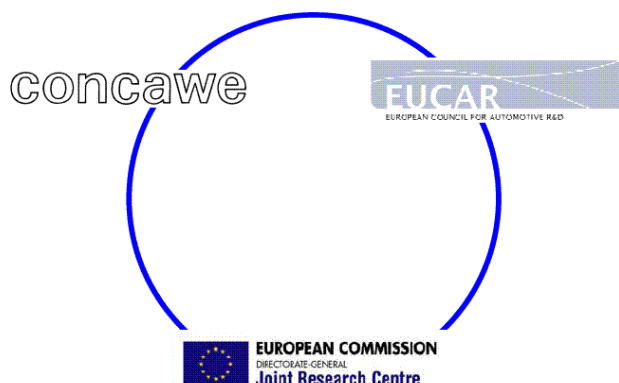# Well-to-wheels Analysis of Future Automotive Fuels and Powertrains in the European Context

WELL-to-TANK Report
Version 3c, July 2011

R. Edwards
European Commission Joint Research Centre, Institute for Energy

J-F. Larivé
CONCAWE

J-C. Beziat
Renault/EUCAR

concawe   EUCAR
EUROPEAN COUNCIL FOR AUTOMOTIVE R&D

EUROPEAN COMMISSION
DIRECTORATE-GENERAL
Joint Research Centre

JRC
EUROPEAN COMMISSION

iet
institute for Energy
and Transport

The mission of the JRC-IE is to provide support to Community policies related to both nuclear and non-nuclear energy in order to ensure sustainable, secure and efficient energy production, distribution and use.

***Europe Direct is a service to help you find answers
to your questions about the European Union***

Freephone number (*):

00 800 6 7 8 9 10 11

(*) Certain mobile telephone operators do not allow access to 00 800 numbers or these calls may be billed.

A great deal of additional information on the European Union is available on the Internet.
It can be accessed through the Europa server http://europa.eu/

Printed in Italy

WELL-TO-WHEELS ANALYSIS OF FUTURE AUTOMOTIVE FUELS AND POWERTRAINS IN THE EUROPEAN CONTEXT

concawe

EUCAR
EUROPEAN COUNCIL FOR AUTOMOTIVE R&D

EUROPEAN COMMISSION
DIRECTORATE-GENERAL
Joint Research Centre
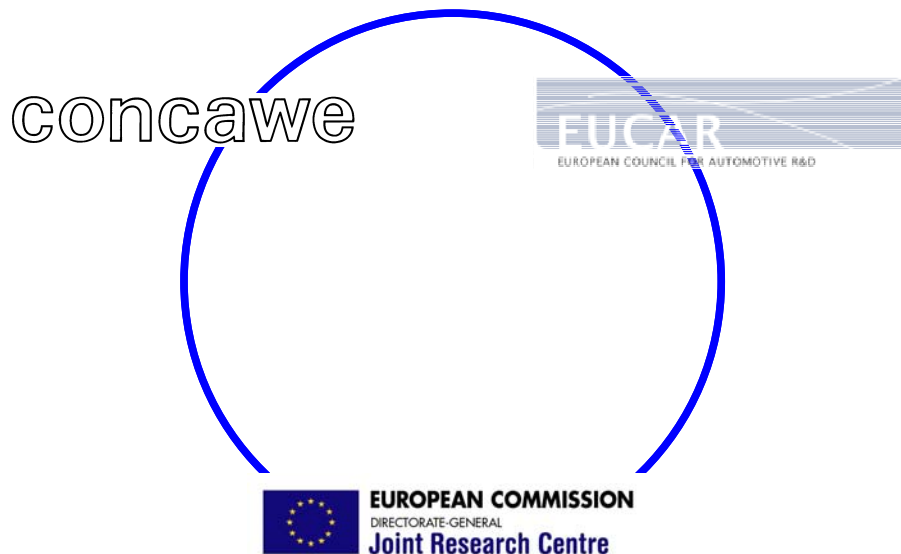
WELL-to-TANK Report

Version 3c, July 2011

http://iet.jrc.ec.europa.eu/about-jec
infojec@jrc.ec.europa.eu

Notes on version number:

This is the third version of this report replacing version 2c published in March 2007.

Although the scope of the study has not been fundamentally altered, a number of additional pathways have been added, mostly in the area of biofuels. The cost data have been updated. The section on availability or potential volumes of biofuels has not been updated, as it is felt that this has now developed into a much wider debate involving many more stakeholders than are involved in our study. As such, a review will need to be performed outside this study.

Acknowledgments

Table of contents

1 Introduction

This part of the study describes the process of producing, transporting, manufacturing and distributing a number of fuels suitable for road transport powertrains. It covers all steps from extracting, capturing or growing the primary energy carrier to refuelling the vehicles with the finished fuel.

As an energy carrier, a fuel must originate from a form of primary energy which can be either contained in a fossil feedstock (hydrocarbons of fissile material) or directly extracted from solar energy (biomass or wind power). Generally a fuel can be produced from a number of different primary energy sources. In this study, we have included all fuels and primary energy sources that appear relevant within the timeframe considered (next decade) and we have considered the issues and established comparisons from both points of view in order to assist the reader in answering the questions:

- What are the alternative uses for a given resource and how can it best be used?
- What are the alternative pathways to produce a certain fuel and which of these hold the best prospects?

Our primary focus has been to establish the **energy and greenhouse gas (GHG) balance** for the different routes. The methodology we used is based on the description of individual processes, which are discreet steps in a total pathway, and thereby easily allows the inclusion of additional combinations, should they be regarded as relevant in the future.

We have not considered the energy or GHG emissions associated with construction or decommissioning of plants and vehicles. There are two reasons for this. First the available data is often sketchy and uncertain. Second the impact of these additional energy requirements on the total pathway balance is generally small and within the range of uncertainty of the total estimates. This may, however, not always be the case and this should be checked when looking at a particular route in more details.

We have not included emissions or changes in albedo caused by indirect land use change, or from marginal intensification due to extra biofuels demand, even though we think these are probably important. These points are discussed in section 3.4.1.

The scale at which a route might be developed is relevant to the selection of appropriate energy data but also to the attention that should be given to a particular option. There used to be a widespread misconception that feedstocks for biofuels used in EU would be sourced from EU production until some limit of availability is reached, after which it would be imported. In version 2 of this report we endeavoured to assess the future "EU availability" of the different fuels and associated feedstocks, but we pointed out that this limit would never be reached in practice as imports would start to increase as soon as prices started to respond to the increased demand from biofuels. This now seems well understood, so the theoretical availability is rather irrelevant, and we have not updated our calculations in this version. The effect of crop demand for biofuels on EU food imports and generally on world agricultural markets has now become the object of many studies by agro-economic modellers, and has been covered in a broad way elsewhere [JRC 2008]. However, our analysis in WTT version 2 contained interesting data and discussion, so we have retained the original text as a reference.

The best options from an energy or GHG point of view are only likely to raise interest if they can be developed at a reasonable cost. Cost estimation is a difficult discipline and one must endeavour to define clearly what is intended. In this case we have attempted to consider the **costs to Europe** of producing a certain fuel in a certain way at a certain scale. This implies for example the cost of

internationally traded commodities (such as oil products or natural gas) is equal to the expected international market price.

In any such study, many choices have to be made at every step. These cannot always be based purely on scientific and technical arguments and inevitably carry an element of judgement. While we do not pretend to have escaped this fact, we have endeavoured to make our choices and decisions as transparent as possible. In particular this report details all primary input data and underlying assumptions.

This study has been conducted in collaboration with LBST[1] through whom we have had access to the comprehensive information database compiled by the TES consortium[2] and in the course of the study carried out in 2001-2002 by General Motors [GM 2002]. With the agreement of these two organisations we have used the information extensively. Over the course of this study, the original database has been to extensively reviewed and updated and a number of new processes and pathways added that had not hitherto been considered.

Help update our database
Our database is continually updated as we receive and evaluate new information. Readers are invited to send suggestions for improvements in our INPUT DATA to

infoJEC@jrc.ec.europa.eu

(note: since the results of life-cycle analysis studies are greatly affected by the methodology used, we cannot comment on why the results of other studies may differ from ours).

Relation with data used by European Commission Renewable Energy Directive
Our input database has been used by the European Commission as the basis for calculations of typical and "default" greenhouse gas savings for biofuels compared to fossil fuels in the 2008 Renewable Energy Directive and its fore-runner the draft Biofuels Directive. Note that those Commission calculations use an entirely different methodology from the one in this report, and therefore give different results.

Since our database is continually updated, the data used by the Commission changed during the process of the legislation. Many figures in the database were updated or improved during contacts with stakeholders in the early part of 2008 in a consultation exercise initiated by DG-TREN. These changes were already incorporated in the version of the database used in the final draft of the RE directive (Nov-Dec 2008). However, other improvements were introduced into our database too late to be taken into account in the Directive text, but are included in this report. They concern the heat requirement for transesterification to biodiesel and the basis for the soy-based biodiesel pathway.

A subset of our database, containing only the data relevant to the calculation of default values for the Renewable Energies Directive is available at

http://re.jrc.ec.europa.eu/biof/html/documents_main.htm

Furthermore, after fixing the WTT data in this report for the purpose of integrating it with TTW data and writing the WTW and WTT reports, more suggestions continued to arrive (affecting, amongst others, soy and palm pathways), which we have not yet been able to evaluate.

---

[1] L-B-Systemtechnik, Germany
[2] Transport Energy Strategy Partnership.

2 Scope, Methodology, Definitions, Structure

2.1 Pathways

A number of existing and potential road transport **fuels** have been identified, in association with existing and/or future powertrains. Each fuel can be produced from a single or several **resources** as the source of primary energy. The combination of steps necessary to turn a resource into a fuel and bring that fuel to a vehicle is defined as a **Well-to-Tank pathway (WTT)**.

Each pathway is described in terms of the successive **processes** required to make the final fuel available to the vehicles. A complete pathway is a combination and succession of processes, many of which are common to several pathways. A process has a main input and a main output, secondary inputs, by-products as well as factors for energy consumption and greenhouse gas (GHG) emissions. Some pathways include closed loops that have to be solved by iteration.

The main calculations have been carried by a software program developed by LBST[3] and which combines a database for all input data and their references with an algorithm for the rigorous calculation of the total energy and GHG associated with a given pathway, including feedback loops.

Each pathway is described to a suitable level of detail including itemised contributions of the different processes. In order to facilitate comparison between sometimes very different pathways the results are also presented according to 5 generic stages:

Production and conditioning at source includes all operations required to extract, capture or cultivate the primary energy source. In most cases, the extracted or harvested energy carrier requires some form of treatment or conditioning before it can be conveniently, economically and safely transported.

Transformation at source is used for those cases where a major industrial process is carried out at or near the production site of the primary energy (e.g. gas-to-liquids plant).

Transportation to EU is relevant to energy carriers which are produced outside the EU and need to be transported over long distances.

Transformation in EU includes the processing and transformation that takes place near the market place in order to produce a final fuel according to an agreed specification (e.g. oil refineries or hydrogen reformers).

Conditioning and distribution relates to the final stages required to distribute the finished fuels from the point of import or production to the individual refuelling points (e.g. road transport) and available to the vehicle tank (e.g. compression in the case of natural gas).

The table below summarises the pathways considered in this study.

---

[3] E³ database by L-B-Systemtechnik, Germany

Table 2.1　　　　　　**Fuels and resources**

Resource		Gasoline, Diesel, Naphtha (2010 quality)	CNG	LPG	Hydrogen (comp., liquid)	Synthetic diesel (Fischer-Tropsch)	DME	Ethanol	MT/ETBE	FAME/FAEE	HVO	Methanol	Electricity
Crude oil		X											
Coal					X[1]	X[1]	X					X	X
Natural gas	Piped		X		X[1]	X	X					X	X
	Remote		X[1]		X	X[1]	X[1]		X			X	X
LPG	Remote[3]			X					X				
Biomass	Sugar beet							X					
	Wheat							X	X				
	Wheat straw							X					
	Sugar cane							X					
	Rapeseed									X	X		
	Sunflower									X	X		
	Soy beans									X			
	Palm fruit									X	X		
	Woody waste				X	X	X	X				X	
	Farmed wood				X	X	X	X				X	X
	Organic waste		X[2]										X
	Black liquor				X	X	X					X	X
Wind													X
Nuclear													X
Electricity					X								

[1] with/without CCS
[2] Biogas
[3] Associated with natural gas production

Electricity is considered both as a fuel and as a resource. The hydrogen pathways involving electrolysis are therefore the combination of one electricity production route and of the electrolytic conversion. Although electric vehicles are not included in the current study, this paves the way for their introduction in later revisions.

2.2 Time horizon

The notional time horizon for the study is about a decade ahead: 2015-2020. The technologies considered are those that have the potential to become commercially available in that time frame. The same applies to supply/demand, availability and potential for substitution of conventional fuels.

2.3 Incremental approach

The ultimate purpose of this study is to guide those who have to make a judgement on the potential benefits of substituting conventional fuels by alternatives. At the 2010-2020 horizon, this substitution is only plausible at a limited level, say between 5 and 15% at the maximum depending on the option considered. The true impact of the change can only be properly assessed by looking at the incremental sources of energy that will provide alternative fuels, and the incremental savings that can be achieved by reducing supply of conventional fuels.

In order to estimate the implications of replacing conventional fossil transport fuels with a certain alternative fuel (one at a time) in terms of energy use, GHG emissions and cost, we calculated the *difference* between two realistic future scenarios: one in which the alternative fuel was introduced or expanded and one "business as usual" reference scenario which assumed that demand was met by the forecast mix of conventional fossil fuels in 2010-2020. The transport demand (number of km driven) and all other factors remained the same in both scenarios. We then derived metrics such as the conventional replacement cost per km or per tonne conventional fuel, the GHG savings per km or per tonne and (by combining these) the GHG mitigation cost.

For conventional fuels, the question to consider is what savings can be realised by producing less of these fuels rather than how much energy, GHG emissions and costs are involved in absolute terms. The methodology for estimating these savings is also based on incremental changes and is further discussed in *section 3.1 and Appendix 3*.

2.4 Methodology for accounting for by-products

Many processes produce not only the desired product but also other streams or "by-products". This is the case for biofuels from traditional crops such as bio-diesel from rapeseed. In line with the philosophy described above we endeavoured to represent the "incremental" impact of these by-products. This implies that the reference scenario must include either an existing process to generate the same quantity of by-product as the alternative-fuel scenario, or another product which the by-product would realistically replace.

This logic is reflected in the following methodology (***Figure 2.4***):
- All energy and emissions generated by the process are allocated to the main or desired product of that process.
- The by-product generates an energy and emission credit equal to the energy and emissions saved by not producing the material that the co-product is most likely to displace.

> For example, in the production of bio-diesel from oil seeds, protein-rich material from oil seeds pressing is likely to be used as animal fodder displacing soy meal that would otherwise be imported into the EU.

For the purpose of analysing policy, we strongly favour this "substitution" method which attempts to model reality by tracking the likely fate of by-products. This approach (otherwise known as "extension of system boundaries" is increasingly used by scientists, and is the method of choice in the ISO standards for life-cycle analysis studies. Some other studies have used "allocation" methods whereby energy and emissions from a process are arbitrarily allocated to the various products according to e.g. mass, energy content, "exergy" content or monetary value. Although such allocation methods have the attraction of being simpler to implement they have no logical or physical basis. It is clear that any benefit from a by-product must *depend on what the by-product substitutes:* all allocation methods take no account of this, and so are likely to give flawed results.

Figure 2.4   By-product credit methodology
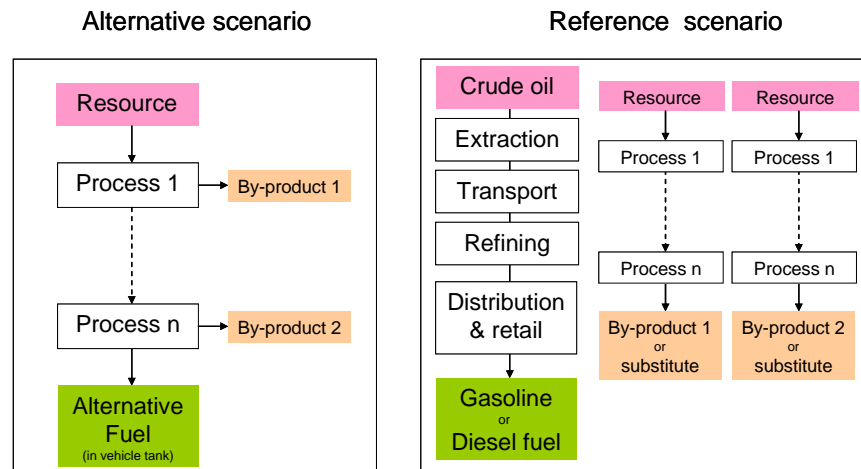
Our substitution methodology attempts to estimate the energy and emissions in *the whole economy* which result from a particular fuel pathway, including the use of by-products. This may not meet the needs of legislation, where the emissions may need to be assigned between economic sectors (transport, electricity, heat, chemicals). This is because policy-makers have made separate emissions-savings targets for different sectors. Furthermore, as for instance in the case of substitution-credits for electricity exports, use of the substitution method in legislation can give rise to a "perverse incentive" to produce more by-product and less biofuel. A practical way to avoid these effects in legislation is to use some sort of allocation, even though this is not scientifically rigorous. For example, the European Commission proposes to allocate emissions to products and material by-products according to their energy-content.

In most cases, by-products can conceivably be used in a variety of ways and we have included the more plausible ones. Different routes can have very different implications in terms of energy, GHG or cost and it must be realised that economics rather than energy use or GHG balance, are likely to dictate which routes are the most popular in real life.

> The following example shows how allocation methods can bear little relation to reality. The manufacture of FAME (biodiesel) produces glycerine as a by-product. Amongst other options, the glycerine could be used instead of synthetic (pharmaceutical) glycerine or as animal feed, instead of wheat grain. Making 1 MJ synthetic glycerine requires about 18 MJ of fossil energy. Making 1 MJ of wheat takes about 0.13 MJ. Clearly much more fossil carbon emissions will be saved in the first option than in the second. Yet the "allocation" approaches based on energy or mass predict that the savings will be exactly the same!

Many processes have more than one energy product: for example, many wood and straw processing pathways include a significant electricity export. The procedure above deals with how to find the greenhouse gas and fossil energy savings for the process, but it does not specify how much of the savings are due to making biofuels and how much is due to making bioelectricity. If one attributes all the GHG/energy credits to the biofuel, one comes to the conclusion that the smaller the fraction of biofuels produced compared to electricity, the better the GHG balance.

That quantity of bio-electricity could have been produced by a free-standing bioelectricity generator: its existence does not depend on the biofuels process. It is clear that to get a balance which pertains only to the biofuel output, we need in some way to subtract the bioelectricity part of the process. This is done by using a dedicated biomass-to-electricity process in the reference scenario; then the difference between the alternative and reference scenarios is only the production of biofuel. The way the credit for electricity export is calculated is explained for individual pathways in Appendix 2.

2.5 Dealing with uncertainties

As already alluded upon in the introduction, the analysis of a certain process or pathway requires choices to be made and figures to be adopted on the basis of criteria that, even if they are logical and documented, always remain somewhat judgmental.

Whenever major contributions were at stake, we have endeavoured to create different pathways to directly show the effect of a particular option or view (e.g. the origin of natural gas has a strong influence on the total pathways through the transport contribution). This approach would, however, be impractical to deal with all sources of variability.

Industry generally uses a range of processes which, at least historically, have not been selected based solely on their energy efficiency but mainly on economic grounds. So established production paths display a range of variability. As we are dealing with the future, we mainly address new processes or improved existing ones, the future performance of which is necessarily somewhat speculative. As a result, each step in a pathway carries a certain variability range representing the combination of the range of performance of the future installations and the uncertainty attached to the expected technical developments. On the basis of the quality of the data available, the degree of development of the process and any other relevant parameter, a judgement has been made as to the level of uncertainty attached to each figure as well as the probability distribution within the range. We have used a Gaussian distribution as default but also a so-called "double-triangle" for asymmetrical ranges and an equal-probability or "square" distribution when there is reason to believe that all values in the range are equally probable.

In order to combine all uncertainties in a pathway and arrive at a plausible range of variation for the total pathway, we have used the traditional Monte Carlo approach. Subsequent calculations have been carried out with the median figure.

2.6 Availability and costs: the bigger picture

A detailed well-to-wheels analysis of each pathway is essential but by no means sufficient to capture the potential value and relevance of a particular route. Indeed issues of availability, feasibility of certain processes, costs, acceptability by the general public on a large scale, all play an important role to assess the practical potential of a certain route.

The choices and assumptions that have to be made when defining the various elements of a pathway are sensitive to the assumed scale at which that pathway might be developed. For example the size of the plants and of the ships, the distance between producer and customer are all affected to a degree. Where this is the case, we have given relevant indications and justified our choices.

In this connection, the availability of the primary resources is obviously critical. Within the timeframe of the study availability is not a major issue for fossil fuels, but the potential of primary renewable resources certainly needs to be carefully considered. The issues to consider here are either physical limitations, or those related to alternative use (e.g. use of arable land for food versus energy crops), or achievability (e.g. number of wind turbines that might conceivably be installed in a certain area). We have attempted to gather relevant information and to develop informed views on these aspects but we recognise that the conclusions remain partially judgmental.

In any study, the forecast of costs is always a particularly thorny problem. The first thing to define is what is included and what is not. In this study, we have elected to consider only the direct costs i.e. those related to investments in and operation of infrastructural equipments. We therefore have not

considered other possible sources of costs (or benefits) related to e.g. employment opportunities, regional development and the like.

We have considered costs from the point of view of the EU as an economic entity ("macro-economic" costs). For those resources that are also internationally traded commodities (such as oil products, natural gas or wheat grain), the market price represents the minimum cost as it corresponds to the amount either required to purchase that commodity or not realised by using that resource elsewhere (for instance the cost of marginal crude oil to the EU is not its production cost but its price on the international market). Production at a higher cost within the EU is only likely to occur if some form of subsidy is available. Since costs and not customer prices are presented, subsidies and taxes are not included in the calculation. The figures represent the full cost to the EU, regardless of how this is shared out. For predominantly locally-produced feedstock (e.g. wood, straw) we have estimated the production cost from the various processes involved.

When it comes to investment in plants and infrastructure, costs are critically dependent on scale. In the integrated WTW analysis, we have estimated the cost of all pathways on the basis of a common scale scenario representing 5% substitution of conventional fuels (see *WTW report*).

2.7 Reference scenario for road fuels demand

In a number of cases, the estimation of energy requirement or cost of certain processes depends on the scale considered. An underlying scenario is therefore required to arrive at reasonable and consistent volume figures. A demand scenario for road transport is the starting point.

European road fuel demand is characterised by a slow decrease in gasoline more than compensated by an increase in diesel fuel. This is the combined result of the increasing shift to diesel passenger cars (encouraged by the drive to reduce CO_2 emissions) and of the increasing road haulage activities. In spite of the already achieved and expected further improvements in efficiency, road haulage should be responsible for a continued increase in diesel fuel consumption as it follows economic growth.

These trends are somewhat less marked when incorporating Eastern European countries where gasoline demand is still expected to grow for some time.

We have used figures from an oil industry study as summarised in the table below.

Table 2.7   ***EU-25 road fuels demand (Mt/a)***

Year	1995	2000	2005	2010	2015	2020
Gasoline	129	124	111	98	93	92
Total road diesel	110	138	169	197	204	199
Total road fuels	239	262	281	295	297	291
Diesel to personal cars						
%	*28%*	*27%*	*32%*	*35%*	*33%*	*29%*
Mt	31	37	54	69	68	57
Total road fuels to personal cars	160	161	165	167	161	149

Source: Wood McKenzie (unpublished Industry study)

These figures represent total demand for road transportation i.e. including what might be supplied by alternative fuels. They can be used as guidance when judging the potential of certain pathways for substitution of a portion of the road fuel market.

Other sources may somewhat deviate from these but this would not have a material effect on the conclusions. Indeed the figures are used to provide orders of magnitude and to ensure consistency between the various options.

2.8 Miscellaneous assumptions

A number of processes in the pathways make use of common assumptions listed below.

2.8.1 GHG coefficients

The CO_2 equivalence is applied to the non-CO_2 greenhouse gases according to the 100 year conversion coefficients recommended by the fourth assessment report of the Inter-governmental Panel for Climate Change [*IPCC 2007a*]. These figures very slightly from the earlier IPCC recommended figures used in version 2 of this study.

Table 2.8.1   *IPCC factors*

Greenhouse gas	t CO_2eq / t
CO_2	1
Methane (CH_4)	25
Nitrous oxide (N_2O)	298

Other GHGs are not emitted in significant quantities in any of the processes considered.

2.8.2 Energy content

All energy contents used are on LHV basis i.e. excluding the heat generated after the combustion process by the condensation of water vapour arising from the hydrogen-content of the material. For materials containing water (crops, animal feed, wood, manure etc), we consider the LHV *of the dry-matter content* of the material. Some other studies have subtracted from this LHV also the heat needed to evaporate the water content. In the case of wet material, like animal slurry the heat content then apparently becomes negative, and one cannot apply the principle of conservation of heat in a process (for example, wood apparently gains energy from no-where as it dries out during storage).

2.8.3 Shipping

Many pathways include long-distance shipping of gases or liquids. In all such case we have used published data for a type of ship consistent with the length of the envisaged trip and the material being carried. Such ships normally return empty and the corresponding fuel consumption has been taken into account through the so-called "Admiralty formula" according to which the fuel consumption of a ship is proportional to the cubic root of the water displacement.

2.9 Presentation of results

2.9.1 Where to find what in this report?

The narrative part of this report is divided into three sections:
- In *section 3* **"From resource to fuel"** we seek to answer the question "what fuel can be made from a given resource?" We discuss the steps or processes necessary to transform a resource into a number of final fuels, indicating the relevant assumptions and choices. This section should be read together with *WTT Appendix 1* which gives process by process input data and reproduces some of the calculations carried out in LBST's E3 database. As a new addition in this version 3 we have provided a set of workbooks as *WTT Appendix 4* giving a step-by-step listing of the input data for each pathway.
- In *section 4* "Final fuels" we consider the question "how can a given fuel be made?" We compare the merits of the different routes from the points of view of energy and GHG balance, for which detailed figures are found in *WTT Appendix 2*.

- In *section 5* "**Potential availability and costs**" we consider the potential volumes that could be produced via the different routes and present the methodology, figures and assumptions used for cost estimates. As discussed above the availability part of this section has not been updated.

2.9.2 Units and conventions

All WTT figures are expressed relative to one MJ of finished fuel delivered into the vehicle fuel tank (MJ_f).

The energy figures are presented as total primary energy expended (MJ_{xt}), regardless of its origin, to produce one MJ_f of the finished fuel under study (LHV basis). The figures exclude the heat content of the fuel itself (i.e. 1 MJ_{xt}/MJ_f means that as much energy is required to produce the fuel as is available to the final user) but include both fossil and renewable energy. As such they describe the energy efficiency of the pathway. For fuels of renewable origin we have also evaluated the fossil energy expended in the pathway (MJ_{xf}), illustrating the fossil energy saving potential of that pathway compared to conventional alternatives.

The figures shown in the main body of this report and in *WTT Appendix 2* for the intermediate steps of a pathway all relate to a MJ of the finished fuel produced by that pathway (1 MJ_f), not to the output of the particular step. In *WTT Appendix 1*, which shows the detailed input data, the figures shown relate to a MJ of the output of each individual process.

GHG figures represent the total grams of CO_2 equivalent (see also *section 2.8.1*) emitted in the process of obtaining 1 MJ of the finished fuel. For fuels of biomass origin, an additional credit is allocated, equal to the amount of CO_2 generated by complete combustion of the fuel. In this way the TTW CO_2 emissions do not need to take account of the origin of the fuel but only of its composition.

2.9.3 References

A complete list of references used in the study is included shown *in WTT Appendix 5* of this version 3. Those essential to the flow of the discussion are cited in the main text, however the majority refer to the text of *WTT Appendix 1*.

3   From Resource to Fuel: production routes

In this chapter we describe the pathways processes necessary to convert a certain primary resource into a final fuel. The stepwise description of the pathways together with the detailed input data and further detailed comments and remarks on individual processes are given in *WTT Appendix 1 & 4*.

3.1 Crude oil pathways

(See also WTT Appendix 1 section 4 and Appendix 4 section 1)

The pathways from crude oil to road fuels are straightforward, as illustrated in the following figure. Note that naphtha has been included here as it is a potential fuel for on-board reformers (see *TTW or WTW report*).

Figure 3-1 Conventional fuels pathways
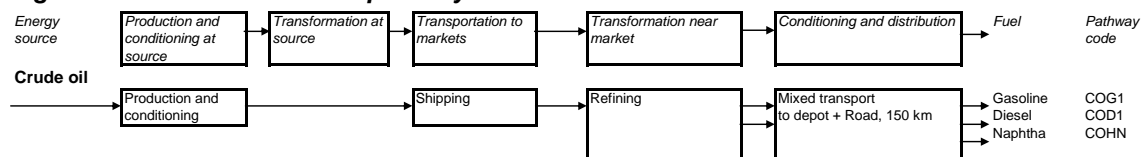
3.1.1 Crude oil production and conditioning at source

Crude oil is generally extracted under the natural pressure of the underground reservoir. In some, mostly older fields, it may be necessary to boost the reservoir pressure by gas injection. In most cases oil is associated with gases and needs to be stabilised before shipment. Water separation is also sometimes required. The associated gases used to be commonly flared but are now in many cases either conditioned and shipped separately (e.g. LPG) or re-injected into the reservoirs. Significant flaring still occurs in certain producing regions notably Central Africa and, to a lesser extent, the FSU.

Production conditions vary considerably between producing regions, fields and even between individual wells and it is only meaningful to give typical or average energy consumption and GHG emission figures for the range of crudes under consideration i.e. those relevant to the EU market. In the light of more recent data we have, in this version 3, revised upwards the energy and GHG figures relevant to crude oil production.

GHG emissions from crude oil production originate from two main sources:
- The energy required to extract and pretreat the oil,
- Flaring and venting (F&V) of associated hydrocarbons.

Although both sources were taken into account in the original JEC data, GHG reporting was not well developed at the time and hard data was not widely available. Since then, oil companies have developed GHG reporting protocols and standards that allows much more accurate and documented estimations of emissions.

There are few publicly available sources of comprehensive data on energy and GHG emissions associated with crude oil production. The International Association of Oil & gas Producers (OGP) has collected such data from its members for a number of years. *Table 3.3.3-1* shows the data collected for 2005 [*OGP 2005*] (reports are also available for 2006, 2007 and 2008 but do not report flaring and venting separately. Overall energy and emissions are at a similar level).

Table 3.3.1-1   Energy and GHG emissions from crude oil production [OGP 2005]

		Total	Africa	Asia	Europe	FSU	ME	NA	SA
OGP production	Mt/a	**2103**	390	298	515	51	235	366	248
Total production	Mt/a	**6382**	614	706	538	1262	1471	1318	473
Coverage	%	**33%**	64%	42%	96%	4%	16%	28%	52%
Energy									
Total	PJ/a	**2688**	325	441	476	59	142	820	425
Specific energy	MJ/MJ	**0.030**	0.020	0.035	0.022	0.027	0.014	0.053	0.041
Emissions									
CO_2	Mt/a	**283.2**	106.8	39.8	33.5	7.1	27.5	41.5	27
	t/kt	**134.7**	273.8	133.6	65.0	139.2	117.0	113.4	108.9
CH_4	kt/a	**2361**	674	566	122	49	139	389	422
	t/kt	**1.12**	1.73	1.90	0.24	0.96	0.59	1.06	1.70
CO_2eq	Mt/a	**342.2**	123.7	53.9	36.6	8.3	31.0	51.2	37.5
	t/kt	**162.7**	317.1	181.0	71.0	163.2	131.8	140.0	151.4
% due to venting		**21%**	16%	36%	9%	17%	13%	23%	39%
% of C in crude		**5.2%**							
Specific emissions	g/MJ	**3.87**	7.55	4.31	1.69	3.89	3.14	3.33	3.60
Figures prorated to total production									
CO_2 eq	Mt/a	**1016.5**	194.7	127.8	38.2	205.9	193.8	184.5	71.6
	t/kt	**494**	499	429	74	4038	825	504	289
Specific energy	MJ/MJ	**0.030**							
% of C in crude		**5.1%**	10.1%	5.7%	2.3%	5.2%	4.2%	4.4%	4.8%
Specific emissions	g/MJ	**3.79**							

The OGP coverage is very good for Europe, fair for Africa and South America but rather patchy for other regions, particularly the FSU (an important EU supplier). It must also be emphasized that grouping many producing provinces into such large regions is an oversimplification as there may be very large differences between producers in a single region.

In *Table 3.3.1-2* we applied the regional data from *Table 3.3.1-1* to the combination of crudes used in Europe in 2005 (as reported by the International Energy Agency, IEA).

Table 3.3.1-2   Estimate of Emissions from crudes used in the EU in 2005

		Total	Africa	Asia	Europe	FSU	ME	NA	SA
IEA consumption data (2005)			19.1%	0.0%	22.0%	33.6%	22.1%	0.0%	3.3%
Specific energy	MJ/MJ	**0.022**							
Specific emissions	g CO_{2eq}/MJ	**3.9**							

EU figures are lower than the overall for energy and higher for GHG emissions because of the comparatively large consumption of low energy / high emissions African crudes. The average figures for both energy and GHG emissions are well within the range used in earlier versions of this study but are somewhat lower than the median for energy and higher for GHG emissions.

The OGP report indicates that about 50% of the GHG emissions that have been attributed are related to F&V. However, 35% of the reported emissions have not been specified. If one assumes that these are not related to F&V, this would reduce the proportion of F&V emissions to about 33% of the total. In other words the OGP data point out to emissions of 2.0 to 2.6 g CO_2/MJ crude for production operations and 1.3 to 2 g CO_2/MJ crude for F&V.

Another source of comprehensive and up-to-date F&V emissions information has been collected by the National Oceanic and Atmospheric Administration [*NOAA 2010*] on the basis of satellite observations. *Table 3.3.1-3* has been constructed with the 2008 NOAA data combined with EU consumption figures for the same year from the International Energy Agency.

Table 3.3.1-3   *Flaring and venting emissions per country and average for EU supply [NOAA 2010]*

2008	EU-27+2 consumption	Specific emissions from F&V					
		Oil only			Total Oil & Gas		
	Mt/a	t CO2/toe	Mt CO2/a	g/MJ	t CO2/toe	Mt CO2/a	g/MJ
Total	**632.6**		**84.7**	**3.2**		**53.8**	**2.0**
Country of origin							
Russia	161.5	23.9%	38.6		11.3%	18.3	
Norway	100.2	0.9%	0.9		0.5%	0.5	
Libya	60.0	12.7%	7.6		10.9%	6.5	
UK	53.0	4.9%	2.6		2.6%	1.4	
Saudi_Arabia	38.9	2.0%	0.8		1.7%	0.7	
Iran	30.4	14.3%	4.3		9.5%	2.9	
Nigeria	23.0	42.0%	9.7		32.2%	7.4	
Kazakhstan	22.8	20.9%	4.8		15.2%	3.5	
Iraq	18.9	16.9%	3.2		16.9%	3.2	
Azerbaijan	18.0	2.7%	0.5		2.1%	0.4	
Angola	14.9	9.7%	1.4		9.7%	1.4	
Algeria	14.8	18.6%	2.8		9.8%	1.4	
Denmark	13.5	3.1%	0.4		1.9%	0.3	
Other EU	12.5	2.6%	0.3		1.4%	0.2	
Venezuela	8.9	5.6%	0.5		4.7%	0.4	
Mexico	8.8	4.8%	0.4		3.6%	0.3	
Syria	7.0	13.0%	0.9		10.4%	0.7	
Kuwait	6.0	3.8%	0.2		3.5%	0.2	
Egypt	4.3	12.5%	0.5		4.9%	0.2	
Brazil	3.5	3.5%	0.1		3.1%	0.1	
Others	11.9	35.0%	4.1		31.9%	3.8	

Satellite observations provide a total figure for F&V but do not discriminate between oil and gas production. In some countries the latter is very large and it is reasonable to expect that a significant proportion of F&V is associated with gas production. To our knowledge there is no widely recognised method for apportioning emissions between all hydrocarbons produced. In the right hand columns, the table gives an indication of this contribution where we have assumed that F&V emissions are distributed in proportion of the energy content of all hydrocarbons produced. This reduces the specific F&V emissions from 3.2 to 2 g/MJ of hydrocarbon produced. It must be noted though, that this method of apportioning emissions is somewhat arbitrary. In any case there is considerable uncertainty attached to these figure. Indeed assigning a single F&V figure to a particular country is an oversimplification (particularly for large producers such as Russia) where real figures are likely to vary between producing provinces, fields and even individual wells.

In any case the figure is somewhat higher than suggested by the OGP data. This is plausible inasmuch as OGP members are primarily International Oil Companies which are believed to have a better performance on F&V reduction than National Oil Companies.

On this basis we have adopted a figure of 2.5 g/MJ with an uncertainty range of ±50%.

The resulting combined figures for crude production are

Energy: 0.058 (.044/0.072) MJ/MJ crude
GHG emissions: 4.8 (3.5/6.2) g CO_{2eq}/MJ crude

The marginal crude available to Europe is likely to originate from the Middle East where production energy tends to be at the low end of the range. From this point of view the use of the above average figures can be considered as conservative. World conventional oil reserves at 1 Jan 2008 were estimated at 1158 billion barrels [*EIA1*][4], with Saudi Arabia, the largest national resource, having about 23% of the world total. Conventional oil sources are expected to meet all of Europe's crude oil needs during the period covered by this study.

Substantial deposits of heavier oils also exist, notably in Canada and Venezuela. Canada's reserves of oil sands are very large (175 billion barrels), equivalent to 15% of world conventional oil reserves, and are already being exploited, almost exclusively for the US and Canadian markets. Venezuela, in addition to large conventional oil reserves (87 billion bbl) also has very large deposits of heavy oils, estimated at 100-270 billion barrels [*EIA2*]. These are located at depths where surface mining techniques are not practical, and so far they have not been developed in a major way.

In Canada, oil sands are concentrated in the Athabaska region of northern Alberta and can be exploited in two ways. Firstly, bitumen, which exists in solid or semi-solid state can be extracted in-situ using steam or solvents. Alternatively, the oil-containing sand can be extracted by surface mining, followed by treatment to separate the oil and treat it in a coker or hydrotreater to produce a light synthetic crude. Some of this is further processed locally, but much is distributed by pipeline to refineries in Canada, the USA and further afield.

Oil sand exploitation is contentious because of the effects of large scale mining, and concerns about air and water pollution as well as the large energy inputs and associated GHG emissions needed to produce and process the fuel. Efforts are continuing to reduce the environmental impact. Whether bitumen is separated from sand in-situ or the oil-sands are mined and processed together, the combined process of extraction and processing is more energy intensive than for conventional crude oil. Heavier oils tend to contain more carbon as a percentage than conventional fuels, so processing to a similar product slate requires more hydrogen. In Canada, most of the energy input is in the form of natural gas. Electricity may either be imported or produced on-site, and may include co-generation producing an excess of electricity for export.

A review of available studies shows a wide range of variation in the energy use and GHG emissions associated with different projects for non-conventional oil production. These range up to 24 gCO_2eq/MJ, equivalent to about 0.36 MJ/MJ, compared with our figures for conventional crude production of 4.5 gCO_2eq/MJ and 0.03 MJ/MJ[5]. A recent review of current Canadian operations [*Trucost 2008*] suggests lower figures, but [*MIT 2008*] projects that the energy needs for future projects will be even higher. Our best-estimate is for an emission of 20 gCO_2eq/MJ of syncrude and energy usage of 0.3 MJ/MJ: substantially higher that of any existing process.

These figures include a small refining credit for syncrude, because less refining energy is required to convert syncrude to gasoline and diesel than is the case for a conventional crude oil. GHG emissions depend on the energy source used to power the production process. In Canada, the source is mainly NG, which is abundant locally.

Figures for Venezuelan unconventional oil reserves are expected to be broadly similar, but will depend on the details of the extraction and processing processes. Where the oils are more fluid, extraction will be easier and heating may not be needed in all cases, which would reduce energy needs. Venezuela has extensive natural gas reserves, so the GHG figures should also be similar to those for Canada. Large

---

[4] Total reserves of 1332 billion barrels, including 174 billion barrels of Canadian oil sands
[5] The ratio between energy use and GHG emissions depends on the source of the energy used

amounts of oil also exist in shale rock formations, and US reserves alone could be as much as the world conventional oil resources. However, recovery of the oil is energy intensive and so far these resources have been less widely exploited.

The very large reserves mean that non-conventional oil may become more important in the future. Current Canadian production of non-conventional oil is 1.2 Mbbl/d, and is expected to increase to around 4.0 Mbbl/d by 2020. Current Venezuelan production is around 0.6 Mbbl/d, and expected to double by 2020 *[MIT 2008]*. Most of this oil is used within the Americas, and we expect little of it to reach Europe in the period to 2020. Middle Eastern crude will remain the marginal oil supply for Europe over this period, so we have retained the same figures for crude oil production as in version 2 of this study.

3.1.2 Crude oil transportation to markets

Crude needs to be transported from the production areas to refineries in Europe. Crude oil is mostly transported by sea. The type of ship used depends on the distance to be covered. The bulk of the Arab Gulf crude is shipped in large ships (VLCC or even ULCC Very/Ultra Large Crude Carrier) that can carry between 200 and 500 kt and travel via the Cape of Good Hope to destinations in Western Europe and America or directly to the Far East. North Sea or African crudes travel shorter distances for which smaller ships (100 kt typically) are used.

Pipelines are also extensively used from the production fields to a shipping terminal. Some Middle Eastern crudes are piped to a Mediterranean port. Pipelines to the Black and Mediterranean seas already serve the developing region of the Caspian basin and several projects are being studied. Crude from central Russia is piped to the Black Sea as well as directly to eastern European refineries through an extensive pipeline network.

Although the majority of refineries tend to be at coastal locations, a number of them are inland. Within Western Europe, there are several inland pipelines from the Mediterranean to North Eastern France and Germany as well as from the Rotterdam area to Germany.

Here again, there is a wide diversity of practical situations. Considering mainly marginal crude originating from the Middle East an energy figure of 1% (0.01 MJ/MJ) has been used, corresponding to 0.8 g CO_2eq/MJ assuming a ship fuelled by heavy fuel oil.

3.1.3 Crude oil refining

Traditionally, crude oil is transported as such and refined near the markets. The advent, from the early 1980's, of large "export" refineries in the Middle East provided another model of refining at source and long-haul product transportation. However, the number of such refineries remains limited and so does their impact, specifically on Europe where the overwhelming majority of finished products are produced by local refineries importing crude oil. Although Europe imports some blending components and finished products (mostly gasoils and jet fuel), the bulk of the fuels sold in Europe is manufactured in European refineries. This study therefore assumes that crude oil based fuels are manufactured from crude oil in European refineries.

An oil refinery is a complex combination of process plants, the objective of which is to turn crude oil into marketable products of the right quality and in the right quantities. This entails
- Physical separation of the crude components,
- Treating to remove such compounds as sulphur,
- Conversion of mainly heavy molecules into lighter ones to match the production slate to the market demand.

European refineries consume about 6-7% of their own intake as processing energy. Some energy is exchanged with the outside (e.g. electricity import/export, natural gas import). Although European refineries are overall importers of energy/fuels other than crude oil, the bulk of the energy used by refineries comes from their crude oil intake. Refineries burn gas (mainly generated in the refinery processes) as well as liquid and solid fuels.

Oil refineries produce a number of different products simultaneously from a single feedstock. Whereas the total amount of energy (and other resources) used by refineries is well documented, there is no simple, non-controversial way to allocate energy, emissions or cost to a specific product. Distributing the resources used in refining amongst the various products invariably involves the use of arbitrary allocation rules that can have a major influence on the results. Although allocation methods are often used for lack of better tools, such a simplistic approach ignores the complex interactions, constraints and synergies within a refinery and also between the different refineries in a certain region and is likely to lead to misguided conclusions. From an energy and GHG emissions point of view, this is also likely to give an incomplete picture as it ignores overall changes in energy/carbon content of feeds and products.

In order to estimate the savings from conventional fuels the question to consider was what could be saved by using less of these rather than how much they cost in absolute terms. We thus considered that, in the context of this study, the energy and GHG emissions associated with production and use of conventional fuels should be representative of how the EU refineries would have to adapt to a marginal reduction of demand. Such figures were obtained through modelling of the EU-wide refining system (see *Figure 3.1.3* and more details in *WTT Appendix 3*). Within the scope of substitution mentioned above and the timeframe considered, production costs of alternative fuels could reasonably be taken as proportional to volumes.

Note that this methodology is entirely consistent with the substitution methodology used for accounting for by-products in other pathways. Both arise from the over-arching principle of a marginal calculation which estimates the difference in emissions between a reference scenario and one with a changed output of the fuel in question. In the case of the oil refinery calculation, the production of by-products is kept constant. Then no substitutions need to be made for by-products, because they cancel out when we take the difference between the two scenarios. The only changes are the diesel (or gasoline) output, and the inputs of crude oil, gas and electricity. This marginal approach to crude oil refining is unique to our study and gives more reliable estimates than the allocation techniques used in other studies.

From this analysis it appears that, in Europe, marginal diesel fuel is more energy-intensive than marginal gasoline. In recent years Europe has seen an unprecedented growth in diesel fuel demand while gasoline has been stagnating or even dropping. According to most forecasts, this trend will continue for some time, driven by increased dieselisation of the personal car and the growth of freight transport in line with GDP. At the same time, jet fuel demand also steadily increases as air transport develops. The ratio of an ever increasing call for "middle distillates" and a call for gasoline that is at best constant goes beyond the "natural" capabilities of a refining system that was by and large designed with a focus on gasoline production. Reducing diesel fuel demand therefore "de-constrains" the system whereas decreasing gasoline demand makes the imbalance worse.

Similar calculations have been performed for marginal naphtha.

Figure 3.1.3   ***Impact of a marginal reduction of conventional gasoline demand***

"Business-as-usual" scenario
Meeting 100% of future demand

Alternative scenario
Marginal reduction of gasoline production

❑ Other product volumes unchanged
❑ Change in energy, GHG, crude intake
"charged" to decremental gasoline
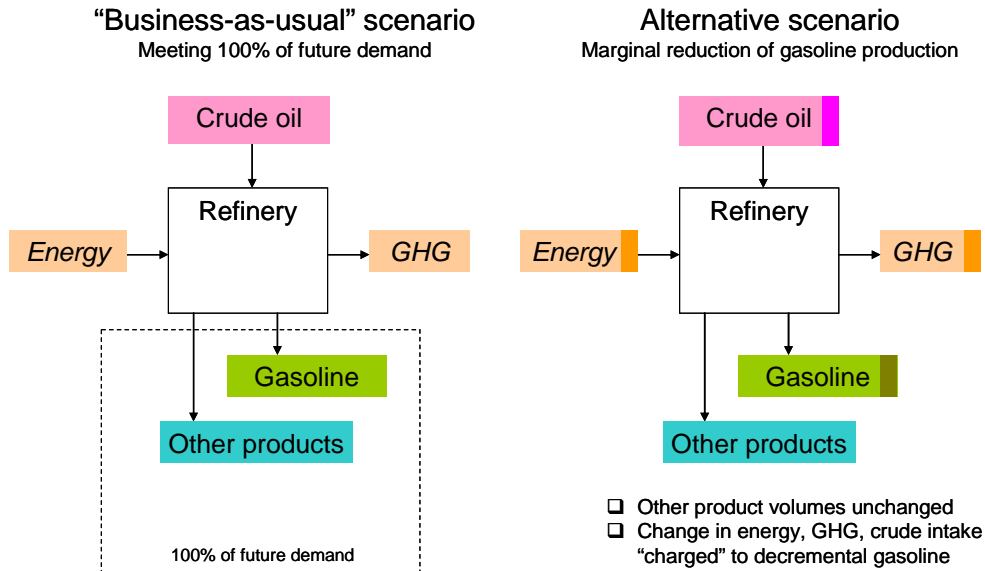
Based on our results, we have adopted the following figures:

		Gasoline	Diesel fuel	Naphtha
Energy	MJ/MJ	0.08	0.10	0.05
GHG	g CO$_2$eq/MJ	7.0	8.6	4.4

Calculations for the refining step were carried out on the basis of a 2010 base case including all foreseen fuel specifications including sulphur-free road fuels, but excluding any effects of biofuel blending. Although the additional quality requirements result in a higher absolute level of energy consumption in the refineries in 2010 compared to earlier fuel specifications, the effect on the marginal values are of a second order of magnitude. Further changes to the EU refining environment are expected beyond 2010 related to quality changes of non-road fuels (mostly marine fuels) and changes in the global EU demand with a further increase in the imbalance between diesel and gasoline. In spite of anticipated improvements in energy efficiency, this is expected to lead to an increase in the specific CO$_2$ emissions per tonne of crude processed, leading to some increase in the footprint of marginal road fuels. Although the change in the refining number is likely to be significant, it represents a small percentage of the total WTW footprint of a fossil fuel. Inasmuch as the figures produced in previous versions have been extensively used by others, including the EU Commission, we have at this stage not changed them.

Note: In principle the same marginal analysis should apply to the other stages of the elaboration and distribution of conventional fuels. However, these figures are small compared to those for refining and it can reasonably be assumed that energy and GHG emissions associated with crude production and transportation as well as product distribution are proportional to the volumes concerned.

3.1.4 Gasoline and diesel fuel distribution

Finished products from the refinery are transported either by road tanker directly to a retail station or, for the larger part, to a depot by pipeline, train or barge. For the calculation a mix of the different transportation modes has been used according to the actual share of each mode in Europe. Depots and service stations also account for a small energy consumption, essentially in the form of electricity.

The total average figure for Europe is estimated at 20 kJ and just over 1 g CO_2eq per MJ of delivered fuel. These figures can reasonably be assumed to be independent of the volumes concerned.

In monetary terms, however, most of the infrastructural costs attached to production and distribution of conventional fuels would not be significantly affected by a limited substitution, particularly as distribution of alternative fuels would rely on the existing network. Therefore only variable distribution costs were taken into account.

3.2 Natural gas pathways

(See also WTT Appendix 1 sections 5 to 7 and Appendix 4 section 2)

Natural gas (NG) is the most plentiful fossil fuel after coal. It is available in most regions of the globe although there are a few very large producing regions such as Russia and, potentially, the Middle East. Only a relatively small part of the known reserves of natural gas is currently exploited. This is partly the result of the relative difficulty to bring natural gas to market when it originates from isolated areas. The exploitation of a natural gas field requires a heavy associated infrastructure in the form of either pipelines or liquefaction equipment and LNG ships. The real availability is therefore limited more by the realisation of projects to develop new fields and transportation systems than by the physical reserves. In recent years the option of turning natural gas into liquids (such as methanol, DME or FT fuels) has become a potentially viable option particularly for the most remote locations.

So far NG has been almost exclusively used in stationary applications, mainly in domestic heating, industrial fuel and electricity production. Use of NG as road fuel (in the form of compressed natural gas or CNG) has been limited to specific markets or niche applications. NG use for power generation has increased tremendously in the EU during the last decade as sulphur emission limits were introduced to combat acidification. The favourable C/H ratio of natural gas compared to coal or oil also makes it the fuel of choice to replace coal or heavy fuel oil when targeting CO_2 emissions. As Europe's indigenous NG production declines, a greater proportion of this demand is coming from imports, mainly through pipeline from Russia, but increasingly via LNG.

3.2.1 Gas sourcing options for pathway calculation

It is clear that, by the second decade of this century, any extra supplies will most likely come from either the Middle East or the FSU. Bringing this gas to Europe will involve either new pipelines or LNG schemes. We have therefore considered two main options viz.
- "Piped" gas transported to Europe via long-distance pipeline. In practice this represents additional availability from the FSU or new sources from Central Asia.
- "Remote" gas from various world producing regions (particularly the Arabian Gulf) either shipped into Europe as LNG or transformed at source into liquids.

In addition we have calculated, for reference, a limited number of pathways based on a notional "EU-mix" representative of the origin of the gas used in Europe in 2002. In line with the marginal approach, we do not consider this as a valid case for assessment of the future potential of natural gas pathways but it provides a reference representing current gas use.

3.2.2 Natural gas production, conditioning and transport via long-distance pipelines

Natural gas is produced from either dedicated fields or as associated gas in oil fields. Although it is primarily methane, the gas mixture coming out of the well can contain a range of light hydrocarbons as well as inert gases, mainly nitrogen and CO_2.

The bulk of the light hydrocarbons need to be separated as they would condense at various stages of the transportation system. These condensates may be used locally or transported to appropriate markets. C3 and C4 hydrocarbons can be used as LPG for various purposes or as chemical feedstocks which is also the case for heavier condensates. Some may be flared but this practice is gradually disappearing.

Inerts are not normally separated except for some fields where the CO_2 content is high. In a limited number of cases, the separated CO_2 is re-injected into the wells and this may become more common in the future. Unless this is the case, this CO_2 ends up in the atmosphere either at the processing plant or at the end consumer. The CO_2 content of the typical gas sources available to Europe is generally in the region of 1% v/v or less. In order to account for this CO_2 in a simple way in all pathways concerned, we have included a 1% v/v CO_2 venting at the production stage. The EU-mix used for the Tank-to-Wheels part of the study includes a small CO_2 content (see *WTT Appendix 1, section 2.2*). This has been included to reflect the correct gas parameters but no additional CO_2 emissions accrue from it.

The energy associated with extraction and processing varies considerably with the producing region. This reflects different gas qualities, practices and climatic conditions. For extraction, most of the energy is supplied directly in the form of natural gas (typically through an on-site power plant). Processing can take place near the wellhead or, as is common in Russia, at a central location where light hydrocarbons can be readily used as chemical feedstocks. In such a case the energy supply may be mixed and include various hydrocarbon fuels as well as electricity from the local grid. Based on the various sources of information available we have used a median figure of 2% of the processed gas with a range of 1 to 4%. We have not included any term for associated condensates, postulating that their production and use would globally be energy/GHG neutral (compared to alternative sources). 0.4% of methane losses are also included.

Transportation accounts for the largest part of the energy requirement because of the large distances involved. Western Siberian fields are about 7000 km from Europe whereas typical future South West Asian locations may be 4000 km away. Pipelines require compression stations at regular intervals, typically powered by a portion of the transported gas. The specific energy requirement therefore increases with distance as the larger the distance the more gas has to be transported initially to obtain a unit of delivered gas. The actual energy consumption figures may vary considerably from one pipeline to another depending on the design and operation parameters (size v. throughput, compressors and drivers efficiency etc). The energy consumption is very sensitive to the pressure at which the pipeline is operated. Existing pipelines operate at pressures of 6 to 8 MPa. New pipelines may be designed to operate at significantly higher pressures which, at constant diameter and throughput, could cut energy requirements by a factor 2 to 3. This is illustrated in ***Figure 3.2.2***.

There is however a trade-off between energy consumption (i.e. operating costs) and pipeline diameter (i.e. capital cost). In order to represent the diversity of current of possible future situations we have used median and maximum values corresponding to today's operations with, as a potential future improvement, a minimum value corresponding to a 50% pressure increase. For the 4000 km case for instance we have used a median value of 8.8% of the delivered gas with a range of 2.9 to 9.9%.

Combined leakages in the transportation system result in some methane losses (directly emitted to the atmosphere). Although it has often been reported that such losses are very high in the Russian system, comprehensive studies such as conducted by Ruhrgas and Gazprom and more recently by the Wuppertal Institute [*Wuppertal 2004*], give a more sedate picture. According to the latter source we have accounted for a loss of 0.13% per 1000 km reduced from the 0.16% figure used in version 1 and based on the former study.

Figure 3.2.2   Impact of pipeline operating pressure on gas transport energy requirement
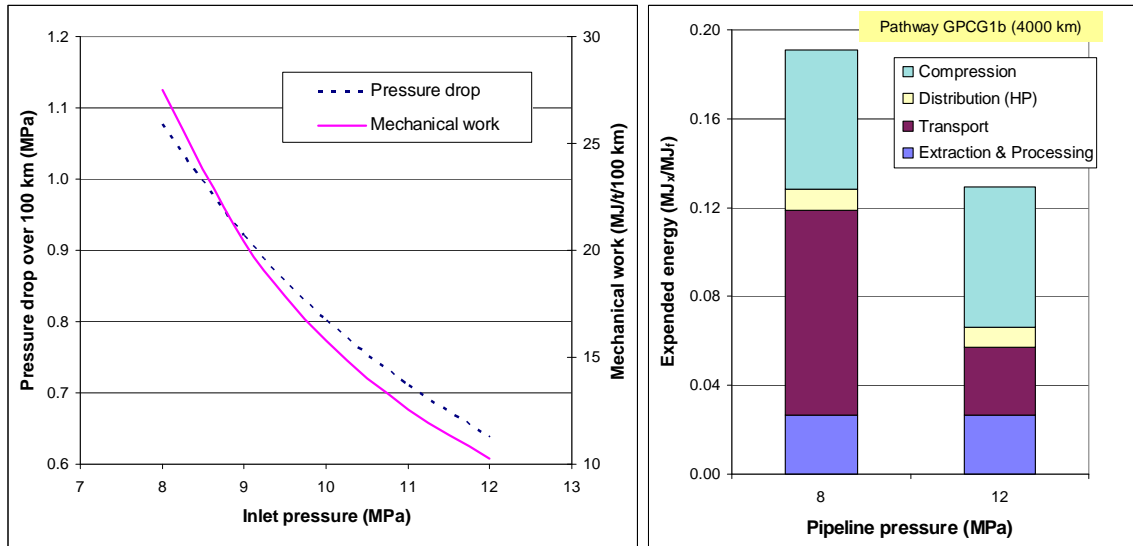
3.2.3 LNG

Liquefied Natural Gas (LNG) provides an alternative to pipelines where these are not practical or when distances are very large. LNG production and long distance shipping is a well-established route widely used throughout the world.

Gas is extracted and cleaned up before being liquefied in a cryogenic plant. For extraction and pre-processing we have assumed the same figure as for other gas sources.

Liquefaction entails essentially electricity consumption, commonly produced from the gas supply itself in a dedicated power plant. There are small associated methane losses (0.17%) while flaring of off-gas (0.25%) contributes to CO_2 emissions.

Transport takes place in dedicated ships. Heat exchange with the environment during transport is compensated by evaporation of a portion of the gas which is typically used as fuel by the ship, the balance being provided by standard residual bunker fuel. We have assumed a typical distance of 5000 to 6000 nautical miles (typical for trips from the Arab gulf to Western Europe via the Suez canal).

Note: LNG from Algeria or West Africa would have to travel significantly shorter distances to reach Europe. These sources are, however, not considered to be representative of the bulk of the future marginal gas supply.

As mentioned in *sections 3.2.1 and 3.2.3,* LNG is likely to play a significant, if not major, role in the gas supply of Europe. LNG imported into Europe is most likely to be vaporised and mixed into the natural gas grid. As the number of terminals increases LNG will become more accessible as such and the possibility to deliver it by road directly to refuelling stations can also be envisaged. This option has a theoretical advantage from an energy point of view as compression and vaporisation can be combined. We have included this case in the analysis.

Liquefaction of natural gas requires a large amount of energy to be spent near the gas fields, essentially in the form of electricity. This provides an opportunity for CO_2 capture and storage (CCS, see *section 3.6*)

3.2.4 NG distribution in Europe

Natural gas is widely available throughout Europe via an extensive network of pipelines covering virtually all densely populated areas. There is a limited network of high pressure pipelines (4-6 MPa) acting as trunk lines for the denser low pressure networks as well as serving large industrial consumers. The local distribution networks operate at different pressures depending on the countries. 0.4 MPa is becoming the norm but a number of countries/regions still operate a 0.1 MPa network while some such as a large part of the UK still have a very low pressure system (a few mbar) inherited from the town gas era. These networks serve small industrial and domestic consumers and are very dense. Transfers between the different pressure levels take place in reduction stations where the pressure energy is effectively lost. From a global point of view there is therefore an incentive to take the gas at the highest possible pressure level in the network although this is not always practical.

These systems do not appear to have serious capacity limitations for the foreseeable future and the additional quantities that can reasonably be foreseen for road fuel applications could in all likelihood be easily accommodated.

There are, however, a number of sparsely populated regions that do not have access to natural gas because the potential volumes cannot justify building a pipeline network. This is unlikely to change in the future even if some potential additional sales can be generated from road fuels. This concerns fairly large areas of e.g. France, Spain and Scandinavia and could be a problem when it comes to developing a dense refuelling station network, in particular along motorways. Direct LNG supply may be a suitable solution for these areas.

There is a small energy consumption attached to the high pressure distribution networks for which we have assumed an average distance of 500 km. Because they are fed directly from the long-distance high pressure pipelines, the local low pressure networks do not generate additional energy consumptions inasmuch as the upstream pressure is more than sufficient to cover the head losses.

Methane losses in the well-maintained European pipeline networks are reportedly very small. In the case of the local networks, they tend to be mostly related to maintenance and are therefore not relevant to marginal gas.

Natural gas from the network can be used to feed CNG refuelling stations. For more details on CNG see *section 4.3.1.*

3.2.5 NG transformation

NG to electricity

See section 3.5.1

NG to hydrogen

Hydrogen can be obtained from NG either directly via steam reforming or indirectly via power generation and electrolysis.

Hydrogen production by steam reforming of methane is an established process widely used e.g. in oil refineries. The catalysed combination of methane and water at high temperature produces a mixture of carbon monoxide and hydrogen (known as "syngas"). The "CO-shift" reaction then combines CO with water to form CO_2 and hydrogen. Many of today's hydrogen plants, serving the needs of refineries and petrochemical industries, are relatively small compared to what would be required for large scale production of hydrogen as a fuel. Scaling up does not, however, present serious technical challenges and some larger plants already exist.

For plants located in Europe we have considered two configurations:
- A "central" plant with a capacity of 200 MW (as hydrogen), equivalent to 5.8 PJ/a of hydrogen (just under 50 kt/a). A minimum of 1.6 MPa feed gas pressure is required which is available from the industrial grid (4-6 MPa). The estimated efficiency is 75%.
- A small-scale "distributed" hydrogen plant serving a few or a single refuelling stations, typically fed from the natural gas domestic grid, with a capacity of up to 10 MW (as hydrogen). This smaller plant would have a lower estimated efficiency of 67%, the difference being mainly due to the fact that use of waste heat would not be practical at that scale.

Remote production and long-distance transport of liquid hydrogen as well as production of liquid hydrogen in the EU (with distribution by road) have also been considered. For this case a larger reformer capacity of 300 MW has been assumed. Indeed such capital-intensive projects are only likely to be justified at large scale. The hydrogen plant efficiency is expected to be similar to the smaller 200 MW plant.

Thermodynamically, the reforming reaction is favoured by lower pressures. The effect is relatively small and the actual pressure at which a plant will deliver the hydrogen has more to do with design considerations and the pressure of the gas supply. Large plants generally deliver the hydrogen at a fairly high pressure, between 3 and 4 MPa. For small "distributed" plants most of the actual or conceptual designs described in the literature indicate a pressure of about 1.5 MPa. To be consistent with the CNG pathways, we have assumed the gas to be available at the plant inlet at 0.5 MPa (abs). The chain then includes a gas compression step to 1.5 MPa.

Hydrogen production involves full decarbonisation of the fuel and production of CO_2, making it an attractive proposition for CCS (see also *section 3.6*).

For a discussion of hydrogen transport and distribution refer to *section 3.7.1*.

NG to synthetic liquid fuels

Besides using natural gas as such as a motor fuel in the form of CNG, several technical options are available to synthesise liquid products that have the advantage of easier transportation and, for some, to be usable in mixture with conventional fuels. These processes rely on either steam reforming or partial oxidation of natural gas to produce to produce syngas which is then used a feedstock to a synthesis process. The most prominent options are:
- Synthetic hydrocarbons via the Fischer-Tropsch route,
- DME,
- Methanol.

The conversion plants can conceivably be located either near the gas production area or near the markets. For liquid fuels, the first option is far more likely to be implemented as it then becomes an alternative to LNG or very long-distance pipelines for remote gas sources. For hydrogen, plants near markets appear to be more logical as long-distance transport of natural gas would normally be preferred over that of hydrogen. Large scale electricity production needs of course to be near the consuming centres. The processes and installations involved are, however, conceptually the same.

The first step, common to all such processes, is the conversion of natural gas to "synthetic gas" (or syngas i.e. a mixture of mainly carbon monoxide and hydrogen) by partial oxidation or steam reforming.

Synthetic diesel fuel (Fischer-Tropsch)

Production of liquid hydrocarbons from syngas via the Fischer-Tropsch (FT) process has been known for many years and the subject of many variations and improvements. The first commercial plant was the Shell Middle Distillate Synthesis (SMDS) plant in Malaysia, and two much larger plants are now being constructed in the Middle East. In this study we assume the synthetic fuels to be saturated i.e. the process scheme to include a hydrocracker to cut and hydrogenate the long chains to the desired fuel type. In the previous version of this study, the assumed FT plant was based on SMDS with an overall efficiency (including syngas generation from natural gas) in the range of 61 to 65%. This excludes any potential synergy with upstream or adjacent complexes which could add a few percent points. The theoretical efficiency is about 78% and, with the considerable R&D effort going into these processes at the moment, it is reasonable to believe that higher efficiencies could be achieved in the future. A lot can be achieved through improved heat integration, particularly in the syngas production step and, with rising energy cost, the extra capital investment required is likely to be easier to justify. To reflect these developments, the mean efficiency figure for future plants in this study has been revised to 65%, with a range of 63-67%.

These plants can produce a complete range of products from LPG to base oils for lubricants and small amounts of specialty products such as waxes. Some plants, particularly early ones, may be designed to produce significant quantities of high value products such as base oils. However the market for such products is limited and naphtha kerosene and diesel fuel will eventually represent the bulk of the output. Yields can be adjusted over a fairly wide range. The maximum practically achievable diesel fuel yield (including the kerosene cut) is around 75% of the total product, the balance being mainly naphtha and some LPG.

The process scheme is essentially the same for all products that can be therefore considered as "co-products". There is no technical basis for arguing that more or less energy and emissions are associated to specific products so that, in this case, allocation on the basis of energy content is justified (i.e. that all products are produced with the same energy efficiency). We have taken this view which leads us to consider that all products and their fate are independent of each other.

The alternative would be to consider diesel as the main product supporting all production energy and emissions and other streams as "by-products". In this case the fate of the by-products has to be considered in order to calculate a credit or debit to be applied to refinery diesel. This is the method that has been applied for biofuels in the present study. Note that this approach would make the implicit assumption that other products are produced as a result of diesel production which, in this instance, may or may not be the case.

If we accept these assumptions, the most likely disposal route for GTL naphtha and LPG would be to substitute for the equivalent petroleum products (in Europe or other world markets). This would result in an energy and GHG debit for the GTL diesel, since conventional production pathways are less energy intensive than the GTL process. The size of the debit would depend on the relative yields assumed for the various products, which may or may not be representative of future situations.

This study starts from the present situation with oil refineries supplying the virtual entirety of the road fuels market. In the reference case this continues for at least the next decade and the EU refining system is adapting accordingly. Within this time frame all identified alternatives to refinery production (e.g. the availability of GTL diesel) could only replace a limited amount of either gasoline or diesel fuel. The impact on the refineries is therefore considered in this context and this forms the basis of the marginal analysis described in *section 3.1.3* and through which the energy and CO_2 emissions associated with a marginal change in either gasoline or diesel fuel production are estimated.

Two studies by PriceWaterhouseCoopers (PWC) and one study by Nexant have taken a different approach to this question. They consider functionally equivalent hydrocarbon processing systems with and without GTL products, and calculate the energy and GHG balances for a portfolio of fuel products meeting the market demand. Their calculations confirm the debits for naphtha and LPG mentioned above. However, their calculations assume that availability of GTL can lead to less crude oil processing. In this situation, if lower availability of heavy fuel oil (HFO) were to result in a switch to natural gas in industrial heating and power generation, this would result in lower GHG emissions. The PWC and Nexant calculations show that, by accounting for the HFO in the refinery system, GHG emissions from the complete system could become broadly equivalent for the scenarios with and without GTL fuels.

The key assumption made in the PWC and Nexant studies that availability of GTL would slow investment in crude oil capacity may well be applicable in rapidly developing markets (such as China) where a clear choice would need to be made between additional crude oil processing capacity and new capacity for making synthetic diesel via a Fischer Tropsch (or other) route. However the assumption is less obviously applicable for Europe which has an established refining industry with no foreseeable major expansion, although diesel is currently imported into the EU because of a structural shortage of middle distillates in the European refining industry due to dieselisation of the light duty market and growth of freight transport. Substitution of HFO by natural gas is already happening to some extent and the trend may be expected to continue for reasons which are not linked to the road fuels market.

Our study does not consider that linking GTL diesel availability to HFO production and making the further assumption that a reduction of HFO production would be made up by natural gas, are appropriate in a European context. This is the key reason for the differences between the WTW results for GTL quoted in this study, as compared to the studies conducted by PWC and Nexant.

GTL plants produce a large amount of low temperature heat that could be of use in certain locations for e.g. seawater distillation or district heating. Such arrangements are highly location-specific and also require complex partnerships that cannot always be realised. As a result they are unlikely to apply to every project. We therefore considered the potential benefits should not be included in a generic pathway, although it is recognized that the Qatar location chosen by a number of parties (see below) would most likely be able to utilize the low grade heat (for sea water distillation).

In the GTL process CO_2 is produced and separated from the syngas upstream of the Fischer-Tropsch synthesis. This provides an opportunity for CCS (see also *section 3.6*).

DME

Di-methyl ether or DME is a potentially attractive fuel for diesel vehicles. It is volatile and must be kept under moderate pressure (similar to LPG) so would require specially adapted vehicles. There is, however, no commercial experience with its direct production from natural gas (via synthesis gas). Present commercial manufacture of DME is via methanol and not for fuel purposes. There are firm plans for a large scale plant to be built in Iran. We have used data available from Haldor Topsoe, scaled to a notional plant with the same gas intake as its methanol equivalent [*Haldor Topsoe 2001/2002*]. As mentioned for synthetic diesel, development of such processes at a large scale would likely lead to process improvements and higher energy efficiency in the long run.

In the DME synthesis process CO_2 is produced and separated from the syngas upstream of the synthesis step. This provides an opportunity for CCS (see also *section 3.6*).

Methanol

Methanol synthesis from methane is a well-established process. We have assumed a state-of-the-art plant of 600 MW (in terms of methanol, equivalent to about 100 t/h), fully self-contained (i.e. with natural gas as only energy source and no energy export) and with an efficiency in the range of 67 to 69% [*Larsen 1998*].

NG to hydrogen via methanol

Methanol synthesised from remote natural gas could be used as energy vector instead of compressed or liquefied gas. Distributed into Europe it could be reformed locally to hydrogen.

MTBE

Methyl-Tertiary-Butyl Ether or MTBE is a high octane blending component for gasoline. Because of its ability to reduce emissions by bringing oxygen into the fuel, MTBE was widely used in US gasoline until water contamination issues led to a partial ban. In Europe MTBE was introduced as one of the measures to recover octane after phasing out of lead in gasoline.

MTBE is synthesised by reacting isobutene with methanol. Some isobutene is produced by refineries and petrochemical plants as by-product of cracking processes. Large MTBE plants include, however, isobutene manufacture via isomerisation and dehydrogenation of normal butane often from gas fields, near which the plants are often located. The entire process is fairly energy-intensive. In that sense MTBE is a fuel derived from natural gas. Marginal MTBE available to Europe is from that source and this is the pathway that we have investigated.

3.2.6 Natural gas pathways

There are a virtually infinite number of combinations of the various processes described above. We have endeavoured to select those pathways that appear the most relevant and plausible.

