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WELL-TO-TANK Report Version 4.0

JEC WELL-TO-WHEELS ANALYSIS

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

Authors: Robert EDWARDS (JRC), Jean-François LARIVÉ (CONCAWE), David RICKEARD (CONCAWE), Werner WEINDORF (LBST)

Editors: Simon Godwin (EUCAR), Heinz Hass (Ford/EUCAR), Alois Krasenbrink (JRC), Laura Lonza (JRC), Heiko Maas (Ford), Robin Nelson (CONCAWE), Alan Reid (CONCAWE), Kenneth D. Rose (CONCAWE)

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Contact information
Laura Lonza
Address: Joint Research Centre, Via Enrico Fermi 2749, TP 230, 21027 Ispra (VA), Italy
E-mail: laura.lonza@ec.europa.eu
Tel.: +39 0332 78 3902
Fax: +39 0332 78 6671

http://iet.jrc.ec.europa.eu/
http://www.jrc.ec.europa.eu/

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WELL-TO-TANK (WTT) REPORT

VERSION 4, JULY 2013

This report is available as an ADOBE pdf file on the JRC/IET website at:

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Notes on version number:

This is version 4 of this report replacing version 3c published in July 2011. The main changes and additions to this version are:

- The base year for this Well-to-Tank evaluation is 2010 with a time horizon of 2020+;
- Minor changes to the fossil fuel pathways based on updated estimates for flaring and venting emissions from crude production (Section 3.1);
- Updated Europe's anticipated crude oil appetite between 2010 and 2020+ (Section 3.1);
- Updated natural gas pathways, including the addition of a European shale gas pathway and natural gas production based on 2011 statistics;
- Added some new biofuel pathways and deleted other pathways that no longer seem likely to be of commercial importance;
- Updated production data for biofuel pathways based on best available information from bio-industry consultations;
- Developed a new data reporting scheme 'by pathway' in which all data and results for individual pathways are provided in seven data workbooks (Appendix 4);
- Added a discussion on direct and indirect land use change effects (Section 3.4);
- Added a globally-applicable analysis of nitrous oxide emissions (N_2O) from farming based on IPCC data (Section 3.4.2);
- Reviewed and updated the EU electricity mix based on 2009 statistics in relation to the recharging of hybrid and battery electric vehicles (Section 3.5);
- Updated references have been cross-referenced to specific pathways or to sections of the WTT report (Appendix 5);
- Data and results on hydrogen pathways (especially Section 4.9) have not been updated from the previous Version 3c but will be updated at a later date;
- As in Version 3c of the WTT report, costs and biofuel/biomass availability are not included.

Acknowledgments

This JEC Consortium study was carried out jointly by experts from the JRC (EU Commission's Joint Research Centre), EUCAR (the European Council for Automotive R&D), and CONCAWE (the oil companies' European association for environment, health and safety in refining and distribution), assisted by experts from Ludwig-Bölkow-Systemtechnik GmbH (LBST) and AVL List GmbH (AVL).

Main Authors, Well-to-Tank (WTT) Report

R. Edwards	JRC
J-F. Larivé	CONCAWE
D. Rickeard	CONCAWE
W. Weindorf	LBST

JEC Scientific Advisory Board

R. Edwards	JRC
S. Godwin	EUCAR
H. Hass	EUCAR/Ford
A. Krasenbrink	JRC
L. Lonza	JRC
H. Maas	EUCAR/Ford
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A. Reid	CONCAWE
K. Rose	CONCAWE

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J. Wind	Daimler

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S. Boreux	TOTAL
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C. Diaz Garcia	Repsol
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E. Marin	Repsol
C. Olivares Molina	CEPSA
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A. Rankine	BP
A. Reid	CONCAWE
D. Rickeard	CONCAWE
K. Rose	CONCAWE
T. Venderbosch	CONCAWE

LBST (Well-to-Tank Consultant)
W. Weindorf

AVL List GmbH (Tank-to-Wheels Consultants)
A. Huss
R. Albrecht
E. Morra

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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 (which broadly speaking is the 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. Our study is forward-looking and considers state-of-the-art technology to help guide future choices. Existing production plant using older technology may not achieve the same efficiency.

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.

For fuels from biomass origin the GHG balance figures as presented do not include emissions caused by land use change, either direct or indirect. We do think these effects are likely to have a significant impact on results, but the current state of knowledge does not allow us to estimate them with confidence. We have, however, included a discussion of current knowledge and understanding of land use change impacts (see *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, this discussion has not been included 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*].

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 the workbooks associated with this report and describing individual pathways detail 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 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, with supporting information, to:

infoJEC@jrc.ec.europa.eu

(Note: since the results of life cycle analysis (LCA) 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 the EU's Renewable Energy Directive (RED)

Our input database has been used by the European Commission as the basis for calculations of typical and "default" GHG savings for biofuels compared to fossil fuels in the 2009 RED and its predecessor the Biofuels Directive. The Commission's calculations used an entirely different methodology from the one in this report, and therefore produced different results.

A subset of our V3c database, containing only the data relevant to the calculation of default values for the RED is available at

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

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[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, co-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 on the next page summarises the pathways considered in this study.

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[3] E^3 database by L-B-Systemtechnik, Germany

Table 2.1: Fuels and resources

Resource \ Fuel		Gasoline, Diesel (2010 quality)	CNG/CBG/SNG	LPG	Hydrogen (comp., liquid)	Synthetic diesel	DME	Ethanol	MT/ETBE	FAME/FAEE	HVO	Methanol	Electricity	Heat
Crude oil		X											X(5)	X(6)
Coal					X(1)	X(1)	X					X	X	
Natural gas	Piped		X		X(1)	X	X					X	X	X
	Remote		X(1)		X	X(1)	X(1)		X			X	X	X
Shale gas			X											
LPG	Remote(3)			X					X					
Biomass	Sugar beet							X						
	Wheat							X	X					
	Barley/rye							X						
	Maize (Corn)		X(2)					X(4)						
	Wheat straw							X						
	Sugar cane							X						
	Rapeseed									X	X			
	Sunflower									X	X			
	Soy beans									X	X			
	Palm fruit									X	X			
	Woody waste				X									X
	Farmed wood				X	X	X	X				X	X	X
	Waste veg oils									X	X			
	Tallow									X	X			
	Organic waste		X(2)										X	X
	Black liquor				X	X	X					X	X	
Wind			X			X							X	
Nuclear													X	
Electricity					X									

(1) with/without CCS
(2) Biogas
(3) Associated with natural gas production
(4) EU and US sources
(4) Heavy Fuel Oil
(4) Heating Oil

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.

2.2 Time horizon

The notional time horizon for the study is about a decade ahead i.e. around 2020-2025. The technologies considered are those that have the potential to become commercially available in that time frame.

Since this study is forward-looking, we have assumed that new production facilities would use state-of-the-art technology to deliver the best technically feasible efficiency. Where efficiency is influenced by different design (and cost) choices, we have shown the effect of these choices through different scenarios. The figures may not reflect the performance of existing production facilities built using older technology. Statistical data are from 2009 for European electricity production and from 2011 for natural gas production.

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 (By conventional fuels, we mean fossil gasoline and diesel produced from crude oil, since these are the fuels against which alternatives such as biofuels are measured). At the 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.

For conventional fossil 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 further discussed in *section 3.1 and Appendix 3*.

2.4 Methodology for accounting for co-products

Many processes produce not only the desired product but also other streams or "co-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 co-products. This implies that the reference scenario must include either an existing process to generate the same quantity of co-product as the alternative-fuel scenario, or another product which the co-product would realistically replace.

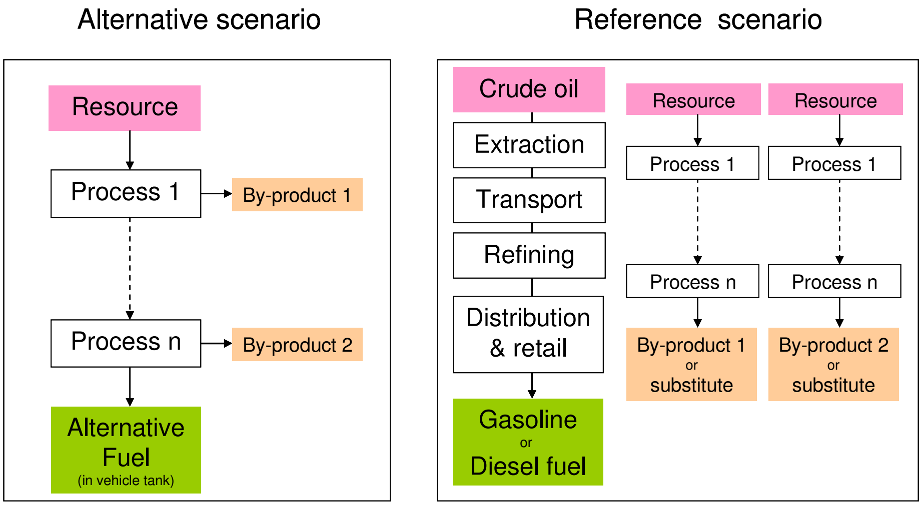
This logic is reflected in the following methodology (***Figure 2.4***):

- All energy and emissions generated by the process are allocated to the main or desired product of that process.
- The co-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 co-products. This approach, (also 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 (LCA) studies. Some other studies have used "allocation" methods whereby energy and emissions from a process are allocated to the various products according to e.g. mass, energy content, "exergy" content or monetary value. Although such allocation methods may be simpler to implement their outcomes in terms of energy use and GHG emissions burden tend to be less realistic. It is clear that the impact of a co-product must *depend on what the co-product substitutes:* all allocation methods take no account of this, and so are likely to give unreliable results.

Figure 2.4: Co-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 co-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 co-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 Renewable Energy Directive requires emissions allocation between co-products according to their energy-content.

In most cases, co-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.

As an example, the manufacture of FAME (biodiesel) produces glycerine as a co-product. Amongst other options, the glycerine could replace synthetic (pharmaceutical) glycerine or be used as animal feed, replacing 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 give exactly the same energy credits for both these potential uses of glycerine.

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 independently of 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 so that 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.

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 Miscellaneous assumptions

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

2.6.1 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*].

Table 2.6.1: 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.

2.6.2 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 nowhere as it dries out during storage).

2.6.3 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. Details of shipping processes are given in sections 3.1.2, 3.2.2 and the associated workbooks.

2.7 Presentation of results

2.7.1 Where to find what in this report?

The narrative part of this report is divided into two 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.
- 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.

In addition, we have created a series or Excel-based workbooks where each pathway is described in detail including overall and stepwise energy and GHG balances and relevant processes with basic data input and literature references.

2.7.2 Units and conventions

The energy figures are presented as total primary energy expended, 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/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 (and nuclear) energy expended in the pathway, illustrating the fossil energy saving potential of that pathway compared to conventional fossil alternatives.

The figures reported for individual steps of the energy and GHG balance of a pathway all relate to a MJ of the finished fuel produced by that pathway and delivered to the vehicle fuel tank (1 MJ_f), rather than to the output of the particular step. They are therefore additive.

By contrast, input data indicated for each process generally relate to the output of that process which may or may not be the finished fuel. These figures are therefore not additive.

The WTT GHG figures as reported represent the total grams of CO_2 equivalent (see also *section 2.7.1*) emitted in the process of obtaining 1 MJ of the finished fuel but do not include the emissions produced by combusting the fuel.

For information we also report the total emissions including combustion which may be used to compare renewable and non-renewable fuels as long as they can both be used in similar vehicles with the more or less the same efficiency.

When integrating WTT and TTW data to obtain WTW balances, it is expedient to consider all TTW CO_2 emissions as fossil irrespective of the origin of the carbon. In order to conserve the correct balance, emissions from combustion of renewable carbon are credited to the relevant fuels before the WTW integration is carried.

2.7.3 References

A complete list of references used in the study is included *in WTT Appendix 5*. As far as possible, references are cited in their proper context in relation to a specific process and specific input data in the pathway workbooks rather than in the main text of this report.

3 From Resource to Fuel: production routes

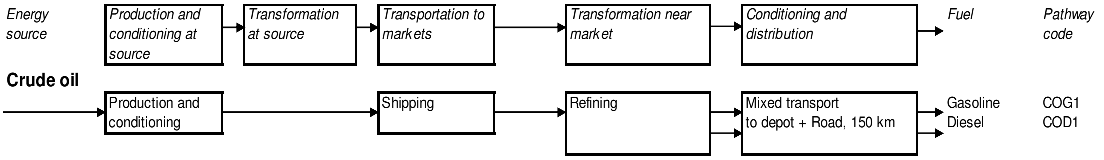
In this chapter we describe the pathways and processes necessary to convert a certain primary resource into a final fuel. The stepwise description of the pathways together with the detailed input data and further detailed comments and remarks on individual processes are given in *individual pathway workbooks*.

3.1 Crude oil pathways

(See also workbook WTT v40 pathways 1-Oil and gas)

The pathways from crude oil to road fuels are straightforward, as illustrated in the following figure.

Figure 3.1: Conventional fossil fuels pathways

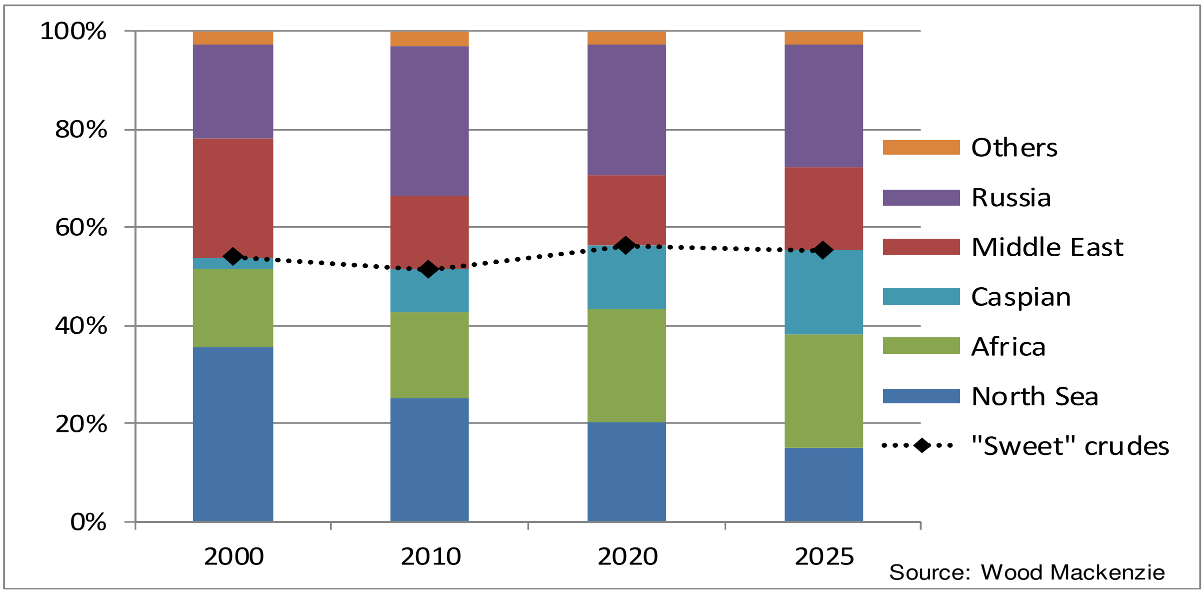


3.1.1 Crude oil production and conditioning at source

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. The favourable geographic location of Europe in relation to light and sweet crude producing regions (North Sea, North and West Africa) has resulted in a fairly light crude diet in the past two to three decades. Light sweet crudes from the Caspian Sea area have recently become a feature of the European crude diet and are expected to grow in importance, compensating the steady decline of North Sea crude production.

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. These crudes are mostly light and low sulphur. Production is in decline, as the inexorable depletion of existing reserves is not compensated by the discoveries of new reserves.
Africa:	North African crudes (Algeria, Libya, 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. There is a wide range of quality amongst these crudes from very light and low sulphur Algerian grades to fairly heavy and sour Egyptians.
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.
Russia:	Russia is a steady supplier of medium quality crude to Europe, partly through an extensive inland pipeline system extending to most former East European block countries.
Caspian:	The Caspian basin is becoming a major producer of light sweet crudes. Geographical proximity and favourable logistics make Europe a natural and growing consumer of these crudes.

Figure 3.1.1-2: EU27 crude oil slate



Source: Wood Mackenzie

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 countries, notably Russia and Nigeria, although this is improving. NOAA satellite data [*NOAA 2011*] indicate an 8% reduction in total worldwide flaring volumes between 2008 and 2010.

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 4, 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) and fugitive losses of associated volatile hydrocarbons. Venting of associated CO_2 occurs in gas production but is not common in oil production.

Although both sources were taken into account in the original JEC data, GHG reporting was not well developed at the time and hard data were 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, although the data do not distinguish between oil and gas production. OGP member companies represent 32% of world oil and gas production. ***Table 3.1.1-1*** shows the OGP data collected for 2011 [*OGP 2011*] and the prorated figures obtained by applying the OGP averages to total global oil and gas production [*BP 2012*].

Table 3.1.1-1: Energy and GHG emissions from crude oil and gas production [OGP 2011]

Data for 2011 oil & gas production		**Total**	Africa	Asia	Europe	FSU	ME	NA	SA
OGP reported production	Mt/a	**2221**	387	355	452	127	411	295	194
	%	**100%**	17%	16%	20%	6%	19%	13%	9%
Total production (BP Statistical Review)	Mt/a	**6951**	600	819	406	1366	1775	1454	531
	%	**100%**	9%	12%	6%	20%	26%	21%	8%
OGP coverage(1)	% of total	**32%**	65%	43%	111%	9%	23%	20%	37%
Energy Consumption (OGP production only)									
Total energy	PJ/a	**3333**	515	611	515	141	321	903	328
Specific energy	GJ/t	**1.50**	1.33	1.72	1.14	1.11	0.78	3.06	1.69
Specific energy(3)	**MJ/MJ**	**0.036**	0.032	0.041	0.027	0.026	0.019	0.073	0.040
Emissions from energy production, flaring, venting and fugitive losses (OGP production only)									
CO_2	Mt/a	**294.0**	83.1	65.2	33.9	12.7	19.5	53.3	26.4
	t/kt	**132.4**	215	184	75	100	47	181	136
CH_4	kt/a	**2801**	592	998	185	75	66	649	237
	t/kt	**1.26**	1.53	2.81	0.41	0.59	0.16	2.20	1.22
GHG as CO_{2eq}(2)	Mt/a	**364.0**	97.9	90.1	38.5	14.6	21.2	69.5	32.3
	t/kt	**164**	253	254	85	115	51	236	167
% GHG due to CH_4		**19%**	15%	28%	12%	13%	8%	23%	18%
Specific GHG emissions	**g CO_{2eq}/MJ**	**3.90**	6.02	6.04	2.03	2.73	1.23	5.61	3.97
Figures prorated to total oil & gas production									
GHG as CO_{2eq}(2)	Mt/a	**1077.2**	151.8	207.8	38.5	156.7	91.4	342.5	88.5
	t/kt	**155**							
Total energy	PJ/a	**10969**	798	1409	515	1516	1385	4449	897
Specific energy(3)	**MJ/MJ**	**0.038**							
Specific GHG emissions	**g CO_{2eq}/MJ**	**3.69**							

(1) OGP production figures include oil and gas volumes consumed in operations and thus may exceed sales volumes reported in the BP Statistical Review

(2) Using a CO_2-equivalent factor of 25 for CH_4

(3) Specific energy includes only the energy consumed for hydrocarbon extraction and pretreatment, not the energy embodied in flared or vented gases

The OGP data coverage is very good for Europe, fair for Africa and South America but rather patchy for other regions, particularly the Former Soviet Union (FSU) which is 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 3.1.1-2*** we applied the regional specific energy and specific GHG emissions data from ***Table 3.1.1-1*** to the combination of crudes used in the OECD EU countries[4] in 2011 as reported by the International Energy Agency [*IEA 2012*].

Table 3.1.1-2: Estimate of emissions from crudes used in the OECD EU in 2011

Crudes by source region 2011		**Total**	Africa	Asia	Europe	FSU	ME	NA	SA
OECD EU consumption (IEA data for 2011)	Mt/a	**567**	94	0	147	207	99	8	11
	%	**100%**	17%	0%	26%	37%	18%	1%	2%
Specific energy	**MJ/MJ**	**0.027**	0.032	0.041	0.027	0.026	0.019	0.073	0.040
Specific GHG emissions	**g CO_{2eq}/MJ**	**2.89**	6.02	6.04	2.03	2.73	1.23	5.61	3.97

The EU 2011 average figures for specific energy (0.027 MJ/MJ) and specific GHG emissions (2.89 g CO_{2eq}/MJ) are lower than the world averages in ***Table 3.1.1-1*** because of the comparatively large EU consumption of low energy / low emissions European and FSU crudes. The EU figures are well within the range used in earlier versions of this study but are somewhat higher than the WTT report v3c

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[4] The OECD EU countries include Norway, Switzerland and 21 of the 27 EU member countries. The 6 excluded EU27 countries are Bulgaria, Cyprus, Latvia, Lithuania, Malta and Romania.

figure for energy (0.022 MJ/MJ) and lower than the WTT report v3c figure for GHG emissions (3.9 g CO_{2eq}/MJ). This is due to an increase in the figures reported by OGP for energy consumption (notably in Africa) and decreases in OGP reported figures for emissions from flaring and venting (notably in Africa and Russia).

The OGP report indicates that about 51% of the GHG emissions that have been attributed are related to energy use, 35% are related to flaring and 14% are related to venting and fugitive losses. The source was specified by OGP members for 54% of the total reported GHG emissions. If one assumes that the reported distribution of GHG emission sources is applicable to 100% of the 2.89 g CO_{2eq}/MJ emissions from crudes used in the EU then the resulting breakdown of emissions by source is:

- 1.5 g CO_{2eq}/MJ crude for energy use in production operations,
- 1.0 g CO_{2eq}/MJ crude for flaring,
- 0.4 g CO_{2eq}/MJ crude for venting and fugitive losses.

The OGP data cover 32% of global oil and gas production (but about 48% of oil consumed in the EU due to the high OGP coverage for EU production). Although this coverage is relatively low, we are obliged by the absence of alternative global data sources to adopt the above figures for emissions from energy use (1.5 g CO_{2eq}/MJ crude) and from venting and fugitive losses (0.4 g CO_{2eq}/MJ crude).

However, an alternative source of comprehensive global data for emissions from flaring is the data collected by the US National Oceanic and Atmospheric Administration on the basis of satellite observations. The most recent set of published data [*NOAA 2011*] gives flare gas volumes for 65 countries for the year 2010, totalling 134 billion cubic metres[5] (BCM). These NOAA flare gas volumes are shown in ***Table 3.1.1-3*** for the top 20 suppliers of crude consumed in the OECD EU countries, together with the corresponding calculated CO_{2eq} emissions. The NOAA data give only flare gas volumes and not the composition of the flared gas, so we estimated the corresponding CO_{2eq} emissions by assuming that the average flared gas composition was 50%m/m methane and 50%m/m ethane[6], corresponding to a gas molecular weight of 20.9, a density of 0.88 Mt per BCM and an emission factor of 3.12 t CO_{2eq}/t flared gas (of which 11% is contributed by unburned methane and ethane), giving an overall conversion factor of 2.75 Mt CO_{2eq}/BCM flared gas. On this basis, the total flaring GHG emissions from all 65 producing countries in 2010 amounts to 368 Mt CO_{2eq}. ***Table 3.1.1-3*** also shows the 2010 oil and gas production figures from the BP Statistical Review [*BP 2012*] and the OECD EU 2010 oil consumption figures from the International Energy Agency statistics [*IEA 2012*] for the top 20 countries supplying crude consumed in the OECD EU. These figures are used in the subsequent table to determine the allocation of the flaring emissions to EU 2010 oil consumption.

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[5] The NOAA does not specify the standard reference conditions for the reported “billion cubic metres” (BCM) of flared gas. We assume that they are expressed at the customary US standard conditions of 60 ºF and 1 atm, giving a molar volume of 23.69 m^3 per kmol, instead of the ISO 10780 standard conditions of 0 ºC and 1 atm which give a molar volume of 22.41 m^3 per kmol.

[6] The assumed flare gas composition of 50%m/m (65%v/v) methane and 50%m/m (35%v/v) ethane and combustion efficiency of 98% were chosen as the upper bound for the possible range of CO_{2eq} emissions calculated from the reported NOAA flare gas BCM. The lower bound corresponds to the simplest possible gas composition, 100%v/v methane, with 100% combustion efficiency, which gives a conversion factor of 1.86 Mt CO_{2eq}/BCM flared gas. The calculated CO_{2eq} emissions at the lower bound would be 33% lower than at the upper bound. Apart from allowing for composition uncertainty, this range also allows for variability in combustion efficiency. Flaring studies have shown [*Gogolek 2012*] that flare combustion efficiencies are typically in the range 98% - 100%, with the lower end of the range corresponding to higher average wind speeds encountered in some countries. For a 100% methane flare a combustion efficiency of 98% is equivalent to 2.16 Mt CO_{2eq}/BCM, which is well below the adopted upped bound conversion factor of 2.75 Mt CO_{2eq}/BCM.

Table 3.1.1-3: Flaring volumes, estimated emissions, oil and gas production and OECD EU oil consumption per producing country for the top 20 crude suppliers to the EU

2010	NOAA Flare gas volume 2010	Total flaring GHG emissions 2010 (1)	Hydrocarbon Production 2010 (BP statistical review)			OECD EU 2010 oil consumption (IEA)	
	Billion cubic metres	Mt CO_{2eq}/a	Oil Mtoe/a	Gas Mtoe/a	Total Mtoe/a	Mt/a	%
Total	133.9	368.2	3940.3	2774.4	6714.7	580.3	100%
Country of origin							
Russia	35.2	96.9	505.1	530.0	1035.1	158.7	27.4%
Norway	0.3	0.9	98.6	95.7	194.3	83.7	14.4%
Libya	3.8	10.4	77.4	15.1	92.6	53.7	9.3%
UK	1.0	2.7	63.0	51.4	114.4	50.0	8.6%
Saudi Arabia	3.4	9.2	466.6	78.9	545.4	30.8	5.3%
Iran	11.3	31.0	207.1	131.5	338.6	29.5	5.1%
Kazakhstan	3.8	10.4	81.6	15.8	97.5	26.3	4.5%
Nigeria	15.2	41.7	117.2	32.9	150.2	22.2	3.8%
Azerbaijan	0.1	0.4	50.8	13.6	64.4	21.2	3.6%
Iraq	9.1	25.1	121.4	1.2	122.6	16.9	2.9%
Denmark	0.1	0.2	12.2	7.4	19.6	11.2	1.9%
Angola	4.1	11.2	92.0	0.0	92.0	8.5	1.5%
Syria	1.0	2.7	19.1	6.9	26.0	7.7	1.3%
Mexico	2.5	6.9	146.3	49.6	195.9	6.8	1.2%
Algeria	5.4	14.8	75.5	72.4	147.9	6.8	1.2%
Venezuela	2.8	7.8	142.5	27.2	169.7	5.0	0.9%
Brazil	1.1	3.0	111.7	12.9	124.6	4.8	0.8%
Egypt	1.5	4.0	35.0	55.2	90.2	4.6	0.8%
Kuwait	1.5	4.1	122.7	10.6	133.2	3.4	0.6%
Congo	1.9	5.2	15.1	0.0	15.1	3.1	0.5%
Others	28.9	79.4	1379.3	1566.2	2945.4	25.3	4.4%

(1) GHG emissions from flaring calculated from NOAA flare gas volume using a factor of 2.75 t CO_{2eq} per BCM (see text for details)

The NOAA satellite observations provide total estimated flare gas volumes per hydrocarbon-producing country but do not distinguish between oil and gas production. In some countries the proportion of gas production is large and it is reasonable to expect that a certain proportion of flaring is associated with gas production. To our knowledge there is no widely recognised method for apportioning flaring emissions between all hydrocarbons produced. The method proposed in ***Table 3.3.1-4*** gives upper and lower bound estimates for the average flaring GHG emissions per tonne or per MJ of crude oil processed in the EU. The upper bound figure of 2.9 g CO_{2eq}/MJ crude is obtained by attributing all the flaring emissions exclusively to oil production, as shown in the columns headed “Assuming flaring GHG emissions from Oil Production Only”. The lower bound figure of 1.8 g CO_{2eq}/MJ crude is obtained by distributing the flaring emissions equally over the total oil and gas production of each producing country, as shown in the columns headed “Assuming flaring GHG emissions from Total Oil+Gas Production”.

Table 3.1.1-4: Calculation of 2010 average flaring GHG emissions per t or per MJ of EU crude consumption

2010	OECD EU 2010 oil consumption		Flaring GHG emissions attributable to OECD EU oil consumption					
			Assuming flaring GHG emissions from **Oil Production Only**			Assuming flaring GHG emissions from **Total Oil+Gas Production**		
	Mt/a	PJ/a	t CO_{2eq} per t oil consumed	Mt CO_{2eq} per year	g CO_{2eq} per MJ oil consumed	t CO_{2eq} per t oil consumed	Mt CO_{2eq} per year	g CO_{2eq} per MJ oil consumed
Total	580.3	24371	0.093	70.7	**2.9**	0.055	44.9	**1.8**
Country of origin								
Russia	158.7	6667	0.192	30.5	4.6	0.094	14.9	2.2
Norway	83.7	3515	0.009	0.7	0.2	0.004	0.4	0.1
Libya	53.7	2257	0.135	7.2	3.2	0.113	6.1	2.7
UK	50.0	2102	0.043	2.2	1.0	0.024	1.2	0.6
Saudi Arabia	30.8	1293	0.020	0.6	0.5	0.017	0.5	0.4
Iran	29.5	1240	0.150	4.4	3.6	0.092	2.7	2.2
Kazakhstan	26.3	1106	0.128	3.4	3.0	0.107	2.8	2.6
Nigeria	22.2	932	0.356	7.9	8.5	0.278	6.2	6.6
Azerbaijan	21.2	889	0.007	0.2	0.2	0.006	0.1	0.1
Iraq	16.9	708	0.207	3.5	4.9	0.205	3.4	4.9
Denmark	11.2	469	0.019	0.2	0.5	0.012	0.1	0.3
Angola	8.5	356	0.122	1.0	2.9	0.122	1.0	2.9
Syria	7.7	325	0.142	1.1	3.4	0.104	0.8	2.5
Mexico	6.8	285	0.047	0.3	1.1	0.035	0.2	0.8
Algeria	6.8	284	0.197	1.3	4.7	0.100	0.7	2.4
Venezuela	5.0	210	0.055	0.3	1.3	0.046	0.2	1.1
Brazil	4.8	203	0.027	0.1	0.6	0.024	0.1	0.6
Egypt	4.6	192	0.116	0.5	2.8	0.045	0.2	1.1
Kuwait	3.4	144	0.033	0.1	0.8	0.031	0.1	0.7
Congo	3.1	132	0.343	1.1	8.2	0.343	1.1	8.2
Others	25.3	1063	0.004	4.1	0.1	0.002	2.0	0.0

There is uncertainty attached to these figures, principally with regard to the flare gas composition and combustion efficiency, as discussed and quantified above (see footnote 6). However, the use of a high-end assumption for the GHG emissions per BCM of flare gas (2.80 Mt CO_{2eq} per BCM) ensures that the estimated EU average range of 1.8 – 2.9 g CO_{2eq} per MJ of crude oil processed is more likely to over-estimate than under-estimate the emissions due to flaring. A further level of un-quantifiable uncertainty relates to the local variability of flaring and oil production for EU consumption within a particular country (particularly for large producers such as Russia) where figures are likely to vary between producing provinces, fields and even individual wells.

The figure adopted in this report for average emissions from flaring attributed to the production of crudes consumed in the EU in 2010 is the midpoint of the above range, rounded to 2.4 g CO_{2eq} per MJ crude, with an uncertainty range of 1.8 – 2.9 CO_{2eq} per MJ corresponding to the upper and lower bound figures mentioned above. This is somewhat higher than the average flaring emissions figure of 1.0 g CO_{2eq} per MJ suggested by the OGP data for 2011. This is plausible inasmuch as OGP members are primarily International Oil Companies which are believed to have a better performance on flaring reduction than National Oil Companies.

The final figures for crude production are:

	GHG emissions g CO_{2eq}/MJ crude	Energy[7] MJ/MJ crude
Energy use in production	1.5	0.027
Flaring	2.4	0.037
Venting and fugitive losses	0.4	0.001
TOTAL	**4.3**	**0.065**

Applying the flaring uncertainty range of 1.8 – 2.9 CO_{2eq} per MJ (0.028 – 0.045 MJ/MJ) to these total figures gives an overall uncertainty range of 3.7 – 4.8 CO_{2eq} per MJ (0.056 - 0.073 MJ/MJ).

For the WTT calculations we need to estimate the energy and GHG associated with the marginal crude available to Europe, i.e. which crude supply would increase or decrease if crude oil demand increased or decreased in the future. This marginal crude 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 the end of 2011 were estimated at 1263 billion barrels [*BP 2012*][8], with Saudi Arabia, the largest national resource, having about 21% 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 (220 billion barrels), equivalent to 10% of world oil reserves, and are already being exploited, almost exclusively for the US and Canadian markets. Venezuela, in addition to large conventional oil reserves (77 billion bbl) also has very large deposits of heavy oils, estimated at 220 billion barrels [*BP 2012*]. 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 Athabasca 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 by Brandt [*Brandt 2011*] of available studies shows a wide range of variation in the energy use and GHG emissions associated with different projects and extraction methods for oil production from Canadian oil sands as a potential feedstock for European refineries. The Brandt review provides a summary of published estimates of GHG emissions from oil sands production ranging from 15.9 gCO_2eq/MJ to 40.6 gCO_2eq/MJ, mainly depending on the extraction method used and the choice of fuel for on-site energy production (for example, natural gas produces lower emissions whereas bitumen or coke gasification produces higher emissions). Brandt estimates the weighted average most likely emissions from oil sands derived crude production at 25 gCO_2eq/MJ, equivalent to about 0.38 MJ/MJ. The assumed processing includes extraction, upgrading and venting and flaring, to produce a synthetic crude of about 30 °API, comparable to a light sweet conventional crude. A more

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[7] Energy from flaring is mainly determined from the energy value of the flared gas burned to produce the CO_2 portion of the flaring emissions = 2.4 gCO_{2eq}/MJ crude x 89% CO_2/CO_{2eq} = 2.1 gCO_2/MJ crude x 48.7 MJ gas/kg x (12/44) /77.5%C /1000 = 0.036 MJ flare gas/MJ crude. A small additional contribution of 0.001 MJ/MJ comes from the energy content of the unburned methane and ethane portion of the flaring emissions.

[8] Total reserves of 1653 billion barrels, including 169 billion barrels of Canadian oil sands and 220 billion barrels of extra-heavy Venezuelan Orinoco crude.

recent study by IHS CERA [*IHS CERA 2012*] evaluated oil sand derived synthetic crude oil production and estimated higher emissions compared to conventional crude production but substantially lower emissions (approx. 15 – 24 gCO2eq/MJ) compared to the Brandt study. These energy and emissions figures can be compared with our average figures for conventional crude production of 4.3 g CO_2eq/MJ and 0.065 MJ/MJ.

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 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. Canadian production of non-conventional oil in 2011 was 1.6 Mbbl/d, and is expected to increase to around 2.9 Mbbl/d by 2020 [*IEA WEO 2012*]. Current Venezuelan extra-heavy oil production is around 0.6 Mbbl/d, and is expected to grow to 1.6 Mbbl/d by 2020 *[IEA WEO 2012]*. A category of non-conventional oil that has developed rapidly in North America in recent years is light tight oil, extracted from shale formations by hydraulic fracturing or “fracking”. Production is estimated to grow from 1.0 Mbbl/d in 2011 to 3.8 Mbbl/d in 2020 [*IEA WEO 2012*]. 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 assumed that there will be negligible change in the energy use and GHG emissions figures for production of crude oil consumed in the EU in the period to 2020.

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.

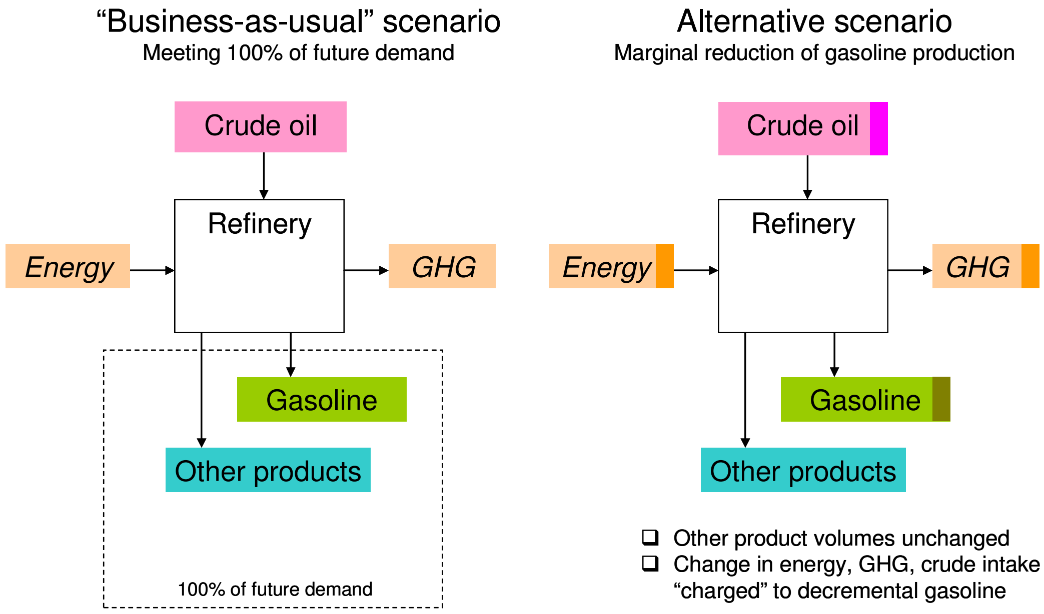
Oil refineries produce a number of different products simultaneously from a single feedstock. Whereas the total amount of energy (and other resources) used by refineries is well documented, there is no simple, non-controversial way to allocate energy, emissions or cost to a specific product. Distributing the resources used in refining amongst the various products invariably involves the use of allocation rules that can have a major influence on the results. Although allocation methods are often used for lack of better tools, such an 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 substituting conventional fuels, the question to consider is what primary energy and GHG can be saved by using less conventional fuels rather than how much energy/GHG emissions are associated with producing fuels today. In the context of this study, we thus considered that the energy and GHG emissions associated with the production and use of conventional fuels should be representative of how the EU refineries would have to adapt to a marginal reduction in 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, energy use and GHG emissions 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 co-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 seems to us to be the best methodology to reflect the specifics of European refining.

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 Gross Domestic Product (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 declining or 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.

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



Dark hatching marks reductions from BAU

Based on our results, we have adopted the following figures:

		Gasoline	Diesel fuel
Energy	MJ/MJ	0.08	0.10
GHG	g CO_2eq/MJ	7.0	8.6

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. However, since the change represents a small percentage of the total WTW footprint of a fossil fuel, we have at this stage not changed the figures used in the previous version of the study.

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 workbooks WTT v40 pathways 1-Oil and gas/5-Synfuels/6-Electricity/7-Heat & Power)

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, although actual realisations remain few and far between.

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 as sulphur emission limits were introduced to combat acidification. When used in a Combined Cycle Gas Turbine (CCGT), electricity can be produced from NG with a much higher efficiency than using solid or liquid fuels and this, combined with the favourable C/H ratio of natural gas compared to coal or oil also makes it attractive to replace coal or heavy fuel oil when targeting CO_2 emissions.

3.2.1 Natural gas supply in the EU

The EU is a significant gas producer, mainly from the Netherlands and the UK (North Sea) with smaller productions in Denmark, Germany, Italy and Romania. Demand, however, far outstrips domestic production leading to substantial imports. Domestic production has been declining and is set to continue shrinking so that imports represent an ever increasing proportion of total consumption. Imports are mostly from Norway, Russia and North Africa via long-distance pipelines. In recent years, LNG imports have become significant opening opportunities for new supply sources in Africa and the Middle East.

Table 3.2.1: EU-27 Natural gas balance (BCM, Billion m^3)

Year	2005	2011
Consumption	511	466
Domestic production	218	161
Imports	293	305
% of consumption	*57%*	*65%*
Source: Eurostat		

In 2011 four countries accounted for 92% of all imports (Russia 34%, Norway 31%, Algeria 15%, Qatar 12%) and 27% of all imports was in the form of LNG which represented nearly 18% of total consumption.

3.2.2 Gas sourcing options for pathway calculation

It is clear that, in the second and third decades of this century, any extra supplies to Europe 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:

- "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 liquid fuels.

In addition we have calculated, for reference, one pathway based on a notional "EU-mix" representative of the origin of the gas used in Europe in 2011. 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. Based on the current EU gas mix we found that the average pipeline transport distance of 1000 km used in previous versions of the study was too low. We have used a figure of 2500 km as a proxy for the actual mix which includes relatively local gas but also long distance transport in the form of both pipeline and LNG.

More recently, development of the "fracking" technology (fracturing of gas-containing rocks) has allowed exploitation of so-called shale gas, opening up potentially large new gas reserves. This has had a major impact in North America and exploitation has started in Europe. The size of the shale-bound gas reserves in Europe is as yet unclear but, in any case, large gas imports will still be needed and will remain the marginal source. Although published technical data is still scarce we have included a new pathway (SGCG1) to represent EU produced shale gas on the basis of a recent study undertaken for the EU Commission [*Perks 2012*].

3.2.3 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.

Inert gases 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 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 energy 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). In addition to the GHG emissions from energy use we have included 1% volume venting as CO_2 and 0.4% volume of methane losses are also included.

