



DTI New and Renewable
Energy Programme

**TECHNOLOGY STATUS REVIEW AND CARBON ABATEMENT POTENTIAL OF
RENEWABLE TRANSPORT FUELS IN THE UK**

B/U2/00785/REP
URN 03/982

Contractor
Imperial College London
Centre for Energy Policy and Technology
(ICEPT)

Prepared by
J. Woods and A. Bauen

With contributions from
F. Rosillo-Calle, D. Anderson, B. Saynor and J. Howes

The work described in this report was carried out under contract as part of the DTI New and Renewable Energy Programme, which is managed by Future Energy Solutions. The views and judgements expressed in this report are those of the contractor and do not necessarily reflect those of the DTI or Future Energy Solutions.

First Published 2003
© Crown Copyright 2003

dti

Department of Trade and Industry

Executive Summary

Objectives

This study reviews the technology status for the production of renewable transport fuels (RTFs), discusses the possible progression in technologies required for the production of increasing quantities and different types of RTFs, and analyses the costs of the different RTF options and their potential contribution to reducing greenhouse gas emissions from the UK transport sector.

Introduction

The primary drivers behind introducing RTFs into the UK are to: reduce transport sector dependency on non-renewable fuels; reduce GHG emissions from transport fuel chains; reduce the impact on air quality and health of transport fuel use; improve energy security in the transport sector; and contribute to rural development through domestic production of biomass-based fuels. A market for RTFs exists today based on ethanol from the fermentation of sugar and starchy crops and biodiesel from oil crops. The market for these fuels has developed mainly as a result of air quality and energy security issues, and to support the agricultural sector. Hence, ethanol and biodiesel use, mainly blended with petrol and diesel, respectively, is common in several countries (e.g. the US, Brazil, France and Germany). It is estimated that 25 Billion litres (Bl) of bioethanol for fuel and about 3 Bl of biodiesel were consumed globally in 2002 (Chapter 2). However, the contribution of RTFs remains very small in relation to the global energy use in road transport. Globally, the market for RTFs, especially bioethanol as a fuel oxygenate, is showing strong signs of growth in response to national programmes stimulated by air quality, global warming, energy security and rural development agendas. In particular, mitigating global warming may require a significant contribution from renewable transport fuels. Interest is also increasing from industry and policy makers in advanced technologies for the production of biodiesel and bioethanol, Fischer-Tropsch and hydrolysis based processes, respectively, and in renewable hydrogen from renewable electricity and biomass. These could deliver larger quantities of RTFs compared to traditional biodiesel and bioethanol routes based on efficiency and resource base considerations.

Renewable energy potential

The UK potential for renewable transport fuels production is large (Chapter 3), as illustrated in table E1. Assuming a conversion efficiency to transport fuel of 50%, UK renewable resources could provide about 40% of current UK transport energy consumption (about 55% of road transport energy consumption).

However, other energy end-uses such as electricity and heat, would also be competing for the renewable energy resources, with trade-offs in terms of economics and the environment that need to be carefully addressed. Also, given the finite availability of renewable resources and the competition for alternative uses, efficiency in energy use for transport will be paramount to its sustainability.

Table E1: Summary of indicative practical energy potentials from the different renewable energy resources.

Resource	Practical potential (PJ)	Share of primary UK transport energy (2001) ^{a,b} (%)
Biomass resources		
Energy crops ^c	360	14%
Residues	400	16%
Waste vegetable oils	10	0.4%
MSW	370	15%
Direct renewable electricity resources		
Wind offshore	360	14%
Wind onshore	290	12%
Wave	180	7%
Tidal	7	0.3%
Hydro	10	0.4%
Photovoltaic	130	5%
Total	2117	84%

a – primary transport energy in the UK (2001) = 54.9 Mtoe (2.51 EJ). DTI, 2002.

b – values do not account for conversion of the resource to potential RTFs. The actual contribution of RTFs would then be lower.

c – energy crops grown on 2 Mha and achieving annual yields of 10 oven dry tonnes per ha.

RTF options and fuel chains

The diversity of options for producing transport fuels from renewable resources is very wide. In total, a realistic sub-set of 88 fuel chains has been identified for the UK, resulting in the production of eight different end-fuels from a range of resources and conversion technologies. These end-fuels are: bioethanol, biodiesel, methanol, hydrogen, DME (di-methyl ether), biogas, bio-oil and electricity.

Of the 88 chains, there are potentially 21 chains for hydrogen production, 12 for ethanol and 10 for biodiesel. The chains chosen are those chains that are at an advanced R&D stage, near-market or mature, and include both biomass and non-biomass renewable energy-based routes of relevance to the UK. However, many more potential chains exist and surprise technologies and pathways cannot be ruled out. The eight potential ‘end-fuels’ highlighted are also a simplification as a number of them are potential intermediaries in the production of other end-fuels; e.g. all the end fuels could be used to produce electricity or hydrogen.

Thirteen renewable transport fuel chains were chosen for detailed evaluation (Chapter 5 and Annexes 1 and 2) following consultation with a range of stakeholders (Annex 3), and extensive literature reviews were carried out in order to assess the technology status and obtain data for each stage in the chain to be evaluated (Chapter 4). The normalisation unit on which the comparison of economic, energy and environmental parameters across different fuel chains is based is a ‘GJ of end-fuel’. Costs, energy inputs, and CO₂ equivalent emissions are calculated for the full fuel chains (well-to-tank) and for each of their main stages:

1. production of feedstock or primary energy carrier;
2. transport of feedstock or primary energy carrier to conversion unit(s);
3. conversion of feedstock or primary energy carrier to end-fuel;
4. distribution of end-fuel to refuelling station.

Direct energy inputs and CO₂ emissions associated with the different stages of the fuel chain are considered. Indirect energy inputs and CO₂ emissions are considered only in a few cases, e.g. agro-chemical inputs to crops, where the contribution is estimated to be significant.

Several RTF chains result in co-products at various stages of the chain. Base case calculations do not consider allocation of costs, energy inputs and CO₂ emissions to co-products. This approach has been adopted because of the uncertainty associated with both the methodology to be used in accounting for co-product credits and in the data available to carry out a co-product allocation. In practice, the importance of co-products can only be ascertained when a commercial scale industry is in place and good time series data is available for end uses of co-products, including possible substitution effects of the co-product. However, the influence of possible revenue from co-products and the allocation of energy inputs and CO₂ emissions to co-products could have substantial beneficial impacts as discussed in the main text of the report.

Because renewable supply options for the production of transport fuels are diverse and generally less commercially mature than the conventional alternatives, the parameters used in the assessment of the fuel chains are presented in a 'low' to 'high' range of values that reflect the variety of the fuel chain options and the uncertainty in knowledge. It must be noted that a 'low' value for one parameter does not correspond to the 'low' value of another parameter, for example, the 'low' cost value does not necessarily correspond to the 'low' GHG value. A detailed discussion of the ranges of values is also provided in the main text of the report.

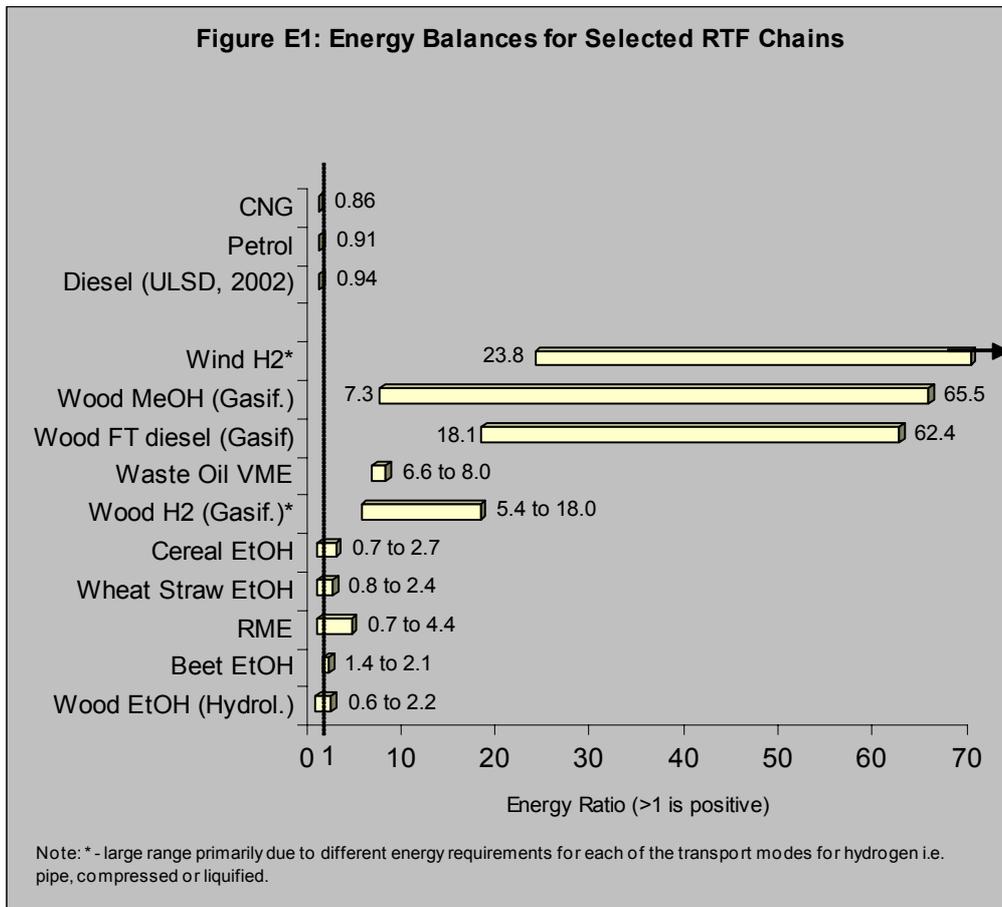
The 'well-to-tank' comparison does not consider differences in conversion efficiencies between different RTFs and conventional fuels once on-board the vehicle (well-to-wheel). The on-board conversion efficiency could have a significant influence in comparing the costs, energy inputs, and CO₂ equivalent emissions of different fuel chains and, therefore, would need to be considered as part of a more exhaustive comparison than provided here.

Full fuel chain summaries, a breakdown of the calculations for the different stages of the fuel chains, and the assumptions underlying the calculations are provided in Annex 1 of the report.

Energy balances

Energy balances are critical to evaluating the net energy outputs from RTF chains. An indication of the efficiency of a fuel chain is provided by the energy input required to produce a unit of energy in the form of RTF. This generally has an effect on the economics of the fuel chain. Fuel chain efficiencies are assessed in the tables in Annex 1.

However, in terms of non-renewable energy substitution it is the amount of non-renewable energy input required to produce a unit of RTF that is of interest. This is also related to the CO₂ emissions of the fuel chain. The energy balance in this study is therefore defined as the amount of RTF energy produced per unit of direct non-renewable energy input. A 'negative' energy balance (<1) means that more non-renewable energy is used to produce an RTF than is in the final renewable fuel itself.



Direct non-renewable inputs are assumed in all cases for the production of biomass feedstock and transport and for the transport of the RTF. This provides a base case, however, it could be envisaged that in the future these inputs could be substituted, in part or entirely, by renewable energy inputs. The energy inputs to the conversion process could be renewable, where process residues are used as fuel, or non-renewable and, together with the process type, will have a significant effect on the range of values for the energy balance of a particular fuel chain.

All the RTF chains evaluated show a positive energy balance, except under the worst case assumptions and then only for a few of the chains. Energy balances between 0.2 (strongly 'negative') and 66 (strongly positive) have been calculated for the non-wind RTF chains, and greater than 28 for the four hydrogen from wind chains, as shown in figure E1.

Biodiesel and bioethanol routes are generally energy intensive. Significantly favourable energy balances are only achieved when renewable fuels, mainly residues from the biomass resource used, are used to produce energy for the process, and when energy is allocated to co-products, in which case the energy in the RTF can be between 2 and 5 times that of the non-renewable energy input. In the case of biodiesel from waste vegetable oil, the energy balance is more favourable, with the energy in the biodiesel estimated at between 6.6 and 8 times that of the non-renewable energy input.

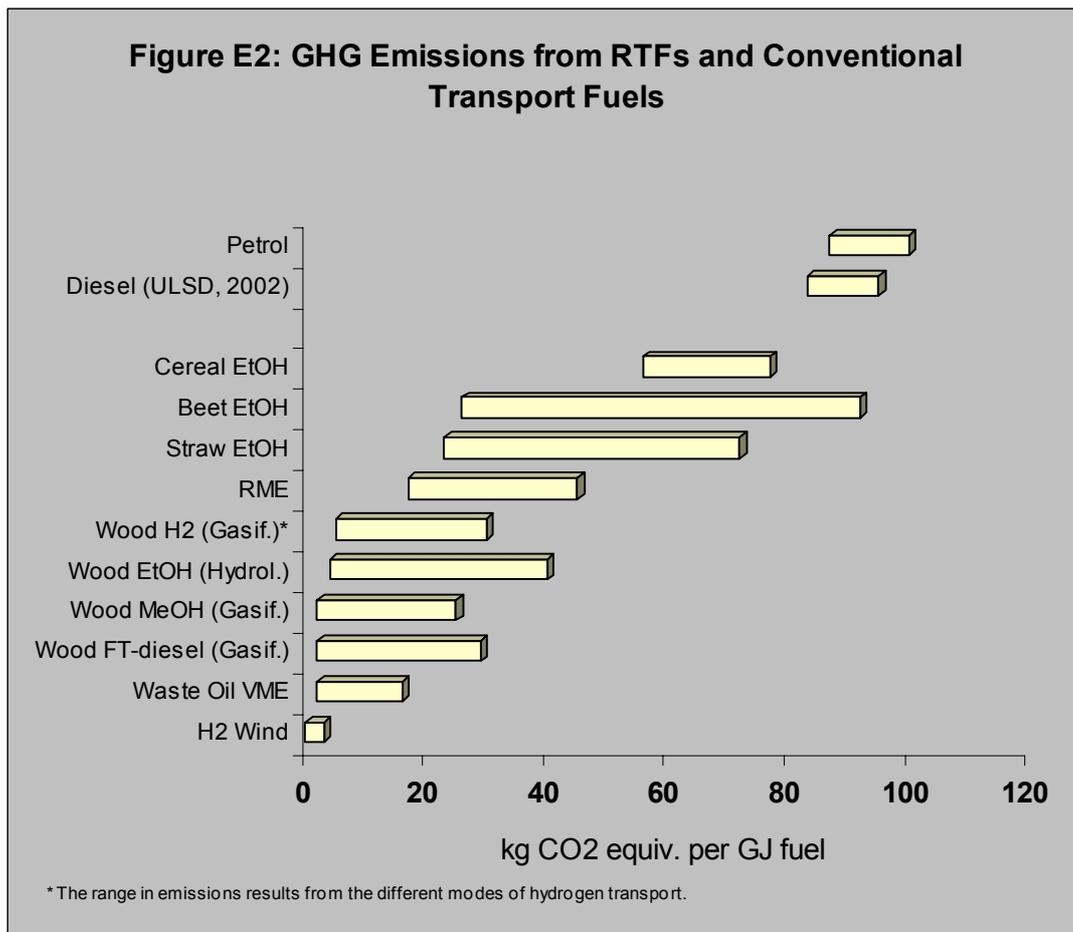
Gasification-based routes (FT diesel, methanol and hydrogen) using woody crops present strongly favourable energy balances. This is a result of less energy intensive processes compared to conventional biodiesel and bioethanol routes and heat and power requirement of the

conversion process being generated within the process using part of the biomass resource. The lower energy balance for hydrogen compared to FT diesel and methanol is mainly a result of the energy consumed by transporting the hydrogen by road in compressed form, which has been assumed for the case illustrated.

Hydrogen production from direct renewable electricity is assumed not to require any direct non-renewable input except for the transport of the hydrogen. This results in very favourable energy balances for wind-to-hydrogen routes.

GHG balances and abatement

Generally, all renewable transport fuel chains considered could result in substantial emissions reductions compared to conventional fossil fuels. All of the RTF chains evaluated show net reductions in fuel chain GHG emissions compared to petrol or diesel (per GJ fuel), except ethanol produced from sugar beet and then only under the worst set of assumptions. GHG emissions ranged from virtually zero for two of the offshore wind hydrogen scenarios (pipeline transport and on-site electrolysis, where fossil energy input for the road-based hydrogen distribution is avoided) to 106 kg CO₂ (equivalent) per GJ of fuel for ethanol from sugar beet, in its worst case scenario, as shown in figure E2.



The sugar beet to ethanol chain also exemplifies the range in potential GHG emissions that are possible from each chain, depending on: the yields achieved; inputs required to achieve those

yields; the technologies chosen at each stage of the chain and the origin of their direct energy inputs. The biomass-to-ethanol chains show the greatest range, primarily because of the large amounts of energy required in the extraction of the sugars and in distillation. As a result, the combination of poor yields and older, less efficient, technologies fuelled with fossil fuels can result in very poor energy balances and relatively high GHG emissions. However, choosing efficient modern technologies and using good crop growth management practices can result in real benefits.

Conventional biodiesel and bioethanol routes could provide significant GHG benefits per unit of fossil fuel substituted, and could potentially reduce GHG emissions by about 80% compared to petrol and diesel. However, the relatively low efficiency of these chains and the limited number of feedstocks on which they currently rely, constrains their role in providing a potentially substantial source of RTF. Therefore, achieving a significant contribution of RTFs in road transport energy provision will need to rely on a greater variety of biomass (residues and dedicated energy crops) and non-biomass energy sources.

Advanced FT diesel and bioethanol conversion technologies are likely to expand the scope for RTF production from biomass. The use of woody crops for ethanol could lead to greater GHG reductions. Although based on a less efficient process, the resulting emissions could be close to those of RTFs based on woody crop gasification. However, although gasification and lignocellulosic hydrolysis technologies could result in greater efficiencies and GHG reductions, they remain to be technically and economically proven at commercial scales. Commercial scale production facilities using these technologies are unlikely within 5 years, and it may take 10 to 15 years to achieve commercial maturity, with supporting policies.

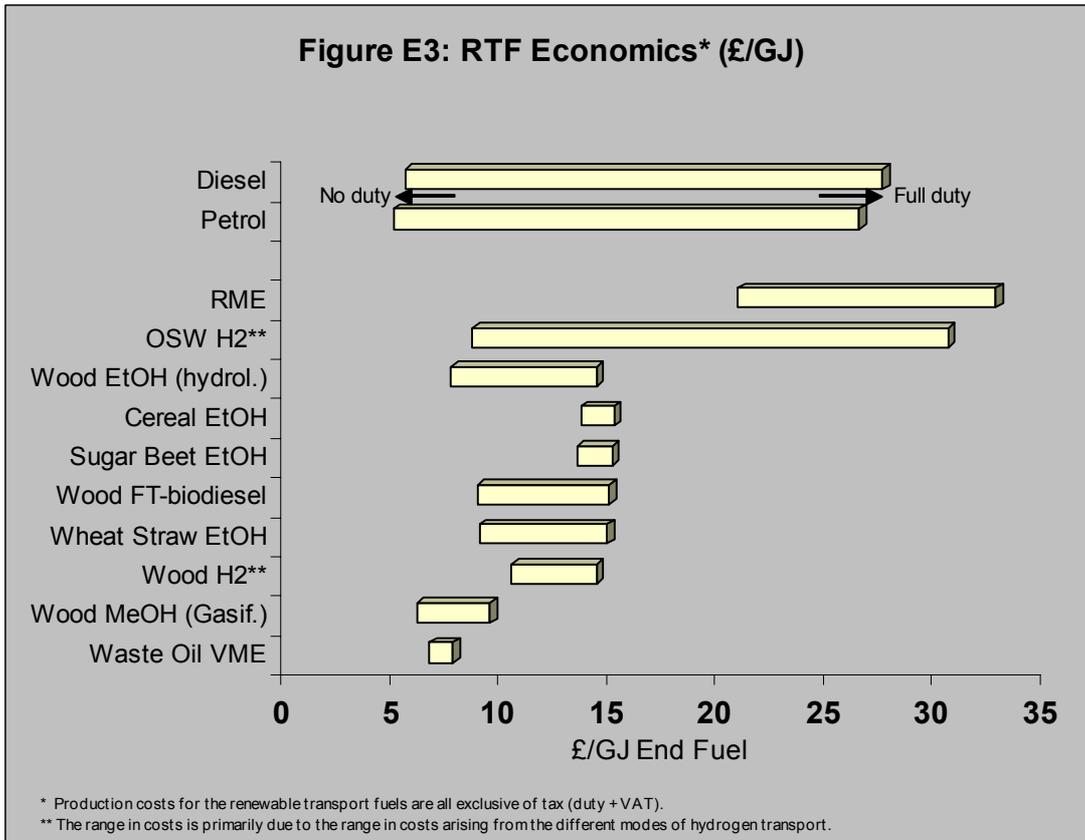
Hydrogen appears to provide a convergence point for RTF production, being able to exploit the entire range of renewable resources, efficiently and with potentially very low emissions. Wind hydrogen supply routes offer the potential for virtually zero emissions. However, the hydrogen option faces important barriers in relation to an establishment of an infrastructure for its distribution. Also, trade offs between the direct use of electricity produced from renewables compared to its use for hydrogen production will need careful consideration.

Further reductions in GHG emissions can be expected where RTFs lead to greater energy efficiency on-board the vehicles, for example possible improvement in combustion efficiency of ethanol blends or use of hydrogen in fuel cells.

Economics

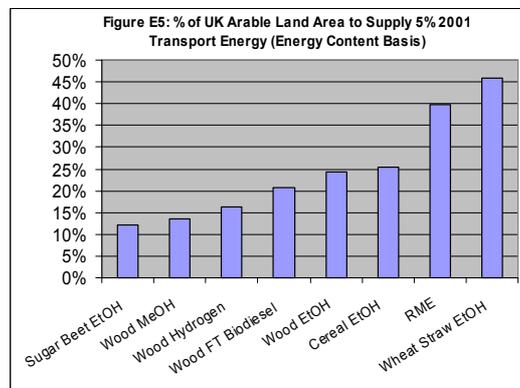
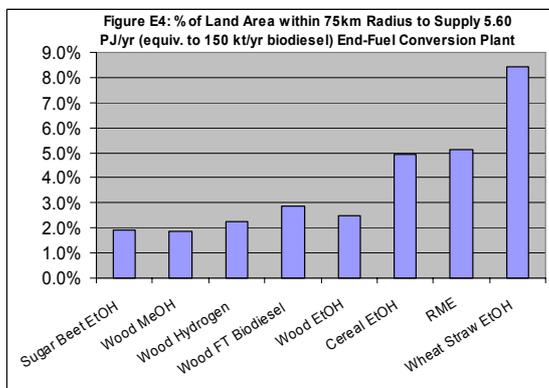
None of the RTF chains evaluated could produce fuels at lower costs than the current (2002) cost of conventional fuels when subsidies/taxes and co-product values are excluded, although a number of chains are close to being competitive on this basis (figure E3). The consideration of co-products from RTF production and external benefits (e.g. environmental benefits) would generally enhance the competitiveness of RTFs compared to petrol and diesel. It is estimated that all the chains, assuming the technologies achieve commercial status, could produce fuels at lower costs (excluding tax) than the current price of conventional fuels (including tax).

The cheapest RTF options are likely to be those produced using wastes (e.g. waste vegetable oil, organic fractions of MSW) and residues (e.g. forest and agricultural residues) as feedstocks. However, such resources will generally be limited. Wood-based (short rotation coppice, in the case of this analysis) ethanol, methanol, biodiesel and hydrogen production are likely to have good prospects for relatively low cost RTF production. Electrolysis-based hydrogen production could also result in relatively low cost RTF production where low cost sources of renewable electricity are available (at or below 2p/kWh), and advantage of electrolytic hydrogen production being that it could be produced at the point of vehicle refuelling.



Resource requirements

Whilst a relatively small percentage of the land area within an economically viable distance to a commercial scale conversion plant is required for crop production (e.g. between 1 and 7%), a significant share of total UK arable land would be required to meet a notional 5% substitution of road transport fuels by biomass-based RTFs (e.g. between 9 and 60% or more depending on crop type and conversion efficiency). This is illustrated by figures E4 and E5 below. Less energy may be required from those end-fuels where their use is associated with higher vehicle efficiency (e.g. the use of hydrogen in fuel cell vehicles).



The substitution of 5% of road transport fuels by hydrogen generated from renewable electricity would require between 0.12 and 0.17EJ of electricity, depending on the efficiency of the electrolysis process and the whether the hydrogen is compressed or liquefied following its production. The electricity requirement corresponds to between 18% and 26% of practical onshore and offshore wind energy potential and between 12% and 18% of practical direct renewable energy potential.

Conclusions

Renewable transport fuels could indicatively substitute over half of road transport fuel in the UK based on the estimated practical renewable energy potential and an average assumed conversion efficiency from renewable resource to transport fuel of 50%. The practical renewable energy resource is roughly equally divided between biomass and waste and direct renewable electricity sources. In practice, there will be a number of technical and economic constraints, and competition between renewable resources for different end uses, that may reduce the potential for RTF production from renewables. On the other hand, competition for land for food production is likely to continue to decrease as subsidies to food crops are reduced and global competition in agricultural commodities grows, particularly for cereals. Also, supplies of renewable transport fuels from abroad may also be cheaper than home production. Therefore, a UK RTF industry will need to make gains in efficiency and cost reductions if it is to become and remain competitive.

Emerging RTF technologies hold the promise of reducing costs, energy inputs and GHG emissions, but they remain to be proven on a commercial scale. R&D activities are occurring in most of the technologies discussed in Europe and the USA, with very little activity in the UK at the moment. In the case of biomass-based RTF chains, the development of suitable feedstocks, including energy crops, and suitable supply logistics will prove critical to their success, and much experience is yet to be acquired.

Traditional biodiesel and bioethanol routes are relatively inefficient and significant GHG emissions reductions require significant amounts of renewable resources. More advanced conversion routes allow for important gains in efficiency. Assuming woody biomass from SRC were used to produce RTFs such as Fischer-Tropsch diesel, methanol and hydrogen via a gasification route, an average GHG saving compared to petrol and diesel could be about 76kg CO₂ equivalent per GJ of fuel. The total abatement of a 20% substitution of petrol and diesel by these biomass-based RTFs would be equivalent to about 38Mt CO₂ equivalent. Assuming the direct renewable electricity sources were used to produce hydrogen via the electrolysis route, an indicative average GHG saving compared to petrol and diesel could be about 90kg CO₂ equivalent per GJ of fuel. The total abatement of a 20% substitution of petrol and diesel by hydrogen from renewable electricity could be about 45Mt CO₂ equivalent. The GHG abatement potential of RTFs could be greater in the case it involved increases in on-board vehicle efficiencies.

All RTF chains could bring about reductions in GHG emissions from road transport. However, conventional biodiesel and bioethanol production routes in the UK, although significant gains in efficiency and emissions reductions are possible, are relatively inefficient in economic and environmental terms, but could be used as stepping stones to prove and develop supply chain and distribution logistics on the road to lower carbon and more cost effective RTF chains. Novel biodiesel and bioethanol routes based on Fischer-Tropsch and hydrolysis processes, respectively, could lead to lower costs, greater CO₂ reductions, and open-up potentially larger markets. These chains could provide fuels for advanced ICE and hybrid ICE vehicles, and have attracted recent interest and investment from automotive and energy companies.

Hydrogen appears to have the ultimate potential for use in fuel cell vehicles, the development, testing and demonstration of which is being actively pursued by the automotive industry. Hydrogen could also be used in ICE vehicles, which may provide a stepping-stone to fuel cell vehicles and could prove to be an interesting future option for high power vehicles. Energy

companies are involved in the implementation of the first hydrogen refuelling stations in association with hydrogen-fuelled vehicle demonstrations fleets in Europe and elsewhere. However, a significant renewable hydrogen penetration is likely to be at least two decades away, as it will take time to develop the demand for hydrogen and related infrastructure. Early action with regard to developing hydrogen demand and supply remains though important in ensuring a low carbon transport future.

Other renewable transport fuels such as methanol, biomethane, DME and direct use of renewable electricity attract limited interest. Methanol is not regarded as a likely fuel for ICE vehicles and, while it could still be an option for fuel cell vehicles, the direct use of hydrogen appears increasingly likely to be the preferred choice. Biomethane could have some potential use in niche markets, in particular in association with the development of a market for CNG vehicles. The direct use of renewable electricity appears as an unlikely prospect given the fading interest in battery electric vehicles outside niche applications.

Minimising the costs, energy inputs and GHG emissions from all RTF chains requires careful technological choices and adequate fuel chain management within a framework of targeted incentives and good regulation.

Recommendations

Based on the findings of this study, a number of recommendations are made with regard to further work.

Develop detailed scenarios for 'best practice' biodiesel and bioethanol chains based on conventional processes that could serve as industry standards.

Develop more detailed analyses of the technical and economic potential of hydrolysis and gasification-based fuel chains.

Develop a better understanding of the trade-offs between biomass use for the production of heat and electricity or transport fuels and the role biomass could have as a future primary energy source for the power and transport sectors.

Develop a better understanding of solutions and policies that could reduce GHG emissions from transport, the role of different renewable transport fuels and the policy mechanisms that would lead to their market introduction.

Table of Contents

Executive Summary	i
Objectives	i
Introduction	i
Renewable energy potential	i
RTF options and fuel chains	ii
Energy balances	iii
GHG balances and abatement	v
Economics	vi
Resource requirements	vii
Conclusions	viii
Recommendations	ix
Table of Contents	i
Glossary:	iii
1. Introduction	1
Study objectives	1
Methodology	2
Report outline	2
2. Current status of world markets in renewable transport fuels	4
2.1. Introduction	4
2.2. Ethanol fuel	4
2.2.1. Major producers and consumers	6
2.2.2. Costs	8
2.3. Biodiesel	9
2.3.1. Major producers and consumers	9
2.3.2. Costs	11
2.4. Biogas	11
2.5. Drivers and policies for RTFs	11
2.6. The alternative fuels debate	13
2.6.1. Effect of government policies	14
2.6.2. Market potential	15
3. Renewable energy potential for transport fuels	16
3.1. Introduction	16
3.2. Biomass resources	17
3.2.1. Energy crops	17
3.2.2. Forestry, agricultural and livestock residues	19
3.2.3. Recovered (waste) vegetable oil and fats	20
3.2.4. Municipal solid waste	21
3.3. Direct renewable electricity sources	21
3.3.1. Onshore Wind	21
3.3.2. Offshore Wind	21
3.3.3. Wave	22
3.3.4. Tidal stream	23
Hydro	23
3.3.5. Photovoltaics	24
4. Overview of Renewable transport fuel chains: options & pathways	25
4.1. Introduction	25
4.2. Renewable Transport Fuel Production Chains	27
4.2.1. Biodiesel and DME	27
4.2.2. Bioethanol	34
4.2.3. Hydrogen	39
4.2.4. Electricity	43

4.2.5.	Methanol	44
4.2.6.	Bio-oil	44
4.2.7.	Bio-Methane.....	46
5.	Renewable transport fuel chains: carbon abatement potentials, energy ratios, costs and technologies	50
5.	Renewable transport fuel chains: carbon abatement potentials, energy ratios, costs and technologies	50
5.1.	Introduction	50
5.2.	Methodology	50
5.3.	Biomass fuel chains (non-hydrogen)	51
5.3.1.	Ethanol.....	52
5.3.2.	Biodiesel	63
5.3.3.	Methanol (from SRC wood)	69
5.4.	Hydrogen fuel chains	71
5.4.1.	Hydrogen from Biomass	71
5.4.2.	Hydrogen from wind.....	73
5.5.	Reference fuel chains: petrol and diesel.....	75
5.6.	Carbon abatement potential of renewable transport fuel chains.	77
5.6.1.	GHG emissions from renewable transport fuels.....	77
6.	Conclusions.....	79

Annexes:

1. Renewable transport fuel chain analysis sheets
2. End-fuel characteristics
3. Response to consultations

Glossary:

Term	Description
Bl	10 ⁹ (billion) litres
BtL	Biomass to Liquids- generally refers to thermal processes for the production biodiesel, DME and ethanol.
C5	Five carbon monomer e.g. fructose (a pentose)
C6	Six carbon Monomer e.g. glucose (a hexose)
CMG	Compressed Methane Gas
CNG	Compressed Natural Gas
CO ₂	Carbon dioxide (global warming potential = 1)
DME	DiMethyl Ether
DDGS	Distillers Dry Grains with Solubles
End-fuel	A fuel that can be used directly to power a vehicle
EJ	Exa Joule (10 ¹⁸ joules)
ETBE	Ethyl Tertiary Butyl Ether
EtOH	Ethanol
FCEV	Fuel Cell Engine Vehicle
FCV	Fuel Cell Vehicle
Fischer Tropsch	A catalytic system for reformulating gasifier-derived syngas. The process is most widely known for the production of ethanol from coal in South Africa by SASOL
FT	Fischer Tropsch (see above)
GJ	10 ⁹ Joules
H ₂	Hydrogen gas
Ha	Hectare = 10 000m ²
Hexose	Six carbon (C6) sugar e.g. glucose
IC	Internal Combustion
ICEV	Internal Combustion Engine Vehicle
MeOH	Methanol
Mha	10 ⁶ ha
MJ	10 ⁶ Joules
MI	10 ⁶ Litres
MSW	Municipal Solid Waste
MTBE	Methyl Tertiary Butyl Ether
Mtoe	Million tonnes of oil equivalent
MW _{th}	MW energy input (rate x energy content of feedstock)
MW _e	MW electricity produced
N ₂ O	Nitrous Oxide (global warming potential = 310 x CO ₂ (IPCC, 2001))
Odt	Oven dry tonne (1000kg)
Pentose	Five carbon (C5) sugar e.g. fructose
SRC	Short Rotation Coppice
R&D	Research & Development
RTF	Renewable Transport Fuel
RME	Rape Methyl Ester
SME	Soya Methyl Ester
t	Metric tonne (1000 kg)
VME	Vegetable Methyl Ester
WDS	Wet Distillers Grains
WVO	Waste Vegetable Oil

Definitions:

'Biomass' – all organic matter of vegetable and animal origin that has not undergone fossilisation.

'Biodiesel' – general term describing the production of diesel substitute fuels based on pressing of oil crops and esterification e.g. RME, VME.

'FT-Biodiesel' – diesel substitute fuel produced from different possible biomass feedstocks using the gasification-based Fischer-Tropsch route.

'Co-products' – all non-transport fuel outputs from a renewable transport fuel chain that have an economic and/or energy value. For example, sugar beet pulp is produced in significant quantities when sugar beet is processed for ethanol or crystalline sugar production. The pulp has economic value as animal feed or could be used to produce process heat and electricity in the sugar beet mill.

1. Introduction

Road transport consumed about 37.4 million tonnes of oil equivalent in 2001, representing about 22% of final energy use in the UK. In 2000, carbon emissions from road transport fuels accounted for about 35 million tonnes of carbon (MtC), representing about 24% UK carbon emissions. These are expected to rise to close to 47 million tonnes per year by 2020 (DfT, 2002). Therefore, road transport is clearly a critical source of dependency on non-renewable energy sources and energy imports, and a principal source of greenhouse gas emissions. Furthermore, although significant improvements have been made in vehicle emissions, road transport remains the main reason for local air quality problems in urban areas.

These and other drivers are behind the key objectives for introducing renewable transport fuels (RTFs) into the UK, which are to:

Reduce transport sector dependency on non-renewable fuels

Reduce GHG emissions from transport fuel chains

Reduce impact on air quality of transport fuel chains

Improve energy security in the transport sector

Contribute to rural development through domestic production of biomass-based fuels

Ensuring sustainable mobility is likely to require a transition to clean and renewable transport fuels (RTFs). However, the economic viability of the introduction of RTFs and alternative means of reducing energy consumption and greenhouse gas emissions in the transport sector will be a key consideration in determining which renewable transport fuels will play a significant role and how they will do so. The relative priority of the above objectives also plays a role.

The UK Government Energy White Paper indicates that 2 to 4 MtC reductions in the transport sector compared to baseline values for the year 2020. This would represent up to a 10% reduction in emissions from the transport sector which is predicted to be achieved through improved vehicle efficiency and biofuels.

Understanding the market and carbon potential of RTFs requires a detailed understanding of the technical, economic and environmental characteristics of the fuel chains, as well as consideration of the broader market, regulatory and policy conditions affecting them.

This study aims to provide a status review of renewable transport fuels and an indication of their potential for carbon abatement in the UK context. It provides a basis for the formulation of conclusions and recommendations with regard to market potential for renewable transport fuels and related policy and regulatory measures, environmental in particular.

Study objectives

The study's principal objectives are to:

- Review the status and discuss the potential evolution of world markets for renewable transport fuels (RTFs).
- Describe the options for producing renewable transport fuels in the UK.
- Review the characteristics, status and prospects of key production and processing technologies, fuel logistics and end-uses.
- Provide a detailed economic and environmental (carbon) analysis of selected RTF chains.
- Discuss the potential for renewable energy resources for transport fuel production in the UK.
- Discuss RTF markets, carbon abatement potentials and the influence of policy and regulatory measures.
- Conduct consultation with experts within industrial, government and non-government organisations.

Methodology

The study considers all principal RTF options, in particular the production of eight renewable transport fuels i.e.: biodiesel from oil-rich crops and from the gasification of other biomass resources, bioethanol, biomethanol, dimethyl ether, biogas, biogasoline derived from pyrolysis oils, hydrogen from biomass and from water electrolysis using renewable electricity, and electricity.

The market and technology status review is based on public domain literature and validation through consultation with experts within industry, government and NGOs.

The RTF analysis consists of the following stages:

1. Identification of RTF chains of relevance to the UK
2. Overview of RTF chains and review of RTF chain analyses in the literature
3. Selection of RTF chains for detailed analysis
4. Detailed RTF chain analyses
5. Presentation of RTF chain analyses in summary sheets
6. Review of UK renewable energy potential and discussion of potential for RTFs
7. Consultation and workshop for validation of results

The detailed RTF chain analyses examined the costs, energy balance and CO₂ balance for the following stages of the fuel chains:

1. Feedstock production (biomass feedstock and electricity)
2. Feedstock transport
3. RTF production
4. RTF distribution

Direct energy inputs and CO₂ emissions associated with the different stages of the fuel chain are considered. Indirect energy inputs and CO₂ emissions are considered where their contribution is likely to be significant. For example where annual crops are the primary feedstock for RTF production, the energy inputs required to produce the fertilisers applied to the crop can represent the single largest energy input to the whole chain. The associated GHG emissions arising from the production of fertilisers can also be significant and are also accounted for. These chains include those where sugar beet, wheat grain and rape are the feedstocks for RTF production. Indirect energy inputs are likely to be minimal in the conversion and transport sectors

Several RTF chains result in co-products and by-products. Base case calculations do not consider allocation of costs, energy inputs and CO₂ emissions to co-products and by-products. However, the influence of possible revenue from co-products, their energy contents and allocation of energy inputs and CO₂ emissions to them is highlighted in the individual chain analysis sheets (appendix 1) and discussed in chapters 4 and 5.

Report outline

Chapter 2 discusses the current RTF market status world-wide, emerging RTFs and provides an overview of the current alternative fuels debate.

Chapter 3 provides a review of renewable resources in the UK and an indication of the potential for RTFs.

Chapter 4 describes and discusses the RTF chains of relevance to the UK context and provides a literature review of relevant recent fuel chain analyses.

Chapter 5 provides an analysis of the costs, energy balance and greenhouse gas emissions for selected key RTF chains for the UK, and an overall assessment of their carbon abatement potential.

Chapter 6 draws conclusions on the RTF chains based on techno-economic and carbon abatement considerations and discusses their potential evolution and market diffusion.

2. Current status of world markets in renewable transport fuels

2.1. Introduction

Internal combustion engines (ICE) and oil-derived fuels have dominated transportation systems for many decades. The ICE has been so successful as a propulsion system that until recently prospects for radical alternatives have attracted little interest.

However, in recent years, a combination of technological, environmental and socio-economic changes, are driving the search for alternatives that could challenge the dominance of the ICE and conventional petroleum-based fuels. For example, acute air quality problems are creating markets for alternative propulsion systems in urban areas through specific policies (e.g. California zero emission mandates).

The challenge is to find sustainable long-term alternatives to conventional petroleum-based fuels for use in ICE and new propulsion systems. A number of alternative fuels such as ethanol, biodiesel and to a lesser extent biogas are currently in use, others such as hydrogen are emerging.

This section focuses on the only two renewable transport fuels that can be considered of commercial relevance at present: ethanol and biodiesel. Chapters 4 & 5 provide a detailed technical evaluation of the possible pathways (chains) and methods for their production. Over the last few decades their production has been increasing rapidly and we estimate that globally, about 25 Bt of ethanol and more than 3 Bt of biodiesel are now consumed annually.

2.2. Ethanol fuel

The history of ethanol as a fuel dates back to the early days of the automobile, when in 1897, Nikolaus Otto used pure alcohol in his first engine. Ethanol (ethyl alcohol) produced by fermentation is currently the most important alternative fuel to gasoline and is used both neat and as a blend.

There are various ethanol categories, which can be divided by: i) *origin* e.g. biological vs. synthetic; ii) *composition* e.g. anhydrous vs. hydrous; or denatured vs. non-denatured; and iii) *use* e.g. industrial, fuel, or potable ethanol.

Sources for production

The many sources from which ethanol can be produced fall into two basic categories: i) *biological alcohol* obtained from any sugar, starch and cellulose-containing biomass material, and ii) *synthetic alcohol* derived from petroleum, gas or coal.

There are two main types of ethanol fuel: i) "hydrous ethanol" (meaning water-containing ethanol), which contains approximately 2-5% water by volume and is used unblended. The only country in the world that uses hydrous ethanol fuel on a large scale is Brazil. ii) "Anhydrous ethanol" (meaning water-free or 'absolute'), which is used in blends with gasoline in various proportions. Blending is currently the main growth area for ethanol fuel use worldwide.

It is recognised that the production and supply of ethanol for use as a fuel could also lead to its illicit use as potable alcohol. Therefore, to prevent ethanol being used for non-fuel purposes, it is "denatured", which is accomplished by the addition of chemical additives (usually 1 or 2%) which are slightly toxic or impart an unpalatable flavour.

Despite the large range of raw materials from which ethanol fuel can be obtained, in practice, its production is limited to a few high productivity crops such as sugarcane and maize, in Brazil and the USA, respectively. In the EU, sugar beet and wheat are also used but on a smaller scale.

There are of course many other sources from which ethanol is currently being produced, for example, in the USA alone, 27 different feedstocks are used for producing ethanol. Globally, sugarcane is likely to remain the most important source of ethanol in the short-term. Most of the planned ethanol fuel programmes around the world include sugarcane as the main source of ethanol. The main exceptions are the EU and USA that will be using a variety of feedstocks more suited to temperate climates.

End-use

Most of the technological problems posed by the utilization of ethanol fuel (neat and blends), have already been overcome. Minor problems still remain, such as cold start problems caused by lower vaporization pressures of blends. These can be overcome without much difficulty with some innovative technologies being developed, such as: onboard distillation, glow plug ignited fuel, electric supercharging, quick heat intake manifold, liquid-heated fuel injectors, and phase-changing catalysts.

A 10% (v/v) ethanol blend in gasoline contains about 97% of the energy of pure gasoline, but this is possibly compensated by increases in combustion efficiency of ethanol blends leading to similar volumetric efficiency. The volumetric energy equivalency of ethanol to gasoline in blends is contentious because most if not all the gains in efficiency result from an increase in octane rating which in turn results from ethanol's greater oxygen concentration compared to gasoline. However, the specifications of gasoline as delivered to the vehicle are tightly controlled, including octane ratings and so unless regulations are changed the increase in octane rating resulting from the addition of ethanol would have to be compensated by removing other high oxygen components in the gasoline. In addition, ethanol has a higher vapour pressure than gasoline and vapour pressure is also tightly controlled in gasoline specifications. Vapour pressure is important because in current ICEs too high a vapour pressure will result in vapour locks in the fuel supply system and too low a vapour pressure and cold starting problems will be encountered. As a result, in the UK, vapour pressure is controlled by the partial removal of butane from gasoline. In summer virtually all the butane is removed to keep vapour pressure within the upper limits of the fuel specifications and to avoid vapour locking on hot days. Therefore, particularly during hot periods, the addition of ethanol will require the removal of additional higher vapour pressure components in gasoline or changes in design to the fuel delivery system in vehicles (Watson, 2003).

If ethanol blends are increased to >20% (v/v), a higher compression ratio compared to a conventional petrol engine may be desirable to take full advantage of the ethanol's higher octane rating. A higher compression ratio can, in turn, increase the pressure on engine bearing, and thus require engine modifications to withstand the extra pressure. Ethanol use (neat or at relatively high blends) in suitably designed engines can lead greater power per engine cylinder volume compared to conventional petrol engines and a few percent improvement in efficiency.

In terms of vehicle technology, ethanol flexible fuel vehicles (FFVs) are of particular interest. The ethanol FFVs incorporate a modern microprocessor that continuously monitors the engine's operation and fuel air ratio, making it possible to adjust automatically to ethanol/petrol blends containing up to 85% ethanol (E85). For E85 vehicles, power, acceleration, payload, and cruise speed are comparable with those of conventional fuels (see www.afdc.doe.gov/afv/; www.ott.doe.gov/biofuels/).

Ethanol-diesel blends. Numerous experiments have been carried out with ethanol blends with diesel worldwide in various proportions. E-diesel is made by splash blending of conventional diesel, with up to 15% of ethanol, and additives (0.2 – 5%). No special mixing protocol or temperature control is required. There are various technical problems which still remain to be solved (e.g. low flash point and tank vapour flammability, acceptability by automobile manufacturers, more tests on health and safety, etc).

2.2.1. Major producers and consumers

Current world production of ethanol (all categories) is estimated to be between 35-40 BI, the majority of which is fermentation-derived alcohol and is therefore of biological origin. The estimated fuel ethanol installed capacity (2002) was about 29 billion litres (c. 23.2 Mt), while total production was approximately 25.5 BI/yr. The largest producers are Brazil with about 12.5 BI/yr, USA with about 8 BI/yr and the EU with about 2.2 BI/yr (2001).

There is considerable difficulty in knowing how much ethanol is used as fuel and how much in other industrial applications, partly because fuel ethanol producers often also dominate the beverage and industrial markets, and they do distinguish between final use in. Large amounts of synthetic ethanol (mainly from coal) are used in industrial applications e.g. solvents. Roughly, 60% of ethanol production is for fuel use but with large variations (e.g. in Brazil over 85%, USA close to 80%, and the EU 60%), although this proportion is changing rapidly as the majority of new plants aim to produce ethanol fuel.

Approximately 3 BI/yr of fuel ethanol is currently traded internationally, with Brazil and the USA being the main exporters and Japan and EU the main importers. Japan is currently considering blending ethanol with gasoline with an initial potential market of 6 BI/yr, although no final decision has been taken with regard to the level of blends. The EU is also a major potential market if its ambitious biofuel targets are to be achieved. Based on current technology, the most promising ethanol producers are sugarcane producing countries and the USA. However, most countries could develop a domestic ethanol fuel industry based on a variety of feedstocks. The international trade in ethanol fuel still faces major difficulties, including high transport and storage costs, trade barriers, and lack of a sizeable international ethanol fuel markets with bilateral trade agreements currently dominating this trade.

Brazil. By 2001, there were 308 sugar/ethanol mills that employed about 0.6 million people directly. Brazil produces 11% of the world's ethanol fuel, 17% of world's sugar and accounts for 25% of sugar exports. Table 2.1 summarises sugar and ethanol production in Brazil.

Table 2.1.: Sugar and ethanol production in Brazil (2001/02 harvest and estimated for 2002/03)

Year	2002/03	2001/02
Cane (million tonnes)	286.3	243.4
Sugar (million tonnes)	20.1	15.9
Ethanol (Million m ³)	11.3	10.1
- Anhydrous	6.5	5.7
- Hydrous	4.8	4.4

Source: UNICA (2003)

Ethanol fuel use has increased steadily in absolute terms, but has decreased in relative terms since the peak of the late 1980s, when almost every passenger car in Brazil was powered by neat (hydrous) ethanol. Brazil's ethanol blends vary from 20% to 24%, or even 26%+, depending on market conditions. Blends offer greater flexibility, both to the sugarcane producers and consumers of ethanol fuel (Rosillo-Calle & Cortez, 1998). In 1999, the Brazilian government withdrew all direct subsidies to ethanol fuel and since then it competes directly with gasoline in the free market. The ethanol market should continue to grow steadily based on ethanol blending with petroleum fuels, as the total car fleet is expected to grow from 14 million units in 2000 to over 29 million by 2015.

USA. The USA has the world's fastest growing fuel ethanol market, with an installed capacity in 2002 of over 11 BI. Table 2.2 summarises existing and planned ethanol production capacity for the period 2001 to 2005. This rapid increase is due to a combination of factors, primarily environmental and agricultural. The main producers are the states of Illinois, Nebraska, Iowa, and Minnesota. Ethanol is sold in all States as an octane enhancer or fuel extender, for blending with gasoline, and currently represents about 2% of the USA's gasoline fuel market.

Table 2.2: USA - Existing and planned ethanol production capacity (Bl), 2001-2005

Existing Industry	Year	2001	2002	2003	2004	2005
	Companies	44	44	44	44	44
Plants	57	58	58	58	58	
Capacity (Bl)	8.4	9.4	10.2	10.50	10.8	
New Entrants	Companies	4	21	40	40	40
	Plants	4	21	43	44	46
	Capacity(Bl)	0.3	2.0	5.0	5.2	6.0
Total capacity (existing & new)	Companies	48	65	84	84	84
	Plants	61	79	101	102	104
	Total capacity (Bl)	8.7	11.4	15.2	15.7	16.7

(All figures have been rounded)

Source: California Energy Commission (2001)

EU. Ethanol production in the EU is concentrated in a few countries, namely, France, Germany, Italy, and more recently Spain, as illustrated in Table 3. Only part of the ethanol production shown in Table 2.3 is destined to the fuel ethanol market. In 2000, it is estimate that about 0.28 Bl of ethanol fuel were used in the transport sector in Europe, representing about 0.2% of petrol consumption. Spain is bound to become the EU's largest producer of ethanol fuel when new plants currently under construction enter operation in 2004, since this new capacity is directed to the fuel market.