Figure 3.2.6   Natural gas pathways

Energy source	*Production and conditioning at source*	*Transformation at source*	*Transportation to markets*	*Transformation near market*	*Conditioning and distribution*	*Fuel*	*Pathway code*

Natural gas (EU mix)

Production and conditioning		Pipelines in EU		NG grid + on-site compression	CNG	GMCG1
				NG grid		
			Reforming (on-site)	Compression	CH2	GMCH1

Natural gas (piped)

Production and conditioning		Pipeline into EU a) 7000 km b) 4000 km		NG grid (LP/MP)+ On-site compression	CNG	GPCG1a/b
				NG grid		
			Reforming (on-site)	Compression	CH2	GPCH1a/b
			Reforming (central) (+CC&S option)	Pipeline, 50 km Compression	CH2	GPCH2a/b/2bC
			Reforming (central)	Road, 50 km Compression	CH2	GPCH3b
			Reforming (central) + H2 Liquifaction	Road, 300 km + vaporisation/compression	CH2	GPLCHb
			Reforming (central) + H2 Liquifaction	Road, 300 km	LH2	GPLH1a/b
			GTL plant	As for refinery fuels	Syn diesel	GPSD1a/b
			Methanol/DME synthesis	Mixed land transport 500 km	Methanol DME	GPME1a/b GPDE1a/b
			CCGT (+ CC&S option)	MV grid	Electricity	GPEL1a/b/bC
			CCGT + on-site electrolyser	Compression	CH2	GPEL1a/b/CH1
			CCGT + central electrolyser	Pipeline, 50 km Compression	CH2	GPEL1b/CH2
			CCGT + central electrolyser + liquefaction	Road, 300 km	LH2	GPEL1b/LH1

Natural gas (remote)

Production and conditioning	Liquefaction (+CC&S option)	Shipping (LNG)	Vapourisation	NG grid + on-site compression	CNG	GRCG1/1C
				Road, 500 km + on-site vap / comp	CNG	GRCG2
			Vapourisation	NG grid		
			Reforming (on-site)	Compression	C H2	GRCH1
			Reforming (central)	Pipeline, 50 km + compression	C H2	GRCH2
			CCGT	MV grid	Electricity	GREL1
			CCGT + on-site electrolyser	Compression	C H2	GREL1/CH1
	Methanol Synthesis	Shipping + Road 500 km	Reforming (on-site)	Compression	C H2	GRCH3
	Reforming H2 liquefaction	Shipping (LH2)		Road, 500 km	L H2	GRLH2
	GTL plant (+CC&S option)	Shipping		As for refinery fuels or Mixed land transport, 500 km	Syn diesel	GRSD1/2/2C
	MeOH/DME syn (+CC&S option)	Shipping		Mixed land transport 500 km	Methanol DME	GRME1 GRDE1/1C

| NG (remote) | Production and conditioning | Isobutene → MTBE | Shipping | | As for refinery fuels | | GRMB1 |
| Field butane | Production and conditioning | Methanol | | | | | |

3.2.7 LPG

LPG (Liquefied Petroleum Gas) is the generic acronym for C3 and C4 hydrocarbons that are gaseous under ambient conditions but can be stored and transported in liquid form at relatively mild pressures (up to about 2.5 MPa for propane). LPG is widely used for heating and cooking as well as petrochemicals. It is also a suitable fuel for spark ignition engines with a good octane rating and favourable emissions performance. LPG is available as a road fuel in a number of European countries.

LPG is produced in oil refineries as a by-product of virtually all treating and conversion processes. This resource is, however, limited and already completely accounted for. Indeed Europe imports a significant proportion of its LPG consumption. Accordingly the marginal LPG consumed in Europe originates from oil or gas fields where it is produced in association with either crude oil or natural gas. We have represented the case of natural gas fields.

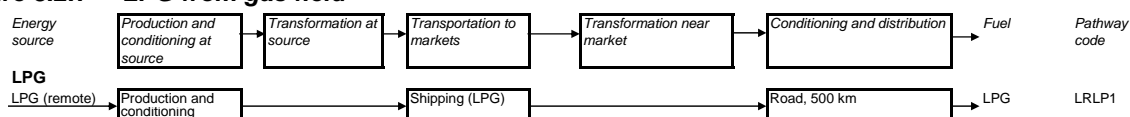Energy is required to produce the LPG and also for subsequent treatment and separation into C3 and C4 hydrocarbons (which tend to have different markets) and C5+ components. The pathway is represented below.

Figure 3.2.7 **LPG from gas field**

3.3 Coal pathways

(See also WTT Appendix 1 section 8 and Appendix 4 section 1)

Although not fashionable in today's carbon-conscious world, coal still plays an important role in the world and even in Europe's energy supply, essentially for power generation. After a steady decline over many years, EU consumption has stabilized around 300 Mtoe since the beginning of the decade. It is, however growing in most other parts of the world, particularly in China. With abundant worldwide reserves, coal is expected to play a major role in world energy for many years to come. "Clean coal" technologies such as gasification followed by electricity generation through combined cycle (Integrated Gasification and Combined Cycle or IGCC) and advanced flue gas treatment schemes can resolve most of the air pollution issues while offering high thermal efficiencies. Gasification can also be followed by synthesis of methanol or by a Fischer-Tropsch plant to produce liquid hydrocarbons (Coal-To-Liquids or CTL). CO_2 capture and storage further offers the vision of virtually carbon-free electricity or hydrogen production from coal and could also reduce the carbon emissions footprint of synthetic fuels.

We have included a number of coal-based pathways representing processing of the current EU hard coal mix into hydrogen, methanol, synthetic diesel and electricity (both conventional boiler + steam turbine and IGCC). We have derived energy efficiency figures from the literature: 51% for hydrogen [*Foster Wheeler 1996*], 57% for methanol [*Katofsky 1993*] and 56% for syn-diesel [*Gray 2001*]. The coal to electricity pathways are further described in *section 3.5.1*.

We have also included the option of CCS for the hydrogen, synthetic diesel and IGCC pathways to illustrate the potential of this technology (see *section 3.6*).

Note: There is no fundamental reason why DME could not be made from coal in the same way as methanol. This option has, however, not been seriously considered so far so we have not included it. By comparison methanol from coal is an established process.

Figure 3.3 Coal pathways

Energy source	Production and conditioning at source	Transformation at source	Transportation to markets	Transformation near market	Conditioning and distribution	Fuel	Pathway code
Coal (typical EU mix)	Production and conditioning		Typical for EU coal mix	Gasification+CO shift (+CC&S option)	Pipeline, 50 km + compression	CH2	KOCH1/1C
				Gasification + Methanol synthesis	Mixed land transport 500 km	Methanol	KOME1
				State-of-the-art conv. technology	MV grid	Electricity	KOEL1
				IGCC (+CC&S option)	MV grid	Electricity	KOEL2/2C
				CTL plant (+CC&S option)	As for refinery fuels	Syn diesel	KOSD1/1C

3.4 Biomass pathways

(See also WTT Appendix 1 section 9 to 14 and Appendix 4 section 3)

The availability of biomass and the production of fuels from it is a complex question intimately tied to the cost, because of the diversity of agricultural conditions in EU. Therefore availability and cost are combined in a single discussion in *section 5.2*.

We have included all sources of biomass which have the potential to substitute a significant amount of transport fuel in the EU i.e. farmed crops such as sugar beet, wheat and oil seeds and woody biomass either in the form of waste or purpose-grown. "Wood farming" incorporates also perennial grasses such as miscanthus or switch grass. New to this version are pathways for biodiesel from soy and palm oil, and from hydrogenation of plant oils. The range of pathways has also been extended to include further alternative uses of by-products, and we have shown more results for heat and/or power generation from biomass.

3.4.1 Land use change and marginal emissions

Emissions from land use change may be important, but are NOT INCLUDED in our WTW GHG balances

If crops for biofuels come from land which was not previously planted with row-crops (e.g. grazing land, pasture or forest) there will be a "direct land use change", which may cause significant releases of carbon from the soil (see below). The "cross-compliance" requirements of the EU Common Agricultural Policy, largely prevent the conversion of grassland land for food crops in EU[6], but one can suppose that if crop prices increase because of extra demand from biofuels, this will decrease the amount of land otherwise in voluntary ("nature") set-aside.

If, on the other hand, the crop used for biofuel comes from arable land which would otherwise be used for food production, the displacement of food production is likely to cause "indirect land use change" (ILUC) somewhere else (often outside EU). The nature and magnitude of ILUC is currently and matter of debate and scientific investigation. There is a concern that it may in turns cause significant emissions of carbon as organic matter is lost from soil and cleared vegetation.

These land-use change emissions are NOT included in the results of this study**. This does not mean that we think they are not important**. It is because they are still very uncertain, and this consortium is not in the best position to evaluate them, since complex economic modelling is required. Understanding of these broader aspects is growing, but such is the level of uncertainty that they are not easy to include in a quantified way into this study.

---

[6] However, there is a recent trend in Germany for intensive *non-food* crops (principally fodder-maize) to be planted on grassland in order to supply feedstock for biogas plants supplying the electricity and gas grids.

The only sources of biofuels which do not cause ILUC are:
- wastes which would otherwise not be used,
- Land which would otherwise be uncropped because of annual (compulsory) set-aside regulations as is the case in the EU (although taking an extra crop may result in a moderate reduction in soil carbon which in principle should be taken into account),

So one can think of our results for EU crops as applying roughly to biofuels from set-aside land[7].

In 2005, when we produced version 2 of this study, a large part of the prevailing 5.75% EU biofuels target could have been met from crops on set-aside. Production of oilseeds and wheat for biofuels on compulsory set-aside land could produce 2-3% of EU road-fuels. As farmers can already grow crops for biofuels on rotational set-aside, most of the potential is already exploited, and set-aside cannot be expected to supply more than a fraction of the extra crops needed to meet the 10% renewable energy target by 2020 proposed with the Renewable Energy Directive.

Marginal emissions due to yield intensification are also not considered

If crops are diverted from food to energy use, this will cause relatively higher crop prices, and this can be expected to cause some extra intensification of farming. The incremental production from this intensification will be associated with incremental emissions from the farming (extra use of fertilizer, pesticides, diesel, more expensive seeds etc). The ratio of extra emissions to extra production is likely to be higher than the ratio of existing emissions to existing production (because of diminishing returns from further intensification). However, we have not attempted to evaluate how much larger the marginal extra emissions are, since they are presently uncertain and the subject of on-going research.

Another effect which is probably important but we cannot yet estimate with acceptable precision is the effect of intensification, or indeed any change in crop or management, on soil carbon stocks. Generally, intensification is thought to reduce soil carbon stocks, whilst low-tillage and organic farming can reverse the historical decline in EU soil carbon, but generally at the expense of lower yields. The soil chemistry model used by JRC to model N2O emissions (*section 3.4.2*) also provides output on annual changes in soil carbon, which are of comparable magnitude to the N_2O emissions in terms of CO_2-equivalent emissions per year. However, the model is not optimized for those calculations, and one needs very good data on the use of the crop residues. This is why we have not reported the results.

GHG payback times for land use changes in EU

This discussion is retained from version 2 of this study: it introduced the concept of "GHG payback time".

The largest potential for expanding EU agricultural production for biofuels would be to increase the arable area at the expense of grazing land. However, there are very serious greenhouse-gas consequences to ploughing up grassland. The change in land-use results in a reduction in the organic carbon stored in the soil. Although this only happens once, the effect is very large and long-lasting. The soil reaches a new (lower) carbon content at a decaying-exponential rate, characterized by about a 20-year time-constant and an annual CO_2 emission (representative of EU-15) of the order of 3.7 t/ha, although the uncertainty range is more than 50% ([*Vleeshouwers 2002*], quoted by [*DG-ENV 2003*]). That makes a total of roughly 73 t/ha CO_2 (±>50%) emitted due to the change in land use. This figure is also congruent with the difference between grassland and arable soil-carbon stocks according to the default IPCC figures for temperate climates [*IPCC 1996/2*].

---

[7] However, even here, a correction should in principle be made for the long-term loss in soil carbon resulting from taking another harvest instead of a break-year. The DNDC soils-chemistry results used by JRC for their nitrous oxide emission calculations (see section below) indicated that even one extra harvest (instead of a year under a cover crop) could result in a significant reduction in soil carbon, but for a correct calculation it would be necessary to simulate soil carbon variations over the whole rotation.

Note:
Table 5.10 of [*IPCC 1996/2*] indicates a soil C stock of 50 t/ha for grassland and improved pasture in cold temperate climate. The table 5.11 indicates the same figure for "native vegetation" in cold temperate conditions on "active" soils (the most likely soil type to be converted to arable cropping), rising to 110 t/ha for moist warm temperate climate. So let us take 50 t carbon /ha (in top 30cm) as a conservative figure for carbon stocks in EU grassland/pasture/native ground cover.

IPCC recommends calculating the change in carbon stocks by the change in the "base factor" for different types of land use. For improved pasture (and therefore we assume also grassland) the base factor is 1.1 (table 5.12). For continuous arable crops the base factor is 0.7. The difference, 0.4, represents the fraction of the nominal C lost due to the land use change from grassland to arable. Thus the expected carbon loss is 0.4x50 = 20 tonnes of C per hectare. This loss is equivalent to 20x44/12 **= 73 tonnes of CO_2 emitted per hectare**.

Every year biofuels produced on the land give a GHG saving, gradually compensating the emissions due to the change in land-use. *Table 3.4.1-1* gives a very rough estimate of the GHG payback time, using GHG balances for the basic pathways for various crops from this study. These should only be taken as an order-of-magnitude guide, because no account is taken of the variation in soil carbon levels in different areas (for example, soil carbon is generally lower in the South, where sunflower is grown than in climates suitable for rapeseed). There is also a huge uncertainty in the soil carbon data.

Table 3.4.1-1   *Rough estimate of GHG payback time for EU biofuels crops on grassland*

Crop	FeedWheat	Sugar Beet	Rapeseed	Sunflower	Farmed wood
Example pathway	WTET1	SBET1	ROFA1	SOFA1	WFSD1
EU av. yield (t/ha)	8.0	61.2	3.0	1.8	11.1
Biofuel (GJ/ha/a)	73	124	42	27	76
GHG saved per GJ biofuel (kg CO_{2eq}/GJ)	9	36	36	58	64
GHG saved (kg CO_{2eq}/ha/a)	660	4429	1505	1545	4806
Total C stock change (t CO_2/ha) +/-50%	-73	-73	-73	-73	0 to -73
Years for GHG to breakeven +/-50%	111	17	49	47	0 to 15

Note:
For simplicity, we have taken EU average yields for arable crops (incremented by 13.5% for feed-quality wheat): this is higher than the yield one would expect on the sort of land converted from grassland, so our break-even times are probably too short. To allow comparison between crops, we estimated the yield of farmed wood which one could expect on average wheat fields, from our yield ratios.

Planting biofuels crops on grassland would probably not pay off in GHG terms for decades.

Reviews of carbon sequestration (e.g. [*Vleeshouwers 2002*]) generally assume soil carbon levels for Short Rotation Forestry (SRF) to be equivalent to forest and grassland. Until now, no-one has measured what happens to soil carbon stocks when SRF is planted on former grazing or forest. A JRC study on a 40-year-old poplar plantation [*Ferré 2005*] shows that total soil carbon had declined 25% compared to the original natural forest: a CO_2 emission equivalent to 42 tonnes/ha. It is well known that soil disturbance releases soil carbon, and the ground is usually ploughed before SRF is planted (although one could develop techniques to avoid this). Thus one expects some reduction in soil carbon, but less than from converting grassland to arable. That is why in the table we give a range of soil carbon loss for grazing-land to SRF as between zero and that for changing to arable.

3.4.2 Nitrous oxide emissions

The ability of biofuels to reduce fossil energy use and GHG emissions rests on the absorption of solar energy and carbon dioxide from the atmosphere by growing plants. These benefits are offset to some extent by the use of fossil energy in producing and processing the crop. Although not a major factor in *energy* terms in the whole pathway, farming is the primary source of GHG emissions associated with biofuels. CO_2 emissions associated with farm equipment use and manufacture of fertilizers and chemicals are not the only GHG emissions to be considered. Significant quantities of another greenhouse gas, nitrous oxide (N_2O), are produced from nitrogen fertilizer production and emissions of N_2O from the field.

Although N_2O emissions are not very large in absolute terms, the very high greenhouse effect of this gas (about 300 times as much as CO_2 on a mass basis) makes them very significant. In particular, the huge **uncertainty** in estimates of GHG emissions from soils dominates the errors in the final GHG balances of biofuels pathways. There are enormous variations in N_2O emissions from one field to another, depending on soil characteristics, climate, tillage, fertilizer rates and crop (in approximate descending order of importance). In Europe emissions generally show much greater local variation than in America, due to the heterogeneity of soils. Therefore it is worthwhile putting a large effort into improving the accuracy of the soils-emissions estimates.

Where they have considered them at all, other biofuels studies have adopted two approaches to estimating nitrous oxide emissions from soils. One is to extrapolate from measurements on individual fields; the other is to use the "tier 1" estimates under the IPCC guidelines. These are designed to estimate national greenhouse gas emission inventories, not emissions for particular crops or fields. The revised tier 1 method guidelines in [IPCC 2006] assume N_2O emissions from managed fields are a constant fraction of the nitrogen applied (as synthetic fertilizer, manure, crop residues or from nitrogen-fixing crops). The fraction is called an "emission factor". Separate emission factors are used for "direct" emissions from the soil and for "indirect" emissions from nitrogen leached off the field.

To account for other variables, IPCC specifies a wide error range: the max/min ratio varies from 10 (for direct emissions) to 50 (for indirect emissions from leached nitrogen).

Life-cycle analysis studies often use the default (best-estimate) IPCC emission factors to calculate nitrous oxide emissions, but ignore the range IPPC attaches to them. This is probably because the uncertainty in the overall GHG balance would then become so great that it would be impossible to say whether any biofuel from agriculture saves GHG or not.

But even this IPCC range is by far not sufficient to cover the range of values which have been measured on individual fields. For example, emissions thirty times the *maximum* value of direct emissions from IPCC guidelines have been measured from crops on drained peat soils. The tier 1 guidelines [*IPCC 2006*] now include a range of emissions from organic soils; but this does not vary according to whether (or how) a crop is grown on those fields, so they are of no use to us.

This study uses a more sophisticated calculation of EU-average nitrous oxide emissions for each crop, exploiting the database-calculation-model of the soils-and-waste unit of the Institute for Environment and Sustainability at JRC-Ispra which was developed to estimate agricultural GHG emissions for monitoring compliance with the Kyoto commitment. This is built on well-validated soils chemistry model, DNDC (version 82N) [*UNH 2003*], which calculates daily direct nitrous oxide emissions from fields, as well as the amount of nitrogen leached off into the groundwater. Already for version 2 of this study, JRC applied the model to points from the LUCAS land-cover survey [*Eurostat 2003*], which reports land use and crop for measurement points on an 18-km grid covering EU-15, in the year 2000. Thus our calculation produces a "snapshot" of N_2O emissions in EU15 in the year 2000.

Another group at JRC has adopted a different approach: instead of the ground-truthed crop identification in the LUCAS dataset, they start off with the mix of crops within a NUTS3 region, and then model where they would be planted on the basis of satellite land-cover data and soils characteristics. That model has the advantage of covering more of the EU and is being linked to the CAPRI regionalized model of EU agriculture to allow emissions effects of future policy changes to be determined. However, we believe our approach, although less flexible, is at present a more reliable method for attaining the EU average emissions per crop, since it eliminates the layer of uncertainty in assigning crops to areas on the map.

The other main inputs were:
- The soil properties for each measurement point: from the soils database maintained by the European Soils Bureau at JRC-EIS, which attempts 1 km resolution by a disaggregating process based on GIS land-cover data.
- Daily weather for the year 2000, obtained from the 50 km meteo-grid of the MARS project at JRC-IHCP Institute.
- Manure rates, per country and crop, derived from the CAPRI model at the University of Bonn.
- Fertilizer rates: we used the crop and soils characteristics at each grid point to derive the recommended N fertilizer rate, according to [*DEFRA 2000*] The most important correction is to reduce the nitrogen rate according to the organic carbon content of the soil. Less nitrogen fertilizer is needed on higher-organic soils, but a larger proportion is emitted as N_2O. The DEFRA recommendations only give (per crop) ranges of nitrogen rate for different categories of soil organic content: resulting in a conceptual bar-chart. For the calculation, we drew a continuous function through the bars. This function halves the N rates for each 13% increase in soil organic matter in the top 90cm of soil (DEFRA definition: we had to fit data on soil carbon profiles to convert this to the units of % soil-carbon in the top 30 cm, used by the DNDC program). Then we applied a separate correction factor to the N rates for each country and crop, in order to make the averages coincide with the actual usage published by the International Fertilizer Association [*IFA 2002*].

Apart from the emissions from the soil, some nitrous oxide emissions arise from nitrate which is leached off the field into groundwater and rivers. These are called "indirect" nitrous oxide emissions (not to be confused with nitrous oxide emissions resulting from food production displaced by biofuels!). The DNDC model estimates the amount of nitrate leached from the soil at each grid-point we considered. From this, we estimated the indirect emissions using the new default IPCC 2006 range of emission-factor (EF_5) in [*IPCC 2007*] for indirect emissions. IPCC decreased the range attached to this emissions factor since the version 2 of this report was published, with the result that this range no longer dominates the uncertainty range of the total emissions. This means we have had to estimate the uncertainty in our direct emissions calculations more carefully, as explained below.

Per-hectare nitrous oxide emissions were averaged for all points sharing a common crop, and divided by the average year-2000 yields from EUROSTAT. In this way we averaged emissions for fields where the crop is actually grown. This removes much of the uncertainty from the calculation in version 1 of this study, where we worked on regions (NUTS-3) and had to average between the dominant soil types of each region.

Figure 3.4.2-1 shows, for points from the LUCAS survey, the calculated N_2O emissions per hectare when growing wheat or unfertilized grass. The difference between the two represents the incremental N_2O emissions from growing wheat on set-aside (see text box).

Figure 3.4.2-1 Nitrous oxide emissions from 3459 EU fields growing either wheat or grass Year 2000
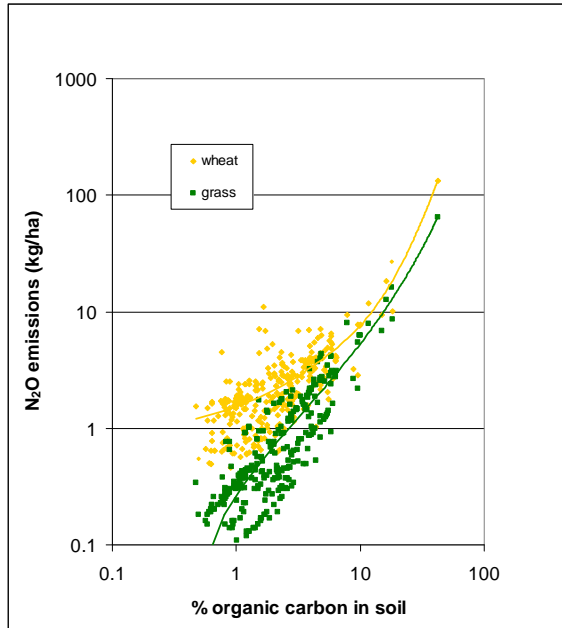
Background N$_2$O emissions and "reference land use"

Soils emit some N$_2$O even if they are not farmed (so-called "background emissions"). These can be quite significant, especially for organic soils. If we are to model the emissions from EU land in annual set-aside used for biofuels, we should subtract the background emissions which would otherwise have occurred. Where annual set-aside land is not already used for non-food crops, it is either left fallow or, increasingly, planted with a cover crop. We could estimate the background emissions by changing the crop specified in the DNDC soil chemistry model. However, DNDC restricts the possibilities to either another arable crop, fallow or grass.

Selecting "fallow" suppresses all vegetative growth; whereas in practice even a fallow field gets a partial covering of weeds, which also act as a cover crop, reducing the loss of nitrogen from the soil by absorbing and storing it until the next ploughing. So we considered that "unfertilized grass" was the best choice offered by DNDC for estimating background emissions. We ignored the small farming inputs for maintaining the field in set-aside.

The amount of manure used in EU depends on how much is available rather than on which crop is grown. So the manure used in the "biofuels crop" scenario does not disappear if the field is in set-aside instead: even if used on another field, it would cause some N$_2$O emissions. Therefore, it is better to assume that the same amount of manure is used on the set-aside field, than to assume none is used. It is quite conceivable that manure would be applied on a field of unfertilized grass (for example, directly by grazing animals), but no-one would put manure on a fallow field: another reason for preferring grass to represent emissions from the reference scenario.

For biofuels crops grown on voluntary set-aside land, [*Kaltschmitt 1997*] considered as reference crop a field under set-aside planted with unfertilized rye grass. This was effectively the same as no reference crop because the N$_2$O emissions were assumed proportional to the extra N applied. [*LBST 2002*] considered both this scenario and one in which clover (a nitrogen-fixing plant) was sown on the reference field. In this case, there was a reduction of between 1 and 2.5% in farming energy inputs (due to a small saving on N fertilizer for the next crop). This is well within the range of overall uncertainties in the farming emissions, and can be neglected, along with the small emissions from establishing the cover crop, which work the other way.

[*LBST 2002*] calculated a negligible effect of the choice reference crop on soil emissions because the saving on nitrous oxide emissions caused by the fertilizer was compensated by soils emissions from the clover.

Our study does not assume N$_2$O emissions to be proportional to the N fertilizer rate, and we find significant emissions also from unfertilized land. Therefore we need to subtract the emissions in the reference scenario.

The most sensitive parameter influencing agricultural N_2O emissions is the soil organic matter content (often indicated by the soil organic carbon (SOC) concentration. Much of the emissions, especially from high-organic fields, would occur even if the field was not ploughed, and this effect is taken into account through the "grass" reference case (see text box). However, the *extra* N_2O emissions from arable farming also increase with SOC, and very rapidly when the SOC is over 10% (the scale is logarithmic). In fact this effect is so strong that the results from a few fields with over 10% SOC significantly affect the whole average.

In Europe, arable crops are unlikely to be grown on peat: the soil is likely to be too waterlogged and acid[8]. In the calculation, however, unlikely apparent combinations of soil type and crop arise because of a difference in the nature of the soils-database and the LUCAS database. The LUCAS dataset gives the actual crop observed on the ground at regular grid-points (in the year 2000). The soils database starts with a list of principal soil types in each region ("soil polygon"), and then assigns one of these soil types to each grid point according to the typical land cover around that point (using pseudo-transfer rules). The typical land cover is taken as the most common land cover reported for the surrounding 100m "pixels" of the CORINE land-use database, based on satellite data. It sometimes happens that a LUCAS measurement point is in an arable field which is not the *typical* land cover in that locality: for example, it could be an "island" of higher ground surrounded by peat-bog. The soils properties for the peat-bog would then falsely be associated with an arable field.

Although rare, these mis-matches have a significant effect on the EU-average results: according to our raw results about 20% of emissions apparently came from just 1% of the fields. The apparent soil carbon content at these locations is very high for an arable field: one suspects a soil-mismatch. Another point to bear in mind is that DNDC is calibrated with measured data: if the results are higher than any measurement, we cannot know if they are correct. We therefore "cap" suspiciously high calculated emissions, before averaging the emissions per crop.

Since the soil C content applies also to the same field under grass (used as a reference), we cap the *difference* in emissions between crop and reference crop (grass). So if the calculated emissions-difference-between-crop-and-grass-reference is above the cap level, we take it to be at the cap (that field is still likely to have a soil C content well above average, so it would be wrong to ignore the point altogether). The derivation of the range of cap levels is explained below:

- The MINIMUM plausible average of emissions-per-crop corresponds to the assumption that the crop is grown only on mineral soils (implying that all fields apparently with organic soils have a soil-mismatch). We approximate this by setting the cap at the average N_2O emissions calculated for soil with 10% soil carbon (to be consistent, we subtract the corresponding average "background" emissions of N_2O from fields with 10% soil carbon under unfertilized grass). This limits the N_2O emissions considered from any field to 2.6 kg/ha/yr N-as-N_2O.

- Our BEST-ESTIMATE of average emissions per crop assumes that the emissions from a field cannot exceed the typical values measured on cultivated peat soils. We use data from *[Regina 2004]*, who measured annual N_2O emissions from cultivated peat soils at various sites in Finland. Because there were relatively few data points, and a significant spread, we average their measurements for all arable crops, and subtract the average emissions they measured on unfertilized pasture at the same sites. The resulting cap is 8 kg/ha/yr N as N_2O.

- The MAXIMUM plausible average-emissions-per-crop assumes that the emissions from any field cannot be higher than the highest measured emissions from cultivated EU fields. Again we subtract

---

[8] However, on a global basis such soils are being deforested and converted to arable use, which will lead to high nitrous oxide emissions as well as the large carbon emissions described earlier in this section

the typical "background" emissions from the same sites. Following the results in [Flessa 1998], we set the cap at 50 kg/ha/yr of N as N_2O. One could argue that it is quite possible that some cultivated fields emit more N_2O than any of the few fields which have actually been measured. On the other hand, DNDC is not calibrated for even higher emissions, and including higher calculated emissions would make the EU average dependent on a few uncalibrated calculations.

Although the level of the "cap" is the largest source of error in our estimates of the average direct N_2O emissions, it is not the only one. In consultation with soils experts, we concluded that, even without the problem of capping, we could not claim better than +/-30% accuracy in the EU-average results, due to the approximations of the DNDC model and the experimental data by which it is calibrated. We combined the errors from the two sources, using the square root of the sum of the squares of the individual error ranges (treating the + errors separately from the - errors). This approximates the flank of the probability distribution to a normal distribution, even if the width of the + and - flanks are not quite the same for the direct emissions.

Finally the range of total average nitrous oxide emissions per crop in EU-15 is found by summing the minimum, best-estimate, and maximum average direct EU-15 soil-emissions with the corresponding range of indirect emissions from run-off nitrogen (here we did not use the square-root-of-the-sum of the squares procedure because the errors are not independent: high indirect emissions are more often than not associated with high direct soils emissions).

To obtain the emissions-per-tonne-of-crop, we divided the average per-ha emissions for each crop (calculated for the year 2000) by the average EU-15 yields for the same year (from EUROSTAT). Yields in 2000 were typical for recent years.

We could only apply our N_2O emissions model to EU15 because that is all that is covered by the LUCAS dataset. National N_2O emissions depend mostly on soil carbon content and climate. The 12 new member-states show the same variation in these conditions as EU15: in the Baltic states they are comparable to those in Finland, whilst in Bulgaria they are comparable to Spain. So it is not clear in which direction inclusion of EU12 would affect the EU-average N_2O emissions. We can suppose that it will not change them outside our range of uncertainty.

The results are shown in **Table 3.4.2-1** for the main crops considered in this study.

Table 3.4.2-1   *Average N$_2$O emissions from biofuels crops grown in the EU*

AVERAGE N2O EMISSIONS FOR WHEAT (background emissions subtracted)				
Direct Emissions from Soil:	min.	best est.	max.	
cap on emissions	2.6	8	50	kgN as N2O/ha
Nitrogen emitted as N2O	0.880	1.187	1.746	kgN as N2O/ha
..combined with other uncertainty	0.717	1.187	1.850	kgN as N2O/ha
…converted to mass of N2O	**1.126**	**1.865**	**2.907**	**kg N2O/ha**
Indirect emissions from N leached from field in run-off water:				
leached N (estimate from model)	10.46	14.94	19.42	kgN /ha
IPCC "EF5" emission factor	0.0005	0.0075	0.0250	kg(NasN2O)/kgN leached
IPCC indirect N2O emission as N	0.0052	0.1120	0.4854	kgN/ha
…converted to mass of N2O	**0.008**	**0.176**	**0.763**	**kg N2O/ha**
TOTAL direct+indirect N2O	1.134	2.041	3.670	kg N2O/ha
EU15 2000 yield EUROSTAT	5.86	5.86	5.86	moist tonnes/ha
N2O per tonne moist crop	0.194	0.318	0.626	kg N2O/moist tonne

AVERAGE N2O EMISSIONS FOR SUGAR BEET (background emissions subtracted)

Direct emissions from soil:	min.	best est.	max.	
cap on emissions	2.6	8	50	kgN as N2O/ha
Nitrogen emitted as N2O	1.511	1.776	2.970	kgN as N2O/ha
..combined with other uncertainty	1.181	1.776	3.083	kgN as N2O/ha
…converted to mass of N2O	**1.855**	**2.790**	**4.845**	**kg N2O/ha**
Indirect emissions from N leached from field in run-off water:				
leached N (estimate from model)	5.14	7.34	9.54	kgN /ha
IPCC "EF5" emission factor	0.0005	0.0075	0.0250	kg(NasN2O)/kgN leached
IPCC indirect N2O emission as N	0.0026	0.0551	0.2386	kgN/ha
…converted to mass of N2O	**0.004**	**0.087**	**0.375**	**kg N2O/ha**
TOTAL direct+indirect N2O	**1.859**	**2.877**	**5.220**	**kg N2O/ha**
EU15 2000 yield EUROSTAT	61.23	61.23	61.23	moist tonnes/ha
N2O per tonne moist crop	**0.030**	**0.047**	**0.085**	**kg N2O/moist tonne**

AVERAGE N2O EMISSIONS FOR RAPESEED (background emissions subtracted)

Direct emissions from soil:	min.	best est.	max.	
cap on emissions	2.6	8	50	kgN as N2O/ha
Nitrogen emitted as N2O	1.621	1.848	2.554	kgN as N2O/ha
..combined with other uncertainty	1.249	1.848	2.746	kgN as N2O/ha
…converted to mass of N2O	**1.963**	**2.904**	**4.315**	**kg N2O/ha**
Indirect emissions from N leached from field in run-off water:				
leached N (estimate from model)	7.46	10.66	13.86	kgN /ha
IPCC "EF5" emission factor	0.0005	0.0075	0.0250	kg(NasN2O)/kgN leached
IPCC indirect N2O emission as N	0.0037	0.0800	0.3465	kgN/ha
…converted to mass of N2O	**0.006**	**0.126**	**0.545**	**kg N2O/ha**
TOTAL direct+indirect N2O	**1.969**	**3.030**	**4.860**	**kg N2O/ha**
EU15 2000 yield EUROSTAT	3.03	3.03	3.03	moist tonnes/ha
N2O per tonne moist crop	**0.650**	**1.000**	**1.604**	**kg N2O/moist tonne**

AVERAGE N2O EMISSIONS FOR SUNLOWER (background emissions subtracted)

Direct emissions from soil:	min.	best est.	max.	
cap on emissions	2.6	8	50	kgN as N2O/ha
Nitrogen emitted as N2O	0.581	0.643	0.643	kgN as N2O/ha
..combined with other uncertainty	0.441	0.643	0.836	kgN as N2O/ha
…converted to mass of N2O	**0.692**	**1.011**	**1.314**	**kg N2O/ha**
Indirect emissions from N leached from field in run-off water:				
leached N (estimate from model)	1.79	2.56	3.33	kgN /ha
IPCC "EF5" emission factor	0.0005	0.0075	0.0250	kg(NasN2O)/kgN leached
IPCC indirect N2O emission as N	0.0009	0.0192	0.0832	kgN/ha
…converted to mass of N2O	**0.001**	**0.030**	**0.131**	**kg N2O/ha**
TOTAL direct+indirect N2O	**0.694**	**1.041**	**1.445**	**kg N2O/ha**
EU15 2000 yield EUROSTAT	1.78	1.78	1.78	moist tonnes/ha
N2O per tonne moist crop	**0.390**	**0.568**	**0.812**	**kg N2O/moist tonne**

SUMMARY

N2O emitted per tonne moist crop				
	min.	best est.	max.	
wheat	**0.19**	**0.32**	**0.63**	**kg N2O/moist tonne**
sugar beet	**0.03**	**0.05**	**0.09**	**kg N2O/moist tonne**
rapeseed	**0.65**	**1.00**	**1.60**	**kg N2O/moist tonne**
sunflower seed	**0.39**	**0.57**	**0.81**	**kg N2O/moist tonne**

GJ per tonne moist crop				
	moisture%	LHV dry	LHV moist [1]	
wheat	**14%**	**17.0**	**14.7**	**GJ/moist tonne**
sugar beet	**77%**	**16.3**	**3.8**	**GJ/moist tonne**
rapeseed	**10%**	**26.4**	**23.8**	**GJ/moist tonne**
sunflower seed	**10%**	**26.4**	**23.8**	**GJ/moist tonne**

[1] LHV moist in this study is defined as the LHV of the dry-matter content of the moist material

N2O emitted per GJ of crop				
	min.	best est.	max.	
wheat	13.2	21.6	42.6	g N2O/GJ
sugar beet	7.9	12.3	22.3	g N2O/GJ
rapeseed	27.3	42.1	67.5	g N2O/GJ
sunflower seed	16.4	23.9	34.2	g N2O/GJ

note: in this study we use the LHV heat content of the dry matter in the crop

Rapeseed has the highest emissions because it is grown in the Northern half of Europe, where soils generally have a higher organic content. Sunflower, grown in the drier South, has the lowest emissions per ha, which the low yield does not entirely compensate. It also has the lowest contribution from "indirect" emissions from leached nitrogen, which reduces the error range.

The high yield of sugar beet, and the fact that it cannot be grown on badly-drained soil, brings its emissions-per-GJ-crop below that of the others. Sometimes a low-yielding or a cover crop, such as mustard, is grown in the year preceding sugar beet, in order to condition the soil for the intensive cropping in the next year. It could be argued that emissions from that previous year should be attributed to the sugar beet crop. We have not done this as we have little information on crop rotations, and the same sort of considerations apply in principle to all the crops.

Significant as these emissions are, a recent study has suggested these 'bottom-up' calculations may still significantly underestimate the real emissions of N_2O from agriculture [Crutzen 2007]. The study compares the known emissions of N_2O to the levels actually found in the atmosphere. Taking into account the mechanisms that slowly remove N_2O from the atmosphere over time, they estimate that N_2O emissions from agriculture may be as much as three times higher than those produced by 'bottom up' calculations as used in our study. They also comment on the implications for biofuels. Although this part of their analysis is not very thorough, higher N_2O emissions would obviously reduce the GHG savings from biofuels, and could even lead to GHG increases. For example, for wheat to ethanol (WTET1a) we estimate a GHG benefit relative to gasoline of 29%. If N_2O emissions were three times higher, this reduces to 10%. For biodiesel (ROFA1), the impact of N_2O emissions is even greater. Our best estimate is for a 56% GHG emission saving compared with diesel. If N_2O emissions were ignored, the benefit would be 81%, but if they are three times higher, the benefit reduces to 5%.

One should note that the N_2O emissions estimates in the Crutzen paper are not beyond the *upper limit* of the IPCC tier 1 calculations, if these are made correctly, taking into account emissions from leached nitrogen, (and including nitrogen from manure and crop residues).

N₂O emissions from crops grown outside EU

We do not have detailed enough information to calculate the N_2O emissions from crops grown outside EU using a soils model. The best we can do is to use the tier 1 2006 IPCC guidelines. This leads to a larger uncertainty in emissions. Fortunately, however, the crops we consider do not have a high ratio of nitrogen input to yield (and therefore generate moderate emissions per tonne, under the IPCC assumption that emissions are proportional to Nitrogen rate), so the effect on the uncertainty in the overall GHG balance is still acceptable.

Between their 1996 and 2006 guidelines, IPCC changed their default emission guidelines for soybeans: this had the effect of drastically reducing the N_2O emissions calculated for soybean. We think the true emissions actually lie between the two, as described below. This discussion originated from the staff of E4tech, UK in 2008, working on behalf of the UK Renewable Fuels Agency. The resulting correction to the N_2O emissions for leguminous plants was incorporated in UK RFA default values for soybeans. Subsequently E4tech discussed their analysis with JRC. JRC agreed, only making a small correction,

described below. The text below is our interpretation of the survey in the original E4tech document, and appears with their permission.

JRC agrees with E4tech that the 2006 IPCC (tier 1) approach significantly underestimates the N_2O emissions from soybeans and other leguminous plants. The old 1996 IPCC methodology for calculating N_2O emissions from soil (used in version 2 of this study) did not consider the below-ground nitrogen (BGN) in plants at all, but did assume that the nitrogen naturally fixed by leguminous plants (such as soybean) contributed to the release of N_2O. This would mean that the nitrogen-fixing bacteria in the roots were emitting N_2O at the same time as they were fixing nitrogen from the air.

However, a paper in 2005 by *[Rochette 2005]* argued that there was little evidence for significant N_2O emissions from legumes during the nitrogen fixation process. Therefore in the revised 2006 methodology (published in 2007), IPCC no longer include emissions directly from the natural nitrogen-fixing process. On the other hand, the 2006 guidelines *do* take into account the contribution of below-ground N content of the plants themselves to the nitrogen pool in the soil which contributes to N_2O emissions.

IPCC attribute these extra emissions to the current crop. However *[Rochette 2004]* shows that most of these will actually take place during the following season. He found that although the soil mineral N content under legumes were up to 10 times greater than under a grass, this was not closely related to the N_2O emissions measured during the growth phase of the plant. However, he found greater emissions of N_2O after the plant had been harvested, strongly dependent on the soil type.

So for the current season, what *should* be taken into account is the contribution of below-ground nitrogen from the residues of the *previous* crop. From the point of view of a national average, it does not matter much to which crop a certain amount of soil nitrogen is attributed. But it does make a difference if you are calculating N_2O emissions *per crop* in a rotation. Of course the distinction is not important if the *same* crop is grown in successive years, which is generally the case in Brazil (the assumed source of soybeans in our study).

Figure 3.4.2-2   *Distribution of biologically-fixed nitrogen in leguminous plants*
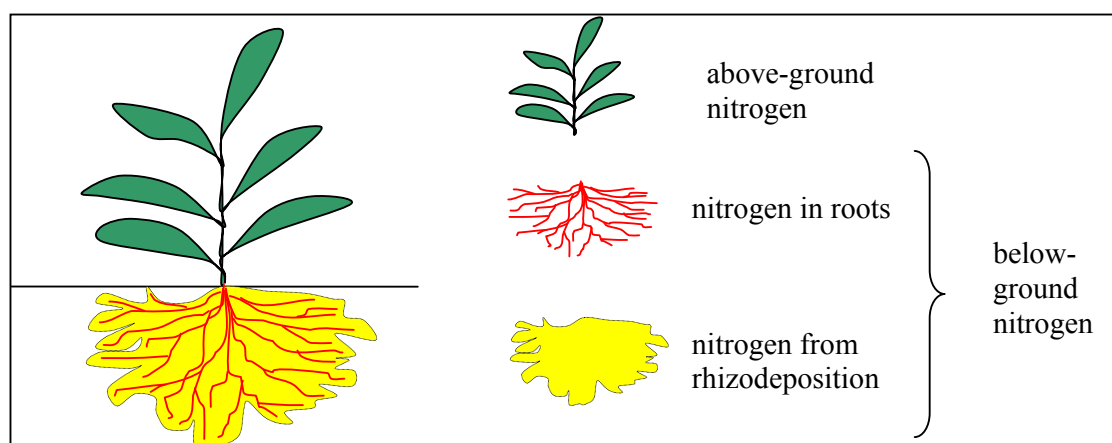
Part of the nitrogen biologically fixed by soy plants ends up in the above- and below-ground crop residues, and in principle IPCC 2006 takes emissions from this into account. However, we think they have seriously underestimated the amount of below-ground nitrogen. This comes from firstly underestimating the below-ground biomass and secondly from ignoring nitrogen from rhizodeposition.

Rhizodeposition *[Jensen, 1995]* is the process whereby N enters the soil from the plant roots in the

form of NH_4, NO_3, amino acids, cell lysates, as well as through decay of sloughed-off and senescent roots. It can now be quantified through techniques such as 15N shoot labelling [Khan 2002a). The literature shows that leguminous plants such as soy exude significant volumes of N from their roots *[Martens, 2006]*.

Table 11.2 of the 2006 IPCC Guidelines gives default factors for estimation of N added to soil from crop residues. According to this, only 16% (= 0.19/1.19) of the soybean plant residues are in the underground biomass, and they all have the same nitrogen concentration. These default factors are based on an extensive literature review, the references for which they provide in Annex 11A.1. The default value for BGN content of soybean comes from a 1925 paper. Whilst E4tech could not obtain a copy of this reference, their review of more recent literature suggests such an old work will have missed not only the N released by rhizodeposition, but also that in fine root hairs that are very difficult to collect using the old techniques of physical root recovery. *[Aruja et al. 2006]* confirms that the roots recoverable by traditional methods only contain 5-10% of the total N accumulated by the plant. For comparison, *[Alves 2003]* report results using modern techniques of between 30-35% of total plant N. This implies IPCC has underestimated nitrogen in the roots themselves by at least a factor 3.

If we include also nitrogen from rhizodeposition, the IPCC defaults look even further out. *[Khan 2002b]* concluded that the traditional methods only recovered 20-30% of the total below-ground nitrogen (including that from rhizodeposition) obtained using N-labelling methods. *[Mayer 2003]* found that N rhizodeposition represented about 80% of the below ground plant N. These studies suggest that the N from rhizodeposition is roughly four times the below-ground nitrogen in the roots, so at least an order of magnitude greater than the below-ground nitrogen calculated from IPCC defaults

We think that in reality only the part of the biologically fixed nitrogen released by rhizodeposition counts towards N_2O emissions from the soil during a particular growing season. The rhizodeposition gradually builds up during the season, but after the harvest the plant residues gradually decay and release their nitrogen into the soil. There are not enough data to estimate the amount of rhizodeposited nitrogen from soy by direct measurements of soil nitrogen. A more pragmatic and accurate approach is to back-calculate the *effective* nitrogen related to below-ground biomass from the measured nitrous oxide emissions from soybeans grown without synthetic nitrogen. That figure would reflect the actual nitrogen content in the soil (we suppose, from rhizodeposition) which is giving rise to N_2O emissions. We only assume that this is proportional to the below-ground biomass. Referring to IPCC 2006 table 11.2, it does not matter if we do this by changing the default value "R_{BG-BIO}", (ratio of below-ground to above-ground biomass) or "N_{BG}", the effective nitrogen concentration in the below-ground biomass (kgN/ kg dry matter). We have chosen the second option (both of these numbers we think are wrong, but do not know how much the error in each contributes to the overall error in the effective below-ground nitrogen estimation).

We start off by averaging the measurements of N_2O emissions from soy without N fertilizer quoted in *[Rochette 2005]*. The result is 1.075 kg $N-N_2O$/ha. We assume this all originated from from rhizodeposition and decay of crop residues from the previous season. Using the IPCC default **direct** emissions factor of 0.01 kg $N-N_2O$/kg N(CR)[9], JRC estimates the total nitrogen which gave rise to those emissions to be 107.5 kgN/ha.

From this we need to subtract the nitrogen in the above-ground residues to find the effective below-ground nitrogen. First we need to estimate the yield. The N_2O data are mostly from USA, where the average yield from FAO (the source suggested by IPCC) *dry-matter* yield is 2.26 tonnes/ha. Using the formula in IPCC 2006 table 11.2, this yield corresponds to above ground residue of 3454 kgDM/ha. Combining this with the default concentration of nitrogen in above-ground biomass (0.008

---

[9]   Only the DIRECT N_2O emissions are measured in the field. E4TECH inadvertently used total direct + indirect emissions

kgN/kgDM, confirmed by *[NREL 2005]*) gives 27.6 kgN/ha in above-ground residue. Subtracting this from the total N in plant-residue leaves us with an effective 79.9 kgN/ha in below-ground biomass.

To find our new value for the default nitrogen concentration in below-ground-biomass, we need to divide the last number by the amount of below-ground biomass. Following the IPCC 2006 method we calculated this was 1086 kg/ha[10]

Now our new value for the effective nitrogen associated with below-ground biomass is N_{BG} = 79.9/1086 = **0.074 kgN/kgDM below-ground biomass**. JRC recommends using this in place of the default value of 0.008 in IPCC 2006 - table 11.2 -, in order to calculate N_2O emissions from soy which are comparable with measurements[11].

We can check whether this value is reasonable by looking at which value it implies for the fraction of the total nitrogen associated with the plant. This can be checked against measurements in the literature, which mostly range from 30 to 35%, according to *[Alvez 2003]* and a wider literature survey by E4tech.

The nitrogen concentration in the beans is 6.5%DM according to *[NREL 2005],* corresponding to 147kgN/ha in beans. The total plant N is this plus below-ground nitrogen and above-ground nitrogen in residues. Adding this all up using the figures above gives a total of 255 kgN/ha associated with the plant. Then the fraction of below ground nitrogen implied by our method is 31%. This is indeed within the range of measured values, giving us confidence that we are at least approximately correct.

It is likely that non-leguminous crops also exude some nitrogen from the roots, but in this case it is only returned to the soil after having been absorbed from the soil, so correcting for it could lead to double-counting.

A significant fraction of oil palms are planted on peat or high-organic soils, and apply nitrogen fertilizer. However, [IPCC 2007] tier 1 methodology offers no method to estimate N2O emissions due to adding nitrogen fertilizer to organic or peat soils. Results from soil chemistry models and field measurements in temperate zones show that the proportion of nitrogen fertilizer emitted as N2O is far higher on organic and peat soils than on mineral soils. However, there is much variability, and there are very few results for tropical areas. Therefore we have not managed to quantify how much this could increase average GHG emissions from palm oil production.

3.4.3 Farming inputs and yields

There are huge variations in yield for different land areas. For example the EU-15 national averages for soft wheat yields vary by a factor 6. The spread between individual farms would be even greater. The situation is similar for other crops, including wood. Therefore extreme caution must be used in using "average" or "typical" yields: they must correspond to the land being considered. In particular, EU land which is not already being used for arable farming is likely to give lower than average yields.

For transparency, in this version 3 we have adopted for all EU crops the fertilizer inputs reported by the European Fertilizer Manufacturers' Association (EFMA) together with their preferred source of national yield data: FAO. In practice, this has had little impact on the results compared to version 2 of this study, where the figures came from [*FfE 1998*] and a variety of other sources. For farming outside EU, yields are also from FAO, and fertilizer data based where possible on values from the International Fertilizer Association. See details in *WTT Appendix 1*.

---

[10] Following the formula underneath equation 11.6 in *[IPCC 2007],* this is calculated by applying the IPCC default ratio of below-ground to above-ground biomass ("R_{BG-BIO}" = 0.19 for soy) to the total above-ground-biomass found by summing the above-ground residue and crop yield shown above.

[11] By considering also indirect emissions, E4tech came to a slightly lower value for N_{BG}

Other farming inputs are taken from [*FfE 1998*] and a variety of other, more recent, sources as detailed for each crop in *WTT Appendix 1*. In all cases the farming inputs are converted to inputs-per-MJ crop using the yield which applies to the particular data. The heat value of crops and other substances are tabulated at the start of *WTT Appendix 1*.

The potassium and phosphorous fertilizer rates vary greatly according to geography, but do not correlate with yield. However, they are only of minor importance in the calculation. We also took the FfE diesel use per tonne of crop as typical. This may lead to a slight underestimate because with a high yield one would expect fewer tractor-km per tonne of crop: on the other hand German farming may be more mechanized than average.

[*DG AGRI 2005*] expect EU yields to continue their slower rate of increase of recent years, averaging 0.89% per year for EU-25 cereals up to 2012. These increases are generally achieved by breeding and technical improvements which allow the crops to make use of more nitrogen. But this extra nitrogen must be provided (as fertilizer) to achieve the higher yield. Therefore the amount of nitrogen fertilizer applied per tonne of crop will not change much, and we considered that our values from [*FfE 1998*] to remain valid. The average soil emissions per MJ crop will also be little affected by yield increases, because, *for a given field*, N_2O emissions due to farming are very roughly proportional to nitrogen fertilizer rate.

Where straw is collected, fertilizers should be added to compensate for the lost minerals; we used figures from [*Kaltschmitt 2001*]. However, the effect of this on the calculations for straw pathways is hardly significant. We do not assume that more nitrogen must be added to compensate for the nitrogen removed in the straw, because the decomposition of the straw consumes nitrogen from the soil. One could indeed argue for a nitrogen *credit* for straw removal. In Southern Europe, where decomposition is fastest, the straw is sometimes removed from the soil (even if it is just piled at the field perimeter) just to prevent this effect.

We also made no correction (in the other direction) for any long-term reduction in yields due to reducing the organic content of the soil (degradation of soil texture) by repeated straw removal. This would be the result of the soils losing some capacity for water retention, which would be important in times of water-stress. However, the effects depend extremely on local soil conditions, weather and hydrology: we assume farmers will not sell their straw if it could be damaging to their soil.

The diesel used for baling and collecting straw was taken from [*GEMIS 4.2*]

Our agricultural inputs per MJ are generally slightly lower than those in [*ADEME 2002*] although their reported diesel fuel use for rapeseed is, strangely, much higher than for wheat. The main reason that ADEME ends up with different results for energy balance is that they arbitrarily allocate energy inputs and emissions to by-products on a mass basis rather than calculating credits for the materials the by-products replace (see *section 2.4* on by-product methodology). Our inputs are also broadly in line with those of other studies.

3.4.4 Credits for animal feed by-products

In this version 3, we introduce a more sophisticated and consistent system for calculating animal feed credits for all pathways.

At present the main by-products of biofuel manufacture are rapeseed meal from biodiesel and DDGS from cereals-ethanol. These are rich in protein, but not as rich as soybean meal, the main protein concentrate feed in EU. Therefore they substitute a mix of soybean meal and carbohydrate feeds. In practice, a wide range of animal feed products are substituted in EU. However, many of these (such as

gluten feed, which is compositionally closest to DDGS) are themselves by-products of another process, so their supply hardly reacts to changes in biofuel production. The main *marginal* source of carbohydrate feed is cereals, which we represent by EU feed-wheat, whilst the main marginal source of protein is clearly soybean meal. We consider soybean meal from Brazil, because this is the largest soybean exporter and the best candidate to be the marginal producer.

The *maximum* proportion of soybean meal a feed can substitute is given by balancing total metabolized protein and digestible energy using a mix of soybean and cereals. The *minimum* proportion of soybean meal replaced is zero. In corn-ethanol producing areas of USA, the large availability of corn-DDGS means that there is effectively no more possibility to substitute soybean meal, and further increases in DDGS supply now substitute corn in animal feed, according to [*Liska 2008*] and several other sources.

For the substitution ratios used in our WTT calculations we chose the *average* of the maximum and minimum extremes. In practice the GHG credit is not very sensitive to the exact choice.

In the EU the present situation is between these extremes. More compound feed is used, and this gives greater flexibility in accommodating changing feed supplies by blending. Nevertheless, the proportion of soybean meal replaced can be expected to decline as the EU production of biofuels increases. As reflected in its higher price, soybean meal is regarded as the "Rolls-Royce" of protein feeds, with the best balance of amino acids and other properties. There are quality issues with substituting it.

Rapeseed meal is less palatable than soybean meal. Depending on the variety of rapeseed and type of farm animal, the animal will not eat more than about 5-15% (by dry mass) rapeseed meal in its diet as a general rule. The amount of rapeseed meal resulting from 10% diesel replacement by rapeseed biodiesel in 2020 would amount to roughly 10% of EU animal feed (according to our forecast of diesel consumption). This means it is close to how much could possibly be consumed if all EU livestock were eating as much rapeseed meal as they could stomach. However, they are unlikely to face this situation, because the fall in rapeseed meal price in EU would make it more economical to crush rapeseed outside EU. So palatability is probably not a limitation if the oilseed meals are uniformly spread amongst EU livestock.

DDGS is more easily tolerated by cattle: trials in US have fed them up to 40% (DM) wet distillers' grains from corn (although the protein in dried DDGS can be less digestible, especially if heat-damaged in drying). However, the cattle can only utilize the protein content of the DDGS at incorporation rates up to 15%: beyond that, extra DGGS provides only digestible energy [*Klopfenstein 2001*].

- However, these figures are for cattle fed US corn plus corn-DDGS. But in Europe, we can expect protein-substitution to be exhausted at significantly lower levels of DDGS incorporation into feed. This is principally because the simultaneous growth of biodiesel in EU provides oilseed meals which also provide part of the overall protein requirement, but also because EU feed cereals already have higher protein content than US ones, and wheat DDGS has a slightly higher protein content too.

Thus, there may well be no soybean-meal imports left for the by-products to replace.

Other reasons to think that the by-products of biofuels will not replace soybean meal on an equal-metabolizable protein basis are:-

1. *Some soybean meal may be imported to supply essential amino acids which are deficient in the biofuel by-products*

Usually, the protein feed requirements for farm animals are determined by the minimum requirements for essential amino acids, rather than the total protein supply. An animal fed mostly on cereals tends to be deficient in certain essential amino acids, but DDGS tends to be deficient in the same ones, because it retains the amino acids from the cereal used to make the bioethanol. Therefore to satisfy the minimum essential amino acid requirements using only cereals and DDGS, the animal ends up much more total metabolizable protein than it needs: the excess protein is just used to provide energy like a carbohydrate feed.

To avoid this, essential amino acids can be added from other sources: soymeal, or more concentrated and expensive sources such as fish-meal or synthetic production. These also have environmental footprints.

2. *Animal diets become richer in protein due to relative price movements*

Increased production of 1st generation biofuels tends to depress the price of protein-rich feeds (like rapeseed meal, DDGS and, indirectly, soybean meal) and increase the price of carbohydrate-feeds like cereals. Even before soybean meal is completely replaced, animals will tend to receive a greater proportion of protein in their diet. The excess protein from the by-products is just used for energy, replacing carbohydrate feeds.

Details of the animal-feed substitution calculation

The calculation is made assuming that the by-products are eaten by cattle. They are not only the largest consumers of animal feed; they are also more suitable for the purpose than pigs and poultry. This is because cattle are relatively less efficient at digesting soybean meal, and are not troubled by the high fibre content of some by-products. To find the maximum proportion of soybean meal substituted, one should ideally balance all the essential amino acids as well as the overall metabolizable protein and digestible energy. Furthermore, depending on what else is fed to the animals, some by-products may improve the weight-gain per tonne of feed ("feed efficiency") more (or less) than indicated by the digestible energy ratio. However, that would be a complex task to take these effects into account for all products and feed combinations. For simplicity we balance only digestible energy and total metabolizable protein.

In cattle, a large proportion of the protein is broken down (degraded) in the rumen, and then most of the decomposition products (notably N compounds) are reassembled by the bacteria there into bacterial protein which the cow later digests and (mostly) absorbs. According to [*BOA 2000*], p16-18, the efficiency of the degradation/reconstruction/absorption process is ~65%, whilst of the proteins which pass the rumen undegraded, about 80% are absorbed by cattle.

Thus the overall weight-fraction of metabolizable (= absorbed) protein (MP) in a feed is given by [*BOA 2000*]:

$$MP = CP* \{0.8*RU + 0.65*(1-RU)\}$$

...where   MP is the fraction of metabolizable protein (= absorbed protein) in the
             CP is the total crude protein content of the feed
             RU (ruminal undegradability) is the fraction of the crude protein which passes *through the rumen undegraded.*

Table 3.4.4-1 shows the properties of animal feeds. Unless otherwise stated, the data comes from [*BOA 2000*], a standard reference for livestock nutrition. We have used data for beef cattle only, because the equivalent data for dairy cows do not tabulate aggregated protein degradability. The protein content of the feed-wheat is taken to be 10.9% of dry matter: DG-AGRI experts confirmed that

this rather new type of low-protein, high-yield feed-wheat will be the cheapest and most suitable type of wheat for bioethanol production. The protein content is confirmed as typical for the most suitable wheat varieties for bioethanol production [*HGCA 2006*]. This has an effect also on the protein content of the DDGS. Our properties for wheat-DDGS are based on [*Univ. Minnesota 2003*], but that is for DDGS from Canadian feed-wheat, which has a higher protein content: 13.1% of dry matter. So we improved the estimate for the protein content for our EU-feedwheat-DDGS by interpolating between the Canadian data and that for US corn-DDGS, produced from maize containing only 10% dry-matter protein.

Table 3.4.4-1   Properties of animal feeds fed to beef cattle

our substitutes:-	Dry matter%	Digestible Energy [1] MJ/dry kg	Crude protein % m dry	"ruminal undegradability" of protein	% of crude protein metabolizable	metabolizable protein % m dry
soy meal	89%	15.48	51.8%	34.0%	70.1%	36.3%
feed wheat EU 2015 (DGAGRI)	87%	16.23	10.9%	23.0%	68.5%	7.5%
by-products from biofuels:-						
rapeseed meal	90%	13.64	40.9%	28.0%	69.2%	28.3%
sunflower meal de-hulled	90%	12.01	26.0%	26.0%	68.9%	17.9%
DDGS (from maize)	93%	16.23	30.4%	52.0%	72.8%	22.1%
DDGS/2015 EU feed-wheat [2]*	93%	16.12	33.2%	56.0%	73.4%	24.3%
dried sugar beet pulp	91%	13.64	9.8%	45.0%	71.8%	7.0%
palm kernel meal, physical crush	90%	12.95 [3]	18.3% [4]	33.8% [3]	70.1%	12.8%

[1] *Metabolizable* energy is arguably more suitable, as it takes into account losses in urine and gas, but it is practically proportional to digestible energy for a particular animal [BOA 200]. Data for ME is not available for all these by-products.
[2] based on [*Univ. Minnesota 2008*] – see text
[3] [*O'Mara 1999*]
[4] [*FAO 2008*]

Table 3.4.4-2   Substitution ratios calculated for by-products of biofuels

	dry kg soybean meal with same metabolizable protein as 1kg dry byproduct	kg dry feed wheat to balance digestible energy	dry kg feed-wheat for equal digestible energy WITHOUT soybean meal	DRY SUBST RATIOS average kg DRY EU-feed-wheat replaced by 1kg dry by-product	average kg DRY soybean meal replaced 1 kg dry by-product	MOIST SUBS RATIOS average kg MOIST EU feed wheat replaced by 1kg MOIST by-product	average kg MOIST soybean meal replaced by 1kg MOIST by-product
Soy meal	1.000	0.000	0.954				
EU feed wheat (bioethanol grade)	0.000	1.000	1.000				
by-products from biofuels:-							
rapeseed meal	0.755	0.121	0.840	0.480	0.377	0.497	0.382
sunflower meal (de-hulled)	0.424	0.335	0.740	0.537	0.212	0.556	0.215
Corn-DDGS (for comparison)	0.502	0.521	1.000	0.761	0.251	0.813	0.262
DDGS/ EU feed-wheat [2]	0.580	0.440	0.993	0.716	0.290	0.766	0.303
dried sugar beet pulp	0.026	0.816	0.840	0.828	0.013	0.866	0.013
palm kernel meal, physical crush	0.234	0.574	0.798	0.686	0.117	0.710	0.118

[1] Since SBP has lower protein content than feed-wheat, a little soybean meal is required (not substituted) for balance

Table 3.4.4-2 shows, for each by-product, first the calculation for the maximum-soymeal substitution ratio, and the corresponding balance of feed-wheat (all in dry-mass terms). Then the straight feed-wheat substitution ratio is calculated (minimum soybean meal). Next the average substitution is calculated in dry-matter terms and finally, in the last two columns this is converted to moist-mass substitution ratio, for use in the GHG and cost calculations.

In the pathways for soybean biodiesel, it is necessary to find a substitute for soybean meal itself. It is no good to say it replaces imported soybean meal: what does that replace? This is tricky: there is no other crop which yields anything like the same protein. But there must be a real market effect of by-producing soybean meal in EU. Bearing in mind the discussion above, we can see that adding soybean meal to a EU protein-meal market already struggling to accommodate the oilseed meal from other types of biodiesel will lead to an increase in the proportion of protein in the livestock diet. This means

that protein is now being used for digestible energy, replacing carbohydrate feedstock which we represent with feed-wheat. *Table 3.4.4-2* shows that 1kg dry soybean meal substitutes 0.954 kg dry feed-wheat. In terms of moist weights, 1 kg moist soybean meal substitutes 0.976 kg moist feed-wheat.

3.4.5 Agro-chemicals production

The energy and GHG input associated with agro-chemicals (mainly fertilizers) is sizable and represents a small but significant share of the total pathway energy.

Our figures for agro-chemicals production are derived from [*Kaltschmitt 1997*]. They are not much different from those in other studies, such as [*ADEME 2002*]. Alternative data provided by stakeholders proved difficult to reconcile with thermodynamic principles, so after a thorough review we decided for the present version, to retain the existing estimates. Fertilizer transport is included, but is negligible.

3.4.6 Other environmental effects of biofuels

Soil quality/erosion

Sugar beet can cause soil erosion, especially if grown on the light soils typical of southern Europe. New techniques of inter-sowing between cover crops can help. However, we do not expect that sugar beet production would spread beyond areas of northern Europe with heavier soils. In wet areas, the heavy machinery used for harvesting sugar beet can cause soil compaction.

We already warned that increase of arable area would cause loss of soil organic carbon from grassland or forest: we assume it will not be allowed.

Continually removing straw instead of incorporating it in the soil will decrease the soil organic content, leading to poorer moisture retention. This should be a larger problem in light southern soils, but ironically this is where straw is most often removed, because its decomposition consumes nitrogen which has to be replaced. It is probably not a significant problem in the prime cereals-growing areas of Northern Europe where a high density of straw availability makes it most economic to site straw-to-biofuel conversion plant.

Eutrophication and acidification

Because intensive agriculture using fertilizers tends to cause eutrophication and acidification, increased crop production for biofuels would tend to exacerbate the problem. The driving force for intensification is crop price: hence meeting biofuels targets will probably cause more intensification of oilseed production than of cereals production. Sunflower, short rotation forest and other "advanced biofuels" crops generally use less fertilizer than the other crops, so have less impact.

Biodiversity

Growing biofuel crops instead of permanent crops, and on "nature" land now in voluntary set-aside, would decrease biodiversity. [*EEA 2004*] concluded that the negative biodiversity impacts are high for rape, medium for sugar beet and low to medium for short rotation forestry. The use of wood residues was considered to have no impact.

Pesticide use affects biodiversity. Break-years encouraged by compulsory set-aside rules tend to reduce pests and diseases, so doing away with it would tend to increase pesticide use. Large increases of pesticide applications are needed if frequency of sugar beet (and to a much lesser extent oilseed rape) crops in a rotation is increased beyond about one year in four. Sugar beet generally requires much more pesticide than other crops. Farmers might escape controls on pesticide levels if the crops are not for food.

Impact on water table

The increased growth of crops requiring extensive irrigation in arid areas will put pressure on water resources. For example sugar beet cultivation in Spain and Greece has a very high percentage of irrigated area (77 and 100% respectively). In Italy it is lower but still over a third of the area compared with 6% for durum wheat and 7% for sunflower. Water use per tonne of dry matter is around 200 litres for sugar beet and 300 litres for wheat.

Increased cultivation of trees can also lead to a lowering of the water table. Lowering of the water table can have significant impact on the natural environment in the area concerned as well as generally diminishing agricultural yields.

Introduction of non-native species and GMOs

There is some risk that non-native energy crops could spread in the wild, because they lack natural predators. Using sterile varieties (including GMOs) greatly reduce this risk. Some are concerned about GMOs in general, though.

Few of these environmental impacts are inevitable

Most of these potential impacts can be controlled, but require appropriate regulations and effective enforcement. The pressure to push the limits of regulations varies from crop to crop: in general sugar beet is the most environmentally suspect crop and short rotation forestry the least.

3.4.7 Biomass transportation

The energy and GHG emissions for biomass transportation to the processing plants are a very minor part of all pathways. However, the cost is very significant especially for materials such as forest residuals and straw (see *section 5*). For describing the emissions and cost-per-tonne, we have used data for Germany estimated by LBST. We made independent estimates of transport distances (see *WTT Appendix 1 section 9*). For farmed crops an average distance of 50 km is considered sufficient to feed a 200 MW plant (such a plant would e.g. consume some 350 kt/a of wood requiring 35,000 ha or about 4% of the area comprised within a 50 km circle). This distance would be reduced to 10 km for a 10 MW plant. Wood residuals are more scattered and would require sea transport over longer distances (400 km, typical of the Baltic Sea) when fed to a large plant. Transport distance for straw is only 25 km for 200 MW because processing plants would only be economic where there is a concentrated resource. The above distances are relevant to the EU. Soy beans road transport in Brazil is estimated to be much longer - 700 km to a port where the crushing plant is deemed to be located.
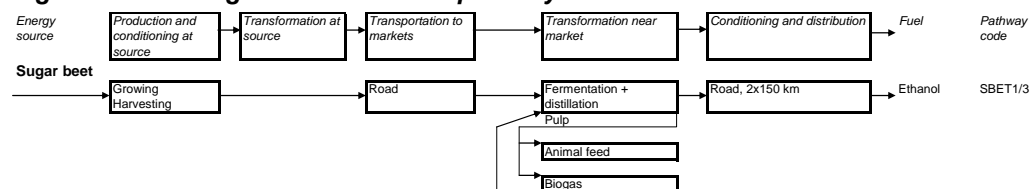
3.4.8 Sugar beet to ethanol

Sugar beet is a high yield crop. It produces carbohydrate already in the form of sugar and is easily crushed and mashed for fermentation which makes the processing into alcohol rather cheap. The economics of its cultivation are highly distorted by the CAP, as discussed in *section 5.2*.

Sugar beet continues to respire in storage causing a material loss. In order to limit the energy loss, the processing "campaigns" average 90 days. But since the syrup extracted from the sliced beets is pasteurised, one supposes that it could be stored to keep the fermentation and distillation parts of the plant running all year. By-products of the conversion process are sugar beet pulp and dried slop (everything insoluble produced by fermentation), which together are the beet equivalent of DDGS from wheat, but with a protein content below that of feed-wheat (see *section 3.4.4*). Because of the cost these by-products are only dried if they are to be sold for animal feed. If they are to be used for providing process-energy, it is more attractive to add them to the process biogas digester (needed for cleaning the waste-water), than to burn them, which gives almost the same energy balance and emissions.

To improve the yield of ethanol, the pulp could, in principle, be treated by a SSCF-type process (Simultaneous Saccharification and Co-Fermentation) to break down the cellulose and hemicellulose. No such process actually exists and we have not further considered this route.

We have therefore considered 3 sugar-beet-to-ethanol pathways as shown below. SBET1a/b consider use of pulp for animal feed with the slops either not used or added to the biogas digester, while SBET3 uses both pulp and slops for biogas production which is used for co-generation of electricity and heat.

Figure 3.4.8   Sugar beet to ethanol pathways

3.4.9 Wheat to ethanol

Ethanol can be produced from wheat grain by hydrolysis and fermentation. The process is more complex and therefore more expensive than with sugar beet. Milling and distilling are the most energetically expensive parts of the wheat-to-ethanol pathway. These processes require some electricity but mostly heat albeit at a low temperature level. This makes the scheme well suited for CHP. We chose wheat-to-ethanol to illustrate the effects of different fuel and CHP options. The figures used in this study for the wheat grain to ethanol plants are essentially the same as in a study carried out in 2004 under the UK's Low Carbon Vehicle Partnership [*LowCVP 2004*].

Energy supply options

The energy can be provided by a variety of sources. We have considered 3 scenarios based on fossil fuels and representing plants actually on the ground or planned in Europe. A fourth scenario uses straw as energy source. Although this is in principle feasible there are no concrete examples of this either existing or considered.

WTET1: Conventional natural gas boiler

Heat is supplied by a conventional natural gas fired boiler and electricity is imported. This can be considered as representative of the vast majority of existing installations and is also by far the cheapest solution.

WTET2: Combined cycle gas turbine

A natural gas fired gas turbine with a heat recovery steam generator (HRSG) provides both heat and electricity. As more heat than electricity is required supplementary firing is applied in the HRSG. As the heat is required only as low pressure steam, a back pressure turbo-generator is also installed behind the HRSG. The plant is assumed to be sized and operated to produce the heat required for ethanol manufacture. There is, however, a surplus of electricity which is exported into the grid, thereby generating an energy and GHG credit.

This solution is considerably more energy efficient but also significantly more complex and expensive to build and operate.

WTET3: Lignite boiler CHP

High pressure steam is produced in a lignite boiler. A back pressure turbo-generator produces electricity and low pressure steam for the process. Here again the plant is assumed to be sized and operated to produce the heat required for ethanol manufacture but it nevertheless generates an electricity surplus.

Lignite (or brown coal) is a cheap and abundant fuel in certain parts of Europe and actual plants are either operating or under construction in Eastern Germany.

