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The potential for renewable hydrogen as a transport fuel for the UK

By
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DECLARATION OF OWN WORK

I declare that this thesis:

The potential for renewable hydrogen as a transport fuel for the UK

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Abstract

Renewably produced hydrogen is identified in many UK strategies as being the future of transport fuel in the long term. This study assesses the renewable resources available for the production of hydrogen in the UK, and defines a model for the costs of hydrogen supply along a number of fuel chains covering production, storage, transport and dispensing. Energy use and carbon dioxide (CO_2) emissions are also considered.

The renewable energy technologies found to have the greatest potential for hydrogen production are biomass (short rotation coppice and forestry wastes), offshore wind, onshore wind, tidal energy, wave energy and small hydro. All of the fuel chain components are available, either commercially or at the demonstration stage. The most significant non-technical constraints identified are for renewable electricity technologies, specifically planning and electricity network regulation.

Biomass production routes are cheapest, with costs of around 1 p/km, (equivalent to £8.80 /GJ), approximately equal to those of hydrogen produced from steam methane reforming, and lower than untaxed petrol travel costs by up to 50%. The cheapest of the renewable electricity technologies in 2002 is onshore wind, with the cheapest options for compressed hydrogen supply being either electrolysis at a regional scale, with delivery by pipeline, or forecourt electrolysis, at 1.4-3.1 p/km. The cheapest option for liquid hydrogen delivery is electrolysis at a regional scale with delivery by road, at 2.0-3.6 p/km. The costs of hydrogen from the majority of other fuel chains modelled are still not prohibitively high, with many of the 58 chains modelled having travel costs lower than those using taxed petrol. Costs for 2020 decrease significantly, given projected technology development and cost reduction through learning. None of the fuel chains are found to have significant life cycle CO_2 emissions when compared with existing 'low-carbon' vehicle technologies.

If the lowest cost fuel chains were used for hydrogen production, 40% of the current UK car fleet could be fuelled at a cost lower than that of untaxed petrol, using biomass, onshore wind, and small hydro schemes. By 2020, this figure increases to 70%.

Currently available renewable sources could provide low cost hydrogen needed during infrastructure development, without use of fossil fuel derived hydrogen as a bridge to renewable production. This suggests that hydrogen should be included in integrated climate, energy and transport policies, to promote renewable production, support technology development, and reduce planning constraints at all stages of the fuel chains.

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List of abbreviations

BIPV	Building Integrated Photovoltaics
CNG	Compressed Natural Gas
CO	carbon monoxide
CO_2	carbon dioxide
CUTE	Clean Urban Transport for Europe
DEFRA	Department for Environment, Food & Rural Affairs
DTI	Department of Trade and Industry
FCV	Fuel Cell Vehicle
GJ	gigajoule
GW	gigawatt
ha	hectare
ICEV	Internal Combustion Engine Vehicle
kg	kilograms
kW	kilowatt
kWh	kilowatt-hour
kW_p	kilowatts peak
LPG	Liquefied Petroleum gas
MPa	megapascal
MSW	Municipal Solid Waste
MW	megawatt
NETA	New Electricity Trading Arrangements
Nm^3	Normal cubic metre (atmospheric pressure and 20?C)
NO_x	oxides of nitrogen
odt	oven-dry tonne
OWC	Oscillating Water Column
PEM	Proton Exchange Membrane
PSA	Pressure Swing Adsorption
PV	Photovoltaics
SMR	Steam Methane Reforming
SRC	Short Rotation Coppice
TNUoS	Transmission Network Use of System
TWh	terawatt-hour

1 Introduction

1.1 The effects of road transport

Over the past thirty years, transport by road in the UK has doubled. Car use now represents over 90% of personal travel, with planning and land use reflecting and encouraging this mode of transport (DfT, 2000). Road traffic has been projected to grow by 22% from 2000 figures by 2010 (DfT, 2000). While growth has brought about many benefits, including increased mobility, economic growth and personal freedom, it has also had environmental impacts, such as increased air pollution and noise. The conditions for road transport have also varied, with availability and price of fuel affected most dramatically by the oil crises of the 1970s and fuel protests in 2000. On a global scale, carbon dioxide emissions from the combustion of hydrocarbon fuels contribute to climate change. Road transport contributes 22% of UK greenhouse gas emissions (EST, 2002). This percentage is expected to increase with increased travel demand, despite improvements in vehicle efficiency (DfT, 2000).

On a regional and local scale, internal combustion engine vehicles lead to the emission of air pollutants such as oxides of nitrogen (NO_x), volatile organic compounds, carbon monoxide, sulphur dioxide and particulates. These pollutants lead to impacts on human health, such as respiratory diseases, and also to damage to wildlife and vegetation. Road transport contributed to 52% of NO_x emissions and 69% of fine particle emissions in London in 1999 (GLA, 2001a). The use of internal combustion engines also contributes to traffic noise. In 1991 it was found that 63% of people in the UK consider noise from road traffic to be a nuisance (GLA, 2001b). Engine noise may become the dominant factor in road noise as roads get quieter and congestion increases.

There are also questions of security of supply for vehicle fuels i.e. the risk of supply interruption. On an international level, the price of oil, and therefore its availability for use, fluctuates with market conditions, political events, and estimates of resource availability. The UK will become further exposed to these strategic risks with increasing reliance on oil imports; the UK is expected to become a net importer of oil by 2006/7 (PIU, 2001). There are also risks to the domestic supply system, seen most recently during the fuel protests in 2000, but also posed by threats such as terrorist action.

To address these issues, research on alternatives to the use of petrol and diesel in internal combustion vehicles has been ongoing for many years. However, current increasing awareness of the impact of road transport, and the need for early action to reduce its impacts has led to several major studies of the possibilities for future vehicles in the UK. These include the Government's Powering Future Vehicles Strategy (2002), and the Energy Saving Trust's Pathways to Future Vehicles Strategy (2002), both of which consider options for reducing carbon dioxide emissions from road transport, through improved vehicle efficiency and low carbon fuels. Possibilities include the use of cleaner fuels such as liquefied petroleum gas, biofuels, hybrid and electric vehicles.

1.2 Fuel cell vehicles and hydrogen

While recognising the many factors that can cause detriment to health and the environment from road transport, a prime driver of Government policy in this area is to reduce carbon emissions to mitigate climate change. However, the Government is keen to stress that low carbon transport policy should not be technology specific, with the market open to any fuel or vehicle technology able to meet life-cycle emissions standards. However, one option, that of hydrogen used in fuel cell vehicles has been seen as 'the most promising option for zero carbon road transport' (EST, 2002) and 'the ultimate low carbon destination' (PFV, 2002).

Hydrogen can be used as a fuel in both modified internal combustion engines vehicles, and in fuel cell vehicles. In both cases, use of hydrogen produces no tailpipe carbon dioxide emissions, no particulates, no carbon monoxide and no sulphur dioxide. A fuel cell combines hydrogen with oxygen from the air in a chemical reaction, producing electricity to power the vehicle, with only water as the by-product. If an internal combustion engine is used, small amounts of NO_x emissions are also produced, as a result of the high engine temperatures.

Fuel cell vehicles are also over 50% more efficient than internal combustion engines (Mercuri et al., 2002). The low temperature chemical reaction providing the vehicle's energy has fewer losses than the high temperature process of combustion, with moving parts, friction and noise. Fuel cell vehicles operate almost silently, with noise only from auxiliary systems such as compressors (Hoffmann, 2001) and tyre noise. Eight major car manufacturers plan to introduce fuel cell vehicles by 2004-5 (Ogden, 1999).

Hydrogen is not a primary fuel, but an energy carrier, which must be produced using energy from another source. It can be produced from a wide range of sources by a number of different routes. Hydrogen could be produced from hydrocarbons such as coal, oil and natural gas, from biomass and wastes, or by electrolysis using nuclear, solar, wind, wave or tidal energy. This diversity of sources and production routes adds to security of supply.

Projects investigating and demonstrating the use of hydrogen as a vehicle fuel are in operation worldwide. The California Fuel Cell Partnership, established in 1999, and comprising 28 auto manufacturers, energy providers, fuel cell companies, government agencies and other interested groups works towards testing and promoting fuel cell cars and buses and a hydrogen infrastructure (CFCP, 2002). The Munich Airport hydrogen project, also opened in 1999, supplies hydrogen to cars and airport buses, from both hydrogen produced on-site, and delivered to it (H2MUC, 2002). The EU Clean Urban Transport for Europe (CUTE) project will include 3 fuel cell buses in London in 2003.

Interest in the potential for hydrogen as a vehicle fuel has led to considerable UK research on the development of a hydrogen infrastructure (e.g. Hart et al., 2000), and on the policy implications of a transition to hydrogen for vehicles (e.g. Foley, 2001).

1.3 Renewable hydrogen

While hydrogen vehicles have no tailpipe carbon dioxide emissions, the life cycle, or 'well-to-wheel' emissions are not necessarily zero. Production of hydrogen from the fossil hydrocarbons listed above results in carbon dioxide and potentially other pollutant emissions at the point of hydrogen production. Although life cycle emissions from the use of fossil-fuel derived hydrogen are likely to be lower than those from conventional petrol and diesel vehicles (Thomas et al., 2000), emissions could be reduced by the use of hydrogen produced using renewable energy. This is the focus of this study.

Hydrogen can be produced by electrolysis, splitting water into hydrogen and oxygen. If the electricity needed for this process were provided from renewable sources such as wind, tidal, wave, hydro, or solar energy, hydrogen could be produced with zero carbon dioxide emissions. If the energy needed to store the hydrogen, and transport it to the point of use were also provided from renewable sources, the hydrogen would be a truly zero carbon fuel. Hydrogen can also be produced directly from any biomass product, through gasification, followed by a series of chemical reactions to strip out the hydrogen. Carbon dioxide is released in this process, but this is offset by the carbon dioxide absorbed in replacement biomass growth.

Several projects have considered the feasibility of a renewable hydrogen economy, and others have begun to plan renewable hydrogen systems. Iceland announced in 1999 its intention to become the world's first hydrogen economy, with all hydrogen for transport produced from geothermal end hydroelectric energy resources. Similar feasibility studies have been carried out for other islands such as Hawaii, Utsire (Norway), and Vanuatu (Dunn, 2000) and even for transport demands in the US (Kruger, 2000). The CUTE project will use renewable energy from wind, solar and hydropower for refuelling stations in four European cities (Jones, 2002). Projects to produce hydrogen at renewable energy generating sites include the Urban Solar Hydrogen Economy Realisation Project (USHER), which includes a project in Cambridge, UK to produce hydrogen for fuel cell buses using electricity generated from a photovoltaic system.

Renewably produced hydrogen is identified in many UK strategies as being the future of transport fuels in the long term (PFV, 2002, EST, 2002, SMMT, 2001). However, the transition to hydrogen, and especially to renewably produced hydrogen is unclear. It has been suggested that natural gas-derived hydrogen would be a first step, allowing hydrogen infrastructure and experience to build up, followed by a transition to renewable production or carbon sequestration (Foley, 2001). Others argue that there will be no 'global fuel choice' at any time, with each region and application choosing the most appropriate fuel source for its situation (Dunn, 2000). Renewably produced hydrogen could have a role in UK hydrogen production in either of these scenarios.

This prompts several key questions: What renewable resources are available for the production of hydrogen in the UK? What production routes would be most suitable for supplying a growing hydrogen demand, both in terms of technical, economic and environmental benefits? And what are the implications of a move to renewable hydrogen for both renewable energy and transport policy?

1.4 Aims

This study aims to begin to address these questions, in order to determine the potential for renewable hydrogen as a transport fuel for the UK. A model for the costs of renewable hydrogen for vehicles along a number of defined 'fuel chains' covering production, storage, transport and dispensing of hydrogen is defined and explored. Costs for the manufacture and operation of hydrogen-powered vehicles have not been included in this study.

1.5 Objectives

To meet these aims, this study will:

?? Identify the range of renewable resources available for hydrogen production

?? Define generic fuel chains for hydrogen production

?? Determine the key technical, economic and environmental parameters needed to assess the fuel chains e.g. efficiency, capital investment, emissions etc as well as non-technical issues to consider, such as planning constraints

?? For each renewable energy resource, identify key technical, economic and environmental characteristics in relation to the fuel chain, including possible constraints to development

?? Consider the characteristics of other components of the chain, e.g. electrolysers, gasifiers, transport and storage technologies

?? Build a model including the key parameters for each stage of the fuel chain. Use the model to compare the chains principally in terms of cost per km driven

?? Use the model results and non-technical considerations to assess which fuel chains would be most viable for the UK, and therefore the likely overall potential for renewable hydrogen.

?? Explore the sensitivities and limitations of the model and identify areas of further research that would help to reduce uncertainties found.

2 Fuel chain introduction

2.1 Fuel chain modelling studies

Previous studies on routes for hydrogen production have tended to focus on production from non-renewable sources, such as steam reforming of natural gas, or electrolysis using non-renewable electricity, or to be specific to the US. Given the wide range of varying assumptions of demand level and distribution, as well as differing production routes, a detailed comparison of the fuel and infrastructure costs of production routes found from the literature is not included here. No detailed studies were found on large scale provision of renewably produced hydrogen for the UK.

Ogden (1999) considered five production routes for hydrogen production for passenger vehicles. These included steam reforming at a centralised facility, and forecourt systems for reforming and electrolysis. Hydrogen produced at the centralised facility was transported to the refuelling station by road, as a liquid, or in compressed gas pipelines. The cheapest method was found to be delivery of liquid hydrogen produced at a centralised facility, at $20-30 /GJ. Schoenung (2001) considered similar production routes, but also considered partial oxidation at the forecourt, and compressed gas delivery by road. The cheapest route was found to be delivery of liquid hydrogen produced at a centralised facility, at just under $20 /GJ. Thomas (1998) considered only forecourt hydrogen production, concluding that small-scale production from electrolysis or reforming provides a viable alternative to centralised production. This avoids the need for large infrastructure investment and allows adaptation to demand growth.

Fewer studies consider large-scale systems for provision of hydrogen from renewable sources. Mann et al. (1998) carried out a technoeconomic analysis of hydrogen production from wind, photoelectrochemical conversion of sunlight, photovoltaics and from biomass gasification and pyrolysis. An assessment of the costs of storing and transporting the hydrogen produced was also included, as this must be included in delivered costs to take account of the varying locations of different fuel chains.

Several papers also include a life-cycle assessment. Dante et al. (2002) considered the variation in carbon dioxide emissions per km driven for forecourt electrolysis and natural gas reforming. Berry (1996) concluded that CO_2 emissions would be lowest from hydrogen production by electrolysis, if renewable electricity were used. If this option were excluded, high efficiency petrol or natural gas vehicles would have lower emissions than vehicles run on hydrogen from natural gas. This was a result of the high energy demands of hydrogen storage (compression or liquefaction).

Spath et al. (2000) considered the economics of hydrogen production from biomass gasification at varying scales. Costs, not including storage and delivery, were found to be $9-21 /GJ. Biomass was considered to be an economically viable component for a renewable hydrogen economy if certain technical and economic uncertainties were reduced. Modelling by Hamelinck and Faaij (2002) also found production from biomass to be economically viable, with a hydrogen cost of $8-11 /GJ, projected to decrease significantly by 2020. Williams et al. (1995) gave delivered costs of $13.6 /GJ for biomass-derived hydrogen, and costs of travel of 1.58 US cents/km if used in a fuel cell vehicle. This was equal to costs of hydrogen from coal gasification. For comparison, travel costs from natural gas derived hydrogen were 1.38 US cents/km.

2.2 A UK focus

Figure 1 shows possible production routes for renewable hydrogen in the UK. There are several technology options available for each step in the fuel chains, each with different technical, economic and environmental characteristics. It would be possible to model the production of hydrogen using many combinations of these technologies, including many interactions between the fuel chains. However, here only those technologies that were considered to have the greatest potential for use in the UK to 2020 were considered, thus reducing model complexity and allowing a more in-depth study of the most viable options. Interactions between the chains, such as the ability of a renewable electricity generator to switch between hydrogen production and export to the grid, will be discussed where appropriate, but were not included in the model.

This study considers a short to medium term timescale, with the model focussing on the current status of the chains, and projections for 2020. Very few technology scenarios extend further than 2020, and there is little detailed work on projected costs beyond this date as a result of a wide range of technical, economic and policy uncertainties. Note that costs found from the literature were not financially adjusted to 2002 values, as details of the dates of each estimate were not always specified.

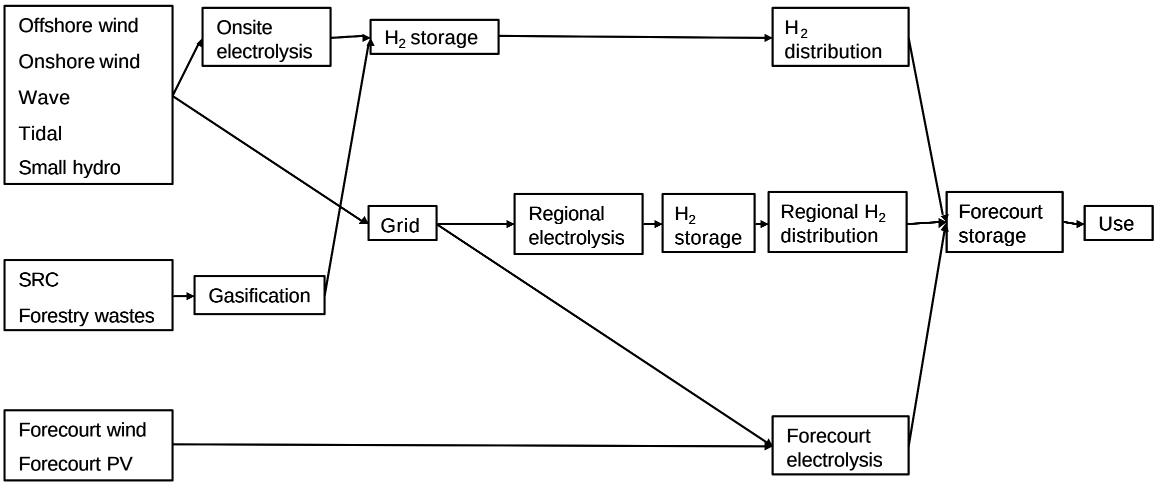


Figure 1: Web diagram of the fuel chains considered in this study.

3 Technology review

3.1 Introduction

The following section introduces options for each step in the chains and reviews their potential, technology readiness and expected technical development. Current and projected costs from the literature are included where available; alternatively the basis for preliminary modelling of costs is discussed. Non-technical issues such as environmental impacts and other policy goals are also included where significant.

3.2 Renewable electricity generation

The renewable technologies considered to have the greatest potential for electricity generation in the UK are wind, wave and tidal stream, building integrated photovoltaics and biomass energy crops (PIU, 2001h). However, studies have also considered the possible contribution from other technologies such as hydro, biomass from agricultural and forestry wastes, municipal solid waste and landfill gas (ETSU, 1998). The use of small hydro will also be discussed here, as it may have a greater potential for distributed hydrogen production than for grid export as considered above. The use of the other technologies to generate electricity will not be considered, as each of these inputs could be gasified and reformed to produce hydrogen directly. This is likely to be considerably more efficient than gasification and electricity generation, followed by electrolysis to produce hydrogen.

The potential contribution of renewable electricity generating technologies to the UK energy demand must be carefully defined. Here the terminology will be based on that used in the working paper on generation technologies prepared for the PIU Energy Review (PIU, 2001h).

The ***technical potential*** of a technology is defined as the amount of energy that could be extracted from the available renewable energy resource, using known technologies.

The ***practicable potential*** is given as the amount of the technical potential that can be extracted if limiting factors are taken into account. These generally include the exclusion of sites that are environmentally sensitive, needed for other uses such as shipping and defence, and constraints of the electricity grid. However, as in this study not all of the fuel chains involve grid connection of the generation site, here the practicable resource may not include connection constraints. This will be clearly defined for each technology.

The ***economic potential*** is the amount of practicable potential that is economically viable. This has been estimated from resource-cost curves, showing the practicable resource as a function of cost at a particular time-scale. The economic potential is then the potential at a cost lower than that of competing energy sources. This parameter is less relevant to this study than the technical and practicable potential, as it considers the economics of grid electricity generation alone.

These parameters give an indication of the potential for renewable electricity generation in the UK, but little information on the likely timescale over which they may be introduced. The timescale for increase in capacity, and the proportion of that capacity available for hydrogen production, is likely to be as dependent on market and policy factors as on technical constraints. Capacity projections are therefore given only as an indication of the relative speed of development and deployment of the generation technologies, for comparison with development of hydrogen systems.

Projected costs of renewable electricity vary widely between studies, given the differences in assumptions of resource, technology and market trends, and the very limited market data on many of the technologies discussed here. Where available, data from the PIU working paper on generation technologies (PIU, 2001h) is used, as this uses a learning curve model to supplement an engineering assessment approach, thereby including the effects of innovation and market development. All costs include grid connection.

It must also be noted that all projections for renewable electricity generation are made for the present electricity market and policy framework. As discussed in section 7.1 the possible interaction of development of renewables capacity needed to generate hydrogen with renewables capacity for the electricity mix is not yet known.

The scale and likely location of generation are considered to allow construction of a generic supply framework (see section 4) to illustrate the effect of these parameters on costs and efficiencies of energy conversion, transport and storage.

3.2.1 Onshore wind

Introduction

Onshore wind turbines for grid connected power generation have a range of power outputs, generally from 600 kW to 2MW. Most planning consents in 2000 were for wind farms with 1.5-2 MW turbines (BWEA, 2000). They are usually grouped in farms of around 20 turbines, with typical outputs of up to 34 MW. Smaller turbines of up to 100 kW have also been used for offgrid applications. Here three scales of onshore wind output will be considered:

- Large scale: 60 MW. This represents the largest wind farms currently planned in the UK, such as that approved for Cefn Croes, Wales (BWEA, 2002).
- Medium scale: 10 MW. There are currently a large number of smaller sites in the UK with 3-10 turbines that could provide distributed generation at this scale.
- Forecourt generation: 2 MW. This represents a single onsite wind turbine, such as the 1.5 MW Ecotricity turbine on the outskirts of Swaffham, Norfolk, with output dedicated to onsite electrolysis.

Technology development

Onshore wind power is an established technology, with a worldwide capacity of over 20 GW (PIU, 2001h). Total UK wind generating capacity is 473.6 MW, giving an annual electricity production of 1.24 TWh (BWEA, 2001).

As the market has grown, there has been a trend towards increased turbine size and decreased capital costs. There is volume production in the EU of turbines in the 600 kW range, but megawatt scale machines in several designs are also commercially available (EWEA, 1999). Continued improvement in turbine power rating, reliability and lifetime is expected in the medium term (ETSU, 1998).

The capacity factor of a wind turbine relates the annual output to the rated output, taking account of the intermittency of the wind, the availability of the turbine, and array connection losses. The annual average capacity factor for UK onshore wind turbines is 0.313 (BWEA, 2002). A value of 0.3 was used in the model for 2002, with a future expected value of 0.4 (OXERA, 2001) to take into account improved reliability and wind farm design.

Potential

The technical potential for onshore wind energy, defined as the total feasible resource minus areas of increased environmental impact and green belt land, was estimated in 1998 to be 317 TWh/yr (ETSU, 1998). This is greater than the total electricity demand for the UK in 1998, of 300 TWh/yr. However, the ETSU study then considered constraints due to planning and the existing electricity network, which reduce the practicable potential to 8 TWh/yr. The major reductions from the technical potential occur in Scotland and Northern Ireland, primarily where electricity network connection is a not available. This would be of concern for the fuel chains with grid output, but would not be a constraint for on site electrolysis.

This practicable potential has been considered to a reasonably conservative estimate, with several subsequent studies estimating greater outputs even by 2010. The British Wind Energy Association notes that in order to generate 26% of the 10% renewable electricity target for 2010, as suggested by the DTI 'High wind' target, an annual output of 9.9 TWh would be needed (BWEA, 2000).

The total contribution to renewable electricity generation by 2010 estimated by summing regional renewable energy targets is also greater than 8 TWh/yr (OXERA, 2002). Under a low wind output scenario, the total contribution is 9.4 TWh, while under the high scenario a total of 11.9 TWh would be generated. The low scenarios generally assume a business-as-usual approach, while the high scenarios a more supportive planning system.

Scenarios modelled for the PIU review have highest practicable capacity values of 10 GW, equivalent to 26 TWh/yr (OXERA, 2001b). These assume a favourable development system, including minimal planning constraints and fast technological progress leading to rapidly reducing costs. The study concludes that the limiting factors in development of onshore wind are principally the speed of planning approval, new network connection and the allocation of subsidies where applicable.

Regional distribution

Onshore wind provides a large contribution to regional targets in Scotland, the West Midlands, the East of England, Wales and the North East (Oxera, 2002). In Scotland, the estimated output is over 3.3 TWh/yr, whilst each of the other regions mentioned have scenarios with contributions of over 1 TWh/yr.

Cost projections

Electricity generated from onshore wind currently costs 2.5-3p/kWh in good wind speed sites. The cost is expected to fall to 1.5-2.5p/kWh by 2020, and less than 2p/kWh in good wind speed sites, making it the cheapest of all generating technologies (PIU, 2001h). There is good evidence for this level of cost reduction, given learning curve analysis and experience with market growth, provided that new build rates do not decline.

Capital costs under a medium cost scenario are estimated to be £600/kW (OXERA, 2001). Future capital costs have been estimated by scaling with the expected electricity cost reduction.

Environmental impacts

Environmental impacts of wind farms in operation are limited to their visual impact and noise. Local opposition to wind farms on grounds of these factors can affect planning decisions (see below). It should be noted that the noise levels from wind turbines have decreased significantly with improved turbine design and wind farm siting, such that noise is considered to no longer be a nuisance (DTI, 2001). Wind farms have also been integrated into the landscape more effectively, giving a smaller area of visual impact.

The energy payback time for an average UK wind farm is three to five months (BWEA, 2002). Decommissioning wind turbines involves removal of the turbine, and burying or removal of the concrete base, with no land contamination or other adverse effects (ETSU, 1998).

Other barriers to development

Onshore wind development has several barriers to rapid achievement of its full potential. The most significant of these are considered to be planning and electricity network constraints (BWEA, 2001, ETSU, 1998).

