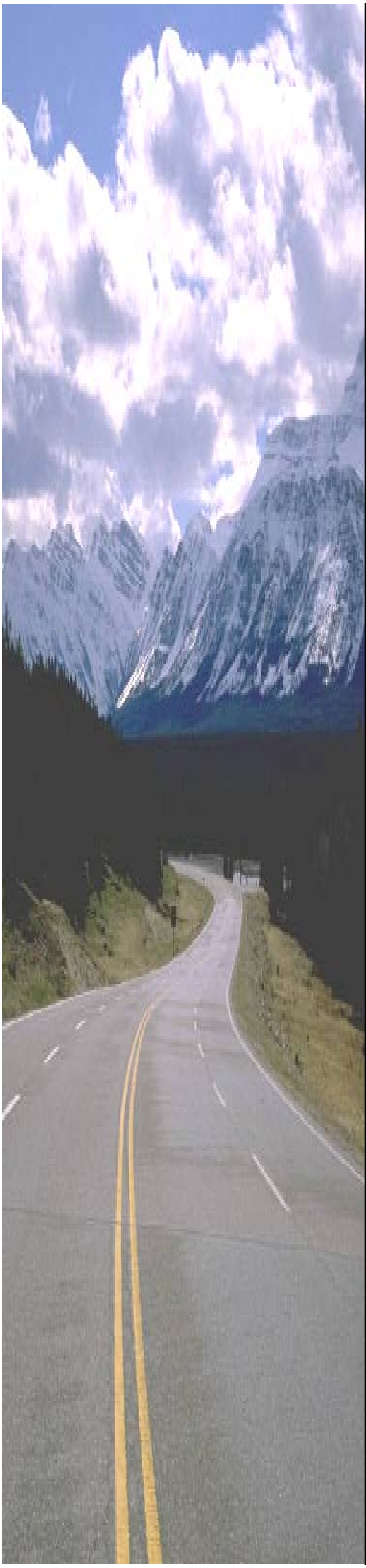

MARKET DEVELOPMENT OF ALTERNATIVE FUELS

Report of the Alternative Fuels Contact Group

December 2003

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EXECUTIVE SUMMARY

The European Commission, following the Communication on alternative fuels in 2001, set up a stakeholder **Contact Group** in 2002 to advise on technical and economic status and developments of alternative fuels for road transport, with priority on natural gas and hydrogen, and on measures by which the Community could promote their use. Topic Groups on natural gas and hydrogen, respectively, and a Working Group on Biomass-to-Liquid fuels deepened the assessment of these alternative fuels. The Contact Group published an Interim Report in March 2003, and now presents this comprehensive report, offering the basis for a more detailed strategy on these fuels.

A **well-to-wheels study** on greenhouse gas emissions, energy efficiency and cost of the use of alternative fuels in cars undertaken by a consortium consisting of organisations representing the European oil industry (CONCAWE), the European car manufacturers (EUCAR) and the Joint Research Centre of the European Commission (JRC, Ispra) accompanied the work of the Contact Group and forms an important basis for the assessments in this report. 75 different pathways from primary energy sources have been investigated. For the reference fuels gasoline and diesel, only technologies with the potential for mass market series production by 2010 were considered, while for alternative fuels also technologies with the potential for market entry by 2010 were accepted.

Natural gas as a motor vehicle fuel has a clear CO_2 advantage over gasoline and is comparable to diesel today. In future, the advantage of natural gas vehicles is expected to surpass diesel. With 2010 technology, natural gas vehicles are projected to have 16% lower CO_2 emissions compared with gasoline vehicles and 13% lower CO_2 emissions compared with diesel vehicles. The inherently lower greenhouse gas intensity of natural gas vehicles could be further exploited by optimised engine technology and new concepts for heavy-duty engines.

Natural gas vehicles today have advantages for local air quality, comparable to projected future improvements of emissions of diesel vehicles, in particular as regards particulate emissions.

A main driving force for the large-scale introduction of natural gas as motor fuel is concern for the security of supply for the transport sector currently solely dependent on oil products. The potential in market share of natural gas as a motor fuel would not be limited by primary supply to the 10% envisaged in the Alternative Fuels Communication for 2020.

Natural gas is the only alternative fuel with potential for significant market share well above 5% by 2020 which could potentially compete with conventional fuels in terms of the economics of supply in a mature market scenario. Expansion of the re-fuelling infrastructure and of captive fleets from ongoing programmes should minimise costs in the transition period. Natural gas could gain a broader market share if supported by long-term tax and excise duty advantages, providing stable conditions until a broad market has developed. Mature vehicle technology is available, but diversity of products and services still need to be improved. Further efforts in research and development should support additional improvements in the technology.

Substitution of gasoline or diesel with natural gas might become economically viable if done at a sufficiently large scale to ensure mass market benefits for vehicle production and infrastructure utilisation. In the early stages, fleet and local markets, such as urban transport, offer the potential for high utilisation of refuelling stations, providing the revenue to sustain further investment and expansion of the network. To the extent that natural gas substitutes diesel, this also relieves the refinery balance in Europe, already stretched by a surplus production of gasoline relative to diesel.

Codes and standards for the use of natural gas as motor vehicle fuel should be harmonised to support a broader commercialisation of natural gas vehicles at European level.

Hydrogen is a potential future main energy carrier. Due to its broad feedstock flexibility it could considerably broaden the energy supply base of the transport sector. Hydrogen offers the long-term potential for full reliance on renewables. The choice of production pathways will be essential to minimise GHG emissions and energy use. Research and technological development programmes should be intensified to provide the basis for decisions on possible routes to mass-market production of automotive systems as well as large scale hydrogen production after 2010. The share of hydrogen in road transport fuels could reach a few percent by 2020. Linking hydrogen and natural gas fuel infrastructures and technologies may support the introduction of hydrogen as fuel.

Internal combustion engines could provide fast track market penetration of hydrogen vehicles. Large market introduction of hydrogen ICE vehicles, however, should only be considered on the basis of low-carbon hydrogen production. Fuel cell vehicles offer high energy efficiency potential and could become competitive, following cost reduction and reliability enhancement of fuel cells.

Hydrogen production from biomass but also from co-production in fossil power plants with CO_2 capture and sequestration have the potential to provide high-volume/low-CO_2 pathways when demand for hydrogen as fuel substantiates; but further R&D is required. A more limited reduction of greenhouse gas emissions could be achieved with high energy efficiency fuel cell vehicles using hydrogen derived from steam reforming of natural gas which currently provides the most economic and energy efficient hydrogen production route.

Large-scale lighthouse projects comprising all key elements of a hydrogen economy should be established to advance the deployment of hydrogen technologies. These projects should bridge the gap between the present stage of prototype vehicle fleets and broader market introduction by providing the frame for in-use reliability and durability testing of key technologies and infrastructure, to the extent necessary to enable decisions on a subsequent start of mass production.

Biomass-to-Liquid (BTL) fuels could largely enhance the market share of biofuels beyond the EU target of 6% for 2010. The maximum technical potential for all biomass-derived fuels is estimated at about 15%. First demonstrations on the pilot plant scale have just started. Purpose-tailored fuels as available in the BTL process could also support improved engine technology with better energy efficiency and lower emissions. Further development projects could help to improve the economics of the production process and the logistics of feedstock supply. They also could combine BTL and hydrogen production. Co-production of BTL fuels and hydrogen could provide a cost-efficient pathway to large volume renewable hydrogen production.

Liquefied petroleum gas (LPG) is an established alternative motor vehicle fuel with scope for additional market share, possibly up to 5% by 2010. LPG, however, may compete with CNG for additional market share unless targeted to different segments. The potential of LPG for improving security of energy supply and reducing greenhouse gas emissions should be assessed on a well-to-wheels analysis under the same conditions as the other recognised alternative fuels, including the perspective of future market and technology developments.

Alternative motor fuels have the technical potential to gain significant market share within the next decades, even exceeding the 20% substitution target suggested by the Commission for 2020. The technical potentials identified for different alternative fuels, however, are not necessarily additive. Competition for raw materials or for customers may result in a somewhat lower actual overall potential. Vigorous and long-term guaranteed action plans across the whole Union are required to build and support a sufficient market pull from the customer side. Such concerted action could improve the environmental performance and start a transition away from today's high dependence on oil in the transport sector, thereby improving security of energy supply.

1. Introduction

The Commission, in its Green Paper on the security of energy supply[1] and in the White Paper on a common transport policy[2], suggests a target of 20% use of alternative fuels in road transport by 2020. Alternative fuels, on the whole, should provide:

- Improvement in security of energy supply, i.e. by source diversification and oil substitution
- Reduction of greenhouse gas emissions on the grounds of climate change concerns

In the Commission Communication on alternative fuels[3] this suggestion was further developed, identifying three main candidates, focussing on alternative fuels that would have a market potential of substituting at least 5% of conventional motor fuels by 2020, in order to ensure a reasonable perspective for infrastructure and product development:

- Biofuels
- Natural gas
- Hydrogen

LPG has also been considered beneficial.

Legislative actions on biofuels have already been launched and adopted[4].

Subsequently, the Commission established a stakeholder **Contact Group (members: Annex 1)**, whose role was to give advice on the technical and economic basis for further developments of alternative fuels for road transport, with priority on natural gas and hydrogen, and on measures by which the Community could promote their use. The Contact Group published an Interim Report in March 2003, and now presents this comprehensive report, outlining a more detailed strategy on these fuels.

The Contact Group has adopted the following guidelines for its work:

(1) Energy balances and greenhouse gas (GHG) emissions should be assessed on the basis of a well-to-wheels analysis, and on the basis of marginal changes to existing systems rather than on average data.

(2) Cost-effectiveness and scale potential of the different alternatives and approaches are important factors.

(3) Emission reductions of regulated pollutants already established in the EU should not be compromised by alternative fuels. Reductions in regulated emissions currently under discussion have to be taken in account.

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[1] COM (2000) 769
[2] COM (2001) 370
[3] COM (2001) 547
[4] Directive 2003/30/EC (8.5.2003), OJ L 123/42 (17.5.2003); Article 16 of Directive 2003/96/EC (27.10.2003), OJ L 283/51 (31.10.2003)

(4) Impacts on regulated and presently non-regulated pollutants on emissions and air quality as well as safety issues should be assessed. The need to set specific emission and safety standards for alternative fuels should be considered.

The Contact Group formed **Topic Groups on Natural Gas and on Hydrogen**.

Natural gas is already in use as a motor vehicle fuel – albeit on a limited scale. Key issues are implementation strategies, costs and technological issues aiming at optimisation and market widening.

Hydrogen is seen as a potential main energy carrier in the long-term, for both mobile and stationary applications. Key issues at present are selection of research and development priorities and implementation of significant demonstration projects to provide the basis for decisions on a broad market introduction of hydrogen/fuel cell technologies.

Biomass-To-Liquid (BTL) fuels have been presented to the Contact Group by a separate Working Group set up by industry with the perspective of considerably increasing the potential market share of biomass derived fuels, possibly to twice that of traditional biofuels. BTL fuels have been assessed by a separate expert group of interested stakeholders, with regular reporting to the Contact Group.

LPG has been recognised as an established alternative fuel with the potential of considerably increasing its present market share. The perspectives have been discussed by the Contact Group and in meetings of the Commission with the Member States.

2. WELL-TO-WHEELS ANALYSIS

2.1 Purpose of the study

A well-to-wheels study of alternative fuels for passenger cars has been carried out by a consortium consisting of organisations representing the European oil industry (CONCAWE), the European car manufacturers (EUCAR) and the Joint Research Centre of the European Commission (JRC, Ispra). The study started in 2002 and a comprehensive report has been published in 2003 (1). The key findings are summarised in this chapter. The study builds on previous well-to-wheels analyses expanding the range of vehicle and fuel pathways where appropriate. While future projections are always uncertain, the assumptions made have been clearly documented, providing a robust database and a transparent methodology that can be used to facilitate further discussion and updating. The tasks were shared among CONCAWE (well-to-tank), EUCAR (tank-to-wheels) and JRC/Institute for Environment and Sustainability (Code assessment, contribution to data collection and control of input assumptions, WTT "bio-pathways", well-to-wheels synthesis). Work was partly contracted out, for the well-to-tank part to Ludwig-Bölkow-Systems Technology (LBST), and for the tank-to-wheels part to Institut Français du Pétrole (IFP). Well-to-tank data collected in the context of two previous studies by General Motors and the German Transport-Energy Strategy (TES) were used as a starting point for a number of pathways.

Parameters considered in the common study are:

- Energy consumption,
- Greenhouse gas emissions (CO_2, CH_4, N_2O),
- Cost (macroeconomic cost without externalities),
- Fuel market potential,
- Time horizon 2010+.

The objectives of the study were to

- Establish, in a transparent and objective manner, a consensual well-to-wheels energy use and GHG emissions assessment of a wide range of automotive fuels and power trains relevant to Europe in 2010 and beyond. For the reference fuels gasoline and diesel, only technologies with the potential for mass market series production by 2010 were considered, while for alternative fuels also technologies with the potential for market entry by 2010 were accepted.

- Consider the viability of each fuel pathway and estimate the associated macro-economic costs.

- Have the outcome accepted as a reference by all relevant stakeholders.

2.2 Well-to-tank analysis

The three main primary energy sources considered at present for transport fuels are:

- Crude oil as a source for gasoline, diesel (and possibly naphtha),
- Natural gas, used as CNG or for the production of synthetic liquid fuels or hydrogen,
- Biomass (including forestry products and waste biomass) for production of biodiesel, ethanol, hydrogen and a range of synthetic fuels (diesel fuel, Di-Methyl-Ether and methanol). Biogas was not evaluated although future evaluations should be done to determine its potential in the context of the fuels evaluated in this well-to-wheel study.

The crude oil derived conventional fuels serve as reference for the other alternative fuels pathways.

Electricity generation pathways are considered from fossil fuels (natural gas and coal), biomass and wind, as well as the current European generation mix. These figures are used as input to many pathways, and also allow a comparison of the relative effectiveness of power generation versus road fuels for the renewable fuel options. Production of hydrogen by electrolysis is also included.

Natural gas steam reforming and coal gasification for either hydrogen or synthetic fuels production are also included. Capture and storage of CO_2 has not been included for any of the pathways, but it is intended to include this aspect in a future update to the study

The scope of the study is Europe in 2010 and beyond. While local and national differences undoubtedly exist for some pathways, the objective of this study was to evaluate the impact on Europe as a whole. Hence, the effect of changes was calculated relative to a baseline situation where current fuels continue to provide Europe's transport needs. This “marginal” approach has been preferred to using average energy consumption and cost data that would not properly reflect the market transitions and limited level of fuel substitutions envisaged here. For the reference fuels, gasoline and diesel, this means a reduction of the anticipated future demand. For natural gas it corresponds to additional volumes over and above the forecast demand for other uses such as domestic, industrial and power generation.

2.2.1 Gasoline and Diesel

The refinery balance between gasoline and diesel in Europe is already stretched due to high and increasing demand for diesel fuel. In addition, diesel production requires increasing amounts of hydrogen in order to meet more stringent sulphur and other quality parameters. As a result, the marginal diesel production in the European refineries is more energy-intensive and consequently also more greenhouse gas emission intensive than that of marginal gasoline. The energy and GHG balance of gasoline and diesel are shown in figures 1 and 2 below.

Fig. 1: Well-to-Tank energy efficiency of gasoline and diesel

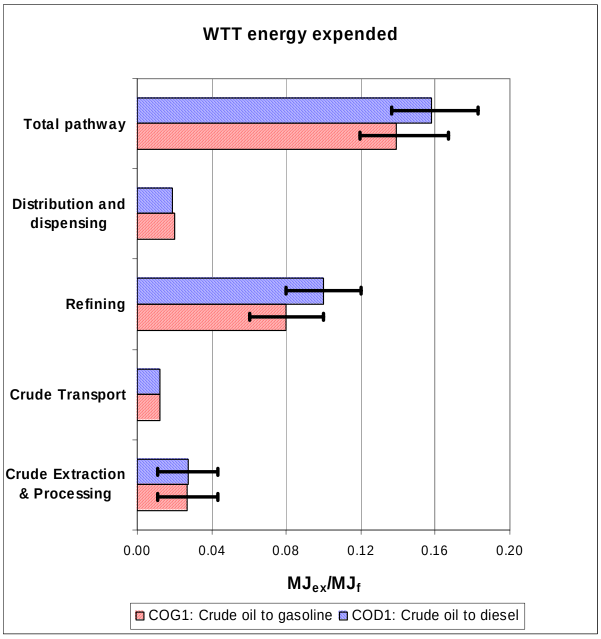
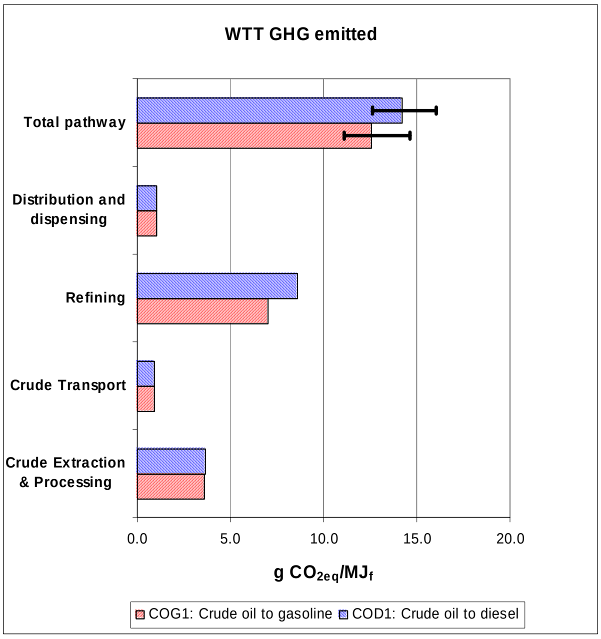


Fig. 2: Well-to-Tank greenhouse gas emissions of gasoline and diesel



2.2.2 Compressed Natural Gas

Marginal natural gas supplies to Europe in 2010+ will come either in gaseous form transported by pipeline or in liquefied form (LNG). For piped gas, South-West Asia (e.g. Iran, Kazakhstan) or Russia are considered the most likely sources. 4000 km is considered a typical transport distance although the most distant gas supply is currently Siberia with 7000 km long pipelines. The most likely source of LNG is the Arabian Gulf. The “current EU mix” situation, corresponding to a typical average transport distance of 1000 km (by pipeline), is also included for reference but supplies from these sources will not be sufficient to satisfy additional future demand.

Piped gas is expected to transit through Europe’s extensive network to reach most of the refuelling sites. Two distribution scenarios are considered for natural gas delivered to the EU as LNG, either in gaseous form through the existing gas grid, or in liquid form up to the refuelling station. In all cases the figures include compression to fill CNG vehicle tanks at 20 MPa. The option of liquefied-to-compressed natural gas has not been considered, but could play a role in expanding opportunities and cost reduction of a natural gas fuelling infrastructure in the future.

The energy and GHG balance of CNG pathways are shown in figures 3 and 4 below. The main factors for energy consumption and greenhouse gas emission are long-distance transport and final compression for piped gas and liquefaction for LNG. Although there were some earlier reports of high leakage from Russian gas pipelines, more recent studies indicate that leakage levels should be very low. Direct LNG delivery to the filling station is somewhat more favourable. The LNG options are close to the 7000 km pipeline case.