WTET4: Straw boiler CHP

Wheat cultivation produces large amounts of straw. Some LCA studies have considered straw as a by-product but this is not necessarily the case. In most of the EU it should be ploughed back to maintain the water-retention properties of the soil (see straw availability, *section 5.2.3*). Where it may be removed from the field it is partly already used for litter and other applications. Therefore it is misleading to systematically assume that straw can be used to fuel the ethanol production process. In practice this should only be proposed where there is little water stress, a high density of cereals production and a low density of livestock. These conditions would apply to concentrated wheat-producing areas in Northern Europe excluding the Low Countries and Denmark. In any case removing straw will reduce soil nutrients, which needs to be compensated by an additional fertiliser input.

This scheme is similar to the previous case but straw in used instead of lignite. The main advantage of this scheme is to use a renewable source of energy to drive the process. It must be realised, however, that handling and burning of solids is considerably more complex and costly than with liquids or gases, particularly in the case of a low energy density material such as straw. This will therefore be the most expensive option.

WTET5: DDGS to biogas

For each of pathways WTET1-4 alternative dispositions of the DDGS by-product (see below) as either animal feed or as co-feed fuel in a coal power station are considered. This pathway considers an alternative use of the DDGS to produce biogas, which is then used to produce heat and electricity to supply all the heat and most of the electricity needs of the ethanol plant. The residue from the biogas digester still has value as a fertiliser and generates a credit for the overall process. A more detailed explanation of the potential uses of DDGS is given in the section below.

Credit for surplus electricity

All CHP schemes produce a surplus of electricity which is assumed to be exported to the grid and must therefore generate a credit (energy and GHG). An ethanol plant with a CHP scheme in effect co-produces ethanol and electricity. If a straightforward credit is applied (e.g. based on substitution of EU-mix electricity) and the emissions savings are divided only by the ethanol produced, all the GHG saved by making electricity is credited to making ethanol. One would conclude that the higher the electricity generation, and the lower the ethanol yield, the better the emissions and fossil energy balance of ethanol! In the case of a natural gas CHP, this could be taken quite far as there is no physical limit to the size of the power plant that can be built.

The real contribution of ethanol to electricity generation is to provide an opportunity for CHP so the credit should be based on the same fuel producing electricity only in a stand alone power plant. Although the energy and GHG saved by the bio-electricity itself is not credited to ethanol, the ethanol pathway does benefit from the extra energy efficiency resulting from the use of CHP (i.e. it gets process heat practically free of emissions)..

DDGS

Ethanol production produces a by-product known as DDGS (Distiller's Dried Grain with Solubles) which is the solid residue after fermentation of the carbohydrates. DDGS is a protein-rich material and is therefore a useful animal feed component. Its nearest equivalent is corn gluten feed. However, since this is a by-product of maize milling, its supply cannot easily be changed. We consider the main marginal or "swing" sources of animal feed are feed-wheat and soymeal, and we assume DDGS

substitutes a mixture of these, as explained in section 3.4.4.. Details of the soymeal pathway are described below, under soybeans. Used as animal feed, DDGS also reduces the *indirect emissions* which could be ascribed to bioethanol production: it reduces the net diversion of crops from feed and food use.

Animal feed is by far the most lucrative usage and therefore the most likely at present; but increasing bioethanol production is likely to lead to lower DDGS prices (as already seen in US). At this point DDGS might be used as fuel, for instance in solid-burning (i.e. coal) power plants that need to meet their renewable energy obligations. Alternatively, DDGS could be used to provide process heat to improve the GHG balance, in line with incentives for reducing the emissions from biofuels manufacture. Note that this foregoes the reduction in *indirect* GHG emissions implied by using DDGS as animal feed. The calorific energy content of DDGS is considerably greater than the energy required to produce the equivalent animal feed, so burning DDGS gives a higher energy credit (since we do not consider indirect emissions here). We have illustrated these two options in sub-pathways:
- WTET2/3/4a: DDGS as animal feed
- WTET2/3/4b: DDGS as fuel in a coal power station

An alternative way of extracting energy from DDGS is through production of biogas in the ethanol plant. This would then be used to co-produce heat and electricity, meeting all the heat needs of the plant, but still requiring a small electricity import.
- WTET/5: DDGS to biogas

The wheat grain to ethanol pathways are illustrated in the figure below.

Figure 3.4.9-1   Wheat grain to ethanol pathways
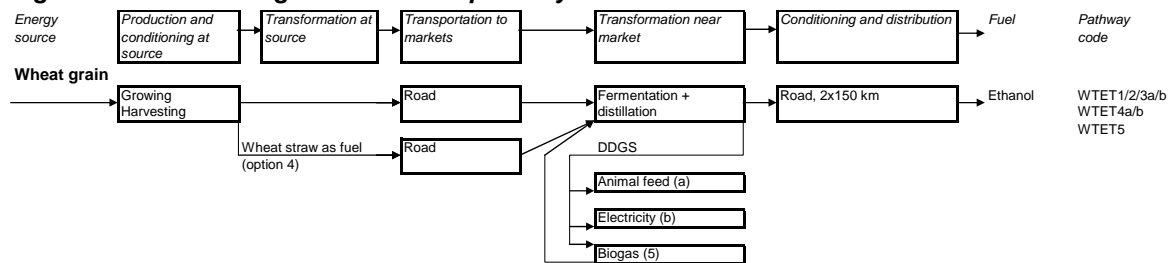
Straw to ethanol

In the above section we have described the conversion of wheat grain to ethanol, with optional use of straw as fuel for the process. The possibility also exists to use the straw as ethanol feedstock through an SSCF-type process (Simultaneous Saccharification and Co-Fermentation) that turns cellulose into sugars and can in principle be applied to all cellulosic biomass materials.

On the basis of experience with their pilot plant, Iogen corp. (Ontario, Canada) provided energy and emissions data for a projected 140 MW$_{th}$ plant straw-to-ethanol plant [*Iogen 2003*]. Straw has a more suitable composition for SSCF than wood, and the Iogen plant claims a slightly higher energy efficiency than the projected SSCF wood-to-ethanol plant from NREL.

Figure 3.4.9-2   Wheat straw to ethanol pathways
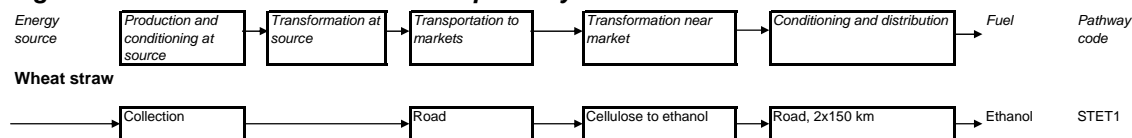
Ethanol to ETBE

As an alternative to using ethanol directly as a gasoline blending component, it can be converted to ETBE (Ethyl-Tertiary-Butyl Ether). ETBE is a high octane component with very similar properties to MTBE but with a somewhat lower solubility in water. The main advantage of ETBE over ethanol as a gasoline component is its low vapour pressure.

Similarly to MTBE, ETBE is synthesised by reacting isobutene with ethanol. The process is very similar and MTBE plants only require minor changes to be able to produce ETBE.

ETBE is currently manufactured by some European oil refineries in plants that used to produce MTBE. The isobutene feed is not produced on purpose but is a by-product of the catalytic cracking process. It is only available in limited quantities. Whereas the energy required by the ETBE plant itself is known, the energy associated with the production of isobutene cannot be estimated in a rational way as isobutene is produced as one of many minor by-products of the cracking process. As a result this cannot be calculated as a discrete pathway. The way to approach the net impact of this route is to compare a base case where ethanol is used as such and MTBE is produced in refineries, to the alternative where ethanol is turned into ETBE in replacement of MTBE (*see section 4.7*).

Should more ETBE be required it would have to be made from isobutene produced by isomerisation and dehydrogenation of normal butane. We have represented this pathway with the assumption that the marginal butane required is imported from gas fields.

Figure 3.4.9-3   Wheat-ethanol to ETBE pathway
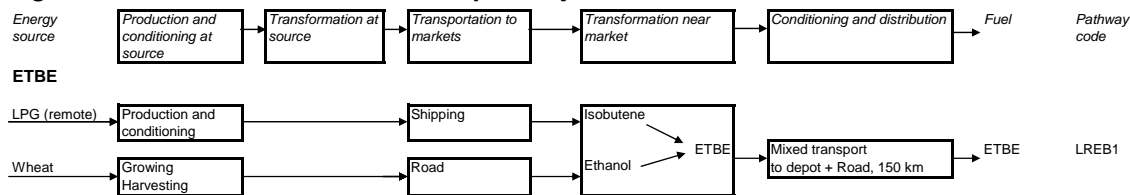
Ethanol from sugar cane (Brazil)

Sugar cane is an excellent biomass crop from almost every point of view, except that it will not produce sugar in Europe. It resembles more a permanent biomass crop like miscanthus than it does an arable crop. In Brazil, there are usually 5 harvests, with very high annualized yields of about 68 t/ha/a (moist). Each tonne yields 86 litres (1.83 GJ) anhydrous ethanol at a conservative estimate. Yields may be much lower in areas that do not benefit from Brazil's favourable combination of warm temperatures and abundant rainfall.

Brazil is the by far the world's largest producer, and has the greatest potential to expand production. The main growing area is in the South of the country, around Sao Paulo province. Expansion of sugar cane growth would occur in this and neighbouring regions, mostly at the expense of rough grazing land. The sugar growing area is a very long way from any surviving rainforest, so moderate expansion should not have a direct impact. There is a small amount of sugar cane production in the coastal areas of the NE, nearer some patches of Atlantic rainforest, but this is not viable without subsidies, and is unlikely to expand. However, new production areas in Mato Grosso and mato Grosso del Sur may impinge on natural cerado (savannah-type) land-cover, either directly, or indirectly through displaced ranching. Cerado has high biodiversity, but does not store as much carbon as rainforest.

Unlike arable crops in Europe, planting sugar cane on grazing land is believed to actually increase the soil carbon stocks, although as shown in figure 3.4.1-1, some studies still show significant land change effects, but with a payback time less than for temperate climate crops. The risk of soil erosion (a major

concern in Brazil) is only heightened in the first year of establishment. The plant has low fertilizer and water requirements and has low levels of minerals in the foliage.

A major benefit of the sugar cane to ethanol process is that the process electricity and heat is entirely provided by the bagasse. The vinasse from the fermentation vats is nowadays recycled to the fields. The emissions calculation takes into account the typical practice of burning the foliage to allow easier harvesting, although this is sometimes banned near populous areas. There is in fact a small surplus of bagasse which can provide fuel for a neighbouring food-processing plant (for example, orange juice production), generating a credit for saved fuel oil. There is also an initiative by Sao Paulo province to encourage co-generation of excess electricity to replace imported electricity from other provinces. However, the ability to capitalise on exports of surplus electricity or heat depend on the availability of infrastructure and local customers, Pathway SCET1a shows the case where exports are possible, while SCET1b considers a plant where bagasse is used solely to meet the needs of the ethanol plant.

We have taken our input data from a thorough analysis by Prof. Macedo et al. [*Macedo 2004*]. Since then, the same team has issued slightly revised figures *[Macedo 2008],* taking into account changes in practice in the Centre-South region of Brazil to 2005/6, and also projected values for 2020.. We have not yet taken these new figures into consideration, because we need to assess to what extent the data can be applied also to new producer regions in Brazil, which have perhaps less developed techniques.

Figure 3.4.9-4   Sugar cane to ethanol pathway
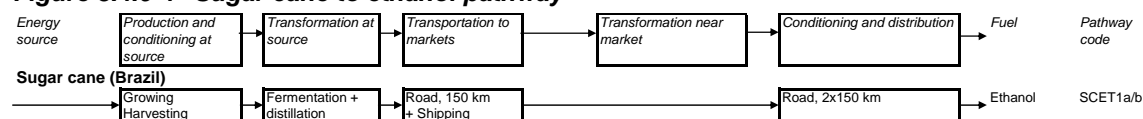
3.4.10   Oil seeds

In Europe the two most used oil seed crops are rape (also known as colza) and sunflowers. ("Canola" is a variety of rapeseed developed in Canada to be give palatable animal feed.) Agricultural yields are much lower than for wheat or sugar beet. In a crop rotation of ,say, one year in four with cereals, rapeseed gives a synergistic improvement of cereal yield. However, EU rapeseed production has increased so much in recent years that it is grown in alternate years or even in successive years, which negates the effect. Rapeseed grows better in the North of EU and is more intensive, whereas sunflower is more suited to southern Europe. Processing of the oil seeds from either source is similar. As demand for biofuels grows, imported oils are becoming of more importance.

Pure vegetable oil cannot be used as a conventional internal combustion engine fuel, because of its high viscosity and gum content. Although special engine modifications have been used to run on pure oils in limited applications, the oil generally needs to undergo processing to produce a fuel that is miscible with conventional diesel and can be used in standard engines. The most common process is esterification i.e. the reaction of the organic acid functions with an alcohol. This is an essential step to ensure the resulting fuel is stable. Vegetable oil can be thought of as three fatty acid "ribs" attached to glycerol (=propan1,2,3-triol) "backbone". This large molecule is viscous and thermally unstable, forming the yellow deposit familiar on frying utensils. The "trans-esterification" process consists of replacing the glycerol with three methanol molecules, so that three separate fatty-acid methyl ester (FAME) molecules are formed from each molecule of plant oil. The processing is relatively straightforward, cheap, and does not require a lot of energy.

Today methanol is used as it is abundantly available and cheap, however ethanol can be used instead. We have included this option in combination with rapeseed to show the impact of using bio-ethanol on the overall energy and GHG balance (to produce a fatty acid ETHYL ester (FAEE). In representing this option, we assumed the same energy input as for FAME for the esterification process, the benefit

coming from the use of a partially renewable alcohol. This has the advantage of exploiting the GHG savings of bioethanol whilst replacing diesel, which eases the imbalance in the refining industry. However, if there is no economic advantage in improving the GHG performance of biodiesel beyond an already-attainable threshold, FAEE is unlikely to be produced extensively in practice.

Rapeseed processing

In the oil mill, the rapeseed is crushed, and oil extracted by steam and hexane. The process we have described is very similar to others in the literature. The by-product is rapeseed meal, a high-protein animal feed, replacing soy bean meal as described in soybean pathways. The production of soy bean meal also makes a by-product: soy oil. In this version of JEC-WTW we have calculated the credit for this based on sunflower oil because this is compositionally more similar than the rapeseed oil substitution used in our previous version. Rapeseed meal could also in principle be burned as a fuel, much in the same way as DDGS, although its high value as animal feed discourages this approach and we have not developed a pathway to cover this. However, consideration is being given to adding it to biogas digestors, and we have modelled this option.

The next step is purification, in which acidity is neutralized and the oil clarified. The trans-esterification reaction mentioned above often takes place in a separate plant inasmuch as it is the only step which is specific to bio-diesel compared to vegetable oil for food.

The raw glycerine stream contains only 80% pure glycerol but can be refined and sold as distilled pharmaceutical-quality synthetic glycerol. Several studies (including [*LBST 2002*]) have used this to calculate a by-product credit. This is very good for the energy ratio, because synthetic glycerol production uses about 18 times its heating value in fossil fuel. However, the scenario is not very realistic if we consider the size of the market. Already in 2003, total EU glycerol consumption was 275 kt/a [*NRC 2004*] and the only remaining synthetic glycerol plant in EU had an output of 36 kt/a. By comparison 10% replacement of EU diesel fuel would pour about 2.3 *million* tonnes of glycerine onto the EU market (about 11 kg per person per year), more than 130 times the production of synthetic glycerol. Therefore we did not consider this substitution option.

Most non-biodiesel glycerine produced today is a by-product of soap-making from fats and oils and the supply will hardly change if more is produced from bio-diesel. Therefore a large increase in supply can only be accommodated by finding other uses, at a lower price. In fact in 2005 the effect of expanding bio-diesel production was already felt on the glycerol market: the crude 80% glycerine from bio-diesel fetched 130-200 €/t on the EU commodities markets, from which it has not recovered. This price reflects the cost of purifying it to the standard vegetable-grade specification the EU price for which declined from 550 to as low as 300 €/t during 2005, whilst by October 2008 the price had recovered to 475 €/tonne.

However, [*DOE 2004*] states that crude glycerine will be attractive as a chemical feedstock if the price remains between 80 and 200 €/t (0.2 to 0.5 $/lb). Therefore, in the long term we can expect industry to develop processes using glycerine which will stabilize the price at the bottom of its current range. On this basis our best-estimate medium term crude glycerine price is 130 €/tonne. This prediction (made in 2005) has been borne out in practice: that is roughly the price of crude glycerine in late 2008 (but low-grade material is worth almost nothing). Growing industrial uses include as fuel for steam-reforming, whilst much commercially-oriented research is going into converting glycerol to higher-value chemicals such as other glycols or even methanol.

To get an idea of the potential size of this market we noted that synthetic propylene glycol and ethylene glycol are chemically similar to glycerol. They have a combined market about 14 times greater than synthetic glycerol [*DOE 2003*] and still fetch around 1100 €/tonne (2008). It would be

technically feasible to replace half the synthetic glycols with glycerine. This market could absorb about 35% of the potential glycerine production from replacing 10% EU biodiesel in 2015-2020.

Since we happen to have an estimate of the fossil energy content of propylene glycol [*GEMIS 4.1*], we have taken this as the upper limit of the energy and emissions credit. On the other hand, crude glycerine is already used as animal feed (in which application it has a digestible energy content of 14 MJ/kg). This gives a much lower energy and emissions credit. If glycerine is used as fuel, the energy and emissions credits lie half-way between these two extremes. We selected the chemical substitution and fuel substitution pathways on the - perhaps optimistic - basis that the chemicals industry will develop higher-value uses for glycerine than animal feed.

Sunflower

Sunflower processing differs from rapeseed mostly inasmuch as the pressing yield is slightly higher, and the sunflower meal by-product has a lower protein content.

Oil seed imports

Europe is short of oil seeds. Historically the trade pattern has been to import the raw materials (oil seeds) rather than vegetable oil. Perhaps this is because until now there has been a ready and profitable market for the animal-feed by-products in the EU. Imports of finished biodiesel from US (benefiting from subsidies on both production and use) are now much reduced after anti-dumping measures by EU. However, one can expect a growing trend to import vegetable oil or biodiesel from low-cost producers (such as Malaysia and Brazil), because continuing quantities of meals will depress their price in EU, and producers seek to improve the added value of their exports.

Palm has now overtaken soy as the largest global source of vegetable oil, although both sectors are expanding rapidly. Rapeseed production comes as a poor third, followed by many much more minor sources including sunflower.

Figure 3.4.10   Oil seeds to bio-diesel pathways

Energy source	Production and conditioning at source	Transformation at source	Transportation to markets		Transformation near market	Conditioning and distribution	Fuel	Pathway code
Rape seed Sunflower seed	Growing Harvesting		Road		Pressing Esterification Methanol (FAME) Ethanol (FAEE)	Road, 2x150 km	FAME (RME) FAME (SME) FAEE (REE) FAME (SYME) FAME (PME)	ROFA1-4 SOFA1-4 ROFE1-4 SYFA1/3 POFA1a/b/c/2
Soy beans (Brazil)	Growing Harvesting		Road Sea					
NG (remote)	Production and conditioning	Methanol	Shipping land transport		Esterification Meal (cake)/glycerine Chemical (glycerine) Animal feed Biogas			
Palm plantation (S.E. Asia)	Growing Harvesting	Pressing	Sea					
Rape seed Sunflower seed	Growing Harvesting		Road		Pressing Hydrotreating	Road, 2x150 km	HRO HSO HPO	ROHY1/2 SOHY1 POHY1
Palm plantation (S.E. Asia)	Growing Harvesting	Pressing	Sea					

Soy beans

Soy beans are already a major element in world trade, and EU soy meal consumption is around 35MT/a.

Soy products are imported both in the form of beans and of separate oil and meal. Imports of soy beans would provide oil for biofuel production, together with additional soy meal. About half of the soy oil consumed in EU is imported as oil, and half as beans. Brazil is the largest overall producer of soy, and shows the fastest export growth. Argentina is the other main producer, where it competes for land with wheat, maize and ranching. Export taxes on beans have encouraged the development of the crushing industry there.

Our figures DO NOT include any provision for emissions from deforestation or other land use change.

Soy bean biodiesel is a particularly tricky pathway to treat using the substitution methodology, because of the high proportion of soy meal by-product compared to the oil. The net GHG savings depend very strongly on how the credit for the soy meal by-product is calculated. The choice of substitution for soy meal is especially difficult because soy meal is itself the main "swing-provider" of protein in animal feed. Other oilseed meals are more clearly by-products of vegetable oil production, and so their production is less influenced by changes in the price of feed-protein. Indeed, if one chooses to substitute another oilseed meal that in turn generates a second-order vegetable oil debit to the soy oil pathway which is larger than the amount of soy oil to start with.

After much thought, we have taken as the principal pathway soy bean farming in Brazil and crushing in Europe, with the meal replacing soy meal which would otherwise be imported from Brazil. In this way, the shipping to EU of the soy meal fraction of the soy beans is cancelled by the credit from avoided soy meal import.

Note that this is a **change from the v3 results put on-line** in November 2008. There, we reported a case where the soy bean meal from a crusher in EU is given a credit based on substituting EU wheat as an animal feed. But we realized afterwards that this was unfair, because it attributed the emissions from shipping of the meal part of the soy beans to the soy oil.

The extra soy meal left in Brazil has the effect of reducing protein feed prices, with the result that in the end livestock will eat a greater proportion of protein feed in their diets. This is in replacement of cereals: in Brazil, principally maize. The amount of maize-farming in the credit is estimated on the basis of equivalent digestible energy.

In fact, the result is practically the same if we assume the crushing takes place in Brazil: in this case the transport of the soy meal does not happen in the first place. The only difference is that the crushing plant uses Brazilian energy inputs. However, upstream emissions from Brazilian gas and electricity are similar to EU mix.

For comparison, we also calculated a pathway on the basis of allocation of soybean farming emissions on the basis of price. This gave much worse emissions for the soy oil than substitution, because soy bean farming has lower fertilizer input and N_2O emissions per unit of digestible energy than cereal farming. Furthermore, we calculated a more complex substitution pathway in which the farming remains in Brazil but the substitution between soy meal and maize takes place in US: this gave a result intermediate between the other two scenarios. To keep things simple, we do not tabulate the results of these comparison scenarios.

To enable fair comparison with other biodiesel pathways, we keep the same two possibilities for glycerine substitution: as a chemical feedstock after purification, and added to a biogas digestor in its crude state (similar result to using it as a fuel). If we had considered glycerine as animal feed, the pathway GHG emissions would be slightly worse.

Palm oil

Oil palms offer a very high oil yield: typically 3-4 tonnes/ha of palm oil, and the recycling of other biomass from the palms reduces fertilizer requirements and makes it an energy-efficient pathway.

Two countries, Indonesia and Malaysia, currently account for 87% of world palm oil production. Indonesia has already overtaken Malaysia as the world's largest producer, and has more land available for expansion: by 2018 Indonesia's oil palm area is projected to expand by 28%, and production by 42% [FAPRI 2009]. Expansion of oil palm plantations has generated criticism from NGOs related to rain forest clearance, biodiversity loss, working conditions and displacement of native populations.

Mature palm oil plantations contain more carbon in *above*-ground biomass than natural forest. However the greenhouse balance including land use change effects depends critically on what happens beneath ground level. In the best case, a plantation established on mineral soil, on anthropomorphic grassland, will sequester ~135 tonnes of CO_2 per hectare. On the other hand plantations established by draining peat-land lead to a loss of at least 1300 tonnes of CO_2 equivalent over the first 25 years [Germer 2008], or roughly 50 tonnes of CO_2 per tonne of palm oil produced.

There is about twice as much carbon stored in peat as in the forests of the world, and tropical peatland contains about 96% of tropical carbon. So draining tropical peatland has the potential to release far more carbon than tropical deforestation. One can see why losing only a small part of this can give very large consequences in terms of greenhouse gas emissions.

If not drained, peat forest continues to sequester carbon as peat, at a rate of roughly 1 tonne per hectare per year. Once drained, the accumulated peat starts to decay aerobically. The level of the peat goes down year by year as the carbon is lost as CO_2. When the soil level approaches the water table, the plantation will die unless the drainage is deepened (in which case the process re-starts). Therefore the loss of soil carbon continues for the entire lifetime of the plantation, or until there is no peat left.

Figures for which proportion of oil palms grow on peat vary greatly. Official Malaysian figures claimed only 8% of *existing* palm oil plantations are on peat, whereas NGOs claim that more than half of *new* palm oil plantations in Indonesia are on peat-land. In many areas, peatland is the only remaining uncropped land available. There is relatively little natural land left to convert in peninsula Malaysia, so expansion is shifting increasingly to Borneo, which contains most of Malaysia's peat. In peninsula Malaysia palm area is still expanding due to displacement of other plantation crops: this does not cause large changes in soil carbon. (However, rubber production may shift to other areas of SE Asia where there is still forest to convert).

We can also expect increased palm oil production from improved yields on existing palm oil plantations, and from plantations established on mineral soils. The limits of this increase are discussed in [Corley 2008]. It is not clear whether average yield will increase in future, because expansion tends to be onto less suitable land. In the past 25 years average yield has hardly changed, but that is at least partly because the acceleration of area expansion has meant that there is an increasing proportion of immature plantations.

Trees have long been extracted from accessible areas of peat-forest, but this does not necessitate drainage, although some may result accidentally from digging ditches to transport out the logs (damming the ditches allows the peat to be re-wetted at modest expense). However, systematic deep and irreversible drainage of peat-land is only done to establish a plantation.

Oil palm is the most profitable of the few crops which grow well on peat, but the initial investment in a network of drainage canals means that the plantations on peat are generally considered less profitable than those on more traditional plantation soils[12]. So one may reasonably expect that higher palm oil prices will incentivize peatland drainage.

Drainage not only affects the plantation itself, but also any forest nearby. The peat here also decays (reportedly at an even faster rate than in the plantation). Furthermore, the dry peat in the forest is prone to catch fire. Plantation operators maintain fire services to put out peat-fires on the plantation, but fires on the drained peat-forest often burn unchecked. Fires are often used to clear undergrowth before plantation. Total emissions from peat fires are estimated at 1.4 GT CO_2 per year, compared to 0.63 GT from tropical peat drainage [Carbopeat 2008].and 1.6+/- 0.8 GT from deforestation worldwide.

NGOs allege that regulations have been ineffective in preventing drainage of peat-forest, mostly because they are not respected, and partly because they only apply to areas with very deep peat. Voluntary schemes for certifying sustainability have the welcome effect of giving a small price premium for sustainably-produced palm oil. However, unless all producers or all customers sign up, unsustainable production will replace certified palm oil diverted to participating customers.

<div align="center">

Our GHG emission calculations DO NOT include any emissions from land use change, including peat drainage or peat fires.

</div>

The life of a palm tree is 20-30 years, so energy inputs for cultivation are low compared with annual crops such as rape seed. Fertiliser needs are significant, but can be mitigated to some extent by return of biomass to the land as mulch. The fruit is harvested as Fresh Fruit Bunches (FFB), and because these deteriorate rapidly in storage the oil is generally extracted in small plants close to the plantation. The FFBs are heated and crushed, yielding palm oil, palm fibre residue, nuts and a slurry of palm oil mill effluent.

---

[12] Increased yields have been reported on experimental test-plots on peat, but these have used higher planting densities and fertilizer rates than in commercial plantations.

The nuts are separated and crushed separately, yielding palm kernel oil (PKO), palm kernel meal and nut shells. PKO (about 11% of palm oil volume) has different properties and specialist uses, but could be used for biodiesel production. For our calculations, we have added the PKO to the PO for biodiesel, on the basis that present specialist markets may saturate as PKO production continues to increase, and it is difficult to model all its possible substitutions.

Palm kernel meal is used as animal feed. We model the case where palm oil is then shipped to Europe where it is converted to FAME in the same way as for other oil feeds. Pure palm oil methyl ester (POME) has too high cloud-point to meet transport fuel specifications, but can be blended with other biodiesels. It can also be used in stationary applications (as can pure palm oil).

The operation of the palm plantation and crushing facilities can significantly influence the GHG emissions. We have assumed that empty fruit bunches are returned to the land, and that correct composting procedures are used. This is best-practice, but examples have been cited where they are allowed to rot in anaerobic conditions, generating considerable methane emissions.

We have assumed the mill is heated using part of the nut shells and palm fibre. In an efficient mill, there is a surplus of biomass, and sometimes, where transport is easy, the excess nut shells are exported for heating elsewhere. We model two alternatives: either no credit, or a credit based on fossil heat replaced.

The water/slurry effluent from the mill is sent to a treatment pond. In the best case, the methane emissions are recovered; but in present practice they are usually released from open ponds. We have modelled both alternatives. Hence there are four pathways:

- POFA1a, residues generate CH_4 emissions, heat credit for excess residue biomass
- POFA1b, CH_4 emissions recovered, heat credit for excess residue biomass
- POFA1c, residues generate CH_4 emissions, no heat credit for excess residue

In the above pathways, glycerine from the FAME plant is assumed to be used as a chemical. The effect of using it to produce biogas is assessed through a separate pathway:

- POFA2, heat credit for FFB residue, glycerine used as biogas to meet part of FAME plant needs

Hydrotreated Plant Oils

The amount of FAME that can be added to conventional EN590 diesel fuel is limited to maintain acceptable fuel quality and compatibility with the vehicles in the market. In addition, the trans-esterification process leaves the basic backbone of the molecule unchanged, so the fuel properties depend to some extent on the type of oil or fat used in the process. Where the oil or fat contains many double bonds, stability may be a problem and conversely if the chains are long and saturated it may be difficult to meet cold flow requirements.

As an alternative to trans-esterification the pure oil can be hydrotreated. This removes double bonds and oxygen from the molecule, yielding a paraffinic fuel similar in properties to Fischer-Tropsch diesel. This can either be used alone or blended with conventional diesel, and the final fuel properties are much less dependent on the original feedstock, so a wider range of feedstocks can be used.

The Neste Oil process (NexBTL®) is the first to be used in commercial production, and we have modelled this process using rapeseed, soy and palm oils. Similar processes are being developed by a number of other companies, and for comparison a process from UOP has been included, using rapeseed oil.

3.4.11   Wood

Wood waste is often presented as a vast untapped source of energy. Upon closer investigation, it appears that industrial wastes or recovered wood are already used as much as is possible (there are some problems with contamination) [*SBH 2000*] and agricultural prunings are mostly uneconomic to collect. The only type of wood waste which could make a significant impact on the transport sector with realistic economics is forest residuals from commercial forestry. These are the branches and tops which are left in the forest with conventional harvesting methods. The main producer countries already have plans to use more forest residuals for electricity and heat, but one could think to convert them to liquid fuels instead. Their use is essentially linked to pulp-mills.

The most efficient way to make biofuels from forest residuals is to use them inside a pulp mill, to substitute the burning of black liquor for process heat. This leads to a separate pathway for the "black liquor route", which is essentially limited to the forest residuals associated with pulp-wood (see specific section below).

Harvested forests absorb carbon dioxide much faster than mature forest stands, so harvesting them for energy use definitely increases the CO_2 uptake from the atmosphere.

If the felling residues and thinnings are left in the forest, they initially add to the stock of carbon in the forest litter, but they rot away with a characteristic exponential decay time of about 10 years. That means the initial rate is about 10% per year. (see fig. 5 in [Liski 2005]). That means the GHG emissions saved by collecting the residues are delayed compared to those saved by substituting fossil fuel.

According to our WTT results, each kg carbon in wood replaces about 0.3-0.65 kg fossil carbon (depending on the pathway: transport fuel or heating, and the carbon intensity of the fossil fuel replaced). So in the first year, more net carbon is emitted by burning than would be sequestered by leaving the residues in the forest. However, the balance of carbon emissions from using those residues turns positive after 3 to 7 years, and the cumulative carbon savings then go on to approach the time-independent values. We have not made any time-discounting of GHG emissions to account for the effect of this time-delay.

However, there is also a long-term effect on soil carbon, which is really a land-use change emission, but on a very long time-scale. If the rate of forest litter removal is changed, the soil carbon stock is modelled to exponentially approach long-term equilibrium, with a characteristic time of about 350 years (fig. 3 in [Liski 2005], which assumes regular 90-year clearcut fellings), On such a long time-scale, it seems reasonable to compare the annualized soil carbon loss with the annual CO_2 saved by using the residues.

[Liski 2005] estimate that reducing the rate of forest litter deposition by 1% causes ~0.36% reduction in the steady-state soil carbon. They estimate a litter rate of $0.4 kgC/m^2/y$ and a soil carbon stock of about $10 kg/m^2$. So removing an average of 1kg carbon in forest litter per year would result in 9 kg loss in steady-state soil carbon stock. Spread over 350 years, that is an annualized rate of soil carbon loss of 26 grams per year. So of the carbon removed in the form of forest residues, about 2.6% is lost from the soil carbon. Burning 1MJ wood releases about 100g CO_2, so the soil carbon loss is equivalent to a CO_2 release of 2.6gCO_2/MJ of forest residues. We neglect this.

There is also the nitrogen balance to consider. Removing residues removes some fixed nitrogen from the forest: one could consider replacing this with artificial fertilizer. This would generate N_2O emissions in the forest soils, but these are only about the same as those from the decomposition of the

forest residues. Overall, we think the effects on the GHG balance are small, and we do not consider them.

The commercial forests in EU grow slightly more than is harvested each year, so there is potential to increase the sustainable supply of stem-wood (as well as residuals) in EU, for energy purposes. The pulp, paper and woodworking industry is understandably concerned about subsidized competition for their feedstock, both stem-wood and wood chips. This is not to be ignored, because life cycle analyses almost all agree that wood saves more greenhouse gas when made into durable products than when burnt for energy.

The other potential source of wood for energy is "wood farming" i.e. short rotation forestry (SRF) using fast-growing species to maximise biomass generation. This can be complemented by perennial grasses such as miscanthus and switchgrass. Miscanthus has yields in the same range as SRF without risking the expense of removing tree-roots if the land-use needs to go back to arable. Switchgrass has lower yields but also lower water requirements, an important consideration when we consider that agriculture is limited by water availability in a large part of the EU. As a fuel perennial grasses are similar to straw: although the lignin/cellulose ratio and dry-matter energy content are similar to wood, they have a higher salt content (which can cause ash agglomeration and corrosion in the burners). This makes them less attractive as a fuel, and perennial grasses command a similar market price to straw. Therefore SRF is usually the more profitable crop. Apart from providing renewable energy, SRF grown on arable land sequesters carbon in the soil (see *section 3.4.1)*.

Perennial crops, such as miscanthus, switchgrass and short-rotation forestry (SRF), are thought to have a higher potential biomass yield than annual crops because the root system is already established at the start of the growing season. However, in practice commercial SRF plantations give only slightly higher biomass yields than wheat on the same land (if the straw is also harvested, wheat will generally give even a greater biomass yield, although with more inputs - see also *section 5.2.2)*. In the past, studies of biomass potential have taken yields from SRF on good arable land, for example 8-10tonnes/ha/y, and applied them to land too poor to support arable crops. In practice much lower SRF yields can be expected on such land; the crop can even can fail altogether.

On the other hand, wood requires less fertilizer, labour and other inputs, and can therefore be grown more cheaply. SRF is also more eco-friendly and wood is generally a better fuel than straw and perennial grasses, having a lower salt content. Furthermore, perennial crops may keep more carbon in the soil than arable crops, so that one might be able to plant them on grassland without causing unacceptable reduction in soil carbon stock. However, in this case one should be prepared for very much lower yields, as explained above.

Wheat + straw as a bio-energy crop
Taking straw with the wheat would give a total (moist) biomass yield of at least 1.65 times the grain yield. If in addition the wheat variety is a high-yield low protein variety, the collectable (moist) biomass yield will be at least 1.78 times the average wheat yield. This corresponds to 1.56 dry biomass / conventional wheat yield. So feed-wheat + straw is actually a higher-yielding biomass crop than SRF, but it requires more inputs (fertilizer, diesel, labour…). In recent years, fodder-maize has been found to be a more economic high-yield, high-input energy crop.

SRF wood can be burned directly to supply heat and possibly electricity via steam-raising. However, a more sophisticated route, which is now attracting a lot of attention, is gasification. The process is rather similar to coal gasification, producing syngas, which can be either used to fuel a gas turbine or further processed to hydrogen or to a synthetic liquid fuel such as methanol, DME or synthetic diesel fuel.

Gasification can be envisioned at either small or large scale. The former would only be suitable for electricity or possibly hydrogen production because of the high cost of investment and plant maintenance for more sophisticated processes.

Wood to hydrogen

Two process scales are considered: 10 MW_{th} and 200 MW_{th} (expressed in terms of biomass input). The larger scale we consider is the feasible limit for EU-produced wood to be available within economical transport distances. The smaller scale is for "local" production of hydrogen, the simplest fuel to make from wood. It applies to farmed wood within 12 km transport distance and forest residuals within 50 km.

For production of hydrogen and other fuels via gasification, it is important that the syngas is not diluted by nitrogen from air-blowing. Gasifiers carry out two reactions: partial oxidation, which is exothermic, and steam reforming (to make hydrogen) which is endothermic. Simple auto-thermal gasifiers carry out the two reactions simultaneously, and would need oxygen separation systems, which are expensive at these comparatively small scales and prohibitive at the 10 MW scale. Therefore allo-thermal (externally heated) gasifiers are preferred for small plants. The DM2 gasifier from Choren Industries is an example which works well at 10 MW. A different system is required at 200 MW, because it is difficult to get the heat in through the walls fast enough. For this case the BCL gasifier uses a pressurized circulating fluidized bed to transfer heat between the two processes.

Wood to synthetic liquid fuels

For biomass-to-liquid (Fischer-Tropsch) fuels, we also used a process analysis based on the BCL gasifier. The efficiency of this process depends strongly on the performance of the FT catalyst. For our "best estimate" we used the middle value of chain growth probability (0.85) quoted by [*Tijmensen 2002*].

The "best case" is the Choren process under development based on a DM2-type gasifier. They claim an efficiency of 51% combined with an output of pure diesel fuel (kerosene and gasoil), which others believe is not achievable, even assuming the best performing catalyst. Note that to produce only diesel fuel, the lighter FT products have to be recycled all the way back to the gasifier, an operation which is bound to require additional energy. The lowest efficiency limit is the BCL-based process again, but with the most pessimistic assumption for catalyst performance.

Apart from Choren, biomass-to-FT plants all produce 2 fuels simultaneously: naphtha and diesel fuel. We adopted the simple approach as considering the two as equally valid products, and quoting the efficiency for the sum of both fuel products.

DME and methanol are produced by the same process: the only difference being the nature of the final catalyst. We found in the literature two analyses: one based on the BCL gasifier [*Katofsky 1993*], which becomes the "best case", and a "worst case" based on the simpler Värnamo auto-thermal pressurized fluidized-bed gasifier, used with oxygen blowing [*Atrax 1999*]. Note that we have no process for DME based on the Choren DM2 gasifier. To compare efficiency between production of FT and DME or methanol, we should compare the "best-case" FT process with the "best-estimate" process for methanol and DME.

Other processes for conversion of wood to liquids are described in the literature such as fast pyrolysis or the HTU process. We have not included these options. Fast-pyrolysis of wood produces products that cannot be used directly as road fuels, but can be fed to a gasifer in the same way as black liquor. Thus fast pyrolysis is a sort of pre-treatment step as far a road-fuel production is concerned. It may be a viable process for making other chemical products, but the capital cost of two processing plants in series is likely to present a major hurdle.

The HTU process has been under bench-scale development for some time. It converts the feedstock to a mix of solid and liquid products in superheated water. It is hoped that the liquid fraction can be upgraded to hydrocarbon fuel by hydrogenation. Clearly it is more attractive for wet feeds like organic waste or wet crops than wood. However, processing sewage is not likely to be economic because its low heat content means low throughput, which would not repay the high investment cost of the pressurized tank. So HTU is best thought of as an alternative to anaerobic digestion to produce biogas. The proposed process has changed greatly since it was included in [*LBST 2002*] and the new process configuration has not yet been costed in detail, so we could not include it.

Wood to ethanol

There are no commercial wood-to-ethanol plants operating at present. NREL have made detailed studies of an SSCF process for converting wood and other biomass to ethanol (see also wheat straw to ethanol in *section 3.4.9*). We have selected their "base case" as our "worst case": it is the design for a plant using the state-of the art technology available in 1999. For our "best cast" we selected their "best of industry" plant, which already anticipates advances which are still at the laboratory stage. We did not consider their projections further into the future to be appropriate for a 2010 timeframe.

Many of the processes described in the literature combine production of a certain fuel and of electricity. As a result the total process will consume more wood per MJ of fuel produced than would be the case without electricity production. This may make good economic sense in practice and, in some cases exploit genuine synergies. If this electricity is deemed to replace fossil electricity or even EU-mix electricity, this can generate a very large credit which considerably distorts the result while it is simply a reflection of the fact that two notionally independent processes are conducted side-by-side.

Accounting for co-production of electricity

Most of the wood processing schemes quoted in the literature produce some surplus electricity (and therefore consume some additional wood to that effect). To arrive at a meaningful comparison and in accordance with our philosophy that the reference scenario should differ from the biofuels scenario only in the production of biofuels, we made all the wood conversion processes electricity-neutral by adding or subtracting an appropriate proportion of a wood-to-electricity process. For each case we chose a power station which closely matched the one in the process: for example, processes making fuels using the BCL gasifier were made electricity-neutral using the efficiency of a wood power station based on BCL. To compare the efficiency of the processes, which now all had about zero emissions, we compare the "primary energy efficiency" defined as (all primary energy in)/(fuel out). Our efficiency values for pure fuel processes do not correspond to the overall process efficiencies quoted in some references such as [*Tijmensen 2002*]: which are for mixed electricity + fuel processes, with the electrical and fuel energies of the products simply added.

Waste wood in combination with black liquor gasification

Paper pulp manufacture involves separation of wood cellulose from the lignin which forms an important proportion of the wood matter and energy content. The residue from this process, known as black liquor, is a water-based slurry, 70 to 80% of which consists of lignin and spent pulping chemicals.

In conventional pulp mills the black liquor is burned in a so-called "recovery boiler". The non-combustible components leave the recovery boiler as the so-called "smelt" mainly consisting of molten sodium sulfide (Na_2S) and sodium carbonate (Na_2CO_3) which are recycled to the pulping process. The corrosive nature of the smelt limits the recovery boiler efficiency to about 65%.

The recovery boiler provides heat and electricity for the pulp mill. Including the combustion of the bark and the use of the sludge from the effluent treatment a modern pulp mill is self-sufficient in energy.

Replacement of the recovery boiler by a gasifier has been considered by the pulp and paper industry for some time. The original drive for such a scheme was increased energy efficiency which would allow combined production of process heat and surplus electricity for export. As the product of the gasifier is syngas, production of synthetic fuels can also be envisaged. However, the energy used for producing the synthetic fuels must be compensated for by another energy source, conveniently supplied in the form of additional (waste) wood intake into the "hog fuel" boiler already present to burn the bark and other residues. The net result is to turn waste wood into synthetic fuels.

Taking the original pulp mill as reference and for the same pulp production and electricity balance, one can calculate the net efficiency of synthetic fuels production, which turns out to be appreciably higher than that of the direct wood conversion processes. The reason is that the additional burning of forest residuals increases the thermal capacity of the plant, whilst the stack losses are reduced because the hog-fuel boiler has higher efficiency than the replaced recovery boiler. Almost all the heat from the syngas is recovered.

Of course this efficiency improvement can only come about through a substantial investment in a black liquor gasifier and fuel synthesis plant. The gasifier is expensive because of the need to resist corrosion by the very high sulphur and salt content of the syngas. Pilot plant operation is reported to be successful after one year.

In [*Ekbom 2003*] the generation of methanol and DME from black liquor has been investigated within the BLGMF (Black Liquor Gasification to Motor Fuels) project. We have included these pathways as well as pathways to synthetic diesel and hydrogen inferred from the methanol and DME data. We have also included the electricity pathway as it will be the reference against which mill operators will judge the attractiveness of fuel manufacture.

The following table summarises the "wood efficiency" of the various wood processes after correction for electricity production as discussed above.

Table 3.4.11   Wood efficiency of various wood conversion routes

MJ wood/ MJ final fuel	10 MW			200 MW			Black liquor route		
(corrected for electridity production)	Mean	min	Max	Mean	min	Max	Mean	min	Max
Electricity	2.8	2.7	3.0	2.1	2.0	2.2	1.1		
Synthetic diesel (200 MW)				2.1	2.0	2.2	1.8	1.7	1.9
Mehanol/DME (200 MW)				2.0	1.7	2.2	1.5	1.4	1.6
Hydrogen	1.9	1.8	2.0	1.5	1.4	1.5	1.2	1.2	1.3
Ethanol	2.9	2.8	3.1						

The various wood pathways considered are illustrated in the figure below.

Figure 3.4.11   Wood pathways
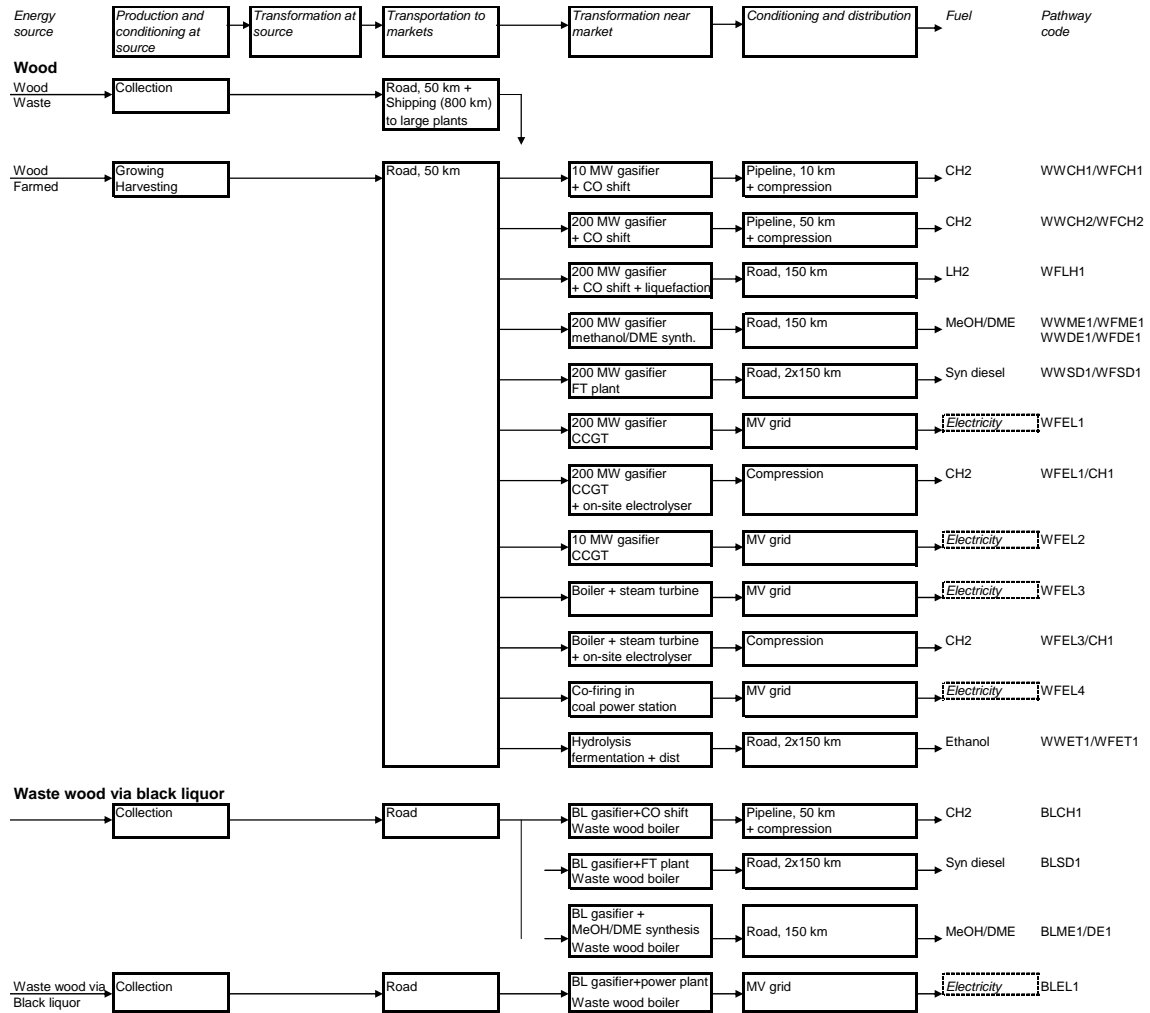
3.4.12   *Organic material to biogas*

The anaerobic fermentation of organic matter produces a gaseous mixture, known as "biogas", consisting mainly of methane and CO_2 (typically 60/40 % v/v although the actual composition varies significantly depending on the type of organic matter). Biogas also contains small amounts of other substances, such as H_2 (0-1%), N_2 (0-7%), H_2S (0-1%) and traces of NH_3 as well as water vapour (in case of landfill gas also small amounts of halogenated compounds can occur).

The process consists of a hydrolysis step, formation of organic acids and of methane. In case of glucose (a saccharide) the methane formation reaction is:

$$C_6H_{12}O_6 \Rightarrow 3 \; CH_4 + 3 \; CO_2$$
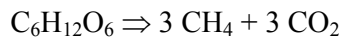
A suitable feedstock is biomass which contains components such as carbohydrates (i.e. saccharides such as glucose), fatty acids and proteins. Cellulose and hemicellulose are converted to saccharides via hydrolysis. Lignin cannot be decomposed via anaerobic fermentation but only via aerobic processes which do not generate methane.

Anaerobic decomposition and formation of methane commonly occurs when manure, crop residues or municipal waste are stockpiled or used as landfill, or when organic matter is immersed in water as

occurs naturally in swamps, or is applied as liquid manure. It is particularly suitable for wet feedstocks, since drying is not required.

Small, often farm-size installations designed to capture this gas have been used for many years. In this case the "raw" biogas is used directly to produce heat and occasionally power e.g. in a dedicated gas engine. Larger scale installations have started to appear in recent years, particularly in Scandinavia, driven both by environmental concerns and, in the case of municipal waste, increasing disposal constraints.

The gas can be used to produce power, possibly combined with a district heating scheme. Alternatively, such plants can produce enough biogas to justify an export infrastructure to a few local service stations for use as automotive fuels or to connect with the local natural gas grid as a substitute to natural gas. In these cases the biogas needs to be treated to remove contaminants, particularly H_2S, and upgraded to a higher heating value or Wobbe index by removing the bulk of the CO_2. Certain feedstocks (e.g. sewage) need to be "hygienised" by heat treatment prior to biogas production to avoid propagation of harmful bacteria or by operating the fermenter at 50 to 55°C (suitable for thermophilic bacteria).

In this study we are primarily concerned by pathways representing biogas use as a motor fuel, which include supply of the feedstock, biogas production, biogas treatment and upgrading, biogas distribution and finally compression to 25 MPa to refuel a vehicle.

For comparison purposes we have also included biogas-to-electricity pathways representing either local small-scale usage or export to the grid and use in a large scale power plant.

We have considered three possible waste feedstocks:
- Organic municipal waste
- Liquid manure
- Dry manure (mixed with straw)

OWCG1: Municipal waste to automotive biogas

Feedstock supply

Municipal waste needs to be collected to a central point in any case so no energy/GHG debit applies to this stage.

Raw biogas production

The feedstock is processed in a "digester" in a batch process that can take several days. The gas produced is collected and sent to the treating section. The required heat and electricity are produced within the plant by a dedicated gas engine running on the raw biogas itself. The conversion level of the organic matter is typically 70%. The unconverted material is a good quality fertiliser for which a credit needs to be calculated (based on the traditional fertiliser substituted). In fact, the nitrogen in digested fertilizer is more quickly available to plants than that in manure, so that its use is more like that of synthetic nitrogen fertilizer. By applying digested fertilizer at the start of the growing season, a greater proportion of the nitrogen can be taken up than is the case with manure. Accordingly, we have given a credit to the biogas pathways corresponding to the equivalent quantity of synthetic nitrogen fertilizer.

Biogas treatment and upgrading

H_2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H_2S into solid sulphur which is collected on the surface of the fermented substrate (biological

desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the "in-house" power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH_4/MJ treated biogas).

Heat and power plant

The concomitant requirement of power and low temperature heat is a favourable situation leading to a high efficiency of the gas engine (nearly 90%). We have assumed that the operation of the gas engine is adjusted to produce the heat requirement of the plant, leading to a surplus of electricity. Exported to the grid, this surplus commands a credit for substitution based on the EU-mix. Minor CH_4 losses are also taken into account.

Distribution and compression

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement. Compression energy is as assumed for natural gas i.e. 0.4 MPa suction and 25 MPa discharge.

OWCG2: Liquid manure to automotive biogas

This pathway is similar to the previous one with a few notable differences:
- Under the assumption of a medium size biogas plant, the manure has to be collected from individual farms and transported to the plant (we assumed a distance of 10 km).
- The biogas production step requires different amounts of heat and electricity due to the different nature of the feedstock.
- The residue left after biogas production still contains all the minerals and nitrogen of the original material and can be used as fertiliser. The credit for this is slightly different from the one considered in OWCG1.
- The largest difference though is due to the large GHG credit related to the avoidance of methane emissions from the manure when used in the traditional way. This is estimated to typically amount to some 15% of the biogas produced.

OWCG3: Dry manure + straw to automotive biogas

Again in this case the general setup is the same with a minor change in the transport energy due to the different nature of the feed. The main difference with OWCG2, however, is the much smaller credit for avoided methane emissions. Indeed with dry manure, these are only estimated to be about 1/10th of those with wet manure.

Liquid manure is mainly produced by intensive pig farms, while dry manure results from more environmentally-aware farming practices. It can therefore be argued that the large credit registered for liquid manure is mostly a compensating mechanism for inappropriate farming practices.

Biogas to electricity pathways

Two scenarios can be envisaged:
- Small scale plant where the raw biogas is used directly in a local power plant.
- Larger scale installation where upgraded gas is exported to the grid and subsequently used in a large power plant.

The main differences between these two cases are the requirement to upgrade the gas in the second case and the significantly higher generation efficiency in larger power plants.

Mixed Feedstock

Long residence time means that biogas plants are larger than thermal conversion plants for a given throughput, which tends to make them more capital-intensive. The economies of scale means that large biomass plants have lower capital costs per unit of output than small ones, and can thus provide biogas more cheaply. This is especially true if purification and compression is to be built into the same plant. Large biogas plants use all the feedstock available within an economic transport distance. Thus they typically use a mixture of animal slurry from local intensive animal farms, concentrated organic waste from the food processing industry, and sometimes municipal organic waste. There is also some synergy in mixing the feeds to optimise the C:N ratio. This point is important in the costs and availability calculation.

Figure 3.4.12-1 Organic waste to biogas pathways
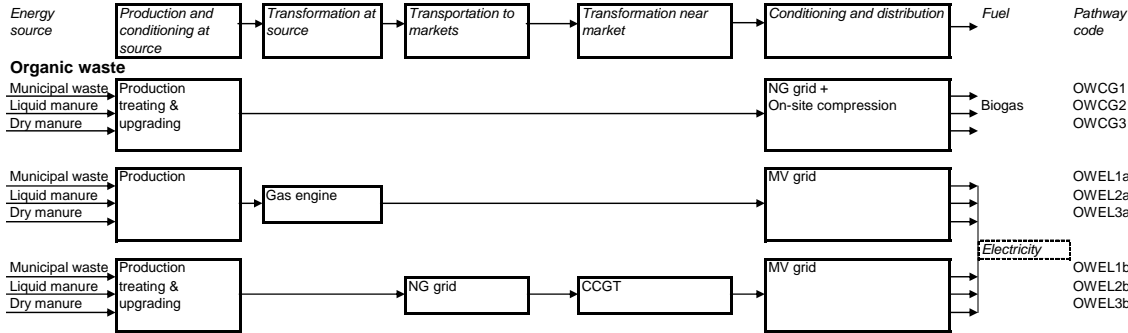
Purpose-grown crops can of course also be used in principle to produce biogas although this has so far received limited attention. Perhaps as a result of the relatively high cost of biogas plants per unit of gas produced, the process appears to be more attractive for (cheap) wastes than for expensive crops. However, traditional fermentation processes to produce ethanol can use only the wheat grain, whereas production of biogas has the advantage that the whole plant including the straw can be used, and hence improve yield.

OWCG4: Farmed wheat to automotive biogas

In pathway OWCG4, the whole wheat plant is converted to biogas which is treated and upgraded before being fed into the NG grid to be used as an automotive fuel. The residue is returned to the fields, producing a credit by substituting chemical fertiliser.

OWCG5: Double-cropped Barley and Maize to automotive biogas

A wide range of organic material can be processed to produce biogas, so farming practices that maximise the amount of biomass produced are attractive. In some cases, two crops can be produced from the land in a single year. In this pathway, we consider maize followed by winter barley. Both crops are cultivated and harvested in the same year and organic agriculture is assumed. The fertilizer requirement is met by the residue of the downstream biogas plant.

Figure 3.4.12-2 Farmed crops to biogas pathways

Energy source	Production and conditioning at source	Transformation at source	Transportation to markets	Transformation near market	Conditioning and distribution	Fuel	Pathway code

Wheat (whole plant)

| Wheat | Growing Harvesting | | Road | | Biogas plant | | Biogas | OWCG4 |

Corn and barley (double cropping)

| Corn & barley | Growing Harvesting | | Road | | Biogas plant | | Biogas | OWCG5 |
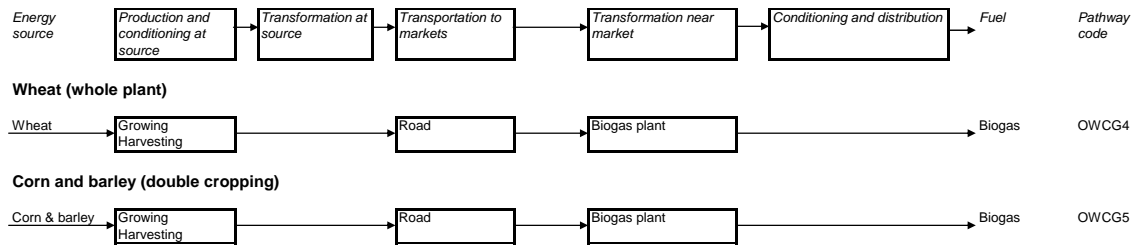
3.5 Electricity production and electrolysis

(See also WTT Appendix 1 sections 15&16)

Electricity is an intermediate source of energy for e.g. the production of hydrogen via electrolysis. It is also the "fuel" for electric vehicles although at this stage we have not included these in the study. It is in any case of interest to establish the energy and GHG balance of the main generation pathways as electricity in effect competes with other fuels for primary energy sources.

3.5.1 Electricity generation pathways

Electricity can be produced from virtually any energy source. We have selected a range of pathways covering the most practical options namely natural gas, coal, biomass (in the form of wood), wind and nuclear. For comparison purposes we have also described the EU-mix generation as a discreet pathway.

Natural gas

Natural gas is already extensively used for power generation, representing about 12% of the primary energy in EU-15. This is due to increase strongly in the coming years where gas will replace some nuclear and coal generation as well as cover the bulk of the increasing demand.

Although gas is used in conventional thermal steam cycles, virtually all new large-scale capacity is and will be based on the CCGT concept (combined cycle gas turbine) which has a much better efficiency (55%). We have also included a CCS option for this process (see *section 3.6*). Note, however, that such high efficiency can only be reached in a new state-of-the-art plant. A simple "switch to gas" in an existing installation will only marginally improve efficiency.

The above processes has been used in the calculations for specific pathways involving NG-based electricity (such as LNG, see *section 3.2.3*) with and without CCS as appropriate. We have also included full NG-to-electricity pathways for three sources of natural gas namely piped gas (7000 and 4000 km) and LNG as well as a CCS option for the 4000 km piped gas case.

Coal

Coal can nowadays be used "cleanly" to produce e.g. electrical power. While gasification associated with a combined cycle scheme (IGCC) can deliver the best overall efficiency, various technological advances have also boosted the performance of the conventional thermal cycle. We have included pathways representing both options. The conventional process represents a typical modern plant with an efficiency of 43.5% (range 40 to 50%, [*TAB 1999*]). For IGCC there is a large range of data from the literature [*TAB 1999*], leading to an average value of 48% ranging from 45 to 52%. A CCS option has also been included in the latter case (see *section 3.6*).

Wood

Wood can be used in a simple boiler + steam turbine configuration or in a more sophisticated scheme involving gasification and CCGT. The expected efficiency is much higher in the latter case although costs will also be higher. Both large and small scale gasifiers and gas turbines can be envisaged. The black liquor route also offers an attractive alternative for efficiently producing electricity from waste wood (see also *section 3.4.11*).

Organic waste via biogas

See *section 3.4.12*

Nuclear

The resource in this case is uranium and more precisely the U_{238} isotope of which there are large reserves. However, the future of nuclear fission as a major power source is a societal issue that goes far beyond the scope of this study and will not be further discussed.

Although nuclear electricity is not strictly renewable, it is virtually carbon-free, the only significant sources of CO_2 emissions being associated to fossil carbon energy used in mining processing and transport of the uranium as well as maintenance of the power plants.

Wind

In theory, there is a virtually unlimited potential for producing electricity from wind power. There are, however, a number of factors that constrain its development. The number of sites suitable for the development of major wind farms and acceptable to society is limited. The intermittent and largely unpredictable nature of wind makes it difficult to integrate large wind farms into existing electrical grids and opens the issue of back-up capacity.

Improvements in wind turbine technology have been very fast and are still expected to contribute a lot to the practical and economic viability of a number of projects, providing ever larger, cheaper, quieter, more efficient and flexible machines.

Nonetheless most forecasts agree that wind power, although growing very fast in the years to come, will not play more than a marginal role in the European energy scene of the next 20 to 30 years (see [*EU energy & transport 2003*]). Once installed, wind power is virtually free and is therefore likely to be used preferentially into national grids. Mismatch between demand and instantaneous production as well as the limited capabilities of grids to deal with sudden large load changes, may lead to surplus generating capacity being available e.g. to produce hydrogen.

Drawing up the energy balance of wind power presents a specific problem inasmuch as the input wind energy cannot be precisely defined and is, for all practical purposes, unlimited. It is therefore generally considered that wind power is created from "nothing" except a minor amount of fossil energy required to cover maintenance activities of the installations.

Hydropower

Hydroelectricity currently represents by far the largest portion of Europe's renewable energy consumption. There are, however, very few sites still available and capacity is not expected to grow substantially.

Hydro electricity is very much a integral part of the European electricity scene, is fully integrated into the "EU-mix" and, being one of the cheapest source of power will always be used in preference to

fossil fuels based power. From this point of view it has no direct relevance to marginal electricity and has not been further considered in this study.

The "EU-mix"

Electricity in the EU is produced via a large number of routes including coal, gas, nuclear, hydro etc. The combination, although not corresponding to a single actual pathway is used in this study to represent the typical electricity supply.

There are several sources of information for this amongst others the International Energy Agency, Eurelectric (the Union of the electricity industry) and the EU Commission's "Poles" model. All sources report slightly different figures for the past years and of course show different forecasts. There is, however, a general agreement to show a decrease of nuclear, solid fuels and heavy fuel oil compensated mainly by natural gas. Renewables, although progressing fast in absolute terms, do not achieve a significant increase in relative terms because of the sharp increase in electricity demand. As a result, although the primary energy composition of the 2010 "kWh" is different from that of 2000, the resulting CO_2 emissions are not very different.

We have opted to use the figures compiled in the German GEMIS database [GEMIS 2002] for the year 1999 resulting from a detailed country-by-country analysis of electricity production. The share of the different primary energy sources in the total electricity production is shown in the following table.

Table 3.5.1   EU-mix electricity sources

Source	Share
Nuclear	37.5%
Coal	22.4%
Oil	9.6%
Gas	15.5%
Hydro	12.4%
Wind	0.4%
Waste	1.8%
Other renewables	0.3%

Including the distribution losses to the medium voltage level the overall energy efficiency is around 35 % and the corresponding GHG emissions 430 g CO_2eq/kWh$_e$ (119 g CO_2eq/MJ$_e$). A further correction is made for those cases where electricity is produced or used at low voltage. The detailed primary energy composition is given in *WTT Appendix 1, section 3*.

Note: the GHG figure quoted above is coincidently quite close to the global figure for generation of electricity with natural gas in a state-of-the-art combined cycle gas turbine, a route often viewed as the most likely marginal electricity source in Europe for the foreseeable future.

Figure 3.5.1   Electricity generation pathways

Resource	Production and conditioning at source	Transformation at source	Transportation to markets	Transformation near market	Conditioning and distribution	Pathway
Electricity						
NG (piped)	Production and conditioning		Pipeline into EU (7000 or 4000 km)	CCGT [+CC&S option]	MV grid	GPEL1a/b/bC
NG (remote)	Production and conditioning	Liquefaction	Shipping (LNG)	CCGT	MV grid	GREL1
Municipal waste / Liquid manure / Dry manure	Production	Gas engine			MV grid	OWEL1a / OWEL2a / OWEL3a
Municipal waste / Liquid manure / Dry manure	Production treating & upgrading		NG grid	CCGT	MV grid	OWEL1b / OWEL2b / OWEL3b
Coal (EU mix)	Production and conditioning		Typical for EU coal mix	State-of-the-art conv. technology	MV grid	KOEL1
				IGCC (+CC&S option)	MV grid	KOEL2/2C
Farmed wood	Growing Harvesting		Road, 50 km	200 MW gasifier CCGT	MV grid	WF/WWEL1
				10 MW gasifier CCGT	MV grid	WF/WWEL2
				Steam power plant	MV grid	WF/WWEL3
				Co-firing in coal power station	MV grid	WF/WWEL4
Waste wood via Black liquor	Collection		Road	BL gasifier+power Waste wood boiler	MV grid	BLEL1
Wind				Wind turbine On/offshore	MV grid	WDEL1
Nuclear fuel	Nuclear fuel provision			Nuclear power plant	MV grid	NUEL1
EU fuel mix	EU mix typical				MV grid	EMEL1

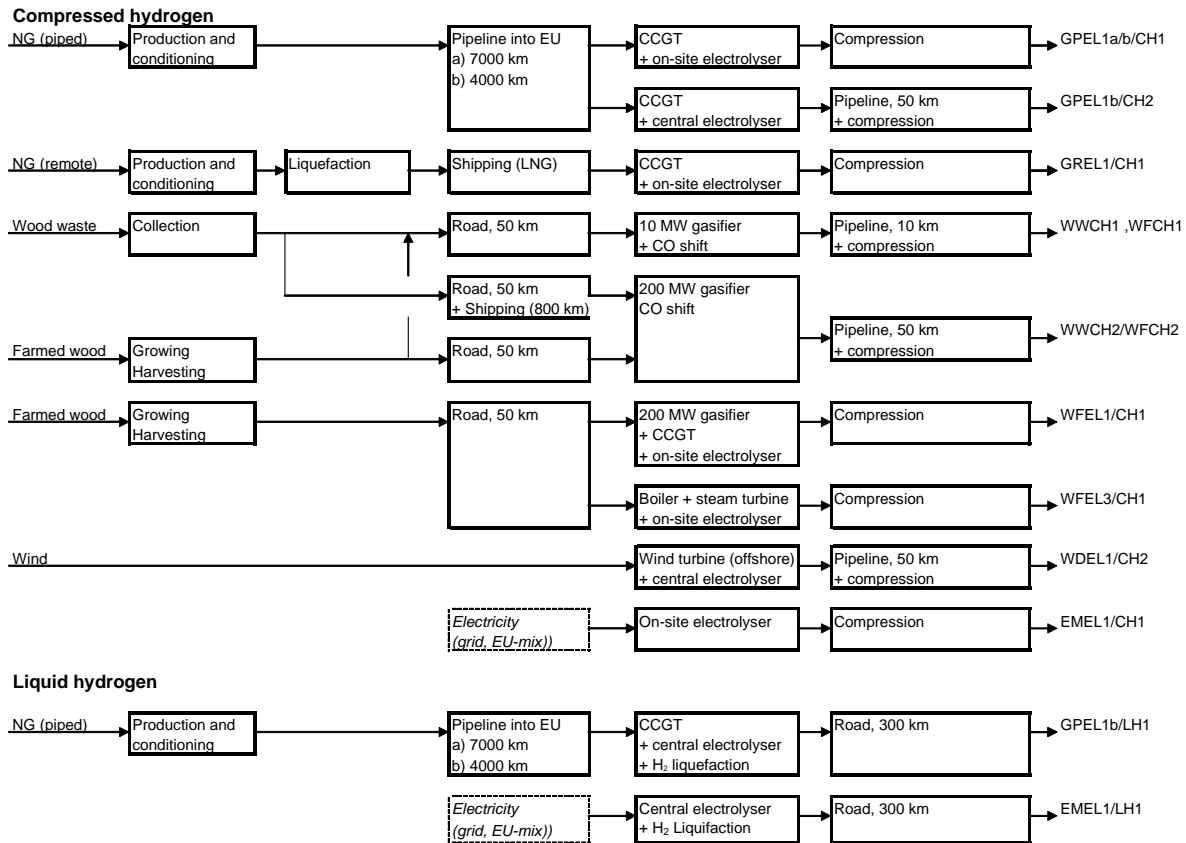## 3.5.2 Hydrogen via electrolysis

The electrolysis of water to hydrogen and oxygen is a long established process. It is possible to build electrolysis plants from very small to very large scale. The efficiency of the electrolysis process as such is largely unaffected by scale although the auxiliaries and the operating pressure can have a significant impact on the overall efficiency

Several sources of data are available, giving figures for both small and large (alkaline) electrolysers with and without auxiliaries. Including the latter most figures fall into the 62 to 70% bracket (related to hydrogen LHV, equivalent to 4.2 to 4.8 kWhe/Nm^3 of hydrogen produced), with no clear size effect ([*GHW 2001, 2004*], [*Hydrogen Systems 2000*], [*Stuart Energy 2005*], [*Vandenborre 2003*]). Some studies e.g. [*Dreier 1999*] have proposed far higher efficiency figures (up to 77% related to hydrogen LHV including all auxiliaries).

On balance we have considered that a figure of 65% with a range of 63 to 68%, irrespective of the size, is a reasonable representation of the available data.

We have considered a large scale plant, typically with the same hydrogen production capacity as a large reformer (200 MW as hydrogen) and a small on-site electrolyser serving a single filling station.

Figure 3.5.2   Hydrogen via electrolysis pathways

Compressed hydrogen

NG (piped) →	Production and conditioning		Pipeline into EU a) 7000 km b) 4000 km	CCGT + on-site electrolyser	Compression → GPEL1a/b/CH1
				CCGT + central electrolyser	Pipeline, 50 km + compression → GPEL1b/CH2
NG (remote) →	Production and conditioning	Liquefaction	Shipping (LNG)	CCGT + on-site electrolyser	Compression → GREL1/CH1
Wood waste →	Collection		Road, 50 km	10 MW gasifier + CO shift	Pipeline, 10 km + compression → WWCH1 ,WFCH1
			Road, 50 km + Shipping (800 km)	200 MW gasifier CO shift	
Farmed wood →	Growing Harvesting		Road, 50 km		Pipeline, 50 km + compression → WWCH2/WFCH2
Farmed wood →	Growing Harvesting		Road, 50 km	200 MW gasifier + CCGT + on-site electrolyser	Compression → WFEL1/CH1
				Boiler + steam turbine + on-site electrolyser	Compression → WFEL3/CH1
Wind				Wind turbine (offshore) + central electrolyser	Pipeline, 50 km + compression → WDEL1/CH2
			Electricity (grid, EU-mix))	On-site electrolyser	Compression → EMEL1/CH1

Liquid hydrogen

NG (piped) →	Production and conditioning		Pipeline into EU a) 7000 km b) 4000 km	CCGT + central electrolyser + H$_2$ liquefaction	Road, 300 km → GPEL1b/LH1
			Electricity (grid, EU-mix))	Central electrolyser + H$_2$ Liquifaction	Road, 300 km → EMEL1/LH1

Many combinations are possible between electricity from various sources, electrolysis either central or on-site and hydrogen distributed in either liquid or gaseous form. We have selected a limited number to illustrate the main points.