Obtaining planning consent for onshore wind energy projects is more problematic than for most other renewable energy projects. It has been suggested that this may be due to efforts to site projects in the most economically viable areas of high wind speed and good grid connection, as opposed to those with lesser visual impact and therefore less local opposition. This may be true in some cases, but it is now thought that a more overriding problem is a lack of planning guidance (BWEA, 2001, OXERA, 2002). Regional renewable energy targets from the recent regional renewable energy assessments have been included in regional planning guidance (RPG) in some regions. Reviewed RPGs for all areas are expected to be in place by 2003/4, providing a more positive framework for renewables development (OXERA, 2002). This will enable local authorities to provide supplementary planning guidance on siting for renewables developers. It was also advised that public awareness raising of the benefits of renewable energy would increase acceptance of projects.

A second constraint to this technology is the electrical distribution network. The network has limits to its physical capacity, and reinforcement to cope with new embedded generation may be a cost barrier (ETSU, 1998). A restriction for network availability has been taken into account in Scottish, Welsh, West Midlands and Northern Irish regional assessments, which have still estimated a large contribution from onshore wind.

There are concerns about the detrimental effect of the New Electricity Trading Arrangements on intermittent generators, which the BWEA sees as a disincentive to investment in wind energy (BWEA, 2001). Interference with radar communications has also been seen as a possible barrier (ETSU, 1998).

3.2.2 Offshore wind

Introduction

Offshore wind is an attractive electricity generation option given the higher wind speeds and larger available area than for onshore projects. Turbines offshore can be larger and have faster tip speeds than those onshore, due to reduced constraints on visual intrusion and noise. Current offshore wind projects use turbines with ratings of 450kW-2MW, with total capacities of 2-20 MW (OWF, 2002). Typical future developments are expected to use turbines of 2 MW or larger, with thirty turbines per development, in groups of one, two or three sites (OWF, 2002).

Here, one scale of offshore development will be considered, with a single development of thirty 2 MW turbines. The majority of sites identified by the Crown Estate are for a single development of this type.

Technology development

Offshore wind generation has been in operation in Denmark since 1991, and there are currently 8 offshore projects world-wide, one sited at Blyth in the UK. The total installed capacity is 80.4 MW (OWF, 2002). Offshore turbine technology is a development of onshore technology, and therefore benefits from experience in this area. 'Marinised' versions of onshore turbine technology are currently used, which have been modified to allow for the more corrosive marine environment and increased wind and wave loading. As many onshore turbines are designed for operation in a coastal atmosphere, little additional marinisation of the turbine itself is necessary for offshore operation (EWEA, 1999). However, the turbine tower must be strengthened to allow for wind and wave loading, and there are more stringent requirements for reliability. Monopile foundation structures and undersea cabling for grid connection are mature technologies, however there is scope for continued improvement in foundation design with respect to interactions between loadings (PIU, 2001h).

Improvement in offshore technology will be made from the use of more specific offshore designs, exploiting the ability for larger sizes and tips speeds (and so greater efficiency) and designed for greater reliability and lower maintenance needs. However, the capacity factor has not been projected to increase significantly above the current value of 0.4 in the medium term. There is also scope for weight and cost reductions as the turbines may be able to exceed onshore noise restrictions (EWEA, 1999). However, there may also be greater technical challenges resulting from the move to deeper waters and less suitable sites after the most favourable sites are developed.

Potential

The technical potential for offshore wind in the UK was estimated at around 3,500 TWh/yr (PIU, 2001h), over ten times the current UK electricity demand. This includes turbines in all waters at a suitable depth and distance from shore, and turbines rated at 1.5 MW. When areas with unsuitable seabed composition or grid connection and those so close to the shore as to cause visual disamenity were excluded, this figure was reduced to 100.18 TWh/yr (ETSU, 1998). This is nearly a third of the current UK electricity demand, however is considered to be conservative in comparison with other studies, which exclude less of the total accessible resource, and consider sites in deeper waters (PIU, 2001h). For example, an EU study considering a maximum distance of 30 km offshore, a maximum water depth of 40 m, and a maximum average wind speed of 10 m/s gives the UK potential as 986 TWh/yr (Border, 1998).

Summing regional targets for offshore wind generation by 2010 gives outputs of 2.6 and 5.2 TWh for low and high scenarios respectively (OXERA, 2002). Under the high scenario, a further 3.5 TWh is added for offshore development in Scotland, which was not included in the regional targets, making the total 8.7 TWh. Offshore wind generation has a large potential in Wales and the East of England, with projected output of 1.6 and 1.3 TWh/yr respectively (OXERA, 2002). As with onshore wind, each region has made different assumptions regarding excluded areas, and also wind speed, water depth and distance from the shore.

Cost projections

Offshore wind developments coming into operation in the period 2002-2005 are expected to generate electricity at costs of around 5.0-5.5p/kWh (PIU, 2001h). This is expected to fall to 2-3p/kWh by 2020. Several market and technology projections give costs at the lower end of this range (PIU, 2001h). These projections are relatively uncertain as world experience with offshore wind is limited. Also, cost trends are affected by technology development and market growth but also by the increasing engineering problems of moving further offshore, as the best sites are developed.

The capital costs of offshore wind were estimated to be £1000 /rated kW for a medium cost model for the PIU Energy Review (OXERA, 2001). Future capital costs have been estimated by scaling with the expected electricity cost reduction.

Environmental impacts

Offshore wind turbines at a distance of more than 1-2 km offshore do not have the problems of visual intrusion and noise seen with onshore turbines. However, there have been concerns as to the effect of their installation and operation on migratory birds and marine wildlife. The effects of an offshore wind farm will be heavily site specific, and should be taken into account in an environmental impact assessment, however, some general conclusions have been seen. No detrimental effects on birds are expected if wind farms are sited away from migration paths or large bird population concentrations (ETSU, 2000). Vibration disturbance from installation of the turbine foundations can be assessed and mitigated, for example, by installation outside the breeding season of local fish and marine mammals. Impacts during operation are not well characterised; further monitoring is needed if turbines are to be installed in areas of importance to particular marine species (ETSU, 2000).

Other barriers to development

The use of offshore areas for wind farms could cause conflicts with other interests such as fishing, military activities navigation, marine conservation areas and marine archaeology. These effects can be reduced by full consultation with local users and the MoD, which may add time to the planning process.

Network reinforcement to allow for increased offshore generation may be needed in the North of England and Scotland, however there is potential for increased generation off the East and South-East of England and off South Wales without extensive reinforcement (ETSU, 2001c).

The siting of offshore wind farms will involve significant consultation (see above), however the planning process itself may be faster, due to reduced objections to visual intrusion (ETSU, 2001c). The DTI is currently preparing guidance notes for developers, and reviewing the procedure for obtaining the multiple planning consents needed for offshore generation, with a view to providing a more streamlined system, whilst ensuring full consideration of local and conservation concerns (DTI, 2002a).

3.2.3 Wave

Introduction

Wave energy devices can be sited at the shoreline, in nearshore areas, or offshore, and there are a wide variety of different devices for electricity generation in each category. Electricity is generated by using either the mechanical motion of the waves, or changes in fluid pressure within the device. A huge range of wave energy devices have been considered, with significant R&D efforts concentrated on the technology since the 1970s. The use of wave energy to generate hydrogen by electrolysis for transport and other uses has already been considered for the island of Islay (Wavegen, 2002).

The wave energy development considered in this model will represent a cluster of offshore devices, with a total rated output of 30 MW. This is due to the increased offshore resource (see below). As a result of the early stage of development of offshore devices, wave energy fuel chains will be considered only for 2020.

Technology development

The principal type of device used on the shoreline is the Oscillating Water Column (OWC), a partially submerged device that uses the movement of a column of air to drive a turbine. A 75 kW OWC operated for ten years in Islay, Scotland (ETSU, 2000b). The OSPREY near-shore device also includes an OWC, together with the possibility of a wind turbine (ETSU, 1998). In general, shoreline and nearshore devices are at the pilot stage, and are not yet commercially competitive.

No consensus has been made on the best offshore technology, and none have become commercially available. Under the third round of the Scottish Renewables Obligation, two offshore schemes were chosen. The first uses two 375 kW floating Pelamis wave energy converters and the second a 400 kW floating wave power vessel (HCSTSC, 2001). Offshore designs are still at the research and development stage (ETSU, 2000b), and therefore there is little experience of their use, or data on costs and performance. The capacity factor needed for the model was calculated from the average annual outputs of offshore technologies given in ETSU 1998.

Potential

The technical potential for wave energy is estimated at over 600 TWh/yr, principally in offshore locations, but with some potential for shoreline and nearshore technologies (ETSU, 1998). When areas with uneconomically low wave power levels, environmentally sensitive areas, shipping lanes and Ministry of Defence areas are excluded, and technical considerations such as efficiency are taken into account, this potential is reduced to around 50 TWh/yr.

	Technical potential (TWh/yr)	**Practicable potential (TWh/yr)**
Shoreline*	~2	0.4
Nearshore	100-140	2.1
Offshore	600-700	50

DTI 1998 *Only for the most favourable locations - greatly underestimates the true resource

Regional renewable energy targets estimate a negligible contribution by 2010; marine technology (wave and tidal stream) has a projected output of 0.2 TWh/yr in the high scenario, in the South West and Wales only (OXERA, 2002).

Cost projections

The practicable resource of 50 TWh/yr given above is the economic resource at less than 4p/kWh in 2025 (ETSU, 1998). The cost projections are based on 4 specific devices, representing shoreline, nearshore, offshore modular and offshore large scale technologies. These devices were not those that could produce electricity most economically, but those about which there was most information available. Costs include connection to the nearest suitable part of the transmission network.

The resource cost curves in ETSU (1998) show that the bulk of the resource will be available at a cost of 3-4p/kWh. These costs will be used for the future costs of offshore devices, as no more specific data were available. These are likely to underestimate the costs, as the resource cost curves include the more commercially developed shoreline and nearshore devices.

Capital costs used in the model for 2020 were the average capital costs of offshore technologies from figures given in ETSU (1998). Given the lack of information on these technologies, projection of these costs to 2020 would have been uncertain.

Environmental impacts

There have been concerns as to the effect of construction and operation of wave energy systems on marine flora and fauna, and on coastal erosion. The influence of wave energy devices on waves, tides and currents is thought be generally benign (ETSU, 1998). Noise from wave devices has been considered to be unlikely to affect marine mammals, though for nearshore devices must be minimised by design to avoid an amenity impact. Installation of the devices, support structures and undersea cables, however, will result in species loss on the seabed, may disturb marine mammals and may have a visual impact. These effects can be minimised by careful site selection, ensuring that sites considered have no rare or endangered species (ETSU, 1998)

Other barriers to development

There may be some conflicts of interests with other sea use, such as shipping. This could be a particular problem with wave devices as they would be difficult to detect by eye or by radar, so would have to be clearly marked (Thorpe, 1999).

As with all offshore technologies, the availability of suitable grid connection and the initial cost of connection may be a barrier.

3.2.4 Tidal stream

Introduction

Tidal stream units generate electricity by using the energy from current resulting from tidal movement to turn a rotor, similar to a submerged wind turbine. The velocity of these currents can be magnified by geographical features such as straits between islands, making these the most suitable locations. This is not the same as tidal barrage technology, which generates electricity from the flow of water stored behind a barrage back into the sea. As the motion of the tides can be predicted accurately, the energy output from tidal energy is intermittent, but predictable.

Here, a cluster of tidal stream devices will be considered, with a total rated output of 25 MW. The current technology is represented by data for horizontal axis devices, while for 2020, data based on vertical axis turbines is used, as these are expected to produce electricity more cheaply (ETSU, 1998).

Technology development

Tidal stream energy is still at the prototype stage, with only small experimental devices in the 5-10 kW range (ATLAS, 2002). A number of device designs have been proposed, and it is not yet clear which of these may be most successful (ETSU, 2001) The first prototype larger scale device, the 150 kW 'Stingray' hydroplane prototype is shortly to be installed in Shetland (DTI, 2002). Subject to the outcome of this trial, a cluster of devices may be installed by 2004. Commercial designs may generate up to 500 kW and be installed in groups of many devices. A JOULE project has proposed a tidal stream farm with a total rated power of 25 MW between mainland Italy and Sicily (ATLAS, 2002).

Current designs are commonly based on horizontal axis turbines or hydroplanes. Development of vertical axis turbines with variable pitch blades would allow use in shallower water sites (ETSU, 2001) and lower installation costs (ETSU, 1998). Annual energy outputs for tidal stream devices were based on those given for horizontal axis devices for 2002, and for vertical axis devices for 2020 (ETSU, 1998).

Potential

The potential tidal stream resource for the most suitable sites in the UK is estimated to be 36 TWh/yr (ETSU, 1998). This figure is the potential from 6 areas, and allows for shipping routes and turbine density. The actual resource is higher but the current velocities in the remaining areas were considered to be so small as to be 'hopelessly uneconomic'. The practicable potential is then given as 1.9 TWh/yr, the economic potential at under 7p/kWh.

A more recent review estimated the potential at between 31 and 58TWh per year (ETSU, 2001). Although most of this resource is in remote areas, 10 TWh/yr could be generated from shallow water sites near to high demand for power.

Very little deployment of tidal stream energy is expected in the UK by 2010; projected values range from zero (OXERA, 2002, ATLAS, 2002) to 0.7 TWh/year (ETSU, 1998).

Cost projections

The overall cost of tidal stream energy is in the range 4 p/kWh to 14 p/kWh including grid connection (Trapp, 2002). By 2020, the cost of electricity from vertical axis turbines has been estimated at 3-7 p/kWh (ETSU, 1998).

Capital costs for 2002 were taken as the average capital costs of horizontal axis technologies from 1998 figures (ETSU, 1998). Capital costs for 2020 were taken as the average capital costs of vertical axis turbines given in the same source. These costs assume a mature technology, which is already close to the theoretical maximum efficiency, and include economies of scale, so capital costs are not expected to fall in the future.

Environmental impacts

The precautions described above for the installation of other marine technologies such as assessment of the local area and timing of installation must also be taken for tidal stream devices. There are no known problems with collisions between fish and mammals and the devices, and the turbines rotate very slowly (ETSU, 1998). Further research is needed on this effect, and on the impact of tidal turbines on tidal flows, the seabed and fishing areas (ETSU, 2001).

Other barriers to development

The planning process for tidal projects may be slowed by consultation, as many of the areas identified are sites of high landscape value, and therefore there may be opposition to the onshore transmission works needed.

As with all offshore technologies, the availability of suitable grid connection and the initial cost of connection may be a barrier.

3.2.5 Small hydro

Introduction

Small hydro schemes are classified as those that have a rated output of less than 5 MW. Here a single 5 MW small hydro scheme is considered. Larger schemes have been excluded, as there is no unexploited large hydro resource in the UK (ETSU, 1998).

Technology development

Hydroelectric power is a mature technology, with no significant technology development expected. Capacity factor for small hydro schemes range between 40 and 60% (ETSU, 1998).

Potential

Very small hydro sites are generally not commercially viable due to the high cost of associated civil engineering works and grid connection. The economic potential at less than 10 p/kWh is estimated at 550 MW or 1.6 TWh/yr (8% discount rate over 15 years).

Cost projections

Prices for small hydro capacity contracted under NFFO-5 were 3.85-4.35 p/kWh. The range of costs has been estimated to increase to 2-7 p/kWh by 2020 (ETSU, 1998). The increased maximum cost may be due to the most profitable sites being exploited first. The potential in this cost range is 1.8 TWh/yr.

Hydro schemes have high initial costs, then very low costs in operation. The capital cost of schemes with a 3-400m head on green-field sites is £1000-2500 (ETSU, 1998)

Environmental impacts

Hydro schemes at any scale have impacts on the ecology of the watercourse both up- and downstream. Changes in flow rate can affect river ecology and any flow obstruction may affect migratory fish. This can be mitigated by careful design (PAN, 2002), though may lead to constraints in protected areas and a lengthened planning process.

Other barriers to development

Most potential small hydro sites are relatively remote, and therefore grid connection can be a large capital cost barrier, especially given the low output of the technology.

3.2.6 Building-Integrated Photovoltaics

Introduction

Photovoltaics (PV) can be used to generate electricity as stand alone units, grid-connected systems, or when integrated into building materials (BIPV). Large scale PV systems are not considered to be feasible for the UK, due to relatively low insolation, and constraints on land use. Therefore BIPV has been considered to be the only significant commercial PV market.

Building integrated photovoltaic units provide electricity and also act as construction materials. PV can be integrated into roofing tiles, facades, cladding and shading materials, or mounted on the building as a separate unit. The advantages of this technology include the ability to be used in urban areas, highly distributed, modular generation and low maintenance needs.

A 300 kW_p BIPV scheme will be considered here. This will be sited at and around the forecourt, with output dedicated to hydrogen production. This is of comparable scale to the USHER solar hydrogen project in Cambridge. The area of PV necessary is approximately 3000 m^2, depending on the PV technology used.

Technology development

Established photovoltaic technology consists of mono- or polycrystalline silicon photovoltaic cells, connected to form modules with efficiencies of 12-15%. Newer thin film technologies use deposited layers of other semiconducting materials to form PV modules directly. Thin film PV modules are currently less efficient than crystalline modules, and therefore require a larger area for the same energy output. However they have several advantages: they are more easily integrated into building materials, use smaller amounts of expensive semiconducting materials, and have the potential to be made in a continuous process.

It is not yet known whether one PV technology will be dominant in the future. The efficiency of whichever technology is used is likely to have increased. A range of efficiencies of 15-22% for commercially available modules is expected by 2010 (Giroult-Matlakowski et al., 1998). PV outputs are generally calculated from their efficiency and site insolation. The 'capacity factor' used in the model for PV has been calculated from the annual outputs of several PV systems (ETSU, 1998, USHER, 2001). The future 'capacity factor' was scaled with the increase in mean efficiency of the modules.

Potential

The technical potential for BIPV is estimated to be 266 TWh/yr in 2025 (ETSU, 1998). This was calculated using a model to predict the electricity that could be generated from placing PV panels on all domestic and non-domestic buildings. When new build rates and the possible rate of PV uptake in new buildings are considered, the practicable potential is reduced to 37 TWh/yr (ETSU, 1998). The electricity generated from this distribution of BIPV modules could be output to the grid, and then electrolysis used to generate hydrogen at varying scales as with the other renewable generating technologies. However, those installing BIPV are likely to use the electricity generated to supply the needs within the building, with little available for grid export.

In order to estimate the potential contribution of forecourt PV to generation of hydrogen in the UK it would be necessary to estimate how many sites would be suitable for this kind of development, having the required space and insolation. This is beyond the scope of this project, as each development would have to be considered on a site-specific basis.

Note that the cheapest technology in the future may not be the most efficient. It may therefore be cheaper to achieve the same output with a large area of more inefficient PV. This may reduce the number of sites with enough space for a system of this type.

Cost projections

The cost of PV is projected to fall from the current value of around 70 p/kWh to 10-16 p/kWh by 2020 (PIU, 2001h). Note that this is based on the historic learning rate for the technology, and therefore does not allow for the significant cost reductions that may result from thin film modules or future innovative PV materials. This longer-term trend in innovation is projected to lead to a potential cost reduction to 6–10p/kWh by 2025 (PIU, 2001h).

The average price for PV modules was $3.46 per peak watt in 2000 (£2260 /kW_p) (EIA, 2000). The future capital cost was found by scaling this value with the decrease in maximum cost per kWh.

Environmental impacts

Photovoltaics have no environmental impacts in operation. Fthenakis and Moskowitz, (2000) present a detailed review of health and environmental hazards posed by photovoltaic materials and the chemicals used in their processing. It was concluded that the risk of harm from these hazards can be managed by careful handling and disposal/recycling of materials used. Problems of resource depletion of the semiconducting materials are thought not to be significant unless one thin film PV technology were to be used to provide a significant proportion of the worlds electricity demand (Alsema et al., 1999). The energy payback time of roof mounted PV systems is currently 2.5-3.5 years; this is expected to decrease to 0.5-1.5 years by 2020 with decreased energy use in manufacture (Alsema, 2000).

3.2.7 Summary of model input data

Technology	Time	Capacity factor	Cost (p/kWh) Low	Cost (p/kWh) High	Capital cost (£/rated kW)	Resource (TWh/yr)
Onshore wind	2002	0.3	2.5	4.6	600	26
	2020	0.4	1.5	2.5	360	26
Offshore wind	2002	0.4	5	5.5	1000	986
	2020	0.4	2	3	400	986
Wave	2002	-	-	-	-	50
	2020	0.37	3	4	1525	50
Tidal	2002	0.23	4	14	1300	36
	2020	0.21	3	7	650	36
Small hydro	2002	0.5	3.85	4.35	1750	1.6
	2020	0.5	2	7	909	1.6
PV	2002	0.1	-	70	2048	Not included
	2020	0.13	10	16	306	Not included

Table 1: Model input data for renewable electricity technologies. Note that a wave energy-based fuel chain was not included for 2002.

3.3 Biomass production

3.3.1 Energy crops

Introduction

Energy crops are those grown specifically for use as a fuel. They can be grown when and where needed, and can be stored, and so do not suffer the problems of intermittency and unpredictability of many other renewables. Although carbon dioxide is released when the harvested crops are combusted or gasified, this is considered to be carbon neutral as carbon was absorbed during crop growth.

The energy crop considered here is short rotation coppice (SRC) of willow. This crop is included in the Energy Crops Scheme, introduced by DEFRA in 2000 in partnership with the Forestry Commission (DTI, 2002b). SRC is perennial, thus minimising energy and fertiliser inputs (ETSU, 1998). The scale of the SRC scheme used will be equivalent to that needed to power a 30 MW_e integrated gasification and combined cycle electricity generation plant, as this scale is thought to be feasible for local generation in the UK (ETSU, 1998)

The potential for miscanthus, a perennial grass will also be discussed, however will not be included in the model due to lack of commercial experience and therefore input data.

Development

The first commercially grown SRC in the UK provides fuel for the ARBRE gasification and electricity generation project in Eggborough, Yorkshire, and covers 2,000 ha (Bauen, 2001a). There is wider experience world-wide, for example in Sweden, where 18,000 ha of willow SRC are grown for district heating (ETSU, 1998). The SRC is grown on a rotation of 2-4 years, with current typical yields in the UK of 10 oven dry tonnes per hectare per year (odt/ha/yr) (Bauen, 2001a). Yields are expected to increase to 15-20 odt/ha by 2020/25 (DEFRA, 2002a, ETSU, 1998). Better plant husbandry, variety selection and breeding are also expected to increase disease resistance and biological stability (ETSU, 1998).

Miscanthus is a tropical grass, non-native to the UK, that can produce higher yields than native plants if planted in the South of the UK (ETSU, 1998). It has been more widely studied than other grasses, but has not yet been widely used on a commercial scale. As the equipment needed to harvest, store and transport miscanthus are similar to those used for SRC and the calorific value of the crops also similar, the modelling carried out for SRC could be easily modified for miscanthus in a further study if required.

Potential

The area of land available for future energy crop production has been estimated at between 1 and 5.5 Mha (Bauen, 2001a). This is surplus agricultural land, such as set-aside land, which is not needed for food production, from a total of 18.5 Mha agricultural land. The more realistic estimates are thought to be at the lower end of this range (Bauen, 2001a, ETSU, 1998).

If between 5 and 20% of the arable land (0.9-3.7 Mha) were used for energy crops with yields of 15-20 odt/ha/yr the available energy crop resource would between 3 and 16 Modt. If 25% (close to 5 Mha) of land were used, a resource of between 70 and 93 Modt would be available (Bauen, 2001b). The switch of land use to energy crop production will depend on additional margins per hectare of energy crops over other uses, and also on a wide range of other policy aims, such as agrienvironmental and rural development.

Regional renewable energy assessments show the largest contribution of biomass (including energy crops, agricultural and forestry wastes) to electricity generation in the South West and in Yorkshire and the Humber, with significant contributions in the East of England, East Midlands, North West, South East and Wales. This shows that biomass energy production is viable at a regional level; for this reason transport distances considered for biomass hydrogen are lower than those for the more remote renewable electricity generation technologies (see section 4.6).

Cost projections

In the short-term, woody energy crops could be produced at a cost of about £1.70 /GJ, assuming a 10 odt/ha/yr yield and excluding transport costs (Bauen, 2001b). The future costs of energy crops will depend heavily on grants, as well as support under the Renewables Obligation (OXERA, 2002). For example, the DEFRA Energy Crops scheme and Capital Grants scheme include SRC and miscanthus, but to be eligible, the crops must be grown for power generation, combined heat and power or heat production. Given that no significant developments in SRC production technology are expected between now and 2020, these costs were also used for the 2020 fuel chains. Establishment costs for SRC schemes are around £890 /ha (Bauen, 1999).

Transport costs used were from an SRC scheme evaluated in Bauen (1999) as £0.2 /GJ. The transport distance for this scheme was 24-33 km one way, which was comparable to the 19-24 km distances modelled here. The costs were not scaled, as the relationship between costs and distance for road transport is non-linear, and there would be very low marginal costs for additional kilometres travelled.

Environmental impacts

The energy ratio, defined as the energy content of the SRC crop divided by the total non-renewable energy needed to produce and transport it, is approximately 20 (Bauen, 2002, DEFRA, 2002a). This energy input includes energy used in manufacture of fertilisers, fuel for agricultural machinery and transport etc. The CO_2 emissions from energy used in production and transport were calculated using data given in Bauen (1999). The transport values were scaled for the average transport distance from the area of SRC used, using a land use factor of 5% and a tortuosity factor of 1.3.

SRC is thought to cause little environmental damage if sited in an appropriate location (ETSU, 1998). It requires few herbicides and pesticides, and can increase biodiversity if sited on agricultural land. There have, however, been concerns about water use by energy crops. Stephens et al. (2001) modelled the effects on hydrology of a change from winter wheat or permanent grass to energy crops, including willow SRC. This study found that the reduction in hydrologically effective rainfall could have serious consequences for water resources in drier areas of the country, such as in East Anglia, but may be beneficial in areas prone to flooding. It was concluded that evaluation of the size and sensitivity of the catchment areas should be investigated when siting energy crops.