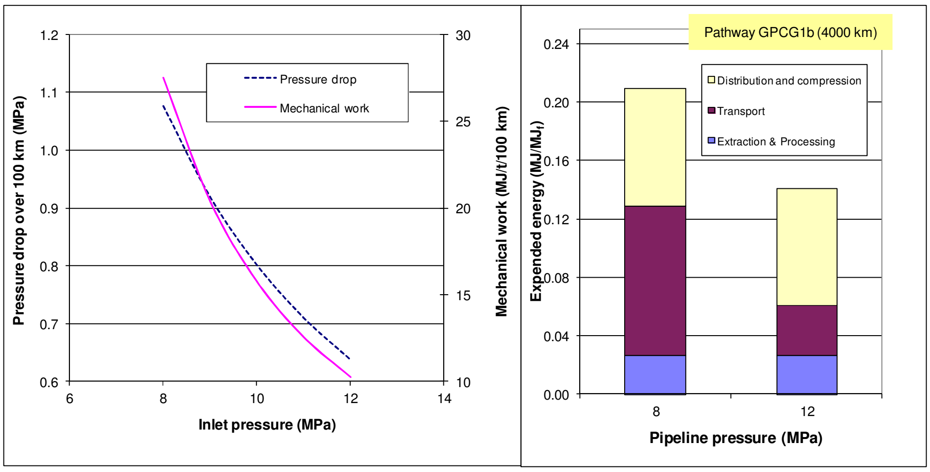
Transportation accounts for the largest part of the energy requirement because of the large distances involved. Western Siberian fields are about 7000 km from Europe whereas typical future South West

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 vs. 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. In this study we assume that the compression power comes from a proportion of the transported gas. For the 4000 km case for instance we have used a median value of 9.6% of the delivered gas with a range of 3.2 to 10.7%.

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% of the transported gas per 1000 km reduced from the 0.16% figure used in version 1 and based on the former study.

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



The energy use and GHG emissions for production of shale gas in Europe are very similar to those for conventional gas sources. Note that in line with our general approach we have excluded energy and emissions related to site preparation, construction and drilling. We have assumed that the gas produced will be injected directly into the European high pressure distribution grid, avoiding the need for long distance transport.

3.2.4 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 while flaring of off-gas 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 Arabian 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 may provide an opportunity for CO_2 capture and storage (CCS, see *section 3.6*).

LNG may be gasified at the terminal and distributed through the natural gas grid or transported to and stored in the service station in liquid form. Although today's natural gas vehicles generally store fuel on-board as compressed gas, a new pathway has been added in this version to model a vehicle carrying liquid natural gas on-board (GRLG1). In this case, the energy use to vaporise and compress the gas at the service station is avoided, although some additional energy will be consumed on-board the vehicle.

3.2.5 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 high pressure trunk 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 supply CNG refuelling stations. For more details on CNG see *section 4.3.1.*

3.2.6 NG transformation

3.2.6.1 NG to electricity and heat

See section 3.5.1and 3.5.3

3.2.6.2 NG to hydrogen

The hydrogen figures have not yet been updated in this version 4 of the study. For this reason, the text from the previous version 3c has been retained for reference.

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.*

3.2.6.3 NG to synthetic liquid fuels

Besides using natural gas directly 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 syngas which is then used as 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. A much larger plant has recently been completed in Qatar. When operating at full capacity (anticipated in mid 2013) this will be capable of producing 140,000 bpd of GTL products. 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 earlier versions 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 retained at the slightly higher figure of 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 led us to consider that all products and their fate are independent of each other and so simply compare the energy and GHG emissions of GTL production with the marginal figures for fossil diesel.

The alternative would be to consider diesel as the main product supporting all production energy and emissions and other streams as “co-products”. In this case the fate of the co-products would have to be considered in order to calculate a credit or debit to be applied to refinery diesel. The most likely disposal route for GTL naphtha and LPG would be to substitute 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 naphtha and LPG production pathways are less energy intensive than the GTL process.

Two studies by PriceWaterhouseCoopers [*PWC 2001*] and one study by Nexant [*Nexant 2003*] 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 studies 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 is that availability of GTL would slow investment in crude oil capacity. This 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. 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 *section 4.6.2*).

DME

Di-methyl ether or DME has attractive characteristics as a fuel for diesel vehicles. However, 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 have been various reports of large plants planned for Iran and particularly China, mainly for domestic fuel. We have used data available from Haldor Topsoe, scaled to a notional plant with the same gas intake as its methanol equivalent. 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 *section 4.6.3*).

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%.

NG to hydrogen via methanol

Methanol synthesised from remote natural gas could potentially be used as an 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. It was originally used for its ability to reduce emissions by bringing oxygen into the fuel and 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.

3.2.7 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 3.2.7: Natural gas pathways

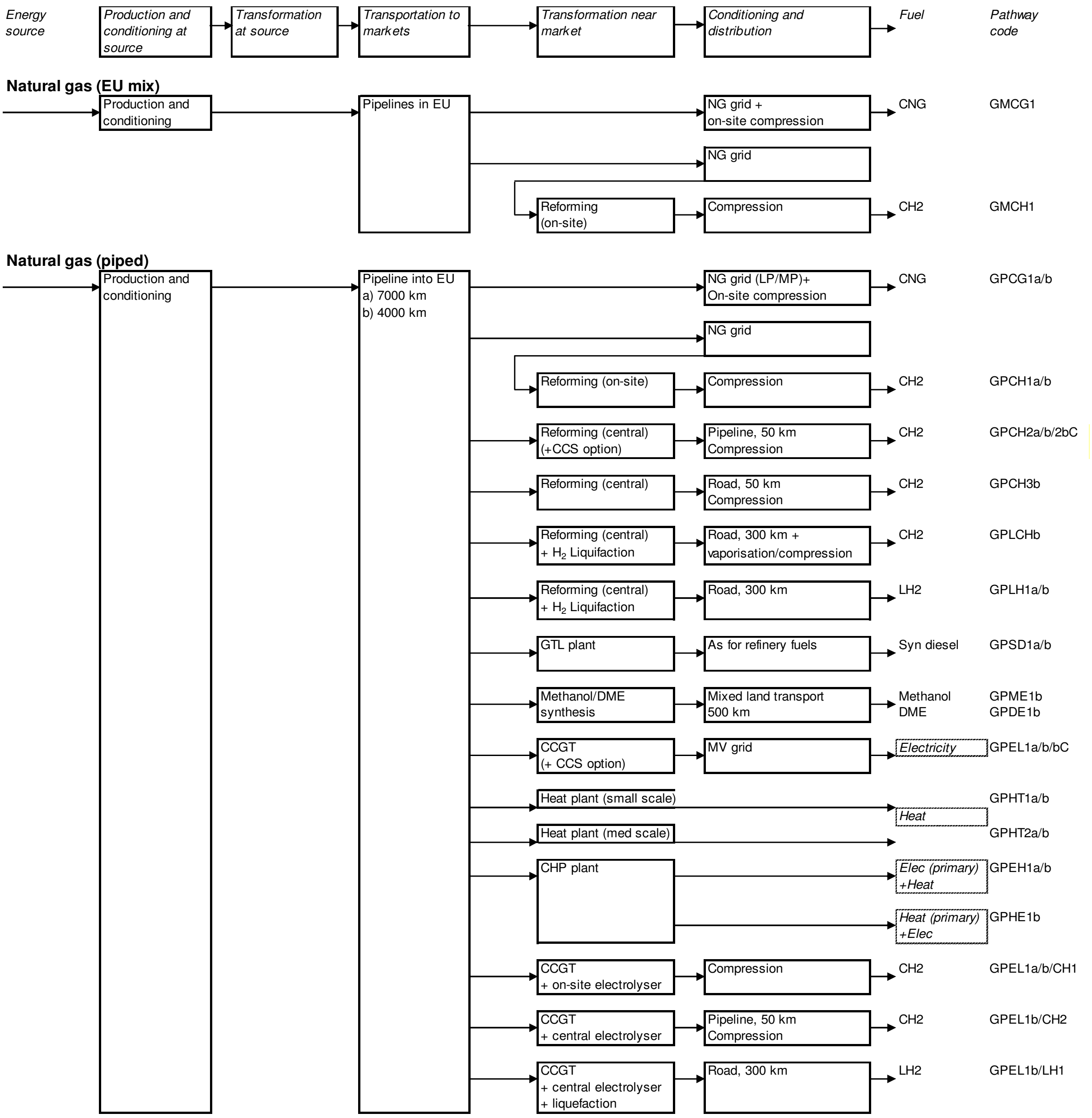
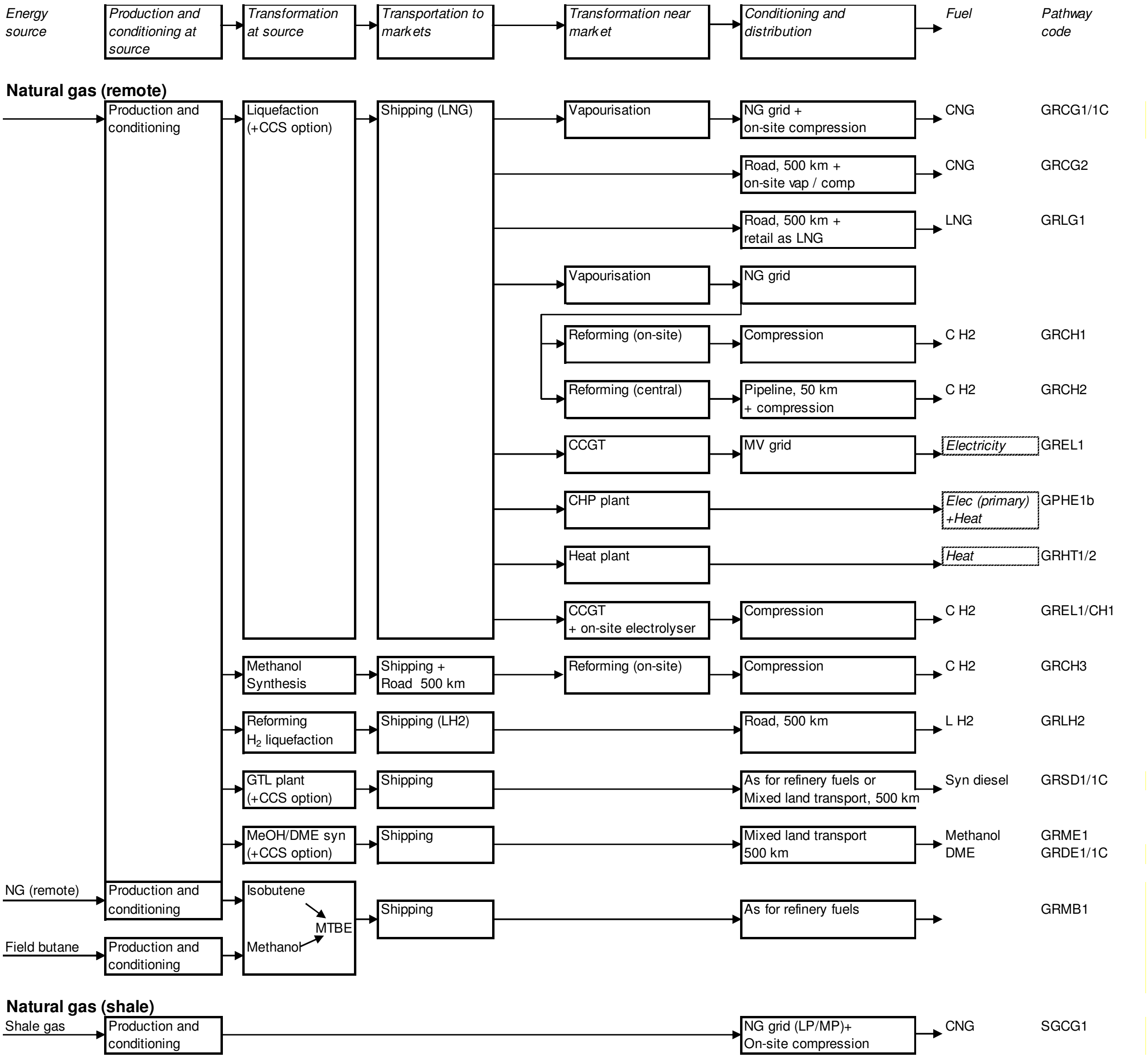


Figure 3.2.7: Natural gas pathways (cont'd)



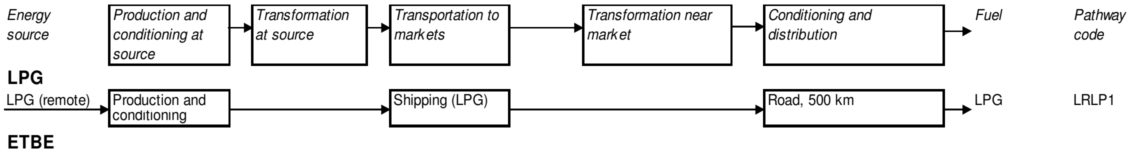
3.2.8 LPG

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. 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 3.2.8: LPG from gas field



3.3 Coal pathways

(See also workbooks WTT v40 pathways 5-Synfuels/6-Electricity)

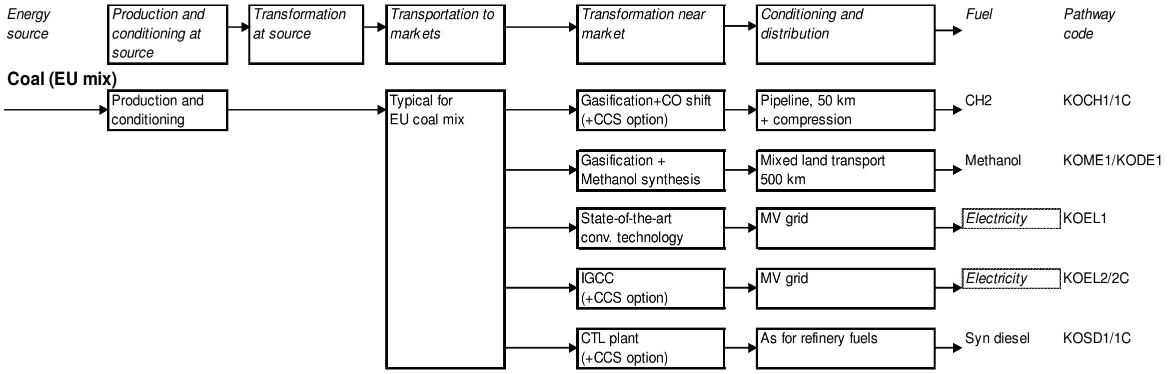
Although not fashionable in today's carbon-conscious world, coal still plays an important role in the world and even in Europe's energy supply, essentially for power generation. After a steady decline over many years, EU consumption has settled around 300 Mtoe since the beginning of the decade. It is, 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 2001-2005*]. 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



3.4 Biomass pathways

(See also workbooks WTT v40 pathways 2-CBG/3-Ethanol/4-Biodiesel/5-Synfuels/6-Electricity/7-Heat & Power)

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.

We have included all sources of biomass which have the potential to produce biofuels 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” also represents perennial grasses such as miscanthus or switch grass.

3.4.1 Land use change and marginal cultivation emissions

Emissions from land use change are important, but are NOT INCLUDED in our WTT GHG balances

From the start of the JEC-WTW project, we adopted the same approach as most traditional LCA studies, namely that the CO_2 emitted when biomass is burned does not count as an emission. The rationale for this assumption is that this carbon in the crops was sequestered from the atmosphere during the previous growing season. The GHG emissions associated with cultivating the crop and processing it into a finished fuel must, however, be taken into account and these are the subject of the various biofuel pathways included in this study.

In addition, crop cultivation may directly change the soil carbon reservoir, for example where forest or grassland is converted to arable use. In some cases the carbon store may increase where a perennial crop replaces annual arable crops. Such Direct Land Use Change (DLUC) can take several years or even decades to reach an equilibrium and the effects may in some cases be large. DLUC refers to effects on the land where the biofuel crop itself is produced.

Changes in land use may also be affected indirectly by biofuels, through the expansion of croplands to replace the land lost to food production where biofuels are produced. GHG emissions may result from removal of existing forest or other vegetation as well as changes in the soil carbon reservoir of new land brought into cultivation. These effects are referred to as Indirect Land Use Change (ILUC)

Both DLUC and ILUC can be important in understanding the impact of biofuels, but they are difficult to estimate and still the subject of debate and research *[EP ILUC 2013]*. For this reason, we have not included LUC effects in the biofuel pathways, but we present this short explanatory section to provide an overview of the topic.

3.4.1.1 Direct Land Use Change Emissions (DLUC)

The European Commission has issued guidelines for the calculation of land carbon stocks for the purpose of Renewable Energy Directive (RED, 2009/28/EC) on the promotion of energy from renewable sources. In the special case that a batch of biofuel is known to come from a particular field which was converted from another land use, the direct land use change emissions can be calculated, and the method for this is prescribed in the detailed guidance *[EU 2009 (2)]*. The calculation for use in the RED and Fuel Quality Directive (FQD, 2009/30/EC) follows the IPCC methodology quite closely. The document includes specific carbon stock values for common biofuels that are absent from the IPCC guidelines. We have used the default values in this methodology to calculate DLUC emissions for some example land use change scenarios in ***Table 3.4.1-1***.

Table 3.4.1-1: DLUC GHG emissions for some example pathway scenarios

Crop	**Sugarcane**		**Wheat**	**Farmed Wood**	**Palm oil**	
Pathway	SCET1		WTET1	WFET	POFA	
Climate region	Tropical wet		Cool Temperate Moist	Cool Temperate Moist	Tropical wet	
Soil type	LAC		HAC	HAC	LAC	
Biomass before conversion	Rainforest	Savannah	Grassland	Grassland	Rainforest	Grassland
Land Management before	Native forest	Moderately degraded	Nominally Managed	Nominally Managed	Native forest	Nominally Managed
Land Management after	No till		Full tillage	No Till	No till	
Land input before	None	Medium	Medium	Medium	None	Medium
Land input after	Medium		High with manure	Medium	Medium	Medium
Carbon stock change (tCO_{2e}/ha/a)	38.6	3.45	1.36	-9.28	28.73	-11.93
Total LUC CO_2 emissions (gCO_{2e}/MJ)	***289.0***	***25.8***	***33.4***	***-142.5***	***192.6***	***-80.0***
Allocated LUC CO_2 emissions (gCO_{2e}/MJ)	***289.0***	***25.8***	***19.9***	***-142.5***	***175.4***	***-72.8***

Note: Total LUC CO_2 emissions and allocated emissions in gCO_2eq/MJ have been calculated using crop yields from BioGrace

The table lists the different biomass types present before conversion for biofuel crop cultivation as well as details of the soil management and input strategies both before and after conversion. Definitions of the terms used here are given in the EU document. The CO_2 emissions figure (in gCO_{2e}/MJ) in the "allocated LUC CO_2 emissions row" of the table is the "land use change factor". This should be added to the "total non-renewable emissions including combustion" figure in the respective GHG balance template to give the total emissions for the particular biofuel including the DLUC scenario.

The different scenarios show the wide variation in possible land use change emissions that can be obtained depending on the particular land that is converted. Not surprisingly, converting rain forest into any crop results in a large release of carbon and a land use change factor that would mean the resultant biofuel having GHG emissions several times the magnitude of gasoline or diesel. Converting grassland, however, produces less GHG emissions, and both the WTET1 and SCET1 pathways produced by converting this type of land would still show some GHG savings relative to gasoline. Conversely, using grassland to grow a perennial, woody crop, such as oil palm or farmed wood can, with this methodology, actually lead to an improvement in GHG emissions associated with the biofuel, due to the sequestration of carbon in parts of the plant that is usually not annually harvested (such as the stem or trunk).

Note that the DLUC calculation guidelines in the Renewable Energy Directive do not include conversion of wetlands, (including tropical peatland drained for oil palm plantation) because the directives exclude biofuels from crops grown on wetland converted after 2008. However, very significant emissions from decomposition of peat continue for decades after drainage, usually for the entire life of an oil palm plantation *[Page 2011]*, whilst historical data in *[Miettinen 2012]* indicates that about 16% of oil palm area in Indonesia and Malaysia was already converted from peat before 2008. Therefore in principle, loss of carbon through peatland drainage should be included in the calculation of emissions from palm oil. However, we have not included soil carbon changes for other pathways because, even though they may be significant even for land which was already under crops, they are very difficult to estimate because they vary depending on the conditions.

3.4.1.2 Marginal Direct Emissions

For biofuel made from food crops, the extra crop demand is a marginal change on top of the existing crop production for food. Therefore the (direct) cultivation emissions attributed to biofuels should be those for the marginal production per tonne of extra crop. That means the sum of the emissions from following two sources of extra crop production. However, as neither are known at present with any accuracy, we continue to use average crop emissions for the existing crop production as a proxy.

Farming on additional land
In future, it may be possible to use models of agriculture to calculate marginal farming emissions. For example, reporting the range in energy use by different farms in EU, [*Kraenzlein 2009*] showed that the quartile of wheat farms with lowest yield used 50% more energy than the average to produce a

tonne of wheat. Therefore one may expect marginal farms to show significantly different cultivation emissions than average.

Emissions from intensification
These are marginal emissions involved in increasing the existing yield in response to the increase in crop price. The incremental production from this intensification will be associated with incremental emissions from the farming (extra use of fertilizer, pesticides, diesel, improved 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).

3.4.1.3 Carbon Debt and Credit

Increased burning of wood produced from existing forests leads to an immediate release of carbon into the atmosphere, but in principle this is replaced as new trees grow, so over time there is no net emission to the atmosphere. However, when trees are cut and replaced the rate of carbon sequestration may change: there is an emissions benefit if it results in an increased rate of carbon sequestration in the forest, a debit if sequestration is slowed.

If trees are removed from an existing forest and the trees replanted, the average age of the forest is reduced. In the best case (where the rate of cutting is still below the “maximum sustainable yield”) this will lead to faster carbon sequestration by tree growth in the forest. However, it typically takes about a century for this to replace the carbon taken from the forest. In the long term, burning wood instead of fossil fuel reduces carbon emission to the atmosphere, but in the short term the forest suffers a “carbon debt” until new growth replaces the lost carbon *(see [Agostini 2013]).* This is important, if one is expecting bioenergy to contribute to climate mitigation targets in, say, 2030.

If there is additional tree growth *before* the wood is harvested, there will be a carbon credit. For new plantations, which include most short-rotation forest and energy crops, this is already the case. But if wood consumption increases without increasing forest area, it is likely to stimulate cutting of *existing* forest and the carbon debt needs to be considered.

Forest residues are branches, tops and sometimes leaves and stumps, which are traditionally left in the forest at harvest, but which can also be collected for energy use. They would rot if left in the forest, but this process can take up to 20 years, so there is a temporary carbon debt. If consistently removed, there is also a small reduction in the long-term soil carbon stock in the forest, which can be considered like a land use change emission.

This study has general categories of waste wood and farmed wood. We do not take carbon debt into account in our calculations. To do so requires at least an approximate forest soils and growth model and a decision on how to deal with a time delay in emissions savings which could exceed a century.

3.4.1.4 Calculating Indirect Emissions from Biofuels: Indirect Land Use Change (ILUC)

Usually, a crop going into biofuels comes from land which was already producing that crop. In this case there is no additional carbon sequestration on that land, i.e. no DLUC. However, diverting food to biofuel potentially results in the food production loss being replaced through more intensive farming to raise yields or by bringing new land into food production.

As noted above, farming more intensively or bringing marginal land into arable cultivation can increase cultivation emissions. Conversion of grass, forest or other natural land into cropland often leads to significant release of carbon, both from the soil and from any vegetation present [*IPCC 2007 (1)*]. Since these Indirect Land Use Changes are a consequence of biofuel production, the GHG emissions associated with the biofuel need to include the ILUC emissions.

Even if the indirect effect would be only a reduction in the amount of cropland abandoned, one needs to consider the carbon which would otherwise be sequestered on that land by reforestation or re-growth of natural land cover. Yield intensification induced by crop price rises is also likely to incur additional emissions from fertilizer and other inputs, because of diminishing returns to spending on inputs.

It is impossible to measure ILUC accurately, even in retrospect, because one cannot be sure what would have happened if biofuels were not introduced. Nevertheless, even though we were not able to include them in this study, a thorough evaluation requires that carbon sequestrations or emissions due to ILUC should be considered when assessing GHG emissions of biofuel production. The magnitude of ILUC is still controversial, and currently a matter of debate and scientific investigation *[Wicke 2012], [Edwards 2010].* It is currently determined by modelling (commonly using econometric modelling), which seeks to look at the global land use change response to increased biofuel demand. This is done by comparing an economic scenario with the biofuel, against a baseline scenario where the biofuel demand is absent. The "shock" to the model is the extra biofuel demand. This can be a given quantity of a particular biofuel (e.g. 1 Mtoe of rapeseed biodiesel in EU) or a whole policy such as the EU Renewable Energy and Fuels Quality Directives *[EU 2009 (1)]*, the California Low Carbon Fuels Standard (LCFS) *[CA LCFS]* or the US Renewable Fuel Standard-2 (RFS-2) [*US RFS-2 2010 (1)]*

Determination of the GHG emissions from ILUC involves assessing changes in carbon content (the "carbon stock") of the land, caused by the change in land use. 2006 guidelines from the Intergovernmental Panel on Climate Change (IPCC) *[IPCC 2006 (1)]* described a detailed way of doing this.

The general approach taken is to divide the land into a series of land-use categories (for example, forestland, cropland, grassland, wetlands, etc.). Carbon stock data for typical above- and below-ground biomass vegetation types, soil compositions and dead organic matter are then defined for these categories, often by climate zone, ecological zone and soil type. Soil carbon stock levels also include factors to take into account levels of cultivation, land management and organic fertilisation. Calculation of the land use change emissions occurring when land is converted between two of these categories (for example, from converting forestland to cropland) is then a matter of determining the difference in carbon stock between the two particular situations.

A complicating feature of land use change emissions, however, is that they occur over a period of time after the land conversion process has begun. Equilibration of soil emissions, for example, can take a particularly long time, while cultivation of perennial crops can lead to carbon accumulation in non-harvestable parts over time as they grow. The common approach to this is to consider the total land use change emissions occurring over a timescale of either 20 or 30 years. The total is then annualised to produce an annual emission value (a "land use change factor") that can be incorporated into the WTW GHG balance for the rest of the biofuel pathway.

We do not attempt to calculate DLUC or ILUC emissions in this report, because the subject is still controversial and we lack the appropriate tools. However, we do consider these emissions essential for accounting the climate change effects of biofuels.

3.4.2 Nitrous oxide emissions

3.4.2.1 Background

As explained in the previous section, the ability of biofuels to reduce fossil energy use and GHG emissions rests on the additional 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, and by land use change emissions. Although not a major factor in *energy* terms in the whole pathway, farming is a major 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. Measured N_2O emissions for individual fields vary by at least three orders of magnitude, 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 and drainage. Therefore it is worthwhile putting a large effort into improving the accuracy of the soils-emissions estimates.

3.4.2.2 Sources of N_2O emissions

Emissions of N_2O resulting from anthropogenic nitrogen inputs to agricultural soils occur through both:

- **a direct pathway**
  - i.e. directly from the soils to which the nitrogen is added/released, and:
- **two indirect pathways**[9]:

  (i) following volatilisation of NH_3 and NO_x from managed soils and the subsequent re-deposition of these gases and their products NH_4^+ and NO_3^- to soils and waters; and

  (ii) after leaching and runoff of nitrogen, mainly as NO_3^-.

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 (1)*] 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 variables other than N input, IPCC tier 1 specifies a wide error range with max/min ratio varying from 10 (for direct emissions) to 25 (for indirect emissions). The IPCC emission factors were designed to help countries report *national* greenhouse gas inventories, not to predict emissions from individual fields. Thus the error ranges can represent the uncertainty in *national average* emissions from a crop, but the uncertainty in emissions from smaller regions or individual fields is very much higher. The reason for that is that IPCC tier 1 approach assumes that the main *local* determinants of N_2O emissions, predominantly soil/drainage properties, tend to average out on the national scale.

3.4.2.3 Methodology

Soil N_2O field measurements are expensive and are not generally available for a particular crops and locations. In addition N_2O emissions vary by orders of magnitude over quite short distances, and also vary significantly between years.

[IPCC 2006] suggests that where suitable input data is available, national emission inventories can be based not on tier 1 but on the more sophisticated 'tier 2' and 'tier 3' approaches.

- tier 2 is the same approach as tier 1 except that the equation linking N_2O emissions to nitrogen inputs is replaced by a more sophisticated one where other, localized, parameters (soils, drainage, climate, crops) are also taken into account. Both equations are based on statistical fitting of measured N_2O data to reported parameters.
- tier 3 foresees the use of experimentally-validated soils chemistry models, or direct measurements, to calculate N_2O on the basis of local parameters.

IPCC tier 1 and tier 2 both start with an equation showing a statistical regression of all (at the time) known N_2O measurements against the known controlling parameters of soils/drainage, climate, management, crop and nitrogen inputs from all sources. In order to estimate the tier 1 emission factor for N inputs, [Bouwman 2002] applied this equation to global GIS data in order to estimate N_2O emissions from global crops. For tier 1 this fit was applied to estimate world N_2O emissions from crops on a 0.5 degree global grid; then the total emissions are divided by the total applied nitrogen to give an estimate of the average emission factor for all crops and locations. A tier 2 approach is similar, except that more results would be averaged for locations in a particular country. In our calculation, the results are averaged for particular crops.

In version 3 of this study we applied a tier 3 approach, estimating N_2O using a soils chemistry model applied to the extensive local data available for sites growing particular crops in the EU15 in the

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[9] These "indirect" nitrous oxide emissions should not to be confused with nitrous oxide emissions resulting from food production displaced by biofuels.

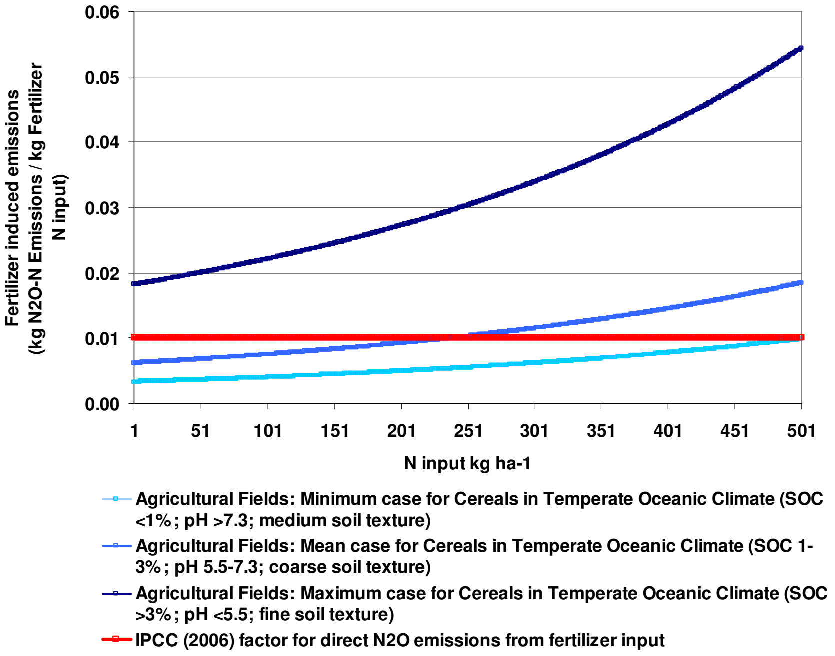
LUCAS land-cover survey. Unfortunately, the same approach was impossible for crops grown outside EU because there was not enough input data available; in these cases we were obliged to fall back on IPCC tier 1.

In this version we use an IPCC "tier 2" approach, because it requires less detailed input data than tier 3, and could thus be applied equally to crops grown both inside and outside EU. Furthermore, although a tier 3 soils model should give a more accurate prediction of emissions on a particular field if all the input data is known, we fear that inaccuracies in the soils chemistry model may lead to systematic errors in the *average* of emissions for a particular crop. This is avoided in our new approach.

The new tier 2 methodology used in this version was developed by the Climate Change Unit of JRC's Institute for Environment and Sustainability (IES), and called 'Global crop and site specific Nitrous Oxide emission Calculator (GNOC)'. It is being developed as on-line tool which will enable estimates to be made of N_2O emissions for any crop in any place in the world, using estimated or specified input parameters.

Example output from the model is shown in ***Figure 3.4.2-1***. The mean line is close to the IPCC generic figure, but takes account of fertiliser input rates. The GNOC models the effect of soil organic carbon and pH, and the impact can be seen by the minimum and maximum cases. Even with this improved discrimination, there remains a large uncertainty in the estimates.

Figure 3.4.2-1: Nitrous oxide emissions from the GNOC calculator for temperate climates



Soils emit some N_2O even if they are not farmed (so-called "background emissions"). These can be quite significant, especially for organic soils. In previous versions of this study we have subtracted N_2O emissions for a reference case of unfertilised grassland to obtain the N_2O emissions directly attributable to biofuel production. With the new GNOC modelling tool used in this version a reference case is no longer needed, since the emissions from an unfertilised control plot are subtracted internal to the model.

The significance of field N_2O emissions in the overall WTT calculation is illustrated by these example figures for the main EU crops considered in the study and shown in ***Table 3.4.2-1.*** Note that the total WTT GHG emissions may be less than the cultivation emissions after by-product credits are taken into account.

Table 3.4.2-1: N_2O contribution to GHG emissions for the main biofuels crops

Final fuel	Crop	Pathway code	GHG emitted (g CO_{2eq}/MJ final fuel)			
			WTT	Cultivation		
			Total	Total	*of which N_2O*	
Ethanol	**EU crops**					
	Sugar Beet	SBET1a	40.3	18.1	*10.1*	*56%*
	Wheat	WTET1a	69.4	49.0	*28.8*	*59%*
	Barley/Rye	BRET2a	76.0	62.8	*34.1*	*54%*
	Maize	CRET2a	80.3	45.1	*27.9*	*62%*
	Wood	WFET1	22.8	6.3	*2.8*	*44%*
	Straw	STET1	9.2	3.1	*0.0*	*1%*
Biodiesel	**EU crops**					
	Rapeseed	ROFA1	53.9	55.0	*32.9*	*60%*
	Sunflower	SOFA3	45.9	41.3	*21.3*	*51%*
	Imported crops					
	Soya	SYFA3a	55.1	56.7	*43.2*	*76%*
	Palm Oil	POFA3a	50.8	27.1	*19.1*	*71%*

Rapeseed has high 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 lower 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 below that of the other grain/seed crops. Farmed wood and straw have the lowest N_2O emissions.

3.4.2.4 Top-Down estimates

Calculation of N_2O emissions remains challenging and there is considerable uncertainty in the results. 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.

However it should be noted that the N_2O emission estimates in [*Crutzen 2007*] 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).

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.

Although many literature sources quote farming inputs per hectare, they all refer to different yields. Because of the large variability of yield data and the relatively good correlation between yield and farming inputs, we present the data in terms of input per MJ of crop produced.

The figures used for fertiliser and other agricultural inputs are documented in *the relevant workbooks.* In this version of the JEC study, we calculate fertilizer (N, P and K) use per tonne from a unified source: the "fertilizer use by crop" database published by the International Fertilizer Association[10] (IFA). This is based on national fertilizer sales data, allocated to different crops by their experts, as we consider this the most neutral and authoritative source. The last database was for 2006/7, because of the disruption from the 2008 commodities price spike. We divided the fertilizer per hectare data by the yield in the appropriate year to obtain fertilizer-per-tonne of crop. Yields have hardly changed since then. Except where a particular country is specified, we calculated a weighted average fertilizer-per-tonne for the regions supplying the EU market.

Nitrogen is the main fertiliser input. Potassium and phosphorous fertilizer rates vary greatly according to geography, but hardly correlate with yield. However, they are only of minor importance in the calculation. EU yields are expected to continue their slow rate of increase of recent years, with an annual growth rate for EU-27 cereals of 0.52% from 2000 to 2012 *[OECD Stat. 2013]*. 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. Where straw is collected, fertilizers should be added to compensate for the lost minerals, but 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 also consumes nitrogen from the soil.

Nitrogen fertilizer causes soil acidification. In version 4 we calculate how much CO_2 is emitted when this acid is neutralized, either by applied agricultural lime (aglime) or by carbonates that are naturally present in the soil or are further down the watershed in rivers or the sea.

We revised our calculations for emissions from aglime. The production emissions are lower than in version 3 because we ignore the contribution of calcined limestone (CaO or $Ca(OH)_2$), as almost all aglime used these days is ground carbonate rock. On the other hand, the carbonate reacts with acids in the soil. According to IPCC guidelines, one should assume that all the CO_2 content of aglime is released; however, we applied a more sophisticated calculation[11] which indicates that on neutral soils (pH > 6.4) only about 18% of the aglime's CO_2 content is released. On this basis, we exploit the JRC's GNOC model to calculate also the emissions from aglime using a GIS basis, depending on aglime application and soil acidity. To avoid double-counting, the local CO_2 emissions attributed to N fertilizer acidification are subtracted from the local aglime CO_2 emissions, so that remaining emissions attributed to aglime application are for where it is applied to counter natural acidity in the soil.

3.4.4 Credits for animal feed co-products

At present the main co-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 co-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.

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[10] There are two exceptions. For sunflower, the IFA data were combined with other crops so we have used Fertilizers Europe instead. Data for farmed wood were not in the IFA database.

[11] The calculation was kindly checked by Profs. Anne and Jean-Luc Probst of the Laboratoire d'Ecologie Functionelle (ECOLAB) of ENSAT, France.

3.4.4.1 The animal-feed substitution calculation

The calculation is made assuming that the co-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 co-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 co-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.

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.

In this version 4, we have based our production emissions for EU nitrogen fertilizer on the declarations made by the EU industry association Fertilizers Europe to the Emissions Trading Scheme (ETS). Their emissions reported in 2005-7 agree roughly with those we assumed in version 3c of this study, but we also take into consideration emissions from imported fertilizer reported by Fertilizers Europe. We assume that all these emissions decrease in proportion, so that the EU figures reach the agreed ETS target for 2020. Fertilizer transport emissions are included, but are negligible.

We assume the same N fertilizer emissions for crops grown outside EU, which generally underestimates their emissions.

3.4.6 Other environmental effects of biofuels

This study concentrates on energy use and GHG emissions, however many other aspects of biofuel production are important and the subject of discussion. They are briefly noted here for completeness.

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 is a bigger problem for light soils typically found in Southern Europe where straw is 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 economical to site a 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 (76 and 99% respectively as reported by Eurostat). 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. The modes of transport and distances considered are summarised in *section 3.7*.

3.4.8 Sugar beet to ethanol

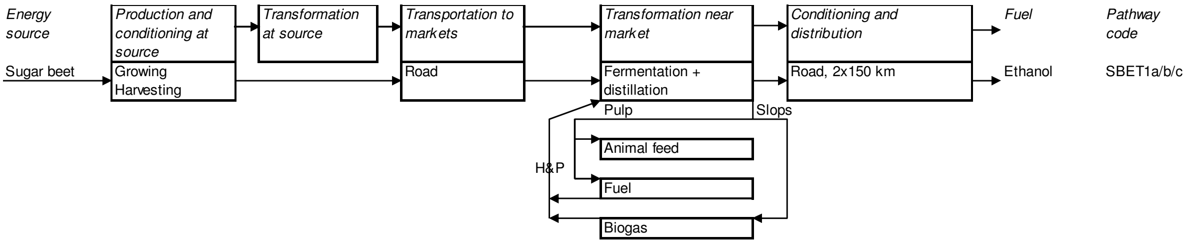
Sugar beet is a high yield crop. It produces carbohydrate already in the form of sugar and is easily crushed and mashed for fermentation which makes the processing into alcohol rather cheap. The economics of its cultivation are highly distorted by the CAP.

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, it can be stored to keep the fermentation and distillation parts of the plant running for a substantial part of the year. Co-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 co-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 SBET1c uses pulp as fuel and slops for biogas production both of which are 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 supplying the energy required with a combined heat and power scheme (CHP). We chose wheat-to-ethanol to illustrate the effects of different fuel and CHP options.

The following options are modelled in the pathways presented in this version of the study. We have made efforts to keep other variables constant so that by comparing the pathways, the true effect of the parameters varied can be seen.

3.4.9.1 Energy supply options

The energy can be provided by a variety of sources. We have considered three scenarios based on fossil fuels and representing plants actually on the ground or planned in Europe. A fourth scenario uses straw as energy source. In a fifth scenario DDGS is used internally to produce biogas and thereby most of the plant energy.

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.

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 studies have considered straw as a by-product, but in most of the EU it should be ploughed back to maintain the water-retention properties of the soil. In practice straw use should only be proposed where there is little water stress, a high density of cereals production and a low density of livestock. 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.

WTET5: DDGS to biogas

This pathway considers 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.

3.4.9.2 DDGS

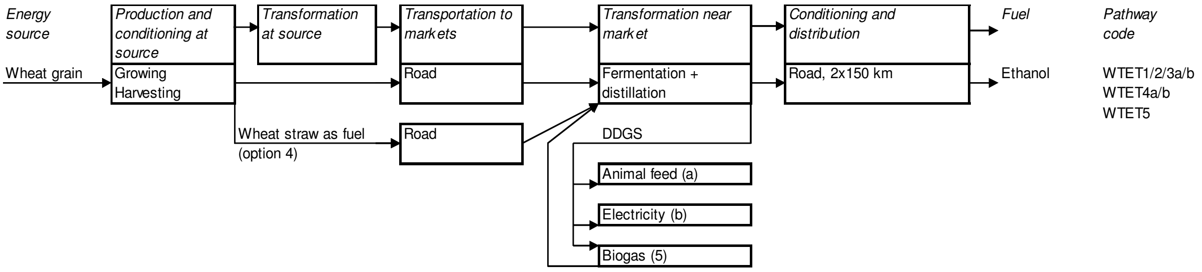
Ethanol production produces a by-product known as DDGS (Distiller's Dried Grain with Solubles) which is the solid residue after fermentation of the carbohydrates. DDGS is a protein-rich material and is therefore a useful animal feed component. It is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy.

An alternative use of the DDGS is also modelled, to produce electricity and heat in the ethanol plant via a boiler and steam turbine.

As described in the fifth scenario above we have also covered use of DDGS for energy production through production of biogas in the ethanol plant

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

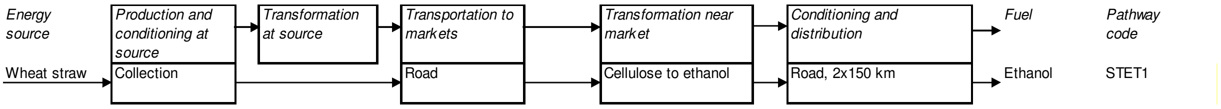
Figure 3.4.9-1: Wheat grain to ethanol pathways



3.4.9.3 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.