One important issue is the pressure at which the hydrogen is available at the electrolyser outlet. Current and foreseeable technology at the 2010 horizon allows about 3 MPa. Higher pressures may be possible in the longer term but this is still somewhat speculative and we have not taken it into account. Hydrogen from a central electrolyser will need to be transported. If this is done through a pipeline network this pressure will be sufficient and a remaining pressure of 2 MPa has been assumed at the refuelling station compressor inlet. For the on-site electrolyser, no hydrogen transport is necessary and the whole 3 MPa outlet pressure is available.

3.5.3 Combined Heat and Power

Electricity generation enters into the WTT calculations primarily as an input to the various fuel production pathways. Some pathways also include generation of electricity as part of the process, either from NG or using the by-products of road fuel production. In these cases, waste heat can often be usefully employed in the production process. For purposes of comparison, we have therefore included new pathways describing typical performance of small and industrial case boilers and large scale CHP plants fed with heating oil, natural gas, biogas or wood. Heat is treated as a by-product, by comparing with stand-alone heat generation using the same fuel.
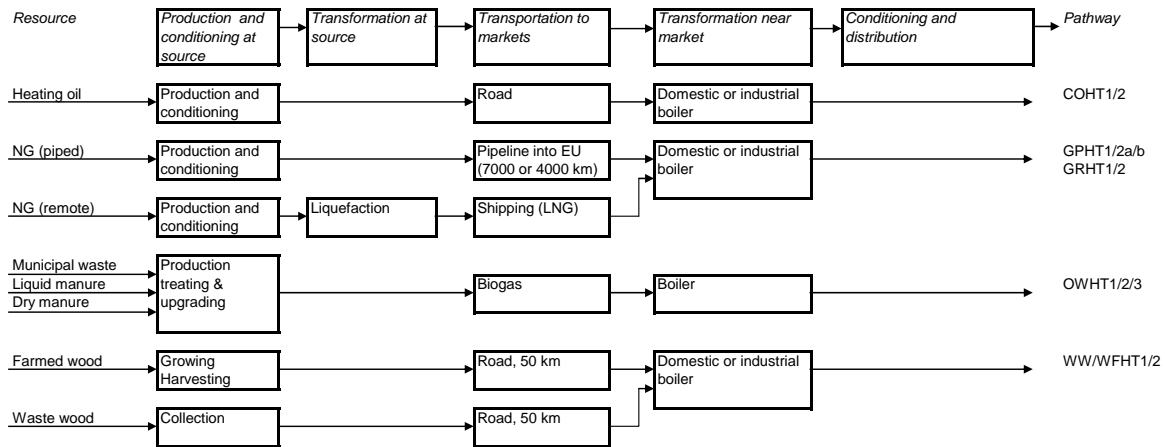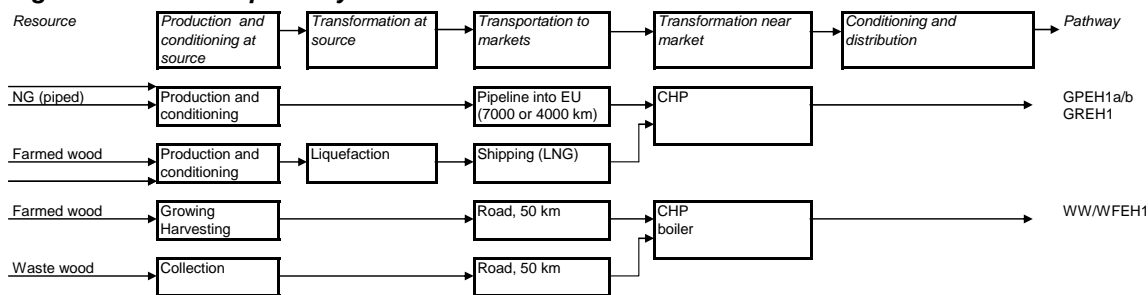
Figure 3.5.3-1 Heat pathways

Resource	*Production and conditioning at source*	*Transformation at source*	*Transportation to markets*	*Transformation near market*	*Conditioning and distribution*	*Pathway*
Heating oil	Production and conditioning		Road	Domestic or industrial boiler		COHT1/2
NG (piped)	Production and conditioning		Pipeline into EU (7000 or 4000 km)	Domestic or industrial boiler		GPHT1/2a/b GRHT1/2
NG (remote)	Production and conditioning	Liquefaction	Shipping (LNG)			
Municipal waste Liquid manure Dry manure	Production treating & upgrading		Biogas	Boiler		OWHT1/2/3
Farmed wood	Growing Harvesting		Road, 50 km	Domestic or industrial boiler		WW/WFHT1/2
Waste wood	Collection		Road, 50 km			

Figure 3.5.3-2 CHP pathways

Resource	*Production and conditioning at source*	*Transformation at source*	*Transportation to markets*	*Transformation near market*	*Conditioning and distribution*	*Pathway*
NG (piped)	Production and conditioning		Pipeline into EU (7000 or 4000 km)	CHP		GPEH1a/b GREH1
Farmed wood	Production and conditioning	Liquefaction	Shipping (LNG)			
Farmed wood	Growing Harvesting		Road, 50 km	CHP boiler		WW/WFEH1
Waste wood	Collection		Road, 50 km			

3.6 CO$_2$ Capture and Storage (CCS)

The concept of isolating the CO$_2$ produced in combustion or conversion processes and injecting it into suitable geological formations has been gaining credibility in the last few years. There are many such structures available in most areas of the globe from depleted gas and oil fields to salt domes and aquifers. CO$_2$ injection can also be used to enhanced and prolonged production from ageing oil and gas fields. Pilot projects are already in operation in the oil and gas industry.

The schemes include separation of CO$_2$ from other gases, compression and liquefaction, transport (by pipeline or ships) to the point of injection and injection under pressure.

Separation of CO$_2$ from other gases is a well-established process consisting in scrubbing the CO$_2$-containing gas mixture with a solvent or a physical absorbent. In combustion applications using air, scrubbing CO$_2$ out of the flue gases is feasible although very large equipment is required because of the large gas volumes. Oxy-combustion is more favourable from this point of view as it delivers virtually pure CO$_2$, although additional energy needs to be expended in the air separation unit. Reforming and gasification processes deliver CO/hydrogen/CO$_2$ mixtures or mostly hydrogen/CO$_2$ after the shift reaction. In these cases CO$_2$ scrubbing is more straightforward. In some cases, for example before syngas is fed to a Fischer-Tropsch reactor, CO$_2$ scrubbing is required irrespective of the CCS option.

CO$_2$ separation and compression require some energy, the amount depending on the composition of the gas to be scrubbed and of the process used. Processes using a chemical solvent (such as MDEA,

Methyl Di-Ethanol Amine) are more energy-intensive than absorption processes because of the heat needed to regenerate the solvent.

The concept can in principle be applied to many schemes. As illustration of its potential, we have included CCS in the following cases:
- Electricity from natural gas and coal (IGCC)
- LNG: CO_2 from the power plant associated to the liquefaction plant.
- Hydrogen from NG and coal: Process CO_2 after shift reaction
- GTL and CTL diesel: Process CO_2 after reforming / partial oxidation
- DME from NG: Process CO_2 after reforming

Note: the DME scheme could also be applied to methanol. We have not included it here because of the relatively minor importance of methanol as a potential automotive fuel.

In attempting to assess the CO_2 benefit and energy requirement of CCS in these different cases we found many literature references. In particular we were guided by a recent study by the IEA's Greenhouse gas R&D programme [*IEA 2005*]. As CCS has so far only been applied on a limited scale in very few locations worldwide, all references refer to theoretical studies. These do not always include details of the envisaged flow schemes and/or full comparative data between the case without CCS and the case with CCS. Many of the process schemes are complex, involving multiple sources of CO_2. In a GTL plant, for instance, CO_2 is emitted by the syngas production process, the Fischer-Tropsch process and the power plant. Each of these sources produces a different gas mixture which would require different systems to separate the CO_2. Generally therefore the degree of CO_2 recovery, the energy involved and the cost of the installations required will depend on which gas streams are being tackled.

Following capture at the point of emission, CO_2 must be compressed and liquefied, transported to the point of storage and injected. We have accounted for the energy required for compression to 15 MPa. No additional energy has been included under the assumption that this pressure level would be sufficient to transport CO_2 by pipeline over a reasonable distance (typically 100-150 km) and inject it into the geological storage.

Because of all these uncertainties and possible lack of consistency between the sources, we consider that the figures shown in this report for the CCS schemes should be regarded as preliminary and indicative of the potential of the technology. As more real-life applications develop, better estimates are expected to become available.

Figure 3.6 Pathways with CCS option

Energy source	Production and conditioning at source	Transformation at source	Transportation to markets	Transformation near market	Conditioning and distribution	Fuel	Pathway code
CCS							
Remote NG	Production and conditioning	Liquefaction (+CCS option)	Shipping (LNG)	Vapourisation	NG grid + on-site compression	CNG	GRCG1/1C
Remote NG	Production and conditioning	GTL plant (+CCS option)	Shipping		Mixed land transport 500 km	Syn diesel	GRSD2/2C
		MeOH/DME syn (+CCS option)	Shipping		Mixed land transport 500 km	DME	GRDE1/1C
Piped NG	Production and conditioning		Pipeline into EU 4000 km	Reforming (central) (+CCS option)	Pipeline, 50 km Compression	CH2	GPCH2b/2bC
				CCGT (+ CCS option)	MV grid	Electricity	GPEL1a/b/bC
Hard coal	Production and conditioning		Typical for EU coal mix	Gasification+CO shift (+CCS option)	Pipeline, 50 km + compression	CH2	KOCH1/1C
				CTL plant (+CCS option)	Mixed transport to depot + Road, 150 km	Syn diesel	KOSD1/1C
				IGCC (+CCS option)	MV grid	Electricity	KOEL2/2C

Electricity

For natural gas two different routes for CCS can be envisaged. The so-called "post-combustion" route involves scrubbing flue-gases of a standard power plant using an amine absorption process. Such systems have been proposed in studies carried out in the USA such as [*Rubin 2004*]. Alternatively the "pre-combustion" route includes reforming NG into hydrogen and separating CO_2 before burning the hydrogen in an adapted CCGT.

In this study we have considered the post-combustion option. Based on [*Rubin 2004*] the overall energy efficiency would decrease from 55% in the reference case to 47% with CCS, for a CO_2 recovery of 90% and including the energy required to compress and inject CO_2 in the storage structure. Indications are that the efficiency loss will be higher for pre-combustion schemes, with overall efficiencies in the order of 42%. Such schemes would, however, offer greater flexibility, not least being able to produce hydrogen in addition to power.

For coal we have considered an IGCC scheme with and without CCS based on [*TAB 1999*] and [*ENEA 2004*].

The table below shows the impact of CCS on energy and CO_2 emissions.

Table 3.6-1   Electricity production with/without CCS

Feedstock		Natural gas		Coal	
Case		Base	with CC&S	Base	with CC&S
Natural gas	MJ/MJe	1.818	2.123		
Coal	MJ/MJe			2.083	2.439
Energy efficiency		55.0%	47.1%	48.0%	41.0%
Net GHG emissions	g CO_{2eq}/MJe	100.1	11.9	200.6	23.4
CO_2 removal efficiency			88.1%		88.3%

Hydrogen

Hydrogen is produced from natural gas via steam reforming followed by CO-shift. The hydrogen-rich gas, including CO_2 is then commonly routed to a pressure swing adsorption (PSA) plant to separate the bulk of the hydrogen. The same scheme applies to coal, replacing steam reforming by partial oxidation (gasification). The tail gas of the PSA is fed to a boiler to provide heat for the endothermic steam reforming reaction or electricity for the air separation plant that provides pure oxygen for coal gasification.

CO_2 capture involves an additional scrubbing process between CO-shift and PSA followed by compression / liquefaction of CO_2 to 15 MPa. We have based our figures on a conceptual plant design described in [*Foster Wheeler 1996*]. The study includes base case (no CCS) and CCS case for both natural gas and coal. In the CCS cases, CO_2 is extracted chemically with activated MDEA as solvent. Heat and electricity are required for the regeneration of the solvent and CO_2 compression.

Note: in the first version of this report we based the NG-to-hydrogen pathway on a reference from Linde [*Linde 1992*]. The latter involved a larger NG input but also surplus electricity production. Taking the appropriate credit into account the net energy balance falls within 1% of the Foster Wheeler case.

The table below shows the impact of CCS on energy and CO_2 emissions.

Table 3.6-2   Hydrogen production with/without CCS

Feedstock		Natural gas		Coal	
Case		Base	with CC&S	Base	with CC&S
Natural gas $MJ/MJ\ H_2$		1.315	1.365		
Coal $MJ/MJ\ H_2$				1.967	2.303
Energy efficiency		76.0%	73.3%	50.8%	43.4%
Net GHG emissions $g\ CO_{2eq}/H_2$		72.4	11.9	189.4	5.6
CO_2 removal efficiency			83.6%		97.0%

The energy efficiency penalty for CCS is much larger for coal but so is the absolute amount of CO_2 removed. In the coal case, virtually all CO_2 is produced in the gasifier and/or CO-shift reactor so that removal can be close to complete. In the natural gas case, the CO_2 produced by the fuel burned in the reformer (recycled PSA off-gas supplemented by additional natural gas) cannot practically be recovered.

Synthetic fuels

Steam reforming and/or partial oxidation is also the first step towards production of DME or synthetic diesel from natural gas or coal. However, CO_2 has to be removed upstream of the synthesis step because CO_2 is not desired in the gas stream entering the synthesis reactor. Usually CO_2 is separated via a selective physical absorption process such as SELEXOL™ which uses an aqueous solution of a di-methyl ether or polyethylene glycol in water. Such processes are generally less energy-intensive than chemical scrubbing processes.

For the DME base case we used data from Haldor Topsoe ([*Haldor Topsoe 2001*] and [*Haldor Topsoe 2002*]). The CCS case was produced by the IEA Greenhouse group [*IEA 2005*] on the basis of the same data.

Table 3.6-3   DME production with/without CCS

Feedstock		Natural gas	
Case		Base	with CC&S
Natural gas $MJ/MJ\ DME$		1.412	1.425
Coal $MJ/MJ\ DME$			
Energy efficiency		70.8%	70.2%
Net GHG emissions $g\ CO_{2eq}/DME$		10.6	0.7
CO_2 removal efficiency			93.7%

For FT liquids from NG there is no literature source where a NG FT plant with and without CCS is compared. FT plants are very complex. The layout differs from licensor to licensor and this can have a large impact on the energy penalty for CCS. [*IEA 2005*] suggests an energy efficiency penalty of 3%. We have used this figure as a basis for our calculation, starting from an overall plant efficiency of 63%

in the base case. The CO_2 generated in the auxiliary power plant is not recovered in this scheme, so that the CO_2 recovery is relatively low at around 75%.

For coal-to-liquid [*Gray 2001*] gives a direct comparison of base and CCS cases.

Table 3.6-4   Syn-diesel production with/without CCS

Feedstock		Natural gas		Coal	
Case		Base	with CC&S	Base	with CC&S
Natural gas	MJ/MJ SD	1.587	1.667		
Coal	MJ/MJ SD			1.784	1.861
Energy efficiency		63.0%	60.0%	56.1%	53.7%
Net GHG emissions	g CO_{2eq}/MJ SD	16.5	4.2	363.2	33.5
CO_2 removal efficiency			74.7%		90.8%

The process as described produces surplus electricity in both cases. We treated this as a credit based on alternative generation with a coal-fired IGCC with and without CCS (as described above).

3.7 Synthetic fuels transport and distribution

3.7.1 Hydrogen transport and distribution

(see also WTT Appendix 1 section 17)

Hydrogen can be transported and/or used in either compressed or liquid form. Liquefaction is an energy-intensive process but liquid hydrogen has the advantage of having a much higher density, becoming more efficient to transport and store on-board a vehicle.

Compressed hydrogen from a central plant can be transported either in pipelines at moderate pressures (2-4 MPa) or at high pressure (20-30 MPa) in cylinders loaded on a road truck. In the case of a large central plant, the average distribution distance has been taken as 50 km. Generally the pressure available at the plant outlet is considered sufficient to carry the hydrogen through a 50 km pipeline without the need for additional energy input. A residual pressure of 2 to 3 MPa has been assumed at the refuelling site, depending on the type of plant. Hydrogen from small on-site plants will generally be available at a somewhat lower pressure of typically 1.5 MPa.

Gaseous hydrogen reaching the refuelling station needs to be compressed to the high pressure required to store sufficient fuel on-board. The current "state-of-the-art" is 35 MPa although tests are already underway for 70 MPa storage tanks. In practice, this requires a compressor discharge pressure of 45 MPa or 88 MPa to ensure an adequate filling time. The 70 MPa level is required to allow an acceptable vehicle range. For this reason it is expected to become the standard and we have calculated the pathways for that case (this is also consistent with the assumptions made for the on-board storage in the *Tank-to-Wheels report*).

Liquid hydrogen has a big advantage in terms of energy density but involves additional energy for liquefaction. Current liquefaction plants require up to 40% of the liquefied hydrogen energy content but figures vary a great deal from plant to plant. Manufacturers argue that existing plants have not always been designed for minimum energy consumption (but often for minimum investment cost). Technology is believed to be able to eventually deliver large scale plants that would reduce the consumption to around 20%. We have used a median value of 30% with a range of 21 to 39%.

Long-distance transport of liquid hydrogen from a remote plant would require special ships for which only design concepts exist today. Liquid hydrogen would be further transported by road from the EU entry port directly to the service stations (assumed distance 500 km). Liquid hydrogen from an EU

plant would also be transported by road albeit along a somewhat lower average distance (assumed 300 km) as it can be surmised that the plant would be better located to serve the market.

Hydrogen can be stored in the vehicle in either compressed or liquid form. The advantage of liquid hydrogen from a transport point of view may lead to its use for transportation even if the end-user vehicle requires the compressed form. In this case the refuelling station must include vaporisation/compression equipment.

3.7.2 Biofuels and Synthetic fuels transport and distribution
(See also WTT Appendix 1 sections 18, 19)

Liquid fuels
Long-distance transportation
Synthetic fuels from a remote plant will be transported by ships appropriate to the type of product. Synthetic hydrocarbons can be transported in conventional oil product carriers. Large methanol ships already exist today.

Distribution within Europe
Distribution within Europe does not generally involve large distances and therefore only accounts for a minor energy consumption.

For biofuels (ethanol, bio-diesel and syn-diesel from wood) manufactured in Europe we have assumed blending with conventional fuels is more likely to occur down the distribution chain, Accordingly, we have used two standard road transport vectors of 150 km each representing trips from the plant to a blending depot (or a refinery) and from the depot to the filling station. We have assumed that synthetic diesel manufactured in Europe in large plants (GTL or CTL) would necessarily go through blending in a refinery and we have used the standard transport vector for conventional fuels followed by the 150 km road transport for final distribution (pipeline/rail/water, see *section 3.1.4*). Imported synthetic diesel from a remote location would be available at an EU entry port. In case of blending with refinery products (variant 1), the conventional fuels transport vector would apply. For the case where the fuel is used neat (variant 2) a 500 km rail/road transport vector was applied. The same vector was also used for bulk ethanol imports (e.g. Brazil).

Methanol cannot be mixed with conventional fuels. Its introduction in the existing multi-product pipeline infrastructure is not technically feasible. It would therefore require a specific distribution system. A dedicated methanol pipeline network is unlikely to be built at least as long as the market remains limited. For bulk imports, distribution from a coastal import terminal was therefore assumed with the same parameters as for imported ethanol. Intermediate depots may be involved but the associated extra energy consumption would be insignificant. For methanol from biomass we assumed a single road transportation leg of 150 km, recognising the fact that the plants would be of limited size and serving the local market.

DME
DME is gaseous under ambient conditions but can be liquefied at moderate pressure. Its logistic is therefore very similar to that of LPG, an already common road fuel in some countries. In case of DME from remote NG long-distance transport would require ships similar to the existing LPG carriers. The transport distance between the port in the EU and the filling stations was assumed to be 500 km (50/50 train/truck). In case of biomass derived DME the transport distance between the DME plant and the filling stations was assumed to be 150 km.

The infrastructure required for storage, road or rail transport and refuelling points would of course have to be built from scratch.

Biogas

Biogas is essentially methane, and after cleaning can take advantage of the general NG pipeline system for distribution. In this sense the points of production and use do not necessarily have to be close to each other, and the biogas can contribute wherever a refuelling infrastructure for CNG vehicles exists. In those areas where a NG pipeline system does not exist, a separate distribution system will be needed, and in this case local use of the biogas is more appropriate.

The following table gives an overview of the transport vectors.

Table 3.7.2   *Fuel transport vectors*

	Transport to EU	Transport within EU	
		Transport to depot	Transport to filling stations
Crude oil based gasoline and diesel, Syn-diesel from piped NG or coal	NA	Ship, 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
Ethanol & FAME produced within EU	NA	Road, 150 km	Road, 150 km
Ethanol bulk imports (Brazil)	Ship, 5,500 nautical miles	Road, 150 km	Road, 150 km
MTBE (remote)	Ship, 5,500 nautical miles	Ship, 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
ETBE		Ship, 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
Syn-diesel from biomass (BtL)	NA	Road, 150 km	Road, 150 km

Syn-diesel from remote NG
 	
  Variant 1
 	
  Variant 2
	Ship, 5,500 nautical miles	Ship, 500 km (20%) Pipeline, (60%) Train, 250 km (20%
		
		NA
			Road, 150 km
			
			Train/Road, 500 km

Methanol or DME from remote NG	Ship, 5,500 nautical miles	NA	Train/Road, 500 km
Methanol or DME from biomass	NA	NA	Road, 150 km
LPG (remote)	Ship, 5,500 nautical miles		Road, 500 km

4   Final fuels: Energy and GHG balance

4.1 Reporting formats

In this section we report the detailed energy and GHG balance of each pathway. In order to illustrate the relative importance of the different stages of the pathway, we give detailed results according to the 5 standard steps defined in *section 2.1*. The actual figures with additional details for each pathway are listed in *WTT Appendix 2*.

In the generic presentation, we focus on total energy expended, i.e. all the energy, regardless of its origin, that needs to be used to produce the desired fuel, *after discounting the energy content of the fuel itself*. The unit used is

$$MJ_{xt}/MJ_f = \text{MJ expended total energy per MJ finished fuel (LHV basis)}$$

For example a figure of 0.5 means that making the fuel requires 50% of the energy that it can produce when burned.

This total energy figure gives a truly comparable picture of the various pathways in terms of their ability to use energy efficiently.

For fuels derived from renewable resources it is also of interest to report the fossil energy used in the pathway, particularly by comparison with the energy content of the final fuel. This is reported and discussed separately as

$$MJ_{xfo}/MJ_f = \text{MJ expended fossil energy per MJ finished fuel}$$

The reported WTT GHG figures exclude CO_2 emissions associated with the combustion of the final fuel.

For the WTW analysis, carbon-containing fuels of renewable origin are, however, given a credit for an amount of CO_2 equivalent to that released during combustion. In the TTW part of the study, all fuels can then be treated in the same way and allocated CO_2 emissions corresponding to their carbon content regardless of its origin.

In many graphs presented in this section, the gasoline or diesel balance is also included. For total energy, this provides a valid reference as long as vehicle efficiency is expected to be essentially the same for fossil and biofuel. To make the same comparison for fossil energy or total GHG emissions, we have added the combustion energy and CO_2 emissions for the fossil fuels.

4.2 Crude oil based fuels (gasoline, diesel fuel, naphtha)

(see also WTT Appendix 2 section 1)

The pathways to conventional fuels are straightforward and have been discussed in *section 3.1*.

Gasoline and diesel fuel from conventional crude oil supply almost the totality of road transport needs today. Within the time frame of this study the market share of alternative fuels is not expected to go beyond 10 to 20% of the market. As noted in Section 3.1.1 non-conventional sources of crude oil are not expected to impact the European market in the time frame of this study.

The energy and GHG "cost" of introducing alternative fuels needs to be measured against the savings related to "not-providing" the conventional equivalents. The energy and GHG balance that we need to be concerned with here pertain, therefore, to the effect of marginally reducing the production of conventional fuels compared to a "business-as-usual" case. The following figures reflect this approach (see also *section 3.1.3* and *WTT Appendix 3*).

Figure 4.2-1   *WTT total energy balance for crude oil based fuels*
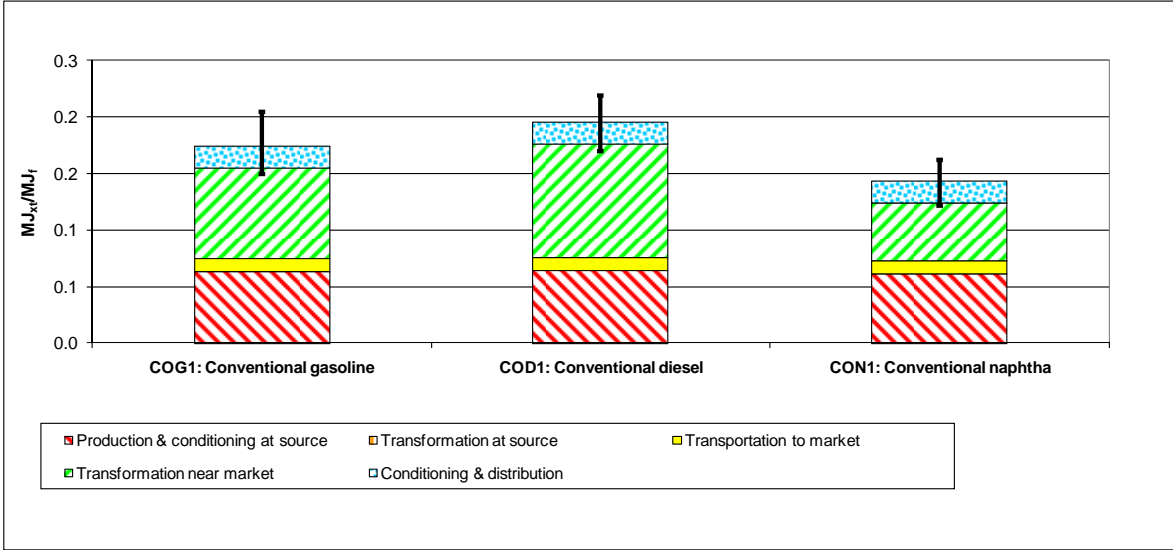
Figure 4.2-2   *WTT GHG balance for crude oil based fuels*
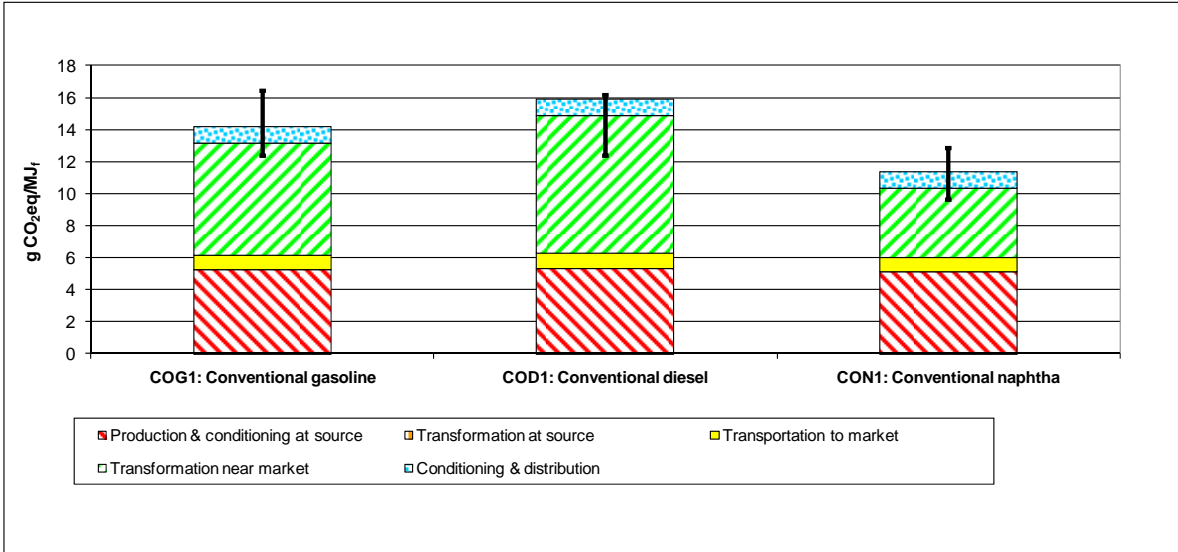
Refining is the most energy-consuming step followed by crude production. For the reasons developed in *section 3.1.3*, the marginal production of diesel fuel is more energy intensive than that of gasoline.

Note that these figures apply to Europe as a result of the specific situation prevailing in the region. The situation will be different in other parts of the world and a similar assessment would have to be made taking into account the local parameters and leading to different figures and conclusions.

Naphtha is not currently used as automotive fuel. It is included here as a potential fuel for on-board reformers.

4.3 CNG, CBG (Compressed Biogas), LPG

(See also WTT Appendix 2 section 2)

4.3.1 Pathways to CNG

In order to be used in a vehicle natural gas needs to be brought to a refuelling station and pressurised into the vehicle tank. Gas from the distribution networks is the first choice but the use of LNG can also be envisaged.

Gas sent down the pipelines from various sources still contains some light hydrocarbons and some inerts so that its composition varies between producing regions. In the case of LNG, practically all heavier hydrocarbons have been removed in the liquefaction process and the gas is virtually pure methane. These differences in composition result in a range of volumetric heating values as well as significant differences in combustion characteristics as measured by the methane or octane number. In spite of these variations, the current European gas grid is estimated to deliver a minimum MON of 115, which is sufficient to allow the use of dedicated CNG vehicles with higher compression ratio.

Based on the current EU supply information we have calculated a notional "EU-mix" used in the study as the standard gas available in the EU distribution network e.g. for use as a road fuel. This composition and quality is used as input to the Tank-to-Wheels part of the study for CNG vehicles.

Table 4.3.1   Notional EU-mix natural gas

Origin	CIS	NL	UK	Norway	Algeria	Notional EU-mix
Notional EU-mix share	21.4%	22.0%	30.4%	11.8%	14.4%	100.0%
Composition (% v/v)						
Methane	98.4	81.5	86.0	86.0	92.1	88.5
Ethane	0.4	2.8	8.8	8.8	1.0	4.6
Propane	0.2	0.4	2.3	2.3	0.0	1.1
Butane and heavier	0.1	0.1	0.1	0.1	0.0	0.1
CO_2	0.1	1.0	1.5	1.5	0.0	0.9
Nitrogen	0.8	14.2	0.8	0.8	6.1	4.5
LHV (GJ/Nm^3)	35.7	31.4	38.6	38.6	33.7	35.7
(GJ/t)	49.2	38.0	47.1	47.1	44.9	45.1
Methane number	105	97	80	80	105	91
MON	138	133	122	122	138	129

We have made the assumption that the changes to European supply at the 2010-2020 horizon will not materially affect the quality of the gas available as automotive CNG.

After reaching the refuelling station the gas needs to be compressed to a sufficient pressure to ensure fast refuelling. For on-board tanks at 20 MPa maximum a pressure of 25 MPa is required. Compression is an energy-intensive process, the energy consumption being strongly dependent on the outlet to inlet pressure ratio. For a given outlet pressure, the higher the inlet pressure, the lower the energy required. A relatively small increase of the inlet pressure can significantly reduce the compression ratio.

Direct connection to the high pressure network would be preferred from this point of view. However, the high pressure pipelines are only few and far between and even if available in the vicinity of a refuelling point may not be accessible for practical or regulatory reasons. In the majority of cases, the standard pressure of the local distribution network is more likely to be used. We have opted for a typical inlet pressure of 0.4 MPa.

In the case of direct LNG distribution the liquid is pumped to the appropriate pressure while the heat of vaporisation has to be supplied by an external source (atmospheric evaporation, although feasible, is unlikely to be fast enough to allow acceptable refuelling times). The total energy requirement is still less than in the compression case.

The pathways selected to represent CNG provision reflect the various supply routes available. In the case of LNG we have included a CCS option.

Figure 4.3.1   CNG pathways
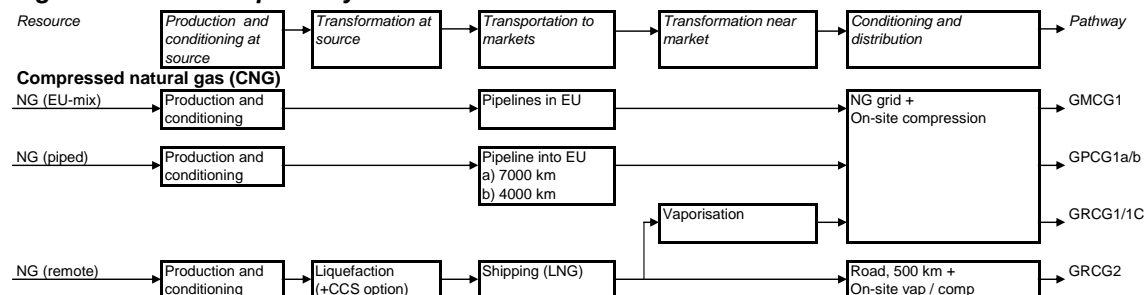
4.3.2 WTT CNG Energy and GHG balance

Figures 4.3.2-1/2 illustrate the contribution of the various steps to the total energy and GHG balance. Transport and compression are the two most important components of the balance.

For piped gas, the transport distance plays a crucial role: changing the length of the pipeline from 7000 to 4000 km reduces both energy requirement and GHG emissions by roughly $1/3^{rd}$. The potential impact of higher pressure pipelines is illustrated by the large downwards error bars for pathways GPCG1a/b. For LNG the liquefaction energy is compensated by the relatively low energy required for shipping over the typical distance of around 10,000 km, so that the total balance is close to that of a 7000 km long-distance pipeline.

The impact of CCS is clearly visible when comparing GRCG1 and 1C: the energy required for liquefaction is somewhat higher but the GHG reduction is significant. Overall LNG with CCS comes close to the 4000 km pipeline option in terms of GHG. The potential of CCS is further discussed in *section 5.4*.

This effect of transport distance will be visible in all other pathways based on piped gas although it will generally have a lower relative share of the total as all those pathways include some form of conversion and are therefore much more energy-intensive. Unless otherwise stated, we have taken the 4000 km case as the reference.

There is little difference between the case where LNG is vaporised into the gas distribution network (GRCG1) and the alternative where LNG as such is trucked to a refuelling station and vaporised/compressed locally (GRCG2). The latter is marginally more energy-efficient because compression is more efficient when starting from the liquid state. The trade-off between the different energy sources used results in the figures being reversed in terms of GHG. We consider that these differences are not significant and therefore view both options as equivalent.

Although not illustrated in the figures, it must be noted that the compression energy is strongly dependent on the suction pressure of the compressor. The figures shown here pertain to a pressure of 0.4 MPa which we believe to be the most typical in Europe. With a suction pressure of 4 MPa, the energy required would be cut by a factor two.

Figure 4.3.2-1 WTT total energy balance build-up for CNG pathways
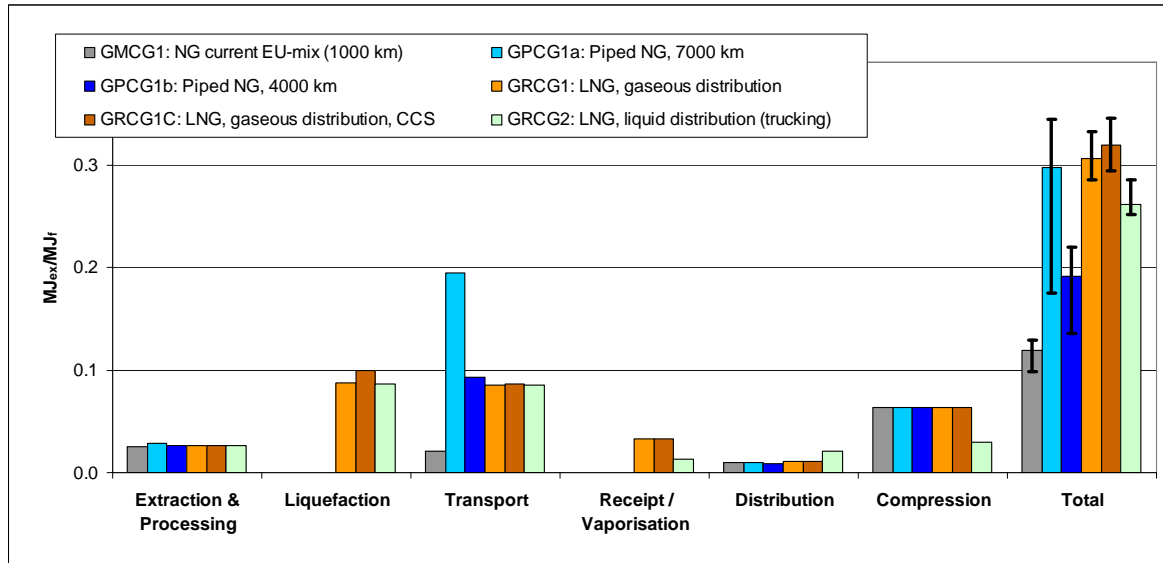
Figure 4.3.2-2 WTT GHG balance build-up for CNG pathways
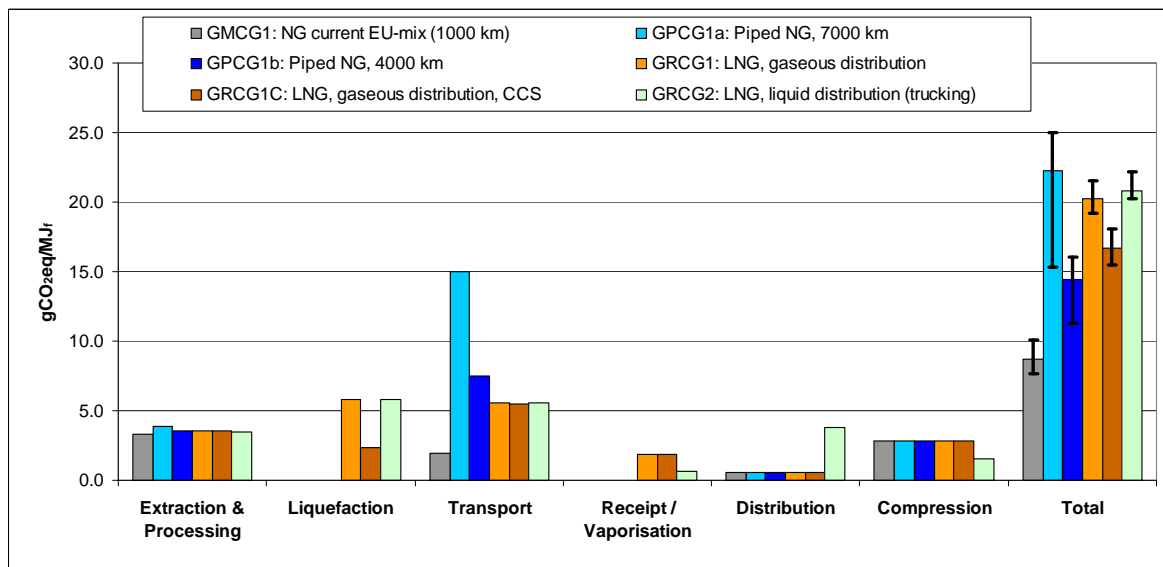
It is also worth noting that direct methane emissions account for a significant share of the total GHG emissions in the CNG chains (***Figure 4.3.2-3***). For the pipeline cases, they stem mainly from extraction and transport and are responsible for up to a third of the total GHG emissions. For LNG the proportion is smaller mainly because methane evaporation during shipping is fully recovered.

Of course the evaluation of such emissions is partly speculative inasmuch as they correspond to losses occurring in different parts of a very large and complex supply system and that are not always well documented. This, however, illustrates the fact that failure to tightly control methane losses could lead to a serious degradation of the GHG balance of natural gas chains.

Figure 4.3.2-3   Share of methane in CNG GHG balance
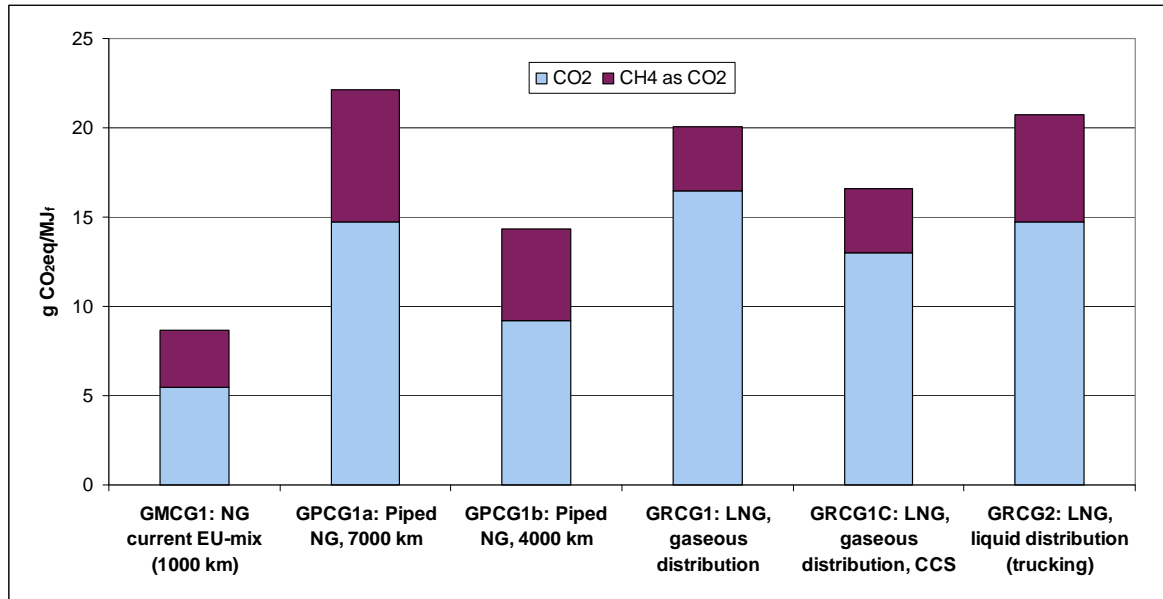
On an energy content basis, CNG from marginal gas supplies is more energy-intensive than conventional fuels. Only the current "EU-mix", partly based on domestic and Algerian gas, comes out better than the conventional fuels but we stress again that this is not a truly "marginal" case. This simply indicates that, because the gas supply to Europe will come from increasingly remote sources, the total energy attached to it will increase in the future.

Figure 4.3.2-4/5 show the energy and GHG balance split into the 5 standard stages used for all other pathways. Direct comparison with conventional gasoline or diesel is only possible on a WTW basis because of the different carbon contents of these fuels and also because of the difference in efficiency e.g. between CNG, gasoline and diesel vehicles (See *TTW* and *WTW report*).

Figure 4.3.2-4   WTT total energy balance of CNG pathways
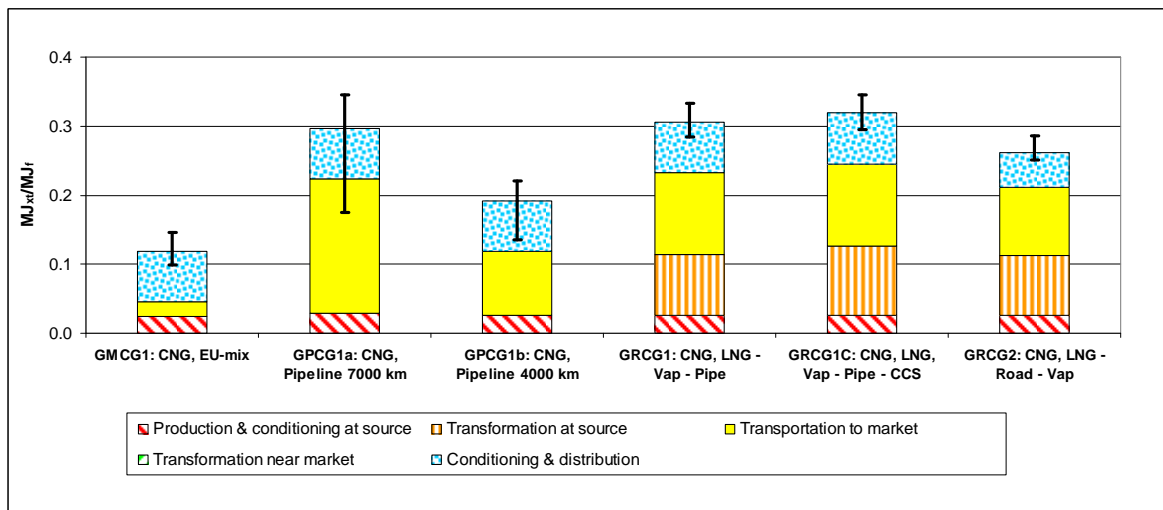
Figure 4.3.2-5 WTT GHG balance of CNG pathways
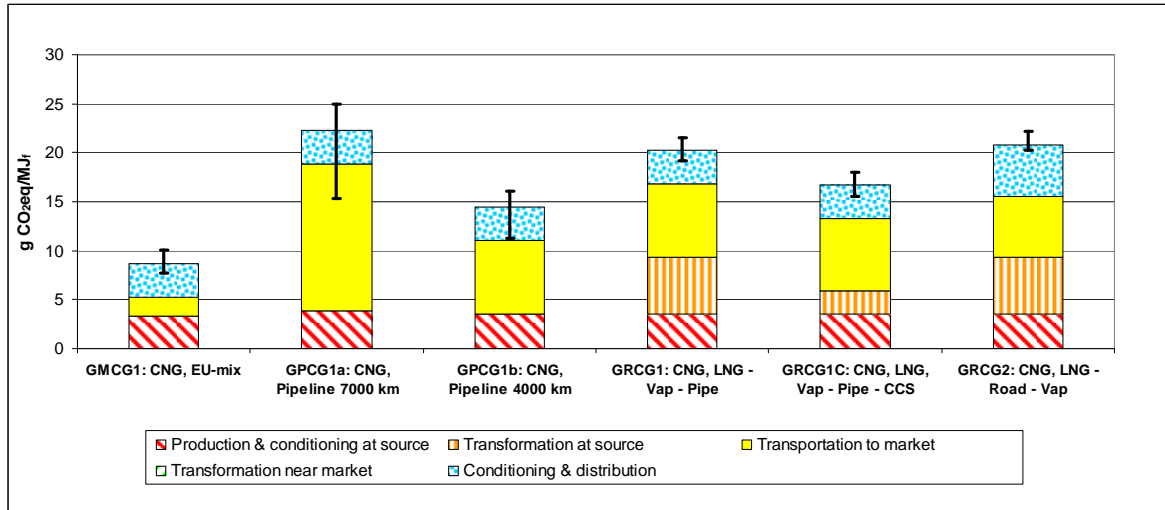
4.3.3 Compressed Biogas (CBG)

In the pathways considered here, biogas is obtained from a waste organic material. As a result there is little fossil energy involved.

Figure 4.3.3-1 CBG pathways
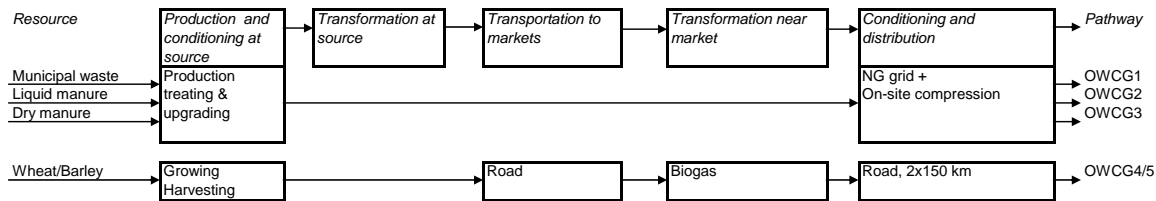
Figure 4.3.3-2 shows a relatively high total energy, mostly related to the limited conversion rate of the biomass used (assumed 70%). For waste materials, inasmuch as this represents the only practical way of using them for energy purposes, this is not important here. The fossil energy share of this is very small indeed ranging from 0.17 MJ_{xf}/MJ_f for municipal waste to 0.01 for dry manure, and is equally low for biogas produced from wheat.

Note: the higher fossil energy for municipal waste results from our decision to limit the on-site energy generation to the process heat requirement, which in this case demands some electricity import (compared to export in the manure cases).

For GHG emissions (*Figure 4.3.3-3*), the diamond symbols show the overall emissions in producing the fuel. The balance is very favourable, the more so in the case of liquid manure because large emissions of methane from the raw manure are avoided in the process (the credit has been given at the collection stage). Collecting liquid manure and using it for biogas production in itself prevents some GHG emissions to the atmosphere. Note that this is essentially the result of bad farming practices which should be avoided in any case. For wheat, the GHG emissions are slightly higher, but comparable to those for production of CNG, and better than most of the wheat to ethanol pathways.

All in all, using organic waste to produce biogas is a good option from an energy and GHG viewpoint. Whether and under which circumstances it can make practical and economic sense to produce biogas and use it as automotive fuel is another matter that is discussed in** section 5 **together with the related issue of potential.

Figure 4.3.3-2   WTT total energy balance of CBG pathways
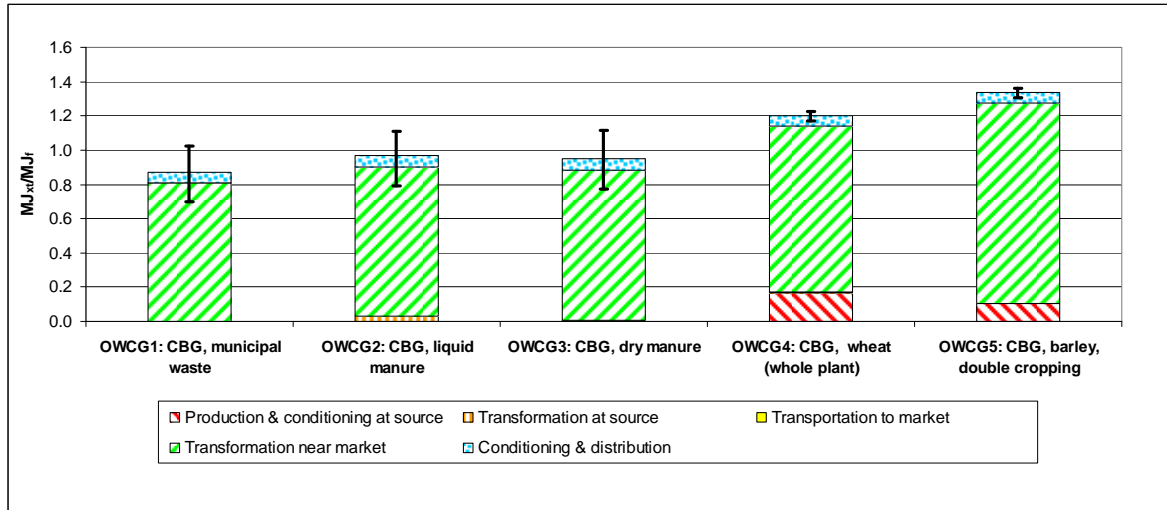
Figure 4.3.3-3   WTT GHG balance of CBG pathways
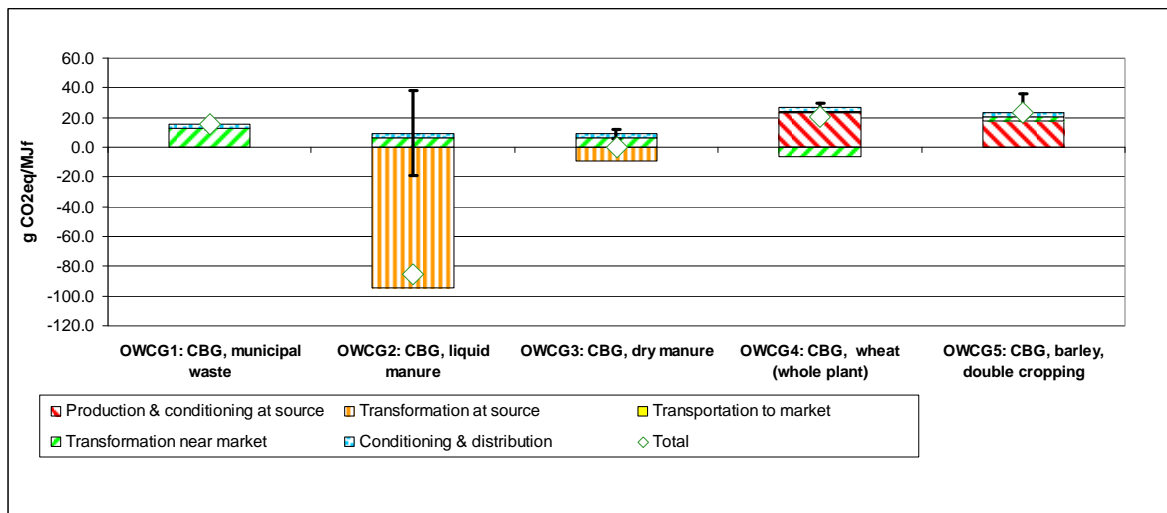
4.3.4 Liquefied Petroleum Gas (LPG)

(See also WTT Appendix 2 section 2.3)

As explained in *section 3.2.7*, we have considered only the marginal LPG imported to Europe from natural gas field condensate.

Figure 4.3.4-1 LPG pathway
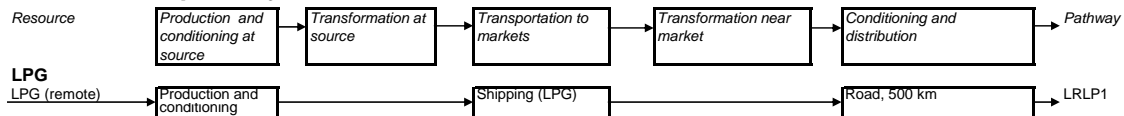
A large proportion of the total energy required relates to separation, treatment and liquefaction near the gas field. Long-distance transport is also more onerous than crude oil because of the smaller dedicated ships used. The same applies to distribution.

The energy required at source in the form of natural gas or other light hydrocarbons and is therefore less carbon-intensive than is the case for crude oil, thereby reducing the total GHG emissions.

In the following figures, the energy and GHG emissions balances are compared to those for gasoline (a valid comparison as the energy efficiencies of gasoline and LPG vehicles are essentially the same, see *TTW report*).

Figure 4.3.4-2 WTT total energy balance of LPG pathway
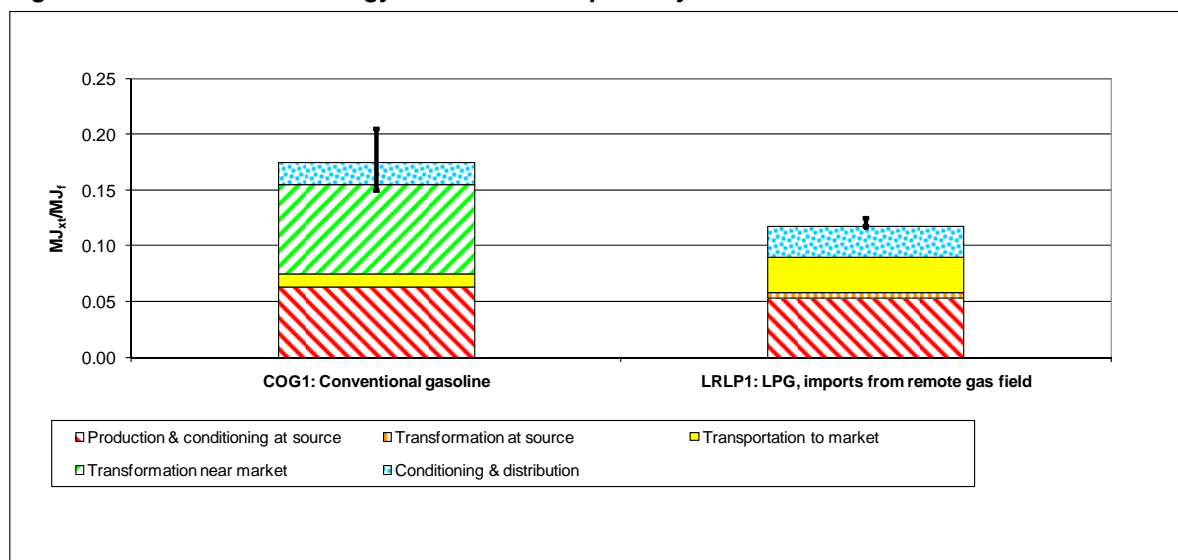
Figure 4.3.4-3 WTT GHG balance of LPG pathway
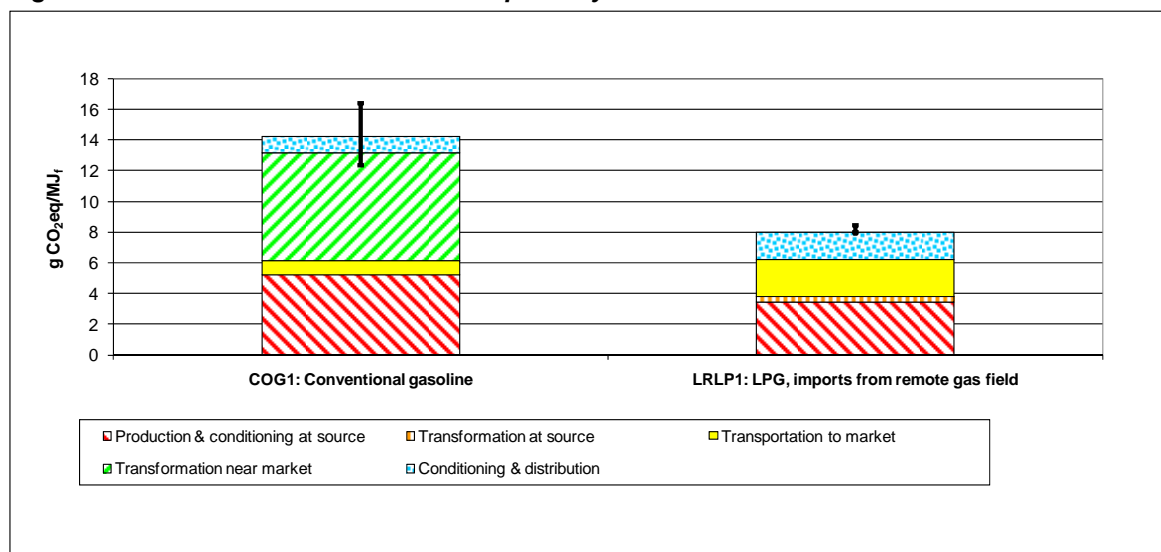
4.4 Ethanol

(See also WTT Appendix 2 section 3)

4.4.1 Ethanol pathways

Ethanol can be produced from a variety of crops. We have represented the most common in Europe i.e. sugar beet and wheat. For each of these crops a number of options are available depending on the use of by-products and the way the energy for the manufacturing process is generated (see *section 3.4.4/3.4.9*).

Also included are two more advanced pathways for the hydrolysis and fermentation of cellulose, one with wheat straw (Iogen process), the second with wood representing the more general group of cellulose feeds. For comparison purposes we have also included ethanol produced in Brazil from sugar cane and imported to Europe.

Figure 4.4.1   Ethanol pathways
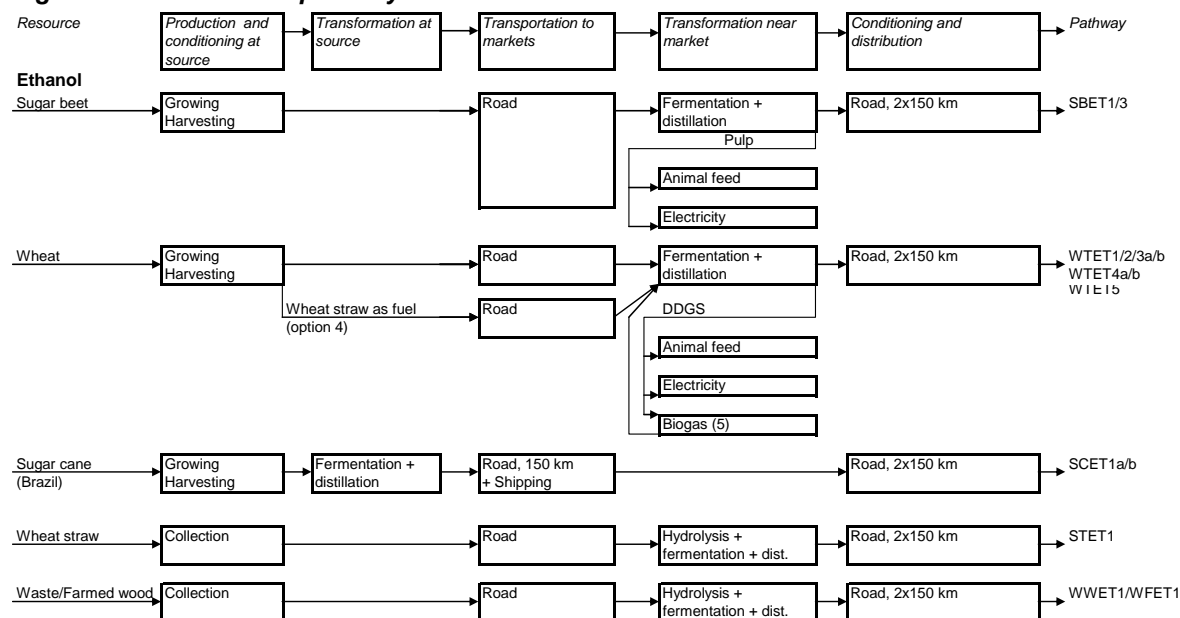
4.4.2 Ethanol WTT energy balance

Total energy

Figure 4.4.2-1a/b show the total energy build-up along the different stages of the more conventional pathways to bio-ethanol. The gasoline balance is also included as reference (gasoline and ethanol are used in the same vehicles delivering the same energy efficiency). In this case "total" energy includes the energy content of the bio-feedstock used (e.g. wheat grain) as well as the energy content of any biomass used as a fuel at any stage of the pathway. As explained in *section 4.1*, this is the energy "expended" i.e. it excludes the energy content of the ethanol produced.

All pathways require several times more energy than is the case for gasoline although there are large differences between the various options. Most of this energy is expended during ethanol manufacturing and to a lesser extent for growing the crop (a large portion of the latter energy stemming from fertilisers).

The energy balance is critically dependent on the specific pathway, particularly with regards to the fate of by-products. As a result of the energy credits generated, the more by-products are used for energy purposes, the better the energy balance (compare e.g. SBET1 to SBET3 and WTET2a to WTET2b).

The way energy for the manufacturing process is produced has also an impact on the energy balance: in WTET2a the use of a CHP scheme reduces the energy requirement by about 15% compared to the more conventional scheme used in WTET1a. For WTET3/4, although CHP is also used the relatively low efficiency of solids burning compared to gas reduces the energy gain to insignificance.

Figure 4.4.2-1a   *WTT total energy balance of sugar beet ethanol pathways*
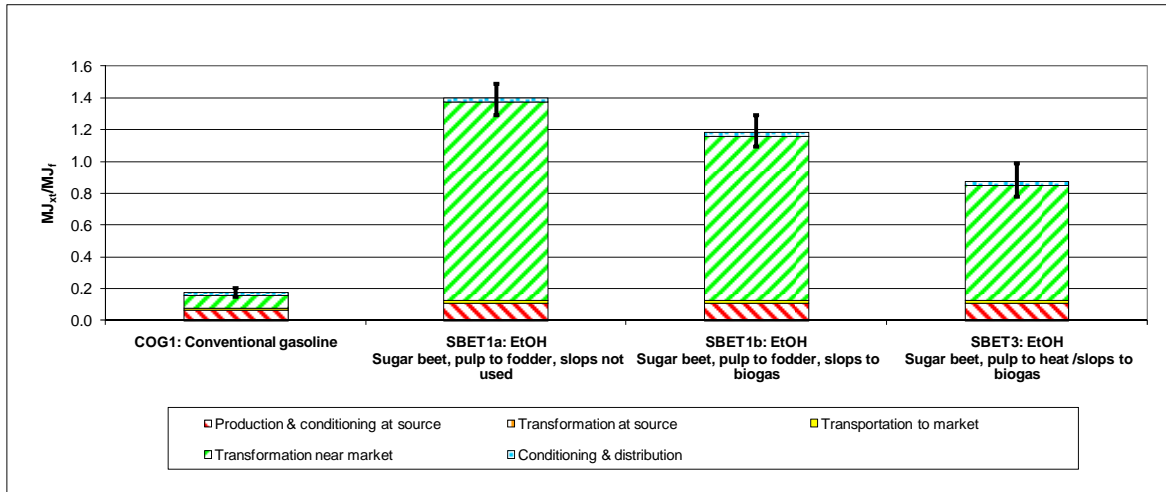
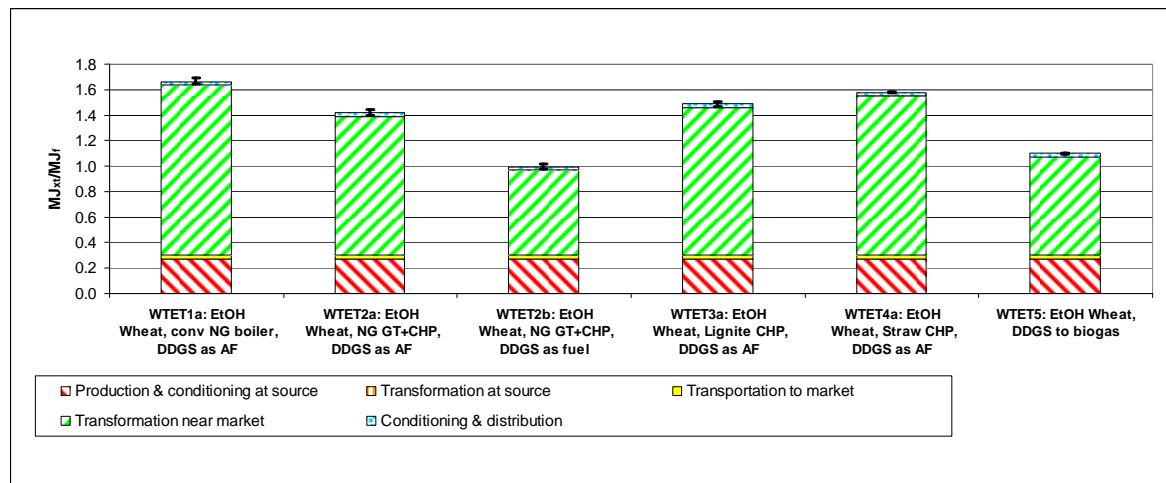**Figure 4.4.2-1b**   *WTT total energy balance of wheat ethanol pathways*

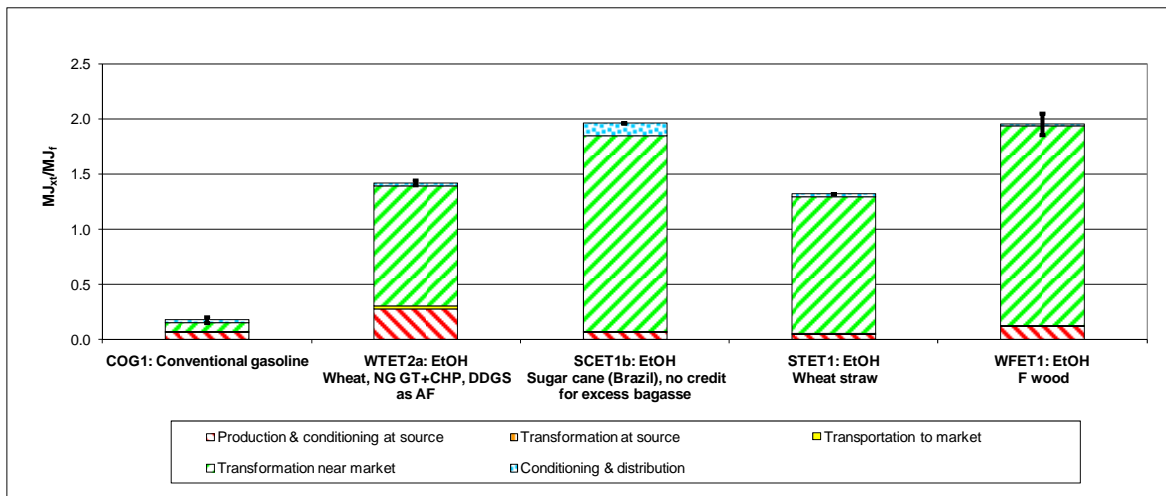**Figure 4.4.2-1c**   *WTT total energy balance of ethanol pathways (various feedstocks)*

Figure 4.4.2-1c shows the total energy balance for more advanced biomass-to-ethanol pathways (WTET2a is repeated for comparison).

Clearly these pathways do not offer much from a total energy point of view. Their interest resides in their potential to save fossil energy and therefore to reduce GHG emissions (see below).

Fossil energy

Figures 4.4.2-2a/b/c compare total and fossil energy as a measure of the "renewability" of the pathways. For ethanol, this is in effect the WTW fossil energy (as no additional fossil energy is expended in the vehicle). To compare to gasoline we would have to add the combustion energy. This is in effect a WTW comparison and reference is made to the WTW report.

The impact of using by-products for energy purposes and/or using bio-energy for fuelling the production process appears very clearly in this case. For the more conventional pathways, this does not, however, generally correspond to either common practice or economic optimum (see also *section 3.4*). The advanced pathways use a lot less fossil energy because the processes used allow usage of biomass for the major energy requirements. Using bagasse to fuel the sugar cane ethanol manufacturing plant is a well-established practice (a credit for additional fuel oil saving further reduce the net fossil energy used in SCET1). In pathways using wood or straw a significant proportion of the energy used is also of renewable origin. Note that using wheat straw induces a small penalty as additional fertilisers have to be used in order to replace the nutrient contained in the straw.