Table 2.3: Ethanol production in the EU, 1997- 2001 (Million litres)

Country	2001	2000	1999	1998	1997
France	800	810	754	780	767
Germany	290	285	340	364	375
Italy	190	205	200	225	230
Spain*	225	145	125	140	136
UK**	430	435	410	420	440
Other EU	222	187	185	187	202
Total EU	2,157	2,067	2,014	2,116	2,150

* Excludes new capacity; ** mostly synthetic ethanol

Source: Berg (2001)

Other regions. Ethanol is being tested in various proportions and with different fuels in many parts of the world. A large number of countries are introducing alternative fuel programs (see Table 2.4).

Table 2.4: Summary of current ethanol production and plans for bioethanol fuel use

Country	Production (2001)	Remarks
Australia	150 million l/yr (current production – all uses)	Plan for 2-5% blend nationwide by 2010, corresponding to 1 – 2 Bl/yr production
Canada	240 million l/yr (current production – all uses)	Target 1.35 Bl/yr by 2010
China	3 Bl/yr (current production – all uses)	Plan to produce additional 3 Bl/yr from maize, sweet sorghum, cassava and sugarcane
India	1.8 Bl/yr (current production – all uses)	Plan for 5% blend, trial at 300 refuelling stations, initial demand 350 million l/yr
Mexico	70 million l/yr (current production – all uses)	Program to produce 1.3 Bl/yr

South Africa	385 million l/yr from coal and gas, 40 million l from cane	Plan for 12% blend nationwide; plan to increase fermentation ethanol from cane
Thailand	150 million l/yr (current production – all uses)	Plan for 10% blend, using molasses, cassava, and sugarcane, corresponding to 0.7 Bl/yr
Others: Colombia, Cuba, Ethiopia, Malawi, etc		Mostly ethanol from sugarcane to be blended with gasoline in various proportions. Some ethanol-diesel blends. Malawi blends 15% since 1982. Other programs are at various stages.

2.2.2. Costs

Estimating costs of ethanol is rather complicated because of the large number of factors involved, including a variety of subsidies.

The cost of ethanol has decreased significantly in the past 20 years. For example, Brazilian production costs are estimated to have been reduced from about 45 US\$ cents per litre in the early 1980s to 15-21 US\$ cents in 2002 (about 60% is the cost of raw material) in the State of Sao Paulo, the largest and most efficient sugarcane and ethanol producing state (Macedo, 2002). This has resulted from a combination of factors e.g. increased sugarcane productivity and conversion efficiency. In the 1980s, ethanol production was about 3 600 l/ha.yr, while in 2001, it reached about 6 500 l/ha.yr.

In the USA, in the early years, a major cost factor of ethanol was the high cost of maize; caused primarily by low productivity and high inputs. However, in recent years productivity has increased while inputs (fertilizers, herbicides, etc), have been reduced and currently ethanol production costs vary from 25 to 29 US\$ cents/l. Table 2.5 compares the price of neat ethanol in the USA relative to gasoline in 1998/1999. There are of course many other factors (i.e. environmental, social, security, etc) that need to be taken into account.

Future production of biofuels is likely to be more diverse, with greater use being made of a variety of residues and wastes and the use of other dedicated energy crops. For example, in the USA, cheese whey, beverage industry wastes, potato wastes, etc., are already used for ethanol production, and of the new plants being built or planned, two will use barley & wheat, one sugarcane bagasse, two forestry and wood residues, one rice straw and one MSW. In total, 27 different feedstocks are being used to produce fuel ethanol. (See www.ethanolrfa.org/).

Table 2.5: Price of neat ethanol relative to gasoline in the USA, July 1998 to June 1999.

Ethanol wholesale price*	103 US cents/gal (27 cents/l)
Ethanol fuel tax incentive	54 US cents/gal (14 cents/l)
Effective ethanol price	49 US cents/gal (13 cents/l)
Gasoline wholesale price**	46 US cents/gal (12 cents/l)

* Average price for neat ethanol; ** average rack price for regular conventional gasoline (i.e. non-oxygenated, standard octane).

Source: See Yacobucci & Womach (2000).

Significant technical and cost improvements are still possible in ethanol production. For example, with regard to fermentation technology, the development of genetically engineered micro-organisms capable of fermenting a broader range of sugars and of new industrially produced enzymes could increase productivity and reduce costs significantly. Also, important advances have been made in the production of ethanol from cellulose-containing materials e.g. bagasse,

maize stalks, wood, straw, but the technology is not yet commercial (see Chapters 4 & 5 for more details).

Because of engine modifications, ethanol fuelled vehicles are more expensive than gasoline cars, but the price difference has decreased considerably with newer technology, experience, etc.

2.3. Biodiesel

In 1997, The Austrian Biofuels Institute (ABI) carried out a detailed study for the IEA to determine worldwide production and potential of biodiesel, covering 28 countries in which biodiesel activities were reported in the previous 15 years (ABI, 2000). In total, 85 biodiesel production plants (44 in Western Europe with a total capacity of 511 MI) were identified of which 40 were in the range 500 to 3 000 t (0.57 to 3.4 MI/yr) and the rest in the capacity range 5 000 to 120 000 t (5.7 to 13.6 MI/yr). The overall capacity in 2002 was estimated at about 2.5 Mt (2.84 BI; Körbitz, 2001). However, biodiesel production has experienced a strong recent growth, and current production in EU-15 is estimated at about 3 BI/yr, with Germany accounting for about 1.2 BI/yr (see Table 2.6).

Sources

The ABI (2000) study identified rapeseed as the most important source with a share of over 80 %, followed by sunflower oil with over 10 %; mostly used in Italy and southern France, while soybean oil is preferred in the USA. Other raw materials are palm oil in Malaysia, linseed and olive oil in Spain, cottonseed oil in Greece, beef tallow in Ireland, lard and used frying oil (UFO) in Austria, and other waste oils and fats in the USA. Synthetic diesel is also being made from coal and natural gas via the Fischer-Tropsch process, and in the future it may be possible to obtain it from ligno-cellulosic biomass using the a similar process. (See Chapters 4 & 5; www.ott.doe.gov/biofuels/).

End-use

Both the automobile industry and biodiesel producers have played a major role in developing the technical and normative prerequisites for biodiesel. Biodiesel has good ignition and combustion characteristics. It is virtually sulphur free and the use of an oxidation catalyst reduces other exhaust emissions drastically, although NO_x and aldehyde emissions may be slightly higher compared to diesel.

Blends of up to 20% (B-20) can be used in almost all diesel engines and are compatible with most storage and distribution equipment. B-20 should not require engine modifications, or significantly affect payload and range compared to diesel, and should not affect engine lubrication. The use of higher blends will generally require some engine modifications, in particular with regard to materials compatibility. The use of neat biodiesel (B100) will result in some engine performance loss (fuel economy, torque and power) because of the lower energy content. (See www.afdc.doe.gov/afv/; www.ott.doe.gov/biofuels/). In fact, increased lubricity may result from biodiesel blending which is reported by some organisations to result in improved engine efficiencies and therefore increased mileage (Greenenergy, 2003).

2.3.1. Major producers and consumers

EU. The EU is the largest global producer and end-user of biodiesel with a current installed capacity of about 3 BI and represents about 1% of the diesel market. The most important

biodiesel producer and consumer is Germany where production has increased since 1998 from about 79.5 MI/yr to about 1.2 BI/yr¹ (Table 2.6).

This expansion seems to continue due to: 1) favourable policies in support of biodiesel e.g. the mineral oil tax², and 2) increasing demand in the EU. It is expected that by the end of 2003 there will be about 1,700 petrol stations selling biodiesel in Germany. Currently one of the limiting factors to further expansion, according to UFOP (German Union for the Production of Oil and Protein Plants; www.ufop.de) is the supply of raw material.

Table 2.6: Estimated installed capacity of biodiesel in the EU Member States.

Country	Installed capacity (MI*)
Germany	1,259.8
France	499.8
Italy	397.6
Denmark	68.1
Austria	51.1
Sweden	34.0
Great Britain	34.0
Total	2,289.2

* One tonne of diesel = 1136 litres

Source: Bockey & Korbitz (2003); www.ufop.de

USA. Biodiesel production in the USA has increased rapidly in the past decade, but production levels remain well below those of the EU. Table 2.7 summarises installed capacity and production of biodiesel in the USA, from 1993 to 1998. In 2001, about 54,000 t (61.34 MI) of biodiesel were sold in the USA.

Table 2.7: Estimated biodiesel installed capacity and production in the USA, 1993 and 2001 (MI)

Year	1993	1994	1995	1996	1997*	1998*	2000	2001
Installed capacity	38.0	41.8	60.7	144.3	406.4	516.6	190	300
Production	3.8	7.6	11.4	19.0	30.9	49.5	26.59	76

* Estimated

Source: ABI (1997), years 1993-1998; www.ott.doe.gov/biofuels/ (2000) and Scurlock (2003) for 2001 figures and 2000 installed capacity figures.

In the US, enabling legislation is advancing to promote biodiesel use, and more state and federal vehicle fleets (e.g. the U.S. Postal Service) are starting to use this fuel. Biodiesel can now be used in blends of 20% (B20) and higher to meet federal and state alternative fuel vehicle fleet requirements, due to a 1999 amendment to the 1992 Energy Policy Act (which previously required only the purchase of alternative fuel vehicles and not the actual use of alternative fuels). A number of city bus fleets, such as Cincinnati and St. Louis, are beginning to use biodiesel on a large scale. State Bills requiring state-wide use of a 2% biodiesel blend have been proposed by the legislatures of Minnesota and North Dakota. These two states alone would create a market for 76 million litres per year using soybean oil methyl ester. The American Biofuels Association (ABA) considers that with government incentives comparable to those provided for ethanol, biodiesel consumption could reach 7.5+ BI, or about 8% of diesel consumption. It would primarily power bus fleets, heavy-duty trucks and agricultural vehicles, mostly in blends of about 20%. The DOE is currently developing low cost biodiesel from mustard seed that could add a further 5-10 billion gallons (20 to 38 bl) if the research proves successful.

¹ Includes plants under construction and due to enter operation in 2003

² See law The Mineral Oil Tax Act of 2002 (Sect. 2 para. 1 and Sect. 3 para 1) which reduces taxes on biofuels until 31st December, 2008.

2.3.2. Costs

Biodiesel technology is mature, with minor scope for technical and cost improvements. Biodiesel has a production cost in the EU of about €0.5/l (approx. \$0.48/l), compared to €0.20 to 0.25/l for traditional petroleum-based diesel, including refinery costs. However, final costs depend on many factors e.g. raw material, yields, size and type of production plant, value of by-products, etc. Table 7 shows a summary of the extra costs of using biodiesel to replace diesel at different crude oil prices based on average current biodiesel production costs (Commission of the European Communities, 2001; com 370).

Table 2.7: Additional costs of using biodiesel to replace conventional diesel

Crude oil price (\$)	Extra cost for 100% biodiesel (Euros)
20 \$/barrel	~ €350/1000-litre
25 \$/barrel	~ €300/1000-litre
30 \$/barrel	~ €250/1000-litre
35 \$/barrel	~ €200/1000-litre

Notes: €0.5/litre is based on average raw material costs, low production cost of a large production plant and by-product price of €50/1000-litre, and 1100 litres of biodiesel replacement per 1000 litres of conventional diesel.

Source: CEC, 2001; com 370.

In the USA, neat biodiesel costs between \$1.30 to \$3 per gallon (34 to 79 \$ cents/litre), and B20 (20% blend) costs 30 to 40 \$cents more per gallon (0.07 to 0.10 US\$ cents/l) than conventional fuels, depending on the feedstock and supplier (Scurlock, 2003).

2.4. Biogas

Biogas has been used as a transport fuel in urban dedicated fleet vehicles e.g. buses. In 1991, Sweden's Transport & Communication Research Board launched a programme to demonstrate the use of biogas, together with ethanol, in buses, heavy vehicles, and cars (See www.engva.org/view). Various full-scale demonstration projects have been implemented and an increasing number of town buses are using biogas e.g. in Linköping, approx. 40-50 buses and 30-40 cars are fuelled by biogas produced from one of the world's largest biogas plants.

The biogas potential from a range of wet biomass streams (e.g. sewage, wet agricultural wastes, organic fraction of MSW) is large. The estimated biogas potential in the EU-15 in 2020 is about 750 PJ (209 TWh/yr, approx. 17.97 Mtoe). The most important producing countries are Germany (about 154 PJ, 3.68 Mtoe), France (about 143 PJ, 3.41 Mtoe), UK (about 95 PJ, 2.27 Mtoe), Italy (about 68 PJ, 1.62 Mtoe) and Spain (about 66 PJ, 1.58 Mtoe). (See www.ad-nett.org/; www.ecop.ucl.ac.be/aebiom/articles/). Biogas is associated with the treatment of wet biomass waste streams and as such is not likely to be an important energy vector, though its use in niche markets such as buses, and refuse vehicles, mostly in urban centres could be significant. Biogas can be integrated in infrastructure and energy applications designed for natural gas. Advances in gas-powered vehicles have greatly benefited the use of biogas in transport applications, though its penetration remains very small compared to natural gas. Its major disadvantage is its low calorific value, which limits vehicle range.

2.5. Drivers and policies for RTFs

The principal drivers for introducing renewable transport fuels (RTFs) into the UK are to:

- Reduce transport sector dependency on non-renewable fuels
- Reduce GHG emissions from transport fuel chains
- Reduce impact on air quality of transport fuel chains
- Improve energy security in the transport sector
- Contribute to rural development through domestic production of biomass-based fuels
- Support for a particular fuel depends on the specific circumstances of a country or region, and can take many forms, ranging from fiscal incentives, tax rebates on vehicles with low emissions, support for RD&D, etc

EU. There are significant differences in the way biofuels are promoted in the EU. For example, the German government provides generous incentives to neat biodiesel; Austria has been, historically, a pioneer in establishing bioenergy programs (e.g. it built the world's first biodiesel plant); Sweden's government has set up an RD&D program to produce ethanol from biomass, aiming a making ethanol from wood competitive in 2004.

The EU proposed new legislation to promote alternative fuels (Commission of the European Communities, 2001; Com 547), includes an action plan and two proposals for directives. The driving force for the support of biofuels in the EU is the Commission's Green Paper: Towards an European Strategy for the Security of Energy Supply (COM(2000) 769), which introduced the objective of substituting 20% alternative fuels in the road transport sector by the year 2020. The directive proposal suggests that Member States set their own national targets and implement measures to achieve them. However, depending on progress in the adoption of alternative fuels and following a review, possibly in 2007, the EU may consider "mandatory objectives acceptable to all Member States". (See e.g. www.eufores.org/).

The biofuels considered are:

- Biodiesel (from rapeseed, sunflower, etc)
- Bioethanol (sugar beet, cereals, etc)
- ETBE (based on bioethanol)
- Biogas
- Biomethanol (based on biomass or biodegradable waste)
- Biodimethylether (based on biomass or biodegradable waste)

The Commission sees little scope for large scale biofuel production under the existing system of set-aside land if the current agreement with the USA (Blair House Agreement) is not changed. This agreement limits support to rapeseed, soybean and sunflower to "one million tonnes" soy meal equivalent. It also limits aid support to oilseed production to a maximum of 5 Mha. However, other sources of production for biofuels, namely cereals (i.e. maize, sugar beet), and woody biomass are not covered by the Blair House Agreement, and thus, are simply subject to normal rules of competition. In addition, any system that requires additional agricultural subsidies would not be possible under the various agreements in place within the EU.

USA. The rapid growth of the fuel ethanol and biodiesel market in the USA has resulted from a combination of factors, including the following:
Government intervention e.g. - the introduction of the Clean Air Act Amendments (CAAA) in 1990, which required that certain regions use oxygenated, reformulated gasoline. The law required that a certain percentage of oxygenates have to be derived from renewable sources.
Tax concessions and loan programmes e.g. since January 1991, the tax exemption has been set at 5.4 cents per gallon for a minimum 10 per cent ethanol blend.
The Energy Policy Act of 2002 establishes a national Renewable Fuels Standard (RFS), requiring an increasing amount of renewable fuels to be blended with conventional motor fuels, starting at 2 billion gal (7.57 BI) in 2003, and increasing to 5 billion gal (18.9 BI) in 2012, remaining more or less constant thereafter.

The development of fuel specifications and standards has helped generate commercial and consumer confidence in biofuels e.g. the approved specification for pure (100%) biodiesel is ASTM D6751 (American Society of Testing of Materials).

Important driving forces behind the adoption of renewable transport fuels in the US are concerns with US dependence on foreign oil supplies and support to US farmers e.g. maize and soybean producers.

Brazil. The initial support for ethanol fuel in Brazil arose from a combination of factors, including: i) high costs of imported oil, ii) vulnerability of oil supplies, iii) support investments in the sugarcane industry. Considerable progress has been made in ethanol production technologies and cost reductions, since the start of the fuel ethanol programme in the early 1970s. The programme also has strong economic, social and political ramifications linked to the sugarcane industry.

In several countries, there is an increased interest in ethanol fuel as an octane enhancer and as a substitute for lead and MTBE. Phasing out of lead (e.g. in Africa), and a potential move away from the use of MTBE, may open significant markets for ethanol fuel.

However, low oil prices, generally high production costs of biofuels, and doubts over long-term policy support, still present barriers to the development of biofuels. Furthermore, the long-term success of biofuels will depend on their ability to meet the requirements of advanced engine technologies and the potential longer term transition to fuel cell vehicles. While ethanol and biodiesel may dominate the short to medium-term, the longer term potential for biomass-based transport fuels may lie with fuels such as methanol and hydrogen which may still be derived from biomass resources.

2.6. The alternative fuels debate

The policy focus in Europe with regard to environmental issues related to road transport has shifted to reducing greenhouse gas emissions while continuing to push for marginal reductions in emissions affecting air quality.

Vehicle manufacturers have committed to reducing average CO₂ emissions from new vehicles by 25% i.e. to 140 gCO₂/km by 2008, the EU's aspirational target for that period being 120 gCO₂/km. Advanced vehicles based on conventional IC engines should be able to reach 110 to 120 gCO₂/km for petrol on a tank-to-wheels basis and 100 to 110 gCO₂/km for diesel (UKPIA, 2002). Further reductions in CO₂ emissions require a move to alternative propulsion systems, hybrid and fuel cell vehicles, and/or the introduction of renewable transport fuels. Petrol and diesel fuelled hybrid vehicles based on advanced IC engines should reduce emissions to about 90 gCO₂/km, similar to those of a natural gas derived hydrogen fuel cell vehicle (UKPIA, 2002).

As a result of the ACEA voluntary agreement and the UK government's Ten Year Transport Plan, UK emissions from road transport are only expected to rise slightly by 2020 compared to the 1990 level, but would remain on an increasing trend. However, government objectives to reduce UK GHG emissions below 1990 levels and increasing global pressure on GHG emissions are likely to require further reductions in CO₂ emissions from road vehicles.

Fossil-fuelled hybrid and fuel cell vehicles could further reduce CO₂ emissions by about 25% over advanced ICE vehicles. These would allow for a stabilisation and possibly some decrease in CO₂ emissions from road transport compared to 1990. However, significant reductions in emissions could only be achieved through the introduction of renewable transport fuels. These are also key in ensuring a sustainable transport future in a world with resource and environmental constraints.

With regard to the introduction of renewable transport fuels, the debate has focused on biodiesel from oil crops and bioethanol from sugar and starch crops, as these are at present the only

commercially available biofuels. However, their large scale introduction in Europe has been restrained by elevated costs, unclear environmental benefits, limited potential for fossil fuel substitution and lack of consistent policy measures (in time and across Member States).

More recently, Fischer-Tropsch (FT) biodiesel from lignocellulosic biomass, renewable hydrogen from water electrolysis using renewable electricity and biomass gasification have attracted increasing interest in the policy debate. However, both the FT-biodiesel and renewable hydrogen fuel chains are not commercially mature. Interest in FT biodiesel lies in the fact that it could provide a larger, possibly cheaper and better quality source of biodiesel with greater environmental advantages compared to biodiesel from vegetable oils, and that it could be readily used in conventional ICE vehicles. Interest in renewable hydrogen lies in the fact that it provides an ideal fuel for fuel cell vehicles with potential zero well-to-wheel emissions.

2.6.1. Effect of government policies

UK government programmes, in the form of alternative vehicle purchase grants and fuel duty reductions, have so far been aimed principally at LPG and CNG vehicles aimed tackling urban air quality concerns. LPG vehicle uptake has been relatively successful with over 65,000 vehicles converted to LPG that can be obtained at over 1 000 refuelling stations. However, LPG vehicles present few advantages compared to advanced ICE petrol and diesel vehicles. CNG vehicle uptake has been less successful than LPG, mainly as a result of higher vehicle conversion and refuelling station costs.

Very little incentive has been directed to date at renewable transport fuels in the UK. A 20p/l (£6.1/GJ) fuel duty reduction applies to biodiesel, which is likely to result in a relatively small increase in demand for biodiesel, mainly derived from waste oils. The current fuel duty reduction is too low to make biodiesel from energy crops a commercially viable proposition, without additional economic incentives along the fuel chain although this may change in the 2003 budget.

A 20p/l (£9.4/GJ) fuel duty reduction is being considered for bioethanol. This incentive could make the lowest cost bioethanol from energy crop options a commercially viable proposition, without additional economic incentives along the fuel chain. However, to ensure that the most environmentally beneficial bioethanol chains are implemented may require additional incentives, with specific requirements attached to them.

Hydrogen from any source is subject to zero fuel duty. While the measure indicates the government's belief in the potential for hydrogen as a sustainable transport fuel, it is likely to have little effect in terms of the hydrogen volume uptake as a transport fuel given the early stages of vehicle and infrastructure development.

The EU's proposed Directive on the Promotion of the Use of Biofuels for Transport (Commission of the European Communities, 2001; com 547) is aimed at facilitating their introduction. The aim is to replace 2% of fossil fuels in transport with biofuels by 2005 and 6% by 2010. Biodiesel from oil crops and bioethanol from sugar beet are likely to be the dominant biofuels given their commercial maturity relative to other biofuel options. The proposed Directive has been subject to criticism based on two main factors: i) the extent of the societal benefits that can be derived from traditional biodiesel and bioethanol fuel chains; and, ii) the inappropriateness of setting fuel type specific targets that do not consider the opportunity cost of the proposed option in relation with other options for achieving environmental targets in the transport sector and/or rural development.

Hydrogen as a transport fuel is still in its infancy. There is increasing policy interest in individual governments, including the UK, and the European Commission is developing actions to take the first steps towards establishing a hydrogen infrastructure.

2.6.2. Market potential

Mature biodiesel and bioethanol production routes in Europe appear to have a limited but important market potential because of the relatively high cost and potentially limited societal benefits.

However, novel biodiesel and bioethanol routes based on Fischer-Tropsch and hydrolysis processes, respectively, open-up potentially larger markets. These fuels could provide significant quantities of renewable transport fuels for advanced ICE and hybrid ICE vehicles once the technologies are developed and commercially demonstrated. As a result, they have attracted recent interest and investment from automotive and energy companies e.g. Volkswagen and Renault's interest in FT-biodiesel (Griessman *et al.*, 2003) and the recent Shell investment in logen (logen, 2002).

Hydrogen appears to have the ultimate market potential as an efficient renewable fuel for use in fuel cell vehicles. Any significant renewable hydrogen penetration is then likely to be at least two decades away, earliest time by which fuel cell vehicles could be the dominant vehicle on the road. Automotive firms are investing considerably in the development, testing and demonstration of fuel cell vehicles. Energy companies (e.g. Shell, BP, TotalFinaElf) are involved in the implementation of the first hydrogen refuelling stations in association with hydrogen-fuelled vehicle demonstration fleets in Europe and elsewhere.

Other renewable transport fuels such as methanol, DME, biomethane and direct use of renewable electricity attract only limited interest. Methanol is not a practical fuel for ICE vehicles and whilst it could still be an option for fuel cell vehicles, hydrogen appears increasingly to be the preferred choice. Biomethane could have some potential use in niche markets, in particular in association with the development of a market for CNG vehicles. The direct use of renewable electricity appears as an unlikely prospect given the developments and fading interest in battery electric vehicles outside niche applications.

3. Renewable energy potential for transport fuels

3.1. Introduction

The total exploitable potential energy available from renewable feedstocks in the UK is estimated (see below) to be between 1083 to 2117 PJ, equivalent to 9.5 to 18.6% of primary UK energy demand in 2001 (11.37 EJ; DTI, 2002). The renewable resources considered to have the greatest potential in the UK are wind, energy crops, wave and tidal, and building integrated photovoltaics (PIU 2001h). Other resources such as hydro, agricultural and forestry wastes, solar thermal, and the organic fraction of municipal wastes have a smaller but significant potential (ETSU, 1998). Only a sub-set of these options is realistically available for renewable transport fuels, although all renewables could lead to the production of RTFs. There is currently no significant production of RTFs in the UK, except for small scale production of biodiesel from rapeseed and waste oils and a fraction of renewable electricity, some of which may end-up powering trains.

Renewable energy contributed about 142 PJ (3.1 Mtoe) in the UK, corresponding to 1.3% of primary energy consumption in 2001. Biomass energy, excluding MSW incineration, accounts for about 0.9% (100 PJ) of the UK's primary energy, or 71% of total renewable energy use in 2001 (DTI, 2002). The dominant sources are landfill and sewage gas, wood for industrial and domestic use (primarily heating), and most recently for electricity generation at the Ely (ELEAN) straw-fired and the Fibrowatt chicken litter-fired plants (Hewson, 2001). Straw combustion accounts for about 2.5% of biomass energy sources and biomass dominates the supply of renewable energy in the UK, but it is currently almost entirely used for heat and electricity production.

There has been a rapid increase in the use of renewables to generate electricity, with growth averaging 15.5% between 1996 and 2001. The use of renewables to generate heat is declining slowly but may be reversed by recent government policies to promote CHP, particularly from biomass.

The potential for renewable energy in the UK is large and its contribution to the supply of fuels for transport could be significant. The basis for the potentials summarised in Table 3.1 is discussed for each resource below.

Table 3.1: Summary of indicative practical energy potentials from the different renewable energy resources.

Resource	Practical potential (PJ)	Share of Primary UK Transport Energy (2001) ^{a,b} (%)
Biomass resources		
Energy crops ^c	360	14%
Residues	400	16%
Waste vegetable oils	10	0.4%
MSW	370	15%
Direct renewable electricity resources		
Wind offshore	360	14%
Wind onshore	290	12%
Wave	180	7%
Tidal	7	0.3%
Hydro	10	0.4%
Photovoltaic	130	5%
Total	2117	84%

a – primary transport energy in the UK (2001) = 54.9 Mtoe (2.51 EJ). DTI, 2002.

b – values do not account for conversion of the resource to potential RTFs. The actual contribution of RTFs would then be lower.

c – energy crops grown on 2 Mha and achieving yields of 10 odt/ha.yr

3.2. Biomass resources

An overview of biomass resources for energy derived from residues and from dedicated energy crops for the UK is provided below. There are a number of issues affecting biomass potential that need to be carefully considered. These are: availability of residues and of land for energy crops; constraints resulting from local hydrological, climatic and environmental conditions; infrastructure issues associated with biomass supply, the quality of biomass resources and their suitability for specific end-uses.

3.2.1. Energy crops

The potential from dedicated energy crops in the UK is dependent on three main factors i.e. i) yields, ii) costs (including subsidies), and iii) land availability for energy crops. The UK's total agricultural land area is about 18.5 Mha, of which about 5.9 Mha is arable land and 3 Mha are under cereal crops. The agricultural set-aside land area was 0.57 Mha in 2000, equivalent to approximately 10% of arable land area and it is possible that land taken out of food production will increase in the future.

Various studies have put the potential land surpluses between 1 Mha and 5.5 Mha (e.g. ETSU, 1994). However, future land availability will depend on a number of factors which are extremely difficult to predict e.g. subsidies and CAP, environmental policies, and the viability of UK cereal

exports. Any surplus land could be used for energy crops and there are also possibilities of growing energy crops on other land, such as reclaimed land.

Potential

Energy crops are increasingly viewed as an important component of agri-environment and rural development activities. A variety of energy crops could be grown, ranging from annual crops such as oilseed rape, sugar beet and wheat, to perennial crops such as short rotation willow or poplar coppice and energy grasses e.g. miscanthus (see Table 3.2).

Current typical arable yields are 7.6 t grain/ha.yr and 5 t harvestable straw/ha (15-20% moisture) for wheat, and 3.1 t seed/ha.yr and 3.0 odt straw/ha.yr of for oilseed rape. Short rotation coppice (SRC) may yield 10odt/ha.yr with wood chips produced at a cost of about £1.9/GJ (excluding transport). Energy grasses are expected to yield 12 to 18 odt/ha.yr (Metcalf & Bullard, 2001), with estimated delivered costs of £2.2 to 2.9/GJ (Bullard, 2000). In addition to achieving high potential sustainable yields, energy grasses such as miscanthus will also require significantly reduced levels of inputs compared to annual crops and so net emissions and energy requirements are expected to be lower.

Gross feedstock energy yields and costs for the five main potential energy crops assessed in this report are provided in Table 3.1 below, highlighting the overall productivity of wheat in the UK but also the high costs of annual crops compared to perennials such as SRC and miscanthus.

Table 3.2: Indicative yields, energy and production costs from energy crops in the UK

	Gross Feedstock Yield (GJ/ha)			Feedstock Costs (£/GJ)	
	Total	Main crop	Straw	Main crop	straw
Beet	207	207	n/a	4.3	n/a
Wheat	188	119	69	4.9	1.6 to 2.2
Rape	122	79	43	10.4	1.6 to 2.2
SRC	180	180	n/a	1.9	n/a
Miscanthus	270	270	n/a	2.2 to 2.9	n/a

Notes: see also individual analysis sheets in Annex 1.

Wheat: 7.6 t grain / ha and 15.7 GJ/t grain. Straw yield 0.65 t recoverable raw straw/t grain, 13.9 GJ/t raw straw, 17.3 GJ/odt straw; £25 to 35/t delivered.

Beet: 54 t beet/ha and 3.84 GJ/t raw beet. Tops and leaves are considered to have too high moisture (85%) and nutrient contents for economic harvesting.

Rape: 3.1 t seed / ha and 25.4 GJ/t seed. Straw yield 0.98 odt straw / t seed and 14.2 GJ/odt; £25 to 35 delivered.

SRC: 10 odt/ha.yr and 18 GJ/t.

Miscanthus: 15 odt/ha.yr and 18 GJ/t.

Without knowing likely land areas available for growing energy crops, assessing the overall potential supply of energy is problematic. However, a rough estimate assuming 10% of current UK arable land is planted to energy crops is provided in Table 3.3. below. This can be compared to the less conservative estimate calculated in Table 3.1 which assumes that in future 2 Mha, or the equivalent of 1/3 of arable land might be available for energy crops.

Cost projections

Current feedstock supply costs of biomass for energy vary between £25 to £55 per delivered oven dry tonne (approximately £1.4 to 3.7 per GJ) depending on demand and supply. These costs are highly variable, site specific, and dependent on the final specifications of the fuel e.g. moisture content, particle size, etc.

Table 3.3: Potential Energy Production from Energy Crops on 10% Arable Land in the UK

	Potential Gross Energy Production on 10% UK Arable Land (crop + straw) ^a (PJ)		Share of Primary UK Transport Energy (2001) ^{b,c}
	Total	Of which Straw	(%)
Wheat	112	41.2	4.5
Sugar Beet	124	n/a	4.9
Rape	73	25.7	2.9
SRC	108	n/a	4.3
Miscanthus	161	n/a	6.4

Notes: based on individual chain analysis sheets (see appendix 1).

a – 10% of UK arable land in 1999 was equivalent to 0.597 Mha.

b – primary transport energy in UK (2001) = 54.9 Mtoe (2.51 EJ). DTI, 2002.

c – values do not account for conversion of the resource to potential RTFs. The actual contribution of RTFs would then be lower.

3.2.2. Forestry, agricultural and livestock residues

Potential

A summary of the potential energy that could be recovered from residues in the UK is provided in Table 3.4. The UK is one of the most sparsely wooded countries in Europe, with only about 10% (2.7 Mha) of its land area covered with trees, predominantly in Scotland and Wales. Part of the wood extracted from managed forests is used for domestic heating (about one sixth of harvested wood, representing about 1 Mt) and approximately 4 Mt (about 2 Modt³; 36 PJ) of residue material is left in forests each year. A fraction of these residues, possibly up to about 70%, could be collected and used for energy with the remainder left in-situ in order not to negatively affect soil quality. Additional wood residues arise at saw mills and at all stages in the processing and use of wood and even via reclamation after the demolition of buildings. Forestry residues represent an important resource for the short-term development of the biomass energy industry and the resource could increase with reforestation and afforestation.

Approximately 13.9 Mt of recoverable⁴ straw (about 11 Modt; 194 PJ) is produced annually from wheat and barley in the UK assuming that 50% of above ground straw production is recoverable on both economic and environmental grounds. The total amount of straw produced annually will vary in relation to annual cereal production. Also, not all the resource will be available because of competing uses and because of the need to leave part of the straw in the soil for agronomic reasons.

Reliable estimates for the potentially recoverable energy that could arise from the collection and treatment of animal wastes, in particular dung, are difficult to obtain. An estimate of the potentially harvestable dung resource (about 25% of total estimated production) from cattle, sheep, pigs and chickens is estimated at about 94 PJ for 1998 (Table 3.3).

Cost projections

Forestry residues are likely to be available at a cost of about £1.75/GJ (excluding transport). It is estimated that straw could be delivered to the plant at a price of £25/t or £1.85/GJ (ETSU, 1994). However, recent experience from the Ely Straw-fired power station suggests that the price is likely to be volatile and may even exceed £40/t or £2.90/GJ (Jaggard, 2003; Hewson, 2001).

³ odt: oven dry tonne

⁴ 'Recoverable' straw is assumed to be 50% (by mass) of total above ground straw (15% moisture).

Table 3.4: Potential Energy from Agricultural, Animal and Forestry Residues in the UK

Residue Resource	Energy Content of Potentially Harvestable Residues ^a (PJ)	Share of Primary UK Transport Energy (2001) provided by 25% residues ^{b,c} (%)
Crop	232	2.3
Forest	84	0.8
Dung	94	0.9
Total	411	4.1

Notes:

a – Production factors for residues are crop and animal specific- for details see Woods & Hall, 1994 or Bauen *et al.* 2003.

b – Primary transport Energy in UK (2001) = 54.9 Mtoe (2.51 EJ). DTI, 2002.

c – values do not account for conversion of the resource to potential RTFs. The actual contribution of RTFs would then be lower.

Some additional potential exists in the form of residues from the food processing industry, including waste recovered vegetable oils (WVOs) as discussed below.

3.2.3. Recovered (waste) vegetable oil and fats

There is currently considerable interest in the production of biodiesel from recovered vegetable oils and animal fats, primarily brought about by the 20p/l reduction in fuel duty awarded to biodiesel by the UK government (see Chapter 2). Estimates of the availability of this resource vary considerably but rough estimates are provided below.

Potential

It is likely that a conservative estimate of the range of total recoverable WVO resource in the UK is between 200 000 and 400 000 t (7.2 and 14.4 PJ). The basis of this estimate is outlined below:

1. Gross estimates calculated from average per capita consumption and the percentage of consumption that is practically recoverable based on previous studies e.g. studies quoted in the Commission of the European Community biofuels directive (2001). The directive states that '17 Mt of oils and fats are consumed in Europe per year' (growing at 2% per year) of which 75% is vegetable oil. Assuming that per capita consumption is uniform across Europe and that 18.5% of the total amount of oil/fat is collectable (as in Austria), a total potential supply of 375 000 t (13.5 PJ) of WVO may be available in the UK.
2. Estimates provided by major potential suppliers e.g. fast-food chains, super market chains, and specific organisations e.g. the Ministry of Defence and the Civil Service. For example, Billins (2002) estimates that annual WVO available from the UK Home Office is about 100 000 t and that about 200 000 t are available from the UK Ministry of Defence (MOD), for a total availability of about 300 000 t (10.8 PJ). In addition, Teal (2003) quotes an A&B Oils industry estimate of 138 000 t WVO from 'multiple chains' e.g. supermarkets.
3. Specific production estimates for the main commercial sources of supply e.g. fish and chip shops, restaurants, hotels, schools, hospitals and prisons. According to Teal (2003), 'average discard rates of 20 l/week for restaurants and hotels and 40 l/week for fish and chips shops can be expected. National total numbers for these types of establishment are being sought to extrapolate a national total potential supply of WVO.

Cost projections

Current prices for delivered commercially recovered WVO are about £165/t or £4.58/GJ.

3.2.4. Municipal solid waste

MSW consists of a similar proportion of household waste and of commercial and industrial waste. Of the 50 Mt of combustible solid waste generated annually in the UK, about 34 Mt is MSW, consisting of about 25Mt of household waste and 9Mt of commercial and industrial waste. The average heating value of household waste is about 9GJ/t, and that of commercial and industrial waste about 16.5GJ/t (ETSU, 1998). It is estimated that about 374 PJ of MSW is generated in the UK each year from the 50Mt of combustible solid waste.

3.3. Direct renewable electricity sources

Electricity production from wind (onshore and offshore), tidal stream, hydro and PV is discussed below.

3.3.1. Onshore Wind

Onshore wind turbines for grid connected power generation are generally in the 600 kW to 2MW range. Most planning consents in 2000 were for wind farms with 1.5 to 2 MW turbines (BWEA, 2000). They are usually grouped in farms of around 20 turbines, with outputs of up to 40 MW.

Potential

The technical potential for onshore wind energy has been estimated at 317 TWh/yr (ETSU, 1998), or 1140 PJ, a value close to current UK electricity demand. However, environmental, electricity network and planning constraints reduce the current practicable potential to 80 TWh/yr (288 PJ). The major reductions from the technical potential occur in Scotland and Northern Ireland, primarily where electricity network connection is not available.

In order to generate a quarter of the 10% renewable electricity target for 2010, as suggested by the DTI 'High wind' target, BWEA estimates that a rated capacity of 3773 MW is needed (BWEA, 2000). This has been calculated using a capacity factor of 0.3 to take into account the intermittent nature of the wind, the availability of the wind turbines and array losses, and results in an estimated annual output of 9.9 TWh (35.6 PJ).

Cost projections

Electricity generated from onshore wind currently costs 2.5-3p/kWh (£6.90 to £8.30/GJ electricity) in good wind speed sites. The cost is expected to fall to 1.5-2.5p/kWh by 2020, and less than 2p/kWh (£5.56/GJ) 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 is possible, based on learning curve analysis and experience with market growth.

3.3.2. Offshore Wind

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 to 2MW, with total capacities of 2-20

MW (OWF, 2002). Typical future developments are expected to use turbines of 2 MW or larger, with 30 turbines per development, in groups of one, two or three sites (OWF, 2003).

Potential

The technical potential for offshore wind in the UK was estimated at around 3,500 TWh/yr or 12.6 EJ (PIU, 2001h). 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 dis-amenity are excluded, the figure is reduced to a practical potential of 100 TWh/yr (360 PJ; ETSU, 1998). Production of electricity from offshore wind at these scales would provide nearly a third of the current UK electricity demand. Even so, this estimate 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 an average wind speed of 10 m/s gives the UK practical potential as 986 TWh/yr (3.55 EJ; Border Wind, 1998).

Summing regional targets for offshore wind generation by 2010 for England and Wales 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 (31.3 PJ electricity).

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 (£13.89 to 15.28/GJ; 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).

3.3.3. Wave

Wave energy devices can be sited at the shoreline, in nearshore areas, or offshore, and there are a wide variety of possible devices for electricity generation in each category. Devices use either the mechanical motion of the waves or changes in fluid pressure within the device.

Potential

The technical potential for wave energy is estimated at over 600 TWh/yr (2.16 EJ), principally in offshore locations, but with some potential for shoreline and near shore technologies (ETSU, 1998).

Table 3.5: Gross Potential Energy Production from Waves in the UK

Location	Annual Energy Production	
	TWh	PJ
Shoreline ^a	~2	~7.2
Nearshore	100-140	360 to 504
Offshore	600-700	2160 to 2520

Notes: ETSU, 1998.

a - Only for the most favourable locations - greatly underestimates the true resource

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, the practical potential is reduced to 50 TWh/yr (180 PJ; see below).

Table 3.6: Recoverable Energy from Waves in the UK

Location	Annual Energy Production	
	TWh	PJ
Shoreline	0.4	1.44
Nearshore	2.1	7.56
Offshore	50	180

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 (0.7 PJ) in the high scenario, in the South West and Wales, and zero in the low scenario.

Cost projections

Electricity costs from nearshore and shoreline devices are estimated at about 4.5-6 p/kWh (£12.5 to 16.7/GJ; PIU, 2001h). These costs are considered to be reasonable for the next 3-4 years for devices in pre-commercial demonstration. The practicable resource of 50 TWh/yr (180 PJ electricity) given above is the economic resource at less than 4p/kWh (£11.1/GJ), based on the commercial development of shoreline, near shore, offshore modular and offshore large scale devices (ETSU, 1998).

3.3.4. Tidal stream

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. It is not the same as tidal barrage technology, which generates electricity from the flow of water stored behind a dam as it flows to and from the sea. As the motion of the tides can be predicted accurately, the energy output from tidal energy is intermittent, but predictable.

Potential

The technical potential tidal stream resource for the most suitable sites in the UK is estimated to be 36 TWh/yr (130 PJ electricity; 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'. 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 (36 PJ) could be generated from shallow water sites near areas of high demand for power. The practicable potential at a cost below 7p/kWh (£19.4/GJ) is estimated at 1.9 TWh/yr (6.8 PJ electricity).

Very little deployment of tidal stream energy is expected in the UK by 2010; projected values range from zero (Oxera, 2002, ATLAS, 2003) to 0.7 TWh/year (ETSU, 1998).

Cost projections

It is estimated that power can be generated at an overall cost in the range 4p/kWh to 14p/kWh or £11.1 to 38.89/GJ (Trapp, 2002).

Hydro

Hydro potential is widely exploited and the associated technologies mature.

Potential

The total hydropower resource for the UK is estimated at 40TWh/year (144 PJ) or 13GW of installed capacity (this is based upon mean annual rainfall figures, land area and elevation data). In Scotland, in addition to the existing large-scale capacity of 1.22GW, there may be an unexploited accessible resource of up to 1GW or 3TWh/year (10.8 PJ), but this is subject to geographical and environmental constraints such as the need for reservoir storage to exploit the resource. This is likely to be the only accessible resource, as there are no large-scale resources in England or Northern Ireland, and the resource in Wales is thought to be small due to environmental considerations. The remaining practically feasible resource consists of small hydro schemes and is estimated at between 40MW and 110MW at a cost below 5p/kWh (£13.89/GJ) and between 300MW and 550MW at a cost below 10p/kWh (£2.78/GJ). There may also be a large resource of several hundred MW at sites with a head of less than 3m that are currently thought to be uneconomical, but would be less socially and environmentally intrusive than large schemes. A potential of 1.8 TWh/yr (6.5 PJ electricity) is estimated at a cost below 7 p/kWh (£19.4/GJ), with a significant proportion of the resource (about 1.4 TWh/yr) available below 6p/kWh (£16.7/GJ).

Cost projections

The cost of generation by existing large-scale schemes is estimated to be 1.5 to 2p/kWh (£4.17 to 5.56/GJ), but costs rise rapidly for smaller schemes.

3.3.5. Photovoltaics

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 is considered to be the only significant (i.e. non-niche) 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 its ability to be used in urban areas, its highly modular and distributed nature and its low maintenance needs.

Potential

The technical potential for BIPV is estimated to be 266 TWh/yr (958 PJ; 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. Roofs and facades at all orientations are considered, therefore those receiving lower insolation will only be available at a significantly higher cost than the rest of the resource. When new build rates and the possible rate of PV uptake in new buildings are considered, a practical potential of 37 TWh/yr is estimated (133 PJ electricity; ETSU, 1998).

Cost projections

The cost of PV is projected to fall from the current value of around 70 p/kWh (£194/GJ) 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 (£16.7 to 2.8/GJ) by 2025 (PIU, 2001h).

4. Overview of Renewable transport fuel chains: options & pathways

In this chapter, an overview of renewable transport fuel chains is provided, including a discussion of the potential feedstocks and conversion technologies. A detailed evaluation of thirteen selected fuel chains is carried out in Chapter 5 covering energy balances, GHG emissions and economics.

4.1. Introduction

The heterogeneity, flexibility and complexity of the range of options for producing transport fuels from renewable resources are highlighted in figure 1. In total, a realistic sub-set of 88 production chains has been identified for the UK, resulting in the production of seven different end-fuels.

Of the 88 chains, there are potentially 21 chains that could result in hydrogen production, 12 for ethanol and 10 for biodiesel. The pathways shown are those chains that are at an advanced R&D stage, near-market or mature and include both biomass and non-biomass renewable energy based routes. A sub-set of 13 representative chains were chosen (chapter 5) for detailed analysis which were selected through a combination of expert consultation (annex 3) and literature review. However, many more potential chains exist and surprise technologies and pathways cannot be ruled out.

The eight potential 'end-fuels' shown (including electricity), are also a simplification with a number of end-fuels being potential intermediaries in the production of other end-fuels. For example, ethanol, methanol and biogas are all potential energy carriers that may also be suitable for on-board reformation to hydrogen for use in fuel cells. In addition, all the 'end-fuels' could be used to produce electricity which in turn could produce hydrogen through electrolysis. Finally, a large number of crops that are not suitable to be grown in the UK's climate are produced outside the UK and the EU. Some of these crops, or derived products, could be imported cheaply into the UK subject to import tariffs.

In part, the complexity of the renewable transport fuel options results from the different feedstock specificities of the biomass-conversion technologies identified. Anaerobic digestion (AD), esterification and conventional fermentation are highly specific in their feedstock composition requirements. On the other hand, the conversion technologies based on thermal decomposition are theoretically almost entirely non-specific in feedstock composition, although in practice feedstock handling parameters, moisture contents and contaminant levels are tightly constrained.

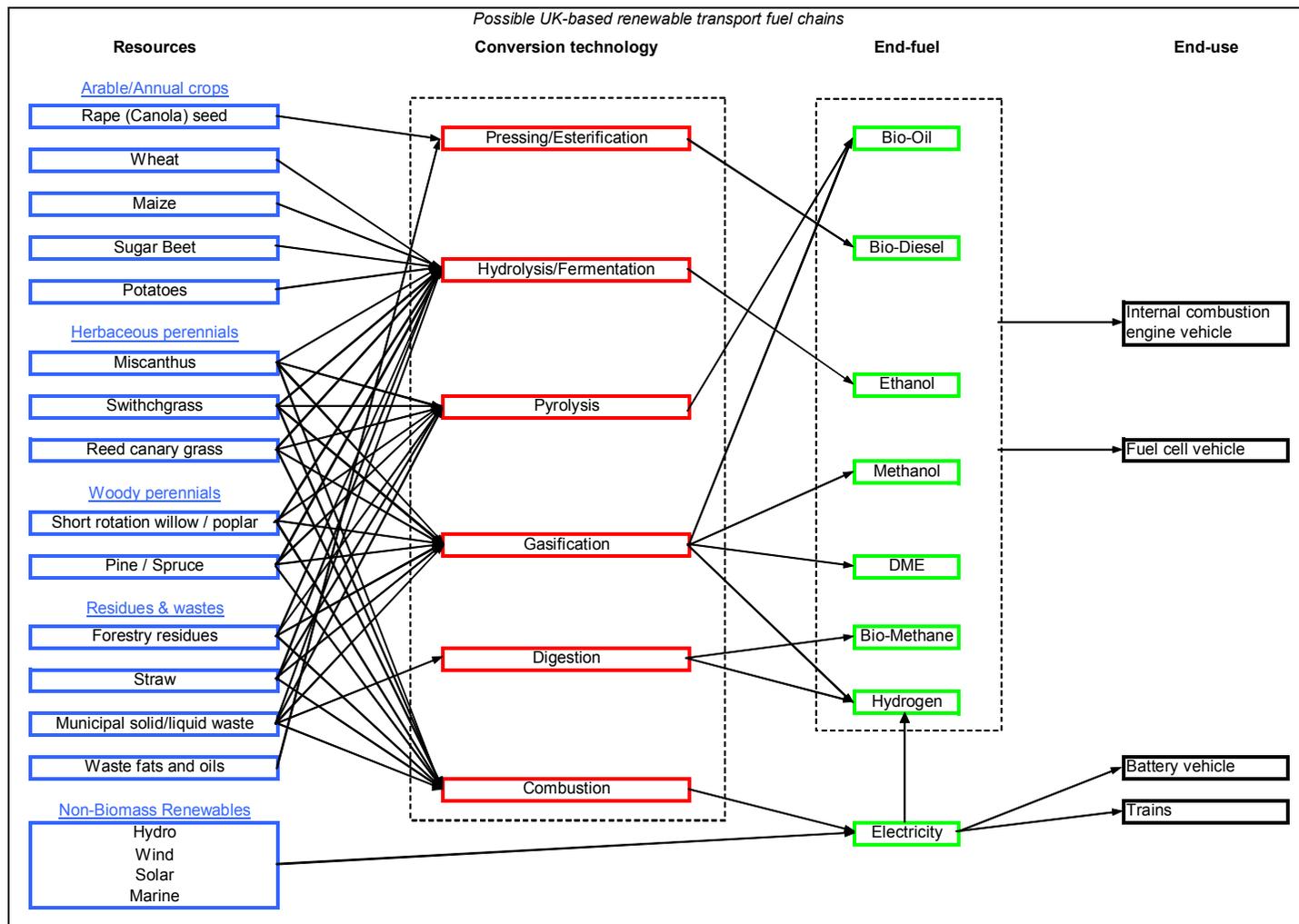


Figure 1: Renewable transport fuel chains considered

In many cases, more than one output is produced, each with different economic values. Where multiple products occur it is necessary to allocate a share of the energy inputs and greenhouse gas emissions to each of the products. The allocation of 'co-product credits' may be contentious and both the energy and emissions balances are sensitive to the allocation methodology.

In this analysis the potential impact of co-product credits is carried out on the basis of energy content. However, the allocation of energy inputs to co-products can be carried out using four different methods i.e. based on:

- i) the energy content of the co-product,
- ii) the energy required to produce a co-product's substitute e.g. rape meal displacing imported soya meal,
- iii) the co-products' market value, and;
- iv) carbon accounting.