Figure 3.4.9-2: Wheat straw to ethanol pathways



3.4.9.4 Ethanol to ETBE

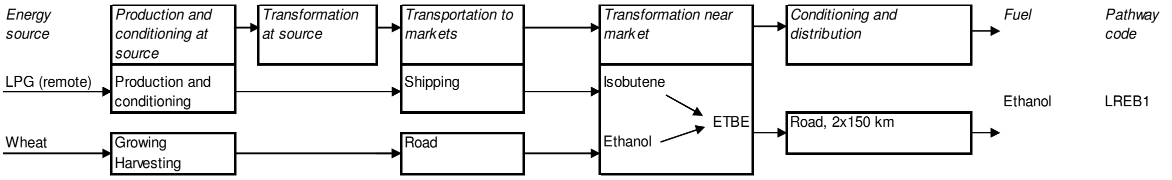
As an alternative to using ethanol directly as a gasoline blending component, it can be converted to ETBE (Ethyl-Tertiary-Butyl Ether). ETBE is a high octane component with very similar properties to MTBE but with a somewhat lower solubility in water. The main advantage of ETBE over ethanol as a gasoline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

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 purpose-built ETBE plants or, much more frequently, 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



3.4.9.5 Ethanol from sugar cane (Brazil)

Sugar cane is an excellent biomass crop from almost every point of view, but cannot practically be grown in Europe. Production of ethanol from sugar cane has been pioneered in Brazil and we have used Brazilian data to represent this pathway. Sugar cane 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.

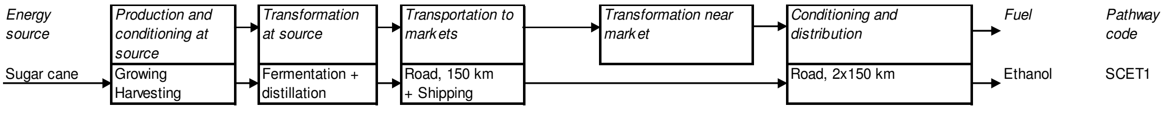
Brazil is the by far the world's largest producer, and has the greatest potential to expand production. The main growing area is in the South of the country, around Sao Paulo province. Expansion of sugar cane growing would occur in this and neighbouring regions, mostly at the expense of rough grazing land. There is a small amount of sugar cane production in the coastal areas of the northeast, nearer some patches of Atlantic rainforest, but this may not be 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 may increase soil carbon stocks, although some studies still show significant land change effects. 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 that sometimes the foliage is burned to allow easier harvesting. There is 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. We have considered that making use of this excess bagasse will become the norm and shown the case where electricity is produced.

We have taken most of our input data from a thorough analysis by Prof. Macedo et al. [*Macedo 2008*], with the exception of fertilizer use, as explained in section 3.4.3.

Figure 3.4.9-4: Sugar cane to ethanol pathway



3.4.10 Vegetable Oils and Animal Fats

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 give palatable animal feed.) Oil seed yields are generally 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 biodiesel grows, imported oils (mostly from soy and palm) play an increasingly important part.

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 (propane-1,2,3-triol) “backbone”. This large molecule is viscous and thermally unstable, forming the familiar yellow deposit 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.

3.4.10.1 Rapeseed processing

In the oil mill, the rapeseed is crushed, and oil extracted by steam and hexane. The by-product is rapeseed meal, a high-protein animal feed which can substitute soy bean meal. The production of soy bean meal also involves soy oil as co-product. In this version of we have calculated the credit for this based on sunflower oil because this is compositionally more similar than the rapeseed oil substitution used in earlier versions. 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 using it as a source of biogas 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 sometimes 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.

In this version of the study we have adopted data on transport and processing of oilseeds to biodiesel kindly supplied by the European Biofuels Board/PROLEA.

The raw glycerine stream contains only 80% pure glycerol but can be refined and sold as distilled pharmaceutical-quality synthetic glycerol. Several studies have used this to calculate a co-product credit. 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 biodiesel. Therefore a large increase in supply can only be accommodated by finding other uses, at a lower price. Crude glycerine is already used as animal feed. This gives a much lower energy and emissions credit compared with pharmaceutical use.

The future uses of glycerine are multiple and uncertain: the chemicals industry is developing higher-value uses for glycerine. To cover the range of options, we have included pathway variants with use of glycerine for chemical substitution, animal feed substitution, biogas production and hydrogen production in the biodiesel plant.

We have included five variants to cover the options described above:

- ROFA1: meal exported as animal feed, glycerine used as chemical
- ROFA2: meal and glycerine exported as animal feed
- ROFA3: meal exported as animal feed, glycerine used to internally produce biogas used for process heat and electricity
- ROFA4: meal and glycerine used to internally generate biogas for further process heat and electricity (surplus for export)
- ROFA5: meal exported as animal feed, glycerine used to internally generate hydrogen

Alternative 3 is regarded as the most practical scenario and we have used this to illustrate the impact of using (bio)ethanol rather than methanol in the transesterification process (ROFE3). Other Rapeseed oil Ethyl Ester (REE) variants have been calculated and overall results are given in the workbook but they are not carried forward into the WTW analysis.

3.4.10.2 Sunflower

Sunflower processing differs from rapeseed mostly with regard to its slightly higher pressing yield, while the sunflower meal co-product has a lower protein content. Further processing is similar to rape seed oil.

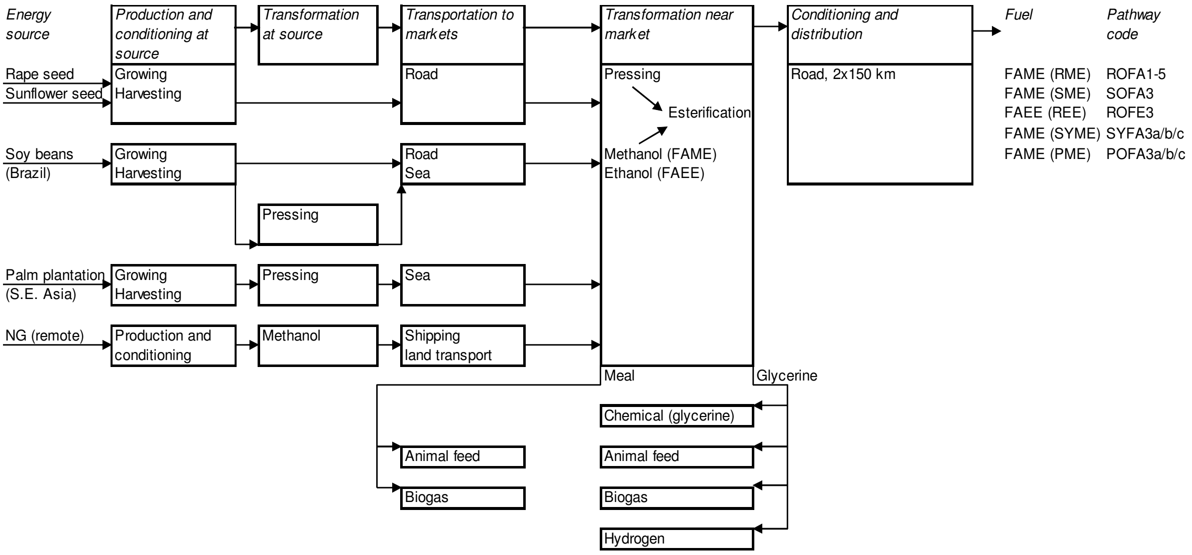
As for REE we describe fully only alternative 3 (SOFA3).

3.4.10.3 Oil seed imports

Europe is short of vegetable oil. 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 co-products in the 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 in as a distant third, followed by many more minor sources including sunflower.

Figure 3.4.10: Oil seeds to bio-diesel pathways



3.4.10.4 Soy beans

Soy beans are already widely traded worldwide. EU soy meal consumption is currently around 30 Mt/a, mostly imported *[Indexmundi 2013 (1)]*.

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. Beside conventional culture the so-called “no till” methods, which greatly reduce the loss of soil carbon, are developing.

While oil is the main product from most oil seeds, soy beans yield much more meal than oil. As a result the net footprint of soy oil is very sensitive to the meal credit. The choice of substitution for soy meal is especially difficult because soy meal is itself the main “swing-provider” of protein in animal feed.

Beans can be either crushed to oil and meal near the production area or exported as beans. Export taxes on beans have encouraged the development of the first option. Soy products are imported into Europe either as beans or separately as oil and meal. About 17% of the soy oil consumed in the EU in 2013 is imported *[Indexmundi 2013 (2)]*.

There is potentially a very large number of combinations of the above elements to form possible pathways from soy beans to biodiesel. We have described three options which we believe to be the most plausible and illustrate the impact of the main variables. In all cases culture and transport distances are relevant to South America and glycerine credit assumes internal use to produce biogas, which gives almost the same result as using glycerine as a fuel. The result is intermediate between using it as animal feed and as a chemical product, so we assume that it represents a mix of all the possible uses.

South America (Argentina and Brazil) is the main exporter of soy beans to EU although anomalies in biofuels subsidies between US and EU have recently created a boom of US soy bean-biodiesel. The cultivation figures are weighted averages assuming a 56.0/26.3/17.7 distribution between Argentina/Brazil/USA for imported beans and 59.4/16.2/24.5 for imported oil. The soybean crushing mill data originates from a review of 7 mills by Ecoinvent, whilst for biofuel processing, EU data for recent plant was used, originating from the European Biofuels Board and Prolea.

SYFA3a includes no till agriculture, bean crushing near production and import of oil into Europe. The extra soy meal left in the local market 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.

SYFA3b includes no till agriculture, bean import into Europe and meal credit based on substitution of EU wheat.

SYFA3c has the same features as SYFA3a but with conventional agriculture.

3.4.10.5 Palm oil

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

Two countries, Indonesia and Malaysia, accounted for 83% of world palm oil production in 2011 (FAOstat). Indonesia has already overtaken Malaysia as the world’s largest producer, and has more land available for expansion: from 2011 to 2020 Indonesia’s oil palm production is projected to expand by 32% *[FAPRI 2012]*

Expansion of oil palm plantations has generated criticism from NGOs related to rain forest clearance, biodiversity loss, working conditions and displacement of native populations. More particularly the potential use of peatland has attracted a lot of attention because of the large release of soil carbon that is associated with it. Although our GHG balance figures do not include land use change effects, we briefly discuss this case in the box below.

Emissions from Tropical Peat Loss are not included in Our Results for Palm Oil

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. For this reason, one can see why losing only a small part of this peatland can result in very large consequences in terms of GHG emissions.

Only plantations need deep drainage

Trees have long been extracted from accessible areas of peat-forest, which reduces the standing carbon lost when it is converted to oil-palm plantation. However, this does not necessitate drainage: although some may result accidentally from digging ditches to transport out the logs, these rapidly silt up again. Systematic deep and irreversible drainage of peat-land is only done to establish a plantation.

Peat-loss CO_2 emissions cover the whole lifetime of the oil palm plantation

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 oxidize to form CO_2. The level of the peat goes down year by year as the carbon is lost. When the soil level approaches the water table, the plantation will die unless the drainage is deepened (then oxidation restarts). Therefore the loss of soil carbon continues for the entire lifetime of the plantation, or until there is no peat left.

Peat-loss emissions are very high and could be considered as a direct annual emission

This means the peat oxidation emissions are in fact an *annual* emission which could be added in to the direct emissions calculation. However, traditionally, they have been treated along with once-off land-use-change emissions. Estimates of the average annual CO_2 emissions from drained peat have converged in recent years, to an average figure of around 100 tonnes CO_2 per ha per year over the 25 year lifetime of a plantation *[Page et al. 2011]*. That corresponds to about 680gCO_2/MJ of palm oil from peat-land (at 4 tonnes/ha palm oil yield) and a similar addition to the emissions per MJ of biodiesel.

Expansion of oil palm onto peatland is accelerating

Oil palm is the most profitable of the few crops which grow well on peat. Although the cost of establishing and maintaining the network of drainage canals means that the plantations on peat are less profitable than those on more traditional plantation soils, an ever increasing proportion of new plantations are on peat. That is driven by high vegetable oil price, the lack of alternative land in some areas and the lack of clear existing ownership of peatland.

The RED sustainability criteria only exclude some of the palm oil from peatland

The sustainability criteria in the RED stipulate that no palm oil for EU biofuel may come from land converted from peat-land after 2008. JRC estimated the proportion of eligible palm oil that comes from peat in Indonesia and Malaysia. Extrapolation of historical data in *[Miettinen 2012]* shows that ~9575 kha of oil-palm are *not* on peat in 2013, and therefore eligible to supply palm oil for biofuel under the sustainability criteria. Interpolating their historical data indicates that ~1810 kha of oil palm were already on peat in 2008. This peat area is also eligible to supply palm oil under RED sustainability criteria. So the fraction of eligible palm oil area which is on peat is 1810/(1810+9575) = 16%. If we were to account for annual CO_2 emissions from this peatland, we would need to add of the order of 100gCO_2/MJ to the average emissions of palm-oil biodiesel satisfying the RED sustainability criteria.

*About 30-40% of **new** palm oil plantations are on peat*

In estimating ILUC, the important number is the fraction of *new* oil palm plantations which are established on peat. According to the Malaysian Palm Oil Board (MPOB) *[Omar 2010]*, if we compare the expansion of oil-palm onto peatland with the total area of oil-palm expansion (given on the same MPOB website), we find that between 2003 and 2009 29.6% of the expansion of Malaysia oil palm area occurred onto peatland. By comparison, combining the area of peatland-to-oil-palm conversion between 2007 and 2010 in *[Miettinen 2012]* with FAO data on total oil-palm expansion, shows 40% of oil-palm expansion in Malaysia was onto peatland, and 30% in Indonesia.

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.

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.

We assume palm kernel meal is used as animal feed, although its high fibre content and a toxin limit its value[12]. 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), and can be processed to diesel specification by deep hydrogenation (see next section).

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 where anaerobic decomposition occurs. 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 we have modelled three pathways representing different combinations of the above options.

- POFA3a: No CH_4 emissions recovery, heat credit (oil mill), glycerine to internal biogas
- POFA3b: CH_4 emissions recovery, heat credit, glycerine to internal biogas
- POFA3c: No CH_4 emissions recovery, no heat credit, glycerine to internal biogas

In all cases the meal is exported as animal feed and the glycerine used to produce biogas internally

In the above pathways, glycerine from the biodiesel plant is assumed to be used to produce internal biogas.

3.4.10.6 Hydrotreated Vegetable Oils (HVO)

The amount of FAME that can be added to conventional 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 into conventional diesel, and the final fuel properties are virtually independent on the original feedstock, so a wider range of feedstocks can be used.

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[12] Recently, EU bioelectricity and heat producers have started importing it as fuel.

The Neste Oil process (NExBTL®) is the first to be used in commercial production, and we have modelled this process using rapeseed, sunflower, 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.

We fully report four HVO pathways covering rape, sunflower, soy and palm with meal to animal feed and based on the Neste process. In addition we show alternatives with rape, with the UOP process and meal used as fuel.

- ROHY1a: Rapeseed to HVO, meal to animal feed, Neste Oil hydrotreating process
- ROHY1b: Rapeseed to HVO, meal to animal feed, UOP hydrotreating process
- ROHY4: Rapeseed to HVO, meal to biogas for heat/power, Neste Oil hydrotreating process
- SOHY1: Sunflower to HVO, meal to animal feed, Neste Oil hydrotreating process
- SYHY1a: Soya to HVO, no till culture, local mill, meal export to animal feed, oil transport to EU, Neste Oil hydrotreating process
- POY1a: Palm to HVO, kernel meal export to animal feed, no CH_4 recovery from waste storage, heat credit from residue use as fuel, oil transport to EU, Neste Oil hydrotreating process

Additional combinations have also been calculated and the results are reported in workbook *WTT v40 pathways 4-Biodiesel*. These will, however, not be carried forward to the WTW analysis.

3.4.10.7 Waste material to biodiesel

Biodiesel can also be produced from a number of waste materials, notably used cooking oils and tallow (one of the products of the rendering process which processes animal carcasses from slaughterhouses).

We have represented these two options with both biodiesel and HVO as final outcome.

Used cooking oils need to be collected in any case so that they are deemed to be available at the processing plant with a zero energy and GHG footprint. They need to be cleaned and refined before the esterification step which is similar but slightly different from the process used for virgin oils.

Animal carcasses are deemed to be waste and have therefore a zero footprint. They need to be collected and transported to the rendering plant, while the rendering process uses some energy. As a result tallow comes with a small but significant energy and GHG cost.

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 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 at a rate of 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 clear cut 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*] estimates 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 kg C/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 if the carbon removed in the form of forest residues, about 2.6% is lost from the soil carbon. Burning 1 MJ wood releases about 100 g CO_2, so the soil carbon loss is equivalent to a CO_2 release of 2.6 g CO_2/MJ of forest residues which we considered as negligible.

There is also the nitrogen balance to consider. Removing residues removes some fixed nitrogen from the forest which may have to be made up by 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 did not include 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 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 8-10 t/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 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.

Because wood farming is not very energy/GHG intensive, the difference between farmed and waste wood is not very large. Where conversion plants have to be large to be reasonably economic (e.g. for biodiesel, methanol and DME plants), waste wood would in addition have to be transported along fairly large distances to provide supply whereas enough farmed wood could be produced in a fairly small area. In such cases the difference is very small and we have only modelled the farmed wood case.

3.4.11.1 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.

3.4.11.2 Wood to synthetic liquid fuels

We have included one pathway for biomass-to-liquid (Fischer-Tropsch) fuel based on farmed wood. This can be considered fairly generic and representative of other biomass resources including perennial grasses like miscanthus. We 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 process formerly being developed by Choren based on an entrained flow 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 two 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.

Lurgi developed an alternative to Fischer-Tropsch first producing methanol as an intermediate step in the production of syndiesel. The outcome in terms of energy use and GHG emissions is close to the FT case so we have not represented this separately.

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 entrained flow 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 gasifier 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. 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.

3.4.11.3 Wood to ethanol

Iogen’s demonstration plant has been producing cellulosic ethanol from wheat straw since 2004, and a new demonstrator was built in Canada by Woodland Biofuels in 2012, but there are no commercial wood-to-ethanol plants operating at present *[Business Week 2013; The Observer 2013].* 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.

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.

3.4.11.4 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.

3.4.11.5 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, containing lignin, hemicellulose 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 sulphide (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.

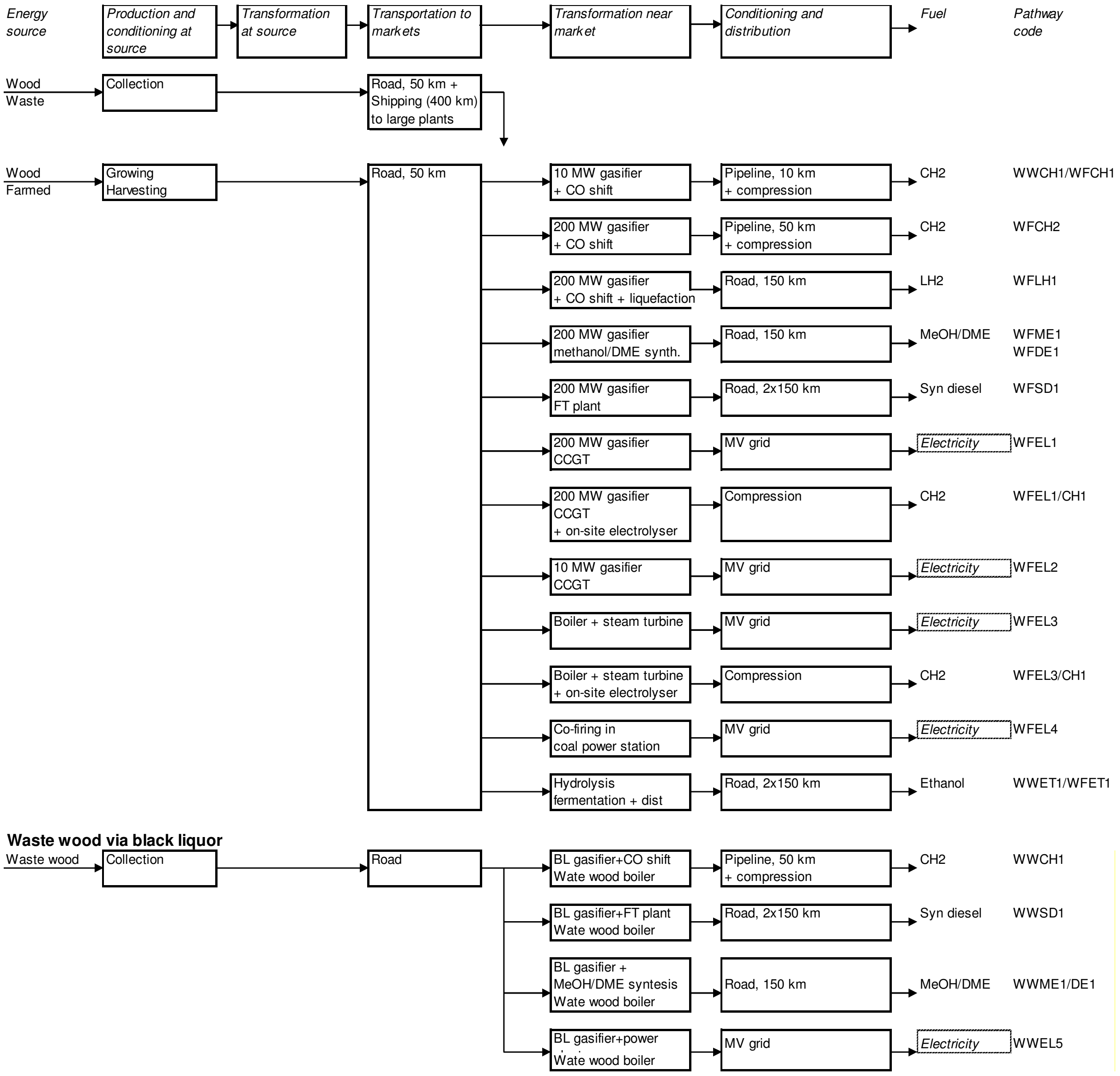
In [*Ekbom 2003*] the generation of methanol and DME from black liquor has been investigated within the BLGMF (Black Liquor Gasification to Motor Fuels) project. We have included these pathways as well as pathways to synthetic diesel and hydrogen inferred from the methanol and DME data. We have also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

We have included pathways as follows:

- WFSD1: Farmed wood to synthetic diesel (Fischer-Tropsch process)
- WFME1: Farmed wood to Methanol
- WFDE1: Farmed wood to DME
- WWSD2: Waste wood to synthetic diesel via black liquor
- WWME2: Waste wood to methanol via black liquor
- WWSD2: Waste wood to DME via black liquor

The various wood pathways considered are illustrated in the figure below. Equivalent electricity pathways are described in *section 3.5.1*.

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).

Following sterilisation of the feedstock, if needed, 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. The process requires inputs of heat and electricity, the latter mainly to power rotating machinery.

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.

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 are now becoming more widespread, driven both by environmental concerns and, in the case of municipal waste, increasing disposal constraints. It is particularly advantageous for wet feedstocks, since drying is not required.

In the larger installations, biogas can be used to produce electricity which provides power and heat for the biogas plant and surplus electricity for export to the grid. In suitable locations additional waste heat may be used off-site, perhaps through 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 fuel 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 with 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 and biogas to heat pathways at small or medium scale

Many feedstocks could in principle be used to produce biogas, however we have included the two waste feedstocks currently of most interest:

- OWCG1: Organic municipal waste
- OWCG2: Wet manure[13]

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 cereal grain, whereas production of biogas has the advantage that the whole plant including the straw can be used, and hence improve yield. In addition there is a trend in Germany for intensive *non-food* crops to be planted on grassland to provide feedstock for biogas plants supplying the electricity and gas grids. We have therefore included pathways for

- OWCG4: Whole plant maize
- OWCG5: Double cropping of barley and maize[14]

The biogas production process itself is much the same for each of these feedstocks, although slightly different digester designs may be used depending on the feedstock. The 'digestate' remaining after biogas production is typically used as a fertiliser and is given a credit since it reduces the amount of artificial fertiliser needed. Some emission of gas will continue in digestate storage and good practice is to use closed storage, capturing any additional gas and adding it to the main production. Although open storage is unlikely to be used because of odour, a variant to OWCG2 has been included to show the potential effect on GHG emissions.

For all biogas pathways providing transportation fuel, heat is assumed to come from a biogas fuelled boiler and electricity from the grid.

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[13] Dry manure is less likely to be used and would give similar performance to dry manure.

[14] In European conditions, maize and barley appear to be the best crops where the objective is simply to maximise the amount of biomass produced.

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.

3.4.12.1Biogas 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 higher generation efficiency in larger power plants.

Figure 3.4.12-1: Organic waste to biogas pathways

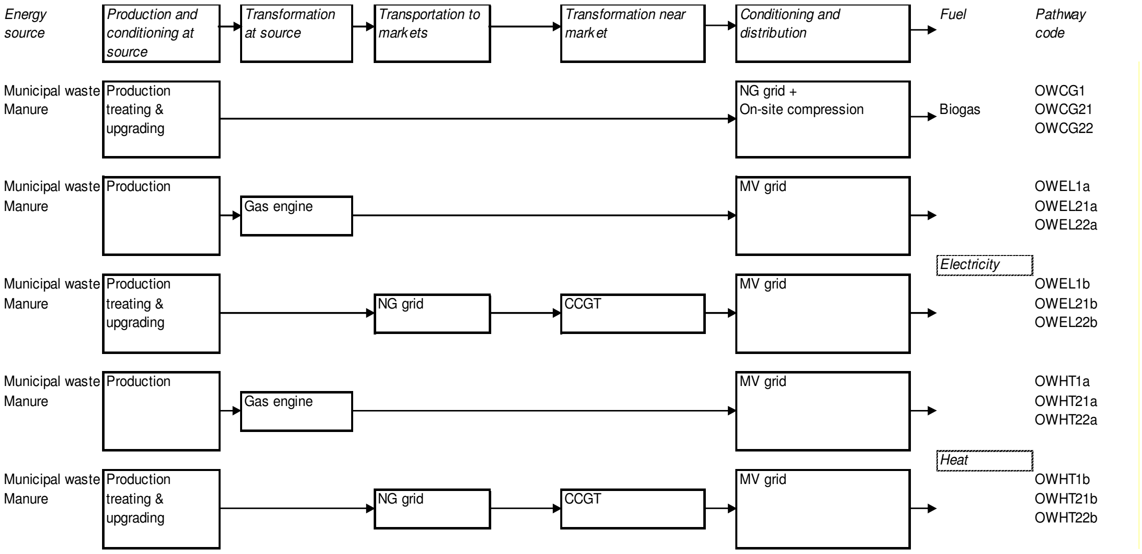
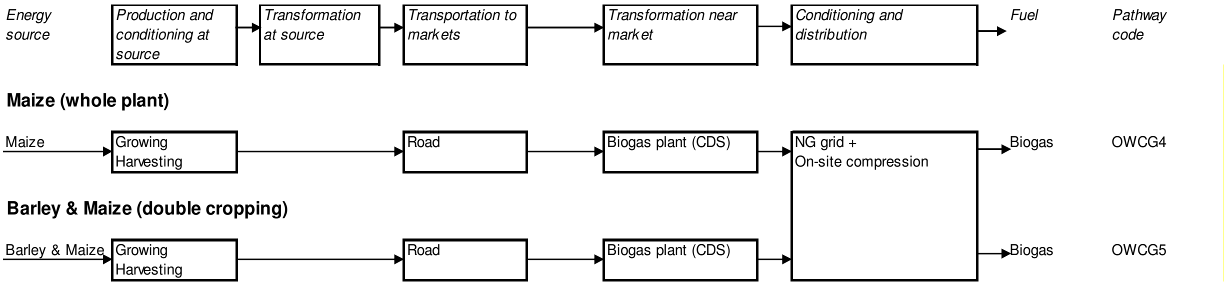


Figure 3.4.12-2: Farmed crops to biogas pathways



3.5 Electricity production and electrolysis

(See also workbooks WTT v40 pathways 6-Electricity/7-Heat & Power)

Electricity is an intermediate source of energy for e.g. the production of hydrogen via electrolysis. 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.

3.5.1.1 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 (we have assumed 58%). 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 process 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.

3.5.1.2 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 modern steam turbine 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*).

3.5.1.3 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*).

3.5.1.4 Organic waste via biogas

Waste material can be used to produce biogas, and electricity generation, either on-site or via export of biogas to the gas grid is one way of using the product. These biogas pathways are described in *Section 3.4.12.*

3.5.1.5 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, transport and enrichment of the uranium as well as maintenance of the power plants.

3.5.1.6 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.

Wind power is growing rapidly, but because it starts from a very low base will take many years to have a significant impact. The EU expects that wind electricity will contribute about 5% of total electricity generation in 2030 [*EC 2009*]. Once installed, wind power is virtually free and is therefore likely to be used preferentially into national grids.

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.

3.5.1.7 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.

Hydroelectricity 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 considered as a separate pathway in this study.

3.5.1.8 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. EU-mix electricity is used to calculate credits in some pathways where surplus electricity is exported to the grid and as the notional electricity source for ancillary electricity consumption.

The specific fuel pathways described in this study look forward to the 2020-2025 timeframe and present figures for state-of-the-art technology that would be used for new fuel production commissioned in this period. Prediction of an EU-mix electricity for a future period is difficult, because it requires a knowledge of what generating capacity will be in place at a future date. For the determination of the EU-mix we have therefore used recent actual data as provided in a JRC study of current EU electricity generation performance [*JRC 2013*].

There are several sources of information including the International Energy Agency (IEA), Eurelectric (the Union of the electricity industry) and ENTSO-E. All sources report slightly different figures for the past years.

Version 3c used figures compiled in the German GEMIS database [*GEMIS 2002*] for the year 1999. In this version we have used updated figures based on IEA statistical data for the year 2009 [*IEA 2011*].

The figures result from a detailed country-by-country analysis of electricity production. As such, they represent electricity production as it exists today, using the actual park of newer and older generating capacity. Thus, the overall generating efficiency of the park will be lower than indicated by the single WTT electricity pathways which are forward-looking and calculate the performance of a new plant using state-of-the-art technology.

National statistics are generally based on the demand for primary fuels. The share of the different primary energy sources in the total electricity generation as reported in [*JRC 2013*] is shown in the following table.

Table 3.5.1-1: EU-mix electricity primary energy sources (2009 data)

Primary Energy Source	% Share
Nuclear	33.0%
Coal, lignite & peat	31.0%
Natural Gas	20.8%
Oil	3.5%
Hydro	4.4%
Wind	1.6%
Waste	1.8%
Other renewables	3.9%

Note that these are the proportions of primary fuel used, not the percentage of total electricity generated from each source. Where the source data expressed the fuel demand in mass terms, a conversion was carried out using LHV values. For renewable energy sources (wind, solar, hydrological and geothermal) and for nuclear energy, the amount of energy in the input of power plants cannot be calculated by using the LHV, as in the case of combustible fuels. For these energy sources, LCA studies often define an equivalent primary energy value. These values have been calculated from the gross electric energy produced in output of the power plants (IEA data), multiplying it by an input–output ratio. The ratio R adopted in this study was R=1 for renewable electricity (because wind and solar input energy are essentially 'free'), and R=0.33 in the case of nuclear energy (because this reflects the efficiency of the nuclear power station).

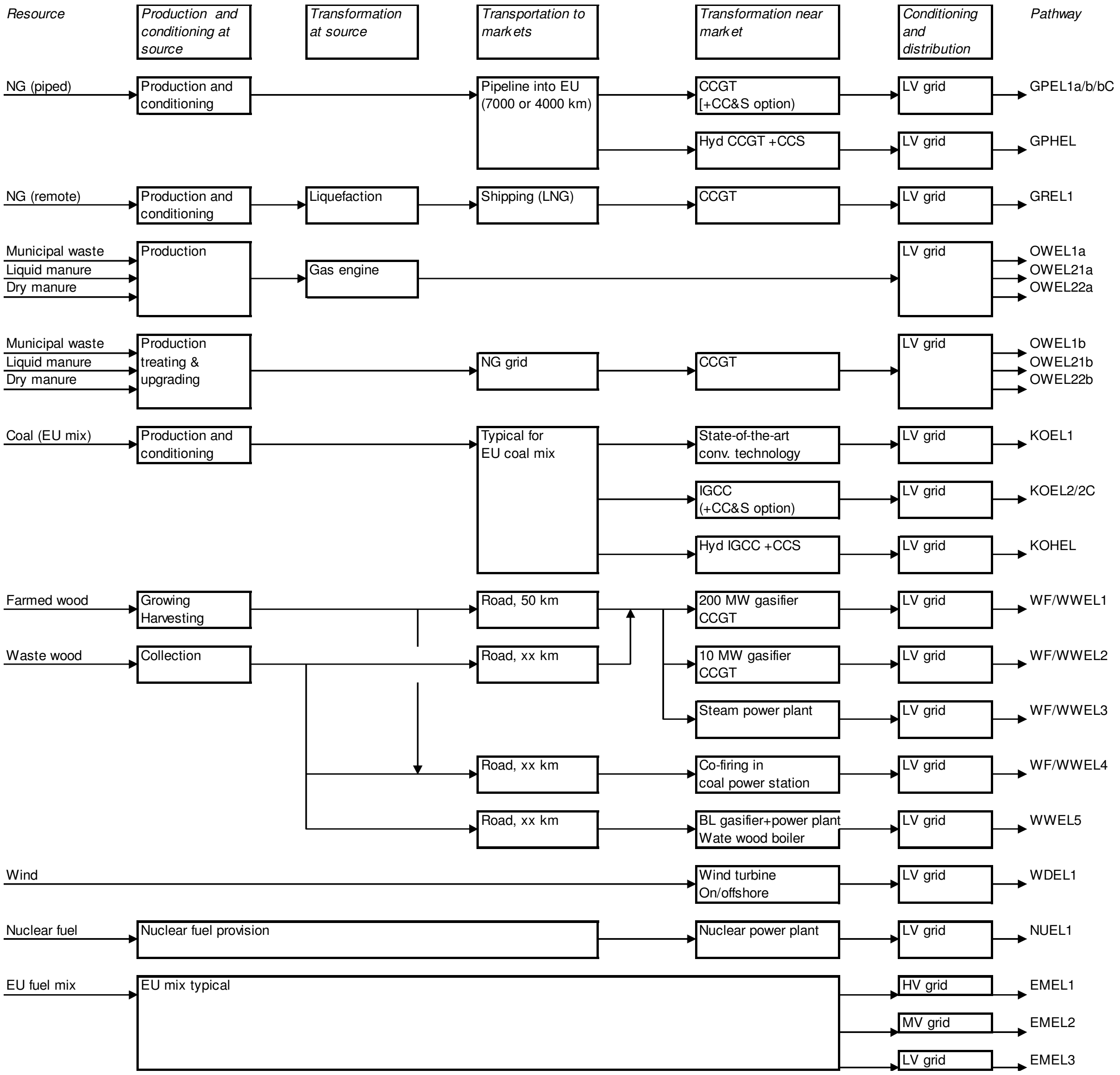
The total energy input needed to generate 1MJ of gross electricity is 2.589MJ at the power stations. When the energy needed to produce the primary fuels and deliver them to the power stations is included (upstream losses), the total consumption of primary energy for electric energy produced in EU 27 in 2009 amounts to 2.744 MJ per MJ of gross electricity production. GHG emissions are calculated for the different primary fuels based on their combustion emissions plus emissions in their production and transport, and taking into account any CHP credits. More information on the calculation of these figures can be found in [*JRC 2013*].

The discussion above relates to gross electric energy which includes electricity used in the power plant itself. On average, 1.04MJ of gross electricity production is needed to produce 1MJ of net electricity in output from the power plant, giving a total energy input of 2.856 MJ, Some additional losses need to be considered before the electricity reaches the user. Firstly, a small amount (1.4%) is used for pumping in hydro-electric schemes. Transmission losses in the High Voltage system are about 1.5%, while losses for Medium Voltage distribution add 4% and Low Voltage distribution a further 6%. The figures are summarised in ***Table 3.5.1-2***.

Table 3.5.1-2: EU-mix electricity primary energy use and GHG emissions (2009 data)

	MJ/MJe	**gCO2eq/kWhe**	**gCO2eq/MJe**
Gross Electricity Production including primary fuel provision	2.743	457	127
Net Electricity Production including primary fuel provision	2.855	476	132
After pumping losses	2.895	482	134
Delivered HV electricity including distribution	2.939	490	136
Delivered MV electricity including distribution	3.050	508	141
Delivered LV electricity including distribution	3.244	540	150

Figure 3.5.1: Electricity generation pathways



3.5.2 Hydrogen via electrolysis

The hydrogen figures have not yet been updated in this version 4 of the study. For this reason, the text from the previous version 3c has been retained for reference.

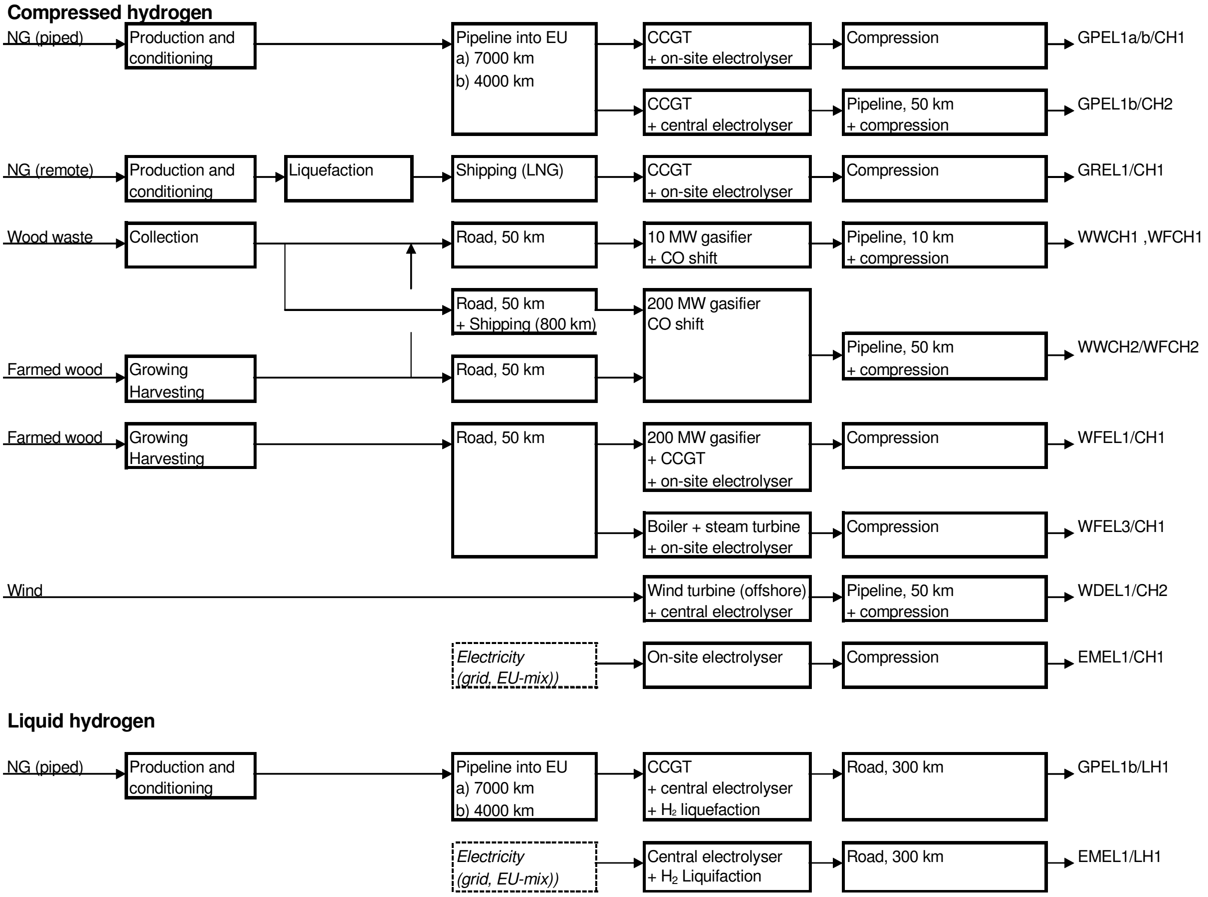
The electrolysis of water to hydrogen and oxygen is a long established process. It is possible to build electrolysis plants from very small to very large scale. The efficiency of the electrolysis process as such is largely unaffected by scale although the auxiliaries and the operating pressure can have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



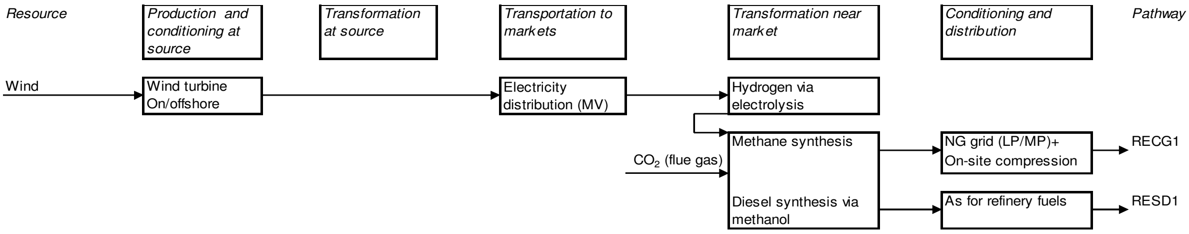
Many combinations are possible between electricity from various sources, electrolysis either central or on-site and hydrogen distributed in either liquid or gaseous form. We have selected a limited number to illustrate the main points.

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 Electricity to synthetic fuels via electrolysis

It is in principle possible to synthesize methanol from hydrogen and CO_2. Methanol can then be turned into either methane or syndiesel (using the Lurgi process mentioned in section 3.4.11). This could be an option for using off-peak wind electricity which could be first used to produce hydrogen while CO_2 could be recovered from e.g. the flue gases from a fossil fuel power station. We have represented such pathways for synthetic methane (RESG1) and syndiesel (RESD1).

Figure 3.5.3: Synthetic fuels from wind electricity and flue gas CO_2 via electrolysis pathways



3.5.4 Heat and Combined Heat and Power (CHP)

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 co-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 pathways describing typical performance of small and industrial case boilers and large scale CHP plants fed with heating oil, natural gas, biogas or wood. In CHP plants electricity is generally considered as the primary product. The results are expressed per MJ of electricity and a credit for excess heat is calculated by comparing with stand-alone heat generation using the same fuel. However, for a limited number of pathways, we have also represented the case where heat is the primary product, surplus electricity being exported to the grid.