Figure 4.4.2-2a WTT fossil energy balance of sugar beet ethanol pathways
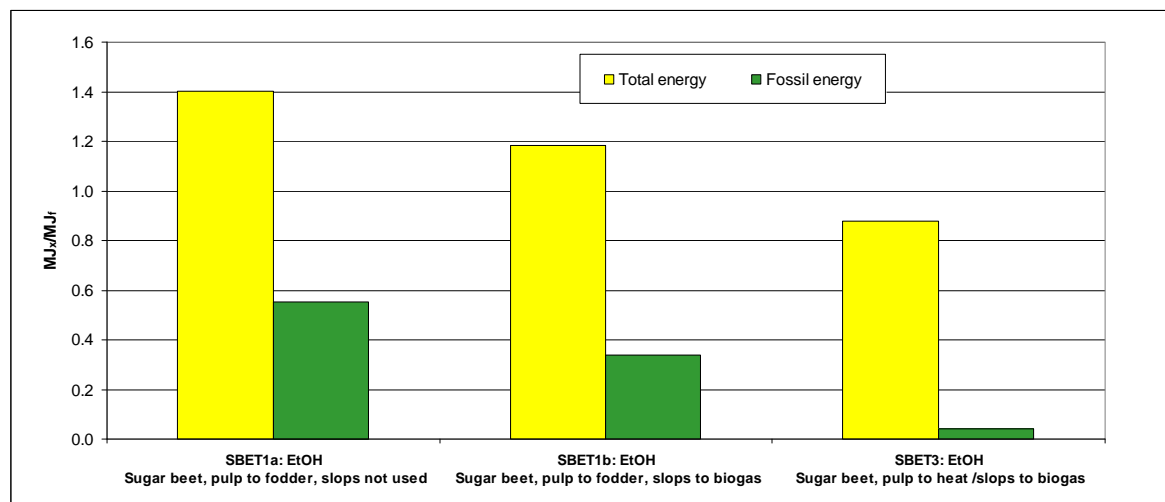
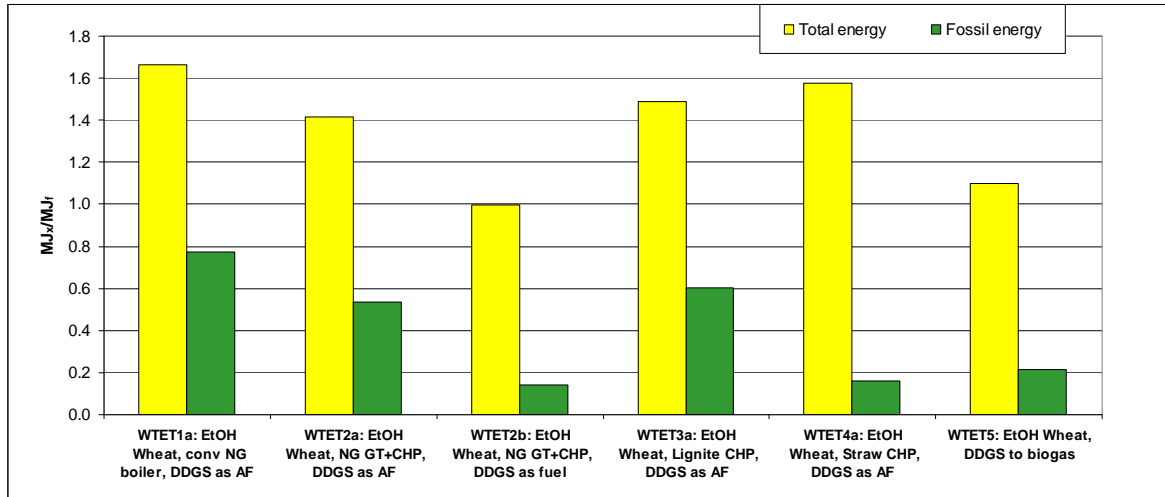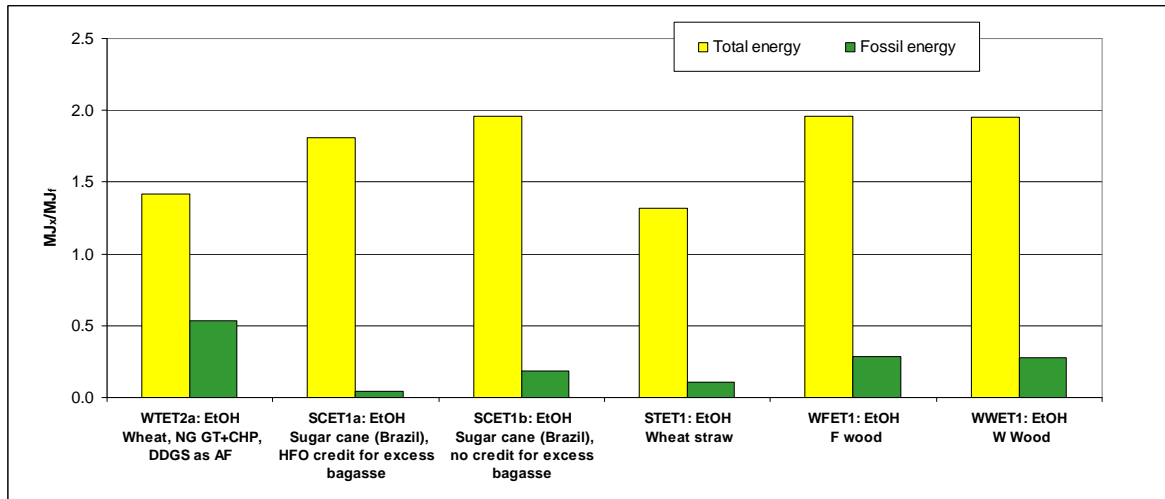*Figure 4.4.2-2b WTT fossil energy balance of wheat ethanol pathways*

Figure 4.4.2-2c WTT fossil energy balance of ethanol pathways (various feedstocks)

4.4.3 Ethanol WTT GHG balance

Figure 4.4.3-1a/b/c show the total GHG build-up along the different stages of the pathways. The gasoline balance is also included in the first figure as reference (the gasoline combustion CO_2 has been added to make the GHG figures comparable).

The figures show the GHG emissions associated with producing the fuel, excluding the emissions when the fuel is used in the vehicle.

The impact of by-product use and production energy generation scheme is again apparent here. The picture is similar to that of fossil energy above although there are additional impacts related to field N_2O emissions and to the type of fossil fuel used.

Wheat production requires more nitrogen than sugar beet resulting in higher field emissions. Sugar cane and farmed wood require much less still. Uncertainties attached to N_2O emissions are also responsible for the relatively large error bars, particularly for wheat.

Switching from natural gas to lignite for fuelling the ethanol plant has a dramatic effect, resulting in an increase of GHG emissions for ethanol compared to gasoline.

For sugar cane, the CO_2 credit attached to additional fuel oil saving from surplus bagasse results in a negative figure for the "transformation" step.

The wood-based pathways yield a very favourable GHG balance as very little fossil energy is involved in the process. The straw option is less favourable because of the increased farming inputs required to compensate for removing the straw from the land (additional energy for fertiliser production and additional N_2O emissions from the fields).

Comparison with gasoline is discussed in the *WTW report*.

Figure 4.4.3-1a GHG balance of sugar beet ethanol pathways
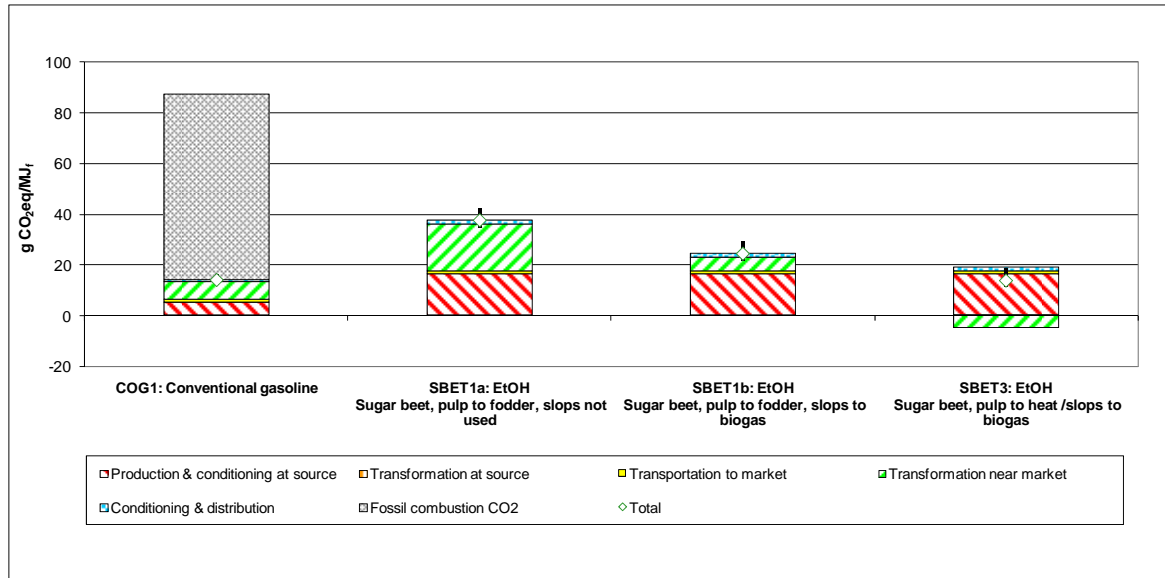
Figure 4.4.3-1b GHG balance of wheat ethanol pathways
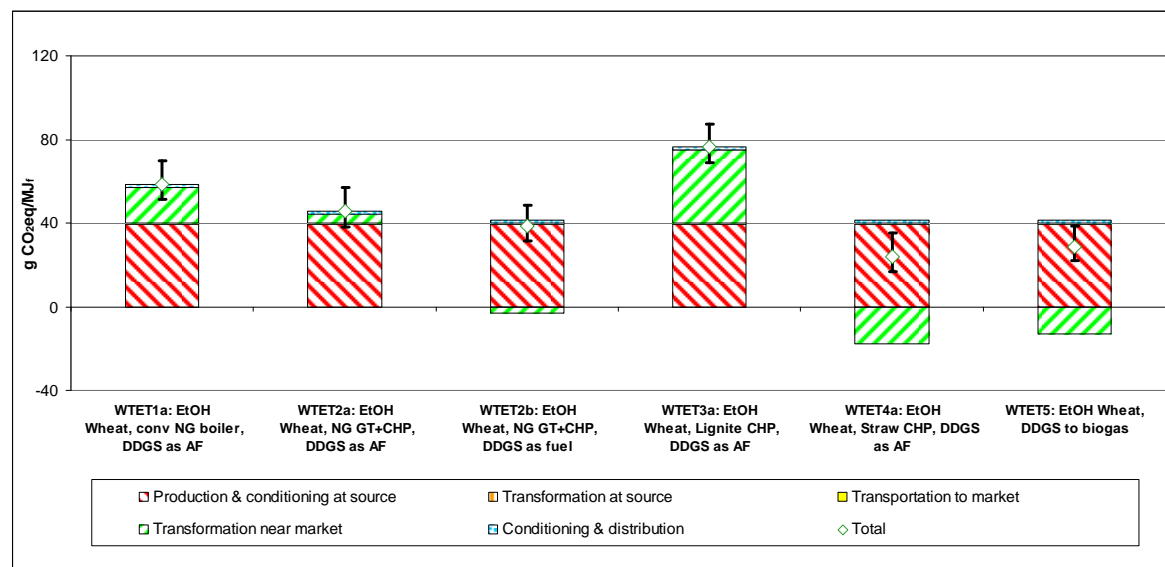
*Figure 4.4.3-1c GHG balance of ethanol pathways (various feedstocks)*
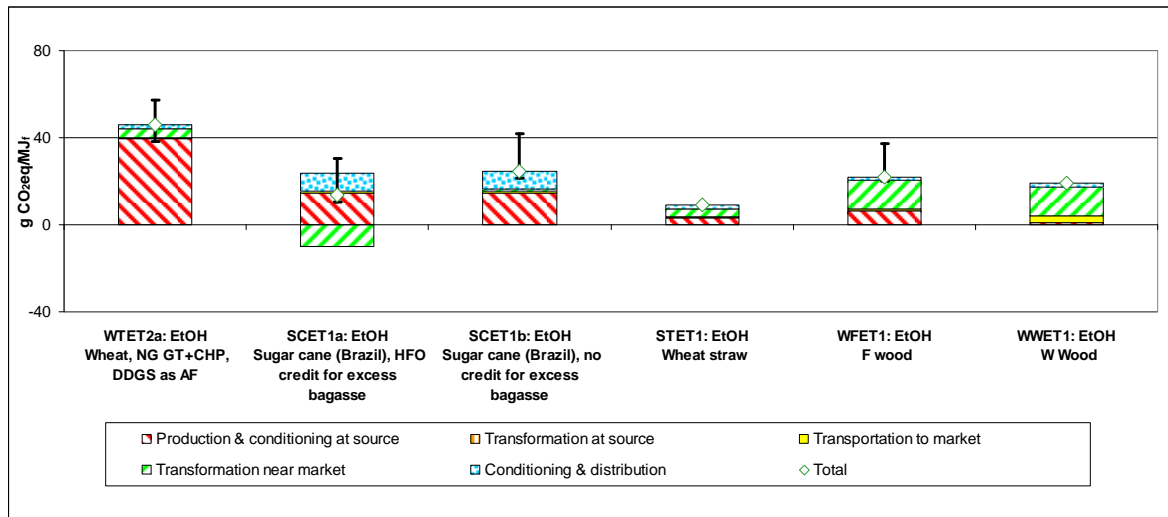
4.5 Bio-diesel (FAME, FAEE and hydrotreated vegetable oils)

(See also WTT Appendix 2 section 4)

4.5.1 Bio-diesel pathways

Bio-diesel is mostly produced from rapeseed as RME. Sunflower is also used in Southern Europe, and as demand grows imported soy beans/oil and palm oil may also contribute. Methanol is commonly used for the trans-esterification step hence the generic name of FAME (Fatty Acid Methyl Ester). We have included both rape and sunflower seeds with two options for the disposal of glycerine. We have also added FAME from soy beans and for palm oil, with a range of pathways to show the impact of different production options. Ethanol can also replace methanol for esterification (FAEE) and we have included this in combination with rapeseeds.

Figure 4.5.1   Bio-diesel pathways
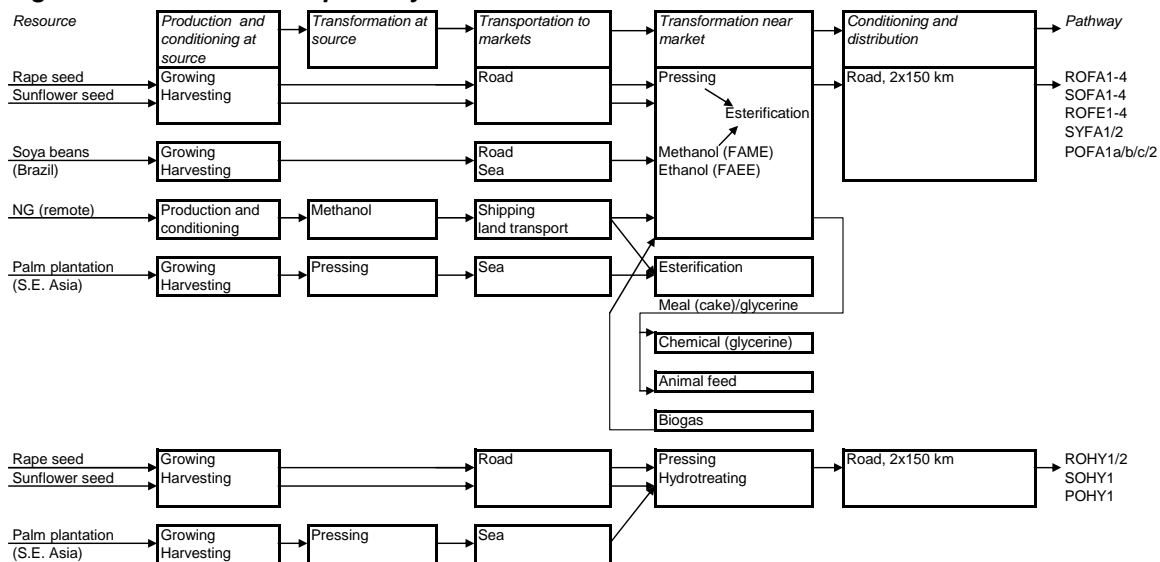
4.5.2 Bio-diesel WTT energy balance

Total energy

Figures 4.5.2-1a/b show the total energy build-up along the different stages for selected bio-diesel pathways. The production energy for fossil diesel is also included as reference – to compare with the biofuels the combustion energy of 1MJ needs to be added. This simple comparison works because conventional and bio-diesel are used in the same vehicles delivering the same energy efficiency. In this case "total" energy includes the energy content of the oil seeds as well as the energy content of any biomass used as a fuel at any stage of the pathway. As explained in *section 4.1*, this is the energy "expended" i.e. it excludes the energy content of the bio-diesel produced.

Bio-diesel requires up to 3 times more total energy than fossil diesel. Rape seed and sunflower consume slightly less than conventional diesel, with sunflower somewhat more favourable than rape in this respect. Palm oil consumes more total energy than conventional diesel.

Soy has the highest total energy use, although this deserves some explanation. Unlike other crops, soy yields more than 4 times as much meal as it does oil. Following the substitution method all energy use for cultivation and processing is allocated to the oil. The credit recovered from the meal for substituting Brazilian corn does not fully compensate. In this case, allocation by economic value may be more appropriate (see pathway SYFA1c in **WTT Appendix 2**).

Using ethanol instead of methanol for esterification slightly increases the required total energy. Use of glycerine as a chemical or animal feed has only a marginal impact.

Figure 4.5.2-1a WTT total energy balance of selected bio-diesel pathways
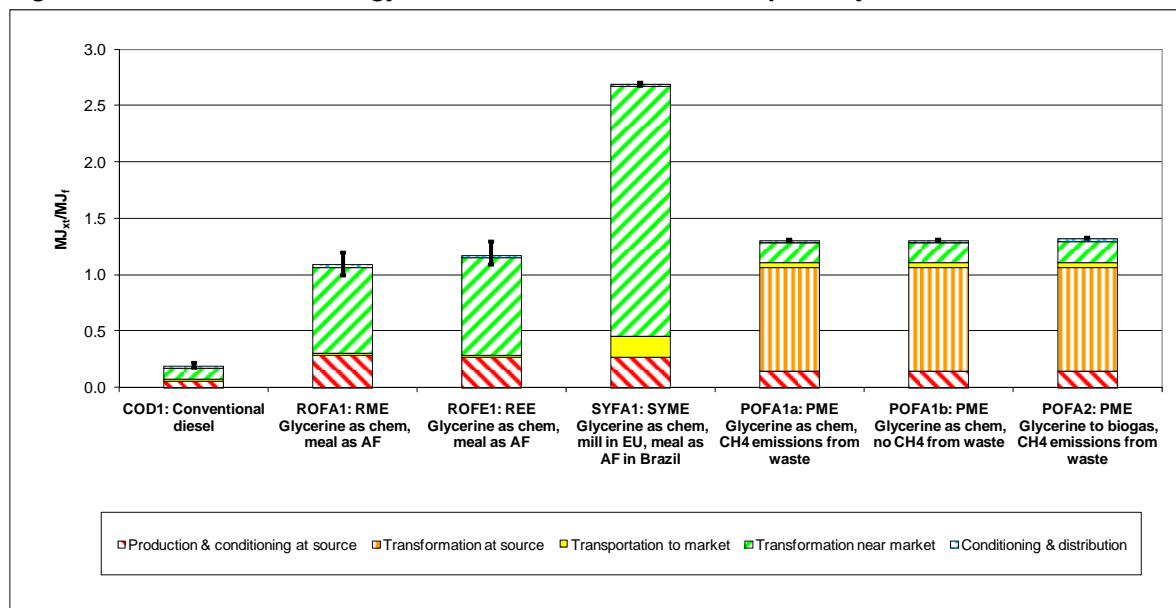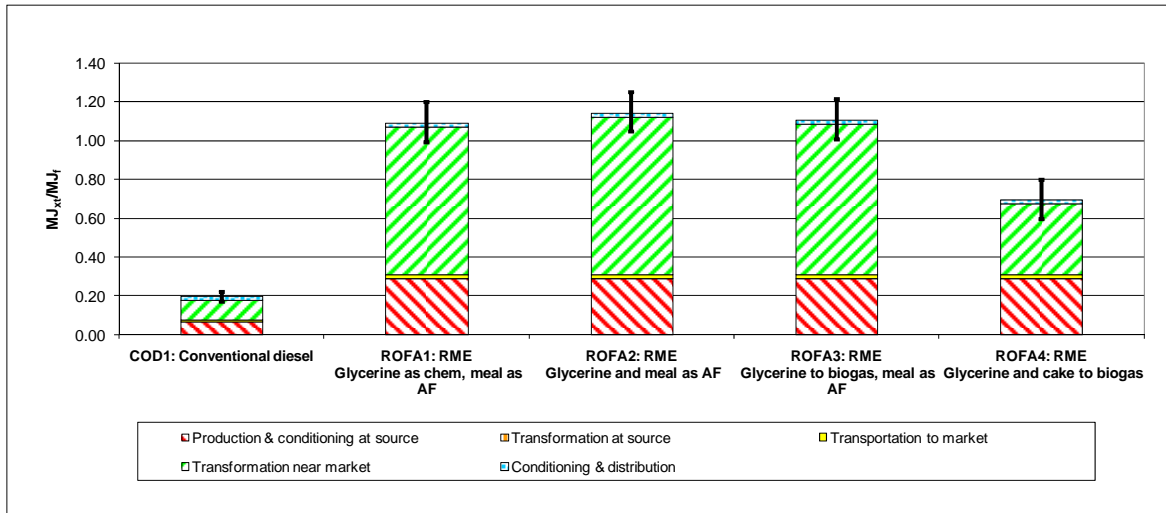
Figure 4.5.2-1b Impact of co-products fate on the WTT total energy balance of RME pathways

Fossil energy

Figures 4.5.2-2a/b compares total and fossil energy as a measure of the "renewability" of the pathways. For bio-diesel, this is in effect the WTW fossil energy (as no additional fossil energy is expended in the vehicle). To compare to conventional diesel we would have to add the combustion energy. This is in effect a WTW comparison and reference is made to the WTW report.

Figure 4.5.2-2a WTT fossil energy balance of bio-diesel pathways
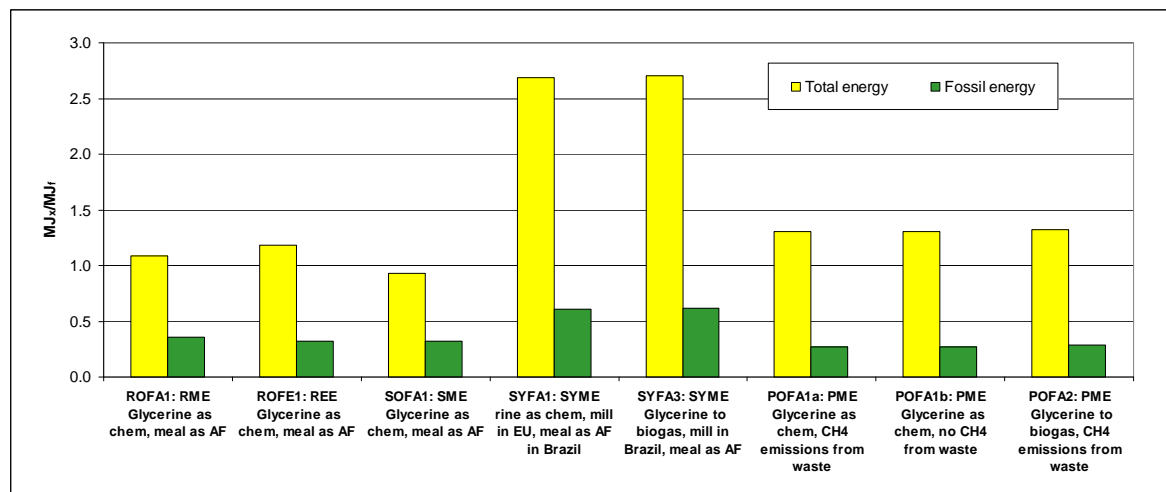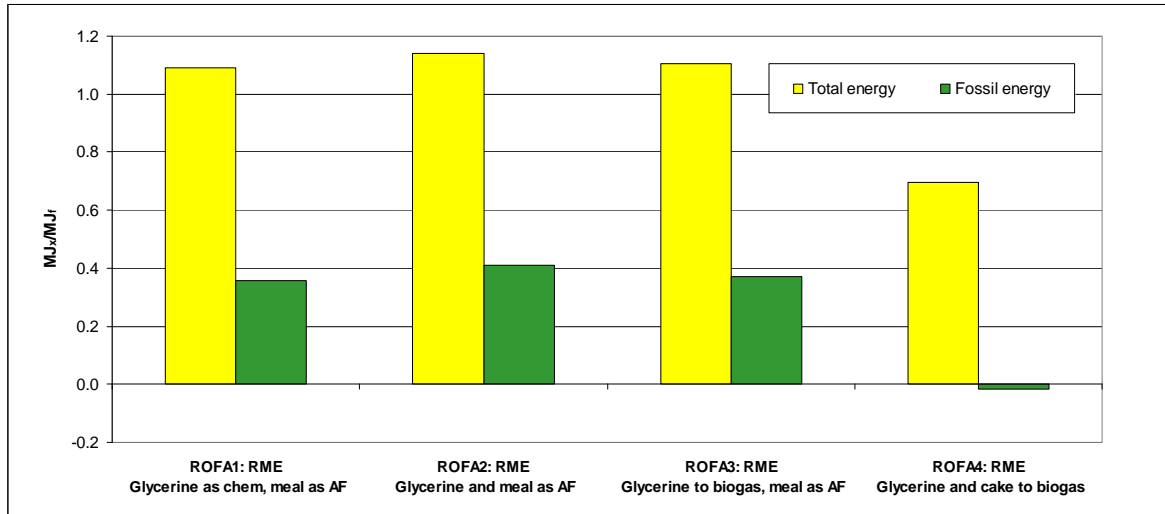
Figure 4.5.2-2b Impact of co-products fate on the energy balance of RME pathways

When focussing on fossil energy, the ratio to fossil diesel is in the region of 0.4 for rape, i.e. a net fossil energy saving of about 60% compared to fossil diesel. Again sunflower is slightly more favourable than rape. Obviously the use of bio-ethanol instead of fossil-based methanol results in a small decrease of the total fossil energy requirement.
Add comment about soy, palm

4.5.3 Bio-diesel WTT GHG balance

Figure 4.5.3-1a/b shows the total GHG build-up along the different stages of the pathways. The fossil diesel balance is also included in the first figure as reference (the fossil diesel combustion CO_2 has been added to make the GHG figures comparable).

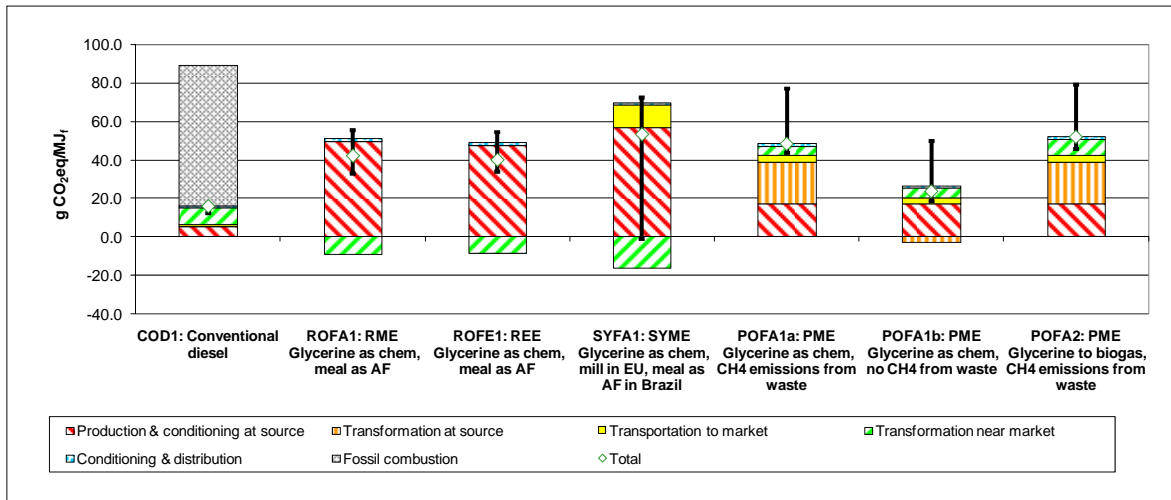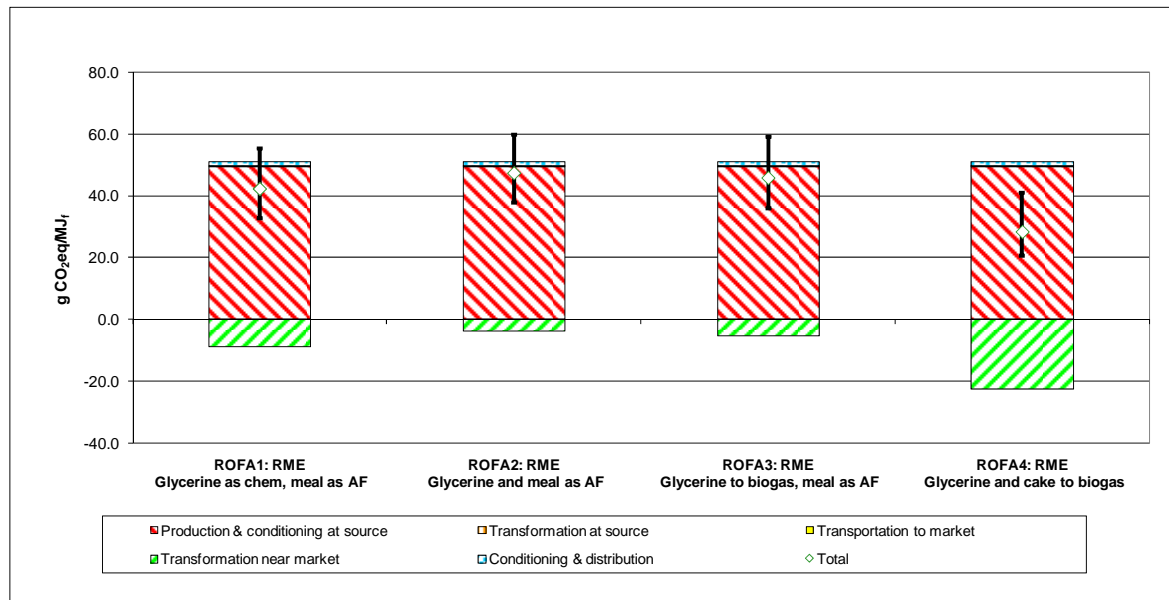*Figure 4.5.3-1a WTT GHG balance of selected bio-diesel pathways*

Figure 4.5.3-1b Impact of co-products fate on the WTT GHG balance of RME pathways

The GHG emissions are dominated by the seed production step, mostly through N_2O emissions. This is largely due to the fact that oil seed crops, and particularly rape, require a lot of nitrogen fertiliser. The uncertainty attached to these emissions is also responsible for the large error bars. In the case of SYFA1, the GHG emissions would decrease by 21.9 g CO_{2eq}/MJ if we calculate the N_2O emissions strictly using the IPCC 2006 tier 1 method, instead of our modification (but then the numbers would not agree with any field measurements).

Here again soy shows the highest values. Unlike energy though, the GHG balance is not significantly improved by changing the treatment of meal from substitution to allocation by economic values because the reductions due to allocation to the meal are compensated by the removal of the credit for meal substitution.

The negative numbers shown for the "transformation" stage are the result of fossil energy credits for by-products including the residue from pressing the oil seeds and the glycerine produced by the esterification process.

Alternative uses of glycerine do not have a big impact.

Comparison with conventional diesel is discussed in the *WTW report*.

4.5.4 Hydrotreated Plant Oils

As outlined in Section 3.4.10, deep-hydrotreating of rapeseed oil, soy oil and palm oil have been evaluated. In the figures that follow, the energy and GHG balances of these pathways are compared with the corresponding FAME pathways for the three feedstocks.

As shown in *Figure 4.5.4-1a/b,* hydrotreating uses less total and fossil energy than converting the oil to FAME. The UOP process uses slightly less total energy than the NexBTL process, but more fossil energy, probably because the latter makes use of cracking products from the bio feedstock as fuel for the process.

Figure 4.5.4-1a WTT total energy balance of hydrotreated plant oil pathways
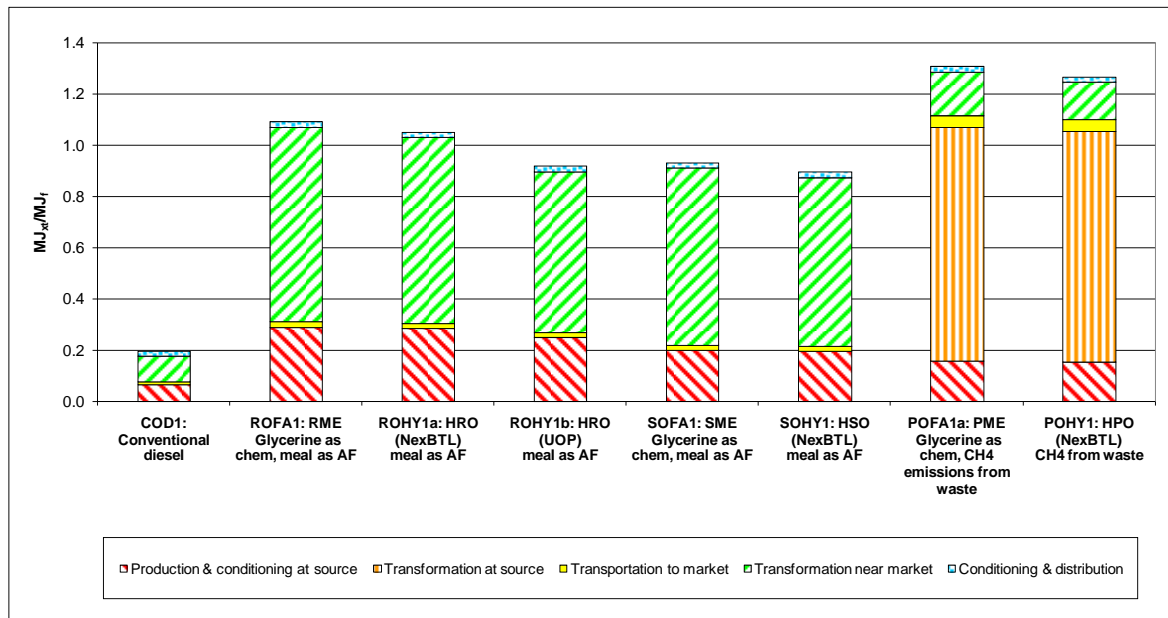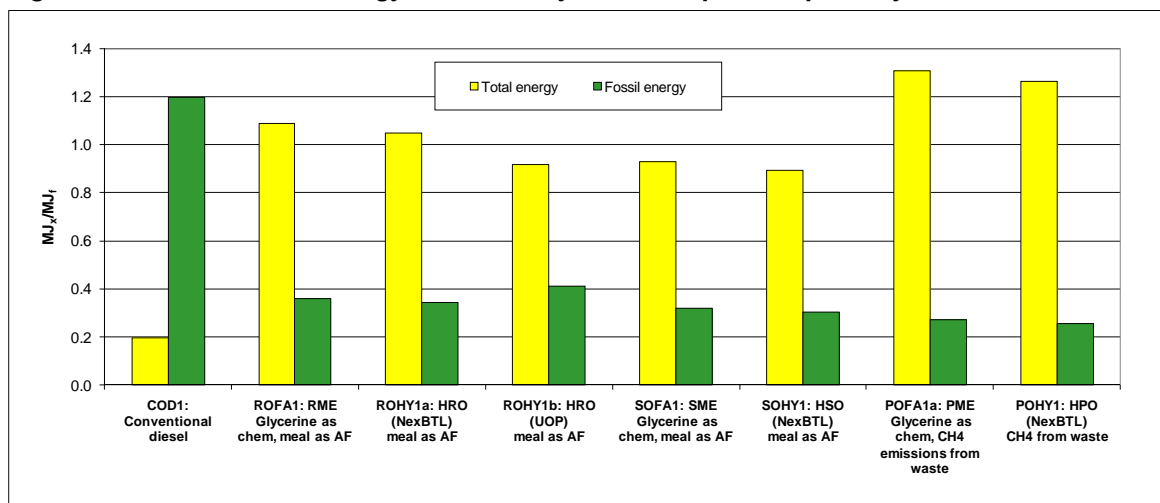

Figure 4.5.4-1b WTT fossil energy balance of hydrotreated plant oil pathways

In terms of GHG emissions there is little difference between FAME and hydrotreated plant oils.

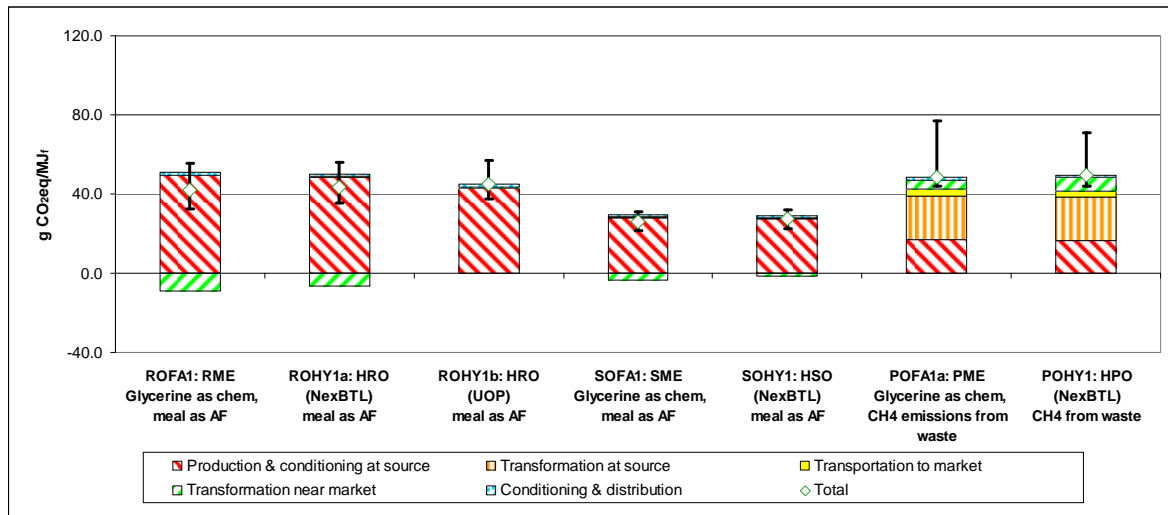*Figure 4.5.4-2a WTT GHG emissions balance of hydrotreated plant oil pathways*

Figure 4.5.4-2b Relative WTT GHG emissions balance of hydrotreated plant oil pathways
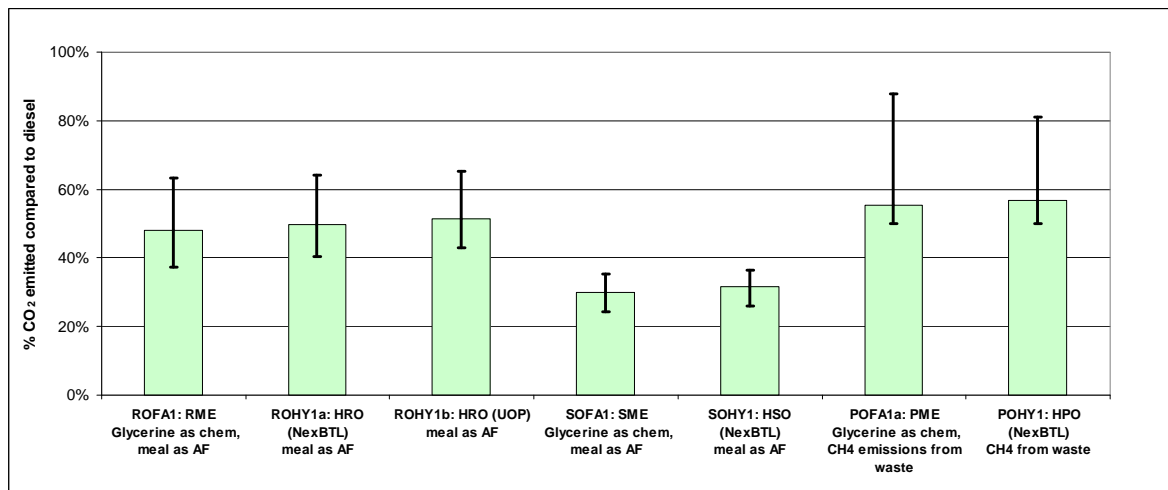
4.6 Synthetic fuels

(See also WTT Appendix 2 section 5)

4.6.1 Synthetic fuels pathways

We have considered three synthetic fuels namely Fischer-Tropsch or syn-diesel, DME and methanol. DME has attractive characteristics as a fuel for diesel engines although the fact that it is gaseous at ambient conditions reduces its appeal. Methanol is only envisaged here as a potential fuel for on-board reformers.

The manufacturing of such fuels relies on steam reforming or partial oxidation of a fossil hydrocarbon or organic feedstock to produce syngas which is, in turn, converted into the desired fuel using the appropriate process.

Natural gas is the most likely feedstock for these processes because of its widespread availability, particularly as stranded (and therefore cheap) gas in remote locations and also because of the relative simplicity of the steam reforming and/or partial oxidation process compared to heavier feedstocks. Coal can also be used although the complexity and cost of the required plant are much higher.

Biomass, most likely in the form of wood or perennial grasses, is also being actively considered as a source of such fuels. Our generic wood pathways represent this group of feedstocks. This includes farmed wood (based on poplar) and waste wood. One particularly attractive option for using waste wood would be the so-called Black Liquor route (see *section 3.4.11*).

Figure 4.6.1   Synthetic fuels pathways

| Resource	Production and conditioning at source	Transformation at source	Transportation to markets	Transformation near market	Conditioning and distribution	Pathway
Syn diesel						
NG (piped)	Production and conditioning		Pipeline into EU	GTL plant	As for refinery fuels	GPSD1a/b
NG (remote)	Production and conditioning	GTL plant (+CCS option)	Shipping		As for refinery fuels or Mixed land transport, 500 km	GRSD1/2/2C
Coal	Production and conditioning		Shipping	CTL plant (+CCS option)	As for refinery fuels	KOSD1/1C
Waste wood	Collection		Road, 50 km + Shipping (800 km)	200 MW gasifier FT plant	Road, 2x150 km	WWSD1/WFSD1
Farmed wood	Growing Harvesting		Road, 50 km			
Waste wood via Black liquor	Collection		Road	BL gasifier+FT plant Waste wood boiler	Road, 2x150 km	BLSD1
Methanol / DME						
Coal (EU mix)	Production and conditioning		Shipping	Gasification MeOH/DME synthesis	Mixed land transport 500 km	KOME1/KODE1
NG (piped)	Production and conditioning		Pipeline into EU	Methanol/DME synthesis	Mixed land transport 500 km	GPME1a/b GPDE1a/b
NG (remote)	Production and conditioning	Methanol/DME syn (+CCS option)	Shipping		Mixed land transport 500 km	GRME1 GRDE1/1C
Waste wood	Collection		Road, 50 km + Shipping	200 MW gasifier methanol/DME synthesis	Road, 150 km	WWME1/WFME1
Waste/Farmed wood	Growing Harvesting		Road			WWDE1/WFDE1
Waste wood via Black liquor	Collection		Road	BL gasifier + MeOH/DME synthesis Waste wood boiler	Road, 150 km	BLME1/DE1

4.6.2 Syn-diesel

Total energy

Making synthetic diesel is an energy-intensive endeavour. The combination of steam reforming, partial oxidation and Fischer-Tropsch synthesis result in overall efficiencies within a broad range of 45 to 65% depending mostly of the feedstock and to a lesser extent the process scheme.

The GTL (natural gas to liquids) processes are the most efficient with figures in the 60-65% bracket. Coal-based processes (CTL) can achieve in the region of 55%. The wood-based processes are expected to be less efficient (up to 50%) because of the inherent complexity of wood processing compared to gas and also because the plants are likely to be much smaller and less optimised in energy terms. This is also the main reason why wood processes are less favourable than CTL from this point of view. Future developments may improve the performance of these processes. In the black liquor case there is a potential for up to 55% efficiency. Wood waste is, as expected, slightly less energy-intensive than farmed wood, the difference being larger for GHG emissions mainly as a result of N_2O emissions related to wood farming.

**Figure 4.6.2-1   WTT total energy balance of syn-diesel pathways**
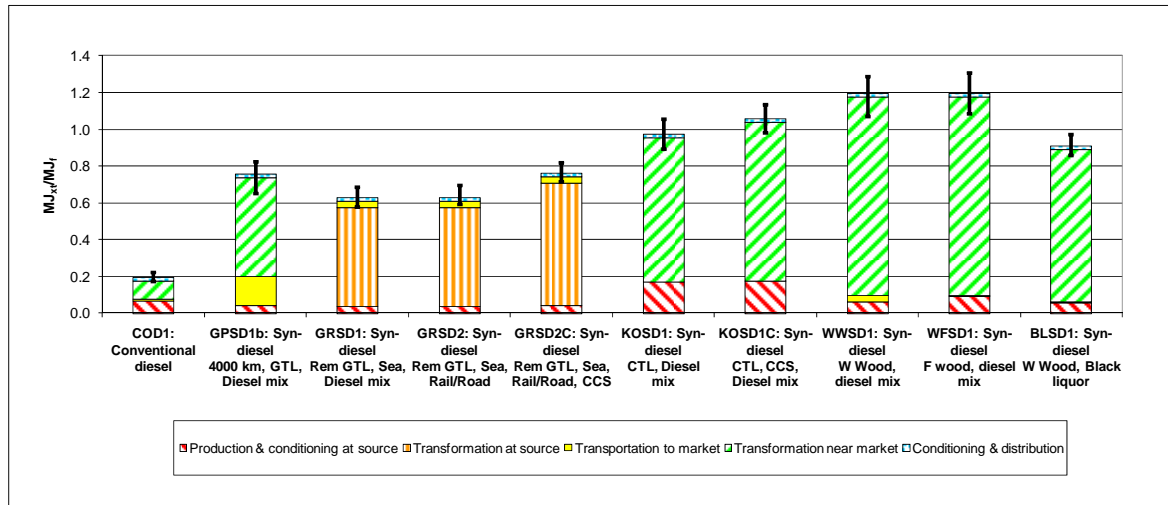
GTL production makes the most sense at a remote location when the large gas transport energy can be avoided and replaced by the much more efficient transport of a liquid (compare e.g. GRSD1 to GPSD1a/b).

In the best case syn-diesel fuel production still requires about 4 times as much total energy as conventional diesel fuel (GRSD1/COD1).

Fossil energy

The total energy graph (Figure 4.6.2-1) represents the *expended* energy i.e. excluding the energy content of the fuel itself (which is of course 1 MJ/MJ in all cases). In order to compare the *fossil* energy or GHG balances of renewable and non-renewable pathways one has to take into account the fossil energy and non-renewable carbon content of the fuels produced through the different routes (i.e. for energy, 1 MJ/MJ for fossil fuels and 0 MJ/MJ for renewable fuels). The fossil energy balance calculated in this way for the different routes to synthetic diesel is shown in ***Figure 4.6.2-2***.

Figure 4.6.2-2   WTT fossil energy balance of syn-diesel pathways
(including fossil energy content of the final fuel)
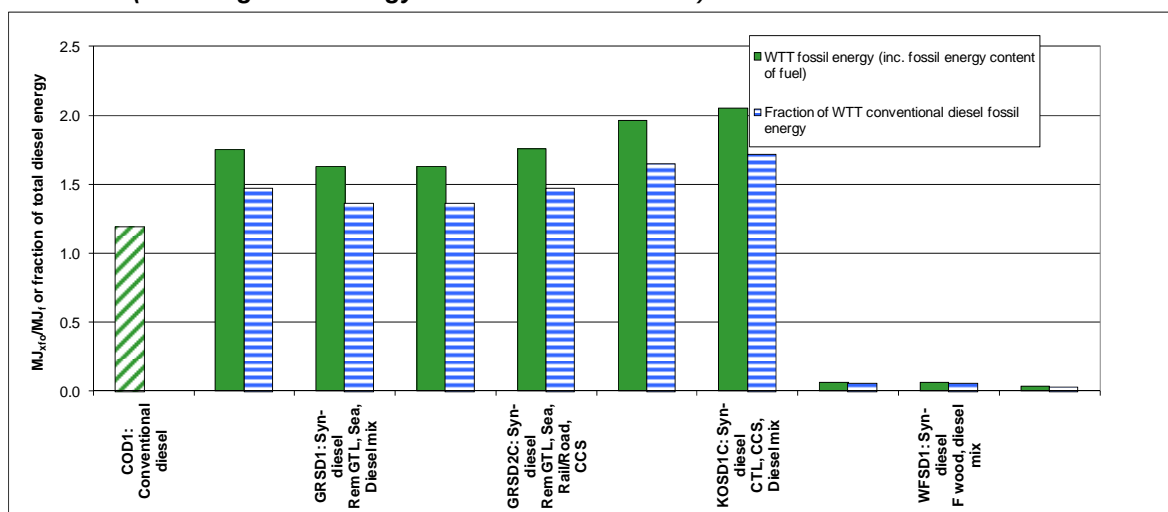
In this case all options produce a diesel fuel that will result in the same efficiency when burned in a given vehicle (see *TTW report*) and the figures calculated in that way are in fact the same as the WTW figures expressed per MJ_f rather than per km.

Figure 4.6.2-2 reveals ratios of 1.4 to 1.8 between conventional diesel and the different fossil-based syn-diesel options. Wood-based options hardly use any fossil energy as these processes are mostly fuelled by their own feedstock (note, however, that this increases the specific rate of biomass usage and therefore the potential of such fuels for a given biomass availability, see also *section 5*).

GHG emissions

The GHG picture (*Figures 4.6.2-3/4*) is more favourable for natural gas as the energy involved is less carbon-intensive (the GTL process is in effect a carbon concentration process and a large fraction of the expended energy is in the form of hydrogen). GHG emissions for GTL are slightly higher than for conventional diesel, but have the potential to match it in the most favourable conditions (lower end of confidence range), where economic conditions allow the most efficient projected processing options to be used. Using coal, however, results in very large GHG emissions. For wood, GHG emissions are mainly incurred for wood growing and collection/transport.

CCS offers an opportunity for substantial reductions of CO_2 emissions. For GTL the reduction potential is in the order of 10% turning the product from slightly more GHG-intensive than conventional diesel to slightly less so. For CTL the reduction is much more dramatic (about 50%) because of the much larger amount of CO_2 emitted during the CTL process. With CCS, CTL becomes only marginally more GHG-intensive than conventional diesel. One has also to remember that the CCS data are only based on technical studies and are only indicative at this stage. As these processes develop, higher CO_2 recovery may be possible. The potential of CCS is further discussed in *section 5.4*.

*Figure 4.6.2-3   WTT GHG balance of syn-diesel pathways
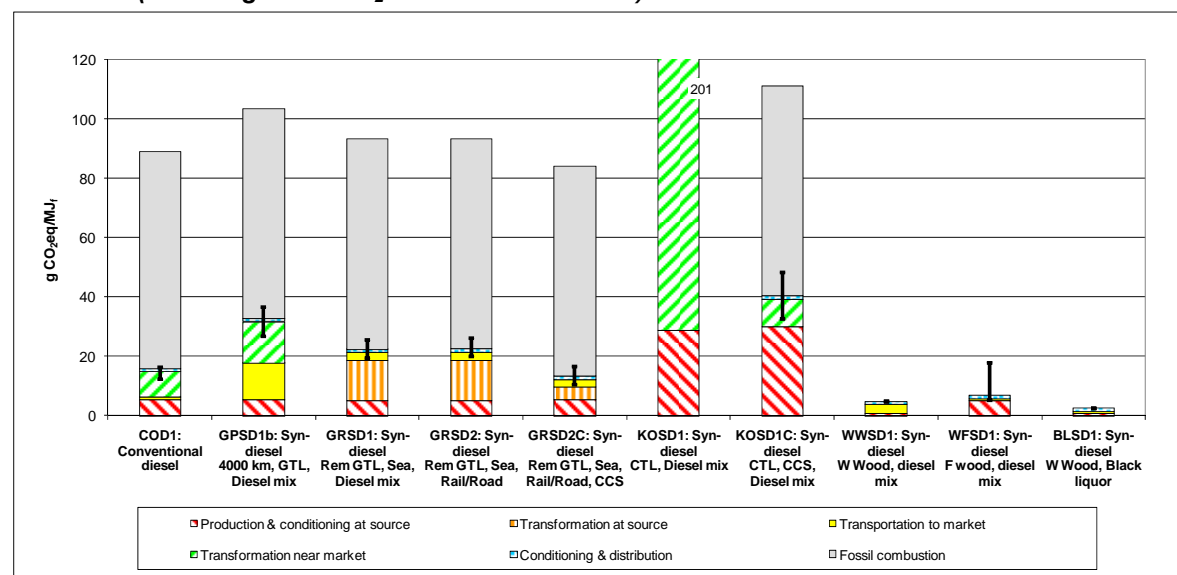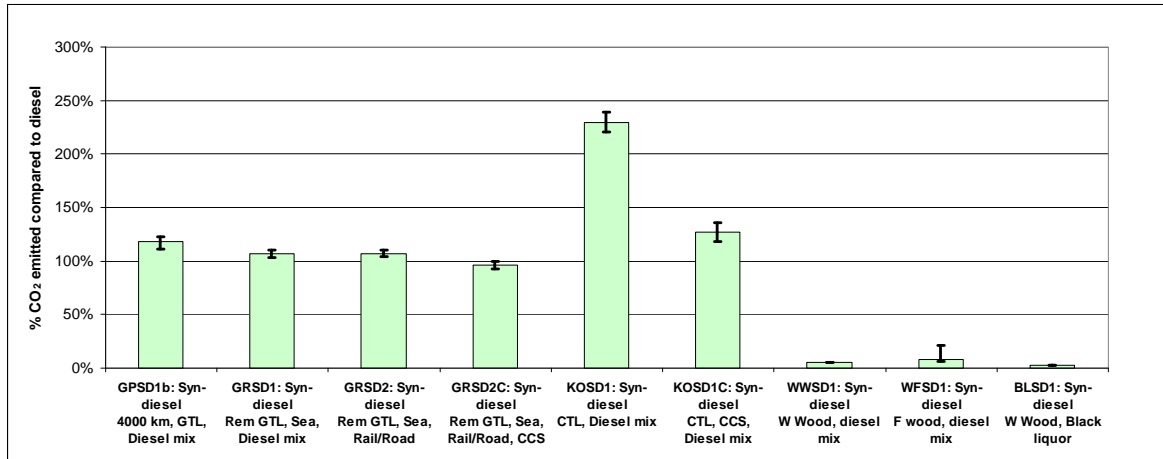(including fossil CO_2 content of final fuels)*

Figure 4.6.2-4 WTT GHG balance of syn-diesel pathways compared to conventional fossil diesel (including fossil CO_2 content of final fuels)

4.6.3 DME

The synthesis of DME is a more efficient than that of FT diesel, resulting is a more favourable energy balance (compare GRSD2 and GRDE1 in *Figure 4.6.3-1*).

DME from wood is much less energy-efficient but virtually all the energy used comes from the wood itself, resulting in a very favourable fossil energy balance (*Figure 4.6.3-2*). The black liquor route offers a substantial energy efficiency improvement when using wood. In terms of fossil energy or GHG balance the difference is of course small in absolute terms (because all figures are small). The main benefit resides in the better utilisation of a limited resource allowing substitution of more fossil energy with the same quantity of wood.

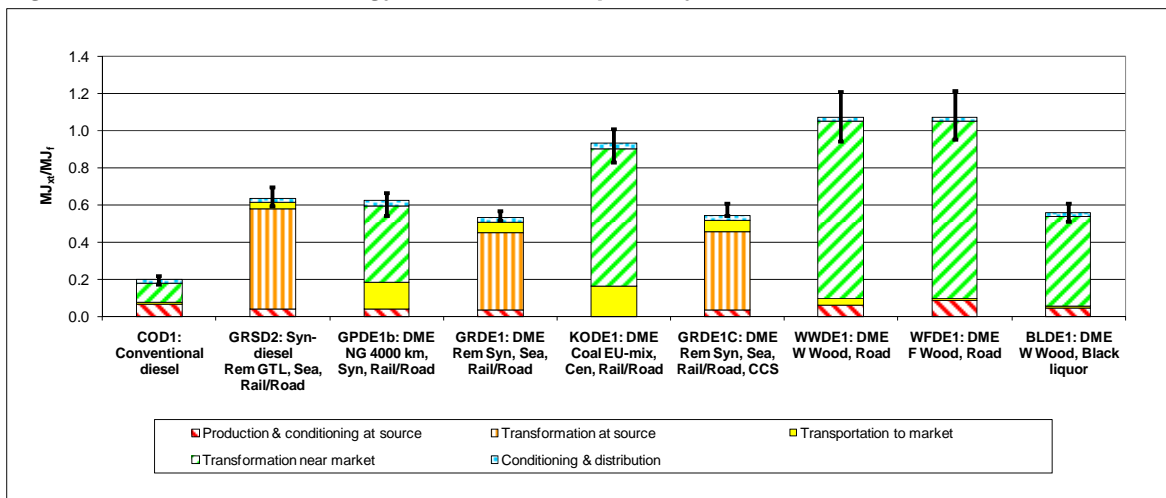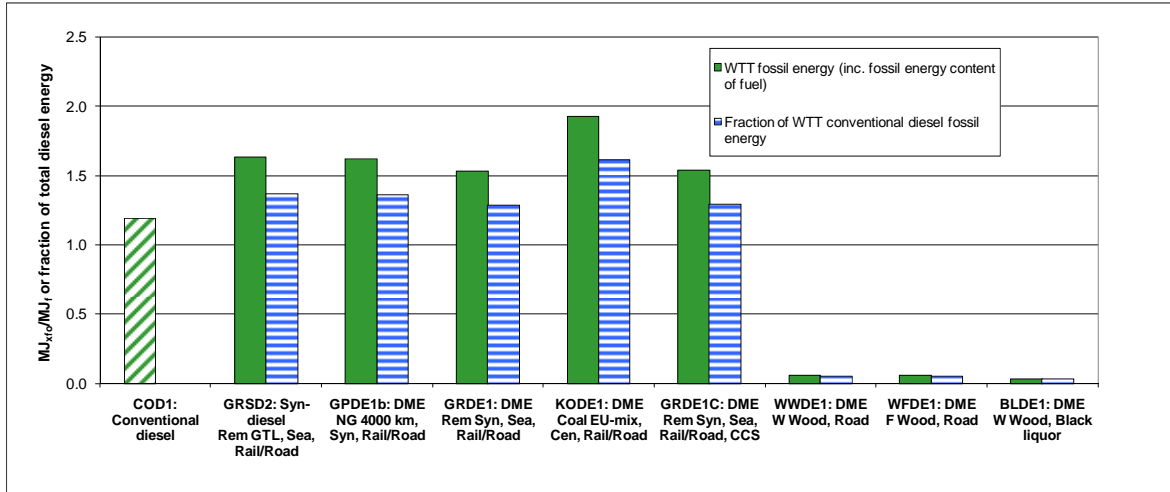**Figure 4.6.3-1 WTT total energy balance of DME pathways**

Figure 4.6.3-2 *WTT fossil energy balance of DME pathways (including fossil energy content of the final fuel)*

Manufacturing of DME near a remote natural gas source is one of the most credible scenarios as DME can be transported in liquid form by simple compression, much like LPG, avoiding the need for expensive LNG installations. For this route DME is on a par with conventional diesel in terms of GHG emissions (*Figure 4.6.3-3/4*). In such a case CCS could be envisaged to capture the CO_2 emitted during the synthesis process. WTT GHG emissions could potentially be cut by a factor 2 for a relatively small energy penalty, making DME somewhat more GHG-efficient than conventional diesel. Note that, when comparing DME with liquid diesel fuels, the WTT fossil energy figures including the fuel fossil energy content are not quite equivalent to the WTW figures because DME allows a somewhat higher efficiency in the vehicle (see *TTW report*).

Figure 4.6.3-3 *WTT GHG balance of DME pathways (including fossil CO_2 content of final fuels)*
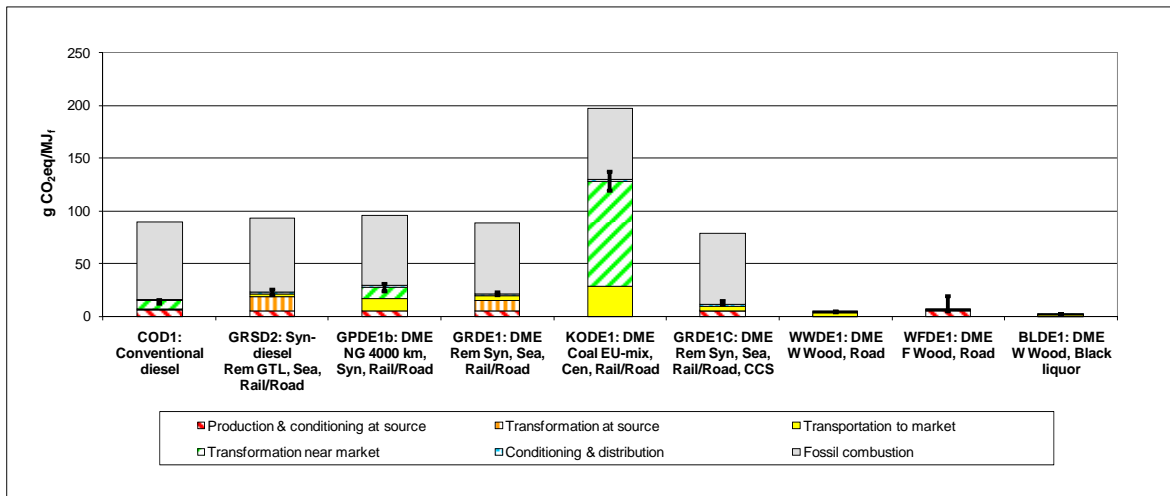
Figure 4.6.3-4 WTT GHG balance of DME pathways compared to conventional fossil diesel (including fossil CO₂ content of final fuels)
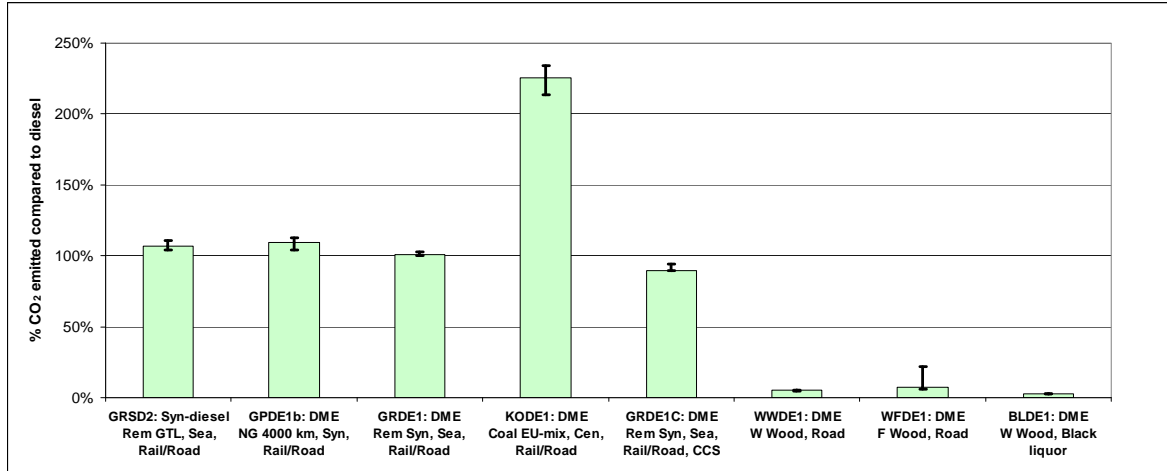
4.6.4 Methanol

WTT figures for methanol are very similar to those of DME and show the same trends. Because of the relatively minor importance of methanol as a future automotive fuel, a CCS option has not been included here. It would of course be perfectly feasible and again bring benefits similar to those seen for DME.

Figure 4.6.4-1   WTT total energy balance of methanol pathways
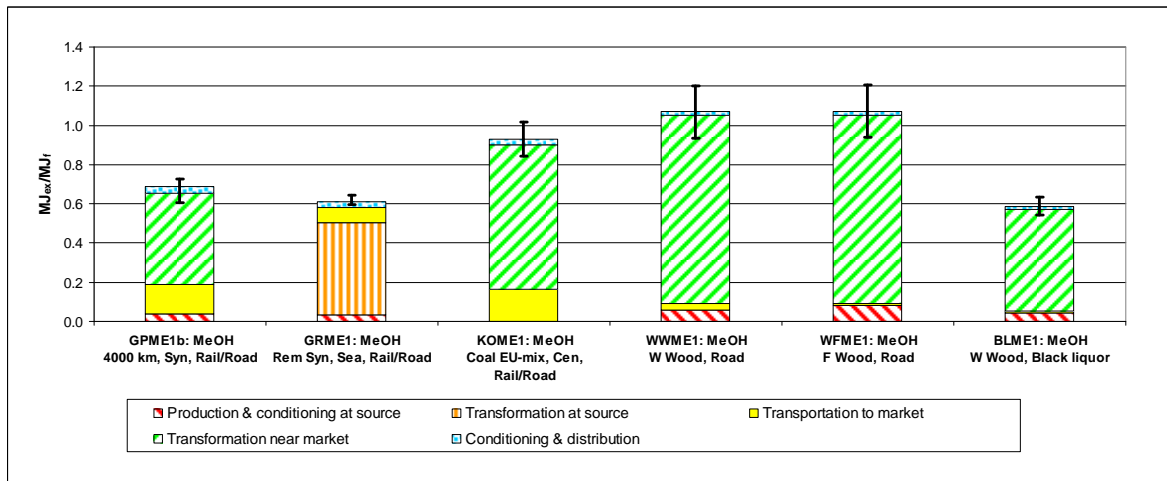
Figure 4.6.4-2   WTT GHG balance of methanol pathways
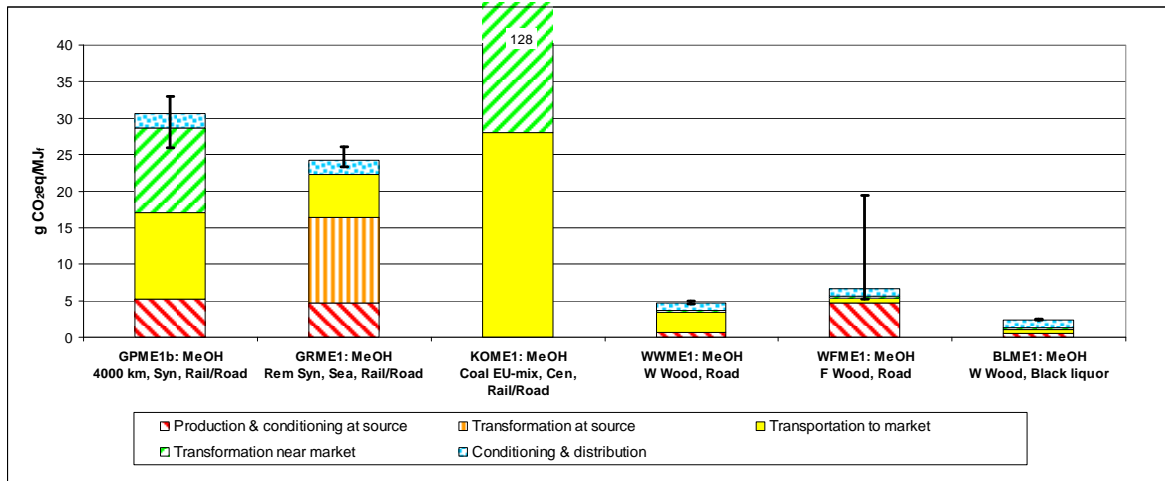
4.7 Ethers (MTBE/ETBE)

(See also WTT Appendix 2 section 6)

Figure 4.7-1   MTBE and ETBE pathways
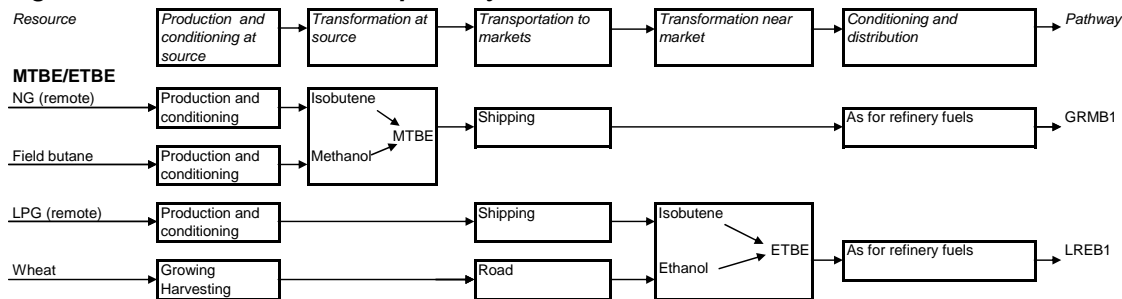
Pathway GRMB1 represents marginal MTBE produced from natural gas and associated butane in a remote plant located near a gas field (see *section 3.2.5*). Pathway LREB1 represents a case where ETBE would be produced in Europe from imported butane and bio-ethanol (from wheat according to pathway WTET2a, see *section 3.4.9*).

MTBE is more energy-intensive than gasoline as it involves several energy-consuming chemical steps. GHG emissions are very close, however, because the bulk of the energy for MTBE manufacture is natural gas rather than heavier hydrocarbons in the case of gasoline.

ETBE's energy footprint is much higher, partly because of the high energy demand for bio-ethanol. Part of that energy is renewable though and this is taken into account when calculating GHG emissions. ETBE is itself partly renewable so that, to compare GHG emissions with purely fossil pathways, only the non-renewable part of the CO_2 combustion emissions (2/3) has to be factored in.

Figure 4.7-2   WTT total energy balance of MTBE and ETBE pathways
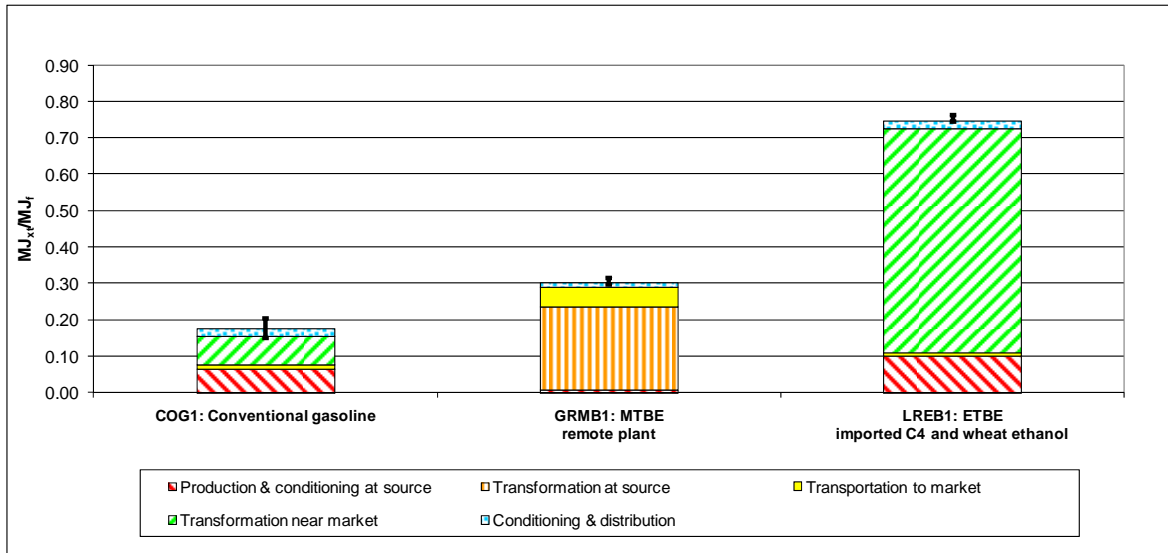
Figure 4.7-3   WTT GHG balance of MTBE and ETBE pathways
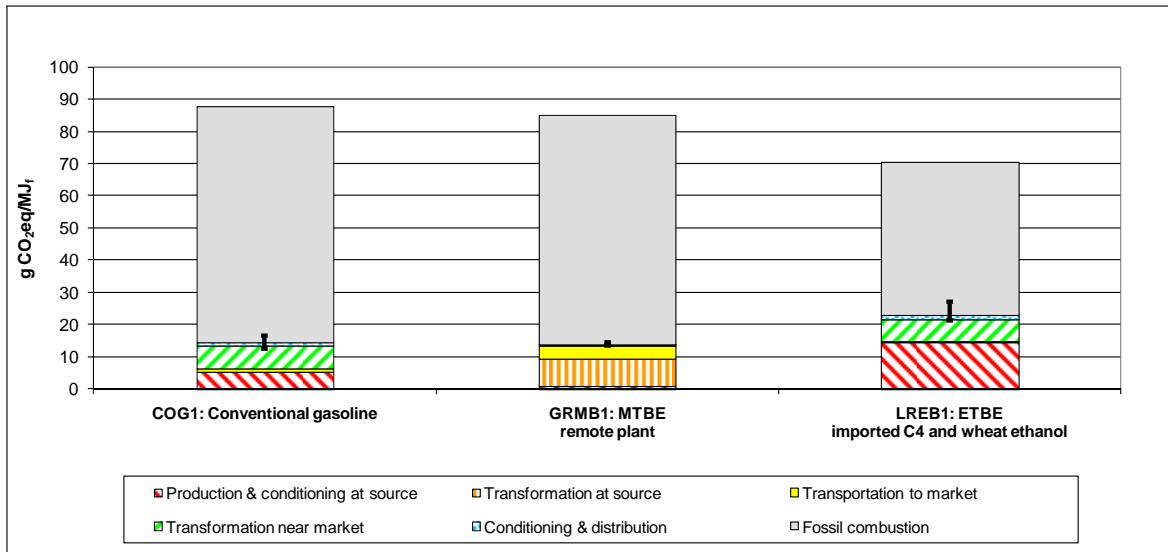
MTBE is more energy-intensive than gasoline as it involves several energy-consuming chemical steps. GHG emissions are very close, however, because the bulk of the energy for MTBE manufacture is natural gas rather than heavier hydrocarbons in the case of gasoline.