Other barriers to development

The switch of land use to SRC, specifically the switch to SRC for gasification and hydrogen production will be heavily dependent on agrienvironmental and rural development policies both at the UK and EU level. The Energy crops scheme is part of the wider England Rural Development programme, drawn up in line with Agenda 2000 Common Agricultural Policy reforms to support the environment and the rural economy.

3.3.2 Forestry wastes

Introduction

Relatively dry combustible materials such as forestry wastes, straw and poultry litter can be dried and gasified in the same way as energy crops.

Here forestry wastes will be considered, at the same scale as for SRC, as an example of a waste material for gasification. The potential resource for this material is not extensive (see below), however the material is currently available, and could be an important input in the transition to other biomass inputs. Due to the small available resource, and the ability to use the same conversion technologies for energy crops and forestry wastes, schemes using forestry wastes as fuel initially are expected to use an increasing proportion of energy crops in the long term (ETSU, 1998).

Development

Forestry wastes consist of wood thinnings from managed forests and branches and other material discarded when trees are felled for timber. Final harvesting typically takes places every 80 years. The yield of forestry wastes averages out to around 1.5 odt/ha/yr (Bauen, 1999), with an energy content of 19 GJ/odt irrespective of species (ETSU,1998). Research has been carried out on improved techniques for the removal and processing of forestry wastes; development in this area has led to a yield of 2 odt/ha/yr being used in the model for 2020 (Bauen, 2002).

Potential

Currently 4 Mt of residue material is left in managed forests every year (Bauen, 2001a). Not all of this can be removed, as the residues form a ‘brash mat’ on the forest floor, protecting the soil from compaction during harvesting and adding nutrients (ETSU, 1998). It has been estimated that 1.4 Modt of this material could be removed and used (Bauen, 2001a) and that the forestry waste resource may increase to 1.7 Modt by 2013 (ETSU, 1998).

Cost projections

Forestry residues are expected to be available at a cost of around £1.75 /GJ. (Bauen, 2001b). These costs were also used for the 2020 fuel chains as no significant cost reduction in harvesting cost is expected.

The establishment cost of forestry residues schemes are difficult to quantify, as they are a waste material. This was estimated at £570 /ha on the basis of costs per unit product given in Bauen (1999) together with the yields and harvesting time given above.

Transport costs used were from scheme evaluated in Bauen (1999) as £0.3 /GJ. The transport distance for this scheme was 38 km one way, which was comparable to the 52-60km distances modelled here.

Environmental impacts

The energy ratio of forestry waste production and transport is approximately 15 (Bauen, 2002). The CO_2 emissions from energy used in production and transport were calculated using data given in Bauen (1999). The transport values were scaled for the average transport distance from the area from which the forestry wastes were collected, using a land use factor of 5% and a tortuosity factor of 1.3.

3.3.3 Other direct inputs

Hydrogen could also be produced directly from the gasification of municipal solid waste (MSW) or sewage solids, from landfill gas, or from the anaerobic digestion of wastes such as sewage, poultry litter and farm slurries. Each of these sources is distributed, and therefore could provide valuable local generation if small-scale conversion technologies were available. Use of these wastes may also contribute to other policy goals, such as improved waste management and pollution abatement.

Investigation of the potential for hydrogen from these sources would be valuable, but was not possible during the timescale of this project.

3.3.4 Summary of model input data

	SRC		Forestry wastes	
Time	2002	2020	2002	2020
Yield (odt/ha/yr)	10	15	1.5	2
Energy content (GJ/odt)	19	19	19	19
Cost (p/GJ)	170	170	175	175
Transport cost (pGJ)	20	20	27	27
Establishment cost (£/ha)	890	890	570	570
Energy ratio	20	20	15	15
Production CO_2 (t/GJ) $x10^{-3}$	5.2	5.2	1.7	1.7
Transport CO_2 (t/GJ/km) $x10^{-3}$	0.055	0.055	0.024	0.024

Table 2: Model input data for biomass production. The energy ratio of a biomass product is equal to its energy content, divided by the total non-renewable energy input to its production e.g. fertilisers, transport fuel etc.

3.4 Electrolysis

An electrolyser uses an electric current to split water into hydrogen and oxygen. A current is passed between two electrodes in an ionically conducting electrolyte, separated by a diaphragm, and hydrogen generated at the cathode. Most renewable energy to hydrogen projects have considered the use of an alkaline electrolyser, the most common technology. However, the Japanese WE-NET project has also investigated proton exchange membrane (PEM) electrolysers (Ulleberg, 2002), and inorganic membrane electrolysers are also commercially available (Floxal, 2002).

3.4.1 Technology development

Conventional low-pressure alkaline electrolysis has been used commercially in the chemical industries for over eighty years. However, the volume of hydrogen produced by this process has been declining due to the availability of cheaper hydrogen produced from natural gas, except for where very cheap electricity is available, for example from hydroelectric plants. 4% of world hydrogen production is from electrolysis of water (Padró and Putsche, 1999).

Conventional alkaline electrolysers have efficiencies of 65-70% (relative to the lower heating value of hydrogen - see appendix A), and output pressures of 0.2-0.5 MPa. New diaphragm materials and design can operate well under fluctuating power supply, making them suitable for direct use from renewable energy technologies (Zittel and Wurster, 1996). They are available in capacities from a few kW to several hundred MW.

Alkaline electrolysers developed specifically for the vehicle refuelling market are at the pilot stage, and are expected to be commercially available in 2004-2008 (Stuart Energy, 2002).

Inorganic membrane alkaline electrolysers developed by Hydrogen Systems have been commercially available since 1987. These modules have the highest efficiency of any electrolyser seen, at 77% (LHV). Inorganic membrane electrolysers operate at up to 0.5 MW. The USHER project in Cambridge, UK will use this technology, and it is thought to be reliable under intermittent supply. The technical challenge for direct operation from renewable energy sources is smooth operation under intermittent power (Ulleberg, 2002, Dutton et al., 2000).

Proton exchange membrane (PEM) electrolysers use a solid polymer electrolyte as in a PEM fuel cell. This allows for an increased current density, and therefore a more compact system than for alkaline electrolysis. The high cost of component parts of PEM electrolysers has restricted their use in the past to niche aerospace and military applications. High pressure PEM units have also been developed, for example Proton Energy Systems has demonstrated a unit with an output pressure of over 13 MPa.

PEM electrolysers are most suitable for small scale systems. They are currently at the demonstration stage in the Japanese WE-NET project, and low pressure units are commercially available at scales of up to 0.04 MW (Proton, 2002). The efficiency of these units, is however, lower than that for alkaline systems, at 50% (6 kWh/Nm^3).

High pressure electrolysers generate hydrogen at pressures of up to 5 MPa without a separate compression step (Zittel and Wurster, 1996). They are also able to perform efficiently under intermittent supply. This technology is being developed for plants in the 100 kW to 30 MW range, using both PEM and alkaline technologies. The refuelling project at Munich airport uses a 0.5 MW alkaline system of this type.

High temperature steam electrolysers could reduce the electricity requirement for electrolysis by using heat to supply some of the energy needed, and by increasing efficiency due to accelerated reaction kinetics. This would be useful where waste heat is available.

3.4.2 Choice of technology

Conventional alkaline electrolysis is the only technology currently available for electrolysis at scales greater than 2 MW. Given that the focus of development of the other electrolysis technologies is generally on small-scale onsite units, this is likely to continue to be the case in the medium term. Heat for high temperature electrolysis is unlikely to be available at the electricity generation sites considered.

For forecourt electrolysis from onsite renewables, inorganic membrane alkaline electrolyser or PEM electrolysers could be used. Here, an inorganic membrane electrolyser was considered as this has higher efficiency and is known to have been chosen for intermittent input from renewables in several demonstration projects.

3.4.3 Large scale electrolysis (> 1 MW)

Kruger (2000) presents a review of electrolyser energy consumption for large scale installations, gathered from the literature and also from manufacturers. Electricity inputs from electrolysers from 100MW to several hundred MW were in the range 4.3-4.9 kWh/Nm^3 in 1995. Energy consumption data available from manufacturers was limited to smaller scale systems, and ranged from 4.1-4.7 kWh/Nm3. The model input for 2002 was an average of the values found.

Projected values for energy consumption given in Kruger (2000) for 2010 and 2050 were 4 and 3.5 kWh/Nm^3 respectively. The value of 3.8 kWh/Nm^3 used here for 2020 was estimated by extrapolation of this development.

Estimates of electrolyser cost given in the literature vary considerably, and do not always give full details of the scale of system considered.

Thomas and Kuhn (1995) cite a range of sources giving the costs of alkaline electrolysis at varying scales. Estimates from 1994 for 6 to 70 MW plants give costs of \$580-\$590 /kW$_{out}$. Padró and Putsche (1999) review studies with costs of \$63-650 / kW. Mann et al. (1998) and several other US DoE studies have used an input value of \$600 / kW for 2000. Given the range of values seen, this seems a reasonable starting input value for electrolysers at scales of over 2 MW. The electrolyser capital cost was estimated to decrease to \$240/kW$_{out}$ by 2020 (DTI and AEA, 2002). This is reasonably consistent with projections of \$300 /kW in the mid term (around 2010) (Mann et al., 1998) and US DoE projections for likely cost of large scale electrolysis with high manufacturing volumes (Thomas and Kuhn, 1995). See appendix B for a review of electrolyser data found.

For the forecourt electrolysers, at a scale of around 1.1 MW, the costs increase significantly. The value used was an average of those given by Carlsson, cited in Padró and Putsche (1999) and Mann et al. (1998) for 0.5MW and 2 MW systems respectively. The capital cost for 2020 was assumed to decrease by the same ratio as the large system cost decrease.

Annual operation and maintenance costs for electrolyser systems were estimated at 3% of capital costs (Mann et al., 1998). This was projected to decrease to 2% by 2020.

3.4.4 Forecourt electrolysis at less than 1 MW

The energy consumption of commercially available IMET? alkaline electrolysers is 3.9 kWh/Nm^3. This was projected to decrease to the average electrolyser energy use of 3.8 kWh/Nm^3 by 2020. The minimum possible energy use for ambient temperature electrolysis is 3.5 kWh/Nm^3, and therefore the decrease in energy use with development is likely to slow in the future as this limit is approached.

The capital costs for very small systems were estimated from a range of data, including those given in Berry (1996) and from personal communications (Madden, 2002). Again, the data are presented in appendix B. Future capital costs were projected to decrease by the same proportion as for the larger systems.

3.4.5 Summary of model input data

	>2 MW	>2 MW	1-2 MW	1-2 MW	<1 MW	<1 MW
Time	2002	2020	2002	2020	2002	2020
Energy use / kWh/Nm^3 (Efficiency)	4.5 (67%)	3.8 (79%)	4.5 (67%)	3.8 (79%)	3.9 (77%)	3.8 (77%)
Capital Cost / \$/kW$_{out}$	600	240	1170	470	2700	1080
O&M cost / % of capital cost	3	2	3	2	3	2

Table 3: Model input data for electrolysis. Note that the efficiency used is on a lower heating value basis

3.5 Gasification

Gasification is a high temperature process used to convert biomass feedstocks to gaseous products. The brief description of this technology given below is summarised from Williams et al. (1995).

The wet biomass feedstock is first dried and sized if necessary. The feedstock is then gasified to form syngas, by being heated to above 700C in the presence of little or no oxygen. The syngas is composed of CO, H_2, CO_2 and H_2O, and in some cases methane and small quantities of other hydrocarbons. The syngas is then cooled and cleaned to remove sulphur compounds and particulates. To produce hydrogen, the gases must then undergo several shift reactions to react the CO with H_2O. Hydrogen is then recovered from the gas stream by pressure swing adsorption (PSA). 97% of the hydrogen passing through the PSA is recovered, and has greater than 99.999% purity. The hydrogen can then be liquefied or compressed for transport.

3.5.1 Technology development

Experience of biomass handling and processing is fairly widespread, as biomass feedstocks are used in several countries for electricity generation via direct combustion. However, experience of hydrogen production by gasification is limited, and the technology is not commercially proven.

For hydrogen production by gasification, all process equipment is well established and in commercial use, except for the gasifier itself (Williams et al., 1995). All the equipment needed to produce hydrogen from coal gasification, a very similar process, is available. Biomass is easier to gasify than coal as it is more reactive, and easier to clean up due to its low sulphur content. However, there are fewer economies of scale than with coal gasification, due to high feedstock transport costs.

Gasifiers can operate at varying pressures, with a range of input flow designs. Those demonstrated successfully for biomass are fluidised bed designs, as used at the ARBRE plant, with thermal efficiencies of 55-65%. All data used for gasifiers were the average of values given for four types of gasifier studied in Williams et al. (1995). Future values were estimated by assuming a 15% improvement in efficiency and a 15% reduction in capital costs. Costs per unit output were estimated using a 25-year plant lifetime.

Gasifiers require an electricity input in addition to the biomass feedstock of approximately 33 kWh/GJ of hydrogen produced. This input is included in the thermal efficiency. However this was assumed to be generated onsite from hydrogen produced using a fuel cell of 50% efficiency. The process efficiency was therefore reduced to take this into account.

3.5.2 Summary of model input data

Time	**2002**	**2020**
Efficiency	61%	71%
Efficiency (including electricity use)	55%	63%
Capital Cost (£/GJ$_{out}$/yr)	16	14
O&M cost (% of capital cost/yr)	4.8	4.8

Table 4: Model input data for gasification.

3.6 Grid transmission

Several of the fuel chains involve transmission of electricity generated from renewable sources to electrolysers, either at a regional or forecourt scale. The potential problem of suitable grid connection of the generation sites has been discussed elsewhere for each generation option. This section considers the model data for grid transmission itself.

The losses of 7.6 % in the transmission and distribution network were estimated using annual generation and loss figures for 2000 (ES, 2000). This was assumed to be the same for 2020.

The cost of transmission and distribution per unit of electricity delivered are more difficult to determine. Currently, generators pay initial charges for grid connection or reinforcement, annual Transmission Network Use of System (TNUoS) charges, and then balancing charges, related to the variation between their predicted and actual output. As the unit prices of renewable energy used include grid connection, this was not estimated separately. Balancing charges were also not considered; it is assumed that the sale of the renewable electricity generated would be regulated by a system such as a long-term bilateral contract that may not be subject to the controls needed to balance the fluctuation in electricity supply and demand.

TNUoS charges vary depending on the generation zone in which the generation is sited. For generation in remote areas, with low demand and/or constraints on grid capacity such as the North of England and Cornwall, a charge of around £8.40 / kW installed capacity/year is levied. For areas with high demand, such as the South-East, the National Grid will *pay* the generator around £9.90 /kW/yr for generation (NG, 2002). This cost per kW installed was divided by the annual generation to obtain a charge/credit per kWh and summed with the generation cost to obtain a low (low generation cost, transmission cost credit) and high (high generation cost, transmission cost charge) delivered electricity cost. These charges were also used for 2020. Projection of future costs would have been very uncertain due to the heavy dependence on the charging mechanisms of the grid operator at the time, and supporting policies for renewable generation.

3.7 Storing hydrogen

Each of the fuel chains analysed includes hydrogen storage at varying scales. A range of storage technologies is available, the most appropriate choice for each fuel chain depending upon a range of factors such as the volume to be stored, storage time, energy density required, and end use (some vehicles may use liquid on-board storage).

The principal options for stationary hydrogen storage are as compressed gas or as liquid hydrogen. Metal hydride systems have not been modelled here for stationary storage, as there are few large scale commercial systems and no economies of scale, making this a competitive option only at very small scales (Amos, 1998, Padró and Putsche, 1999). Drivers for stationary storage improvement include higher energy densities and lower costs.

The most recent and consistent data available on hydrogen storage was from Amos (1998). As a result of the dependence of the cost of storage on the factors given above, using data that was generalised, or not appropriate to the scale of application considered would have led to model insensitivity. The modelling approach used in Amos (1998) was therefore modified to allow a more detailed analysis. A summary of these modifications is provided at the end of this section.

3.7.1 Conversion technologies

Compression

Hydrogen can be stored as a compressed gas in a pressure vessel at pressures of up to 30 MPa. Compression to high pressures is usually carried out in several stages, the first being pre-compression to 3-4 MPa.

Technology development

The compressor used can be a modified version of those used for natural gas compression, with seals modified to take into account the higher diffusivity of hydrogen (Amos, 1998). Compression technology is well developed and widely available, although hydrogen compressors are still more expensive than those for natural gas. The technical and economic parameters used for compressors were those used in Amos (1998). As the technology is mature, energy use was estimated to be unchanged in 2020, however a future capital cost reduction of 5% was included. Costs of compressors increase somewhat at small scales; a sizing exponent of 0.8 was used (Amos, 1998).

It is also possible to use metal hydrides for compression, by adsorbing hydrogen at a low pressure and then heating up the hydride so the hydrogen is released at a higher pressure. This process can achieve compression ratios of over 20:1. This would be an interesting option for applications with waste heat available, avoiding the need for a separate compressor.

Energy use

The energy for compression is an exponential function of the relative initial and final pressures. The energy use is dominated by the initial pressure, and therefore the first stages of compression are most energy intensive. Initial compression from 0.1 to 1 MPa requires the same energy as compression from 1 to 10 MPa (Zittel and Wurster, 1996). Therefore the use of high pressure electrolysis, avoiding the need for the pre-compression step, could reduce energy consumption significantly (Amos, 1998).

All energy needed for compression was from the renewable energy source considered. In the renewable electricity chains, this was a proportion of the electricity input, and in the biomass chains a fuel cell was used to produce electricity from a proportion of the hydrogen produced. There are therefore no emissions from compression.

Liquefaction

Technology development

Hydrogen can be liquefied and stored as a liquid at -253 ?C. There are several possible liquefaction processes, which all involve compression to at least 2MPa and liquid nitrogen pre-cooling, followed by controlled expansion through a valve, causing liquefaction (Zittel and Wurster, 1996). The process requires a considerable amount of energy, up to 30% of the energy of the liquid hydrogen produced (Conte et al., 2001). Adding extra heat exchangers and multiple compressors can reduce the energy required for liquefaction, and thus reduce operating costs, but increases capital costs (Amos, 1998).

Large scale liquefaction plants have been used worldwide since the mid 1950s, with outputs of between 25 and 60 t/d. There are also now around 10 medium scale plants with capacities of 10-60 t/d, and newer small plants in the range 3-12 t/d (Zittel and Wurster, 1996, Amos, 1998). Research units operate at 0.2t/d, but the smallest commercial plant is over 1 t/d. It has been considered that small-scale liquefaction is unlikely to be economically viable, given thermodynamic constraints to small systems, and that 60 t/d is a suitable size for a modular unit (Bracha, 2002). Very large scale plants have been considered; Mercuri et al. (2002) consider liquefaction plants with outputs of up to 237 t/d. In the WE-NET project, a target liquefaction plant capacity of 300 t/d is considered, still considerably larger than the largest existing plant (Matsuda and Nagami, 1997).

In liquefaction technology, the drive is towards lower cost of plant, and lower energy use. A reduction in capital cost of 15% was used for 2020. The sizing exponent of liquefaction plants used was 0.65 (Amos, 1998); small liquefaction plants are considerably more expensive due to low production volumes of equipment at this scale.

Energy use

In the review of liquefaction data presented in Amos (1998) power requirements varied from 8.0 kWh/kg to 12.7 kWh/kg. The Ingolstadt liquefaction plant, with a capacity of 4.4 t/d, commissioned in 1991, has an energy use of nearly 14 kWh/kg. A value of 8 kWh/kg was used here, as this was the lowest available in 1998.

Magnetocaloric conversion processes are being developed in order reduce energy use and to aid conversion from ortho to para forms of hydrogen during liquefaction (Zhang et al., 2000). This is needed to minimise boil-off losses in storage; 75% of the hydrogen is in the ortho form at room temperature, but at 20 K is nearly all para. Any ortho remaining at 20K will later be converted to para in an exothermic reaction, which could lead to evaporation of up to 50% of the liquid hydrogen in 10 days (Amos, 1998).

Magnetocaloric cooling processes could have energy requirements as low as 4.94 kWh/kg (Amos, 1998). This is approaching the ideal energy of liquefaction of 3.228 kWh/kg. Zittel and Wurster (1996) consider that this level of efficiency is commercially achievable, though gives no indication of timescale. It was estimated for this model that learning in liquefaction technology would decrease the energy use to this level by 2020, either by magnetocaloric processes or other technology improvements.

As for compression, all energy needed for liquefaction is sourced from the renewable energy input to the fuel chain, and so no non-renewable energy use or emissions are considered.

3.7.2 Stationary storage systems

Compressed hydrogen

Storage of hydrogen in compressed gaseous form is the most commonly used storage method. This is usually high pressure storage, with commercial products available in the range 20-25 MPa (Conte et al., 2001). The gas is stored in cylinders, or spherical containers for large volumes (Padró and Putsche, 1999). Small volumes are also stored in cylindrical tubes at 20 MPa.

Low pressure storage at 1-5 MPa is also used in some applications (Amos, 1998). Storage at low pressures in cylindrical vessels is available with capacities of up to 400 kg, and in spherical vessels at up to 1,300 kg (Amos, 1998). There is considerable experience with low pressure storage in cylindrical tanks, but no experience of low pressure storage of large volumes of hydrogen unlike that for natural gas (Zittel and Wurster, 1996).

The advantages of compressed hydrogen storage are simplicity; only a compressor and pressure vessel is needed, and the considerable experience of the technologies used. Disadvantages include low storage density, cost of pressure vessels and the large volume of cushion gas that can be left in large storage vessels (Amos, 1998)

Here, storage at 20 MPa will be considered as in Amos (1998). The costs of storage decrease with a sizing exponent of 0.75 at higher volumes, due to a lower material requirement per unit volume stored. Capital costs of compressed storage vessels given in Amos (1998) are consistent with those given in previous studies cited in Padró and Putsche (1999), and are considerably higher than for liquid storage vessels of the same capacity (see table 5). This is due to a much lower energy density, and the more modular nature of compressed storage (Ogden, 1999). The overall storage cost is heavily dependent on the storage time. The higher the annual throughput of the storage system, the lower the capital cost per unit throughput. The sensitivity of the cost to this parameter will be discussed further in section 5.7. The capital costs of compressed storage vessels were estimated to decrease by 10% by 2010.

Liquid hydrogen

Liquid hydrogen is stored in insulated cryogenic containers. Energy inputs to the system must be minimised, as this will lead to evaporation of hydrogen, known as boil-off. This is achieved by ensuring ortho-to-para conversion, using double walled heavily insulated tanks, and usually by using spherical tanks, as they have the lowest surface area to volume ratio for heat transfer. Cylindrical tanks are sometimes used, as they are easier and cheaper to produce and have nearly the same surface area to volume ratio (Amos, 1998).

Boil off rates depend on the size and insulation of the storage vessel. A typical rate is 0.1% per day, but rates can vary from 2-3% for small vessels to 0.06% for large vessels (Amos, 1998) Hydrogen evaporated in boil-off can be vented, returned to the liquefaction process or used directly if the application requires gaseous hydrogen.

Cryogenic vessels are smaller than compressed gas cylinders, as the energy density of liquid hydrogen is higher than that of compressed hydrogen, therefore more hydrogen can be stored in the same volume (Ogden, 1999).

There is experience with large-scale storage of liquid hydrogen as a result of the space program, and small scale storage uses the same technology as for liquid helium – either super-insulated or continuously cooled tanks (Zittel and Wurster, 1996). Liquid hydrogen storage requires ten times more insulation than liquefied natural gas (Nakajima et al., 1997) and so liquefied natural gas technology cannot be applied directly to liquid hydrogen (Iwata et al., 1996).

As a result of the increased energy density of liquid storage, the material costs per unit volume of hydrogen are lower than for compressed gas storage. As with compressed gas, costs are sensitive to system size and storage time, with a sizing exponent of 0.7 (Amos, 1998).

Other storage technologies

Underground storage

Hydrogen can be stored underground in caverns such as rock or salt caverns, in porous rock structures such as aquifers and in abandoned natural gas wells. ICI have used salt caverns to store hydrogen at pressures of up to 5 MPa, and Gaz de France have stored town gas containing 50% hydrogen in an aquifer (Zittel and Wurster, 1996). Underground storage can be used for very large volumes of hydrogen, up to a billion Nm^3 for aquifers or gas fields, and several million Nm^3 for caverns (Ogden, 1999). It is not suitable for smaller gas volumes, as the 'cushion gas' that needs to be left in the storage site throughout the storage cycle in order to maintain gas pressure can be up to two thirds of the storage volume. This gas can be displaced by pumping in brine, however this increases capital and operating costs (Amos, 1998).

The capital cost of underground storage depends on whether a suitable underground feature is available, or whether one must be mined. Clearly, using existing features such as abandoned natural gas wells is the cheapest option, however caverns can be mined nearer to where needed, with solution salt mining costs \$23 /m^3 and hard rock mining costs \$34-\$84 /m^3 depending on the depth (Amos, 1998). In general the levelised cost of large scale underground storage is estimated to add about \$2-6 per GJ to the cost of hydrogen for daily or monthly storage, with increased costs for seasonal storage (Ogden, 1999). Padró and Putsche (1999) estimate this cost at \$1-4.7 /GJ.

Underground storage has not been included in this generalised model, as it would not be possible in all locations. It would also require large capital investment and would not be suitable for gradual development due to high costs at low throughputs.

Metal hydride

Metal hydrides are metal alloys that can store hydrogen within their chemical structure. Most metal hydrides can adsorb hydrogen at a slightly raised pressure, and must be simultaneously cooled as the process is exothermic. To recover the hydrogen, heat is added, and the hydrogen is released at a higher pressure. Some hydrides can also adsorb hydrogen at atmospheric pressure, and so can be used for compression. Each hydride has a different range of operating temperatures and pressures, which can be over 10 MPa and 500 ?C, as well as a different cycle life (Conte et al., 2001). The hydride must be stored within a pressure vessel that allows rapid heat transfer.

Metal hydrides can store 2-7% hydrogen by weight (Conte et al., 2001). The energy density tends to increase with the operating temperature range of the hydride. The hydrogen can be stored indefinitely, only being released when heat is applied. It can be difficult to remove the last 10% of hydrogen in the normal charge-discharge cycle as it is strongly bonded to the hydride structure.