Fig. 3: Well-to-Tank energy efficiency of different CNG pathways

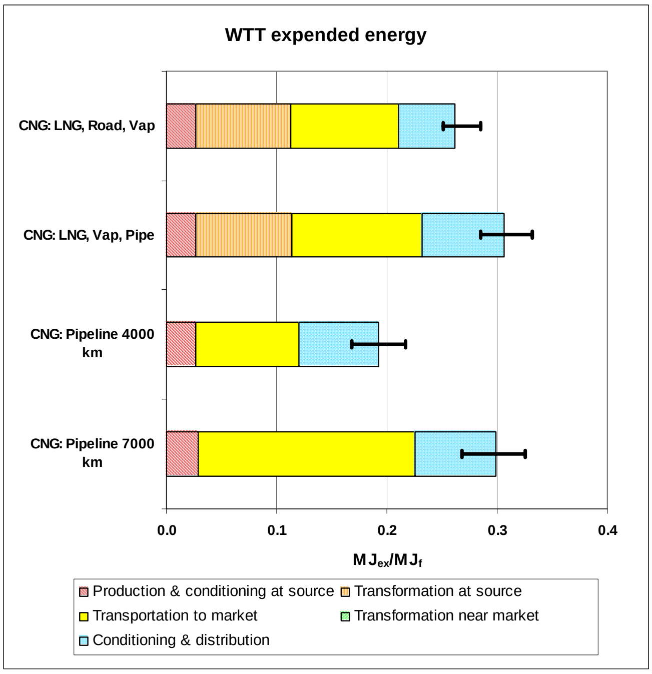
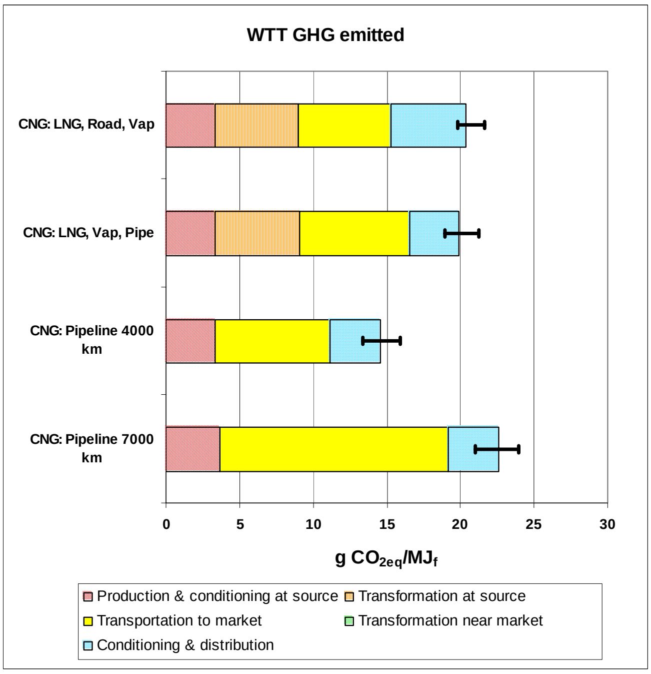


Fig. 4: Well-to-Tank greenhouse gas emissions of different CNG pathways



2.2.3 Hydrogen

Hydrogen is not an energy source but an energy carrier. At the outset, energy input is used to extract hydrogen from compounds such as hydrocarbons or water. Part of this energy is carried by the hydrogen molecule and can be recovered in a chemical reaction combining hydrogen with oxygen to water. Hydrogen 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 combined with thermal splitting of water or through electrolysis of water.

Steam reforming of natural gas is a fully commercial process that can be carried out either in a central plant or at/near the refuelling station. Large plants can be made more efficient than small ones through heat integration and recovery. Central production also opens the possibility of CO_2 capture and storage, although this is not included in the current study.

Partial oxidation of a carbonaceous feedstock in the presence of water can be applied to a wide range of materials, in particular heavy ones such as oil residues, coal as well as biomass feeds such as wood. Coal gasification is a commercial process but is only suitable to large installations.

The process for wood gasification is of the same nature as for solid feedstock such as coal but has been much less researched. Various sizes of wood gasifiers for electricity production have been developed at pilot plant stage and could conceivably be adapted for hydrogen production.

Electricity production is considered from coal, natural gas, wood, wind and nuclear, as well as the current EU-mix. Hydrogen is then produced by electrolysis centrally or at the refuelling site.

Direct solar energy can also, in principle, be used to produce hydrogen either by thermal splitting of water or electrolysis through photovoltaic electricity. The first type of process is at an early development stage while the latter is not expected to be viable at a very large scale until well after 2010. These options, therefore, have not been considered in this study.

Hydrogen is commonly transported in gaseous form in pipelines or in pressurised cylinders on road or in liquid form in cryogenic tanks. The study includes options for pipeline distribution (50 km average distance), road transport in pressurised cylinders or in liquid form in cryogenic tanks. Depending on the technology used in the vehicle, the hydrogen can be either delivered as a liquid at near atmospheric pressure or needs to be compressed to 88 MPa at the refuelling station, to meet the needs of vehicles with 70 MPa on-board tanks.

Energy and GHG balance for a selection of the main pathways considered in the study are shown in figures 5 and 6 below.

Fig. 5: Well-to-Tank energy efficiency of the main hydrogen pathways

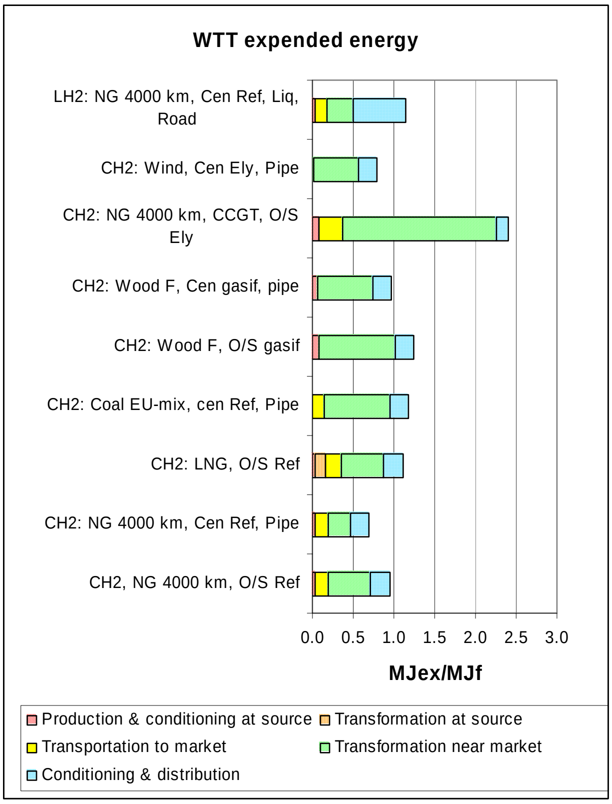
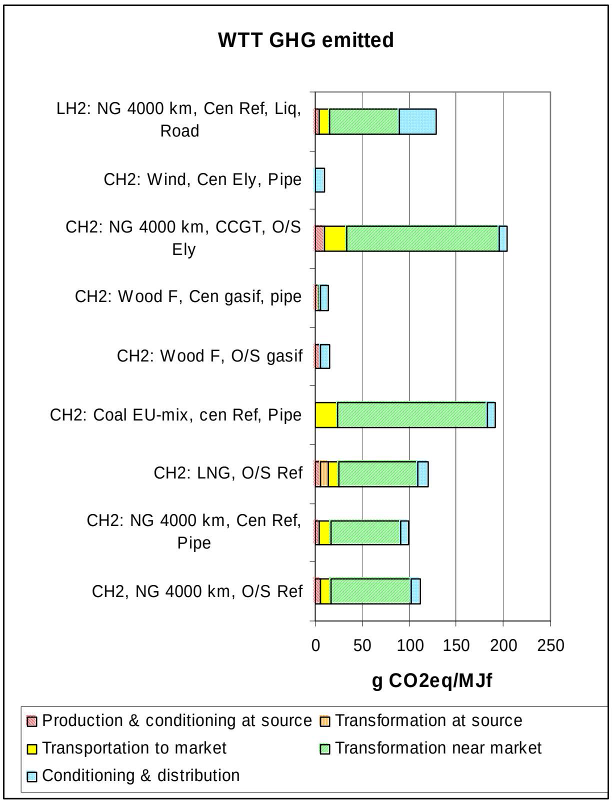


Fig. 6: Well-to-Tank greenhouse gas emissions of the main hydrogen pathways



The main contribution to the energy balance comes from the hydrogen production step where the energy in the carbon is utilised, releasing CO_2. The origin of the gas still has a significant impact although less in relative terms than for CNG pathways.

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. The option of hydrogen supply in liquid form is less energy-efficient than the gaseous option because of the high energy required for liquefaction (with present technology typically 30% of the final hydrogen energy content).

Producing hydrogen from coal is less energy-efficient than the gas route (because the gasification process is less efficient). The difference is even greater when it comes to GHG emissions because of the higher carbon content of coal.

The wood pathways are sensitive to the energy efficiency of the gasification plant, the larger scale having again the edge because of waste heat recovery. The GHG emission figures are 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.

Electrolysis has much lower energy efficiency because of additional energy losses already incurred in the electricity production from primary energy sources. For a given source of electricity, central and on-site electrolysis give nearly equal results with compressed hydrogen (electrolysis efficiency is insensitive to scale). The low energy consumption shown for the wind pathway reflects the somewhat arbitrary definitions in general energy balances for the part of wind energy, setting the electricity output there equal to primary energy input, thereby implying an energy conversion efficiency of 100% by definition. It has been assumed that the hydrogen compression energy is electricity from the EU-mix rather than wind electricity. The pathway therefore shows some GHG emissions. In locations remote from the grid, electrolysers might also be directly coupled to the Wind-Energy Converters. The wood pathways GHG figures again are very low as most of the energy used is renewable.

2.2.4 Alternative Liquid Fuels

Fischer-Tropsch (FT) diesel can be produced from natural gas (gas-to-liquids or GTL). GTL plants will only be economically viable where remote “stranded” (and therefore cheap) gas is available, thereby off-setting the cost of the conversion by cheaper transport of liquid products. Synthetic diesel is most likely to be used mainly as a blending component in conventional diesel. Similar pathways are included for production of methanol and DME from natural gas. These are considered to be used as pure fuels: in fuel cell vehicles equipped with an on-board reformer in the case of methanol, in modified diesel vehicles in the case of DME. DME could also be used for on-board reforming although this option has not been included in this study.

The current search for alternative transport fuels has increased the level of interest for the biomass-to-liquid (BTL) route, and a number of pilot and demonstration projects are at various stages of development. The process combines wood gasification with an adaptation of the Fischer-Tropsch synthesis. These integrated plants are complex engineering projects and require many practical problems to be resolved before they become reliable and commercially viable. The attractive GHG potential justifies further research and development in this area.

The GTL and BTL process schemes can produce a variety of products. Although diesel often is the main product in volume terms its fraction in the total product cannot in practice exceed 75% (higher yields may be achieved by recycling lighter products but at a considerable cost in energy). Naphtha takes the largest share of the balance. In the study it has been considered that each product is produced with the same energy efficiency.

The combined process of primary energy conversion and FT synthesis is energy-intensive, more so for wood than for natural gas. This is because the overall process is more straightforward and more energy efficient for gas. Also future GTL plants are expected to be very large and highly heat integrated. This is likely to be less so in smaller wood conversion plants where such complexity may not be economically justified. Methanol and DME synthesis are more efficient than Fischer-Tropsch.

The energy efficiency and the greenhouse gas emissions on the well-to-wheels are summarised in figures 7 and 8 for various alternative liquid fuels.

Fig. 7: Well-to-Tank energy efficiency of various alternative liquid fuels

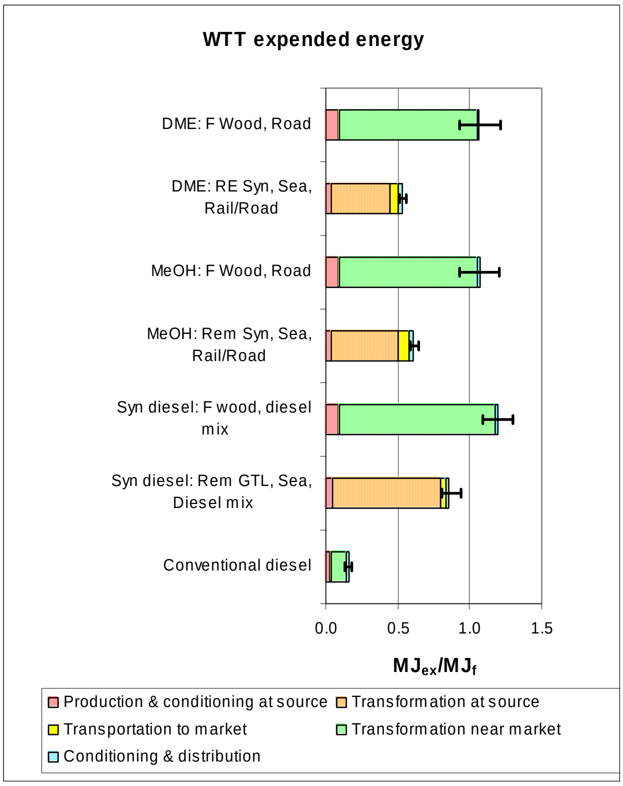
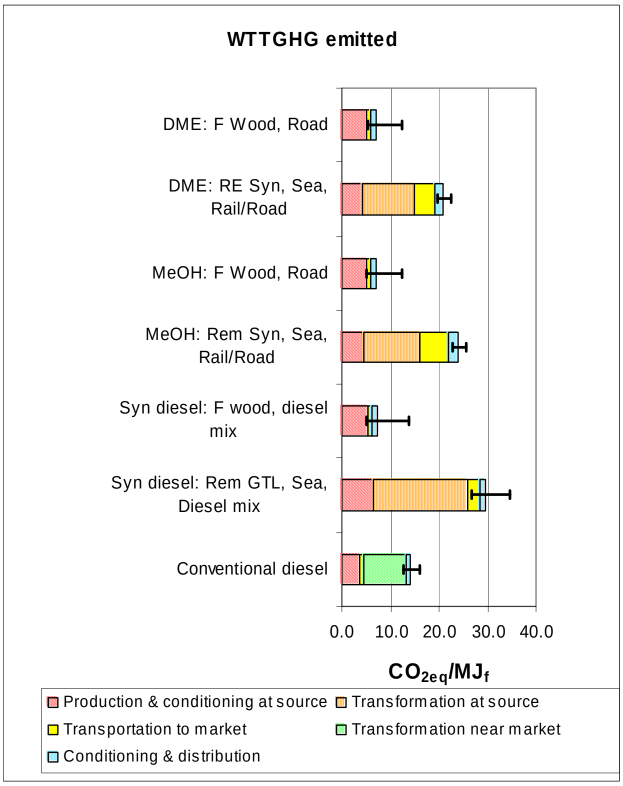


Fig. 8: Well-to-Tank greenhouse gas emissions of various alternative liquid fuels



2.3 Tank-to-wheels analysis

A common model vehicle platform was used, based on a mid-range European car (VW Golf size 1.6 l gasoline). The results do not pretend to represent a fleet average but a representative market sector, using the most sold car segment in Europe as the basis. In a first phase, engine technologies typical of 2002 state of the art, complying with Euro-III emission standards were considered. Phase 2 addressed engine technologies expected to be on the market 2010+. The power-trains addressed for 2010 include conventional and advanced ICE engines, hybrids and fuel cell vehicles.

The level of engine technology has a significant impact on fuel efficiency. For example, turbo-charging and down-sizing can improve the efficiency of spark-ignited engines. To give a true comparison of the merits of different fuel options, engines are compared as far as possible at the same levels of technology. Thus, for 2002, gasoline and CNG engines are represented naturally aspirated engines, with turbo-charging and down-sizing being applied to both fuels for the 2010+ scenario. For diesel, since turbo-charging is already common technology in the market, this option is included for both the 2002 and 2010+ scenarios.

A common set of minimum performance criteria was used for all vehicles/power trains to ensure a sound comparison between the different options. In addition, where different fuels were available for the ICE options, the technology level used was the same for each fuel as far as possible.

The tank-to-wheels energy consumption and greenhouse gas emissions were calculated according to standard NEDC test cycle conditions, including cold start. The intention was to reproduce the roller bench test conditions for the standard certification test. To do so, vital functions of the vehicle fixed at 400 W electric load were applied. But no ‘comfort’ loads like heated seats or air conditioning were taken into account. The effect of additional loads is considered in the full WTW report, but would have only a proportionally similar add-on effect on each pathway. Heavy duty (trucks, buses) vehicles were not considered in the study. Heavy duty applications represent some 70% of the diesel fuel used in Europe today. Therefore future extensions of the study should include this sector.

2.3.1 Internal Combustion Engine Options

The baseline 2002 PISI (Port-Injection-Spark-Ignition) vehicle uses a 1.6 l naturally aspirated engine and the same displacement is adopted for the DISI (Direct-Injection-Spark-Ignition) vehicle. To match the performance, a 1.9 l turbo-charged DICI (Direct-Injection-Compression-Ignition) engine is used for the diesel option. For 2010+, the gasoline engines are down-sized to 1.3 l and turbocharged, while the diesel engine remains at 1.9 l.

PISI internal combustion engines can be adapted to burn hydrogen directly. Advanced combustion concepts are being explored for hydrogen engines, as for gasoline, diesel and CNG, however, in the 2010+ timeframe the maximum efficiency of these hydrogen ICEs is expected to be very close to the best 2010 gasoline engines since they employ similar combustion processes and engine thermodynamics. The hydrogen ICE also uses a turbo-charged 1.3 l format.

The 2002 bi-fuel (gasoline/CNG) vehicle meets the performance criteria when operated on gasoline, but suffers a 12% torque reduction when running on CNG. The dedicated CNG engine needed to be upsized to 2.0 l to match the minimum acceleration criteria. This results in 9% higher fuel consumption and cancels out a 9% gain in fuel efficiency from the increase in the compression ratio from 9.5 to 12.5 made possible by the high octane rating of natural gas. Somewhat surprisingly, therefore, bi-fuelled and dedicated natural gas vehicles have virtually equal fuel consumptions, although the bi-fuel vehicle does not meet the acceleration criteria when operated on CNG.

A recent General Motors (GM) study for Europe claimed lower energy consumption for a dedicated CNG vehicle compared with gasoline. However, the GM study compared a turbo-charged and downsized CNG vehicle with a naturally-aspirated gasoline vehicle. Both technologies can benefit from turbo-charging, and when compared at the same technology levels, the energy consumption is nearly the same for gasoline and CNG.

The diesel vehicle as produced in 2002 already benefits from turbo-charging, and for this reason shows less potential for improvement than the spark engine options, as promising novel diesel technologies, such as Homogeneous Combustion Compression Ignition (HCCI) have not been considered in the study, because they are not expected to be in series production on the market already by 2010.

By 2010 significant improvements are expected for all power trains although diesel which has already largely benefited from turbo-charging and downsizing will show a relatively smaller efficiency improvement than the spark ignition engine. The introduction of a particulate filter (DPF) in particular is expected to have a notable effect on efficiency. The forecast improvement percentages between 2002 and 2010 are shown in the table below.

	PISI	DISI	DPF	w/o DPF	
	Gasoline	**Gasoline**	**Diesel**	**Diesel**	**CNG**
2010 improvement	**15%**	**10%**	**2%**	**6%**	**16%**

In the future, gasoline, diesel and CNG engines could potentially benefit from more advanced combustion systems, including diesel cycle CNG operation and homogeneous compression ignition concepts, but these are still in the research stage and considered to be beyond the timeframe of the current study.

All TTW energy and GHG figures are shown in **Annex 2**.

2.3.2 ICE Hybrid Vehicles

In this study a parallel hybrid configuration was selected combining an IC engine and an electric motor with battery as torque generators. The engine displacement for the gasoline engines was 1.6 l, for the diesel 1.9 l and for the hydrogen engine 1.3 l. For CNG a dedicated 1.6 l engine was used: the availability of the electric motor allows the acceleration criteria to be met with the smaller engine.

The fuel consumption has to be evaluated at balanced energy level in the battery: the state of charge (SOC) at the end of the cycle has to return to the initial state. The simplest computational method is to adjust the initial SOC to get a null difference on the cycle. This is sometimes not possible to achieve in which case extrapolated or interpolated results were used.

The sizing of the electric motor (14 kW) was selected after several simulations, which demonstrated that the energy efficiency benefit was asymptotic above this level. The battery is a Li- ion 42V unit and should be able to ensure a 20 km ZEV range.

Generally all configurations benefit from hybridisation (15% efficiency gain for gasoline and 18% for diesel), although the return of the gas engine to the common 1.6 l displacement makes this option particularly attractive for CNG (24%).

2.3.3 Fuel Cell Vehicles

Although hydrogen can be used in an internal combustion engine, the real efficiency breakthrough comes from fuel cells, the commercial development of which is a crucial issue.

Three types of configurations are considered:

- Fuel cell with H_2 tank without battery
- Fuel cell with H_2 tank and with battery ("hybrid")
- Fuel cell with battery and reformer to provide H_2 to the fuel cell

Since fuel cells are more efficient than ICEs, a smaller quantity of hydrogen is necessary to comply with the range criterion and the tank can therefore be smaller and lighter.

The fuel cell system fed from on-board stored H_2 clearly has no CO_2 emissions. Nevertheless, the possibility to re-store electric energy in batteries during recuperative braking may noticeably influence the energy efficiency and hence the WTW GHG emissions. A 75kW electric motor was used. The reformer vehicles used a 42V Li-ion battery similar to the hybrid configurations, while for the hydrogen hybrid a smaller version of the same battery was employed. The fuel cell efficiency map used was based on information from three sources (GM, DC and the European FUERO Project).

