CHAPTER 5
HYDROGEN FUELS FOR ENERGY SECURITY

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5.1 INTRODUCTION

The four aspects of energy security – resilience, access to resources, affordability, and sustainability – to a large extent refer to issues of energy supply and especially the access to fuels. The latter three will be discussed at length in this chapter whereas 'resilience' of energy systems will be covered to a broader extent in the following Chapter 6. 'Access to resources' and 'affordability' are short-term goals. 'Sustainability', on the other hand, is a long-term goal of policy and aims at no less than the safe and materially secured societal life of many generations to come.

Plans for future developments in fuels used in the power supply, heating, and transport fuels sectors need to look into where the primary energy for these sectors is sourced in the long term and how the requirements of emission mitigation and sustainability can be met. At the same time, world market price volatility and access or lack of access to imports influence consumer prices and have to be kept at a level that is accepted by UK citizens. Due to the low standards of energy efficiency, especially in UK housing, energy bills tend to be higher than in other parts of Europe with a recurring theme of 'energy poverty'. On one hand this could easily be reduced by increasing energy efficiency, on the other hand, it has been widely acknowledged that energy prices are currently too low to, in the long term, introduce the highly efficient technologies that will secure sustainable and affordable heating and electricity supply.

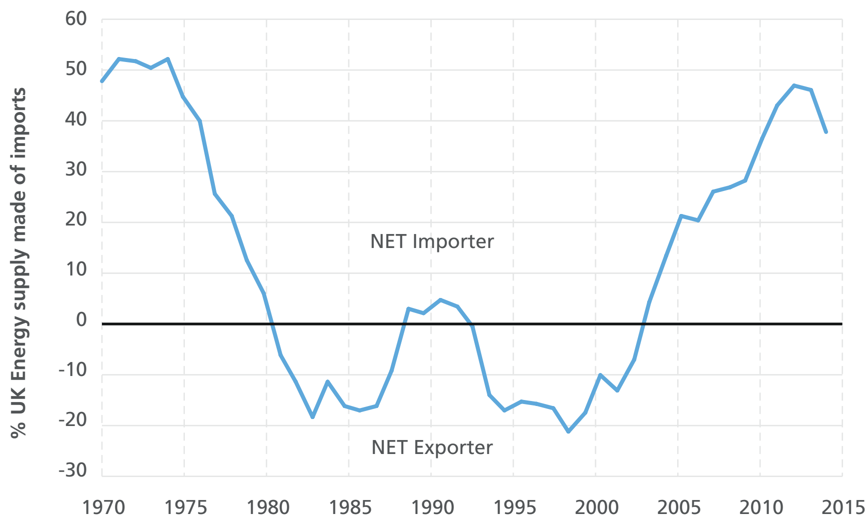
The vast possibilities to produce hydrogen from indigenous energy sources allow for reduction in imports and improvement of long-term security of supply. Hydrogen may also be converted to synthetic fuels based on renewable energy input that are fully compatible with today's energy infrastructure of natural gas or transport fuels. Using the existing infrastructure for hydrogen and methane (synthetic natural gas, SNG) substantially reduces the cost of infrastructure conversion and makes best use of existing public assets.

5.2 UK ENERGY SUPPLY TODAY

Today, the UK consumes less energy than it did in 1998, with a decrease of 17% from 1998 to 2015 [113]. This decrease is largely attributed to 1) the increased use of energy-efficient technologies by consumers and companies, 2) government policies designed to reduce energy consumption, and 3) a decline of UK manufacturing, especially in energy-intensive industries. Moreover, increasing amounts of the energy consumed in the UK are coming from renewable energy sources – an increase from 1% to 9% (of total energy consumption) was seen in renewable sources, such as wind, solar and biomass, from 1998 to 2015 [114].

However, the declining supply of oil and gas from the North Sea has made the UK increasingly dependent on imports of energy. Figure 5.1 shows the change in the net import and export of UK energy sources since 1970: The UK became a net exporter of energy in 1981 due to North Sea oil and gas development, with a short period of net imports after the 1988 Piper Alpha disaster. Since 1999, when UK energy production peaked, the UK trend once again reversed to imports with the UK becoming a net importer of fuels since 2004, with the import dependency steadily increasing and peaking in 2013 due to decreases in North Sea oil and gas production. In 2014, due to overall reduction in demand caused by high fuel prices and a warm winter, imports temporarily decreased by 8% [113]. In 2015, the UK energy production was up by 9.6% on a year earlier, its first increase since 1999, which enabled reduction in imports for a second consecutive year. This rise in availability of indigenous fuel was due to the rise in UK Continental Shelf output of both oil and gas, following high world market prices, as well as the growth in renewable electricity production capacity, which accounted for 25% of the total electricity generation in 2015 [114]. Despite the reduction in imports and increase in exports in 2015, the net import was still 30% of primary energy used in the UK by the end of 2016 [114].

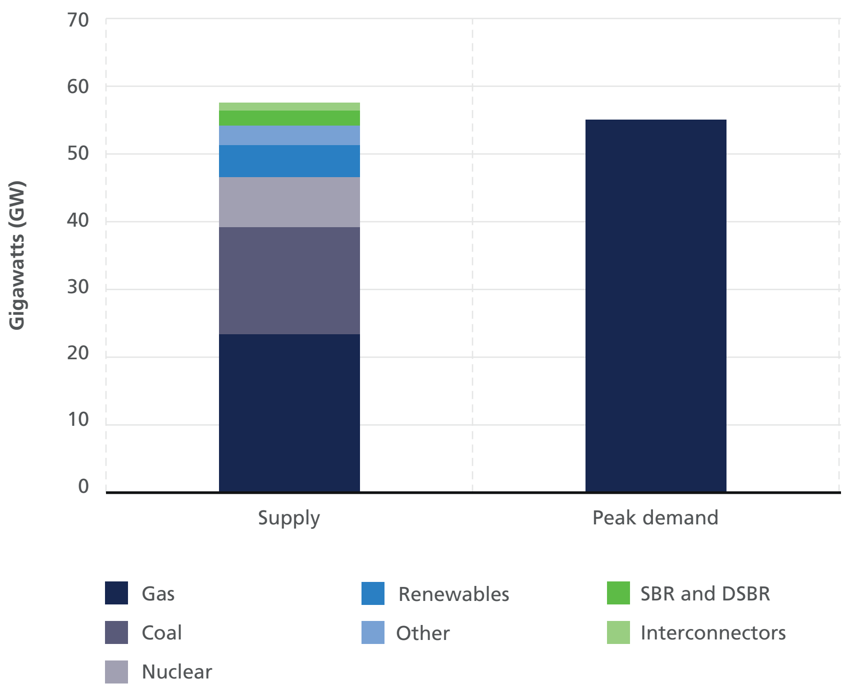
Figure 5.1 UK energy import dependency: the percentage of UK energy supply made up of net imports, 1970 to 2015, source: [113].



With electricity production, we currently have adequate capacity, but there are risks to security of supply over the medium term as around a fifth of capacity available in 2011 has to be closed down within this decade. The Government has implemented a capacity market within the Energy Market Reform to build a capacity market ensuring sufficient electricity generating capacity is kept available by the utilities to safely operate the electricity grid [116].