It is worth noting that in some cases the energy content of the potentially harvestable residues associated with the main feedstock e.g. wheat straw, could theoretically cover the entire energy requirements of the associated conversion processes. However, positive and negative impacts may result from the use of the co-products for energy purposes which must also be accounted for. For example, one estimate of the fertiliser value of rape straw is about £6/t (Jaggard, 2002). Therefore, farmers selling the straw will need to apply additional fertilisers to their next crop to replace the nutrients in the harvested straw.

The following sections of this chapter provide an overview of the chain of technologies required to produce the seven end-fuels discussed above. The chain descriptions identify potential primary feedstocks and the range of conversion technologies required to produce and deliver the end fuel but do not cover issues of use in vehicles. The current status of the range of conversion technologies available is also evaluated.

4.2. Renewable Transport Fuel Production Chains

The main stages and technology issues in the production of the seven end-fuels i.e.:

Biodiesel and DME (Dimethyl Ether).
Bioethanol.
Hydrogen.
Electricity.
Methanol.
Bio-oil.
Bio-methane.

The production chains for each of these end-fuels are described below and selected chains analysed in detail in Chapter 5 and Annex 1.

4.2.1. Biodiesel and DME

10 possible pathways to biodiesel production based on 2 major conversion technologies are assessed, of which the only demonstrated and mature biologically-based conversion technology is esterification. The two technologies for the production of biodiesel are:

- i. Esterification - 2 routes:
 - a. oil extraction from seeds or oil-rich nuts via pressing and then esterification,
 - b. purification and esterification of recovered waste vegetable oils and animal fats,

- iii. Gasification to produce:
 - a. FT-Biodiesel e.g. biomass gasification, gas cleaning and detoxification and catalytic reformulation via Fischer Tropsch, and;
 - b. DME (dimethyl ether) e.g. biomass gasification, gas cleaning and detoxification and catalytic reformulation to produce gaseous DME followed by liquefaction.

Key feedstocks

- Rape (canola)
- Sunflower
- Waste / recovered used cooking oils and animal fats
- Lignocellulosic materials (SRC, agricultural residues, MSW)

Biodiesel can be produced from potentially all oil producing crops, however, in the UK, rape (canola) and sunflower are likely to dominate in the near future. According to Choo and Ma (2000) some of crops studied as potential biodiesel resources include: rape/canola, sunflower, coconut, maize, safflower, jatropha, cottonseed, peanut and palm. Of these crops, rape comprises more than 80% of current global biodiesel production, Sunflower 13%, Soya Bean 1% and Palm Oil 1%. Other crops are at the R&D stage but are unlikely to be of significance in the UK.

Recovered cooking oils and animal fats also represent a potential resource for biodiesel production. Indeed, agricultural cooperatives in Austria have supplemented RME production with collections of used cooking oil from local towns for a number of years. Waste oils from automotive and industrial lubricants are also possible resources for diesel replacement fuels e.g. 320 000 t/yr of uncollected waste oil is produced in Australia according to Marshall *et al.* 1999 (quoted in Beer, *et al.* 2000). See also: Yu *et al.*, 2002.

As a result of the relatively low net energy production per hectare of biodiesel from rape, attention has been paid to the co-products of biodiesel production. These include glycerine which is used in the soap making and the cosmetics industry, and a protein rich press-cake which is used for animal feed. Because these outputs are not fuels there is some confusion about the energy substitution credits that should be applied as discussed below.

Conversion Technologies

- Pressing, filtration and batch esterification.
- Continuous high pressure esterification.
- Gasification and Fischer Tropsch (FT) biodiesel production.

The production of VME, FT-Biodiesel and DME is described below with the technology options chosen for detailed analysis in Chapter 5 and Annex 1, highlighted in blue.

Vegetable Oil Methyl Esters

The production of VME (including RME) requires the extraction of the oils from the seeds of the crop or the collection of used vegetable oils and fats. The oil (and fat) is then filtered / purified and an esterification step using methanol (or ethanol) follows in the presence of a catalyst and heat. Because of the simplicity of the process and the limited scope to improve efficiencies in the production of biodiesel from the oil, R&D has concentrated on plant breeding and the use of co-products. Under certain circumstances it is also possible to use straight vegetable oil (SVO) as a transport fuel and to power modified diesel engines for electricity and heat production. However, in temperate climates and where stringent fuel standards apply SVO is unlikely to be a major replacement for diesel.

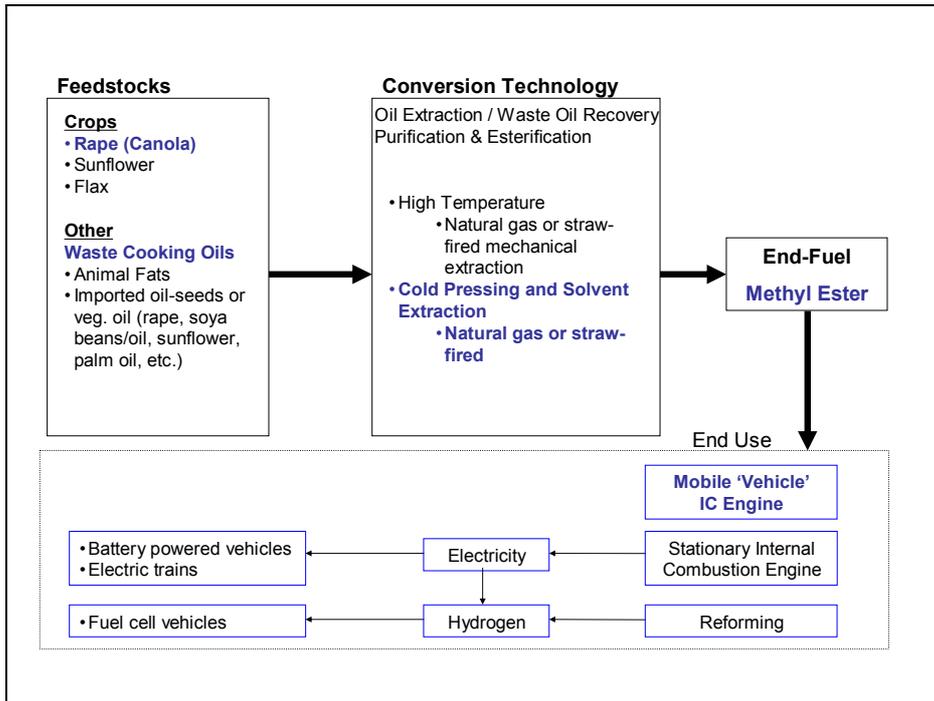


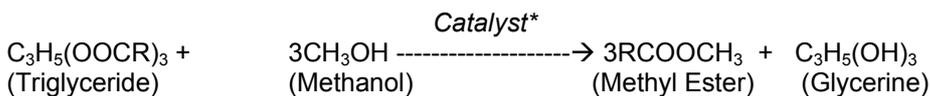
Figure 2: Biodiesel Production via Esterification

Simple mature technologies including pressing, filtering and esterification are used. At the small scale (<1 t seed per hour) screw presses are used. At larger scales, high and low temperature presses with or without solvent extraction in hexane are used.

Esterification takes place at about 50°C, by the addition of alcohol (methanol or less commonly ethanol) to the vegetable oil. The outputs of this process are the esters (biodiesel) and glycerine. Approximately 100kg of glycerine is produced per 1000kg of esters. Sodium or potassium hydroxides are used as catalysts to speed up the esterification process. The most common technology uses batch processing with commercial plants operating at scales of 500 to 10 000 t/yr. More recent technologies include the Henkel Trans-esterification system, which relies on two tube reactors followed by settling tanks, operating at 4 to 5 bar pressure and 70 to 80 °C. A new 'continuous deglycerolisation' (CD Process) technology developed by Leer GmbH & Co, runs at ambient pressure and temperatures between 65 and 70 °C and uses a centrifugal glycerine separation system. It is operating in Germany at scales of 80 000 to 150 000 t/yr.

These more modern systems can be compared to previous systems which required operating pressures of 50 to 100 bar and temperatures of 200 to 240°C and are therefore more energy efficient (Connemann and Fischer, 1999).

The basic chemical process involved in the production of methyl ester is shown below and highlights the role of the alcohol (in this case methanol) and the associated production of glycerine in the process.



Note: * Catalysts used include Sodium Hydroxide (NaOH) and Potassium Hydroxide (KOH). 'R' represents long chain esters.

Using Waste Vegetable Oil (WVO)

The use of recovered waste cooking oils is more complex than pure vegetable oils such as rape seed oil. WVO is a mixture of oil species (including animal fats) and as a result has a much

greater concentration of free fatty acids (FFAs) than SVO. The FFAs arise from the partial breakdown of the oils and animal fats when SVO is used for cooking and in addition the WVO may be contaminated by water by the time it has been collected. The FFAs can cause problems in engines and fuel supply systems and therefore they must be treated or removed from WME.

There are three main approaches to dealing with FFAs:

Re-esterify with concentrated sulphuric acid and MeOH at 35°C then transesterify with NaOH and MeOH.

Neutralise with CaO (quicklime) before transesterification.

Accept loss of yield and more difficult washwater treatment.

For all three options, it is necessary to measure the amount of FFA in each batch before calculating how much base catalyst is required. As vegetable oils are non-polar, the WVO must be dissolved in a co-solvent (isopropanol) before titration with a pH indicator. This is in contrast to SVO, which always needs 3.5 g NaOH per litre SVO. Water is particularly problematic, as its presence will divert some feedstock and reagents to a saponification reaction, producing soap which will in turn emulsify oil, di and mono glycerides as well as the desired esters. Removal of the water is difficult and potentially dangerous as dehydration is often carried out by boiling (Teal, 2003).

Co-products

Three major co-products are produced in the production of RME:

- a. Rape straw
- b. Rape meal
- c. Glycerine

The straw has a potential value as an energy feedstock to provide heat to the conversion process and / or in the production of electricity. Theoretically, it could also be used to produce ethanol (see lignocellulosic ethanol production), FT-diesel (see FT-diesel) and all the potential range of end-fuels derived from re-formulated syngas produced from gasified biomass. Rape meal has value as a cattle feed and can substitute for soya meal imported from the USA.

Biodiesel via Gasification – the Fischer Tropsch (FT) route

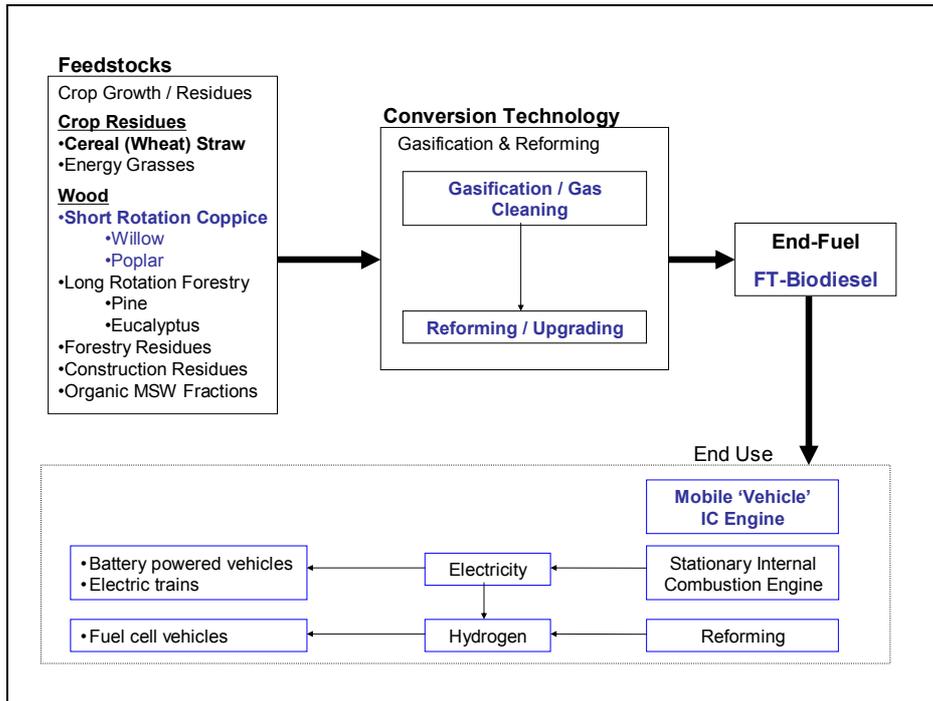


Figure 3: Biodiesel Production via Fischer Tropsch

Lignocellulosic feedstocks (e.g. woodchips or straw) are supplied to a gasifier equipped with a down-stream FT catalytic reactor. The gasifier feeds an FT reactor, which produces a mixture of kerosene, diesel and naphtha. Lighter gaseous hydrocarbons are also produced by FT reactors, which can be used to power a combined cycle gas turbine in order to co-produce electricity.

Biomass FT plants can be configured in many different ways depending principally upon gasifier type, method of syngas cleaning, whether electricity is to be co-generated, and what liquid hydrocarbon outputs are required as the final output.

Gasifiers

Gasifiers convert biomass into 'syngas' which is a mixture of several gaseous components. Syngas is principally comprised of hydrogen and carbon monoxide, the feed gases required for FT synthesis. There are three principal options for the gasification of solid fuels to produce syngas for FT-Biodiesel production:

- low pressure autothermal oxygen-blown gasification
- high pressure autothermal oxygen-blown gasification
- indirectly heated steam-blown gasification

Gasifiers are of three main types: fixed bed, fluidised bed and circulating fluidised bed, the choice being dictated mainly by the type of feedstock and the capacity required. Gasification is an endothermic process requiring the input of heat. In oxygen-blown gasifiers, the heat necessary for gasification is generated within the gasifier via partial oxidation of the biomass. In indirectly heated gasifiers, heat is provided externally to the gasifier via, for example, the combustion of char from the gasifier itself as described below.

Pressurised or Atmospheric

Pressurised gasifiers are well suited to the co-generation of electricity and require smaller downstream equipment, which is less expensive. This is because the output gases from an FT reactor fed by a pressurised gasifier are also pressurised, and are therefore suitable to supply a

gas turbine directly. In contrast, the off-gases from an FT reactor fed by an atmospheric gasifier must be compressed, which requires energy. Atmospheric gasifiers generate less co-produced electricity and require larger downstream equipment than pressurised gasifier systems, but benefit from more commercial experience.

Air-Fed or Oxygen-Fed

Air-feeding is cheaper and simpler than oxygen-feeding, since no air/oxygen separation plant is required. However, air-feeding results in nitrogen-diluted syngas being produced, which reduces the proportion of C₅₊ hydrocarbons produced in the final product and significantly reduces the energy content. They also require more expensive downstream equipment. Oxygen-fed gasifiers are more complex and expensive, but avoid these problems.

Direct or Indirectly Heated

Directly heated gasifiers operate by partially oxidising the feedstock biomass to provide the energy for the gasification. They produce fewer tars, thereby, addressing one of the major problems associated with biomass gasification. Indirectly heated gasifiers require a heat exchanger and produce more tars, but have the advantage that they do not suffer from nitrogen dilution.

Syngas Cleaning

Although predominantly CO and H₂, syngas also contains many other products, notably particulates, condensable tars, alkali compounds, H₂S, HCl, and NH₃. These potential contaminants need to be removed from the gas stream to prevent poisoning of the iron or cobalt catalysts in the FT reactor. At present this cleaning involves tar cracking, cyclone separation, filtering, hydrolysis and scrubbing.

Some uncertainty remains over this gas cleaning stage, because most FT operational experience has been gained using natural gas, which produces a less contaminated syngas than that produced from biomass. In addition, the size of a plant needed to gain from scale efficiencies may be larger than any other type of large-scale biomass using industry (e.g. pulp and paper or sugar) and logistical feedstock supply problems may be significant.

FT Reactor

FT reactors can be designed to maximise their production of hydrocarbon (HC) liquids or to co-produce electricity. To maximise HC liquid production a feedback loop is included in the reactor. This returns the lighter gaseous hydrocarbons (some of which are always produced) back to the FT reactor input. If electricity is to be co-produced, then these lighter hydrocarbon 'off-gasses' are used to power a gas turbine. These off-gases will often be mixed with natural gas in order to increase the overall calorific value of the gas supply, and will usually feed a combined cycle gas turbine.

FT reactors co-produce diesel, naphtha and kerosene. The proportions of these three liquid hydrocarbons can be varied to an extent, but producing more than approximately 50% kerosene reduces overall plant efficiency. It is assumed that the reactor is optimised for bio-diesel production.

Co-products:

Electricity may be co-produced with the FT-liquids and used some of the electricity is will be used to provide all of the energy required at each stage of the conversion processes.

Dimethyl Ether (DME) production as a diesel substitute

The process of producing DME is similar to FT-biodiesel, being based on the gasification of lignocellulosic feedstocks, downstream cleaning, detoxification and finally catalytic reforming. DME can act as a non-toxic, non-corrosive, methanol replacement with similar physical properties to LPG. It has good ignition properties and may therefore be a useful diesel extender / modifier. Despite being at an early R&D stage, DME is being advocated by Volvo as a major potential renewable diesel replacement of the future (Danielsson, 2002). However, there is too little current data for reliable energy, emissions or economic evaluation in this report.

Key Feedstocks

- SRC – willow and poplar
- Miscanthus
- Forestry and agricultural residues
- MSW (organic fractions)

Conversion Technologies

The conversion technologies for the production of DME are similar to FT but very much in the experimental phase. The main advantage of DME compared to FT-biodiesel or mineral diesel are its prospective extremely low emissions. More details are provided in de Feber and Gielen (2000). However, due to a different combination of catalysts used in the reactor vessel than in the FT-reactor, the product is a gas (DME) at RTP that is reported to be easily liquefied and can then be treated in a similar way to LPG. Liquefied DME would require specifically designed injection systems for use in diesel engines and it is expected to have: low NOx emissions, high Well-to-Wheel efficiency, a low cost per km and could be used as an energy carrier for use in solid oxide fuel cells (Danielsson, 2002).

Co-products:

The co-production of electricity may be possible but will depend on the exact plant specification and the energy requirements for compression.

Technology status

1. Biodiesel from Rape Seed: Mature. Full-scale commercial plant could be producing in UK by 2005/6.
2. Biodiesel from FT: R&D (scale up issues and logistics). Full scale commercial plant may be producing by 2007/10 (see Choren Industries, 2003).
3. Biodiesel from DME: R&D (early lab-based). Full scale commercial plant may be producing by 2015 (Volvo / Ducent).

Fuel quality and specifications:

The historical use of 'straight vegetable oil (SVO)' as a fuel was rapidly superseded by petroleum derived mineral diesel as a result of both economic and technical factors. Modern diesel engines are manufactured to high engineering tolerances and therefore cannot cope with gums that build up during the combustion of straight vegetable oil (SVO). SVO is also prone to solidification at temperatures below 15 to 20°C requiring modified fuel storage and delivery systems in vehicles designed for its use particularly when starting and stopping. In order to overcome these issues, filtration/purification and esterification processes are used as the resulting vegetable oil methyl ester (VME) has similar physical properties to mineral diesel, better lubricant properties than modern ultra low sulphur diesel and does not result in gum problems (Greenergy, 2002). However, it does have a significantly lower energy content on a mass or volume basis compared to mineral diesel and rubber components in the fuel delivery systems need to be replaced with resistant alternatives e.g. neoprene. Around a 10% loss in power can be expected in vehicles powered with 100% biodiesel compared to mineral diesel. DME has a lower energy content on a

mass basis than biodiesel and so will result in similar or greater reductions in power compared to biodiesel. FT-biodiesel is chemically identical to mineral diesel and so would pose the least problems of any of the RTFs for blending or complete substitution of diesel in the fuel supply.

4.2.2. Bioethanol

12 possible pathways for the production of ethanol are considered here. As a liquid fuel, ethanol holds most promise as a petrol oxygenate, substitute and / or extender. It can be used as a lead / MTBE replacement by blending with petrol in blends up to 24% with minimum modifications to vehicles. Although, ethanol has a significantly lower energy content than petroleum, it has better combustion characteristics and so 1 l of ethanol is often regarded as the replacement equivalent of 1 l of petrol at low blend ratios e.g. 10% or lower (on a mass or volume basis; Goldemberg *et al.* 1993; Jolly, 2002; Reading *et al.* 2002). Ethanol does have a significantly higher vapour pressure than petrol and this may lead to problems in producing blends that meet current fuel standards in the UK and it is highly hydrophilic leading to possible phase separation and water contamination issues. For more detail on issues involved with ethanol blending see 'Fuel quality and specifications' below and section 2.2.

Conventional ethanol production is based on the conversion of monomers and polymers of six carbon sugars that are fermented by yeasts, typically 'bakers yeast' (*Saccharomyces*), which is ubiquitous and therefore cheap. Non-sugar crops and residues from sugar crops are rich in lignocellulose which is a mixture of complex polymers of six (C6) and five (C5) carbon sugars (and other aromatic molecules). Whilst both the six and five carbon sugars are theoretically available for fermentation to produce ethanol, there are two main obstacles to commercial production:

Economically viable systems to mobilise (hydrolyse) the five and six carbon sugars in the cellulose and hemi-cellulose are needed. Isolation of bacterial systems (genes and enzymes) or genetic modification of C5-fermenting bacteria to make them viable candidates for C5-fermentation at commercial scales and conditions are required.

A number of companies around the world now believe that they have the right combinations of technologies for the commercial production of ethanol from lignocellulose and at least one full-scale (100 000 t EtOH/yr or more) plant is at the early planning stage in Europe (Shell/Logen).

Key Feedstocks

- Sugar beet
- Wheat (cereals)
- Key Lignocellulosic feedstocks include:
 - Short rotation coppice (SRC; e.g. poplar, willow (*salix*))
 - Energy grasses (e.g. Miscanthus, Reed Canary Grass, etc)
 - Residues (cereal crop straw, forestry residues, etc)

The most likely sugar and starch-rich crops to be grown for ethanol production in the UK are sugar beet and wheat. Recent advances in enzymatic modification and their production on industrial scales have sharply reduced the costs of producing ethanol from lignocellulose opening up a much wider range of possible feedstocks including SRC, Miscanthus and agricultural residues such as straw, but further cost reductions are necessary. Despite continued R&D efforts in using winter wheat as a potential feedstock for ethanol production both in Europe and the USA / Canada, the superior yields of fermentable sugars obtained from sugar beet in the UK and Europe mean that it is likely to remain the most likely primary resource for indigenous ethanol production assuming good positive energy balances can be demonstrated. Significant revenue

may be obtained from a number of co-products produced with the ethanol (see 'co-products' below).

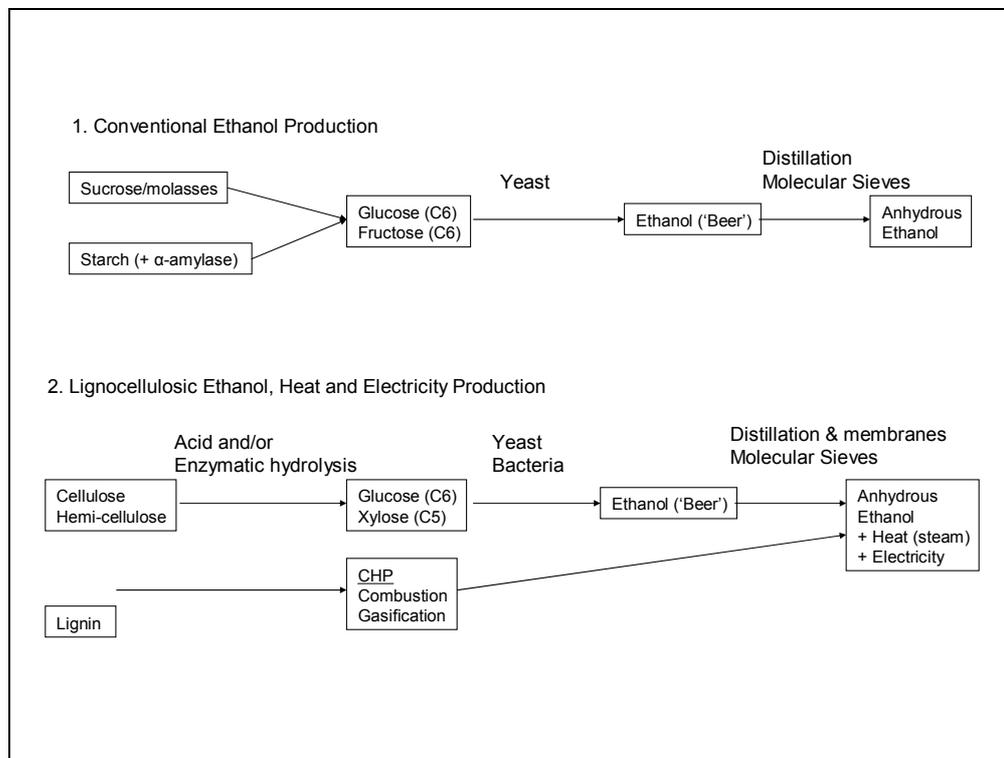


Figure 4: Sugar and Lignocellulosic Ethanol Production Pathways

Conversion Technologies

Figure 4, summarises the two main pathways to bio-ethanol production. These are conventional ethanol production from sugars and starch and the novel ethanol production systems using lignocellulosic materials. The conversion technologies for both these pathways are described below.

The main technologies include:

- Fermentation (standard and thermophilic)
- Starch hydrolysis: saccharification and fermentation (simultaneous and batch)
- Cellulose/hemicellulose hydrolysis (thermophilic, acid, enzymatic)

Sugars and Starch:

Conventional ethanol production from biological sources is based on the fermentation of C6 sugars which can be efficiently carried out by yeast in simple batch and continuous fermentation processes.

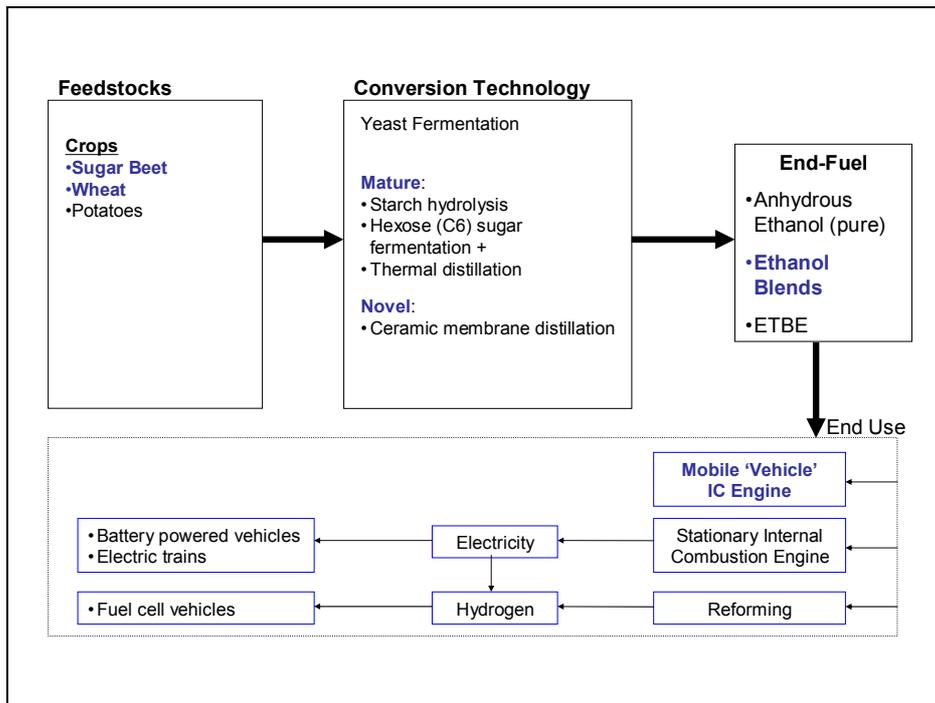


Figure 5: Ethanol from Hexose Fermentation

Fermentation and then distillation of simple C6 sugars obtained from crops such as grapes, sugarcane and sugar beet is an ancient technology. Naturally occurring yeasts are able to convert these sugars into alcohol (ethanol) via the Embden-Meyerhoff-Parnas pathway. In the previous century, R&D focused on the isolation and development of efficient strains of yeast, but now, the theoretical efficiency of this type of biochemical conversion system is nearing its limit. Therefore, recent R&D has concentrated on starch and cellulosic hydrolysis to produce simple sugars and then fermentation using existing technologies.

Starch hydrolysis relies on the degradation of starch which is a mixture of two polysaccharides:

- Amylose (long chain glucose polymer)
- Amylopectin (shorter branched chain glucose polymer)

The commercial success of ethanol produced from starch is based on the cheap production of α -amylase enzymes isolated from bacteria and fungi. These enzymes hydrolyse the starch into 2-glucose units (Maltose) and longer glucose polymers. The products of the hydrolysis, all C6 sugars, are good substrates for yeast-based fermentation.

In the US, ethanol from corn has become a very substantial industry which has been forced to respond to early criticism that the energy balances were either very low or even negative. The industry has responded by trying to reduce energy requirements and increase yields aimed at improving the energy ratio.

Two basic conversion technologies are currently being used in the ethanol production facilities of the US. These are: i) Wet-milling and ii) Dry-milling. Wet milling still accounts for 60% of US bioethanol production but only uses the concentrated starch fraction of the kernel whilst dry milling allows the use of the entire kernel but does not allow sweetener or oil production (Sparks Co., 2002; Coltrain, 2001).

Co-products:

- a. Animal feed, including pulp pellets and distiller's dry / wet grains (DDGS or DWS)
- b. Electricity and heat
- c. Carbon dioxide

- d. High value secondary plant compounds and oils for the cosmetics and health industries.

Lignocellulose:

The viability of lignocellulosic ethanol production requires the production of ethanol from both C6 and C5 sugars which is not yet demonstrated at commercial scales. R&D is concentrating on the isolation and production of cheap enzymes from bacterial and fungal sources and the development of recombinant organisms. Currently, approximately, 300 l of ethanol can be produced per tonne of fibre (e.g. straw), however, much of the technology is proprietary and detailed energy, emissions and economic balances are difficult to achieve.

Lignocellulose is a complex mixture of glycopolymers requiring complex biochemical systems to mobilise the simple sugars (hydrolysis) enabling the production of ethanol. It is comprised of three polymers requiring different hydrolysis and fermentation technologies which may take place in the same reactor vessel as follows:

Cellulose is a glucose polymer: requiring simple enzymatic and/or acid hydrolysis then fermentation

Hemicellulose is a C5 and C6 sugar polymer (mainly xylose, manose, arabinose and galactose): requiring acid hydrolysis and complex enzymatic hydrolysis then fermentation

Lignin: polymer of complex aromatic compounds with random cross-linkages between the aromatic groups. This makes lignin very resistant to biological degradation. However, its high oxygen content means a higher energy density than the cellulosic fractions and lends it to thermal decomposition for the production of process heat (via steam) and electricity.

The hydrolysis of cellulose and hemicellulose leads to a complex cocktail of sugar monomers and simple polymers, nearly all of which are substrates for fermentation and therefore ethanol production. However, the quantities of ethanol produced per tonne of biomass feedstock depend on the relative quantities of the monomers and polymers and indeed on the relative composition of cellulose:hemicellulose:lignin as shown in Table 4.1.

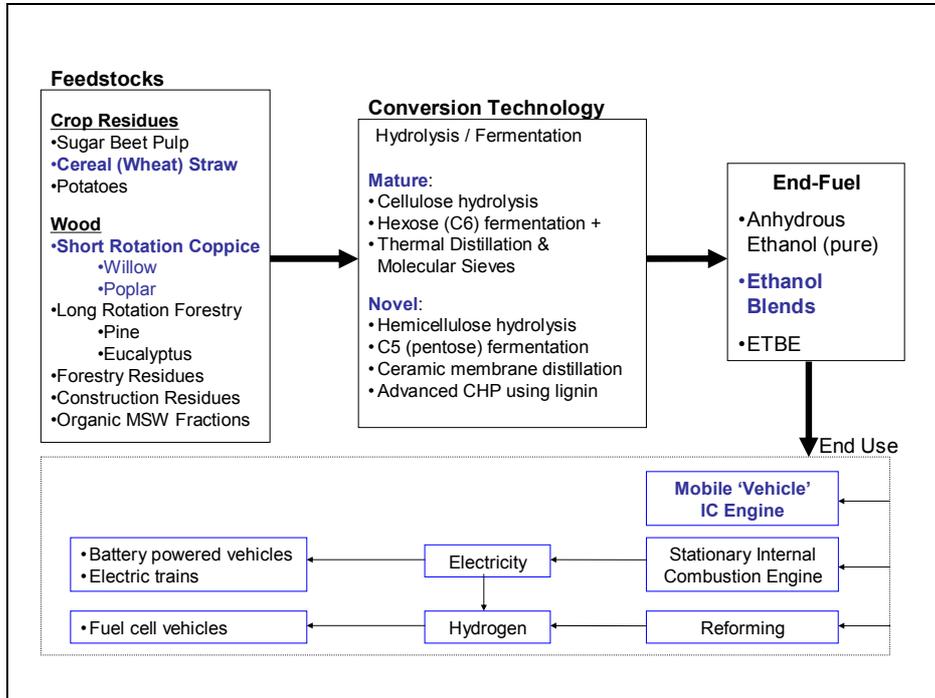


Figure 6: Lignocellulose to Ethanol Hydrolysis and Fermentation

In addition, because lignin is likely to be the main (or even exclusive) energy source for the conversion energy inputs, feedstocks with a low lignin content e.g. sugar beet pulp, may not provide sufficient energy to power the conversion process and external energy may be needed adversely affecting the energy and CO₂ balances.

Table 4.1 : Composition of different kinds of biomass feedstock for ethanol production

	Cellulose	Hemicellulose	Lignin	LHV MJ/kg dry mass
	% Dry Biomass			
Straw	30	50	15	17.2
Sugar beet pulp	27	29	3	15.6
Wood	40-43	21-35	20-28	18.4-18.7
Wood (poplar)	43	24	28	18.4

Source: LBST_GM (2002).

Lignin has an energy content of 25.4 MJ/kg (LHV) and Cellulose and Hemicellulose 16.3 MJ/kg reflecting the different chemical composition (lower oxygen content) of Cellulose and Hemicellulose compared to Lignin.

Co-products:

- Electricity is likely to be the only significant co-product but surplus production will depend on the lignin content and the energy required at each stage of the conversion processes.

Technology Status

1. Ethanol from Sugar beet: Mature. Full-scale commercial plant could be producing EtOH in UK by 2005/6.
2. Ethanol from Cereals (Wheat): Mature. Full-scale commercial plant could be producing in UK by 2005/6.
3. Ethanol from Lignocellulose: R&D (particularly enzyme production). Full scale commercial plant may be producing by 2010.

Conventional hexose-based fermentation fuel chains are mature for both the feedstock supply and conversion stages. However, continuous developments are occurring in both stages resulting in improved productivities, efficiencies and reduced costs and energy requirements. For example, wheat yields have continued to improve from 5 to 6 t/ha in the 70s and 80s to 8+ t/ha now and improvements are expected to continue, albeit at a slower rate. Beet yields have also undergone a similar increase in productivity and are expected to increase significantly over the next two decades, although the 20% increase predicted by Leeds (2002) may be difficult to achieve.

Energy is required in various stages during processing / conversion and highly integrated plants that recover and re-use heat and water have made substantial savings to the energy requirements of producing both sugar and ethanol from sugar beet. The distillation process itself is a major energy consumer and recent developments in membrane distillation, particularly molecular sieve techniques, may result in future energy and emissions savings.

Lignocellulose to ethanol conversion technologies are still at the demonstration stage and therefore, both the energy inputs and costs are uncertain. Energy is required in various stages during processing / conversion, particularly for the production of enzymes. Improvements in the conversion technologies are expected as the technology matures and NREL predict cost reductions in enzyme production by 40% over the next 10 years (Wooley, 1999). Reductions in the costs of enzymes and recombinant bacteria and yeast are central to the overall economic viability of lignocellulosic ethanol and a number of private sector companies are actively involved in this area including: Iogen, BCI International, Genencor, Novzyme, and Arkenol.

Fuel quality and specifications:

Ethanol has now been used at significant scales (see chapter 2) for about 30 years around the world as both neat (hydrous) ethanol and as a blending agent / oxygenate to replace or extend petrol (gasoline). It has long been stated that ethanol can be regarded as an equivalent replacement for petrol on a mass or volume basis, despite its significantly lower energy content, see for example Goldemberg *et al.* (1993). Recent vehicle tests carried out by Reading *et al.* (2002) under UK conditions which compared unleaded petrol to a 10% splash blend of anhydrous ethanol appear to confirm the equivalency. In fact, the tests carried out suggest that at this level of ethanol blending fuel use efficiency may even be enhanced and emissions significantly reduced, particularly with modern state-of-the-art engines but this will mostly result from an increase in octane rating.

Concerns do exist over increases in vapour pressure which would result from ethanol being blended with petrol. In order to meet current fuel specification it may be necessary to convert ethanol to the ether ETBE (Ethyl Tertiary Butyl Ether) or remove other volatile components e.g. butane. However, the conversion to ETBE requires further energy inputs and additional costs. Changes in specifications and fuel supply systems may also be considered to allow higher vapour pressure fuels to be used.

ETBE can be used as a direct replacement for MTBE (Methyl Tertiary Butyl Ether) derived from mineral methanol (produced from natural gas). MTBE blends of up to 15% are permissible under EU and UK regulations but MTBE is only used in smaller percentages in the UK. Oxygenates are used as anti-knock agents when lead was prohibited and as a fuel enhancing additive but concerns exist over the safety of MTBE primarily on human health grounds particularly through ground water pollution routes. These concerns have led to legislation to phase its use out in USA but the UK Environment Agency is less concerned about the potential risks from MTBE (Environment Agency, 1997) primarily because of its low rates of use here. Typically, oxygenates represent about 1% of UK petrol and this is unlikely to change significantly unless a mandated ethanol blend is announced or the reduced cost of ethanol as a result of duty exemptions means that significant amounts are blended.

4.2.3. Hydrogen

The potential for hydrogen from renewable resources is possibly very large and could represent the most important renewable transport fuel option in the longer term. Its attractiveness derives from the fact that it can be derived from all renewable resources through the electrolysis of water or the decomposition of biomass materials as shown in figure 7.

Three different levels of production are considered: large scale (30-80 MWe), medium scale (2-30 MW), and small scale on-site (under 2 MW). A distinction was made between generation at different scales as capacity will affect costs and efficiencies of energy conversion, transport and storage. Energy is transported to the refuelling station in the form of electricity or liquid or gaseous hydrogen.

Large scale renewable electricity generation (30-80 MWe)

The electricity generation technologies considered in this section are on- and offshore wind. These technologies are considered to have the greatest potential contribution to direct renewable electricity generation in the UK (PIU, 2001h). Both are technologically mature, their most significant constraint at present being planning consent. Typical installations could be of the order of 30MW for onshore and 60MW for offshore.

The electricity generated is used either to power on-site electrolysis to produce hydrogen directly, or is exported to the grid. Use of the electricity for on-site electrolysis would reduce the need for

grid extension and reinforcement to new wind sites (however, issues associated with the transport of the hydrogen need to be considered). Intermittency of supply may also be less of an issue for hydrogen production than for grid export.

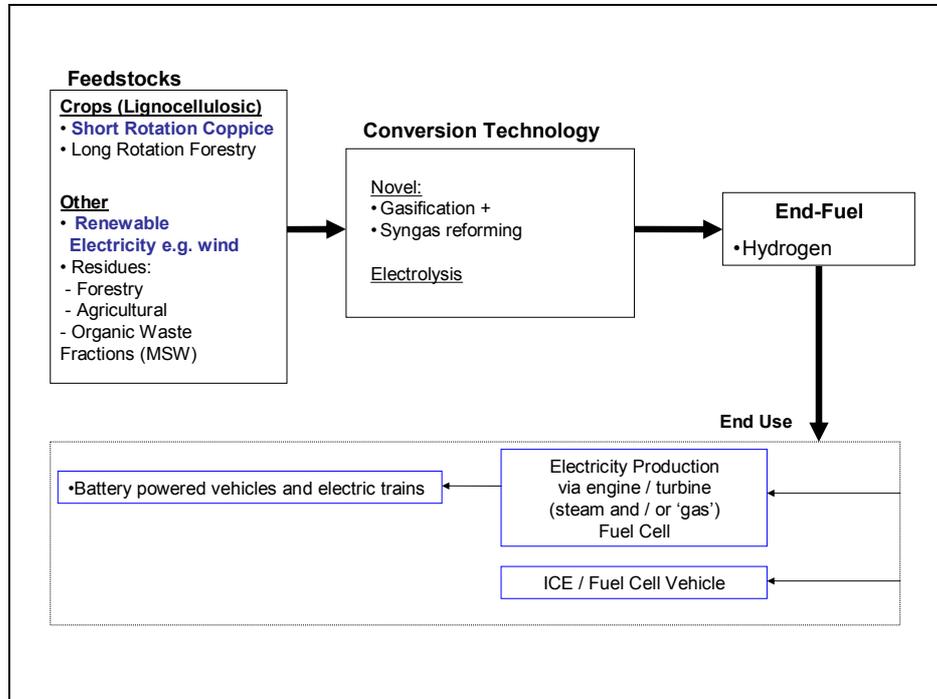


Figure 7: Renewable hydrogen fuel chain details

Onshore and offshore wind technologies are being developed for the provision of electricity in the UK and elsewhere. Issues of public amenity and proximity to the grid dominate the scale and number of on-shore wind turbines whilst proximity to grid, depth of water and scale are the main factors in the development of off-shore wind turbines as discussed below.

Onshore wind electricity

Onshore wind power is an established technology, with a world-wide 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, 2000).

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.

Offshore wind electricity

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, 2003). 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).

In the future, improvement in offshore technology will be made from the use of more specific offshore designs, exploiting the ability for larger sizes and tip speeds (and so greater efficiency) and designed for greater reliability and lower maintenance needs. There is also scope for weight and cost reductions as the turbines may be able to exceed onshore noise restrictions (EWEA, 1999; BWEA, 2000). 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.

Medium scale renewable electricity generation (2-30 MWe) and biomass gasification (>50MWth)

This section includes electricity generation from smaller scale wind farms, wave and tidal energy, and the conversion of biomass to electricity, liquid and gaseous feedstock for the production of hydrogen. As before, electricity generated is either output to the grid, or used to power on-site electrolysis.

Wind, wave, tidal and hydro

A large proportion of the wind farms currently operating in the UK have outputs at this scale (BWEA, 2003). Wave and tidal stream energy technologies are still at the pilot stage (ETSU, 2001), and are expected to have little installed capacity by 2010 (Oxera, 2002). They have been included because of their large potential contribution to UK electricity generation (ETSU, 1998). Prototype devices currently installed have capacities under 2 MW, but are expected to be used commercially in clusters of many devices. Small hydro schemes are considered to have a significant potential (ETSU, 1998), however many sites are not considered to be economically feasible for electricity generation due to lack of grid connection and low local power demand. Direct hydrogen generation would remove the grid connection problem, but there is also likely to be low hydrogen demand in these areas, leading to the need for hydrogen transportation from dispersed, relatively small scale sites. See Chapter 3 for further discussion of this issue.

Biomass

Biomass is another potential hydrogen source. Biomass energy crops, such as SRC and miscanthus were identified as being one of the major renewable energy technologies for the UK (PIU, 2002). However, several other sources contribute to the biomass energy potential: straw, forestry wastes, sewage gases, landfill gases and municipal solid wastes (MSW). All these sources may have a potential for distributed hydrogen production.

Three possible routes for hydrogen from biomass are: electrolytic hydrogen production using biomass electricity, biomass liquid fuel reforming to hydrogen at the forecourt, and on-site reforming of biomass gases from gasification and anaerobic processes.

Biomass combustion systems are in commercial use in niche markets around the world for electricity production, using disparate technologies but generally based around CHP. Biomass gasification technology status, particularly at the large scale (>10 MWe), ranges from research, development to commercial. Anaerobic digestion processes for the treatment of a variety of wet biomass streams are in commercial use. The biomass gasification or pyrolysis routes are more efficient routes than the use of biomass-derived electricity and are discussed further below.

Hydrogen from biomass gasification. The biomass feedstock is first dried and sized if necessary. The feedstock is then gasified to produce a gas (syngas). Details of the gasification of biomass

can be found in section 4.2.1. 'Biodiesel via Gasification'. To produce hydrogen, after gasification, the cleaned syngas must then undergo several shift reactions. This usually involves two shift reactors in series, the first at 450C and the second at 230C to react the CO with H₂O to form H₂. H₂ is then recovered from the gas stream by pressure swing adsorption (PSA). PSA uses selectively adsorbing porous material, which adsorbs at high pressure and desorbs at low pressure, to first adsorb all CO₂ and H₂O, then to desorb all the gases except H₂. 97% of the H₂ passing through the PSA is recovered, and has greater than 99.999% purity. The H₂ can then be liquefied or compressed for transport.

Gasification and gas cleaning equipment is still at the pre-commercial stage. Reforming, shift reaction and PSA equipment is commercially available at large scale and is widely used for industrial hydrogen production, mainly from natural gas. Developments are underway to scale down the equipment and for its use with a variety of gaseous feedstocks.

Hydrogen from biomass pyrolysis. Pyrolysis technology is at the research, development and demonstration stage. Like gasification, it is a high temperature reaction taking place in an oxygen poor environment. Biomass pyrolysis takes place in a lower oxygen environment compared to gasification and produces a mix of solid, liquid and gaseous products. The mix depends largely on the level of oxygen input to the process. The liquid fuel produced can be transported and stored and allows for de-coupling of the fuel production and energy conversion stages. Liquid fuels from pyrolysis could be reformed to hydrogen at the forecourt. Small scale reforming systems are the advanced development stage and are not yet commercially available (Wolff, 2001). See also, section 4.2.6. 'bio-oil'.

Small scale generation (<2MW)

Electricity could be generated renewably at or near the refuelling site using photovoltaics or wind generation. The output of a photovoltaic array or a single wind turbine could be dedicated to hydrogen production via small scale electrolysis. Photovoltaic technology is commercially available in the UK, with ongoing development to reduce costs and increase efficiency of the modules. Wind turbines, such as the 1.5 MW turbine at Swaffham, Norfolk, have been sited on the outskirts of urban areas.

Electrolysis

Large scale alkaline electrolysis is a well established commercial technology, however research is continuing into improving efficiency through other electrolysis methods, and improving electrolyser performance under intermittent supply (Kruger, 2001, HyWeb, 2003). Small scale electrolysers are now also commercially available. The option for larger scale regional electrolysis, as well as electrolysis at the generating site is included in this assessment. The scale of electrolysis and its relation to the scale electrolyser may affect the efficiency and cost of hydrogen production storage and distribution.

Stationary hydrogen storage

Storage of hydrogen generated or transported may be required at different stages of the chain. Large to medium scale storage can be required at sites where hydrogen is produced on-site from renewables or at regional electrolysis sites where hydrogen is produced using transported electricity, and small scale storage at the forecourt. However, each site will have differing requirements in terms of capacity, storage time, transport needs, space available and many other factors, all of which will determine the most suitable storage option.

The principal storage options for hydrogen are as compressed (low to high pressure) gas or as liquid hydrogen. Underground storage is suitable for very large gas volumes, and has been

carried out commercially at several sites, including at Teesside in the UK (Ogden, 1999). Compressed hydrogen can be stored above ground in pressure vessels at a range of sizes and pressures. Equipment for compression is similar to that used for natural gas, and all equipment for compressed hydrogen storage is in commercial use. Liquid hydrogen technology has been used for some long-distance transport, but there is little widespread experience with large scale storage (Amos, 1998, Ogden, 1999).

Hydrogen transport and distribution

Hydrogen can be transported as a compressed gas, either in dedicated pipelines or by container or as liquid hydrogen, by tanker. Hydrogen pipelines have been used successfully both in the US and EU, with lengths of 8-200 km (Ogden, 1999). This may also be a viable option for transporting large volumes of hydrogen for relatively short distances, or when a stable market is established (Ogden, 1999). Transport of both compressed and liquid hydrogen by road is currently used in industry, with liquid hydrogen being favoured for long distances, due to a lower transport cost per unit of energy. However, compressed gas road transport can be viable for short distances, or where the high capital cost of liquefaction plant is prohibitive.

If the hydrogen is to be stored on-board the vehicle as a liquid, only liquid transport to and storage at the forecourt will be considered. If the hydrogen will be stored on board as a compressed gas, or using a metal hydride, both liquid and compressed hydrogen transport and storage will be considered.

Refuelling equipment

Gaseous hydrogen refuelling equipment is analogous to that for compressed natural gas, and is pre-commercial (Ogden, 1999). Equipment for liquid hydrogen refuelling has been in development for over ten years, and has improved significantly in terms of refuelling time and boil off losses (Wetzel, 1998). It is currently at the pilot stage.

Hydrogen use

Hydrogen can be used as a fuel in both internal combustion engine vehicles (ICEV) and in fuel cell vehicles (FCV). FCEVs using hydrogen produce no on-board emissions, and are quieter and more efficient than ICEVs. However, they are at an earlier stage of commercial development.

4.2.4. Electricity

The direct use of electricity for transport occurs in trains, trams, the underground and electric vehicles. The electricity is generally taken from the grid but could be supplied from both biomass and non-biomass renewables.

Renewable electricity can be produced directly from wind, hydro, solar and wave resources.

Biomass can also be converted to electricity through a variety of conversion routes.

Potentially all the liquid fuel production chains could be used to produce fuel for electricity generation via combustion. However, the most cost effective chains are likely to be the most direct and hence steam turbine / combustion systems or closely coupled gas turbine / gasification conversion systems are likely to be the most efficient.

Technology status

For the non-biomass renewables, wind power is the most mature and economic of the renewable energy technologies. The technology status is described in section 4.2.3.

Technologies for producing electricity from biomass range from fully-mature to pilot scale. Cost reductions are expected to be achieved through the commercialisation of efficient gasification-based systems.

4.2.5. Methanol

Methanol production generally consists of two operations: gas (syngas) production and methanol synthesis. In the case of most gaseous and liquid fuels, syngas is processed using steam reformers with the upgrading consisting of CO₂ removal and the removal of any contaminants, such as sulphur. The gas is then fed into the methanol synthesis process.