Hydrogen generation from a liquid fuel on-board the vehicle has been proposed. The advantages of avoiding the hydrogen distribution infrastructure and on-board storage are counterbalanced by the much greater complexity of the vehicle, the challenge of building a reformer that is small and efficient, the control system involving the reformer, the fuel cell and their interface, and the additional vehicle weight. For this "indirect" hydrogen route best estimates of the energy efficiency of the on-board methanol reformer were used. In the absence of more specific data, the same efficiency was used for the 2 other fuels: Diesel and Naphtha.

On the NEDC cycle, fuel cells perform much better than ICEs, achieving roughly double the energy efficiency of the gasoline ICE reference. The results for hydrogen are valid for both compressed and liquid hydrogen inasmuch as both have the same cycle test mass and efficiency map. CO_2 emissions for fuel cell with reformer are all below 120 g/km, in the same range as most of the IC hybrid configurations. Nevertheless, it has to be mentioned that the uncertainty on the simulation results is quite large for these fuel cell configurations (mainly due to the evaluation of the cold start over-consumption).

2.4 Well-to-wheels chain

2.4.1 Compressed Natural Gas

The origin of the natural gas and the supply pathway are critical to the overall WTW energy use and GHG emissions. CNG engines are currently less efficient than diesel engines, but since spark engines have more potential for improvement, the gap narrows for the 2010+ scenario.

The higher hydrogen to carbon ratio gives natural gas an advantage over crude-based fuels in GHG terms at the final combustion stage but, on a WTW basis, this is compensated by extra energy requirement for fuel provision and somewhat lower vehicle fuel efficiency. In the 2002 configurations CNG applications are more energy-intensive than both gasoline and diesel and between gasoline and diesel in GHG terms. This is the case even with a dedicated CNG engine because of the required up-sizing. For the 2002 technology, the WTW GHG emissions of a CNG vehicle are distinctly below gasoline and comparable to diesel vehicles.

The differences for the 2010+ technology level come from improvements in the respective vehicles. WTW GHG emissions become better than diesel although WTW energy use remains higher than for conventional fuels.

2.4.2 Hydrogen

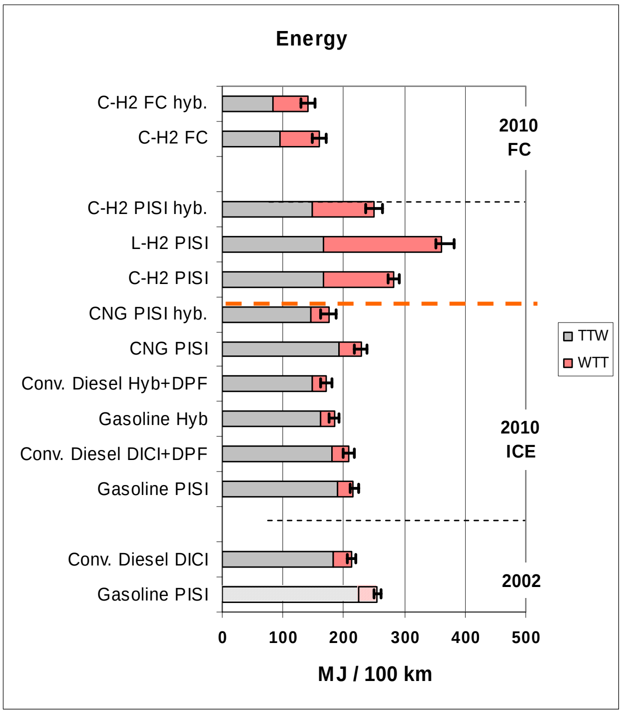
Many potential hydrogen production routes exist and the results are critically dependent on the pathway selected. In the short to medium term, natural gas is the cheapest and only viable source of large scale hydrogen supply. The WTW performance of hydrogen ICE and FC vehicle options is compared with that of conventional fuel/vehicle and CNG pathways in figures 9 and 10. For hydrogen and CNG, the source energy is natural gas supplied through a 4000 km pipeline.

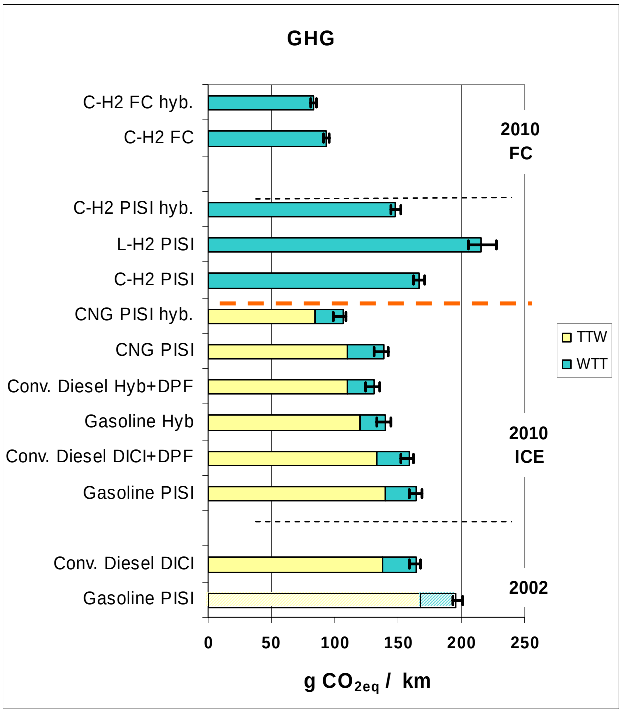
WTW energy use and GHG emissions are higher for hydrogen ICE vehicles than for conventional fuels and CNG vehicles, with hydrogen produced from natural gas. This holds for CH_2 and even more so for LH_2 which requires noticeably more energy. Among the different hydrogen options shown, fuel cell vehicles have the lowest WTW energy consumption and GHG emissions.

The combination of on-board reforming of a hydrocarbon feedstock and of a fuel cell is less efficient than the direct route to hydrogen from NG combined with a fuel cell. The main reason for this is the lower expected efficiency of the on-board reformers because of their small size. With gasoline as the fuel, the on-board reformer option would give lower GHG emissions than the ICE, matching the gasoline ICE hybrid. Methanol provides a carrier to use natural gas and other non-liquid feeds for such vehicles but is penalised by the energy loss attached to the methanol synthesis.

Fig. 9: Well-to-wheels energy efficiency of ICE and fuel cell vehicles (C-H2 based on NG, piped 4000 km)

Fig. 10: Well-to-wheels greenhouse gas emissions of ICE and fuel cell vehicles (C-H2 based on NG, piped 4000 km)





Electrolysis using EU-mix electricity results in higher GHG emissions than producing hydrogen directly from NG, due to the losses in the additional energy conversion processes when turning primary energy into electricity and then electricity into hydrogen. Even when combined with the most efficient converter, the energy consumption remains higher than for conventional fuels and power trains, and GHG emission reductions are achievable only if electricity from renewable or nuclear energy is used.

The WTW balances for fuel cell vehicles supplied with compressed hydrogen from various sources are shown in figures 11 and 12.

Natural gas reforming is more efficient when carried out centrally in a large plant, where waste energy can be recovered to produce electricity, rather than in a small local or on-site plant. The source of natural gas plays a role through the transportation energy. In relative terms this is less important than for CNG because of the larger total energy required for hydrogen.

Gasification processes tend to be less energy-efficient because of the nature of the feedstock, but where wood is used, give low GHG emissions.

Large scale central hydrogen production (from coal or gas) offers the potential for GHG emissions reduction via CO_2 capture and sequestration and this merits further study.

Fig. 11: Well-to-wheels energy efficiency of CH2 fed fuel cell vehicles

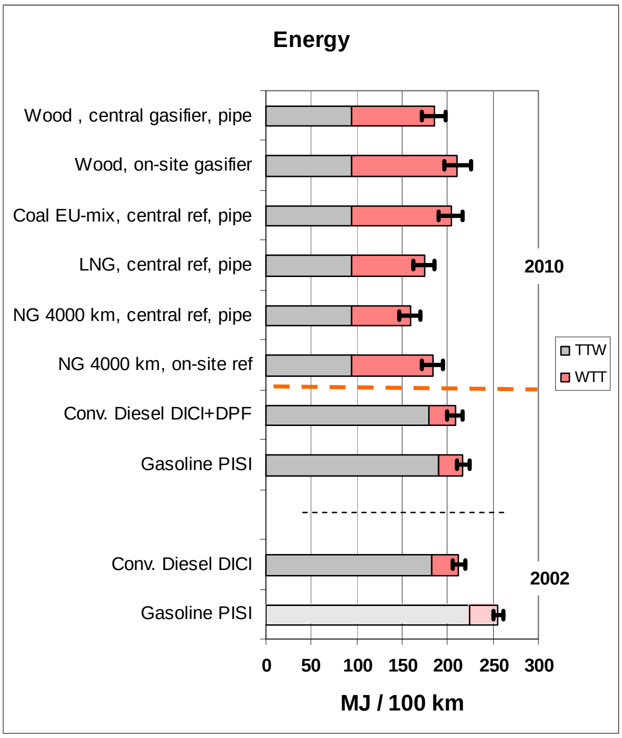
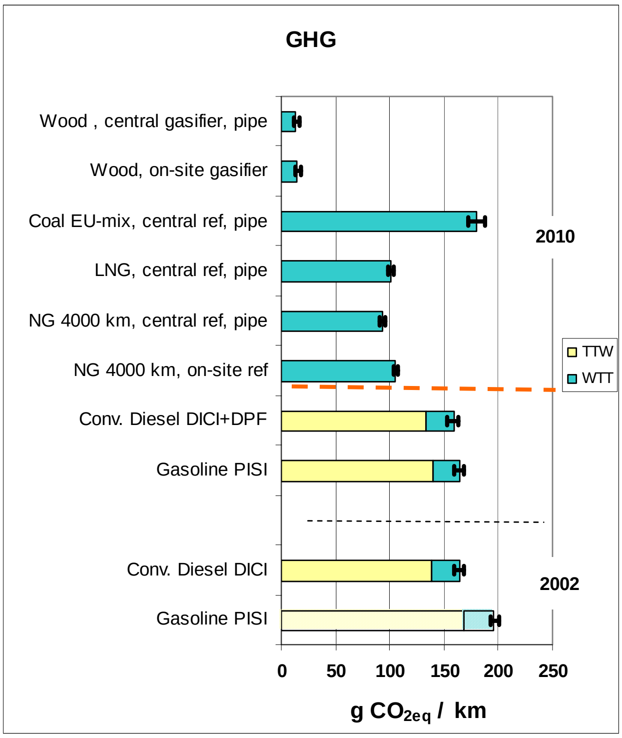


Fig. 12: Well-to-wheels greenhouse gas emissions of CH2 fed fuel cell vehicles



2.4.3 Alternative Liquids Fuels

The energy and GHG balances for conventional biofuels have been extensively studied, and these fuels are also included in the current WTW study, where updated figures will be found. However, for the purpose of this report, attention is focussed on other potential fuels produced from biomass. Production of hydrogen from biomass (directly or via methanol) has already been mentioned, and in this section, use of biomass to produce synthetic liquid biofuels (synthetic diesel and DME) is discussed. The production of synthetic diesel and DME from natural gas is also addressed here. Finally, the alternative options for use of biomass resources are compared.

The schemes for synthetic diesel (GTL) and DME from natural gas are for a plant near a remote gas field. The use of GTL would correspond to a small increase in GHG. In each case, the fuel is assumed to be used in conventional diesel vehicles.

The higher efficiency of the synthesis process gives DME a slight edge over synthetic diesel fuel.

The WTW energy efficiencies and greenhouse gas emissions are summarised in figures 13 and 14 for various synthetic diesel pathways.

Fig. 13: Well-to-wheels energy efficiency of synthetic diesel pathways

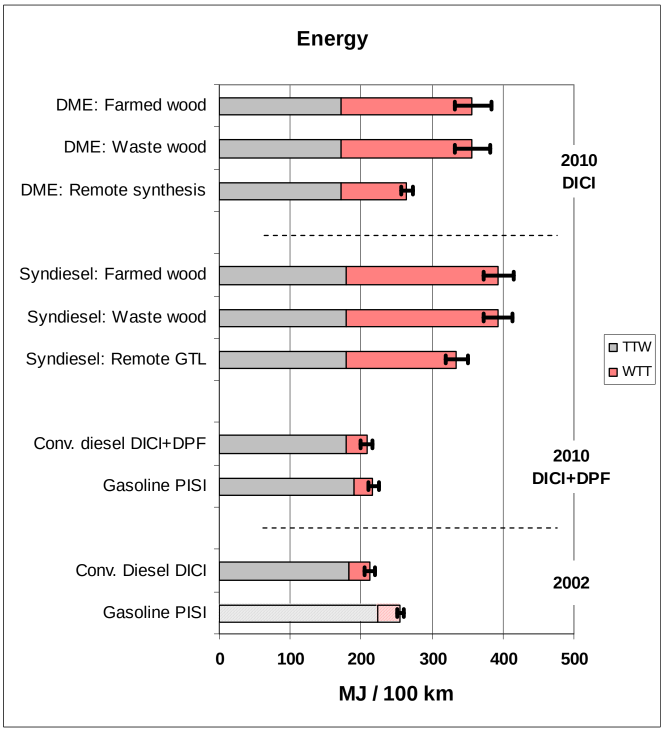
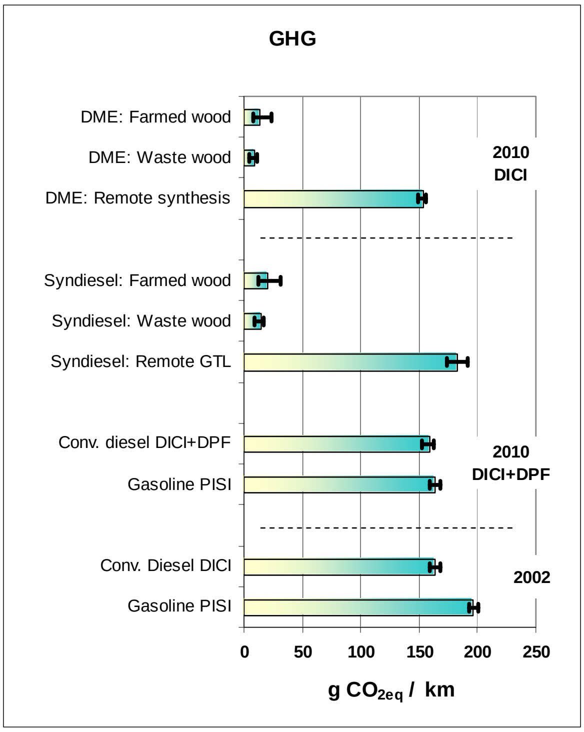


Fig. 14: Well-to-wheels greenhouse gas emissions of synthetic diesel pathways



Potential Production Volumes

GTL plants are very complex and need to be large to be economically viable. They would normally be sited near a remote gas field in order to have access to a cheap and abundant feedstock. A typical state-of-the-art plant would be designed to produce 2-3 Mt/a of total products, about 2/3 of which would be diesel (DME synthesis does not have any co-product). Investment is expected to be in the region of 2 G€. Many conditions have to be fulfilled for such large and expensive projects to be developed successfully. Although gas reserves are available and many potential sites exist, it is generally considered that there will not be more than about 10 large scale plants world-wide by 2020. Synthetic diesel will, therefore, remain a potential diesel blending component rather than become a mainstream fuel.

Land can, of course, only be used for one purpose at a time so figures discussed for different fuels are not all cumulative. Wood produces the highest amount of fuel from the available land and waste resources, mainly synthetic diesel because of the high yield of wood and the good conversion efficiency of the underlying process.

It has been estimated that a total of 872 PJ/a (20.8 Mtoe/a) of synthetic diesel could be produced from wood: 132 PJ/a from forestry waste, 234 PJ/a from set-aside land and 507 PJ/a from agricultural surplus. This represents 10.4% of the projected EU-25 demand for road diesel fuel in 2010. This estimate is based on supplies of feedstock from current land use patterns and does not take into account any changes to e.g. the Common Agricultural Policy.

The wood route would also produce naphtha in ratio of about 1 to 3 to the diesel. The potential for this volume and GHG emission reductions means that effort is justified to further develop the technology. The need to feed the plant in a practical and economic manner is likely to call for fairly small plants with output capacities in the region of 50 to 100,000 t/a. Between 200 and 400 such plants would be required across Europe to achieve the production levels mentioned in the previous paragraph - it remains to be seen what level of production would prove feasible.

Recently a potentially attractive scheme was proposed to integrate synthetic fuels and paper pulp production by gasification of the so-called black liquor (an aqueous solution of the wood's lignine that traditionally serves as an energy source in a pulp mill). There appears to be large synergistic gains between the two processes, potentially significantly increasing the net wood conversion efficiency. This could also make the prospect of producing synthetic fuels much more plausible by providing an established industrial environment to do so (there are about 50 paper mills in Europe). Investments would still be high though.

These alternatives are, of course, extremes and a mixture of the three is more likely to occur in reality. The "all wood" scenario in particular is not very likely and it would require vast tracks of land to be turned over to short Rotation Coppice (SRC), with a large visual impact on the countryside, as well as a complex logistic system to collect and transport all this wood to the processing plants.

Costs

GTL diesel will be manufactured in remote plants and proposed on the world markets as a premium diesel fuel for use mainly as blending component or to be used neat in specific niche applications. As a (somewhat arbitrary) marker a 20% premium over the standard EN 590 2010 diesel is used. As this price is assumed to be available at major European trading locations (e.g. Rotterdam or Sicily) there are virtually no other costs associated to the use of GTL diesel.

The cost of BTL diesel will be associated to its production scheme, the limitation being of course the market price for high quality diesel components. The proposed estimates for a 50,000 t/a of diesel are in the order of 200 M€. When adding the cost of wood, one arrives at a total annual cost of some 10 G€ for the 5% substitution scenario.

As a liquefied gas, DME would face the problem of distribution and retail infrastructure as well as require specially adapted vehicles. Experience with LPG, with some 8000 LPG filling stations in Europe, has shown that this can be handled in an economical way. In cost terms this is also partly compensated by less complex and therefore less costly production plants, as well as higher yields of fuel suitable for diesel engines.

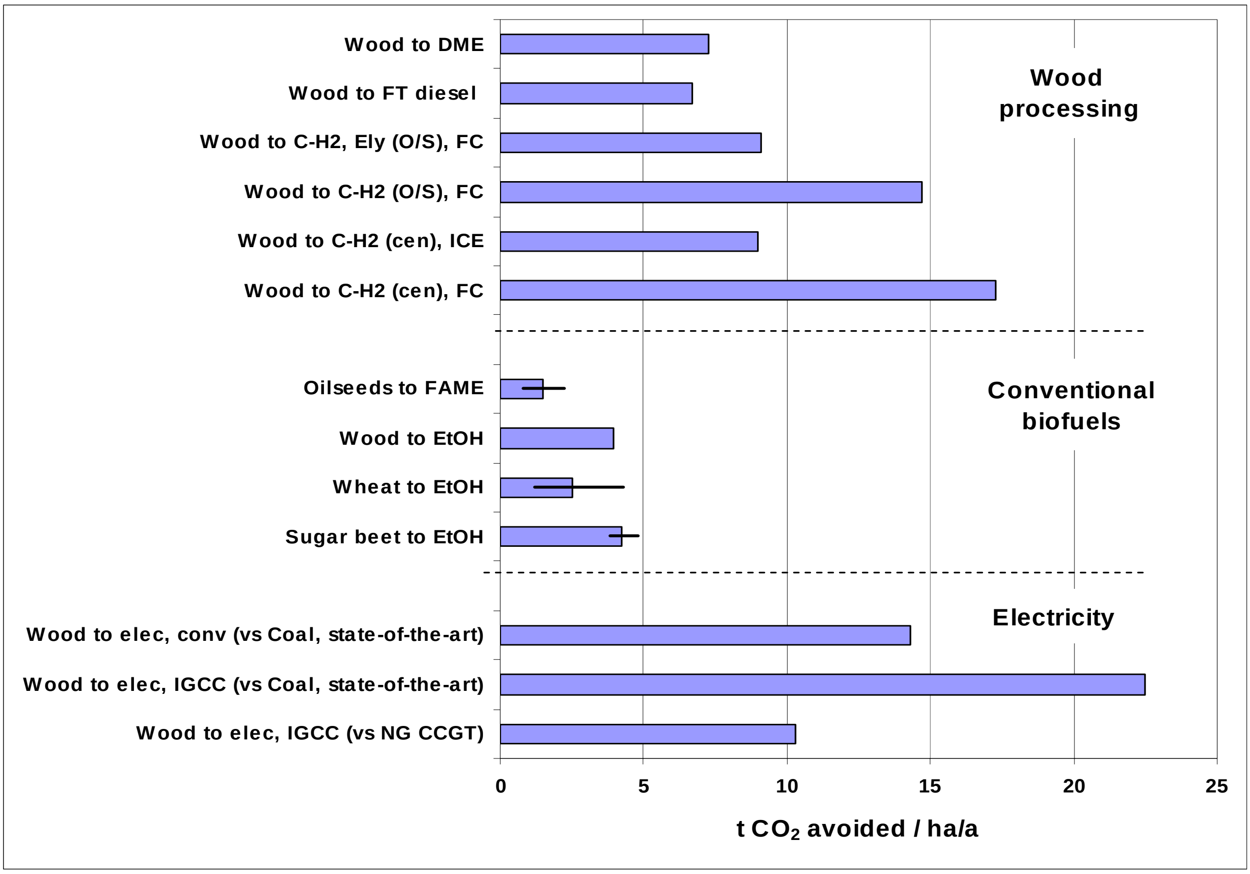
Optimum Use of Biomass

Land is the common biomass resource. It can be used in different ways but its availability for growing crops is essentially limited, particularly under the current support systems that provide only limited disincentives for the overproduction of food crops. In figure 15 we consider an EU average hectare of land and compare its "CO_2 avoidance potential" when used with different energy crops.