Figure 3.5.4-1: Heat pathways

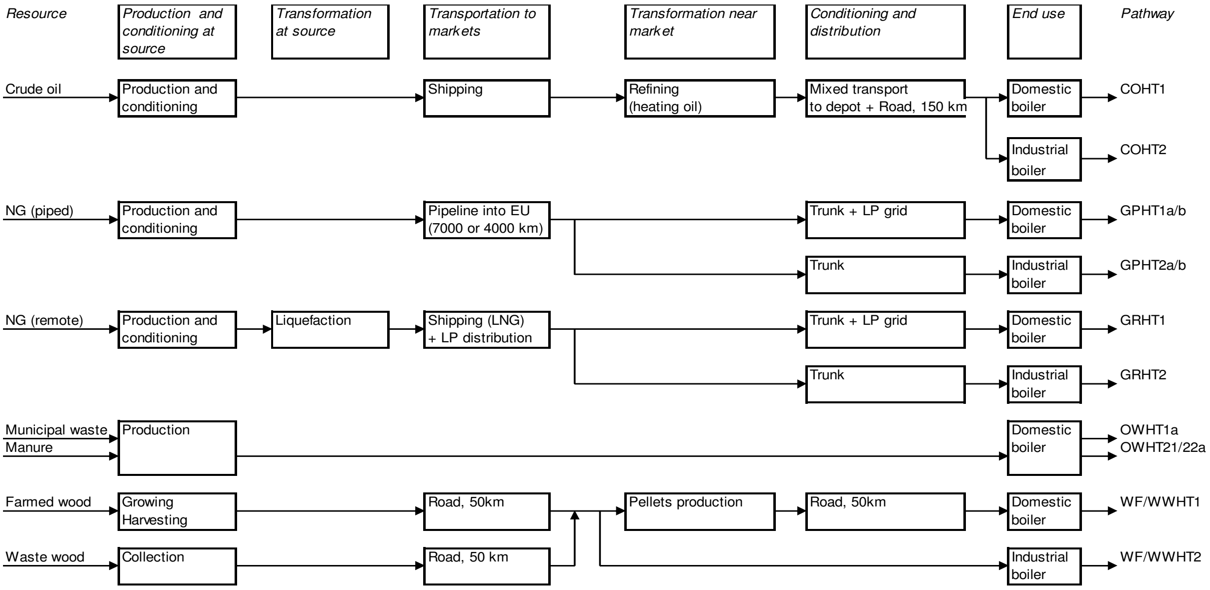
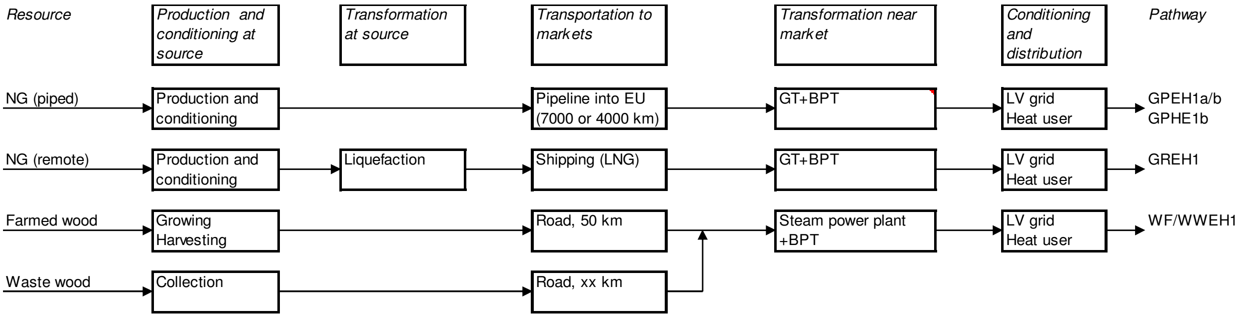


Figure 3.5.4-2: CHP pathways



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 a CCS variant 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

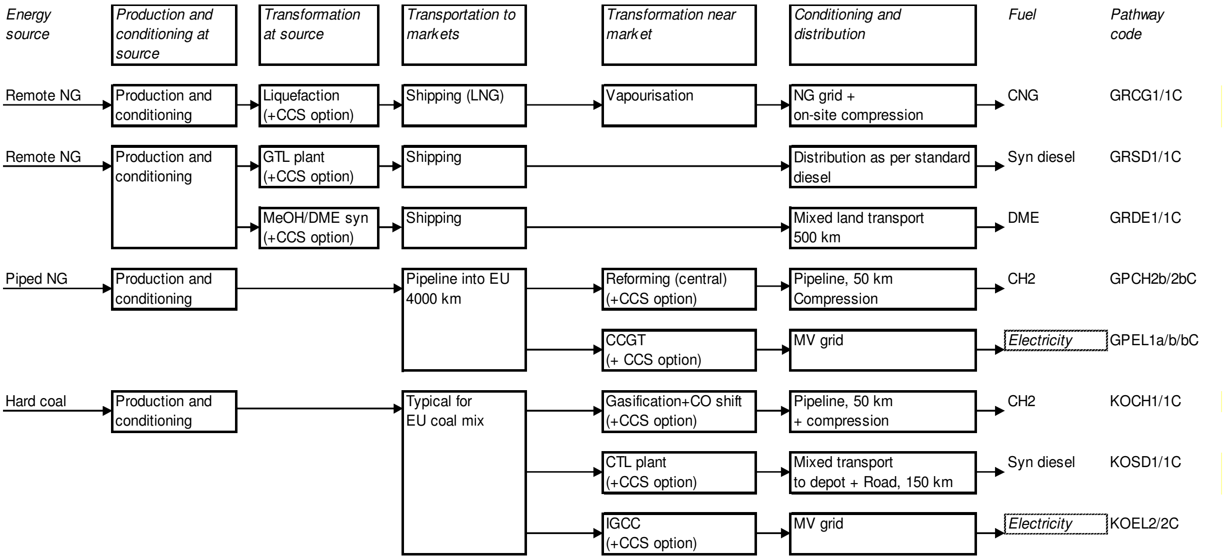
In attempting to assess the CO_2 benefit and energy requirement of CCS in these different cases we found many literature references. In particular we were guided by a recent study by the IEA's Greenhouse gas R&D programme [*IEA 2005*]. As CCS has so far only been applied on a limited scale in very few 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.

In order to show a meaningful impact of applying CCS in a particular case, it is important that both schemes be based on otherwise the same premises. There are relatively few examples reported in the literature where this is the case and this has imposed a constraint on the number of CCS schemes that we could include.

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



The impact of CCS is presented in the relevant parts of *Section 4*.

3.7 Transport and distribution

3.7.1 Feedstock transport

Feedstocks such as agricultural crops may be transported locally to processing plants (in or outside Europe) or over long distances generally by bulk carrier ships.

In Europe there is a large diversity of situations and, on balance, we considered that the fairest approach was to use the same transport vector for all crops (100 km by road. Note that the impact on the complete pathways is very small).

Local transport vectors for crops and intermediates from outside Europe (e.g. soy beans in Brazil, vegetable oils) are based on advice from stakeholders.

Sea shipping distances are based on actual distance between the assumed source and Europe.

Table 3.7.1: Transport vectors for feedstocks

	Local	To EU	Within EU
Maize to biogas (whole plant)	NA	NA	NA
Double crop to biogas	NA	NA	Road, 20 km
Manure to biogas	NA	NA	Road, 10 km
Other EU crops	NA	NA	Road, 100 km
Soy beans Import to EU	Road, 447 km Rail, 99 km Inland bulk carrier (8.8 kt), 382 km	Bulk carrier (Panamax), 13171 km	NA
Soy beans processed at source	Road, 373 km Rail, 61 km	NA	NA
Vegetable oil	Inland tanker (1.2 kt), 529 km	Tanker (23 kt), 12986 km	NA

3.7.2 Biofuels and Synthetic fuels transport and distribution

(See also workbooks WTT v40 pathways 2-CBG/3-Ethanol/4-Biodiesel/5-Synfuels)

3.7.2.1 Liquid fuels

Long-distance transportation

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. Ethanol and biodiesel do not have specific requirements either but are likely to be transported in smaller ships because of the volumes involved and/or the capacity of loading ports. 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 syndiesel 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 (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 and in case of blending with refinery products (the most likely use) the conventional fuels transport vector would apply. Ethanol cannot generally be transported in standard multiproduct pipelines so 150km road transport was assumed for bulk ethanol imports (e.g. Brazil) cannot use pipelines, so (the same distance as applied to European-produced biofuels).

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 of 500km from a coastal import terminal was therefore assumed on the basis that bulk products would be distributed over a wide area. 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.

3.7.2.2 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.

3.7.2.3 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. Where biogas is used to produce electricity, export through the grid provides an alternative distribution channel.

Table 3.7.2: Transport vectors for fuels

	To EU	Within EU	
		To depot	To filling stations
Crude oil based gasoline and diesel, Syn-diesel from coal	NA	Inland barge (9 kt), 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)	Road, 700km Tanker (13 kt), 5,500 nautical miles	Road, 150 km	Road, 150 km
MTBE (remote)	Tanker (50 kt), 5,500 nautical miles	Inland barge (9 kt), Pipeline (60%), Train, 250 km (20%)	Road, 150 km
ETBE		Inland barge (9 kt), 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	Tanker (50 kt), 5,500 nautical miles	Inland barge (9 kt) Pipeline (60%), Train, 250 km (20%	Road, 150 km
Methanol from remote NG	Tanker (50 kt), 5,500 nautical miles	NA	Rail, 250 km Road, 250 km
DME from remote NG	LPG carrier (84 km^3), 5,500 nautical miles	NA	Rail, 250 km Road, 250 km
Methanol or DME from biomass	NA	NA	Road, 150 km
LPG (remote)	LPG carrier (84 km^3), , 5,500 nautical miles	NA	Road, 500 km

3.7.3 Hydrogen transport and distribution

The hydrogen figures have not yet been updated in this version 4 of the study. For this reason, the text from the previous version 3c has been retained for reference.

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.

4 Final fuels: Energy and GHG balance

4.1 Reporting formats

In this section we report and compare the 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 *the relevant workbooks*.

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 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 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)

(see also workbook WTT v4 pathways 1- Oil & Gas in Appendix 4)

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

Gasoline and diesel fuel from conventional crude oil supply the bulk 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, although of growing importance in North America, 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

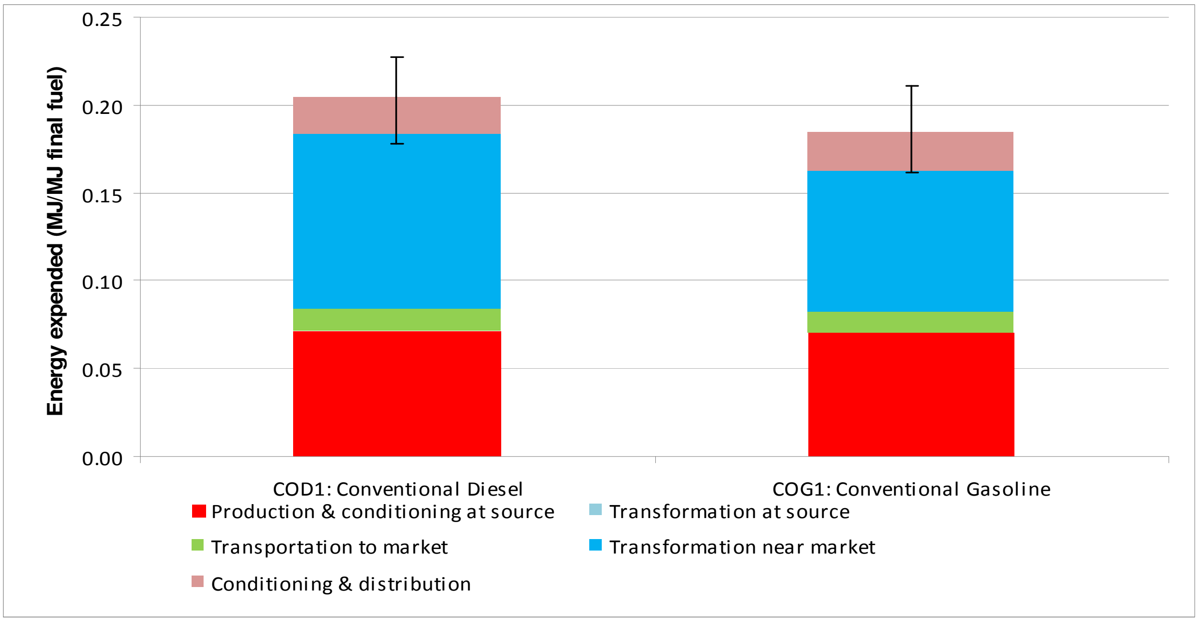
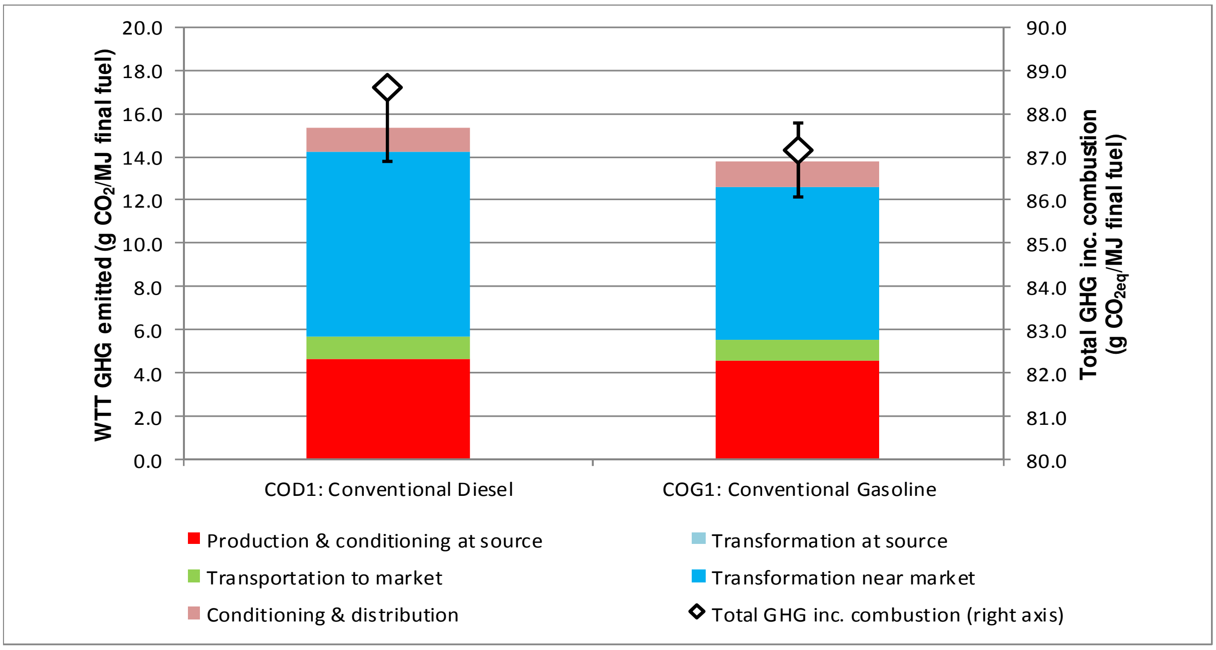


Figure 4.2-2: WTT GHG balance for crude oil based fuels



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.

At this stage, there is no credible prospect for naphtha to be used as an automotive fuel and it has therefore not been included in this version.

4.3 CNG, CBG (Compressed Biogas), LPG

4.3.1 Pathways to CNG

(See also workbook WTT v4 pathways 1-Oil & Gas in Appendix 4)

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.

In previous versions of this study, we calculated a notional composition of the standard gas available in the EU distribution network and that would be available for use as 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 composition of NG distributed in the EU

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

Although the new EU supply data discussed in section 3.2.1 points out to somewhat different distribution of sources, the impact on the mix properties is marginal and we have continued using the above composition for the WTT simulations.

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

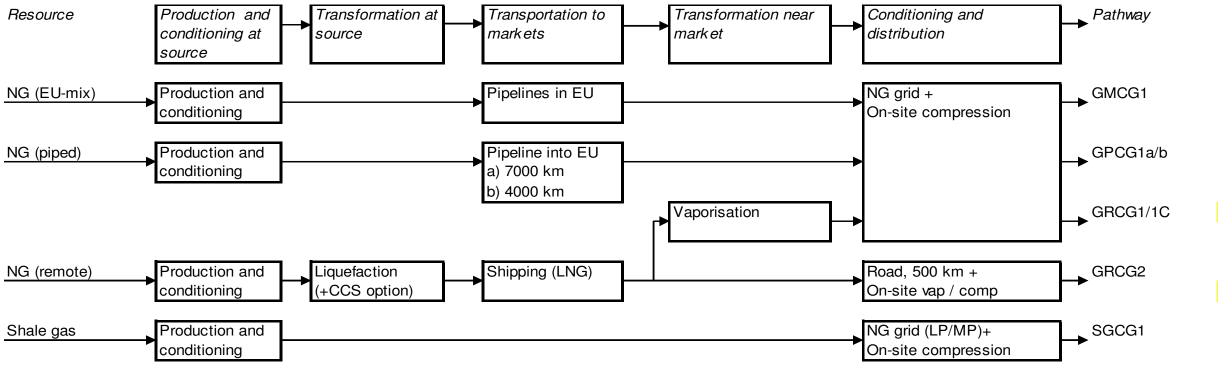
After reaching the refuelling station the gas needs to be compressed to a sufficient pressure to ensure fast refuelling. For on-board tanks at 20 MPa maximum a pressure of 25 MPa is required. Compression is an energy-intensive process, the energy consumption being strongly dependent on the outlet to 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. In this version, we have added a further option for a vehicle able to accept liquid NG fuel. In this case, the energy cost of vaporisation and compression is avoided although some additional energy will need to be used in the vehicle.

The pathways selected to represent CNG provision reflect the various supply routes available, i.e. medium and long distance pipeline or LNG. We have also included a pathway representing shale gas produced in the EU. 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 and ***-2*** illustrate the contribution of the various steps to the total energy and GHG balance. The most important components of the balance are:

- Transport to Europe via long distance pipeline, or ship in the case of LNG.
- Liquefaction at source for LNG.
- Compression of the gas at the service station

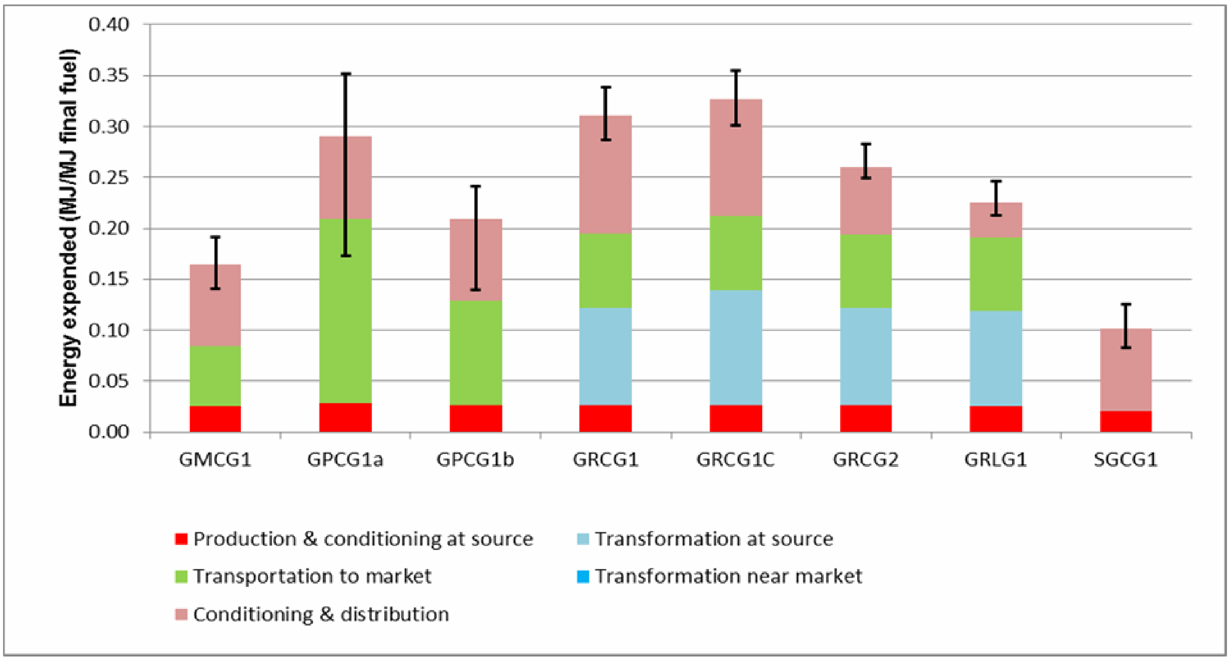
For piped gas, the transport distance plays a crucial role: changing the length of the pipeline from 7000 to 4000 km reduces both energy requirement and GHG emissions by over 40%. The potential impact of higher pressure pipelines is illustrated by the large downwards error bars for pathways GPCG1a/b. 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 long distance transport energy is avoided in the case of EU shale gas.

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. Slightly higher GHG emissions in distribution of LNG to the service station mean that the overall GHG emissions are similar for the two options. We consider that these differences are not significant and therefore view both options as equivalent. Both energy and emissions are somewhat reduce if LNG can be directly fed to the vehicle (GRLG1) although, as mentioned above, the vaporisation energy then needs to be supplied inside the vehicle which may in turns increase emissions (unless it is in the form of waste heat).

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 of two.

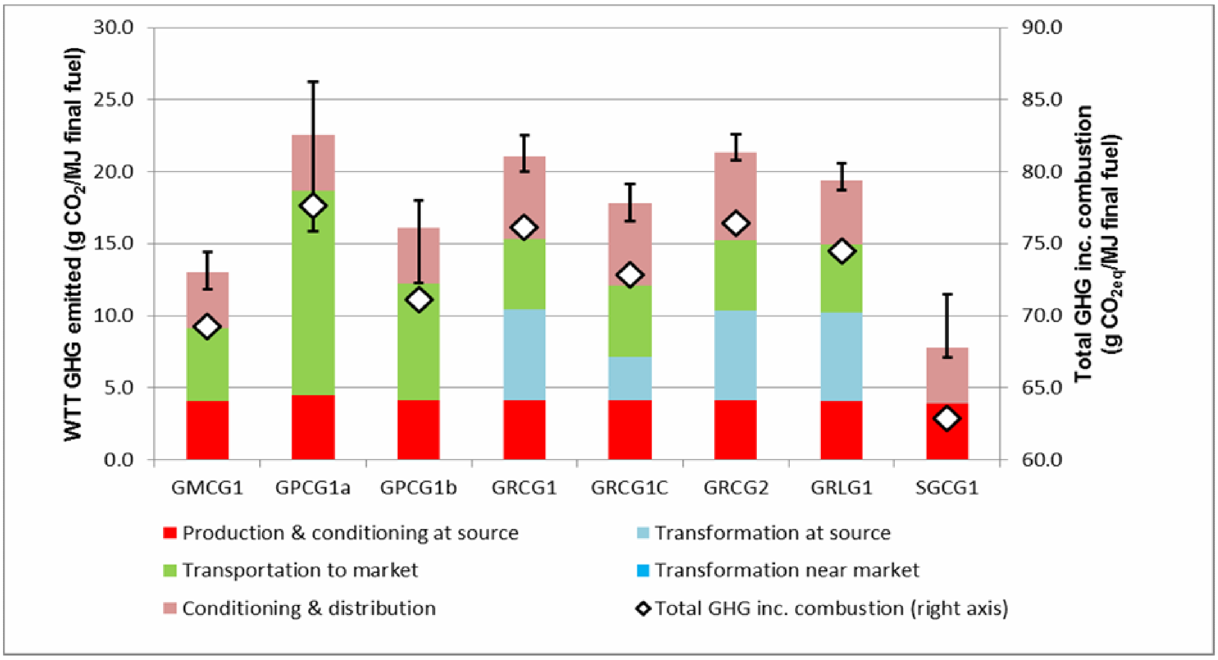
Figure 4.3.2-1: WTT total energy balance build-up for CNG pathways



Key to pathway codes

GMCG1	CNG from EU-mix NG supply
GPCG1a	CNG from imported NG 7000 km (typically Russia)
GPCG1b	CNG from imported NG 4000 km (typically Middle East)
GRCG1	Remote LNG, vaporisation at import terminal
GRCG1C	Remote LNG + CCS at liquefaction plant, vaporisation at import terminal
GRCG2	Remote LNG, vaporisation at retail point
GRLG1	Remote LNG, use as LNG in vehicle
SGCG1	Shale gas (EU)

Figure 4.3.2-2: WTT GHG balance build-up for CNG pathways



Direct methane emissions account for a significant share of the total GHG emissions in the CNG chains. 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, although there is some loss if LNG is transported to the service station by truck.

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.

On an energy content basis, CNG from imported marginal gas supplies is more energy-intensive than conventional fuels (0.20/0.18MJ/MJ final fuel for diesel and gasoline). Although the current “EU-mix”, partly based on domestic and Algerian gas, comes out better than the conventional fuels, we stress again that this is not a truly “marginal” case. EU shale gas does have the potential for lower energy intensity than diesel and gasoline production. However, because the gas supply to Europe is expected to come from increasingly remote sources, the total energy attached to it will increase in the future.

A true comparison of NG options 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*).

4.3.2.1 CCS in CNG/LNG production

The carbon in it the CNG molecules is mostly carried to the end-user. In the case of power generation or hydrogen production there are opportunities for CO_2 to be captured as the fuel is used (see *sections 4.8.2, 4.9.5)*. These opportunities do not exist where the CNG is used in dispersed applications such as domestic buildings or road vehicles, however in the case of LNG, the smaller amount of CNG consumed in generating electrical power for liquefaction does offer some potential for CO_2 capture. Similar possibilities occur in the production of synthetic fuels and are discussed in *sections 4.6.2/3.*

In all gas transformation schemes requiring significant amounts of electricity, we have assumed that power is produced on-site by a gas-fired combined cycle gas turbine (CCGT). In this process CO_2 would be scrubbed out of the gas turbine flue gases. It is estimated that some 88% of the CO_2 could be recovered. The energy penalty is sizeable, the overall efficiency of power generation being reduced by about 8 percentage points (from 55% to 47%), but the effect on the overall pathway is much less as shown in ***Table 4.3.2***.

Table 4.3.2: LNG production with/without CCS

Feedstock		Natural gas	
Case		Base GRCG1	with CCS GRCG1C
Natural gas	MJ/MJ DME	1.08	1.10
Energy efficiency		92.3%	91.0%
Net GHG emissions	g CO_{2eq}/MJ DME	5.6	2.4
CO_2 removal efficiency			57.1%

4.3.3 Compressed Biogas (CBG)

(See also workbook WTT v4 pathways 2-CBG in Appendix 4)

The pathways considered here illustrate the impact of producing biogas in different ways. To that end, parameters have been kept constant as far as possible with different options represented by the individual pathways. Biogas is typically obtained from waste organic material in which case little fossil energy is involved. We have also included pathways for biogas sourced from purpose-grown crops. In these cases there will be fossil energy inputs to produce the crop. The pathways are described in *Section 3.4.12*.

Figure 4.3.3-1: CBG pathways

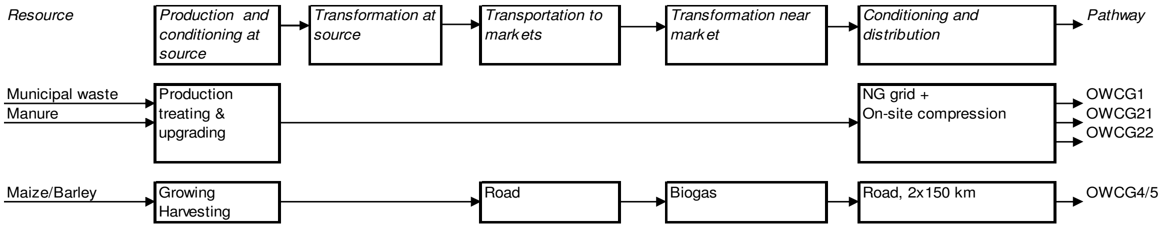


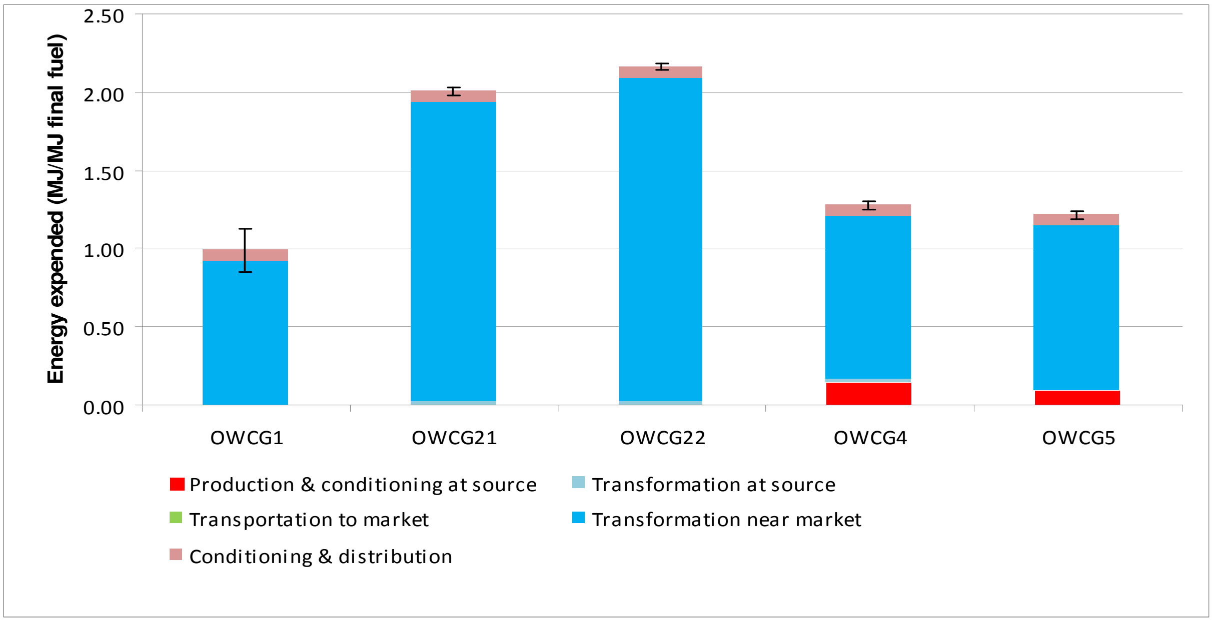
Figure 4.3.3-2 shows a relatively high total energy, mostly related to the limited conversion rate of the biomass used (assumed 70%). For waste materials, inasmuch as this represents the only practical way of using them for energy purposes, this is not important here.

The fossil energy share is shown in ***Figure 4.3.3-3*** and for the municipal waste and manure options is in the range 0.15-0.17 MJ/MJ$_{f.}$ Note that these figures result from our decision to limit the on-site energy generation from biogas to the process heat requirement, which means that the electricity requirement comes from the grid. For maize and double cropping, the fossil energy input is higher, 0.23-0.29 MJ/MJ$_f$, reflecting the energy used in crop production and transport to the processing plant.

For GHG emissions (***Figure 4.3.3-4***), the diamond symbols show the overall emissions in producing the fuel. The balance is very favourable, the more so in the case of 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 maize and double cropping, 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, particularly where it avoids uncontrolled anaerobic biomass decomposition and emission of methane to the atmosphere. Whether and under which circumstances the best use of biogas is as automotive fuel is another matter. The figures presented here should be compared with those in section 4.8.2 where use of biogas for power generation is considered.

Figure 4.3.3-2: WTT total energy balance of CBG pathways



Key to pathway codes

OWCG1	Municipal waste (closed digestate storage)
OWCG21	Manure (closed digestate storage)
OWCG22	Manure (open digestate storage)
OWCG4	Maize (whole plant) (closed digestate storage)
OWCG5	Double cropping (closed digestate storage)

Figure 4.3.3-3: WTT fossil energy balance of CBG pathways

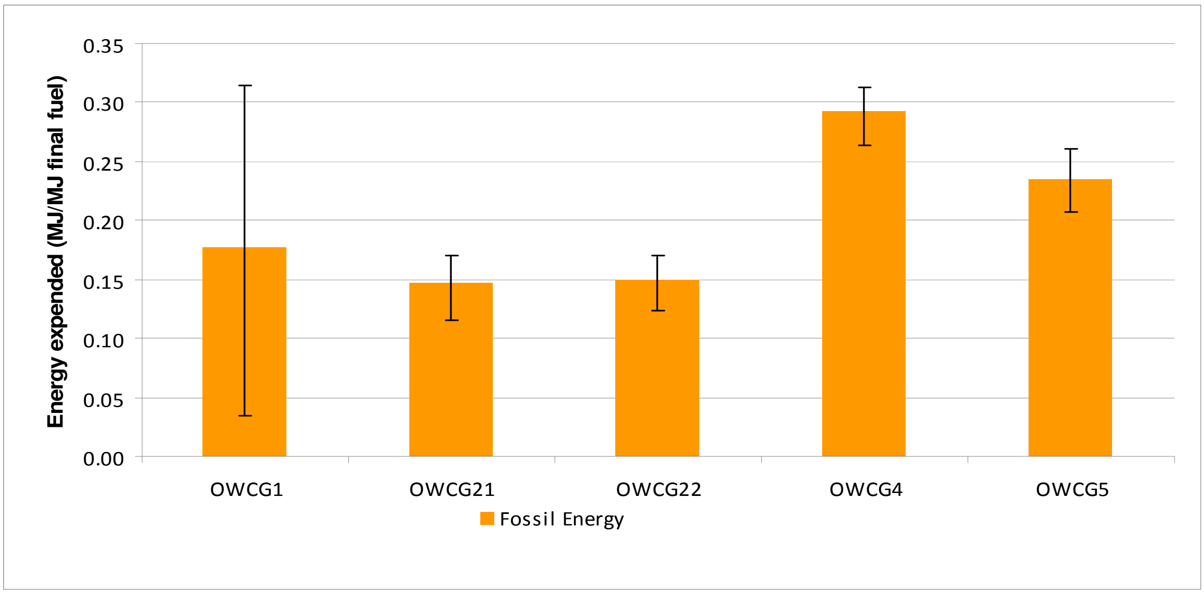
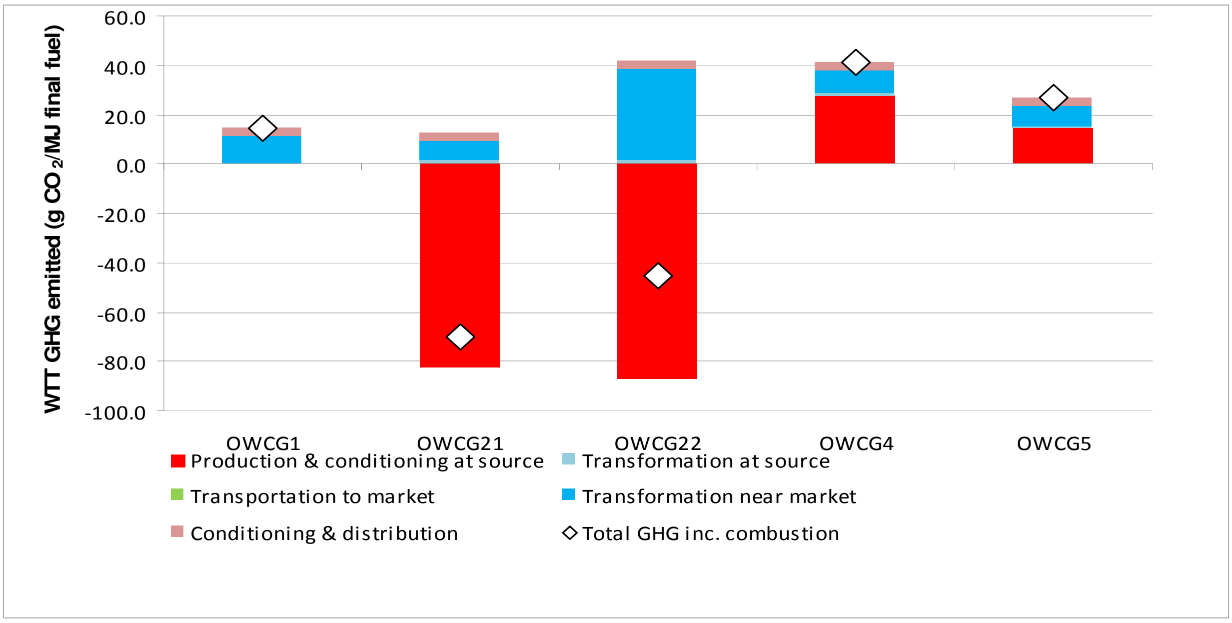


Figure 4.3.3-4: WTT GHG balance of CBG pathways

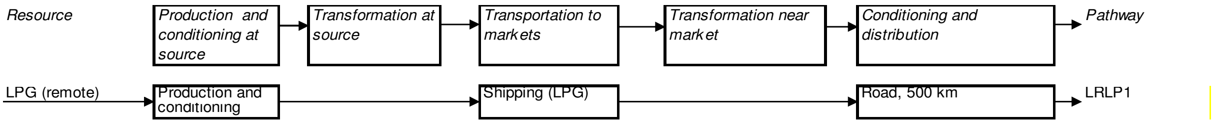


4.3.4 Liquefied Petroleum Gas (LPG)

(See also workbook WTT v4 pathways 1-Oil & Gas in Appendix 4)

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 is 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

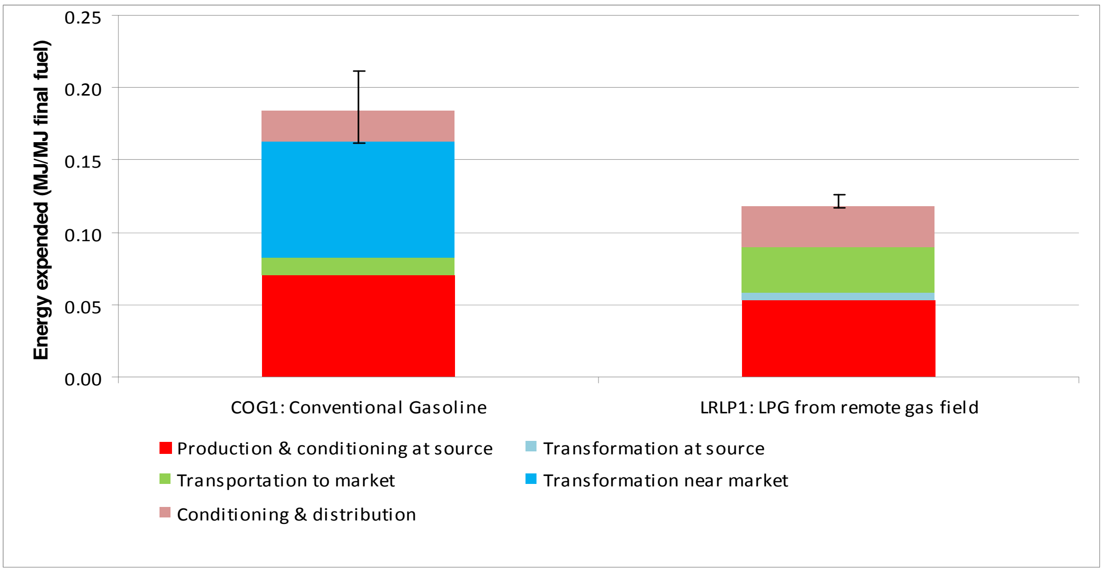
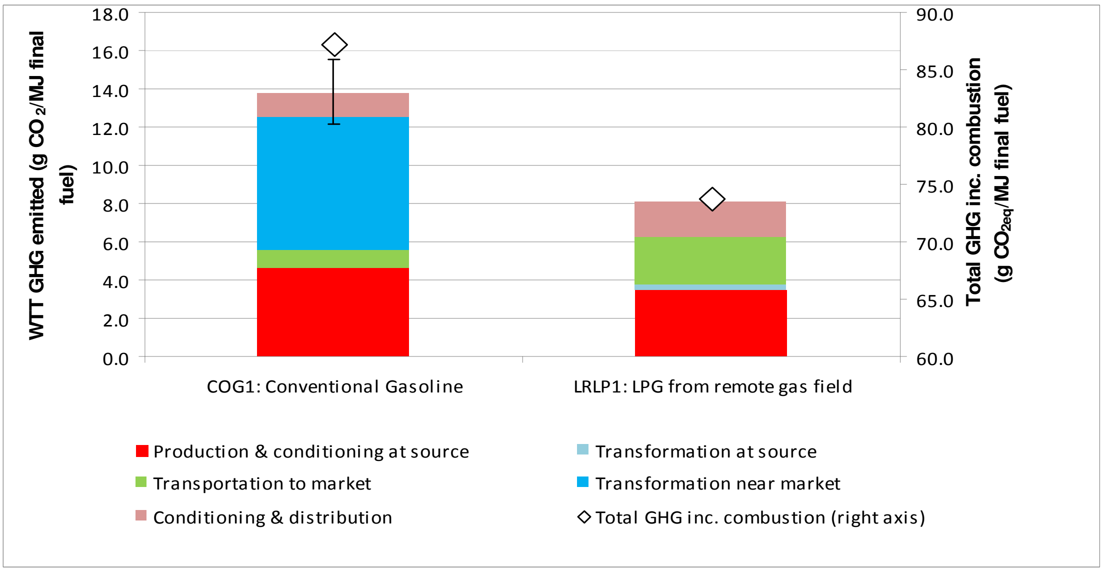


Figure 4.3.4-3: WTT GHG balance of LPG pathway



4.3.5 CNG (synthetic methane) from wind electricity

This pathway, described in *section 3.5.3*, is essentially carbon-free, the only potential emissions being related to gas compression at the service station. The energy expended, although mostly renewable, is relatively large due to the efficiency of the electrolysis and the energy requirement of the synthesis process.