The UK's electricity demand may double by 2050 [117]. With the ongoing closures of old and polluting coal power plants, the challenge facing the future of the electricity network is growing. To keep the lights on, while transitioning to a low carbon electricity supply system, the power grid requires renewal, reinforcement and reconfiguration with a diverse, reliable, and resilient electricity supply affordable to the consumers. Currently, the UK electricity generating capacity available for peak demand (de-rated capacity) stems from a range of fuel sources: coal (27%), gas (41%), nuclear power (13%), renewables (8%) and other (5%), as shown in Figure 5.2. The UK also imports some electricity from other countries via interconnectors. The difference between total generation capacity and the highest demand peaks is defined as the capacity margin. The capacity margin has been tightening in the last few years as a result of decreased power generation capacity, mostly due to old power stations being closed down as they reach the end of their lives. The de-rated capacity margin for the 2016/17 winter is predicted as 2.5% [118]. The lack of replacement of power generation infrastructure, has driven the government, working with Ofgem, to introduce tools and mechanisms that enable National Grid to maintain system balance and to ensure sufficient supply exists to meet peak demand. The mechanisms introduced to ensure flexibility and security of electricity supply will be discussed in Chapter 8.

Figure 5.2 The de-rated capacity vs. projected peak demand for electricity in 2016/17, source: [119].



The UK, as Europe's second largest gas market, following Germany, has historically had a strong security of supply provision. The supply of gas from the North Sea enabled gas to displace the more carbon intense coal and oil products in space heating and power generation sectors over the past decades [120]. However, the considerable decline in the indigenous production of gas from the UK Continental Shelf, which began in 2001, has made the UK increasingly reliant on imports. Today, the net import dependency on gas is 50% and this is expected to increase to about 70 per cent by 2025 [116]. With the increasing costs of extraction of gas from the North Sea, the security of gas supply in the UK is on the decline. While the country has adequate capacity in terms of gas distribution infrastructure [116], more import infrastructure is needed to compensate for the loss in indigenous supply.

The composition of the gas capacity in UK and the expected demand for the 2016/17 winter is shown in Figure 5.3. Unlike the situation for electricity supplies, the margin between demand (465 Mm^3/day being the highest ever) and supply, is 148 Mm^3 based on current supply capacity. The supply capacity is composed of domestic Continental Shelf production (18%), gas pipeline from Norway (38%), gas interconnectors to the Netherlands, Belgium, Scotland and Ireland (19%), Liquefied Natural Gas (LNG) (16%) and stored gas (24%, the total gas storage being approximately 2,200 Mm^3 of natural gas) (Figure 5.3). Future projections into 2035 by National Grid show the demand will remain constant in the future in the worst case scenario (Figure 5.4). It is projected that either the demand will decrease from today's level of about 75,000 Mm^3/y in both the Gone Green and Slow Progression scenarios (based on increasing renewables in the power sector and the electrification of heating). Alternatively, demand will remain relatively stable (in the Consumer Power and No Progression scenarios) based on gas retaining a greater role in the power sector and economic growth increasing, with energy efficiency offsetting the difference arising from both factors. The figures suggest National Grid expects current gas supply capacity to be more than sufficient to meet even the highest levels of demand. However, in terms of the sources and cost of the supplies, with the declining domestic sources, the outlook is less clear.

The gas supply will become increasingly reliant on international markets. The IEA has described the global gas resource base as "vast and widely dispersed geographically", with estimated remaining recoverable resources of natural gas equivalent to 130 years [121]. However, with the increasing global demands, the uncertainty of the amount of gas available for imports in the long run is quite high. So is the political risk with dependency on energy exporting countries. Today, much of Europe's natural gas imports come from Russia with these supplies in the past years having been recurrently threatened by political intervention. LNG markets are expected to tighten towards the end of the decade. Furthermore, the supply of gas could be subject to disruption by external events, such as the geo-political situation with gas suppliers like Russia and the Middle East. Furthermore, as a result of leaving the EU, the UK increases the political risk associated with natural gas imports, as the infrastructure crosses EU territory and this could be used as a bargaining chip, if conflicts arise between both parties. All these factors create a high degree of uncertainty about the accessibility, reliability and affordability of future gas supply to the UK. For this reason, the UK Government is interested in understanding the potential of national shale gas resources, as well as the benefits of converting the UK national gas grid to hydrogen.

Figure 5.3 UK daily gas supply vs peak demand expected for winter 2016/17, source: [119].

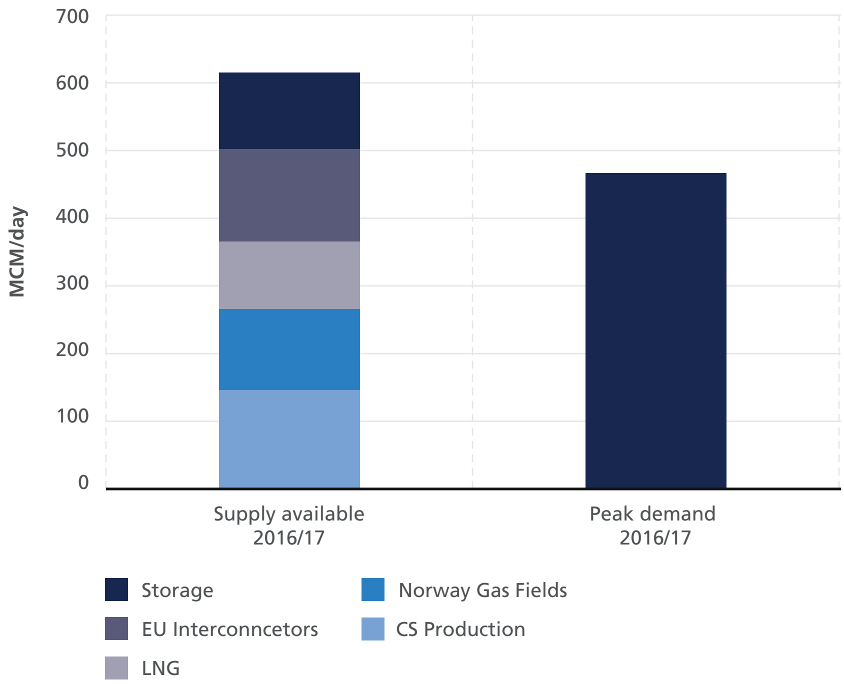
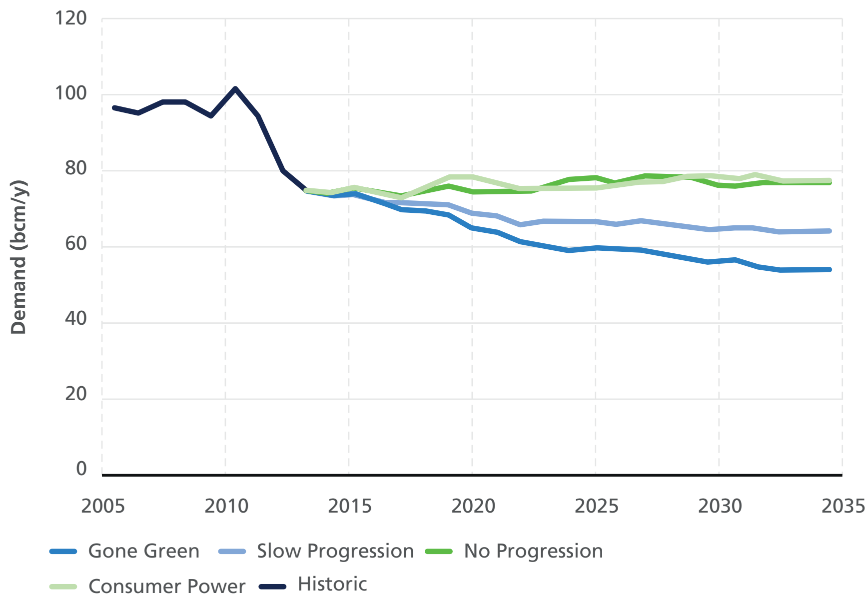


Figure 5.4 Historic and projected annual UK gas demand, source: National Grid scenarios from [121].