Electricity production is energy intensive and results in large CO_2 savings, particularly when coal is being substituted. The technology used for biomass conversion can make a lot of difference, the IGCC concept being far superior to a conventional boiler + steam turbine system (but also a lot more expensive). Note that wood is used here as a proxy for all high biomass yield energy plants.

Coal substitution for electricity is the best option. Direct hydrogen production from wood is also attractive because of the reasonable efficiency of the conversion plants. It can be better than substituting natural gas for electricity but only as long as the final converter is an efficient fuel cell. Producing hydrogen from wood via electricity and electrolysis is less efficient.

Fig. 15: Greenhouse gas emissions avoidance with different biomass pathways



Note: the CO_2 avoided is estimated by comparison to the base case scenario relative to each case (e.g. 1 ha planted with wheat can produce an amount of ethanol which would substitute fossil gasoline as fuel to an PISI vehicle). The same ha planted with wood could alternatively produced hydrogen to be used in a FC vehicle, substituting a mixture of fossil gasoline and diesel used in PISI and DICI vehicles).

Producing synthetic diesel from wood also gives attractive GHG reductions, and has the advantage over hydrogen that the products can be easily integrated into the existing fuel infrastructure. DME has a slight advantage over BTL but requires its own distribution infrastructure and adapted vehicles.

Ethanol and FAME, although the only liquid biofuels currently being produced commercially, are much less attractive mainly because of lower yields per ha and because only part of the crop is currently used for fuel production. Developments are under way to improve the usage of waste e.g. straw.

However, any decision on the optimal use of biomass would also have to take account of other factors, including the maturity of the technology, the production cost, and the contribution to the Commission’s objectives for alternative fuels as well as renewable energy sources.

WTW Conclusions for Alternative Liquid Fuels

A number of routes are available to produce alternative liquid fuels that can be used neat or in blends with conventional fuels in the existing infrastructure and vehicles.

- Conventionally produced bio-fuels such as ethanol and FAME provide some GHG benefits but are energy-intensive.
- *The potential contribution of ethanol and FAME produced from EU feedstock to the Commission's 20% target may be limited by current land use patterns and the effect of fiscal incentives in the agricultural sector. The cost/benefit depends on the specific pathway, by-product usage and N_2O emissions from agriculture.*
- GTL processes enable high quality diesel fuel to be produced from natural gas. However, the WTW GHG emissions are higher than for conventional diesel fuel.
- *Limited GTL volumes may be expected to be available by 2010 and beyond.*
- New processes are being developed to produce synthetic fuels from biomass (BTL) which offer lower overall GHG emissions, though still high energy use.
- *BTL processes have the potential, though probably not before 2010 to any great extent, to save more GHG emissions than current bio-fuel options.*
    - *Issues such as land and biomass resources, material collection, plant size, efficiency and costs, may limit the application of these processes.*
- DME can be produced from natural gas or biomass with similar results as those for GTL and BTL fuels.

    Implementation costs would be much higher as DME would require specifically designed engines and a dedicated distribution and refuelling infrastructure

2.4.4 Well-to-wheels summary

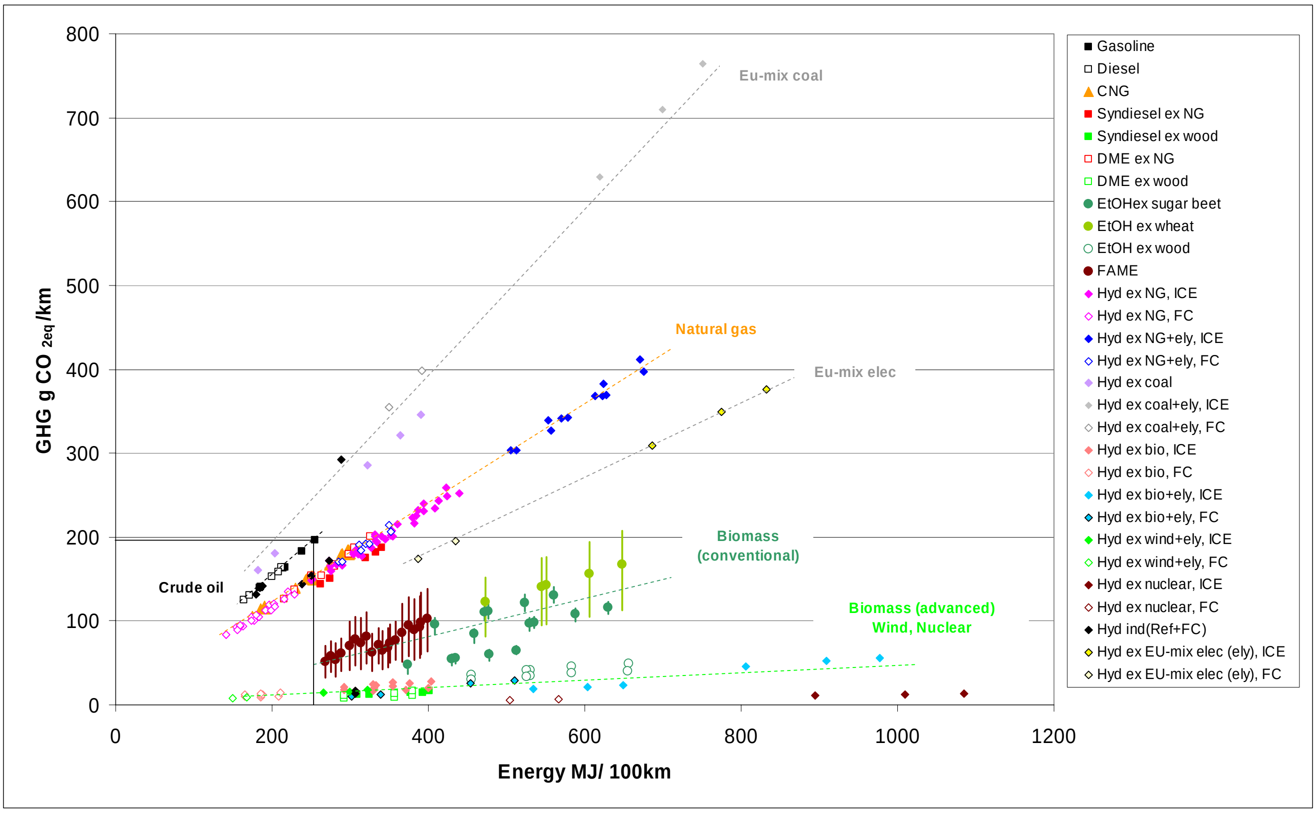
The overall WTW results are summarised in figure 16, plotting WTW total GHG emissions per km versus WTW total energy consumption per km. Each point on the chart represents a different pathway combining the WTT data with the appropriate TTW vehicle options.

The results cluster on trend lines representing the different fuel sources, with a large range of variation along the trend lines – depending on how the fuel is produced and used. The box in the lower left corner of the chart highlights the performance of current gasoline vehicle technology.

Many of the possible pathways derived from natural gas, oil or coal produce more GHG emissions than today's conventional pathways. Fuels derived from biomass produce less GHG emissions, but again with a wide variation in the performance of different pathways. Since renewable resources are limited, those options giving the lowest energy use are most attractive. Advanced renewable fuels, including biomass-to-liquids, give lower GHG emissions than conventional biofuels and merit further development.

Overall GHG emissions savings of up to 35 Mt CO_{2eq}/a are achievable in a 5% substitution scenario with alternative fuels by 2010. All pathways considered, in principle, provide the potential in terms of availability of the energy resources to reach this substitution level.

Fig. 16: WTW greenhouse gas emissions and energy efficiencies for various primary energy sources with different vehicle technologies



3. Natural Gas

3.1 General aspects

The Commission's Communication on alternative fuels identified natural gas as the alternative fuel most likely to deliver the biggest single contribution to a 20% substitution of gasoline and diesel aimed at by 2020, with a contribution estimated at around 10% market share.

The work of the Contact Group has confirmed that if a 20% substitution is to be achieved by 2020, natural gas will have to deliver a significant contribution. If this is to be achieved, the long lead times linked to mass market introduction of new fuel and vehicle technology make it essential that the process towards a mass market for natural gas vehicles is accelerated as soon as possible. A 2% substitution by 2010, as projected in the Communication of 2001, is only a possible scenario if a number of facilitating steps are taken by governments and industry during the next 1-2 years.

Natural gas as a motor vehicle fuel is already in use – albeit only on a limited scale. Natural gas vehicles are offered in a limited number of types so far; but the major car manufacturers are starting to offer a greater number of models. Key issues are implementation strategies and technological issues aiming at optimisation and market widening. Particularly important is the build-up of the fuel infrastructure.

Main drivers for policy actions fostering the market penetration of alternative fuels are:

- Improvement of security of supply through fuel diversification
- Reduction of greenhouse gas emissions
- Additional environmental benefits, in particular short-term reduction of particulate emissions

Any political decision on the promotion of natural gas as a motor vehicle fuel depends on an assessment of the performance of natural gas in relation to these drivers and the following common criteria:

- Potential for market share
- Time scale of market penetration
- Cost of market development

The potential market share of natural gas as a motor fuel is not limited by primary supply. A share of 10% in road transport by 2020 would only represent about 5% of the total gas demand in the EU expected by that time. The necessary high-pressure gas distribution system already required for the future forecast uses of natural gas in other sectors, therefore, can also ensure the envisaged additional demand for transport fuel, assuming – of course – that this additional quantity carries its proportional part of the overall infrastructure cost.

The time scale of the market broadening for natural gas in the motor vehicle sector strongly depends on the build-up of refuelling infrastructure, which under otherwise favourable conditions should encourage vehicle production and consumer acceptance. Ambitious programmes in place in some Member States aim at a coverage of about 10% of the filling stations by new natural gas filling points within 5 years. Market studies have shown that a 10% passenger car fuel share would require about 25% of the filling stations equipped for supplying it. Such an objective for 2020 appears feasible. In Germany, e.g. 1000 new stations are expected to be added within 4 years, which then would result in coverage of 10 % of all stations by 2007. The refuelling network build-up should find sufficient fuel demand to optimise investment. In the early stages, fleet and local markets, such as urban transport, offer the potential for high utilisation of refuelling stations, providing the revenue to sustain further investment and expansion of the network.

It must be underlined that a broader penetration of natural gas as a motor fuel can only be expected if pursued at the European level. Car owners will hesitate to buy vehicles that cannot be used throughout Europe, and car manufacturers will only invest in a broad range of vehicles if there is a market of sufficient size. National initiatives can be important catalysts, but long-term success is fundamentally dependent on an overall European approach.

The assessments of the Contact Group – and the well-to-wheel study – has been based on the so-called H-gas, the high methane content gas (more than 95% methane) most commonly transmitted throughout the EU and covering practically all imported natural gas.

L-gas (around 85 % methane, 15% inert gas) is widely distributed in the Netherlands and parts of Germany. It causes no technical problems in natural gas engines but offers somewhat less efficiency because of the presence of inert material.

Whereas fossil fuel natural gas from the European grid seems likely to deliver the main contribution to a European natural gas vehicle fleet, the potential of biogas should not be ignored. Biogas, after appropriate purification, can be used like natural gas as a motor fuel, the same way biogas can substitute natural gas for any other purpose (power generation, heating, chemical feedstock).

Biogas offers a low-CO_2 emission fuel due to the biological origin of the carbon in the gas. Raw materials can either be waste (animal manure, waste water treatment sludge, etc.) or energy crops turned into methane rather than into other fuels. Production cost of biogas depends on circumstances, but is normally higher than natural gas. Biogas qualifies to meet requirements under the biofuels directive (targeting 2% market share by 2005, increasing to 5.75% by 2010). In view of the relatively high cost of other biofuels, Member states might find it attractive to cover part of their bio-fuels obligations by biogas; it can also assist in meeting the EU waste requirements. This option would be much encouraged if natural gas becomes a generally distributed motor fuel although it is already used in some cities as a fuel for captive fleets thereby removing much of the need for additional infrastructure.

The technical feasibility of using biogas has been demonstrated in Sweden, where 4000 vehicles (as of the end of 2003) operate on biogas. This option is particularly relevant in areas without natural gas network. Development of biogas and development of a broader natural gas vehicle market can be mutually supportive. The broader market development creates the basis for broader use of biogas and development of biogas supplies in areas without natural gas distribution will make it possible to use natural gas vehicles practically anywhere in Europe.

As with other biofuels, the CO_2 advantage is only a net advantage in the overall balance if the biomass used, or energy produced, is over and above what would otherwise have been the case. With competition to be expected between different uses of the same biomass feedstock for methane gaseous fuel, stationary heat and power production and possible hydrogen production, decisions on the preferred choice will need to take into account several criteria, such as security of energy supply, energy efficiency and greenhouse gas emissions, in the frame of the overall economics of biomass use.

3.2 Security of supply and fuel diversification

The almost 100% dependency on oil in the transport sector is generally recognized as a particular concern beyond the general concern over increased energy import dependency of the EU in the coming decades.

Dependency on only one energy source increases vulnerability. This is further accentuated by the expectation of around 50% increase in oil demand worldwide over the next 20-25 years and decreasing production outside the Middle East during the same period.

Natural gas imports are also forecast to increase, offering however, a different security of supply perspective. Whereas oil moves worldwide in a very flexible transport system, most of international natural gas trade is linked to a fixed, in-place pipeline system, linking closely the seller to the buyer as much as the buyer to the seller. Liquefied natural gas transport is offering flexibility, in principle comparable to oil transport. But the number of available ships and terminals is and will remain much more limited than the corresponding oil infrastructure.

Neither oil nor gas will run out over the next 20 or 30 years. However, it seems increasingly difficult (contrary to earlier progress) to identify in particular new conventional oil resources corresponding to present or expected future consumption. For gas the situation seems less stressed, but may well follow the oil scenario with a number of years delay.

The objective of reducing the high level of oil dependency in the transport sector should be seen against this backdrop. Diversification towards non-oil alternatives is valuable even if alternatives are not domestic. In this context it is important to recognize that the different types of potential vulnerability of a combined system relative to a system fully dependent on one source by itself offers lower over-all vulnerability. It is also worth noting that an energy supply system based on several sources offers a much shorter response time in case of crises than a system based on one source only. Moving from 90% oil, 10% gas to 80% oil, 20% gas would be a much simpler and faster operation than introducing 10% gas into a 100% oil-based system.

3.3 Greenhouse gas emissions

Natural gas has been and is likely to remain an important energy source in the EU’s climate change policy. It contains less carbon than other fossil fuels (coal, oil) and it can often be used with higher efficiency in stationary applications.

The summary of well-to-wheels greenhouse gas emissions for natural gas, diesel and gasoline vehicles are shown in figure 18, together with the corresponding energy consumption data in figure 17. Further explanation of the data is found in chapter 2.4.1 under the well-to-wheels study.

Fig. 17: Well-to-wheels energy efficiency emissions of natural gas vehicles

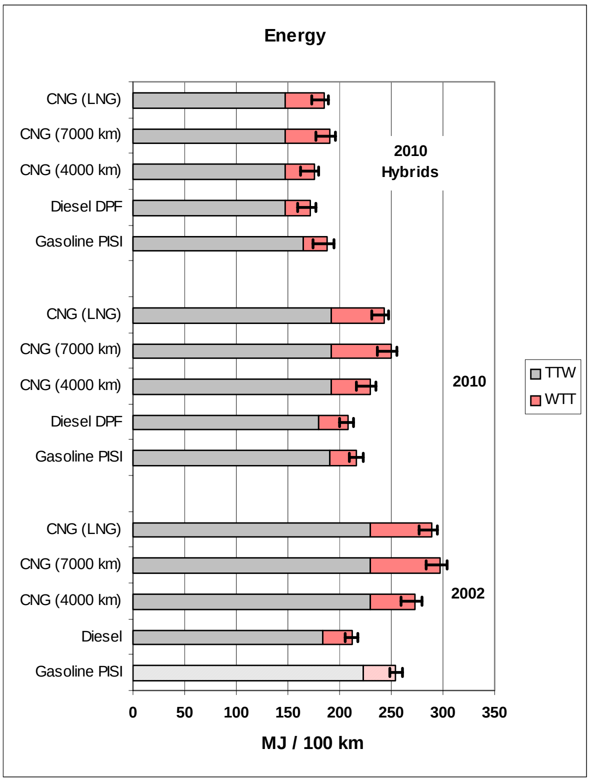
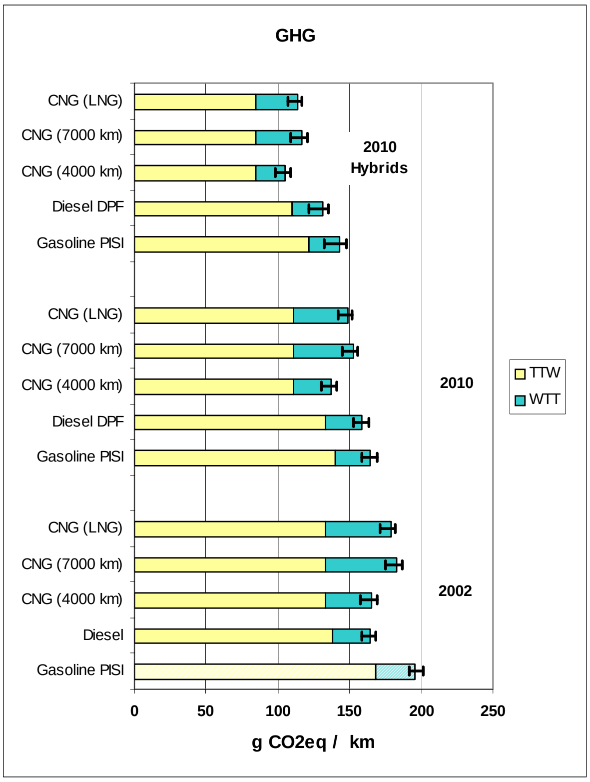


Fig. 18: Well-to-wheels greenhouse gas of natural gas vehicles



It can be seen from the data that, for today, with marginal natural gas supplies within 4000 km distance, natural gas vehicles have a clear CO_2 advantage over gasoline and are comparable to diesel vehicles. Calculating the CO_2 emissions on the basis of the present EU mix (average transportation distance 1000 km) would give an approximately 15 g $CO_{2\ equ}$ / km lower value. The relevance of this number can, however, be questioned since even today changes in natural gas consumption will not result in changes in EU production but rather in increased imports from fields further away.

In the future, the WTW GHG balance of CNG is expected to become more favourable than that of diesel (by about 13% for the 4000 km case, see figure 18 above). The main reason for this is the larger potential for efficiency gains in spark ignition engines compared to compression ignition engines (16% improvement for CNG vehicles compared to present technology, against only 2% for diesel vehicles fitted with a particulate filter - See also section 2.3.1). Further possible technological developments have the potential of additional future CO2 reductions natural gas vehicles.

The use of renewable biogas, if produced for this purpose over and above what would otherwise be produced for other purposes, could lead to considerably higher emission savings.