Costs of metal hydride storage systems include the storage material itself, the pressure vessel, heat exchangers for cooling and heating during adsorption and desorption and compression if required. As the principal capital cost is for the hydride material, there is little economy of scale (Amos, 1998). This cost depends on the required properties of the material, such as temperature and pressure ranges and storage density. The cost of using metal hydrides for large scale 30 day storage is 20 times the cost of the original hydrogen. However, very small systems are expected to be cost competitive with the other storage technologies. The largest metal hydride units constructed have held 27 kg (Amos, 1998).

Carbon materials

Hydrogen could be stored in carbon materials such as nanofibres or nanotubes. The hydrogen is adsorbed onto the surface of the storage medium, giving a high energy density, but also potentially a low weight density of storage. Carbon can absorb up to 5-10 wt% hydrogen (Padró and Putsche, 1999), with research continuing into new materials to improve this figure.

Other possibilities

Another method being investigated involves reacting sponge iron (iron oxide) with hydrogen to form iron and water, then recovering the hydrogen by reacting the iron with steam. This method would have high energy density and low storage cost, but is in a relatively early stage of development (Amos, 1998).

Other possibilities include the use of liquid storage in the form of liquid hydrides or ammonia (Amos, 1998), in zeolites or as a cryogenic slush (Ogden, 1999). Permeable glass microspheres have also been used that are permeable to hydrogen at high temperatures, but store it at room temperatures (Zittel and Wurster, 1996).

3.7.3 Summary of model input data

The hydrogen storage model was based on that developed by Amos (1998). The principal modifications to this model were:

?? Changes to capital cost formulae from a straight line depreciation model to discounting at 10% over the lifetimes given, in line with the rest of the modelling

?? Removal of the parameters concerning volume and cost of water used to reduce model complexity. This was less than 1p/GJ$_{out}$ for both compression and liquefaction.

?? Addition of factors for reduction of future capital costs of:

- ?? 5% for mature technologies e.g. compressors
- ?? 10% for less mature technologies e.g. storage vessels
- ?? 15% for technologies not widely commercially available at the range of scales considered e.g. liquefaction

	Compressor		**Compressed storage**	
	2002	2020	2002	2020
Reference size	4000 kW	4000 kW	227 kg	227 kg
Reference cost (£/unit)	655	620	865	780
Reference pressure (MPa)	20	20	20	20
Sizing exponent	0.8	0.8	0.75	0.75
Pressure factor	0.18	0.18	0.44	0.44
Energy use (kWh/kg)	2.2	2.2	-	-
Lifetime (years)	22	22	22	22
Input pressure (MPa)	0.1	0.1	-	-
Output pressure (MPa)	20	20	-	-

Table 5: Model input data for compression and compressed storage. Units given are not standard, but are those commonly used for the technology, for ease of comparison with other studies. The use of pressure and sizing exponents is explained in detail in Amos (1998).

	Liquefier		**Liquid storage**	
	2002	2020	2002	2020
Reference size	454 kg/h	454 kg/h	45 kg	45 kg
Reference cost (£/unit)	28,820	24,500	290	245
Sizing exponent	0.65	0.65	0.7	0.7
Energy use (kWh/kg)	8	5	-	-
Lifetime (years)	22	22	22	22
Boil off rate (%/day)	-	-	0.1	0.1

Table 6: Model input data for liquefaction and liquid storage

3.8 Hydrogen transport

3.8.1 Introduction

The hydrogen transport options considered here are as compressed gas, as liquid hydrogen, transported by road and compressed gas pipeline delivery. The most suitable option for each fuel chain considered depends on factors including the transport distance, volume transported, cost, and demand distribution. Any other hydrogen storage technologies could also be considered for transport, their viability principally depending on their energy density by mass and volume and on cost.

3.8.2 Compressed hydrogen

Compressed hydrogen can be transported in high pressure cylinders, in tube trailers or by pipeline (see below).

Compression to high pressures is desirable, to increase the hydrogen carried per vehicle, however very high pressures require more expensive pressure vessels. High pressure cylinders used store the gas at up to 40 MPa, and hold up to 1.8 kg hydrogen (Amos, 1998). Tube trailers, where gas cylinders are mounted on a framework, can also be used to transport hydrogen at 20-60 MPa, with each trailer holding several tubes to give totals of up to 460 kg (Amos, 1998).

Cost

Amos (1998) estimated the costs of compressed hydrogen transport by tube trailer. Costs depend on the pressure at which the gas is stored, the capacity of the trailer, the distance travelled and the quantity transported per year. Costs cited in Padró and Putsche (1999) were based on the data from Amos (1998). It was therefore decided to use the more detailed information available from the Amos model results. This was possible as data was available for the same distances as those considered and for very similar throughputs. It would have been more accurate to modify the transport models developed by Amos for the UK case, for example using UK vehicle specifications, speeds, wages etc., however this was not possible within the timescale of this project.

Environmental impacts

The capacity of a compressed gas tube trailer used was 181 kg (Amos, 1998). This is considerably smaller than the capacity of a liquid hydrogen tanker (see later) due to the much lower gas density. The transport of hydrogen as a gas will therefore require a higher number of vehicles and so lead to increased traffic flows, and potentially higher energy use and CO_2 emissions.

The CO_2 emissions of hydrogen transport were estimated using UK road transport emissions data (TRL, 2002). The emission rate in g/km is given as a function of the average vehicle speed. New hydrogen transport vehicles were considered to be diesel powered, and conform with EURO III legislation. Ideally, hydrogen powered vehicles would be used to transport hydrogen, however HGVs are likely to be one of the last vehicles to adapted for hydrogen use. The emission rate for 80 km/h was 936 g/km.

3.8.3 Liquid hydrogen

Liquid hydrogen can be delivered in cryogenic vessels or transported in a tanker to refill stationary storage facilities. As with stationary storage, liquid hydrogen must be transported with heavily insulated or externally cooled tanks to minimise boil off losses. Tankers can carry 360-4,300 kg liquid hydrogen. Amos (1998) considered a liquid hydrogen storage tanker, with a capacity of 4082 kg. The truck boil off rate, of 0.3%/day is higher than for stationary storage.

Liquid transport and storage could also be used if the end use required compressed gas, using a dispensing system that allows evaporation of the liquid (DT, 1997).

Cost

The cost of liquid hydrogen transport increase with distance and quantity transported. As for compressed gas transport, the closest available data from Amos (1998) was used to estimate transport costs. The transport cost for a throughput of 45 kg/hr was under half the cost for compressed gas (see table 7).

Environmental impacts

The higher energy density of liquid hydrogen storage results in nearly 23 times more energy transported per vehicle than for a compressed gas tube trailer at 20 MPa.

CO_2 emissions were calculated in the same way as for compressed gas. This could have been improved by the use of emissions factors that take into account the mass of the vehicle, or that are based on fuel consumption. However fuel consumption at a given scale would have had to be obtained from Amos' model, which was derived using US-specific data.

3.8.4 Pipeline

Compressed hydrogen can be transported both through dedicated hydrogen pipelines, and through existing natural gas pipelines, subject to some modification to allow for the higher diffusivity of hydrogen, and assessment of the possibility of embrittlement of the steel pipeline (Padró and Putsche, 1999). Typical operating pressures for pipeline delivery are 1-3 MPa, with flows of 310-8,900 kg/h (Amos, 1998). Several hydrogen pipeline distribution networks are currently in operation, for example in the Ruhr, Germany, over 50 km of pipeline carrying hydrogen at 2 MPa has operated for over 50 years serving the chemical industries (Zittel and Wurster, 1996). The longest pipeline in operation is 400 km long (Amos, 1998).

Pipeline delivery can also be used as a form of storage, by allowing pressure changes in the system. This is currently done with natural gas to help manage demand fluctuation (Dincer, 2002). As a result, no storage at production sites or at the forecourt will be considered for fuel chains involving pipeline transport.

There has also been discussion of the integration of hydrogen into the natural gas pipeline network. There is considerable UK experience with 'town gas', a mixture of up to 50% hydrogen with methane formed from coal, which was used up until the 1970s (Hart et al., 2000). If hydrogen for transport were to be transported by this method, small-scale forecourt systems for stripping the hydrogen back from the mixture would be needed.

There are liquid hydrogen pipelines of up to 40 km in the USA (Zittel and Wurster, 1996). Liquid hydrogen pipelines require high insulation, as well as pumping and re-cooling. They have not been widely considered as a viable transport option.

Cost

Capital costs include the steel pipeline itself and installation. Operating costs include compressor power and maintenance. Hydrogen losses in pipeline transport are not known; for natural gas, losses are less than 1 % (Amos, 1998).

The total cost of hydrogen delivered by pipeline increases with distance delivered, and decreases with the energy delivery rate. Padró and Putsche (1999) summarise earlier work estimating capital and total costs / GJ delivered. The data reviewed is for transmission rates of a minimum of 0.15 GW, and from sources assuming a range of pipeline diameters (Amos, 1998, Oney, 1994). This is equivalent to 4500 kg/hr, when the largest flow rate considered here is 540 kg/hr.

From analysis of the data presented, it was found that the cost scaled approximately linearly with distance for shorter distances presented, so that costs could be estimated for the lower distances needed for this model. However, the costs could not be linearly extrapolated to lower flow rates. The cost of a pipeline is a complex function of its diameter, which is in turn a function of the flow rate required, friction factors etc. (Ogden, 1999). The rapidly increasing cost at small flow rates and diameters was therefore estimated by applying a power law ($y = cx^b$) least squares fit trend line to the data cited from Oney (1994) in Excel 2000 and projecting it back to lower flow rates. The trend line fitted the data very well, with an R-squared value of 0.986 for costs per unit throughput, and 0.996 for capital costs.

Pipelines have high capital costs compared with road transport option, but very low operating costs. The use of pipelines is also inflexible; routes and capacities cannot be easily changed. Given the uncertainty on uptake of hydrogen technologies, it would be very difficult to determine the capacity of any system built, in order to allow for future demand.

Environmental impacts

The compression needed for pipeline delivery was assumed to be equal to that needed for compressed storage, as in Amos (1998) and the energy used from the renewable source. The pressure needed for pipeline delivery is much lower, at 1-3 MPa. However, some booster compression may be needed at stages along the length of the pipeline.

The installation of pipelines, particularly to remotely situated renewable energy generation sites may have an impact on the local environment, for example disruption of habitats. However, the significance of these impacts would likely be taken into account in an environmental impact assessment, required under the Pipeline Works (Environmental Impact Assessment) Regulations 2000 for pipelines over 10 miles in length (ODPM, 2002). The environmental impacts of the pipeline in operation would be minimal compared with the noise and emissions from road transport, or the visual impact of overhead power lines.

3.8.5 Summary of model input data

Type	Quantity / kg/hr	Distance / km	Cost $/ kg	Capital cost / $
Compressed	45	32	0.64	250,000
Compressed	45	161	1.39	250,000
Liquid	45	32	0.26	500,000
Liquid	45	161	0.29	500,000

Table 7: Model input data for road transport

Pipeline:

Cost $/GJ/km	$= 186.14\,x^{-0.6278}$
Capital cost $/GJ/year/km	$= 33244\,x^{-0.8376}$

Table 8: Model input data for pipeline transport. x is the annual throughput in GJ

Future unit cost and capital cost reduction for all transport methods: 5 %

3.9 Forecourt systems

Forecourt storage of compressed or liquid hydrogen was modelled in the same way as for storage at the generation site. No losses in filling these storage vessels were included. This leaves the last step in fuel distribution, and the last contribution to the delivered cost, dispensing.

3.9.1 Compressed hydrogen dispensing

Dispensing of compressed hydrogen can be achieved in several ways. Each of the methods involves compressing hydrogen from the storage pressure to that needed for onboard storage. Praxair compared the costs and performance of cascade and booster refuelling with onboard storage at 34.5 MPa (DT, 1997). In the cascade system, a series of interconnected tanks is used, with the first at low pressure, and the last at the delivery pressure. This was found to be twice as expensive as a booster system, where the gas is stored at 25 MPa, and then a single booster compressor used to fill an intermediate tank at the delivery pressure.

A vehicle requiring compressed hydrogen could also be refuelled from a liquid storage system using a dispenser that allows the liquid hydrogen to evaporate and then compresses it. This option has not been included in the model, but could be reconsidered if it is found that liquid hydrogen distribution and storage is cheaper than that for compressed gas. Cost estimates for dispensers of this type vary considerably despite being of similar designs (DT, 1997), but for the scale of refuelling station considered are around $24,000 /kg/hr.

Cost

There is limited experience with compressed hydrogen dispensing technology, with ongoing development of compression staging and dispensing equipment (Schoenung, 2001, DT, 1997). The majority of forecourt cost estimates in the literature do not give separate costs for storage and dispensing (DT, 1997, Thomas et al., 1999, Ogden, 1999). Capital cost estimates of $25,000 for an 8.3 kg/hr dispenser were taken from Ogden (1995) cited in Schoenung (2001). Costs for larger systems were then scaled using the same capital cost/kg/hr and discounted over the total output of the system over 20 years. The cost of dispensing technology in 2020 was estimated to be 5% lower than the 2002 value. Despite the lack of experience with this technology, there are unlikely to be significant improvements in relatively mature compression equipment. Also, as with compressed natural gas (CNG), a significant proportion of dispenser cost is likely to be due to gas flow metering (Arcadis, 1999).

The energy use of dispensing equipment was not included. The delivered cost of hydrogen was intended not to be specific to a particular fuel cell vehicle technology, and therefore not specific to an onboard storage method or pressure. The energy use of the dispenser would depend heavily on these parameters.

Other issues

Dispensing of CNG has suffered from problems of a lack of standardisation of the technology (Arcadis, 1999). Dispensers with varying performance, reliability and metering systems installed before standards were established are now being modified to comply with safety and weights and measures standards, at significant cost to the supplier. The variation in design of refuelling stations also has an impact on the ease of use for the consumer unlike lack of standardisation of earlier stages of the fuel chains.

3.9.2 Liquid hydrogen dispensing

Liquid hydrogen dispensing can be achieved either from a tank with a small over pressure, or using a pump system (Wetzel, 1998). The Munich airport hydrogen project uses automated robot refuelling, resulting in improved safety and refuelling time, and minimal leakage (Pehr, 2001).

Cost

The Munich airport hydrogen project is the only public liquid hydrogen refuelling station in operation. Therefore experience of the technology is very limited, and cost estimates are for 'one-off' systems. The capital cost estimate of $100,000 per 8.3 kg/hr dispenser used was a BMW estimate from 2000 taken from Schoenung (2001). Again, this was spread over the output of the dispenser over 20 years to obtain a cost per unit. Costs for 2020 were estimated to decrease by 15% from this value, as the technology is at a very early stage of development.

The energy need to power the liquid hydrogen pump has not been included, to reduce model complexity. Its energy requirement is estimated to be very small, at only 1 kW when in operation (Schoenung, 2001).

3.9.3 Summary of model input data

	Capital cost /$/kg/hr	Lifetime /years	Cost reduction for 2020	Minimum capital cost / $
Compressed	3,000	20	5%	25,000
Liquid	12,000	20	5%	100,000

Table 9: Model input data for dispensing. The minimum capital costs were needed to account for very low throughput forecourt generation and electrolysis systems.

3.10 End use

Hydrogen could be used both in fuel cells and internal combustion engines (ICEs) to power a range of road and other vehicles. The end use considered for the hydrogen produced by the fuel chains is as a fuel for cars, and is compared with petrol car technology. A detailed study of the technology status of fuel cell and hydrogen ICE vehicles is beyond the scope of this project, however this section will introduce the key data needed for demand estimation and comparison of hydrogen and petrol costs.

The characteristics of the hydrogen fuel cell vehicle (FCV) will be used to provide the primary comparison with petrol ICEVs. The fuel cell vehicle has advantages over the hydrogen ICE which include improved efficiency, zero tailpipe emissions, improved low speed acceleration and quieter operation. However, there is considerably more long term and widespread experience with ICE technology, such that the hydrogen ICE has been considered to be an important technology either in the interim before FCVs are commercially developed, or in the case of the FCV never becoming a commercially viable option.

Vehicle characteristics

An FCV was assumed to have an energy consumption of 1.2 MJ/km (Mercuri et al., 2002). The onboard storage method was not specified, but was assumed to have a capacity of 3.75 kg, as used in Ogden (1999). This was consistent with a range of other studies and industry assessments using values of around 4 kg (Schoenung, 2001). The energy consumption of a hydrogen ICE is higher, at around 2.7 MJ/km, and therefore all results given per km for an FCV can be multiplied by 2.25 to give values for use of an ICEV.

3.10.1 Summary of model input data

	Energy use (MJ/km)	Storage capacity (kg)
FCV	1.2	3.75

Table 10: Model input data for the fuel cell vehicle

4 Model design

4.1 Introduction

The model was set up to evaluate the technical, economic and environmental parameters of each fuel chain, giving results per unit of energy delivered (/GJ) and per unit of distance travelled (/km). This was carried out for two timescales, 2002 and 2020. The detailed parameters for each chain are given in section 3, but in general involve the efficiency, cost per unit output and indicative capital cost for each fuel chain component. Non-renewable energy use, carbon dioxide emissions and land use are included where appropriate. The software used was Microsoft Excel 2000.

4.1.1 System boundaries

In taking a life cycle analysis based approach to energy use and emissions, often known as a 'well-to-wheels' evaluation for vehicle fuels, it is important to define the system boundaries used. The energy use and CO_2 emissions considered in the model related only to the operation of the fuel chain, for example in transporting biomass and hydrogen. No energy use or emissions were included related to construction, decommissioning or recycling of the components. Emissions of pollutants other than CO_2 were not modelled, however will be discussed qualitatively.

4.1.2 Technical and economic assumptions

Lower heating value of hydrogen	10.783 MJ/Nm^3
Density of hydrogen	0.899 kg/Nm^3
Discount rate	10%
Exchange rate: US dollars to GB pounds	0.654 £/$
Exchange rate: Euro to GB pounds	0.634 £/€
Exchange rate: DM to GB pounds	0.327 £/DM

Table 11: Technical and economic assumptions. All exchange rates from www.xe.com, 8 August 2002

4.1.3 Demand distribution

It was necessary to estimate the density of refuelling stations in the UK, and their current and future demand in order to size the fuel chain components appropriately. These data were used to provide a generic demand profile for a region of radius 50 km, considered to be appropriate for the UK. It was assumed that the entire transport demand of each station was supplied by hydrogen, to be used in fuel cell vehicles.

The throughput of a medium sized refuelling station in the UK in 2000 was 2.12 million litres per year (OGD, 2002). The average fuel consumption of the UK vehicle fleet in 1999/00 was 0.096 l/km (DfT, 2001). These data were used to calculate the daily travel demand per station, of around 60,500 km/day. Then assuming this is provided entirely by hydrogen FCVs, this translates to a hydrogen demand of 25 kg/hr, or 0.6 t/d.

The calculation was repeated for 2020, using a refuelling station throughput of 2.77 million litres per year. This medium sized station throughput was estimated by extrapolating the throughput increase from 1990 to 2000 to 2020. The hydrogen demand was found to be 33 kg/hr, or 0.8 tpd.

It should be noted that these values were not used to provide an indication of total demand, purely to allow for the trend towards larger stations. The throughput of stations in 1996 varied from about 1 to 8.5 million litres per year (OFT, 1998).

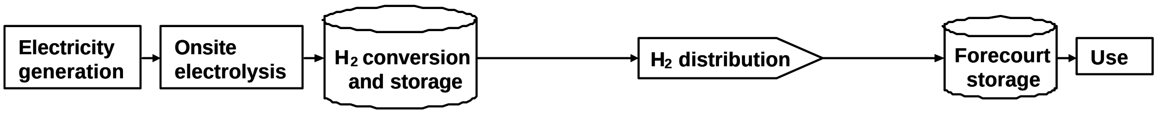
The number of petrol refuelling stations in the UK was just over 12,200 in 2001 (UKPIA, 2002). The total land area of the UK is 241,590 km^2 (CIA, 2002). This gives an average density of refuelling stations of 0.05 stations/km^2. Therefore in the 50km regional distribution radius there would be approximately 400 stations. Assuming the stations are laid out in a grid, this gives a distance between stations of 4.45 km. This value is needed to estimate the length of pipeline network needed. A value of 10,000 stations was used for 2020, extrapolated from the continuing decline in numbers of refuelling stations with increasing market share of large supermarkets (UKPIA, 2002).

The demand profile of the refuelling station must be considered in order to provide appropriate storage at the forecourt. The refuelling station was assumed to be open 24 hours a day, but with very low night time demand, and with morning and evening peak demand (DT, 1997).

The following sections describe the five forms of fuel chain modelled. The first three chains A-C consider large scale renewable electricity generation followed by electrolysis at varying scales. Fuel chain D considers electricity generation at the forecourt, with forecourt electrolysis. Fuel chain E uses biomass gasification to generate hydrogen at a regional site. A summary of the assumptions behind each chain are presented in appendix C.

4.2 A: Electricity generation – onsite electrolysis - transport 160 km

The inputs to this fuel chain are offshore wind, onshore wind at 60 MW and 10 MW scales, wave, tidal and small hydro. The location of the generation is not defined, but a generic distance of 160 km from the forecourt is considered. This is reasonable, given that no point in the UK is further than 125 km from the sea (CIA, 2002), allowing for some tortuosity. The electricity generated is used to power an electrolyser at the generation site, which is sized at the rated output of the generation technology. The hydrogen produced is then compressed using a compressor also sized for the rated output of the generation. The hydrogen is then delivered by one of three routes: by compressed gas road transport, liquid road transport, or by pipeline.



4.2.1 Advantages and interactions

The principal advantage of this fuel chain is that the generation site does not necessarily have to be connected to the electricity network. This could allow the installation of generating technology near to adequate road networks, existing pipeline networks or where new pipelines could be installed more easily than extending or reinforcing the electricity network.

Electricity network connection, however, would allow the generator to switch between export of electricity to the network and hydrogen production. Inclusion of a fuel cell in the system would allow electricity generation, so that the hydrogen storage facility could be used as buffer storage to balance intermittency of network output.

4.2.2 Compressed storage and road transport

The onsite compressed storage acts as a buffer for the variation in output of the generation. Offshore wind, onshore wind and wave technologies are intermittent, and so are assumed to have storage volumes equal to 3 days average output. This allows hydrogen produced at peak output to be stored to allow for below average output on subsequent days. It would obviously be preferable to have a much larger storage volume, to allow for longer term levelling of the hydrogen supply, such as over seasonal variations. The average capacity factor of wind turbines in the UK varies from 0.167 in the summer to 0.445 in the winter (BWEA, 2002). However, adding longer term storage may add considerably to the cost of the system. Therefore the 3 day short term storage was chosen as a base case, with the sensitivity of the cost to this parameter discussed later. The tidal generation has predictable diurnal peaks in output. Therefore if the variations due to spring tides etc. are excluded, 0.5 days storage will allow a levelled output of hydrogen to be supplied. The output of small hydro schemes is likely to be reasonably consistent over a timescale of several days, and therefore 0.5 days storage was also used. Again, small hydro output shows considerable seasonal variation, and the additional cost of long term storage may need to be considered further.

The compressed gas is then transported by tube trailer 160 km to the refuelling stations. This is assumed to be a straight return journey to each station. The number of stations to which it is delivered is equal to the total output divided by the demand per station, and is therefore different for each generating technology, and differs between 2002 and 2020. For example, offshore wind supplies over 18 stations in 2002, whereas the small hydro scheme considered supplies fewer than 2. Note that it is only this fuel chain (A) that is scaled with supply, the others being scaled from forecourt demand. The delivery rate is equal to the demand rate for each station e.g. 25 kg/hr for 2002.

Storage at the forecourt is scaled with the interval between hydrogen deliveries. Since supply of the total hydrogen demand by tube trailer would currently require three 181 kg tube trailers per day (!), only 0.3 days storage would be required. However to allow for fluctuating demand, and therefore fluctuating storage requirements, storage of 0.5 days demand has been assumed. Again, the sensitivity to this parameter will be discussed in section 5.7.

4.2.3 Compressed storage, liquid storage and road transport

The hydrogen produced is again stored as a compressed gas, using the same storage volumes as given above. The gas is then liquefied for transport, with a short storage time equal to the interval between tanker refuelling. This pre-compression and compressed storage system has been included to allow liquefier sizing for the average output of the generation. In this way, the liquefier is operated at a constant rate, at its full capacity. Running a liquefier scaled at the rated output of the generation technology at as low as a third of its capacity would represent considerable wasted capital investment, due to the high cost of liquefaction technology. The liquefier has a throughput of 1-12 t/d, scales that are commercially available (see section 3.7.1).

The liquid hydrogen is then transported 160 km to the refuelling stations by road tanker. The assumptions of number of stations served and delivery rate are as for compressed delivery.

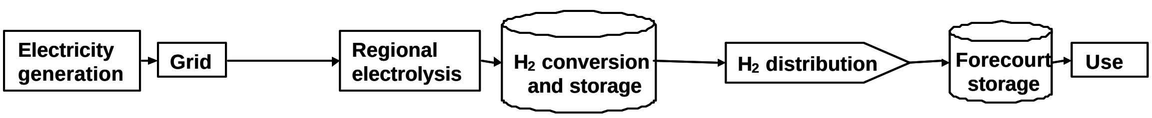
Delivery to each refuelling station is needed every 4.9-6.8 days. The forecourt storage volume was oversized by 10% to allow for fluctuations in demand (allowance for boil-off is already considered in the storage model used).

4.2.4 Pipeline storage and transport

The compressed gas is transported 160 km to the forecourts, with the number of refuelling stations served determined as above. The pipeline network is considered to be 156 km of bulk pipeline, taking the entire output of the generating site to a central point. For connection of each station, 4 km of additional pipeline, sized at the demand of a single station is added. This is equivalent to a long distance transport of 156 km, followed by regional distribution as considered in fuel chains B and E, and will be discussed further in section 4.3.4. The possibilities for pipeline distribution would change considerably once a network began to be built up; this network format can be used only to provide an indication of the costs of new networks. The pipeline is considered to act as storage, and so no onsite or forecourt tank storage is considered.