Feedstocks

Key renewable feedstocks include:
SRC – willow and poplar
Miscanthus
Forestry and agricultural residues
MSW

Key Conversion Technologies

- Gasification / catalytic gas reforming (R&D, niche market).

The gasification process is the same as for FT-biodiesel production and is described in section 4.21. 'Biodiesel via Gasification – the Fischer Tropsch (FT) route'.

The syngas from the gasifier, after suitable cleaning, reforming and upgrading, is used for methanol synthesis. The equipment downstream of the gasifier is the same as that used in producing methanol from natural gas. The methane-rich reformed syngas is cooled, compressed and passed over a copper-zinc catalyst to produce crude methanol – about 80% methanol and 20% water. Finally the methanol product goes through the methanol purification stage which removes water and organic products present, to different degrees according to the final use of the methanol.

When dealing with syngas from MSW there are a series of contaminants e.g.: particulates, heavy metals, sulphur, tars and oils, which must be removed prior to being fed into the methanol synthesis unit in order to prevent the poisoning of the catalyst beds in downstream reactors.

Co-products:

- Electricity and heat are likely to be the only significant co-products from biomass-based methanol production.

Technology status

Although, natural gas derived methanol dominates the world market, coal-based plants exist in the USA and China, sewage is used as a feedstock in one German plant, and a demonstration plant using wood waste has been built in Louisiana (Allard, 1998).

4.2.6. Bio-oil

This chain as outlined in figure 8, is based around the rapid pyrolysis of organic matter which leads to its thermal decomposition under high temperature and pressure in the virtual absence of

oxygen. Pyrolysis results in a cocktail of liquid biochemical fractions which can be directly combusted as a fuel-oil substitute or upgraded to liquid fuels through hydrogenation / reforming.

Key Feedstocks

- SRC – willow and poplar
- Miscanthus
- Forestry and agricultural residues
- MSW
- Waste / recovered cooking oils and fats

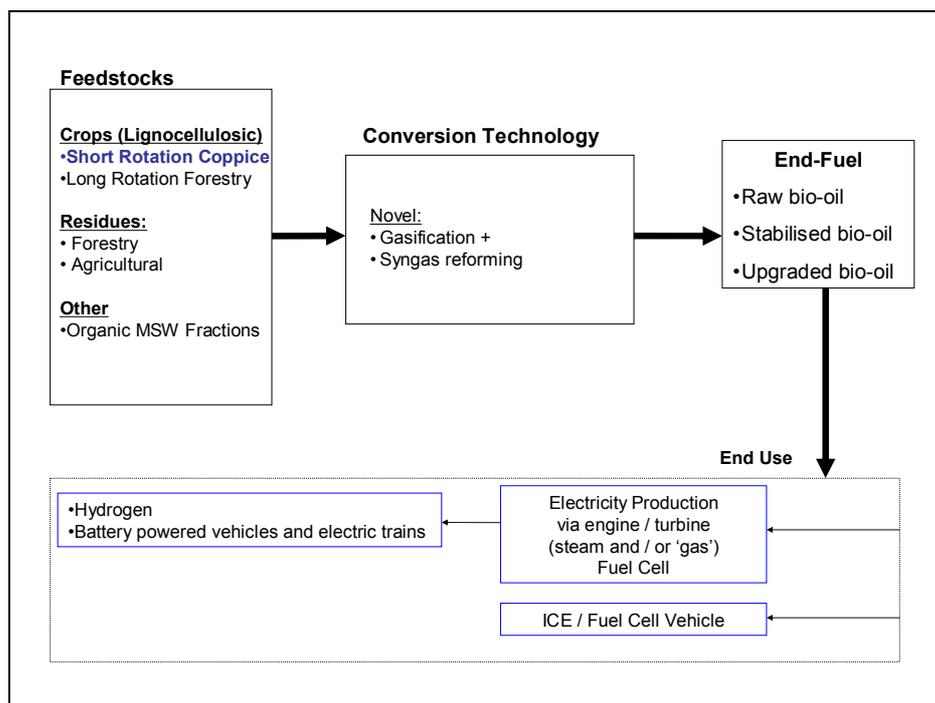


Figure 8: Bio-oil from Pyrolysis

Conversion Technologies

Pyrolysis: this technology is based around the ancient technology of charcoal production and has been modified to create more stable, controllable and rapid reaction conditions. A number of reactor types are in use or under development, including bubbling bed, fluidised bed and ablative reactors. The requirement for rapid heat transfer into the biomass means that the biomass must be fed into the reactor as a finely ground powder and can not have high moisture contents. Bio-oil production efficiencies of up to 80% wt/wt can be achieved with the residual products being gas and char, which can be consumed internally to provide the heat to drive the reactions. The bio-oil produced is dense, with a specific gravity of 1.2 and a Higher Heating Value (HHV) of between 16 and 19 MJ/kg.

The bio-oil is toxic, corrosive and unstable, and will slowly decompose to char residue at room temperatures and much more rapidly at higher temperatures. Direct applications are therefore preferred for heat or electricity generation but the oil can be stabilised and upgraded for diesel and petrol replacement (Bridgwater, 1999). However, this process is currently too costly for commercial applications but a well established R&D network continues with the development of the technology: see www.pyne.co.uk.

Co-products:

May be an important future source of high-value biochemicals.

Technology status

R&D and pilot demonstration at relatively small scales.

4.2.7. Bio-Methane

Renewed interest in bio-methane (biogas) has occurred in the last decade in Europe as a result of increasingly stringent regulations regarding the disposal of animal waste and sewage. Biogas can be used directly as a compressed gas in ICEs as a petrol or diesel replacement (with modifications to the engines, see Figure 9).

Key Feedstocks

- Animal waste
- Sewage (human and animal)
- Household organic matter
- Landfill gas

Conversion Technologies

Atmospheric temperature and pressure or thermophilic anaerobic digestion at small, medium or large (10 000 m³) scales are commercially deployed. Large scale anaerobic digesters are widespread in Denmark and Germany but are supported by legislation to control the disposal of animal manure.

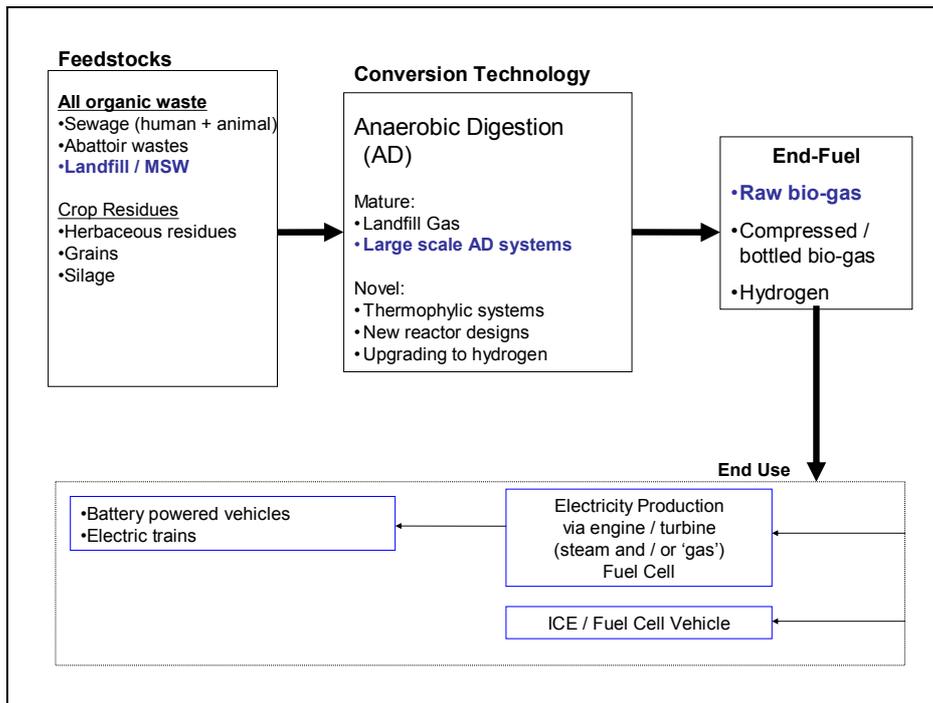
Co-products:

- a. Heat
- b. Land rehabilitation
- c. Waste disposal

Technology status

Commercially proven (Heiermann *et al.*, 2001; Barber and Stuckey, 1999).

Figure 9: Bio-Methane Production Pathways



4.3. Technology status summary & timeline for commercial introduction

The technological maturity of the conversion technologies available for each of the end-fuel production chains described above varies from commercial to laboratory. In addition, the technologies used through a production, conversion and distribution chain for a specific end-fuel may differ in preparedness for each stage of the chain with the potential for a seemingly insignificant stage or technology to be a 'show stopper'. In general, although there was an overall paucity of detailed references and therefore data for any of the 13 chains chosen for detailed analysis, the more commercially mature the chains were the more data was available. An exception to this rule was found in the lack of economic data (capital and / or operation and maintenance costs) for ethanol and biodiesel conversion facilities both of which are established commercial technologies in Europe and USA.

The developmental stages for each chain have been described above and an indicative 'Time Line' for end-fuel production technologies to commercial production has been included in the conclusions. It is clear from the timeline that there are significant lead-times for the development and construction of facilities for the production of RTFs, even when the potential delays in obtaining planning permissions are disregarded. When an assessment of the existing technology status compared and the likely development stages required to move from R&D to commercial are included it is obvious that some technologies will not be able to make a real contribution to RTF provision within a decade or more. In fact, it is clear that anything more than a token contribution from RTFs will not be possible in the UK over the next couple of years during which time significant policy stimulus will be required to kick-start the development of RTF chains and conversion facilities.

4.4. Fuel chain analyses literature review

In order to produce representative and realistic energy, emissions and financial balances for the 13 chains analysed in detail (Chapter 5 and Annex 1) an extensive literature review and expert consultation process was carried out. For twelve of those chains, references were found which had sufficiently detailed data to be used to develop our analysis as shown in Table 4.2. Individual spreadsheet-based reviews were carried out on these references in order to standardise the data contained and where necessary to convert the units to SI. Where references contained analysis of more than one end-fuel production chain individual sheets were prepared for each chain. In particular an exhaustive analysis of a large range of potential renewable and non-renewable chains was carried out by LBST and General Motors in 2002 (LBST_GM, 2002). This LBST_GM report has been relied on extensively for the production of this report. Although difficult to follow in places, this report and the analysis and detailed modelling work that it embodies are not available elsewhere. However, the LBST team were willing to provide requested information including details of the primary energy inputs into various sections of requested chains, where difficulties in understanding the methodology or data arose. A second more dated, but in its time ground breaking reference, was the report for the OECD and IEA (OECD/IEA, 1994) prepared by Laurie Michaelis entitled 'Biofuels'. This report provided baseline data for energy, emissions and costs for the main biomass-based chains and includes estimates of indirect energy inputs.

Armstrong *et al.* (2002) highlight the range in data found in the literature on energy, emissions and economic balances for biomass-to-energy in general but in particular for bio-fuels which reflects the four main areas of uncertainty i.e.:

1. Genuine variations in physical factors such as soils and climate and therefore productive potential of the biomass feedstock or non-biomass renewable energy supply.
2. The range of technological options available throughout the production and delivery chain.
3. The potential impact of R,D&D and logistical / institutional learning in increasing efficiencies and decreasing costs.
4. The scale of co-products and the accounting methodology used.

In order to overcome these uncertainties two basic approaches have been adopted in the literature. The first is to reflect the uncertainties by providing data to show the variation either through high and low values as provided in this report, or by providing plus and minus error ranges. The second approach, as demonstrated by LBST_GM (2002) is to carry out extremely detailed input output modelling of each of the potential technology options and present the data in a range of 'case studies' or scenarios.

Table 4.2.: Summary of references used for detailed analysis in this report

Reference	Chain
Armstrong <i>et al.</i> , 2002 (CONCAWE)	RME and Ethanol from wheat and beet
ECOTEC, 2001	RME and Wheat to Ethanol
LBST_GM, 2002	RME, SRC to ethanol, sugar beet to ethanol. 3 to 4 scenarios for each fuel.
OECD/IEA, 1994	RME, wheat and sugar beet to ethanol.
NREL, 1998	Soya Methyl Ester
Mortimer <i>et al.</i> , 2002	RME
Wooley <i>et al.</i> , 1999	Lignocellulosic ethanol
Groves, 2002	RME
Rosenberger <i>et al.</i> , 2002	Wheat to Ethanol in Germany
Reith <i>et al.</i> , 2001 (ECN)	Lignocellulosic ethanol from waste (including agricultural and forestry residues)
EUCAR, 2002	FT-Biodiesel
Hamelinck <i>et al.</i> , 2001	Biomass to hydrogen chains
Hydrogen from wind	Various (see section 4.2.3)

The scale of the evaluation task undertaken in this work has meant a heavy reliance on literature-based data. Often, for the individual RTF chains analysed a number of different references have been accessed to generate representative data on each of the three variables (energy, emissions and costs) at each of the four production and conversion stages outlined per chain. Where two reliable estimates for a specific data point were found they were used to generate the 'high' and 'low' values for that point. If three or more references were found, it was sometimes possible to generate an 'intermediate value'. In many cases, no published data could be found for a specific data point. Where this occurred, the 'missing' data point was generated 'in-house' using representative data from other chains or expert knowledge. Therefore, generating 'high' and 'low' values at each stage was not always possible and an 'intermediate' value representing either a single data point found in the literature or an in-house generated data point as described above, was used.

5. Renewable transport fuel chains: carbon abatement potentials, energy ratios, costs and technologies

5.1. Introduction

Thirteen renewable transport fuel chains have been evaluated in detail using a standard methodology to allow direct inter-comparison. The individual chains are summarised in Table 5.1. and the complete data sets are available in the individual analysis sheets in Annex 1. The chains assessed are not a comprehensive representation of the entire set of potential production routes for renewable transport fuels. However, these chains were considered to be the most likely contenders for a significant potential contribution to RTFs by 2020 through expert consultation and literature review, as outlined in chapter 4.

Table 5.1: Chains Assessed by Project

	Chain Description		End-fuel
1	Ethanol from Sugar Beet	C6 fermentation	Ethanol
2	Ethanol from Wheat (grain)	Starch hydrolysis, C6 fermentation	Ethanol
3	Ethanol from Straw (Wheat)	Hydrolysis, C5 & C6 fermentation	Ethanol
4	Ethanol from Wood (SRC)	Hydrolysis, C5 & C6 fermentation	Ethanol
5	Rape Methyl Ester (RME)	Oil extraction & esterification	Biodiesel
6	Vegetable Oil Methyl Ester (VME) from waste oils	Filtration / purification & esterification	Biodiesel
7	Fischer-Tropsch (FT) Biodiesel from Wood (SRC)	Gasification & catalytic gas upgrading	Biodiesel
8	Methanol from Wood (SRC)	Gasification & catalytic gas upgrading	Methanol
9	Hydrogen from Wood (SRC)	Gasification and gas upgrading	Hydrogen
10	Hydrogen from Off-shore Wind- 1	Regional electrolysis - compressed H2 distribution.	Hydrogen
11	Hydrogen from Off-shore Wind- 2	Regional electrolysis - liquid H2 distribution	Hydrogen
12	Hydrogen from Off-shore Wind- 3	Regional electrolysis - pipeline distribution	Hydrogen
13	Hydrogen from Off-shore Wind- 4	Forecourt electrolysis - compressed local storage	Hydrogen

Notes: see Annex 1 for complete analysis sheets for each chain.

5.2. Methodology

Renewable transport fuel production chains in this study are assessed primarily on the basis of the following full fuel chain characteristics: energy, GHG balances, economic costs, and technology status. For meaningful comparison between RTFs and with conventional fuels for transport, the evaluation has been carried out on a full fuel chain basis and encompasses feedstock supply, conversion to end-fuel and distribution to the vehicle or fuel supply depot. It does not evaluate the use of renewable transport fuels in vehicles where significant differences between energy densities and engine efficiencies may occur between the conventional and renewable fuels. Because renewable supply options for the production of transport fuels are diverse and generally less commercially mature than the conventional alternatives, the parameters used in the assessment of the fuel chains will be in ranges of values that reflect the variety of the fuel chain options and the uncertainty in knowledge.

For each of the thirteen renewable transport end-fuel supply chains shown above extensive literature reviews and consultations with industry experts were carried out (see section 4.4) in order to obtain data for each stage of the fuel chain. Comparable units have been used throughout in order to facilitate comparisons and to allow cross-checking. The primary unit of evaluation is a 'GJ of end-fuel' and 'low' and 'high' estimates have been provided where possible for each of the four main stages of a supply chain based on literature-derived estimates or in-house calculations i.e.:

1. Feedstock / primary energy carrier (e.g. wood) production
2. Feedstock / primary energy carrier delivery to conversion unit(s)
3. Conversion for production of end-fuel
4. Distribution of end-fuel to refuelling station forecourt.

For each of these stages and as a full fuel chain summary, the energy inputs, GHG emissions and economic costs have been estimated out as shown in the analysis sheets (see Annex 1) and summarised below for each chain. Where possible actual costs for the production and delivery of RTFs are provided which exclude profit margins and the effects of subsidies, taxes and co-products. In some cases it has not been possible to completely remove subsidies (see for example the wheat to ethanol chain) at the agricultural production stage and this is clearly stated in the text. This chapter should be read in conjunction with the individual analysis sheets provided in Annex 1 where detailed data and assumptions are provided.

5.3. Biomass fuel chains (non-hydrogen)

There is an extraordinary diversity of potential production and conversion chains for transport fuels derived from biomass. The large range of options arises from the large number of crops species which could be grown to produce transport fuels, the multiple outputs that can be derived from one crop and the range of conversion technologies that are applicable. We have attempted to simplify this complexity by basing the production chains evaluated below on the 'end-fuel' produced and by addressing specific fuel chains; see figure 1.

The type of RTF produced is to some extent dependent on the composition of the biomass material provided to a conversion plant. Plant material is composed of a complex mixture of polymers, primarily based around the six-carbon glucose monomer. Typically, between 40 and 50% of the biomass is composed of cellulose fibres embedded in a matrix of hemi-cellulose and phenolic lignin-carbohydrate polymers which together with proteins, sugars and starch comprise the bulk of the material. The proportions of these components can vary considerably between crop types but the lignin component is typically 5 to 10% of the dry biomass and is highly resistant to modification except thermally.

For thermal conversion processes, the detailed biochemical nature of biomass is not critical except that different compositions affect aspects such as drying rates and handling parameters especially if pre-processing is required e.g. chipping or pelletisation. For fermentation and esterification conversion systems the composition of the biomass may be critical. Therefore, energy crops can be sub-divided into 4 distinct categories for transport fuel production depending on the conversion system used and end-fuel produced i.e.:

1. Sugar-rich crops suitable for conventional yeast-based fermentation for bioethanol production.
2. Starch-rich crops suitable for enzymatic hydrolysis (e.g. Amylase and others – see below) and then conventional fermentation for bioethanol production.
3. Lignocellulosic crops suitable for:
Hydrolysis and advanced fermentation for ethanol production;

Gasification and upgrading of product gas to a variety of fuels including methanol, Fischer-Tropsch (FT) biodiesel and hydrogen.

4. Oil-rich crops suitable for biodiesel production.

In total, biomass-derived transport fuels include: ethanol, biodiesel, electricity, methanol, hydrogen, biogas, bio-oil, electricity and dimethyl ether (DME). However, with the exception of ethanol, biodiesel and electricity, none of the technologies for the production of these fuels are yet commercially demonstrated. Production chains for each of these end-fuels are evaluated below.

5.3.1. Ethanol

Ethanol production using a range of technologies is evaluated. Traditional hexose (C6) fermentation is evaluated in the sugar beet to ethanol chain and the more complex hexose-based ethanol production from starch hydrolysis of cereals is evaluated in the wheat grain to ethanol chain. Lignocellulosic ethanol production based on a combination of acid and enzymatic hydrolysis and pentose & hexose fermentation using recombinant bacteria and yeasts, is assessed in the ethanol from straw (wheat) and wood obtained from short rotation coppice (SRC) chains.

Ethanol from sugar beet (*Beta vulgaris*).

Chain summary:

Sugar beet is produced by and delivered an average distance of 50km to a 120,000 t EtOH/yr plant (3.2 PJ; 151 MI) requiring approximately 1.6 Mt beet per year. The ethanol is then distributed an average distance of 150 km (300km round trip) by tanker truck to local distribution depots for blending with gasoline.

At current yields (55 t beet /ha) a 120 kt EtOH per year facility would require 28.5 kha or 1.6% of the surface area within a 75km radius (3.6%; 50km radius). Details of the assumptions for the ethanol from sugar beet chain can be found in the related analysis sheet in annex.

Technology status:

Proven mature technologies are evaluated in all stages of the chain. Large commercial beet to ethanol operations exist in other European countries, most notably France. The UK has the world's largest beet to crystalline sugar production plant processing 2.4 Mt beet per year at the rate of 16 000 t/day at British Sugar's Widdowson factory (British Sugar, 2002). Despite the commercial maturity of the industry, improvements in energy efficiency and beet varieties could have a significant impact on the energy balance, emissions and costs.

Feedstock production and delivery

Sugar beet yields of between 45 and 80 t/ha (harvested fresh biomass) are quoted in the literature (see for example, OECD/IEA, 1994; Sugar Beet Review, 2002). The UK 2001 national average was 46 t/ha and the EU average was 55 t/ha (FAOSTAT, 2002). However, 2001 was a bad year for beet yields in the UK with the average yields between 1995 and 1998 being nearly 54 t beet / ha (May, 2001). Yields of these magnitudes would lead to gross ethanol yields of 4800 to 7800 l EtOH / ha. In addition, significant amounts of tops and leaves are produced along with the beet tubers, but the high moisture ($\approx 85\%$) and nutrient contents makes the economic and sustainable exploitation of these residues unlikely.

The crop rotation system adopted is also important as expanding the area of sugar beet will mean replacing existing crops. Sugar beet is likely to replace either N-fixing (e.g. Egyptian Clover) or

non-N-fixing (e.g. Rye Grass) crops in the rotation (LBST-GM, 2002). Replacing Egyptian Clover would mean that no nitrogen will be added to the fields by the Egyptian Clover and so additional synthetic nitrogen fertiliser will be required with the associated energy and emissions costs. LBST_GM (2002), estimate that approximately 40 kg additional N is required where this occurs. The average transport distance for delivering sugar beet (farm to mill) in the UK, supplying British Sugar's factories, is currently 45 km (28 miles). The delivery distance continues to decrease as suppliers concentrate their activities closer to the mill in order to minimise transport costs (Punter, 2003, pers comm.). Unless otherwise stated an average transport distance from farm to conversion plant of 50km has been used throughout this analysis for feedstock transport.

Costs: The cost of producing sugar beet is estimated to lie between £8.00 and £9.64 per GJ EtOH or 60 and 70% of the final delivered ethanol cost excluding subsidies. This represents a production cost of between £990 and £1100 / ha (Leeds, 2002; May, 2001, and Bennett 2002) and depends on land quality, management factors and climatic conditions. The actual value to the farmers of delivered beet in 2002 was £11.70 / GJ EtOH (£29.50/t; Leeds, 2002) because of the high EU quota value of beet, making it one of the most profitable crops grown in the UK. The average enterprise price paid to farmers (which includes quota subsidies) increases the value to the farmers of beet to £29.54/t which can be compared to the actual delivered costs of £19.75/t. Incurring the average quota value of the beet for ethanol production would raise the ethanol production cost to £0.365 per litre or £17.14 / GJ EtOH under current average grower conditions. Transport costs are relatively high compared to the other biomass feedstocks e.g. cereals, because sugar beet is over 80% water on harvest (16% sucrose) compared to 15% to 20% for cereals. Transport is estimated to cost £4.20 and £4.40/t beet (£0.084 and £0.088/t.km) or between £2.15 and 2.50 per GJ EtOH produced (Leeds, 2002).

Energy: Sugar beet production is an intensive agricultural activity accounting for 16 to 18% (between 0.13 and 0.21 GJ/GJ EtOH) of the total energy inputs for ethanol production (LBST_GM, 2002; OECD/IEA, 1994). However, gains continue to be made in reducing energy inputs and improving yields and it is likely that our analysis overestimates the current energy requirements for producing sugar beet. For example, average nitrogen fertiliser applications have been reduced from over 150 kg N/ha in 1970 to around 100 kg/ha currently (May, 2001). The energy intensity of nitrogen fertiliser production has also fallen during this period (Mortimer, 2002).

The transport of the beet to the conversion plant also requires energy inputs of between 0.04 and 0.06 GJ/GJ EtOH, approximately 6% of total energy inputs (LBST_GM, 2002; OECD/IEA, 1994).

GHG/CO₂ emissions: GHG emissions from feedstock production and transport are estimated to be between 24 and 33 kg CO₂ equivalent per GJ EtOH. These rates of emission are higher than the other biomass chains as a result of the high level of inputs required per ha and the intensive nature of harvesting a below-ground crop. In particular, nitrogen fertiliser inputs are relatively high, increasing the potential rate of N₂O emissions, a potent greenhouse gas. Feedstock transport emissions are also relatively high at 4 kgCO₂eq./GJ EtOH, compared to the other biomass chains because of the high share of non-fermentables (e.g. water) being transported (LBST_GM, 2002).

Resource potential: The current UK land area dedicated to sugar beet production is continuing to fall, primarily as a result of increasing yields but static demand. In 1998, there were 188 000 ha of land under sugar beet which fell to 175 000 by 2001 and the trend is continuing (May, 2001). British Sugar estimate that sufficient ethanol could be produced on 300 000 ha of farmland for a 5% ethanol:petrol blend (v/v) in the UK requiring 1.2 Mt EtOH (British Biogen, 2002).

Feedstock conversion

Costs: Conversion costs are difficult to obtain. Costs of £4.90 per GJ EtOH (10.3p/l) are based on OECD/IEA 1994 and are therefore dated and exclude capital costs. However, 'operating

costs, including marketing', but excluding feedstock supply, were estimated by British Sugar at 9.81p/l (£4.6/GJ EtOH) with additional projected costs depending on the period of guaranteed duty reduction of 15.70, 9.96 and 8.29 p/l for 'capital recovery' over 5, 10 or 15 years respectively (see Table 5.2). Capital recovery would therefore add between £3.90 to £7.38 per GJ EtOH.

Energy: The conversion process represents the greatest consumer of energy inputs in the chain requiring about 65% (0.33 to 0.55 GJ/GJ EtOH) of total energy inputs (OECD/IEA, 1994; LBST_GM, 2002). This high level of energy input reflects the energy intensive nature of the sugar (fermentables) rich juice extraction (pulping and diffusion) and of distillation.

GHG/CO2 emissions: GHG emissions of between 0.6 and 67.5 kg CO₂eq./GJ EtOH produced are estimated. The low estimate is based on LBST_GM (2002) GHG emissions where the pulp co-product is used to provide the energy requirements for conversion. The high value is from OECD/IEA (1994) and thus represents older, less efficient conversion technologies and the use of fossil fuels to supply conversion energy without any co-product credits. Comprehensive and reliable data on GHG emissions for the conversion of sugar beet to ethanol are scarce and further work is required to establish emissions from state-of-the-art facilities.

Distribution

Distribution (300km round-trip) is estimated to require less than 2% (0.016 GJ/GJ EtOH) of the total chain energy inputs and contributes less than 5% (£0.60/GJ EtOH) of the overall cost of producing and delivering EtOH. The share of total GHG emissions from distribution is even lower being less than 1% (0.9 kg CO₂ equivalent / GJ EtOH) of total chain emissions (LBST_GM, 2002). Much higher distribution costs are given by IEA (1999), which for ethanol were estimated at £3.41 per GJ EtOH (US\$5.12) including margins and interest on working capital.

Summary and conclusions

Costs:

Full fuel chain costs for the production of ethanol are estimated to be between £13.5 and £15.1 per GJ delivered ethanol, equivalent to 29 to 32p/l excluding profits or co-product credits. It is likely that at least initially, the costs will lie at the upper end of this scale as a result of capital recovery and the risks associated with the establishment of a new industry (see also Bennett, 2002).

The costs shown above can be compared with the project costs provided by British Sugar (British Biogen/British Sugar, 2001), as shown in table 5.2. The difference between the bioethanol selling price and that of the petrol has been used to show the duty reduction required.

Table 5.2.: Estimated costs of Ethanol Production

Cost Breakdown (Pence per litre)	Project Life		
	5 years	10 years	15 years
Raw materials + direct labour	20.23	20.23	20.23
Operating costs, including marketing	9.81	9.81	9.81
By-product selling price	-5.86	-5.86	-5.86
Capital repayment	15.70	9.96	8.29
Selling price	39.88	34.14	32.47
Duty reduction required*	27.88	22.14	20.47

Notes: (Source, British Biogen/ AFB British Sugar, 2002)

*assumes petrol price at 12p/litre

The main co-product associated with the processing of sugar beet to crystalline sugar is a high energy animal feed produced from the pulp. The estimated value of pulp pellet feed is £2.57/GJ EtOH, equivalent to 5.45 p/l EtOH which is similar to the value provided by British Sugar of 5.86 p/l (see above) which will include additional by-products such as 'lime-X' and biogas (see Environmental and co-product issues below). Other innovative high value secondary compounds such as Betaine may also be produced and sold, which is now becoming current practice by British Sugar in the UK from crystalline sugar extraction. However, evaluating the elasticity of the market for Betaine and similar products is beyond the scope of this report and so potential co-product credits for this type of co-product are not given.

Energy: The total energy requirement for the production of ethanol from sugar beet is estimated to lie between 0.52 and 0.84 GJ/GJ EtOH produced excluding the use of co-products. It is possible that with good incentives, a new sugar beet ethanol production chain set up in the UK would require a lower rate of energy inputs than the low estimate provided above. The gains in energy efficiency would result primarily from the use of co-products and CHP within the conversion facility. We estimate the energy content of by-products to be between 0.07 (biogas from effluent treatment only) and 0.45 (biogas plus animal feed pulp pellets) GJ/GJ EtOH. By factoring in the energy value of these by-products an overall energy ratio of between 1.4 and 2.1 GJout/GJin could be expected.

GHG/CO₂ emissions: GHG emission of between 30 and 106 kgCO₂eq./GJ EtOH are estimated based on the data provided above, but further work is required to validate this scale and range of emissions under current practices and technologies. The use of co-products for energy and as saleable products would reduce both gross emissions and the share of emissions allocated to ethanol production but insufficient data was available to calculate the detailed impact of using co-products in this way. The low end of the emissions range is based on LBST_GM (2002) which provides a GHG balance for ethanol production from sugar beet where the pulp is used to fuel the conversion facility. The use of pulp results in virtually zero GHG (0.6kgCO₂eq/GJ EtOH) net emissions from the conversion stage in ethanol production. This can be compared to an estimate of 47 kgCO₂eq/GJ EtOH, also derived from LBST_GM (2002), for ethanol produced in a sugar refinery without pulp credits. We estimate that conversion could result in over 2/3 of the total chain GHG emissions and therefore, demonstrating reductions in emissions at the conversion stage will be critical to the long term sustainability of ethanol produced from sugar beet. For an overall comparison, Armstrong *et al.* (2002) provide a detailed evaluation of energy balances and GHG emissions comparing seven relevant references which provide full fuel chain emissions for beet, wheat and corn (maize) ranging from 41.5 to 110 kgCO₂eq/GJ EtOH. The only beet-based reference quoted in Armstrong *et al.* is Levy (1993) with whole chain GHG emissions of 41.5 and 59.7 kgCO₂eq/GJ EtOH but the conversion-only share of emissions is not provided.

Environmental and co-product issues: Co-products from sugar beet ethanol production include: i) pulp pellets (animal fodder or fuel), ii) CO₂ from fermentation (industrial use and fizzy drinks), iii) biogas derived from the vinasse / slops (fuel credit), iv) Betaine (secondary plant compound), and v) approximately 450,000 tonnes of liming material is produced as a co-product of the sugar manufacturing process. "LimeX" is sold for a variety of agricultural and industrial applications. (<http://www.britishsugar.co.uk/bsweb/bsgroup/facts/fsheet3.htm>).

Resource potential: Using current technologies, ethanol can be produced from sugar beet at the rate of between 3.9 and 6.2 t/ha. Therefore, in order to produce sufficient ethanol for a 10% blend of petrol (10% EtOH:90% petrol; v/v) nationally, between 6 and 9% of the arable land (344 000 and 550 000 ha) would be needed, roughly equivalent to the current set-aside land area in the UK.

Ethanol from Wheat Grain (*Triticum*).

Chain summary:

Wheat is produced and delivered within an average distance of 50km to a 120 000 t EtOH/yr plant (3.2 PJ; 151 MI) requiring approximately 0.4 Mt grain per year. The ethanol is then distributed by tanker truck 150 km to local distribution depots.

At current UK grain yields (7.6 t/ha), a 120 kt/yr ethanol plant would require 53.3 kha of wheat or 3% of the land area in a 75km radius of the plant (7%; 50km radius). Details are provided in the associated analysis sheet in Appendix 1.

Technology status:

All stages of this chain could use proven mature technologies. Large commercial industries exist in the USA (based on maize (corn)) and other European countries, e.g. Germany and France (based on wheat). However, continued improvements in enzyme production, energy efficiency and wheat varieties could have a significant impact on the energy balance, emissions and costs. There is also the potential to combine ethanol production from the grain and straw but only grain-based ethanol production is evaluated here and straw-based production separately below.

Feedstock production and delivery

Average UK wheat yields of grain in 2001 were 7.1 t/ha and for the EU 5.5 t/ha. For the UK, ethanol yields of between 2400 and 3000 l/ha are estimated depending on conversion efficiency. In contrast to the tops and leaves produced with sugar beet which are unlikely to be recoverable, up to 1.3 t raw straw are produced per t grain of which about 50% is recoverable. Straw is lignocellulose-rich and could be used to produce both ethanol (see 'conversion technologies' below) and/or provide the energy to supply the conversion process. The removal of straw would however, result in the removal of some nutrients which may need to be replaced, incurring additional fertiliser costs. See 'Lignocellulosic Ethanol Production from Wheat Straw' below for details.

Costs: UK-specific industry-based feedstock costs (including subsidies) are derived from HGCA.com 2002, which provides the 'average' prices for 'feed' and 'bread' wheat production in the UK as 'delivered' and as 'ex-farm' prices. The 'transport' cost was then calculated by subtraction. A cost £9.70/GJ EtOH is based on the HGCA-derived cost of £76.7 per tonne wheat representing the 'average' delivered feedstock cost for the UK in 2001 (HGCA, 2002) including any subsidies. Rosenberger (2001), in the 'medium intensity' scenario for wheat production in Germany, provides a cost for wheat (triticale cv 'Modus') of DM1293/ha at a productivity of 5.3 t wheat/ha (£76.0/t at 2001 average annual exchange rates; Oanda, 2002). It is worth noting that although wheat prices are quite volatile there has been a sustained downward pressure on prices which are currently just above £50/t for feed wheat (Nov 2002). At this price farmers only just break even, even with production subsidies of £230 per hectare.

Transport costs of £0.34/GJ EtOH (£2.65/t wheat; £0.053/t.km) were derived from the 'ex-farm' and 'delivered' prices for wheat in the UK (HGCA, 2002) which is approximately 60% the costs of sugar beet transport (mass basis).

Energy: OECD/IEA (1994) data was used to derive energy input requirements for the production and transport of wheat of between 0.14 and 0.15 GJ/GJ EtOH depending on yield achieved. Energy requirements for transport-only are estimated to be between 0.01 and 0.02 GJ/GJ EtOH (see Appendix 1). Feedstock production and transport therefore requires approximately 16% of the total chain energy inputs.

Direct and indirect energy inputs into feedstock production are included because it was impossible to disaggregate them in the OECD/IEA (1994) data. Therefore, the energy requirements for the production and application of fertilisers and pesticide(s), farm fuel use, energy costs of equipment manufacture, transport of feedstock, processing, and drying are included. Fertiliser (particularly nitrogen) inputs dominate feedstock production energy inputs.

Feedstock transport energy requirements were derived from LBST_GM (2002) sugar beet transport data because of the lack of wheat-specific data relating to energy use. The reduced energy requirements of wheat grain transport versus sugar beet transport as a result of the lower moisture content (15% wheat grain versus 80%+ sugar beet) is highlighted by the significantly lower share of total chain energy inputs for wheat grain transport (less than 1%) compared to sugar beet (5%). Transport is estimated to require between 0.006 and 0.020 GJ/GJ EtOH depending on the data source i.e. LBST_GM, 2002 (beet transport) and Shapouri *et al.*, 1995 (maize (corn) transport) respectively.

GHG/CO₂ emissions: Feedstock production and transport accounts for 16 to 22% of total chain emissions. 'Feedstock transport' emissions are impossible to disaggregate from 'farm fuel' emissions in OECD/IEA (1994). Therefore, GHG emissions from feedstock production plus feedstock transport of between 9 and 17 kgCO₂eq./GJ EtOH are calculated of which transport is likely to account for between 1.2 and 1.8 kgCO₂eq./GJ EtOH based on data from the other fuel chains and data quoted in Armstrong *et al.* (2002). The emissions include primary emissions from fertiliser and pesticide manufacture and use, and on-farm nitrous oxide emissions - 'by-product credits' are not included.

Resource potential: Ethanol productivities of between 1.9 and 2.4 t/ha are estimated resulting in a land requirement of between 0.89 and 1.14 Mha (15% and 19% of UK arable land area) in order to produce sufficient ethanol for a 10% blend (ethanol:petrol, v/v).

Feedstock conversion

Costs: Conversion costs are derived from OECD/IEA (1994), Sparks (2002) and Rosenberger (2002). Conversion costs are estimated to lie between £3.38 and £4.87/GJ EtOH produced or about 25% of total production costs. The 'high' cost is derived from OECD/IEA (1994) which reflects the costs of producing ethanol from a 395 t EtOH/day plant (approx. 120 kt/yr) including fixed and variable costs in the early 1990s. The 'Low' estimate is derived from Sparks (2002) and is based on modern corn (maize) to ethanol plants located in the US for a range of plant scales ranging from 45 to 300 thousand t EtOH per year. The 40 million gallons (120 kt EtOH) per year 'Dry-Mill' plant data was used as most representative for EU/UK conditions.

Energy: 0.75 GJ energy inputs are required per GJ EtOH produced for mashing, enzyme production, hydrolysis, fermentation and distillation (OECD/IEA, 1994), representing over 80% of the full fuel chain energy requirement.

GHG/CO₂ emissions: Emissions of between 47 and 62 kgCO₂eq. per GJ EtOH produced from the conversion process are estimated (OECD/IEA, 1994; Armstrong *et al.*, 2002), accounting for 81% to 84% of total chain emissions. No recent literature could be found to verify this estimate under current conditions.

Distribution

Energy, GHG emissions and costs are the same as for sugar beet – see above.

Summary and conclusions

Costs:

Whole chain costs for the production of ethanol are estimated to be between £13.7 and £15.2 per GJ delivered ethanol including agricultural subsidies, equivalent to 29 to 32p/l and are similar to ethanol produced from sugar beet. It is likely that at least initially, the costs will lie at the upper end of this scale as a result of capital recovery and the risks associated with the establishment of a new industry (see also Bennett, 2002).

The potential value of the co-products is estimated to range from £3.54 to £4.32 per GJ of ethanol. See 'Environmental and by-product issues' below for production factors. The 'Low' value is based on the 2001 US value of distillers dry grains with solubles (DDGS; \$98.5/t or £68.4/t DDGS; Sparks, 2002) and a production rate of 0.31t/tgrain. The 'High estimate' includes the value of straw at £25/t, DDGS and CO₂ (£0.04/kg CO₂; UK Stats Office, 2001) and 0.31 tCO₂/tgrain (Markham, 2002). However, Coltrain (2001), states that carbon dioxide capture and sale is only worth considering if an 'easily accessible market' is nearby and even so because of the low value of industrial CO₂ it may be difficult to make a profit.

Energy: An energy ratio of between 0.7 and 1.7 is calculated excluding co-product credits. We estimate the energy content of the co-products to be between 1.0 and 1.2 (straw only, depending on yield and conversion efficiency) GJ/GJ EtOH. By factoring in the energy value of these by-products an overall energy ratio of between 1.8 and 2.7 GJout/GJin could be expected. Other high value co-products such as DDGS (or WDS) will also be produced and sold. Coltrain (2001) states that up to half of the total amount of natural gas used in the ethanol plant is for drying DDGS and is included in our energy inputs. However, an alternative is to sell the un-dried version called 'Wet Distillers Grains' (WDG) which is reportedly preferred by cattle but has a much shorter shelf-life (measured in days) and higher transport costs (having a water content of 60%).

GHG/CO₂ emissions: GHG emission of 56 to 77 kgCO₂eq./GJ EtOH are estimated based on the data provided by OECD/IEA (1994), but further work is required to validate this scale and range of emissions under current practices and technologies. The use of co-products would reduce both gross emissions and the share of emissions allocated to ethanol production but insufficient data was available to calculate the impact of using co-products in this way.

Environmental and by-product issues: Co-products from cereal based ethanol production include: i) Distillers Dry Grains and Solubles (DDGS), 310kg per tonne grain processed; ii) straw (0.65 t recoverable straw /t grain; 1.3 tstraw total/tgrain); and iii) carbon dioxide (310kg /t grain). DDGS is produced by drying the stillage resulting from distillation and fermentation- it can then be sold as cattle, poultry or pig feed and has a high phosphorous content (Shurson, 2002). See Appendix 1 for details.

Resource potential: Using current technologies, ethanol can be produced from wheat grain at the rate of between 1.7 and 2.7 t/ha. Therefore, in order to produce sufficient ethanol to produce a 10% blend of petrol (10% EtOH:90% petrol; v/v) between 15 and 18% of the arable land (890 000 and 1 120 000 ha) would be needed.

Lignocellulosic Ethanol from Wheat Straw (Triticum).

Chain summary:

Wheat straw is harvested and baled for delivery over an average distance of 50km to a 150 000 t EtOH/yr plant (400 PJ; 190 MI) requiring approximately 0.6 Mt straw per year. The residual lignin is used as a fuel in the conversion plant and excess electricity may be produced and sold. The ethanol is then distributed 150 km by tanker truck to local distribution depots.

Technology status:

The feedstock supply chain is fully proven with straw currently being baled and delivered to the Ely plant near Cambridge for electricity production via combustion. However, logistical problems can prove difficult to solve. The ethanol conversion technologies still require demonstration at pilot and commercial scales. In particular, continued improvements in enzyme production and significantly reduced costs need to be demonstrated. The straw to ethanol chain is fully

compatible with the wheat grain to ethanol chain and it is likely that a future production plant in the UK would be an integrated facility processing grain and straw and probably a range of other lignocellulosic supply streams.

Resource potential: Potential ethanol production rates from straw are estimated to lie between 0.95 and 1.41 t/ha. At current UK recoverable wheat straw yields (c. 5 t/ha), a 150 kt/yr ethanol plant would require 120 kha of wheat or 7% of the land area in a 75km radius of the plant (15%; 50km radius). A combined grain and straw facility could theoretically produce ethanol at the rate of 3.5 t/ha which would reduce the land requirements for the 150 kt/yr plant to 42.9 kha and 2.4 % of the land area within a 75km radius.

Feedstock production and delivery

Approximately 1.3 oven dry tonnes of straw is produced per tonne of wheat grain of which about 50% is considered recoverable on a sustainable basis. Therefore, 5 odt of straw can be harvested and delivered per ha of wheat under current UK wheat yields of grain. We estimate rates of ethanol production from straw of 1 200 and 1 800 l/ha depending on wheat and straw yields and on the conversion efficiencies assumed. Straw is lignocellulose-rich and could be used to produce both ethanol (see 'conversion technologies' below) and to provide the energy to supply the conversion process and surplus electricity from the lignin component. The removal of straw results in the removal of some nutrients which a farmer will need to replace, incurring additional fertiliser costs. Jaggard (2002, pers comm.) estimates that for a typical straw yield of 5 t/ha, the fertiliser value of straw is about £8.95/ha (£1.79/t straw), based on P₂O₅ and K₂O contents of 1 and 8 kg/t raw straw respectively, and the current fertiliser prices are £0.27/kg P₂O₅ and £0.19/kg K₂O.

Costs: UK-specific feedstock costs for delivered straw are estimated to lie between £20 and £35 per tonne as delivered but during periods of high demand may be much higher (e.g. up to £55/t). Transport costs of £0.22/GJ EtOH (£0.053/t.km 50km oneway) were derived from the costs for wheat transport in the UK (HGCA, 2002), adjusted for the energy and moisture content of straw as delivered.

In practice, contractor costs for delivered bales (500kg bales) to the Ely power station result in a delivered cost of about £24/t straw to the power station or £1.73/GJ straw (derived from Jaggard, pers. comm., 2002). Of this cost, the transport component is £10/t straw (£0.2/t.km, 50km oneway). This is significantly higher than the other chains and arises as a result of the lower energy density and difficulty in handling of straw bales.

Energy: Energy inputs into delivered feedstock production are estimated to be between 0.059 and 0.098 GJ/GJ EtOH. These energy inputs include the energy requirements for the production and application of fertilisers and pesticide(s), farm fuel use, energy costs of equipment manufacture, transport of feedstock, processing, and drying. Calculating the energy inputs into straw production are complicated by the need to allocate total energy inputs between the grain and recoverable straw production. Details of the energy allocation methodology can be found the relevant analysis sheet (Annex 1).

Feedstock transport energy requirements of approximately 0.01 GJ/GJ EtOH and are assumed to be the similar to those for wheat grain per litre of ethanol produced- see above.

GHG/CO₂ emissions: Feedstock production and transport accounts for 13% to 27% (8.0 and 12.2 kgCO₂eq./GJ EtOH) of total chain emissions. The emissions include a share of the primary emissions from fertiliser and pesticide manufacture and use, and on-farm nitrous oxide emissions for wheat grain production; co-product credits are not included. The high value is based on OECD/IEA (1994) for wheat grain production of 17 kgCO₂eq./GJ EtOH with emissions allocated between grain and straw on an energy content basis. The low estimate is derived from LBST_GM (2002).

Feedstock conversion

Costs: Conversion costs are derived from Reith (2001), Wooley (1999), OECD/IEA (1994) and Sparks (2002). Conversion costs are estimated to lie between £4.98 and £9.14/GJ EtOH produced or 55 to 61% of total production costs. The high costs included the current costs of enzyme production and the low costs represent the predicted reduction in costs for enzyme production of 10 times over the next 10 years (Wooley, 1999). Capital costs are included.

Energy: 0.75 GJ energy inputs are estimated to be required per GJ EtOH produced for mashing, enzyme production, hydrolysis, fermentation and distillation (OECD/IEA, 1994), representing over 80% of the whole chain energy requirement. LBST_GM data could not be used because it was unclear how to disaggregate energy inputs from the use of lignin for energy provision to the conversion process.

GHG/CO₂ emissions: between 15.6 and 61.8 kgCO₂eq. are estimated to be emitted per GJ EtOH produced from the conversion process (LBST_GM 2002; OECD/IEA, 1994), representing 68% to 86% of total chain emissions. A great deal of uncertainty exists regarding emissions from lignocellulosic ethanol production.

Distribution

See sugar beet derived ethanol distribution- see above.

Summary and conclusions

Costs:

Conversion costs remain uncertain until full scale demonstration. However, we estimate delivered ethanol costs to lie between £9.0 and £14.9/GJ (19 to 32p/l) based on data from Reith *et al.* (ECN 2001), LBST_GM (2002) and Wooley *et al.* (NREL 1999). Current costs, based on a full scale implementation of existing technologies are likely to be about £16/GJ (42p/l EtOH; Punter, 2003).

The potential value of the surplus electricity co-product is estimated at £0.015 per litre of ethanol (Reith, 2001; Wooley, 1999). No other significant co-products will be produced.

Energy: The total chain energy ratio for ethanol from straw is estimated to lie between 0.78 and 1.79 GJ/GJ EtOH produced excluding co-product credits. We estimate the energy content of co-products to be between 0.43 and 0.60 (lignin only, depending on yield) GJ/GJ EtOH. By factoring in the energy value of the lignin an overall energy ratio of between 1.3 and 2.3 GJ_{out}/GJ_{in} is calculated.

GHG/CO₂ emissions: GHG emission of 23 to 72 kgCO₂eq./GJ EtOH are estimated based on the data provided by OECD/IEA (1994) and LBST_GM (2002). The range reflects the range in energy inputs to feedstock production (and the allocation between wheat grain and straw) and the use of lignin to power the conversion process. Further work is required to validate this scale and range of emissions under current practices and technologies.

Environmental and by-product issues: Electricity is likely to be the only co-product produced with surplus electricity exported to the grid after the internal requirements of the conversion facility for both electricity and heat are satisfied.

Resource potential: Ethanol productivities of between 0.9 and 1.4 t/ha are estimated resulting in a land requirement of between 1.53 and 2.37 Mha (25% and 39% of UK arable land area) in order to produce sufficient ethanol for a 10% ethanol:petrol blend (v/v). Ethanol produced from wheat straw plus grain would result in a combined ethanol production rate of 2.83 to 3.81 tEtOH/ha requiring between 0.56 and 0.75 Mha (9% and 12% of arable land).

Lignocellulosic Ethanol from Wood (SRC willow and poplar)

Chain summary:

SRC willow or poplar is produced and delivered within an average distance of 50km to a 150 000 t EtOH/yr plant (400 PJ; 190 MI) requiring approximately 0.6 Mt oven dry wood per year. The residual lignin is used as a fuel in the conversion plant and excess electricity may be produced and sold. The ethanol is then distributed 150 km by tanker truck to local distribution depots.

Technology status:

The feedstock supply chain is at early commercial stage although coppicing is an ancient industry. However, as with straw, logistical problems can prove difficult to solve. The conversion technologies still require demonstration at pilot and commercial scales. In particular, continued improvements in enzyme production and significantly reduced costs need to be demonstrated. One of the main advantages of using wood is the potential harvest and store it for use throughout the year maximising plant availability and minimising costs.

Resource potential: Based on R&D data (Wooley, 1999; Reith, 2001; LBST_GM, 2002), ethanol can be produced from wood at the best estimate rate of 2.35 t/ha. At current UK best estimate SRC yields (10 odt/ha), a 150 kt/yr ethanol plant would require 63.8 kha of SRC or 4% of the land area in a 75km radius of the plant (14%; 50km radius).