Figure 4.3.5-1: WTT total energy balance of synthetic CNG pathway

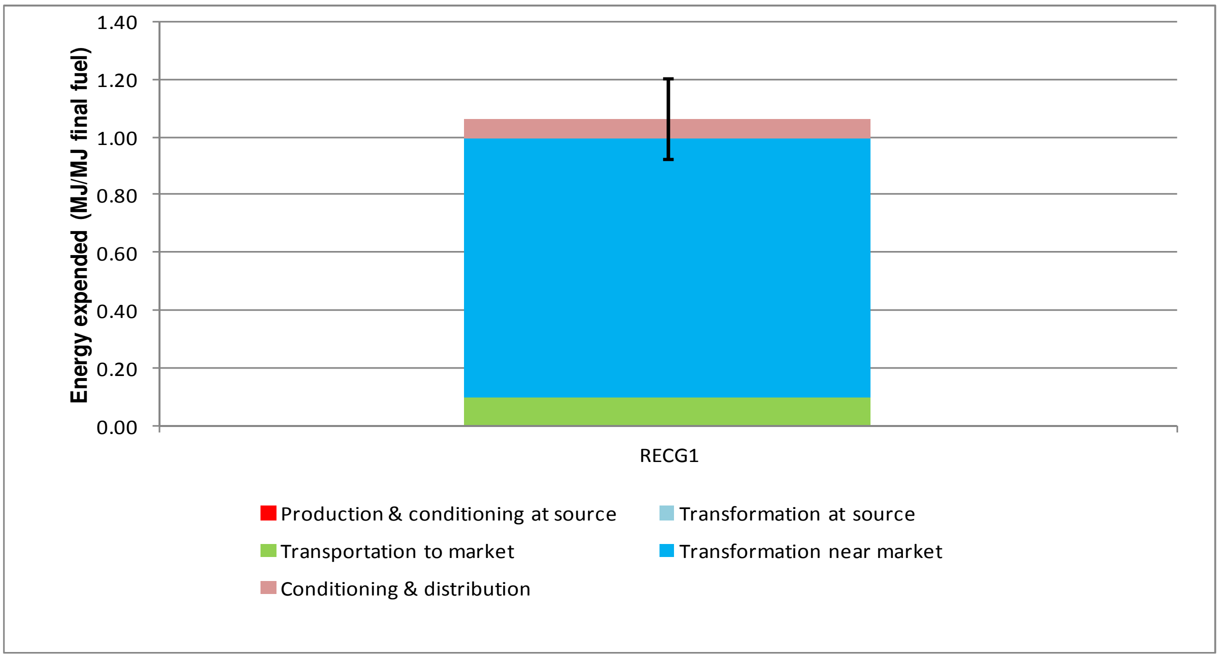
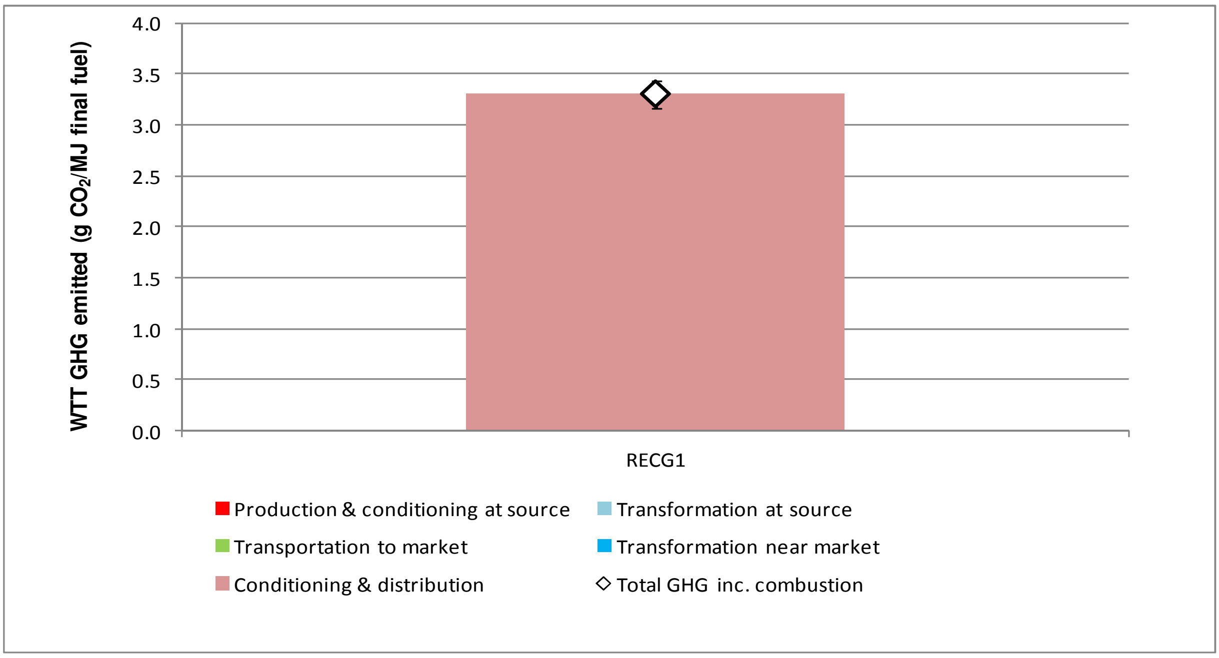


Figure 4.3.5-2: WTT GHG balance of synthetic CNG pathway



4.4 Ethanol

(See also workbook WTT v4 pathways 3-Ethanol in Appendix 4)

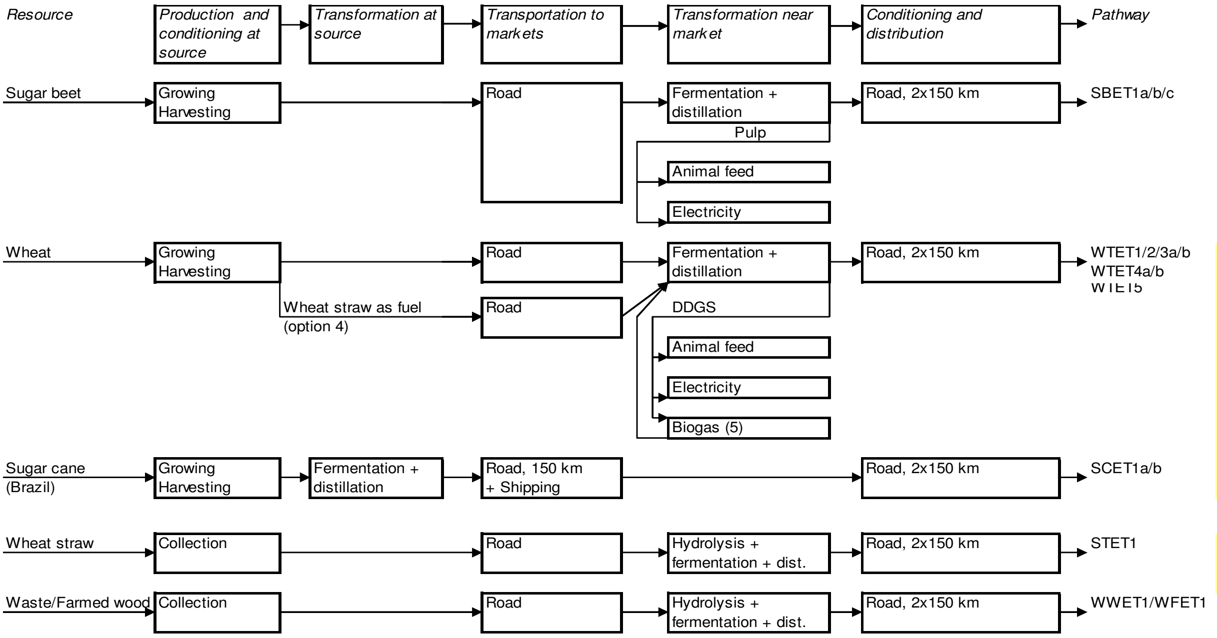
4.4.1 Ethanol pathways

Ethanol can be produced by traditional fermentation methods 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*). In this version of the study we have in addition included pathways for European crops of a barley/rye mixture and of maize.

For comparison purposes we have also included ethanol produced in Brazil from sugar cane, and ethanol from US corn (maize) and imported to Europe.

For the future, more advanced pathways for the hydrolysis and fermentation of cellulose may become more important and we have included one with wheat straw (logen process) and two with farmed or waste wood representing the more general group of cellulose feeds.

Figure 4.4.1: Ethanol pathways



4.4.2 Ethanol WTT energy balance

4.4.2.1 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. 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. 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. SBET1b to SBET1c, WTET1a to WTWT1b and WTET2a to WTET2b where using the process residue to produce electricity saves more energy than using it as animal feed).

The way energy for the manufacturing process is produced has also an impact on the energy balance. The ethanol plant requires heat for distillation and drying of the ethanol: in WTET2a the use of a natural gas fired gas turbine CHP scheme reduces the energy requirement by about 15%, because it is more efficient than 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 and wheat ethanol pathways

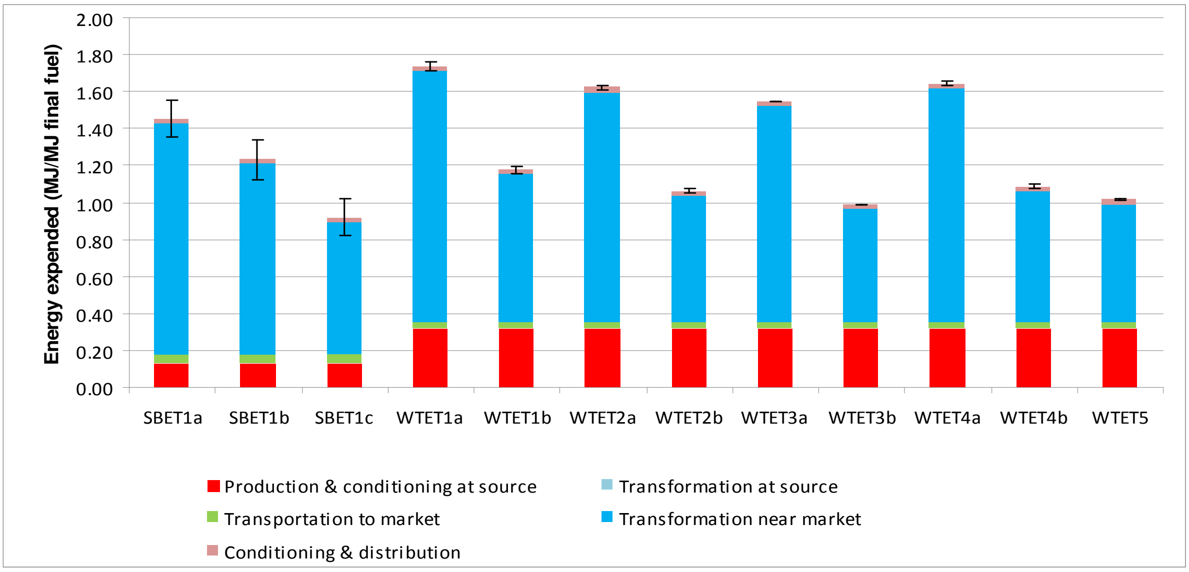
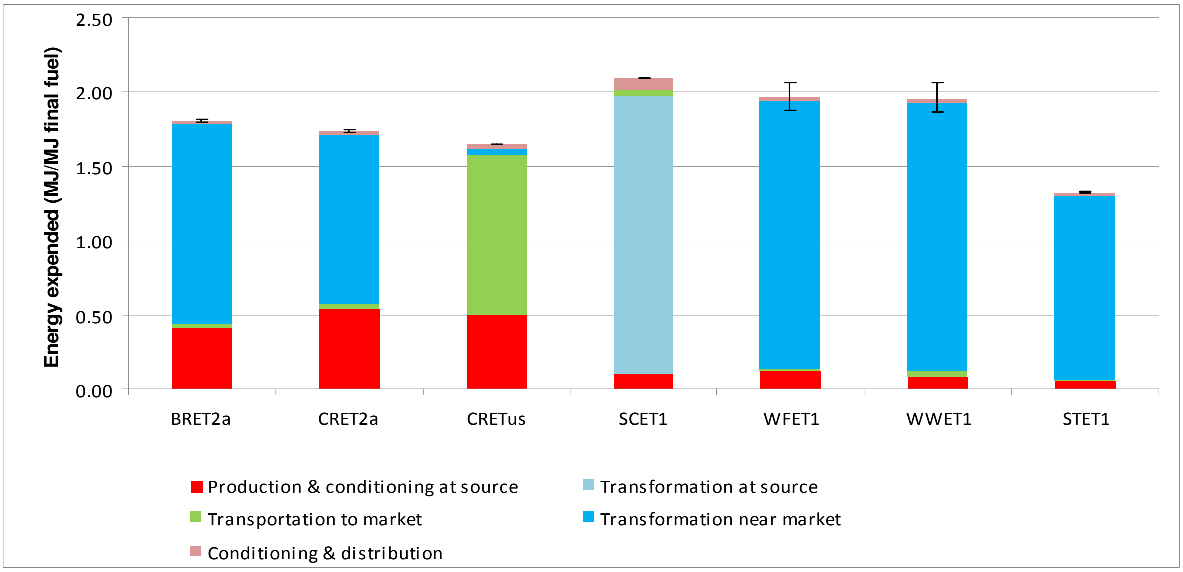


Figure 4.4.2-1b: WTT total energy balance of other ethanol pathways



Key to pathway codes	
SBET1a	Sugar beet, pulp export to animal feed, slops not used
SBET1b	Sugar beet, pulp export to animal feed, slops to internal biogas production
SBET1c	Sugar beet, pulp use as internal fuel, slops to internal biogas production
WTET1a	Wheat grain, process heat from conventional NG boiler, electricity from grid, DDGS export to animal feed
WTET1b	Wheat grain, process heat from conventional NG boiler, electricity from grid, DDGS internal use to produce electricity
WTET2a	Wheat grain, process heat and electricity from NG-fired CHP, DDGS export to animal feed
WTET2b	Wheat grain, process heat and electricity from NG-fired CHP, DDGS internal use to produce electricity
WTET3a	Wheat grain, process heat and electricity from lignite-fired CHP, DDGS export to animal feed
WTET3b	Wheat grain, process heat and electricity from lignite-fired CHP, DDGS internal use to produce electricity
WTET4a	Wheat grain, process heat and electricity from straw-fired CHP, DDGS export to animal feed
WTET4b	Wheat grain, process heat and electricity from straw-fired CHP, DDGS internal use to produce electricity
WTET5	Wheat grain, process heat from conventional boiler, DDGS internal use for electricity via biogas
BRET2a	Barley/Rye grain (50/50), process heat and electricity from NG-fired CHP, DDGS export to animal feed
CRET2a	Maize grain (EU), process heat and electricity from NG-fired CHP, DDGS export to animal feed
CRETus	Corn (US)
SCET1a	Sugar cane (Brazil), bagasse to heat
SCET1b	Sugar cane (Brazil), bagasse to electricity
WFET1	Wood (farmed)
WWET1	Wood (waste)
STET1	Straw (wheat)

Figure 4.4.2-1b shows the total energy balance for other advanced biomass-to-ethanol pathways. The overall energy balance for barley/rye and maize grown in Europe is slightly higher than the equivalent wheat pathway (WTET2a). The overall energy balance for US-produced corn ethanol is very similar, long distance marine transportation being energy efficient,

The more advanced cellulosic ethanol routes based on waste or farmed wood or straw 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).

4.4.2.2 Fossil energy

Figures 4.4.2-2a/b show a breakdown of fossil and renewable (i.e. biomass) 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. As an example, SBET1a uses grid gas and electricity to meet the heat and power needs of the plan. SBET1b uses slops to produce biogas, this reducing the amount of grid energy needed. SBET1c in addition uses the pulp as a heat source for the plant, so that the demand for grid energy is much reduced. For the more conventional pathways, this does not, however, generally correspond to either common practice or economic optimum (see also *section 3.4*). See also the text box at the end of section 4.4.3.

Sugar cane and advanced cellulosic ethanol 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, coming from the non-fermentable part of the cellulosic feed material. 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 and wheat ethanol pathways

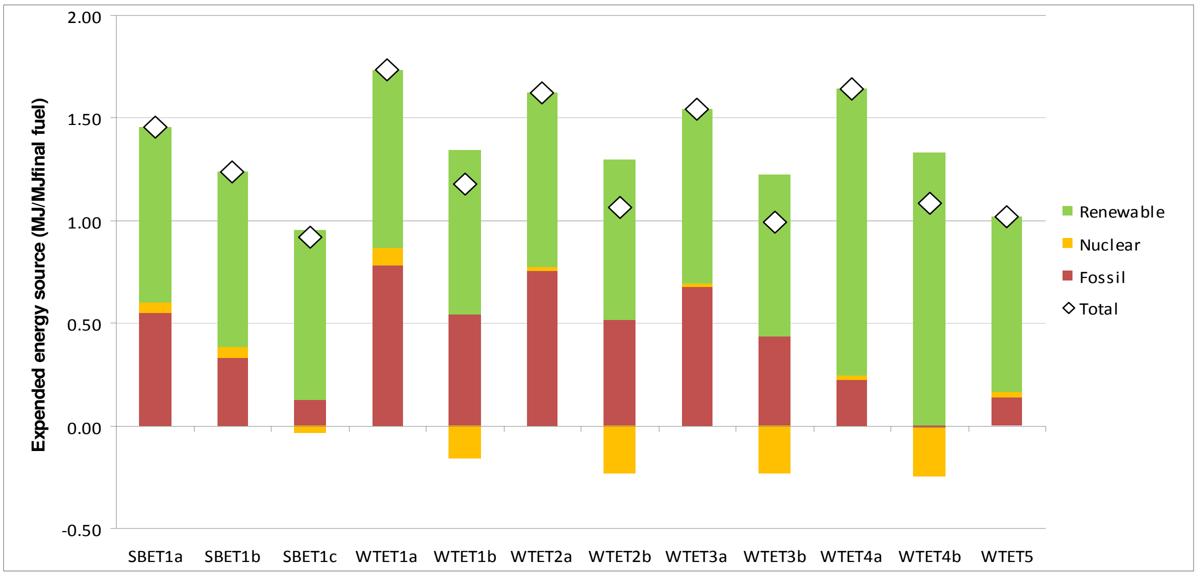
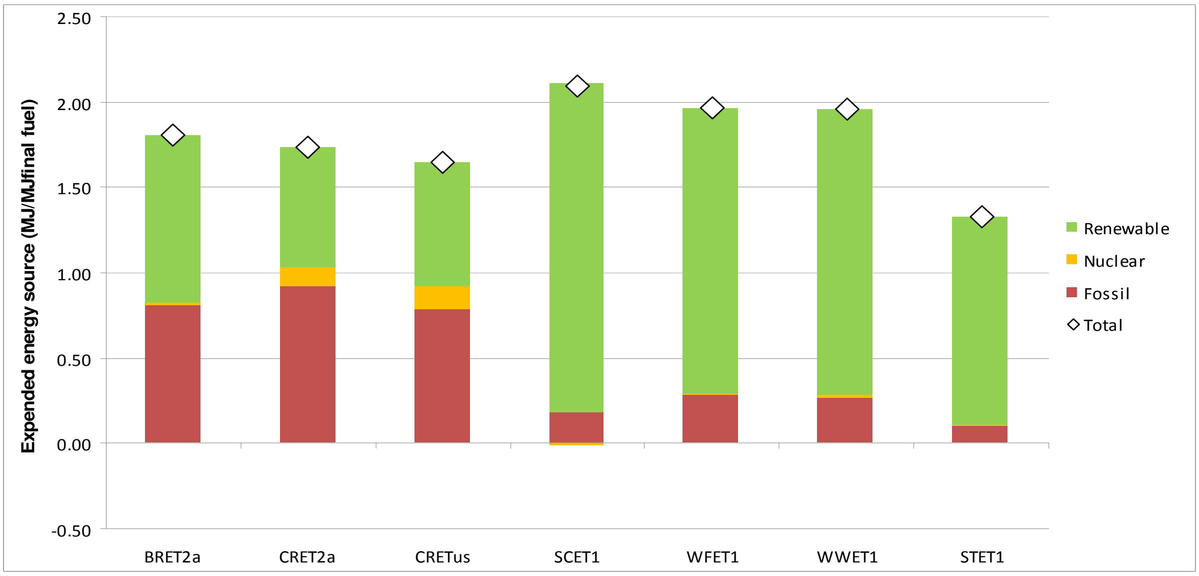


Figure 4.4.2-2b: WTT fossil energy balance of other ethanol pathways



4.4.3 Ethanol WTT GHG balance

Figure 4.4.3-1a/b show the total GHG build-up along the different stages of the pathways. For reference, the gasoline WTT GHG emission figure is 14.1 g CO_{2eq}/MJ and adding the combustion CO_2 to make the GHG figures comparable gives 87.8 g CO_{2eq}/MJ.

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 little or no GHG emissions saving for ethanol compared to gasoline. Conversely, using straw and DDGS for energy production in the plant (WTET4 & 5) reduces fossil fuel use, resulting in a negative figure for the "transformation" step and hence reducing overall GHG emissions, in the best case almost matching the sugar cane and advanced ethanol processes.

For sugar cane, the CO_2 credit attached to additional fuel oil saving from surplus bagasse also 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, energy coming from the non-fermentable portion of the feedstock. 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 and wheat ethanol pathways

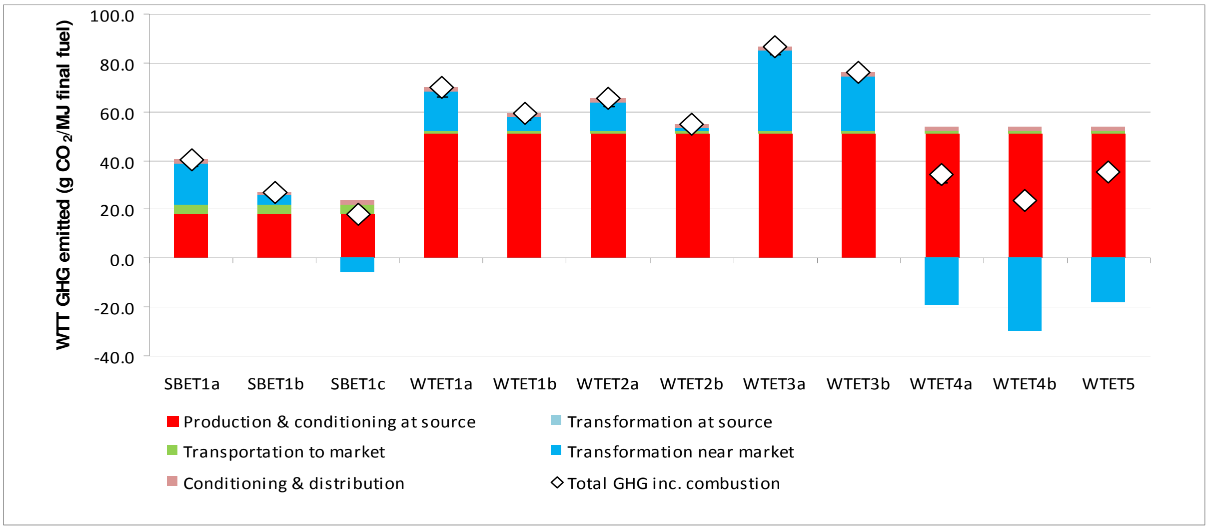
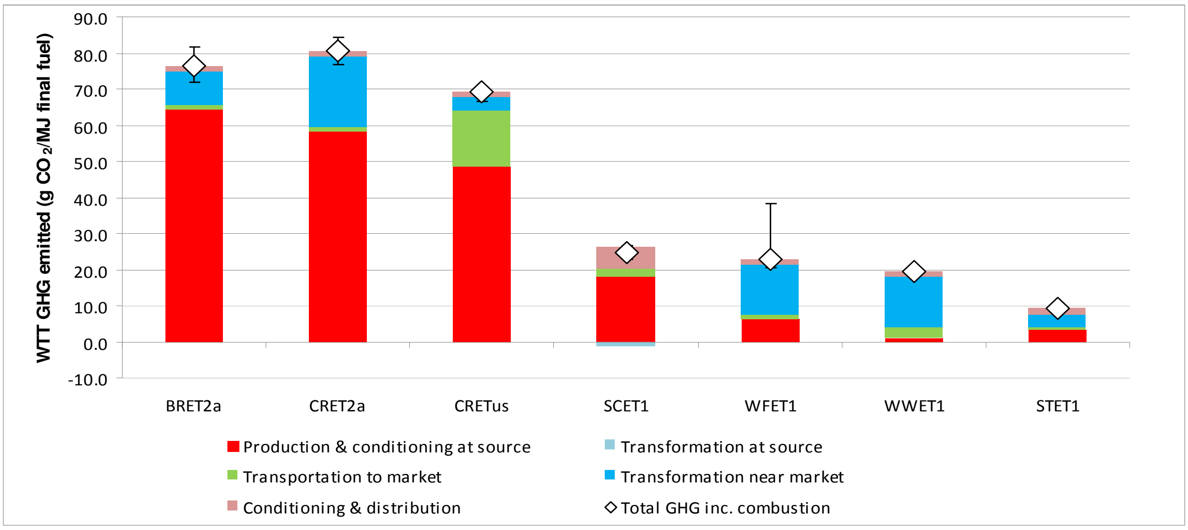


Figure 4.4.3-1b: GHG balance of other ethanol pathways



Using by-products as animal feed gives an ILUC credit

The conclusion that energetic use of by-products reduces emissions for biofuel production could be reversed if ILUC emissions were to be included. That is because the use of by-products for animal feed rather than energy reduces the land needed to grow animal feed and hence generates a credit in the calculation of ILUC emissions. This credit is taken into account in models estimating ILUC, but would be lost if the by-products are used for energy.

4.5 Bio-diesel (FAME, FAEE and hydrotreated vegetable oils)

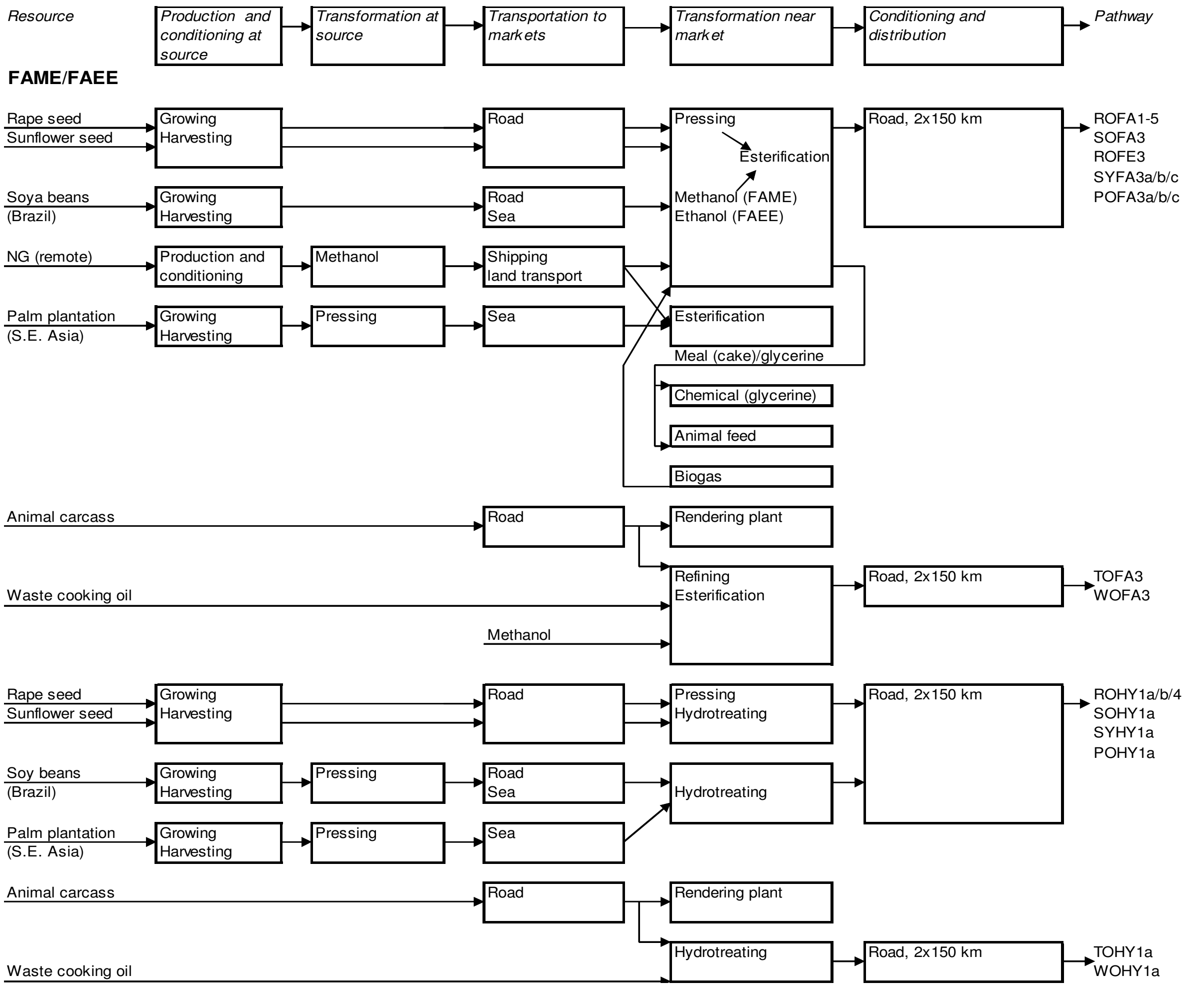
(See also workbook WTT v4 pathways 4-Biodiesel in Appendix 4)

4.5.1 Bio-diesel pathways

Bio-diesel in Europe 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. Waste materials such as tallow and waste cooking oils are also used as feedstocks for biodiesel production in Europe. 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, palm oil and waste 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.

An alternative processing option is to hydrotreat the plant oils, either alone or mixed with petroleum products to produce HVO (hydrotreated vegetable oil). This has the advantage that it produces a high quality diesel fuel, but requires significant energy input for the hydrotreating process (see *Section 3.4.10*). We have included HVO pathways from rapeseed, sunflower, soya and palm and waste oil and compared them with the equivalent FAME processes.

Figure 4.5.1: Bio-diesel pathways



4.5.2 Bio-diesel WTT energy balance

4.5.2.1 Total energy

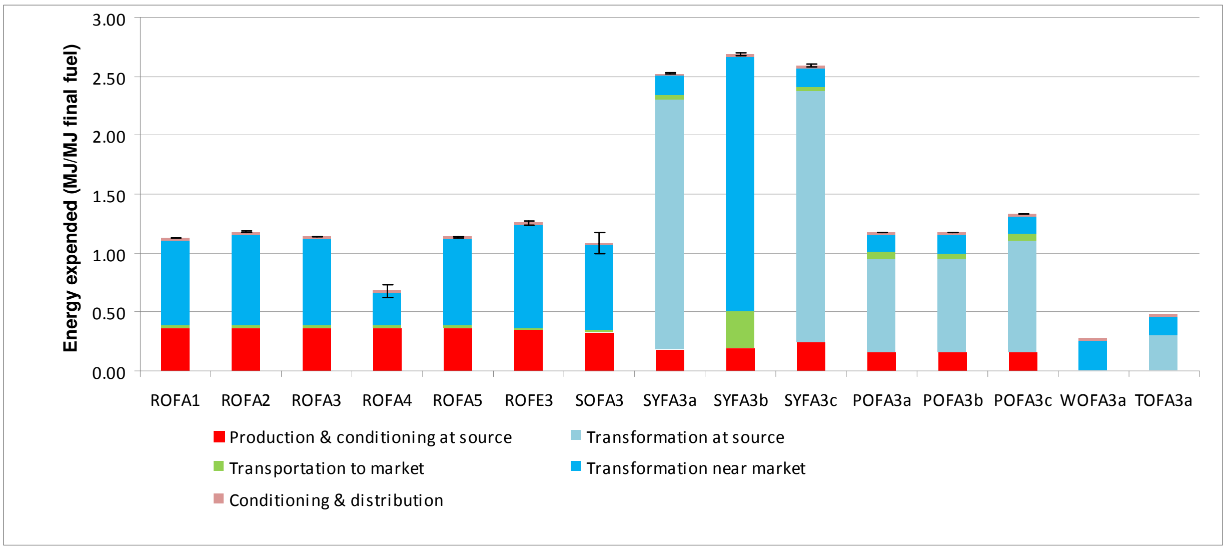
Figure 4.5.2-1 shows the total energy build-up along the different stages for selected conventional bio-diesel (FAME) pathways. For comparison, the production energy for fossil diesel including the combustion energy of 1 MJ is 1.20 MJ/MJ final fuel. This simple comparison works because conventional and bio-diesel are used in the same vehicles delivering the same energy efficiency. For the bio-diesel, "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.

Except for Soy, biodiesel consumes about the same amount of energy in its production and use as fossil diesel fuel. Its advantage lies in the extent to which this energy comes from non-fossil sources and reduces GHG emissions (see below).

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. The effect is exacerbated in this case because the alternative use of meal as animal feed saves relatively little energy.

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; however use of meal and glycerine for energy production (ROFA4) reduces the overall energy requirement considerably.

Figure 4.5.2-1 WTT total energy balance of conventional bio-diesel pathways



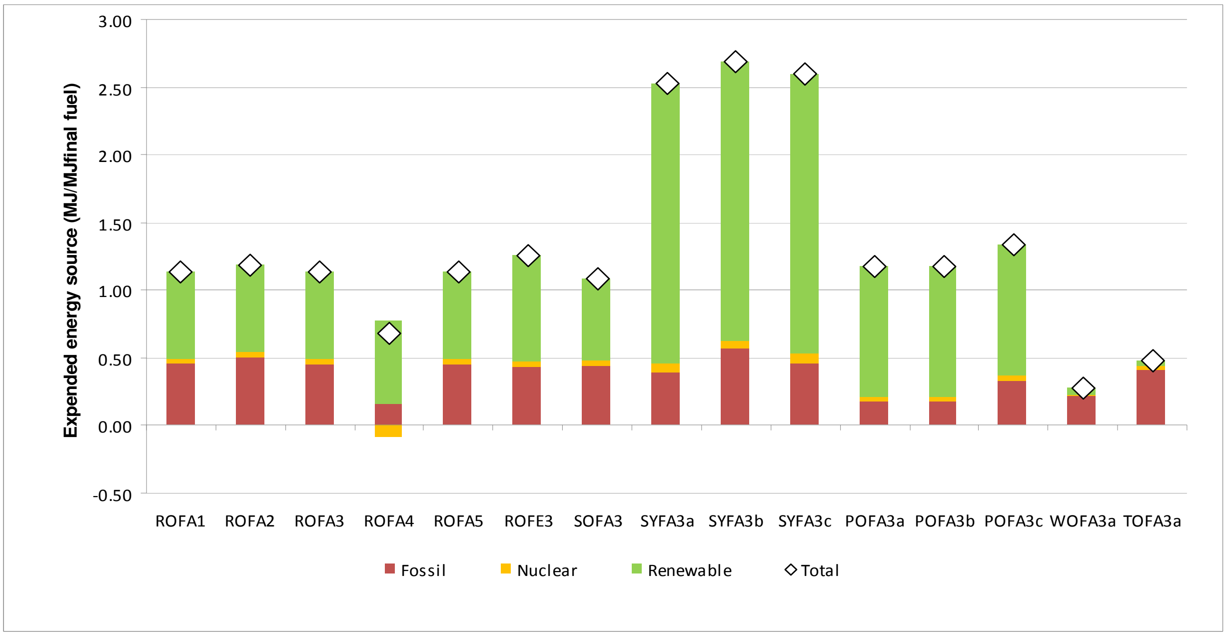
Key to pathway codes

ROFA1	Rape (RME), meal export to animal feed, glycerine export as chemical
ROFA2	Rape (RME), meal and glycerine export to animal feed
ROFA3	Rape (RME), meal export to animal feed, glycerine to internal biogas production
ROFA4	Rape (RME), meal and glycerine to internal biogas production
ROFA5	Rape (RME), meal export to animal feed, glycerine to internal hydrogen production
ROFE3	Rape (REE: esterfication with ethanol), meal export to animal feed, glycerine to internal biogas production
SOFA3	Sunflower (SME), meal export to animal feed, glycerine to internal biogas production
SYFA3a	Soy (SYME), no till culture, local mill, meal export to animal feed, oil to EU, glycerine to internal biogas production
SYFA3b	Soy (SYME), no till culture, beans to EU, meal export to animal feed, glycerine to internal biogas production
SYFA3c	Soy (SYME), conventional culture, local mill, meal to animal feed, oil to EU, glycerine to internal biogas production
POFA3a	Palm (POME), kernel meal to animal feed, no CH4 recovery from waste storage, heat credit from residue use as fuel, oil to EU, glycerine to biogas
POFA3b	Palm (POME), kernel meal to animal feed, CH4 recovery from waste storage, heat credit from residue use as fuel, oil to EU, glycerine to biogas
POFA3c	Palm (POME), kernel meal export to animal feed, no CH4 recovery from waste storage, no heat credit from residue use as fuel, oil transport to EU, glycerine to biogas
WOFA3a	FAME from waste cooking oil
TOFA3a	FAME from tallow

4.5.2.2 Fossil energy

Figures 4.5.2-2 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, which as noted above gives a total of 1.2 MJ/MJ final fuel. This is in effect a WTW comparison and reference is made to the WTW report.

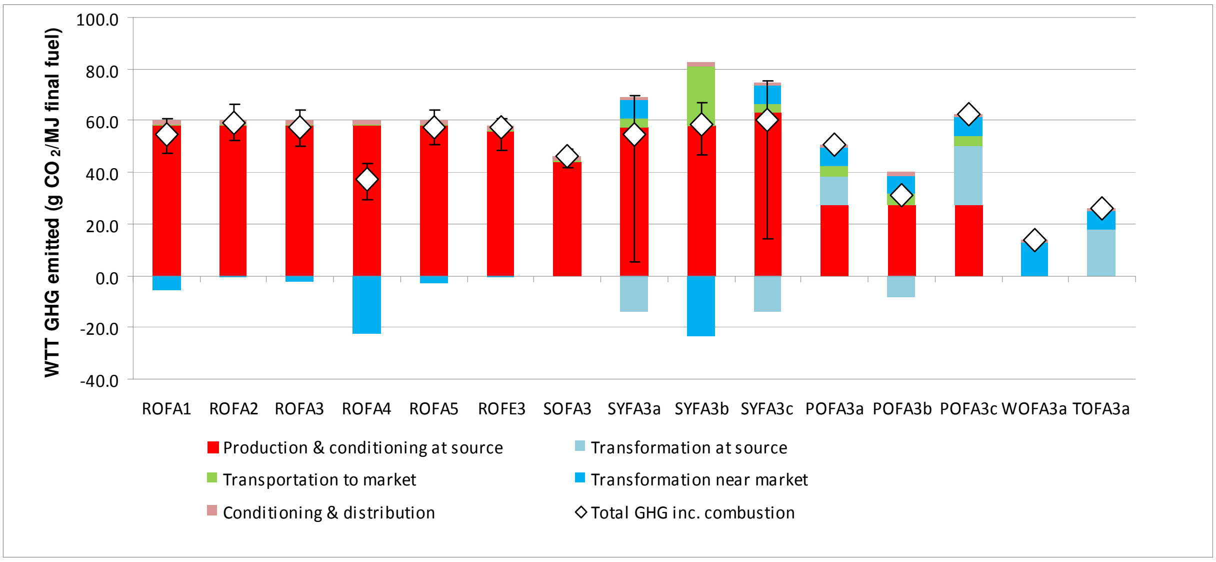
Figure 4.5.2-2: WTT fossil energy balance of conventional bio-diesel pathways



4.5.3 Bio-diesel WTT GHG balance

Figure 4.5.3-1 shows the total GHG build-up along the different stages of the pathways. For comparison, the fossil diesel balance including the combustion CO_2 is 89.2 g CO_{2eq}/MJ final fuel.

Figure 4.5.3-1: WTT GHG balance of conventional bio-diesel 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.

Here again soy shows the highest values, although the difference from the rapeseed cases is relatively small, following the fossil energy figures more closely than the total energy figures. 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, although switching the larger amount of meal from animal feed to energy production does reduce the overall direct GHG emissions, although it would increase ILUC emissions if these were included (see section 4.4.3). Note that our results from palm oil do not include the large emissions from oxidation of tropical peat (see text box in section 3.4.10).

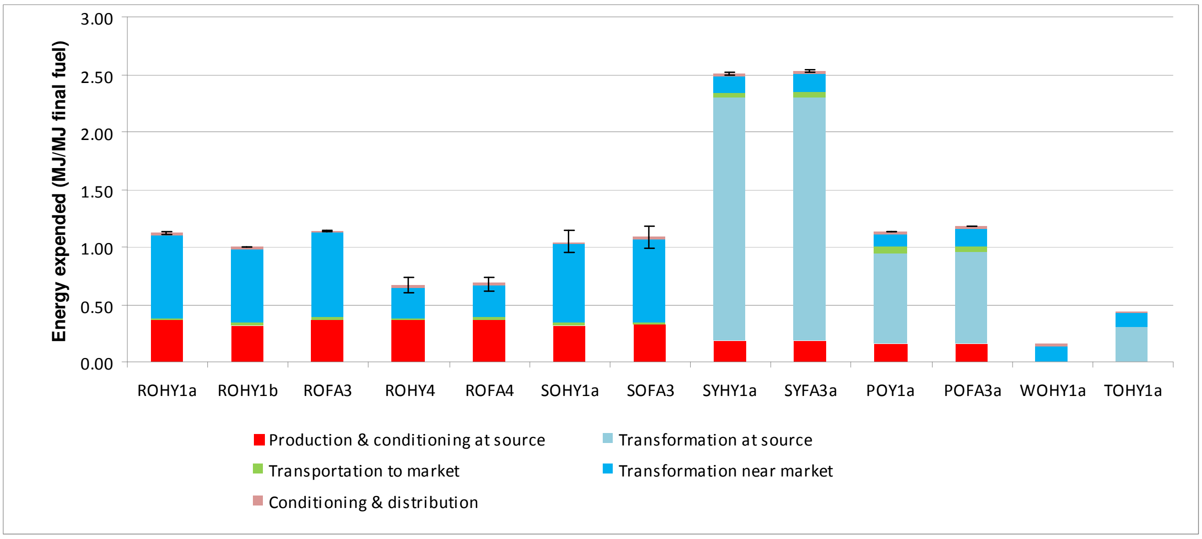
Used cooking oils and animal fats are deemed to be available at the processing plant with a zero energy and GHG footprint, but nevertheless incur some energy us for cleaning and refining. The rendering process for animal fats adds a further small energy/GHG cost.

4.5.4 Hydrotreated Vegetable Oils (HVO)

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.

Figure 4.5.4-1 shows the HVO pathways for rapeseed, sunflower, soya and palm oil and compares them with the equivalent FAME pathway. The overall energy consumption is very similar, whether HVO or FAME is produced.