4.3 B: Electricity generation – grid – regional electrolysis - transport 32 km

The inputs to this fuel chain are the same as for fuel chain A. However in this chain, the electricity output is then exported to the electricity transmission and distribution network. This is then used to provide a proportion of the power needed to run an electrolyser sized for the demand of all the stations within a 50 km radius. The capital cost of the electrolyser is spread over its *total* output over 20 years. The capital cost of the whole electrolyser apportioned to the generation route considered is in proportion to their relative outputs. The hydrogen is then stored and delivered by compressed gas or liquid road transport, or by pipeline.



4.3.1 Advantages and interactions

This fuel chain has several advantages over distributed hydrogen production as in fuel chains A, C and D. The ability to buy in electricity from different renewable electricity generators (both intermittent and predictable) allows the plant to be run at constant capacity, and removes the need for buffer storage. Centralised compression, liquefaction and storage gives economies of scale over numerous smaller systems. The operation and maintenance of the system is also likely to be easier; there is no need for expertise with hydrogen processing at multiple small sites. The shorter hydrogen distribution distance than in fuel chain A will result in less road traffic or need for the disruption of pipeline installation.

4.3.2 Compressed storage and road transport

The hydrogen produced by the electrolyser is compressed and stored. The storage tank is sized for one hours' output. This is because there is no uncertainty in the output of the electrolyser, and the time between the arrivals of delivery vehicles to transport the hydrogen to the forecourt is very short. The one hour storage is used as a minimum buffer to allow some flexibility. Again, the compressor and storage tank costs are spread over the total throughput of the regional site, and capital costs apportioned according to relative throughput.

The compressed gas is then supplied to all the refuelling stations in the 50 km radius. The average transport distance is 33 km (the average distance of a point in a circle from the centre is two thirds of the radius). For the purposes of comparing the capital investment needed for the whole fuel chain, however, the number of stations that could be supplied from the output from the generation site used was still calculated. The forecourt storage assumptions used were the same as those for fuel chain A.

4.3.3 Liquid storage and road transport

There is no need for pre-compression and compressed storage in this fuel chain, as the liquefier can be sized at the constant rated output of the electrolyser. A very small volume of liquid storage is then needed to allow for refilling of the road tankers. This was taken to be one hour's rated output.

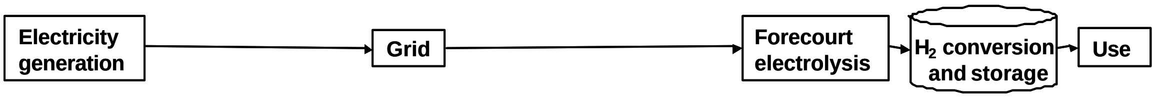
The liquid hydrogen is then delivered an average distance of 33 km to the forecourts as for compressed gas. One tanker-load is considered to be delivered to each forecourt, to reduce model complexity. It would be possible to model the logistics of delivery more rigorously to allow for more regular refuelling of several stations, as part of a more responsive travel cost model (see section 3.8). Forecourt storage assumptions are the same as those for fuel chain A.

4.3.4 Pipeline storage and transport

The pipeline infrastructure used to distribute hydrogen to refuelling stations within the 50km radius could be established in a number of ways, the extremes being from a radical switch to hydrogen provision, with a centrally planned full capacity network to a more organic growth of the network from a regional hydrogen production point. The installation would need to be planned to avoid the need to increase the capacity of the main pipelines as demand for pipeline branches and throughput increased. As a path for possible growth of a pipeline network is not known, and this model is constructed around a generic system, a marginal length of 4.45 km was considered (equal to the distance between stations). The throughput of the marginal length is the demand of one station. This could represent an estimate of the capital cost apportioned to one station from the construction of a full capacity network, or the cost of connection to the next nearest connected station in a growing system. Again, the pipeline was also assumed to provide all necessary storage.

4.4 C: Electricity generation – grid – forecourt electrolysis

In this fuel chain, the output from the same range of generating technologies is assumed to be transmitted and distributed via the electricity network to the forecourt. Here it is used to power a forecourt electrolyser at a scale of around 1 MW. The electrolyser is scaled to meet the forecourt hydrogen demand if run continuously (several studies consider forecourt electrolysis to only operate at night, to take advantage of off-peak electricity prices e.g. DT (1997)). The capital cost per unit output of the electrolyser used is higher than in fuel chains A and B as a result of its small capacity. The hydrogen produced is then compressed and or liquefied and stored. In order to estimate capital costs of the whole fuel chain, the number of stations supplied by the average output of each generation technology is calculated.



4.4.1 Advantages and interactions

This fuel chain involves no transport of hydrogen by road or pipeline and therefore less new infrastructure than for chains A, B and E providing there is suitable grid connection to the refuelling station. There is therefore also no dependence on hydrogen delivery from an external source and so greater security of supply and greater control of the volume of hydrogen stored for use. As with fuel chain B, it is assumed that renewable electricity can be bought in from a variety of sources, both intermittent and predictable, such that the system can be run at its full capacity. However, the modelling assumes the input is entirely from one source, to allow the cost data from one source to be used. There is also no need for any of the chains to be exclusive – a refuelling station could be supplied by a combination of hydrogen generated onsite and that brought in from regional or national production. Given that there may not be scope for liquefaction at a forecourt scale, this could be important if both liquid and compressed hydrogen are required. It would also be possible to use a higher output electrolysis system and produce hydrogen to match the daily demand profile. This would depend on the electrolyser performance at variable load, and the relative sensitivity of costs to electrolyser and storage costs. A disadvantage of this fuel chain might be a lengthened planning process. Production of a gaseous or liquid fuel onsite may be subject to greater controls than storage alone. Efficient planning regulation for hydrogen production and handling facilities would be a prerequisite for a successful hydrogen infrastructure.

4.4.2 Compressed storage

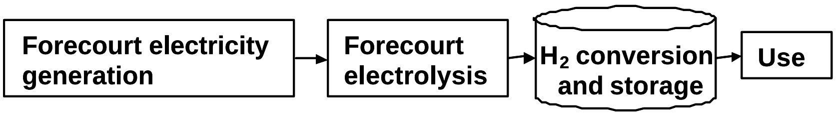
The hydrogen is compressed by a compressor sized for the rated output of the electrolyser. 0.5 days' storage is provided; this allows hydrogen produced during the night, when demand is low, to be stored for the daytime demand peaks.

4.4.3 Liquid storage

As discussed in section 3.7.1, there is some doubt as to the viability of very small scale liquefiers. The liquefier output here is 0.6-0.8 t/d, smaller than current commercially available plant. This option will still be considered, however, as modelling by Amos (1998) considers liquefaction at scales down to a fifth of those considered here, and also to allow for technology development. The liquefier is scaled at the rated output of the electrolyser, and operates continuously. 0.5 days' liquid storage is provided as above.

4.5 D: Forecourt electricity generation – forecourt electrolysis

This chain considers generation of electricity at the forecourt, either from a single 2 MW wind turbine, or from a 300 kW_p PV array. The output is used to power an electrolyser sized for the rated output of the generation. The hydrogen produced is then compressed using a compressor also sized for the rated output of the generation.



4.5.1 Advantages and interactions

This fuel chain is a completely decentralised system, with no dependence on external supply of hydrogen or electricity. Neither generation technology supplies enough hydrogen for the whole of the refuelling station demand, however there is a value to any secure generation capacity, especially if this is found to be competitive with other forms of supply.

4.5.2 Compressed storage

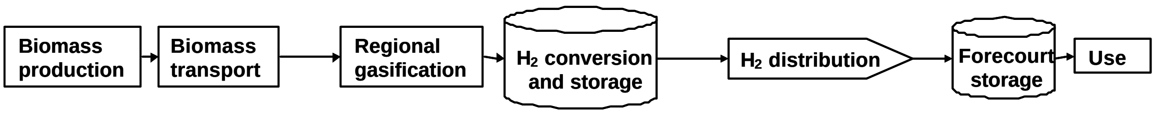
3 days compressed storage is provided to act as a buffer to intermittency of the generation. As in fuel chain A, longer term storage would allow a more consistent output, however may add significantly to the cost of the system, especially at this scale. The sensitivity of the hydrogen cost to the storage time will be considered later.

4.5.3 Liquid storage

A liquefier sized at the average output of the generation is used to liquefy the stored compressed hydrogen at a constant rate. The output of the chain with input from wind is 0.2-0.4 t/d, comparable with research scale liquefaction, but the PV chain would require liquefaction at 0.01 t/d. This is unlikely to be viable at present, but has been included to allow for possible developments in the technology. 0.5 days liquid storage is provided to store liquid hydrogen produced during the night.

4.6 E: Biomass production – gasification – regional transport 32 km

The inputs to this fuel chain are short rotation coppice and forestry wastes. These biomass products are harvested from an area large enough to provide 70 MW biomass input to a gasification plant (see section 3.5). This area is determined using the crop yield per hectare and an assumption of land use, and used to find the transport distance for biomass harvesting (see section 3.3). The biomass production and gasification plant are considered to be sited closer to the hydrogen demand than the electricity generation technologies, and therefore hydrogen distribution by compressed and liquid road transport and by pipeline is considered on the regional scale used for fuel chain B. The assumptions used for distribution of the hydrogen are therefore the same as those used for fuel chain B.



4.6.1 Advantages and interactions

A biomass crop could be used interchangeably as a feedstock for electricity, heat or hydrogen production depending on market conditions, demand or plant availability. Electricity generated could even be used in the other fuel chains (and would be available more cheaply than some other renewable generating technologies (ETSU, 1998)), however this would be a less efficient use of the biomass crop (see section 3.3).

5 Results and analysis

5.1 Results data

The costs, energy use and emissions from the fuel chains are presented in appendix D. The travel cost per kilometre driven assumes the use of hydrogen in a fuel cell vehicle. Capital costs for the whole fuel chain are given per vehicle served. Note that the total number of vehicles served by each refuelling station is several times greater than the number refuelled per day, as each vehicle has to refuel approximately once every 7 days. Energy use and emissions are also given per kilometre driven in a hydrogen FCV.

Appendix D gives the full results of the model. This study does not present an analysis of all 58 combinations of fuel chain, generating technology and distribution method, for both 2002 and 2020, as this would be lengthy, and would not highlight the key results. The principal trends and sensitivities of the model will therefore be discussed, using individual generating technologies and fuel chains as examples. The results from other generating technologies will be discussed if they differ significantly from the trends seen.

This section will first explain how the results obtained were compared with alternatives such as petrol and hydrogen produced from fossil fuels. The trends in hydrogen cost with energy source, time, fuel chain and delivery method will then be discussed for selected fuel chains. In order to understand the factors contributing to these trends, the results will then be broken down into constituent component costs, and the sensitivity to variation in these costs analysed. The trends in energy use and emissions from the chains will also be considered.

It must be considered that there is potential for all of the generation technologies considered here, and the aim is not to make a technology choice, but to assess a range of possibilities. It is also important to consider the available resource for each generation technology. Once the range of fuel chains with the greatest potential has been identified, using the considerations given above, the resources for each generation technology will be used to derive an approximate resource cost curve.

5.2 Comparison with alternatives

Travel costs per kilometre from renewable hydrogen will be compared with those from driving a petrol car in 2002 of 5.2 p/km. These costs were calculated using the average fuel consumption for new cars in 2000 (0.079 l/km) and the petrol price from June 2002 (74.1 p/l) (DfT, 2002, DTI, 2002). This petrol price includes VAT and fuel excise duty, which together make up around 73% of the pump price (IFS, 2000). The travel costs using hydrogen will therefore also be compared with the untaxed price of 1.4 p/km. Current prices will also be compared with 2020 hydrogen costs; it would be very difficult to project petrol prices to this date, given the heavy dependence of travel costs using petrol on crude prices, fuel duty and vehicle efficiency improvements. Note that none of the costs considered include an allowance for the capital costs of the vehicle used, which are likely to be considerably higher for fuel cell vehicles in the short term.

Transport policy and fiscal regimes heavily influence the price of any automotive fuel. It is not possible to forecast how these may change over a twenty year period. However, pilot projects using hydrogen in the UK will be exempt from fuel duty (Foley, 2001). It is not clear what level of fuel duty would be levied once the use of hydrogen became more widespread. Foley (2001) suggested that the government should make a commitment to set the duty at zero over a 5-year period to boost market confidence. Alternatively, it could be set at a level commensurate with the externalities, such as emissions, involved in its production and use. This is seen with the low current duty on road gases (LPG and CNG) in recognition of their low emissions of particulates and oxides of nitrogen (Brevitt, 2002).

The travel costs of hydrogen from renewable sources must also be compared with those for hydrogen produced other methods such as steam methane reforming. The cost of hydrogen from industrial scale steam methane reforming has been estimated at £3-5.6 /GJ (Hart et al., 2000). If this is assumed to be produced at a regional site, and distributed as in fuel chain B as a compressed gas, the delivered cost would be approximately £8-10.5 / GJ. This gives a travel cost of 0.95-1.26 p/km. Note that this is a cost, and not a price, and therefore includes no profit margin, fuel duty or VAT.

5.3 Variation of hydrogen costs with energy source

Fuel chain E, with inputs from the biomass products SRC and forestry wastes provides the cheapest delivered hydrogen, irrespective of distribution method. SRC and forestry wastes give very similar costs, within 0.02 p/km, with SRC being marginally cheaper.

For fuel chains A-D, with renewable electricity input, onshore wind gives the lowest travel costs. This is shown in figure 2 for fuel chain B for 2002. Onshore wind has the lowest generation costs of the electricity technologies considered. The electricity generation cost makes up a large proportion of the travel cost, and the travel cost is most sensitive to it for most fuel chains (see section 5.7).

Comparison of the fuel chains and their components will therefore be carried out using results from SRC and onshore wind fuel chains. Results from other technologies will be included where they differ significantly from these trends.

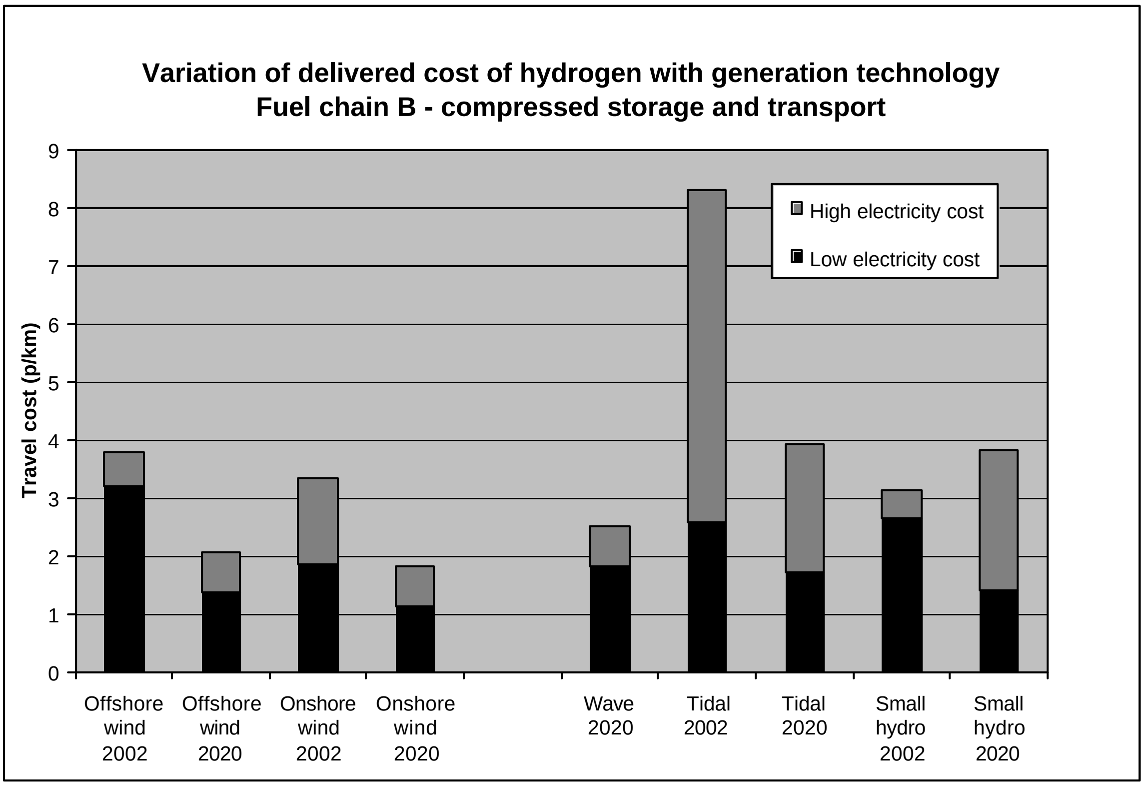


Figure 2: Variation of hydrogen cost with electricity generation technology. Note that wave energy based chains were not considered for 2002, and that fuel chain E (biomass) is not included here

5.4 Variation of hydrogen costs with fuel chain and transport method

Figure 3 shows that for 2002, the lower bound of the travel cost of hydrogen from all of the fuel chains would be lower than the current taxed travel cost of petrol. Pipeline transport is the lowest cost distribution method for all fuel chains where used; compressed storage and transport is cheaper than liquid storage and transport.

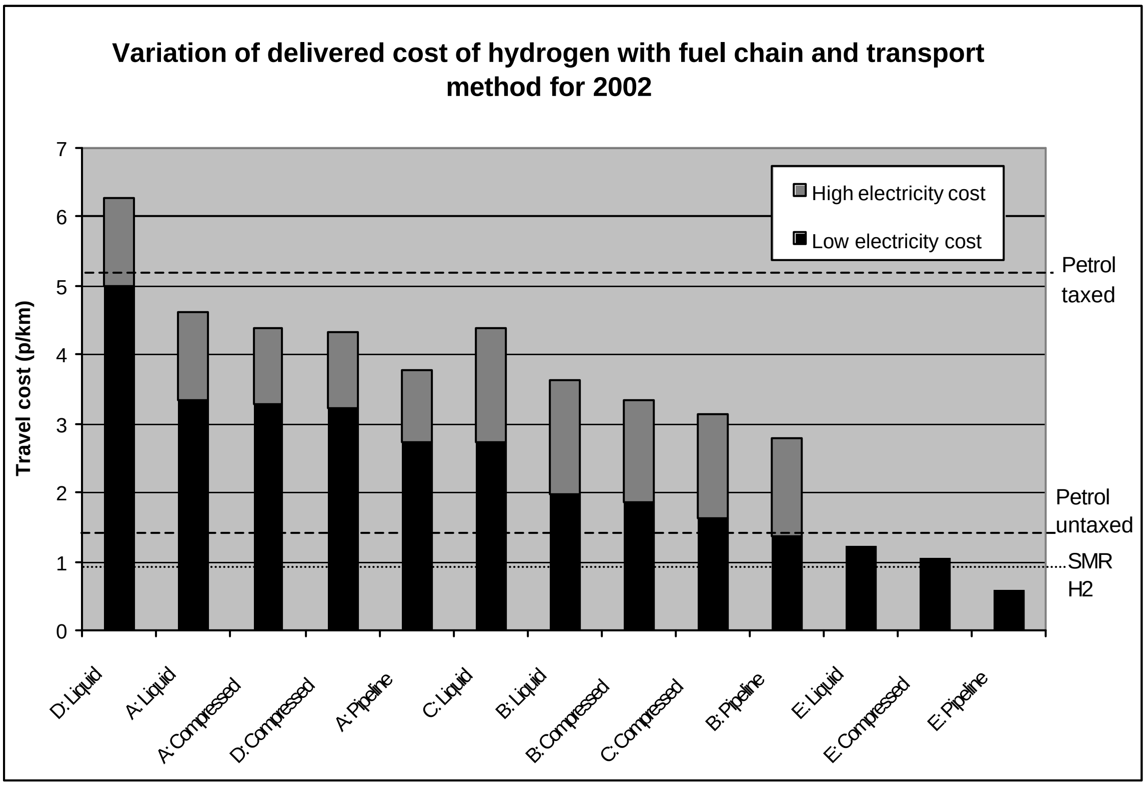


Figure 3: Variation of hydrogen cost with fuel chain and transport method for 2002.

Fuel chain E provides the lowest cost hydrogen, with travel costs lower than that of untaxed petrol for all distribution methods. Note that the value indicated from hydrogen produced regionally by steam methane reforming is the lower bound of the range given, and is for transport and storage as compressed gas. Therefore delivered costs for hydrogen production from biomass via fuel chain E are about the same as those from SMR, at around £8.80 /GJ.

Regional electrolysis and distribution, as represented by fuel chain B, also provides hydrogen at a lower cost than untaxed petrol, but only if pipeline transport is used (£11.40 /GJ). Chain B is cheap for all three distribution methods because of the short transport distance and because of economies of scale in conversion and storage. However, if the pipeline case is excluded, compressed hydrogen could be delivered at a lower cost using forecourt electrolysis via fuel chain C. This also avoids the need for road transport of hydrogen, reducing traffic and emissions. If liquid hydrogen is required, fuel chain B costs less than fuel chain C. This is as a result of the high cost of small-scale liquefaction, which outweighs the saving made by avoiding liquid transport.

Electrolysis and conversion at the wind farm, as represented by fuel chain A, has costs over a third higher than for fuel chain B. This is a result of reduced economies of scale of conversion technologies, and the high cost of hydrogen transport when compared with transmission and distribution of electricity. The higher cost of chains A and D may also be due to the need for oversizing of components to allow for intermittency. The sensitivity to costs of the components will be assessed in section 5.7.

Liquefaction at the electricity generation site, as in fuel chain A, or at a forecourt wind turbine, as in D, adds considerably to the system cost, making these the most expensive options. This is as a result of both the need for pre compression to allow for intermittency of generation, and the high cost of small-scale liquefaction plant.

5.5 Variation in hydrogen costs over time

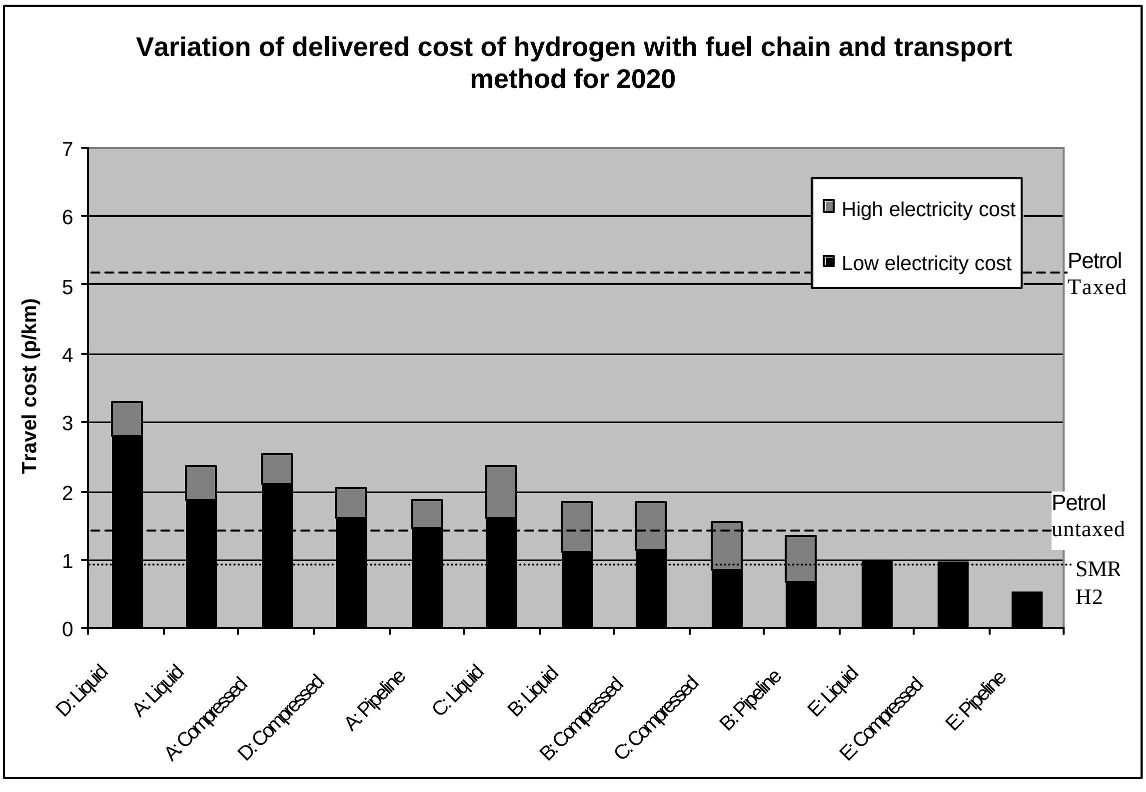


Figure 4: Variation of hydrogen cost with fuel chain and transport method for 2020

Figure 4 shows that travel costs for all the fuel chains decrease for 2020. Note that this is not the case for the chains based on input from small hydro, for which the high electricity cost value increases for 2020. This is because the upper bound of the electricity cost range increases as the best sites are developed.

The results in figure 4 have been presented in order of decreasing cost for *2002*. This is to allow easy comparison across figures 3 and 4. The petrol prices given are the same (as discussed earlier), and the SMR hydrogen cost was projected to decrease to a low value of 0.87 p/km, given a 10% decrease in SMR cost, constant gas price, and the same decrease for the other components as used in fuel chain B.

The results from fuel chain E do not decrease greatly between 2002 and 2020. The significant decrease in cost of the electricity-based chains results in the cheapest of these now being available at lower cost than the biomass-based ones. This is an important result given the limited biomass resource (see section 5.10). The lowest cost electricity based-chains would also be available at a lower cost than hydrogen from SMR. In 2020, over half of the fuel chains provide hydrogen at a travel cost lower than the untaxed travel cost of petrol.

The relative costs of chains with liquid storage decrease relative to the other chains. For example, in 2020, A (liquid) is cheaper than A (compressed), there is less discrepancy between liquid and compressed values for fuel chain C, and the costs are approximately the same for liquid and compressed in fuel chains B and E.

The travel costs of chains with pipeline transport also decrease more significantly than those with compressed or liquid transport. This is because there are fewer cost components of the pipeline fuel chains, and so the decrease in electricity cost has a greater effect.