ETBE's energy footprint is much higher, partly because of the high energy demand for bio-ethanol. Part of that energy is renewable though and this is taken into account when calculating GHG emissions. ETBE is itself partly renewable so that, to compare GHG emissions with purely fossil pathways, only the non-renewable part of the CO_2 combustion emissions (2/3) has to be factored in.

Pathway LREB1 is thus far a hypothetical case inasmuch as ETBE is currently made by substituting methanol by ethanol in existing refinery MTBE plants. In order to assess the impact of this route we have looked at the differential between a base case where MTBE is made in the refinery and an alternative where ETBE is made instead. The calculations are summarised in the table below:

Table 4.7   Substitution of methanol by bio-ethanol for ETBE manufacture in refineries

		Gasoline components available				Additional gasoline	Feedstocks used			Balance		**Balance /MJ EtOH**	
		MTBE	ETBE	Ethanol	Total		Isobutene	Methanol	Ethanol	/MJ MTBE	/MJ ETBE		
Use of ethanol as such													
Used or produced	MJ_f	1.00		0.40	1.40		0.82	0.21					
Total energy	MJ_{xt}			0.98						0.98		**2.45**	
Fossil energy	MJ_{xfo}			0.23						0.23		**0.57**	
GHG	g CO_{2eq}			19.37						19.37		**48.5**	
ETBE instead of MTBE													Net
Used or produced	MJ_f		1.20		1.20	0.20	0.82	-0.21	0.40				
Total energy	MJ_{xt}					0.230		-0.33	0.98	0.88	0.73	**2.20**	**-0.26**
Fossil energy	MJ_{xfo}					0.23		-0.33	0.23	0.13	0.10	**0.31**	**-0.26**
GHG	g CO_{2eq}					17.3		-19.2	19.4	17.49	14.61	**43.8**	**-4.7**

1 MJ of MTBE requires 0.82 MJ of isobutene. That same amount can produce 1.2 MJ of ETBE by replacing 0.21 MJ of methanol by 0.40 MJ of ethanol (this is simply the result of the chemical balance). Thus in the base case 1 MJ of MTBE is available along with 0.40 MJ of ethanol that can both be used as gasoline. When making ETBE a total of only 1.2 MJ is available to the gasoline pool while 0.21 MJ of methanol have been "saved". In order to bring both cases to the same basis one has to add to the ETBE case the amounts related to production of additional gasoline (1.40-1.20 = 0.20 MJ).

The ETBE route is slightly more favourable from a GHG point of view, i.e. using ethanol to make ETBE as a substitute to refinery MTBE saves more GHG than using that ethanol as such. The reason for this is that making ETBE saves in part methanol instead of gasoline, the former having a larger GHG footprint.
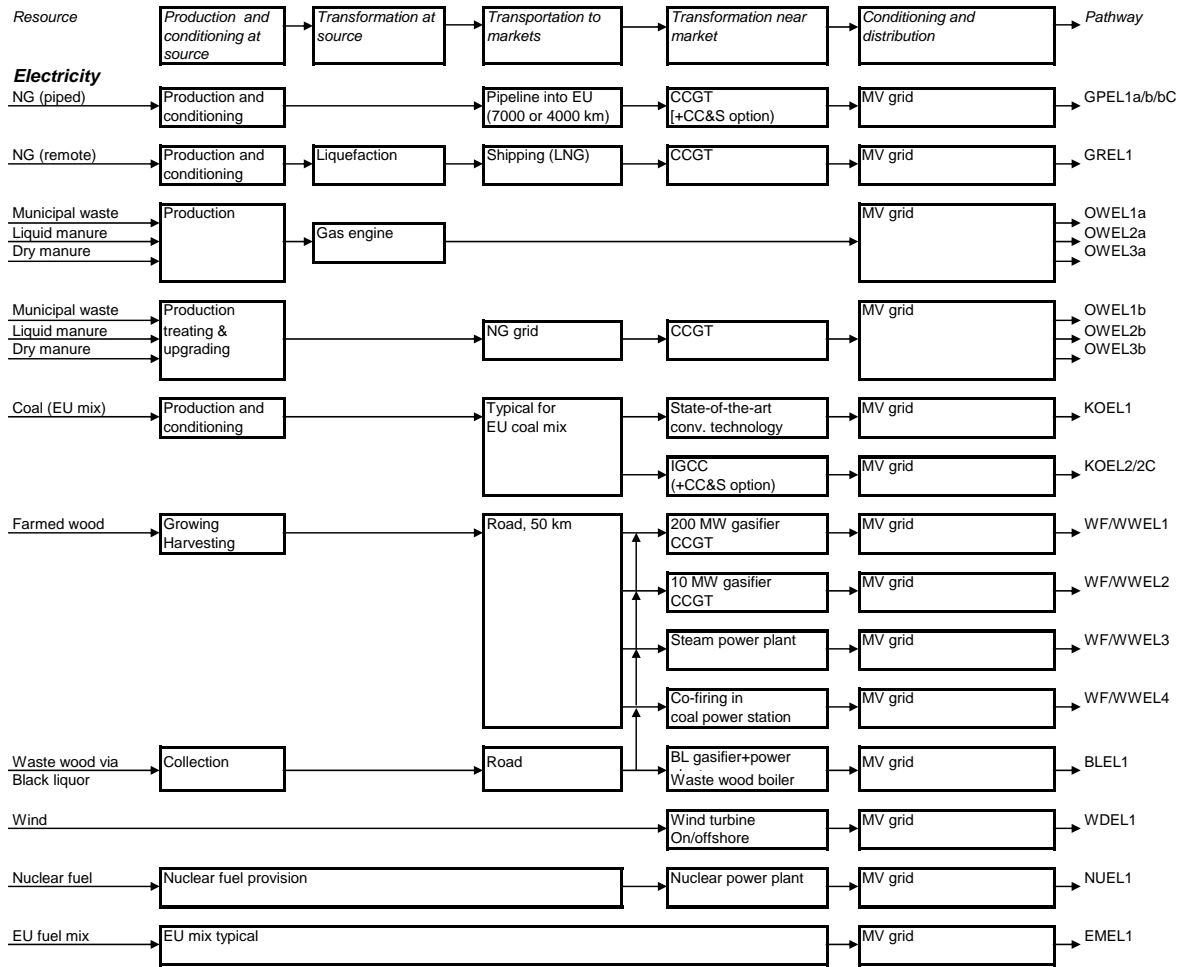
4.8 Heat and power generation

(See also WTT Appendix 2 section 7)

4.8.1 Electricity generation pathways

The pathways to electricity are included here as a reference against other fuels with which electricity competes for primary resources. Electricity is also used as intermediate stage for electrolysis pathways to hydrogen (see *section 4.9*).

Figure 4.8.1   Electricity generation pathways

Resource	Production and conditioning at source	Transformation at source	Transportation to markets	Transformation near market	Conditioning and distribution	Pathway

Electricity

NG (piped) → Production and conditioning → Pipeline into EU (7000 or 4000 km) → CCGT [+CC&S option] → MV grid → GPEL1a/b/bC

NG (remote) → Production and conditioning → Liquefaction → Shipping (LNG) → CCGT → MV grid → GREL1

Municipal waste / Liquid manure / Dry manure → Production → Gas engine → MV grid → OWEL1a / OWEL2a / OWEL3a

Municipal waste / Liquid manure / Dry manure → Production treating & upgrading → NG grid → CCGT → MV grid → OWEL1b / OWEL2b / OWEL3b

Coal (EU mix) → Production and conditioning → Typical for EU coal mix → State-of-the-art conv. technology → MV grid → KOEL1

→ IGCC (+CC&S option) → MV grid → KOEL2/2C

Farmed wood → Growing Harvesting → Road, 50 km → 200 MW gasifier CCGT → MV grid → WF/WWEL1

→ 10 MW gasifier CCGT → MV grid → WF/WWEL2

→ Steam power plant → MV grid → WF/WWEL3

→ Co-firing in coal power station → MV grid → WF/WWEL4

Waste wood via Black liquor → Collection → Road → BL gasifier+power Waste wood boiler → MV grid → BLEL1

Wind → Wind turbine On/offshore → MV grid → WDEL1

Nuclear fuel → Nuclear fuel provision → Nuclear power plant → MV grid → NUEL1

EU fuel mix → EU mix typical → MV grid → EMEL1

4.8.2 Energy and GHG balance for electricity pathways

In the section the energy figures are presented in the same way as for the road fuels, i.e. the energy needed to produce 1 MJ of electricity, less the energy in the produced electricity.

Since electricity is used as an intermediate energy source (e.g. for electrolysis) rather than a "road fuel", it is sometimes more useful to include the energy content of the electricity produced. to obtain these numbers a fixed quantity of 1 MJ should be added to the figures shown.

The overall efficiency of the power generation process through resource extraction, power station and distribution is then given by

$$\text{Efficiency}_{\text{overall}} = 1 / (1 + \text{MJ}_{xt})$$

Total energy

In terms of total energy (***Figures 4.8.2-1a/b/c***), the very efficient gas-fired CCGT (combined cycle gas turbine) fares best amongst fossil fuels. Coal is significantly more energy-intensive.

Figure 4.8.2-1a Total energy balance for various fossil and nuclear electricity pathways
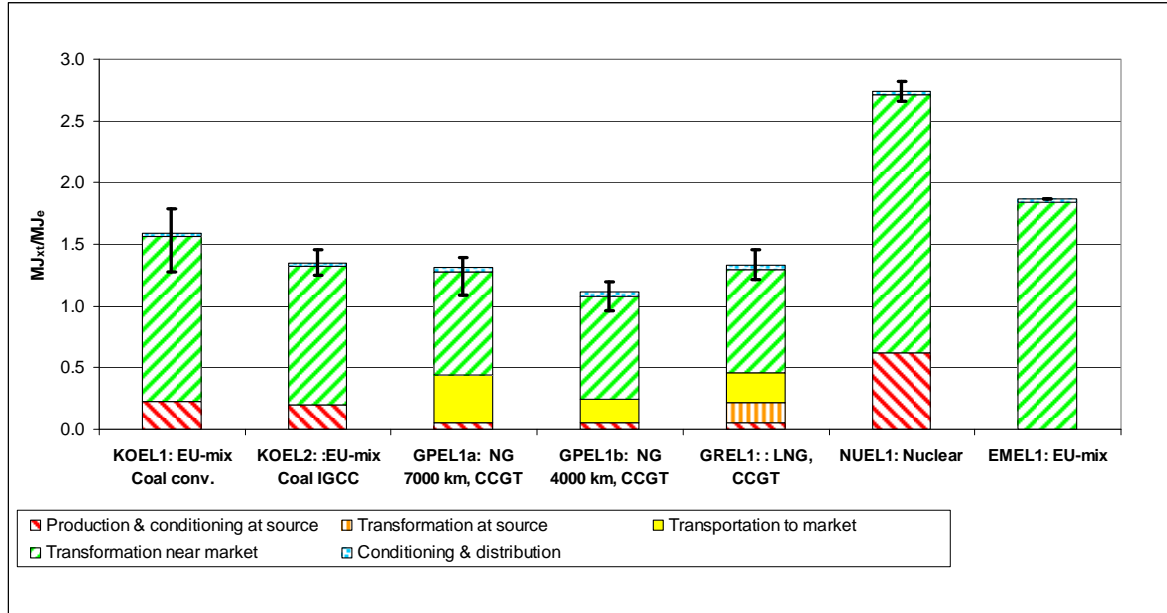**(excluding final electrical energy)**

Figure 4.8.2-1b Total energy balance for various wood to electricity pathways
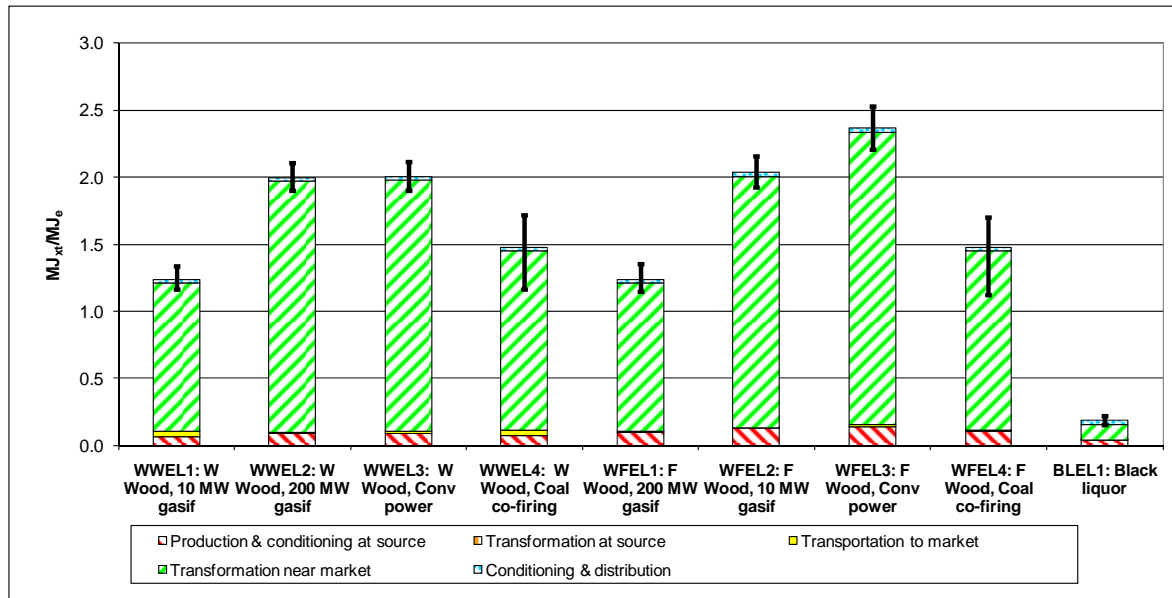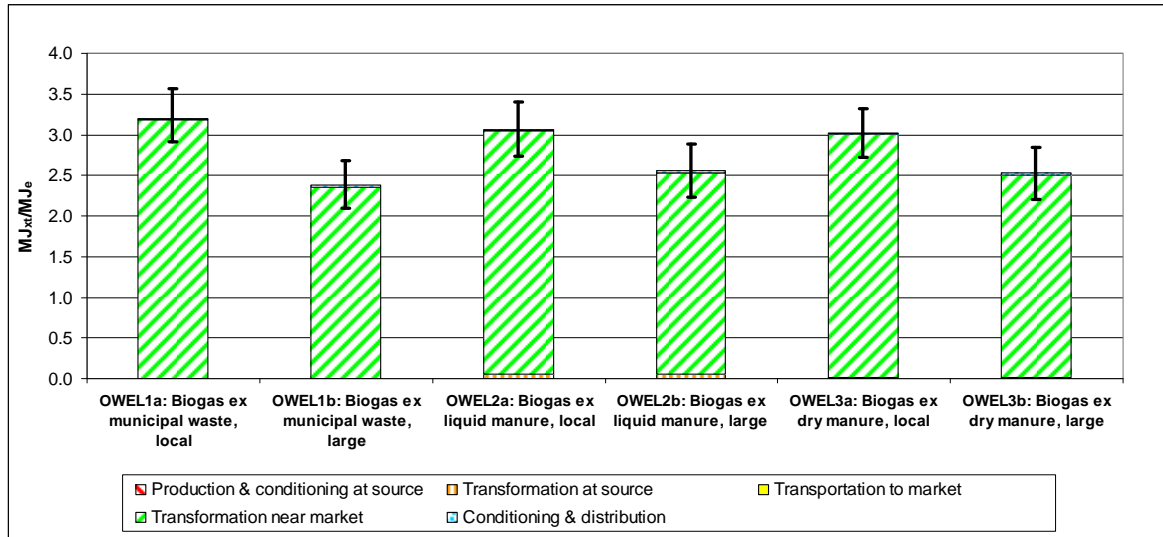**(excluding final electrical energy)**

Figure 4.8.2-1c Total energy balance for biogas to electricity pathways (excluding final electrical energy)

The average generation efficiency of the EU-mix electricity is not as good as the gas-fired CCGT scheme. However, the shares of renewables and nuclear compensate for this, resulting in very similar GHG figures.

Wood comes close to gas in the case of a large gasifier associated to a CCGT but other schemes such as small gasifiers or conventional steam plants are much less efficient. The wood GHG balance is of course much more favourable that that of fossil fuels. The black liquor scheme achieves a remarkably high energy efficiency due to the synergy with the requirements of the paper mill.

Wind is a course a special case inasmuch as the input energy cannot be measured and, being in effect unlimited, can be considered as totally "free".

It is common practice to calculate the efficiency of a nuclear power plant as the fraction of the energy transferred to the steam that is turned into electricity which explains the fairly high energy use figures. Provision of nuclear fuel also requires a significant amount of energy.

Fossil energy

When it comes to fossil energy only (**Figures 4.8.2-2a/b**), wood and wind fare very well of course.

If nuclear energy is considered to be fossil the EU-mix figure is poor relative to fossil hydrocarbon options. When considering only the fossil hydrocarbons part, EU-mix has a fossil energy footprint similar to natural gas.

All of the biogas figures are less than 1 (i.e. there is a net saving in fossil energy), and most of them are negative (i.e. biogas saves more fossil energy than it uses). Please also note the difference in scale between **Figures 4.8.2.-2a/b**). The seemingly inconsistent figure for OWEL1b stems from the fossil electricity requirement of the biogas plant. This requirement is different in OWEL2b and 3b because of a different heat to electricity ratio.

Figure 4.8.2-2a Fossil energy balance for various electricity pathways
(excluding final electrical energy)
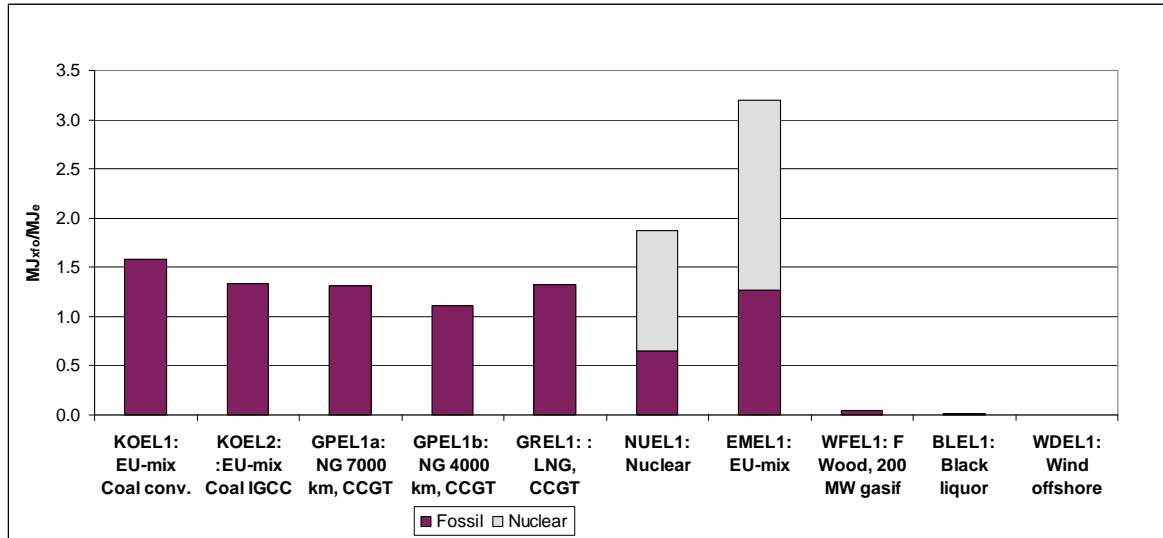
Figure 4.8.2-2b Fossil energy balance for biogas to electricity pathways
(excluding final electrical energy)
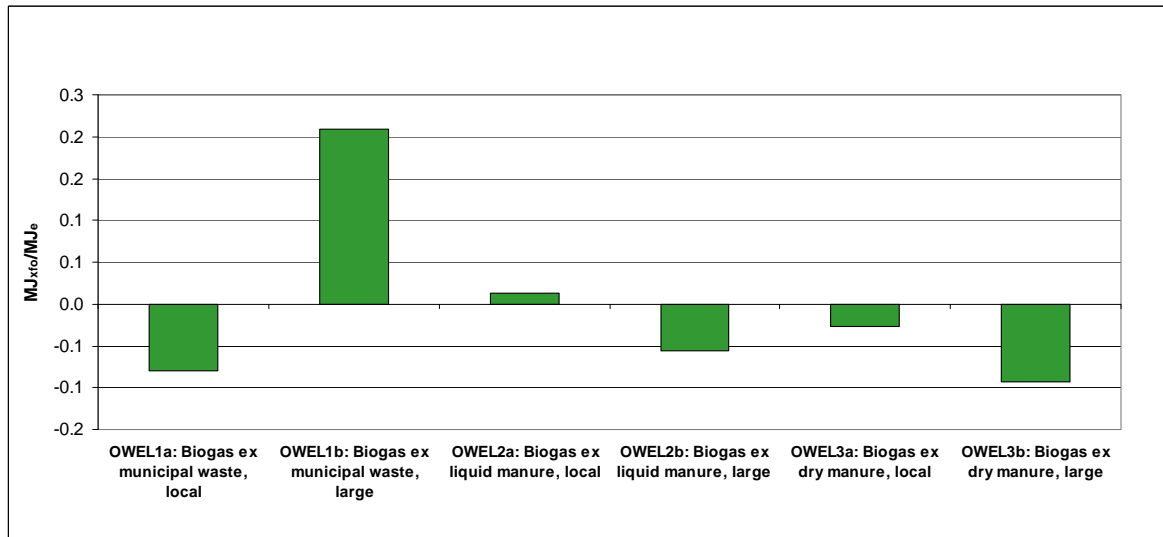
GHG emissions

The picture for GHG emissions is very similar to fossil energy. The notable exception is biogas from liquid manure for which a large GHG credit is accrued from avoided methane emissions from untreated manure. Again, please note the differences in scale between *Figures 4.8.2.-3a/b/c*)

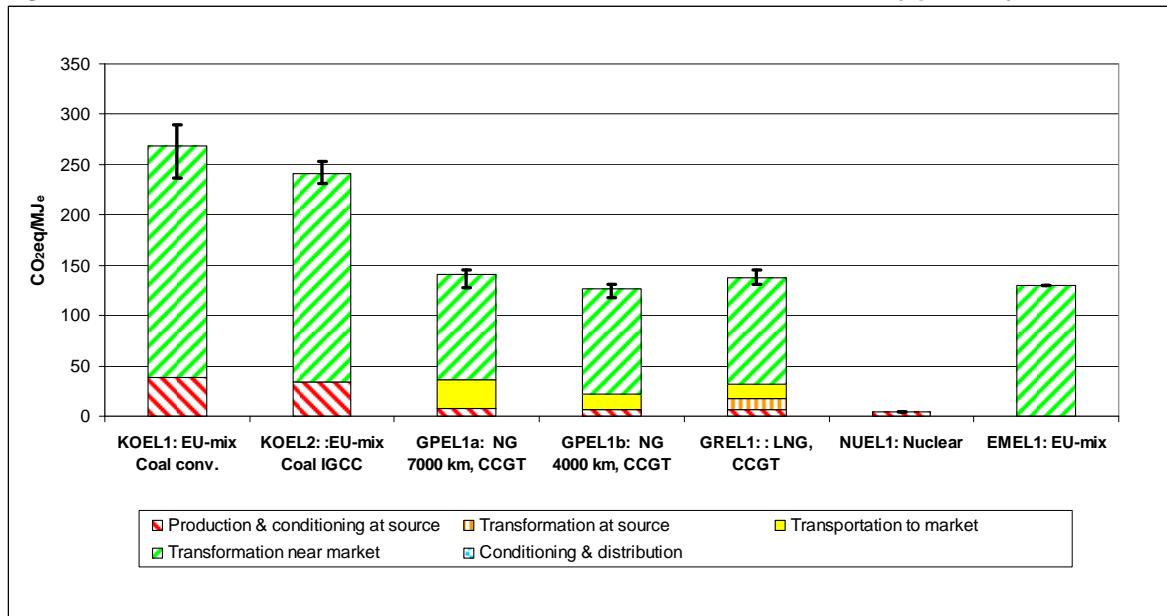*Figure 4.8.2-3a*   **GHG balance for various fossil and nuclear electricity pathways**

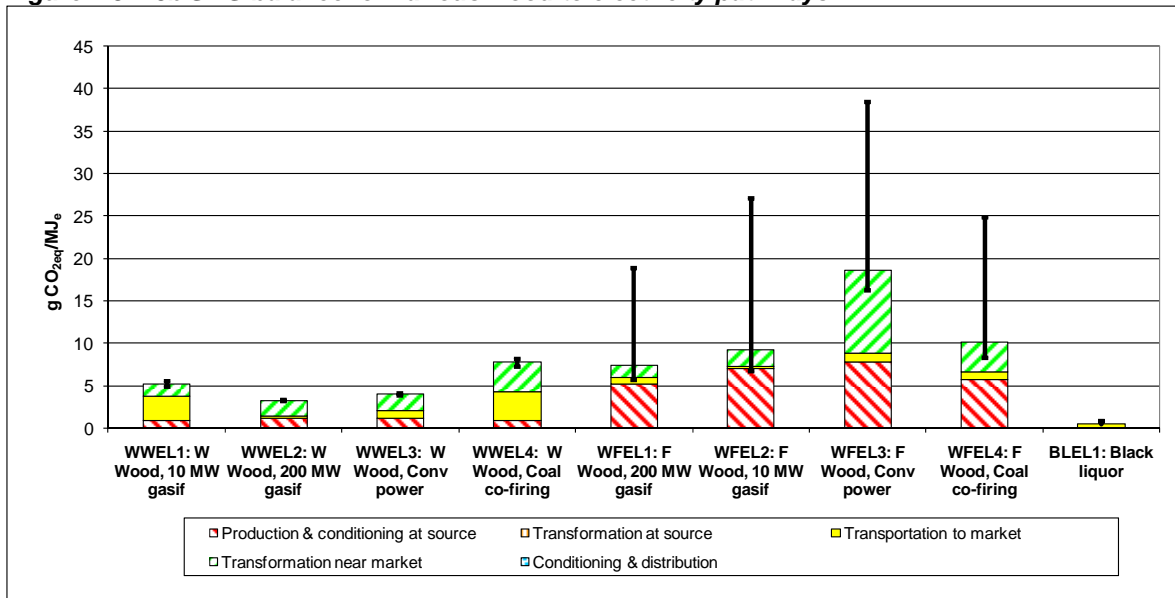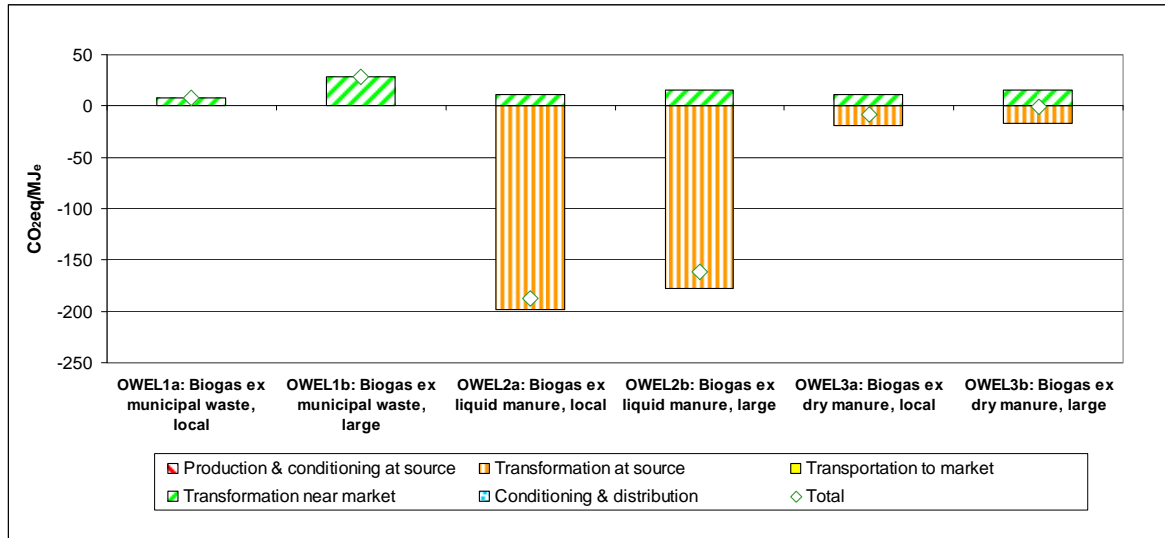*Figure 4.8.2-3b* **GHG balance for various wood to electricity pathways**

Figure 4.8.2-3c GHG balance for biogas to electricity pathways

4.8.3 Heat & Power

Heat is needed in many road fuel pathways as input to the process and has traditionally been produced in steam boilers fed with variety of fuels. In conventional power generation a significant amount of energy is rejected as heat. If this heat could be usefully employed, the overall efficiency of energy use could be improved.

The benefits of combined heat and power (CHP) are well known, and whether the primary product is heat or electricity, efficiency gains are possible if both can be produced together and any surplus exported and put to good use. A number of pathways have been included for comparative purposes. These describe typical performance of heat production in small and industrial case boilers and large scale CHP plants fed with various feedstocks. Several of the road fuel pathways (e.g. WTET1) include CHP options as a way of efficiently meeting the energy needs of the fuel production process. In these cases the primary product may be heat, with surplus electricity being exported to provide a credit. In the CHP pathways we focus first on electrical power as the primary product with the associated heat 'exported' and providing a credit, but also show the comparison where heat is the primary product and electricity considered as an export credit. The credit arising from exported heat depends very much on how that heat would be generated in the absence of a CHP scheme, and a very wide range of options exists. To preserve a degree of objectivity we have assumed if there were no CHP, the heat would be generated in a steam boiler using the same fuel as used for the CHP plant.

Heat Pathways

The scale of the boiler used to produce steam will affect the overall efficiency, so for each fuel considered,a domestic boiler and an industrial boiler are both modelled.

COHT1/2	Heating oil in domestic or industrial boiler
GPHT1/2	Piped NG (7000km or 4000km) in domestic or industrial boiler
GRHT1/2	LNG in domestic or industrial boiler
OWHT1/2/3	Gas boiler, biogas from municipal waste, liquid or dry manure
WWHT1/2	Waste wood in domestic or industrial boiler
WFHT1/2	Farmed wood in domestic or industrial boiler

Figures 4.8.3-1 and 4.8.3-2 show the energy use and GHG emissions to produce heat using fossil or renewable fuels. For the fossil fuels, the figures show the total fuel energy input, whereas for the renewables, only the energy expended is included and the energy in the biomass consumed is not

included. For NG, the domestic boiler is more efficient than the industrial boiler, because households can use lower temperatures and so less heat is wasted.

Figure 4.8.3-1   Energy and GHG balance of fossil heat pathways
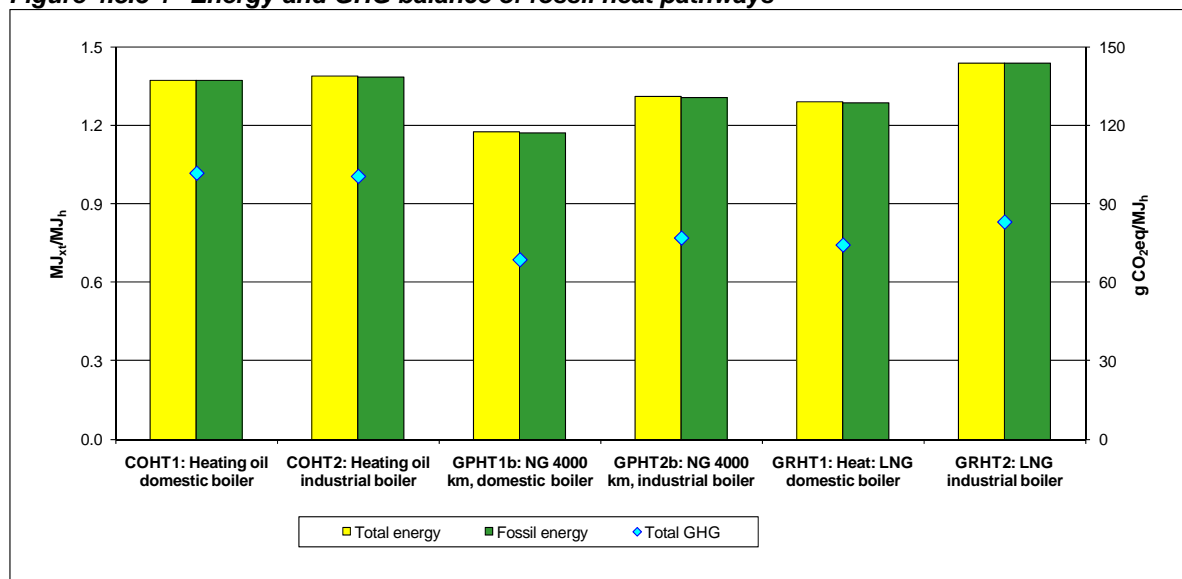
Figure 4.8.3-2   Energy and GHG balance of renewable heat pathways
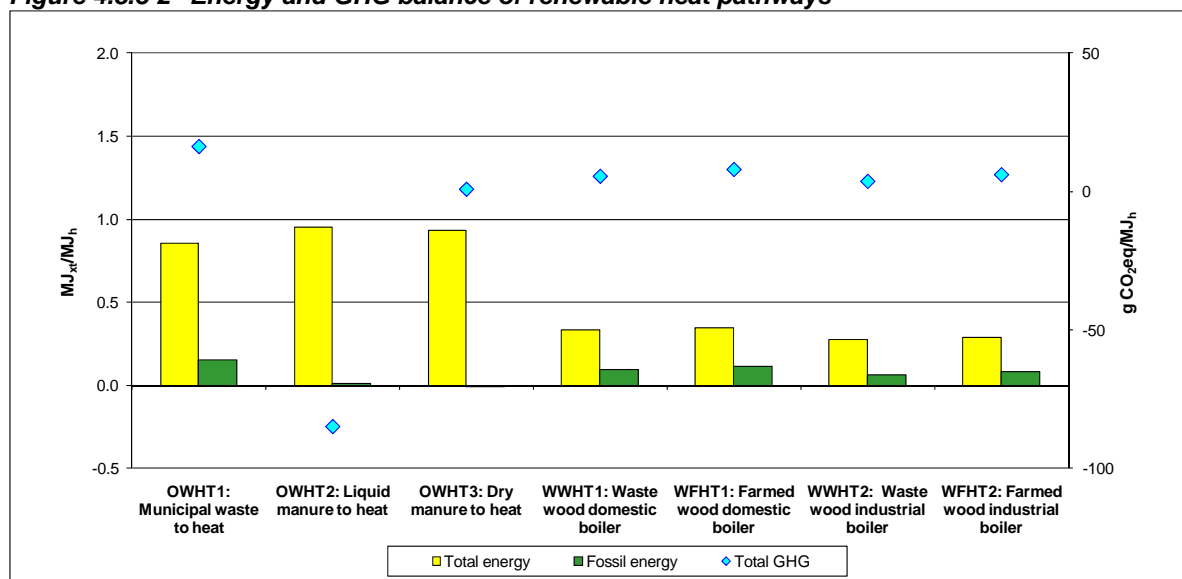
CHP Pathways

The CHP cases consider a large scale NG fired CCGT power plant operating in CHP mode, and a smaller scheme fired by waste or farmed wood. The primary product is electricity, and a credit is given for exported heat.

GPEH1a	Piped gas 7000km, CCGT
GPEH1b	Piped gas 4000km, CCGT
GREH1	LNG, CCGT
WWEH1	Waste wood boiler/steam turbine
WFEH1	Farmed wood boiler/steam turbine

Figure 4.8.3-3 Energy and GHG balance CHP pathways
             (expressed per MJ electricity)
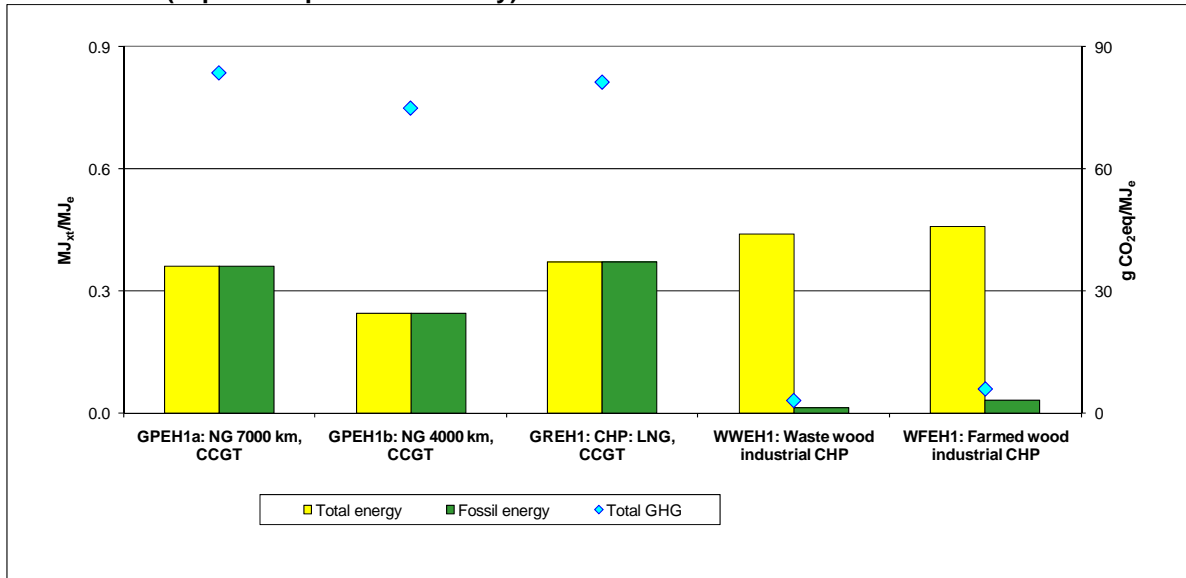
Where CHP is used, there is a benefit for producing both electricity and heat together instead of separately. In ***Figure 4.8.3-4***, the energy use and GHG emissions for electricity production are compared for simple electricity generation and for the same process where heat is exported and a credit given based on production of heat using the same feedstock.

Figure 4.8.3-4 Energy and GHG balance for electricity production using CHP
             (expressed per MJ electricity)
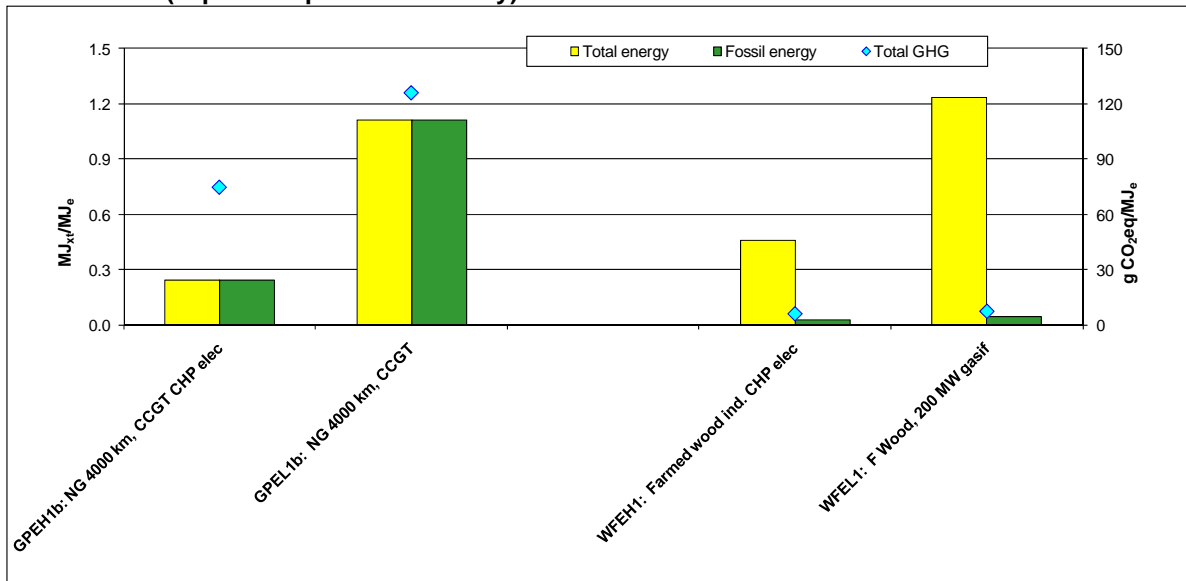
In ***Figure 4.8.3-5***, the figures for heat production are shown for stand-alone processes, and for comparable CHP schemes where a credit has been given for the exported electricity, based on CCGT production using the same feedstock.

    GPHT3b   Piped gas 4000km, CCGT in CHP mode with electricity export
    WFHT3   Farmed wood, CCGT in CHP mode with electricity export

Figure 4.8.3-5   Energy and GHG balance for heat production using CHP (expressed per MJ heat)
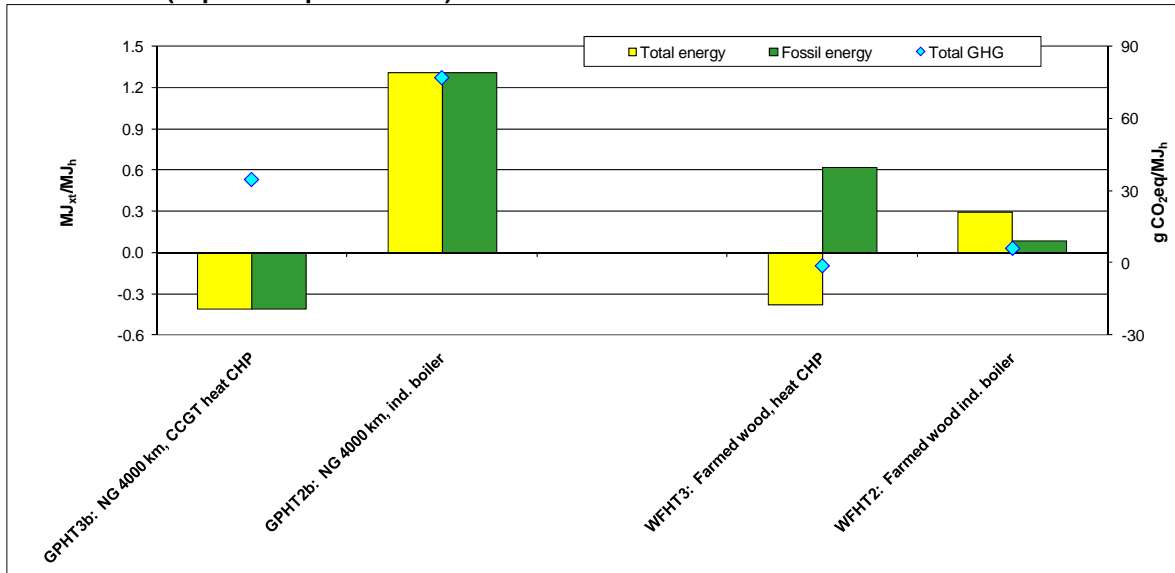
Compared to standalone production of heat and electricity, CHP uses less energy, whether it be from a fossil or renewable source.

4.9 Hydrogen

(See also WTT Appendix 2 section 8)

4.9.1 Pathways to hydrogen

One of the perceived merits of hydrogen is that it can in principle be produced from virtually any primary energy source. This can be done either via a chemical transformation process generally involving decarbonisation of a hydrocarbon or organic feedstock and splitting of water or through electricity via electrolysis. Most of these processes can be put to work in large "central" facilities or in small "distributed" plants near or at a refuelling station.

The different hydrogen production routes are described in *section 3.2.5 for natural gas, 3.3 for coal and 3.4 for biomass*.

The pathways selected to represent hydrogen provision reflect the various supply routes available.

Figure 4.9.1a   Compressed hydrogen pathways

Resource	Production and conditioning at source	Transformation at source	Transportation to markets	Transformation near market	Conditioning and distribution	Pathway

Compressed hydrogen

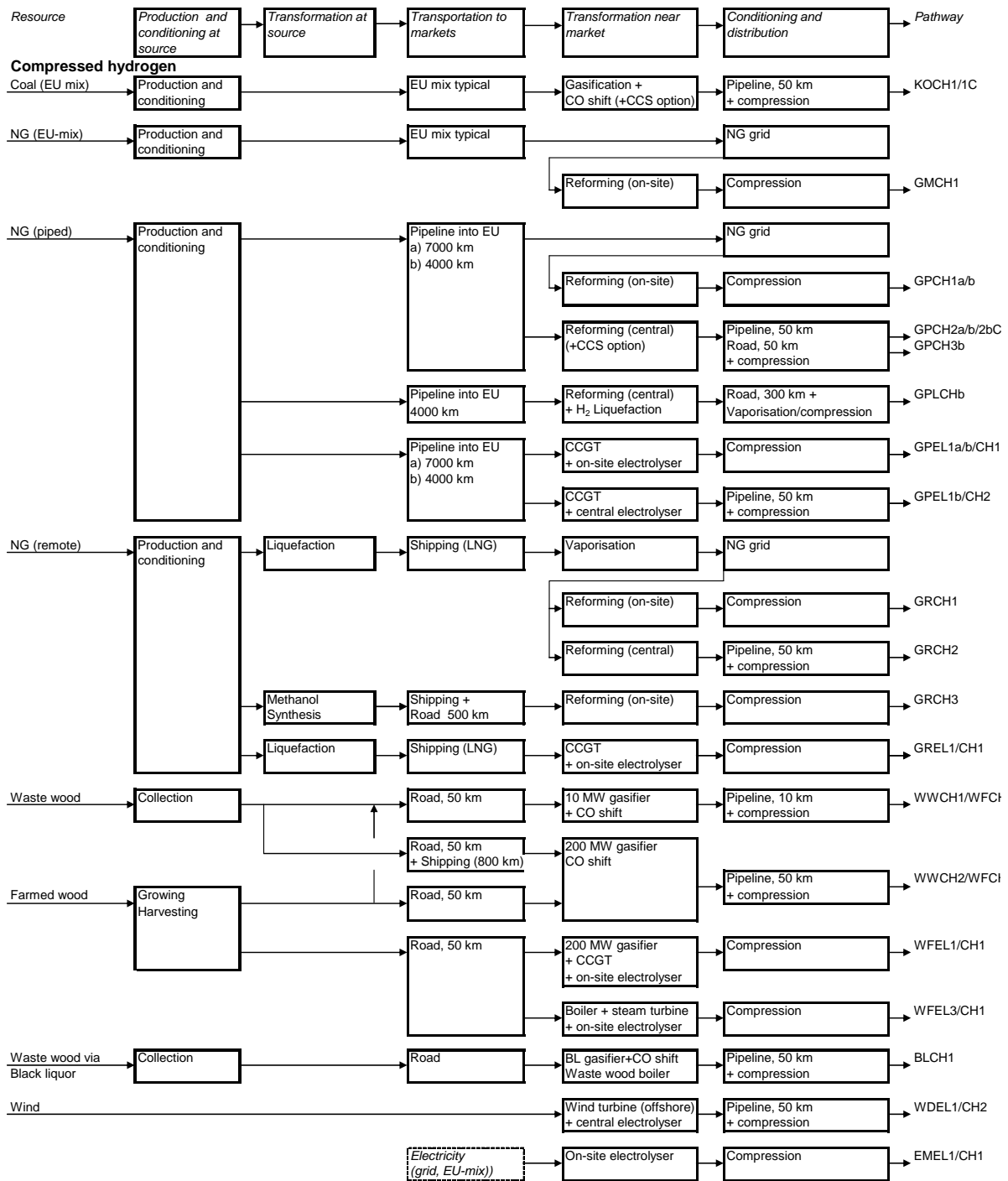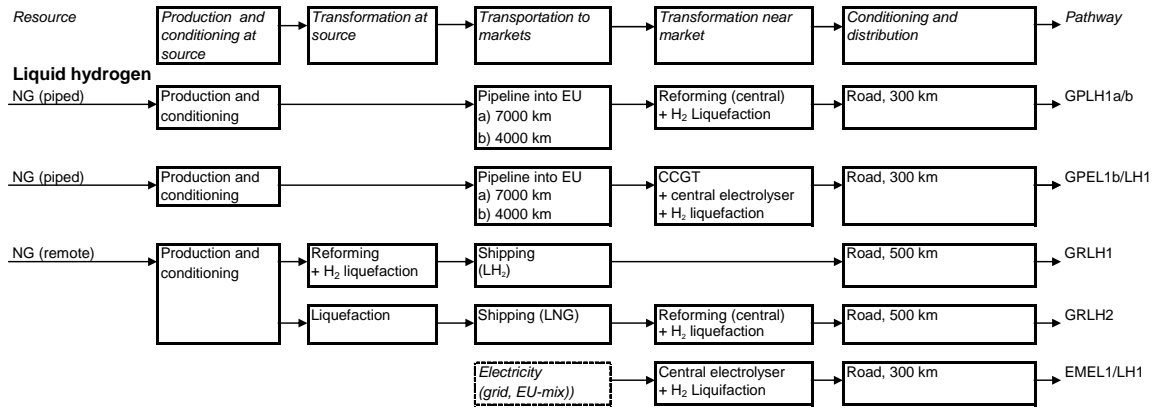| Resource	Transformation/steps				Pathway
Coal (EU mix)	Production and conditioning		EU mix typical	Gasification + CO shift (+CCS option)	Pipeline, 50 km + compression → KOCH1/1C
NG (EU-mix)	Production and conditioning		EU mix typical		NG grid
				Reforming (on-site)	Compression → GMCH1
NG (piped)	Production and conditioning		Pipeline into EU a) 7000 km b) 4000 km		NG grid
				Reforming (on-site)	Compression → GPCH1a/b
				Reforming (central) (+CCS option)	Pipeline, 50 km Road, 50 km + compression → GPCH2a/b/2bC GPCH3b
			Pipeline into EU 4000 km	Reforming (central) + H₂ Liquefaction	Road, 300 km + Vaporisation/compression → GPLCHb
			Pipeline into EU a) 7000 km b) 4000 km	CCGT + on-site electrolyser	Compression → GPEL1a/b/CH1
				CCGT + central electrolyser	Pipeline, 50 km + compression → GPEL1b/CH2
NG (remote)	Production and conditioning	Liquefaction	Shipping (LNG)	Vaporisation	NG grid
				Reforming (on-site)	Compression → GRCH1
				Reforming (central)	Pipeline, 50 km + compression → GRCH2
		Methanol Synthesis	Shipping + Road 500 km	Reforming (on-site)	Compression → GRCH3
		Liquefaction	Shipping (LNG)	CCGT + on-site electrolyser	Compression → GREL1/CH1
Waste wood	Collection		Road, 50 km	10 MW gasifier + CO shift	Pipeline, 10 km + compression → WWCH1/WFCH
			Road, 50 km + Shipping (800 km)	200 MW gasifier CO shift	
Farmed wood	Growing Harvesting		Road, 50 km		Pipeline, 50 km + compression → WWCH2/WFCH
			Road, 50 km	200 MW gasifier + CCGT + on-site electrolyser	Compression → WFEL1/CH1
				Boiler + steam turbine + on-site electrolyser	Compression → WFEL3/CH1
Waste wood via Black liquor	Collection		Road	BL gasifier+CO shift Waste wood boiler	Pipeline, 50 km + compression → BLCH1
Wind				Wind turbine (offshore) + central electrolyser	Pipeline, 50 km + compression → WDEL1/CH2
			Electricity (grid, EU-mix))	On-site electrolyser	Compression → EMEL1/CH1

Figure 4.9.1b   Liquid hydrogen pathways

4.9.2 Hydrogen from NG energy and GHG balance

Compressed hydrogen

Not surprisingly the main contribution comes from the hydrogen production step which requires energy and where all carbon is effectively "shed". The transport distance of the gas still has a significant impact although less in relative terms than for CNG pathways (GPCH1a/b).

For a given transport distance, central reforming is more efficient (because of the better waste heat recovery potential of a large plant), irrespective of mode of transport to the delivery point (GPCH1/2/3b). Although it could be quite attractive from an economic point of view especially in the early stages of development, the option of transporting hydrogen in liquid form is not energy-efficient (GPCLHb).

CCS is obviously a very attractive option for hydrogen because all carbon is turned into CO_2 during the process. There is a small energy cost which in practice will depend on the process scheme used in the base case. More efficient CO_2 recovery than has been assumed here could be possible in the future making the scheme even more beneficial. The potential of CCS is further discussed in *section 5.4*.

Figure 4.9.2-1   WTT total energy balance of selected NG to compressed hydrogen pathways
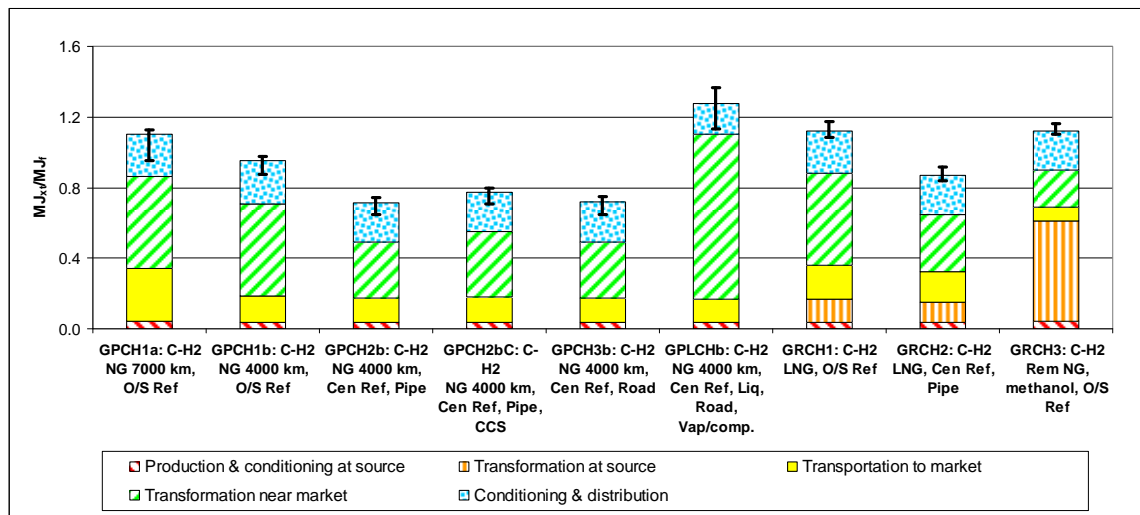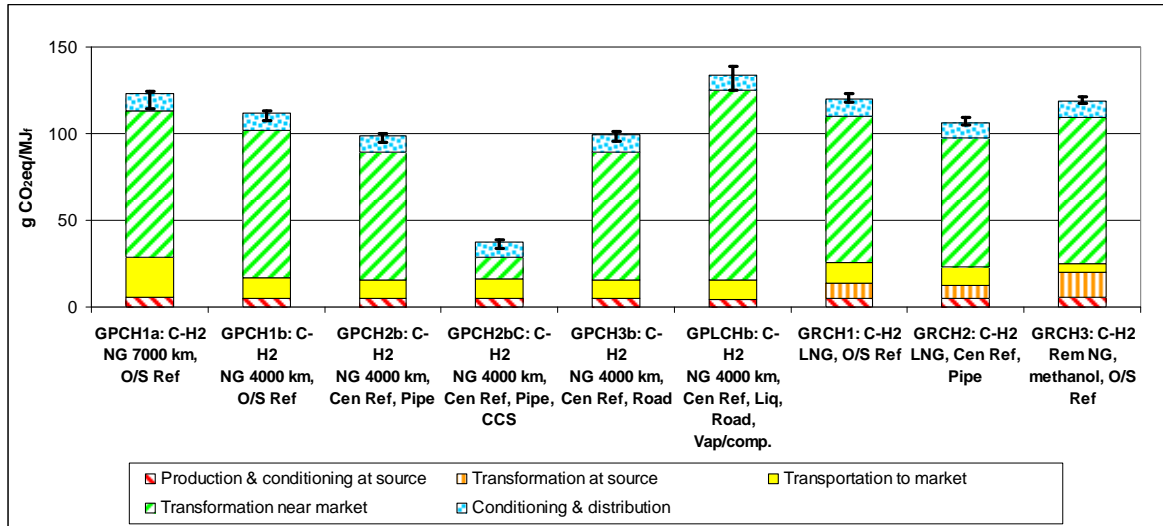
Figure 4.9.2-2 WTT GHG balance of selected NG to compressed hydrogen pathways

The option of using methanol as an energy carrier (rather than gas) does not appear to offer any advantage from an energy/GHG point of view, in particular because the scheme can only be justified with relatively inefficient small scale reformers (GRCH3).

As we have seen for CNG, the LNG route fares similarly to the longer pipeline distances.

Liquid hydrogen

The energy required for liquefaction penalises the liquid hydrogen option (the attractiveness of liquid hydrogen rather stems from practicality and economics considerations). The fairly large error bar for the liquid hydrogen pathways is mainly due to the large range of liquefaction energy. The somewhat far-fetched option of remote hydrogen production and long-distance hydrogen (GRLH1) transport does not appear to match the local production options.

Figure 4.9.2-3 Energy balance of selected NG to liquid hydrogen pathways
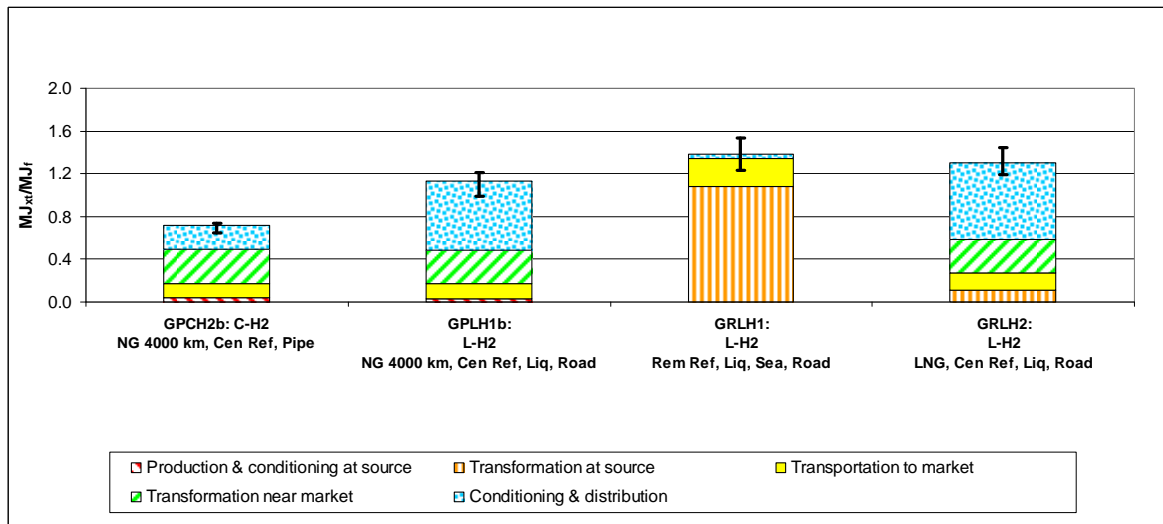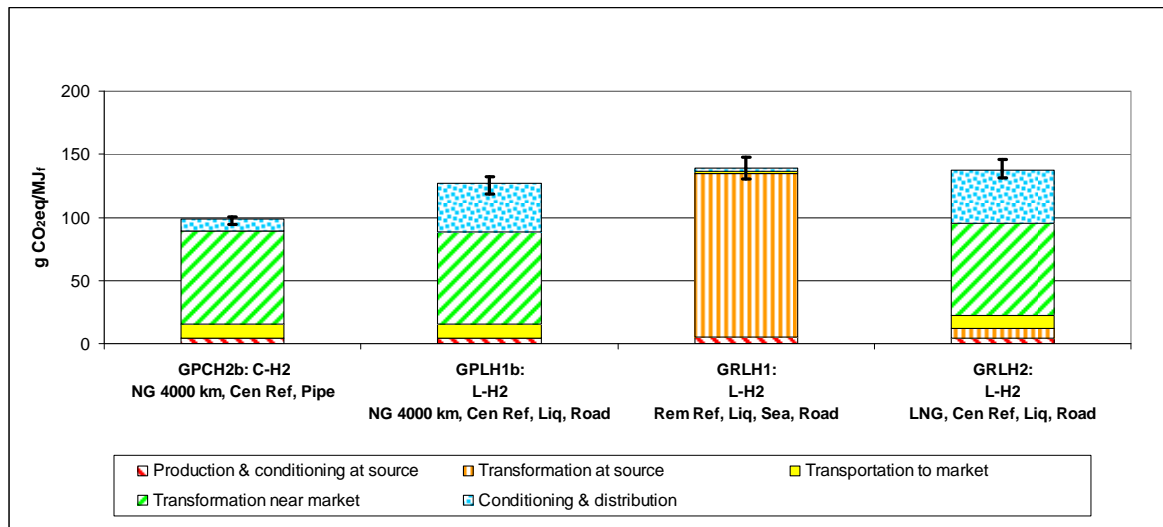
Figure 4.9.2-4   GHG balance of selected NG to liquid hydrogen pathways

4.9.3 Hydrogen from coal and wood, energy and GHG balance

The coal route is more energy-intensive than the gas route (because the gasification process is less efficient). The difference is even greater when it comes to GHG because of the higher carbon content of coal. As a corollary, however, a large amount of CO_2 can be captured, albeit with an energy penalty. When applying CCS to both the gas and the coal schemes, the residual GHG emissions are still somewhat higher for coal but the difference is much smaller than without CCS. The potential of CCS is further discussed in *section 5.4*.

The gasification is also less efficient with wood than gas. For wood the ranking between the large and small scale gasifier is very much a result of the extent to which waste heat can be recovered to produce surplus electricity. The GHG emission figures are of course very small as the main conversion process uses nothing but wood as energy source. The differences between the wood options are not very significant and are all much smaller than those observed in equivalent pathways based on fossil fuels.

Figure 4.9.3-1   Energy balance of coal and wood to compressed hydrogen pathways
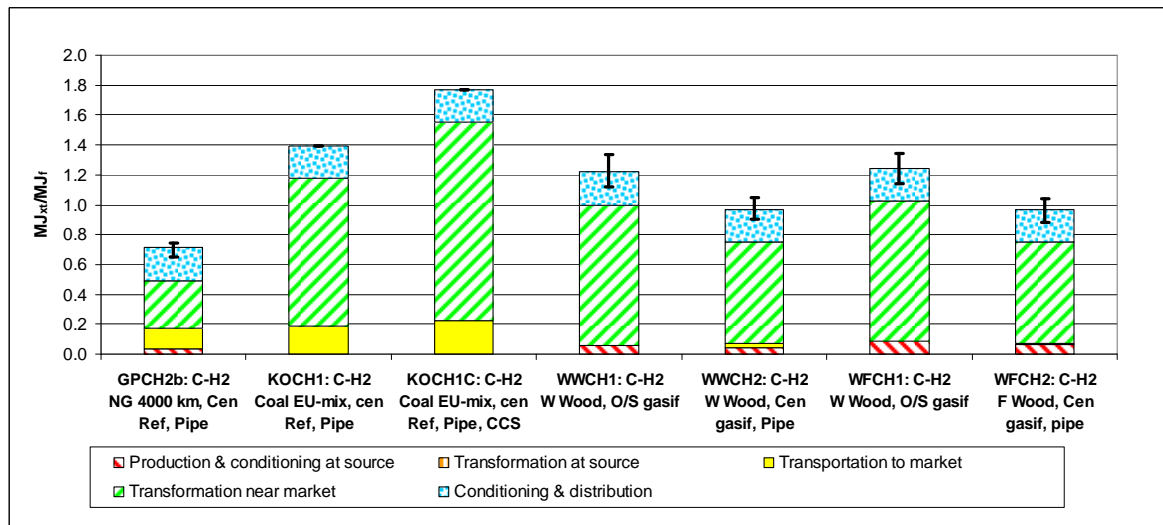
Figure 4.9.3-2   GHG balance of coal and wood to compressed hydrogen pathways
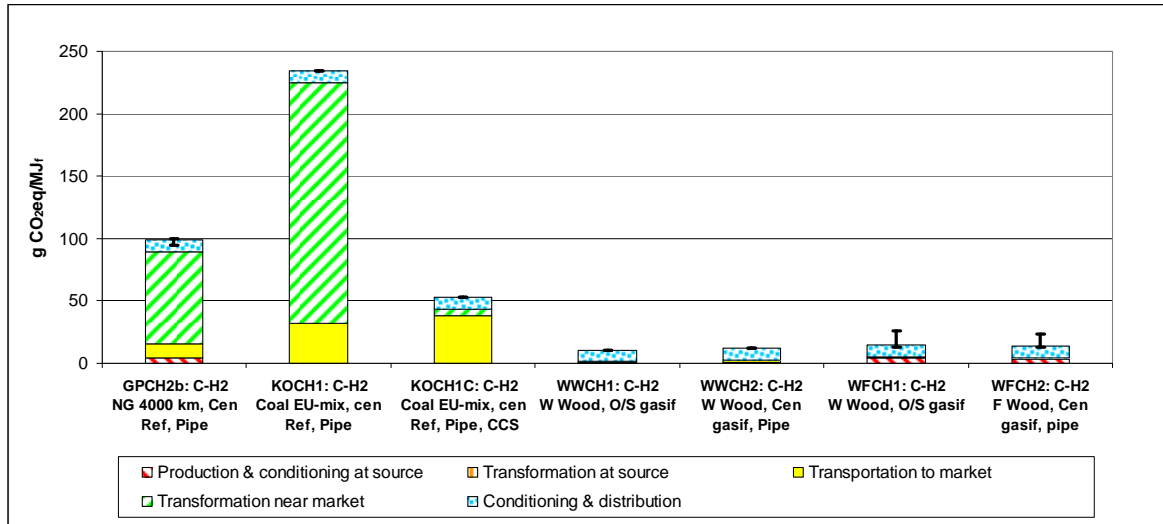
4.9.4 Hydrogen via electrolysis, energy and GHG balance

For a given source of electricity, central and on-site electrolysis give nearly equal results with compressed hydrogen, the only small difference coming from the somewhat lower final compressor suction pressure in the central case (e.g. GPEL1b/CH1/CH2). The relative merits of the different energy sources are of course the same as discussed for electricity generation in *section 4.8*.

The low energy consumption of the wind pathway (WDEL1/CH2) reflects the somewhat arbitrary assumption that the wind energy harnessing is 100% efficient. As this energy is renewable and, for all practical purposes, unlimited this is a somewhat academic debate anyway. It is reasonable to consider that the hydrogen compression energy is electricity from the EU-mix rather than wind electricity. The pathway therefore shows some GHG emissions.

Here again the wood pathways GHG figures (WFEL1-3/CH1) are very low as most of the energy used is renewable.

Figure 4.9.4-1   Energy balance of selected electrolysis pathways
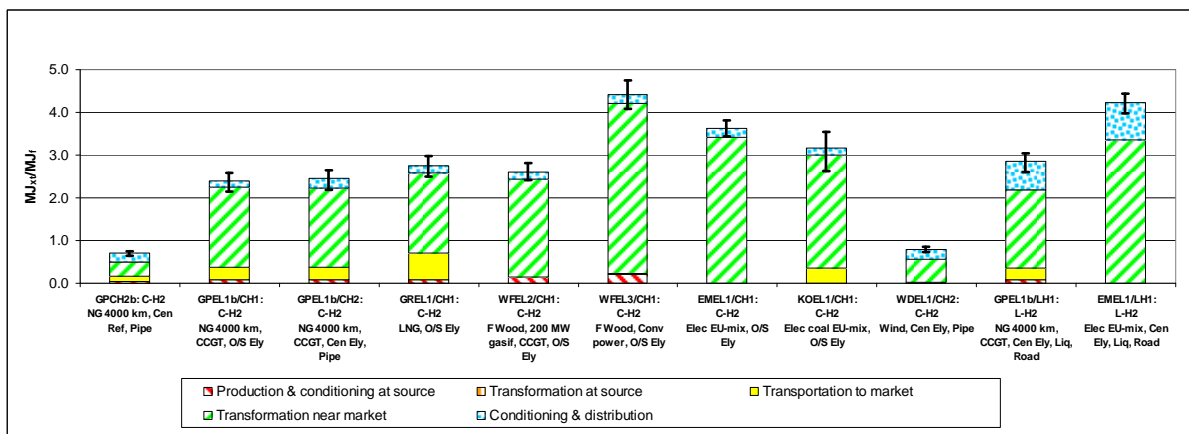
Figure 4.9.4-2   GHG balance of selected electrolysis pathways
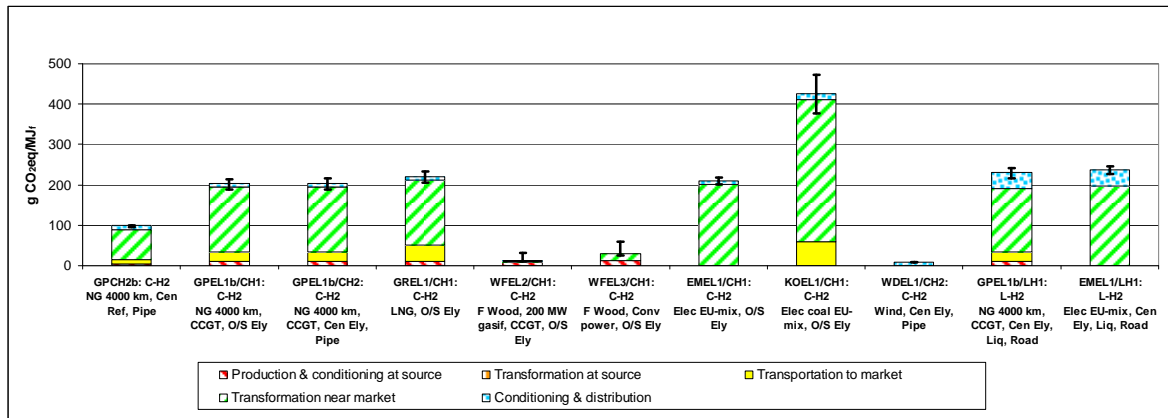
Comparison of the straightforward NG to hydrogen pathway (GPCH1b, 112gCO$_{2eq}$/MJ$_f$) with the comparable electroysis pathway (GPEL1b/CH1, 204gCO$_{2eq}$/MJ$_f$) highlights the poor energy efficiency of the electrolysis route. Turning usable electricity into hydrogen is unlikely to make sense from a global energy or GHG point of view.

Renewable electricity, in particular, is a case in point. The real issue is not whether these pathways have a favourable GHG profile, which is obvious, but rather under what circumstances it would make sense to use them. This issue can only be addressed on a global well-to-wheels basis and the reader is referred to *section 9 of the WTW report*.

Of course the total energy required to produce hydrogen and the total GHG emitted are in all cases much higher than is the case for CNG (or conventional gasoline of diesel fuel). The latter is only shown here to put the hydrogen figures in perspective. Indeed, the simple "well-to-tank" assessment finds its limits here as there is no point comparing "carbon-containing" fuels that are to be used in a conventional engine to a carbon-free fuel that may be used in an inherently more efficient fuel cell.

5 Potential availability and costs

IMPORTANT NOTICE
This section remains largely unchanged since the last issue of this report. We recognise that regulations, market conditions and access to imports have changed since the last version and that a more thorough update is warranted at a later date. However the technical information may still be pertinent, so we have retained the earlier text virtually unchanged as a reference document, pending a more thorough update. The original text is shaded in grey to indicate its provisional nature. One addition to the earlier text is a simple estimate of the land needed to replace 10% of transport fuel with first generation biofuels, taking into account by-products. This and other significant additions or changes to the text are clearly marked by blue highlighting and black text.

The strong increase in crude oil prices over the past year seems to have abated, and current crude oil prices are consistent with our range of €25-50/bbl (equivalent to around $35-70 at current exchange rates).

The question of how much of a certain fuel could conceivably be made from a given feedstock and at what cost is, of course, central to an analysis of competing fuel pathways. It is, however, arguably the most difficult part.

The potential availability of a feedstock or resource to produce a certain fuel depends on many factors. There may be physical limitations (e.g. land) and practical ones (e.g. number of sites for wind turbines). There may also be issues of competing uses of resources, social and political choices etc.

Cost evaluations and forecasts are always fraught with difficulties, particularly so when it comes to processes or systems that do not yet exist at any notable scale. The future cost of feedstocks or of access to resources will depend on more or less the same factors as availability.

Although a definitive analysis is clearly not possible we believe the available data can provide a valuable insight into the various options.