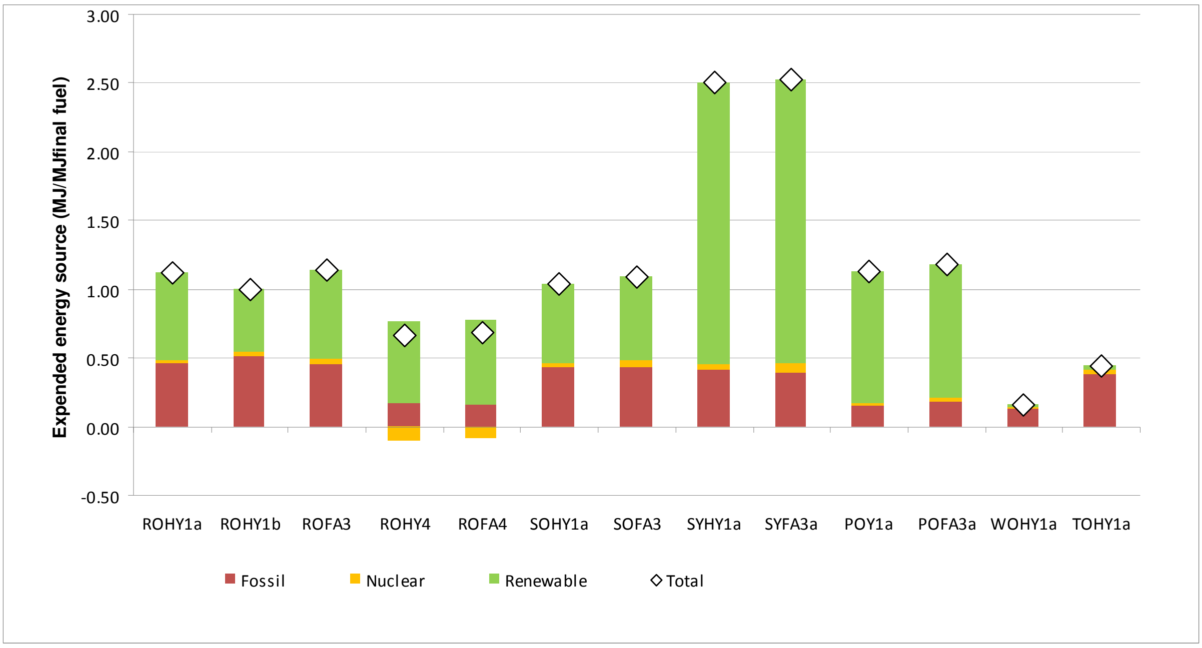
Figure 4.5.4-1: WTT total energy balance of HVO pathways and comparison with equivalent FAME pathways



Key to pathway codes

ROHY1a	Rape (HVO), meal export to animal feed, NexBTL hydrotreating process
ROHY1b	Rape (HVO), meal export to animal feed, UOP hydrotreating process
ROFA3	Rape (RME), meal export to animal feed, glycerine to internal biogas production
ROHY4	Rape (HVO), meal export to internal biogas production, NexBTL hydrotreating process
ROFA4	Rape (RME), meal and glycerine to internal biogas production
SOHY1	Sunflower (HVO), meal export to animal feed, NexBTL hydrotreating process
SOFA3	Sunflower (SME), meal export to animal feed, glycerine to internal biogas production
SYHY1a	Soy (HVO), no till culture, local mill, meal export to animal feed, oil transport to EU, NexBTL
SYFA3a	Soy (SYME), no till culture, local mill, meal export to animal feed, oil to EU, glycerine to internal biogas production
POY1a	Palm (HVO), kernel meal export to animal feed, no CH4 recovery from waste storage, heat credit from residue use as fuel, oil transport to EU, NexBTL
POFA3a	Palm (POME), kernel meal to animal feed, no CH4 recovery from waste storage, heat credit from residue use as fuel, oil to EU, glycerine to biogas
WOHY1a	HVO from waste cooking oil
TOHY1a	HVO from tallow

Figure 4.5.4-2: WTT fossil energy balance of HVO pathways and comparison with equivalent FAME pathways

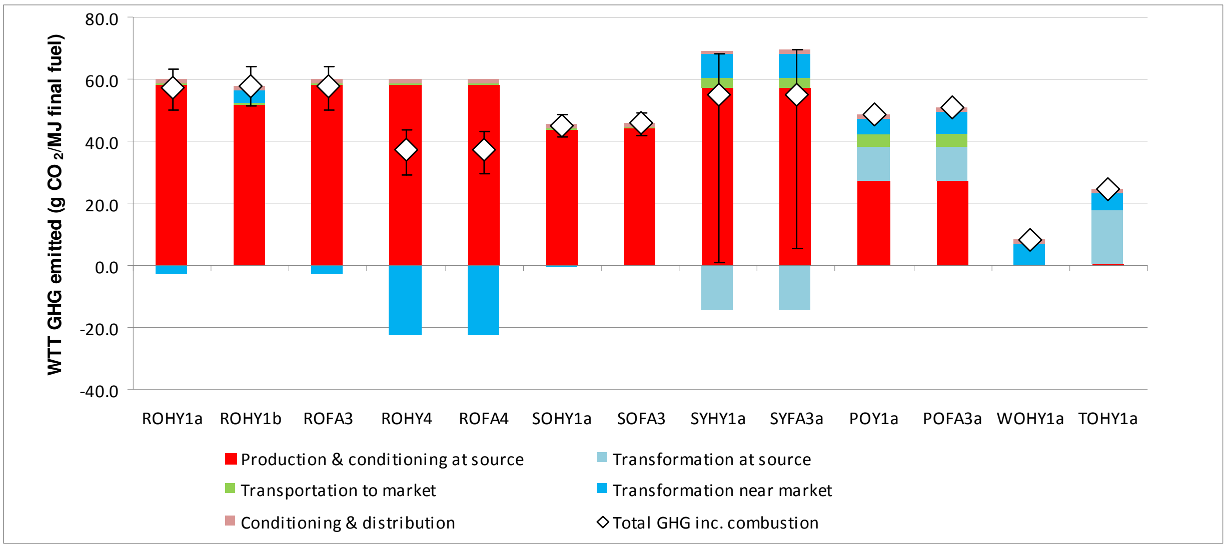


When focussing on fossil energy, the ratio to fossil diesel is in the region of 0.4 for rape, i.e. a net fossil energy saving of about 60% compared to fossil diesel. Again sunflower is slightly more favourable than rape. Obviously the use of bio-ethanol instead of fossil-based methanol results in a small decrease of the total fossil energy requirement. Using by-products for energy production (ROFA4) displaces fossil fuels otherwise needed for heat and electricity generation and so reduces the WTT fossil fuel needs (but increases ILUC: see section 4.4.3). Again, we do not include the large emissions from oxidation of tropical peat in the palm oil results see text box in section 3.4.10).

The high total energy use for soy-derived FAME has been mentioned above; however most of this energy is contained in the soya beans themselves and hence appears as renewable energy. The fossil energy use in this calculation is comparable to or slightly lower than for rapeseed. Palm oil has lower fossil energy use than rapeseed, because waste biomass from the oil extraction is used for heat generation in the production process.

Comparing ***Figures 4.5.4-1*** and ***-2,*** 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 4.5.4-3: WTT GHG emissions balance of hydrotreated plant oil pathways



In terms of GHG emissions, ***Figure 4.5.4-3*** there is little difference between FAME and hydrotreated plant oils when similar plant energy provisions are compared.

4.6 Synthetic fuels

(See also workbook WTT v4 pathways 5-Synfuels in Appendix 4)

4.6.1 Synthetic fuels pathways

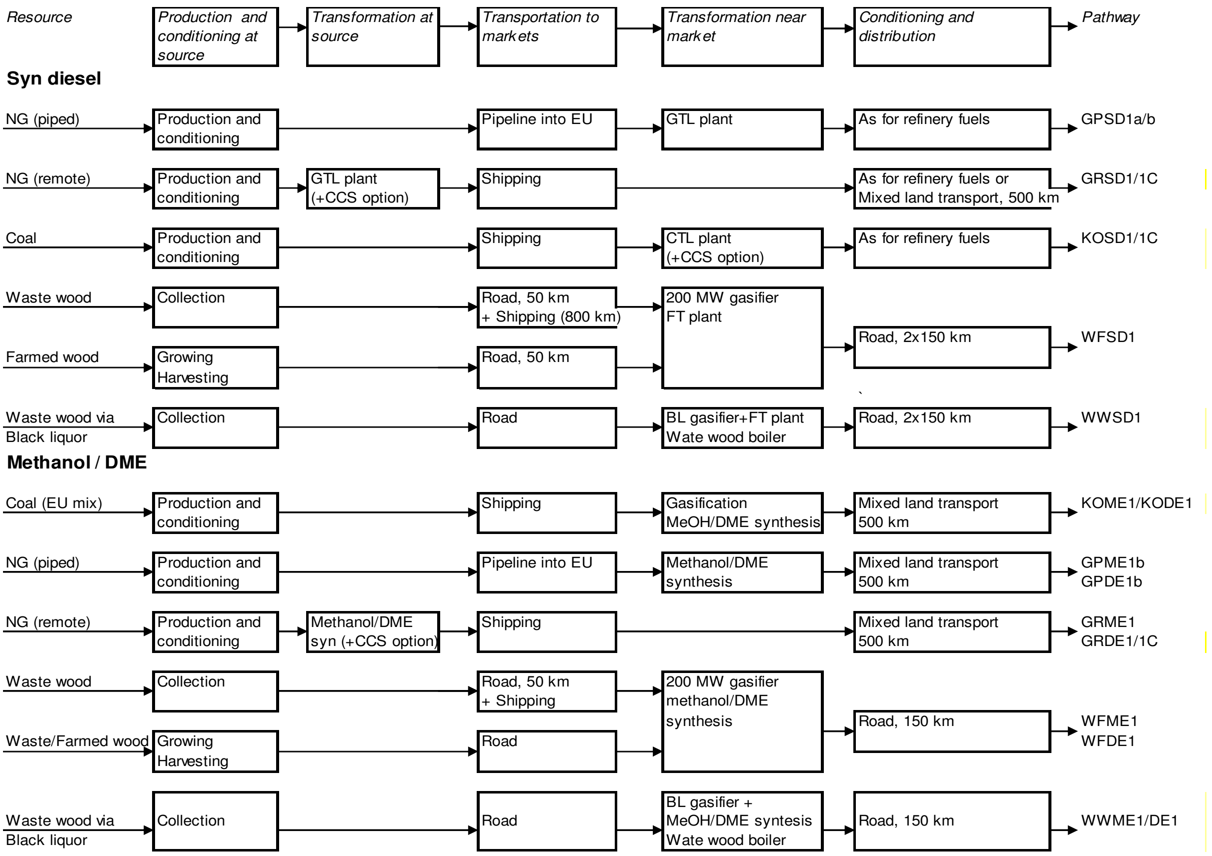
We have considered three synthetic fuels namely Fischer-Tropsch or syndiesel, Di-Methyl Ether (DME) and methanol. Fischer-Tropsch diesel fuel can in principle be used alone or blended as a component of normal diesel fuel and used in conventional vehicles. DME has some attractive characteristics as a fuel for diesel engines although the fact that it is gaseous at ambient conditions means it can only be used in vehicle specially designed for the purpose. Methanol is only envisaged here as a potential fuel for on-board reformers to produce hydrogen in fuel-cell vehicles.

The manufacturing of these synthetic 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. In other words, the fuel is reduced to smaller molecular components (CO, H_2) from which new products can be built.

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. Both coal and gas lend themselves to large scale facilities which are beneficial in terms of cost. Cost considerations also mean that these facilities tend to be located near to the natural resource, to avoid or minimise shipping of raw materials.

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 pathway based on farmed wood (poplar) represents this group of feedstocks. An alternative option for producing liquid fuels from waste wood would be the so-called Black Liquor route (see *section 3.4.11*),

Figure 4.6.1: Synthetic fuels pathways



4.6.2 Syndiesel

WTT Energy use and GHG emissions for the synthetic diesel pathways are shown in ***Figures 4.6.2-1*** and ***-2.*** 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 on the feedstock and to a lesser extent the process scheme.

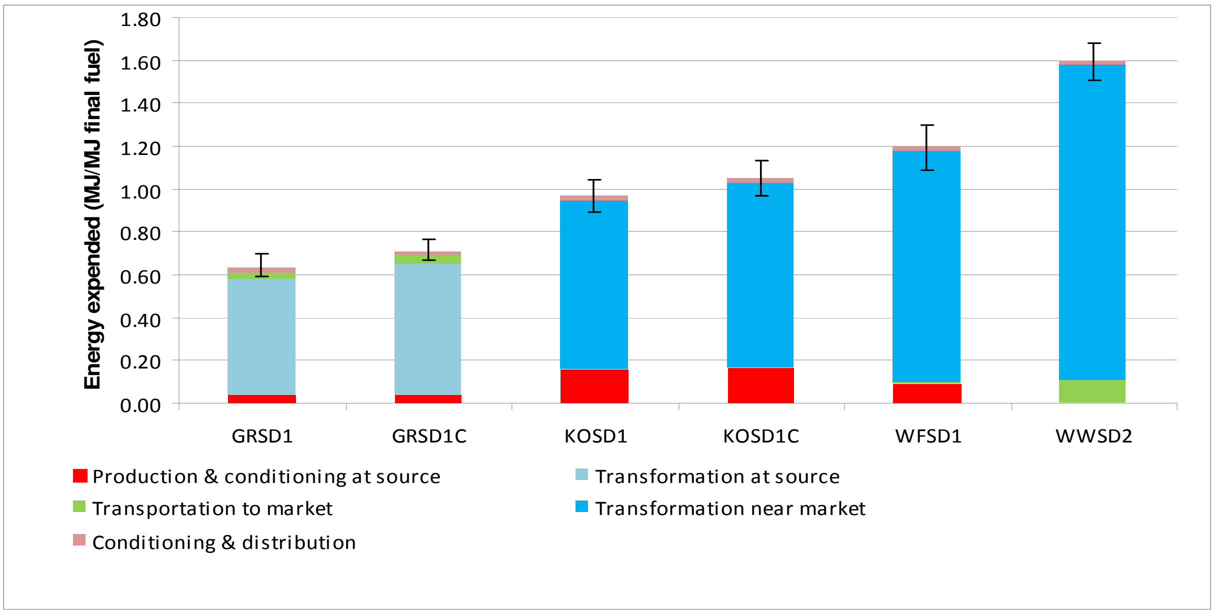
The GTL (natural gas to liquids) processes are the most efficient with figures in the 60-65% bracket, because of the relative ease of producing a syngas from natural gas. GTL production makes the most sense at a remote location when the large gas transport energy can be avoided and replaced by the much more efficient transport of a liquid, so in this version we have modelled only the remote gas case. In the best case syndiesel fuel production from NG requires about 3 times as much total energy as conventional diesel fuel (GRSD1/COD1), and syndiesel from coal much more.

Coal-based processes (CTL) can achieve efficiencies in the region of 55%. The wood-based processes are expected to be less efficient (up to 50%). Solid fuels require a more complex gasification process than NG and because solid residues are formed, the syngas must be cleaned before further processing. In the case of wood processing, 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.

Although the total energy use for the pathways based on wood is fairly high, this is almost entirely renewable energy and the fossil inputs are very low. The black liquor route, where this process can be applied, has a potential for up to 55% efficiency and uses less energy than the Fischer-Tropsch pathway. The differences between farmed and waste wood are small in energy terms.

Syndiesel produced from wind electricity and flue gas CO_2 as described in *section 3.5.3*, is essentially carbon-free, the only potential emissions being related to distribution of the finished fuel. The energy expended, although mostly renewable, is relatively large due to the efficiency of the electrolysis and the energy requirement of the synthesis process.

Figure 4.6.2-1: WTT total energy balance of syn-diesel pathways



Key to pathway codes

GRSD1	Remote NG to syndiesel, GTL plant near gas field
GRSD1C	Remote NG to syndiesel, GTL plant near gas field + CCS
KOSD1	Coal (hard, EU-mix) to syndiesel, CTL plant in EU
KOSD1C	Coal (hard, EU-mix) to syndiesel, CTL plant in EU + CCS
WFSD1	Wood (farmed) to syndiesel
WWSD2	Wood (waste) to syndiesel via black liquor

Figure 4.6.2-2: WTT GHG of syndiesel pathways

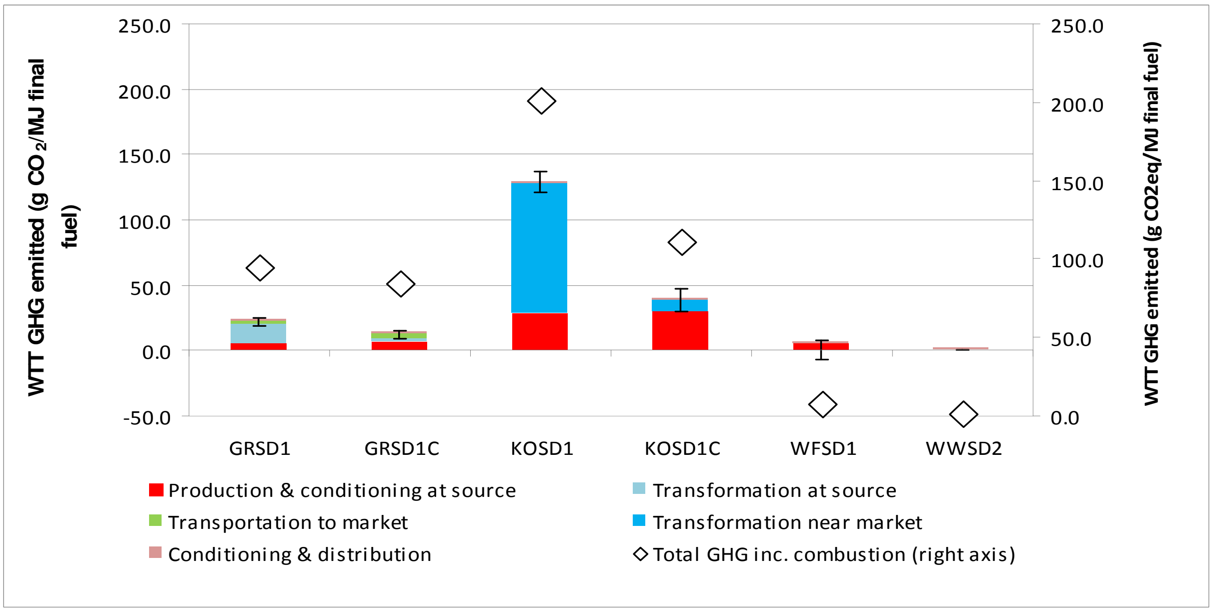


Figure 4.6.2-2 shows the GHG emissions at each stage of fuel production as stacked bars and in addition the total GHG emission including the combustion emissions as diamond symbols. All the options produce a diesel fuel that will result in the same efficiency as fossil diesel when burned in a given vehicle.

The GHG picture 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). Combustion CO_2 emissions of syndiesel are lower than for fossil diesel, because the C/H ratio is lower. Including combustion 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. Without CCS, syndiesel from coal emits twice as much GHG as fossil diesel or syndiesel from natural gas, reflecting both the higher energy inputs and the high C/H ratio of coal. For wood, GHG emissions are mainly incurred for wood growing and collection/transport and since the combustion CO_2 is considered as renewable, the overall GHG emission is very low.

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 fossil 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, emissions for CTL are about 20% higher than for fossil diesel from crude oil. 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.

4.6.2.1 CCS in syndiesel production

Steam reforming and/or partial oxidation is 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. The solvent absorption processes commonly used produce a virtually pure CO_2 stream so that only compression is required for potential transport and eventual storage. Most GTL plants will be built near gas or oil fields where the CO_2 can be re-injected.

For GTL there is no literature source where a plant with and without CCS is compared. GTL plants are very complex. The layout differs from licensor to licensor and this can have a large impact on the energy penalty for CCS. We have used a literature estimate of 3% energy efficiency penalty as a basis for our calculation, starting from an overall plant efficiency of 65% 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 we used a literature source giving a direct comparison of base and CCS cases.

Table 4.6.2-1: Syndiesel production with/without CCS

Feedstock		Natural gas		Coal	
Case		Base	with CCS	Base	with CCS
		GRSD1	GRSD1C	KOSD1	KOSD1C
Natural gas	MJ/MJ SD	1.54	1.61		
Coal	MJ/MJ SD			1.78	1.86
Energy efficiency		65.0%	62.0%	56.1%	53.7%
Net GHG emissions	g CO_{2eq}/MJ SD	13.9	3.6	100.4	9.1
CO_2 removal efficiency			74.3%		91.0%

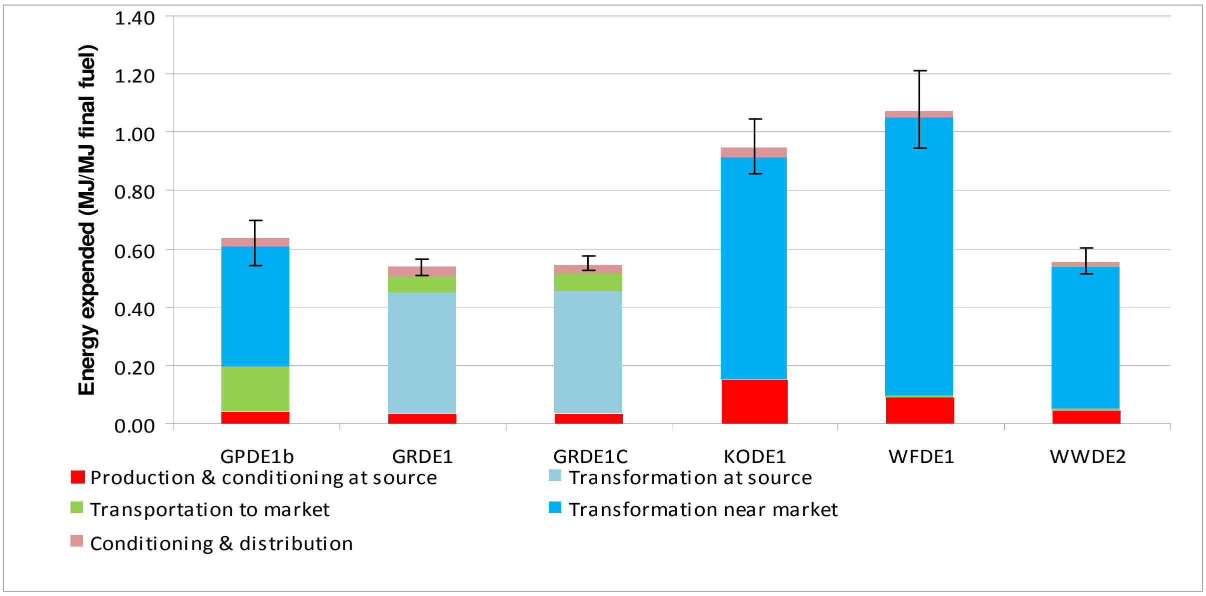
The process as described produces surplus electricity in both cases. We treated this as a credit based on alternative generation with a coal-fired IGCC with and without CCS (as described above).

4.6.3 DME

WTT Energy use and GHG emissions for the DME pathways are shown in ***Figures 4.6.3-1*** and ***-2.*** The synthesis of DME is a more efficient than that of FT diesel, resulting is a more favourable energy balance (compare GRSD1 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. The black liquor route offers a substantial energy efficiency improvement when using wood, and the overall energy use is comparable to DME from NG.

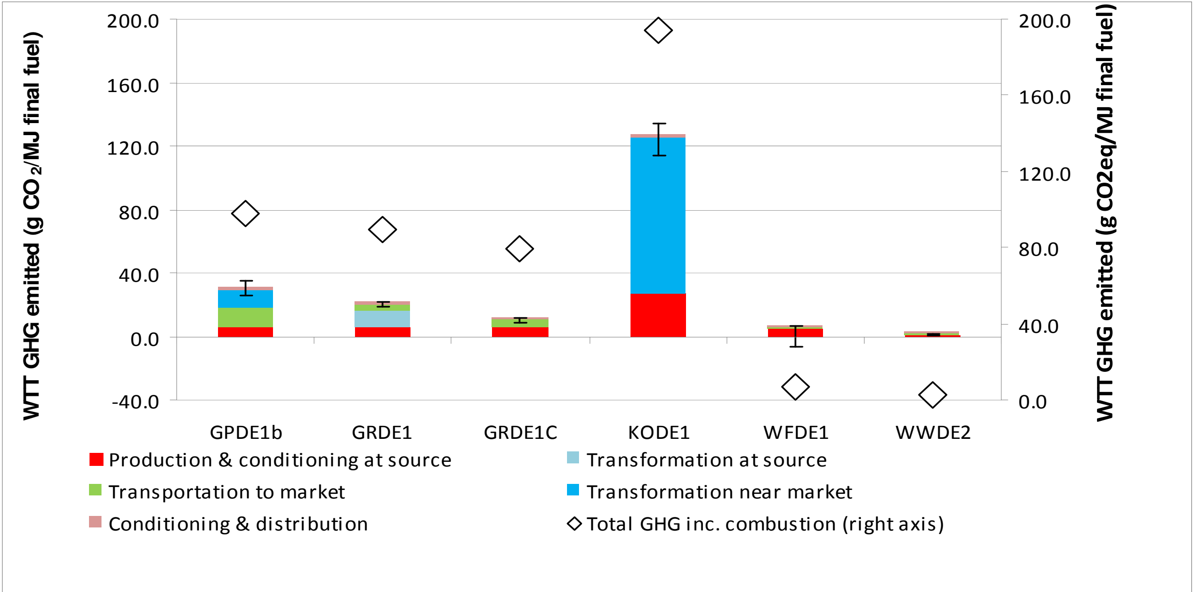
Figure 4.6.3-1: WTT total energy balance of DME pathways



Key to pathway codes

GPDE1b	Piped NG (4000 km) to DME, synthesis plant in EU
GRDE1	Remote NG to DME, synthesis plant near gas field
GRDE1C	Remote NG to DME, synthesis plant near gas field + CCS
KODE1	Coal (hard, EU-mix) to DME, synthesis plant in EU
WFDE1	Wood (farmed) to DME
WWDE2	Wood (waste) to DME via black liquor

Figure 4.6.3-2: WTT GHG emission balance of DME pathways



Total GHG emissions including combustion are again shown. This is appropriate since DME can be used in diesel-type engines, albeit specially designed ones, so will be burned with much the same efficiency as fossil diesel 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.

In such a case CCS could be envisaged to capture the CO_2 emitted during the synthesis process. WTT GHG emissions could be cut by a factor of nearly 2 for a relatively small energy penalty, making DME somewhat more GHG-efficient than fossil diesel.

The pathways based on wood have very low GHG emissions since the combustion carbon is renewable and most of the process energy also comes from the wood. The difference in GHG balance between the farmed wood and black liquor approaches is of course small in absolute terms (because all figures are small). The main benefit of black liquor resides in the better utilisation of a limited resource allowing substitution of more fossil energy with the same quantity of wood.

4.6.3.1 CCS in DME production

DME production is similar to syndiesel in that there is an opportunity to capture CO_2 from the syngas. There is limited information available on DME and there are no full scale commercial plants on the ground at the moment. The data used here are from Haldor Topsoe, the main proponent of DME. This process is applicable to both a remote plant and a large “central” plant located in Europe. In both cases electricity is deemed to be produced by a dedicated gas-fired CCGT power plant.

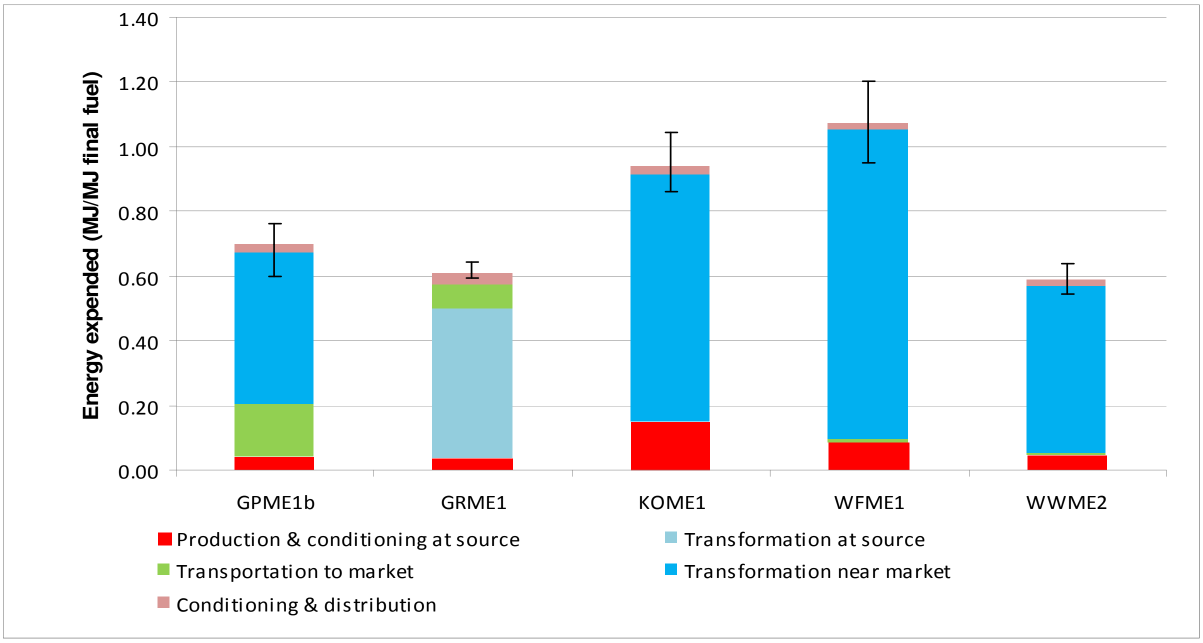
Table 4.6.3: DME production with/without CCS

Feedstock Case		Natural gas	
		Base GRDE1	with CCS GRDE1C
Natural gas	MJ/MJ DME	1.41	1.42
Energy efficiency		70.8%	70.4%
Net GHG emissions	g CO_{2eq}/MJ DME	10.6	0.6
CO_2 removal efficiency			94.8%

4.6.4 Methanol

WTT Energy use and GHG emissions for the methanol pathways are shown in ***Figures 4.6.4-1*** and ***-2.*** WTT energy 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.

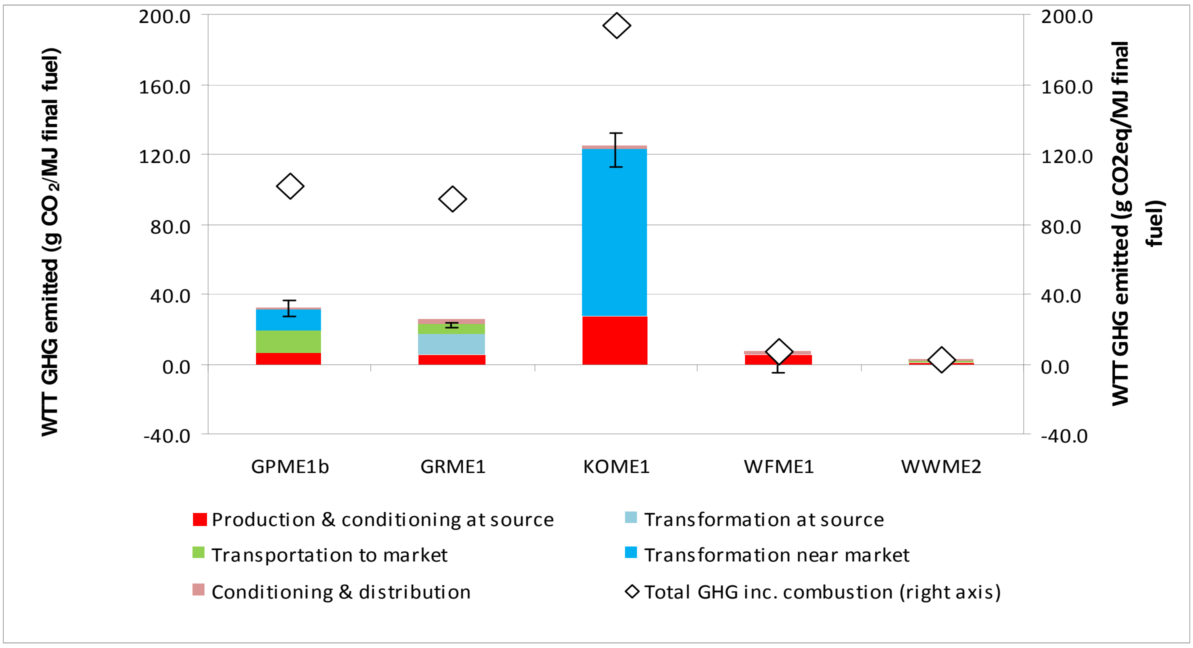
Figure 4.6.4-1: WTT total energy balance of methanol pathways



Key to pathway codes

GPME1b	Piped NG (4000 km) to methanol, synthesis plant in EU
GRME1	Remote NG to methanol, synthesis plant near gas field
KOME1	Coal (hard, EU-mix) to methanol, synthesis plant in EU
WFME1	Wood (farmed) to methanol
WWME2	Wood (waste) to methanol via black liquor

Figure 4.6.4-2: WTT GHG balance of methanol pathways

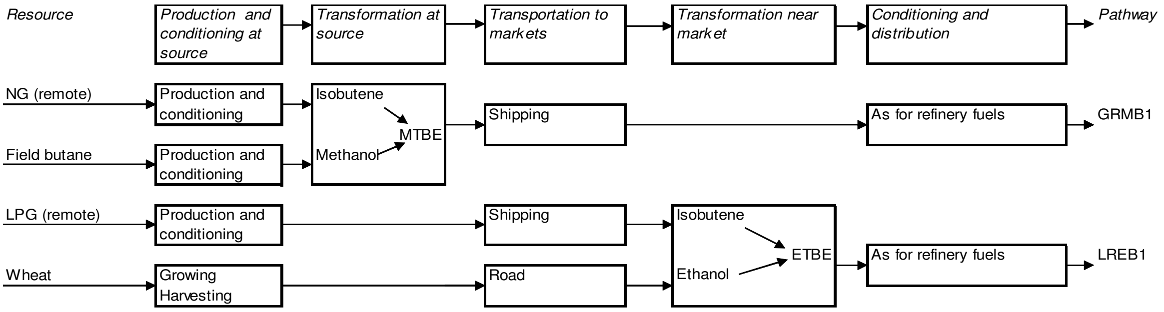


The comments on GHG emissions for methanol production mirror those on energy use. For all practical purposes, the figures are very similar whether DME or methanol is produced. Figures including combustion CO_2 have not been included in this case, because the potential uses of methanol are still unclear. In principle methanol could be used as a blend component in gasoline, but consideration would need to be given to its toxicity and water solubility. Neat methanol has also been proposed as a fuel for on-board reforming to hydrogen for fuel cell vehicles. The reader is referred to the more complete discussion in the WTW report where vehicle efficiency factors are properly integrated.

4.7 Ethers (MTBE/ETBE)

(See also workbooks WTT v4 pathways 1-Oil&Gas/3-Ethanol in Appendix 4)

Figure 4.7-1: MTBE and ETBE pathways



As explained in *section 3.4.9*, ETBE is currently manufactured by some European oil refineries in purpose-built ETBE plants or, much more frequently, in plants that used to produce MTBE. The isobutene feed is a by-product of the catalytic cracking process and is only available in limited quantities. 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. We 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.

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*). The energy and GHG balances are shown in ***Figures 4.7-2*** and ***-3***.

Figure 4.7-2: WTT total energy balance of MTBE and ETBE pathways

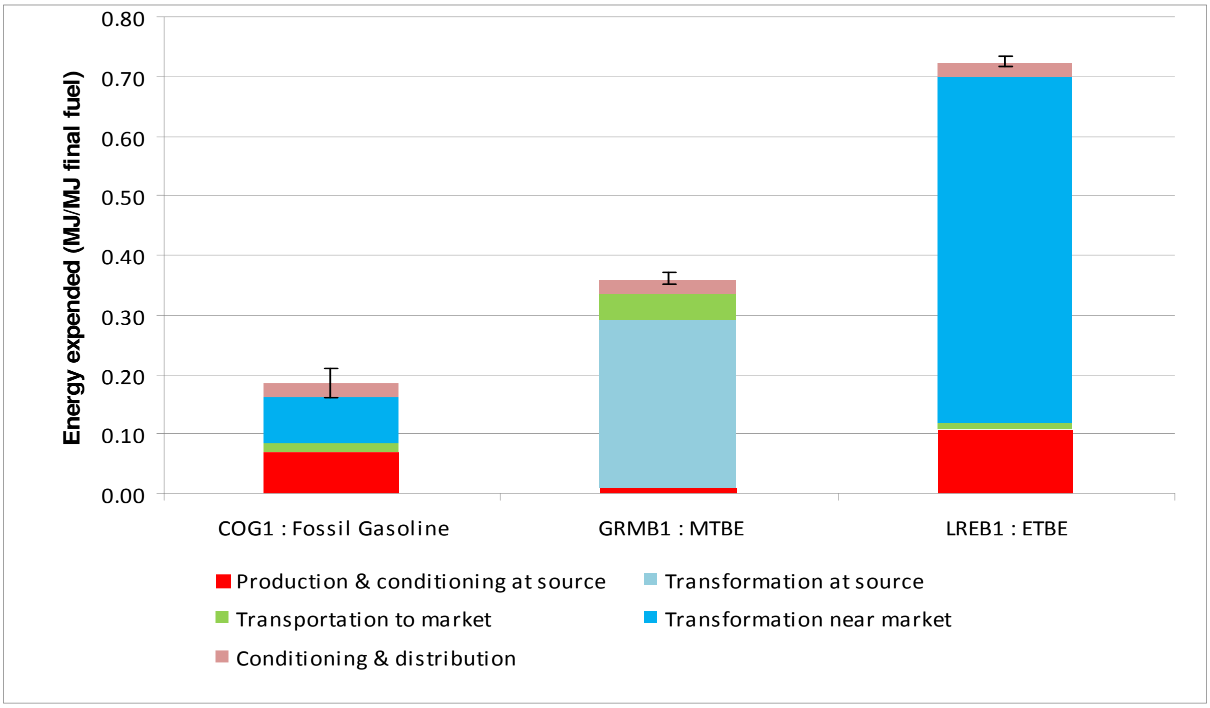
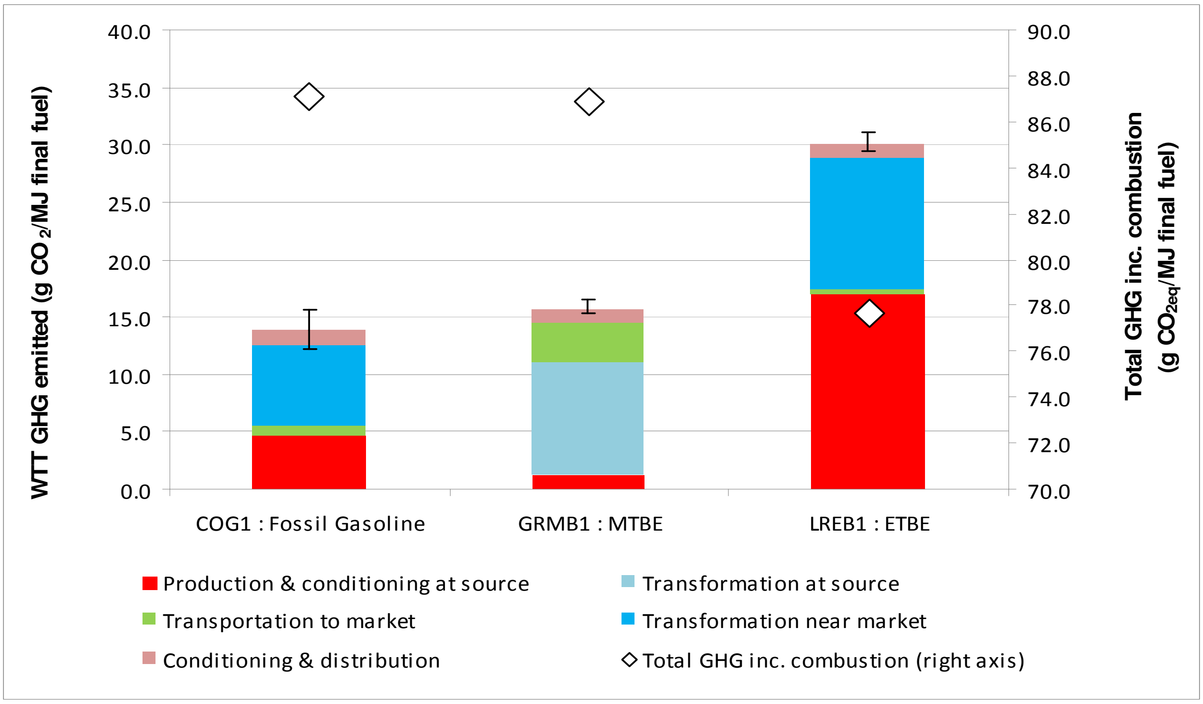


Figure 4.7-3: WTT GHG balance of MTBE and ETBE pathways



MTBE is more energy-intensive than gasoline as it involves several energy-consuming chemical steps: methanol is produced from natural gas, and isobutene from LPG. 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. ETBE has 6 carbon atoms, 2 of which come from ethanol hence 33% of the combustion CO_2 emissions are renewable.