5.6 Costs of fuel chain components

The discussion of total travel costs from all the fuel chains showed that it is necessary to consider the relative costs of the fuel chain components and their decrease to 2020 in order to explain the range of fuel chain travel costs. It would not be possible to assess the effects of all components of all fuel chains within this thesis. Fuel chains B and E were chosen as representative examples, as both include all components studied. Fuel chain D was also considered, as the results for PV inputs to this fuel chain are significantly different from those for other chains modelled.

Figure 5 shows the breakdown of costs for fuel chain B, which gave the lowest costs for an electricity chain for all three transport methods.

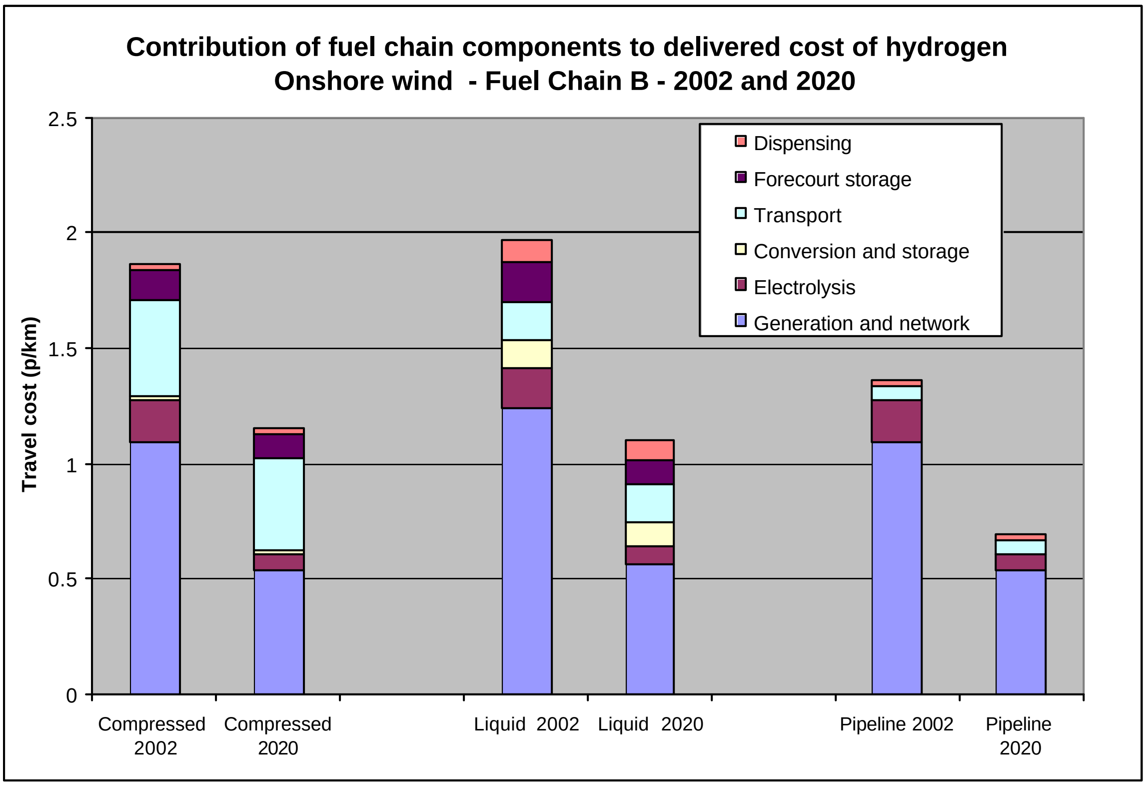


Figure 5: Component costs for fuel chain B: onshore wind for all transport methods, for 2002 and 2020

Figure 5 shows that electricity generation contributes to more than half of the travel cost of hydrogen, irrespective of transport method and time. The reductions in cost for 2020 are principally due to reductions in the electricity cost. Other important effects shown include the high contribution of compressed transport to travel costs, and the impact of high costs of liquefaction and liquid dispensing. Note that the costs of electricity generation per km driven are not the same; the same output of electricity is produced, but the cost is higher per km for the liquid chain as the chain is less efficient.

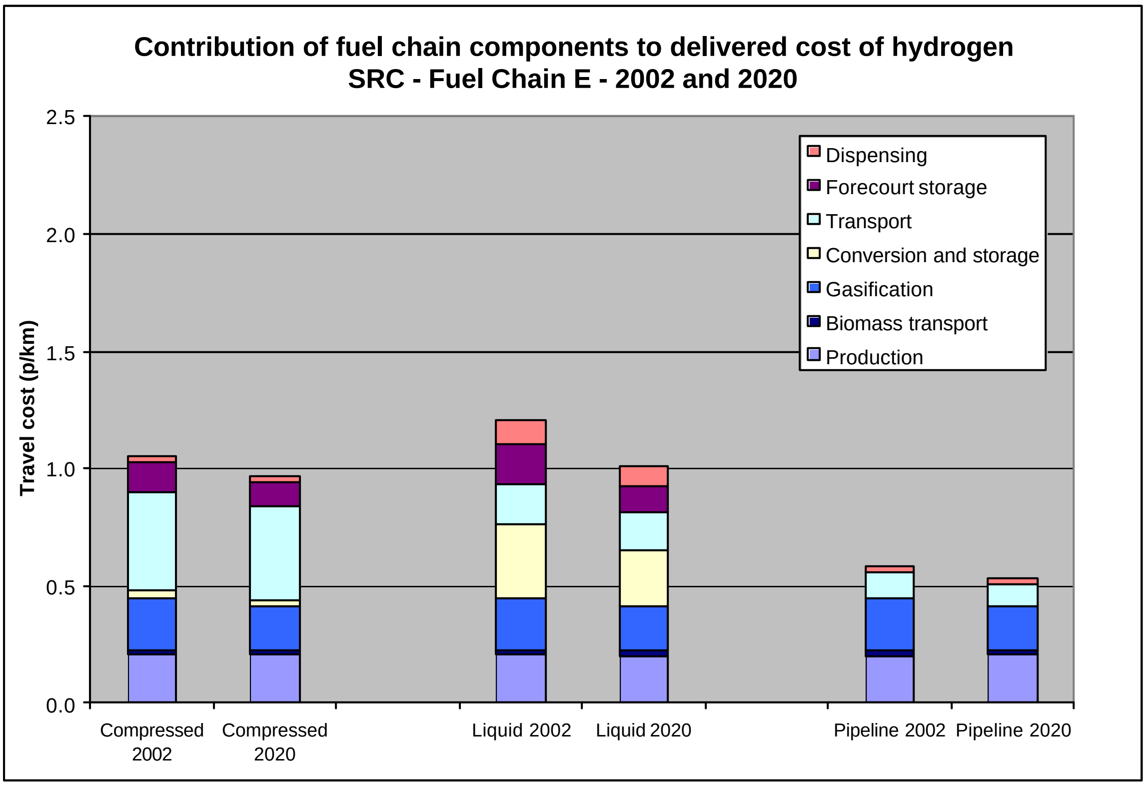


Figure 6: Component costs for fuel chain E for all transport methods, for 2002 and 2020

Figure 6 shows the breakdown of costs for fuel chain E. The conversion, transport, forecourt storage and dispensing costs are the same as those for fuel chain B. The cost of energy input, here the biomass production, is a much smaller proportion of the travel cost. There is a much smaller decrease in cost to 2020 as the cost of biomass production and transport was not projected to decrease. The reduction in cost is due to cost reductions in gasification and conversion with technology development and learning.

Figure 7 is provided to show how the breakdown of costs varies for forecourt generation systems (chain D). The forecourt wind generation is large enough to benefit from some economies of scale in the electrolyser and conversion equipment. The PV chains, however, have such small output that even costs such as that from the dispenser, which is minimal for the other fuel chains, become important. This is the only fuel chain where the cost and scale of generation varies so much as to have a large effect on the travel cost. PV also has the largest projected decrease in generation cost for 2020.

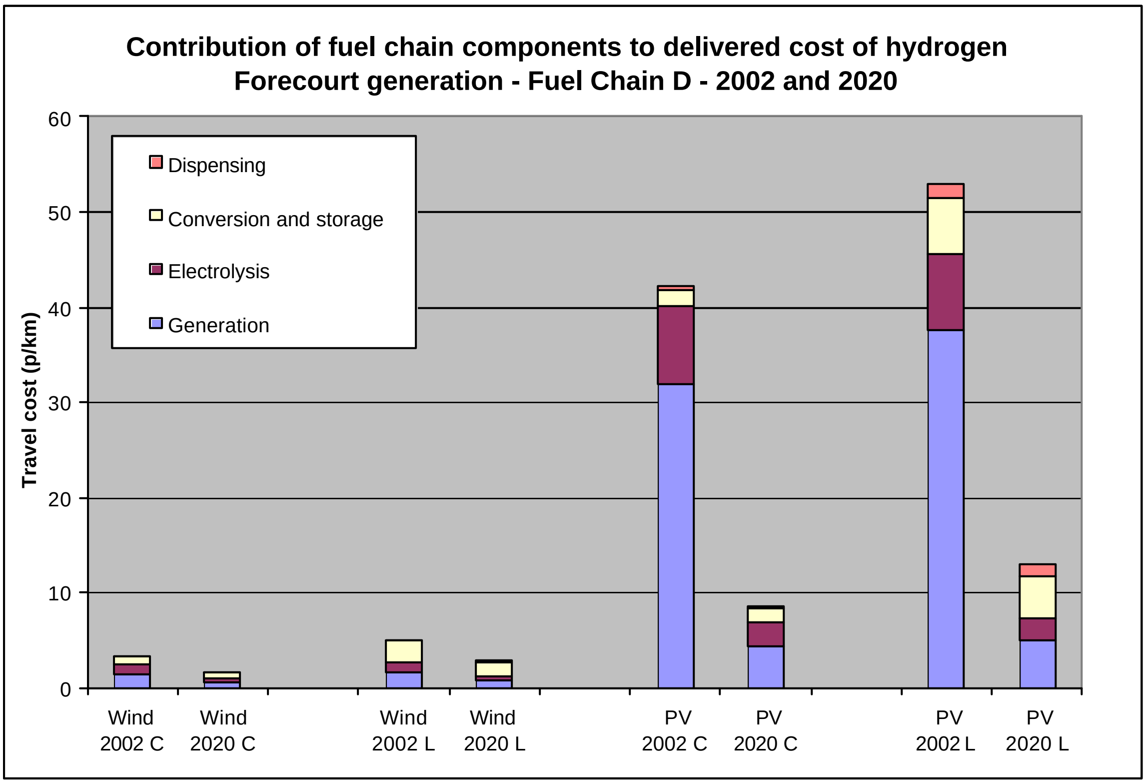


Figure 7: Component costs for fuel chain D, for both wind and PV generation for 2002 and 2020

These figures show the impact of the input cost parameters on the travel cost, but do not show how sensitive the costs are to these parameters, or their range of variation.

5.7 Sensitivity analyses

Sensitivity analysis was carried out on fuel chains A-E, with compressed storage, for the low electricity cost values for onshore wind and SRC for 2002. The compressed storage option was chosen as it allowed comparison of the sensitivity of travel costs to the same parameters across all five fuel chains, and was one of the lower cost options for each. In order to allow this comparison across the storage and transport methods, sensitivity analysis of compressed, liquid and pipeline options was also carried out for fuel chain B. This chain provides low travel cost hydrogen for each transport and storage option, can be compared with fuel chain E, and the spider graphs obtained can be compared with the component cost charts in figure 6. All possible parameters were varied for the sensitivity analysis. The model was not sufficiently sensitive to allow variation of some parameters, such as truck volume and delivery logistics. This would be a useful improvement for future models. The following table shows the parameters used, and the range over which they were varied.

Parameter	**Min**	**Original**	**Max**	**Notes**
Electricity price (p/kWh)	1.5	2.5	4.6	Future low cost estimate and current high cost estimate
Electrolyser cost ($/GJ $_{out}$) for >2MW	7.6	19.0	31.7	Future cost estimate and highest value seen in literature (Padró and Putsche (1999))
Electrolyser cost ($/GJ $_{out}$) for 1.1 MW (forecourt)	14.8	37.0	55.5	In proportion with future cost estimate and highest value seen in literature (Padró & Putsche (1999)
Electrolyser energy use (kWh/Nm^3)	3.5	4.5	6.1	Lowest possible value and highest value seen for commercially available system
Compressor cost (£/kW)	-20%	-	+20%	Established technology
Tank cost (£/kW)	-40%	-	+40%	Variation in tank type and material
Storage time at generation site (days) compressed	2	3	4, 5	Variable buffer storage (Chains A and D)
Storage time at regional production site (days)	-	0.04	0.06, 0.08	The low value is the one-hour minimum, higher values allow flexibility
Compressed and liquid transport costs	-50%	-	+50%	Value used was not specific to the volume transported and so large potential for variation
Forecourt storage time for delivered compressed hydrogen (days)	0.4	0.5	1	The low value is the interval between deliveries and the high value allows for increased truck capacity
Compressed dispenser cost ($/kg/hr)	2400	3000	6000	Low value is –20%, highest value was quoted for a small system
Forecourt storage time for delivered liquid hydrogen (days)	6.8	7.5	8.2	The lowest is the delivery interval, highest is +10%
Liquefier energy use (kWh/kg)	4.9	8.0	14.0	Lowest is magnetic liquefaction, highest is Linde Ingolstadt plant
Liquefier cost (£/kg/hr)	-40%	-	+40%	Liquefaction is at a relatively early stage of commercialisation so a wide range is used
Dewar cost (£/kg)	-40%	-	+40%	There is little experience with very large scale Dewars and a range of types and materials can be used
Pipeline cost (£/GJ/yr)	-20%	-	+20%	At small flows the variation of cost with flow rate is steep, giving potential inaccuracy in pipeline cost, estimated at ? 20%
Pipeline branch length (km)	2.2	4.4	8.9	The distance of a refuelling station from a pipeline may vary
Biomass feedstock cost (£/GJ)	-20%	-	+20%	Little information was available on biomass costs, however they are unlikely to vary widely
Gasifier efficiency (%)	50	55	58	Range given in Williams (1995) for different gasifier types (minus electricity requirements)
Gasifier cost (£/GJ/yr)	-40%	-	+40%	A wide range is used given the early stage of commercialisation of gasification to hydrogen

5.7.1 Across fuel chains

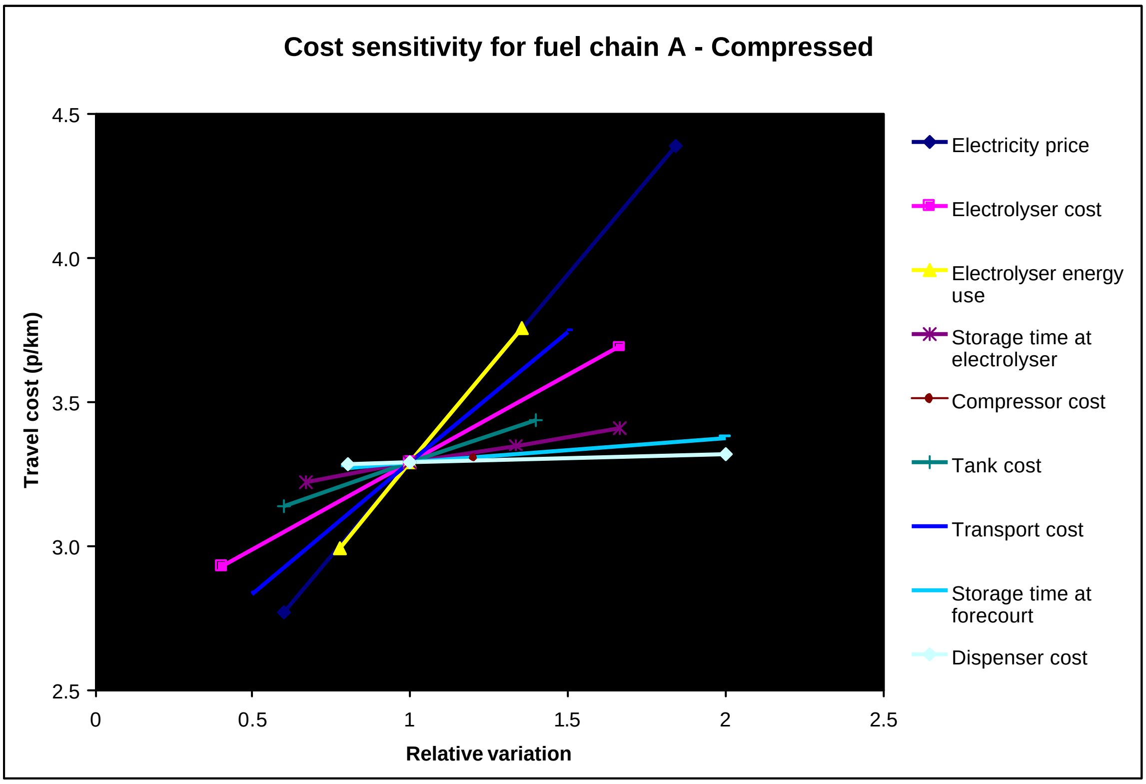


Figure 8: Cost sensitivity for fuel chain A: compressed. 'Tank cost' is the compressed storage cost, and affects both the storage costs at the production site and at the forecourt

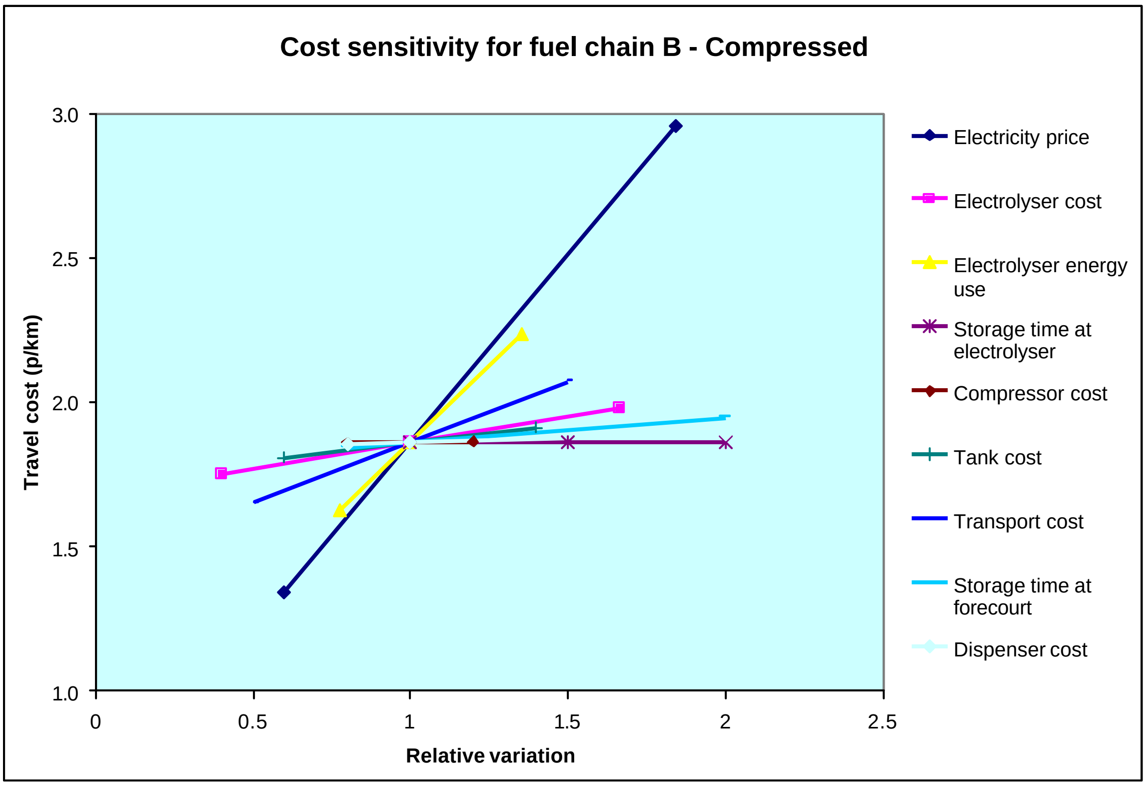


Figure 9: Cost sensitivity for fuel chain B: compressed

Figures 8 and 9 show the sensitivity of costs to the parameters used in fuel chains A and B. Note that the scales are the same, to allow comparison of the gradients of the lines. Both chains are most sensitive to the cost of electricity and therefore also to the energy use of the electrolyser, which has the largest energy consumption of the fuel chain components. This result shows the effect of uncertainty in projecting future renewable electricity cost on future hydrogen costs. The uncertainties in projected costs of many of the hydrogen technologies, which are in some cases significant given their early stage of development and commercialisation, have a minimal effect when compared with those for electricity generation. It should be noted, however, that one hydrogen technology having a direct effect on the costs per km driven is the hydrogen consumption of the FCV itself. The use of a hydrogen ICE, with an efficiency less than half that of the FCV would more than double the travel costs.

The cost of compressed transport is also an important factor, more so for fuel chain A, due to the longer transport distance. A more sensitive model for transport costs would therefore be beneficial in future work. Electrolyser and tank costs have a lesser effect on costs in fuel chain B than in fuel chain A, due to economies of scale. It can also be seen that storage time at the generation site and forecourt has a much lesser effect on chain A than expected. It might therefore be possible to increase the buffer storage included to balance intermittency of generation without adding significantly to the system cost. This may need to be assessed on a site-by-site basis, knowing the specific capacity factor and transport parameters for that site.

Figure 10 shows the cost sensitivity for fuel chain C, forecourt electrolysis. The cost of hydrogen from fuel chains B and C is more heavily dependent on the electricity price and electrolyser energy use than for fuel chain A. This is because the electricity price is a higher proportion of total costs. In general, the sensitivity of costs to the cost of each component increases with decreasing number of components. Therefore a variation in the cost of one component that may not have been identified in the model is likely to have a greater impact on the fuel chains with fewer stages, i.e. C and D.

Fuel chain D is more sensitive to the cost of electrolysis and forecourt storage than the other fuel chains, as costs increase for small systems, and all components are oversized. Figure 11 shows that a decrease in cost of the electrolyser could have a greater effect than electricity price reduction, reducing the travel cost to 2.5 p/km.

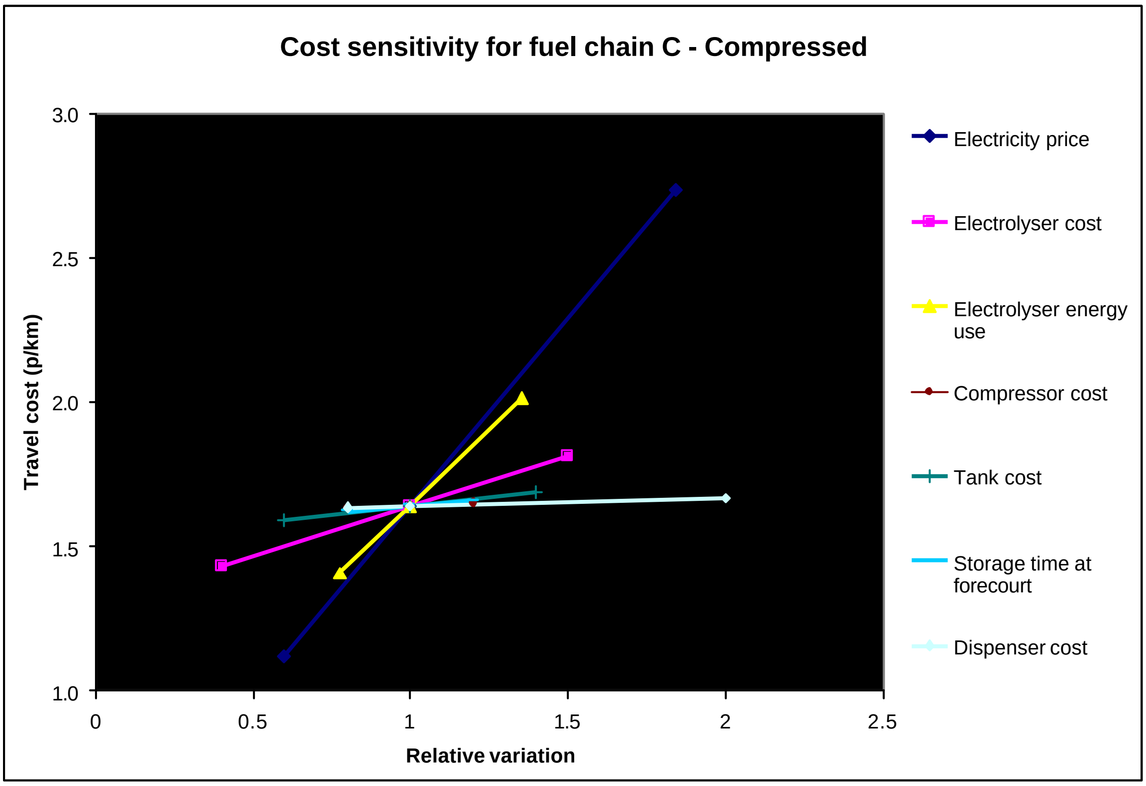


Figure 10: Cost sensitivity for fuel chain C: compressed

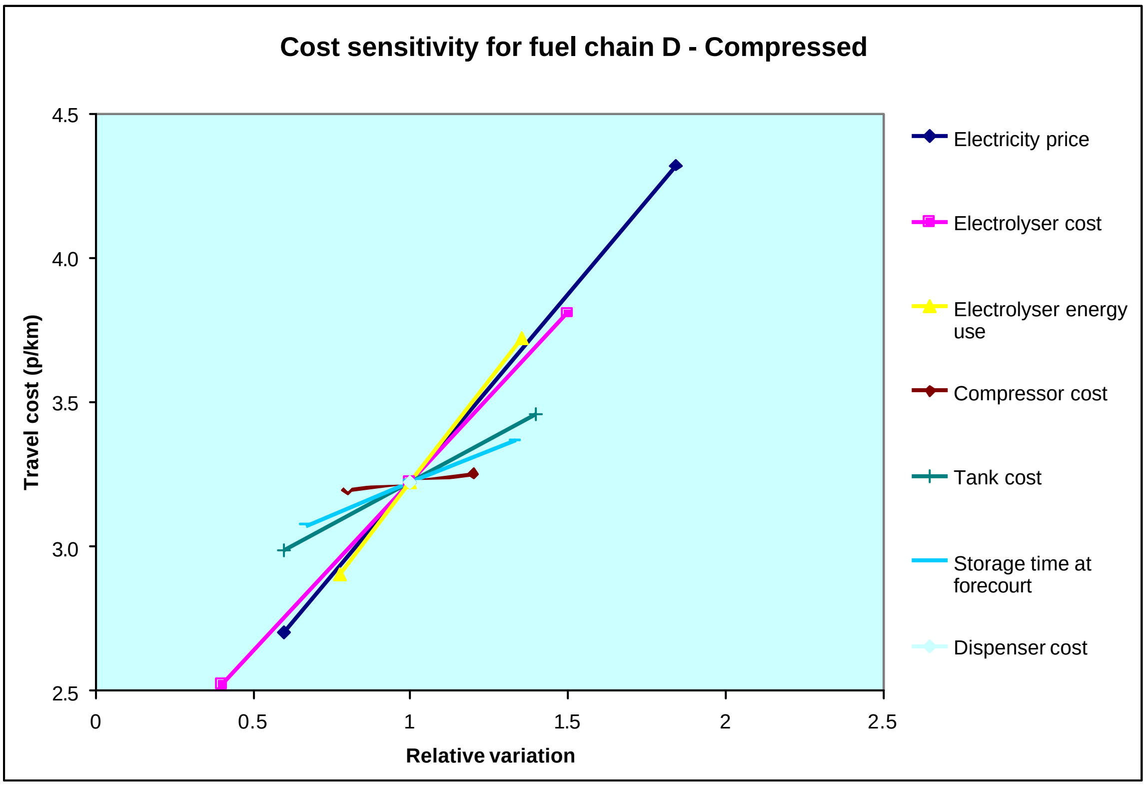


Figure 11: Cost sensitivity for fuel chain D: compressed

5.7.2 Across transport and storage options

As liquid transport is cheaper than compressed transport, the costs of liquid hydrogen from fuel chain B are less sensitive to transport costs than those for compressed hydrogen (see figure 9). Costs are relatively stable (variations of less than ?10%) with variation in all parameters except electricity cost and electrolyser energy use.