Feedstock production and delivery

Yields of between 5 and 15 odt wood can be expected under current UK climate, soils and management. Rates of ethanol production of between 1 700 and 6 000 l/ha are estimated, depending on wood yields and conversion efficiencies. As with straw, wood is lignocellulose-rich and could be used to produce both ethanol (see 'conversion technologies' below) and to provide the energy to supply the conversion process and surplus electricity.

Costs: UK-specific feedstock costs for delivered SRC wood chips are estimated to lie between £25 and £60 per odt (£1.4 and 3.3/GJ wood). Wood chip costs can vary widely depending on yield and management practices. A wider range of \$1.4/GJ to \$6.4/GJ (£0.88 to £4.00) reflects the full range of costs commonly cited in the literature e.g. Wooley (1999) quotes a generic cost of \$25/dry ton (\$1.40/GJ) for delivered yellow poplar in the US. UK-specific cost calculations for SRC willow show that SRC willow wood chips could be produced for £1.5/GJ (\$2.4/GJ or £27/t), assuming a yield of 10t (oven dry)/ha and efficient crop management practices. A 100km return transport distance adds between £0.15 and £0.37/GJ (£0.055 and £0.013/t.km (50km one way) feedstock; £0.34 and £1.10/GJ EtOH) to the cost of the feedstock, based on a specific transport cost of £0.0015 to 0.0037/GJ.km for trucks of 60m³ capacity (HGCA, 2002; Bauen, 2000).

Energy: Feedstock production and transport is estimated to require less than 3% of the total chain energy inputs. We have estimated energy input requirements for the production of wood to be between 0.01 and 0.07 GJ/GJ EtOH (0.016 - 0.030 MJ/MJ feedstock) depending primarily on yield, fertiliser inputs and harvesting technology including chipping. Indirect energy inputs, in the form of energy inputs for the production and supply of machinery and agro-chemicals used, have not been considered. The energy input to feedstock production ranges between 0.0044 and 0.065GJ per GJ of biomass feedstock (wood chips) produced (Bauen, 2000; LBST_GM, 2002). Feedstock transport energy requirements are estimated to lie between 0.005 and 0.043 GJ/GJ EtOH, approximately 1% of total chain requirements. The energy input to feedstock transport ranges between 0.0027 and 0.010GJ per GJ of feedstock (wood chips) transported.

GHG/CO₂ emissions: Feedstock production and transport activities result in direct greenhouse gas and other emissions associated with the consumption of mineral diesel in agricultural machinery and trucks. Feedstock production and transport accounts for approximately 50% (between 3 and 30 kgCO₂eq./GJ EtOH) of total chain emissions (Bauen, 2000; LBST_GM 2002). Greenhouse gas emissions from feedstock production range between 0.92 and 13.05 kgCO₂ equivalent per GJ of feedstock (wood chips) produced with a best estimate of 3.37 kgCO₂ equivalent per GJ feedstock (Bauen, 2000; LBST_GM, 2002). Transport contributes between 0.20 and 0.74 kgCO₂ equivalent per GJ of feedstock (wood chips) transported. CO₂ emissions from transport are calculated based on a 73.5kgCO₂/GJ energy consumed by road transport.

Feedstock conversion

Costs: Conversion costs are derived from Wooley (1999). Conversion costs are estimated to lie between £4.86 and £8.91/GJ EtOH produced or about 54% of total ethanol production costs. As with straw to ethanol (see above), the costs reflect a predicted reduction in enzyme costs by a factor of 10 over the next 10 years.

Energy: 1.75 GJ energy inputs are estimated to be required per GJ EtOH produced for wood shredding, enzyme production, hydrolysis, fermentation and distillation (Reith, 2001), representing over 80% of the whole chain energy requirement.

GHG/CO₂ emissions: Between 0 and 11.2 kgCO₂eq. are estimated to be emitted per GJ EtOH produced from the conversion process (LBST_GM 2002) depending on whether the residual lignin or natural gas is used to supply the conversion energy. This represents between 0 and 28% of total chain emissions.

Distribution

GHG emissions of 0.9 kg CO₂eq/GJ EtOH and costs of £0.53/GJ EtOH are the same as the other ethanol chains; see above.
Energy requirements of 0.016 GJ/GJ EtOH are the same for all the ethanol chains (see above).

Summary and conclusions

Costs:

Conversion costs remain uncertain until full scale demonstration. However, delivered ethanol costs are estimated to lie between £7.7 and £19.4/GJ (16 to 41p/l). These costs include a credit for surplus electricity sales (1.6p/l EtOH) and capital cost recovery of 13.1p/l (Wooley, 1999; 1997 values). Current costs, based on a full scale implementation of existing technologies are likely to be about £16/GJ (42p/l EtOH; Punter, 2003).

Energy: An energy ratio of between 0.19 and 2.33 is calculated ranging from a 'worst case scenario' where old, inefficient, technologies are used and co-product credits are excluded, to the use of modern efficient technologies and lignin is used as a fuel in the conversion process. The total energy requirement for the production of ethanol from wood is estimated to lie between 1.78 and 2.10 GJ/GJ EtOH produced. However, the use of the residual lignin for internal energy provision reduces the net energy requirement to between 0.21 and 1.4 GJ/GJ EtOH produced.

GHG/CO₂ emissions: GHG emission of 4 to 40 kgCO₂eq./GJ EtOH are estimated based on the data provided by Bauen (2000) and LBST_GM (2002). The range reflects the range in sources of energy inputs to feedstock production including the use of lignin to replace fossil fuel inputs in the conversion process. Further work is required to validate this scale and range of emissions under current and future practices and technologies.

Environmental and by-product issues: Electricity is likely to be the only co-product produced with surplus electricity exported to the grid after the internal requirements of the conversion facility for both electricity and heat are satisfied.

Resource potential: Ethanol productivities of between 1.35 and 4.73 t/ha are estimated resulting in a land requirement of between 0.45 and 1.58 Mha (7% and 26% of UK arable land area) in order to produce sufficient ethanol for a 10% ethanol:petrol (v/v) blend.

5.3.2. Biodiesel

Three possible 'biodiesel' production chains are evaluated:

- i) rape methyl ester (RME),
 - ii) vegetable oil methyl ester produced from waste recovered vegetable oil, and;
 - iii) biodiesel produced from SRC-derived wood which is called 'FT-biodiesel' in this report.
- FT-biodiesel differs from both RME and VME in that it is chemically identical to mineral diesel. Vegetable oil methyl esters, primarily RME, are most synonymous with 'biodiesel'. However, we apply the term 'biodiesel' to all biologically derived end-fuels which are considered as substitutes for mineral diesel. These biodiesel fuels may require few or no modifications to the diesel distribution infrastructure or engines e.g. RME and VME, or may require significant modifications to both infrastructure and engines e.g. DME, an LPG-like diesel replacement.

Rape Methyl Ester (RME)

Note: this is the only chain where sufficiently detailed and reliable data was available for 'best estimates' to be generated at the 'chain summary' level, primarily because access was granted to the detailed UK-specific work by Mortimer *et al.* (2003).

Chain summary:

Rape seed is produced and delivered an average distance of 130km (260km roundtrip) to a small-scale 2000 t/yr oil extraction plant. The oil is then transported 120km to central esterification plant fuelled by gas and/or grid electricity, from where the RME is finally distributed 170 km (340km roundtrip) by tanker truck to garage forecourt for use as neat fuel or local distribution depot for blending. Considerable variation was found in the literature on transport distances and the distances quoted above are likely to be at the high end of the scale (see for example, Mortimer, 2002; HGCA, 2002; Groves, 2002; and LBST_GM, 2002). Sufficiently detailed data on larger conversion facilities could not be found, but conversion facilities of 120 kt/yr RME (454 PJ; 136 MI) are likely to be typical of commercial operations. At current UK rape seed yields (3.1 t/ha), a 120 kt/yr RME plant would require 123.6 kha of rape or 7% of the land area in a 75km radius of the plant (16%; 50km radius).

Technology status:

All stages of this chain could use proven mature technologies and large commercial industries exist in European countries, e.g. Germany, Austria and France (based on rape and recovered vegetable oils). Continued marginal improvements are expected in rape seed yields and in reducing the energy requirement for oil extraction and esterification and therefore also the emissions.

Feedstock production and transport

Costs:

Feedstock production costs are estimated to lie between £14.5 and £34.9 / GJ RME produced for rape seed yields of between 2.2 and 4.1 t/ha (ECOTEC, 1999; Groves, 2002, Mortimer, 2002). Transport from field to oils extraction plant is expected to add another £0.61/GJ RME. Much larger oil extraction plants may incur unsustainably high seed delivery costs due to longer average transport distances but larger extraction plants can be co-located with appropriately sized esterification plants saving on the transport of vegetable oil between the extraction and esterification plants.

Energy:

Energy inputs to feedstock production are between 0.238 and 0.567 GJ/GJ RME, and transport accounts for between 53 and 67% of total energy inputs. A detailed evaluation of energy requirements for the production of RME in the UK can be found in Mortimer *et al.*, 2002.

GHG/CO₂ emissions:

GHG emissions for feedstock supply (production and transport) of between 15.0 and 29.7 kg CO₂eq/GJ RME account for 66 and 89% of total emissions but are likely to be towards the upper end of the range in practice. The best estimate is 29.7 kg CO₂eq/GJ RME or 67%. Estimates of GHG emissions are sensitive to the rate of nitrogen fertiliser application assumed, the GHG accounting methodology used, particularly the N₂O emission factor and the energy inputs (type and quantity) used in the manufacture of the fertilisers applied (LBST_GM, 2002; Mortimer, 2002).

Feedstock conversion

Costs:

An estimated conversion cost of £6.14/GJ RME includes oil extraction (crushing) + transport of raw vegetable oil 120 km + esterification and accounts for 18% to 29% of total RME production costs. There was insufficient data found in the literature to generate low and high values. The conversion cost is based on the average costs for small scale crushing systems and large scale esterification plants. Detailed costs for oil extraction could only be found for relatively small scale systems capable of processing 15 to 750 kg seed/h and producing 5 to 2000 t RME per year (Folkecentre). Costs for esterification are based on IEA/OECD (1994) which quotes a cost for esterification only (i.e. not including oil extraction) of US\$ 16/l RME (1991 US\$) equivalent to £3.30 per GJ (£0.10/l; 1991 GBP exchange equiv) for a 60 t RME per day plant.

Energy:

Estimated energy inputs for conversion (oil extraction and esterification) lie between 0.21 and 0.27 GJ/GJ RME accounting for 32 to 47% of total energy inputs. Detailed, disaggregated calculations of the energy requirements for conversion of rape seed into RME were only found in a few references. As a result, the 'Best Estimate' of 0.22 GJ/GJ RME is derived from Groves (2002) and is assumed to represent current business practice. The 'High' estimate is derived from IEA/OECD (1994) and represents the energy requirements for RME production at the start of the last decade. The 'Low' estimate is taken from Mortimer (2002) and represents the state-of-the-art in RME production technologies available now, showing the improvements that have occurred over the last decade in energy efficiency. Both heat and electricity are required in significant quantities to power the oil extraction and the esterification processes. The electricity is generally derived from the grid and the heat from natural gas. However, some references are made to natural gas CHP systems being operated and the potential to supply the heat from either rape straw or wood (LBST-GM 2002).

GHG/CO₂ emissions:

Conversion and distribution account for between 11 and 34% (1.78 and 15.18 kgCO₂eq/GJ RME, respectively) of total GHG emissions. For both conversion and distribution, the 'Low' estimate is based on ECOTEC (2001) and 'High' emissions are derived from Mortimer (2002). Very significant reductions could be made in the use of fossil fuels for energy inputs by using rape co-

products as fuels, however, so far there are no published examples of this happening to our knowledge.

Distribution

Distribution costs, energy inputs and emissions are minimal. Distribution costs represent less than 1% of total costs, just over 1.5% of energy inputs and 2% of emissions.

Summary and conclusions

Costs:

Whole chain costs for the production of RME (delivered to distribution depot or garage forecourt) are estimated to be between £20.87 and £32.82 per GJ RME (62 and 97p/l). This cost does not include potentially valuable co-product credits and excludes any set-aside land payments or agricultural subsidies.

Economics of biodiesel production are highly dependent on the feedstock cost. If produced from rape in the UK, without any subsidies, the feedstock cost (delivered seed to the mill), is estimated to represent about 80% of the final cost of delivered biodiesel. Where processed recovered oil is used, costing around £0.15 per litre (£165/t; £4.4/GJ WVO) the feedstock cost is reduced to less than 60% of final costs and an estimated final cost of RME of about £300/t (£8.0/GJ RME). See also Biodiesel from recovered waste oils below.

Co-products are potentially a highly valuable potential additional revenue stream to RME, estimated to be worth between £1.50 and £6.45 per GJ RME. The three main co-products assessed are: i) straw, ii) glycerine, and iii) rape meal are produced during the production of RME. See 'Appendix 1' for details.

Energy:

Energy balances for RME production are generally more favourable than for ethanol production and are estimated to be between 0.7 and 3.3 GJ of energy in RME per GJ of energy input. When the energy of the straw is included the energy balance improves to 1.8 to 4.4 GJ_{out}/GJ_{in}. Mortimer (2003), estimates a net energy ratio of 2.3 GJ_{out}/GJ_{in} including a detailed evaluation of co-product credits and fertiliser production energy requirements.

GHG/CO₂ emissions:

Whole chain GHG emissions are estimated to be between 16.8 and 44.9 kgCO₂eq/GJ RME. The 'best estimate' GHG emissions rate of 44.1 kgCO₂eq/GJ is similar to the Mortimer (2002) estimate of 41 kgCO₂eq/GJ. GHG emissions from RME are expected to be lower than the emissions for ethanol production primarily because of the high external energy requirements for distillation in ethanol production.

Resource potential:

Using currently available technologies, RME production rates of 0.69 to 1.65 tRME/ha can be expected. At these production rates a 10% blend RME:diesel (v/v) in the UK would require between 15 and 36% (0.93 to 2.23 Mha) of UK arable land.

Environmental and by-product issues:

Three potential co-products are produced with RME (straw, glycerine, and rape meal) and careful evaluation of the substitution/replacement values and emissions is required to account for the net impact of their use on the energy, GHG and economic balances for RME production. Other environmental impacts will also occur. For example, the use of straw to provide energy for the conversion process and / or to produce electricity for export to the grid will have impacts on soil nutrient balances, soil organic matter levels and soil moisture. However, assessments have shown that up to 50% of straw can be removed with minimal impact to the soil if the removal of nutrients is adequately compensated for.

Biodiesel from waste recovered oil

Chain summary:

Recovered waste oils from households, restaurants, fast food shops and the catering and food processing industry is collected and supplied to esterification plants with a nominal capacity of between 1 and 500 t/day. The esterified oil (VME) is then transported 175km (330km round trip) to a distribution depot for blending or garage forecourt for use as a neat fuel.

Between 60 000 and 400 000 t of waste oil is estimated to be potentially available for biodiesel production in the UK. However, these estimates remain highly uncertain as reflected by the range shown and in practice, the likely resource is probably more than the higher estimate.

Technology status:

All stages of the production and delivery chain are mature but the processing of waste oils requires a degree of technical competence to ensure that impurities in the oil are adequately treated and the final fuel meets current fuel specifications.

Feedstock production and transport

Feedstock costs (delivered) are estimated to be £4.43 per GJ based on the current commercial value of waste oil of £165/t (de Winne, 2002), and accounts for about 50% of final production costs.

Energy inputs into feedstock transport are included and are assumed to be equivalent to the distribution energy inputs as the waste recovered oils will need to be transported from collection points to the esterification units. However, these inputs are highly uncertain as no specific data or estimates could be found in the literature.

Feedstock conversion

Filtering, purification and de-watering followed by esterification of the oil can take place in small simple units or larger, partially automated units ranging in scale from less than 1t to over 500 t per day. See chapter 4 for a more detailed description of the conversion process.

Costs:

Conversion costs of £2.99/GJ VME are estimated based on energy, catalyst and methanol inputs and comprises about 40% of final costs. Capital costs are minimal.

Energy:

De-watering and esterification require thermal inputs which can be supplied using electricity or gas (Natural Gas, butane or propane). Thermal de-watering requires the temperature of the oil to be raised to 100°C and esterification benefits from temperatures of 50°C or higher. The esterification reagent (methanol or ethanol) is also a significant energy input. Both methanol and ethanol are currently produced by the reformulation of natural gas but could be produced from biomass (see other chains evaluated here).

GHG/CO₂ emissions:

These emissions arise as a result of the energy inputs into supply, conversion and distribution. Emissions from the conversion stage arise from the thermal inputs and the energy requirements for the production of the reagent e.g. methanol or ethanol. Methanol is currently the dominant reagent in use.

Distribution

Distribution costs, emissions and energy requirements are assumed to be the same as the other biodiesel chains (see above and analysis sheet).

Summary and conclusions

Costs:

Whole chain costs of £7.8/GJ VME if glycerine has no value to £6.7/GJ VME if full 2002 market value is obtained for glycerine. Glycerine (£388/t) sales could result in an income of £1.09 per GJ VME produced but the market value is currently falling as global production is rising but demand is static. Estimating future costs for waste oil is problematic and is likely to be highly sensitive to the scale of future biodiesel production based on waste oil because of the limited nature of the resource. Rapid and extreme fluctuations have occurred in the value of pure vegetable oils on the world market as a result of German legislation encouraging the production of VME and similar perturbations to prices might be expected in the waste oil markets if significant stimulus is given to VME production in the UK. However, the use of glycerine as an energy input to the conversion process and perhaps for CHP production would have a number of financial and environmental benefits.

Energy:

Compared to the other biodiesel chains, energy inputs are significantly lower primarily because there are no feedstock production or oil extraction energy requirements. This is reflected in the high energy ratio of between 7 and 8 GJout:GJin and primarily reflects the energy requirements for the production and use of methanol or ethanol as the esterification agent and the energy inputs required for dehydration and distribution.

GHG/CO2 emissions:

Whole chain GHG emissions of 1.9 to 16.1 kg CO₂eq./GJ VME produced are estimated and primarily depend on the emissions from the conversion process and distribution (see analysis sheet, appendix 1, for details).

Resource potential:

The 'High' estimate for potentially recoverable oil in the UK of 400 000 t, is derived from an evaluation of regional EU and national production and consumption rates and on Austrian data which suggests that 18.5% of total production is economically recoverable (Commission of the European Communities, 2001). An EU ban on the incorporation of WVO into animal feed is expected to come into force in 2005 in order to reduce theoretical prion (BSE) pathways in the human food chain and this will result in decreased competition for WVO and therefore increased availability for VME production if no other competition emerges for its disposal and use.

Environmental and co-product issues:

The only co-product produced is glycerine, which is produced at a rate of 100 to 200kg per tonne of waste oil processed. However, the exact amount depends on the quality of the waste oil and its content of animal fats and other impurities. Real environmental benefits are likely to result from the exploitation of WVO for biodiesel production where it results in its safe disposal and a reduction in GHG emissions from diesel use.

FT biodiesel from short rotation coppice

The term 'BtL' (biomass to liquids) is becoming synonymous with this biodiesel production chain.

Chain summary:

Short rotation coppice (SRC) willow grown by UK farmers is harvested and chipped and delivered to an indirectly heated 367 MW_{th} atmospheric gasifier. The resulting syngas is then reformed prior to being fed into the FT reactor producing FT liquid fuels. Electricity generated using off-gases. The FT liquids are assumed to be comprised of 60% diesel, 25% kerosene, 15% naphtha (energy basis) and therefore annual production of 68 kt FT-biodiesel, 31 kt kerosene and 18 kt naphtha (27, 38 and 88 MJ respectively) could be expected from this type of plant. In order to supply the gasifier, 70,000ha or 700km² of SRC plantation would be needed occupying 1% of land within a 150km radius (4% of land in a 75km radius).

Technology status:

Feedstock production is in the early commercial stage. Biomass gasification technology is at the demonstration to early commercial stage. FT process technology is mature (proven since 1950s using fossil fuel derived feedstock). However, the integration of biomass gasification with the FT process is only at demonstration stage.

In Europe, a pilot plant is presently under construction, aiming to produce 500 to 1000 t BtL fuel per year before the end of 2003. The creation of this pilot plant is supported by the German government, Choren Industries, DaimlerChrysler and Volkswagen (Choren Industries, 2003).

Feedstock production and transport

Feedstock costs (delivered) are estimated to be between £3.31 and £7.94/GJ FT liquid produced with a best estimate of £5.29/GJ FT liquid, accounting for 37 to 53% of final production costs. Feedstock production and supply account for between 93 and 98% of whole chain energy inputs and 55 and 98% of GHG emissions.

See 'Lignocellulosic ethanol from SRC' above for details of costs, energy inputs and emissions from SRC production and delivery in the UK.

Feedstock conversion

The 367MW_{th} feedstock input gasifier evaluated here was chosen based on considerations of economies of scale and feedstock supply. The specific biomass-derived FT biodiesel fuel chain is based on the Battelle Columbus Laboratory (BCL) indirectly heated gasifier under demonstration in Burlington, Vermont (Paisley *et al.*, 1997; Kaltschmitt, 1997). FT liquid production is 154MW_{FTliq}. In FT diesel mode, the following FT liquid production split is assumed: 60% FT diesel, 25% kerosene and 15% naphtha (energy basis). FT diesel is produced at the rate of 92MW, equivalent to about 8t/h. The conversion plant also produces about 21MW electricity. The overall conversion efficiency is 48% (LHV), 42% net of electricity production. On-site FT biodiesel storage costs are not considered.

Costs:

Conversion costs of £7.77/GJ FT liquid are estimated accounting for between 52% and 88% of final costs. The capital costs of the gasifier, gas cleaning equipment and the FT reactor are estimated at \$395 million (£250 million).

Energy:

The energy required to heat the gasifier is derived from the feedstock biomass and so no external energy inputs are required. In fact, the plant may produce surplus electricity.

GHG/CO₂ emissions:

As virtually no external energy requirements are envisaged during conversion, GHG emissions are virtually zero.

Distribution

Distribution accounts for between 2 and 7% of energy inputs, less than 1% of whole chain costs and between 0.3 and 4% of GHG emissions.

Summary and conclusions

Costs:

Full fuel chain costs, excluding electricity credits, of between £8.85 to £15.01/GJ FT liquid produced are estimated. Surplus electricity sales could result in an income of between £0.77 and £2.31 per GJ FT liquid produced.

Energy:

Energy balances for the production of FT biodiesel are extremely favourable. Energy ratios of 18 to 62 are estimated.

GHG/CO₂ emissions:

Full fuel chain GHG emissions of 2.4 to 28.9 kg CO₂eq./GJ FT liquid produced are estimated and primarily depend on the feedstock production emissions.

Resource potential:

Assuming 10dt wood (18GJ) produces 93.9kg FT liquids (4.32 GJ), 0.94 t FT liquids are produced per ha (10odt wood/ha). A 10% diesel: FT diesel (60% of total FT liquids produced on an energy content basis) would require 2.73 Mha (45% arable land).

Environmental and by-product issues:

Three potential co-products are produced with FT-biodiesel i.e.: i) electricity (0.14 GJ electricity / GJ FT liquid), ii) FT-naptha, and; iii) FT-kerosene at the rates shown above. The production of SRC is less intensive in agricultural inputs and management than annual energy crops, but a variety of issues ranging from water consumption to amenity need consideration.

5.3.3. Methanol (from SRC wood)

Chain summary:

Short rotation coppice (SRC) willow grown by UK farmers is harvested and chipped and delivered to an indirectly heated 400 MW_{th} atmospheric gasifier (BCL). Methanol is produced at the rate of 320 kt (7.1PJ; 405 MI) of methanol per year. The overall conversion efficiency (wood to methanol) is 56% (LHV) net of the electricity used in the process.

In order to supply the gasifier, 70,000ha or 700km² of SRC plantation would be needed occupying 1% of land within a 150km radius (4% of land in a 75km radius).

Technology status:

Feedstock production is in the early commercial stage. Biomass gasification technology is at the demonstration to early commercial stage. However, the integration of biomass gasification with the MeOH production process is only at the R&D stage and scale-up and environmental issues may prove difficult to overcome.

Feedstock production and transport

Feedstock costs (delivered) are estimated to be between £2.48 and £5.95/GJ MeOH produced with a best estimate of £3.97/GJ, accounting for 41 to 62% of final MeOH supply costs.

Feedstock production and supply accounts for between 83 and 99% of whole chain energy inputs and 50 and 56% of whole chain GHG emissions.

See 'Lignocellulosic ethanol from SRC' above for details of costs, energy inputs and emissions from SRC production and delivery in the UK.

Feedstock conversion

The 400MW_{th} feedstock input gasifier evaluated here was chosen based on considerations of economies of scale and feedstock supply. The methanol production rate is 224MW_{MeOH} or 40t methanol per hour. The overall conversion efficiency is 56% (LHV), and no surplus electricity production is expected to occur although internal electrical consumption will be met by on-site generation. Calculations based on BCL indirectly heated gasifier under demonstration in the USA (Burlington, Vermont).

Costs:

Conversion costs of £3.40/GJ methanol are estimated, accounting for 36 to 56% of the of the final methanol supply costs. Cost estimates are based on BCL indirectly heated gasifier under demonstration in Burlington, Vermont. Feedstock pre-treatment, gasifier and gas cleaning investment costs are estimated at 106.7 M\$. Steam reforming and liquid methanol production and refining investment costs are estimated at 104.1 M\$. The plant requires an electrical power input of 25MW and investment in power generation is estimated to contribute about 15 M\$.

Energy:

Although the BCL gasifier is indirectly heated, the energy required is derived from the feedstock biomass and so no external energy inputs are required and electricity inputs are produced from the 'off gas' supply from the gasifier.

GHG/CO2 emissions:

As virtually no external energy requirements are envisaged during conversion, GHG emissions are virtually zero.

Distribution

Distribution accounts for between 2 and 17% of energy inputs, less than 2% of whole chain costs and between 0.8 and 9% of GHG emissions.

Summary and conclusions

Costs:

Whole chain costs of £6.05 to £9.52/GJ MeOH produced are estimated. No co-products are expected to be produced.

Energy:

Energy balances for the production of bio-methanol are very favourable. Energy ratios of 7 to 66 are estimated.

GHG/CO2 emissions:

Whole chain GHG emissions of 2.2 to 24.9 kg CO₂eq./GJ MeOH produced are estimated and primarily depend on the feedstock production emissions.

Resource potential:

Assuming 10dt wood (18GJ) produces 497kg MeOH (10.1 GJ; 20.3 GJ/t_{MeOH}), 4.97 t MeOH is produced per ha (100dt wood/ha). A 10% MeOH:petrol (v/v) blend would therefore require 0.43 Mha or 7% of UK arable land. A 5 to 15% blend of the methanol derivative MTBE can be added to petrol in the UK and Europe as an oxygenate under current UK and EU regulations. However,

the manufacture of biologically derived MTBE from wood-based methanol would require additional energy inputs and production costs and the toxicity of methanol and MTBE may make significant levels of production and blending unlikely in European countries.

Environmental and by-product issues:

No co-products are expected to be produced with the methanol. Methanol is however a toxic compound and serious health and environmental issues would need to be considered before large scale blending could be considered. The production of SRC is less intensive in agricultural inputs and management than annual energy crops but amenity issues are reported and water use needs to be assessed.

5.4. Hydrogen fuel chains

5.4.1. Hydrogen from Biomass

General description

The biomass-derived hydrogen fuel chain selected for more detailed analysis consists of large-scale short rotation coppice (SRC) willow wood chip gasification followed by product gas reforming and upgrading. The wood chips are transported by truck an average distance of 50km to a large-scale hydrogen production plant (400 MW_{th} input) capable of a production of 7.7 tonnes hydrogen per hour (256MW_{th}). The hydrogen could then be transported as a compressed gas by tube trailer or pipeline, or as a liquid by road tanker.

Technology status:

The individual technologies considered in this fuel chain range from early demonstration to early commercial stage. SRC feedstock production is at the early commercial stage. Large-scale wood chip gasification is at the demonstration stage, while product gas reforming remains to be demonstrated. However, hydrogen production systems based on biomass gasification are currently at the pilot stage. There is scope for technical and cost improvements along the entire fuel chain.

Biomass feedstock production

Feedstock costs (delivered) are estimated to be between £2.67 and £6.41/GJ hydrogen produced, accounting for 28 to 47% of final hydrogen supply costs. Feedstock production and supply also account for between 23 and 77% of fuel chain energy inputs and 42 and 90% of fuel chain GHG emissions. See 'Lignocellulosic ethanol from SRC' above for details of costs, energy inputs and emissions associated with SRC production and delivery in the UK.

In order to supply the gasifier, 70,000ha or 700km² of SRC plantation would be needed occupying 1% of land within a 150km radius (4% of land in a 75km radius). Supply of biomass to such a plant could prove to be a serious issue if biomass were to be transported by road. Other biomass transport means (rail, barge or boat) may need to be considered, as well as a careful consideration of the location of such a plant.

Conversion (gasification and product gas reforming and upgrading)

The specific biomass-derived hydrogen fuel chain is based on the BCL indirectly heated gasifier under demonstration in Burlington, Vermont (Paisley *et al.*, 1997; Kaltschmitt, 1997). The

conversion plant also includes gas cleaning, steam reforming, CO shift reaction, pressure swing absorption and hydrogen compression and/or liquefaction equipment. A detailed description of biomass-to-hydrogen chains is also provided in Hamelinck et al. (2001). The biomass-to-hydrogen conversion efficiency of the hydrogen production plant is estimated at 66% (LHV). But, the plant requires an electrical power input of 22MW, reducing the overall efficiency of the hydrogen conversion process to about 52%, assuming the electricity is generated on-site. The actual hydrogen output from the plant would then be 6.2t/h (206MW_{th}).

Costs

The feedstock pre-treatment, gasifier and gas cleaning equipment investment cost is estimated at £65 million (\$103.8 million). The steam reforming, CO shift reaction and pressure swing absorption equipment investment cost is estimated at £84 million (\$134 million). The investment in power generation equipment is estimated to contribute an additional £9.4 million (\$15 million) to the overall capital costs. The contribution of gasification, reforming and upgrading equipment and O&M costs (excluding electricity) to the production cost of hydrogen is estimated at £3.53/GJ hydrogen. Based on the overall efficiency of the plant, the contribution of the biomass feedstock is between £2.67 and £6.41/GJ hydrogen supplied. The total hydrogen production cost prior to compression/liquefaction, on-site storage and delivery ranges then between £6.20 and £9.94/GJ hydrogen.

Compressing the hydrogen to 200bar requires 17MW of compressor power for the plant considered, based on an electricity requirement for compression estimated at 0.20 kWh/Nm³ (2.2kWh/kg) for a hydrogen output pressure from the PSA of 10bar. On-site hydrogen storage is set at 10t, and no losses are assumed from storage. Compressor capital costs at the scale considered are estimated at £30/kW(H₂) and storage capital costs at £335/kg (storage capacity). Investment in equipment for compressing and storing the hydrogen at a pressure of 200bar contributes an additional £0.99 to £1.00/GJ to the cost of hydrogen, including the additional cost of the electricity required for compression.

Liquefying hydrogen requires a 62MW power input for the plant considered, based on an electricity requirement for liquefaction, estimated at about 0.73kWh/Nm³ (8.0kWh/kg). On-site hydrogen storage is set at 10t, and no storage losses are considered. Liquefaction equipment capital cost at the scale considered is estimated at £295/kW(H₂). On-site hydrogen storage equipment capital cost is estimated at £57/kg. Liquefying and storing the hydrogen would contribute an additional £4.23 to £4.45/GJ to the cost of hydrogen, including the additional cost of the electricity required for liquefaction.

Energy

It is assumed that no significant direct external energy inputs are required by the conversion stage. Direct energy requirements for the operation of the plant consist mainly of electricity, which is assumed to be produced on-site directly from the product gases or hydrogen used in turbines or fuel cells.

Emissions

On-site electricity production would result in low or virtually zero emissions.

Hydrogen distribution

Hydrogen could be transported as compressed gas by tube trailer or pipeline, or as a liquid by road tanker.

Costs

Compressed (200bar) hydrogen transport by tube trailer over a distance of 64km (return) is estimated to contribute between £3.30 and £3.50/GJ hydrogen. Liquid hydrogen transport by road tanker over a distance of 64km (return) is estimated to contribute between £1.30 and £1.40/GJ hydrogen. Compressed (10-30bar) hydrogen transport by pipeline over a distance of 75km is estimated to contribute between £0.73 and £0.90/GJ hydrogen.

Energy

The distribution of compressed hydrogen by tube trailer or liquid hydrogen by road tanker (64km return distance) would require an estimated energy input of 0.042GJ/GJ hydrogen and 0.0016GJ/GJ hydrogen, respectively. However, it must be noted that in the future the vehicles could be fuelled by renewable hydrogen instead of mineral diesel. In the case of pipeline transport, it is assumed that there are no significant direct energy inputs associated with its distribution.

Emissions

In the case of mineral diesel use, compressed and liquid hydrogen transport would result in 3.1 and 0.083 kgCO₂eq./GJ hydrogen, respectively. Pipeline transport is assumed not to result in any direct emissions.

Summary and conclusions

Hydrogen production from biomass gasification is currently not a proven technology. Future commercial installations could lead to attractive costs for hydrogen production from renewables. The overall cost of delivered hydrogen will vary considerably depending on its mode of distribution. Costs for compressed (200bar) hydrogen delivered by tube trailer (64km return) are estimated to range between £10.5 and £14.4/GJ of hydrogen delivered. Costs for liquid hydrogen delivered by tanker (64km return) are estimated to range between £11.7 and £15.8/GJ of hydrogen delivered. Liquid hydrogen transport becomes more economically viable than compressed hydrogen transport for distances greater than about 100km return. Costs for hydrogen delivered by pipeline are estimated to range between £6.9 and £10.8/GJ of hydrogen delivered.

The 400 MWth gasifier requires 80t (1 440 GJ) of wood per hour. 1t wood results in the production of 96kg hydrogen. An indicative potential of hydrogen from SRC for the UK, based on 2 million ha of SRC with average yield of 10t oven dry/ha/yr, is 187PJ of H₂, equivalent to about 1.6 million t. As a comparison, total petrol and diesel consumption for road transport in the UK in 2001 was 37.35 Mtoe, equivalent to about 1,564PJ. However, a more efficient conversion of H₂ in fuel cell vehicles compared to diesel and petrol use in internal combustion engines could lead to a reduction in energy requirements of transport.

5.4.2. Hydrogen from wind

Hydrogen can be produced via electrolysis, and so can be produced from any electricity producing fuel chain. The non-biomass renewable chains include wave, hydro, geothermal and wind, but wind, offshore in particular, is likely to have the largest short to medium term commercial potential. Therefore, offshore wind is used to develop four 'cases' for the production of hydrogen, as illustrated below.

General description of the chains

The different components of the fuel chains for hydrogen production via electrolysis are commercially available. Also, there is a relatively large range of options available at each stage of the production and distribution chain. Four possible hydrogen production chains are evaluated here based on electricity produced from offshore wind power. The chains differ in the nature and/or location of the hydrogen production, distribution and storage technologies.

Description of each chain:

- Case 1: Offshore wind electricity generation; transmission to regional electrolysis plant of about 500MWe capacity; compressed hydrogen is transported 50km to a refuelling station.
- Case 2: Same as 'case 1' except liquid hydrogen is transported 50km to a refuelling station.
- Case 3: Same as 'Case 1' except hydrogen is transported 50km by pipeline to refuelling station.
- Case 4: Offshore wind electricity generation; electricity is transmitted to a refuelling station forecourt with a 1.25MWe electrolysis plant and forecourt compressed hydrogen storage.

Current offshore wind electricity costs are estimated to be 5-5.5 p/kWh (based on an installed wind turbine capital cost of about £1000/kW) and these are estimated to decline with time to about 2-3 p/kWh (based on an installed wind turbine capital cost of about £400/kW). No external direct energy inputs are assumed for the operation of the offshore wind installations, apart from some energy used for periodic maintenance purposes. The indirect energy inputs to the system, associated with the production of the materials and equipment used for the installation and with the building of the installation, are estimated to be small compared to the wind electricity output over the lifetime of the installation. Some emissions will be associated with the production of the materials and equipment used for the installation and with the building of the installation. However, the indirect emissions are also likely to be small over the lifetime of the installation. Similarly, wind electricity generation does not result in any direct emissions of polluting agents, apart from emissions from occasional maintenance procedures (CEC ExternE). The electricity requirement of electrolysis plants is estimated to range between 3.8 and 4.5kWh/Nm³ (42 – 50kWh/kg), corresponding to a 67% to 79% efficiency in relation to hydrogen production. The power requirement of a 10t/h electrolyser is then between 423 and 498MW at full load and that of a 25kg/h electrolyser is between 1 and 1.25MW. The current capital cost of large and small scale electrolysers of the capacities considered are estimated to be £375/kW(H₂) (£1125/Nm³/h) and £600/kW(H₂) (£1740/Nm³/h), respectively, and costs are estimated to decline in the future to about £150/kW(H₂) (£450/Nm³/h) and £300/kW(H₂) (£900/Nm³/h). Compressing the hydrogen to 200bar requires between 0.11kWh/Nm³ (1.2kWh/kg) for an electrolyser hydrogen output pressure of 30bar and 0.20 kWh/Nm³ (2.2kWh/kg) for an electrolyser hydrogen output pressure of 10bar. Following compression, the overall efficiency of the electrolysis plant is between 64% and 75%. On-site hydrogen storage is set at 10t for the regional plants and at 0.3t for the on-site electrolysis plant, and no losses are assumed from storage. Compressor capital cost is estimated at £30/kW(H₂) for large scale plants and at £100/kW(H₂) for small on-site plants. Storage capital cost is estimated at £335/kg (storage capacity) for large scale plants and at £810/kg (storage capacity) for small scale plants. Liquefying hydrogen requires a 80MW power input for the large scale regional electrolysis plant considered, based on an electricity requirement for liquefaction estimated at about 0.73kWh/Nm³ (8.0kWh/kg). Following liquefaction, the overall efficiency of the electrolysis plant is between 57% and 71%. Liquefaction equipment capital cost at the scale considered is estimated at £295/kW(H₂). On-site hydrogen storage equipment capital cost is estimated at £57/kg. The only significant energy input to the operation of the electrolysis plant consists of wind electricity, hence it is assumed that no direct non-renewable energy input or emissions of pollutants result from the electrolysis plant.

Summary

A detailed breakdown of the costs, energy inputs and GHG emissions for the offshore wind to hydrogen fuel chains are provided in the Annex.

Costs

The overall range of predicted costs for the 4 cases range from a low of £8.7 to a high of £30.6 per GJ of hydrogen delivered as shown in Table 5.3. The bulk of the hydrogen production cost

consists of electricity costs, which range between 74% and 90% of the hydrogen cost for the different options considered. The wide range in hydrogen production costs is then essentially due to the range in offshore electricity costs used (2-5.5p/kWh).

Table 5.3: Offshore wind hydrogen production costs (£/GJ delivered hydrogen)

Hydrogen production Case	Low	High
1	11.4	29.1
2	10.7	30.6
3	8.7	26.4
4	9.7	28.2

Energy

Direct external energy inputs to hydrogen production are virtually zero resulting in large energy ratios.

Emissions

Because external energy inputs are virtually zero, emissions are also virtually zero. Measurable emissions are only likely to result from cases 1 and 2 which have road based transport. The highest level of emissions is estimated to be 3.1 kgCO₂eq/GJ hydrogen delivered.

5.5. Reference fuel chains: petrol and diesel

General description

Full LCA assessments for the supply of petrol and diesel on a 'Well-to-Wheel' basis have been used to provide data on costs, GHG emissions and energy balances for comparison with the RTF chains evaluated above.

Technology status

The technologies considered are the current state-of-the art for the supply of petrol and diesel in Europe and the UK.

Costs

Delivered costs for both diesel and petrol have been highly volatile over the last five years and the current tense political situation in the Middle East is pushing the price of oil towards historic highs of over US\$ 40 per barrel (c. £4.6/GJ). According to Watson (2002), between 1998 and 2002, wholesale prices of petrol have varied between £1.85 to 4.2 per GJ and diesel £1.6 to 3.8 per GJ. A generic 'wholesale price' of £2.95 per GJ for petrol and £2.92 for diesel has been assumed based on US\$20 per barrel of oil (Barbour, 2003). UK 'pump prices,' including tax (duty and VAT) and margins, of £21.4 per GJ petrol and £22.0 per GJ diesel are taken from the Department for Transport (DfT, 2002). The high rates of duty and VAT paid in the UK and the resulting difference between the wholesale and pump prices is highlighted in figure 10 below which also shows the potential incentives to RTFs that could be provided by selective reductions in duty.

Energy balances

Detailed wheel-to-well energy balances for petrol and diesel were obtained from LBST (2002). LBST (2002) report energy inputs for crude oil production, transport, refining and distribution of:

- 0.160 MJ/MJ petrol
- 0.119 MJ/MJ diesel

Resulting in energy ratios of:

- 0.86 for petrol ($\text{energy}_{\text{out}}:\text{energy}_{\text{in}}$)
- 0.89 for diesel

GHG emissions

GHG emissions from the supply and use of petrol and diesel were also derived from LBST (2002; lower heating value basis). Diesel-only emissions derived specifically for the UK are from Mortimer *et al.* (2002). LBST's 'best estimate' of GHG emissions resulting from the production and supply of petrol and diesel were:

- 13.2 g CO₂ equivalent per MJ petrol (LBST_GM, 2002).
- 10.4 g CO₂ equivalent per MJ diesel (LBST_GM, 2002).

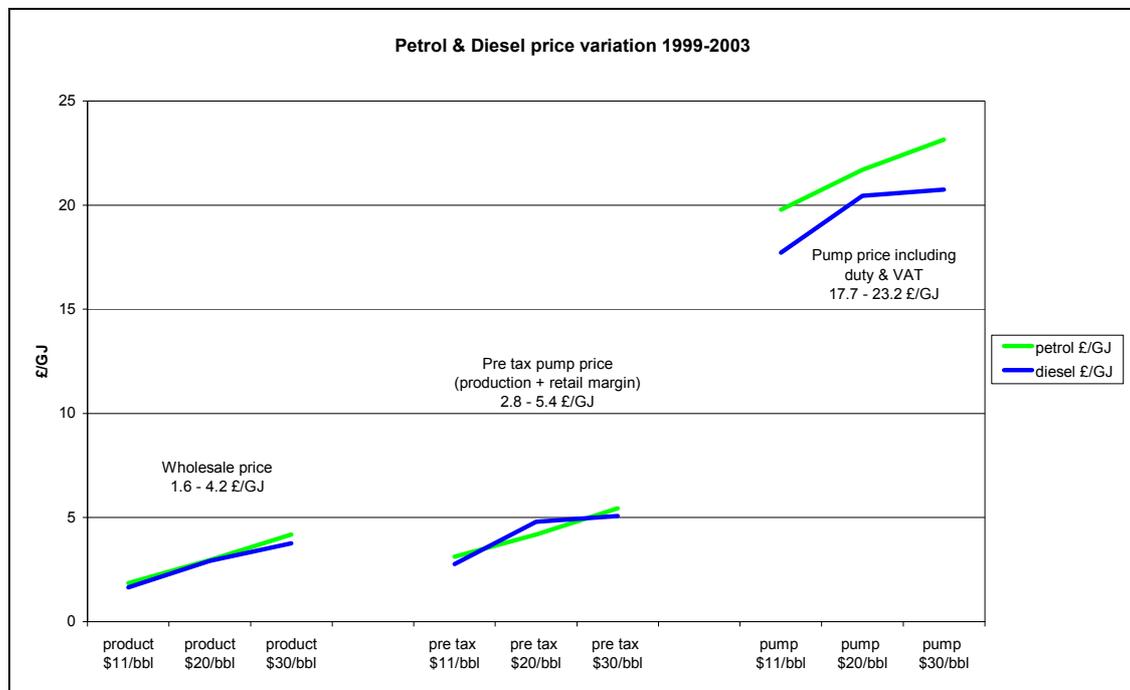


Figure 10: Relationship between wholesale, pre-tax and pump prices of petrol and diesel in the UK (Barbour, 2003).

However, unlike the carbon-based RTFs, where it is assumed that the carbon content of the fuels is derived from carbon already fixed from atmospheric CO₂, the carbon content of the fossil-derived fuels results in a net gain to the atmosphere on combustion. Therefore, total GHG emissions must also include this carbon by assuming that all of the carbon contained is released as CO₂ when used. Therefore total GHG emissions are calculated as follows.

CO₂ released on combustion:

- 73.4 kg CO₂ per GJ petrol (LBST_GM, 2002).
- 72.8 kg CO₂ per GJ diesel (LBST_GM, 2002).

Total GHG emissions are therefore:

- 86.6 kg CO₂ per GJ petrol
- 83.2 kg CO₂ per GJ diesel

Total GHG emissions for diesel according to Mortimer *et al.* (2002) are:

- 91 kg CO₂ per GJ for Low Sulphur Diesel
- 95 kg CO₂ per GJ for Ultra Low Sulphur Diesel.

5.6. Carbon abatement potential of renewable transport fuel chains.

Greenhouse gases are emitted during the extraction, production, conversion and distribution phases of the production of both conventional (fossil) and renewable transport fuels. GHG emissions can be estimated per vehicle km driven or per unit energy content of the fuel used. Estimating emissions per vehicle km requires assumptions to be made about vehicle type and fuel use efficiency. However, estimating emissions per unit fuel energy content will not capture the different efficiencies of the range of engine technologies in use or inherent differences in conversion efficiencies between fuel types e.g. petrol versus diesel. For simplicity and transparency, we have chosen to estimate GHG emissions per unit fuel energy content (kg CO₂eq/MJ end fuel). Care must be taken in extrapolating this data to the entire transport sector.

5.6.1. GHG emissions from renewable transport fuels

High and low estimates of GHG emissions has been provided for each of the thirteen RTF chains assessed in detail and are shown in Table 5.4 below. As with energy inputs, there is a large range between the high and low values for a number of the fuel chains, reflecting the number of technologies available for each stage of the production chain and the potential to produce co-products.

As in the rest of the report, co-products are not included except where their use is integral to the conversion. For example, a state-of-the-art sugar beet to ethanol plant constructed now and without CHP would have gross GHG emissions roughly equivalent to conventional petrol supply. However, the use of the pulp as a high value animal feed substituting for imported animal feed products would significantly reduce net GHG emissions and the direct use of pulp to supply the conversion energy would reduce net GHG emissions to between 50% and 30% of conventional petrol. Pulp-fired CHP systems would reduce the emissions still further.

Table 5.4.: GHG emissions from renewable transport fuels

RTF Chain	kg CO ₂ equivalent per GJ fuel		
	Low	High	% reduction from reference ^a
Ethanol from Sugar Beet ^b	26	92	0 to 70%
Ethanol from Wheat (grain)	56	77	18 to 36%
Ethanol from Straw (Wheat)	23	72	46 to 74%
Ethanol from Wood (SRC)	4	39	55 to 95%
Rape Methyl Ester (RME)	17	45	53 to 82%
Waste Vegetable Oil Methyl Ester (VME)	2	16	83 to 98%
Fischer-Tropsch Biodiesel from Wood ^b	2	29	69 to 98%
Hydrogen from Wood ^b	5	30	66 to 94%
Hydrogen from Off-shore Wind- 1	3.1	3.1	96%
Hydrogen from Off-shore Wind- 2	0.1	0.1	≈ 100%

Hydrogen from Off-shore Wind- 3	0	0	≈ 100%
Hydrogen from Off-shore Wind- 4	0	0	≈ 100%
Methanol from Wood (SRC) ^b	2	25	77 to 98%
Reference Values			
Diesel (ULSD; Mortimer, 2002)		95	
Petrol (derived from LBST_GM, 2002)		87	
Electricity from SRC (Mortimer, 2002)		36	

Notes:

a- emissions resulting from the CO₂ emissions arising during the combustion of the RTFs would be 71.3 kgCO₂/kg EtOH and 76.7 kgCO₂/GJ VME (assuming all carbon in fuel ends up as carbon dioxide in the atmosphere). No direct CO₂ emissions would result from the use of hydrogen. It is assumed that ethanol and hydrogen replace petrol and RME, VME and FT Biodiesel replace mineral diesel.

b- Low value includes the use of co-products as energy in the conversion process.

6. Conclusions

The potential for renewable transport fuels production is large. However, other energy end-uses, i.e. electricity and heat, are also likely to be competing for the same renewable energy resources. Trade-offs in terms of economics and the environment between these competing end uses will need to be carefully addressed. Indicatively, renewable transport fuels could substitute about 40% of road transport fuel in the UK based on the estimated practicable renewable energy potential of 2.1EJ and an average estimated conversion efficiency of 50% as highlighted in table E1.

All the RTF chains show a positive energy balance, except under the worst-case assumptions and even then only for a few of the chains evaluated. Energy balances between 0.2 (strongly negative) and 66 (strongly positive) have been calculated for the biomass-based RTF chains, and greater than 28 for the four hydrogen from wind chains. Biodiesel and ethanol routes are generally energy intensive and significantly favourable energy balances are only achieved when renewable fuels, mainly residues from the biomass resource, are used to produce energy for the process, and when energy and emissions are allocated to co-products.

All of the RTF chains evaluated show net reductions in fuel chain GHG emissions compared to petrol or diesel (per GJ fuel), except ethanol produced from sugar beet and then only under the worst set of assumptions. Generally, all renewable transport fuel chains considered would result in substantial emissions reductions compared to conventional fossil fuels. GHG emissions range from virtually zero for two of the offshore wind hydrogen scenarios (pipeline transport and on-site electrolysis, where energy input for the road transport distribution of the hydrogen fuel is eliminated) to 106 kg CO₂ (equivalent) per GJ of ethanol for ethanol from sugar beet, in its worst-case scenario.

Conventional bioethanol and biodiesel routes could provide significant GHG benefits per unit of fossil fuel substituted. However the relatively low efficiency of these chains and the limited number of feedstocks on which they can rely, constrains their role in providing a potentially substantial source of RTF in the UK. Therefore, a substantial contribution of RTFs to road transport fuels will need to rely on a variety of biomass resources (residues and dedicated energy crops) and non-biomass energy sources. Advanced ethanol and biodiesel conversion technologies are needed to expand the scope for RTF production from biomass, with potential for improved efficiency and GHG benefits. However, hydrogen appears to provide a convergence point for RTF production being able to exploit the entire range of renewable resources efficiently and with potentially very low emissions.