The well-to-wheels analysis has taken into account, to the extent possible, the expected development of engine technology and fuel quality for the near future. Similar calculations of the 2015-20 situation where natural gas may have achieved a more respectable share of the fuel market will necessarily be more speculative.

Within these uncertainties, there is reason to believe that further natural gas engine development, following a more widespread availability and use of the fuel could bring the CO_2 advantage closer to the 25% lower carbon content of the fuel. This would particularly be true if current efforts, aimed at combining the advantage of diesel and gasoline engines will be successful, since such technology would also be applicable to natural gas.

The full exploitation of technology options requires an attractive market share of CNG vehicles. Only then a dedicated mono-fuel engine would be optimised. This holds even more for heavy duty engines.

3.4 Other environmental aspects

Natural gas vehicles normally use spark-ignited engines with three-way catalysts. These provide low levels of regulated pollutants (particulate matter (PM), CO, NO_x, non-methane hydrocarbons). The same is, however, the case for other spark-ignition fuels (gasoline and LPG) and - with the exception of NO_x and PM - for diesel engines. Compared to the majority of today's diesel engines, natural gas still maintains an air pollution advantage even beyond the significant reduction in emissions required by the most recent standards (Euro-4 in 2005 for passenger cars and Euro-5 for heavy-duty vehicles in 2008). In the longer term, the limit values for NO_x and PM from diesel passenger cars, light commercial vehicles and heavy duty vehicles will be further tightened. In these conditions, it is likely that it will make little if any difference, from an air quality point of view about 5 to 10 years from now, whether new ICE-based vehicles will be fuelled by gasoline, diesel, LPG or natural gas. Since the introduction of low-emission diesel vehicles and large-scale introduction of CNG vehicles will need about the same phasing-in time, there is no reason to expect significant long-term differences with regard to the impact on air quality between these technologies.

There remains, however, concern over the health impact of diesel emissions particularly in cities where more people are affected. The bigger the city, the more severe, in general, is the impact. Therefore, big cities and/or cities with elevated levels of PM and NO_x pollution have good reason to consider measures to promote high-mileage vehicles (taxis, buses, certain types of distribution vehicles) operated on natural gas, biogas or other low emission technology. Such a change has already been undertaken in some cities in the EU.

The fact that methane is the predominant hydrocarbon component in the exhaust gas and that methane is only slowly decomposed in the catalytic converter means that the quantity of noble metal (platinum) in the catalytic converter must be increased to approximately 6 times the normal quantity if methane emission has to be reduced to the level required by the current total hydrocarbon limit value. Since the elimination of methane offers only a marginal – if any - benefit for air quality, it would be advisable to develop a separate non-methane emission standard adapted to the actual impact on air quality as well as on the greenhouse effect.

3.5 Cost

Assessment of the cost of substituting a certain quantity of gasoline and/or diesel with natural gas can be done from different perspectives:

- Overall cost for society in the longer term where a certain level of substitution (say 5-10%) will have taken place.

- Transition cost covering up-front additional investment and additional cost for infrastructure and vehicles until mass-production and full utilisation takes over.

- Cost of ownership, that is the cost structure for the owner or operator of the natural gas vehicle.

The first two assessments will typically be carried out with the exclusion of taxes whereas fuel and vehicle taxation is an important element of the cost of ownership. For any strategy promoting natural gas as a motor vehicle fuel, all three assessments have to be acceptable.

In view of the fact that the basic overall cost assessment is addressing a situation some 10 years ahead and with assumptions on cost reduction linked to transition to mass production, a certain caution on the possible accuracy of such assessment is necessary.

3.5.1 Overall cost assessment

This section considers the longer term cost when CNG is an established fuel. Costs during the transitional period are discussed in section 3.5.2. A number of factors must be addressed to assess the difference between natural gas and gasoline or diesel as a fuel. This assessment will address the following:

- Fuel cost (commodity price)
- Distribution cost (including delivery to vehicle)
- Vehicle cost
- Maintenance and operating costs
- External cost.

3.5.1.1 Fuel cost

Gasoline and diesel prices (excl. taxes) fluctuate with oil prices and with the season (gasoline is usually relatively more expensive during summer). Prices in Euro do not follow prices in US dollars when exchange rates vary. Gas prices have traditionally been linked to longer term trends in oil prices, showing, however, much less fluctuation than oil prices.

Crude oil prices during the last couple of years have moved around 25 € per barrel, translating into roughly 20 €c/litre for gasoline and diesel when leaving the refinery or being imported in bulk. During the same period, the EU weighted average border price for natural gas has been around 10 €c/ m^3 (in the range 8-13 €c/m^3). 1 m^3 of natural gas replaces 1.1 litre of gasoline and 0.9 litre of diesel. This implies a commodity price advantage of roughly 55% over gasoline and 45% over diesel.

Prediction of the future price differential between oil products and natural gas is uncertain. In principle the huge oil reserves in the Middle East could be brought into production at a cost much below 25 €/barrel but the relative success of OPEC over most of the previous 30 years in keeping prices well above production cost, coupled with the expected strong increase in oil demand over the coming decades makes a more permanent low oil price scenario unlikely. More likely is a long term price increase, as the projected future oil demand will lead to a stronger world market position of Middle-East oil producers.

Demand for natural gas is also expected to show strong growth. Prices are likely to be increasingly linked to production and transmission cost and the fact that an increasing amount of gas is expected to go to electricity production where coal is a cheap and abundant alternative, makes it less likely that long term prices for natural gas will be subject to the same risks for increases as oil prices.

Therefore, - using the present price differential as a basis for the longer-term assessment seems to be a reasonable and supportable assumption. Higher, maybe also lower, differentials may well materialise but it is difficult to argue convincingly for one over the other.

3.5.1.2 Distribution and dispensing cost

Fuel distribution and retailing cost varies over a broad range, to a minor extent depending on distance from refinery or terminal, to a larger extent on the size, type and utilisation of the refuelling station.

For gasoline and diesel an amount of 10 €c/litre can be taken as a representative average. Taking that the simple distribution to the refuelling point is comparable for natural gas and liquid fuels (approximately 2 €c/litre or m^3 marginal cost) and that all fuels will have to contribute on an equal basis to the general cost of the refuelling station, the difference in distribution and dispensing cost is linked to the higher capital cost (investment) and operational cost (compression) of a natural gas refuelling point.

An efficiently utilised, mass produced natural gas refuelling point with a capacity of 1 million m^3/year is expected to have a capital cost of 3 €c/m^3 and electricity cost of 2 €c/m^3, implying an overall distribution and dispensing cost for natural gas of 15 €c/m^3 or an overall “pump price” of 26 €c/litre.

Bearing in mind that it takes 0.9 m^3 natural gas to replace 1 litre gasoline and 1.1 m^3 to replace 1 litre diesel the overall cost advantage for natural gas under the assumptions used is 7-8 €c/litre against gasoline and 2-3 €c per litre against diesel.

The uncertainty on assumptions made, particularly the long term price differential between oil and gas may well exceed the 2-3 €c per litre diesel equivalent, whereas some advantage over gasoline would certainly remain unless real life development would be very different from the assumptions.

3.5.1.3 Vehicle cost

Existing pricing patterns show bi-fuelled natural gas cars at around 2.400 € above similar gasoline models. Roughly the same cost is reported for retrofitting existing gasoline vehicles with a parallel natural gas fuelling system. City busses with dedicated natural gas drive cost about 35,000 – 50,000 € more than diesel buses.

Existing price or cost data for natural gas vehicles reflect the situation of a “niche market” that has not so far been able to benefit from the mass market economics and competitive pressure presently benefiting gasoline and diesel vehicles.

In addition, most natural gas vehicles, particularly private cars, are bi-fuelled with a gasoline based fuel system in parallel to the natural gas system, which makes the vehicle more expensive. The gasoline option will remain a necessity as long as natural gas refuelling possibilities remain limited.

Uncertainty remains as to what extent the additional cost for a natural gas vehicle (mono-fuelled or bi-fuelled) will be reduced with mass production. The inherently more expensive high-pressure gas tank implies that a certain additional cost for a natural gas vehicle will remain in spite of mass production advantages. The Natural Gas Topic Group is of the opinion that an additional vehicle cost of 1200-2000 € for a natural gas vehicle over the equivalent gasoline vehicle offers the best estimate at present for the long term differential. Incidentally, this price differential is close to the price differential between gasoline and diesel engines (60-100 kW at 20 €/kW equals 1200-2000 €), putting the cost of the natural gas vehicle at the same level as a comparable diesel engine vehicle.

3.5.1.4 External costs

Any assessment of costs and benefits must, to the extent possible, take external cost into account. Assessment of the external cost on the basis of today's situation is a case for departure but it needs to be kept in mind that the correct period of comparison might be the second half of the next decade where natural gas substitution may reach a level of 5-10%. The three main differences from today's situation that one could envisage at that time are:

- Particulate and NO_x emissions from diesel vehicles will be reduced from today's level
- Urban air quality will have improved considerably up to 2020 over present levels
- Improved efficiency of CNG vehicles is likely to provide a CO_2 advantage relative to diesel by 2020.

Taking today's situation, in the case of gasoline substitution the main reduction of externalities relates to the lower CO_2 emissions of the natural gas vehicles. If natural gas substitutes diesel, the main reduction in externalities relates, in short term, to the avoided PM and NO_x emissions, whereas CO_2 emission reductions can be hoped for in the longer term. On the basis of these assumptions the value of the CO_2 advantage of natural gas over gasoline will amount to 0.1 €c/km or around 1.5 €c/l gasoline equivalent, an amount within the uncertainty on the future differential between natural gas and gasoline. Even taking into account potential improvements in natural gas engines, the economic value of the avoided CO_2 emissions is likely to remain relatively small in the longer term.

As far as particulate matter is concerned, the EURO 4 standard for passenger cars (coming into force in 2006) sets a maximum emission standard of 0.025 g/km and the EURO 5 standard for heavy duty vehicles (coming into force in 2008) 0.02 g/kWh in for steady state and 0.03g/kWh for transient cycle. In short term, this results in an external cost advantage for CNG compared to diesel.

However, this advantage is not likely to represent a long-term advantage. In the future, with the introduction of more stringent limit values for diesel vehicles the estimated PM benefit is expected to be reduced, while CNG might maintain a small advantage for NO_x. There is still uncertainty as to the impact on fuel consumption of strict diesel emission standards, and on how gasoline and CNG engine efficiency might improve in the longer term.

In conclusion, quantifying the external costs of gasoline and diesel over CNG does not seem to provide a significant economic contribution to the effect of fuel substitution in the long run. Measures implemented before the tighter limits for diesel vehicles come into force will have external costs advantages. This calculation, in any case, stresses the importance of continued reduction of particulate emissions, in particular in urban areas.

3.5.1.5 Conclusions on long term macroeconomics

Substitution of gasoline or diesel with natural gas appears to be economically viable if done at a sufficiently large scale to ensure mass market benefits and full utilisation of vehicles and infrastructure. Compared to gasoline, the additional cost of the natural gas vehicle (1,200-2,000 € for passenger cars) is to a significant extent compensated by the saving on the fuel (assuming a lifetime consumption of 12,000 litres gasoline equivalent at 7-8 €c price advantage per litre). In addition, the reduced CO_2 emission could amount to a value of 200 € over the lifetime (200,000 km), if valued at 50 €/ton. Substitution of diesel will pay off if the efficiency of natural gas vehicles improves as predicted.

In all cases the overall cost implications are small relative to the cost of vehicle ownership (less than 1% of overall cost, even with taxes excluded), - and compared to the uncertainties linked to price and cost developments on fuels, vehicles and equipment.

3.5.2 Transition cost

Over and above the economic assessment of an established natural gas vehicle system an up front investment will be necessary in order to achieve market sustainability.

The fact that there is a necessary up front investment adds cost in form of higher capital charge. The capital cost of the refuelling installation is already part of the cost assessment for the fuel distribution, but it must be supported for a transitional period with little return before the fuel market is developed. A number of additional cost elements arise during the build up phase compared to the situation when natural gas has achieved a market share characterising "mass market" level.

These additional cost elements are:

- Higher cost for the natural gas vehicles than assumed in the long term economic assessment
- Lower utilisation of refuelling infrastructure during build up phase.
- Higher maintenance cost as long as natural gas vehicles remain a niche product.

The three points will be addressed in the following section. The calculation covers the period up to 2010 where a 2% natural gas substitution is assumed. The calculations will remain subject to significant uncertainties as long as the pathway to a 2% substitution remains uncertain. The arguments developed below continue to be valid beyond and certainly at least up to 10%. Consequently on-going support is likely to be required well beyond 2010.

3.5.2.1 Vehicle cost

Two percent substitution of the total quantity of motor vehicle fuel in 2010 corresponds to roughly 6 Mtoe. Assuming the substitution happens in vehicles with above average yearly mileage, a number of 20.000 km/year (against an overall average of 13,000 km/year) seems reasonable. With additional fuel efficiency improvements a consumption of 5 l / 100 km gives an average fuel consumption of 750 kg implying that 8 million natural gas vehicles will be necessary to deliver a 2% substitution (for the purpose of an overall estimate all substitution is assumed from gasoline vehicles).

There is reason to believe that the actual number will be less than this, since part of the substitution will take place in buses, garbage trucks, service vehicles with higher yearly mileage but, since these vehicles will also have higher specific cost the economic assessment is not likely to come out much differently. As the majority of the vehicles necessary to achieve a 2% substitution will go on the road towards the end of the decade, most of the vehicles will benefit from the mass production (more than 1 million vehicles per year) advantage already before 2010.

A realistic assumption could be that the extra vehicle cost could be equivalent to one third (2.5 mill. vehicles) being subject to a cost of 1200€ over and above the mass production cost level. This assumption would imply a total transition cost for vehicles in the range of 3 billion €.

3.5.2.2 Fuel cost

The higher fuel cost in the transition period reflects the lower level of utilisation of the refuelling infrastructure during the period. A way to reflect this additional cost is to calculate the capital cost of the investment which will not be fully utilised. Assuming that infrastructure will be established ahead of the corresponding demand in a way that implies less utilisation corresponding to 2 years of turnover per installation, the equivalent cost for the transition period will be equivalent to 20% of the investment. With an investment of 250,000 € for refuelling points this represents 50,000 € per point or 350 million € for the 7,000 stations necessary for the 2010 substitution.

It may be argued that a more aggressive fuel supply strategy will be necessary to convince consumers to buy natural gas vehicles. The numbers, however, show that the overall transition cost is not very sensitive to this, since vehicle cost will still be the more important. Nevertheless, considerable investment is needed to establish a refuelling network. In the early stages, fleet and local markets, such as urban transport, offer the potential for high utilisation of refuelling stations, providing the revenue to sustain further investment and expansion of the network.

3.5.2.3 Maintenance costs

Experience with large captive fleets with mainly public transport operators in Europe and in the U.S. has shown about 15-20% higher maintenance costs for natural gas buses. On the other hand, numbers of studies of European and U.S. experiences also have shown marginal reductions in maintenance costs for NGVs. More frequent maintenance and service attendance also may reduce the availability of the vehicle, as shown in case studies. Re-fuelling station maintenance also will be an issue, particularly in the market entry and early expansion phases. System redundancy is necessary to ensure continuous availability. Additional training costs also can be anticipated. For a transition period, therefore, sufficient maintenance infrastructure should be provided to strengthen consumer confidence. On the longer term, broad market development with steady series production and uptake by a broad customer base is the most promising and most economic way to ascertain high quality standards and reduce maintenance costs.

3.5.3 Cost of ownership

Whereas in the longer term a fully established natural gas vehicle market may well be cost competitive with gasoline or diesel fuelled cars, this will not be the case in the transition period, as demonstrated in the previous chapter. The established gasoline and diesel vehicle market, including fuel supply, have been continuously optimised over decades and are operating at full capacity, at least in principle. Any newcomer alternative fuel will be disadvantaged in the process of entering the established market, unless the newcomer is either seen by the consumer as obviously superior to the existing alternatives or is given one or another sort of support. Natural gas as a motor fuel does offer fuel costs savings but at this stage in market development the consumers who are aware of NGVs remain concerned about fuel availability. Consequently, natural gas is likely to make a breakthrough only if incentives are offered that make consumers decide for the alternative fuel. Several such incentives are possible. Most of them are economic in nature. Reduced fuel taxation is the most obvious way of making alternative fuels attractive to consumers. Other advantages could be reduced circulation and registration tax, or exemption from distance-based tolls, parking fees or access charges (e.g. London). Non economic measures can be access to otherwise restricted areas or permission to circulate during periods where pollution levels would incur restrictions on other vehicles.

Reduced or foregone fuel taxation

European energy excise taxation legislation already grants Member States the possibility to apply a lower taxation rate on natural gas as a motor vehicle fuel. The recently agreed minimum rate of 2.6 €/GJ, approximately 9 €c/m^3 corresponds to only 20-30% of the rates typically applied to gasoline or diesel. Whether to take advantage of this option or not is left to Member States to decide. Germany, as a progressive example, has decided to use a level of approximately 12 €c/m^3 until 2020 in order to create both a sufficiently strong incentive and the necessary long term stability for consumers that might consider investing in a natural gas vehicle.

A crucial question in addressing cost of ownership is whether minimum taxation of natural gas will deliver a sufficient incentive in the short-to-medium term to provide the intended penetration of natural gas vehicles. The answer to this question depends on two factors:

1. The level of gasoline and diesel taxation in the respective country. Member States have different levels of fuel taxation and minimum taxation of natural gas obviously will deliver a much stronger incentive in Member States with a high level of fuel taxation than in Member States applying only the legally required minimum levels. In the latter case the minimum fuel taxation of natural gas is not likely to deliver by itself a sufficient incentive to make car owners shift to natural gas.

2. The segment of cars aimed at. First, it takes less of an incentive to make natural gas an attractive alternative to gasoline than to diesel, which generally is subject to lower taxation and has higher engine efficiency. It will also take a stronger fuel price incentive to make natural gas competitive for a car with an annual mileage of 15,000 km (close to average) than for a car with an annual mileage of 30,000 km or for a taxi with an annual mileage of 80,000 km, since the added cost of the natural gas vehicle translates into a (largely) fixed annual cost, whereas the fuel de-taxation advantage is proportional to the fuel consumption and, therefore, the annual mileage.

On the basis of existing EU legislation and on Commission proposals to harmonise taxation on diesel for professional uses a realistic gasoline taxation level for the period 2005-2010 could be estimated at 500 €/1000 litre and diesel taxation of 400 €/1000 litre. Values around the levels would apply in the major part of the central EU (Germany, France, Netherlands, Denmark, Italy). These taxation levels would result in retail prices of approx. 1.00 €/litre (gasoline) and 0.85 €/litre (diesel).

Compared to this natural gas could sell at around 0.50 €/m^3 if taxed at the minimum level and assuming a compression and dispensing cost in the early transition period 0.15 €/m^3.

For the case of gasoline substitution, where one 1 m^3 of natural gas roughly replaces 1.1 litre of gasoline an annualised cost of 480 € (20% of 2400 € higher vehicle cost) takes a fuel consumption of around 1000 litres of gasoline to break even. This corresponds to 14.000 km annually with a specific fuel consumption of 7 litre/100 km. In order to compensate for other inconveniences in the transition period (refuelling restriction, more frequent refuelling, fewer skilled maintenance professionals) it is to be expected that fuel "de-taxation" is only delivering a necessary incentive per se for drivers with relatively high annual mileage. As price differentials for natural gas vehicles and fuel distribution cost will come down users with more limited annual mileage will see an advantage as well.

Concerning diesel, a price differential of 0.35 € between 1 litre of diesel and 1 m^3 of natural gas is estimated sufficient to make natural gas attractive, when compensating for the efficiency factor (0.8 l diesel equivalent to 1 m^3 of natural gas with today's efficiencies). In the longer term, CNG vehicles are expected to match the costs of gasoline and diesel vehicles. But customers may still need a price advantage to assure their continued use of CNG. This factor needs to be included in any assessment of future taxation revenue, but is, in principle, no different from the taxation advantage diesel has benefited from for many years.

3.6. Future perspectives

The different assessments presented above are based on existing experiences and possible developments in the near future, based on ongoing development work, particularly in the car industry.

This methodology is by its nature conservative even though the 2010 assessments try to compensate for this. It compares a 'newcomer' in this case natural gas vehicles, with technology which has achieved a high level of technical maturity and which is even at this stage of maturity benefiting from much higher investment in future improvement than natural gas technology.