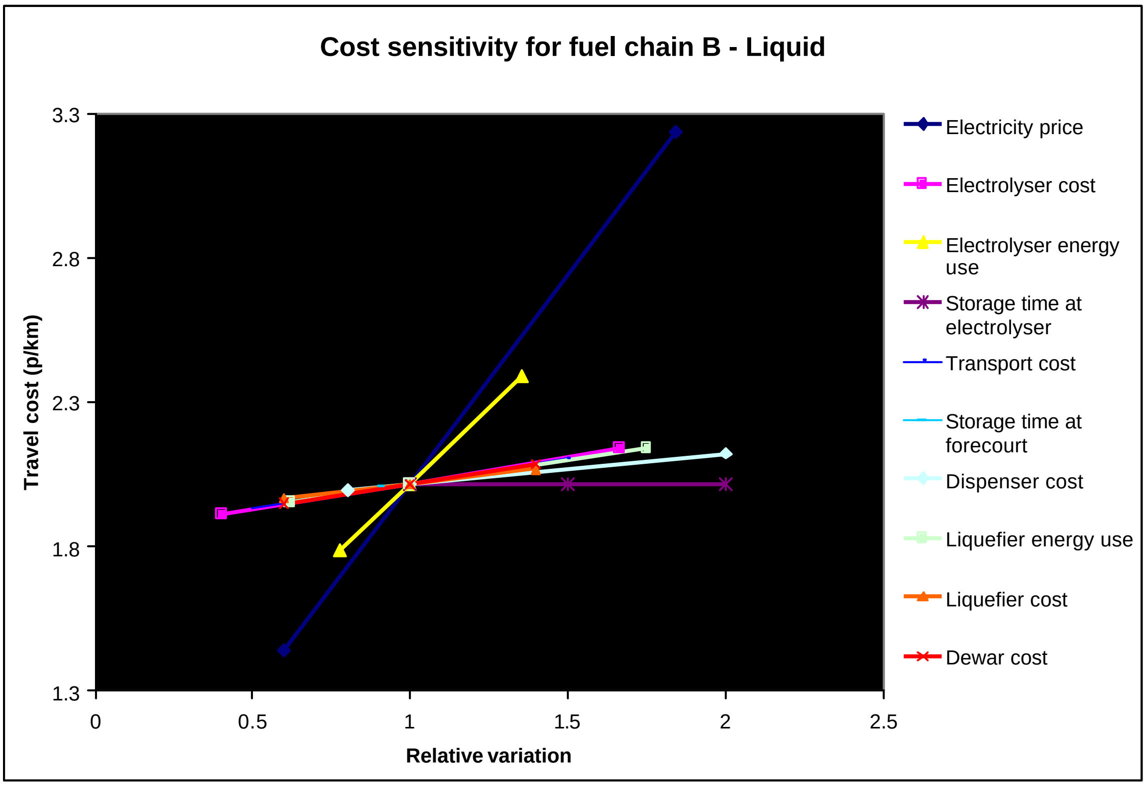


Figure 12: Cost sensitivity for fuel chain B: liquid

This is also the case for regional distribution by pipeline (see figure 13). Due to the small contribution of pipeline costs to the travel cost, there is also relatively low sensitivity to the length of branch pipeline needed to connect the refuelling station to the nearest connected site. The low hydrogen costs from this chain mean that electricity price and electrolyser energy use cause significant variation in the result, to a maximum increase of over 75%. A cost lower than the cost of untaxed petrol may therefore not be achieved in all cases.

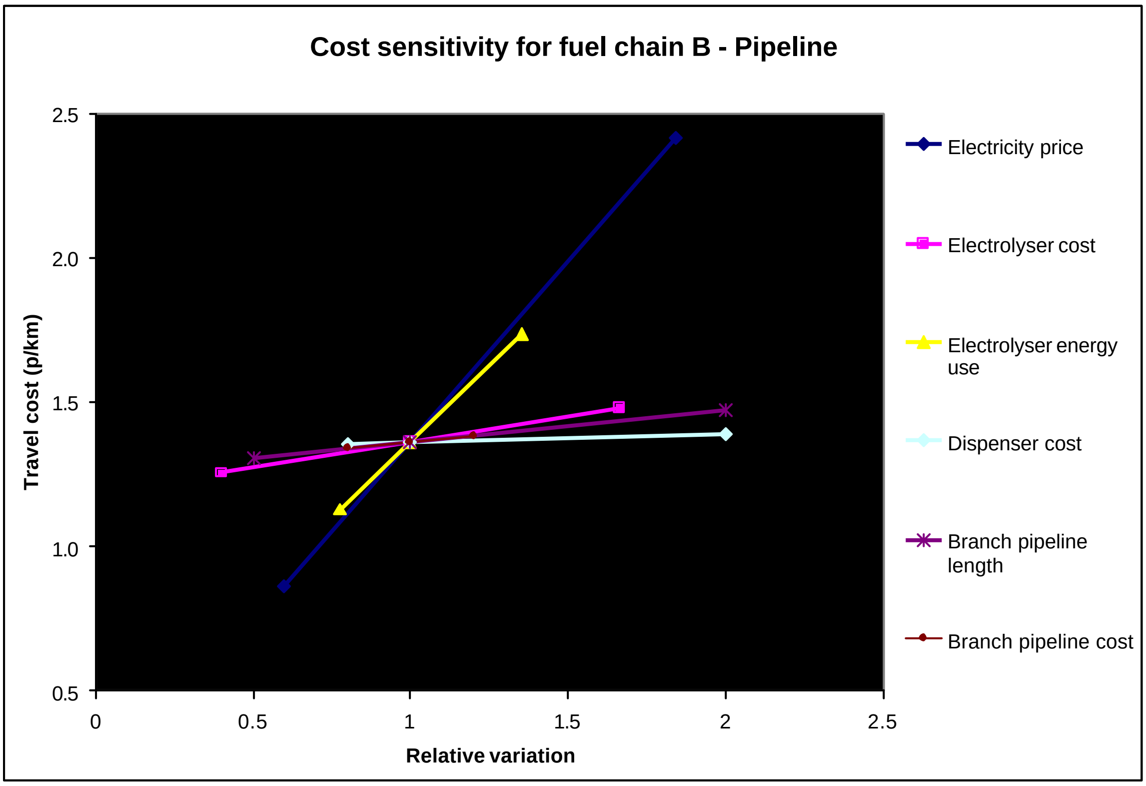


Figure 13: Cost sensitivity for fuel chain B: pipeline

5.7.3 Fuel chain E

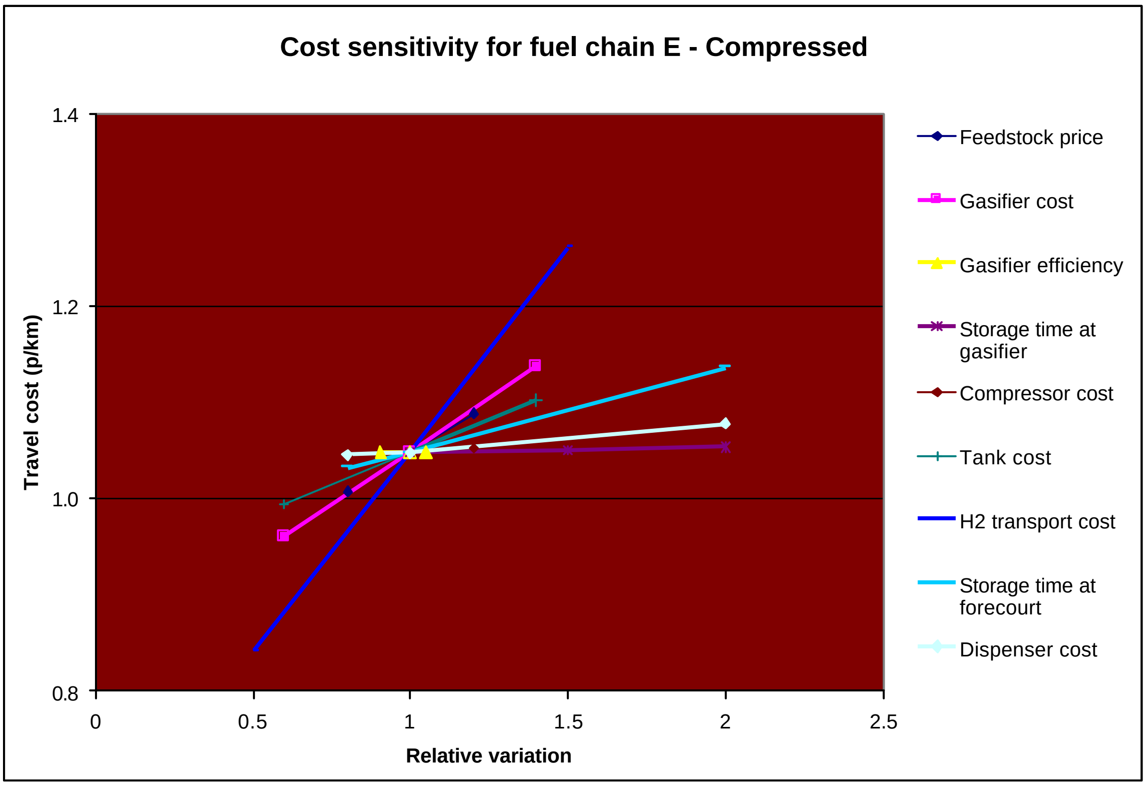


Figure 14: Cost sensitivity for fuel chain E: compressed

The cost of hydrogen from fuel chain E is far more stable than from the electricity-based chains (note the increased scale of figure 14). Only the cost of compressed transport causes a variation in cost of more than ?10%. The sensitivity to the costs of the other hydrogen technologies are larger than those for compressed transport in fuel chain B, as they comprise a higher proportion of the final costs. However, the cost of hydrogen is more stable with respect to the cost of the biomass crop, cost of the gasifier and gasifier efficiency in this chain than to the costs of electricity generation and conversion in chains A-D.

5.8 Energy use, emissions and the environment

The life cycle energy use of a petrol ICE is 2.84 MJ/km (Shell, 2001). Appendix D shows that the non-renewable energy use of the fuel chains modelled here does not exceed 9% of this value. The non-renewable energy use of fuel chain A is 21% of the energy content of the fuel used per km. As the only non-renewable energy use considered here is diesel for hydrogen and biomass transport, and for biomass production, many of the fuel chains have zero values.

The hydrogen production efficiency (the energy content of hydrogen produced per unit of electricity or biomass energy input) of the fuel chains A-D also varies depending on the energy consumption of electrolysis and conversion. The fuel chains with compressed storage or pipeline delivery have an efficiency of 64% (excluding non-renewable energy input) in 2002, increasing to 75% in 2020. The 2002 values reduce to 53% for liquid storage in fuel chains B, C and E, and 51% for fuel chains A and D, where pre-compression adds to the energy use of the conversion step. Fuel chain E is only 49% efficient in 2002 for compressed or pipeline transport, increasing to 56% in 2020 with improved gasification.

The ‘energy ratio’, i.e. the energy content of hydrogen produced divided by the energy input for each chains also varies considerably. The only energy inputs to the electricity-based fuel chains are from transport, as electricity generation has a very large energy ratio. Thus the energy used in compressed transport in fuel chain A results in a very low energy ratio, of only 4.7. This increases to 24 for fuel chain B with compressed transport, and to 600 if liquid transport is used. For electricity-based fuel chains not including road transport, the energy ratio is very large, and cannot be estimated within the scope of this study. Energy ratios for fuel chain E are between 6.9 and 9.8 depending on distribution method, as a result of the energy used in biomass production and transport.

Appendix D also shows that carbon dioxide emissions are greatest from the use of short rotation coppice in fuel chain E, at 16-21 g/km, depending on transport option. Fuel chains A and B have non-zero emissions for compressed transport, of 17 and 3 g/km respectively, with the rest of the chains having negligible emissions. These figures are very small compared with the average well-to-wheel CO_2 emissions of a new petrol car in 2000 of 170 g/km (EST, 2002). The smallest, most efficient petrol cars such as the Smart and Prius petrol hybrid have well-to-wheel emissions of under 140 g/km, with a level of 100g/km being set as the threshold for consideration as a 'low carbon' technology (EST, 2002).

Given that the compressed hydrogen tube trailers have a capacity of only 180 kg, a very large number of trailers are needed for even small volumes of hydrogen supply. For example, the hydrogen demand of one refuelling station in 2002 would require 3.3 trailers per day. If a regional distribution site, as considered in fuel chain B were to supply the whole regional demand with compressed hydrogen delivered by tube trailer, over 1300 trailers would leave the site every day, i.e. nearly one trailer every minute. This volume of large vehicle traffic, fuelled by diesel for the foreseeable future, would have a detrimental effect on the local area in terms of noise, air quality and congestion. Such frequent resupply of refuelling stations would also be disruptive to the operation of the station. This option is therefore only really suitable for a small hydrogen demand, i.e. infrequent delivery. Improvements in trailer capacity, using higher storage pressures or alternative storage methods (see section 3.7) would be needed to make compressed delivery a viable option for supplying the entire transport demand of a refuelling station.

5.9 Fuel chain comparison

In order to estimate the potential for renewably produced hydrogen in the UK, the most viable fuel chains for its production must be identified. As discussed above, all of the fuel chains considered are available at costs in the same order of magnitude, and the most suitable option will depend on the specific location and supply characteristics of the generation site, location and demand of the refuelling site, demand growth and the form of hydrogen required by consumers. However, several of the chains have particular benefits that would make them a viable option in a wide range of cases.

Fuel chain E provides the lowest cost hydrogen, with the lowest capital cost requirement per vehicle served. Pipeline delivery is the lowest cost and lowest energy use and emissions option, however this lacks short-term flexibility of supply volume. Compressed delivery could be used for very small demands, though liquid delivery would be a viable option during market growth.

Fuel chain B with liquid or pipeline delivery would supply hydrogen at low cost, has low carbon dioxide emissions and energy use, and no problems of road traffic volume. As with fuel chain E, centralised hydrogen production gives economies of scale and means that maintenance is not needed for a large number of distributed sites.

Fuel chains C and D could be used if compressed hydrogen were required, and may be very useful in the early stages of infrastructure introduction, but are unlikely to be viable in the short term for liquid hydrogen supply. Fuel chain C is available at lower cost than fuel chain B in some cases, has zero emissions, and allows the refuelling station to manage its own production to meet demand.

5.10 Resource

The renewable energy resources given in section 3.2 can be used to derive an approximate resource cost curve for renewable hydrogen transport. It was assumed that hydrogen was produced from renewable electricity by fuel chain B and from biomass from fuel chain E, with pipeline delivery in both cases, as this is the cheapest and one of the most efficient options. The fuel chain efficiencies and other data used in derivation of the curve are given in table 12 below. It was assumed that the resource stated was only available at the high travel cost, i.e. the upper bound of the cost range. This was necessary because the proportion of the resource available at lower costs was not known. A more accurate and less conservative estimate could be made by summing hydrogen resource cost curves derived from those for each generation technology. Note that the resource available from forecourt generation, as modelled in fuel chain D, was not included, as the number of possible sites for single wind turbines, or refuelling stations with space for a significant area of PV panels could not be estimated.

	2002	2020
Efficiency of fuel chain B: pipeline	64%	75%
Efficiency of fuel chain E: pipeline	49%	56%
Vehicle energy consumption (MJ/km)	1.2	1.2
Annual travel per vehicle (km)	15,150	15,150
SRC resource (Modt/yr)	16	24
Forestry wastes resource (Modt/yr)	1.4	1.7
Onshore wind resource (TWh/yr)	26	26
Offshore wind resource (TWh/yr)	986	986
Small hydro resource (TWh/yr)	1.6	1.6
Wave resource (TWh/yr)	50	50
Tidal resource (TWh/yr)	36	36

Table 12: Data used in estimation of the resource cost curve.

The annual travel per vehicle was calculated from a figure of 9410 miles/year (DfT, 2002). To facilitate comparison of the results for 2002 and 2020, the vehicle travel parameters were kept constant for 2020. This avoids error in projecting the combined effect of decreasing vehicle energy consumption with increase in travel demand given the relatively early stage of fuel cell vehicle commercialisation and the possible policy influences on personal travel.

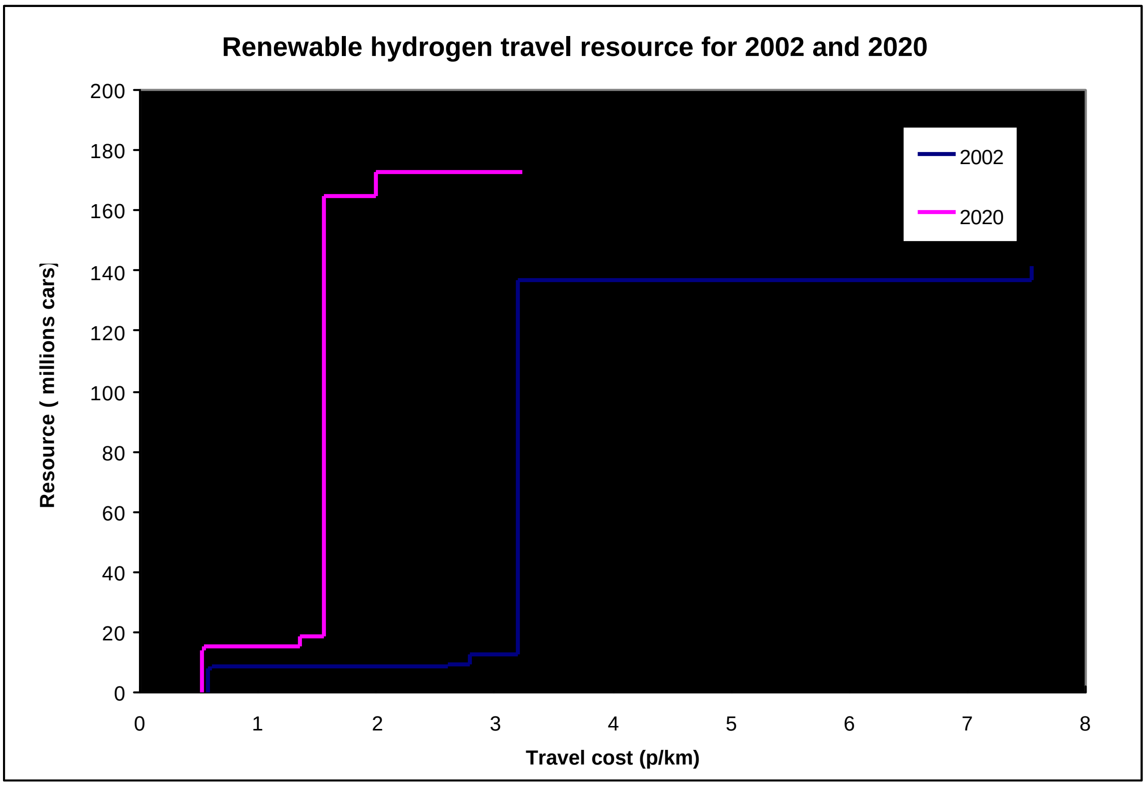


Figure 15: Estimated resource-cost curve for 2002 and 2020

Figure 15 shows that if the total resource of the renewable technologies considered here were used to produce hydrogen, enough could be produced to refuel the UK fleet of 24.4 million cars (DfT, 2002) nearly six times over. Even if the total electricity demand of the UK of 300 TWh/yr (equivalent to about 41 million cars) was assumed to be produced from renewable sources, the fleet could be fuelled four times over. Note that this does depend heavily on the offshore wind resource, responsible for the large increases in resource at 1.6 p/km in 2020 and 3.2 p/km in 2002. If the potential for offshore wind were reduced to the most conservative estimate of 100 TWh/yr (ETSU, 1998), the total resource would be reduced to only 29 million cars in 2002.

Figure 15 is more useful for demonstrating the significant resource available at low cost. Nearly 19 million cars, or 40% of the UK car fleet could be fuelled at a cost lower than that for untaxed petrol in 2002. Biomass, onshore wind and small hydro contribute to the resource below this cost (1.4 p/km). In 2020, over 75% of cars could be fuelled at this cost. Note that these figures do not include a contribution from offshore wind, and therefore are not affected by the differing estimates of its potential.

This represents the total practicable hydrogen resource available, from the practicable resource of each renewable energy source. In practice, the number of cars fuelled by renewable hydrogen will depend on the level of renewable energy generation, and the proportion of that generation used for hydrogen production. Switching of renewable electricity generation to hydrogen production, or investment in renewables capacity dedicated to hydrogen will depend on a range of market and policy factors, discussed in section 7.

6 Discussion of model results

6.1 Introduction

The identification of possible hydrogen production routes, review of the status of their component technologies, and subsequent modelling of their performance shows that renewable production of hydrogen can be considered to be a viable option for the UK. Whilst not including a detailed system simulation for each fuel chain, the model provides the important result that the majority of the fuel chains provide hydrogen at travel costs in the same order of magnitude, which for 2020 are lower than for untaxed petrol if used in a fuel cell vehicle. This allows choice between fuel chains based on other, more system specific factors, such as whether a refuelling site is suitable for hydrogen production, or would benefit more from hydrogen being delivered to it by road or by pipeline. It also allows interactions between the fuel chains, so that a combination of hydrogen supply chains could be used at any one time. Infrastructure and expertise developed during use of one fuel chain could be used as building blocks for new chains becoming more viable with increasing demand or technology development.

This result does, however, bring up the question of whether the model is sufficiently sensitive and accurate to distinguish between the fuel chains effectively. It also means that to determine the most suitable range of fuel chains for a particular demand, a more detailed study may be needed. This section will therefore consider the quality of the model structure and input data, and suggest improvements that could be included in further work based on this initial study.

6.2 System choice

The scope of the technologies included in the model was narrow enough to allow detailed consideration within the timeframe of the project, but wide enough to incorporate the principal options. In future work it would be valuable to assess further technology options such as other biomass crops and wastes for hydrogen and electricity production. Further consideration of hydrogen storage and transport options such as underground storage, and the use of metal hydrides for compression and storage could also reduce the costs of some fuel chains considered. Consultation with developers of hydrogen technologies could help in assessing the potential timescale for introduction of novel components, such as smaller scale liquefaction.

The greatest benefits of many of the fuel chains could lie in the interactions between them, particularly the switching of output from hydrogen to electricity production possible with biomass gasification or with electrolysis at the remote generation site as in fuel chain A. Modelling these interactions as part of a modular energy system would entail considerably more complexity than the linear model used, and therefore preferably the use of a more sophisticated program to deal with feedbacks and enable optimisation. A detailed study of the technical and economic characteristics of the electricity network would be also needed, and the most valuable results obtained when modelling generation at a defined location. This would allow use of specific capacity factors, network availability and transport distances.

In a more detailed study, the system boundaries used for estimation of energy use and carbon dioxide emissions could be widened. Embedded energy in fuel chain components and energy used in their operation and maintenance could be included. Consideration of other emissions such as NO_x and particulates would allow comparison of local air quality impacts.

6.3 Input data

The data were obtained from a thorough review of papers from peer reviewed journals, the US Department of Energy publications and UK government department statistics. For some parameters there was a significant discrepancy between estimates from different sources, such as for the potential of renewable electricity resources, or the cost of electrolysers at varying scales. In these cases, the different estimates, and if possible the assumptions behind them were discussed. The values chosen were then those on which there appeared to be a consensus from several sources, or those that were most recent and/or applicable to the systems studied in this model. In several cases the values used were checked through discussion with others working in the field (e.g. Hart, Bauen, Madden). As a result of this process, the input data for 2002 can be considered to be the best available from a literature review. For a more detailed system study, it would, however, be preferable to contact a range of component manufacturers directly to obtain up-to-date quotes and technical data not available in the public domain. For some of the parameters, it was not possible to find data applicable to the scale of system used, or to find a suitable scaling factor. The assumptions used to extrapolate the data found to the scale needed were described in the technology review, and will be assessed in section 6.4.