Oil is somewhat secondary, in which small supply interruptions can be tolerated and in which there is a stronger international market so the key risk is affordability rather than availability. Oil within the UK is currently resourced predominantly from the UK Continental Shelf. The make-up of UK's refinery capacity means that it currently has a surplus of petrol and a deficit of diesel and aviation fuel. These fuels are imported from continental Europe and the Middle East. As the production from the Continental Shelf declines, the UK will be increasingly dependent on oil imports, reducing the security of supply. To maintain the energy security of the country diversity of fuel supply, including imports, will need to increase – reliance on global oil markets will therefore surge. With demand predicted to rise globally, and oil supply becoming more diffuse due to recent technological advances, supply uncertainty and price volatility are expected to intensify. With a 90% dependency of the transport sector on oil derived fuels, this underlines the importance of developing more sustainable ways of powering transportation and linking the energy from renewables in the most cost effective way, while ensuring customer uptake of low carbon technologies.

5.3 FLEXIBILITY OF FUEL CHOICE

Historically, the UK has experienced a number of transitions between energy sources, namely the replacement of coal heating for buildings by town gas, followed by natural gas, and the replacement of coal fuel for power generation, again by natural gas. Whilst the former can be considered a permanent change of fuel source, the latter still depends on world market price developments and recent years have seen a (limited) return to coal as imported coal prices were low whilst natural gas prices increased. This relative 'fuel flexibility' relies on the availability of both coal and gas fired power stations in parallel at any given time. Transition times and barriers for changing the energy source for heating buildings, on the other hand, will be less flexible and depend on investment in new boilers rather than the potential of quickly switching fuels. Today, the UK, as previously discussed, very much depends on natural gas and very little coal as the prominent fuels for heating and power generation, and on oil for transport fuels. Few exceptions exist, for instance the fledgling market of natural gas and battery electric vehicles.

As explained in Chapter 3 hydrogen needs to be converted from other primary energy sources. This can be done from a multitude of primary energy types. Therefore, the use of hydrogen as a fuel in any of the three market segments mentioned above opens up possibilities to funnel a large variety of feedstocks into these markets. This would change the current situation dramatically where the heating market to a high extent relies on natural gas, transport fuels are dominated by oil, and electricity generation by gas and coal. In a future energy system with a major contribution from hydrogen, a diverse range of primary energy sources would feed into all these markets. This creates a hitherto unknown flexibility in the energy markets with respect to the primary energy sources at the base of end energy supplied to customers.

This also means that end-use devices using hydrogen would be decoupled from short-term commodity price hikes or supply interruptions which would be mitigated by switching to other production plants. In this regard, hydrogen offers similar advantages and versatility as electricity. A long-term strategy would be required to shape the resulting hydrogen production 'fleet' to:

- provide sufficient diversity in the hydrogen production portfolio to enable sufficient short-term production flexibility if one type of primary energy were to become unavailable or scarce for any reason; and,
- implement backup and reserve capacities to have sufficient production capacity to enable ramping up production from unaffected types of production when fuel switching is necessary.

With the high diversity of such a system, a 'system architect' or 'clearing house' approach is needed that allows for a well organised design, arranging for the interfaces with the players in the liberalised energy market. Policy planning needs to prepare this conversion of energy infrastructure, as we will further discuss in Chapter 8 (Section 8.4.1), in order to secure long-term investments. At the moment the choice of production technology depends primarily on the feedstock availability and overall technology and process cost. This will vary depending on the level of carbon pricing introduced over time leading up to an 80% decarbonised energy system by 2050 (cf. Section 5.8). A national hydrogen production technology roadmap is needed to show how hydrogen can be best produced in the short, medium and long-term. This needs to take into account the availability of the feedstock and technology readiness levels, with international considerations such as future price volatility of feedstocks, the cost of policy intervention (e.g. carbon pricing), and fuel import and export opportunities that can be developed over time. Currently without a CO_2 tax, the hydrogen production (based on commodity prices) from steam methane reforming (SMR) or SMR+CCS (£1–2/kgH_2eq) appears to be the cheapest way forward (cf. Chapter 3). Thus, the government needs to re-assess and make a decision on the support it will provide for developing CCS technology. But with introduction of a carbon tax at a rate of £250/tCO_2, hydrogen production from Biomass + CCS becomes cheaper than petrol and gas. With technology optimisation and economies of scale, hydrogen production costs from electrolysis can also be reduced. The U.S. DoE claims this will be the case by the year 2020 [76].

In Chapter 7 we will show that when hydrogen is introduced as a vector for decarbonising the energy system, it broadly displaces natural gas and petroleum-fuelled technologies rather than electrical devices, so the increase of diversity within the whole system is limited to the gas and transport fuel markets. On the other hand, hydrogen tends to increase diversity over strategies that focus on electrification, but not in all parts of the energy system or in all circumstances; the 'Full Contribution Scenario' from Chapter 7, based on high levels of hydrogen deployment, suggests the highest diversity. The policy planning for infrastructural investment for energy security should take this factor into account, in terms of both feedstock availability over time (e.g. expected changes in availability of indigenous coal and gas reserves) and the necessary funding needed to enable economic viability of more sustainable options (e.g. hydrogen production from electrolysis and biogas). Research and development funding for hydrogen production (to name but a few of the options) will be needed to further diversify hydrogen production and to reduce reliance on fossil fuels [8].

5.4 DECARBONISATION FOR SUSTAINABILITY

Hydrogen can be produced from coal, oil, or natural gas, releasing the carbon dioxide emissions connected to these fossil energy sources. It has been demonstrated that producing hydrogen from fossil primary energy does not reduce the overall emissions as compared to direct utilisation. The increased efficiency when using hydrogen in fuel cells is offset partly or completely by the energy losses in hydrogen production [122].

With hydrogen production from renewable energy sources, including biomass, wind, solar, and also wastes, the environmental impact is minimised. Since there will be fossil fuel input to the total life cycle of hydrogen production and use, we use the term 'low carbon' throughout, even for 'green hydrogen' from 100% renewable sources, although systems can be envisaged that would supply 'zero' carbon in the long-term.