In the UK in 2001, 162Mt CO₂ equivalent were emitted by road transport on a well-to-wheel basis. Assuming biomass and waste resources were to be used to produce RTFs such as Fischer-Tropsch biodiesel, methanol and hydrogen via a gasification route, an indicative average GHG saving of about 76kg CO₂ equivalent per GJ of fuel compared to petrol and diesel would be achieved. The total abatement from a 20% substitution of petrol and diesel by these biomass-based RTFs could be about 38Mt CO₂ equivalent. Assuming the direct renewable electricity sources were used to produce hydrogen via the electrolysis route, an indicative average GHG saving compared to petrol and diesel of about 90kg CO₂ equivalent per GJ of fuel could be achieved. The total abatement from a 20% substitution of petrol and diesel by hydrogen from renewable electricity could be about 45Mt CO₂ equivalent.

None of the RTF chains evaluated could produce fuels at costs lower than the current (2002) cost of conventional fuels when subsidies/taxes and co-product values are excluded, although a number of chains are close to being competitive. The consideration of co-products from RTF production and external benefits (e.g. environmental benefits) would generally enhance the competitiveness of RTFs compared to petrol and diesel. It is estimated that all the chains,

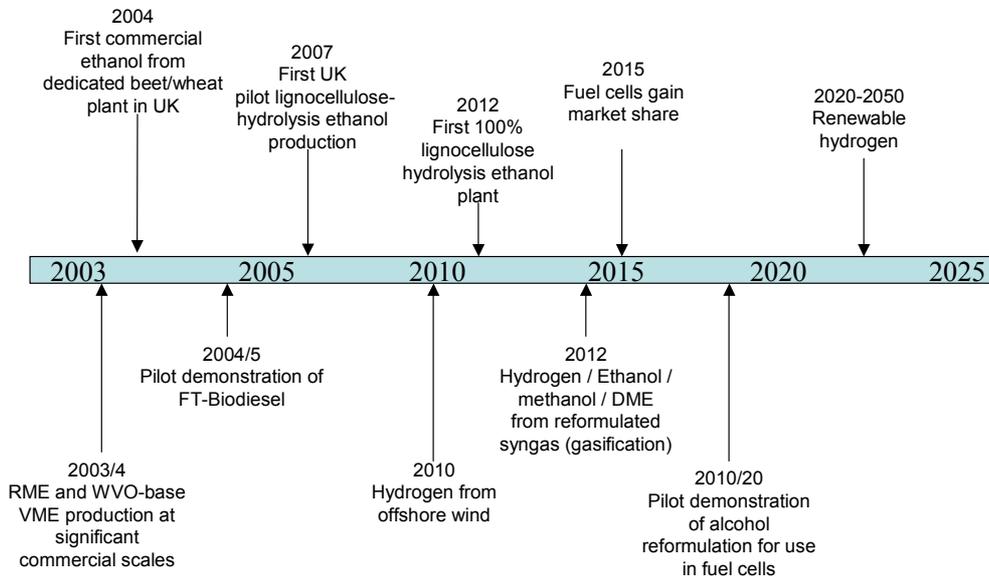
assuming the technologies achieve commercial status, could produce fuels at lower costs (excluding tax) than the current price of conventional fuels (including tax).

Under UK conditions, the conventional bioethanol and biodiesel production options based on energy crops are technologically proven but relatively costly and significant cost reductions may be difficult to achieve. The cheapest RTF options are likely to be those produced using waste (e.g. waste vegetable oil, organic fractions of MSW) and residue (e.g. forest and agricultural residues) streams as feedstock. However, such resources will generally be limited in terms of the quantities of waste or residues available. Wood-based (short rotation coppice, in the case of this analysis) ethanol, methanol, biodiesel and hydrogen production offer good prospects for relatively low cost RTF production. Electrolysis-based hydrogen production could also result in relatively low cost RTF production if low cost sources of renewable electricity can be obtained (at or below 2p/kWh).

Emerging RTF technologies hold the promise of sharply reducing costs, energy inputs and GHG emissions but remain to be proven on a commercial scale. An illustration of a possible timeline for the emergence of RTF technologies is provided in figure 11. The actual rate of development will be largely dependent on government incentives and public support, both in the UK and abroad, that will be directed to the sector. R&D activities are occurring on most of the technologies discussed in Europe and the USA, with very little activity in the UK at the moment.

Minimising the costs, energy inputs and GHG emissions from all RTF chains requires careful technological choices and adequate fuel chain management. In the case of biomass-based RTF chains the development of suitable feedstocks, including energy crops, and suitable supply logistics will prove critical to their success, and much experience is yet to be acquired.

Fig 11: Indicative timeline for RTF technology implementation



References

- ABI. Trends in Biodiesel Production and Consumption.<http://195.54.163.25/default.asp> : Austrian Biofuels Institute. www.biodiesel.org. 2000.
- AEAT. CO2 Abatement by Production and Use of Gas to Liquids Transport Fuels. IEA.AEA Technology. PH4/12:1-93 2002.
- Allard, M. Existing Methanol Production Plants and Their Feedstocks. *Personal communication to: Hart, D.*
- Amos, W.A. Costs of Storing and Transporting Hydrogen. <http://www.eren.doe.gov/hydrogen/pdfs/25106.pdf>. 1998.
- Antolin, G., Tinaut, F.V., Briceno, Y., Castano, V., Perez, C., and Ramirez, A.I. Optimisation of biodiesel production by sunflower oil transesterification. *Bioresource Technology* 83 (2):111-114. 2002.
- Armstrong, A.P., Baro, J., Dartoy, J., Groves, A.P., Nikkonen, J., Rickeard, D.J., Thompson, N.D., and Larive, J.-F. Energy and Greenhouse Gas Balance of Biofuels for Europe - an update.Brussels, Belgium:Concawe. 2/02:1-19. www.concawe.be. 2002.
- ATLAS. Tidal Energy: introduction. http://europa.eu.int/comm/energy_transport/atlas/htmlu/tidalintro.html. 2003.
- Audus, H. IEA Greenhouse Gas R&D Programme: Full Fuel Cycle Studies. *Energy Conversion and Management* 37 (6-8):837-842. 1996.
- Barber, W. and Stuckey, D.C. The Use of Anaerobic Baffled Reactor (ABR) for Waste Water Treatment: a review. *Water Research* 33 (7):1559-1578. 1999.
- Barbour, J. Wholesale, pre-tax and full pump prices for petrol and diesel in the UK. *Personal communication to: Woods, J.* 6-2-2003
- Bauen, A., Woods, J., and Hailes, R. Bioelectricity Vision: achieving 15% of electricity from Biomass in OECD countries by 2020.Brussels, Belgium: WWF. 2003.
- Beer, T., Grant, T., Brown, R., Edwards, J., Nelson, P., Watson, H., and Williams, D. Life-Cycle Emissions Analysis of Alternative Fuels for Heavy Vehicles. CSIRO, Aspendale, Victoria, Australia:CSIRO. C/0411/1.1/f2:1-130 2000.
- Bennett, M.C. Bioethanol Fuels from Sugar.Clippings Green Farm, Mattishall, Norfolk, NR20 3RG, UK. 2002.
- Berg, C. Towards a World Ethanol Market? First World Ethanol Conference: preparing for global competition. Ratzeburg, Germany: F.O.Licht. 1998.
- Berg, C. World Ethanol Production and Trade- A Review.www.distill.com/berg/:F.O. Licht, editor International Molasses and Alcohol Report. 1998.
- Berg, C. World Ethanol Markets, Analysis and Outlook (Summary). www.distill.com/world_ethanol_production.html: F.O. Lichts. www.distill.com/world_ethanol_production.html. 2001.
- Billins, P. Biomass Potentials in the UK: response to draft RTF report. *Personal communication to: Bauen, A. and Woods, J.*
- Bockey, D. Biodiesel Production and Marketing in Germany. www.ufop.de: German Union for the Production of Oil and Protein Plants. 2001.
- Bockey, D. and Körbitz, W. Situation and Development Potential for the Production of Biodiesel- An International Study.www.ufop.de:German Union for the Production of Oil and Protein Plants. www.ufop.de. 2003.
- Border Wind. Offshore Wind Energy - building a new industry for Britain. Greenpeace. <http://www.borderwind.co.uk/frames.htm> . 1998.
- Borgwardt, R.H. Transportation Fuel from Cellulosic Biomass: a comparative assessment of ethanol and methanol options. *Proceedings of the Institution of Mechanical Engineers Part A- Journal of Power and Energy* 213 (A5):399-407. 1999.
- Bridgwater, A.V. A Guide to Fast Pyrolysis. PYNE, Aston University, UK: www.pyne.co.uk. 1999.
- Bridgwater, A.V. and Peacocke, G.V.C. Fast Pyrolysis Processes for Biomass. *Renewable & Sustainable Energy Reviews* 4 (1):1-73. 2000.
- British Biogen and ABF/British Sugar. The Case for a Fuel Duty Reduction for Bioethanol. ABF British Sugar. 1-26 2002.

- Brown, M.A. Market failures and barriers as a basis for clean energy policies. *Energy Policy* 29 (14):1197-1207. 2001.
- Bucksch, S. and Egeback, K.E. The Swedish program for investigations concerning biofuels. *Science of the Total Environment* 235 (1-3):293-303. 1999.
- Bullard, M. Miscanthus Agronomy: for fuel and industrial purposes. Agri-Industrial Materials. MAFF. <http://www.defra.gov.uk/MAFF/DEFRA.NF0403:1-60> 2002.
- BWEA. Prospects for Offshore Wind Energy. Brussels: EU (DGXVII) and OWF. 1-53 <http://www.offshorewindfarms.co.uk/reports/altreport.pdf>. 2000.
- BWEA. Planning for Wind Energy: planning for regional targets. London, UK: BWEA. 1-24 <http://www.bwea.com/pdf/planning.pdf>. 2000.
- BWEA. Current Status of UK Wind Power Production. www.bwea.com: British Wind Power Association. 2003.
- California Energy Commission. US Ethanol Industry-Production Capacity Outlook. 2001.
- Campbell, J. Shell Buys C\$46M Stake in Ottawa Bioethanol Firm. Ottawa: *The Ottawa Citizen* www.iogen.ca. 2002.
- Choo, Y.-M. and Ma, A.-N. Plant Power. *Chemistry & Industry* 16:530-534. 2000.
- Choren Industries GmbH. The Carbo-V Process. Choren Industries GmbH. http://www.choren.de/e_html/ecarbo_10.htm. 2003.
- Chum, H.L. and Overend, R.P. Biomass and renewable fuels. *Fuel Processing Technology* 71 (1-3):187-195. 2001.
- Commission of the European Communities. Proposal for a Directive of the European Parliament and of the Council on the Promotion of the Use of Biofuels for Transport. Brussels, Belgium: CEC. COM(2001) 547 final:1-50. europa.eu.int. 2001.
- Commission of the European Communities. European Transport Policy for 2010: time to decide. Brussels, Belgium: CEC. COM(2001) 370 final:1-124 http://europa.eu.int/eur-lex/en/com/wpr/2001/com2001_0370en.html. 2001.
- Connemann, J. and Fischer, J. Biodiesel in Europe 2000: Biodiesel Processing Technologies and Future Market Development. Biodiesel - Fuel from Vegetable Oils for Compression-Ignition Engines. Web site above:1-11 www.biodiesel.de/biodiesel2000.htm. 1999.
- Contreras, A., Yiöit, S., Özay, K., and Veziroölu, T.N. Hydrogen as Aviation Fuel: a comparison with hydrocarbon fuels. *International Journal of Hydrogen Energy* 22 (10/11):1053-1060. 1997.
- Curreli, N., Agelli, M., Pisu, B., Rescigno, A., Sanjust, E., and Rinaldi, A. Complete and efficient enzymic hydrolysis of pretreated wheat straw. *Process Biochemistry* 37 (9):937-941. 2002.
- Danielsson, P. Volvo's position on DME. *Personal communication to: Woods, J.*
- Dante, R.C., Guereca, L.P., Neri, L., Escamilla, J.L., Aquino, L., and Celis, J. Life Cycle Analysis of Hydrogen Fuel: a methodology for a strategic approach of decision making. *International Journal of Hydrogen Energy* 27 (2):131-133. 2002.
- de Feber, M.A.P.C. and Gielen, D.J. Biomass for Greenhouse Gas Emission Reduction. Task 7: energy technology characterisation. P.O. Box 1, 1755 ZG Petten, The Netherlands: ECN. ECN-C--99-078:1-43 www.ecn.nl. 2000.
- Dell, R.M. and Rand, D.A.J. Energy storage - a key technology for global energy sustainability. *Journal of Power Sources* 100 (1-2):2-17. 2001.
- DTI. UK Transport Fuel Standards. <http://www.og.dti.gov.uk/downstream/environment/>. 2003.
- DTI. Digest of United Kingdom Energy Statistics 2001. UK Energy Statistics. DTI. 1-32 <http://www.dti.gov.uk/epa/dukes.htm>. 2002.
- Dupont-Roc, G., Schulz, P., Borg, P., Foure, M., and Le Breton, D. Energy, hydrogen and fuel cells. *Actualité Chimique* (12):11-16. 2001.
- ECOTEC. Financial and Environmental Impact of Biodiesel as and Alternative to Fossil Diesel in the UK. Priestley House, 28-34 Albert Street, Birmingham, B4 7UD, UK:ECOTEC. 1-22 www.ecotec.com. 1999.
- ECOTEC. Emissions from Liquid Biofuels- report for British Association for Bio-Fuels and Oils (BABFO). Priestley House, 28-34 Albert Street, Birmingham, B4 7UD, UK:ECOTEC. 1-16 www.ecotec.com. 2000.

- ECOTEC. Lifecycle Greenhouse Gas Assessment of RME - comparative emissions from set-aside and Wheat. Priestley House, 28-34 Albert Street, Birmingham, B4 7UD, UK:ECOTEC. 1-22 <http://www.biodiesel.co.uk/ecoteclifecycle.htm>. 2001.
- Edwards, D. UK Waste Oil Production Estimates. *Personal communication to*: Woods, J. and Billins, P.
- Environment Agency (UK). A review of current MTBE usage and occurrence in groundwater in England and Wales. R&D Publications. London, WC2B 6PQ:The Stationery Office. ISBN 011310181 3:1-60 1997.
- Eriksson, E., Blinge, M., and Lovgren, G. Life Cycle Assessment of the Road Transport Sector. *The Science of the Total Environment* 189/190:69-76. 1996.
- ETSU. New and Renewable Energy: prospects in the UK for the 21st century: supporting analysis. Harwell, UK:ETSU. ETSU R 112:1-277 <http://www.engb.com>. 1998.
- ETSU. The Value of Electricity Generated from Photovoltaic Power Systems in Buildings. Harwell, UK:ETSU, New & Renewable Energy Programme. ETSU S/P2/00279/REP:1-98 <http://www.dti.gov.uk/renewable/pdf/00279.pdf>. 1998.
- ETSU. Renewable Energy Assessment for the South West (UK): Chapter 3. Bristol, UK:Government Office for the South West. 1-31 http://www.gosw.gov.uk/docbank/ch3_resource_assess.PDF. 2001.
- EuroStat. Inland deliveries of petroleum products in 2000. Statistics in Focus. ISSN 1562-3106 2001.
- EWEA. Wind Energy: the facts - Volume 1. Brussels:EU-DG Energy. 1-198 <http://www.ewea.org/doc/ewea.pdf>. 1999.
- Faaij, A., Hamelinck, C., and Tijmensen, M. Long Term Perspectives for Production of Fuels from Biomass; integrated assessment and RD&D priorities- preliminary results. First World Conference and Exhibition on Biomass for Energy and Industry.:1-5 2000.
- Faaij, A., Tijmensen, M., van Hardeveld, M.R.M., and Hamelinck, C.N. The Production of Fischer Tropsch Liquids and Power Through Biomass Gasification. The Netherlands: STS. 1-2 2002.
- Folkecenter. Influences on product quality in decentralised oil mills. www.folkecenter.dk:oil/publications/efdcpo.html! Rape Seed Oil Web 2.html. 1998.
- Forsberg, G. Biomass energy transport - Analysis of bioenergy transport chains using life cycle inventory method. *Biomass & Bioenergy* 19 (1):17-30. 2000.
- Gouli, S., Serdari, A., Stournas, S., and Lois, E. Transportation fuel substitutes derived from biomass. *Journal of Energy Resources Technology-Transactions of the ASME* 123 (1):39-43. 2001.
- Greene, D.L. and Plotkin, S.E. Energy futures for the US transport sector. *Energy Policy* 29 (14):1255-1270. 2001.
- Greenenergy. Bioethanol and Biodiesel Fuel Duty Incentives (in the UK). 2003.
- Greenenergy. Technical Specification / Standards for biofuels in UK versus fossil equivalents. http://www.greenenergy.com/knowledge_centre/fuels/technical_standards.html: 2002.
- Griesemann, J.-C. Biomass to Liquid' (BtL) Fuels in Europe: perspectives and state of progress. J-C. Griesemann. France: BtL Consultative Group. 1-6 2003.
- Groves, A.P. Well to Wheels Assessment of Rapeseed Methyl Ester Biodiesel in the UK. Second World Biofuels Conference. F.O.Lichts. London, UK:Shell Global Solutions. 1-32. 2002.
- Gumerman, E., Koomey, J.G., and Brown, M.A. Strategies for cost-effective carbon reductions: a sensitivity analysis of alternative scenarios. *Energy Policy* 29 (14):1313-1323. 2001.
- Hamelinck, C. and Faaij, A. *Future Prospects for Production of Methanol and Hydrogen from Biomass*. Universiteit Utrecht: Utrecht, Netherlands: 82 pages. ISBN:90-73958-84-9. 2001.
- Hart, D., Fouquet, R., Bauen, A., Leach, M., Pearson, P., Anderson, D., and Hutchinson, D. Methanol Supply And Its Role In The Commercialisation Of Fuel Cell Vehicles. Harwell, UK:ETSU. ETSU F/02/00142/REP :1-50 2002.
- Heiermann, M., Plöchl, M., Linke, B., and Schelle, H. Biogas Production in Agriculture by Co-Fermentation of Energy Crops. *Aspects of Applied Biology* 65:65-70. 2001.

- Hewson, J. Elean - the UK's first Straw Fired Power Station. *Aspects of Applied Biology* 65:1-4. 2001.
- HGCA. Haulage Survey. 2001. <http://www.hgca.com/Articles/DisplayArticle.asp?ArticleID=3170>. 2001.
- Himmel, M.E., Adney, W.S., Baker, J.O., Elander, R., McMillan, J.D., Nieves, R.A., Sheehan, J.J., Thomas, S.R., Vinzant, T.B., and Zhang, M. Advanced bioethanol production technologies: A perspective. *Fuels and Chemicals from Biomass* 666:2-45. 1997.
- HyWeb. Hydrogen and Fuel Cell Information System. <http://www.hydrogen.org/index-e.html> : LBST. 2003.
- IEA. Automotive Fuels for the Future: the search for alternatives. Breda, The Netherlands: IEA/IFIS. <http://www.iea.org/books/studies/1999/autofuel.pdf>. 1999.
- IOGEN. Shell Invests in Iogen. www.io-gen.ca: Iogen Corporation. 2002.
- Isenberg, G., Edinger, R., and Ebner, J. Renewable energies for climate benign fuel production - Powering fuel-cell vehicles. *Environmental Science and Pollution Research* 9 (2):99-104. 2002.
- Jaggard, k. The Fertiliser Value and economic costs of Wheat Straw. *Personal communication to:* Woods, J. 17-12-2002
- Johansson, B. and Martensson, A. Energy and environmental costs for electric vehicles using CO₂- neutral electricity in Sweden. *Energy* 25 (8):777-792. 2000.
- Jolly, L. Ethanol - Future Implications for Sugar.1 Canada Square, Canary Wharf, London E15 5AA, UK: International Sugar Organisation. 1-22 2002.
- Kadam, K.L. Environmental benefits on a life cycle basis of using bagasse- derived ethanol as a gasoline oxygenate in India. *Energy Policy* 30 (5):371-384. 2002.
- Kaltschmitt, M., Reinhardt, G.A., and Stelzer, T. Life Cycle Analysis of Biofuels Under Different Environmental Aspects. *Biomass & Bioenergy* 12 (2):121-134. 1997.
- Koomey, J.G., Webber, C.A., Atkinson, C.S., and Nicholls, A. Addressing energy-related challenges for the US buildings sector: results from the clean energy futures study. *Energy Policy* 29 (14):1209-1221. 2001.
- Körbitz, W. Worldwide Trends in Production and Marketing of Biodiesel. P.O.Box 97, A-1014, Vienna, Austria: Austrian Biodiesel Institute. <http://195.54.163.25/Userfiles/LiteraturPDF/Paper-worldwide.trends-TU.Graz.pdf>. 2000.
- Körbitz, W. New Trends in Developing Biodiesel World-wide. World Fuel Ethanol Congress. Austrian Biofuels Institute: F.O. Lichts. 1-9 2001.
- Kruger, P. Electric Power Requirement in the United States for Large-Scale Production of Hydrogen Fuel. *International Journal of Hydrogen Energy* 25 (11):1023-1033. 2000.
- Kuwahara, N., Berni, M.D., and Bajay, S.V. Energy supply from municipal wastes: The potential of biogas- fuelled buses in Brazil. *Renewable Energy* 16 (1-4):1000-1003. 1999.
- LBST-GM. Annex: GM Well-to-Wheel Analysis of Energy Use and Greenhouse Gas Emissions of Advanced Fuel / Vehicle Systems- A European Study. Ottobrun, Germany. L-B-Systemtechnik GmbH. p.1-425 www.lbst.de/gm-wtw. 2002.
- Leeds, S. 20:20 Vision and CPI 2001. *British Sugar Beet Review* 70 (2):14-19. 2002.
- Louis, J.J.J. Well-to-Wheel Energy Use and Greenhouse Gas Emissions for Various Vehicle Technologies.Shell Global Solutions. 2001-01-1343:1-8 2001.
- Macedo, I.C. Energy from Sugar Cane in Brazil. Sweden: SEI, CARENSA. *CARENSA meeting presentations* www.carensa.net. 2002.
- MacLean, H.L., Lave, L.B., Lankey, R., and Joshi, S. A life-cycle comparison of alternative automobile fuels. *Journal of the Air & Waste Management Association* 50 (10):1769-1779. 2000.
- May, M. Crop Protection in Sugar Beet. *Pesticide Outlook*:188-191. 2001.
- McLaughlin, S.B. and Walsh, M.E. Evaluating environmental consequences of producing herbaceous crops for bioenergy. *Biomass & Bioenergy* 14 (4):317-324. 1998.
- Melis, A. and Happe, T. Hydrogen production. Green algae as a source of energy. *Plant Physiology* 127 (3):740-748. 2001.
- Metcalfe, P. and Bullard, M. Life Cycle Analysis of Energy Grasses. *Aspects of Applied Biology* 65:29-38. 2001.

- Mortimer, N.D., Cormack, P., Elsayed, M.A., and Home, R.E. Evaluation of the Comparative Energy, Environmental and Socio-Economic Costs and Benefits of Biodiesel. Sheffield Hallam University: Resources Research Unit, School of Environment and Development. 20/1:1-72 www.shu.ac.uk/r ru/reports. 2002.
- Nathan, A.N. Fuels from Sugar Crops. DOE Critical Review Series. A. N. Nathan. Oak Ridge, TN, USA:USDOE. 1-137, 0-87079-111-7. 1978.
- Neureiter, M., Danner, H., Thomasser, C., Saidi, B., and Braun, R. Dilute-acid hydrolysis of sugarcane bagasse at varying conditions. *Applied Biochemistry and Biotechnology* 98:49-58. 2002.
- NRC. Review of the Research Strategy for Biomass-Derived Transportation Fuels. Washington, D.C., USA: National Academic Press. 1-48 1999.
- Oanda. Currency Exchange Rates. www.oanda.com: www.oanda.com. 2003.
- OECD/IEA. BIOFUELS. Energy & Environment, Policy Analysis Series.2 rue Andre Pascal, 75775, Paris, CEDEX 16, France: OECD Publications. ISBN 9264-14233-9:1-117 1994.
- Ortizcanavate, J. Characteristics of different types of gaseous and liquid biofuels and their energy-balance. *Journal Of Agricultural Engineering Research* 59:231-238. 1994.
- OWF. Worldwide Status of Off-Shore Wind. Offshore Wind Farms - sponsored by DTI. <http://www.offshorewindfarms.co.uk/else.html>. 2003.
- OXERA Environmental. Regional Renewable Energy Assessments. Blue Boar Court, Alfred Street, Oxford, OX1 4EH, UK:OXERA, ARUP Economics & Planning. 1-44 2002.
- Paisley, M.A., Farris, G., Slack, W., and Irving, J. Commercial Development of the BATTELLE / FERCO Biomass Gasification Process: Initial Operation of the McNeil Gasifier. Making a Business from Biomass in Energy, Environment, Chemicals, Fibres and Materials. Proceedings of the 3rd Biomass Conference of the Americas. R. P. Overend and E. Chornet. Oxford:Elsevier Science. 1:579-588 1997.
- Philippidis, G.P. and Hatzis, C. Biochemical engineering analysis of critical process factors in the biomass-to-ethanol technology. *Biotechnology Progress* 13 (3):222-231. 1997.
- PIUf. Energy Systems in 2050. R. Gross and J. Chapman. London, UK: Cabinet Office. 1-43 <http://www.cabinet-office.gov.uk/innovation/reports/reports.shtml>. 2002.
- PIUh. Technical and Operating Potential of Renewable Energy Generating Technologies: potentials and cost reductions to 2020. R. Gross and J. Chapman. London, UK: Cabinet Office. 1-43 <http://www.cabinet-office.gov.uk/innovation/reports/reports.shtml>. 2002.
- Pohl, H.W. and Malychev, V.V. Hydrogen in future civil aviation. *International Journal of Hydrogen Energy* 22 (10-11):1061-1069. 1997.
- Poitrat, E. The Potential of Liquid Biofuels in France. *Renewable Energy* 16 (1-4):1084-1089. 1999.
- Powers, S.E., Rice, D., Dooher, B., and Alvarez, P.J.J. Will Ethanol-Blended Gasoline Affect Groundwater Quality? USA: pubs.acs.org/est. 2001.
- Punter, G. Lignocellulosic Ethanol. Peterborough: British Sugar. 1-8 2002.
- Putun, A.E., Ozcan, A., Gercel, H.F., and Putun, E. Production of biocrudes from biomass in a fixed-bed tubular reactor: product yields and compositions. *Fuel* 80 (10):1371-1378. 2001.
- Raizada, N., Sonakya, V., Anand, V., and Kalia, V.C. Waste management and production of future fuels. *Journal of Scientific & Industrial Research* 61 (3):184-207. 2002.
- Raynolds, M.A., Checkel, D.M., and Fraser, R.A. A Case Study for Life Cycle Assessment (LCA) as an Energy Decision Making Tool: The Production of Fuel Ethanol from Various Feedstocks. Total Life Cycle Conference and Exposition, Graz, Austria. December 1998.400 Commonwealth Drive, Warrendale, PA 15096-0001:SAE International. 1-16 1998.
- Reith, J.H., Veenkamp, J.M., and van Ree, R. Co-production of Bio-ethanol, Electricity and Heat from Biomass Wastes: potential and R&D issues. Petten, The Netherlands: ECN. ECN-RX-01-011:1-12 2001.
- Ribeiro, S.K. and Younes-Ibrahim, P.S. Global warming and transport in Brazil - ethanol alternative. *International Journal of Vehicle Design* 27 (1-4):118-128. 2001.

- Rosenberger, A., Kaul, H.P., Senn, T., and Aufhammer, W. Costs of bioethanol production from winter cereals: the effect of growing conditions and crop production intensity levels. *Industrial Crops And Products* 15 (2):91-102. 2002.
- Rosillo-Calle, F. and Cortez, L.B. Towards ProAlcool II- A review of the Brazilian national bioethanol programme. *Biomass & Bioenergy* 14:115-124. 1998.
- Sanstad, A.H., DeCanio, S.J., Boyd, G.A., and Koomey, J.G. Estimating bounds on the economy-wide effects of the CEF policy scenarios. *Energy Policy* 29 (14):1299-1311. 2001.
- Schindler, J. and Weindort, W. Fuels for Transportation Derived from Renewable Energy Sources. 2000.
- Scurlock, J.M.O. Status of Biodiesel Production and Consumption in USA: comments on draft RTF report.
- Sparks & Co. and Kansas State University. Corn Based Ethanol Costs and Margins: attachment 1.Kansas State University (KSU). 1-24 2003.
- Speidel, H.K., Lightner, R.L., and Ahmed, I. Biodegradability of new engineered fuels compared to conventional petroleum fuels and alternative fuels in current use. *Applied Biochemistry and Biotechnology* 84-6:879-897. 2000.
- Steynber, A.P., Espinoza, R.L., Jager, B., and Vosloo, A.C. High Temperature Fischer-Tropsch Synthesis in Commercial Practice. *Applied Catalysis A: General* 186:41-54. 1999.
- Strehler, A. and Stütze, W. Biomass Residues. In: *Biomass: regenerable energy*, edited by D. O. Hall and R. P. Overend. John Wiley & Sons Ltd.: London. p. 75-102. 1997.
- Sun, Y. and Cheng, J.Y. Hydrolysis of lignocellulosic materials for ethanol production: a review. *Bioresource Technology* 83 (1):1-11. 2002.
- Teal, D. Estimating the availability of waste vegetable oil in the UK. *Personal communication to: Woods, J.* 17/Feb/2003.
- Tickell, J. From the Fryer to the Fuel Tank: the complete guide to using vegetable oil as an alternative fuel. K. Roman. P.O. Box 876, Covington, LA 70434, USA: Tickell Energy Consultants. 1-162, 0-9707227-0-2. 2002.
- Trapp, T. and Lomax, C. Developing a Tidal Stream Energy Business. www.engb.com: The Engineering Business Limited. <http://www.engb.com>. 2002.
- UK Department for Transport. Transport Statistics Great Britain: 2002 Edition. London, UK: The Stationery Office. ISBN 0-11-552559-9:1-100 2002.
- UK Transport Dept. Powering Future Vehicles: the Government strategy.1:1-27 2002.
- UKPIA. Response to the (UK) Government's Consultation on "Powering Future Vehicles: draft Government strategy. London, UK: UK Petroleum Importers Association. 2002.
- UNICA. Sugar and ethanol production in Brazil (2001/02 harvest and estimated for 2002/03).www.unica.com.br: União da Agroindústria Canavieira do Estado de São Paulo (São Paulo Sugarcane Agro-industrial Union). 2003.
- Wang, W.G., Lyons, D.W., Clark, N.N., Gautam, M., and Norton, P.M. Emissions from nine heavy trucks fuelled by diesel and biodiesel blend without engine modification. *Environmental Science & Technology* 34 (6):933-939. 2000.
- Watanabe, Y., Shimada, Y., Sugihara, A., and Tominaga, Y. Enzymatic conversion of waste edible oil to biodiesel fuel in a fixed-bed bioreactor. *Journal of The American Oil Chemists Society* 78 (7):703-707. 2001.
- Watson, M. Comments on Draft report – Technology Status Review and Carbon Abatement Potential of Renewable Transport Fuels (RTF) in the UK. *Personal communication to: Woods, J.*
- Weiss, M.A., Heywood, J.B., Drake, E.M., Schafer, A., and Au Yeung, F.F. On the Road in 2020: a life-cycle analysis of new automobile technologies. Cambridge, Massachusetts 02139-4307, USA:MIT Energy Laboratory. MIT EL 00-003:1-160 2000.
- Wetzel, F. Improved Handling of Liquid Hydrogen at Filling Stations: review of six years' experience. *International Journal of Hydrogen Energy* 23 (5):339-348. 1998.
- Williamson, A.M. and Badr, O. Assessing the viability of using rape methyl ester (RME) as an alternative to mineral diesel fuel for powering road vehicles in the UK. *Applied Energy* 59 (2-3):187-214. 1998.
- Wolff, D. Proton Energy. *Chemical Processing*. 2001.

- Woods, J. and Hall, D.O. Bioenergy for development: technical and environmental dimensions. Environment and Energy Series. G. Best. Rome: FAO. 13 (ISBN 92-5-103449-4):1-78 <http://www.fao.org/docrep/T1804E/t1804e00.htm#Contents>. 1994.
- Woods, J. and Bauen, A. Technology Status Review and Carbon Abatement Potential of Renewable Transport Fuels (RTF) in the UK.DTI; AEAT. 1-150 2003.
- Wooley, R., Ruth, M., Sheehan, J.J., Ibsen, K., Majdeski, H., and Galvez, A. Golden, Colorado, USA:NREL. TP-580-26157:1-132 1999.
- Worrell, E. and Price, L. Policy scenarios for energy efficiency improvement in industry. *Energy Policy* 29 (14):1223-1241. 2001.
- Yacobucci, G.D. and Womach, J. Fuel Ethanol: Background and Public Policy Issues. Washington, D.C., USA:CRS / Congress. RL30369 2000.
- Yorgun, S., Sensoz, S., and Kockar, O.M. Flash pyrolysis of sunflower oil cake for production of liquid fuels. *Journal of Analytical and Applied Pyrolysis* 60 (1):1-12. 2001.
- Yu, C.W., Bari, S., and Ameen, A. A comparison of combustion characteristics of waste cooking oil with diesel as fuel in a direct injection diesel engine. *Proceedings of the Institution of Mechanical Engineers Part D- Journal of Automobile Engineering* 216 (D3):237-243. 2002.



DTI New and Renewable
Energy Programme

**ANNEXES TO:
TECHNOLOGY STATUS REVIEW AND CARBON ABATEMENT POTENTIAL OF
RENEWABLE TRANSPORT FUELS IN THE UK**

B/U2/00785/REP
URN 03/982

Contractor
Imperial College London
Centre for Energy Policy and Technology
(ICEPT)

Prepared by
J. Woods and A. Bauen

With contributions from
F. Rosillo-Calle, D. Anderson, B. Saynor and J. Howes

The work described in this report was carried out under contract as part of the DTI New and Renewable Energy Programme, which is managed by Future Energy Solutions. The views and judgements expressed in this report are those of the contractor and do not necessarily reflect those of the DTI or Future Energy Solutions.

First Published 2003
© Crown Copyright 2003

dti

Department of Trade and Industry

ANNEX 1 Chain Analysis Sheets

Summary of Chain Analysis Sheets Provided in Annex 1

	Chain Description		End-fuel
1	Ethanol from Sugar Beet	C6 fermentation	Ethanol
2	Ethanol from Wheat (grain)	Starch hydrolysis, C6 fermentation	Ethanol
3	Ethanol from Straw (Wheat)	Hydrolysis, C5 & C6 fermentation	Ethanol
4	Ethanol from Wood (SRC)	Hydrolysis, C5 & C6 fermentation	Ethanol
5	Rape Methyl Ester (RME)	Oil extraction & esterification	Biodiesel
6	Vegetable Oil Methyl Ester (VME) from waste oils	Filtration / purification & esterification	Biodiesel
7	Fischer-Tropsch (FT) Biodiesel from Wood (SRC)	Gasification & catalytic gas upgrading	Biodiesel
8	Methanol from Wood (SRC)	Gasification & catalytic gas upgrading	Methanol
9	Hydrogen from Wood (SRC)	Gasification and gas upgrading	Hydrogen
10	Hydrogen from Off-shore Wind- 1	Regional electrolysis - compressed H2 distribution.	Hydrogen
11	Hydrogen from Off-shore Wind- 2	Regional electrolysis - liquid H2 distribution	Hydrogen
12	Hydrogen from Off-shore Wind- 3	Regional electrolysis - pipeline distribution	Hydrogen
13	Hydrogen from Off-shore Wind- 4	Forecourt electrolysis - compressed local storage	Hydrogen

Ethanol from Sugar Beet (<i>Beta vulgaris</i>)									
Sugar beet produced to supply a 120 000 t EtOH/yr plant in UK based on UK-production practices.									
Fuel chain summary									
Cost (no co-product credits):						Low		High	Unit
						13.5		15.1	£/GJ EtOH
						0.29		0.32	£/l EtOH
Energy ratio:	No co-product credits					1.36		1.61	GJout:GJin
	Co-products used as fuel					1.43		2.06	GJout:GJin
GHG emissions:	No co-product credits					72		92	kgCO ₂ eq./GJ
	Co-products (pulp) used as fuel						26		kgCO ₂ eq./GJ
UK Specific?						Yes			
Technology status (feedstock, conversion and distribution)						Both feedstock production and conversion technologies are mature. However, improvements are expected to continue in feedstock yields and conversion efficiencies.			
Intermediary fuel chain stage parameters									
Production and transport	Low	Intermediate	High	Unit	Conversion and distribution	Low	Intermediate	High	Unit
Feedstock cost (delivered):	4.27		5.14	£/GJbeet	Costs from conversion	4.87	4.87	4.87	£/GJ EtOH
	8.00		9.64	£/GJ EtOH					
Feedstock transport cost:		1.15		£/GJbeet	Ethanol production	3.85	4.72	6.12	t EtOH/ha
		2.53		£/GJ EtOH		102.7	126.0	163.4	GJ EtOH/ha
							0.077		t EtOH/t beet
Feedstock yield (beet):	50	62	80	t/ha raw beet	Distribution cost		0.60		£/GJ EtOH
					By-product value (pulp pellet feed)		2.57		£/GJ EtOH
Energy input to feedstock production:	16.5		26.7	GJ/ha	Energy input to conversion process	0.33		0.55	GJ/GJ EtOH
	0.13		0.21	GJ/GJ EtOH	Energy input to distribution		0.016		GJ/GJ EtOH
Energy input to feedstock transport:	5.08	6.24	8.09	GJ/ha	Energy content of by-products	0.07	0.38	0.45	GJ/GJ EtOH
	0.04	0.05	0.06	GJ/GJ EtOH					
GHG from feedstock production + transport:	24	29	33	kgCO ₂ eq./GJ EtOH	GHG from conversion process	0.6	47.4	57.4	kg CO ₂ eq. /GJ EtOH
GHG from feedstock transport only:		4		kgCO ₂ eq./GJ EtOH	GHG from distribution		0.9		kg CO ₂ eq. /GJ EtOH
					Allocation of GHG to by-products	None			kg CO ₂ eq. /GJ EtOH

Technology Status

[ECOPORT plant id: 48742 (www.ecoport.org)]

Ethanol production is based on conventional hexose (C6) fermentation systems.

Costs

Fuel Chain Summary Costs: The costs provided here may not represent the full range of potential costs for the production of ethanol because of the difficulty in obtaining representative reliable costs for conversion facilities and so the range reflects the likely sensitivity of ethanol production costs to feedstock supply economics. There are no co-product credits calculated in the costs provided.

Feedstock costs: UK-specific industry based feedstock costs are derived from Sugar Beet Review 2002 and are provided as the 'average' and 'highest 10%' for 300 growers surveyed and broken down into detailed 'variable' and 'operational' costs (which include harvesting and delivery). The '**Low Estimate**' assumes that the 'highest (best) 10%' practice will become the norm. The '**High**' estimate is the 'average enterprise' delivered feedstock cost for the UK in 2001. The average enterprise price paid to farmers (which includes quota subsidies) increases the value to the farmers to £29.54/t beet against delivered costs of £19.75. The increased value of the beet would increase the cost of ethanol production to £0.365 per litre or £17.14 / GJ EtOH.

Feedstock transport costs: UK-specific industry based transport costs are derived from Sugar Beet Review 2002 and are provided as the 'average' and 'highest 10%' for 300 growers surveyed. The '**Low Estimate**' assumes that the 'highest (best) 10%' practice will become the norm. The '**High**' estimate is the 'average enterprise' delivered feedstock cost for the UK in 2001. Although not stated in the Sugar Beet Review (2002), average transport distances for delivering the sugar beet from farm to sugar mill was 28 miles (45 km) in 2002 (Punter, 2003) resulting in a transport cost of £0.098/t.km (one way).

Conversion costs: Unless stated, costs are derived from OECD/IEA (1994) which provides estimated costs for the EU in 1991 US\$. The prevailing exchange rate (www.oanda.com) was used to convert these costs to GBP, but the value was NOT then inflated by RPI. These costs reflect the costs of producing ethanol from a 395 t EtOH/day plant (approx. 120 kt per year) including fixed and variable costs. Juice separation (extraction), fermentation and distillation or energy intensive processes and energy costs dominate. There is a lack of good quality data on large scale conversion costs and so a single value is used.

Distribution costs: Indicative costs are taken from Coltrain (2001) who quotes established costs for 'transporting ethanol' in the US of USc 2 per gallon (3.785 litres) for local markets, USc 7 for 'regional markets' and USc 13 for shipping 'to the East or West coasts'. The 'regional markets' cost is used here of USc7 per US gallon and converted to GBP (£0.013/l EtOH) at the prevailing average exchange rate for 2001 (www.oanda.com).

Co-product value: An animal feed value for pelleted pulp is calculated. 55kg pellets are produced per t beet processed (LBST_GM 2002) with a market value in 2002 of £95.54/t.

Energy

Energy Ratio: The '**Low**' and '**High**' energy ratios are calculated here from the overall chain ethanol production (21.6 MJ/l EtOH) and the energy input requirements (as primary energy) for feedstock production + delivery + conversion energy inputs + distribution transport energy requirements. No co-product credits have been applied- see below for potential co-product credits. LBST_GM 2002 derived energy ratios show negative energy balances of 0.64 to 0.84 even with energy or animal fodder credits for the pulp.

Feedstock production: '**Low**' is derived from LBST_GM 2002 and is based on a detailed evaluation of life-cycle energy inputs for sugar beet production in the EU. '**High**' is derived from OECD/IEA 1994 and so represents the state-of-the-art in the early 1990s i.e. high energy inputs, primarily into fertiliser manufacture. Energy inputs into feedstock production include the energy requirements for the production and application of fertilisers and pesticide(s), farm fuel use, energy costs of equipment manufacture, transport of feedstock, processing, and drying. The UK 2001 national average was 46 t/ha and the EU average was 55 t/ha (FAOSTAT, 2002). However, 2001 was a bad year for beet yields in the UK with the average yields between 1995 and 1998 being nearly 54 t beet / ha (May, 2001). Yields of these magnitudes would lead to gross ethanol yields of 4800 to 7800 l EtOH / ha.

Feedstock Transport: Energy input is taken from LBST_GM 2002 for a 50km trip (field to ethanol plant) and divided by the average yield used in LBST and for the '**Low**' estimate, multiplied by the 'low' sugar beet yield, for the 'Intermediate' estimate multiplied by the 'intermediate estimate' yield and for the '**high**' estimate multiplied by the high yield.

Conversion Energy: '**low**' estimate is taken from IEA/OECD 94 and '**high**' estimate from LBST_GM 2002. '**Intermediate estimate**' is the average of the low and high estimates.

Ethanol Distribution: Energy input is taken from LBST_GM 2002 for a 150km trip ('in tank trailer trucks to refueling station').

Co-product energy contents: based on LBST_GM 2002 data. '**Low**' estimate is the energy content of biogas production from wastewater treatment (0.1455 MJ biogas/kg sugar beet processed) using 'best est' sugar beet yields divided by 'best estimate' ethanol production (GJ/ha). '**Intermediate**' estimate is the energy content of the pulp pellets (9% moisture, 14.2 GJ/t, 55kg per tonne beet processed). '**High**' estimate is the energy content of the biogas + pulp pellets i.e. 'low' plus 'best' estimates.

GHG / CO2 emissions

GHG emissions: GHG emissions for feedstock production, transport, conversion and distribution have been calculated (as shown) per GJ EtOH produced with '**Low**' '**Intermediate**' and '**High**' values calculated representing the range found in the literature. It should be noted that these values include estimates of N2O emissions arising from feedstock production - see below.

Feedstock production + transport: 'Feedstock transport' emissions are impossible to disaggregate from 'Farm fuel' emissions in OECD/IEA 1994 although LBST_GM 2002 provides a breakdown of farm fuel-based emissions and feedstock transport emissions, therefore, GHG emissions from feedstock production + transport are shown above and for illustrative purposes the value for 'feedstock transport only' taken from LBST_GM 2002 is also provided. '**Low**' estimate for GHG emissions from 'feedstock production + transport' is based on OECD/IEA 1994 and included primary emissions from fertiliser and pesticide manufacture and use and on-farm nitrous oxide emissions - 'by-product credits' are not included here. '**High**' GHG emissions data is derived from LBST_GM 2002 and even with the 'feedstock transport' component (889 gCO₂equiv./lEtOH) is higher than the OECD/IEA 1994 figure. The differences may arise from changes in the IPCC 100 year GWP factors used e.g. OECD/IEA used IPCC 1993 and LBST_GM 2002 used IPCC 1996.

Conversion: LBST (2002) emissions data used for the '**high**' estimate: no co-product credits. '**Low**' is from LBST_GM (-70.7 kgCO₂equiv./GJEtOH) minus the carbon content of the final ethanol fuel (71.3 kgCO₂/GJEtOH) and credits for the carbon savings as a result of displacing natural gas with pulp as a primary fuel. '**Intermediate estimate**' is calculated from ETSU 1996 (quoted in Armstrong *et al.* (2002) of 2.77 tCO₂eq/ha and an ethanol yield of 2.19t/ha resulting in 47.1 kgCO₂eq/GJEtOH. To cross-check the 'High' estimate, the LBST_GM (2002) data for beet ethanol produced in a sugar refinery and no use of co-products for energy results in GHG emissions of 57.4 kgCO₂eq/GJ EtOH was compared to 67.5 kgCO₂eq/GJ from Michaelis (1994) which evaluated older less efficient technologies.

Resource potential

Feedstock production: Yield- data from Sugar Beet Review (UK; 2002) provides results (from 300 UK growers) for 'average enterprise' of 50.0 t beet/ha (taken as low estimate, and 'highest 10% enterprise' of 61.7 t/ha which is taken as 'best estimate'. UK Average sugar production from sugar beet is approximately 8.0 t sugar/ha in 2001. 'High' estimate is a long term 2020 yield prediction. The UK average yield for 2001 was 46.2 t raw beet per ha (50.0 tbeet/ha 2002 according to Sugar Beet Review 2002). The EU-15 average yield was higher at 55.0 t/ha. There is scope for improving yields and research trial yields in the UK currently exceed 70 t/ha- see 'technology status' below for more details. Substantial increases in yields are also expected from sugar beet in the UK with the BBRO expecting yields to increase by 20% to 66t/ha.yr by 2006 and production costs to reduce by 20% as a result. According to LBST_GM (2002) the 'energy related sugar beet yield is about 196 GJ/ha' for the average yield of 51 t/ha.yr providing an energy density of sugarbeet (moisture content approx. 75%) = 3.84 GJ/t raw sugar beet. Fertiliser and lime (CaO) inputs dominate feedstock production energy inputs.

Conversion: reliable data on costs, energy inputs and emissions from commercial scale conversion facilities are extremely difficult to obtain. Ethanol production plant conversion efficiencies provided by OECD/IEA 1994 is 0.077 tEtOH/tbeet and LBST_GM 0.076 tEtOH/tbeet. Therefore, for the calculations used here an assumed efficiency of 0.0765 will be used equivalent to 2.04 GJ EtOH/tbeet.

Co-products: Sugar beet pulp is produced when the sugar-rich juice is extracted from the beet. The pulp residue can be dried and pelletised for sale as an animal feed which could substitute for imported soymeal from USA. According to LBST_GM 2002, 1t of raw beet will result in the production of 55kg of pulp pellets (9% moisture) with an energy content of 780 MJ. Assuming that pulp pellets have the same economic value as rape meal then 1t pulp pellets would be worth £95.54/t (www.hgca.com) in 2001/2002. In addition, the 'vinasse' (or 'stillage') resulting from fermentation and distillation when combined with various other waste streams can be treated using anaerobic digestion systems resulting in the production of biogas which can be used as a fuel. According to LBST_GM 2002, processing 1 t raw beet will result in the production of 145.5 MJ of biogas. In addition, significant amounts of tops and leaves are produced along with the beet tubers, but the high moisture ($\approx 85\%$) and nutrient contents makes the economic and sustainable exploitation of these residues unlikely.

Ethanol from Wheat (<i>Triticum</i>) grain									
Wheat grain supplied to a central integrated ethanol production facility producing about 120 000 t/yr of anhydrous ethanol.									
Fuel chain summary									
Costs						Low		High	Unit
						13.7		15.2	£/GJ EtOH
						0.29		0.32	£/l EtOH
Energy ratio:	Straw not used as fuel					0.69		1.67	GJout:GJin
	Straw used as fuel					1.84		2.72	GJout:GJin
GHG emissions						56		77	kgCO ₂ eq./GJ
UK Specific?						Yes			
Technology status (feedstock, conversion and distribution)						Feedstock production is based on current British practice. Data on commercial scale conversion facilities are based on US corn-to-ethanol plants. No wheat-to-ethanol plants are operating in the UK currently.			
Intermediary fuel chain stage parameters									
Production and transport	Low	Intermediate	High	Unit	Conversion and distribution	Low	Intermediate	High	Unit
Feedstock cost (delivered):		4.89		£/GJwheat	Costs from conversion	3.38	3.59	4.87	£/GJ EtOH
		9.70		£/GJ EtOH		0.072	0.076	0.104	£/l EtOH
Feedstock transport cost:		0.17		£/GJwheat	Ethanol production	1.71		2.65	t EtOH/ha
		0.34		£/GJ EtOH		45.7		70.6	GJ EtOH/ha
Feedstock yield	5.8	7.6	8.2	t/ha wheat		0.295		0.325	t EtOH/t Wheat
					Distribution cost		0.60		£/GJ EtOH
					By-product value	3.54		4.32	£/GJ EtOH
Energy input to feedstock production + transport:	7.01	9.22	9.84	GJ/ha	Energy input to conversion process		0.75		GJ/GJ EtOH
	0.14		0.15	GJ/GJ EtOH	Energy input to distribution	0.016		0.042	GJ/GJ EtOH
Energy input to feedstock transport:	0.29	0.39	1.42	GJ/ha	Energy content of co-products (straw)	1.04		1.15	GJ/GJ EtOH
	0.006		0.020	GJ/GJ EtOH					
GHG from feedstock production	8		15	kgCO ₂ eq./GJ EtOH	GHG from conversion process	47.4	55.8	61.8	kg CO ₂ eq. /GJ EtOH
GHG from feedstock transport only:	1.2		1.6	kgCO ₂ eq./GJ EtOH	GHG from distribution		0.9		kg CO ₂ eq. /GJ EtOH
					Allocation of GHG to by-products		n/a		kg CO ₂ eq. /GJ EtOH

Notes: [Ecoport crop id:2114 (www.ecoport.org)]

Conversion efficiencies: Ethanol production plant conversion efficiencies provided by OECD/IEA 1994 is 0.366 tEtOH/tWheat and KSU/Sparks 2002 0.325 tEtOH/tbeet. Therefore, for the calculations used here an assumed efficiency of 0.366 tEtOH/tWheat is assumed for the 'High' and 0.325 t/t for the 'Low' estimate.