Costs have been evaluated on a macro-economics basis for Europe (EU-25) as a whole. This implies that the minimum cost of an international commodity is its market price (delivered to Europe). This holds true when the commodity is imported but also when is it produced within Europe as any amount used internally denies Europe a revenue based on the market price (in this last case, it is the minimum cost assuming the production cost is not higher). We did not attempt to forecast fuel prices: the oil price is a variable, and other prices are related to it. For crop prices in 2012 we used a respected forecast, upon which we added our own estimates of the market effects of increasing biofuels use.

All costs are expressed in EUROS. Whenever the literature source indicated cost in US Dollars we have assume €/$ parity. However, forecasts of agricultural commodity prices follow [*DG-AGRI 2005*] in converting 2012 prices from dollars at a rate of 1.15 $/€.

When it comes to cost of new facilities (production, distribution etc) one has to rely mainly on literature sources which, even when carefully selected, often cannot be independently checked. Because they mostly refer to facilities which exist either at a limited scale or not at all, cost figures are often only rough estimates with both upwards (unforeseen items) and downwards (experience, scale) potential.

Our analysis is limited to the more tangible costs such as feedstock costs, processing costs and the like. It does not include any possible credit or debit for e.g. employment, regional development, environmental impact etc.

In the following sections we discuss the cost data and calculations for each set of pathways. *WTW Appendix 2* gives a convenient summary of the calculations and results.

## 5.1 Fossil fuels supply and cost to Europe

5.1.1 Crude oil

Crude oil is a worldwide commodity. Although most grades are traded on a wide geographical basis, consuming regions tend, for logistic and geopolitical reasons, to have preferred supply sources. In Europe the main sources are:

- North Sea: this is indigenous production for which Western Europe has a clear logistic advantage. Although some North Sea crude finds its way to the US, the bulk is consumed in Europe.
- Africa: North African crudes (Algeria, Lybia, Egypt) are naturally part of Southern Europe's "captive" production. West African crudes can profitably go either to North America or to Europe and the market is divided between these two destinations.
- Middle East: The region is an important supplier, mainly of heavy, high-sulphur grades, typically used for the manufacture of bitumen or base oils for lubricant production and by refineries with appropriate desulphurisation and residue conversion facilities.
- FSU: Russia is a steady supplier to Europe, partly through an extensive inland pipeline system extending to most former East European block countries. The Caspian basin is poised to become a major producer with Europe as a preferred customer because of favourable logistics.

EU-25 will consume about 650 Mt of crude oil in 2005 (plus some 85 Mt of various feedstocks). This is set to grow slightly up to around 665 Mt in 2015 with a subsequent slight decrease at the 2020 horizon. Although it is considered that supply should be adequate within this timeframe, the sources of supply for Europe will change. North Sea production will decline but other regions such as West Africa and the Caspian basin will take over. These changes in the origin of the crude oil will not significantly affect the average quality and the current proportion of around 48% of sweet (i.e. low sulphur) crudes should remain essentially constant over the next decade. Non-conventional oil (oil sands and bitumen) are not expected to contribute to Europe's supply needs during the review period, however some information on these fuels is included in Section 3.1.1.

The current and forecast European supply is shown in the following figure.

Figure 5.1.1   Current and future EU crude oil supply
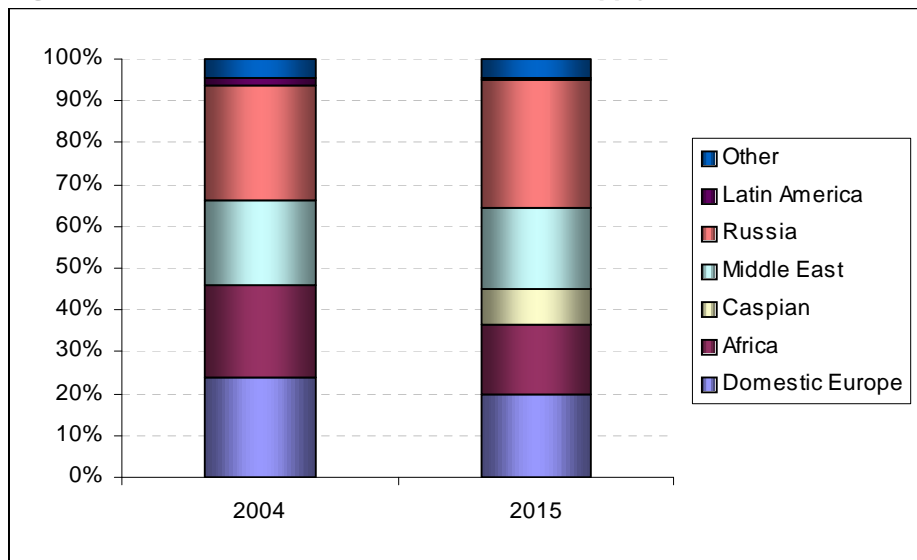
(Source Wood MacKenzie)

Reference oil price and Oil Cost Factor (OCF)

In order to represent the fluctuations of the oil price we made the calculations for 25 and 50 €/bbl (i.e. around 30 and 60 €/bbl respectively at current exchange rate). A major change in oil price, if sustained over a long period, would undoubtedly have an effect on prices of other commodities, resources and services. We have taken this into account by applying an "oil cost factor" (OCF) to all major cost items, expressed as a fraction of the change in crude price (with an OCF of 1 the price would track that of crude oil; with an OCF of 0.5 a doubling of crude price would result in a 50% increase). For energy commodities the OCF reflects the linkage of the particular form of energy to crude oil. For goods and services, it reflects the fraction of the cost that originates from energy and the energy mix used.

5.1.2 Natural gas

EU-15 consumed 417 Mtoe of NG in 2004, up from 375 in 2000 [*BP 2005*], about a quarter of which was for power generation. Demand has increased at a steady 4% per annum over the past 10 years and is expected to increase strongly over the coming years as more power stations as well as industrial users switch to gas under the pressure of environmental legislation. A gas industry projection foresees a sustained EU demand increase with forecast of 500-530 Mtoe in 2010 and nearly 575-600 Mtoe in 2020 [*Source OGP[13], unpublished*]. In comparison, a 10% share of the 2020 European road fuel market would represent 25-30 Mtoe/a, i.e. only some 5% extra demand.

Whereas a number of EU countries have some NG production, the UK, and the Netherlands are by far the largest EU producers. Norway is also a large producer, with the EU as its captive market through a largely integrated pipeline system in the North Sea area. Europe is, however, not self-sufficient and imports large quantities mainly from Algeria and the FSU, with both of which it has large capacity pipeline links. The current origin of the gas used in Europe is shown in the following table.

---

[13] Oil and Gas Producers association

Table 5.1.2-1   Origin of the gas consumed in Europe

Netherlands	18.6%
UK	25.6%
Other EU	12.3%
Norway	10.0%
FSU	18.10%
Algeria	13.10%
Others	2.30%

Source: International Energy Agency 1999

Worldwide NG reserves are vast and in many parts of the world, untapped. A number of existing and potential producing regions are located such that Europe would be one of their most natural markets from a logistic and therefore cost point of view.

- Algeria is an established supplier of Europe and still has sufficient reserves to play a role in the medium term. The European market, with already existing pipeline connections and additional ones under development, is obviously the most attractive. Algeria is also developing its LNG exporting capacity which could favour some exports to e.g. North America.
- Nigeria has a large potential of associated gas, the development of which has just started. From a logistic point of view, Europe is in direct competition with North America. Transport will be in the form of LNG.
- The Middle East, both in the Arabian Gulf area and in Iran, holds vast, virtually untapped reserves. LNG is a likely transport route although pipelines to Europe are a very real possibility.
- The FSU, both Russia and a number of States in the Caspian areas have the largest reserves. Whereas Eastern Siberian gas would be most likely to find its way into the Far East, the rest of Russian and the Caspian outputs will naturally flow to Europe through expanded existing and new pipelines.

Table 5.1.2-2   Natural gas reserves economically available to Europe
(Source OGP)

	Billion m^3 (BCM)				Mt Oil Equivalent (Mtoe)			
	Reserves [1]	Discovered potential [2]	Undiscovered potential [3]	Total	Reserves [1]	Discovered potential [2]	Undiscovered potential [3]	Total
EU/EEA	5512	2645	3940	12097	4683	2247	3348	10279
Accession countries	358	264	350	972	304	224	297	826
Africa	6544	4942	7240	18726	5560	4199	6152	15911
ME	15410	33760	23950	73120	13094	28685	20350	62129
FSU	32960	14906	29830	77696	28006	12665	25346	66017
Carribean	850	142	1100	2092	722	121	935	1778
Total	61634	56659	66410	184703	52369	48142	56427	156939

[1] Reserves that are confirmed and will be exploited with current technology and economic conditions

[2] Reserves that are known to exist and would be economically recoverable with either an improvement in technology or better economic conditions

[3] Potential for additional reserves based on detailed field-by-field analysis

Reserves are sufficient to cover any realistic demand scenario for a number of decades to come. Bringing the gas to market may, however, be an issue. Natural gas projects are large, costly and involve a complex network of interest that has to include the investors, the producing country but also the consuming countries and, in case of pipelines, the countries through which the pipelines travels. Because of the weight of the infrastructure these are long-term projects. The large investments required are only likely to be realised if the economic and political conditions are right. Data in the *Table 5.1.2-3* has been compiled assuming a fairly conservative investment scenario, essentially based on the exploitation of the first category of reserves shown in *Table 5.1.2-2*.

As European production decreases, it is replaced by new sources in the Middle East and in the FSU. In this scenario the total production decreases from around 2010 pointing out to a relative lack of investments and possible tightening of the world supply.

Table 5.1.2-3   Europe natural gas balance sheet (EU-25+Norway)
(Source OGP)

	BCM			Mtoe		
	2002	2010	2020	2002	2010	2020
Production potentially available to Europe						
Europe	310	300	190	292	282	179
Africa	110	130	110	104	122	104
ME	60	300	160	56	282	151
FSU	220	240	320	207	226	301
Carribean	10	20	0	9	19	0
Total	710	990	780	668	932	734
European demand	460	570	630	433	536	593
Potential coverage	154%	174%	124%			
EU Shortfall	150	270	440			
EU internal demand coverage	67%	53%	30%			

Similarly to oil, gas is an internationally traded commodity. As the gas business develops and grows, the infrastructure becomes more flexible, markets become deregulated leading to less long term contracts and more spot sales and therefore a more liquid market. The cost of natural gas to Europe is therefore directly linked to gas price on the international markets. Prices are normally quoted at the customer end of pipelines and terminals i.e. the producer supports the energy cost of production and transport. For this reason we have not considered the actual costs related to extraction, production and transport of natural gas.

Historically the price of natural gas has been loosely linked to that of crude oil, trading in Europe at around 60 to 80% of North Sea crude oil on an energy content basis. Although there are very large short-term fluctuations in the gas to crude ratio, this long-term range appears to hold (during 2004 for instance EU gas prices have both risen by about 50%). We have used a ratio of 0.8 irrespective of the price of crude oil. This corresponds to 3.7 and 7.3 €/GJ or approximately 0.13 to 0.26 €/Nm^3 in the 25 and 50 €/bbl oil scenario respectively.

This cost is relevant to all pathways where gas is imported into Europe before being transformed into a final fuel. The operating and investment costs within Europe have to be added. For those pathways where gas is transformed at source, the cost of gas is irrelevant to this analysis. The fuel produced has to be traded on the appropriate commodity market and the same reasoning applies with regard to the cost to Europe.

5.1.3 Conventional gasoline and diesel

In this study we are considering the marginal substitution of conventional fuels. The relevant cost figure is therefore not the cost of providing these marginal fuels but rather the savings that would be realised by not producing them.

When faced with a decrease in demand refiners can either reduce production or trade i.e. seek to export more if the product is globally in surplus in the region or reduce imports if the product is in deficit. The most economically attractive route will depend on the interplay between the international markets of crude and products. In a "short" market, typical of diesel fuel in Europe, the price will be driven towards that of imports, most likely to be above the domestic costs of production. The most likely outcome of a reduction of demand will be a sustained domestic production and a reduction of imports. In a "long" market, typical of gasoline in Europe, the price will be dragged down towards that of the marginal available export market. Export will only make sense if a net profit can be made on the marginal volumes which may or may not be the case. So far in Europe export markets have been available for gasoline while diesel fuel prices have encouraged maximum domestic production. For the purpose of this study we have assumed this situation to remain.

The "saving" to Europe of not consuming a fuel is therefore equal to its international market price in a European port. Refined product and crude prices are loosely linked but the ratios fluctuate considerably. Gasoline and diesel fuels typically trade at 1.2 to 1.4 times crude price on a mass basis. At the 25 €/bbl crude price level the typical road fuel price would then be in the 225-260 €/t bracket. We have used a ratio of 1.3 for both fuels, irrespective of crude price.

5.1.4 Synthetic fuels from natural gas

There has been a lot of interest in GTL in recent years and a number of projects have been considered. Such plants are extremely complex and capital-intensive. When the original version of the report was produced, only the existing 12,000 bbl/d SMDS plant in Malaysia was considered. Four large GTL plants have now been announced for Qatar, bringing the total announced global GTL production to 700,000 bbl/d by 2015.

Synthetic diesel fuel will be offered on world markets and mostly used as a high quality blending component to help meet diesel fuel specifications. It is therefore likely to trade at diesel fuel price plus a certain quality premium. Attempting to estimate how much this premium might be would be pure guess work. For argument's sake we have used a 20% premium corresponding to about 100 €/t in the 50 €/bbl crude scenario. This will be valid for synthetic diesel fuel imported into Europe from remote GTL plants but will also provide a backstop (outside any subsidy) for any material produced internally from biomass.

Methanol is already widely traded today as a chemical. It is overwhelmingly made from natural gas. Over the last 3 years, the international market price has broadly followed the increase of oil and gas, the mass ratio fluctuating between 0.9 and 1.15. We have used a factor of 1 irrespective of the crude price, translating into 9.6 €/GJ for 25 €/bbl crude. In the context of this study, methanol would be used as an energy vector to produce hydrogen either at or near a refuelling station or directly on-board a vehicle. A dedicated distribution infrastructure would be required generating additional distribution cost in the form of fixed operating costs and capital charge. Also methanol having a low LHV, its transport is more energy-intensive when expressed in energy terms.

Because methanol is an international commodity, its market price can be used as opportunity cost i.e. either the cost of buying it or the minimum cost of using any amount that is internally produced. This is not the case for DME for which we have estimated the actual production cost.

DME is thus far not a commodity. Its production route is, however, very similar to that of methanol both in terms of feedstock and in terms of hardware to the extent that plants producing DME could feasibly also produce methanol. It is plausible that DME would trade at a price corresponding to the methanol equivalent. We have nevertheless ignored this potential link and have reported DME production costs.

5.2 Availability and cost of biomass for production of road fuels

(Revised text, version 3c)
The Renewable Energy Directive (RED) requires 10% renewable energy in road transport by 2020. Although other alternatives may play a minor role, it is generally accepted that the bulk of the RED requirement will have to be met by biofuels, mostly first generation such as ethanol and FAME.

Within this context, a three-yearly technical exercise was launched by the JEC consortium at the beginning of 2008 with the objective of defining and assessing possible biofuel and other renewable fuel implementation scenarios for achieving the RED targets. Results of this collaboration are available at:

For illustration we discuss below a "maximum" case where first generation biofuels would have to fulfil the entire 10% target.

How much land would be needed to replace 10% of EU road fuels with biofuels from EI crops?

In version 2 of this study, we attempted to answer the question "how much biofuel feedstock could be produced by EU agriculture in 2012?" The exercise was illuminating, but we cannot update this approach because the forecasts from DG-AGRI now include biofuels in the baseline. We have therefore left the old text in grey, below. In reality, the "availability" of crops for biofuels in EU is not a fixed quantity. The extra demand for biofuels will impact on crop prices, which in turn will:
   o increase the area devoted to biofuels crops, mostly at the expense of other crops
   o increase the imports of biofuels-crops (as well as finished biofuels)
   o slightly increase the yield of crops by intensification
   o decrease food exports and increase food imports
   o generally increase the area devoted to row-crop farming in the world
These effects will be countered to some extent by the use of by-products from biofuel production for animal feed.

The actual amount of extra feedstock production in EU (compared with the increased volume of imports and decreased volume of exports) depends on the interplay of these factors in the commodities market: a full agro-economic model is required to assess the effects which is beyond the scope of the present study.

Nevertheless, it is useful to get an idea of the scale of the agricultural resources involved. We have opted to do this by making an estimate of the amount of land which would be required to produce enough biofuels crops to satisfy the 10% renewable energy target in 2020 in the European Union's Renewable Energy directive, on the fictitious assumption that it would all come from EU production of first generation biofuels. For this, it is necessary to make some assumption on how the overall 10% transport-fuels-replacement target would be distributed between the diesel and gasoline markets. We make the arbitrary assumption that biofuels will substitute equal proportions of each.

Land for 10% biodiesel in EU-2020 diesel

10% first-generation biodiesel in 2020 diesel would require about 31 million tonnes of vegetable oil[14], EU agriculture produced ~8 million tones/yr vegetable oil (for all uses), and about an equal amount was imported[15].

For the purpose of scoping the land requirements, we shall pretend that all EU biodiesel could be sourced from EU production of rapeseed, although this is not what will happen[16]. The production of vegetable oils in EU generates animal-feed by-product, which should be taken into account when looking at the land requirements, but of course does not actually decrease the requirement for vegetable oil.

---

[14]   [DG AGRI 2007a] estimates that 10% of 2020 EU diesel demand is ~19.2 million tonnes-of-oil-equivalent, whilst our market forecast from Wood-Mackenzie gives 19.9 Mtoe. It takes 1.59 tonnes veg oil to make 1 toe biodiesel (see WTT app.1), principally because of the difference in heating value between vegetable oil and diesel..

[15]   EU oilseed production and net imports ran at about 20 Mt/yr in 2004-6 [DG-AGRI 2007b, table A.7]; the average oil yield is roughly 40% (42% for rapeseed, much less for soy, more for sunflower)

[16]   In practice biodiesel will be sourced from a mix of direct biodiesel and vegetable oil imports, oilseed imports, EU rapeseed diverted from the food market, and incremental EU rapeseed production. The by-product is produced where the oilseed is crushed, and the amount of useful by-product depends on which oilseed is used. For example, producing a tonne of rapeseed oil also generates 1.38 tonnes rapeseed meal, used for animal feed, whilst the main by-product of palm oil is only good for fertilizer.

First let us calculate the credit for the rapeseed meal byproduct. In section 3.4.4 we estimate that 1kg rapeseed meal substitutes a total of 0.88kg of a mix of wheat and soybean meal. How do we turn this into an EU land credit? For the wheat it is clear, but soybean meal is imported. It is obviously not appropriate to subtract areas of low-yielding land outside EU from high-yielding EU land. Hence, equivalence between soybean meal and cereals has to be be reached.

The main sources of soybean meal are Argentina and Brazil. Argentina is the better place to examine, because there soybeans compete with wheat for non-irrigated land, whereas in Brazil the main soy production areas tend to be separated from cereals growing areas. The average soybean yield in Argentina has (to our surprise) overtaken that of wheat in recent years [FAOSTAT 2008], but let us assume they are the same. Then 1 tonne of soybeans replaces 1 tonne of wheat [17], and 1 tonne rapeseed meal is equivalent to 0.88 tonnes of wheat. The 1.38 tonnes of rapeseed meal co-produced with 1 tonne of rapeseed oil will then replace 1.21 tonnes of wheat or similar cereal. The average EU soft wheat yield is expected to reach about 6 tonnes/ha by 2020[18]. Then the by-product from one tonne of rapeseed oil would save 1.21/6 = 0.20 ha of the same type of land (since rapeseed rotates principally with soft wheat).

In 2020 the average oil yield of rapeseed cultivation in EU is expected to increase to 1.49 tonnes oil/ha[19]. So it will take 0.67 ha to make 1 tonne oil. From this we subtract the land credit for the by-product, leaving 0.47 ha net land needed per tonne of rapeseed oil. Of course, this is land which is suitable for growing rapeseed.

If we want to add this with other land requirements, we should take into account that the land suitable for rapeseed has significantly higher cereals yield than the EU-average: at least 6 tonnes/ha compared to 5.5t/ha for average cereals (in 2020). This means in terms of EU-average cereals land, the net requirement is at least 0.51 ha/t rapeseed oil. **1 toe biodiesel will then require net** 1.59x0.51 = **0.81 ha of average-EU-2020-cereals-land.**

Then 31 Mt rapeseed oil for reaching 10% EU diesel substitution in 2020 would take at least **15.9 Mha** of average EU cereals land.

Land for 10% bioethanol in 2020-gasoline
1 toe bioethanol requires about 4.9 tonnes grain. However each tonne of cereals used for bioethanol also generates about 0.33 tonnes of DDGS by-product. According to our animal-feed substitution section, 1 kg DDGS is equivalent to 1.06 kg of a mix of wheat and some soybean meal. In the section on rapeseed, above, we showed that in the main place where soybeans and wheat compete for land, they have about the same yield, so we can say that 0.33 kg DDGS replace 0.35 kg cereals. So the *net* cereals requirement for 1 toe ethanol is 0.65x4.9 = 3.19 tonnes grain.
The average EU cereals yield in 2020 is projected to be about 5.5 tonnes/ha[20], so the **net average-EU-cereals-land required for 1 toe ethanol will be 0.58 ha.** Less land is required for bioethanol than for biodiesel basically because cereals have higher yield than rapeseed.

The Wood-Mackenzie projection of road fuel use, used in this study, foresees 92 Mtoe gasoline demand in 2020. Substituting 10% of that with ethanol would need ~45 Mt cereals gross. However, [DG AGRI 2007a] work from a different fuels projection, and estimate ~59 Mt gross cereals would be

---

[17] Strictly, we should treat soybean meal and oil separately and give the soybean meal a second-order credit using rapeseed oil. This procedure would result a slightly higher land requirement for rapeseed oil, but is difficult to explain. Ignoring the difference in yield between wheat and soybeans also acts to underestimate the EU land requirement for rapeseed oil.
[18] soft wheat yield in DG-AGRI's published agricultural outlook to 2013, extrapolated to 2020 by assuming a 0.7% per year yield increase.
[19] FAPRI projected rapeseed yield (for 2017) extrapolated to 2020 is 3.54 tonnes seed/ha, and the oil crushing yield is ~42%
[20] It is appropriate to use average cereals yield (rather than soft wheat) because various cereals are used for bioethanol production. For simplicity we have assumed all bioethanol comes from cereals rather than sugar beet. Extrapolated to 2020, the average EU cereals yield projection from [DG AGRI 2007b] is 5.38 t/ha and that of [FAPRI 2007] is 5.79 tonnes/ha.

needed. Let us take the average: 52 Mt gross, which corresponds to 0.65x52= 33.4 Mt net cereals, and an average-EU-2020-cereals-land area requirement of 6.1 Mha.

Combined land requirements for biodiesel and bioethanol
Reaching the 10%-2020 renewable energy target using only 1st generation bioethanol and biodiesel would need at least 15.9 + 6.1= **22 mill. ha** of average EU cereal land. This corresponds to **37% of the combined area for cereals (52 mill. ha) and oilseeds (7.7 mill ha)** in EU-2005 [EUROSTAT].

So far, we have calculated as if there were two separate biofuel data points: 10% gasoline substitution and 10% diesel substitution. In practice there is only one combined target[21]. Since bioethanol has lower land requirements, one is tempted to substitute more gasoline than diesel. However, substituting more gasoline than diesel would aggravate problems in the refining industry, which is already struggling to produce a high enough ratio of diesel/gasoline.

These land requirements are all reduced if one assumes that 30% of the 10% biofuels target is met by 2nd generation biofuel instead of first-generation bioethanol and biodiesel. However, the reduction is less than 30%, inasmuch as some of the "freed" land would be needed for energy-crops for second-generation biofuels.

Important caveat on the use of equivalent land areas
There are huge differences in the productivity of agricultural land. Yields on any incremental arable area in EU will generally give much poorer yields, as well as possibly causing serious emissions of carbon from the soils. Furthermore, yields outside EU, are also generally lower.

What proportion of biofuel feedstock will be imported?
The latest DG-AGRI projection [DG_AGRI 2008], which assumes that compulsory set-aside rules are abolished, projects that an extra 10.2 Mtonnes/y of oilseeds[22] will be used for energy purposes in 2015 compared to 2006, whilst EU production of oilseeds would rise by only 2.3 Mt/y. However, imports of oilseeds are projected to rise only 5.28 Mt/y in the same period, because a projected 12% *reduction* in EU non-energy oilseed consumption makes up the difference. Without this reduction, ~87% of that extra oilseed demand for energy use would need to be imported.

Non-energy uses of oilseeds are principally food and oleochemicals, and have historically shown a steady increase with time, (and previous DG-AGRI outlook projections extrapolated this trend), so a sudden reversal of this trend is surprising, especially since other food and feed consumption, as well as GDP, is projected to increase. Possibly the 2008 projection assumes that oilseeds will be diverted from the EU oleochemicals industry, because it would not be able to compete for feedstock with subsidized biodiesel production. If this is the case, the result would be oilseeds being imported indirectly in the form of oleochemical products. Thus we think the projection is consistent with our conclusion in v2 of this study (below) that most of the feedstock for increased biodiesel consumption will be imported (although possibly indirectly rather than directly).

---

[21] Note that for the 2020 10% renewable energy target laid out by the RED, fuels beyond first generation biofuels in road, aviation, inland-navigation & rail could contribute to the target. However, it is assumed that FAME and Ethanol will be main contributors. See JEC Biofuels Programme report

[22] (presumably rapeseed-equivalent)

Table 5.2:1: DG-AGRI projections for cereals and oilseed markets to 2015

DG-AGRI Outlook 2008			
OILSEEDS: Million tonnes per year	2006	2015	increase
consumption for bioenergy	8.3	18.5	**10.2**
other consumption	30.3	26.6	**-3.7**
EU production	22.5	24.8	**2.3**
imports	16.1	21.3	**5.2**
exports	0.9	0.9	0
CEREALS: Million tonnes per year	2006	2015	increase
bioenergy consumption	2.8	20.4	**17.6**
other consumption	263.2	267.6	4.4
EU prod	267.1	302	**34.9**
imports	10.1	10.5	0.4
exports	26.5	25.3	**-1.2**

[DG-AGRI-2008] projects an increase of 17.6 Mt/y in cereals used for energy (principally bioethanol production) between 2006 and 2015. This is almost matched by a projected 17.2 Mt increase in EU cereals production in the same period, so EU exports are decreased by only 4.5% compared to 2006.

This confirms our conclusion in v2 (below) that EU biofuels policy can be expected to have a much larger impact on the vegetable oil market than on the cereals market.

(original text of version 2 follows)

Availability depends on cost

It is very important to bear in mind that for all crops (and other biomass resources) the potential supply is a strong function of the price one is prepared to pay. There is a tendency in the literature to report the costs from the cheapest supply scenario while choosing the maximum availability limit regardless of cost. To remain in touch with reality it is essential that availability and cost are assessed *together*: we need to know how much biofuel can be produced for the cost we are considering. Ideally, one would like to generate a cost-supply curve for each resource, but this is beyond the resources of this study.

5.2.1 Methodology for agricultural availability calculations

Learning curves for future yields and costs

For conventional crops (including oilseeds and cereals) our method automatically includes DG-AGRI's moderate estimate of future agricultural yield improvements, (0.8% per year in EU15; higher in the new Member States) but we added new data on newly-developed high-yield varieties of feed wheat.

Some studies have proposed strong learning curves, which reduce the cost estimates for future biomass supplies. This makes sense for long-term estimates of relatively undeveloped processes (e.g. energy crops such as short rotation forestry). However, for our relatively short time horizon, we assumed only that the best current commercial practice of short-rotation forestry will be typical by 2012. . For wastes, where the costs are dominated by collection and especially transport, we saw little opportunity for future cost reductions, so we used present-day costs.

### Using yield ratios is much more accurate than "average yield" calculations

As much as possible, we have tried to avoid estimating the potential supply of crops for biofuels by multiplying an estimate of the available area by an estimate of a "typical yield". This is because of the extreme variation of yield between different types of land. Even within the area presently planted with

wheat, some EU-15 land yields seven times less than the best. If more marginal land was planted in order to increase total production even worse yields could be encountered.

However, there is a relatively good correlation between the yield of different crops on the same land (see *Figure 5.2.1*). Cereals are grown on 86% of EU arable land. Since it grows on most areas, we prefer to express the agricultural resources of EU in terms of how much cereals could be grown on the available land, rather than on the number of hectares available. We measure the agricultural capacity in "Mt **A**verage **C**ereals **E**quivalent". 1 Mt feed wheat has an average cereals equivalent (ACE) of 1.135 Mt, because the new varieties of feed wheat now coming into use show 30% better yield than soft bread-wheat, and 13.5% better yield than the weighted average of the present mix of wheat types.

Our approach automatically takes into account the limitations on agricultural potential imposed by water resources, which is the dominating constraint in many of the drier parts of Europe.

Figure 5.2.1   *Correlation between yields of different crops in EU-25*
                     (National averages, excluding irrigated crops)
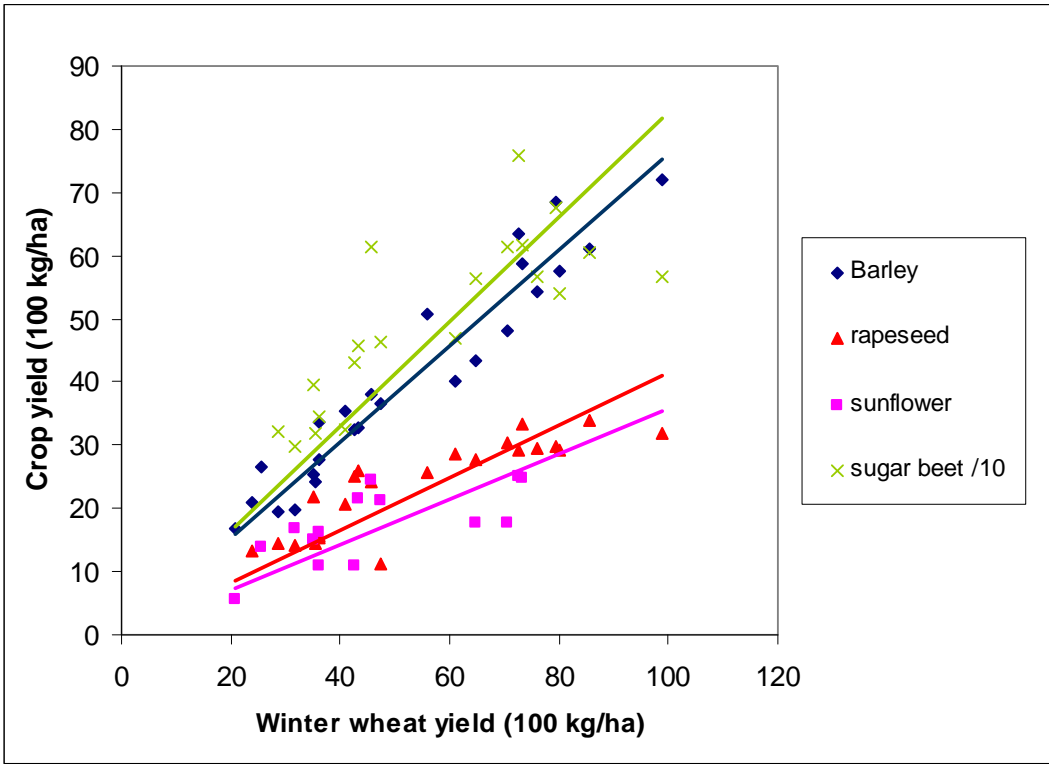
Impact of geographical distribution and break-crop effect on yield ratios

According to [*Christen 1999*], the yield of wheat after a crop of rapeseed is 10% higher than after another wheat crop. An increase in EU oilseed production would be met principally by increasing the frequency of oilseeds in a cereals rotation. If we take a typical rotation of wheat-wheat-barley-rapeseed, it would shorten to wheat-rapeseed-wheat-rapeseed. Then for each extra rapeseed crop, one barley crop is lost and one wheat crop grown after wheat is replaced by one wheat crop grown after rapeseed. The net loss of cereals is about 85% of the average yield on that land.

Note added in Version 3c: The "break crop effect" described in the preceding paragraph hardly exists today. The increase in rapeseed production in EU (especially in Germany), due to the relatively higher price of rapeseed oil, means that rapeseed is grown more frequently in cereals rotations than was considered agronomically viable in 2003: instead of one harvest in four, rapeseed is now grown in alternating years or even in successive years. In this case, increasing oilseeds production will no longer

improve cereals yields, and so now it would be more appropriate to take the simple yield ratio. This has the effect of decreasing the amount of oilseeds expected from a given resource expressed in "average cereals equivalents".

Using EUROSTAT crop distribution and yield data, we calculated the average cereals yield in the area where rapeseed is grown: 5.76 t/ha. On the basis of an average rapeseed yield of 3 t/ha (= EU15 average yield), growing an extra 1 Mt rapeseed by increasing the frequency of rapeseed-years in a cereal rotation leads to the loss of (only) 1.58 Mt average cereals, much less than the simple yield difference would indicate. So 1 Mt rapeseed has an Average Cereals Equivalent (ACE) of 1.58. The same calculation for sunflower indicates 1.47 Mt cereals lost per Mt sunflower seed. So 1 Mt sunflower seed is 1.47 Mt ACE.

5.2.2 Defining the baseline scenario

Our "business as usual" baseline adds sugar-reform to an existing DG-AGRI agricultural market projection, which assumes no expansion of biofuels.

In July 2005 DG-AGRI released a projection for EU agricultural markets up to 2012 in EU-25 [*DG-AGRI 2005*]. This assumes the implementation of planned CAP reforms and the transitional measures for the new Member States. Also taken into account are the Uruguay Round Agreement on Agriculture (URAA) commitments on subsidized exports and import barriers. This projection is significantly amended from the first results of the 2002 version of the DG-AGRI agro-economic model, used in version 1 of this study.

It includes a qualitative discussion of a scenario where the Biofuels Directive is implemented by subsidizing biofuels consumption, under the current CAP and trade regimes (see box in *section 5.2.4*). However, the quantitative projections are for biofuels production at expected 2005 levels. This constitutes a baseline onto which we can build the foreseeable effects of expanded biofuels production.

Table 5.2.2-1   *2012 total cereals and oilseeds production and prices according to [DG-AGRI 2005]*

		Cereals	Oilseeds
World production (FAPRI)	Mt/a	1602.4	334.4
EU-25			
Production	Mt/a	270.9	19.9
Consumption	Mt/a	256.0	37.8
Exports-imports	Mt/a	14.9	-17.9
Consumption for biofuels	Mt/a	1.5	5.6
Commodity price (FAPRI)[1]	€/t	150 [2]	215 [2] [3]

[1]Converted at 1.15 $/€ (DG-AGRI's assumed exchange rate)

[2]For US hard red wheat. Equivalent price for feed wheat 85 €/t

[3]FAPRI rapeseed price (FOB Hamburg)

In 2012 [*DG-AGRI 2005*] projects that the arable area would remain practically unchanged from the 2005 level: 58 Mha of which 50 Mha are devoted to cereals. Out of a total EU-25 cereals production of 271 Mt in 2012, there would be a surplus of 14.9 Mt (equal to exports–imports if stocks are constant). Other crops would be roughly in balance except for oilseeds: if bio-diesel remained at the present level of production the EU would continue to import almost half its total oilseed requirements: 17.9 out of 37.8 Mt in 2012.

The area of set-aside is expected to increase to 8.3 Mha, because of the extension of compulsory set-aside in the new Member States and the extension of voluntary set-aside due to declining profitability there. This accounts for a large proportion of the present "land reserve" of abandoned or under-utilized agricultural land in Eastern and Central Europe.

However the DG-AGRI projection does not include the effects of the proposed reform of the sugar regime, which would have a significant effect on EU arable potential. Since these reforms do not depend on biofuels production, we should add them in to our baseline projection.

Reform of the EU sugar policy will probably release about 9 Mt cereals capacity

In [*EC 2005*] the EC describes its proposals to reduce EU sugar production by reducing the support price. Some type of reform is forced by international trade agreements, but it was not yet considered in [*DG-AGRI 2005*].

The present support regime for sugar beet leads to its cultivation in many regions of the EU that are not agronomically very suitable. However, the proposed reduction in price will, by 2012, confine its growth to the lowest cost regions: France, Belgium, Denmark, and a few parts of the Netherlands, Germany and UK. A price reduction from the present 41 €/tonne to 25 €/tonne is expected to reduce sugar beet production by 76 Mt, from the present total of 182 to 106 Mt (22.7 Mt to 13.2 Mt sugar equivalent), assuming the option of buying an extra 1 Mt "C sugar" quota under the reform is taken up [*EC 2005*].

Our calculations confirm that the total anticipated sugar beet production in [*EC 2005*] corresponds to growing one crop of sugar beet for every four crops of wheat in the most suitable areas: this is the maximum frequency recommended to avoid the survival of pests in the soil from one sugar beet crop to the next (sugar beet can be grown more frequently only by intensive use of pesticides to disinfest the soil).

For simplicity, we assume all the land released goes to making cereals in the baseline scenario. To estimate how much extra cereals would be produced, we need to find a suitable ratio of sugar beet to cereals yield. Sugar beet requires good soil and plenty of water, so one expects winter wheat to be the preferred replacement crop, and to show a better-than-average wheat yield. On the other hand, the locations where sugar beet production will be abandoned will be where yields are poorest. Assuming these effects roughly cancel each other out, we used the simple ratio of EU-average sugar beet to winter-wheat yield. According to EUROSTAT data for the year 2000 (an average year) the average EU-25 yield for sugar beet at 76% moisture was 56.24 t/ha and for winter wheat at 13% moisture 6.49 t/ha: a ratio of 8.66 to 1 (not quite the same value as the slope of *Figure 5.2.1*, because that is a line through un-weighted national yields). The ratio for EU-15 is the same because both yields are 9% higher.

Thus, at 2005 yields, an extra 8.8 Mt/a cereals could be produced on the land released from the sugar reform. [*DG AGRI 2005*] assume 0.8% per year improvement in cereals yields, which would raise the **cereals production on ex-sugar-beet land to 9.3 Mt/a (ACE) in 2012. This raises the cereals surplus from 14.9 Mt/a in [*DG-AGRI 2005*] to 24.2 Mt/a in our baseline scenario.**

Table 5.2.2-2   Calculation of baseline total cereals and oilseeds production

		Cereals	Oilseeds
Production	Mt/a	270.9	19.9
+ from land released by sugar reform	Mt/a	9.3	0.0
= total production in baseline	Mt/a	**280.2**	**19.9**
EU consumption	Mt/a	256.0	37.8
Baseline exports-imports	Mt/a	24.2	-17.9
Baseline biofuel feedstock price [1]	€/t	85 [2]	215 [3]

[1]Converted at 1.15 $/€ (DG-AGRI's assumed exchange rate)

[2]For low-protein wheat. Corresponding FAPRI price for US hard bread-wheat is commodity price is 140 €/t

[3]FAPRI rapeseed price (FOB Hamburg)

We note that EU imports almost half its oilseed requirements, both now and in the 2012 projection. When we come to estimate the maximum bio-diesel which can be made in the EU, we assume the absolute level of imports to be the same as in the baseline.

Table 5.2.2.3 shows the amount of biofuels which would be produced from EU sources in our baseline scenario for 2012. The amounts of cereals and rapeseed for biofuels are those in the [*DG-AGRI 2005*] 2012 projection, based on conservative estimates of the EU biofuels production figures for 2005.

Note added in Version 3c: the availability estimates below neglected the availability-benefits of biofuel by-products being used as animal feed. On the other hand they were for the 5.75% (2010) transport fuel replacement target and not for the 10% (2020) target, and over-estimated the break crop effect (see above).

Table 5.2.2-3   Biofuels in the 2012 baseline scenario: fixed at 2004/5 levels

	Crop		Ethanol	Bio-diesel
	Mt/a	PJ/a	PJ/a	PJ/a
Rapeseed	5.6	133		78
Cereals	1.7	25	13	
Gasoline/diesel market coverage			**0.3%**	**0.9%**
Total road fuel market coverage			**0.7%**	

Organization of section 5.2

In *section 5.2.3* we looked at conventional biofuels: first we considered how much could be grown in EU regardless of cost and concluded that it is not possible to reach the targets in the biofuels Directive from EU production only. To allow the fulfilment of the Directive's targets, we then considered scenarios allowing imports. In these cases we assumed the targets are exactly achieved and looked at the effect on agricultural prices and on how much of the crops required would be produced in the EU. The first scenario is the simplest: set-aside rules would be kept unchanged. The second scenario looks at what would happen if set-aside was abolished: we used agricultural prices in the scenario for our calculations of total biofuels costs. Both import scenarios assume that the present agreements on agricultural trade are respected.

Using alternative biofuels one can think to exceed the biofuels Directive targets for 2010 using domestic production. *Section 5.2.3* looks at the cost and supply of crop residuals, wood waste and farmed wood, transported to biofuels conversion plants. Finally, *section 5.2.4* examines how much compressed biogas could be produced in EU at the present cost.

5.2.3 Conventional biofuels production in the EU

In this first section we estimate in a transparent way how much bio-ethanol (from cereals and sugar beet) and bio-diesel could possibly be produced from EU domestic sources in 2012, regardless of how this would affect prices.

Starting assumptions

- We excluded the expansion of arable area by ploughing up pasture or forest land, to avoid loss of historical soil carbon stocks (see *section 3.4.1*).
- We assumed the same food consumption and food imports as in the reference "business-as-usual" scenario. This includes continuing to import about half the EU's food-oilseed requirements.
- EU-grown animal feed crops could be diverted to increase biofuel production, but these would have to be replaced by imported animal feed. In other words biofuels from this source would be made from indirectly-imported crops, so we didi not take it into consideration.
- On the other hand, biofuel production in Europe will generate animal feed as a by-product, reducing the need for purpose grown animal feed.
- We allowed the diversion of EU exports to biofuel production.
- The biofuels Directive target of 5.75% replacement of road fuels by 2010 does not specify how this should be split between gasoline and diesel. We assume that 5.75% of diesel should be replaced by bio-diesel and 5.75% of gasoline by bio-ethanol.

There are three sources for increased EU production of biofuels crops in 2012

I   Diversion of the baseline cereals exports (including land from sugar reform)
Although the present EU cereals production is roughly balanced with consumption, table 5.2.2-2 shows that our 2012 baseline scenario projects 23.7 Mt ACE surplus cereals for export. This comprises 14.9 Mt ACE in [*DG AGRI 2005*] (due to improved yields) and an additional 8.8 Mt ACE on land released by the sugar reform. To maximize EU-produced biofuels we assumed all this arable capacity would be devoted to making biofuels.

II   Additional production on ex-set-aside land

The extra production from set-aside cannot be calculated simply from the average EU wheat yield
Production of oilseed and cereals for biofuels is already permitted on set-aside land, but only if the farmer has a contract with a biofuel producer. The effect is to confine production on set-aside to farms in the region of biofuels factories. However, if set-aside rules were abolished there would be a general increase in cereals output, which could translate directly and indirectly into increased EU production for biofuels. First we estimate the general increase in cereals output.

Rotational set-aside is already part of cereal rotations and the effect of removing these compulsory break-years is offset by the need for break-years anyway and by the benefit of break-crops to subsequent cereals yields. Voluntary set-aside land would also give lower-than average yields because it is relatively poor land where cereal farming is hardly profitable. Much of the land would not be good enough for wheat production: a mix of cereal types would be produced. Statistical analysis of data from the 1990s, when set-aside rates were changed several times, indicated that set-aside at 14% reduced cereals production by 10% [*DEFRA 2000*].

Looking at the variation in cereals area as compulsory set-aside was reduced from 10% to 5% in 2004 and then increased again to 10% in 2005 suggests that the effect on cereals production is now significantly lower than this, implying that farmers have learnt how better to integrate set-aside years in their crop rotations (but the set-aside increase for 2004 was announced too late to allow planting of winter wheat, so one should not take these data alone). Another reason why the DEFRA ratio will give an overestimate of set-aside production is that, in 2012, there would be a substantial increase in

voluntary set-aside on poorly-yielding marginal land in the new Member States. Nevertheless, we shall use the DEFRA ratio for giving the **upper limit** of EU production.

The overall rate of set-aside projected for 2012 in our baseline [*DG-AGRI 2005*] is 13.6%, so we could expect this to reduce the potential cereals output by a maximum of 10%. The projected 2012 cereals production is 270.9 Mt, so the maximum on set-aside would be about 27 Mt. About 19 Mt of this would be from compulsory set-aside. To find how much *extra* biofuels could be grown on set-aside, we have to subtract baseline production of biofuels crops on set-aside, which amounted to 2.4 Mt rapeseed [*DG-AGRI 2005*] (equivalent to 3.8 Mt average-cereals), plus roughly 0.3 Mt cereals-for-ethanol. So the *extra* production on set-aside would be equivalent to 23 Mt average-cereals at maximum. The extra production on only *compulsary* set-aside would be 15 Mt ACE.

What is a set-aside?

There are two types of set-aside at present in EU-15: compulsory (or "rotational") and voluntary (or "permanent") set-aside. Compulsory set-aside forbids cereals farmers growing food on part of their land. The "default" area of obligatory set-aside is 10% of the area of all farms growing a significant amount of cereals, but the reference rate is adjusted according to the level of EU cereals stocks.

However, farmers are allowed to grow non-food crops on set-side land without further subsidy: these are generally part of a crop rotation with cereals. At present about 20-30% of set-aside in EU-15 is planted with "industrial" oilseeds (mostly rape for bio-diesel production) as part of cereals rotations, producing about 2.2-2.4 Mt/a of seeds designated as "industrial" [*FEDIOL 2002*][*DG-AGRI 2005*]. Set-aside rules will come into force in the new Member States in 2009: they will set-aside about 1.25 Mha arable land.

If planted year-after-year, cereals decline in yield because of disease build-up and soil degradation. This applies especially to soft wheat, which has the highest yield. As a result, most wheat in Europe is grown in rotation with a lower-yielding "break" crop. The farmer can declare a field to be in rotational set-aside and still use it for a break-crop, such as grass, clover or rapeseed. So the effect of set-aside is to encourage more frequent break-crops, and the reduction in EU cereals output is less than would be predicted by the % area in set-aside (a phenomenon known as "slippage").

Although small farms are exempted from set-aside obligation, the overall set-aside rate in EU-15 is well above 10% (14% in 1999/2000 [*DEFRA 2000*]) of the eligible area, because of the operation of permanent set-aside: farmers are rewarded for turning up to 50% of their land over to "nature" for at least five years. According to current CAP rules, permanent set-aside cannot be used to grow arable biofuels crops, but can be used for wood farming.

Not much sugar beet would be grown on set-aside

Sugar beet is grown in rotation with other crops, especially wheat. In areas where sugar beet production at 25 €/t is more profitable than wheat, sugar beet will already be planted as frequently as possible in the rotation. That means roughly once in 4 years if large pesticide applications are to be avoided. Where sugar beet is the most profitable crop, farmers time set-aside years to be in the part of the rotation where sugar beet is not grown. So eliminating set-aside would not increase sugar beet production significantly: it would mostly increase the other crops in the rotation, most likely wheat. The land in voluntary set-aside is not good enough to produce sugar beet at all.

A significant amount of extra sugar beet might be produced at a competitive price if the wheat price increased significantly, for example if total ethanol production was pushed beyond 5.75% gasoline replacement.

III   Use of "C" sugar beet

"C sugar" is sugar produced in excess of the food-quota. It cannot be sold for food in the EU but can be exported (assumed in the baseline) or sold for ethanol production. The sugar reform proposal allows up to 1 Mt of "C sugar" production (equivalent to 8 Mt sugar beet).

[*EC 2005*] estimates that the price of sugar beet should be 25 €/t to reach the planned levels of production. By a happy coincidence, our processing-cost calculations show that ethanol production from sugar beet at 25 €/t is just competitive with ethanol from wheat. So the production cannot anyway be increased much above this level without making ethanol from sugar beet uncompetitive.

Crop rotations limit maximum rapeseed production

Flexibility calculations are not really valid for such large changes. The large oilseed price increases found to accompany this maximum EU production scenario indicate that it is probably beyond what is agronomically reasonable. To quote [*DG-AGRI 2005*]: "under an extreme scenario with substantial price increases, the rise in domestic production of cereal and oilseed could meet 50% of the additional demand from the biofuels Directive" (although the assumptions behind this calculation are not clear). Our maximum EU production amounts to 68% of the additional demand from the biofuels Directive.

At the moment almost all bio-diesel grown in EU is from rapeseed, because it is the cheapest and most suitable vegetable oil grown in EU. Soil and climate limitations mean that rapeseed is usually rotated with common wheat. Common wheat production would be about 140 Mt in 2012 [*DG-AGRI-2005*], whereas our upper limit of oilseed (rapeseed + sunflower in table 5.2.3.1) cultivation is 24.7 Mt. The unadjusted yield ratio of wheat/rapeseed is about 2.3, so, if all extra production is rapeseed, there would be only about 2.5 wheat crops to each rapeseed crop. Bearing in mind that less land is suitable for rapeseed than common wheat, this is an extreme scenario. It means that rapeseed would have to be grown in 3 or even 2-year rotations (which reduces the benefit of the break-crop and may allow survival of pests between crops), and/or on land for which it is not very suited, probably rotating with coarse cereals.

One expects that the lower yields and dilution of the break-crop benefit would increase the marginal cost of rapeseed production substantially. The increasing price of rapeseed oil would drive biofuels producers to mix in other oils such as sunflower oil, which can be grown in EU areas unsuitable for rapeseed. We assumed 20% of the oil demand would come from sunflower oil, but the proportion is not critical to the calculation of the overall biofuels production potential.

The contribution of animal fats and used cooking oil is small and uncertain

(Revised text, version 3c)
Argent Energy in UK produce biodiesel from tallow as well as used cooking oil. Animal fats give FAME with high cetane number but also a high cloud point, so they need to be diluted with other biodiesels to reach transport specification.

Table 5.2.2.4   EU uses for animal fats, from [APAG 2008]

EU USES OF ANIMAL FAT 2007 (million tonnes/y)	
animal/pet feed	0.87
oleochemicals	0.75
industrial furnaces (unsubsidized)	0.60
subsidized burning for bioenergy	0.06
subsidized biodiesel manufacture	0.06
food	0.15
soap	0.07
TOTAL	2.56

There is a range of animal fat qualities, reflected in their price. The highest grades are used for food and feed; only the lowest grades are used for fuel. As by-products of meat production, their availability will hardly increase even if they become more valuable because of new (subsidized) uses. Burning tallow in industrial furnaces has been facilitated since it has been released from the list of materials covered by EU's waste incineration Directive. EU rendering plants produce about 2.5 Mtonnes animal fats per year, and more is imported by the EU oleochemical industry. About 0.6 Mt/y is used to fire furnaces, usually inside rendering plants. Together with what was already used in bio-electricity and biofuels schemes, about 0.72 Mt could potentially be diverted without detracting from non-energy uses.

The furnaces would then probably be converted to natural gas. Allowing for the likely better efficiency of a natural gas burner, the upstream emissions for animal fat use in biodiesel could be represented by ~95% of the equivalent amount of natural gas in terms of heating value.

[BioDieNet 2008] estimates that, 3.55 Mt of used cooking oil could be collected annually in EU, and somewhat more than 0.7 Mt/y are actually collected in EU at present. Of this, roughly 0.5 Mt/y is made into biodiesel.

We have not included these sources in our availability scenarios for conventional biofuels.

5.2.4 Estimate of bio-fuel crop prices

(New text added for version 3, 2009
In version 3 we base crop prices on the FAPRI projection

In JEC-WTW we have whenever possible always used market prices rather than bottom-up estimates of production costs. We believe market prices are more reliable indicators of marginal production cost, and they also represent both the cost-to-EU of importing feedstock, and the income-to-EU foregone if the feedstock is used for EU-biofuels production instead of export. We are pleased to see that other researchers have now almost all adopted the same approach.

For v3 we are fortunate to be able to use the latest world agricultural-commodity price projection to 2018 from [FAPRI 2009], which now takes into account price movements due to all present biofuels targets, including the 10% replacement in EU. Previously, we also considered price projections from DG-AGRI. However, DG_AGRI no longer specify the projected prices for oilseeds in their outlook, and they agglomerate the oilseeds sector, so we cannot extract prices for individual oils and meals. FAPRI is an inter-university organization set up by U.S. Congress to model developments in the food and agriculture industry for use by US government and others. Another well-respected annual agricultural outlook projection is produced by OECD/FAO, and generally the results do not differ very much from FAPRI. However, the OECD/FAO outlook agglomerates the oilseeds sector, and, at the time of writing, the latest OECD/FAO had not yet incorporated the effects of the EU RE biofuels target.

To arrive at the prices used in our calculations, we had to convert the projected 2018 prices in FAPRI from dollars in 2018 to net present value in 2008 euros. The oil price assumed for 2018 converts to 44 euros/barrel (using the exchange rates and inflation assumed by FAPRI) which is close to our lower oil price scenario. Finally, for the wheat price, we had to apply a quality correction to estimate the price of low-protein feed wheat used for distillation.

We cannot update the following analysis for the impact of the (then 5.75%) biofuels replacement target on crop prices, because crop price projections *without* biofuel targets are no longer published.

Market prices rather than bottom-up costs

Some LCA studies attempt to calculate costs of agricultural products by bottom-up estimates of farming cost. We think this is a very difficult way to approach the subject: it is almost impossible to represent an average "cost to EU" and it is very easy to lose touch with farming reality. The reforms of the CAP have largely brought internal EU prices in line with world prices (with the exception, until now, of sugar beet). In any case, since biofuels crops are internationally traded commodities, the cost to EU is the price which EU gets for exporting them or pays for importing them. Not only are these world prices known, but there are sophisticated projections available about how they may develop in the future.

In this section we confine ourselves to estimating the implications of meeting the targets for road-fuels replacement in the biofuels Directive, in the year 2012. The effects on domestic production, imports, exports and cost are considered.

Ligno-cellulosic resources (wood waste, short rotation forestry and crop residuals) are treated separately, since their production is not confined to arable land.

Key assumptions are:
- *5.75% (energy content) of the 2012 gasoline and diesel fuel demand* is replaced by bio-ethanol and bio-diesel respectively,
- *There is no expansion of arable area onto forest or grazing land*, to avoid loss of historical soil carbon stocks (see *section 3.4.1*),
- *Existing trade agreements are maintained.*
  The EU is committed to various trade treaties, and probably cannot erect new tariff barriers even if it was desirable to restrict imports of feedstock for biofuels.
- *Cereals are treated as a single market*
  Even though not all types of cereals are equally suited for making ethanol, there is plenty of flexibility in competing uses, especially animal feed. Furthermore some farmers will change the cereals crop they grow, if one or other becomes relatively more expensive. Therefore we think it appropriate, when estimating the effect on prices of demand changes, to consider cereals as a single market, and not to consider wheat only. There is an argument for including also alternative carbohydrate animal feeds, such as manioc, but the effect on the results would be marginal.
- *Oilseeds are treated as a single world market*
  At present, quality standards restrict EU bio-diesel production effectively to rapeseed. In the future we may expect technology and legislation to evolve to permit use of a wider range of oilseeds. But even if this does not happen, rapeseed oil is easily substituted by other oils in the food market. Thus at the moment most EU bio-diesel is made from domestically grown rapeseed, but this is partly substituted by importing other oilseeds to satisfy the food demand.
- *The single farm payment is not included in the costs*
  In line with other costs, the cost considered is the direct cost-to-EU. However, the cost does not include the single farm payment. This incorporates the former "direct area payment" of 63 €/t nominal historic cereal production on the land, including rotational set-asides, no matter what crop the farmer produces. This payment would remain the same whatever use is made of the crops so that it does not have to be taken into account in the biofuels cost assessment.
- *Food and feed demand are the same as in the baseline 2012 scenario*
  This means we only consider the supply elasticity. Although in theory we should also consider the demand elasticity, the demand elasticities in the literature are caused by people switching from one type of cereal or oilseed for another. If we are considering the whole cereal or oilseed market, the demand elasticities will be very low: people and cows will not eat much less in total even if the price rises.

We started from DG-AGRI's prices projection for 2012 without extra biofuels

[*DG-AGRI 2005*] forecasts EU prices on the basis of the interaction of the CAP and other EU agronomic and trade rules. The introduction of the single farm payment, combined with the

progressive lowering of trade barriers in agriculture according to obligations under trade treaties, means that the price of agricultural products in the EU is tied to the world market price. Thus [*DG-AGRI 2005*] bases its agricultural prices for 2012 on two different forecasts of the world market, from FAPRI and OECD, which predict the price of agricultural commodities at EU ports. For the products which interest us, the two forecasts are very similar: they differ by much less than the uncertainty from fluctuations in the $/€ exchange rate (which is assumed to stabilize at 1.15 $/€ in [*DG-AGRI 2005*]). We used the price forecast from [*FAPRI 2005*] because it differentiates between different oilseeds.

The prices in [*FAPRI 2005*] and [*DG-AGRI 2005*] assume that biofuel production stays at 2005 levels (0.6% road fuel replacement, mostly by bio-diesel). Thus they could serve for calculating the cost of biofuels *where there is only a marginal increase in biofuels production*. But as we show below, attaining 5.75% road fuels substitution will have a large effect not only on EU agricultural markets, but even on the world market.

Distillation-quality wheat costs 95 €/t in the baseline scenario

[*DG-AGRI 2005*] quote the [*FAPRI 2005*] price projection of 159 $/t for the standard commodity "hard red US wheat FOB Gulf". EU soft wheat trades at about 40$/t less than this, and experts expect further improvements in yields of distillation-quality very-low-protein feed wheat to reduce the production cost by a further 10$/t by 2012, bringing the price to 109$/t, or **95€/t**. At this price it could be competitive with imported feed-barley, even without an import tariff barrier. This type of wheat requires adequate water, so is especially suitable for growing in the highly-intensive wheat-growing regions of Northern Europe.

In our baseline scenario, the extra cereals production on land released by the sugar reform would decrease world cereals prices by a negligible 1% or so.

Effect of meeting the biofuels Directive targets on trade, food and feedstocks prices:
DG-AGRI's analysis

[*DG-AGRI 2005*] warns that achieving the biofuels directive's target of 5.75% road-fuels substitution by biofuels in 2010 would have a "major impact" on cereal and oilseed prices.

The effect on ethanol production cost would be partially offset by an increase in the value of by-products as animal feed, due to ethanol production competing for the supply of feed-wheat. On the other hand, the EU would end up paying substantially more not only for the crops used for biofuels, **but also for the crops used for food and animal feed.** This would be reflected in sharply improved farm incomes and higher food prices for consumers.

Effect of biofuels targets on imports
On the assumption that the trade regime follows current obligations (import tariffs and quotas), [*DG-AGRI 2005*] discusses the effect on the market and on production of achieving 5.75% replacement of gasoline and diesel by bioethanol and FAME respectively.

The report states that "under an extreme scenario with substantial price increases, the rise in domestic production of cereal and oilseed could meet 50% of the additional demand from the biofuels directive".

Of the remaining demand, 25% would be met through direct imports and 25% by diverting wheat, maize and rapeseed from animal feed and food use. The supplies of animal feed and food would then be made up by imports, so in the end at least 50% of the extra biofuel supplies would come directly or indirectly from imported crops.

Thus DG-AGRI contends that the EU would become a net importer of cereals, despite the substitution of feed-wheat by other (partly imported) animal feeds, and the existence of import barriers. The EU already imports half its oilseed requirements and the production of oilseeds is constrained by crop rotations, climate, and the Blair House agreement. Therefore, under the current trading regime, **more than half of the extra vegetable oils needed to reach 5.75% diesel substitution by FAME would come from imported oilseeds or vegetable oil.**

5.2.5 Meeting the Biofuels Directive with imported crops: impact on prices and EU production

No change in trade barriers

We have seen that attempting to maximize EU-produced biofuels can give large price increases and lead to a shortage of oilseeds. EU imports about half its present oilseed requirements, and they attract no import tariff. Furthermore, it would be legally difficult to erect new trade barriers against imports of oilseeds. Therefore, we consider trade to be an essential part of a realistic scenario for biofuels pricing. EU has a 90€/t tariff on imports of cereals, but this has limited impact because the EU is expected to have a net cereals surplus.

5.75% EU ethanol in gasoline would increase world cereals prices slightly

The rate at which cereals supply varies with price is called the supply flexibility. Estimates vary widely, partly because of geographical variations and (often unspecified) statistical uncertainty, but also because different effects may be included. Values for individual cereals types reflect the flexibility of farmers to switch between different cereals crops, but we need the flexibility for the cereals sector as a whole. Furthermore, we should not include the inertia for change from one growing season to the next, because in our case the change happens over a number of years. An analysis which produced a sensitivity measure suitable for our purposes is described in [*DEFRA 2000*], p.132. Separating out the inertia for change in a separate coefficient, they find the EU-15 cereals sectorial supply flexibility to be 0.62 +/- 0.26.

Although there would be little increase in EU *production cost* due to the extra demand from biofuels, there will be a small increase in cereals *market price* compared to baseline, because expanding biofuels production would deprive the world market of the baseline EU exports. These total 24.2 Mt ACE (see *Table 5.2.3-1*) or 1.5% of the projected world 2012 cereals production of 1600 Mt. If production on set-aside was unchanged, this would cause a 2.3% increase in world price (± 1.2 %). But we remember that the baseline price should anyway be 1% below the DG-AGRI/FAPRI projection due to the effects of the sugar reform: the net price change is insignificant.

This is a simplified analysis: the effects of making biofuels on local prices may be more significant due to the isolating effects of transport and shipping costs. Here we are talking of differences in the region of 10-20 €/t: still less than the annual variation due to weather.

5.75% EU bio-diesel would increase world oilseed prices significantly

Replacing 5.75% of EU 2012 diesel with bio-diesel from rapeseed would require 36 Mt of oilseed. Subtracting the oilseeds already used for EU bio-diesel in the baseline scenario, the demand *increase* would be 30.8 Mt, 9% of the projected world oilseed supply in 2012 (or 160% of projected 2012 EU production in the baseline scenario).

We need the world supply flexibility of the oilseed sector as a block. The nearest we could get to this was long-term area response flexibilities for the oilseed block in different countries. These may be used as a proxy for supply flexibility, because yields hardly change with price [*DEFRA 2000*]. According to [*Meilke 1998*], the flexibilities range from 0.2 to 1.03 for different countries. If we take an average figure of 0.8 ± 0.3, we conclude that a 9% increase in oilseed supply would require a **rise in world price between 8% and 18%.** If set-aside is liberated, the price rise should be lower because of the increase in arable area. However, the effect on the price estimate is insignificant. We set the oilseeds prices for our biofuels cost calculations **10% above the 2012 FAPRI-projection prices** quoted in [*DG-AGRI 2005*]. That brings them to **237 €/t for rapeseed and 265 €/t for sunflower.**

EU cereals production for biofuels should increase more than oilseed production

Our cost analyses show that bio-ethanol from cereals and bio-diesel are approximately cost-competitive. At the time of writing, bio-diesel production is expanding more rapidly than ethanol, but that is probably because of the shorter lead-time and lower capital cost for bio-diesel production plants; furthermore EU oilseed production is not keeping pace with the increase in bio-diesel processing capacity. In the longer term, the EU oilseed price can be expected to increase much faster than that of cereals (for comparable increases in FAME and ethanol production) because the EU oilseed supply potential is much smaller (being limited by rotations, climate and soils). If bio-diesel and bio-ethanol are given equal incentives, we should expect that bio-diesel would use more imported feedstock than bio-ethanol processed in EU.

Since the EU is projected to produce more cereals than it consumes for food and feed, its use for ethanol production inside the EU also avoids the costs associated with exporting it. This does not apply to oilseeds which would not be exported anyway, because the EU has a deficit in supply.

So one may expect most of the spare EU arable capacity to go towards satisfying the cereals-for-ethanol demand until that market is saturated (in *Table 5.3.2-1* we assumed that it happened at 5.75% gasoline replacement). After that, using EU arable capacity for oilseeds becomes more interesting because any *more* cereals produced would then have to be exported, with associated costs.

The effect of liberating or freezing production on set-aside

There is presumably no legal barrier to EU relaxing its set-aside rules in order to reduce imports. Even if the present set-aside rules are not changed, we can expect some expansion of production on set-aside. But the extra production will be limited by logistics, because according to the present CAP rules, crops from set-aside must be contracted to go directly to a processor, rather than joining the larger food/feed market. Furthermore, production of oilseeds on set-aside is partially constrained by the Blair House agreement (see box).

The Blair House agreement

The Blair House agreement, extended in 2002, limits the effect on US soy bean exports of the oilseed-meal by-products from subsidized "industrial" oilseeds grown on EU set-aside land. In practice it limits oilseed production on EU-15 set-aside land to about 2.4 Mt, grown on approx. 0.95 Mha. [*DG-AGRI 1997*]. Current production of rapeseed on set-aside runs at close to this level.

But biofuels manufacturers are already using almost three times this amount of oilseeds: they have to buy unsubsidized "food" rapeseed at the world market price.

Blair House would not seem to prevent set-aside areas being used to grow food crops in replacement of crops grown for biofuels on non-set-aside, or simply doing away with set-aside altogether. Anyway, Blair House only applies to *subsidized* oilseed farming: it is not applicable if bio-diesel production is encouraged by fuel tax exemptions rather than by direct farming subsidies. So in practice Blair House need not limit bio-diesel production, even if set-aside land is used.

If the EU wishes to increase oilseed production for biofuel, it appears that Blair House disallows the use of more subsidized oilseeds but allows subsidies on biofuels production.

To cover the range of outcomes for different set-aside policies, we considered two extremes. In one case we froze production on set-aside at the 2004/5 levels assumed for 2012 in [*DG-AGRI 2005*]. In the second case we assumed that set-asides were liberalized, so farmers could choose which crops to grow on that land, and that the produce could be sold freely on the market. The maximum possible production on set-asides was already estimated in *section 5.2.3*. The problem now is to analyse how much oilseeds and how much cereals would actually be produced in the EU.

Only production on voluntary set-aside would cost more than baseline

The supply calculated for a given market price would not be valid if that price was exceeded by the production cost. The extra sources of arable potential for expanded biofuels, compared to baseline scenario, are production on set-asides and diverted exports. The cost of crop production on compulsory (rotational) set-aside is about the same as on the same land not in set-aside [*DEFRA 2000*]. Exported cereals (from increased yields and the good farmland liberated by the sugar reform) could be diverted to biofuel production even with a cost saving, because no shipping is needed. Only the marginal land typically volunteered for voluntary set-aside would have higher crop production costs. Arable farming on most of this land would probably not be profitable even with the price rises due to biofuels. Furthermore, although there may be little historical accumulation of soil carbon to lose on voluntary set-aside land, ploughing it up would prevent any *increase* of soil carbon uptake.

If we do not account for the potential production from voluntary set-aside, we get the EU cereals potential at the baseline production cost. Voluntary set-aside contributed about 30% to our total EU 2012 set-aside production potential, leaving a contribution of about 16 Mt average-cereals from rotational set-aside. This is included in *Table 5.2.5-1*.

Table 5.2.5-1   *Achieving the biofuels Directive targets with trade*
                      Set-aside frozen at baseline production (2004/5)

	ACE[1]	Crop		Ethanol	Biodiesel
	Mt/a	Mt/a	PJ/a	PJ/a	PJ/a
I Diverted baseline cereal exports:					
From land released by sugar reform	9.3				
Fom improved yields	14.9				
II Maximum extra cereal from set-asides[2]	0.0				
Total spare cereals	24.2				
To feed-wheat for ethanol	22.4	25.4	376	202	
To rape seeds[3]	1.8	1.1	27		16
Oil seeds imports		**29.6**	**704**		**412**
III Ethanol from"C" sugar beet		8.0	31	16	
Existing crops for energy in baseline[4]					
Rapeseed		5.6	133		78
Cereals		1.5	22	12	
Total				**230**	**505**
Gasoline/diesel market coverage				**5.75%**	**5.75%**
Total road fuel market coverage				**5.75%**	

[1]Average Cereals Equivalent (our measure of arable capacity)

[2]Excluding biofuels already grown on set-asides

[3]Small extra production, most cheaply from rapeseed

[4]i.e. in the baseline scenario, including those grown on set-aside

The market would favour exporting cereals and importing most oilseeds

Having estimated the effect of the biofuels Directive on the world price, we will now see how this would affect EU oilseed output. We recall from the previous section (*5.2.5*) that for our cost calculations in the "biofuels" scenario, we chose an oilseed price of 10% above the business-as-usual price, although the calculation showed the increase could be in the range 8 to 18%.

[*Meilke 1998*] states that the long-term area response flexibility for oilseeds sector in EU is 0.87. Therefore a price increase of 10% results in a production increase of about 8.7% (assuming constant yield). Our baseline EU oilseed production is 19.9 Mt/a. So, on the same arable area one would expect to get an additional 1.7 Mt oilseeds. However the sugar reform increases arable capacity by 4% and the possible liberation of compulsory set-aside by a further 7%, so the total **increase in EU oilseeds supply would be about 2 Mt/a** according to our reference price increase, with a range is between 1.5

and 3.4 Mt/a. This is only a small part of the extra 31 Mt/a oilseeds needed to reach the 5.75% bio-diesel target.

Note: Shipping costs tend to favour local production. However, the calculation is based on changes from the baseline scenario, where oilseeds already compete with EU production in spite of shipping costs, so this effect should cancel out. Furthermore the cereals are exported also in the baseline scenario, so shipping costs should make no difference there either. Anyway, adding 10% costs for shipping would not change the main conclusion.

The main point is that it would be more profitable for EU farmers to use most their increased arable capacity in 2012 for cereals exports rather than growing oilseeds, and it would be cheaper for biofuels producers to import (directly or indirectly) most of their feedstock. This reflects the reality that, compared to the rest of the world, EU is more suited to growing cereals than oilseeds. In practice, rapeseed is preferred for bio-diesel production, whereas soy, sunflower and maize oils (mostly imported) are preferred for food. Therefore EU rapeseed oil would be diverted from food-use to bio-diesel, to be replaced by imported food oils. Thus the feedstock for bio-diesel would largely come *indirectly* from imports.

Table 5.2.5-2   *Achieving the biofuels Directive targets with trade*
                      Set-aside abolished

	ACE[1]	Crop		Ethanol	Biodiesel
	Mt/a	Mt/a	PJ/a	PJ/a	PJ/a
I Diverted baseline cereal exports:					
From land released by sugar reform	9.3				
Fom improved yields	14.9				
II Maximum extra cereal from set-asides[2]	16.0				
Total spare cereals	40.2				
To feed-wheat for ethanol	22.4	25.4	376	202	
To rape seeds[3]	3.0	1.9	46		27
To cereal exports	14.8				
Oil seeds imports		**28.8**	687		**401**
III Ethanol from"C" sugar beet		8.0	31	16	
Existing crops for energy in baseline[4]					
Rapeseed		5.6	133		78
Cereals		1.5	22	12	
Total				**230**	**506**
Gasoline/diesel market coverage				**5.75%**	**5.75%**
Total road fuel market coverage				**5.75%**	

for notes see table 5.2.5-1

We see that without increasing production on rotational set-aside, there is only just enough arable capacity in the EU to produce 5.75% ethanol in gasoline; very little left over for oilseeds or exports.

Comparing the two scenarios, we see that the main effect of liberating rotational set-aside would be to increase cereals exports. In either case nearly 30 Mt of oilseeds (rapeseed equivalent) would be imported in a free agricultural market. Of course this could also be in the form of vegetable oil or processed bio-diesel. Importing processed bio-ethanol would lead to a little more oilseed production if set-asides are frozen, but mostly to more cereals exports in a free agricultural market.

Of course, EU could intervene in the market in various ways to promote use of EU-produced oilseeds for bio-diesel at the expense of cereals exports, but this would be at additional cost.

By-product markets

Large additional production of protein animal feed by-products would cause a price decrease

Both ethanol and bio-diesel lead to the production of protein animal feed by-products viz. DDGS and oil-meal respectively. They are produced in the EU if the processing is done there, regardless of

whether the feedstock is imported or not. For the energy and emissions balance, we gave a credit representing the present main source of animal protein in the EU: soy meal made from imported beans. In version 1 of this study we used the same feed-replacement ratio to estimate the costs of the by-products. However, in this version we could use forecasts of the by-products themselves.