Most of the development work on natural gas engine technology has been on the conditions set by the gasoline engine. Market potential has been insufficient to justify large scale development of genuine natural gas vehicle technology that would – ab initio - take full advantage of the inherent properties of natural gas. Furthermore, national government support for basic research and development has been limited compared to other vehicle technologies.

Recent research work reported, i.e. by FEV to the Contact Group points to potential improvements in engine efficiency that would deliver CO_2 emissions even below what it has been possible to use for future development in this report. Whether such promises can be turned into reality on the road remains to be seen. It is however obvious that these developments are significantly closer to market introduction than the developments necessary to turn hydrogen vehicles into practical reality. It is also clear that unless natural gas becomes a main stream motor fuel, investment in natural gas technology development will remain at modest levels.

Codes and standards for the use of natural gas as motor vehicle fuel should be harmonised at international level in the respective normalisation and standards committees. This is essential to support a broader commercialisation of natural gas vehicles. Proposals for harmonisation within the EU are specified in Annex 3.

4. Hydrogen

4.1 Security of supply and fuel diversification

Fossil energy resources in principle are plentiful and could meet the energy demand still for many decades. Climate change concerns, however, are imposing increasingly severe constraints on their use. Their present level of use without capturing and sequestration of the greenhouse gases produced is incompatible with the need to reduce these emissions. In the longer term, production rates of fossil energy supply might fall behind increasing demand and then give rise to increased prices and market instabilities. The most vulnerable sector is transport, which nearly entirely depends on oil based fuels. Any fuel diversification therefore would contribute to reducing the exposure of the transport sector to perturbations in oil supply, as well as reducing the social and environmental impact of oil extraction, transport and use.

Hydrogen has the potential to become a future universal energy carrier, similar to electricity, and can be produced from any energy source. Hydrogen can be used as fuel both in mobile and stationary applications and provides very flexible storage options, from large volume storage near production to tailor-made on-board storage. This is the basis for the vision of a sustainable hydrogen economy. Hydrogen propulsion systems exist or have been conceived for all modes of transport. This wide range of applications differs considerably from the narrow range of battery based electric traction systems. Hydrogen, therefore, offers a means to open the transport sector to a wide range of energy sources, with the long-term potential for full reliance on renewables.

The importance of hydrogen for our future energy system choices has been given due recognition at the highest political level, by Commission President Prodi, who stated at the occasion of the June 2003 conference on Hydrogen and Fuel Cell Technologies that “what makes the European hydrogen programme truly visionary (…) is our declared goal of achieving a step-by-step shift towards a fully integrated hydrogen economy, based on renewable energy sources, by the middle of the century.” The long-term vision of a hydrogen economy has been developed by the Hydrogen High Level Group, which was called by the European Commission in October 2002 and presented in its final report (18). Following the recommendations of the High Level Group, a European Hydrogen Technology Platform is being established, as announced in a Communication presented by President Prodi, together with Vice-President de Palacio and Commissioner Busquin in September 2003, to bring together all actors in the field of hydrogen and fuel cells in Europe and stimulate and guide the development of a strategic research agenda and support the development of a deployment programme, including large scale lighthouse projects. The European Commission also participates in the International Partnership on a Hydrogen Economy launched in November 2003.

Key technological and economical issues associated with production, distribution, storage, safety, and applications of hydrogen still have to be solved before a broad market introduction of hydrogen technologies in the transport sector can be envisaged. The market introduction of hydrogen could be accelerated by demand side management. Higher end use efficiency increases the value of energy and could compensate for higher unitary cost. The overall CO_2 balance, however, is very sensitive to how the hydrogen is produced and distributed, as discussed in the following sections. As far as not otherwise stated, the energy and/or greenhouse gas emissions comparisons between different pathways will be based on the results of the EUCAR/CONCAWE/JRC study (1).

4.2 Hydrogen production

Hydrogen does not exist in free form but only chemically bound in molecules such as water or hydrocarbons. Energy input serves to split these compound molecules and produce pure hydrogen molecules. Energy is then released again in chemical reactions of hydrogen with oxygen to water. This energy conversion process through production and re-combination of hydrogen molecules is conceptually analogous to electricity production from primary energy sources and subsequent consumption in electrical applications, with the electrons being the energy carrier there.

Hydrogen can readily be produced in industrial scale either from fossil energy resources, such as natural gas through reforming and coal through gasification, or with electricity through electrolysis of water. The key factors in all these processes are cost of the energy input and the efficiency of energy conversion. Hydrogen production from biomass gasification could offer the most efficient pathway from renewable resources. Other ways of producing hydrogen, such as bio-production by algae and bacteria and high-temperature direct water splitting in solar thermal plants or co-production power plants are still in early stages of research. The most probable pathways to hydrogen have been considered in the reference well-to-wheels study (section 2.2.3).

Natural gas steam reforming in large-scale industrial plants currently provides by far the most economic and most energy efficient hydrogen production route. At present it dominates the market and is expected to remain the leading process up to the time horizon of 2020. The steam reforming process has been optimised and used in large industrial scale over several decades, mainly in the chemical industry for fertiliser production and for oil refining.

Electrolysis of water is a mature technology of hydrogen production as well. Its economics strongly depend on the electricity prices, varying in range about a factor 3 between low cost excess base load electricity and high cost off-shore wind electricity. The energy efficiency of the water electrolysis/fuel cell conversion chain, however, is low. Hydrogen from electrolysis is typically at least twice as expensive as from natural gas steam reforming. Production of hydrogen through electrolysis can be of particular interest for buffering fluctuating renewable sources such as wind and solar power plants and for optimising steady operation of base load plants such as large hydropower and nuclear at maximum output, using their excess “low-cost” electricity production at times of low demand. The use of electricity from (non-hydro) renewable resources for hydrogen production, however, is not a viable solution as long as it does not create additional demand for renewables. At the present level of this renewable electricity production, feed-in to the grid is by far more economic and achieves much larger greenhouse gas avoidance through substitution of fossil power production.

Hydrogen production from natural gas steam reforming or coal gasification could become an environmentally acceptable option by including CO_2 capture and storage presently under research and large-scale demonstration. Carbon capture processes under study could provide for a CO_2 removal rate of 90%. Cost for carbon capture, with a high CO_2 removal rate of 90%, is estimated at about 0.8-1.1 €/GJ for hydrogen production from natural gas and at 1-3 €/GJ for coal gasification, depending on plant capacity and feedstock prices (JRC (16), IIASA (17)). In contrast to thermal power stations that generate electricity, the efficiency penalty in hydrogen production plants is small and the increased fuel consumption is less than 10% (JRC). Transport and storage costs for CO_2 are estimated at around 10±5 €/t CO_2, depending on CO_2 volume, transport distance and storage site (IEA GHG R&D Programme). Coal could become economically attractive in case of rising natural gas prices. Coal gasification has reached industrial maturity in large integrated combined cycle (IGCC) power plants. Co-production of hydrogen and electricity (and heat) in power stations with coal gasification and co-combustion of opportunity fuels, including biomass, and integrated carbon capture and storage could be a particularly attractive scheme worthy considering along with low carbon pathways for the economic large-scale hydrogen production with highly reduced greenhouse gas emissions. However, research and demonstration efforts are needed to reduce capital costs and efficiency penalty; to identify potential CO_2 storage sites and assess storage capacity and retention times; and to develop methodologies for monitoring and verification, in order to guarantee the safety and environmental compatibility of CO_2 sequestration.

Biomass gasification for hydrogen production could provide a relatively efficient path for the use of this renewable energy source. Efficiency above 50% should certainly be achievable. Energy efficiency in the range 60-75% is indicated in small-scale EU-funded experimental projects on the various biomass pathways to hydrogen. The data from different studies, however, show large variations concerning efficiencies and cost. Therefore more R&D efforts are needed to gain reliable data for an evaluation. Biomass resources for hydrogen production are constrained by land availability and competition with other biomass utilisation routes such as liquid biofuels and electricity and heat generation.

A possible scenario for the use of renewable energy sources in an overall energy supply system containing hydrogen technology, until production of substantial amounts of renewable energy, could be the following branching into electricity and hydrogen production:

- Biomass for hydrogen production through gasification, with better economic and environmental balances than hydrogen production from renewable electricity,
- Excess production from fluctuating renewable sources for hydrogen production through electrolysis,
- Hydropower, wind energy and other direct renewable electricity sources preferentially for electricity production feeding into the grid (substituting fossil fuel-based generation).

4.3 Hydrogen distribution and storage

Market introduction of a new fuel and build-up of the fuel supply infrastructure are closely interlinked. Sufficient offer in fuel supply is a pre-requisite for the market take-up of new technology on the consumer side. For economic reasons, focus on geographically confined areas of high population density and fleet applications would offer a more practical and efficient use of available infrastructure and new installations during the initial period of commercialisation of hydrogen vehicles. This pattern generally mirrors the build-up of the natural gas fuelling infrastructure for NGVs.

Hydrogen as an energy carrier is disadvantaged by its low energy density per volume, compared to liquid and solid fossil fuels. The volumetric energy density of hydrogen can be increased by compressing it to high pressures in gaseous form or even more so by cooling it down to liquid state.

Liquefied hydrogen provides relatively the highest volumetric energy density for hydrogen (8.5 MJ/l), which is still a factor 4.2 smaller than for diesel (36 MJ/l). Liquefaction, however, requires around 30% of the energy content carried by the hydrogen for liquefaction. Hydrogen loss rates through boil-off can also be significant (up to 5% at present, but could be lowered to less than 1%). Vehicle tanks at present are subject to loss rates of 0.3 % -1% per day after initial filling. Tanks are already available for storing liquid hydrogen for 90 days without losses, using improved insulation, with low-temperature liquid nitrogen surrounding the container of liquid hydrogen. Similar technology as used there may be adapted to passenger vehicles in the future. Cost reduction and efficiency improvement of the liquefaction process may be obtained by raising the pressure, with the gain saturating around about 60 bar. Liquid hydrogen should be produced in central production facilities and distributed by trucks in liquefied form to the filling stations to obtain maximum energy efficiency.

Gaseous hydrogen has a lower energy density per volume than liquefied hydrogen. Hydrogen compressed to 800 bar, the highest pressure presently envisaged, has about 65% of the energy density of liquefied hydrogen. At present, storage tanks up to 700 bar are used. The energy input required for hydrogen compression is lower than for liquefaction. The energy consumed for compression from 1 bar to pressures in the range 300-800 bar is in the range of 10-15% of the energy content carried by the hydrogen. Pressure electrolysis (at 30 bar) and onsite reforming with subsequent PSA purification (15-20 bar) can decrease the energy consumption of this step to about 4-6% of the energy content of the hydrogen, as the energy consumption for compression is much lower when starting at the higher pressure resulting from the preceding hydrogen production process. The low volumetric energy density of gaseous hydrogen, however, results in high energy consumption for road transport when centrally produced and distributed in trailers. On the other hand, on site production of hydrogen and subsequent compression shows advantages in comparison to central production, liquefaction and distribution of the liquid hydrogen on the road.

Hydrogen could either be produced on site at the re-fuelling station or in central plants. On-site co-production of hydrogen, heat and power could also provide for consumption by stationary fuel cell installations, and better balance uneven hydrogen intake in early market development phases. On-site hydrogen production in small quantities, however, would preclude biomass gasification, co-production in power plants and also liquefaction – all processes efficient and economically viable only in large-size installations.

For central production of hydrogen, three main distribution ways could then be used: Pipelines for the transport of gaseous hydrogen, trucking of gaseous hydrogen in steel cylinders, and trucking of liquid hydrogen in refrigerated containers. Pipelines will be excessively expensive for small quantities consumed, and should only be considered in an advanced phase of market uptake of hydrogen. In the initial phase, on-site reforming of natural gas is the most economical solution. Truck distribution of gaseous hydrogen would be inefficient due to the low payload of hardly more than 1% of the overall weight, which is mostly used up for high pressure steel containers. More costly but more flexible for hydrogen supply to the end user, in particular in the early stage of market build-up, would be trucking of liquid hydrogen from central liquefaction plants to the re-fuelling stations. Delivery of liquefied hydrogen to re-fuelling stations would give the option of providing, from the liquid hydrogen stored at the station, both liquefied and compressed gaseous hydrogen outlets at the filling point, with one single distribution system. Much less weight is needed for packaging, resulting in a useful payload for liquid hydrogen on trucks about an order of magnitude larger than for gaseous hydrogen. This means a factor ten less trucks would need to run over the same distance for hydrogen distribution to the re-fuelling stations.

The balance between central and on-site production of hydrogen depends more on the demand of either liquid or gaseous hydrogen than on the consumption level. It is still an open question if more central production and distribution to local re-fuelling stations or on site production would prevail in the early phase of market introduction. Integration of mobile and stationary applications, however, could support the development of economically viable decentralised systems.

Hydrogen storage is an open issue for both liquefied as well as compressed hydrogen, and should be a top priority for research and development. In particular, the low volumetric energy density of hydrogen represents a main challenge to ensure acceptable driving range. Storage of compressed gaseous hydrogen requires new high pressure tank technologies, which are currently under development and still need to be proven in durability demonstrations. An operation licence for a hydrogen vehicle with a 700 bar tank on board has recently been granted in Japan.

Advanced storage technologies, such as metal hydrides, which are already a well known technology in some applications, or the more recently studied carbon nanotubes are still far from industrial application. Metal hydrides would be confined to the lightest metals to keep overall weight low. On nanotubes, some of the more promising research publications already have been revised and optimistic expectations may need scaling back. Successful and reliable R&D results in this area are still required.

4.4 Hydrogen power train

Two different propulsion systems are presently being developed for the use of hydrogen in transport, the internal combustion engine (ICE) powered by the thermal energy released from hydrogen combustion, and fuel cell systems driven by electricity produced in a chemical reaction of hydrogen with oxygen.

Hydrogen vehicles have been built by all major car manufacturers as prototypes and in small fleets, totalling about 250 world-wide at present.

High energy efficiency is expected for fuel cell vehicles, superior to ICE vehicles, particularly in part-load operation typical for passenger cars in urban traffic, buses, short range utility services and delivery vans. In the high load range, fuel cell and internal combustion engine efficiencies come closer together. With present technology, 37% has been achieved with fuel cell vehicles in the New European Drive Cycle (NEDC) used for all certifications in Europe. This compares to efficiencies of close to 20% for gasoline and around 24% for diesel engines under the same conditions. All types of engines are expected to improve in efficiency in future. Values up to 50% are expected from the automotive industry for fuel cell drive trains. For technologies expected to be ready for market introduction by 2010, the reference well-to-wheel study gives an energy consumption of 0.94 MJ/km (2.6 l/100 km diesel equivalent) for the fuel cell vehicle and 1.68 MJ/km (4.7 l/100 km diesel equivalent) for the comparable hydrogen-internal combustion engine.

Fuel cell propulsion systems currently are bigger and heavier than internal combustion engines at the same power, as they have a lower power density and a higher power-specific weight. While volume and weight of fuel cell stacks increase linearly with total power, this dependence is much weaker for internal combustion engines. This gives the internal combustion engine an advantage over fuel cells in the high power range. Rapid progress, however, has been made on fuel cells in recent years, with an increase in the power density by a factor 5 to about 1.5 kW/l (1 kW/kg) within about 3 years. In the laboratory, 2 kW/l has been achieved. In the long term, higher power densities can be expected. The fuel cell does not offer the same benefits for long haul trucks due to the different driving pattern (long intervals with high engine load) as for passenger cars, buses or delivery vehicles, where the high efficiency at part-load operation can better come into play. Fuel cells, beyond the moderate power vehicles, delivery vehicles and buses, presently are considered particularly suited as auxiliary power units (APUs) in premium class cars and in trucks.

As the technology of a hydrogen internal combustion engine is similar to the gasoline internal combustion engine that already has been adapted for natural gas, it is expected that an economic series production is possible earlier than for fuel cell cars. Fuel cell driven engines for passenger cars are not likely to reach the power level of high power internal combustion engines (above 100 kW) and will not come down to their cost level in near future. Therefore, an early market introduction of hydrogen in the automotive sector could be facilitated by a faster parallel build-up of vehicles with hydrogen powered internal combustion engines, provided the appropriate hydrogen infrastructure is timely available.

The hydrogen internal combustion engine also takes profit of the mature technology and all investment linked to the gasoline combustion engine and would allow a direct link-up of gasoline and hydrogen, as the same type of engine could run on both fuels. Bi-fuelled gasoline/hydrogen vehicles would also allow a smooth market introduction, based on a more limited hydrogen re-fuelling infrastructure in the initial phase.

The main issues for the two lines of hydrogen use in fuel cells or internal combustion engines are costs for fuel cells and the energy efficiency of the hydrogen internal combustion engine. It requires a high tank-to-wheels efficiency to compete with overall energy efficiency and CO_2 emissions from the direct use of natural gas. High-efficiency fuel cell vehicles may provide this, while hydrogen internal combustion engine vehicles would have higher well-to-wheels CO_2 emissions.

The energy efficiency of hydrogen fed internal combustion engines presently is comparable with the efficiency of a traditional gasoline engine. Scope is seen for considerable improvement, through optimisation of the hydrogen injection and combustion processes. The low temperature of liquid hydrogen would contribute to the efficiency gain. These considerations have raised expectations on efficiencies coming closer to a fuel cell system. The possibilities of such an efficiency enhancement of a hydrogen internal combustion engine are under investigation in laboratory tests.

4.5 Greenhouse gas emissions

Low-carbon production routes from either non-fossil energy sources or fossil fuels with carbon capture and sequestration are essential for a broad introduction of hydrogen in order to obtain significantly lower greenhouse gas emissions over the full well-to-wheels chain, compared to the oil based fuels currently used. Greenhouse gas emissions related to the hydrogen production pathway dominate the overall well-to-tank emissions under present conditions. The emissions vary in a wide range, depending on the process used. Hydrogen from non-fossil sources (biomass, wind, nuclear) offers low overall greenhouse gas emissions. CO_2 capture and sequestration added to natural gas steam reforming and coal gasification could reduce the level of greenhouse gas emissions on the fossil hydrogen pathways to the level of the biomass gasification pathway to hydrogen. The long-term potential of carbon sequestration, however, still needs to be further assessed and demonstrated.

Hydrogen ICE vehicles have higher WTW GHG emissions than conventional fuel and CNG vehicles when hydrogen is produced from natural gas via steam reforming (see figure 10 in section 2.4.2). Larger market introduction of hydrogen ICE vehicles therefore should only be considered on the basis of low-carbon hydrogen production.

Overall well-to-wheel greenhouse gas emissions can be reduced for high efficiency hydrogen fuel cell vehicles, compared to conventional present-day petrol based internal combustion engine vehicles, even on the basis of natural gas hydrogen production. On the assumption that fuel cell vehicles would penetrate the market substantially in the time frame 2015-2020, it is expected that they would have WTW greenhouse gas emissions similar to further evolutions of petrol/diesel vehicles, in particular hybrid petrol/diesel vehicles. Subsequently, their CO_2 balance could be further improved through continuing de-carbonisation of the hydrogen production pathways and through further improvements in the efficiency of fuel cells.

Greenhouse gas emission reductions therefore are expected to remain small, however, up to 2020 in any scenario of hydrogen introduction as motor vehicle fuel. An important potential of emission reductions could be realised in a later period with a gradual transition to hydrogen, aligned with a progressive decarbonisation of hydrogen production and the further development of the efficiency of fuel cell systems.

4.6 Economics

4.6.1 Fuel cost

The production cost of hydrogen is currently lowest for the process of natural gas steam reforming. A reference price would be 10 €/GJ for this process, with a natural gas price of 2.8 €/GJ and an electricity price of 9 €/GJ. Cost for hydrogen from electrolysis is at least twice as high, at 20 €/GJ or above, depending mainly on the cost of electricity. The commodity price for gasoline, for comparison, is about 7 €/GJ at leaving refinery, for a crude price of 25 €/barrel.

Hydrogen commodity costs could vary considerably, depending on the feedstock (natural gas, biomass gasification, renewable electricity). Quantitative estimates for biomass produced hydrogen are still subject to large uncertainties because of the absence of commercial installations. The cost build-up from feedstock exploitation over hydrogen production, compression/liquefaction to distribution is shown in figure 19 below, established by TES and Imperial College London from a comparison of their respective studies.