Pathway LREB1 is an unusual case inasmuch as there are few purpose-built ETBE plants in Europe and most ETBE is currently made in existing refinery MTBE plants that have been converted to produce ETBE, using ethanol feed instead of methanol. 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	Feedstocks used			Balance		**Balance**	
		MTBE	ETBE	Ethanol	Total	gasoline	Isobutene	Methanol	Ethanol	/MJ MTBE	/MJ ETBE	/MJ EtOH	
Base case													
	MJ	1.00			1.00		0.82	0.21					
Use of ethanol as such													
Used or produced	MJ	1.00		0.40	1.40		0.82	0.21					
Total energy expended	MJ			1.05						1.05		**2.62**	
Fossil energy expended	MJ			0.30						0.30		**0.75**	
GHG	g CO_{2eq}			25.88						25.88		**64.8**	
ETBE instead of MTBE													Net
Used or produced	MJ		1.20		1.20	0.20	0.82	-0.21	0.40				
Total energy expended	MJ					0.237		-0.33	1.05	0.95	0.79	**2.38**	**-0.24**
Fossil energy expended	MJ					0.24		-0.33	0.30	0.20	0.17	**0.51**	**-0.24**
GHG	g CO_{2eq}					17.7		-19.4	25.9	24.17	20.19	**60.6**	**-4.3**

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

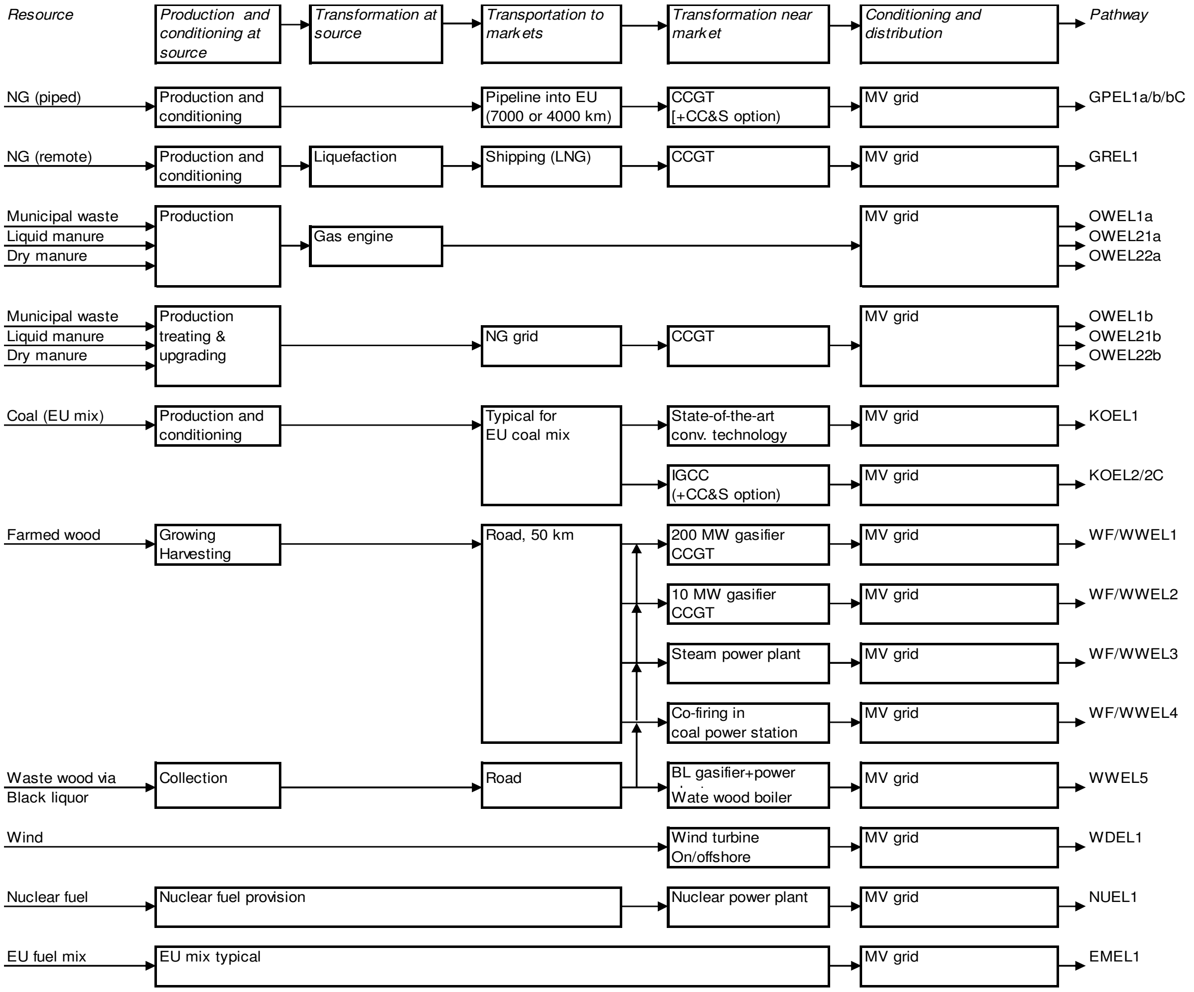
(See also workbooks WTT v4 pathways 6-Electricity/7-Heat & Power in Appendix 4)

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*). Electricity is also a potential road fuel for electric vehicles which as described in the version of this study.

The pathways presented here represent power generation from specific primary energy sources using state-of-the-art technology. For a discussion of the current EU-mix power generation see *section 3.5.1*.

Figure 4.8.1: Electricity generation pathways



4.8.2 Energy and GHG balance for electricity pathways

In this 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

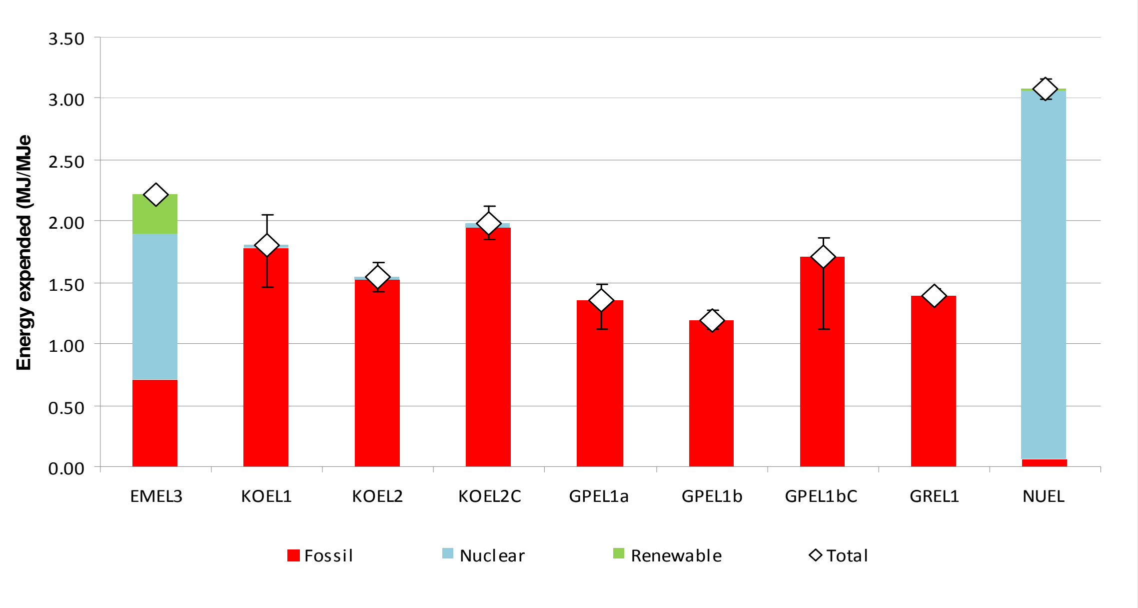
$$\text{Efficiency}_{\text{overall}} = 1 / (1 + \text{MJ expended})$$

4.8.2.1 Electricity from fossil and nuclear fuels

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, although new coal plants can achieve efficiency over 40%. We have used efficiencies of 58.1% for CCGT and 43.5% for a conventional coal plant, representative of state-of-the-art technology. Where the energy source is biomass, the efficiency of electricity generation depends on the scale of the operation. For a large scale IGCC the efficiency is 48.2%, whereas a smaller scale IGCC may only achieve 35.2%, which is little better than a conventional small scale steam turbine at 32%. Co-firing in a conventional power station would achieve the same efficiency as coal, i.e.43.5%. Wind energy is effectively considered 100% efficient. Efficiencies are estimated for the lifetime of the plant and may be higher when the plant is new.

Older power plants already in production may not achieve state-of-the-art efficiency, and for comparison we have included a pathway showing current EU-average power generation, based on JRC statistical data from 2009.

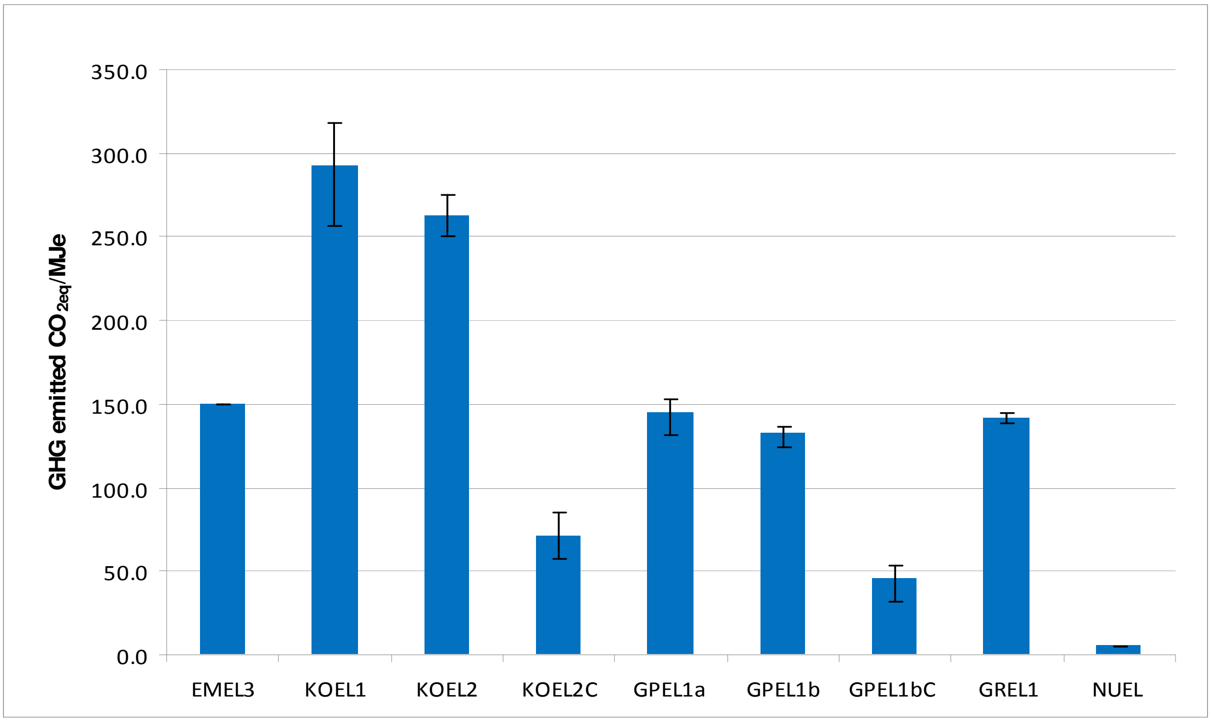
Figure 4.8.2-1a: Total energy balance for fossil and nuclear electricity pathways (excluding final electrical energy)



Key to pathway codes

EMEL3	EU-mix LV
KOEL1	Coal (hard), conventional
KOEL2	Coal (hard), IGCC
KOEL2C	Coal (hard), IGCC + CCS
GPEL1a	NG, pipe 7000 km, CCGT
GPEL1b	NG, pipe 4000 km, CCGT
GPEL1bC	NG, pipe 4000 km, CCGT, CCS
GREL1	LNG, CCGT
NUEL	Nuclear

Figure 4.8.2-1b: GHG balance for fossil and nuclear electricity pathways



Energy and GHG emission figures for fossil and nuclear electricity are shown in ***Figures 4.8.2.-1a*** and ***-1b***. If we take conventional coal electricity as a benchmark, introduction of IGCC provides relatively small reductions in energy use and GHG emission reductions, because the IGCC efficiency is less than can be achieved with a gas powered CCGT. Electricity production from natural gas benefits both from generating efficiency and the lower carbon content of gas, so that GHG emissions are about half those of coal, even when the gas is sourced through a long distance pipeline or as LNG. CCS has the potential to reduce GHG emissions by more than 2/3 for both coal and natural gas at the cost of some increase in energy consumption.

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, since the efficiency of the steam turbine is around 33%. Extraction and upgrading of nuclear fuel also requires a significant amount of energy. However, nuclear power draws on a different source of energy than fossil hydrocarbon sources and has very low GHG emissions.

The average generation efficiency of the EU-mix electricity is not as good as the gas-fired CCGT. However, the shares of renewables and nuclear compensate for this, resulting in very similar GHG figures. Note that the efficiency of current generating capacity is slightly lower than the state-of-the-art figures used in the other pathways, also that the EU-mix energy figures are based on primary energy rather than the amount of electricity generated from each fuel. When considering only the fossil hydrocarbons part, EU-mix has a fossil energy footprint similar to natural gas.

4.8.2.2 CCS in electricity generation

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. Alternatively the "pre-combustion" route includes reforming NG into hydrogen and separating CO_2 before burning the hydrogen in an adapted CCGT.

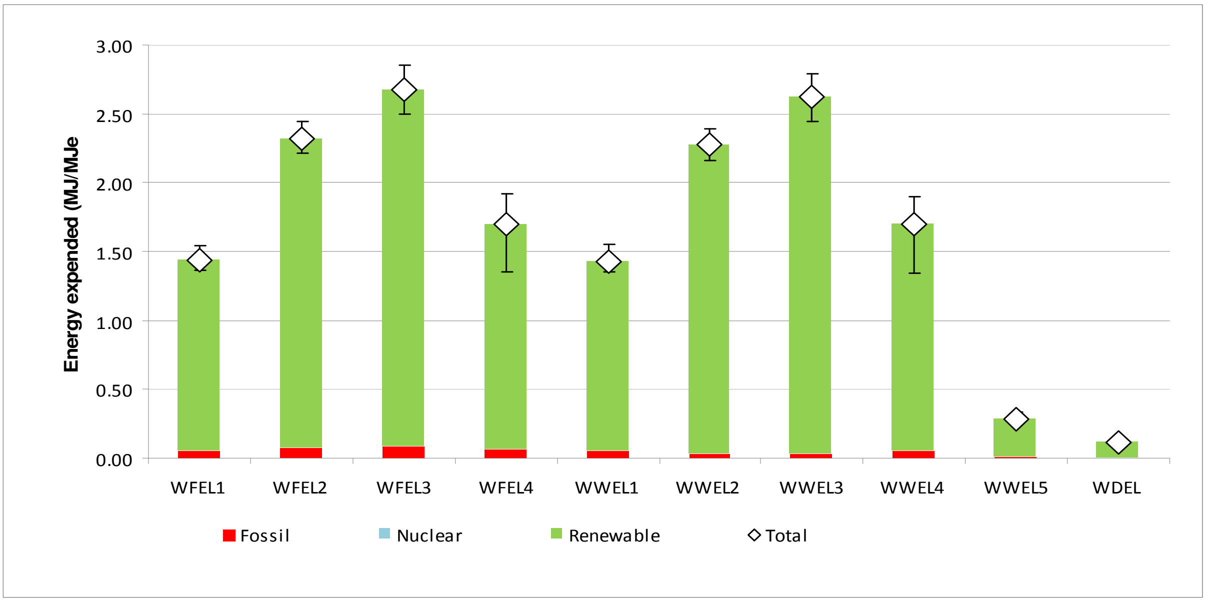
In this study we have considered the post-combustion option. The energy required to compress and inject CO_2 in the storage structure is included. Indications are that the efficiency loss will be higher for pre-combustion schemes. Such schemes would, however, offer greater flexibility, not least being able to produce hydrogen in addition to power.

The coal IGCC process is well suited to CO_2 capture, since syngas can be converted, via the shift reaction, to hydrogen and virtually pure CO_2 upstream of the gas turbine. This is, however at a significant energy cost. The calculations are based on a pre-feasibility study since there is no commercial-scale plant in operation. Results are shown in the figures above, and summarised in ***Table 4.8.2***.

Table 4.8.2: Electricity production with/without CCS

Feedstock		Natural gas		Coal	
Case		Base GPEL1b	with CCS GPEL1bC	Base KOEL2	with CCS KOEL2C
Natural gas	MJ/MJe	1.81	2.26		
Coal	MJ/MJe			2.21	2.61
Energy efficiency		55.3%	44.3%	45.2%	38.3%
Net GHG emissions	g CO_{2eq}/MJe	107.8	14.3	251.2	27.4
Overall CO_2 removal efficiency			86.7%		89.1%

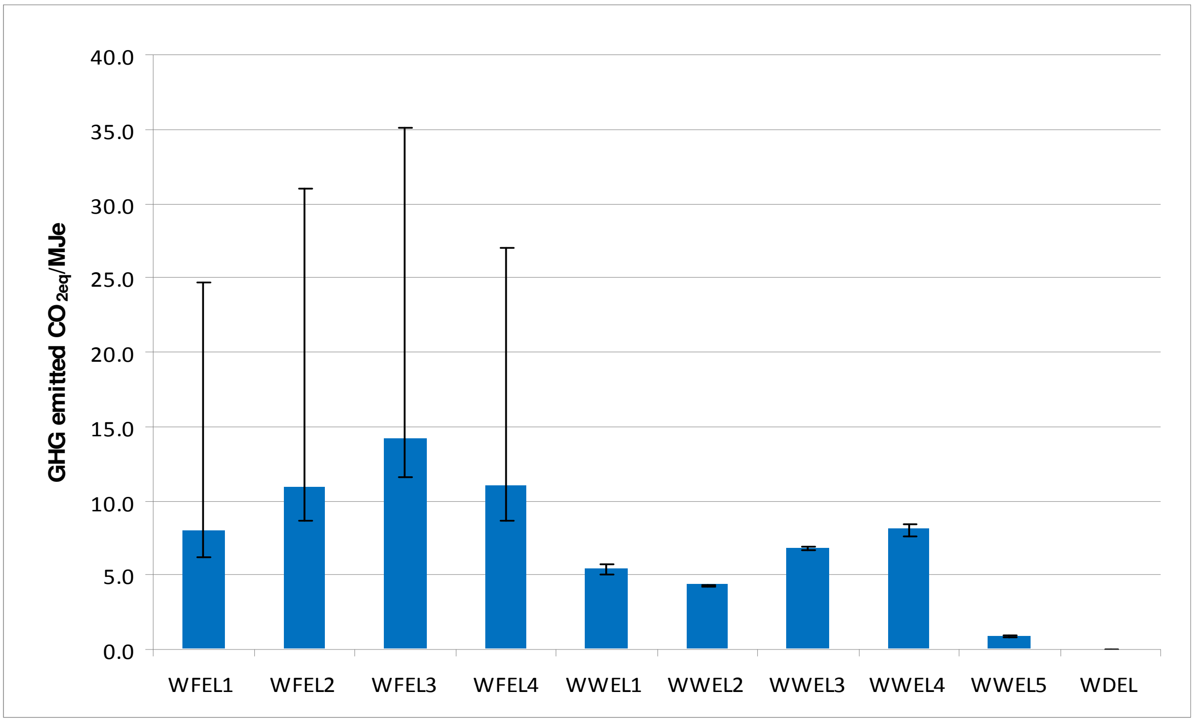
Figure 4.8.2-2a: Total energy balance for wood and wind to electricity pathways (excluding final electrical energy)



Key to pathway codes

WFEL1	Wood (farmed), large IGCC
WFEL2	Wood (farmed), small IGCC
WFEL3	Wood (farmed), small conventional
WFEL4	Wood (farmed), cofiring in coal plant
WWEL1	Wood (waste), large IGCC
WWEL2	Wood (waste), small IGCC
WWEL3	Wood (waste), small conventional
WWEL4	Wood (waste), cofiring in coal plant
WWEL5	Wood (waste) via black liquor
WDEL	Wind

Figure 4.8.2-2b: GHG balance for wood and wind to electricity pathways

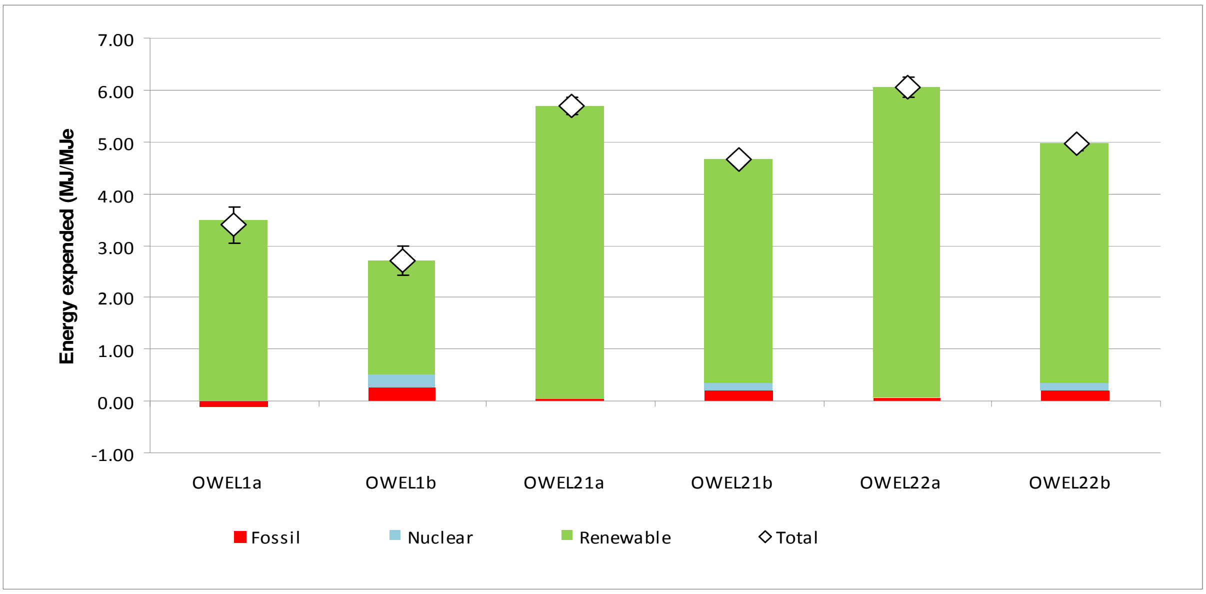


Energy and GHG emission figures for electricity produced from wood and wind are shown in ***Figures 4.8.2.-2a/b***. Wind is a course a special case inasmuch as the input energy cannot be measured and, being in effect unlimited, can be considered as totally “free”. Electricity produced by the black liquor route achieves a remarkably high energy efficiency due to its synergy with the requirements of the paper mill.

For the other wood pathways, overall energy efficiency depends on the scale. Efficiency 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. Most of the energy consumed comes from the wood itself, so the fossil energy use and GHG emissions are very low for all the pathways.

The CO_2 released from burning wood is not included in the above figures since it is sequestered CO_2 and does not add to the overall atmospheric burden. Being consumed in a central facility, CCS could in principle be applied, potentially giving negative GHG emissions for these pathways.

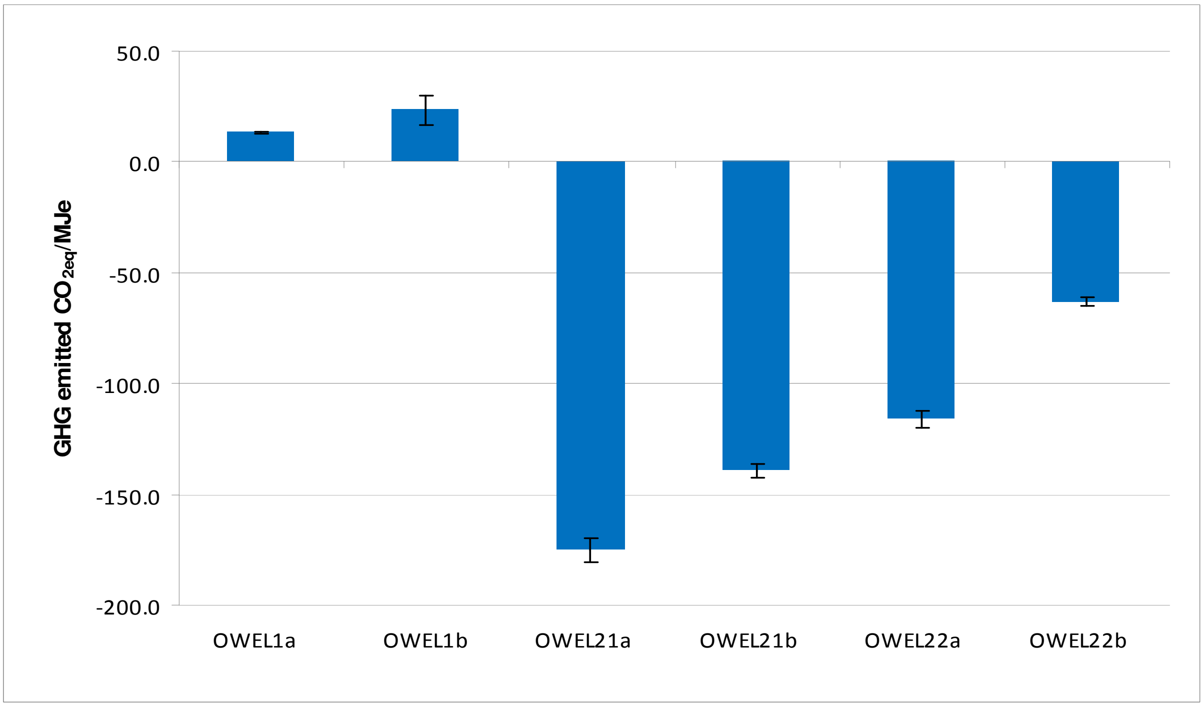
Figure 4.8.2-3a: Total energy balance for biogas to electricity pathways (excluding final electrical energy)



Key to pathway codes

OWEL1a	Municipal waste (closed digestate storage), small CHP
OWEL1b	Municipal waste (closed digestate storage), co-firing in large CCGT
OWEL21a	Manure (closed digestate storage), small CHP
OWEL21b	Manure (closed digestate storage), co-firing in large CCGT
OWEL22a	Manure (open digestate storage), small CHP
OWEL22b	Manure (open digestate storage), co-firing in large CCGT

Figure 4.8.2-3b: GHG balance for biogas to electricity pathways



Results for electricity produced from biogas are shown in ***Figures 4.8.2.-3a/b.*** Where biogas is produced from waste materials there are benefits both in using an energy source that might otherwise be discarded and in avoiding GHG emissions from disposal of the material. Electricity production provides one way of using the biogas and the figures shown here may be compared with those for biogas as a road fuel in *section 4.3.3*.

Results are shown for municipal waste and wet manure. In each case, two options for electricity generation are considered. In the gas engine case, we consider a modern gas generator with an efficiency of 40% which provides electricity and heat for the biogas plant with excess electricity being exported to the grid (a small CHP system). There is no credit for any surplus heat generated. The alternative scenario is that the gas is cleaned and fed to the gas grid from where it can be extracted and contribute to the gas supply to a large CCGT power station, thus benefiting from the higher generating efficiency this offers. In the latter case, EU-mix electricity is taken from the grid for the biogas plant needs, and heating is provided from a steam boiler fuelled by a small part of the produced biogas.

Since most of the energy comes from the waste material, the overall energy figures are of less interest in this case. In all cases the fossil energy use is low. Pathway OWEL1a has a negative fossil energy, because of a credit for N fertilizer. Pathway OWEL1b also has that credit but there is some fossil energy involved in upgrading that more than cancels out the credit. For municipal waste, exporting gas to a CCGT uses less total energy than electricity generation in the plant, so more electricity is produced from a given amount of waste material. On the other hand, more fossil energy is consumed by this route. GHG emissions for biogas electricity from municipal waste are low (note the different scales between ***Figures 4.8.2-1b*** and ***4.8.2-3b***).

For the pathways based on wet manure, a credit has been given for the uncontrolled methane emissions that might otherwise occur. While this is essentially the result of bad farming practices which should be avoided in any case, it is introduced here for comparability with the road fuel pathways presented in *section 4.3.3*. With this credit GHG emissions are negative, however comparison of the pathways shows that this benefit is eroded if open digestate storage is used, allowing some methane to escape to the atmosphere. The benefit is greater for the on-site gas engine than for exported gas burned in a CCGT, but this is largely a reflection of the higher efficiency of the latter process, because the results are presented per MJ of electricity produced rather than per MJ of energy input.

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.

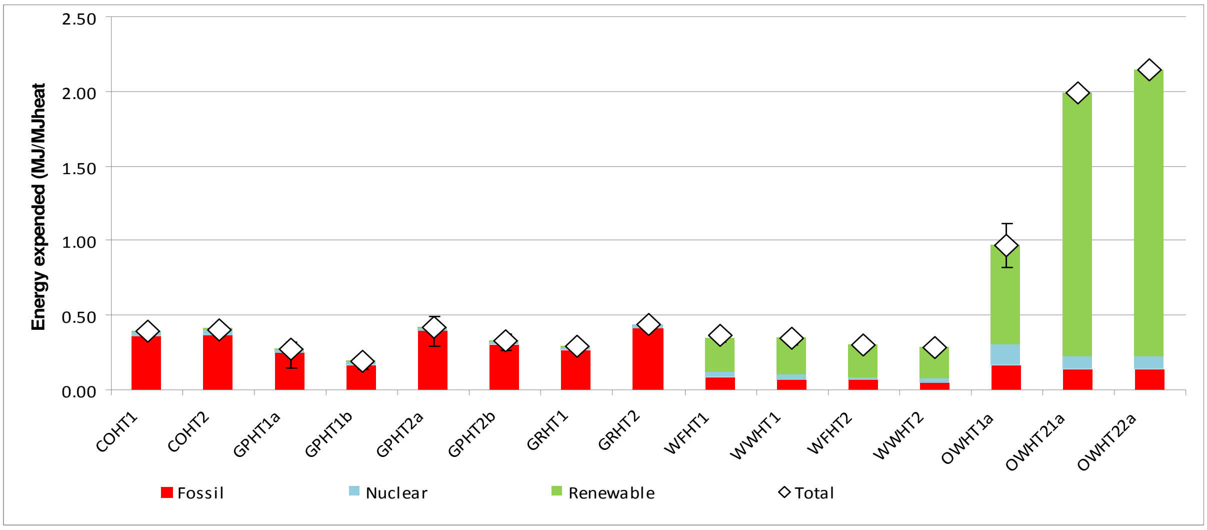
The benefits of combined heat and power (CHP) are well known, and whether the primary product is heat or electricity, efficiency gains are possible if both can be produced together and any surplus exported and put to good use. A number of pathways have been included for comparative purposes. These describe 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.

4.8.3.1 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.

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. The energy figures show both the total fuel energy input and the proportion derived from fossil sources. For NG, the domestic boiler is more efficient than the industrial boiler, because households can use lower temperatures and so less heat is wasted, although the difference is not large.

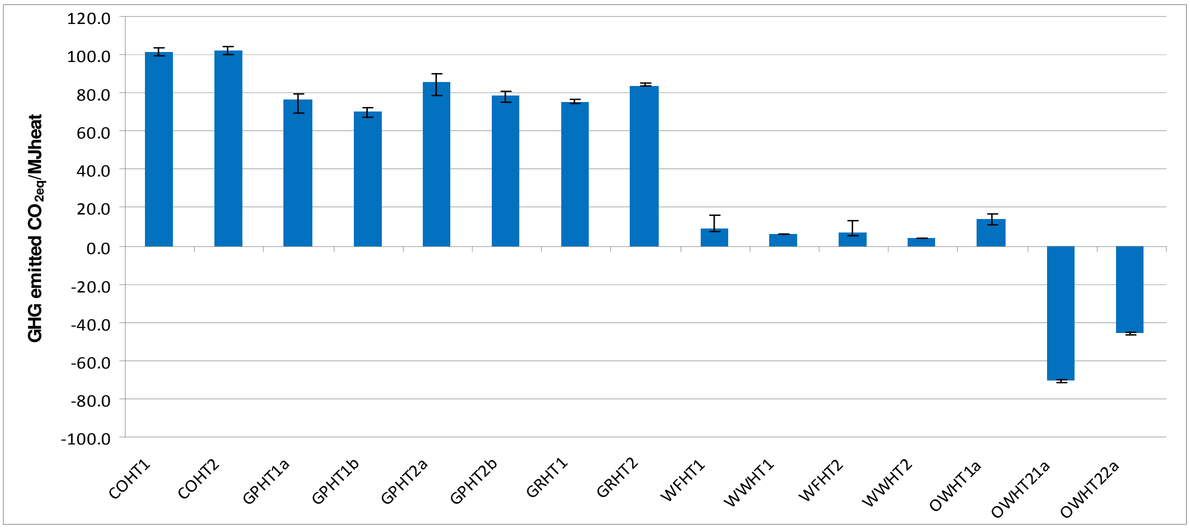
Figure 4.8.3-1: Energy balance of fossil heat pathways



Key to Heat pathway codes

COHT1	Diesel, small scale domestic boiler
COHT2	Diesel, large scale industrial boiler
GPHT1a	NG, pipe 7000 km, small scale domestic boiler
GPHT1b	NG, pipe 4000 km, small scale domestic boiler
GPHT2a	NG, pipe 7000 km, large scale industrial boiler
GPHT2b	NG, pipe 4000 km, large scale industrial boiler
GRHT1	LNG, small scale domestic boiler
GRHT2	LNG, large scale industrial boiler
WFHT1	Wood (farmed), small scale domestic boiler
WWHT1	Wood (waste), small scale domestic boiler
WFHT2	Wood (farmed), large scale industrial boiler
WWHT2	Wood (waste), large scale industrial boiler
OWHT1a	Municipal waste (closed digestate storage), biogas, small scale domestic boiler
OWHT21a	Manure (closed digestate storage), biogas, small scale domestic boiler
OWHT22a	Manure (open digestate storage), biogas, small scale domestic boiler

Figure 4.8.3-2: GHG balance of fossil heat pathways



The energy efficiency for heat production in a steam boiler ranges from 69% to 84%. The process is much the same for all the fuels considered, with pipelined NG giving the best efficiencies. For biogas, as with other pathways based on wet manure, large amounts of total energy are consumed, but the fossil inputs are modest. The GHG emissions are negative because large emissions of methane from the raw manure are avoided in the process. Collecting liquid manure and using it for biogas production in itself prevents some GHG emissions to the atmosphere. This is essentially the result of bad farming practices which should be avoided in any case.

4.8.3.2 CHP Pathways

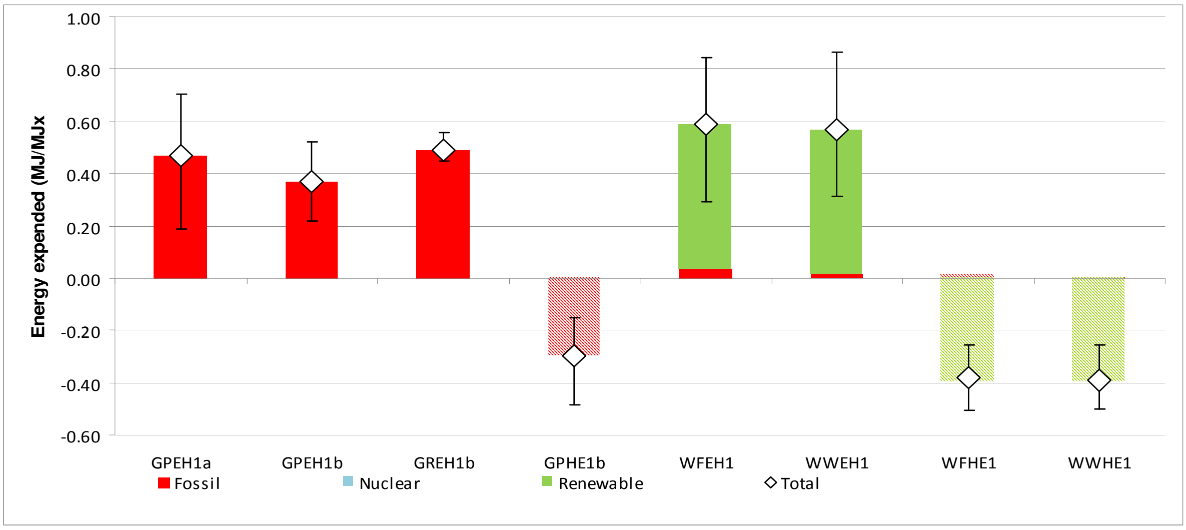
If we exclude special situations like black liquor and wind energy, the most energy efficient power generation available today is a gas-fired CCGT with an efficiency of 58%. Even in this case, 42% of the fuel energy is being converted into heat which is usually lost. For smaller power generation schemes the efficiency will be lower, for example for a biomass-fuelled stream turbine generator we use a figure of 32% and the amount of heat available is correspondingly greater.

It is something of a truism to say that energy savings can be made if this heat can be productively used - the combined efficiency of electricity and heat generation can reach 90%: the challenge is to find applications where the heat can be usefully employed. Many of the pathways evaluated in this study do use both electricity and heat and present good opportunities to apply CHP. For example, ethanol production requires large amounts of heat to distil and dry the ethanol, so CHP is attractive, particularly where surplus electricity can be exported to the grid and thus generate a credit.

There may also be situations where there is a demand for electricity and an opportunity for savings by using or exporting surplus heat. However, heat export depends on having a convenient neighbouring recipient, and this is not always the case. We have generally therefore restricted credits for heat to cases where it can be used in the process and hence avoid energy imports for separate heat generation.

Energy and GHG balances for the CHP schemes considered here are presented in ***Figures 4.8.3-3/4***.

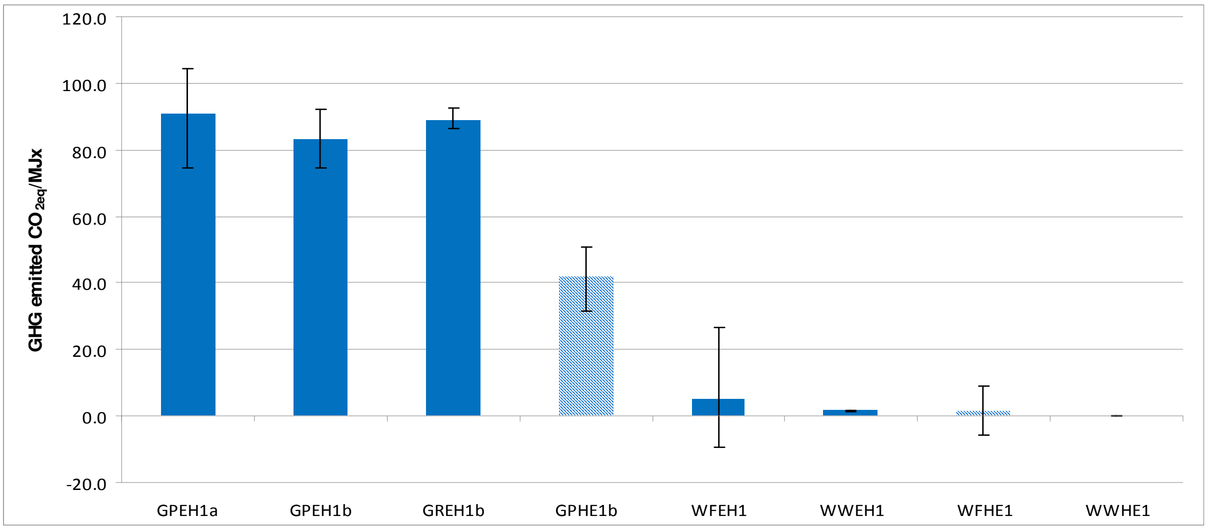
Figure 4.8.3-3: Energy balance for CHP pathways



Key to CHP pathway codes

GPEH1a	NG, pipe 7000 km, CHP, elec as primary product
GPEH1b	NG, pipe 4000 km, CHP, elec as primary product
GREH1b	LNG, CHP, elec as primary product
GPHE1b	NG, pipe 4000 km, CHP, heat as primary product
WFEH1	Wood (farmed), CHP, elec as primary product
WWEH1	Wood (waste), CHP, elec as primary product
WFHE1	Wood (farmed), CHP, heat as primary product
WWHE1	Wood (waste), CHP, heat as primary product

Figure 4.8.3-4: GHG balance for CHP pathways



The NG processes represent a large scale gas-fired CHP plant. Electricity is generated directly by the natural gas-fired gas turbine while steam raised from the flue gases generates extra electricity through back-pressure steam turbines. The electrical efficiency will be lower than a CCGT using a condensing steam turbine, because in this case medium pressure steam is recovered as a source of heat. The overall thermal efficiency is 90%.

In GxEH electricity is the primary product and surplus heat is assumed to be exported, substituting heat generated by a standard natural gas boiler. In GxHT pathways (shown by hatched bars) heat is the primary product and is assumed to be used in a district heating scheme. The electricity surplus substitutes electricity generated by a state-of-the-art gas-fired CCGT.

Export credits are calculated on primary energy and so the credits per MJ are greatest where the alternative production pathway is least efficient. The electricity generating efficiency for the NG CCGT is 58%, while a NG-fuelled steam boiler can reach 90% efficiency. Overall energy and GHG balances are therefore most favourable for schemes where heat is the primary product, where these can be achieved.

The vertical graph axes are based on the primary fuel, i.e. per MJ electricity for the solid bars, per MJ heat for the hatched bars.

4.9 Hydrogen

The hydrogen figures have not yet been updated in this version 4 of the study. For this reason, the text from the previous version 3c has been retained for reference.