Technology Status

Wheat yields continue to improve from 5 to 6 t/ha in the 70s and 80s to 7 t/ha in the 90s and 8+ t/ha now. Energy is required in various stages during processing / conversion and highly integrated plants that recover and re-use heat and water have made substantial savings to the energy requirements. The distillation process itself is a major energy consumer and recent developments in membrane distillation techniques may result in future energy and emissions savings. Improvements in the conversion technologies are also expected and the change from 'wet' to 'dry' milling as is happening in the US is reducing costs. It is expected that wheat-ethanol plants in the UK would be based on 'dry milling' technologies.

Costs

Fuel Chain Summary Costs: The costs provided here may not represent the full range of potential costs for the production of ethanol because of the difficulty in obtaining representative reliable costs for conversion facilities and so the range reflects the likely sensitivity of ethanol production costs to feedstock supply economics. There are no co-product credits calculated in the costs provided.

Feedstock production and transport costs: UK-specific industry based feedstock costs are derived from HGCA.com 2002 which provides the 'average' prices for 'feed' and 'bread' wheat production in the UK as a 'delivered price' and an 'e: farm price', the 'transport' cost can therefore be calculated by subtraction. Estimates are all based on the single HGCA cost per tonne wheat figure representing the 'average' delivered feedstock cost for the UK in 2001 of £76.7/t wheat. Rosenberger (2001) in their 'medium intensity' scenario for wheat growth provides a cost for wheat (*tritcale cv 'Modus'*) of DM1293.1/ha for 5.3 t wheat/ha or £76.02/t wheat at 2001 average annual exchange rates. It is worth noting that although wheat prices are quite volatile there has been a downward pressure on prices which are currently just above £50/t for feed wheat (Nov 2002) at which price the farmers only just break even, even with production subsidies of £23 per hectare.

Conversion costs: costs are derived from OECD/IEA (1994), KSU / Sparks (2002) and Rosenberger (2002). A yield of 7.63 t wheat/ha is used throughout the economic analysis. **High** the OECD/IEA data provides estimated costs for wheat to ethanol conversion plants based in the EU in 1991 US\$. The prevailing exchange rate (www.oanda.com) was used to convert these OECD/IEA costs to GBP, but the value was NOT then inflated by RPI. The OECD/IEA costs also reflect the costs of producing ethanol from a 395 t EtOH/day plant (approx. 120 kt per year) including fixed and variable costs, and unsurprisingly, provided the highest cost per litre as it represents the state-of-the-art of the late 1980's. The **Low** estimate is derived from KSU/Sparks 2002 data which is for modern corn to ethanol plants based in the US for a range of plant scales ranging from 45 to 300 thousand t EtOH per year. For these calculations the 40 million gallons (120 kt EtOH) per year 'Dry-Mill' plant data was used as most representative for EU/UK conditions.

The **intermediate estimate** value is derived from Rosenberger 2002, with a conversion plant producing 105 kt EtOH/yr requiring 377 kt wheat and operating 330 days a year; capital costs were estimated at £54.5 million (DM 175 million); Juice separation (extraction), fermentation and distillation or energy intensive processes and energy costs dominate. There is a lack of good quality, public domain data on conversion costs for wheat ethanol chains and so the data provided here should be regarded as provisional.

Distribution costs: Indicative costs are taken from Coltrain (2001) who quotes established costs for 'transporting ethanol' in the US of USc 2 per gallon (3.785 litres) for local markets, USc 7 for 'regional markets' and USc 13 for shipping 'to the East or West coasts'. The 'regional markets' cost is used here of USc7 per US gallon and converted to GBP (£0.013/l EtOH) at the prevailing average exchange rate for 2001 (www.oanda.com).

Co-product value: **Low** is based on the 2001 US value of DDGS (\$98.5/t or £68.4/t DDGS; KSU/Sparks 2002, p22) and a production rate of 0.31t/grain. The **Intermediate Estimate** is calculated from the DDGS value (low estimate) plus the straw value at £25/t straw (Mortimer, 2002) and 0.65 tstraw/t grain and multiplied by the 'best estimate' yield. **High estimate** same as 'best estimate' except using the 'high' estimate grain yield plus the CO2 value at £0.04/kg CO2 (UK Stats Office, PRQ24110, 2001) and 0.31 tCO2/tgrain (Markham, 2002). (1259 l EtOH/t EtOH). See 'Resource potential' below for production co-efficients for co-products.

Subsidies: ethanol prices quoted above include 'set-aside' subsidies for wheat production being based on the UK average 'delivered' wheat price according to HGCA 2002. The current set-aside payment of £230/ha for wheat if used for ethanol production would result in an effective subsidy to ethanol of £0.081 per litre under 'best estimate' conditions. The relative impact of the set-aside payment on HGCA quoted traded wheat prices could not be disaggregated here.

Energy

Energy Ratio: The **Low** and **High** energy ratios are calculated here from the overall chain ethanol production (21.6 MJ/l EtOH) and the total energy input requirements (as primary energy) for feedstock production + delivery + conversion energy inputs + distribution transport energy requirements. In the 'straw not used as a fuel' row, no co-product credits have been applied- see below for potential co-product credits. Coltrain (2001) quoting a USDA report, states an energy ratio for corn to ethanol of 1.24 (GJout/GJin) but doesn't state if this value contains credits for co-products. In the 'straw used as fuel' row, the energy content of the 'recoverable straw' (see 'co-product energy content' footnote below) is assumed to be used for process heat (via steam) and electricity production in the conversion plant and so is added to the non-straw energy ratio above.

Feedstock production: Energy inputs into feedstock production include the energy requirements for the production and application of fertilisers and pesticide(s), farm fuel use, energy costs of equipment manufacture, transport of feedstock, processing, and drying. According to OECD/IEA (1994) the energy inputs for feedstock production and transport are 8093 MJ/ha to produce a wheat yield of 6.5 t/ha (15% grain moisture content). The energy content of the grain is 15.7 GJ/t (www.fao.org). Fertiliser (particularly nitrogen) inputs dominate feedstock production energy inputs. The **Low** estimate is derived from OECD/IEA 94 which provides a feedstock energy requirement per t wheat of 1210 MJ (8093MJ / 6.7 t wheat), multiplied by the 'low' wheat yield estimate above. **Intermediate est** as with 'low' estimate except yield is from best estimate yield above. **High** - high yield above used.

Feedstock Transport: Energy inputs for transport for **low** and **intermediate estimate** (MJ/t feedstock) are based on LBST_GM 2002 estimates for sugar beet and divided by the average LBST sugar beet yield to provide energy inputs per tonne feedstock transported. For the **Low** estimate, the energy inputs/t feedstock are multiplied by the 'low' wheat yield, for the **Best estimate** multiplied by the 'intermediate estimate' yield and for the **high** estimate multiplied by the high yield. The **High** estimate is based on Shapouri *et al.* (1995) for Maize (corn) transport to ethanol facilities in USA based on 100mile (160km) round trip requiring 2000 BTU/ton.mile on loaded delivery stage and 1000 BTU/ton.mile for the empty return leg: Journey average of 173.8 MJ/t or 0.00109 GJ/t.km (160km).

Conversion Energy: derived from IEA/OECD 94 which provides an energy input of 16 MJ/l EtOH produced.

Distribution Energy: **low estimate** is derived from sugar beet based ethanol distribution costs which in turn is based on LBST_GM 2002 estimates. The **high** value is from Shapouri *et al.* (1995) of 3173 BTU/gal EtOH : page 12; but did not provide distances.

Co-product energy content: Only the energy content of straw is considered here. Wheat straw has an energy content of 17.3 GJ/ oven dry t, 12.9 to 14.9 GJ/t raw straw and 1.3 t 'raw' straw are produced per t grain (Strehler and Stütze, 1987). We estimate that 50% of the 'raw' straw is recoverable (on environmental and practical grounds) leading to a potential **intermediate estimate** of 68.7 GJ potentially harvestable straw/ha (7.6*0.65*13.9).

GHG / CO2 emissions

GHG emissions: GHG emissions for feedstock production, transport, conversion and distribution have been calculated (as shown) per GJ EtOH produced with **Low** and **High** values calculated representing the range found in the literature. It should be noted that these values include estimates of N2O emissions arising from feedstock production - see below.

Feedstock production + transport: 'Feedstock transport' emissions are impossible to disaggregate from 'Farm fuel' emissions in OECD/IEA 1994, therefore, GHG emissions from feedstock production + transport are shown above and for illustrative purposes. GHG emissions from 'feedstock production + transport' are based on OECD/IEA 1994 and included primary emissions from fertiliser and pesticide manufacture and use and on-farm nitrous oxide emissions - 'by-product credits' are not included here. It is not possible to estimate emissions from 'transport only' based on beet ethanol transport emissions because of the different physical properties of beet and wheat.

Feedstock transport GHG emissions: the '**high**' estimate is derived from Mortimer (2002) for GHG emissions for rape seed transport in the UK e.g. 42 kg CO₂equiv./t biodiesel and a conversion efficiency of 0.332 t oil/t rape seed i.e. 13.944 kg CO₂equiv/t rape seed. Assuming that the transport of wheat is equivalent to rape seed, then emissions per ha for wheat transport are 106.0 kg CO₂equiv./t wheat (13.944*7.6) or 1.8 kgCO₂equiv/GJ EtOH (106.2/60.1). The '**Low**' estimate is calculated from ETSU (1996) quoted in *Armstrong et al.* (2002) which provides separate data from agricultural and transport operations.

Conversion: emissions data are used for the '**low**' ETSU 96 (quoted in *Armstrong et al.*, 2002), '**intermediate**,' Marland & Turhollow (1991; quoted in *Armstrong et al.*, 2002) and '**high**' OECD/IEA (1994) estimates.

Resource potential

General Notes: **Feedstock:** Yield- data from HGCA.com; 'best estimate' is the 12 year mean (1980 to 2002), **Low** is the lowest yield during this 12 year period and **High**; is the highest yield during this period. Conversion: Ethanol production plant conversion efficiencies provided by OECD/IEA 1994 is 0.366 tEtOH/tWheat and KSU/Sparks 2002 0.325 tEtOH/tbeet. Therefore, for the calculations used here an assumed efficiency of 0.366 tEtOH/tWheat is assumed for the '**High**' and '**Intermediate**' estimates and 0.325 t/t for the '**Low**' estimate.

Improvements in wheat yields of approximately 1 t grain per ha per decade may be expected to continue if sufficient incentives are available to farmers. In addition, approximately 1.3 t straw are produced with each t grain, a share of which (approximately 50%) could be used to provide process energy for ethanol production or could provide a lignocellulosic feedstock for lignocellulosic ethanol production - see section on lignocellulosic ethanol production. The energy content of the straw is between 12.9 to 14.9 MJ/kg. As a result, a wheat field yielding 8 t wheat / ha could also produce 72.8 GJstraw/ha gross (8*1.3*0.5*14.0).

Co-products: These include: i) Distillers Dry Grains and Solubles (DDGS), 310kg per tonne grain processed; ii) straw (0.65 t recoverable straw /t grain; 1.3 tstraw total/tgrain); and iii) Carbon Dioxide (310kg /t grain). DDGS is produced by drying the stillage resulting from distillation and fermentation- it can then be sold as cattle, poultry or pig feed and has a high phosphorous content (see Shurson, 2002). Coltrain (2001) states that upto half of the total amount of natural gas used in the ethanol plant is for drying Distillers Dry Grains, however, an alternative to selling DDGS is selling the undried version called 'Wet Distillers Grains (WDG) which is reportedly preferred by cattle but has a much shorter shelf-life (measured in days) and transport costs (having a water content of 60%). Coltrain also states that carbon dioxide capture and sale is only worth considering if an 'easily accessible market' is nearby and even so because of the low value of industrial CO₂ it may be difficult to make a profit.

Conversion costs: costs are derived from OECD/IEA (1994), Reith (2001), Wooley (1999) and KSU / Sparks (2002). The OECD/IEA data provides estimated costs for wheat to ethanol conversion plants based in the EU in 1991 US\$. The KSU/Sparks data is for modern corn to ethanol plants based in the US for a range of plant scales ranging from 45 to 300 thousand t EtOH per year. For these calculations the 40 million gallons (120 kt EtOH) per year plant data was used as most representative for EU/UK conditions. The OECD/IEA costs also reflect the costs of producing ethanol from a 395 t EtOH/day plant (approx. 120 kt per year) including fixed and variable costs. Juice separation (extraction), fermentation and distillation or energy intensive processes and energy costs dominate.

There is a lack of good quality, public domain data on conversion costs for wheat ethanol chains and so the dated OECD/IEA data is compared to the KSU/Sparks data for corn-ethanol systems to derive a likely range of conversion costs. Unsurprisingly, the OECD/IEA data provided the highest cost as it represents the state-of-the-art of the late 1980's and is therefore used to provide the 'high est' here. The 'low' and 'Best Estimate' values are derived from the KSU/Sparks estimates for 'Wet Milling' and 'Dry Milling' respectively.

Distribution costs: Indicative costs are taken from Coltrain (2001) who quotes established costs for 'transporting ethanol' in the US of USc 2 per gallon (3.785 litres) for local markets, USc 7 for 'regional markets' and USc 13 for shipping 'to the East or West coasts'. The 'regional markets' cost is used here of USc7 per US gallon and converted to GBP (£0.013/l EtOH) at the prevailing average exchange rate for 2001 (www.oanda.com).

Co-product value: 'Low' assumes that because the lignin content of straw (15%) is lower than wood (28%) there is insufficient lignin for the production of surplus electricity. 'High' is based on a UK 'green' premium value for electricity of 6p/kWh and an electricity production rate of 0.23kWh per l EtOH, 50% lower than the potential electricity production from wood per litre EtOH .

Energy

Energy Ratio: The 'Low' and 'High' energy ratios are calculated here from the overall chain ethanol production (21.6 MJ/l EtOH) and the energy input requirements (as primary energy) for feedstock production + delivery + conversion energy inputs + distribution transport energy requirements as provided. Co-product credits are applied in the 'lignin used as fuel' row based on the energy content of the recovered lignin as shown in 'energy content of by-products'- see below for potential co-product credits. Energy is required in various stages during processing / conversion, particularly for the production of enzymes. The distillation process itself is a major energy consumer and recent developments in membrane distillation (molecular sieve) techniques may result in future energy and emissions savings.

Feedstock production: Energy inputs into feedstock production are complicated by needing to allocate a share to grain and recoverable straw production. Inputs include the energy requirements for the production and application of fertilisers and pesticide(s), farm fuel use, energy costs of equipment manufacture, transport of feedstock, processing, and drying. According to OECD/IEA (1994) the energy inputs for feedstock production and transport are 8093 MJ/ha, producing a wheat yield of 6.5 t/ha (15% grain moisture content). The energy content of the grain is 15.7 GJ/t (14% moisture; www.fao.org). The energy content of straw is 13.9 MJ/kg (17% moisture; Strehler & Stützel, 1987) and 1.3 t raw straw are produced per t wheat grain- see 'resource potential' below. Fertiliser (particularly nitrogen) inputs dominate feedstock production energy inputs.

The 'Low' estimate is based on apportioning total energy inputs between grain and straw by the relative economic value of the grain versus recoverable straw i.e. £0.326 straw/£grain (straw £25/t delivered and grain £76.7/t delivered). 'Intermediate est' energy input share (straw:grain) based on energy contents (i.e. 13.9 GJ/t straw and 15.7 GJ/t grain; ratio = 0.576 GJstraw/GJgrain per ha), yield is from best estimate yield above. 'High est' - as 'best estimate, except high' straw yield used.

Energy inputs for transport (inter-estates) are derived from LBST_GM 2002 estimates for sugar beet and divided by the average yield used in LBST to provide energy inputs per tonne feedstock transported. For the 'Low' estimate, the energy inputs/t feedstock are multiplied by the 'low' wheat yield, for the 'intermediate estimate' multiplied by the 'best estimate' yield and for the 'high' estimate multiplied by the high yield.

Conversion Energy: derived from IEA/OECD 94 which provides an energy input of 16 MJ/l EtOH produced.

Distribution Energy: derived from sugar beet based ethanol distribution costs which in turn is based on LBST_GM 2002 estimates.

By-product energy content: Wheat straw has a lignin content of 15% (LBST_GM 2002). Lignin's energy content is 25.4 MJ/kg (LHV). Virtually all of this lignin plus small quantities of combustible material from other 'waste streams' and some biogas from waste water treatment is available for the production of electricity and process heat (via steam) through conventional combustion or novel gasification CHP routes. The 'Low' estimate is the energy content of the lignin contained in the 'low' straw yield, the 'Best' estimate is the energy content of the lignin in the best estimate straw yield and the 'High' in the 'high' yield. All three estimates are divided by the 'best estimate' ethanol yield/ha to the GJ/GJ EtOH estimates.

GHG / CO2 emissions

Summary GHG emissions: GHG emissions for feedstock production, transport, conversion and distribution have been calculated (as shown) per GJ EtOH produced with 'Low' and 'High' values calculated representing the range found in the literature. It should be noted that these values include estimates of N2O emissions arising from feedstock production - see below.

Feedstock production + transport: 'Feedstock transport' emissions are impossible to disaggregate from 'Farm fuel' emissions in OECD/IEA 1994, therefore, GHG emissions from feedstock production + transport are shown above and for illustrative purposes. 'Low' estimate is based on LBST_GM emissions and 'High' is for 'feedstock production + transport' from OECD/IEA 1994 assuming total emissions are allocated between straw and grain on an energy content basis (see 'Energy' feedstock production above) - 'by-product credits' are not included here. It is not possible to estimate emissions from 'transport only' based on beet ethanol transport emissions because of the radically different nature of beet and wheat. 'Intermediate estimate' is the average of 'Low' and 'High'.

Feedstock transport GHG emissions: derived from Mortimer 2002's estimate for GHG emissions for rape seed transport in the UK e.g. 42 kg CO2equiv./t biodiesel and a conversion efficiency of 0.332 t oil/t rape seed i.e. 13.944 kg CO2equiv./t rape seed. Assuming that the transport of wheat is equivalent to rape seed emissions per ha for wheat transport are 106.0 kg CO2equiv./t wheat (13.944*7.6) or 1.42 kgCO2equiv./GJ EtOH (106.2/74.6). There was insufficient wheat-specific data to calculate the 'Low' and 'High' estimates.

Conversion: OECD/IEA 1994 emissions data are used for the 'low', 'intermediate' and 'high' estimates. LBST_GM data could not be used here because co-product credits / penalties could not be disaggregated.

Resource potential

Improvements in wheat yields of approximately 1 t grain per ha per decade may be expected to continue if sufficient incentives are available to farmers. In addition, approximately 1.3 t straw are produced with each t grain, a share of which (approximately 50%) could be used to provide process energy for ethanol production or could provide a lignocellulosic feedstock for lignocellulosic ethanol production - see section on lignocellulosic ethanol production. The energy content of the straw is between 12.9 to 14.9 MJ/kg. As a result, a wheat field yielding 8 t wheat / ha could also produce 72.8 GJstraw/ha gross ($8 \times 1.3 \times 0.5 \times 14.0$).

Feedstock: Wheat grain yield data from HGCA.com multiplied by a straw production factor of 1.3 t straw (17% moisture; likely range 12-22%) per t grain (Strehler & Stützel, 1987) and further assuming that only 50% of the total straw production is available for environmental reasons. 'Best estimate' is calculated from the 12 year grain yield mean (1980 to 2002), 'Low' is calculated from the lowest grain yield during this 12 year period and 'High' is the highest national annual grain yield during this period. The grain yield is multiplied by 1.3×0.5 to provide an indication on the sustainable harvestable quantity of straw per ha.

Co-products: These include electricity and/or biogas which may itself be used for heat and electricity production within the facility. The energy requirements for the conversion facility are expected to be provided entirely from the combustion of the lignin contained in the straw but which can not be converted to ethanol.

Ligno-cellulosic Ethanol from SRC Wood									
SRC wood chips supplying a central integrated ethanol production facility producing about 150 000 t/yr of anhydrous ethanol. Feedstock production is based on current British practice. Lignin is used to provide heat and electricity; excess electricity sold to grid.									
Fuel chain summary									
Cost (no co-product credits)						Low		High	Unit
						7.7		14.4	£/GJ EtOH
Energy ratio:	Lignin not used as fuel					0.16		0.31	£/l EtOH
	Lignin used as fuel					0.55		0.56	GJout:GJin
GHG emissions						1.23		2.24	GJout:GJin
UK Specific?						4		40	kgCO2eq./GJ
Technology status (feedstock, conversion and distribution)	Wood to ethanol is a near market technology for both the feedstock supply (SRC) and conversion systems (enzymatic / acid hydrolysis and fermentation of both C6 and C5 sugars). However, a number of obstacles still need to be overcome to demonstrate feasibility at larger commercial scales e.g. 100 kt ethanol/yr or higher.								
Intermediary fuel chain stage parameters									
Production and transport	Low	Intermediate	High	Unit	Conversion and distribution	Low	Intermediate	High	Unit
Feedstock cost (delivered)	1.29	1.94	2.58	£/GJwood	Costs from conversion	4.86	8.10	8.91	£/GJ EtOH
	2.37	3.96	4.97	£/GJ EtOH		0.103	0.172	0.190	£/l EtOH
of which Feedstock transport cost		0.15		£/GJwood	Ethanol production	1.35	2.35	4.73	t EtOH/ha
		0.42		£/GJ EtOH		36.1	62.8	126.3	GJ EtOH/ha
						0.225	0.235	0.315	t EtOH/t dry wood
Recoverable wood yield (dry basis)	6.0	10.0	15.0	t/ha oven dry wood	Distribution cost		0.53		£/GJ EtOH
					Co-product value (electricity for grid)	-0.012	-0.018	-0.028	£/l EtOH
Energy input to feedstock production:	0.48	1.84	4.32	GJ/ha	Energy input to conversion process	1.76	1.76	1.76	GJ/GJ EtOH
	0.008	0.029	0.069	GJ/GJ EtOH	Energy input to distribution		0.016		GJ/GJ EtOH
Energy input to feedstock transport:	0.29	1.14	2.70	GJ/ha	Energy content of co-products (Lignin only)	0.67	1.12	1.68	GJ/GJ EtOH
	0.005	0.018	0.043	GJ/GJ EtOH					
GHG from feedstock production	3	10	28	kgCO2eq./GJ EtOH	GHG from conversion process	0.0		11.2	kg CO2eq. /GJ EtOH
GHG from feedstock transport only	1		2	kgCO2eq./GJ EtOH	GHG from distribution		0.9		kg CO2eq. /GJ EtOH
					Allocation of GHG to by-products		n/a		kg CO2eq. /GJ EtOH

Technology Status

Yields of SRC are likely to continue to improve from 5 to 6 dry t/ha on-farm now to 12+ t/ha in the near future if SRC is produced on a significant scale (10 000 ha or higher). Because the conversion technology(ies) is still at the demonstration stage both the energy inputs and costs are uncertain. Energy is required in various stages during processing / conversion, particularly for the production of enzymes. The distillation process itself is a major energy consumer and recent developments in membrane distillation (molecular sieve) techniques may result in future energy and emissions savings. Improvements in the conversion technologies are expected as the technology matures and NREL predict cost reductions in the order of 40% over the next 10 years (as calculated in our 'low' cost estimate). It is expected that the Shell/logen plant which is likely to be based in Europe would be based on cereal straw conversion. Major cost reductions are expected to be achieved primarily through reductions in the costs of producing enzymes likely to arise by the production of better modified organisms.

Notes: [Ecoport crop id:1782 'poplar' (www.ecoport.org)]

General Notes: The data presented here is based on wood from short rotation coppice (SRC) supplying a central integrated ethanol production facility producing about 150 000 t/yr of anhydrous ethanol. Feedstock production is based on current British practice, but reliable data on costs, energy inputs and emissions from commercial scale conversion facilities is not yet available as there is only one pilot demonstration plant currently running. This plant is the logen facility in Canada which uses wheat and barley straw, producing about 5000 t EtOH per year (www.iogen.ca).

Conversion efficiencies: Ethanol production plant conversion efficiencies; **Low**' estimate provided by Wooley 1999 (NREL), 0.225 tEtOH/twood, **Intermediate**' LBST_GM 2002, 0.235 tEtOH/tpoplar wood and **High**' assumes a 40% improvement ('future') in conversion efficiency to 0.315 tEtOH/twood which is very close to the theoretical maximum yield.

Costs

Fuel Chain Summary Costs: The costs provided here may not represent the full range of potential costs for the production of ethanol because of the difficulty in obtaining representative reliable costs for conversion facilities and so the range reflects the likely sensitivity of ethanol production costs to feedstock supply economics. Conversion costs are based on Wooley 1999 (NREL) and are projected costs based on research-scale systems. The lignin residues are assumed to provide all the internal energy requirements in the conversion facility and a surplus for electricity production and so no costs are incurred from the purchase of natural gas or electricity.

Feedstock production and transport costs: Rough estimates and ranges for SRC-based feedstock supply costs are provided. **Intermediate** assumes a price of £25/t dry wood, **Low** £20/dry t wood and **High** estimate assumes a delivered price of £30/dry t wood. The costs are based on the likely production costs per tonne dry wood in the UK, however, £20/t dry wood is comparable to estimates of large scale delivered wood costs in USA which Wooley estimated at US\$25/dry US ton or £16.8/t (1997 US\$ value).

Conversion costs: costs are derived from Wooley 1999 (NREL). Wooley (Appendix D) provides estimated costs for wood (yellow poplar) to ethanol for a model conversion plant based in the USA in 1997 US\$. The prevailing exchange rate (www.oanda.com) was used to convert these costs to GBP, but the value was NOT then inflated by RPI. The **Intermediate estimate** is based on actual conversion costs as estimated by Wooley 1999 for a 157 000 t/yr EtOH production facility using a combination of acid hydrolysis followed by pentose and hexose co-fermentation. Wood is delivered to the plant for £25/oven dry t. The **High** cost assumes a 10% increase in conversion costs plus a delivered wood cost of £30/dry t. The **Low** cost is based on a 40% decrease in conversion costs by 2010 (Wooley 1999) and a delivered wood price of £20/dry t.

Distribution costs: Indicative costs are taken from Coltrain (2001) who quotes established costs for 'transporting ethanol' in the US of USc 2 per gallon (3.785 litres) for local markets, USc 7 for 'regional markets' and USc 13 for shipping 'to the East or West coasts'. The 'regional markets' cost is used here of USc7 per US gallon and converted to GBP (£0.013/l EtOH) at the prevailing average exchange rate for 2001 (www.oanda.com).

Co-product value: **Low** is based on Wooley 1999 US value or electricity produced for export to the grid of USc7.2 per gallon EtOH produced. **Intermediate estimate** is based on Reith 2001 which states that a 150 kt EtOH per year plant would produce 10.9 Mwe or approximately 0.47 kWhe per l EtOH produced at €0.06/kWhe or €0.03/l EtOH. **High** is based on a UK 'green' premium value for electricity of 6p/kWh and a production rate of 0.5kWhe per l EtOH as derived

Subsidies: A set-aside payment of £230/ha is available for SRC in the UK plus a number of establishment grants. The set-aside grant would result in an effective subsidy to ethanol of £0.078 per litre under 'best estimate' conditions.

Energy

Energy Ratio: The **Low** and **High** energy ratios are calculated here for the overall ethanol production chain (21.6 MJ/l EtOH) and the energy input requirements (as primary energy) for feedstock production + delivery + conversion energy inputs + distribution transport energy requirements as taken from LBST_GM 2002 and Reith 2001 (both based on Wooley (NREL) 1999). In the 'Lignin used as fuel' data, co-product energy credits have been applied for the energy content of the lignin- see below for potential co-product credits. It is likely that the lignin (which can't be converted into ethanol) and other combustible waste streams would be burnt to produce process heat (via steam) and electricity. The energy content of the lignin (25.4 MJ/kg) in the wood (18 GJ/oven dry t) is sufficient to provide all the conversion energy input requirements for both electricity and heat as can be seen from the data provided.

Feedstock Production: energy input requirements for the production of wood to be between 0.01 and 0.07 GJ/GJ EtOH (0.016 - 0.030 MJ/MJ feedstock) depending on yield, fertiliser inputs and harvesting technology including chipping. Indirect energy inputs, in the form of energy inputs for the production of machinery and agro-chemicals used, have not been considered. The energy input to feedstock production ranges between 0.0044 and 0.065GJ per GJ of biomass feedstock (wood chips) produced (Bauen, 2000; LBST_GM, 2002). The value used as best estimate is 0.016 GJ/GJ of feedstock (wood chips) produced (Bauen, 2000). LBST_GM (2002) estimate a net energy input for the supply of poplar wood of 0.075MJ/MJ wood delivered, approximately five times higher than our 'high' estimate. The broad range is attributable to the range in the intensity of activities associated with crop establishment and management.

Feedstock Transport: Energy inputs for transport (MJ/MJ feedstock) are derived from Bauen estimates for SRC and multiplied by the energy content per ha of the wood produced. For the **Low** estimate, a 48km round trip (plus low 'other costs') requiring 0.0027 MJ/MJ wood, multiplied by the 'low' wood yield, for the **intermediate estimate** an average of the low and high energy requirements 0.0064 MJ/MJ wood, multiplied by the 'best estimate' yield and for the **high** estimate, 66km round trip and 0.010 MJ/MJ biomass, multiplied by the high yield. A value of 0.82MJ/t.km has been used for the mineral diesel energy input to transport (value derived from average truck consumption of 0.03l/t.km and diesel energy content of 36.4MJ/l (Bauen 2000).

Conversion Energy: **low** **high** and **intermediate estimate** is for the total energy input required by the conversion process and is derived from Reith 2001, based on NREL data, calculated as 1.76 GJ/GJEtOH produced. For comparison, LBST_GM 2002, also quote an 'energy loss' of 1.77 MJ/MJEtOH. There is sufficient residual lignin produced, which if burnt in the plant would meet all the internal steam (heat: 95 MWth) and electricity requirements (33 MWe) and a further 10.9 MWe could be exported to the grid (Reith, 2001).

Distribution Energy: derived from sugar beet based ethanol distribution costs which in turn are based on LBST_GM 2002 estimates. 0.0011GJ/t.km is assumed for the fossil energy input to transport (value derived from average truck consumption of 0.03litre/t.km and diesel energy content of 36.4MJ/litre - Bauen 2000).

Co-product energy content: According to Wooley (1999) 28% of the wood (bone dry basis) is comprised of lignin which has an energy content of 25.4 GJ/t (LHV). Virtually all of this lignin plus small quantities of combustible material from other 'waste streams' and some biogas from waste water treatment is available for the production of electricity and process heat (via steam) through conventional combustion or novel gasification CHP routes. The **Low** estimate is the energy content of the lignin contained in the 'low' SRC yield (i.e. 6t/ha wood), the **intermediate** estimate is the energy content of the lignin in the intermediate estimate wood yield and the **High** in the 'high' yield.

GHG / CO₂ emissions

emissions are derived from Bauen 2000. **Low**- 3.47 g/MJ dry biomass multiplied by 6 t/ha at 18GJ/t. **Intermediate Est** is the average unit emissions (g/MJ biomass) of low and high multiplied by 10t/ha (18GJ/t).

High- based on LBST_GM 2002 calculated emissions from 'feedstock supply' of 29.9 g/MJEtOH produced or 10.3 g/MJ dry wood- transport emissions have been subtracted based on high 'transport' only emissions of 2kgCO₂eq/GJ EtOH. GHG emissions from 'feedstock production + transport' include primary emissions from fertiliser and pesticide manufacture and use and on-farm nitrous oxide emissions..

Feedstock transport GHG emissions: emissions are derived from Bauen 2000. The **Low** estimate is based on unit emissions of 2.26 g/MJ biomass and multiplied by low yield (18 GJ/t). The **High** estimate is based on a unit emission of 3.12 g/MJ biomass, 'high' yield (18 GJ/t).

Conversion: LBST_GM 2002 emissions data are used for the **Low** and **high** estimates. The LBST_GM data were adjusted for the carbon content of the ethanol (71.3 g CO₂/MJ) which under their methodology is accounted for on combustion in the vehicle. This was the only estimate for wood-based ethanol production conversion emissions that could be found in the literature. **Low** assumes that residual is used to provide all the energy inputs for the conversion process and so net emissions are virtually zero.

Resource potential

The resource potential for wood-to-ethanol in the UK is heavily dependent on demonstration of commercial scale plants and the policy / support framework within which growers are likely to operate.

Feedstock production: Energy inputs into feedstock production include land preparation, crop management and harvesting. The **Low** and **High** estimates are based on Bauen 2000 and the **Intermediate** is a simple average of the low and high values per unit of biomass produced, multiplied by the 'best est' SRC yield. SRC yields provided above represent the likely range of yields in the UK depending on land quality, location and management practices (including the levels of nitrogen fertiliser applications) . 'Best estimate' is good average yield under UK conditions, 'Low' is likely to represent yields on upland areas, wetlands and areas where nitrogen application rates are extremely sensitive. 'High' is a good yield on good quality land in the UK.

Co-products: These include process heat, electricity and/or biogas which may itself be used for heat and electricity production within the facility. On a dry mass basis 26.7% of wood (yellow poplar) is lignin with an energy content of 25.4 MJ/kg. The energy content of the lignin is roughly equal to the energy content of the produced ethanol and it is likely that the lignin will be burnt within the facility to produce the heat (steam) and electricity requirements for the fermentation, distillation and enzyme production systems. There is also likely to be a surplus of electricity of about 1kWh for every 4kWh produced using conventional bioler and steam turbine systems. Small amounts of additional combustible waste streams are also produced which would also be fed into the boiler. Wooley (1999) states an excess electricity production rate of 1.762 kWh per gallon EtOH produced or 0.47 kWh/l EtOH.

Rape (<i>Brassica napus</i>) Methyl Ester (RME)											
Life Cycle evaluation of Rape Methyl Ester (RME) production in the UK based on mature, or near market, technologies. The energy balance is calculated without any co- or by-product benefits i.e. all energy inputs to rape seed production and conversion are assigned to RME production. Low, Best Estimate and High values are provided for feedstock production, transport, conversion and RME distribution and key 'fuel chain summary' factors provided as derived from the literature and explained in the footnotes.											
Fuel chain summary											
						Low	Best Est	High	Unit		
Cost (no co-product credits):						20.87		32.82	£/GJ RME		
						0.62		0.97	£/litre RME		
<i>Energy ratio</i> No co-product credits						0.7	1.9	3.3	GJout:GJin		
Straw used as fuel						1.8	3.1	4.4	GJout:GJin		
<i>CO2 emissions</i>						26.7	27.8	41.4	kgCO2/GJ RME		
<i>GHG emissions</i>						16.8	44.1	44.9	kgCO2eq./GJ RME		
<i>UK Specific?</i>						Yes					
<i>Technology status (feedstock, conversion and distribution)</i>						Both feedstock production and conversion technologies are mature. However, improvements are expected to continue in feedstock yields and conversion efficiencies.					
Intermediary fuel chain stage parameters											
Production and transport		Low	Best Estimate	High	Unit	Conversion and distribution		Low	Best Estimate	High	Unit
<i>Feedstock cost (farm gate)</i>		9.75	10.41	10.41	£/GJseed	Costs from conversion			6.14		£/GJ RME
		14.47	23.20	34.88	£/GJ RME	RME production		0.69	1.03	1.65	t RME/ha
<i>Feedstock transport cost</i>			0.28		£/GJseed	RME production		25.6	38.5	61.6	GJ RME/ha
			0.61		£/GJ RME	By-product value		1.50	5.88	6.45	£/GJ RME
<i>Feedstock yield (seed)</i>		2.2	3.1	4.1	t/ha	Distribution cost			0.20		£/GJ RME
Energy input to feedstock production:		8.93	8.93	21.17	GJ/ha	Energy input to conversion process		0.21	0.22	0.27	GJ/GJ RME
		0.232		0.550	GJ/GJ RME	Energy input to distribution		0.001	0.010	0.013	GJ/GJ RME
Energy input to feedstock transport:		0.24	0.51	0.6657	GJ/ha	Energy content of by-products		1.12	2.04	2.08	GJ/GJ RME
		0.006		0.017	GJ/GJ RME						
GHG from feedstock production:		14.8	28.6	28.6	kgCO2eq./GJ RME	GHG from energy input to conversion process		1.7		14.3	kg CO2eq. /GJ RME
CO2 from feedstock production:		13.6		21.8	kgCO2/GJ RME	CO2 from energy input to conversion process		12.3	13.1	17.7	kg CO2/GJ RME
GHG from feedstock transport:		0.2	1.1	1.1	kgCO2eq./GJ RME	CO2 from distribution		0.08	0.10	0.88	kg CO2/GJ RME
CO2 from feedstock transport:		0.8	1.0	1.0	kgCO2/GJ RME	Allocation of CO2 to by-products		None			

NOTES: [ECOPORT plant id: 549 (www.ecoport.org)]

COSTS

Overall costs:

Cost (no co-product credits): '**Low**' cost (£/GJ) is based on the median market value of rape seed in the UK for 2002 (£150.00 per t; HGCA, 2002). The conversion and distribution costs are estimated at £6.14/t RME produced (as shown). '**High**' cost is based on actual production costs (ECOTEC 1999) without any set-aside subsidies- conversion costs are assumed to the £6.14/t RME. ECOTEC 1999, provides estimated 'pump prices' for RME in the range of 25 to 37p/l (£7.62 to £11.28/GJ RME).

Feedstock costs:

General Notes: Feedstock production costs of £892/ha as calculated in ECOTEC 99 (p11) are used for both the 'low' and 'Best Est' calculations above - assumed to include harvesting but not transport costs. 70% of these feedstock costs are 'fixed' and 30% 'variable'. For comparison, the market value of rape seed was £130/t seed (£468/ha) in ECOTEC 99 which combined with the set-aside subsidy of £256/ha resulting in a net loss to farmers for rape seed production of £168/ha. Mortimer (2002) provides an average price for Rape Seed of £152/t seed (p27) and a gross margin per ha for winter rape of £261/ha or £586 with subsidies. Set-aside land used for RME production benefits from a subsidy of £256/ha (£7.5/GJ RME) and using ECOTEC 99 data this equates to a benefit of £0.169/l RME. In addition, a tax break of 20p/l RME is available in the UK equivalent to £6.8/GJ RME.

Feedstock production Low estimate: calculated from production costs of £892/ha (ECOTEC 99) and a rape seed yield of 3.6 t/ha (as quoted). The energy density of the rape seed taken to be 25.424 GJ/tseed, based on Groves 2002. £/GJ RME is calculated from the 'low' rate of RME production shown above in the conversion and distribution section.

Feedstock production Best and High estimates: Production costs of £892/ha (ECOTEC 99) and rape yields of 3.6 t/ha (as quoted). Energy density (LHV, 10% moisture) for Rape Seed of 23.8 MJ/kg quoted in the LBST_GM (2002) study (page 258 annex) compared to seed energy density used in 'Low Est' of 25.424 GJ/t seed (Groves 2002). £/GJ RME is calculated from the 'best est' and 'high' rates respectively, of RME production shown above in the conversion and distribution section.

Feedstock transport costs are based on HGCA (2002) haulage costs for a 120 km journey (75 miles) of £6.60 per tonne- £0.055 per t.km. Groves (2002) states a distance of 100km from field to crusher and Mortimer 2002 (p27) quotes an average round trip distance of 260 km for raw rapeseed transportation.

Conversion & Distribution costs:

Conversion costs include oil extraction (crushing) + transport (120 km) + esterification. Only a single **Best Est'** figure is provided because there is insufficient data in the literature to generate a low and high value.

The value provided above is based on the average costs for small scale crushing systems and large scale esterification plants- detailed costs for conversion (oil extraction) could only be found for relatively small scale systems e.g. 15, 130 and 750 kg seed/h, 0.1 to 6 t RME per day (www.folkcenter.dk). Costs for esterification are based on Michaelis (IEA/OECD, 94) who quotes a cost for esterification only (i.e. not including oil extraction) of US\$ 16/l RME (1991 US\$) equivalent to £0.10/l (1991 GBP exchange equiv) for a 60 t RME per day plant. Groves (2002) estimates an 80 km round trip for transporting the oil from the crushing unit to the esterification plant. In Mortimer 2002, the crushing and esterification units are assumed to be co-located. We have used data from the HGCA (www.hgca.com) 'Haulage Survey 2001' for haulage economics in the UK of £6.60/tonne hauled for an average distance of 75 miles (120 km)

Distribution costs ('Best Est' only) are based on HGCA (2002) haulage costs (120 mile journey; 75 miles) of £6.60 per tonne. It should be noted that the HGCA survey states that 'the most common length of journey in the UK continued to be between 25 and 50 miles in 2001.'

By-product value(s): Three main by-products are produced during the production of RME which have a potential value: i) straw: Mortimer 2002 quote a straw production rate of 0.98 tstraw/t raw rape seed and an economic value of £25/t straw and Groves (2002) 1.6 tstraw/tseed. ii) Glycerine: £388/t crude glycerine (Mortimer 2002) which is produced at the rate of 100 kg/t vegetable oil or 31 to 45 kg glycerine / t seed depending on the oil extraction efficiency. ECOTEC 99 quote a co-product value for Glycerine of £0.22 per l RME. iii) Rape Meal: £95.5/t (HGCA 2002) and 580 to 630 kg/tseed depending on the oil extraction efficiency.

'Low': glycerine only (high oil extraction efficiency- therefore high glycerine yield). **Best Est'** is based on the sale of both glycerine and meal, but not straw, at the low production rates and values stated above.

'High' is calculated from the value of the glycerine+meal+straw (based on the values quoted above) and the high seed production rate and therefore represents the maximum possible practical financial return from by-products.

ENERGY

Energy input into feedstock production is dominated by the energy requirements of the production of nitrate fertiliser. In total, Nitrogen inputs to RME production represent between 40 and 50% of energy inputs to feedstock production. Energy inputs into conversion are based on heat requirements being met from natural gas and electrical requirements being met by grid-based electricity.

Energy ratio (balance): 'no co-product credits': calculated from the feedstock production, transport, conversion and distribution values provided above. The **high'** estimate is calculated from the lowest seed yield and highest production, transport conversion and distribution energy inputs. The **low'** estimate is based on the highest seed yields and the lowest production, transport conversion and distribution energy inputs.

Therefore, it is important to note that this is a theoretical calculation and is extremely unlikely to represent a practical implementation e.g. the highest yields will not result from the lowest agricultural energy inputs, but the data does provide an indication of the range in energy balances that could occur between good and bad implementation. The **Best Est'** of 1.9 GJout/GJin is in line with a number of the more detailed studies evaluated, however, it does not include any co-product credits and so in practice represents the low end of likely future energy balances.

Straw used as fuel: energy content of recoverable straw under 'best estimate' conditions (see 'co-product energy credits' below) e.g. 1.12 GJ/GJ RME is added to the 'low', 'best estimate' and 'high' energy ratios without co-product credits (see above) to provide an estimate of the impact of using straw as a fuel either to power the conversion process or for the provision of other energy services e.g. CHP.

Feedstock production energy requirements:

Energy inputs for feedstock production are derived from the range found in the literature. The **'Best Est'** is derived from Mortimer (2002) as this is the most detailed review of UK specific energy requirements for RME production to date. The Mortimer 2002 figure is also used for the **'Low'** estimate and the **'High'** is the maximum energy requirement found quoted in the literature. In total 25 estimates for feedstock energy production have been evaluated with a mean energy requirement of 13 254± 3132 MJ/ha.

Feedstock transport energy requirements:

Feedstock Transport- although not a major component in total energy input requirements, considerable differences in assumptions exist in the literature. The **Best Est'** is based on Mortimer et al. (2002) which quotes a round trip distance 260km (160 miles) between field and mill. The **Low'** estimate is based on Groves (2002) which quotes a 190 km round trip (120 miles). The **High'** estimate calculation is based on the energy requirement per tonne of rape seed for the 'Best Est' multiplied by the 'High' seed yield value above.

Conversion & Distribution energy requirements:

Conversion: Detailed, disaggregated calculations of the energy requirements for conversion of rape seed into RME were only found in a few references. As a result, the **Best Est** is derived from Groves (2002) and being based on Shell data probably represents current business practice. The **High** estimate is derived from IEA/OECD (1994) and represents the energy requirements for RME production at the start of the last decade. The **Low** estimate is taken from Mortimer (2002) and represents the state-of-the-art in RME production technologies available now, showing the improvements that have occurred over the last decade in energy efficiency. Both heat and electricity are required in significant quantities to power the oil extraction and the esterification processes. The electricity is generally assumed to be derived from the grid and the heat from natural gas, however, some references are made to natural gas CHP systems being operated and the potential to supply the heat from either rape straw or wood (LBST-GM 2002). **Distribution** energy inputs are based on Groves and Mortimer. The **Low** estimate is derived from Groves (2002) who estimates a transport energy cost of delivering the RME from the Esterification plant to a refinery for blending with mineral diesel. The **High** estimate is taken from Mortimer (2002) which estimates the energy requirements of transporting the RME from the Esterification plant to a refinery and then on to the sales outlet (forecourt)- a return journey of 450 km. The **Best Est** is calculated from Mortimer (2002) but is revised from Louis (2001) who provides detailed estimates for transport distances from refineries to sales outlet reducing the round trip journey quoted by Mortimer (2002) by 25%.

Co-product energy credits:

Co-product allocation: Three potential by-products result from the production of RME. These are: i) straw (14.2 MJ/kg, 0.98 tstraw/tseed), ii) glycerine (17 MJ/kg, 0.0332 tglycerine/tseed) and iii) rape meal (18 MJ/kg, 0.627 tmeal/tseed). The energy content of the co-products are provided. The allocation of energy inputs to co-product outputs is controversial and can be done by i) the energy content of the co-product, ii) the energy required to produce the co-products substitute e.g. rapemeal for soyameal and iii) the co-products market value. It is worth noting that the energy content of the potentially harvestable rape straw could theoretically cover the entire energy requirements of the conversion processes many times over. In addition, Mortimer 2002 notes that CO₂ recovery during ammonium nitrate fertiliser manufacture occurs and is subsequently used as an industrial gas (£0.21/kg CO₂) and a credit (on economic value basis) is applied, although this does not lead to a significant reduction in carbon requirement for fertiliser manufacture allocated to rape production.

Low is the energy content of straw only given 'best' estimate seed yields and RME production efficiency. **Best** estimate is the energy content of the straw plus meal and **High** is the energy content of the straw+meal+glycerine calculated from 'best' estimate seed yields and RME production efficiency (tRME/tseed).

GHG & CO₂ EMISSIONS

GHG emissions are generally calculated using IPCC (1996) guidelines and are based on emission factors from fertiliser use and 100 year global warming potentials.

Feedstock production emissions:

CO₂ and GHG emission are provided for comparison above but this footnote refers only to GHG emissions. For both feedstock production and feedstock transport, **Low** estimate is based on ECOTEC (2001) and **Best Est** and **High** emissions are derived from Mortimer (2002). Nitrogen fertiliser use represents the most significant source of emissions resulting from both the energy requirements from its production and the in field emissions after application to the soil. Nitrogen fixing rotational crops can help reduce the nitrogen fertiliser requirements for crop growth.

Conversion & Distribution emissions:

CO₂ and GHG emission are provided for comparison above but this note refers only to GHG emissions. For both conversion and distribution, **Low** estimate is based on ECOTEC (2001) and **Best Est** and **High** emissions are derived from Mortimer (2002). Very significant reductions could be made in the use of fossil fuels for energy inputs by using rape co-products as fuels, however, so far there are no published examples of this happening to our knowledge. The similarity between the CO₂ and GHG emissions data provided for conversion arises because there are no nitrogen fertiliser-based N₂O emissions during the conversion and distribution phases of RME production.

OTHER EMISSIONS

N₂O emissions primarily arise from complex reactions between synthetic nitrogen fertilisers, soils, organic matter and climate and are accounted for here in the GHG emissions calculations provided above but a high degree of uncertainty exists as a result of the complexity of its genesis and the lack of good 'in-field' data. Emissions of particulates, carbon monoxide and water are not evaluated here although the health and environmental impacts may be extremely important. A more complete analysis of emissions including Sulphur Oxides (SO_x), Nitrogen Oxides (NO_x), Particulates and Volatile Organic Carbon (VOC) and Carbon Monoxide (CO) is provided in ECOTEC 99.

RESOURCE POTENTIAL

Rape seed yields are derived from the range found in the literature and cross-checked with the UK average for 2001 (FAOSTAT 2002). The **Best Est** is the mean of the literature derived range and the **Low** and **High** are the minimum and maximum yields found quoted in the literature. The energy content of raw rape seed is taken from LBST_GM (2002) as 23.8 MJ/kg seed.

RME Production: **Low** is low conversion efficiency (high temperature pressing) and low seed yield. **Best Est** is based on Mortimer (2002) average extraction efficiency and 'Best Est' seed yield. **High** is solvent extraction and high seed yield.

TECHNOLOGY STATUS

The evaluation provided here is based on the range of data found in the literature. It represents the range of technologies available for both production and conversion of rape to produce methyl ester and all the technologies are technologically mature.