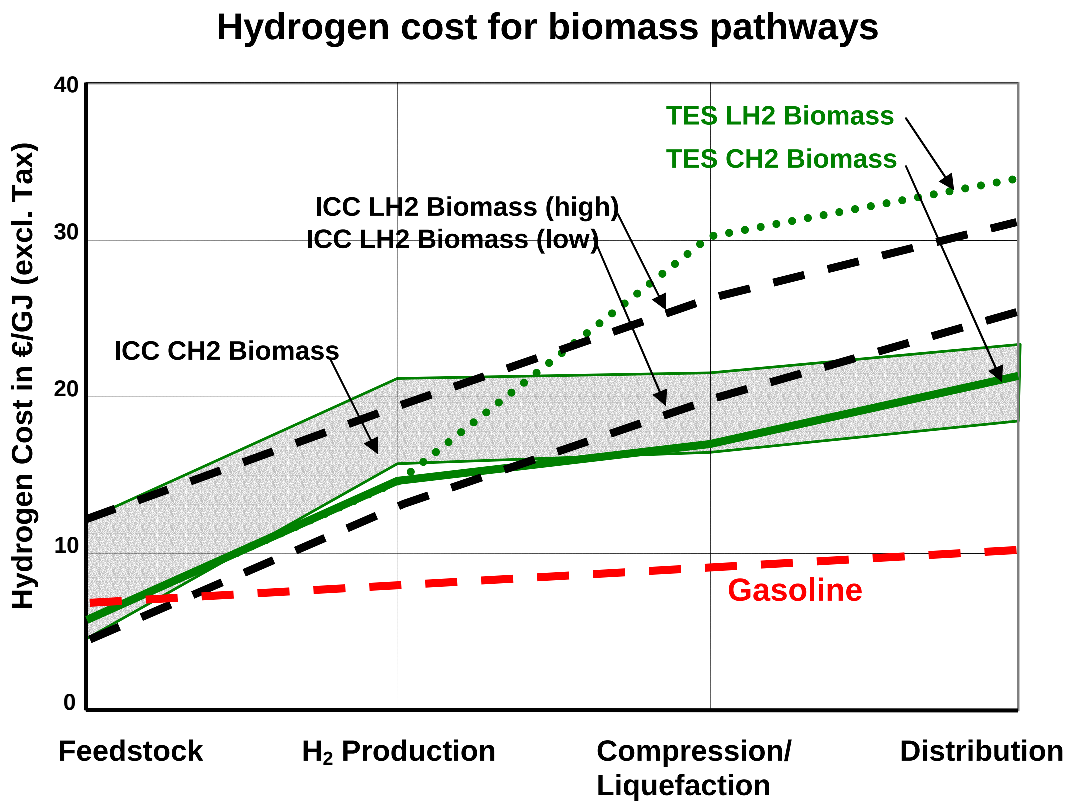
The price for hydrogen at the re-fuelling point essentially depends on the consumption level. Retail fuel prices are expected to rapidly fall with market development, up to a 2% market share due to economies of scale, still somewhat up to a 10% market share, and to remain essentially independent of market share above that. Under economic considerations on the operation of a re-fuelling station, with a customer base of 500 vehicles, a retail price of hydrogen at the pump around 20 €/GJ, before tax, can be expected. Costs at pump delivery are comparable for compressed and liquefied hydrogen. For comparison, the retail price for gasoline/diesel is about 10 €/GJ, before taxes, on the basis of a crude oil price of 25 €/barrel.

A consistent market introduction scenario has been developed by the EU-Framework Programme funded HyNet project for the Contact Group. The sensitivity of fuel prices has been studied over a wide range of electricity and gas prices and for different hydrogen supply schemes; hydrogen production from natural gas steam reforming and electrolysis, with either central production and subsequent distribution in liquid form, or on-site production and delivery in gaseous compressed form. For an early mass market, with 2-9 million vehicles (corresponding to about 1-5 % of the total present EU passenger car park), fuel cost at the pump could be about 0.65 €c / litre gasoline equivalent, at its lowest. Details are given in Annex 4.

The different analyses on the hydrogen fuel economics in the market build-up phase consistently conclude that the retail price level for hydrogen at the filling station can be expected to be about twice the present price for gasoline/diesel before tax, if compared in terms of price with respect to energy content. The higher efficiency of fuel cell systems – typically at least twice that of conventional combustion engines – however, allows for at least a factor two higher energy based retail prices of hydrogen, compared to petrol, on a purely economic basis. Hydrogen therefore could become an economically fully viable fuel in a developing mass market so long as it was built around fuel cell technology. This would have implications for the timing of the mass market development.

Competitive pricing of hydrogen in the initial phase, however, would require full de-taxation at re-sale to kick-start broad market introduction and rapidly reach the stage of economic self-subsistence. For full tax exemption of hydrogen up to a market share providing substitution of 5% of conventional motor fuels, as envisaged for 2020, this would amount to a total hypothetical support corresponding to about 8 b€ foregone taxes annually, assuming otherwise an average tax level of 0.40 €c/l on oil based motor fuels. At this level of market penetration, however, the economics of the full hydrogen chain should already allow a substantial digression of economic incentives. Rising market pressure on oil eventually also may lead to higher petrol prices and energy prices in general and thereby gradually reduce the need for economic incentives on alternative fuels.

Fig. 19: Build-up of hydrogen fuel cost from feedstock to pump for different biomass pathways.



Source: TES / Imperial College of London

4.6.2 Infrastructure cost

Infrastructure investment costs for the different elements of the hydrogen supply chain are expected to rapidly fall with growing market development. Extrapolations based on economy of scale considerations and comparisons with the development of natural gas re-fuelling stations presently underway in Germany, project a unit price of about 250,000-300,000 € for the installation of a hydrogen filling station, with mass market conditions of more than 1000 filling stations.

The total investment costs for the complete hydrogen supply infrastructure for a market of 2-4 million vehicles (about 1-2 % of the present EU vehicle park), comprising 5000 filling stations and the required hydrogen production and compression/liquefaction facilities and trailers for distribution, would be of order 4 b€, according to the recent HyNet study (Annex 4). Investment has been assumed to be fully amortised on economic terms, with a depreciation period of 15 years.

Overall investment costs are comparable for the four scenarios of hydrogen supply considered: hydrogen from electrolysis or natural gas steam reforming, either in liquid form from central plants with truck distribution, or in gaseous compressed form on-site. Doubling the customer base from 2 to 4 million vehicles, would require about 50% higher investment cost for the scenarios with liquefied hydrogen from central plants, but no additional investment in the scenarios with on-site hydrogen production. With beginning of broad market opening, at the level of 1-2% market share, on-site hydrogen production could therefore have an economic advantage over central production. On-site production also appears to feature more cost-efficient and flexible in a rapidly growing market, due to its ability to cope with rising demand at little additional investment.

4.6.3 Vehicle cost

Costs of hydrogen vehicles are mainly determined by the hydrogen on-board storage or – if so applied – reforming system and the power train. Hydrogen internal combustion engines could more rapidly approach conventional petrol engines in price while fuel cell systems are likely to remain much more costly for some time. Costs of fuel cells are strongly determined by the membrane, the water management, the bipolar plates and the requirements for precious metal. Membranes already can be fabricated at large scales. There is indication that significant cost savings may be achieved for current membranes, and the development of novel membranes and fabrication techniques suited for mass production may also lead to considerable cost reductions. Precious metal use currently amounts to about 1 gram of platinum per kW, with a price of about 20 €/g platinum at present. This price level is historically high, but increasing demand in future also may lead to increases of precious metal prices. Power density and amount of precious metal employed are closely linked. Performance and economy therefore present conflicting requirements to reconcile. Lower catalytic loadings are under development.

Costs for fuel cells in automotive applications are estimated to decrease by an order of magnitude from present levels, assuming economy of scale from mass volume production of present-day technology. This, however, would still leave the cost an order of magnitude above the costs for internal combustion engines presently at about 30 €/kW for gasoline and 50 €/kW for diesel engines. So far, fuel cell cars have only been produced as prototypes and, recently, for captive fleets in very limited numbers. The considerable cost reductions required for fuel cell propulsion systems to become competitive for the mass market are expected to be achieved through technological improvements and economy of scale in large production series.

4.6.4 Overall system cost

A clear picture arises for the ordering of the economic issues for the market introduction of hydrogen/fuel cell technologies:

(1) **Fuel costs** per km could become comparable for hydrogen vehicles and gasoline/diesel vehicles if the expected high efficiencies of fuel cell vehicles are reached. Large scale deployment of hydrogen systems also requires cost-effective low-carbon routes to hydrogen.

(2) **Infrastructure investment costs** could be reasonably amortised already in the medium term with selective market development, starting in aggregation zones.

(3) **Vehicle costs** are the dominant issue and by far the largest cost factor in the transition to a hydrogen economy. The hydrogen internal combustion engine might offer a less expensive fast track route in the initial phase and prepare the wider market for fuel cell vehicles. But high efficiency fuel cell systems are essential for the long-term full benefit from a hydrogen economy.

The bottleneck of the development of a hydrogen economy in fact lies with the availability of hydrogen vehicles and the high cost of hydrogen technologies there. The necessary hydrogen supply infrastructure, on the other hand, can well be built up on economic terms. Market development strategies therefore should give highest attention to the technologies and the economics of the vehicle sector. A chicken-and-egg issue therefore does not exist if market entry conditions are properly organised.

4.7 Market introduction strategy

The Commission Communication on alternative fuels of November 2001 suggests for hydrogen a development scenario of 2% road transport fuel market share in 2015 and 5% in 2020. Though the envisaged market shares appear modest, large numbers of vehicles are required to meet these estimates and in particular large introduction rates of new technology not yet existing commercially.

The build-up of vehicle production would go in three phases. Back-casting from the envisaged target of up to 5 million vehicles in 2015 would require several mass production lines, each with a production line capacity of at least 50,000 – 100,000 per year, operating by 2010 and plans for these plants to be ready by 2005 at latest. None of the big car manufacturers involved in the development of hydrogen powered cars has announced an intention to start mass market series production before 2010. Slower mass market introduction than previously projected with the estimates of 2% in 2015 and 5% by 2020 may therefore be expected. Japanese car manufacturers still envisage broad market introduction of fuel cell hybrid cars before 2010, with a target set at 50,000 vehicles in 2010.

At the present development stage of hydrogen vehicles, car manufacturers still need technology tests on one further generation of vehicles for a hydrogen internal combustion engine vehicle before series production could be envisaged. One experimental vehicle generation requires about 2-3 years. Four to five years for final product development have to be added. This would lead to a start time for series production around 2010, with a few years margin either direction, anticipating some overlap between concept and series development phases of subsequent generations. Fuel cell vehicles are expected still to need two experimental generations before series production maturity could be attained. This would support a possible scenario with hydrogen internal combustion engine vehicles as forerunners, providing a fast track market opening for a broader range of fuel cell vehicles following suite.

Smooth market introduction of hydrogen vehicles therefore could be facilitated by a parallel development of internal combustion engines with bi-fuel options and of fuel cell systems, which on their own would require a disruptive market transition. Hybrid vehicle technology, combining either an internal combustion engine with electromotive drive fed by a battery or a fuel cell with a battery, could facilitate the market introduction of hydrogen vehicles by reducing their early cost and the period of market opening.

The system transition from internal combustion engine vehicles to fuel cell vehicles is expected to lead to major restructuring of car manufacturing and supplier industries and of the workforce due to different professional qualifications required. A large shift from mechanical to electrical applications has to be expected. Therefore training and education programmes should start in time to build up the necessary qualifications.

Optimisation of the economics of building up the hydrogen supply infrastructure and maintenance service would suggest starting the market with selected geographically concentrated pilot zones. This would avoid long periods of loss-making of dispersed re-fuelling stations with marginal turn-over. Concentration of the limited vehicle output in the hydrogen start-up phase to selected areas would provide higher vehicle densities already in early phases of the market development, thus offering the perspective of better utilisation rate of new re-fuelling stations. The proto-clusters would best be strategically located in densely populated areas selected across Europe in order to take in a wide range of market conditions. In a second phase, the pilot zones could be expanded to provide a larger market base and profitable infrastructure and interconnected through corridors. In a third step, finally the network could be densified. The cost for installing a hydrogen refuelling station is expected to drop to about 0.3 M€ with the installation of a larger number of units above several thousand.

Large-scale lighthouse projects integrating all key elements of a hydrogen economy in a limited number of selected regions have been proposed by the European Commission at the Brussels Hydrogen Conference in June 2003. Such a project could link up the present prototype stage of hydrogen vehicles to the beginning of series production. It could provide a stable frame for the transition from the present R&D prototype vehicles to several generations of small fleets for reliability and durability tests. The objective of a hydrogen lighthouse project should be the development of all key technologies of a hydrogen economy to market maturity, and in parallel the development of market acceptance, so that decisions on the start of mass production could be taken. The integration of all elements into large cluster projects should ensure the interaction between the different levels of the hydrogen chain and particularly between stationary and mobile applications. This should provide the basis for an integrated assessment of market maturity.

Public transport vehicles such as buses and taxis, delivery vehicles and high-use private or public passenger car fleets could offer interesting captive fleets for a later market development in the aggregation areas of lighthouse projects.

Hydrogen production for lighthouse projects should first come from existing facilities in order to minimise costs during the run-in phase. A gradual build-up of demand with increasing hydrogen consumption from a larger number of users should allow a cost-effective step-wise integration of additional hydrogen production from natural gas steam reforming, electrolysis and biomass gasification. The integration, at the development/demonstration stage of biomass gasification plants delivering either liquid hydrocarbon fuels in a Fischer-Tropsch process or hydrogen could provide a convenient way of proving both routes in a cost-effective way. Technological development of this process through demonstration plants to industrial scale should be promoted. Large volume hydrogen production from fossils (gas, coal) with integrated carbon capture and sequestration and from direct water splitting through the process heat of high temperature power stations could also be included in a later stage with mature hydrogen consumption.

5. Biomass-to-Liquid (BTL) fuels*)*

5.1. Background

Biofuels, originally, were not included in the scope of the mandate of the Contact Group. During the early stages of the work of the Contact Group, however, a number of stakeholders pointed out the potential benefits of synthetic diesel produced from biomass using gasification and subsequent fuel synthesis thereby widening considerably the range of potential biomass resources and their possible share in the fuel market. Although strictly speaking falling within the category of biofuels covered by the separate biofuels directives, including possible detaxation of the final product, synthetic biofuels from cellulose products were not originally considered as main contributors to delivering on the targets of the recently adopted biofuels directive.

The term BTL fuels in principle covers several potential motor vehicle fuels being produced from synthesis gas (a mixture of carbon monoxide and hydrogen) by gasification of biomass: methanol, dimethylether (DME), gasoline hydrocarbons or diesel hydrocarbons. Producing fuels suitable for diesel combustion seems particularly attractive:

– Diesel is growing in demand beyond what is easily produced through oil refining;

– BTL-diesel and DME have exceptionally good diesel properties (high cetane number, naturally low sulphur and aromatics, flexible boiling characteristics as required)

– BTL-diesel can be used as high value blending component in oil derived diesel without any additional cost for separate distribution network or engine modifications.

For these reasons the work on BTL has particularly focussed on BTL-diesel.

A demonstration plant for BTL-diesel (expected full size production of 13.000 tons diesel per year) has recently been inaugurated in Freiberg, Germany. Production of DME/methanol via black liquor gasification is projected in Sweden, as well as fuel manufacture based on traditional biomass gasification (Värnamo).

On the background of these new elements**,** it was decided to establish a separate working group to assess the potential and constraints of BTL fuels as an alternative motor fuel. The work has been encouraged by car manufacturers, which see the BTL-fuels as a particularly interesting contribution to engine developments towards cleaner and more efficient diesel technology.

5.2. The raw material basis

Whereas ‘conventional’ biofuels (ethanol, biodiesel) are based on the conventional agricultural crops such as plant oil, sugar or cereals, BTL fuels would primarily be produced on the basis of either waste products from agriculture (straw), forestry (thinning wood, residuals) or wood-based industries (saw dust, ‘black liquor’ from pulp and paper industry) or on energy plants specifically grown for the purpose (short rotation trees or other cellulose material).

The biological origin of the raw material implies that the final product is CO_2-neutral. In practice some net greenhouse gas emissions will occur from the different steps of cultivating the crops, transportation and processing, but this can be kept to a low level (approximately 15%) if the overall design maximises the use of biomass energy during the process.

The potential for BTL fuels, depending on land availability for the necessary crops beyond what can be supplied by waste products, is subject to different estimates ranging normally between 5 and 15% of overall motor fuel consumption in EU 15. The higher land area relative to fuel consumption in the new Member States will add to the potential as well as high yield biomass production schemes.

The already agreed expansion of biofuels in the period up to 2010 will be based on potential agricultural land (primarily set aside land). An advantage of BTL fuels is that the resource supply has a more modest impact on agricultural land than conventional biofuels. This implies a possible continued expansion of biofuels during the period 2010-20, beyond the 7-8% foreseen as a maximum in the Commission Communication of 2001.

5.3. The production plant

Production of BTL fuels is a two-stage process (with several sub-steps):

– Gasification of the biomass and adjusting the raw gas into a mixture of hydrogen and carbon monoxide (approx. 2:1)

– Hydrocarbon synthesis over a Fischer-Tropsch Process catalyst and subsequent treatment of the raw product to obtain a diesel-fraction mixture of hydrocarbons – or synthesis to produce pure DME.

Alternatively to the second step, the synthesis gas can be used to produce hydrogen by the CO-shift reaction where carbon monoxide is reacted with water. This constitutes the most promising road to hydrogen from renewable energy sources and offers a highly relevant link between BTL-technology and a future hydrogen economy.

The overall “biomass to diesel” process is believed to be able to deliver around 50% energy efficiency corresponding to approximately 200 kg diesel per ton “dry” biomass (15% moisture). DME can be produced at an energy efficiency of around 65% via black liquor. These numbers are based on plants where the energy for the gasification is delivered by the biomass (autothermal). With external energy input, the fuel mass yield can be increased significantly at a slightly improved energy efficiency. However, the resulting CO_2 then depends on the CO_2 emission prospects of the external energy source. The choice between biomass only (autothermal) or additional external energy input (allothermal) depends on local circumstances, particularly on available external energy sources.

5.4. Economic aspects - the plant capacity issue

Little real life experience exists on the economics of BTL production. The Fischer-Tropsch synthesis, in the second step, is a relatively well established technology, but based on synthesis gas produced from coal or natural gas. The methanol process is also well known and producing DME is essentially a variation of methanol production. Apart from the uncertainty of the cost aspects of the gasification step, two cost factors are important:

– The size of the plant (crucial for efficiency, determined by heat recovery);

– The cost of the raw material.

Unfortunately, the two work against each other. The bigger the plant, the higher the cost of transport of raw material supply which will have to be brought in over longer distances and consequently higher transportation cost. Optimum size depends on how much of the surrounding land can be made available for delivery of raw material and which level of crop diversity will be required. The BTL Working Group has estimated that a plant size of 100.000 ton / year fuel production would present a reasonable compromise between the big scale advantages and need for limited transportation of raw material. Assuming 5 tons raw material per ton liquid fuel, this is equivalent to approximately 1,500 t of biomass being processed daily. Such a level is usually achieved in modern paper pulp mills. With a production of 10 tons per hectare, the plant would require biomass from 50,000 hectare, which in an ideal case would correspond to a surface area of about 30 km diameter, assuming 70% of the available land being used for energy crops.

A 100.000 t/year plant to produce Fischer-Tropsch diesel is estimated to require an investment of 250-300 M€ or a capital cost of around 300 € / ton diesel (assuming 10-12% capital charge). The total production cost will amount to about 600 € / ton to 800 € / ton. (These costs compare to prices of around 250 € for crude oil-based diesel or a price level of the same order of magnitude as 'conventional' plant oil-based biodiesel.) The cost for BTL diesel is comparable to that of 'conventional' plant oil based biodiesel and a further 2.5 – 3 times the cost of present crude oil based diesel (approximately 250 €/t). When using black liquor to produce DME, the product cost is expected to be much lower and approach that of crude oil based fuels, 300-350 €/ton diesel equivalent

5.5. Environmental aspects

BTL fuels have a high greenhouse gas avoidance potential, up to 85% reduction over crude oil-based diesel. BTL fuels could offer advantages on regulated emissions in the existing fleet equipped with an older engine technology. As with other alternative fuels, BTL is not likely to be available in large quantities prior to a time when regulated emissions from most vehicles are down at very low levels. However, it could still be used with benefit in vehicles not equipped for the highest level of pollutant emission reduction.

The further environmental aspects of the production of biomass remain uncertain. Intensive wood production for pulp and paper (e.g. eucalyptus plantations) has been questioned for its impact on water balance and biodiversity. Any definitive decision on large scale, European wide, biomass production for BTL fuels (or hydrogen) needs further impact assessment.