As mentioned in Chapter 3, the possibility of carbon sequestration exists, though not commercially viable, so that even fossil energy sourced hydrogen could be produced without immediately releasing CO_2 to the atmosphere. CCS technologies, though, remain high cost and have not been proven to be economically or environmentally viable in any way. It appears that additional cost premiums would better be spent on technologies that by principle are sustainable – such as renewable energy developments – than simply deferring release of CO_2 to the environment by decades, or maybe centuries. Nevertheless, CCS might be necessary in a transitional period if the growth of renewable energy sources is not sufficiently supported.

Hydrogen and synthetic methane fuels produced from renewables, to name the two most important options to produce zero-carbon-balance fuels, can be converted to electricity and heat in fuel cells. This indicates pathways towards a fully de-carbonised energy economy. The higher efficiency of fuel cells as compared to, for example, ICEs or many stationary power generation types contributes to the efforts of reducing energy demand whilst at the same time avoiding harmful emissions at point of use, improving air quality. Using the electrochemical fuel cycle shown in Chapter 3 (Figure 3.7) will allow to utilise renewable energy input both in the form of primary electricity (solar, wind, ocean etc.) and biomass/waste to drive a fully de-carbonised conversion cycle of primary energy and zero-carbon fuels.

The result is a fully sustainable future energy system that will deliver a de-carbonised energy supply along with a high degree of national independence from fuel imports (cf. following section), and an equally high degree of energy price stability (cf. Section 5.8).

5.5 INDEPENDENCE OF FUEL IMPORTS

Production of gas and oil from the UK Continental Shelf is declining at a sharp rate. The production of gas has decreased by 60% since 1999 [114]. The UK will therefore be increasingly dependent on imports by pipeline from Norway and The Netherlands bringing in further North Sea and Dutch production, as well as passing through gas deliveries that enter Europe from Russia, and the Middle and Far East through the major European pipeline projects. As production in The Netherlands is also reaching its climax, an overall growing dependency of Europe on gas imports is imminent. Oil import dependency has already reached the mark of 80%.

Gas will in the future also be delivered increasingly as liquified natural gas (LNG) by tankers from Indonesia, Malaysia and other production sites not connected to Europe by pipeline [123], and to a certain extent also from the U.S.A. who claim to have considerably reduced natural gas prices by extensive use of fracking. It remains to be seen, though, whether this low-cost reserve will be allowed to leave the country.

Growing dependence on imports puts the economy and politics in a difficult position since political pressure on the UK could increase with increasing dependency on gas imports, especially as much of the European gas market may in the future be dominated by Russia which is today the world's leading natural gas supplier [123]. This can be avoided if imports can be drastically reduced in the face of a domestic gaseous fuel production based on renewables.

When hydrogen is produced from renewable energy sources within the UK, it can be fully considered as an indigenous energy carrier. This will decouple domestic energy use influences from world market volatility. The flexibility of feedstock choice to produce the hydrogen, as discussed above, will allow for a more diverse energy market with less pressure from single market players since any dominating specific feedstock can to a certain extent be compensated from numerous alternatives.

5.6 LINKING ENERGY SECTORS: HYDROGEN AND METHANE INFRASTRUCTURE

Hydrogen can be produced from a number of different energy sources, including fossil and renewable resources, as was previously explained (Chapter 3 and above). Biomass and wastes in solid or liquid form can be converted into hydrogen rich gases. Renewable electricity can be used in electrolysers to directly split water and carbon dioxide. Hydrogen and hydrogen rich gases can be converted to synthetic natural gas (SNG) through a methanation step that combines hydrogen with CO_2. These gas mixtures can also be used in chemical industry as an essential raw material for the production of plastics and fertilizers. Hydrogen and hydrocarbon gases and liquids can be converted to electricity at high efficiency in low (80 to 200°C) and high temperature (500 to 950°C) fuel cells. These brief examples are intended to underline the versatility of both hydrogen and fuel cells as elements of a future UK energy system.

The main point to be made here, though, is the linking function that both, hydrogen and synthetic natural gas, fulfil across the whole energy system. Traditionally, specific fuels are limited to certain sectors of the energy supply chain – coal being today practically exclusively used for power conversion, liquid energy carriers for mobile applications, natural gas for house heating and power generation, with a very low level of employment in transport, and with electricity being the most versatile energy form with a variety of different usages across the energy sectors, from heating buildings to powering public transport.

The use of hydrogen across a broad range of applications in all energy sectors introduces a novel aspect to the energy system, namely the linking of different applications and primary energy sources through the use of the same 'raw material' across these sectors. This aspect is slightly different from the 'fuel flexibility' aspect discussed in Section 5.3 which looked into the various sources of energy used to produce hydrogen. Here, we are looking at the ways hydrogen production supplies a 'linking' element between the three main energy markets by shifting flows of energy from one to the other.

This is illustrated in Figure 5.5, which shows the three main energy conversion pathways (Power-to-Gas, Power-to-Power and Gas-to-Gas) in a future renewable energy integrated system in which hydrogen acts as a common denominator to transfer energy from the electricity grid to the gas grid, and vice versa:

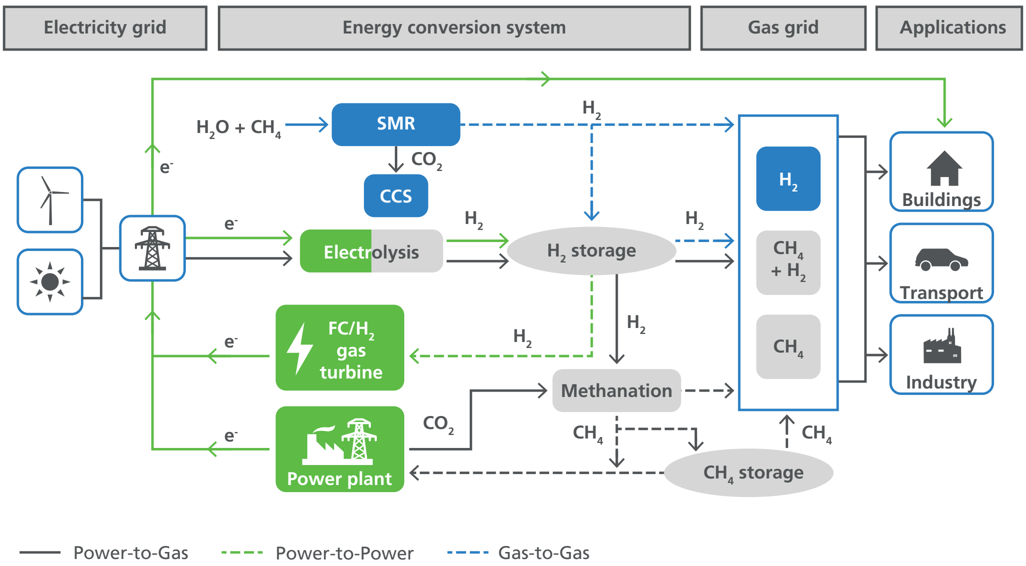
- **Power-to-Gas (P2G)**: in this case, electricity is used to generate hydrogen via electrolysis. The hydrogen is then either injected into the gas distribution grid or transformed to synthetic methane (SNG) in a subsequent methanation step [124]. The CO_2 required for the methanation can be sourced from biogas anaerobic digesters which, combined with CCS at the point of use of the SNG, effectively results in negative CO_2 emissions [125]. A systems analysis of power-to-gas can be found in [124] and [126], with the short term and long term business opportunities analysis provided in [127].