Note: The description of CCS in hydrogen production has been moved from section 3.6 to the end of section 4.9 for consistency with the rest of this report

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, section 3.3 for coal and section 3.4 for biomass.*

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

Figure 4.9.1a: Compressed hydrogen pathways

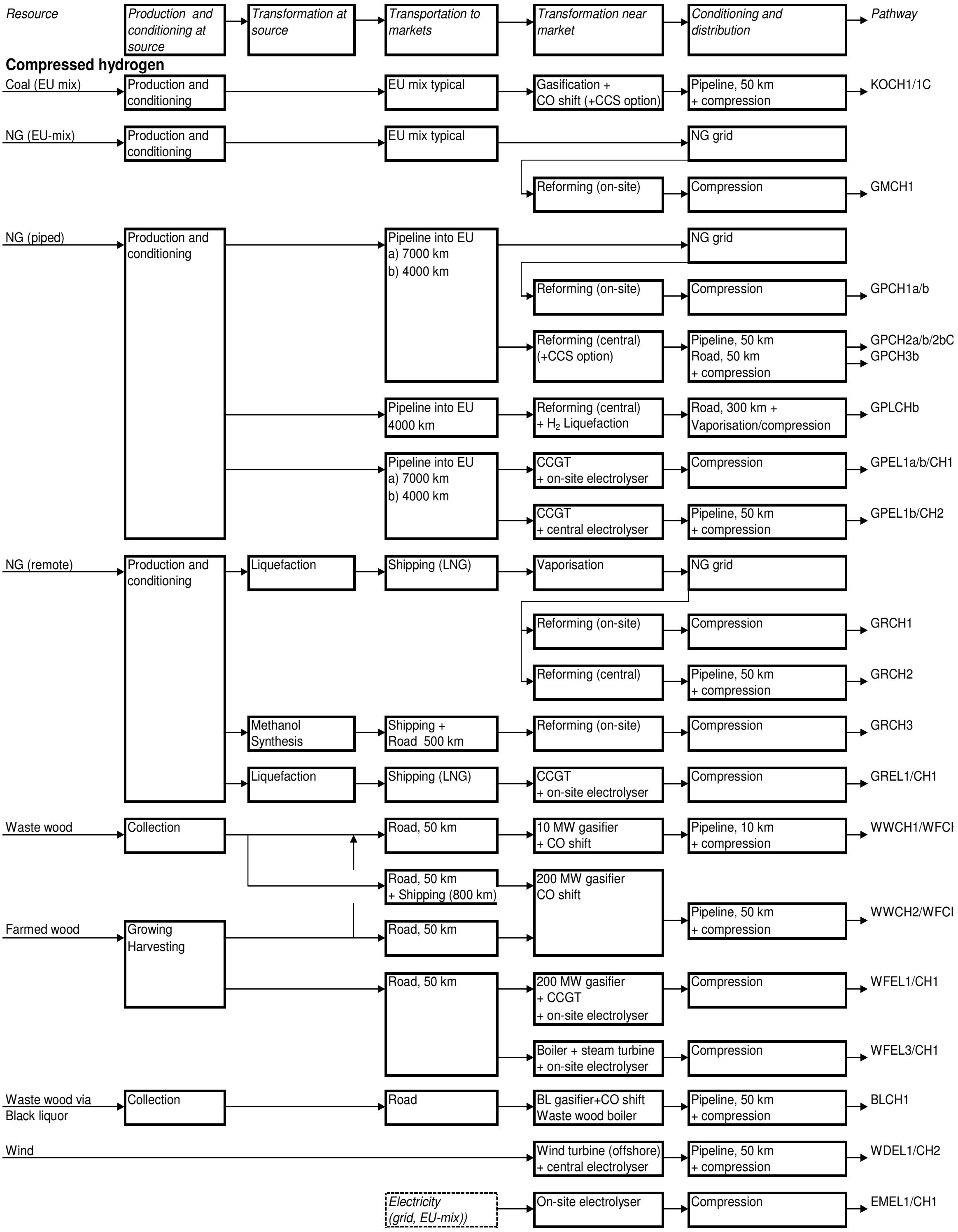
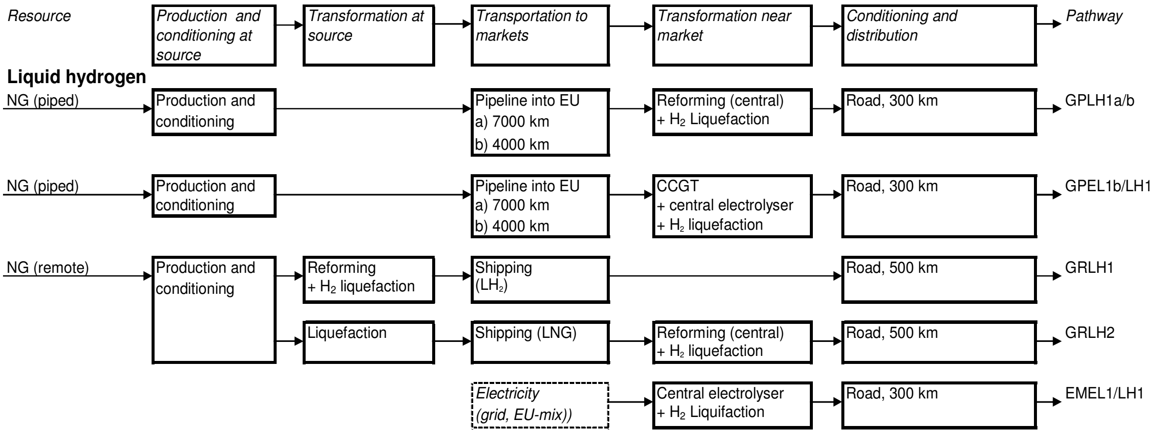


Figure 4.9.1b: Liquid hydrogen pathways



4.9.2 Hydrogen from NG energy and GHG balance

4.9.2.1 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

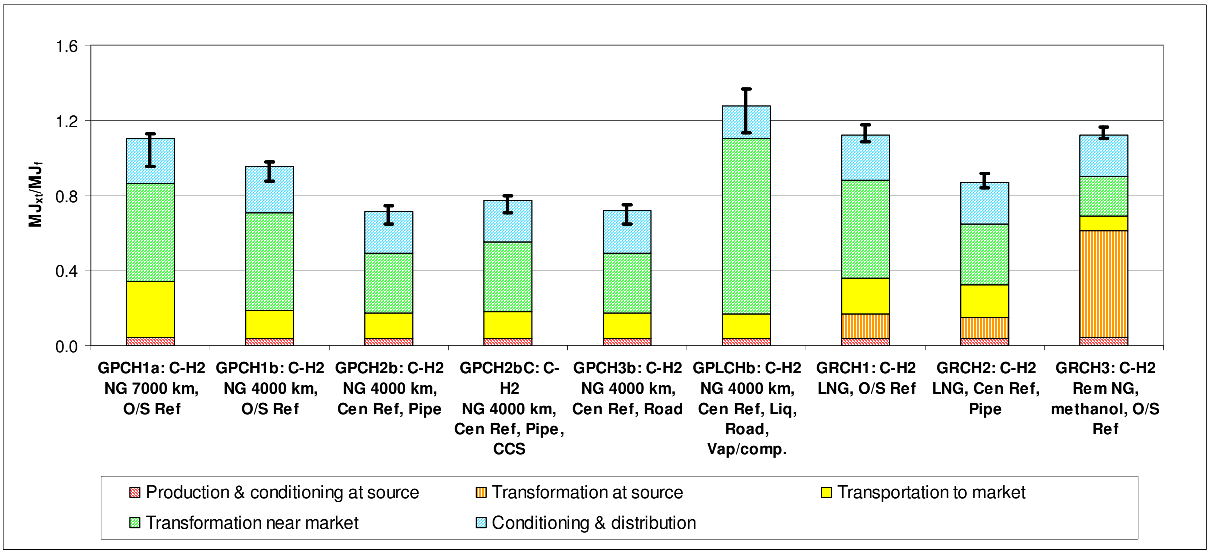
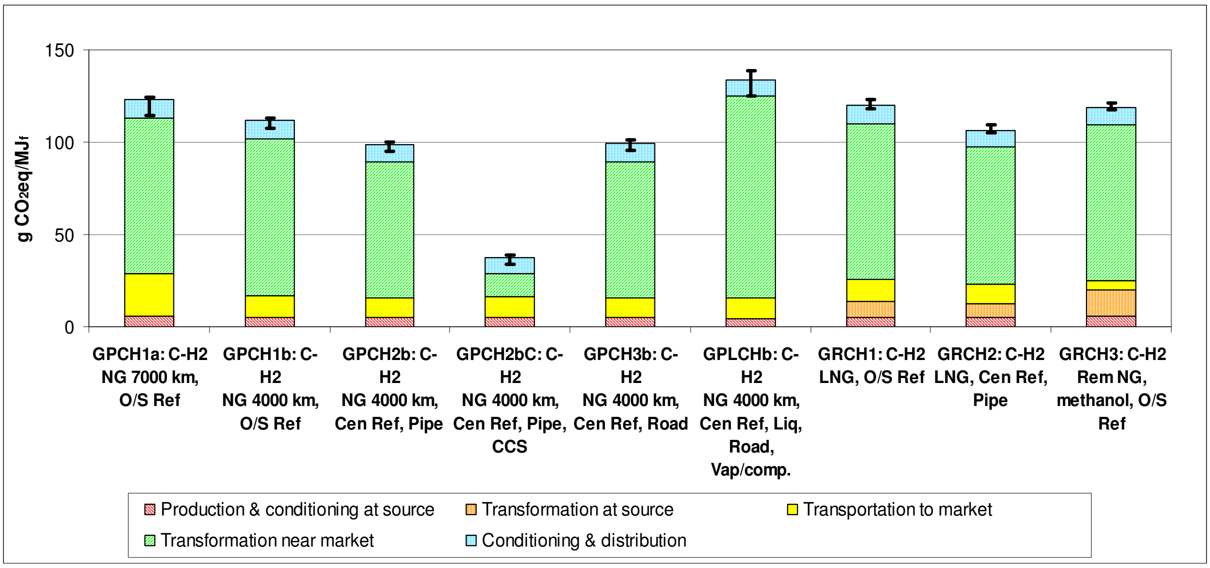


Figure 4.9.2-2: WTT GHG balance of selected NG to compressed hydrogen pathways



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.

4.9.2.2 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

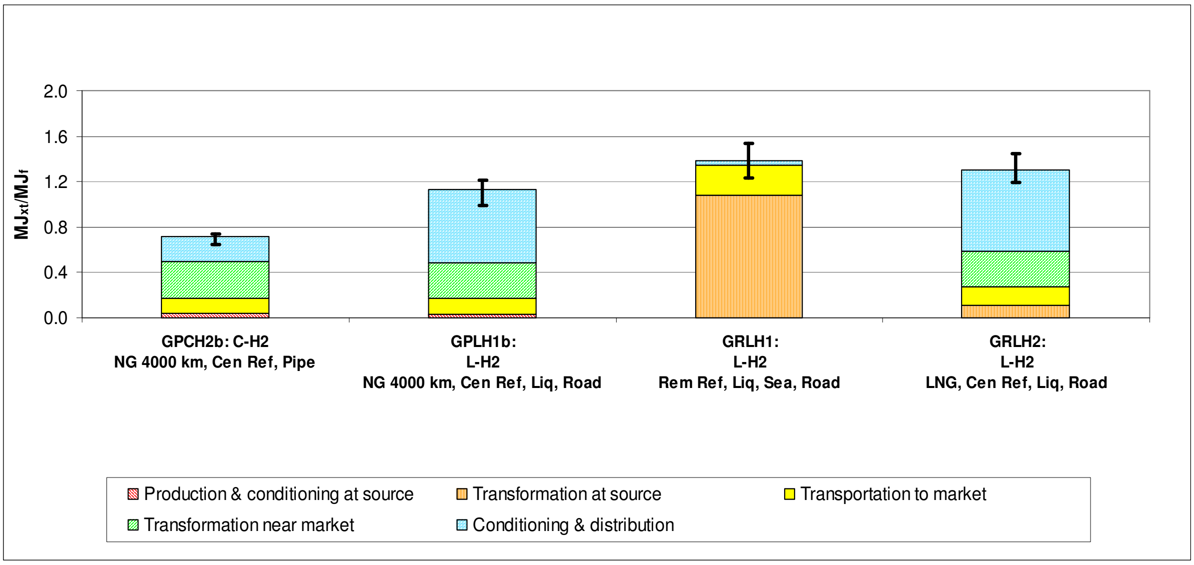
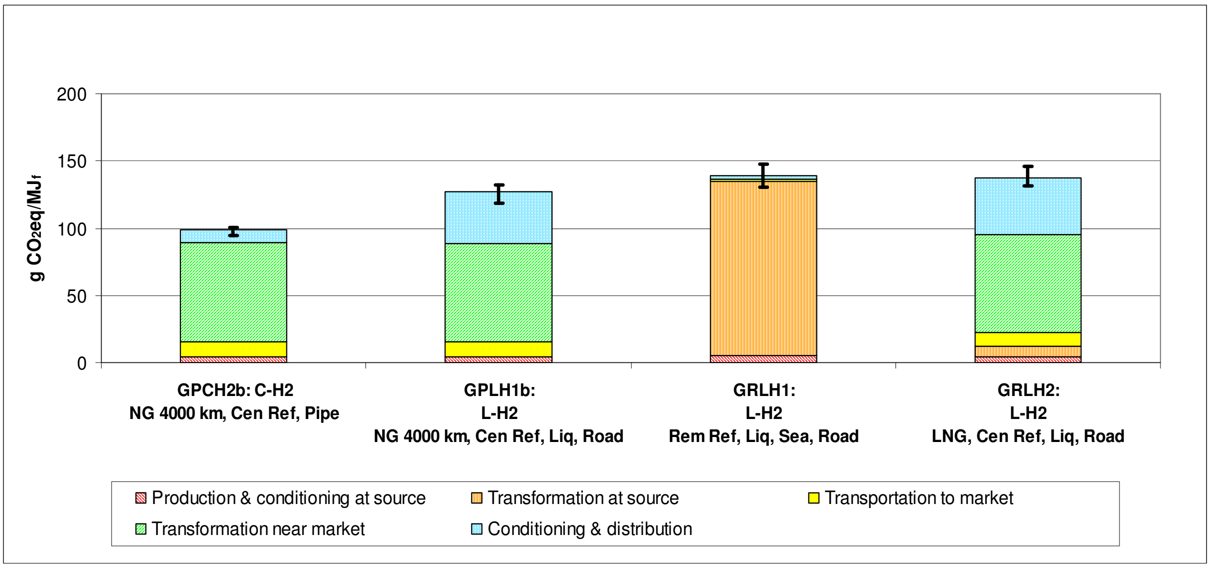


Figure 4.9.2-4: GHG balance of selected NG to liquid hydrogen pathways



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

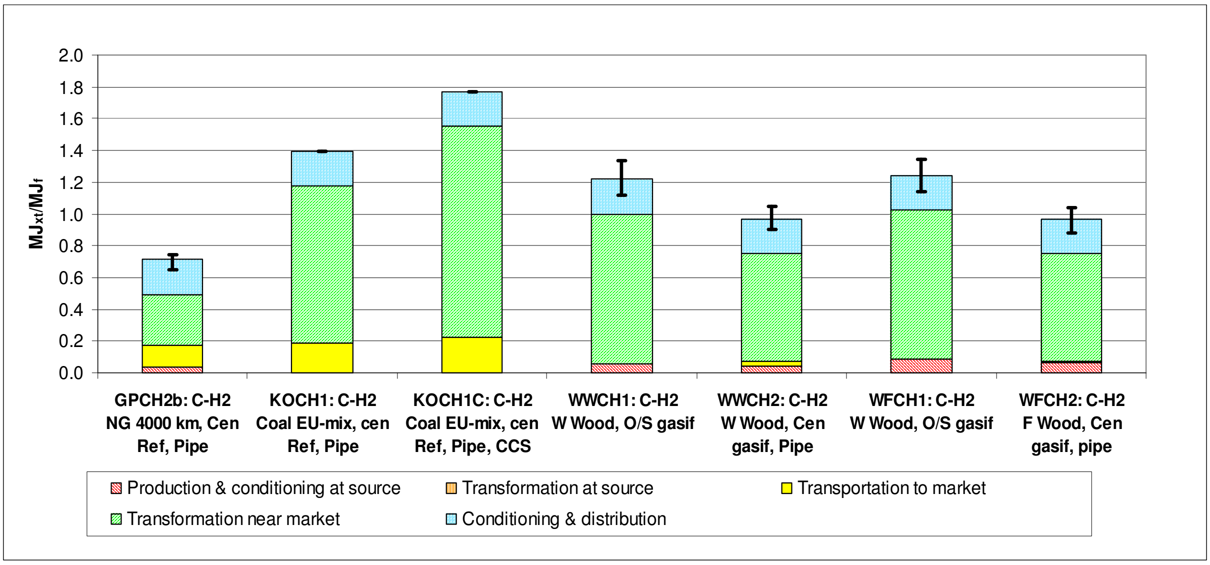
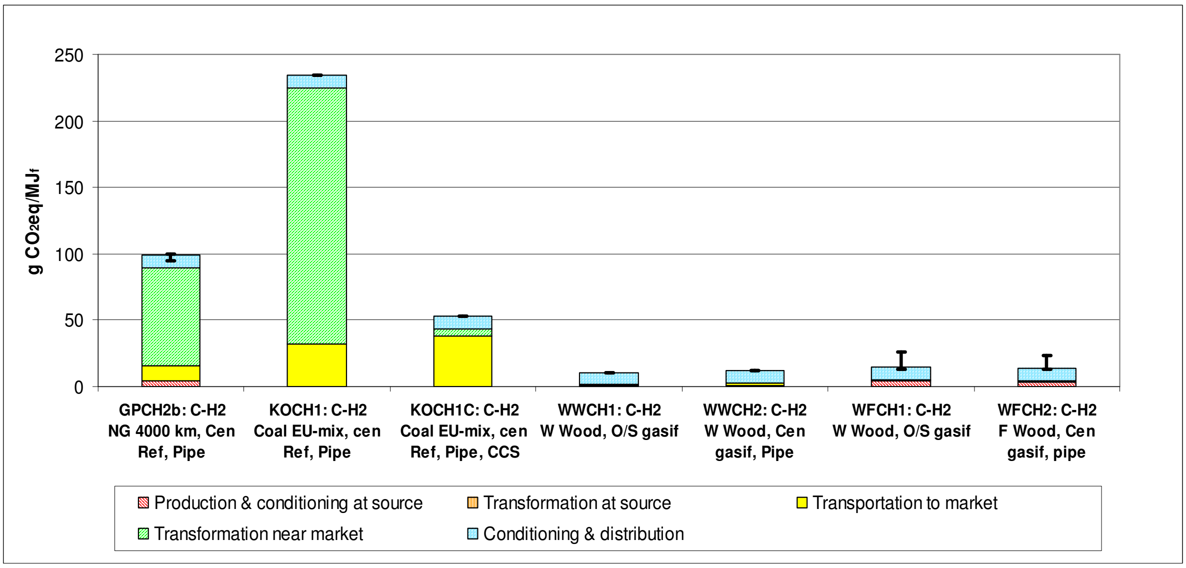


Figure 4.9.3-2: GHG balance of coal and wood to compressed hydrogen pathways



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

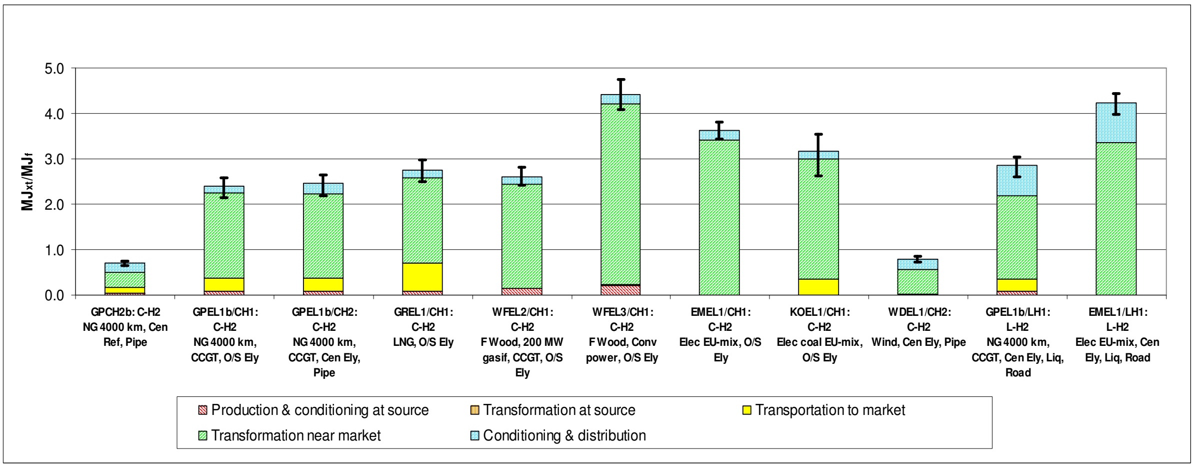
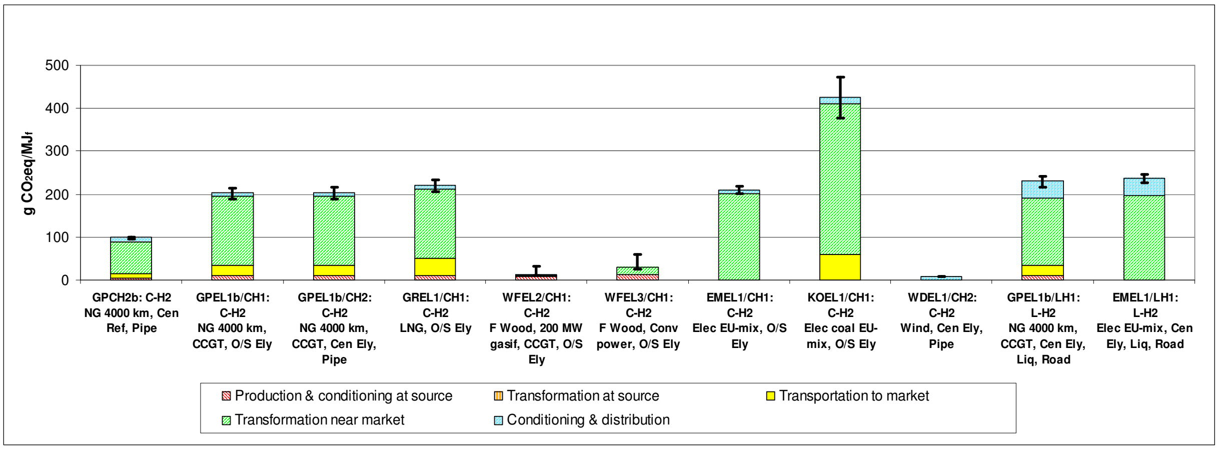


Figure 4.9.4-2: GHG balance of selected electrolysis pathways



Comparison of the straightforward NG to hydrogen pathway (GPCH1b, 112gCO_{2eq}/MJ_f) with the comparable electrolysis 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.

4.9.5 CCS in hydrogen production from gas or coal

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. 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.

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

Table 4.9.1: Hydrogen production with/without CCS

Feedstock		Natural gas		Coal	
Case		Base	with CCS	Base	with CCS
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}/MJ 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.

5 Acronyms and abbreviations used in the WTT study

API	American Petroleum Institute
BCL	Battelle Columbus Laboratory (biomass gasifier)
BCM	Billion Cubic Meters
BLGMF	Black Liquor Gasification to Motor Fuel
BTL	Biomass-To-Liquids: denotes processes to convert biomass to synthetic liquid fuels, primarily diesel fuel
C3/C4	Propane/Butane
CAP	Common Agricultural Policy (of the European Union)
CBG	Compressed Biogas
CCGT	Combined Cycle Gas Turbine
CCS	CO_2 Capture and Storage
C/H	Carbon/Hydrogen (ratio)
CH_4	Methane
CH_2	Compressed Hydrogen
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_{2eq}	CO_2 equivalent
CONCAWE	The oil companies’ European association for environment, health and safety in refining and distribution
CTL	Coal-To-Liquids
DDGS	Distiller’s Dried Grain with Solubles: the residue left after production of ethanol from wheat grain
DG-AGRI	EU Commission's Directorate-General for Agriculture
DG-TREN	EU Commission's former Directorate-General for Transport and Energy
DLUC	Direct Land Use Change
DM2 type	Dr Muehlen GmbH & Co KG (gasifier unit)
DME	Di-Methyl-Ether
ETBE	Ethyl-Tertiary-Butyl Ether
ETS	Emissions Trading Scheme
EU	European Union
EU15/EU25/EU27	European Union of 15, 25, or 27 Member States
EUCAR	European Council for Automotive R&D
EU-mix	European average composition of a certain resource or fuel, typically used to describe natural gas, coal and electricity
F&V	Flaring and Venting (emissions)
FAEE	Fatty Acid Ethyl Ester
FAME	Fatty Acid Methyl Ester
FAPRI	Food and Agriculture Policy Research Institute (USA)
FFB	Fresh Fruit Bunch

FQD	Fuel Quality Directive (2009/28/EC)
FSU	Former Soviet Union
FT	Fischer-Tropsch: process that converts syngas to linear hydrocarbons
GDP	Gross Domestic Product
GEMIS	Global Emissions Model for Integrated Systems
GHG	Greenhouse Gas
GIS	Geographic Information System
GJ	Gigajoule
GMO	Genetically Modified Organism
GNOC	Global crop and site specific Nitrous Oxide emission Calculator
GTL	Gas-To-Liquids
HC	Hydrocarbons (as a regulated pollutant)
HFO	Heavy Fuel Oil
HRSG	Heat Recovery Steam Generator
HTU	Hydrothermal Upgrading (process unit)
HVO	Hydrogenated (or Hydrotreated) Vegetable Oils (and animal fats)
IEA	International Energy Agency
IES	Institute for Environment and Sustainability (JRC)
IFA	International Fertilizer Association
IGCC	Integrated Gasification and Combined Cycle
ILUC	Indirect Land Use Change
IPCC	Intergovernmental Panel for Climate Change
JEC	JRC, EUCAR, and CONCAWE
JRC	Joint Research Centre (of the European Commission)
LBST	Ludwig-Bölkow-Systemtechnik GmbH
LC	Lignocellulose
LCA	Life Cycle Analysis
LCFS	Low Carbon Fuel Standard (California)
LH_2	Liquid (or Liquefied) Hydrogen
LHV	Lower Heating Value (‘Lower” indicates that the heat of condensation of water is not included)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LUC	Land Use Change
LUCAS	Land Use/Cover Area Survey
MDEA	Methyl Di-Ethanol Amine
ME	Middle East
MJ	Megajoule
MTBE	Methyl-Tertiary-Butyl Ether
MON	Motor Octane Number

MPa	Mega Pascal, unit of pressure (1MPa = 10bar). Unless otherwise stated pressure figures are expressed as "gauge", i.e. over and above atmospheric pressure
MPOB	Malaysian Palm Oil Board
M_{toe}	Million tonnes oil equivalent. The “oil equivalent” is a notional fuel with a LHV of 42 GJ/t
MW	Megawatt
N	Nitrogen
N_2O	Nitrous oxide
NA	North America
NG	Natural Gas
NGO	Non-Governmental Organisation
NExBTL®	Proprietary technology for producing renewable diesel (Neste Oil)
NH_3/NH_4^+	Ammonia/Ammonium (cation)
NOAA	National Oceanic and Atmospheric Administration (USA)
NO_x	Nitrogen oxides emitted from vehicles and combustion sources
NO_3^-	Nitrate (anion)
NREL	National Renewable Energy Laboratory (USA)
OECD	Organisation for Economic Co-operation and Development
OGP	Oil & Gas Producers (Association)
pH	Measure of acidity
PJ	Petajoule
PKO	Palm Kernel Oil
PO	Palm Oil
POME	Palm Oil Methyl Ester
PSA	Pressure Swing Absorption (unit)
PWC	PriceWaterhouseCoopers
RED	Renewable Energy Directive (2009/30/EC)
REE	Rapeseed Ethyl Ester
RFS	Renewable Fuel Standard (USA)
RME	Rapeseed Methyl Ester: biodiesel derived from rapeseed oil (colza)
SA	South America
SMDS	Shell Middle Distillate Synthesis (process)
SME	Sunflower Methyl Ester: biodiesel derived from sunflower oil
SOC	Soil Organic Carbon
SRF	Short Rotation Forestry
SSCF	Simultaneous Saccharification and Co-Fermentation: a process for converting cellulosic material to ethanol
Syngas	A mixture of carbon monoxide and hydrogen produced by gasification or steam reforming of various feedstocks
TES	Transport Energy Strategy, a German consortium that worked on alternative fuels, especially hydrogen
TTW	Tank-to-Wheels: description of the burning of a fuel in a vehicle
ULCC	Ultra Large Crude Carrier

UOP	A Honeywell Company, formerly known as Universal Oil Products LLC
VLCC	Very Large Crude Carrier
WEO	World Energy Outlook
WI	Wobbe Index
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

6 Summary of WTT pathways codes and description

Code	*Short description*	*Details*
Conventional fuels		
COG1	Gasoline	Conventional fossil gasoline
COD1	Diesel	Conventional fossil diesel fuel
LRLP1	LPG (remote)	LPG imported from remote gas field
Compressed Natural Gas		
GMCG1	EU-mix	CNG from EU-mix NG supply
GPCG1a	Pipeline 7000 km	CNG from imported NG 7000 km (typically Russia)
GPCG1b	Pipeline 4000 km	CNG from imported NG 4000 km (typically Middle East)
GRCG1	LNG, vap, pipe	CNG from remote LNG, vaporisation at import terminal
GRCG1C	LNG+CCS, vap, pipe	NG from remote LNG + CCS at liquefaction plant, vaporisation at import terminal
GRCG2	LNG, road, vap	CNG from remote LNG, vaporisation at retail point
GRLG1	LNG, road	Remote LNG, use as LNG in vehicle
SGCG1	Shale gas (EU)	CNG from shale gas produced in EU
Compressed Biogas and synthetic methane		
OWCG1	Municipal waste	Upgraded biogas from municipal organic waste as CBG, Closed digestate storage
OWCG2	Liquid manure	Upgraded biogas from wet manure as CBG, Digestate storage closed (21) or open (22)
OWCG4	Maize (whole plant)	Upgraded biogas from maize (whole plant) as CBG, Closed digestate storage
OWCG5	Barley/maize (double cropping) whole plant	Upgraded biogas from double cropping (barley/maize) as CBG, Closed digestate storage
RECG1	Synthetic methane	CNG from synthetic methane from renewable electricity and CO_2 from flue gases
Ethanol		
SBET1a	Sugar beet, pulp to AF, slops not used	EU sugar beet to ethanol, Pulp to animal feed, Slops not used.
SBET1b	Sugar beet, pulp to AF, slops to biogas	EU sugar beet to ethanol, Pulp to animal feed, Slops used as feed for biogas
SBET1c	Sugar beet, pulp to fuel, slops to biogas	EU sugar beet to ethanol, Pulp used as fuel, Slops used as feed for biogas
WTET1a	Wheat, conv NG boiler, DDGS as AF	EU wheat to ethanol, Production heat provided by NG-fired boiler and electricity from grid, 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	EU wheat to ethanol, Production energy provided by a NG-fired CHP plant, DDGS to animal feed
WTET2b	Wheat, NG GT+CHP, DDGS as fuel	As above but DDGS used as fuel
WTET3a	Wheat, Lignite CHP, DDGS as AF	EU wheat to ethanol, Production energy provided by a lignite-fired CHP plant, DDGS to animal feed.
WTET3b	Wheat, Lignite CHP, DDGS as fuel	As above but DDGS used as fuel.
WTET4a	Wheat, Straw CHP, DDGS as AF	EU wheat to ethanol, Production energy provided by a wood-fired CHP plant, DDGS to animal feed.
WTET4b	Wheat, Straw CHP, DDGS as fuel	As above but DDGS used as fuel.
WTET5	Wheat, DDGS to biogas	EU wheat to ethanol. DDGS used as internal fuel to produce electricity via biogas.
BRET2	Barley/Rye, NG GT+CHP, DDGS as AF	50/50 mix EU barley/rye grain to ethanol, Production energy provided by a NG-fired CHP plant, DDGS to animal feed.
CRET2	Maize, NG GT+CHP, DDGS as AF	Maize (average used in EU) to ethanol, Production energy provided by a NG-fired CHP plant, DDGS to animal feed.
CRETus	Corn US, DDGS as AF	Corn (USA) to ethanol, Import into EU, Typical US production conditions, DDGS as animal feed
WWET1	W Wood	Ethanol from waste wood
WFET1	F wood	Ethanol from farmed wood
STET1	Wheat straw	Ethanol from wheat straw
SCET1	Sugar cane (Brazil)	Brazilian sugar cane to ethanol. Excess bagasse used for electricity production

Code	*Short description*	*Details*
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 from wheat ethanol (WTET2b) and isobutene.
Bio-diesel		
ROFA1	RME: Meal as AF, glycerine as chem,	Rapeseed to biodiesel (Rapeseed Methylester), Meal export (animal feed), Glycerine export to chemical
ROFA2	RME: Meal and glycerine as AF	Rapeseed to biodiesel (Rapeseed Methylester), Meal export (animal feed), Glycerine to animal feed
ROFA3	RME: Meal as AF, glycerine to biogas	Rapeseed to biodiesel (Rapeseed Methylester), Meal export (animal feed), Glycerine to internal biogas
ROFA4	RME: Meal and glycerine to biogas	Rapeseed to biodiesel (Rapeseed Methylester) ,Meal to internal biogas, Glycerine to internal biogas
ROFA5	RME: Meal as AF, Glycerine to hydrogen	Rapeseed to biodiesel (Rapeseed Methylester), Meal export (animal feed), Glycerine to hydrogen
ROFE3	REE: Meal as AF, glycerine to biogas	Rapeseed to biodiesel (Rapeseed Ethylester) Ethanol via WTET2b, Meal export (animal feed), Glycerine to internal biogas
SOFA3	RME: Meal as AF, glycerine to biogas	Sunflower to biodiesel (Sunflower seed Methylester), Meal export (animal feed), Glycerine to internal biogas
SYFA3a	SYME: No till, oil import, meal as AF, glycerine to biogas	Soy beans to biodiesel (Soy Methylester), No till, Oil imported into EU, Meal export (animal feed), Glycerine to internal biogas
SYFA3b	SYME: No till, beans import, meal as AF, glycerine to biogas	Soy beans to biodiesel (Soy Methylester), No till, beans imported into EU, Meal export (animal feed), Glycerine to internal biogas
SYFA3c	SYME: Conv. culture, oil import, meal as AF, glycerine to biogas	Soy beans to biodiesel (Soy Methylester), Conventional culture, Oil imported into EU, Meal to animal feed), Glycerine to internal biogas
POFA3a	POME: Meal as AF, no CH4 rec., heat credit, glycerine to biogas	Palm oil to biodiesel (Palm oil Methylester), Meal export (animal feed), No CH4 emissions recovery, heat credit (oil mill), glycerine to internal biogas
POFA3b	POME: Meal as AF, CH4 rec., heat credit, glycerine to biogas	Palm oil to biodiesel (Palm oil Methylester), Meal export (animal feed), CH4 emissions recovery, heat credit (oil mill), glycerine to internal biogas
POFA3c	POME: Meal as AF, no CH4 rec., no heat credit, glycerine to biogas	Palm oil to biodiesel (Palm oil Methylester), Meal export (animal feed), No CH4 emissions recovery, No heat credit (oil mill), glycerine to internal biogas
WOFA3	FAME: waste cooking oil	Waste cooking oil to biodiesel, Glycerine to internal biogas
TOFA3	FAME: tallow oil	Tallow oil to biodiesel, Glycerine to internal biogas
Hydrotreated plant oil		
ROHY1a	HRO (NExBTL), meal as AF	Hydrotreated rape oil (NExBTL process), Meal export (animal feed)
ROHY1b	HRO (UOP), meal as AF	Hydrotreated rape oil (UOP process), Meal export (animal feed)
ROHY4	HRO (NExBTL), meal to biogas	Hydrotreated rape oil (NExBTL process), Meal to internal biogas
SOHY1a	HSO (NExBTL), meal as AF	Hydrotreated sunflower oil (NExBTL process), Meal export (animal feed)
SYHY1a	HSO (NExBTL), oil imported	Hydrotreated soy beans, no till, oil EU import, NExBTL
POHY1a	HPO (NExBTL), no CH4 rec.	Hydrotreated palm oil (NExBTL process), No CH4 emissions recovery
WOHY1a	HWO (NExBTL), waste cooking oil	Hydrotreated waste cooking oil (NExBTL process)
TOHY1a	HTO (NExBTL), tallow oil	Hydrotreated tallow oil (NExBTL process)

Code	*Short description*	*Details*
Synthetic diesel		
GRSD1	Rem GTL, diesel pool	Remote NG to Syndiesel (GTL): GTL plant near remote gas field, Syndiesel imported into Europe and incorporated into diesel pool.
GRSD1C	Rem GTL+CCS, diesel pool	Remote natural gas to Syndiesel (GTL): GTL plant near remote gas field with CCS, Syndiesel imported into Europe and incorporated into diesel pool.
KOSD1	CTL, diesel pool	Synthetic diesel from (hard) coal (EU supply mix) in EU plant, incorporated into diesel pool.
KOSD1C	CTL, CCS, diesel pool	Synthetic diesel from (hard) coal (EU supply mix) in EU plant with CCS, incorporated into diesel pool.
WFSD1	F wood, diesel pool	Synthetic diesel from farmed wood in EU plant, incorporated into diesel pool.
WWSD2	W Wood via black liquor, diesel pool	Synthetic diesel from waste wood in EU paper mill (black Liquor route) , incorporated into diesel pool.
RESD1	Renewable electricity, diesel pool	Renewable electricity to Syndiesel via methanol (CO_2 from flue gases)
Methanol / DME (Di-Methyl-Ether)		
GPME/DE1b	NG 4000 km, EU prod., rail/road	Methanol/DME from NG piped over 4000 km, distributed by rail + road
GRME/DE1	Rem prod., sea/ rail/road	Methanol/DME produced remotely from NG, transported by sea, distributed by rail + road
GRDE1C	Rem prod. with CCS, Sea, Rail/Road	DME produced remotely from NG with CCS, transported by sea, distributed by rail + road
KOME/DE1	Coal EU-mix, EU prod., rail/road	Methanol/DME from (hard) coal (EU supply mix), large plant in EU, distributed by rail + road
WFME/DE1	F Wood, road	Methanol/DME from farmed wood, distributed by road
WWME/DE2	W Wood via black liquor, road	Methanol/DME from waste wood in EU paper mill (Black Liquor route), distributed by road

Code	*Short description*	*Details*
Electricity		
EMEL1	EU-mix high	Electricity from average EU supply. High voltage
EMEL2	EU-mix medium	Electricity from average EU supply. Medium voltage
EMEL3	EU-mix low	Electricity from average EU supply. Low voltage
FOEL1	HFO	Electricity from heavy fuel oil (HFO), Conventional power plant (state-of-the-art)
KOEL1	EU-mix Coal conv.	Electricity from (hard) coal (EU supply mix), Conventional power plant (state-of-the-art)
KOEL2	EU-mix Coal IGCC	Electricity from (hard) coal (EU supply mix), IGCC
KOEL2C	EU-mix Coal IGCC+CCS	Electricity from (hard) coal (EU supply mix), IGCC with CCS
GPEL1a	NG 7000 km, CCGT	Electricity from NG piped over 7000 km, Combined Cycle Gas Turbine
GPEL1b	NG 4000 km, CCGT	Electricity from NG piped over 4000 km, Combined Cycle Gas Turbine
GPEL1bC	NG 4000 km, CCGT+CCS	Electricity from NG piped over 4000 km, Combined Cycle Gas Turbine with CCS
GREL1	LNG, CCGT	Electricity from imported LNG, Combined Cycle Gas Turbine
OWEL1a	Biogas ex municipal waste, local	Electricity from biogas plant ex municipal waste, Gas engine
OWEL1b	Biogas ex municipal waste, large power plant	Electricity from biogas plant ex municipal waste, injected in grid and used in large gas power plant (CCGT)
OWEL2xa	Biogas ex wet manure, local	Electricity from small scale biogas plant ex wet manure , Gas engine, Digestate storage closed (21a) or open (22a)
OWEL2xb	Biogas ex wet manure, large power plant	Electricity from small scale biogas plant ex wet manure, injected in grid and used in large power plant, Digestate storage closed (21b) or open (22b)
WFEL1	F Wood, 200 MW gasif	Electricity from farmed wood , Large scale gasifier + Combined Cycle Gas Turbine
WFEL2	F Wood, 10 MW gasif	Electricity from farmed wood , Small scale gasifier + gas turbine
WFEL3	F Wood, Conv power	Electricity from farmed wood , Small scale conventional power plant
WFEL4	F Wood, co-firing coal plant	Electricity from farmed wood , Co-firing in conventional coal power plant
WWEL1	W Wood, 200 MW gasif	Electricity from waste wood , Large scale gasifier + Combined Cycle Gas Turbine
WWEL2	W Wood, 10 MW gasif	Electricity from waste wood , Small scale gasifier + gas turbine
WWEL3	W Wood, conv.	Electricity from waste wood , Small scale conventional power plant
WWEL4	W Wood, co-firing coal plant	Electricity from waste wood , Co-firing in conventional coal power plant
WWEL5	Wood via black liquor	Electricity from wood via black liquor IGCC
NUEL1	Nuclear	Electricity from nuclear plant
WDEL1	Wind offshore	Electricity from offshore wind farm

Code	*Short description*	*Details*
Heat		
COHT1/2	Diesel	Heat from fossil diesel-fired boiler. (1) small scale domestic boiler, (2) large scale industrial boiler
GPHT1a/b	NG (piped) small scale	Heat from piped gas 7000km (a) or 4000km (b) in small scale domestic boiler
GPHT2a/b	NG (piped) industrial	Heat from piped gas 7000km (a) or 4000km (b) in large scale industrial boiler
GRHT1/2	LNG	Heat from LNG in domestic (1) or industrial boiler (2)
OWHT1a	Biogas (Municipal waste)	Heat from biogas from municipal waste in gas boiler, closed digestate storage
OWHT2xa	Biogas (wet manure)	Heat from biogas from wet manure in gas boiler, Digestate storage closed (21a) or open (22a)
OWHT22a	Biogas	Heat from biogas from wet manure in gas boiler, open digestate storage
WFHT1/2	Farmed wood	Heat from farmed wood in domestic (1) or industrial boiler (2)
WWHT1/2	Waste wood	Heat from waste wood in domestic (1) or industrial boiler (2)
Combined Heat and Power		
GPEH1a/b	Elec: Piped gas, GT-CHP	Electricity from piped gas 7000/4000 km in GT-based CHP plant with credit for export surplus heat
GREH1	Elec: LNG, GT-CHP	Electricity from LNG in GT-based CHP plant with credit for export surplus heat
WWEH1	Elec: Waste wood, CHP	Electricity from waste wood in CHP plant with credit for export surplus heat
WFEH1	Elec: Farmed wood, CHP	Electricity from farmed wood in CHP plant with credit for export surplus heat
GPHE1b	Heat: Piped gas 4000km, CHP	Heat from piped gas 4000 km in CHP plan, with credit for exported electricity
WWHE1	Heat: Waste wood, CHP	Heat from waste wood in CHP plant with credit for exported electricity
WFHE1	Heat: Farmed wood, CHP	Heat from farmed wood in CHP plant with credit for exported electricity

Hydrogen pathways as per version 3c

These pathways have not been updated in this version 4a

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 CO2 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 CO2 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

Code	*Short description*	*Details*
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
Liquid hydrogen ***(not updated from version 3c)***		
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 ***(not updated from version 3c)***		
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

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Title: WELL-TO-TANK Version 4.0. JEC WELL-TO-WHEELS ANALYSIS

Author(s): Robert EDWARDS (JRC), Jean-François LARIVÉ (CONCAWE), David RICKEARD (CONCAWE), Werner WEINDORF (LBST)
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Abstract

The Well-to-Tank 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.

This Version 4.0 replaces Version 3.c [Report EUR 24952 EN] published in 2011

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