It is important to know the amount of animal-feed by-product in order to check that the market can absorb it all. An extra 218 PJ of ethanol is needed to replace 5.75% of EU gasoline consumption (above baseline). The DDGS by-product is most valuable as animal feed, replacing 7 Mt soybean meal. Replacing 5.75% diesel with bio-diesel would produce enough extra rapeseed and sunflower meal (compared to baseline) to replace a further 14 Mt soybean meal. The combined total of 21 Mt soybean meal equivalent compares to EU 2012 imports of 24.8 Mt (FAPRI forecast).

If biofuels are imported as fuels or vegetable oil, then of course a portion of these by-products will be produced outside EU, but they still impact on the world market price. At the moment the pattern is to import oilseeds rather than bio-diesel, so the by-products are still produced in EU, but by 2012 one may anticipate a shift to the use of palm oil and other oils not pressed in EU.

FAPRI quoted in [*DG-AGRI 2005*] project a 2012 world oilseed meal supply of 212 Mt. In [*Meilke 2005*]; the average supply flexibility for the major world producers is about 0.3. On this basis one expects the extra biofuels needed to meet the biofuels Directive to depress the price of oilseed meal by about **30%,** although the margin for error is wide, because of many unforeseeable factors in the market and the scarcity of clear statistical data on which to base the estimates of the market flexibility. This makes our **best-estimate prices 76 €/t for rapeseed meal and 66€/t for sunflower meal** (both at conventional 10% moisture). Both have an error margin of +/-20%.

DDGS prices

The market for DDGS is not sufficiently developed for world market prices to be quoted. Therefore we had to use a price based on the protein-replacement ratio with soybean meal (see *WTT Appendix 1*). Like oilseed meal, DDGS is considered a poorer quality feed than soy meal. Therefore we have linked both DDGS price and oilseed prices, via their protein-replacement ratios, to a "virtual soy meal price", which is lower than the expected soy meal price to take account of the quality differences. This virtual price (labelled "animal feed substitute" in the price table) is set to give the prices of oilseed meals we already estimated in the last paragraph. The resulting **price estimate for DDGS is 74 €/tonne**.

Rapeseed meal, sunflower meal and DDGS are not as easily digested as soybean meal, so that they cannot replace it entirely. This would suggest that some of the output would have to be exported. Bearing in mind the cost of sterilization, packaging and shipping, the fall in price at the factory gate could be even more dramatic. Of course the figure given is very uncertain, but it warns that the glut of protein-animal feed from biofuels by-products is likely to severely impact protein-feed prices, which will increase the costs of biofuels production.

The market outlook for glycerine affects the choice of substitution (see *section 3.4.10*)

5.2.6 Advanced biofuels scenario

Farmed wood availability

Farmed wood price

The highest yield from forestry on an annualized basis comes from short-rotation forestry (SRF). The best-yielding varieties are willow and poplar in north of Europe and eucalyptus in the south. Willow is more suited to wet conditions. It is harvested ("coppiced") every 2-4 years by cutting the shoots which grow up from the trunk. The remaining root system allows trees to re-grow biomass quicker than annual crops. After about five cuts, the whole tree is harvested. Poplar stems are cut after 8-15 years. The cost for establishing SRF and returning the land to arable again is very high, so there should be a

long-term policy. Wood is the preferred type of biomass fuel: it has lower salt content and higher bulk density than other energy crops.

There is a huge range of farming costs for SRF in the literature: from about 39 €/dry tonne [*Bauen 2001*] up to 153 €/dry tonne [*FfE 1998*]. In version 1 of this study we could not find any commercial price information and had to infer the SRF cost from bottom-up costing studies of SRF profitability, comparing it to wheat. The cost in version 1 came out higher than the present one, partly because at the time of writing wheat prices were at a historic high, and partly because we probably overestimated the quality of the land in the SRF study.

In the present version, we have been able to calculate the cost-to-EU of SRF wood directly from the commercial price paid to UK willow farmers by power utilities, who buy it to meet their renewable energy obligation by co-firing in coal-burning power stations. These prices and the prevailing subsidy regime are sufficient to persuade some farmers to grow willow, without causing a rush to cover the countryside with willow plantations. So they seem a good basis for our cost estimate.

Industry sources told us that utilities pay about £38 (≈55 €) per dry tonne of delivered willow chips. This is broadly confirmed by the Renewable Energy Farmers' Association website, which quotes £30. However growers also get subsidies of £1000/ha (≈1450 €/ha) establishment grant from UK government and 45€/ha energy crop subsidy from CAP. We can treat the establishment subsidy like a plant investment, which also has a 15-20 year lifetime: we apply our standard capital charge of 12% (equivalent to 8% discount rate). For a typical UK yield of 10 dry tonnes/ha, the **unsubsidized cost** including delivery works out at

$$55 + (1450 * 0.12 + 45) / 10 = \textbf{77 €/dry tonne}.$$

The UK is generally very suited to growing willow and the first plantings are likely to be in the lower cost locations, so one could argue that we have underestimated the cost of SRF for large-scale planting of SRF elsewhere in the EU. On the other hand one expects costs to fall as farmers get more experience with the new crop. Our costs are towards the higher end of the range assumed in the VIEWLS project, but we should remember that ours are for 2015; theirs are for 2030 (see text box).

Best current practice gives SRF yields only 1.57 times cereals yield

In the 1980s people were very optimistic about the potential yields from SRF on the basis of trials by various research institutes. Experience in the 1990s with real plantations brought down yield expectations: [*Mitchell 1999*] wrote "realism is creeping in, lower yields than anticipated are being accepted, matched by lower costs".

[*Unseld 1998*] reported trials of short-rotation forestry on various sites in Germany. Annualized yields varied from 1 to 29 dry tonnes per year, depending mostly on the water availability. We can see that it will be difficult to establish an average EU yield. The concept of average yield can anyway be misleading when considering establishment of SRF on former arable land, because the productivity of arable land varies enormously itself. The best approach is to estimate the ratio between the yield of crops and SRF wood, because yield variations for different crops are strongly correlated: land which is good for one crop is usually good for another. The problem is that few trials of SRF state the cereals yield on the same land.

In the UK willow farming was established for the ARBRE project. Most SRF production goes now to co-firing in coal-burning power stations. Industry sources say that "grade 3" ex-cereals land yields 10-12 dry tonnes per ha, but that results on "grade 4" arable land are poor. On grade 3 agricultural land in the area wheat yield was estimated to be about 7 t/ha, also giving a yield ratio of 1.57.

On the other hand, an association of energy farmers told us that, as a rule of thumb, the yield of SRF is about equal to the winter wheat yield on the same field. This may be based on information from the earliest cuts, but [*Mitchell 1999*] states that the anticipated increases in yield on subsequent cuts did not materialise on commercial plantations; implying the yield ratio would stay at only 1.

Comparing returns from SRF to those from arable crops, [*Mitchell 1999*] implies that 10 dry t/ha SRF yield is to be expected from land with 8 t/ha winter wheat yield (a ratio of 1.25).

[*LWF 2000*] also states that previous average yield estimates were too optimistic for SRF in Bavaria. Their careful assessment of SRF potential in Bavaria gives an average yield of 8-10 dry t/ha. We can compare this to an average wheat yield in Bavaria of about 6 t/ha (yield ratio 1.57).

For 2012**, we assume a yield ratio of 1.57** dry tonnes of annualized SRF production per tonne of winter wheat production (mix of bread-making and feed varieties) at the standard 13% moisture. This implies wood farmers adopt current best practice.

So the resource potential for farmed wood is higher than "conventional" biofuels. The question marks are the costs, the time to develop the technology, infrastructure and plantations, and whether it is better to use the wood for electricity and heating.

SRF: The view from VIEWLS

[*VIEWLS 2005*] includes a sophisticated analysis of cost and availability of biofuels that could be produced in the EU by 2030. Basically, the study assumes maximum biofuels production by re-assigning the use of all land (not just agricultural land) not already built on or foreseen for urban development.

The land available for biofuel crops is assessed by subtracting from this total:
- the land needed for food crops to feed each country's population
- the forest area needed to grow the estimated wood requirements
- the land needed to grow fodder for animals (no grazing).

ALL the remaining land (predominantly grazing and unharvested forest) is assigned to a biofuel crop: either rapeseed, sugar beet, miscanthus or willow. The cost of growing the biofuels crops is then calculated on the basis of various agro-economic scenarios, bearing in mind the varying yields on different types of land. Curves of average production cost against availability for each crop and scenario are then derived.

The VIEWLS availabilities of sugar beet and rapeseed do not apparently take into account the limits imposed by crop rotations or the negative effect on soil carbon of the proposed land use changes from forest and grassland to arable. Therefore it is pointless to compare the arable crops results with our figures. But the rotation limits do not apply to the permanent crops, and the size of the soil carbon reduction by planting SRF or miscanthus on forest or grazing land is much less certain (although probably detrimental to some extent), so one may tentatively consider the VIEWLS estimate for these crops.

Willow gives the highest forecast availability at a given cost. To attain an availability figure for willow to compare with ours, we chose the VIEWLS agro-economic scenario closest to DG-AGRI forecasts ("scenario 3"). The availability–cost curve shows a broad plateau up to **8000 PJ** followed by a steep cost increase. This forecast 2030 availability would be at an estimated production cost of 3.2 €/GJ (HHV), or 62 €/ dry tonne. The reasons the availability is much higher than ours for EU25-2012 are as follows:
- SRF expands onto grazing, forest and other land, whereas we only considered arable land
- VIEWLS assumes much improved SRF yields by 2030

For another VIEWLS scenario (V5), where CEEC costs matched EU-15 costs, the corresponding plateau cost was about 4.2 €/GJ (HHV), or 82 €/dry tonne. In this scenario, the production cost on second-grade "suitable" land in Poland is 3.2 €/GJ (HHV) = 62 €/ dry tonne. These values compare with our delivered unsubsidized cost for willow chips of 77 €/dry tonne, or about 70 €/t at the farm gate. So the costs seem to be in the same ballpark.

The costs do not look much different, until one compares the corresponding wheat yields. VIEWLS propose SRF yields on their second-category "suitable" land in Poland to average about 11.2 t/ha. The record 2004 winter wheat yield in Poland averaged 4.28 t/ha and that was presumably mostly on "very suitable" land. So VIEWLS is expecting SRF yields to be at least 2.5 times higher than winter wheat yields. Comparing this with the present yield ratio of 1.57 at most, implies VIEWLS anticipates an increase in SRF yield of more than 60% from now to 2030. Although the tendency until now has been for SRF yield expectations to fall, it is not unreasonable to expect that from now on there will be rapid improvements in varieties and commercial farming techniques for this new crop.

Availability of agricultural and forestry wastes

Far more waste is available for energy than for biofuels production

Lignocellulosic materials can be converted to ethanol by the wet SSCF process or to other fuels via gasification. Both these are complex processes with economics dominated by the high plant investment costs: to make them viable it is important to use economies of scale. The straw-to-ethanol pilot plant of Iogen Corporation has a capacity of 140 MW_{th}, and gasifiers in general should be larger still for good economics. By contrast, reasonably efficient and clean biomass boilers are available at much smaller scales, for heating commercial buildings or small industrial processes, and the size of combined-heat-and power electricity generating plants is anyway limited by the demand for heat. Biomass power stations are less complex and capital-intensive than a second-generation biofuel plant, and so are likely to be economic at smaller scale.

Thus, when estimating the availability of feedstock, one should consider not only how much is there in the field or forest and how much can technically environmentally and economically collected, but also how much can logistically be brought to large processing plants.

Straw and other agricultural residues

Text modified for version 3

The price of straw depends strongly on local conditions and the quantities involved; there is a great spread of cost data in EUROSTAT. However, a good basis for our purpose is the price paid at Ely straw-burning power station in the UK (the world's largest). Straw is sourced from within 40 km of the plant making the average transport distance about 35 km.

Straw price varies from season to season, and with the cost of fertilizer needed to replace the minerals lost in the straw. The power station can cope with relatively low quality, damp, straw, and so they can obtain supplies at less than the regional UK farm-gate straw prices quoted in the *Farmers Weekly*. On the other hand, transport to the plant and intermediate storage has to be considered. Altogether we estimate the delivered cost at the power station to be roughly 40 £/t (~45 €/t) at 15% water. There is no subsidy on the collection of straw. This cost is for a 120MWth power plant sited in an area with a very high density of high-yield cereals farming. Costs would be higher in most areas of EU, except perhaps in new member states, where lower labour costs might outweigh the lower resource density.

[*Edwards 2005*] reported on a GIS-based study on the availability of straw in EU for feeding power stations. Taking into account competing uses, they estimated that EU produced 820 PJ straw in excess of the existing requirement. They used GIS techniques to map the cost of straw delivered to a 120Mw power plant. JRC subsequently held two expert consultations of the straw availability issue with industry, agronomists and soils experts *[JRC 2007],[JRC 2008b]*. The general conclusion was that the JRC estimate was too optimistic: it did not take sufficient account of the limitations imposed by:-
- o year-on-year supply variability
- o the need for straw to preserve soil texture and labile soil carbon, and avoid erosion of some fields
- o inaccessible fields
- o the need for the plant operator to maintain a bargaining position with farmers

The conclusion was that these practical limitations would restrict straw use to roughly 1/3 of the surplus straw (i.e. after subtracting existing uses). That means a maximum of about 16 Mt (270PJ) of straw in EU 25. Furthermore, especially for large plants, the collection cost rises as the density of cerals cultivation decreases. From the GIS data generated for [*Edwards 2005*], we have managed to construct the following approximate cost-supply curve for straw in EU27. The low-cost tail stems from the assumption that labour costs are 30% lower in new member states than in EU15: with time, one expects this differential to diminish.

Fig. 5.2.6.1   Approximate cost-supply curve for cereals straw delivered to 120 MW power stations in EU 25

EU-25 supply of surplus straw as a function of cost delivered to 120MW thermal plant
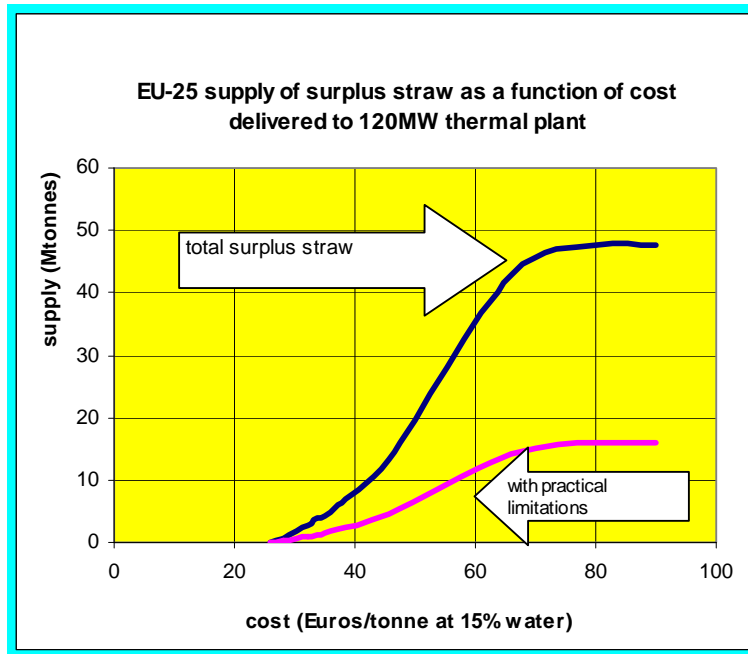
[*Edwards 2005*] dealt with straw from cereals which occupy 86% of the EU arable land. Of course many other crops produce prunings and residues, but these are far more dispersed, all have different processing characteristics, and many are already used for animal feed (a point overlooked in some surveys). Therefore we think their possible contribution to making renewable transport fuels would probably be less than the uncertainty in our straw estimate. Again, they could contribute more to bio-energy resources than biofuels.

Waste wood

Sources of waste wood

There are several types of wood wastes:
- "Forest residuals": branches, tops, undersize thinnings and, with latest forestry technology, roots.
- "Mill residues" bark and other wastes produced at the pulp mill.
- "Secondary wastes": from the wood industry (sawdust, shavings etc)
- "Used wood" from building demolition, pallets etc
- "Agricultural residues" from woody plants such as fruit trees and vines
- Forest litter: dead wood removed from old stands or natural forest to reduce fire risk

There is no industrial-scale production of transport fuels from wood waste at present. Current EU total wood waste now used for energy production (heat/electricity) is 50 dry Mt/a [*EUREC 2002*]. This represents 48% of total wood used for energy, the rest being non-industrial trees cut for firewood. It subdivides into 40% residues, 39% secondary residues and 21% used wood.

Apart from straw, very little woody agricultural residue is currently used to produce energy in EU commercial plant. Generally residues occur at a very low density over a wide geographical area and are only available once a year. The cost of transport makes waste wood cogeneration only marginally economic even in the middle of a forested region, where the density of production is high and the

wood can be transported all year round. With the exception of cereal straw (see above), we therefore considered that there is no possibility to economically collect a significant part of the agricultural woody residues for energy use. The special situation of straw is considered above.

Secondary waste is the most consistent in quality and easy to obtain. It has been used in many pilot studies of gasification etc. However, it is already almost completely recycled within the wood industry (40% for products, 60% for heat and electricity). Life cycle analysis studies almost all agree that use in products is better for greenhouse gas than use as energy.

Used wood is the driest and therefore convenient for small pilot plant studies. At present it has near-zero or negative cost at source. But the source is extremely dispersed. Furthermore, there is a problem of contamination: only a fraction of the potential supply can be used within health regulations. Detoxification is under study by the wood industry, who would like to recycle more of it.

Mill waste is completely used within the pulp/paper mills (for process heat and electricity export) and so is not available for conversion to road fuel.

It is sometimes claimed that forest litter could be a useful woody biomass resource: the high cost of collection might be justified by the external credits from avoiding forest fires. We are not competent to make this calculation. However, the resource would certainly be very dispersed, making it suitable for energy use in local heating, for example, but probably not for transporting to large centralized plants for conversion to biofuels.

Summarising, it appears that **forest residuals are the only significant potential source of more woody waste for transport fuel**.

Availability of forest residuals

When harvesting trees in commercial forestry, the branches and tops are stripped from the trunk at the harvest site and forwarded to a baler or a roadside chipper. The bales or chips are carried to the mill by adapted log-trucks. Recently, integral harvesters have been developed. These remove the roots as well, but cannot be used in difficult terrain. An advantage of taking the roots is that they are better fuel: drier, and with a lower mineral content than branches; the disadvantage is that the disruption of the soil could lead to loss of soil carbon and soil erosion at sensitive sites.

As with many other sources of biomass for energy, studies conducted 15 years ago were far more optimistic about availability than the latest studies. For example, estimates in six successive studies of the possible availability of Swedish forest residues have declined by a factor five from around 380 PJ in 1995 to 75 PJ in 2005 (of which 32 PJ already used) [*Lundmark 2005*]. Therefore the estimates in version 1 of this study, which were conservative compared to previous pan-European studies, are roughly confirmed by more recent work.

[*METLA 2004*] used broadly the same approach as we did in version 1 of this study to estimate the technically and economically available forest residuals in EU-25: they started from the statistics on fellings and then estimated extension factors to find the amount of residuals associated with these. However, the METLA study is more detailed and includes cost-supply curves for various countries. Therefore we adopted their results for the present study.

[*METLA 2004*] also considers using the excess roundwood for energy purposes (i.e. the annual excess of commercial forest growth over actual fellings). METLA assume 25% of the excess growth could be used. At present, some countries such as Portugal have no excess growth whereas others, for example Finland, have a large excess growth but are reluctant to cut it for energy use.

Additional material for version 3:

JRC *[JRC 2008a]* used the data in *[METLA 2004]*, *[Lundmark 2005]*. and other sources to construct a cost-supply curve for forest chips, comprising "waste" wood residues and wood-chips from cutting some of the marginal between the annual wood growth in exploited EU forests and the demand. Note these figures include those felling residues which are already used, but do not include other (traditional) firewood. Since then doubts have been raised whether this reserve of net growth increment really exists, or whether it is not due to data gaps *[Mantau 2007]*. UNECE (http://timber.unece.org/) is coordinating experts to produce a realistic picture of EU wood availability for energy and other markets.

Unlike *[METLA 2004]*, *[EEA 2006]* (prepared by European Forest Institute) did not set an implicit limit on the maximum "reasonable" price of wood chips. This means they have a higher estimate than JRC/METLA of the maximum EU availability (the figure comparable to the maximum in the JRC curve is 115 Mt dry wood), but with a *much* higher price. Unfortunately, this price did not appear in the EEA summary report *[EEA 2006]*, but the subsequent more detailed report *[EEA 2007]* on the forest-based studies specifies that the price for this level of supply in 2020 is 120 €/m3, or about 300 €/dry tonne!

The price-availability figures in *[EEA 2007]* correspond well with the lower part of the JRC curve, but the slope is lower meaning *[EEA 2007]* prices are higher for a given level of availability. The *[EEA 2007]* price comes from a market model of the forest and wood industries, whereas the JRC/METLA costs are bottom-up estimates of marginal production cost. It is indeed plausible that the market price of wood chips in EU would run ahead of the marginal production cost at times of rapidly-increasing energy-demand for wood chips.

Fig. 5.2.6.2   Estimated cost-supply curve for wood chips delivered to 100 MW EU plant
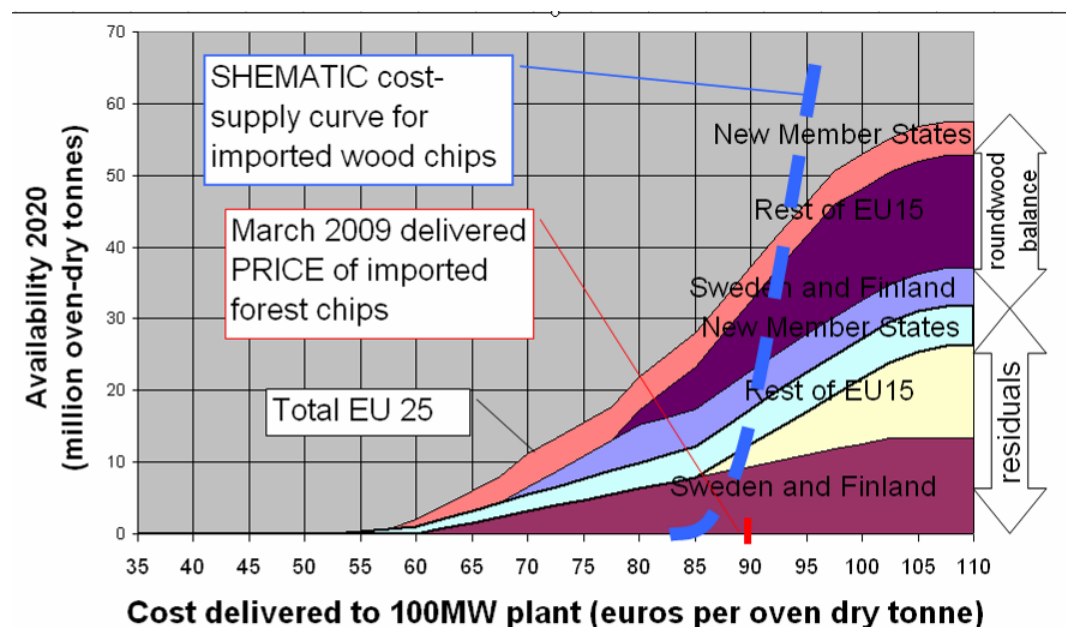
The order of the sources (Sweden and Finland, rest of EU...) is arbitrary: the graph just sums the wood chips available from each. Note these data do NOT include existing traditional firewood, and are calculated including transport costs to large processing plants, which would be needed to make economic sense of converting to liquid fuels.

The March 2009 market price of imported wood chips in railway trucks at Ukrainian/Polish border is about 75 Euros/oven-dried tonne (quoted as 45 Euros/tonne at ~40%water). To get that to a plant on

the railway in Germany (for example) would cost roughly an extra 15 Euros/dry-tonne, making a total delivered cost of 90 euros/dry-tonne.

This must represent one of the cheaper sources of EU energy-wood imports. However, once the EU price passes a level where the extra transportation costs of imported wood can be paid, the availability of imports increases much faster than that of EU-produced energy wood, because of the much higher potential production capacity in the rest of the world (assuming no trade barriers are erected). Therefore we expect the proportion of imported energy-wood to rise rapidly as the delivered price exceeds 90 euros/dry tonne. That limits further price rises in the long term, but means that most of the theoretical extra capacity of EU forests to provide extra energy supplies will never be used.

Forest residuals for replacement of gasified black liquor

Black liquor is the by-product of pulp-making containing the lignin fraction of the wood, mixed with process chemical in a slurry. In existing pulp mills, it is burnt in a recovery boiler for process heat. Instead, one can gasify the black liquor and make up the missing process heat using a boiler fired by forest residuals. The syngas from the gasifier can be used to produce either electricity or transport fuels.

The amount of fuels that can be made in pulp mills using the efficient black liquor route depends on how many mills have large enough boilers to make black liquor gasification economic. This is the case for about 80% of EU plants and they could be converted gradually as their recovery boilers come up for renewal over the next 20 years.

According to [*Ekbom 2003*], EU-15 produced 395 PJ black liquor in the year 2000. We first added 11% to this figure to account for pulp production in the new Member States (proportional to the pulp production figures from EUROSTAT). We then used the growth rates projected by [*Ekbom 2003* to calculate an EU-25 black liquor production of 527 PJ in 2012. However, only about 80% of this would come from plants large enough for economic conversion to black liquor gasification so the amount available for gasification would be 422 PJ. Again according to [*Ekbom 2003*] 408 GJ forest residuals would replace 487 GJ of gasified black liquor in their model black liquor gasification plant. This results in a potential demand of 353 PJ forest residuals to fully exploit the possibilities of black liquor gasification in EU-25 in 2012.

[*METLA 2004*] estimated the technical availability of forest residuals and roundwood balance country-by-country. Comparison of the results of [*METLA 2004*] with the black liquor potentials of [*Ekbom 2003*] gasification study shows that each pulp-producing country in EU-15 can supply just enough forest residuals to fully exploit its potential of black liquor gasification.

The cost-supply curves for Finland in [*METLA 2004*] and for Sweden in [*Lundmark 2005*] indicate that these two principal producers could provide just sufficient forest residuals at a price of 2.8 €/GJ. The cost-supply curve for Poland in [*METLA 2004*] indicates that new Member States could supply it for even less. The cost-supply curve for France indicates that almost no forest residuals would be available at 2.8 €/GJ, and the same is probably true of other small EU-15 pulp producers. But France, Austria and Spain could possibly supply the biomass at that price by exploiting some of their roundwood balance. Portugal has no roundwood balance to exploit, and Germany and the UK have no pulp industry. In all EU-25, we estimate **325PJ woody biomass would be available to pulp mills at 2.8 €/GJ**: 92% of that required for full exploitation of black liquor gasification.

A larger constraint is techno-political: even if the maximum number of EU pulp-mills were converted for black liquor gasification, some might prefer to produce electricity (or methanol rather than transport fuels) either for economic reasons or more likely as a result of renewable policies in certain countries. Even though black liquor gasification is a very efficient way of producing transport fuel

from biomass, making electricity could save more GHG from the same biomass and for less money. In particular there is little enthusiasm for producing transport fuels in Finland, after some disappointing tests in the 1970s. And of course, the whole concept is still at the pilot plant stage: we do not yet know how long gasifiers will withstand the severe sulphidation conditions. Accordingly, we have assumed that a maximum of **2/3 of the black liquor gasification capacity could realistically be exploited to produce transport fuels. This would consume 238 PJ woody biomass, mostly forest residuals.**

Forest residuals for other conversion routes

In our advanced biofuels scenario, the cheapest sources of forest residuals have mostly been exploited for the black liquor at pulp plants, because collecting residues is a large-scale operation combined with clear-fell harvesting and can make use of the same transport infrastructure to bring the residuals to the pulp mills.

[*METLA 2004*] estimated the maximum technical availability of forest residuals and roundwood balance in EU-25 at 1008 PJ/a. If we subtract the 325 PJ available at pulp mills for processing by the black-liquor gasification route, we are left with 683 PJ for other uses. However, this resource is far more dispersed than the residuals at pulp mills: it could be brought to saw-mills (typically much smaller than pulp-mills) or supplied along with traditional fire-wood. A larger proportion is from forest thinnings. This is a comparable situation to straw availability: it is logistically difficult to get the resource to large plants of the type needed to convert it to transport fuel. It could much more easily be exploited for energy in the form of local heating and CHP plant. A detailed GIS study is needed for a proper estimate. Since none is available, we made our estimate congruent with the situation of straw supply and assumed that at most 1/3 of the supply could be brought to a plant with a capacity greater than 130 MW$_{th}$. That means about 230 PJ, similar to the maximum amount that could be processed into transport fuels via the black liquor route.

In [*METLA 2004*] the cost-supply curve for France shows that to collect most of the available residues here one would need to increase the price to around 4.1 €/GJ which is our price for SRF wood. We supposed that prices in other EU-15 countries, notably Germany and Austria, would be comparable.

Conservatively we did our cost calculations using the lower price of 2.8 €/GJ for the entire waste wood supply.

5.2.7 Organic waste for compressed biogas

The potential for biogas is much higher for energy than for transport fuel

As with other energy-from-waste schemes, the availability of compressed biogas as a transport fuel is much less than that of biogas as an energy source for heating and small-scale electricity generation. Heat and electricity can be made even on simple farm-size plants, but *compressed* biogas for transportation requires a purification plant, a compressor, consistent quality and preferably an output sufficient for at least one filling station. Because of all these factors compressed biogas for transport needs to be produced in large centralized plants of the scale presently seen in Denmark to be economically viable.

Animal manure from intensive livestock farms is the biggest resource for transport-biogas at our production price

[*FfE 1998*] and [*Holm-Nielsen 1997*] have estimated how much potentially-digestible waste is produced in EU-15. The largest resource is animal manure, and by far the largest contribution is from cattle ([*FfE 1998*] use 18 t/a for the average amount of manure produced by cattle, a very high figure compared to other studies which report between 8.5 and 15 t/a. We favour average figures of 11 t/a per head of cattle and 1.7 t/a for pigs). This size of plant is only possible in areas of intensive livestock farming, where animals are kept indoors and manure is collected as slurry.

Sewage is more dilute and more dispersed than animal manure, giving higher biogas production costs. Agricultural wastes could be made into biogas, but many of the suitable ones are more valuable as animal feed. There is also a problem of year-round availability.

Organic wastes from separated municipal waste and from the food industry are very suitable for biogas production: they produce much more biogas per tonne than does manure, and they cost money to dispose of by other routes. Furthermore, there are synergistic advantages in mixing manure and organic wastes: the temperature of the fermentation and the C:N ratio can be kept nearer the optimum. The problem is that there is much less of it than animal manure, and it is difficult to get enough together in one place to make a biogas plant large enough to make compressed biogas at our price.

Purpose-grown crops, or grass collected from surplus grassland can also be digested, but the cost is far higher than using wastes. Since our cost results show that compressed biogas from waste already has trouble to compete on price with conventional biofuels in EU, we do not think this option is likely to be developed in our time horizon. It could possibly be considered competing with more expensive advanced-biofuels concepts in the more distant future.

Capital costs dominate

Biogas production is highly capital intensive: the typical feedstock of manure has a low specific energy content, and the residence time in the reactor is much longer than for thermal conversion processes. This makes the plant very large for a specific energy output, so that capital servicing is the main component of the total gas cost.

Large Danish plants process 300 tonnes biomass a day and would produce 6000 m^3/day (1.6 MW) raw biogas if they were fed only from animal slurry. This is the amount of manure produced by about 8000 cattle or 50,000 pigs. In Denmark these plants typically collect manure from about 50 farms within a radius of less than 10 km.

Adding organic waste makes the process viable at our costs

Usually manure slurry is not paid for. It is collected from the farm and the processed fertilizer returned without charge to the farmer (but farmers often own a share of the biogas plant). Danish plants are only economically viable because of co-feeding with organic wastes from the food industry (slaughterhouse waste, fisheries processing waste, dairy waste etc.), both because these boost the biogas yield and because, being expensive to dispose of by other safe routes (incineration etc.) the biogas producer actually gets paid to process them.

One tonne of a typical mix of 20% organic waste with 80% slurry produces a net 30 Nm^3 biogas ("net", because some of the total biogas production is used to warm the fermentor), whereas animal slurry alone produces only about 20 Nm^3/t. So the same size and cost of plant produces 50% more gas. Already biomass plants are competing for the supply of organic wastes, so that most are operating at the edge of profitability [*Hjort-Greersen 1999*].

Our biogas price estimates corresponds to this model of biogas production, but with no gate fee for the organic waste. Thus our price does not take into account the cost of alternative treatments for the slurry and organic wastes. According to [*AEA 1998*] these are higher than for anaerobic digestion, but it is beyond the scope of this study to evaluate them.

A typical mix is 80% animal slurry / 20% organic waste. It is cheaper to transport the organic waste than the animal slurry, so the plants would be located in areas of intensive indoor livestock farming, producing manure as slurry. EUROSTAT statistics show that 30% of EU cattle live on farms of more than 200 head, and 36% pigs live on farms of more than 2000 head. This may give a rough indication

of the availability of slurry from intensive farms. The conclusion is that the biogas production at this price is limited by the availability of organic waste.

The availability of organic waste limits the EU supply of compressed biogas to 200 PJ at our biogas price

Total municipal organic waste in EU-15 is estimated at 57 Mt/a [*Fazoino 2005*]. The figure is close to the estimate in [*FfE 1998*] and [*Barth 2000*]. The fraction collectable is difficult to estimate for the whole of the EU: at present it ranges from 0% in Greece to 78% in Germany. We took a figure of 62%: the present performance in Flanders. The estimate of food industry waste was from [*FfE 1998*].

If we assume ALL the organic waste could be brought to a biogas plant at a site where there is a sufficient local slurry to supply a plant of our size, we find that AT MAXIMUM about **200 PJ/a** purified biogas, suitable for compression, could be available**.**

The problem is that intensive animal farming tends to be concentrated in a few regions of the EU: Western Denmark, Po Valley, etc. So even though one could afford to transport organic waste as far as 200 km, much of it could still be produced in areas far from where there is a sufficiently concentrated source of slurry. However, we could not find sufficient data on how slurry sources are distributed in EU, so we could not refine our estimate further.

Table 5.2.7   *Biogas potential from animal slurry and organic waste at 15.5 €/GJ*

		EU-15	EU-25*
Total digestible fraction of MSW	Mt/a	57	69
Realistically collectable as separate waste	Mt/a	34	41
PLUS food industry waste	Mt/a	12	14
Total digestible organic waste	Mt/a	46	56
Biogas potential from organic waste	PJ/a	76	92
Animal slurry for 4:1 mixture	Mt/a	185	223
Biogas potential from slurry + organic waste	PJ/a	164	197

* scaled by population

Of course, more biogas would be available if the *price* was increased to allow production from pure slurry, or the use of specially-grown crops. However, we reasoned that the most economic production of compressed biogas for transport is all that one could hope to develop within the next 10-20 years. We repeat that much more biogas could be available for small-scale *energy* use (heat or small-scale electricity generation).

5.2.8 Potential production of advanced biofuels

Using the availability figures discussed above we have built a number of extreme scenarios illustrating the potential of a number of single options for using the available biomass. It must be noted that these scenarios are mutually exclusive inasmuch as they represent alternative ways of using the same resource. The numbers are shown in ***Table 5.2.9***.

The second and third columns show the availability of the different types of biomass. In all scenarios it is assumed that surplus sugar beet is still grown and is turned to ethanol, and so is straw which accounts for a base ethanol production of 117 PJ/a. All surplus cereals as well as the area currently used for oilseeds are converted to SRF or equivalent to produce woody biomass. This "wood" is then converted, together with waste wood to either ethanol, syndiesel (with co-production of naphtha), DME or hydrogen.

Because these fuels apply to different engine configurations, a full comparison of these scenarios must be done on a WTW basis. Reference is made to the *WTW report, section 8.6*.

Table 5.2.9   *Advanced biofuels production potential*

Resource	Mt/a	PJ/a	Ethanol PJ/a	Syn-diesel PJ/a	(Naphtha) PJ/a	DME PJ/a	Hydrogen PJ/a
Surplus sugar beet	8.0	31	16				
Wheat straw	15.9	230	97				
Surplus grain (as food grade wheat)							
Set-asides	*22.9*						
From net land released by sugar reform	*9.3*						
Improved yields	*14.9*						
	⇩				Or		
As farmed wood	83.9	1511	518	472	*157*	771	942
Existing oil seeds for energy	7.1						
	⇩						
As farmed wood	19.7	355	122	111	*37*	181	221
Waste wood	26.2	471	162	167	*56*	274	332
Scenarios							
Max ethanol			914				
Max syn-diesel			113	750	*250*		
Max DME			113			1226	
Max hydrogen			113				1495

[1] i.e. gasoline for ethanol, diesel for syn-diesel and DME and combination for hydrogen
Assumptions for all scenarios:
  Marginal sugar beet still grown
  Straw only used for ethanol production
  50% of waste wood used though black liquor route

5.3 Hydrogen production potential

Hydrogen is already produced in significant quantities today mostly for industrial applications. Oil refineries, in particular, are large hydrogen consumers for hydrodesulphurisation of various streams such as gasoils and heavy oil conversion processes.

The most widespread hydrogen production process is steam reforming of natural gas (see *section 3.2.5)*. The process is technically and commercially well-established and natural gas is a widely available and relatively cheap feedstock. Steam reforming of heavier hydrocarbons is also possible but little applied, if at all, in practice because the process equipment is more complex and the potential feedstocks such as LPG or naphtha have a higher alternative value. Existing reformers are mostly large industrial plants but small scale prototypes have been developed.

Partial oxidation of a carbonaceous feedstock in the presence of water also produces syngas and can be applied to a wide range of materials, in particular heavy feedstocks such as oil residues, coal (see *section 3.3*) as well as biomass feeds such as wood (see *section 3.4.11 and 5.2*). The front end of the process is essentially the same as for the manufacture of synthetic liquid fuels. The synthesis section is replaced by the CO-shift step. Small scale wood gasifiers for electricity production have been developed at the pilot plant stage and could conceivably be adapted for small scale hydrogen production.

Reformers and gasifiers produce CO_2 in one place and, when using oxygen rather than air, in a virtually pure form. Large scale installations may offer a viable platform for possible CO_2 capture and sequestration projects.

Electrolysis is also a well established technology both at large and small scale. Interest in large scale hydrogen production is likely to result in improvements in terms of efficiency and costs. One particularly promising development route is high pressure electrolysers. The use of electricity as the energy vector to produce hydrogen opens the door to the use of a large variety of primary energy sources including fossil and biomass but also wind energy and of course nuclear.
Direct solar energy can also, in principle, be used to produce hydrogen either by thermal splitting of water or electrolysis through photovoltaic electricity. The development of the former type of processes

is in its infancy while the latter is not expected to be viable at very large scale within the timeframe of this study. We have therefore not considered these options.

All in all a lot of hydrogen can theoretically be produced. In practice though and in view of the availability of both feedstock and technology, only natural gas reforming provides a short term avenue for flexible large scale hydrogen production. The coal route requires large scale, costly plants with major financing and public acceptance issues. Biomass is of course an option but of a limited nature and where hydrogen competes with other uses (see further discussion in *section 9 of the WTW report*). The same applies to wind energy which can mostly be used directly as electricity. Only in "stranded wind" situations where electricity from wind could not practically be fed into the grid, would hydrogen production make sense. Nuclear energy is of course a potentially very large supplier of energy including in the form of hydrogen. Its development opens societal and political issues, the discussion of which does not have its place in this report.

5.4 Potential and cost of CCS

From inspection of the pathways including CCS described in section 4, it will be clear that these technologies have a real potential to reduce CO_2 emissions. *Figure 5.4* gives an overview of the achievable reductions against the associated energy penalty. As mentioned before these figures should be considered as preliminary and higher CO_2 recovery may be possible in the future.

There is considerable scope for CO_2 storage (*Table 5.4*). Depleted oil and gas reservoirs or deep underground aquifers containing saline water that is permanently unsuitable for other purposes, offer large storage potentials both in Europe and globally. CO_2 can be injected into operating oil wells to enhance petroleum production. In the U.S. this accounts for 4% of total oil production. 20% (5 Mt/a) of the CO_2 used has previously been captured at natural gas processing or fertilizer manufacturing plants and is transported by pipeline. In Turkey, 6 Mt/a of CO_2 have been injected for enhanced oil recovery. Deep coal seams for coal bed methane production also offer some space for sequestration. CO_2 displaces methane, thus enhancing its recovery, and is absorbed by the coal. The deep sea and biomass, both areas of large storage capacities, are also examined in academic research. Small amounts of carbon dioxide can be put to use, though not permanently fixed, in commercial applications, such as greenhouses (potential of 4 million tonnes per year in the Netherlands), feedstock for chemicals, freeze-drying, carbonating beverages and to grow algae for biofuels.

Aspects to consider for the various options are capacity, integrity, stability over time, safety, any environmental impact, and cost-effectiveness.

The actual facilities required for a CCS scheme, and therefore the costs, are likely to be very dependent of the type of plant, the specific process scheme used, the distance to the storage location as well as possible installations for preparing, maintaining and monitoring the storage. We therefore decided to refrain from giving specific cost estimates for each pathway as this would be suggesting a level of knowledge and understanding of the issues that has as yet not been achieved. Instead we briefly discuss below the main factors that may influence the eventual cost of CCS schemes.

Figure 5.4 WTT energy and GHG balance of selected pathways with and without CCS
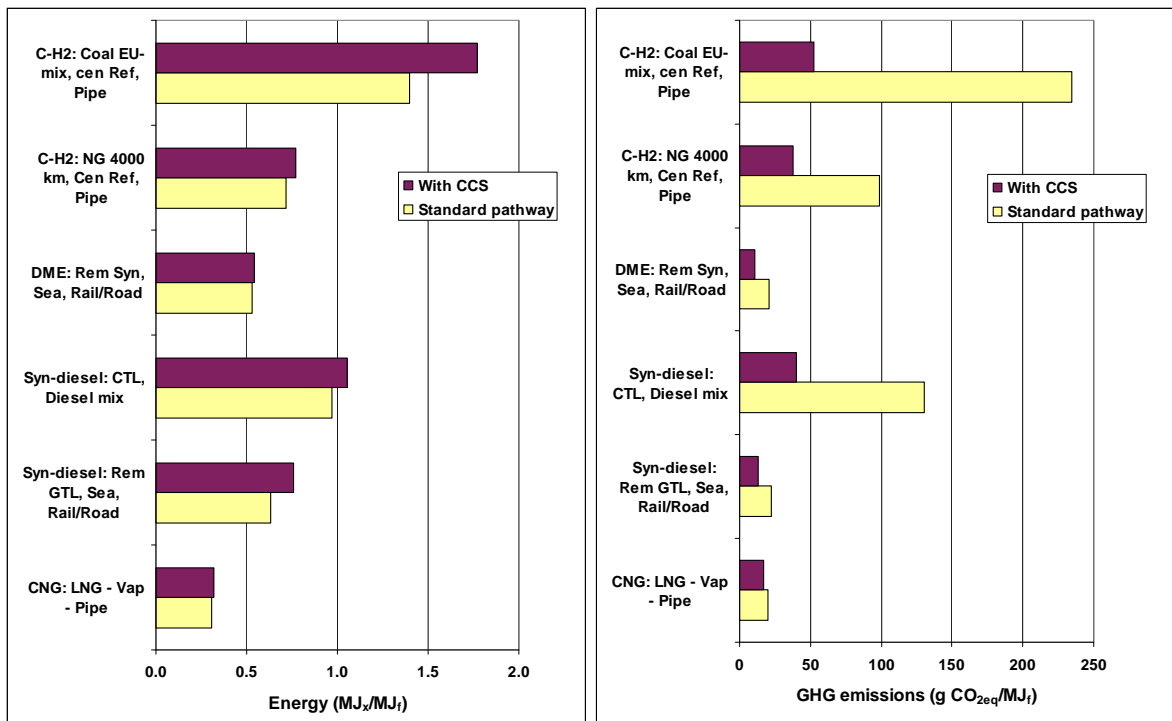
Table 5.4 Carbon dioxide reception areas and their capacities in comparison

Receptor	Capacity (Gt CO_2)	Remarks
Atmosphere	Holds 2750	

Depleted fields
  Gas
  Oil
	510-1140
	150-700
		Oil and gas fields offer space for 46% of emissions to 2050 according to the IPCC's IS92a projection

Enhanced oil recovery	240	
Aquifers	330-10,000	North Sea Utsira formation could hold 800 Gt. Deep saline aquifers could offer space for 20-500% of emissions to 2050 according to the IPCC's IS92a projection.
Oceans	Hold 150,000 Estimated potential several times that amount	
Forests	Hold 2200 Estimated additional potential through reforestation: 150-400	Takes 40-50 years for a large forestry plantation to grow sufficiently

Source : OGP

Some processes are effectively already capturing CO_2 (e.g. Fischer-Tropsch synthesis where CO_2 must be scrubbed from the syngas before the synthesis step). In such cases the in-plant costs would be limited to CO_2 compression.

Processes that do not use air as combustion medium produce relatively CO_2-rich gas streams from which CO_2 can be separated at a reasonable cost. The worst case is for conventional combustion processes where CO_2 is present in low concentration (typically around 15%) in the flue gases. Obviously the scale of the plant will also play a role. Rough estimates from the literature indicate costs between 5 and 40 €/t CO_2.

CO_2 may be transported by pipeline or even by ship in some cases. In the former case a figure of 500-1000 k€/km of pipeline should be reckoned with, depending on the diameter, pressure and location. In the case of a large plant producing a lot of CO_2 (e.g. large scale CTL), this may only account for a few €/t. For smaller scale plants it might prove prohibitively expensive.

Sequestration costs still have to be studied. They will depend on physical conditions i.e. what investment will be required to allow sequestration to proceed, but also on the regulatory framework under which CO_2 storage sites will have to operate, including potential costs for monitoring and maintaining the sites.

5.5 Fuel production and distribution costs

For all fuels produced in Europe and for those, such as DME which cannot be linked to a commodity price, we have estimated a cost of production based on published literature.

Unless there was clear evidence to support other numbers we have considered that a processing plant would have annual operating costs of 3% of the initial capital investment for established technologies and 4.5% for new technologies or high-tech plants. This included personnel and maintenance but not energy which was accounted for separately according to its source. For processes that already exist today, we used a range of ±20% for investment costs. For new or future processes we have used ±30%.

In order to express all costs on a common basis, capital investments need to be turned into a cost item expressed e.g. per annum or per MJ of product. We use the concept of capital charge which is the revenue that a facility must produce every year of the project life (in addition to operating costs) for the investment to be repaid and to produce a desired rate of return. The capital charge is a function of a number of factors such as lifetime of the project, building time, expected revenue profile, inflation and also tax on profits. As we are looking at cost for Europe as a whole we considered the tax element as an internal issue rather than an external cost. It would of course be taken into account by individual investors wishing to undertake a project. A commonly accepted rate of return for capital investment is 8% (real terms) being the long term return of stocks and shares. For a typical industrial project with a lifetime of 15-20 years and 2-3 years building time, this corresponds to a capital charge of about 12% which is the figure that we have used.

Distribution and retail costs include energy cost (transport, compression, dispensing etc), cost of incremental distribution infrastructure and cost of specific refuelling infrastructure. In line with our incremental approach, we have taken the view that the existing infrastructure for conventional fuels would not be significantly affected by a limited introduction of alternative fuels. As a consequence the savings from "not distributing" marginal conventional fuels were limited to variable costs (essentially energy-related). Conversely, however, the extra cost for refuelling infrastructure when required only related to the cost of the additional equipment and did not include any contribution to fixed costs e.g. for establishment and maintenance of a site and the like. According to the same philosophy we did not, for CNG, include the full contribution to the cost of the natural gas grid.

The calculations are shown in detail for each fuel in *WTW Appendix 2* where literature references are also indicated. These tables are therefore not repeated here.

Acronyms and abbreviations used in the WTW study

ADVISOR	A powertrain simulation model developed by the US-based National Renewable Energy Laboratory
BTL	Biomass-To-Liquids: denotes processes to convert biomass to synthetic liquid fuels, primarily diesel fuel
CAP	The EU's Common Agricultural Policy
CCGT	Combined Cycle Gas Turbine
CCS	CO_2 capture and storage
C-H_2	Compressed hydrogen
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO	Carbon monoxide
CO_2	Carbon dioxide: the principal greenhouse gas
CONCAWE	The oil companies' European association for environment, health and safety in refining and distribution
DDGS	Distiller's Dried Grain with Solubles: the residue left after production of ethanol from wheat grain
DG-AGRI	The EU Commission's General Directorate for Agriculture
DICI	An ICE using the Direct Injection Compression Ignition technology
DME	Di-Methyl-Ether
DPF	Diesel Particulate Filter
DISI	An ICE using the Direct Injection Spark Ignition technology
ETBE	Ethyl-Tertiary-Butyl Ether
EUCAR	European Council for Automotive Research and Development
EU-mix	The average composition of a certain resource or fuel in Europe. Applied to natural gas, coal and electricity
FAEE	Fatty Acid Ethyl Ester: Scientific name for bio-diesel made from vegetable oil and ethanol
FAME	Fatty Acid Methyl Ester: Scientific name for bio-diesel made from vegetable oil and methanol
FAPRI	Food and Agriculture Policy Research Institute (USA)
FC	Fuel Cell
FSU	Former Soviet Union
FT	Fischer-Tropsch: the process named after its original inventors that converts syngas to hydrocarbon chains
GDP	Gross Domestic Product
GHG	Greenhouse gas
GTL	Gas-To-Liquids: denotes processes to convert natural gas to liquid fuels
HC	Hydrocarbons (as a regulated pollutant)
HRSG	Heat Recovery Steam Generator
ICE	Internal Combustion Engine
IEA	International Energy Agency
IES	Institute for Environment and Sustainability
IFP	Institut Français du Pétrole
IGCC	Integrated Gasification and Combined Cycle
IPCC	Intergovernmental Panel for Climate Change
JRC	Joint Research Centre of the EU Commission
LBST	L-B-Systemtechnik GmbH

LCA	Life Cycle Analysis
L-H_2	Liquid hydrogen
LHV	Lower Heating Value ('Lower" indicates that the heat of condensation of water is not included)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gases
MDEA	Methyl Di-Ethanol Amine
ME	The Middle East
MTBE	Methyl-Tertiary-Butyl Ether
MPa	Mega Pascal, unit of pressure (1 MPa = 10 bar). Unless otherwise stated pressure figures are expressed as "gauge" i.e. over and above atmospheric pressure
Mtoe	Million tonnes oil equivalent. The "oil equivalent" is a notional fuel with a LHV of 42 GJ/t
N_2O	Nitrous oxide: a very potent greenhouse gas
NEDC	New European Drive Cycle
NG	Natural Gas
NOx	A mixture of various nitrogen oxides as emitted by combustion sources
OCF	Oil Cost Factor
OGP	Oil & Gas Producers
PEM fuel cell	Proton Exchange Membrane fuel cell
PISI	An ICE using the Port Injection Spark Ignition technology
PSA	Pressure Swing Absorption unit
RME	Rapeseed Methyl Ester: biodiesel derived from rapeseed oil (colza)
SMDS	The Shell Middle Distillate Synthesis process
SME	Sunflower Methyl Ester: biodiesel derived from sunflower oil
SOC	State Of Charge (of a battery)
SRF	Short Rotation Forestry
SSCF	Simultaneous Saccharification and Co-Fermentation: a process for converting cellulosic material to ethanol
SUV	Sport-Utility Vehicle
Syngas	A mixture of CO and hydrogen produced by gasification or steam reforming of various feedstocks and used for the manufacture of synthetic fuels and hydrogen
TES	Transport Energy Strategy. A German consortium that worked on alternative fuels, in particular on hydrogen
TTW	Tank-To-Wheels: description of the burning of a fuel in a vehicle
ULCC	Ultra Large Crude Carrier
VLCC	Very Large Crude Carrier
WTT	Well-To-Tank: the cascade of steps required to produce and distribute a fuel (starting from the primary energy resource), including vehicle refuelling
WTW	Well-To-Wheels: the integration of all steps required to produce and distribute a fuel (starting from the primary energy resource) and use it in a vehicle
ZEV	Zero Emission Vehicle

Summary of WTT pathways codes and description

Code	*Short description*	*Details*
Conventional fuels		
COG1	Gasoline	
COD1	Diesel	
CON1	Naphtha	
LRLP1	LPG imports from remote gas field	
CNG		
GMCG1	EU-mix	Current average composition of NG supply in EU
GPCG1a	Pipeline 7000 km	NG piped over 7000 km
GPCG1b	Pipeline 4000 km	NG piped over 4000 km
GRCG1	LNG, Vap, Pipe	LNG from Middle East regasified and distributed by pipeline within EU
GRCG1C	LNG, Vap, Pipe, CCS	As above with capture and sequestration of CO_2 produced in production process
GRCG2	LNG, Road, Vap	LNG from Middle East distributed by road within EU, regasified at filling station
CBG: Compressed Biogas		
OWCG1	Municipal waste	Biogas produced from municipal waste, cleaned and upgraded
OWCG2	Liquid manure	As above with liquid manure
OWCG3	Dry manure	As above with dry manure
OWCG4	Wheat (whole plant)	Biogas produced from the whole wheat plant
OWCG5	Wheat (whole plant, double cropping)	Biogas produced from the whole wheat plant with double cropping
Ethanol		
SBET1a	Sugar beet, pulp to fodder, slops not used	Ethanol from sugar beet, pulp used for animal fodder, slops not used
SBET1b	Sugar beet, pulp to fodder, slops to biogas	Ethanol from sugar beet, pulp used for animal fodder, slops used to produce biogas
SBET3	Sugar beet, pulp to heat/slops to biogas	As above but pulp used as fuel to produce process heat
WTET1a	Wheat, conv NG boiler, DDGS as AF	Ethanol from wheat, process heat from conventional NG-fires boiler, DDGS to animal feed
WTET1b	Wheat, conv NG boiler, DDGS as fuel	As above but DDGS used as fuel
WTET2a	Wheat, NG GT+CHP, DDGS as AF	As WTET1a but process heat from NG-fired gas turbine with combined heat and power scheme
WTET2b	Wheat, NG GT+CHP, DDGS as fuel	As WTET1b but process heat from NG-fired gas turbine with combined heat and power scheme
WTET3a	Wheat, Lignite CHP, DDGS as AF	As WTET1a but process heat from lignite-fired combined heat and power scheme
WTET3b	Wheat, Lignite CHP, DDGS as fuel	As WTET1b but process heat from lignite-fired combined heat and power scheme
WTET4a	Wheat, Straw CHP, DDGS as AF	As WTET1a but process heat from straw-fired combined heat and power scheme
WTET4b	Wheat, Straw CHP, DDGS as fuel	As WTET1b but process heat from straw-fired combined heat and power scheme
WTET5	Wheat, DDGS to biogas	Ethanol from wheat with DDGS used to biogas production to supply part of the plant energy requirement
WWET1	W Wood	Ethanol from waste wood
WFET1	F wood	Ethanol from farmed wood
STET1	Wheat straw	Ethanol from wheat straw
SCET1a	Sugar cane (Brazil), not credit for excess bagasse	Ethanol from sugar cane in Brazilian conditions, no credit for excess bagasse
SCET1b	Sugar cane (Brazil), credit for excess bagasse	Ethanol from sugar cane in Brazilian conditions, heart credit for excess bagasse
Ethers		
GRMB1	MTBE: remote plant	MTBE produced in a remote plant from locally produced methanol (from NG) and associated butanes
LREB1	ETBE: imported C4 and wheat ethanol	ETBE produced in EU from imported butanes and wheat ethanol

Code	Short description	Details
Bio-diesel		
ROFA1	RME: Glycerine as chem., meal as AF	Rapeseed oil Methyl Ester, glycerine used as chemical, meal used as animal feed
ROFA2	RME: Glycerine and meal as AF	Rapeseed Methyl Ester, glycerine and meal used as animal feed
ROFA3	RME: Glycerine to biogas, meal as AF	Rapeseed oil Methyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement, meal used as animal feed
ROFA4	RME: Glycerine and meal to biogas	Rapeseed oil Methyl Ester, glycerine and meal used to produce biogas to supply the plant energy requirement
ROFE1	REE: Glycerine as chem.,meal as AF	Rapeseed oil Ethyl Ester, glycerine used as chemical, meal used a animal feed
ROFE2	REE: Glycerine and meal as AF	Rapeseed oil Ethyl Ester, glycerine and meal used as animal feed
ROFE3	REE: Glycerine to biogas, meal as AF	Rapeseed oil Ethyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement, meal used a animal feed
ROFE4	REE: Glycerine and meal to biogas	Rapeseed oil Ethyl Ester, glycerine and meal used to produce biogas to supply the plant energy requirement
SOFA1	SME: Glycerine as chem., meal as AF	Sunflower oil Methyl Ester, glycerine used as chemical, meal used as animal feed
SOFA2	SME: Glycerine and meal as AF	Sunflower oil Methyl Ester, glycerine and meal used as animal feed
SOFA3	RME: Glycerine to biogas, meal as AF	Sunflower oil Methyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement, meal used as animal feed
SOFA4	RME: Glycerine and meal to biogas	Sunflower oil Methyl Ester, glycerine and meal used to produce biogas to supply the plant energy requirement
SYFA1	SYME: Glycerine as chem., mill in EU, meal as AF in Brazil	Soy oil Methyl Ester, glycerine used as chemical, soy produced in Brazil, shipped and milled in EU. Meal credit for transport (replace meal import) and for animal feed in Brazil (corn)
SYFA1a	SYME: Glycerine as chem., mill in EU, meal as AF in EU	Soy oil Methyl Ester, glycerine used as chemical, soy produced in Brazil, shipped and milled in EU. Meal credit animal feed in EU (wheat)
SYFA1c	SYME: Glycerine as chem, mill in EU, market values	Soy oil Methyl Ester, glycerine used as chemical, soy produced in Brazil, shipped and milled in EU. Allocation by value between oil and meal.
SYFA3	SYME: Glycerine to biogas, mill in Brazil, meal as AF	Soy oil Methyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement. soy produced in Brazil, shipped and milled in EU. Meal credit for transport (replace meal import) and for animal feed in Brazil (corn)
POFA1a	PME: Glycerine as chem, CH_4 emissions from waste	Palm oil Methyl Ester, glycerine used as chemical, methane emissions from waste, heat credit from burning fruit bunches crushing residue
POFA1b	PME: Glycerine as chem, no CH_4 emissions from waste	Palm oil Methyl Ester, glycerine used as chemical, **no** methane emissions from waste, heat credit from burning fruit bunches crushing residue
POFA1c	PME: Glycerine as chem, CH_4 emissions from waste, no heat credit	Palm oil Methyl Ester, glycerine used as chemical, methane emissions from waste, **no** heat credit from burning fruit bunches crushing residue
POFA2	PME: Glycerine to biogas, CH_4 emissions from waste	Palm oil Methyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement, methane emissions from waste, heat credit from burning fruit bunches crushing residue
Hydrotreated plant oil		
ROHY1	HRO (NExBTL), meal as AF	Hydrotreated rape oil (NExBTL process), meal used as animal feed
ROHY2	HRO (UOP), meal as AF	Hydrotreated rape oil (UOP process), meal used as animal feed
SOHY1	HSO (NExBTL), meal as AF	Hydrotreated sunflower oil (NExBTL process), meal used as animal feed
POHY1	HPO (NExBTL), CH_4 from waste	Hydrotreated palm oil (NExBTL process), methane emissions from waste

Code	Short description	Details
Synthetic diesel		
GRSD1	Rem GTL, Sea, Diesel mix	Synthetic diesel from NG in remote plant , sea transport, blended with conventional diesel at refinery
GRSD2	Rem GTL, Sea, Rail/Road	As above but distributed separately
GRSD2C	Rem GTL, Sea, Rail/Road, CCS	As above with capture and sequestration of CO_2 produced in production process
KOSD1	CTL, Diesel mix	Synthetic diesel from coal in EU plant , blended with conventional diesel at refinery
KOSD1C	CTL, CCS, Diesel mix	As above with capture and sequestration of CO_2 produced in production process
WWSD1	W Wood, diesel mix	Synthetic diesel from waste wood in EU plant, blended with conventional diesel at refinery
WFSD1	F wood, diesel mix	Synthetic diesel from farmed wood in EU plant, blended with conventional diesel at refinery
BLSD1	W Wood, Black liquor	Synthetic diesel from waste wood in EU paper mill (Black Liquor route) , blended with conventional diesel at refinery
Methanol		
GPME1a	NG 7000 km, Syn, Rail/Road	Methanol synthesis from NG piped over 7000 km, distributed by rail + road
GPME1b	NG 4000 km, Syn, Rail/Road	Methanol synthesis from NG piped over 4000 km, distributed by rail + road
GRME1	Rem Syn, Sea, Rail/Road	Methanol produced remotely from NG, transported by sea, distributed by rail + road
KOME1	Coal EU-mix, Cen, Rail/Road	Methanol from large coal (average EU supply quality) plant in EU, distributed by rail + road
WWME1	W Wood, Road	Methanol from waste wood, distributed by road
WFME1	F Wood, Road	Methanol from waste wood, distributed by road
BLME1	W Wood, Black liquor	Methanol from waste wood in EU paper mill (Black Liquor route), distributed by road
DME (Di-Methyl-Ether)		
GPDE1a	NG 7000 km, Syn, Rail/Road	DME from NG piped over 7000 km, distributed by rail + road
GPDE1b	NG 4000 km, Syn, Rail/Road	DME from NG piped over 4000 km, distributed by rail + road
GRDE1	Rem Syn, Sea, Rail/Road	DME produced remotely from NG, transported by sea, distributed by rail + road
KODE1	Coal EU-mix, Cen, Rail/Road	DME from large coal (average EU supply quality) gasification plant in EU, distributed by rail + road
GRDE1C	Rem Syn, Sea, Rail/Road, CCS	As above with capture and sequestration of CO_2 produced in production process
WWDE1	W Wood, Road	DME from waste wood, distributed by road
WFDE1	F Wood, Road	DME from waste wood, distributed by road
BLDE1	W Wood, Black liquor	DME from waste wood in EU paper mill (Black Liquor route), distributed by road

Code	Short description	Details
Compressed Hydrogen		
GMCH1	EU-mix, O/S Ref	Compressed hydrogen from reforming of average NG supply in small plant at or near retail site
GPCH1a	NG 7000 km, O/S Ref	Compressed hydrogen from reforming of NG piped over 7000 km in small plant at or near retail site
GPCH1b	NG 4000 km, O/S Ref	Compressed hydrogen from reforming of NG piped over 4000 km in small plant at or near retail site
GPCH2a	NG 7000 km, Cen ref, Pipe	Compressed hydrogen from reforming of NG piped over 7000 km in large EU plant, distributed by pipeline
GPCH2b	NG 4000 km, Cen Ref, Pipe	Compressed hydrogen from reforming of NG piped over 4000 km in large EU plant, distributed by pipeline
GPCH2bC	NG 4000 km, Cen Ref, Pipe, CCS	As above with capture and sequestration of CO_2 produced in production process
GPCH3b	NG 4000 km, Cen Ref, Road	Compressed hydrogen from reforming of NG piped over 4000 km in large EU plant, distributed by road
GPLCHb	NG 4000 km, Cen Ref, Liq, Road, Vap/comp.	Compressed hydrogen from reforming of NG piped over 4000 km in large EU plant, liquefied, distributed by road and compressed on retail site
GRCH1	LNG, O/S Ref	Compressed hydrogen from reforming of imported LNG in small plant at or near retail site
GRCH2	LNG, Cen Ref, Pipe	Compressed hydrogen from reforming of imported LNG in large EU plant, distributed by pipeline
GRCH3	Rem NG, methanol, O/S Ref	Compressed hydrogen from methanol produced remotely from NG in small plant at or near retail site
KOCH1	Coal EU-mix, cen Ref, Pipe	Compressed hydrogen from large coal (average EU supply quality) gasification plant in EU, distributed by pipeline
KOCH1C	Coal EU-mix, cen Ref, Pipe, CCS	As above with capture and sequestration of CO_2 produced in production process
WWCH1	Wood W, O/S gasif	Compressed hydrogen from waste wood in small plant at or near retail site
WWCH2	Wood W, Cen gasif. Pipe	Compressed hydrogen from waste wood in large plant, distributed by pipeline
BLCH1	Wood W, Black liquor	Compressed hydrogen from waste wood in EU paper mill (Black Liquor route), distributed by pipeline
WFCH1	Wood F, O/S gasif	Compressed hydrogen from farmed wood in small plant at or near retail site
WFCH2	Wood F, Cen gasif, pipe	Compressed hydrogen from farmed wood in large plant, distributed by pipeline
Compressed hydrogen by electrolysis		
GPEL1a/CH1	NG 7000 km, CCGT, O/S Ely	Electricity from NG piped over 7000 km, in Combined Cycle Gas Turbine, small scale electrolyser at or near retail site
GPEL1b/CH1	NG 4000 km, CCGT, O/S Ely	Electricity from NG piped over 4000 km, small scale electrolyser at or near retail site
GPEL1b/CH2	NG 4000 km, CCGT, Cen Ely, Pipe	Electricity from NG piped over 4000 km, in Combined Cycle Gas Turbine, large scale electrolyser, distributed by pipeline
GREL1/CH1	LNG, O/S Ely	Electricity from imported LNG, in Combined Cycle Gas Turbine, small scale electrolyser at or near retail site
WFEL2/CH1	F Wood, 200 MW gasif, CCGT, O/S Ely	Electricity from large farmed wood gasifier + Combined Cycle Gas Turbine, small scale electrolyser at or near retail site
WFEL3/CH1	F Wood, Conv power, O/S Ely	Electricity from large farmed wood conventional power plant, small scale electrolyser at or near retail site
EMEL1/CH1	Elec EU-mix, O/S Ely	Electricity from average EU supply, small scale electrolyser at or near retail site
KOEL1/CH1	Elec coal EU-mix, O/S Ely	Electricity from coal (average EU supply quality), small scale electrolyser at or near retail site
KOEL1/CH2	Elec coal EU-mix, Cen ely, Pipe	Electricity from coal (average EU supply quality), large scale electrolyser, distributed by pipeline
NUEL1/CH1	Elec nuclear, O/S Ely	Electricity from nuclear plant, small scale electrolyser at or near retail site
WDEL1/CH2	Wind, Cen Ely, Pipe	Electricity from wind, large scale electrolyser, distributed by pipeline

Code	Short description	Details
Liquid hydrogen		
GPLH1a	NG 7000 km, Cen Ref, Liq, Road	Liquid hydrogen from reforming of NG piped over 7000 km in large EU plant, distributed by road
GPLH1b	NG 4000 km, Cen Ref, Liq, Road	Liquid hydrogen from reforming of NG piped over 4000 km in large EU plant, distributed by road
GRLH1	Rem Ref, Liq, Sea, Road	Liquid hydrogen from reforming of remote NG transported by sea, distributed by road
GRLH2	LNG, Cen Ref, Liq, Road	Liquid hydrogen from reforming of imported LNG in large EU plant distributed by road
WFLH1	Wood F, Cen gasif, Liq, Road	Liquid hydrogen from farmed wood in large EU plant distributed by road
Liquid hydrogen by electrolysis		
GPEL1b/LH1	NG 4000 km, CCGT, Cen Ely, Liq, Road	Electricity from NG piped over 4000 km, in Combined Cycle Gas Turbine, small scale electrolyser at or near retail site
EMEL1/LH1	Elec EU-mix, Cen Ely, Liq, Road	Electricity from average EU supply, large scale electrolyser, distributed by road
KOEL1/LH1	Elec coal EU-mix, Cen Ely, Liq, Road	Electricity from coal (average EU supply quality), large scale electrolyser, distributed by pipeline
Electricity		
KOEL1	EU-mix Coal conv.	Electricity from coal (average EU supply quality), conventional power plant
KOEL2	EU-mix Coal IGCC	Electricity from coal (average EU supply quality), IGCC
GPEL1a	NG 7000 km, CCGT	Electricity from NG piped over 7000 km, in Combined Cycle Gas Turbine
GPEL1b	NG 4000 km, CCGT	Electricity from NG piped over 4000 km, in Combined Cycle Gas Turbine
GREL1	LNG, CCGT	Electricity from imported LNG, in Combined Cycle Gas Turbine
WFEL1	F Wood, 10 MW gasif	Electricity from farmed wood , in small scale gasifier + gas turbine
WFEL2	F Wood, 200 MW gasif	Electricity from farmed wood , in large scale gasifier + Combined Cycle Gas Turbine
WFEL3	F Wood, Conv power	Electricity from farmed wood , in large scale conventional power plant
EMEL1	EU-mix	Electricity from average EU supply
WDEL1	Wind offshore	Electricity from offshore wind farm
NUEL1	Nuclear	Electricity from nuclear plant
OWEL1a	Biogas ex municipal waste, local	Electricity from small scale biogas plant ex municipal waste (gas engine)
OWEL1b	Biogas ex municipal waste, large	Electricity from biogas produced in small scale plant ex municipal waste, injected in grid and used in large power plant
OWEL2a	Biogas ex liquid manure, local	Electricity from small scale biogas plant ex liquid manure (gas engine)
OWEL2b	Biogas ex liquid manure, large	Electricity from biogas produced in small scale plant ex liquid manure, injected in grid and used in large power plant
OWEL3a	Biogas ex dry manure, local	Electricity from small scale biogas plant ex dry manure (gas engine)
OWEL3b	Biogas ex dry manure, large	Electricity from biogas produced in small scale plant ex dry manure, injected in grid and used in large power plant
BLEL1	Black liquor	Electricity from black liquor IGCC
Heat		
COHT1/2	Heat from Heating Oil	In domestic or industrial boiler
GPHT1/2	Heat from NG	Piped gas (700km or 4000km) in domestic or industrial boiler
GRHT1/2	Heat from LNG	In domestic or industrial boiler
OWHT1/2/3	Heat from biogas	Biogas from municipal waste, liquid or dry manure in gas boiler
WWHT1/2	Heat from waste wood	In domestic or industrial boiler
WFHT1/2	Heat from farmed wood	In domestic or industrial boiler
Combined Heat and Power		
GPEH1	Piped gas 7000km, CCGT	Electricity production with credit for export ed heat
GPEH1b	Piped gas 4000km, CCGT	Electricity production with credit for export ed heat
GREH1	LNG, CCGT	Electricity production with credit for export ed heat
WWEH1	Waste wood, CCGT	Electricity production with credit for export ed heat
WFEH1	Farmed wood, CCGT	Electricity production with credit for export ed heat
GPHT3	Piped gas 4000km, CCGT	Heat production, with credit for exported electricity
WWHT3	Waste wood, CCGT	Heat production, with credit for exported electricity
WFHT3	Farmed wood, CCGT	Heat production, with credit for exported electricity

Abstract
WELL-TO-WHEELS ANALYSIS OF FUTURE AUTOMOTIVE FUELS AND POWERTRAINS IN THE
EUROPEAN CONTEXT

The JEC research partners [Joint Research Centre of the European Commission, EUCAR and CONCAWE]
have updated their joint evaluation of the well-to-wheels energy use and greenhouse gas emissions for a wide
range of potential future fuel and powertrain options.

This document reports on the third release of this study replacing Version 2c published in March 2007.

The original version was published in December 2003.

How to obtain EU publications

Our priced publications are available from EU Bookshop (http://bookshop.europa.eu), where you can place an order with the sales agent of your choice.

The Publications Office has a worldwide network of sales agents. You can obtain their contact details by sending a fax to (352) 29 29-42758.

The mission of the JRC is to provide customer-driven scientific and technical support for the conception, development, implementation and monitoring of EU policies. As a service of the European Commission, the JRC functions as a reference centre of science and technology for the Union. Close to the policy-making process, it serves the common interest of the Member States, while being independent of special interests, whether private or national.

LB-NA-24952-EN-N

JRC
EUROPEAN COMMISSION

Publications Office