- **Power-to-Power (P2P)**: here, electricity is used to generate hydrogen via electrolysis, the hydrogen is subsequently stored, and then used to generate electricity via a fuel cell (kW_{el} to MW_{el} scale) or a hydrogen gas turbine (multi MW_{el} scale) at times of increased demand. The hydrogen produced can also be used as a fuel for fuel cell electric vehicles (FCEVs) in the transport sector, which is referred to as **Power-to-Fuel (P2F)**. In P2F the electrolysers can be placed in re-fuelling stations and large pressurised storage tanks can be used to store the hydrogen.

- **Gas-to-Gas (G2G)**: indicates the case where steam methane reforming (SMR) is used to produce hydrogen from natural gas. As discussed in Chapter 3, approximately 95% of hydrogen produced worldwide is produced via SMR. However, as CO_2 is released in this process, CCS technology is needed to reduce the carbon footprint. The hydrogen can substitute natural gas in the supply to buildings and be used in fuel cells for micro-CHP or in heating boilers. This pathway has been presented by the 'H21 Leeds City Gate' study for decarbonising heat in the UK [128]. Further analysis is required to clarify how much of the natural gas could be replaced by methane from biomass sources.

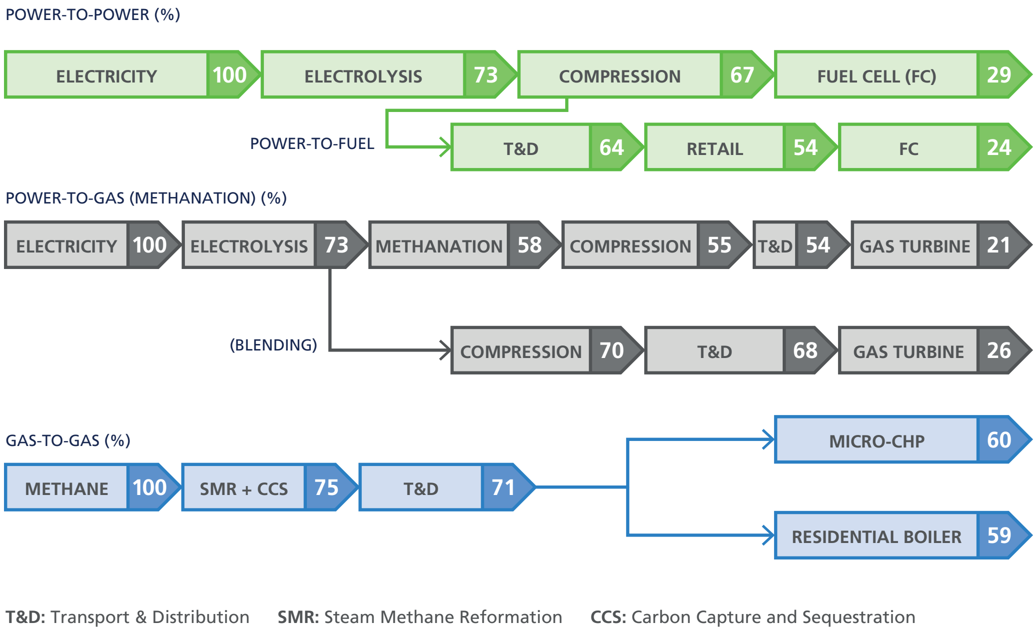
The hydrogen generated through these processes can be stored in pressurised tanks (for small scale applications) or in natural gas pipelines and/or underground caverns (for grid scale applications). P2G and P2P enable flexibility in a highly renewables integrated system by balancing the fluctuations of renewables. The G2G pathway, on the other hand, enables the use of the existing gas infrastructure with hydrogen replacing natural gas as the energy vector for heating, cooking etc. In the case of G2G the Leeds City Gate assessment shows that the modifications required for the gas grid will costs no more than the upgrades being undertaken through the current Iron Mains Replacement Programme [128].

Figure 5.5 Schematic diagram showing the three main energy conversion pathways (Power-to-Gas, Power-to-Power and Gas-to-Gas) in a renewable energy integrated energy system, source: [129].



The choice of the optimum hydrogen pathway with lowest costs and highest benefits depends on the trade-off between several factors, including system costs, efficiency, decarbonisation impact, and the practical feasibility (e.g. public acceptance) of changing the existing gas distribution system in a given area to supply hydrogen. Ultimately, the choice depends on capital expenditure, policies, and the pace of commercialisation of the technologies needed for each pathway. Blending of hydrogen with natural gas in the existing gas infrastructure (using P2G) may be more desirable in the short term in view of lower initial capital expenditure, even though it is not the most optimal in terms of carbon savings. For example, 80% hydrogen in the gas mixture by volume reduces CO_2 emissions by 50% [130]. Nevertheless, it provides the opportunity to off-load surplus hydrogen produced from excess renewable power, rather than curtail it. However, the amount that can be blended depends on national gas standards, which needs to be reviewed as the current standards set a limit that is significantly lower than what the pipelines can carry from the point of view of gas safety. On the end-use point, blends in excess of 20% hydrogen requiring end-user appliances to be converted or replaced [131] because of the effects of hydrogen on the Wobbe index [132] and sustaining safe combustion.

Figure 5.6 **The step conversion efficiencies for the hydrogen supply pathways being considered, data from [129].**



The economic benefits of implementing storage to manage high levels of renewable electricity generation have been shown in several studies. One study shows £10bn/year savings can potentially be realised in the UK with storage technologies in a 2050 high renewable energy scenario [133]. One of the balancing strategies deployed by National Grid is to pay wind farms to switch off ('wind curtailment') when energy is produced that cannot be immediately absorbed by the grid. This has cost the UK customers £80 million in 2015 [134]. With increasing level of renewables connected to the power grid, without the grid capacity increased, this cost will be increasing. In 2016 with 10% total wind capacity available on the grid, 6% was constrained at some point in time [134].

Besides hydrogen, several different technologies are being investigated for grid scale electricity storage including lithium ion batteries, redox flow batteries, compressed air energy storage, supercapacitors, thermal energy storage and flywheels [115]. A mixture of these options can be used for balancing supply and demand, supplying frequency control and other benefits such as curtailment minimisation, demand-side management, contingency grid support, etc. [135]. Hydrogen offers several advantages over these options:

- hydrogen is one of the most versatile of all energy storage options and the possibility to use it in both the power and gas grid offers the opportunity to decarbonise all energy use sectors (transport, buildings, industry). The multitude of pathways in which non-renewable and renewable primary energy can be converted into hydrogen enables unprecedented system flexibility.
- hydrogen can store larger amounts of energy per unit volume than other large scale energy storage options being considered: it has over 200 times the volumetric

energy storage density of pumped hydro storage and 50 times that of compressed air [115]. In any case, the hydrogen gravimetric energy density of 33 kWh/kg is unsurpassed by any other energy carrier.

- hydrogen can be used for both intra-day and inter-seasonal storage, enabling a greater degree of flexibility with diurnal and seasonal variations.