There was very little available information on projected costs and efficiencies for 2020 for the majority of the fuel chain components excluding the renewable electricity generation technologies. As a result, costs and in some cases, efficiencies for 2020 were estimated using a relatively simple method linked to the stage of technology development. More detailed analysis, such as the combined engineering development/learning curve approach used in the working paper on electricity generation technologies for the PIU Energy Review (PIU, 2001h) would provide more accurate projections. However this would be very difficult for many of the fuel chain components given the lack of market experience with their use. This study was also intended to assess the potential for all the fuel chains concurrently, without considering each to be the dominant option, with large manufacturing volumes of the components. As learning curve approaches rely on projected manufacturing volumes it would have been difficult to apply them in this case.

Section 5.7 showed that the travel costs obtained from the model were sensitive principally to the electricity price and to the cost and energy use of the electrolyser. The best projected data were available for the electricity generating technologies, making the results fairly robust with respect to this component. However, the data for electrolysers were one of the areas of greatest uncertainty (see below).

In a longer-term study, it would be beneficial to send the model input data and assumptions out for discussion and review among those working in the area, such as manufacturers, academics and developers of hydrogen projects.

6.4 System design

The fuel chains modelled include all major components, as seen in the other similar studies reviewed but did not go into detail of more minor components such as inverters. These components would be unlikely to contribute significantly to the system cost, unless their energy consumption was on the scale of the liquefaction or electrolysis, given the sensitivities seen in section 5.7.

The electrolyser costs for systems above 2 MW were not scaled to the system size, as data given for 'large' systems in the literature reviewed was generally not specific to a given rated output, and no mention of scale factor at this scale were seen. This may be because the technology is modular, and therefore few economies of scale are seen for large systems, or because there has been little consideration of widespread large scale electrolysis. Sources contacted were not forthcoming with details of the variation of cost with scale. Given the sensitivity of the results to the electrolysis parameters further consultation with manufacturers would be beneficial. It should be noted, however, that economies of scale not included for large electrolysers would further reduce the costs of fuel chain B, which was generally the lowest cost option for production of hydrogen form renewable electricity.

As explained in section 3.8, a detailed logistic model for hydrogen transport by road was not used. Costs were estimated from data applicable to a throughput of 45 kg/hr, when the throughputs used were 25-33 kg/hr. Similarly, biomass transport costs used were for similar scale projects, but could not be adjusted for the transport distances used. Given that the costs for fuel chain A were sensitive to the transport costs, especially for compressed transport, a detailed model should be used in further studies. Again, this would be most valuable for a system with defined geographical locations for supply and demand, as described by Row et al. (2002). It would also allow use of UK specific input data.

The extrapolation of US pipeline cost data to lower flow rates is also relatively uncertain, given the power law relationship between flow rate and cost and the differences in costs for the UK. The results, however, are stable with respect to variation in pipeline costs. Figure 5 shows that even if pipeline costs were several times greater than those used, pipeline transport would still be the lowest cost option. If a system with defined supply and demand locations were used, consultation with gas supply industries to estimate network costs would provide a more accurate estimate.

6.5 Conclusion

Despite the inevitable limitations of a study in this timescale, the model designed provides a valuable synthesis of the available data on the fuel chain components. The data used are sufficiently detailed and representative for the majority of the parameters to enable comparison of the fuel chain characteristics. The model scale is appropriate for the UK renewables potential and likely system scale, and identifies sensitivities which can be explored further in further work.

7 Market development and policy options

7.1 Autonomous development

There are several possibilities for the development of a market for renewable hydrogen within the existing policy framework. The possibilities are not entirely independent of policy, as they may occur as a reaction to policies, such as electricity market mechanisms, or in expectation of future regulation. They are not, however, the result of directed promotion of the technology, as discussed in section 7.2.

7.1.1 Interaction with electricity market

Hydrogen production could improve the economics of electricity generation for small renewable generators under the New Electricity Trading Arrangements (NETA). Since the introduction of this system in 2001, generators have had to pay increased penalties for imbalance between their predicted and actual output. These penalties have been considered to impact unfairly on small, intermittent generators such as wind farms (Smol, 2001, Milborrow 2001). Onsite hydrogen production could counteract this decrease in revenue in several ways.

At times of low electricity demand, and therefore low prices, a generator may be able to gain higher revenues from hydrogen production than from grid export. If the level of renewable generation capacity became so high as to exceed the minimum national demand, it would make sense to use the excess output at times of high supply (e.g. windy summer nights) for hydrogen production (Eyre, 2002). For intermittent generators, only a proportion of the output can be bid for sale to the grid in periods of uncertain output, with output above this level used for hydrogen production (Chambers, 2002).

7.1.2 Premium pricing

Renewable electricity generators may even benefit from switching the majority of their output to hydrogen production, if they could command a higher price for hydrogen than for grid export of electricity. This would occur if a market for hydrogen developed in parallel with the development of fuel cell cars and public transport projects. Renewably produced hydrogen could be sold at a premium, in the same way as renewable electricity is now sold through 'green' tariffs. If the price of onshore wind for 2002 used in the model is doubled from 2.5 to 5 p/kWh, the hydrogen travel cost for fuel chain B with pipeline delivery is still below 5 p/km, and so still lower than the taxed travel cost of petrol. Eyre (2002) notes that the long term cost of fuel cell vehicles could be comparable to the long term costs of petrol ICEs. Given that fuel cell vehicles could be over 50% more efficient than ICEs, hydrogen could be sold at a price 50% higher than that of petrol.

A high market price for hydrogen, or a premium for renewably produced hydrogen could stimulate investment in renewables with output dedicated to hydrogen production. These could be sited away from electricity network connections without incurring initial grid connection or reinforcement charges, or near to areas of high transport demand.

7.1.3 Energy storage

The economics of the use of intermittent generation to supply a large proportion of electricity demand could rely on the use of energy storage. Small proportions of intermittent generation (up to 15-20%) could be integrated into the existing transmission and generation network with no technical difficulties, as the output of individual wind farms, for example, is not highly correlated (Strbac, 2001, Milborrow 2001). At higher proportions, additional reserve generation capacity or energy storage would be needed. Many options for storage exist, for example pumped storage, flywheels and electrochemical methods such as Regenesys. Hydrogen has several advantages over these methods, such as the ability to be stored seasonally underground and also to be used as a medium for transport and distribution of energy.

7.1.4 Policy impacts of development

The use of renewably produced hydrogen in transport would contribute to policy goals of reduced well-to-wheel vehicle emissions of greenhouse gases and local air pollutants, and reduced noise. The security of energy supply for transport fuel would be improved by using the large domestic renewable electricity resource. Prices of renewably produced hydrogen would also be likely to fluctuate less than those of the international oil market. Renewably produced hydrogen would be likely to promote development and innovation in the renewable electricity market and hydrogen systems industries. There have been some concerns, however, at to whether the use of renewable electricity to produce hydrogen is advantageous in terms of avoided CO_2 emissions.

Provisional estimates by Eyre (2002) have suggested that generating one kWh of renewable electricity would save the emission of 110 g carbon if used to replace gas-fired power generation. If used to produce hydrogen for transport in a fuel cell vehicle, 90g carbon emissions would be saved. If this were correct, then it would be preferable to use all renewable generation to displace non-renewable technologies, given the limited renewables capacity at present. However, most of the possibilities for hydrogen production described above would provide greater total avoided carbon emissions than at present, whatever the relative emissions savings of the end use options. Competition for emissions savings between electricity and hydrogen use would only become an issue if existing renewables generators switched to hydrogen production. If avoided carbon emissions were the sole policy concern, this switch would need to be discouraged by changing supply-based policy support such as the Renewables Obligation and Climate Change Levy, which do not distinguish between end uses of the electricity supplied, to avoided emissions-based systems such as the UK and EU emissions trading schemes.

The likelihood that the majority of hydrogen production options considered will reduce carbon emissions, and also improve air quality, reduce noise and increase security of supply together mean that hydrogen use in transport should be supported by the energy, transport and environmental policy framework.

7.2 A supportive policy framework

It is first necessary to clarify whether policy measures to support renewable hydrogen should be technology specific, or be part of wider support for hydrogen, or for low carbon transport methods in general. Note that the policy discussions in section 7.2.1 onwards are those related to renewable hydrogen production; it is beyond the scope of this report to review all policy for hydrogen

Using renewably produced hydrogen in fuel cell vehicles has been described as likely to be 'the ultimate low carbon destination' (PFV, 2002), with non-technology specific policy needed to aid interim technologies en route to this destination. Any general support for low carbon transport options, such as reduced vehicle excise duty on cleaner vehicles, reduced fuel duty, tighter vehicle emissions standards, encouragement of uptake amongst fleets and public authority vehicles and provision of information on options available will also be of benefit to renewable hydrogen development.

The use of hydrogen in fuel cell vehicles does, however, contribute more effectively to policy goals of reduced CO_2, air pollutant emissions and noise than other low carbon alternatives. There is therefore an argument for greater promotion of hydrogen vehicles in reflection of this improved environmental performance. It has also been suggested that increased support is currently needed for hydrogen, given the need for new infrastructure, and for continued development of component technologies in order to keep the option for hydrogen open (EST, 2002, Foley, 2001).

For the same reasons, renewably produced hydrogen should be promoted further, given its increased environmental and supply security benefits. Possible policy measures with this aim are discussed below.

7.2.1 Options for renewable hydrogen

Just as policy should not provide a detailed and technology specific route to low carbon vehicles, there does not seem to be a need for a commitment to a single route for production and delivery of renewable hydrogen. As discussed in section 5.9, there are many fuel chains available, each with many possible interactions with other chains and advantages for specific forms of supply and demand. It is therefore unlikely that hydrogen used for a large proportion of transport demand would be produced and delivered using one set of technologies.

The relative costs of hydrogen production routes now and in 2020 are not the same. Some production routes are also more flexible, allowing for variation in level and location of demand. Therefore it is important to look not only at support for what would be possible in the short term, but to keep the transition to future possibilities in mind. It is also essential to consider technology development on which the future possibility may rely - is there an essential factor, such as the development of improved compressed storage, needed to make the option viable? Commitment to a hydrogen production technology available in the short term may delay the introduction of an improved one, through diversion of resources and expertise. This ‘lock-in’ is similar to the suggestion that the introduction of other alternative fuels, or of fuel cell vehicles with onboard reforming technology could delay the transition to hydrogen fuel cell vehicles (Foley, 2001). It is therefore essential to ensure that policy support continues to facilitate new technology development even after the success of initial hydrogen projects.

7.2.2 Transport policy

It may be easier to promote the use of renewable hydrogen in transport through transport policy than through renewable electricity policy, given the greater range of fiscal measures available in this area.

Graduated vehicle excise duty and company car tax are currently used to give incentives for purchase of cars with lower carbon emissions. This would promote the use of hydrogen vehicles in general, however in order to support only renewably produced hydrogen, the duty of the fuel itself would need to be adjusted. As mentioned previously, there is a fuel duty differential for cleaner fuels such as LPG and CNG. Fuel duty on hydrogen for pilot projects is set at zero. In the longer term, it would be reasonable to set the fuel duty for hydrogen produced from natural gas at a higher level than that produced renewably (EST, 2002).

An alternative or complementary policy would be to include hydrogen production in the Climate Change Levy. This would mean that a levy of 0.15 p/kWh would be placed on the use of natural gas for hydrogen production, and 0.43 p/kWh for non-renewable electricity use. Currently, the levy does not apply to fuels used for production of other sources of energy (such as hydrogen) or to any electrolysis processes (DEFRA, 2002b). This would give an incentive for producers to use renewable sources, however it has been suggested that the government should not place too many restrictions on producers at an early stage (Foley, 2001). The production of hydrogen from natural gas could help to build the rest of the supply system, as well as consumer confidence. However, given that modelling in this study has shown that hydrogen from biomass could currently be produced at around the same price as steam methane reformed hydrogen, there are options open now to producers for renewable production. There may also be opportunities for low cost hydrogen form sources not modelled here, such as sewage gases and landfill gas. Inclusion in the climate change levy would provide a clear signal for a move to entirely renewable generation.

Renewable hydrogen use in pilot projects with fleet vehicles, such as hydrogen bus partnerships would demonstrate to the public that both renewables and hydrogen are viable energy technologies. The schemes would have improved environmental credentials, and may help to boost the renewable electricity industry as well as the public acceptance of hydrogen technologies.

7.2.3 Rural development policy

The use of energy crops or biomass wastes for hydrogen production is not included in the Energy Crops scheme (see section 3.3). Given that it is more efficient to produce hydrogen directly from biomass gasification than from electricity production and electrolysis, it would be advantageous to allow for this in a related support scheme.

7.2.4 Planning

The speed of development of many of the renewable generation options considered is currently limited by the length of the planning process (see section 3.2). If generation sites were to include facilities for hydrogen production, as modelled in fuel chain A, it would be essential that obtaining consents for these components did not lengthen the planning process significantly.

Effective planning guidelines would be needed for production and/or storage of hydrogen at regional and forecourt sites. These could be developed in conjunction with standards and safety legislation for forecourt systems. Initiatives for public awareness of the benefits and safety aspects of hydrogen technologies may aid acceptance of these sites. The current reform of planning guidelines for renewables could be used as an opportunity to add signal general support for hydrogen projects.

Consents for the transport of natural gas by pipeline vary depending on whether the developer is licensed as a Public Gas Transporter (PGT). PGTs are exempt from having to obtain pipeline construction authorisation from the Secretary of State under the Pipelines Act 1962 (ODPM, 2002). A similar system could be introduced for licensed developers to facilitate planning of hydrogen pipelines.

7.2.5 Research and development support

Many of the technologies required for a successful hydrogen infrastructure would benefit from increased support for research and development. Several of them, however, are not needed in systems for hydrogen production from natural gas, and therefore may not be promoted by general hydrogen research support. These include electrolysis technology, and systems design and control of electrolysers run directly from renewable output. It is also possible that production from electrolysis could be viable on a smaller scale than other hydrogen production routes, resulting in a need for smaller scale conversion technology such as liquefaction.

7.3 Future demand

As mentioned previously, several auto manufacturers plan to introduce fuel cell cars commercially by 2004-5 (Ogden, 1999). Fuel cell buses are currently in operation, with many further demonstration projects starting in the next few years. The majority of the fuel cell vehicles in question use hydrogen as a fuel, rather than reforming other fuels such as petrol or methanol on board. Whatever the motives of the manufacturers and developers involved, whether acting in anticipation of clean vehicle regulation, or adding a new product to their range, a demand for hydrogen will be created. The demand for renewable hydrogen will be related to the size of the total market for hydrogen as a fuel. This section gives a brief review of UK and world projections.

The first market for hydrogen is likely to be in buses and other fleet vehicles. The Government's Powering Future Vehicles Strategy (PFVS) sets a target of 600 low carbon (30% emissions reduction) buses coming into operation every year by 2012.

Fergusson (2001) agrees that the first commercially available fuel cell cars could be introduced in the next five years (2003-4). Rapid commercialisation would continue to the end of the decade, with 10% of new car sales by 2015 being fuel cell vehicles. If the growth in sales of new vehicles over the past decade (DfT, 2002) is projected to 2015, this would be equivalent to over 4.1 million vehicles. Fergusson projects fuel cell vehicles to become the dominant vehicle technology after 2030. If the total number of cars increased at the rates projected for 2010, there would be a total of 38 million vehicles on the road in 2030. If this were the case, over 19 million *non zero* carbon vehicles would still be on the road, equivalent to 80% of the current UK car fleet.

The PFVS sets a target for 10% of new cars to be low carbon (with well-to-wheel emissions under 100g/km) by 2012. By 2020, 10% of vehicles should be 'ultra low carbon'. This level has yet to be defined, by a significant proportion of the vehicles are projected to be zero carbon. Hydrogen fuel cell vehicles, biofuel vehicles and electric vehicles are the only technologies that could currently fit into this category. The PFVS states that most experts feel that fuel cell cars will not reach mass-market costs before

2010-2015. However, it also notes that sales of fuel cell cars in Japan have been projected to reach 500,000 per year by 2010, or nearly 12% of new car sales.

The ‘advanced scenario’ for the US described in Brown (2001) has fuel cell vehicles representing 10% of the new light duty vehicle market by 2020. This is equivalent to 2.2 million vehicles. Hydrogen fuel cell vehicles are the dominant technology, with 1 million of the sales. In business as usual and moderate scenarios, with limited policy support and technology development, alternative vehicle technologies and fuels cannot overcome the initial capital cost barriers to their uptake.

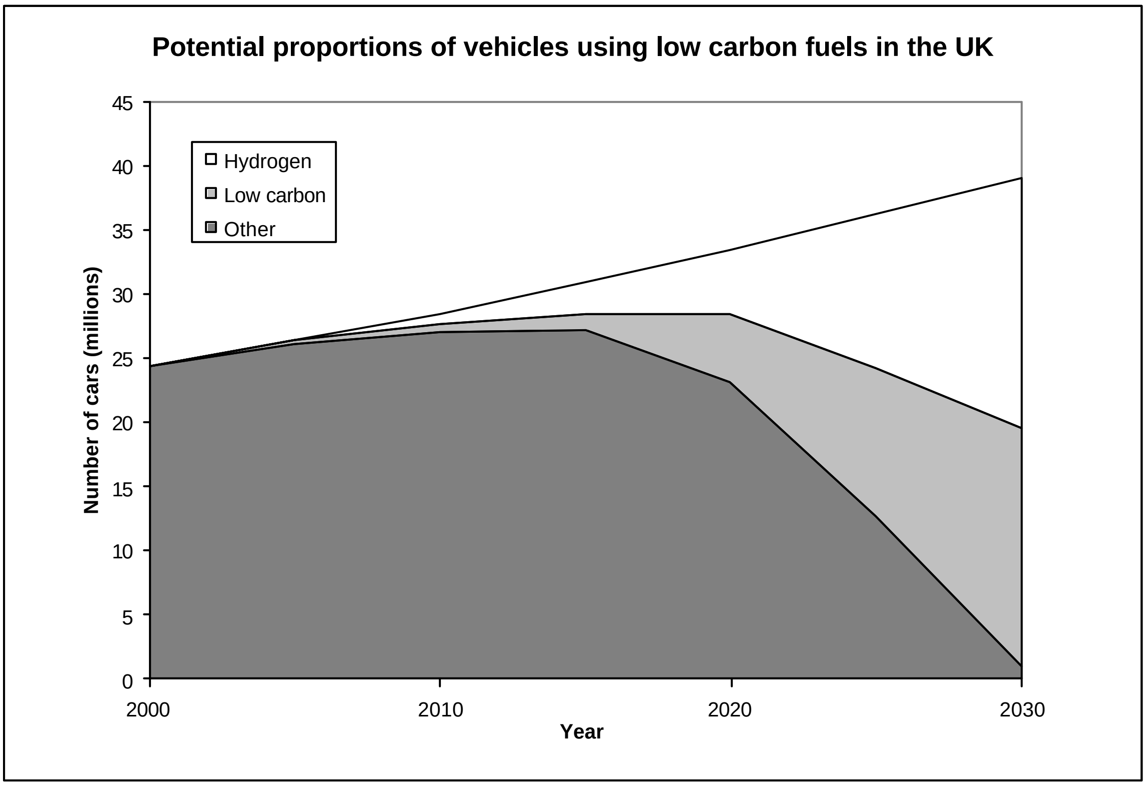


Figure 16: Scenario for introduction of low carbon and hydrogen vehicles, based on proportions of new vehicles projected in the references given above. Principal assumptions: The total number of cars increases by 17% every ten years (DfT, 2002). The number of new cars increases at the same rate as for 1996-2000, using figures from (DfT, 2002). In 2000, 2% of new cars are low carbon., increasing to 30% by 2015 and 90% by 2030. The proportion of new cars being hydrogen vehicles increases annually to a figure of 10% in 2015. The number of hydrogen cars then increases to 50% of the total by 2030.

8 Conclusion

This study considered that the renewable electricity technologies with the greatest potential for hydrogen production in the UK were offshore wind, onshore wind, tidal energy, wave energy and small hydro. The cost of photovoltaic systems proved to be a barrier to their commercial use at present, but future cost reductions could give potential for distributed generation using photovoltaics by 2020. The biomass products considered, short rotation coppice and forestry wastes, provided examples of low cost hydrogen production routes. Many other biomass crops and wastes available in the UK, such as sewage and landfill gases could be considered in further work.

The fuel chains defined provided a range of options for hydrogen production, transport and storage from each energy source. All of the fuel chain components were found to be available, either commercially or at the demonstration stage. Technology improvements, coupled with significant cost reductions through learning, are expected for components including tidal, wave and photovoltaic systems, biomass gasifiers, small-scale electrolysers, and liquid hydrogen technologies. The most significant non-technical constraints identified were for renewable electricity technologies, specifically planning and electricity network regulation.

The model set up was sufficiently sensitive as to allow comparison of the costs of hydrogen, and capital investment required for each fuel chain. It provides an initial comparison of the chains, and assesses the sensitivity to component costs, which could be used as a basis for further, more detailed studies on individual fuel chains. These studies could include wider consultation with component manufacturers and hydrogen systems developers to provide more specific input data, and use more complex models allowing interactions with other systems, such as the electricity network.

The results of fuel chain modelling showed that hydrogen provided by four of the fuel chains in 2002 would result in a lower travel cost if used in a fuel cell vehicle than if petrol were used in an internal combustion engine at *untaxed* prices. Biomass production routes were cheapest, with costs of around 1 p/km, approximately equal to those of hydrogen produced from steam methane reforming. Biomass hydrogen travel costs were lower than the untaxed petrol travel costs by up to 50%.

The cheapest of the renewable electricity technologies was onshore wind, with the cheapest options for compressed hydrogen supply being either electrolysis at a regional scale, with delivery by pipeline, or forecourt electrolysis, at 1.4-3.1 p/km. The cheapest option for liquid hydrogen delivery was electrolysis at a regional scale with liquid hydrogen delivery by road, at 2.0-3.6 p/km. The costs of hydrogen from the majority of other fuel chains modelled was still not prohibitively high, with many of the 58 fuel chains modelled having hydrogen travel costs lower than those using taxed petrol. This range of options would allow flexible infrastructure development, with the fuel chain used dependent on the relative locations of supply and demand, demand growth and available capital for large-scale infrastructure investment. None of the fuel chains were found to have significant well-to-wheels carbon dioxide emissions when compared with existing ‘low-carbon’ vehicle technologies.

If the most efficient, and lowest cost fuel chains were used for production and supply of hydrogen from each renewable energy source identified, the UK vehicle fleet could be fuelled several times over. More interestingly, 40% of the current UK car fleet could be fuelled at a cost lower than that of untaxed petrol, using hydrogen from biomass, onshore wind, and small hydro schemes. By 2020, this figure increases to 70%.

In a supportive policy climate, including improved planning guidelines and agrienvironmental policies, large volumes of renewable hydrogen could be produced at prices competitive with production from steam methane reforming. Currently available renewable hydrogen sources, such as biomass wastes, would provide the low cost hydrogen needed whilst infrastructure is developed. This would reduce the dependence on fossil fuel derived hydrogen as a stepping-stone to renewable hydrogen.

Given the benefits of renewable hydrogen, not only in reducing the environmental impacts of road transport, but also in providing options for renewable generators, a supportive policy framework is needed. Hydrogen must be included in integrated climate, energy and transport policies, to promote renewable production, support technology development, and reduce planning constraints at all stages of the fuel chains.

Many routes for renewable hydrogen production are technically feasible and economically competitive. Renewable hydrogen should not be dismissed as a long term solution, but considered as a viable option for low carbon transport now.

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10 Appendices

10.1 Appendix A: Conversion factors

	Value	Unit
Lower heating value of hydrogen	10.783	MJ/Nm^3
Higher heating value of hydrogen	12.745	MJ/Nm^3
Density of hydrogen	0.0899	kg/Nm3
One mile =	1609	km
One bar =	0.1	MPa
One atmosphere =	0.101	MPa
One pound per square inch (psi) =	6895	Pa

10.2 Appendix B: Electrolyser data

Manufacturer	Model/reference	Available output scale [Nm3/h]	Energy input [kWh/Nm3]
Stuart Energy	TTR (H)	12-36	5.9
Norsk Hydro	AP	60-377	4.1
Norsk Hydro	AP	60-485	4.3
Teledyne Brown	Titan HM 50	2.8	6.1
Teledyne Brown	Titan HM 100	5.6	5.7
Teledyne Brown	Titan HM 125	7	5.7
Teledyne Brown	Titan HM 150	8.4	5.7
Teledyne Brown	Titan HM 200	11.2	5.3
Teledyne Brown	Titan EC	28-42	5.6
Teledyne Brown	Titan HP	75-150	5.6
Fluor Daniel	Cited in Kruger	21788	4.4
Norsk Hydro	Cited in Kruger	45205	4.9
Stuart Energy	Cited in Kruger	22000	4.5
Hydrogen systems	IMET 30	30-120	3.9

Reference	Details	Time	Output (Nm^3/h)	Rated input (MW)	Capital cost ($/GJ $_{out}$/yr)	Capital cost ($)	Capital cost ($/kW$_{out}$)
Berry		1996	**18**	0.1		**110,000**	2031
Hydrogen Systems	IMET 30	2002	**30**	0.135		**305,972**	3405
Berry		1996	**108**	0.5		**650,000**	2000
Carlsson	Cited in Padró	1998		**0.5**	**55**		1734
Mann		1998		**2**			**600**
Berry		1996	**542**	2.4		**2,100,000**	1293
Lawrence Livermore	Cited in Thomas	1994		**2.5**			**1275**
Mann		1998	**635**	2.9			**600**
Ogden	Cited in Thomas	1994		**10**			**580**
Carlsson	Cited in Padró	1998		**12**	**32**		1009
Andreassen	Cited in Padró	1998	**4000**	18	**31.88**		1005
Scherer		1999		**80**			**670**
Fluor Daniel	Cited in Thomas	1991		**100**			**770**
Electrolyser	Cited in Thomas	1995		**100**			**590**
Kirk-Othmer	Cited in Padró	1991	**116667**	525	**2.95**		93
Thomas	Cited in Padró	1995		**530**	**42.8**		1350
Los Alamos	Cited in Thomas	1986		**530**			**1350**
Foster-Wheeler	Cited in Padró	1996	**281250**	1265	**30.97**		977

Only alkaline electrolyser data are included. Figures in bold are those given in the reference, with other figures provided for comparison. An energy consumption of 4.5 kWh/Nm^3 was used to calculate these figures.

10.3 Appendix C: Model design assumptions

10.4 Appendix D: Results