Waste (Recovered) Oils - Biodiesel									
Waste (recovered) vegetable oils for the production of vegetable oil methyl ester (VME) i.e. biodiesel, in the UK based on purification followed by esterification (nominally 120 kt/yr biodiesel capacity). Glycerine will be produced as a by-product.									
Fuel chain summary									
Cost (preliminary):						Low	Intermediate	High	Unit
						6.72	0.25	7.82	£/GJ VME
Energy ratio						6.6		8.0	£/litre VME
GHG emissions						1.9	14.5	16.1	GJout:GJin
UK Specific?						Yes			kgCO2equiv./GJ VME
Technology status (feedstock, conversion and distribution)									Mature
Intermediary fuel chain stage parameters									
Production and transport	Low	Intermediate	High	Unit	Conversion and distribution	Low	Intermediate	High	Unit
<i>Feedstock cost (delivered)</i>		4.43		£/GJoil	Costs from conversion		2.99		£/GJ VME
		4.65		£/GJ VME					
<i>Feedstock transport cost</i>		0.18		£/GJoil	RME production:	58520	285000	356385	t VME national total
						2182796	10630500	13293143	GJ VME national total
Feedstock yield (recovered oil)	61600	300000	375142	t national total	By-product value	0.00		1.09	£/GJ VME
	2217600	10800000	13505098	GJoil national total	Distribution cost		0.18		£/GJ VME
NB: All energy data below refers to non-renewable energy									
Energy input to feedstock production		None		GJ/GJ oil	Energy input to conversion process	0.12	0.12	0.12	GJ/GJ VME
Energy input to feedstock transport	0.001	0.010	0.013	GJ/GJ VME	Energy input to distribution	0.001	0.010	0.013	GJ/GJ VME
					Energy content of by-products (Glycerine)	0.02	0.02	0.02	GJ/GJ VME
GHG from feedstock production		None		kgCO2equiv./GJ VME	GHG from energy input to conversion process	1.7	14.3	14.3	kg CO2equiv. /GJ VME
GHG from feedstock transport	0.08	0.10	0.88	kgCO2equiv./GJ VME	GHG from distribution	0.08	0.10	0.88	kg CO2equiv./GJ VME
					Allocation of CO2 to by-products		None		

NOTES: 'VME' - vegetable oil methyl ester

TECHNOLOGY STATUS

The evaluation provided here is based on estimates of potentially available waste vegetable oil from large potential suppliers e.g. the Ministry of Defence (MOD). It is assumed that the major costs (energy and financial) are incurred during the purification and esterification process. However, because there is no extraction or feedstock production compared to rape seed methyl ester, the energy balance is higher and the financial costs of production significantly lower.

COSTS

Feedstock costs:

General Notes: Feedstock (waste vegetable oil) is based on a delivered price of £165/t (de Winne, 2002) for 'processed recovered oil'.

Feedstock production: **Low, Intermediate** and **High** estimates assume a 5% loss in mass between delivery of waste oil and production of vegetable oil methyl ester.

Feedstock transport costs are not available separately and so assumed to be the same as distribution costs as both delivery and distribution involve the transport of liquids (with similar chemical and physical characteristics) over similar distances.

Conversion & Distribution costs:

Conversion costs include estimated purification + esterification costs. Only a single estimate is provided because there is insufficient data in the literature to generate low and high values. It is based on the average costs for a large scale esterification plants. Costs for esterification are based on Michaelis (IEA/OECD, 94) which quotes a cost for esterification only (i.e. not including oil extraction) of US\$ 16/l RME (1991 US\$) equivalent to £0.10/l (1991 GBP exchange equiv) for a 60 t RME per day plant.

Distribution costs: based on HGCA (2002) haulage costs (120 km journey; 75 miles) of £6.60 per tonne.

By-product value(s): The only by-product produced during the production of VME from waste oil is Glycerine: £388/t crude glycerine (Mortimer 2002) which is produced at the rate of 100 kg/t vegetable oil or 31 to 45 kg glycerine / t seed depending on the oil extraction efficiency. ECOTEC 99 provide a by-product value for Glycerine of £0.22 per l RME (£6.7/GJ VME). Mortimer data is used here. **Low** does not include any by-product credits, **high** includes the value of the glycerine production.

ENERGY

Energy inputs are dominated by the energy inputs in to oil purification and esterification. Energy inputs into conversion (esterification and purification) are based on heat requirements being met from natural gas and electrical requirements being met by grid-based electricity and the primary energy inputs into methanol production. The energy content of 'waste oil' is assumed to be 36 GJ/t and for vegetable oil methyl ester (VME) 37.3 GJ/t i.e. equivalent RME.

Feedstock production energy requirements:

None. As waste product no energy inputs for feedstock production are provided.

Feedstock transport energy requirements:

Feedstock Transport- assumed to be equal to distribution energy inputs as no reliable data could be found on energy requirements for collection to central distribution point and on-ward transfer to an esterification plant. Therefore energy inputs for feedstock collection are assumed to be limited to the energy costs of transport of the oil to the esterification facility from collection points, as per distribution - see below.

Conversion & Distribution energy requirements:

Conversion: Most sources in the literature quote a combined energy input requirement for 'oil extraction' (crushing) and esterification/purification. Heat (via steam) and electricity are required in significant quantities for both the oil extraction and the esterification processes. The electricity is generally assumed to be derived from the grid and the heat from natural gas, however, some references are made to natural gas CHP systems being operated and the potential to supply the heat from either straw or wood (LBST-GM 2002). LBST_GM 2002, does provide estimates of energy inputs for crushing, purification and esterification separately, however, these are in the form of energy inputs into the process and not primary energy requirements. In communication with LBST (Weindorf, pers comm) it was established that the boiler efficiency is assumed to be 85% and that electricity is assumed to be provided by the national grid (est. 35% efficiency) and so the steam and electricity inputs have been modified to calculate primary energy inputs here. LBST data is used to calculate primary energy inputs for only the esterification and purification processes.

Distribution costs are based on Groves (2002) and Mortimer (2002). The **Low** estimate is derived from Groves (2002) which estimates a transport energy cost of delivering the RME from the Esterification plant to a refinery for blending with mineral diesel. The **High** estimate is taken from Mortimer (2002) which estimates the energy requirements of transporting the RME from the Esterification plant to a refinery and then on to the sales outlet (forecourt)- a return journey of 450 km. The **Intermediate Est** is calculated from Mortimer (2002) but is revised to account for a lower average delivery distance in Louis (2001) who provides detailed estimates for transport distances from refineries to sales outlet reducing the round trip journey quoted by Mortimer (2002) by 25%.

Co-product energy credits:

Co-product allocation: The only by-product that results from the production of VME from waste oil is glycerine (17 MJ/kg, 0.0332 tglycerine/tseed). No co-product credits are calculated here, however, the energy content of the co-products is provided.

GHG & CO2 EMISSIONS

Feedstock production emissions:

None as derived from waste product.

Conversion & Distribution emissions:

For both conversion and distribution, **Low** estimate is based on ECOTEC (2001) and **Intermediate Est** and **High** emissions are derived from Mortimer (2002). Very significant reductions could be made in the use of fossil fuels for energy inputs by using biomass or by-products as fuels, however, so far there are no published examples of this happening to our knowledge.

RESOURCE POTENTIAL

Waste Vegetable Oil Production: **Low** is lowest estimate found to date in the literature (Guardian, 21Oct02) quoting 70 Ml per year. **Intermediate Est** is based on Billins (2002, pers comm) guesstimate of annual available waste vegetable oil of 100 000 t from UK-Home Office plus 200 000 t from UK Ministry of Defence (MOD). **High** is derived from CEC (2001) which provides estimates of 17Mt of WVO in Europe (EU-15) of which 75% is WVO.

Assuming that per capita consumption is the same throughout Europe gives a consumption of 0.0339 t/cap. UK supply is therefore 2.028 Mt (0.0339*59.8 million) of which 18.5% is recoverable (based on Austrian experience) 375 000 t used vegetable oil might be available in the UK.

Also- see main report for more detailed evaluation of resource potentials.

SRC Biomass Derived Fischer-Tropsch Diesel									
Fuel chain summary									
Wood chips from short rotation coppice (SRC) willow. Biomass gasified in an indirectly heated atmospheric gasifier (BCL gasifier). Syngas reforming prior to full conversion FT process (40% per pass) with generation of electricity using off-gas. FT liquids production assumed to be 60% diesel, 25% kerosene, 15% naphtha.									
						Low	High		Unit
Biofuel cost						8.85	15.01		£/GJ(FTliq)
Reference price (diesel)						5.40	21.10		£/GJ
Energy ratio (biofuel energy produced per unit non-renewable energy input)						18.05	62.43		GJ(FTliq) out/GJ in
Reference energy ratio (diesel)						0.89	0.89		GJ(diesel)/GJ(fossil) in
GHG emissions:						2.4	28.9		kgCO2 eq/GJ(FTliq) out
Reference GHG emissions (diesel):						84.4	84.4		kgCO2 eq/GJ(diesel)
UK Specific?									Yes for SRC
Technology status (feedstock, conversion and distribution)									Feedstock production is early commercial. Biomass gasification technology is at the demonstration stage. FT process technology is mature (proven since 1950s using fossil fuel derived feedstock). Integrated biomass gasification FT process is at demonstration stage.
Intermediary fuel chain stage parameters									
Production and transport	Low	Intermediate	High	Unit	Conversion and distribution	Low	Intermediate	High	Unit
<i>Feedstock cost (delivered):</i>	1.39	2.22	3.33	£/GJ (biomass)	<i>Costs from conversion</i>	7.77		7.77	£/GJ(FTliq)
<i>Feedstock cost (delivered):</i>	3.31	5.29	7.94	£/GJ (FTliq)	<i>FT Liquid production efficiency</i>	36.9	73.7	110.6	GJ (FTliq)/ha
<i>Feedstock transport cost:</i>	<i>Above costs include feedstock transport</i>				<i>By-product electricity</i>	0.14		0.14	GJ (el)/GJ (FTliq)
					<i>By-product value:</i>	0.02		0.06	£/kWh
						0.77		2.31	£/GJ(FTliq)
					<i>Distribution cost</i>	0.079		0.079	£/GJ(FTliq)
NB: All energy data below refers to non-renewable energy									
<i>Energy input to feedstock production:</i>	0.004		0.016	GJ/GJ(biomass)	<i>Energy input to conversion process</i>	None			GJ/GJ(FTliq)
	0.009		0.033	GJ/GJ(FTliq)					
<i>Energy input to feedstock transport:</i>	0.003		0.010	GJ/GJ(biomass)	<i>Energy input to distribution</i>	0.0012		0.0012	GJ/GJ(FTliq)
	0.006		0.021	GJ/GJ(FTliq)					
<i>GHG from feedstock production:</i>	0.92	3.37	13.10	kgCO2 eq./ GJ(biomass)	<i>GHG from energy input to conversion process</i>	None			kgCO2 eq./ GJ (FTliq)
	1.92	7.02	27.29	kgCO2 eq./ GJ (FTliq)	<i>GHG from energy input to distribution</i>	0.09		0.09	kgCO2 eq./ GJ (FTliq)
<i>GHG from feedstock transport:</i>	0.20		0.74	kgCO2 eq./ GJ(biomass)					
	0.41		1.53	kgCO2 eq./ GJ (FTliq)					

Notes:

Costs

Feedstock costs

Wood chips from short rotation coppice willow are assumed as feedstock. Feedstock costs can vary widely depending on yield and management practices. A range of £1.4/GJ to £3.3/GJ has been used (equivalent to about £25 to £60 per tonne), which reflects costs commonly cited in the literature. UK-specific cost calculations for SRC willow have shown that the feedstock could be produced for £1.5/GJ for a yield of 10t(oven dry)/ha and efficient crop management practices. Transport cost is based on transport by truck of 60m³ capacity at costs of between £0.0015 and £0.0037/km.GJ. A 100km return transport distance contributes about £0.25/GJ to the cost of feedstock.

Conversion cost

367MWth feedstock input gasifier is considered based on considerations of economies of scale and feedstock supply (would require 70,000ha or 700km² of SRC plantation - i.e. planting of 1% of land within a 150km radius). FT liquid production is 154MW(FTliq). In FT diesel mode, the following FT liquid split is assumed: 60% FT diesel, 25% kerosene and 15% naphtha (energy basis). FT diesel production is 92MW, equivalent to about 8t/h. The conversion plant also produces about 21MW electricity. The overall conversion efficiency is 48% (LHV), 42% net of electricity production. Calculations based on BCL indirectly heated gasifier under demonstration in Burlington, Vermont. Total investment cost is estimated at 395 mill \$. On-site FT diesel storage costs are not considered.

By-product value

The range of by-product (electricity) prices is typical for present day. High price assumes 'green' premium, low price assumes no premium

Distribution cost

Transport to the refuelling station is assumed to be by tanker at a cost of £0.053/(t km). For comparison with hydrogen fuel chain, transport distance is estimated to be 32 km (64km return). (The energy density of FT diesel is assumed to be the same as that of fossil diesel 42.8 MJ/kg).

Energy

All references to input energy refer to non-renewable energy inputs

Only direct non-renewable energy inputs to biomass feedstock production and transport are considered - Bauen 2000. Non-renewable energy inputs associated with the establishment of the conversion plant are not considered - these have been estimated to be of the same order of the energy input to feedstock production on an annual basis (Bauen 2000).

Energy inputs are allocated between FT liquid fuels and by-product (electricity) in proportion to the energy content of the two outputs

The heat and electricity requirements of the conversion plant are met by biomass energy produced on-site so net elec demand and non-renewable energy input to the plant is zero

It is assumed that all machinery and transport vehicles are fuelled with diesel. A value of 0.00082GJ/(km t) has been used for the fossil energy input to transport (value derived from avg truck consumption of 0.03litre/(km t) and diesel energy content of 36.4MJ/litre - Bauen 2000). However, the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO₂ emissions from the transport stage.

GHG (CO₂ equivalent) emissions

Direct CO₂ emissions from biomass production and transport activities are considered.

No CO₂ emissions are associated with the conversion plant.

CO₂ emissions from transport are based on a 73.5kgCO₂/GJ energy consumed by road transport

CO₂ emissions are allocated between FT liquid fuels and by-product (electricity) in proportion to the energy content of the two outputs

Resource potential

Indicative potential for the UK based on 2 mill ha of SRC with avg yield of 10t(oven dry)/(ha yr): 8.6PJ of FT liquid, of which about 5.2PJ of FT diesel - corresponding to about 145 Ml of FT diesel. Annual diesel consumption for road transport in the UK in 2001 was 16.42 mill toe (total petrol and diesel consumption for road transport was 37.35 mill toe).

Notes:

April 2002 diesel price £0.769/litre (£21.1/GJ), of which £0.573/litre is tax (£15.7/GJ).

Sources:

Tijmenssen et al. (2002)

ETSU (1996)

Borjesson (1998)

Methanol from biomass gasification									
Wood chips from short rotation coppice; atmospheric indirectly heated gasification (BCL gasifier); syngas reforming and liquid phase methanol production and refining; liquid methanol distribution by tanker.									
Fuel chain summary									
Methanol cost	6.05					Low	9.52	High	Unit
Energy ratio (non-renewable energy input per unit biofuel produced)	7.33						65.51		£/GJ(MeOH)
GHG emissions	2.2						24.9		GJ(MeOH)/GJ in
UK Specific?	Yes for SRC								
Technology status (feedstock, conversion and distribution)	Feed stock production is in early commercial stage. Biomass gasification technology is at the demonstration stage. Methanol production from biomass syngas is at the demonstration stage.								
Intermediary fuel chain stage parameters									
Production and transport	Low	Intermediate	High	Unit	Conversion and distribution	Low	Intermediate	High	Unit
Biomass feedstock cost (delivered)	1.39	2.22	3.33	£/GJ (biomass)	Conversion cost	3.40		3.40	£/GJ (MeOH)
Biomass feedstock cost (delivered)	2.48	3.97	5.95	£/GJ (MeOH)	Electricity consumption	0.11		0.11	MJe/MJ(MeOH)
					Distribution cost	0.17		0.17	£/GJ (MeOH)
					Methanol Production	56.8	113.5	170.3	GJ MeOH/ha
NB: All energy data below refers to non-renewable energy									
Energy input to feedstock production:	0.0044	0.016	0.065	GJ / GJ(biomass)	Energy input to conversion process	None			GJ /GJ(MeOH)
Energy input to feedstock production:	0.008	0.029	0.116	GJ /GJ(MeOH)	Energy input to distribution	0.0026		0.0026	GJ /GJ(MeOH)
Energy input to feedstock transport:	0.0027		0.010	GJ / GJ(biomass)					
Energy input to feedstock transport:	0.005		0.018	GJ /GJ(MeOH)					
GHG from feedstock production:	0.92	3.37	13.10	kgCO2 eq./ GJ(biomass)	GHG from energy input to conversion process	None			kgCO2 eq./ GJ (MeOH)
GHG from feedstock production:	1.6	6.0	23.4	kgCO2 eq./ GJ (MeOH)	GHG from energy input to distribution	0.19		0.19	kgCO2 eq./ GJ (MeOH)
GHG from feedstock transport:	0.20		0.74	kgCO2 eq./ GJ(biomass)					
GHG from feedstock transport:	0.35		1.31	kgCO2 eq./ GJ (MeOH)					

Notes: For more details on feedstock production and transport see also 'Lignocellulosic Ethanol from SRC' and 'Hydrogen from Biomass' analysis sheets

Costs

Feedstock cost

Wood chips from short rotation coppice willow are assumed as feedstock. Feedstock costs can vary widely depending on yield and management practices. A range of £1.4 to £3.3/GJ has been used, which reflects costs commonly cited in the literature. UK-specific cost calculations for SRC willow have shown that the feedstock could be produced for £1.5/GJ for a yield of 10t(oven dry)/ha and efficient crop management practices. Transport cost is based on transport by truck of 60m3 capacity at a cost of £0.0037/(km GJ). A 100km return transport distance contributes about £0.37/GJ to the cost of feedstock.

Conversion cost

400MWth feedstock input gasifier is considered based on considerations of economies of scale and feedstock supply (would require 70,000ha or 700km2 of SRC plantation - planting of 1% of land within a 150km radius). Methanol production is 40t/h (224MW(MeOH)). The overall conversion 56% (LHV) net of electricity used in the process. Calculations based on BCL indirectly heated gasifier under demonstration in Burlington, Vermont. Feedstock pre-treatment, gasifier and gas cleaning investment cost is estimated at 106.7 mill \$. Steam reforming and liquid methanol production and refining investment cost is estimated at 104.1 mill \$. The plant requires an electrical power input of 25MW and investment in power generation is estimated to contribute about 15 mill \$. On-site methanol storage costs are not considered.

Transport

Transport to the refuelling station is assumed to be by tanker at a cost of £0.053/(t km). For comparison with hydrogen fuel chain, transport distance is estimated to be 32 km (64km return). (The energy density of methanol is 20.3 MJ/kg).

Energy

All references to input energy refer to non-renewable energy inputs.

Feedstock production: The energy input to feedstock production ranges between 0.0044 and 0.065GJ per GJ of biomass feedstock (wood chips) produced (Bauen, 2000; LBST_GM, 2002). Our **Intermediate** estimate is 0.016 GJ/GJwood (Bauen, 2000). LBST_GM (2002, p193, Annex) estimate a net energy input for the supply of poplar wood of 0.075MJ/MJ wood delivered, approximately five times higher than our 'best' estimate (0.016GJ). The broad range is attributable to the range in the intensity of activities associated with crop establishment and management and possibly to energy inputs for drying.

Only direct non-renewable energy inputs to biomass feedstock production and transport are considered - Bauen 2000. Non-renewable energy inputs associated with the establishment of the conversion plant are not considered - these have been estimated to be of the same order of the energy input to feedstock production on an annual basis (Bauen 2000).

Conversion: No direct non-renewable energy inputs are associated with biomass conversion. Electricity needed for the plant is assumed to be produced from biomass on-site. 80 odt wood/hr are required to supply the 400MWth input and 40t MeOH/hr are produced i.e. 0.5t MeOH/odt wood. MeOH energy content (LHV) is 22.7 GJ/t.

It is assumed that all machinery and transport vehicles are fuelled with diesel. A value of 0.00082GJ/(km t) has been used for the fossil energy input to transport (value derived from avg truck consumption of 0.03litre/(km t) and diesel energy content of 36.4MJ/litre - Bauen 2000). However, the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO₂ emissions from the transport stage.

CO₂

Direct CO₂ emissions from biomass production and transport activities are considered.

No CO₂ emissions are associated with the conversion plant.

CO₂ emissions from transport are based on a 73.5kgCO₂/GJ energy consumed by road transport

Resource potential

Indicative potential for the UK based on 2 mill ha of SRC with avg yield of 10t(oven dry)/(ha yr): 200PJ of MeOH, equivalent to about 10 mill litres. Annual diesel consumption for road transport in the UK in 2001 was 16.42 mill toe, equivalent to about 687PJ (total petrol and diesel consumption for road transport was 37.35 mill toe, equivalent to about 1,564PJ).

Notes:

Methanol energy density is 20.3 MJ/kg. Ethanol energy density is 26.7 MJ/kg, volumetric density is 0.79kg/l. Biodiesel energy density is 37.8 MJ/kg, volumetric density is 0.88kg/l. Fossil diesel energy density is 42.8 MJ/kg, volumetric density is 0.84kg/l.

Sources:

Hamelinck (2001)

Bauen (2000)

Mortimer (2002)

Hydrogen from biomass gasification (compressed hydrogen storage and transport by tube trailer)							
Wood chips from short rotation coppice; atmospheric indirectly heated gasification (BCL gasifier); syngas reforming and shift reaction; hydrogen purification; compressed hydrogen storage and transport.							
Fuel chain summary							
					Low	High	Unit
Hydrogen cost (delivered to forecourt)					10.49	14.44	£/GJ(H2)
Energy ratio (biofuel energy produced per unit non-renewable energy input)					5.37	17.97	GJ(H2)/GJ in
GHG emissions					5.2	29.6	kgCO2eq/GJ(H2)
UK Specific?						Yes	
Technology status (feedstock, conversion and distribution)					SRC feedstock production is early commercial. Biomass gasification technology is at the demonstration stage. Syngas reforming to hydrogen needs to be demonstrated.		
Intermediary fuel chain stage parameters							
Production and transport				Conversion and distribution			
	Low	High	Unit		Low	High	Unit
Biomass feedstock cost (delivered)	1.39	3.33	£/GJ (biomass)	Conversion cost	3.53	3.53	£/GJ(H2)
Biomass feedstock cost (delivered)	2.67	6.41	£/GJ (H2)	Compression / liquefaction and storage cost	0.99	1.00	£/GJ(H2)
				Hydrogen production per ha (net)	46.8	140.4	GJ(H2)/ha
				Electricity consumption	0.064	0.064	MJe/MJ(H2)
				Distribution cost	3.30	3.50	£/GJ(H2)
NB: All energy data below refers to non-renewable energy							
Energy input to feedstock production:	0.0044	0.065	GJ / GJ(biomass)	Energy input to conversion process	None		GJ /GJ(H2)
	0.008	0.125	GJ /GJ(H2)	Energy input to compression / liquefaction and storage cost	None		GJ /GJ(H2)
Energy input to feedstock transport:	0.0027	0.010	GJ / GJ(biomass)	Energy input to distribution	0.042	0.042	GJ /GJ(H2)
	0.005	0.019	GJ /GJ(H2)				
GHG from feedstock production:	0.92	13.05	kgCO2 eq./ GJ(biomass)	GHG from energy input to conversion process	None		kgCO2 eq./ GJ (H2)
	1.8	25.1	kgCO2 eq./ GJ (H2)	GHG from energy input for distribution	3.1	3.1	kgCO2 eq./ GJ (H2)
GHG from feedstock transport:	0.20	0.74	kgCO2 eq./ GJ(biomass)				
	0.38	1.41	kgCO2 eq./ GJ (H2)				

Notes: GJ (H2): Hydrogen energy output at the production plant

Costs

Feedstock cost

Wood chips from short rotation coppice willow are assumed as feedstock. Feedstock costs can vary widely depending on yield and management practices. A range of £1.4/GJ to £3.3/GJ has been used (£25 to £60/dry t delivered), which reflects costs commonly cited in the literature. UK-specific cost calculations for SRC willow have shown that the feedstock could be produced for £1.5/GJ for a yield of 10t(oven dry)/ha and efficient crop management practices. Transport cost is based on transport by truck of 60m3 capacity at a cost of between £0.0015 and £0.0037/(km GJ). A 100km return transport distance contributes about £0.25/GJ to the cost of feedstock. (Bauen 2000)

Conversion to hydrogen

400MWth feedstock input gasifier is considered based on considerations of economies of scale and feedstock supply (would require 70,000ha or 700km2 of SRC plantation - i.e. planting of 1% of land within a 150km radius). Hydrogen production is 7.7t/h (256MW(H2)). The overall conversion efficiency 52% (LHV) net of electricity used in the process. Calculations based on BCL indirectly heated gasifier under demonstration in Burlington, Vermont. Feedstock pre-treatment, gasifier and gas cleaning investment cost is estimated at \$103.8 million (£65 million). Steam reforming, CO shift reaction and pressure swing absorption investment cost is estimated at \$134 million (£84 million). The plant requires an electrical power input of 22MW and investment in power generation is estimated to contribute about \$15 million (£9.4 million). Compressed storage (200bar) is assumed. The hydrogen production plant in question requires 17MW compressor power. Compressor capital cost at this scale is estimated at £30/kW(H2). On-site hydrogen storage is set at 10t. Storage cost at this scale is estimated at £335/kg. (Hamelinck 2001, Howes 2002)

Distribution

Transport to the refuelling station is assumed to be by tube trailer of capacity up to 460kg. Transport distance is estimated to be 32 km (64km return).

Energy

All references to input energy refer to non-renewable energy inputs.

Only direct non-renewable energy inputs to biomass feedstock production and transport are considered (Bauen 2000). Non-renewable energy inputs associated with the establishment of the conversion plant are not considered - these have been estimated to be of the same order of the energy input to feedstock production on an annual basis (Bauen 2000).

No direct non-renewable energy inputs are associated with biomass conversion. Electricity needed for the plant is assumed to be produced from biomass on-site.

See EtOH from wood analysis sheet for details. It is assumed that all machinery and transport vehicles are fuelled with diesel. A value of 0.00082GJ/(km t) has been used for the fossil energy input to transport (value derived from avg truck consumption of 0.03litre/(km t) and diesel energy content of 36.4MJ/litre - Bauen 2000). However, the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO2 emissions from the transport stage.

GHG (CO2 equivalent) emissions

Direct CO2 emissions from biomass production and transport activities are considered. See Lignocellulosic Ethanol from SRC sheet for details.

No CO2 emissions are associated with the conversion plant.

CO2 emissions from transport are based on 73.5kgCO2/GJ energy consumed by road transport.

Resource potential

Indicative potential for the UK based on 2 million ha of SRC with avg yield of 10t(oven dry)/(ha yr): 187PJ of H2, equivalent to about 1.6 million t. Total petrol and diesel consumption for road transport in the UK in 2001 was 37.35 Mtoe, equivalent to about 1,564PJ. Note that a more efficient conversion of H2 in fuel cell vehicles could lead to a reduction in energy requirements of transport.

Note:

For comparison with liquid hydrogen and compressed hydrogen by pipeline storage and transport options see "Offshore wind" sheets.

Sources:

Bauen (2000)

Hamelinck (2001)

Howes (2002)

Hydrogen from regional electrolysis of offshore wind electricity (compressed hydrogen transport to forecourt via tube trailer)							
Offshore wind electricity generation; transmission to regional electrolysis plant of capacity up to about 500MWe; compressed hydrogen transport to refuelling station within 50km radius.							
Fuel chain summary							
					Low	High	Unit
Hydrogen cost (delivered to forecourt)					11.45	29.11	£/GJ(H2)
Energy ratio (Hydrogen energy produced per unit non-renewable energy input)					23.8	23.8	GJ(H2)/GJ in
GHG emissions					3.1	3.1	kgCO2eq/GJ(H2)
UK Specific?						Yes	
Technology status (feedstock, conversion and distribution)					Electrolysis and offshore wind technology are commercial, but with potential for cost reductions.		
Intermediary fuel chain stage parameters							
Production and transport				Conversion and distribution			
Electricity cost (delivered):	Low	High	Unit	Electricity cost	Low	High	Unit
	2.00	5.50	p/kWh		0.60	1.50	£/GJ(H2)
	7.41	23.96	£/GJ H2	Compression / liquefaction and storage cost	0.14	0.15	£/GJ(H2)
				Distribution cost	3.30	3.50	£/GJ(H2)
				Electricity consumption	1.33	1.57	MJe/MJ(H2)
NB: All energy data below refers to non-renewable energy							
Energy input to electricity production:	None		GJ / GJ(elec.)	Energy input to electrolysis process	None		GJ /GJ(H2)
	None		GJ /GJ(H2)	Energy input to compression / liquefaction and storage	None		GJ /GJ(H2)
Energy input to electricity transport:	None			Energy input to distribution	0.04	0.04	GJ /GJ(H2)
GHG from electricity production:	None		kgCO2 eq./ GJ(elec)	GHG from energy input to electrolysis process	None		kgCO2 eq./ GJ (H2)
	None		kgCO2 eq./ GJ (H2)	GHG from energy input for distribution	3.1		3.1 kgCO2 eq./ GJ (H2)

Notes: GJ (H2): Hydrogen energy output at the production plant

Costs

Electricity cost

Current offshore wind electricity costs are estimated to be 5-5.5 p/kWh (based on installed turbine capital cost of about £1000/kW). Future (2020) offshore wind electricity costs are estimated to be 2-3 p/kWh (based on installed turbine capital cost of about £400/kW). It has been assumed that the figures include electricity transport and distribution costs.

The electricity cost per unit of hydrogen generated accounts for the electrolysis (3.8-4.5kWh/Nm3h) and compression (2.2kWh/kg) energy requirement per unit of hydrogen produced.

Electrolysis cost

Electrolysis plant hydrogen production capacity is 334MW (10t/h). High value is based on current electrolyser capital cost estimated at \$600/kW(H2) (£375/kW(H2)) (this corresponds to about \$1800/Nm3/h (£1125/Nm3/h)). Low value is based on estimated future electrolyser cost of \$240/kW(H2) (£150/kW(H2)) (this corresponds to about \$720/Nm3/h (£450/Nm3/h)). Calculations based on 20 year lifetime and 10% discount rate. O&M costs estimated at 2-3% of annualised capital cost. The contribution of water costs to the cost of hydrogen are low (assuming a £1/m3 cost of water, its contribution to the cost of hydrogen would be £0.083/GJ).

Compression / liquefaction and storage cost

Compressed storage (200bar) is assumed. The hydrogen production plant in question requires 22MW compressor power. Compressor capital cost at this scale is estimated at £30/kW(H2). On-site hydrogen storage is set at 10t. Storage capital cost at this scale is estimated at £335/kg. Electricity cost is included as part of the total electricity input to the electrolysis plant.

Transport cost

Transport to the refuelling station is assumed to be by tube trailer of capacity up to 460kg. Transport distance is estimated to be 32 km (64km return).

Energy

All references to input energy refer to non-renewable energy inputs.

No direct non-renewable energy inputs are associated with offshore wind energy production. Indirect energy input has not been considered, but is assumed to be low over the lifetime of the installation (<10%).

No direct non-renewable energy inputs to electrolysis plant. Indirect energy has not been considered, as not considered significant.

Energy input to transport consists of diesel use (based on 6 mile per gallon consumption) in the 'high' case. However, the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO2 emissions from the transport stage ('low' case).

CO2

No direct CO2 emissions from offshore wind electricity production. Indirect emissions have not been considered, but are assumed to be low over the lifetime of the installation.

No direct CO2 emissions from electrolysis plant. Indirect emissions have not been considered.

CO2 emissions from transport are based on 73.5kgCO2/GJ energy consumed by road transport

Resource potential

The technical potential for offshore wind electricity in the UK is estimated at 3,500TWh/yr. Practicable exploitable potential in the range 100 - 1,000TWh. Exploitable potential by 2010 is estimated at about 10TWh/yr. Exploiting 100TWh of offshore wind electricity for H2 production would provide about 69TWh (250PJ) of H2. Total petrol and diesel consumption for road transport in the UK in 2001 was 37.35 mill toe, equivalent to about 1,564PJ.

Sources:

Howes (2002)

Hydrogen from regional electrolysis of offshore wind electricity (liquid hydrogen transport to forecourt via road tanker)							
Offshore wind electricity generation; transmission to regional electrolysis plant of capacity up to about 500MWe; liquid hydrogen transport to refuelling station within 50km radius.							
Fuel chain summary							
					Low	High	Unit
Hydrogen cost (delivered to forecourt)					10.7	30.6	£/GJ(H2)
Energy ratio (Hydrogen energy produced per unit non-renewable energy input)					625	625	GJ(H2)/GJ in
GHG emissions					0.083	0.083	kgCO ₂ eq/GJ(H2)
UK Specific?					Yes		
Technology status (feedstock, conversion and distribution)					Electrolysis, liquefaction and offshore wind technologies are commercial, but with potential for cost reduction.		
Intermediary fuel chain stage parameters							
Production and transport		Low	High	Unit	Conversion and distribution		
Electricity cost (delivered):		2.00	5.50	p/kWh	Electrolysis cost		
Electricity cost (delivered):		7.88	26.62	£/GJ H2	Compression / liquefaction and storage cost		
					Distribution cost		
					Electricity consumption		
					0.60	1.50	£/GJ(H2)
					0.88	1.10	£/GJ(H2)
					1.30	1.40	£/GJ(H2)
					1.42	1.74	MJe/MJ(H2)
NB: All energy data below refers to non-renewable energy							
Energy input to electricity production:		None		GJ / GJ(elec.)	Energy input to electrolysis process		None
Energy input to electricity production:		None		GJ /GJ(H2)	Energy input to compression / liquefaction and storage		None
Energy input to electricity transport:		None			0.0016	0.0016	GJ /GJ(H2)
Energy input to electricity transport:		None			Energy input to distribution		0.0016
GHG from electricity production:		None		kgCO ₂ eq./ GJ(elec)	GHG from energy input to electrolysis process		None
GHG from electricity production:		None		kgCO ₂ eq./ GJ (H2)	0.083	0.083	kgCO ₂ eq./ GJ (H2)
					GHG from energy input for distribution		0.083

Notes: GJ (H2): Hydrogen energy output at the production plant

Costs

Electricity cost

Current offshore wind electricity costs are estimated to be 5-5.5 p/kWh (based on installed turbine capital cost of about £1000/kW). Future (2020) offshore wind electricity costs are estimated to be 2-3 p/kWh (based on installed turbine capital cost of about £400/kW). It has been assumed that the figures include electricity transport and distribution costs.

The electricity cost per unit of hydrogen generated accounts for the electrolysis (3.8-4.5kWh/Nm³h) and liquefaction (5 - 8kWh/kg) energy requirement per unit of hydrogen produced.

Electrolysis cost

Electrolysis plant hydrogen production capacity is 334MW (10t/h). High value is based on current electrolyser capital cost estimated at \$600/kW(H2) (£375/kW(H2)) (this corresponds to about \$1800/Nm³h (£1125/Nm³h)). Low value is based on estimated future electrolyser cost of \$240/kW(H2) (£150/kW(H2)) (this corresponds to about \$720/Nm³h (£450/Nm³h)). Calculations based on 20 year lifetime and 10% discount rate. O&M costs estimated at 2-3% of annualised capital cost.

Compression / liquefaction and storage cost

Liquefied storage is assumed. The hydrogen production plant requires 80MW liquefaction power. Liquefaction capital cost at this scale is estimated at £295/kW(H2) . On-site hydrogen storage is set at 10t. Storage capital cost at this scale is estimated at £57/kg. Electricity cost is included as part of the total electricity input to the electrolysis plant.

Transport cost

Transport to the refuelling station is assumed to be by tanker of capacity between 360 and 4300kg liquid H2. Transport distance is estimated to be 32 km (64km return).

Energy

All references to input energy refer to non-renewable energy inputs.

No direct non-renewable energy inputs are associated with offshore wind energy production. Indirect energy input has not been considered, but is assumed to be low over the lifetime of the installation (<10%).

No direct non-renewable energy inputs to electrolysis plant. Indirect energy has not been considered, as it is estimated not to be significant.

Energy input to transport consists of diesel use (based on 6 mile per gallon consumption) in the 'high' case. However, the use of a renewable transport fuel would result in zero non-renewable energy input to transport and zero CO₂ emissions from the transport stage ('low' case).

CO₂

No direct CO₂ emissions from offshore wind electricity production. Indirect emissions have not been considered, but are assumed to be low over the lifetime of the installation.

No direct CO₂ emissions from electrolysis plant. Indirect emissions have not been considered.

CO₂ emissions from transport are based on 73.5kgCO₂/GJ energy consumed by road transport

Resource potential

The technical potential for offshore wind electricity in the UK is estimated at 3,500TWh/yr. Practicable exploitable potential in the range 100 - 1,000TWh. Exploitable potential by 2010 is estimated at about 10TWh/yr. Exploiting 100TWh of offshore wind electricity for H₂ production would provide about 64TWh (230PJ) of H₂. Total petrol and diesel consumption for road transport in the UK in 2001 was 37.35 mill toe, equivalent to about 1,564PJ.

Sources:

Howes (2002)

Hydrogen from regional electrolysis of offshore wind electricity (compressed hydrogen transport to forecourt by pipeline)									
Offshore wind electricity generation; transmission to regional electrolysis plant of capacity up to about 500MWe; pipeline hydrogen transport to refuelling station within 50km radius.									
Fuel chain summary									
					Low	High	Unit		
Hydrogen cost (delivered to forecourt)					8.7	26.4	£/GJ(H2)		
Energy ratio (Hydrogen energy produced per unit non-renewable energy input)					Very large		GJ(H2)/GJ in		
GHG emissions					0	0	kgCO2eq/GJ(H2)		
UK Specific?					Yes				
Technology status (feedstock, conversion and distribution)					Electrolysis and offshore wind technology are commercial, but with potential for cost reductions.				
Intermediary fuel chain stage parameters									
Production and transport		Low	High	Unit	Conversion and distribution		Low	High	Unit
Electricity cost (delivered):		2.00	5.50	p/kWh	Electrolysis cost		0.60	1.50	£/GJ(H2)
Electricity cost (delivered):		7.41	23.96	£/GJ H2	Compression / liquefaction and storage cost		0	0	£/GJ(H2)
					Distribution cost		0.73	0.90	£/GJ(H2)
					Electricity consumption		1.33	1.57	MJe/MJ(H2)
NB: All energy data below refers to non-renewable energy									
Energy input to electricity production:		None		GJ / GJ(elec.)	Energy input to electrolysis process		None		GJ /GJ(H2)
Energy input to electricity production:		None		GJ /GJ(H2)	Energy input to compression / liquefaction and storage		None		GJ /GJ(H2)
Energy input to electricity transport:		None			Energy input to distribution		0	0	GJ /GJ(H2)
GHG from electricity production:		None		kgCO2 eq./ GJ(elec)	GHG from energy input to electrolysis process		None		kgCO2 eq./ GJ (H2)
GHG from electricity production:		None		kgCO2 eq./ GJ (H2)	GHG from energy input for distribution		0	0	kgCO2 eq./ GJ (H2)

Notes: GJ (H2): Hydrogen energy output at the production plant

Costs

Electricity cost

Current offshore wind electricity costs are estimated to be 5-5.5 p/kWh (based on installed turbine capital cost of about £1000/kW). Future (2020) offshore wind electricity costs are estimated to be 2-3 p/kWh (based on installed turbine capital cost of about £400/kW). It has been assumed that the figures include electricity transport and distribution costs.

The electricity cost per unit of hydrogen generated accounts for the electrolysis (3.8-4.5kWh/Nm3h) and compression (2.2kWh/kg - at refuelling station) energy requirement per unit of hydrogen produced.

Electrolysis cost

Electrolysis plant hydrogen production capacity is 334MW (10t/h). High value is based on current electrolyser capital cost estimated at \$600/kW(H2) (£375/kW(H2)) (this corresponds to about \$1800/Nm3/h (£1125/Nm3/h)). Low value is based on estimated future electrolyser cost of \$240/kW(H2) (£150/kW(H2)) (this corresponds to about \$720/Nm3/h (£450/Nm3/h)). Calculations based on 20 year lifetime and 10% discount rate. O&M costs estimated at 2-3% of annualised capital cost.

Compression / liquefaction and storage cost

The pipeline is assumed to act as the storage medium. Typical pipeline operating pressure would be 1-3MPa.

Transport cost

The total pipeline length to serve 17 stations within a 50km radius from the plant is estimated at about 75km. The pipeline capital cost is estimated at between £110,000/km and £180,000/km for throughput varying between 3.6GJ/h (30kg/h) and 57GJ/h (475kg/h). Total investment cost ranges between £8 million and £14 million.

Energy

All references to input energy refer to non-renewable energy inputs.

No direct non-renewable energy inputs are associated with offshore wind energy production. Indirect energy input has not been considered, but is assumed to be low over the lifetime of the installation (<10%).

No direct non-renewable energy inputs to electrolysis plant. Indirect energy has not been considered, as considered not to be significant.

No direct non-renewable energy inputs to pipeline transport.

CO2

No direct CO2 emissions from offshore wind electricity production. Indirect emissions have not been considered, but are assumed to be low over the lifetime of the installation.

No direct CO2 emissions from electrolysis plant. Indirect emissions have not been considered.

No direct CO2 emissions from pipeline transport.

Resource potential

The technical potential for offshore wind electricity in the UK is estimated at 3,500TWh/yr. Practicable exploitable potential in the range 100 - 1,000TWh. Exploitable potential by 2010 is estimated at about 10TWh/yr. Exploiting 100TWh of offshore wind electricity for H2 production would provide about 69TWh (250PJ) of H2. Total petrol and diesel consumption for road transport in the UK in 2001 was 37.35 mill toe, equivalent to about 1,564PJ.

Sources:

Howes (2002)

Hydrogen from forecourt electrolysis of offshore wind electricity (compressed hydrogen storage)									
Offshore wind electricity generation; transmission to forecourt electrolysis plant of capacity up to about 1.25MWe; compressed hydrogen storage.									
Fuel chain summary									
				Low	High	Unit			
Hydrogen cost (delivered to forecourt)				9.74	28.18	£/GJ(H2)			
Energy ratio (Hydrogen energy produced per unit non-renewable energy input)				Very large		GJ(H2)/GJ in			
GHG emissions				0	0	kgCO2eq/GJ(H2)			
UK Specific?				Yes					
Technology status (feedstock, conversion and distribution)				Electrolysis and offshore wind technology are commercial, but with potential for cost reductions.					
Intermediary fuel chain stage parameters									
Production and transport		Low	High	Unit	Conversion and distribution		Low	High	Unit
Electricity cost (delivered):		2.00	5.50	p/kWh	Electrolysis cost		1.10	2.80	£/GJ(H2)
Electricity cost (delivered):		7.41	23.96	£/GJ H2	Compression / liquefaction and storage cost		1.23	1.42	£/GJ(H2)
					Distribution cost		0	0	£/GJ(H2)
					Electricity consumption		1.33	1.57	MJe/MJ(H2)
NB: All energy data below refers to non-renewable energy									
Energy input to electricity production:		None		GJ / GJ(elec.)	Energy input to electrolysis process		None		GJ /GJ(H2)
Energy input to electricity production:		None		GJ /GJ(H2)	Energy input to compression / liquefaction and storage		None		GJ /GJ(H2)
Energy input to electricity transport:		None			Energy input to distribution		0	0	GJ /GJ(H2)
GHG from electricity production:		None		kgCO2 eq./ GJ(elec)	GHG from energy input to electrolysis process		None		kgCO2 eq./ GJ (H2)
GHG from electricity production:		None		kgCO2 eq./ GJ (H2)	GHG from energy input for distribution		0	0	kgCO2 eq./ GJ (H2)

Notes: GJ (H2): Hydrogen energy output at the production plant

Costs

Electricity cost

Current offshore wind electricity costs are estimated to be 5-5.5 p/kWh (based on installed turbine capital cost of about £1000/kW). Future (2020) offshore wind electricity costs are estimated to be 2-3 p/kWh (based on installed turbine capital cost of about £400/kW). It has been assumed that the figures include electricity transport and distribution costs.

The electricity cost per unit of hydrogen generated accounts for the electrolysis (3.8-4.5kWh/Nm3h) and compression (2.2kWh/kg) energy requirement per unit of hydrogen produced.

Electrolysis cost

Electrolysis plant hydrogen production capacity is 0.84MW (25kg/h). High value is based on current electrolyser capital cost estimated at \$930/kW(H2) (£580/kW(H2)) (this corresponds to about \$2800/Nm3/h (£1740/Nm3/h)). Low value is based on estimated future electrolyser cost of \$480/kW(H2) (£300/kW(H2)) (this corresponds to about \$1440/Nm3/h (£900/Nm3/h)). Calculations based on 20 year lifetime and 10% discount rate. O&M costs estimated at 2-3% of annualised capital cost.

Compression / liquefaction and storage cost

Compressed storage (200bar) is assumed. The hydrogen production plant in question requires 50kW compressor power. Compressor capital cost at this scale is estimated at £100/kW(H2). On-site hydrogen storage is set at about 300kg or half the average daily demand. Storage capital cost at this scale is estimated at £812/kg. Note: forecourt storage costs are not included in the costs in the table above as these could also apply to the other chains considered.

Transport cost

No transportation is required by this chain

Energy

All references to input energy refer to non-renewable energy inputs.

No direct non-renewable energy inputs are associated with offshore wind energy production. Indirect energy input has not been considered, but is assumed to be low over the lifetime of the installation (<10%).

No direct non-renewable energy inputs to electrolysis plant. Indirect energy has not been considered, as not considered significant.

CO2

No direct CO2 emissions from offshore wind electricity production. Indirect emissions have not been considered, but are assumed to be low over the lifetime of the installation.

No direct CO2 emissions from electrolysis plant. Indirect emissions have not been considered.

Resource potential

The technical potential for offshore wind electricity in the UK is estimated at 3,500TWh/yr. Practicable exploitable potential in the range 100 - 1,000TWh. Exploitable potential by 2010 is estimated at about 10TWh/yr. Exploiting 100TWh of offshore wind electricity for H2 production would provide about 69TWh (250PJ) of H2. Total petrol and diesel consumption for road transport in the UK in 2001 was 37.35 mill toe, equivalent to about 1,564PJ.

Sources:

Howes (2002)

Annex 2: Basic Fuel Characteristics

Diesel

	Value	Units
Net Calorific Value	42.8184	MJ/kg
Net Calorific Value	35.71	MJ/l
Density	0.834	kg/l
Density	1.199	l/kg
%wC	86.200	%
%wH	13.800	%
%wO	0.000	%
GHG: LBST_GM	83.2	kgCO ₂ eq/GJ
GHG: Mortimer + others	95	kgCO ₂ eq/GJ
GHG: LBST_GM	3.0	kg CO ₂ eq/litre
GHG: Mortimer + others	3.4	kg CO ₂ eq/litre

Biodiesel (RME)

	Value	Units
Net Calorific Value	37.27	MJ/kg
Net Calorific Value	32.80	MJ/l
Density	0.88	kg/l
Density	1.136	l/kg
CO ₂ content	76.7	gCO ₂ /MJ RME
GHG: LBST_GM	2.5	kg CO ₂ eq/litre

Wood

	Value	Units
Net Calorific Value	18.00	MJ/kg LHV
Net Calorific Value	15	MJ/kg LHV; air dry (15%)
Moisture content	0.050	Dry mass basis
Density	0.5	kg/l; softwood
Density	2	l/kg
C content oven dry wood	48%	

Sources:

Louis, 2001.
 Contreras *et al.* 1997.
 LBST_GM, 2002.
 Mortimer, 2002.

Gasoline / Petrol

	Value	Units
Net Calorific Value	43.9914	MJ/kg
Net Calorific Value	32.95	MJ/l
Density	0.749	kg/l
Density	1.335	l/kg
%wC	86.500	%
%wH	13.500	%
%wO	0.000	%
GHG: LBST_GM	86.6	kgCO ₂ eq/GJ
GHG: ORNL	102.1	kgCO ₂ eq/GJ
GHG: LBST_GM	2.9	kg CO ₂ eq/litre
GHG: ORNL	3.4	kg CO ₂ eq/litre

Ethanol (C₂H₅OH)

	Value	Units
Net Calorific Value	26.8	MJ/kg
Net Calorific Value	21.28	MJ/l
Density	0.794	kg/l
Density	1.259	l/kg
Carbon content	52.2%	%w
CO ₂ content	71.3	gCO ₂ /MJ EtOH
GHG: LBST_GM	1.5	kg CO ₂ eq/litre

Fischer Tropsch Diesel (SMDS)

	Value	Units
Net Calorific Value	46.0	MJ/kg
Net Calorific Value	35.88	MJ/l
Density	0.78	kg/l
Density	1.282	l/kg

Kerosine (C_{12.5}H_{24.4})

	Value	Units
Net Calorific Value	42.906	MJ/kg
Net Calorific Value	34.38	MJ/l
Density	0.801282	kg/l
Density	1.248	l/kg
%wC		%
%wH		%
%wO		%
GHG: LBST_GM		kgCO ₂ eq/GJ
GHG: ORNL		kgCO ₂ eq/GJ
GHG: LBST_GM		kg CO ₂ eq/litre
GHG: ORNL		kg CO ₂ eq/litre

Methanol (CH₃OH)

	Value	Units
Net Calorific Value	22.7	MJ/kg
Net Calorific Value	17.96	MJ/l
Density	0.791	kg/l
Density	1.264223	l/kg
Carbon content	37.5%	%w

DME

	Value	Units
Net Calorific Value	29.6	MJ/kg
Net Calorific Value	20.04	MJ/l
Density	0.677	kg/l
Density	1.477	l/kg

Hydrogen (H₂)

	Value	Units
Net Calorif	120	MJ/kg
Net Calorific Value		MJ/l
Density	0.071	kg/l
Density	14.085	l/kg

Lignin

	Value	Units
Net Calorif	25.36	MJ/kg LHV
lignin/twoc	0.277	Dry mass basis
Density		kg/l
Density		l/kg

Annex 3: Consultation process

The consultation process was carried out in three stages to:

1. Validate project methodology and RTF chains selected for detailed analysis.
2. Validate results of RTF chain analysis.
3. Obtain broad consensus over RTF chain analysis results and content of the report.

Stages 1 and 2 were carried out through e-mail contact with experts and stakeholders and some telephone and face-to-face conversations.

Stage 3 was carried out through the organisation of a workshop at Imperial College London with over 30 national and international participants representing the energy and automotive industries, trade associations, NGOs and government.