The most important aspect of this part of the discussion is that fuel cells and electrolysers introduce the novel possibility of the conversion of electricity to a gaseous fuel and back again, with all the advantages gaseous fuel transport and storage offers over electricity. Ultimately, a fuel can even be produced (SNG) that can be transmitted in the existing natural gas grid with no modifications at all [128]. Through these supply pathways, hydrogen can ultimately become a universal fuel that can be used across the complete energy system.

Overall energy efficiency is considered an important factor for deciding on the choice of technology and supply pathway. While fuel cells have higher electrical efficiencies (ranging from 40 to 60% based on the type, as discussed in Chapter 4) and total efficiencies (combined electrical and thermal, up to 95%) than internal combustion engines (40% in their best point), the conversion losses in P2G gas and P2P result in overall conversion chain efficiencies in the range 20% to 30% (Figure 5.6). But in the case of G2G the final efficiency can be as high as 60% due to the employment of CHP schemes. While a comparison of the overall efficiency of the different pathways with alternative options for storage can aid decisions for selecting the most optimal configurations, they must be considered in light of all the benefits enabled by hydrogen, fuel cells and electrolysers. Hydrogen, through P2G, P2P and G2G, is the only low carbon energy vector that allows a similar degree of versatility enabled by fossil fuels today, even adding further flexibility, as discussed previously.

There are approximately 40 power-to-gas demonstration projects in Europe [136]. Germany is currently leading the way in terms of demonstrating P2G and P2P concept at grid scale: 20 plants were reported to be in operation with 10 facilities being planned or under construction in August 2015 with a power range of 100 kW_{el} to 6 MW_{el} [108]. During the charging phase, the power of the system is determined by the size of the electrolyser, whereas the energy stored is determined by the size and pressure of the hydrogen store (as discussed in Chapter 3). Both elements are independent of each other so that the power absorbed by the P2G system is in no way tied to the storage capacity. This is a decisive advantage over batteries.

5.7 HYDROGEN TRANSPORT AND DISTRIBUTION

Hydrogen transport and distribution (T&D) infrastructure consists of pipelines connecting hydrogen production and storage points to end use sites. Currently, much of the existing high pressure distribution and transmission pipelines are made of high strength steel. Hydrogen can embrittle steel, so the pipelines will need to be changed if hydrogen is to be transported through the natural gas pipeline network. However, in the UK most steel pipelines originate from when town gas was distributed, which had a fraction of up to 50% of hydrogen. Low pressure natural gas pipelines require upgrades to reduce methane leakage on both safety and environmental grounds, and these are currently being converted to polyethylene pipes through what is known as the Iron Mains Replacement Programme. Polyethylene pipes are suitable for transporting hydrogen at low pressures [137]. Further work is needed to assess the suitability and, if need be, the conversion costs of all other system components such as seals between pipes, pressure reduction stations and the end use components. Such a transition to G2G pathway will take time, and decisions will need to be made in the near term if the Governments is to meet the 2050 CO_2 reduction targets on time. Globally, the feasibility of gas network conversion should be assessed on the basis of infrastructural changes (e.g. upgrades) that will nevertheless be needed, even without the conversion to hydrogen.

The blending of hydrogen with natural gas could be a transition step towards the conversion of the gas grid to transport 100% hydrogen. Currently, the main uncertainty in this supply pathway is with the amount of hydrogen that can be blended safely. In the UK, [137] suggests that early levels of hydrogen should be limited to 2–3% within the UK natural gas pipeline. A directed assessment is needed to determine the limits of hydrogen that can actually be stored safely when mixed with natural gas.

Globally the figures differ, as the amount depends on the characteristics of the natural gas used, as well as on the design of existing appliances [138], and therefore will vary by region. An EU study (NaturalHy) [139] concludes that 30% hydrogen can be added without an adverse increase in risk to the public, another study suggests a safety limit of 20% in the Netherlands, although the current standards set the limit as 12% [138]; in Germany the set limit is 5%, with potential to increase to 20%. In the U.S. State of Hawaii, 10% hydrogen is already mixed into the natural gas grid. Furthermore, the currently used end use appliances need to be considered when setting limits. According to the NaturalHy study, with modifications to the appliances and favourable conditions of natural gas quality, the appliances can safely operate with up to 20% H_2 in natural gas [139].

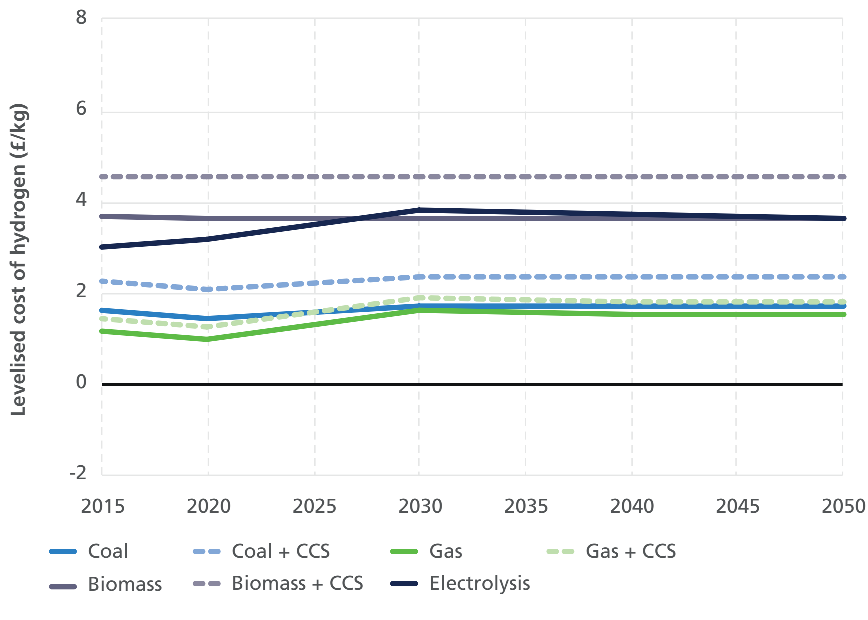
5.8 AFFORDABILITY

Affordability is an important axiom of energy security. The cost of hydrogen can be estimated by calculating the levelised cost of hydrogen (LCOH), which is analogous to the levelised cost of electricity that is often used to compare power generation technologies. This approach looks into the cost of providing services, not the end-use cost to the customer. Hydrogen today is sold as a vehicle fuel at £10/kgH_2 and less at hydrogen filling stations [140, 141]. This equates to £0.30/kWh of fuel energy content, which is roughly seven times the price of natural gas. Compared to petrol, this is about double (all taxes and levies included in all prices). In this case, though, the difference is over-compensated for by the higher conversion efficiency of fuel cell electric vehicles (FCEV). This results in hydrogen today being competitive with diesel as a vehicle fuel – as far as the costs of operation (excluding the vehicle investment) are concerned.

The LCOH is shown for several of the hydrogen production technologies discussed in Chapter 3 and Figure 5.7. SMR and coal gasification have the lowest costs. As might be expected, CCS versions of each technology are more expensive than the unabated plants. Very limited cost reductions through innovation are forecast, and are generally balanced by higher feedstock prices. The impact of levying a carbon tax on hydrogen production, increasing from £50t/CO_2 in 2020 to £250/tCO_2 in 2050 are shown in Figure 5.8. Unabated plants become substantially more expensive than CCS plants as the tax increases. Biomass CCS changes from the most expensive to the cheapest option as the carbon tax increases, as it is assumed that such conversion would be paid for removing carbon from the atmosphere with effectively negative carbon emissions as atmospheric CO_2 is sequestered underground.

