstrations; the technical requirements of hydrogen pipeline infrastructure; and the geography of the UK and characteristics of areas within it as both potential supply and demand centres for hydrogen.

In parallel to this initial qualitative storyline development process, modelling analysis was undertaken within UKTM. This was initially based primarily on constraining the model according to 2050 end-point conditions derived from the basic scenario definitions. The outputs of these initial runs were then compared to the initial qualitative storyline development, and a process of iteration begun. In some cases, modelling outputs were felt to take insufficient account of certain technical realities, such as transition and ramp-up rates for new vehicles – in which case further constraints were placed on the model. In other cases, modelling insights provided a depth not otherwise available to the qualitative narrative – such as sources of hydrogen production and the interaction of these sources with electricity generation options – in which case modelling outputs were described within the scenario storyline.