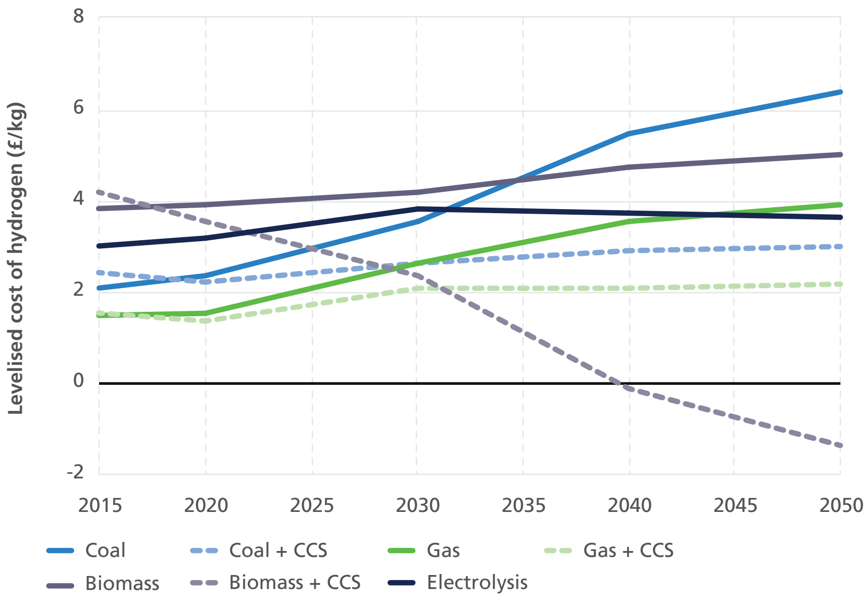
In Figure 5.9 the lower-cost hydrogen production technologies rely on the development of CCS in conjunction with high carbon taxes. There is much uncertainty over the technological feasibility and political will to build CCS facilities.
In the absence of carbon taxes, the cost of producing low-carbon hydrogen will be much higher.

Figure 5.7 Levelised cost of hydrogen forecasts for the UK, without a CO_2 tax (£/kg).



Capital cost data are from [51]. Feedstock price forecasts are primarily from [142] and [143]. Other data are taken from the UK TIMES energy system model.

Figure 5.8 Levelised cost of hydrogen forecasts for the UK, with a CO_2 tax increasing from £50/tCO_2 in 2020 to £250/tCO_2 in 2050. No tax is levied on electricity in this diagram.



Price volatility is an important facet of energy security. Figure 5.9 shows the uncertainties in the LCOH in 2050 that result from commodity cost and capital cost uncertainties. The capital cost uncertainties would be removed once a production plant were constructed, leaving only the commodity cost uncertainty shown by the boxes. With the exception of electrolysis, the commodity cost uncertainties for hydrogen are substantially lower than the uncertainty in the oil price for transport, but similar or higher than the uncertainty in the gas price for heat provision. Figure 5.10 shows the same graph when a CO_2 tax is levied. The level of uncertainty does not increase as the overall price increases, because the tax is levied at a fixed rate of £250/tCO_2 and uncertainties in this are not considered. Hydrogen is cheaper than fossil fuels with this tax, even after accounting for price volatility.

Figure 5.9 **Hydrogen production cost forecast ranges in 2050 without a CO_2 tax. The boxes show the impact of feedstock price uncertainty. The lines show the impact of capital cost uncertainty. The fossil fuel costs are for the quantities of fuel that are required to provide the same energy service that 1 kg of hydrogen would provide, assuming the dominant hydrogen technologies would be gas boilers for heating and fuel cell hybrid electric vehicles for transport.**

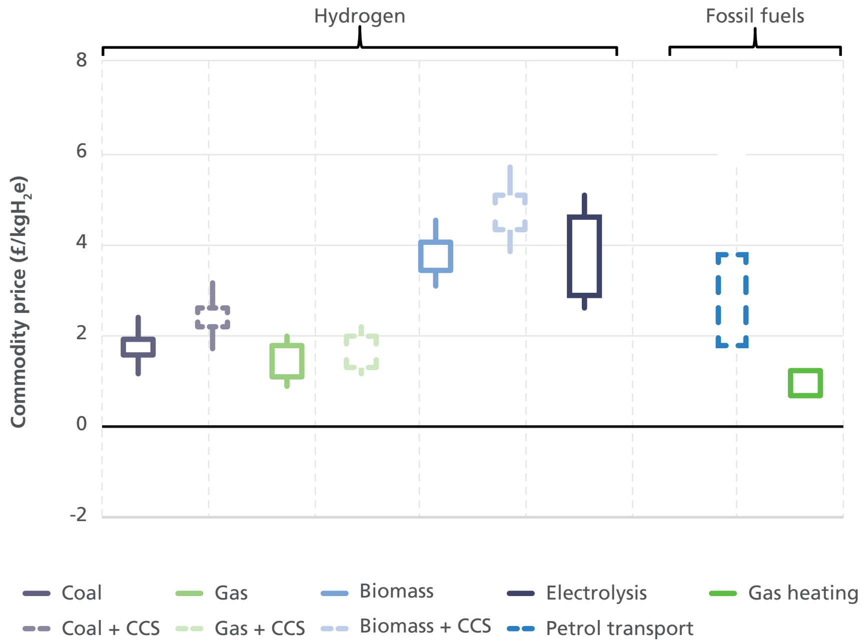
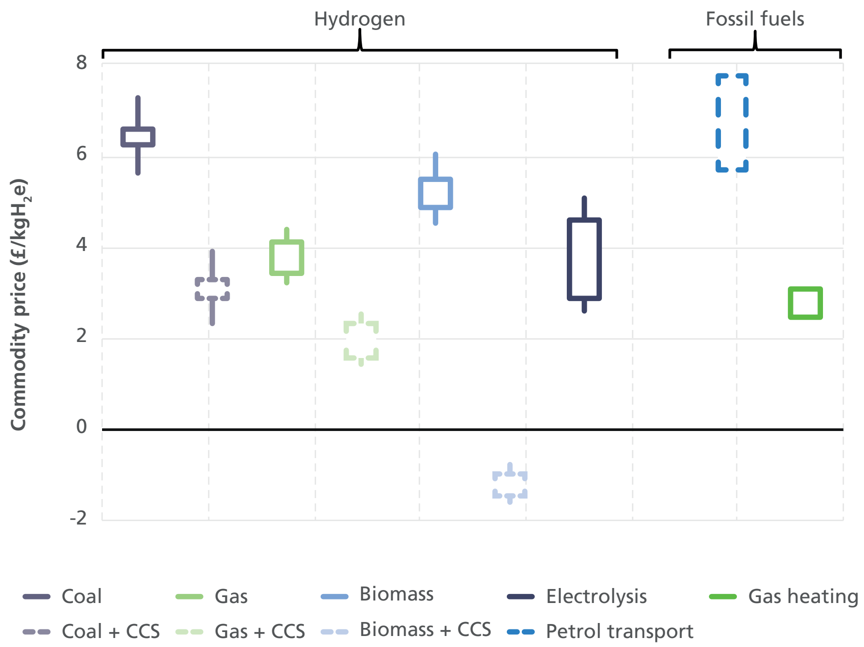


Figure 5.10 **Hydrogen production cost forecast ranges in 2050 with a CO_2 tax of £250/tCO_2.**



Producing bulk amounts of hydrogen from renewable energy sources not only supports a sustainable primary energy supply infrastructure but also allows investments to remain in the country and contribute to local job growth instead of being exported to the countries selling fossil energy. Since most renewable energy developments are capital intensive but low-cost on the side of operations (quite contrary to fossil energy conversion), investment in national renewable energies and hydrogen production can contribute to long-term stability of energy prices. The only exceptions are schemes that use biomass and wastes, such as the recycling business. As the business grows and with it the value of the wastes processed, companies might have to pay for waste, instead of being paid to remove it. In these cases the operating costs do not remain constant and the business model collapses. A recent move of supermarkets to give away food wastes to charities was not welcomed by waste processors [144].

When building on hydrogen from renewable energies, the UK economy significantly reduces influences from world market energy price volatility. This adds a decisive element of both security of supply and affordability, since the risk of an impact of external energy markets and policy developments on the UK economy is greatly reduced. Transport fuels are an outstanding example of the impact that world politics can take on key aspects of a healthy economic development. With a high dependency of the pricing of processed oil products on international markets, world market price volatility of crude oil and oil products will immediately take a hit at the economic competitiveness of UK businesses. Successfully introducing hydrogen and SNG fuels in road transportation will reduce the dependency on fuel imports and mitigate the impact of oil price fluctuations, as well as securing long-term price stability in this sector. It also reduces risk and therefore allows to reduce the contingency margins costed into market prices of oil products and the services that depend on them.

As mentioned above, renewable energy, fuel cell, and hydrogen projects suffer from the fact that they induce a high capital investment. This can be partly offset by operational savings. What makes things worse in the case of these technologies is that they are essentially ‘very low carbon’ but compete with heavily polluting incumbent technologies. The expectation in government policies that low carbon technology should not induce additional costs is misleading in that it ignores the high cost the taxpayer carries for compensation measures caused by the externalities of fossil energy use. A large part of the environmental and health costs of energy use result in Government expenditure to cover for the increasing impact of natural disasters, climate change mitigation, emission control programmes, compensation for farmers with reduced crop harvests (e.g. due to high concentrations of ozone), damage by acidification of soils and water and to the built environment (e.g. acid rain on facades) etc. The costs of fossil fuels should therefore internalise the cost of the externalities that they produce. In addition to these costs effectively carried by the tax payer, UK citizens pay in the way of considerable impacts to health and wellbeing, for instance when considering the impact of smog in urban agglomerations, such as London, on premature deaths. Air pollution levels have been substantially higher than allowed leading to an estimated 29,000 premature deaths [145, 146]. According to EU rulings, citizens have a statutory right to healthy living conditions which is largely ignored by councils in the EU urban agglomerations. An increasing number of legal claims is being brought forward to hold councils accountable, causing considerable legal costs.

In economic assessments of the viability and competitiveness of technical alternatives to incumbent technologies, a total cost of delivery would have to be employed in order to avoid any bias in the comparisons. Today, this is not the case and zero-carbon technologies are compared to highly polluting and damaging technologies. These have a history of causing long-term costs to future generations even when they cease operation [147]. The situation results is a biased assessment. A level market field approach is needed where the full costs of service need to be costed into comparisons of different energy technologies.

A fairer distribution of costs, where cause and effect are more intimately linked, i.e. by energy use being charged with the full societal cost ('polluter pays' principle), would be difficult to implement. Nevertheless, even in the short term this would trigger the correct incentives to reform the energy market and automatically provide long-term sustainability. Fuel cells and hydrogen fuels are prone to cost more than century-old incumbent, but polluting technologies, since they are new arrivals to the energy market. Integrating the environmental costs of energy services into market pricing would immediately give these technologies the place in the market that corresponds to their environmental performance.

Much progress has been made worldwide in estimations of environmental and individual costs of energy services for instance as estimates of the cost of climate change [148], the external costs of electricity supply [149], and the external costs of transport services [150]. In all cases, a considerable premium is required to level out the cost of conventional and fossil energy provision, with the increasingly unsupported zero- and low-carbon options. In the case of passenger vehicles, this is a surcharge of around 100% on the pump price of petrol and especially diesel (depending on current oil prices). Though the inclusion of externalities in end-use pricing would increase consumer prices, it would be income-neutral at the national level, since it removes respective government expenditure sourced from taxes.

Careful analysis, though, shows [151] that even with supposedly clean fuels – such as hydrogen produced from conventional grid electricity which causes zero-emissions at point of consumption – the environmental premium may increase due to the primary energy inputs. Care has to be taken, therefore, that any implementation of hydrogen and fuel cell technology actually takes heed of the environmental and emission issues in full. Mixing technologies that will deliver zero-carbon services at point of use (e.g. battery electric or fuel cell vehicles) with a supply of fuels from highly polluting sources (e.g. grid electricity and hydrogen from natural gas steam reforming) will cause more damage than the incumbent technologies. This again underpins the need for a full societal cost analysis in going forward to choosing future energy options.

5.9 CONCLUSIONS

This chapter has shown that hydrogen can be produced close to economic viability from a range of feedstocks. Depending on the end use of hydrogen, operational costs might be cheaper than conventional fuel systems. This is certainly the case for fuel cell electric vehicles (FCEV) where hydrogen prices at filling stations already outperform diesel, considering the powertrain efficiency gains in the vehicle. In the future, the environmental benefits of hydrogen applications need to be captured in the pricing of the fuel. Fossil fuel prices do not mirror the high pollution levels that they incur and the political risks that they bear. The systematic bias of the energy supply system towards fossil fuels needs to be addressed so that fuel prices reflect their true social costs, including a contribution towards mitigating environmental damages (GHG emissions and air quality pollution). This approach will support the competitiveness of hydrogen, accelerating its market penetration.

End-use devices using hydrogen are decoupled from the primary energy source, such that the impacts of short-term commodity price hikes or supply interruptions are mitigated by switching to other production sources. Hydrogen offers similar advantages to electricity in this regard since in its application it is of no relevance where the energy used to generate it originated from. Hydrogen contributes substantially to increasing the flexibility of the energy system by increasing the options for access to primary energy sources, as well as reducing the risk of unavailability of any one source.

Hydrogen is versatile and can be either used directly or converted to many other gases, starting from a variety of feedstocks. This includes synthetic natural gas (SNG, pure methane) or town gas. In the long run, the feedstock can in principle be 100% renewable. This offers options for supplying fuels for a fully sustainable energy system with a perspective of securing energy supply for several centuries.

Using electrolysers and fuel cells, hydrogen can contribute significantly to balancing electricity grids with high proportions of renewable electricity and links the electricity and gas networks. Excess electricity can be stored as hydrogen at lower cost, compared to other electricity storage options, for longer periods of time. Gas storage is simpler and cheaper to implement than electricity storage.