Individual plants with the purpose of testing the technology are of less concern. It goes without saying that any large scale operation (such as 100.000 ton / year) must be subject to concrete impact assessment, including broader assessment of raw material generation.

6. LPG

The European Association for LPG (Liquefied Petroleum Gas) has presented a review on economic and environmental aspects of LPG as motor fuel to the Contact Group. The Association has made the point that LPG should be considered an alternative fuel along with biofuels, natural gas and hydrogen. There would be scope for significant expansion of LPG as motor fuel. About twice the amount of LPG presently used on vehicles would already be available in Europe from refineries and would allow the present motor fuel market share of 1% to be increased towards 5% by 2010.

Commission services have expressed their support for additional uptake of LPG as a motor vehicle fuel. Use of LPG originating from natural gas production contributes to security of supply of oil products and CO_2 emission avoidance, partly due to a somewhat lower carbon content than gasoline and diesel, partly due to low “well to tank” greenhouse gas emissions.

Commission services further expressed the view that the development of LPG in the motor fuel market is on a good track. Refuelling points exist in sufficient numbers in most Member States and are expanding in others. LPG vehicles are available in several models, and fuel tax incentives are in place to make LPG an attractive fuel particularly for car owners with high yearly mileage. In addition, a number of national restrictions on access for LPG vehicles are being reduced or abandoned in parallel with improved safety regulations for LPG vehicles. Important for further market broadening would be an expansion of the LPG re-fuelling network, particularly in urban areas.

LPG therefore could be considered an established motor vehicle fuel, alternative to gasoline and diesel, with potential for additional market share, a development which seems to be already advancing well on the basis of efforts within the respective industries and supported by existing incentives. LPG, however, may compete with CNG for additional market share unless targeted to different segments.

The potential of LPG for improving security of energy supply and reducing greenhouse gas emissions should be assessed on a well-to-wheels analysis under the same conditions as the other recognised alternative fuels, including the perspective of future market and technology developments.

The Contact Group has expressed its support for the analysis presented by the Commission services and for the suggested approach.

7. Conclusions

Alternative fuels should be developed in a consistent step-up process:

(1) **Natural gas** could gain a broader market share if supported by long-term tax and excise duty advantages providing stable conditions for industry and customers. Mature vehicle technology is available. Expansion of the re-fuelling infrastructure and of captive fleets from ongoing programmes could substantiate the customer base. Initially, fleet and local markets, such as urban transport, offer the potential for high utilisation of refuelling stations. Reduction of gas transport costs in a liberalised European gas market has already lowered the commodity price of natural gas so that, once CNG becomes established the costs to the customer are potentially no more than for conventional motor fuels. Additional public support appears necessary for the transition period of building up the infrastructure required for a market share of 10% envisaged for 2020. On this level, compressed natural gas could become an economically competitive alternative fuel.

Natural gas vehicles today have a CO_2 advantage over gasoline and are comparable to diesel vehicles. In future, the advantage of natural gas vehicles is expected to surpass diesel. With technology foreseen for 2010, natural gas vehicles are projected to have 16% lower CO_2 emissions compared with gasoline vehicles and 13% lower CO_2 emissions compared with diesel vehicles. The inherently lower greenhouse gas intensity of natural gas vehicles might be further exploited by optimised engine technology and new concepts for heavy-duty engines. Natural gas vehicles today also have advantages for local air quality, comparable to projected future improvements of emissions of diesel vehicles, in particular as regards particulate emissions.

A main driving force for the large-scale introduction of CNG as motor fuel is concern for the security of supply for the transport sector currently solely dependent on oil products. The potential in market share of natural gas as a motor fuel would not be limited by primary supply. A share of 10% in road transport by 2020 would only represent about 5% of the total gas demand in the EU expected by that time. The long-distance gas distribution infrastructure required for stationary uses of natural gas would be able to ensure also the additional demand for transport fuel.

(2) **Hydrogen** is a potential future main energy carrier. Due to its feedstock flexibility it could considerably broaden the energy supply base of the transport sector. Hydrogen offers the long-term potential for full reliance on renewables. Research and technological development programmes should be intensified to provide the basis for decisions on possible mass-market production of automotive systems after 2010. The contribution of hydrogen to fuel consumption could reach a few percent by 2020.

Hydrogen production pathways differ widely in terms of the greenhouse gas emissions incurred, energy efficiency and cost. Hydrogen production from biomass but also from co-production in cleaner fossil power plants should be given attention in technological development programmes in view of providing high-volume/low-CO_2 pathways when demand for hydrogen as a fuel substantiates. Both liquid and gaseous forms of hydrogen should be offered at re-fuelling stations to allow development of the full range of applications. Internal combustion engines could provide a fast track pathway to a broad market introduction of hydrogen vehicles. Larger market introduction of hydrogen ICE vehicles, however, should only be considered on the basis of low-carbon hydrogen production. Fuel cell vehicles offer high energy efficiency potential and could become competitive, following cost reduction and reliability enhancement of fuel cells.

Reduction of greenhouse gas emissions compared to petrol engine vehicles can be achieved with hydrogen vehicles on the basis of the currently most common and most economic hydrogen production process by steam reforming of natural gas, provided fuel cell vehicles are available and achieve the high energy efficiencies predicted. With hydrogen internal combustion engine vehicles, total greenhouse gas emissions may be higher than for conventional vehicles, depending on the hydrogen source.

Market development starting from strategically placed clusters can avoid the chicken-and-egg inter-dependence problem of hydrogen supply and applications. This allows economically viable infrastructure build-up and competitive hydrogen fuel supply. The main issue remains with technology and cost of the hydrogen applications.

Large-scale integrated lighthouse projects comprising all key elements of a hydrogen economy therefore should be established to advance on the deployment of hydrogen technologies. Stationary fuel cell systems should have an important place in such lighthouse projects as well, as they would attain market maturity faster than hydrogen vehicles and therefore allow a more efficient utilisation of new hydrogen infrastructure. Co-production of hydrogen and electricity would be important to explore. The lighthouse projects should bridge the gap between the present stage of prototype vehicle fleets and a broad market introduction. They should provide the frame for in-use reliability and durability testing of key technologies and infrastructure, to the extent necessary to enable decisions on the start of mass production.

(3) **Biomass-to-Liquid (BTL) fuels** could largely enhance the market share of biofuels, beyond the EU target of 6% for 2010. The maximum total potential of biomass-derived fuels is estimated at about 15%. First demonstrations at the pilot plant scale have just started. It would need at least one additional development step until large scale production can be started. BTL fuels can benefit from the fiscal incentives now offered to biofuels. Purpose tailored synfuels could also enable improved engine technology with better energy efficiency and lower emissions. Further development projects could help improve the economics of the production process and the logistics of feedstock supply. Co-production of BTL fuels and hydrogen could provide a cost-efficient pathway to renewable hydrogen production.

(4) **Liquefied petroleum gas (LPG)** is an established alternative motor vehicle fuel with scope for additional market share, possibly up to 5% by 2010. The potential of LPG for improving security of energy supply and reducing greenhouse gas emissions should be assessed on a well-to-wheels analysis under the same conditions as the other recognised alternative fuels, including the perspective of future market and technology developments.

Alternative motor fuels have a potential of gaining significant market share within the next decades, and on the longer term exceeding targets considered so far for 2020. Estimates for the main alternative fuels arrive at potentials for biomass derived fuels of 15%, natural gas 10%, LPG 5% and hydrogen a few per cent by 2020. Vigorous and long-term guaranteed action plans across the whole Union are required to build and support a sufficient market pull from the customer side. Such concerted action could improve the environmental performance of transport and start a transition away from today’s high dependence on oil in the transport sector, thereby improving security of energy supply.

Annex 1a : ALTERNATIVE FUELS CONTACT GROUP : EXPERT MEMBERS

Name	Group	Company
ANASTASIADIS Stephanos	T&E	European Federation for Transport and Environment
ANDERSON Jason	Climnet	Climate Action Network Europe
BAUEN Ausilio	Imperial College	Imperial College of Science, Technology and Medicine
BÖCKELT Achim	HyNet	BMW AGI
BOISEN Peter	Engva	Fordonsgas Vst
BOUT Peter	EIHP	Air Products Nederland B.V.
CELARD Bruno	Europia	European Petroleum Industry Association
CUCCHI Carlo	ACEA	Association de Constructeurs Européens d'Automobiles
DUWE Matthias	CAN-E	Climate Action Network Europe
GRIESEMANN Jean-Claude	Eucar	Renault
GRILL Johann	AIT & FIA	The European Bureau of the Alliance internationale de Tourisme et Fédération Internationale de l'Automobile
HART David	Imperial College	Imperial College of Science, Technology and Medicine
HEINRICH Hartmut	Eucar	Volkswagen AG
HEC Daniel	Marcogaz	Technical Association of the European Gas Industry
HOWENER Hubert	F.Z. Jülich	Research Center Jülich
LARIVE Jean-François	Concawe	Oil Companies European Organisation for Environment, Health and Safety
LE BRETON Daniel	Europia	European Petroleum Industry Association
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McCarthy Adam	AIT & FIA	The European Bureau of the Alliance internationale de Tourisme et Fédération Internationale de l'Automobile
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MEYER Hermann	ACEA	Association de Constructeurs Européens d'Automobiles
PÛTZ Ralf	UITP	Verband Deutscher Verkehrsunternehmen
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RÖJ Anders	ACEA	Association de Constructeurs Européens d'Automobiles
SAUERMANN Peter	TES	Aral KG
SCHEUERER Klaus	HyNet	BMW AG
SCHOOTERS Karla	Climnet	Climate Action Network Europe
SCHOLTISSEK Bernhard	Europia / Concawe	BP
SCHULZ Philippe	Europia / Concawe	Total
SEISLER Jeffrey M.	Engva	European Natural Gas Vehicle Association
SONNABEND Peter	IRU	Deutsche Post/DHL
THOMPSON Neville	Concawe	Oil Companies European Organisation for Environment, Health and Safety
VAN ZYL	Eucar	European Council for Automotive R&D
VANCLUYSEN Karen	Eurocities	
WAARA Rolf	UITP	Union Internationale des Transports Pubics
WEIDNER Hans	EIHP	Adam Opel AG – Fuel Cell Activities
WILKS Chris	Europia	BP

Annex 1b : ALTERNATIVE FUELS HYDROGEN : EXPERT MEMBERS

Name	Group	Company
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BECKMANN Joerg	T&E	European Federation for Transport and Environment
BÖCKELT Achim	HyNet	BMW AG
BOUT Peter	EIHP	Air Products Europe + European Integrated Hydrogen Project.
BRAESS Holger	HyNet	BMW AG
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DUWE Matthias	CAN-E	Climate Action Network Europe
HART David	Imperial College	
HASS Heinz	ACEA	Ford Research
HÖWENER Hubert	F.Z. Jülich	Research Center Jülich
KLEIN Alain	ACEA	
KLOV Kare	Engva	Statoil
MACHENS Christian	EIHP	Vandenborre Hydrogen Systems
MARSCHEIDER-WEIDEMANN Frank	Fraunhofer Gesellschaft	Fraunhofer ISI
NEUMANN Norbert	TES	B.P. Global Fuels Technology
RYTTER Erling	Engva	Statoil R&D
SAUERMANN Peter	TES	B.P. Global Fuels Technology
SCHMIDTCHEN Ulrich	EHA	European Hydrogen Association
SCHULZ Philipe	Europia	Total
TREZONA Patrick	Fuel Cell Europe	Fuel Cell Europe
VAN SCHOONHOVEN VAN BEURDE Gijsbrecht	Engva	Ingenieurbüro Van Schoonhoven
VAN ZYL Arnold	Eucar	European Council for Automotive R&D
WEIDNER Hans	EIHP	A Opel AG Fuel cell activities
WIND Jörg	TES	DaimlerChrysler Research and Development EADS/Dornier GmBh
WOLF Joachim	TES	Linde AG
WOLFF Guillermo	Europia	Repsol YPF

<u>Annex 1c</u> : ALTERNATIVE FUELS <u>NATURAL GAS</u> TOPIC GROUP : EXPERT MEMBERS

Name	Group	Company
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CROCHETET Didier	Marcogaz/eurogas	Gaz de Franc
CUCCHI Carlo	ACEA	Association de Constructeurs Européens d'Automobiles
DVORETSKY Vladimir	CAN-E	AMEK Bulgaria
JULIA SIRVENT Antoni	Marcogaz/eurogas	Technical Association of the European Natural Gas Industry
MARIANI Flavio	Engva	ENI Gas & Power
SCHOLTISSEK Bernhard	Europia / Concawe	BP Global Fuels Technology
SEISLER Jeff	Engva	Engva
TABACS Gabor	CAN-E	Energy Club Hungary
VERBEEK Henk	Engva	Engva
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WILKS Chris	Europia	BP

Annex 1d: BIOMASS TO LIQUIDS GROUP: EXPERT MEMBERS

Name	Company
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HEINRICH Hartmut	Volkswagen AG
DANIELSSON Peter J.	Volvo Bus Corp.
LEBORGNE Rozenn	PSA Peugeot Citroen
GROOVES Adrian.A.	Shell Global Solutions
WOLF Bodo	Choren Industries AG
RUDLOFF Matthias	Choren Industries AG
SEILER Jean-Marie	CEA Grenoble
HIS Stephane	IFP
SJUNNESSON Pr. Lars	Sydkraft AB
STAHL Krister	Ducente AB
MURACH Dieter	Technische Universität Eberswalde
BAUEN Ausilio	Imperial College

<u>Annex 1e</u> : ALTERNATIVE FUELS CONTACT GROUP : <u>COMMISSION</u> MEMBERS

HENNINGSEN Jørgen (Chairman)	DG TREN Principal Adviser
SÖLDNER Franz (Secretary)	DG TREN B4
HADFIELD Richard	DG TREN D1
HODSON Paul	DG TREN D1
HANSSEN Jan Erik	DG TREN D3
KOPANEZOU Eleni	DG TREN D4
HODGSON Ian	DG TREN D4
SABATER Inigo	DG TREN D4
HOERMANDINGER Günter	DG ENV C1
ZIEROCK Karl-Heinz	DG ENV C1
VERGOTE Stefaan	DG ENV C2
GREENING Paul	DG ENTR F5
LAGUNA GOMEZ José Pablo	DG ENTR F5
BORTHWICK William	DG RTD J2
CHIRON Daniel	DG RTD H2
VAN HONACKER Hughes	DG RTD J2
NAEGELE Erich	DG RTD J3
BOESHERTZ Daniel	DG TAXUD C4
MAHIEU Vincent	JRC Ispra H4
PETEVES Estathios	JRC Petten F2
VEYRET Jean-Bernard	JRC Petten F2
SORIA RAMIREZ Antonio	JRC Sevilla J2

ANNEX 2

TTW energy consumption and GHG emission figures

	Fuel cons.	GHG emissions	% change
	MJ	Total	Energy
Conventional ICEs			
2002			
PISI			
Gasoline 2002 (ref)	*223.5*	*167.9*	*Reference*
Ethanol neat (back calcula	223.5	161.3	
Gasoline/ ethanol 95/5	223.5	167.7	0.0%
CNG bi-fuel	229.1	133.1	2.5%
CNG dedicated	230.0	133.7	2.9%
Hydrogen (C)	180.2	0.9	-19.4%
Hydrogen (L)	180.2	0.9	-19.4%
SIDI			
Gasoline	208.8	157.0	-6.6%
Ethanol neat (back calcula	208.8	150.8	
Gasoline/ ethanol 95/5	208.8	156.8	-6.6%
CIDI			
Diesel	183.1	138.0	-18.1%
FAME	183.4	143.2	-17.9%
Diesel/FAME 95/5	183.0	138.2	-18.1%
DME	183.4	126.9	-17.9%
FT diesel	183.1	133.0	-18.1%
2010			
PISI			
Gasoline	190.0	140.3	-15.0%
Ethanol neat (back calcula	190.0	137.4	
Gasoline/ ethanol 95/5	190.0	140.2	-15.0%
CNG bi-fuel	192.5	110.4	-13.9%
CNG dedicated	193.2	110.8	-13.6%
Hydrogen (C)	167.5	0.5	-25.0%
Hydrogen (L)	167.5	0.5	-25.0%
SIDI			
Gasoline	187.9	138.8	-15.9%
Ethanol neat (back calcula	187.9	135.9	
Gasoline/ ethanol 95/5	187.9	138.7	-15.9%
CIDI			
Without DPF			
Diesel	172.1	127.8	-23.0%
FAME	172.4	133.2	-23.0%
Diesel/FAME 95/5	172.0	128.5	-22.9%
DME	172.4	117.9	-23.0%
FT diesel	172.1	123.6	-22.9%
With DPF			
Diesel	179.5	133.2	-19.7%
FAME	179.7	138.8	-19.7%
Diesel/FAME 95/5	179.3	133.9	-19.6%
FT diesel	179.7	129.0	-19.8%
Hybrid ICEs (2010)			
PISI			
Gasoline	161.7	119.6	-27.7%
CNG	146.8	84.7	-34.3%
Hydrogen (C)	148.5	0.5	-33.6%
Hydrogen (L)	141.4	0.5	-36.7%
SIDI			
Gasoline	163.0	120.5	-27.1%
Ethanol neat (back calcula	163.0	118.1	
Gasoline/ ethanol 95/5	163.0	120.4	-27.1%
CIDI			
Without DPF			
Diesel	141.1	105.1	-36.9%
FAME	141.1	109.3	-36.9%
Diesel/FAME 95/5	141.1	105.7	-36.9%
DME	141.1	96.8	-36.9%
FT diesel	141.1	101.7	-36.9%
With DPF			
Diesel	147.8	110.0	-33.9%
FAME	147.8	114.4	-33.9%
Diesel/FAME 95/5	147.8	110.6	-33.9%
FT diesel	147.8	106.4	-33.9%
Fuel cells (2010)			
Hydrogen w/o battery	94.0	0.0	-57.9%
Hydrogen hybrid	83.7	0.0	-62.6%
Gasoline	162.4	119.6	-27.3%
Methanol	148.0	108.9	-33.8%
Naphta	162.4	115.9	-27.3%
Diesel	162.4	119.2	-27.3%

ANNEX 3

NATURAL GAS CODES AND STANDARDS HARMONISATION

(1) National inspections and testing

European whole vehicle type approvals (WVTA) of CNG cars and light commercial vehicles require the vehicles fulfilling the UN ECE R110 regulation. This regulation allows the installation of pressure tanks with life time up to 20 years. The regulation also assumes a regular INSPECTION (at least every three years) of the tanks and the complete gas system in order to detect any damage which might affect the safety of the CNG system. Rules in the different Member States concerning regular controls of CNG vehicles differ considerably and usually date back to the period before the introduction of the R110 regulation (when CNG cars typically were converted petrol vehicles with one cylindrical steel tank fitted in the luggage compartment). Modern factory built CNG cars have up to four tanks of different types fitted in various suitable locations in the vehicle, and not necessarily easy to detach from the vehicle. Some authorities still insist on regular disassembly and hydraulic pressure testing of the gas tank in the vehicles (and often, notwithstanding R110 approval, apply different rules for different types of tanks). The OEMs, however, are very reluctant to carry the product liability for vehicles tampered with by outside agencies, and would prefer a system where the earlier tank testing system is abolished, and controls instead limited to a visual inspection aiming to detect any signs of corrosion, untight connections or mechanical damage. The working life of the tanks is, after all, guaranteed by each respective tank manufacturer. In Italy the national rules have already been modified to reflect the new conditions, but most other countries have so far not changed their national regulations.

RULES CONCERNING REGULAR INSPECTIONS OF THE GAS SYSTEMS IN GAS DRIVEN VEHICLES SHOULD BE HARMONISED WITHIN THE EU.

(2) Gas tank capacity differences due to national rules

During tank filling operations the temperatures inside the tank will increase with increasing pressures. Some time after the tank filling the temperatures drop to roughly the ambient temperature and the pressure inside the tank settles to a lower pressure than the one used to fill the tank. The maximum allowed settled working pressure in the tanks according to R110 is 200 bars. To arrive at this settled working pressure inside the tank a higher filling pressure is required. It is, with suitable equipment both on the dispenser and the vehicle, technically feasible to compensate for temperature variations and supply gas at a filling pressure high enough to ensure a settled working pressure of 200 bars. Different national regulations on maximum allowed filling pressure, however, lead to a situation where the fillable mass of gas will vary from one country to another. This obviously will have an impact on the operating range of a vehicle, and confuse vehicle users travelling from one country to another. It also makes it very complicated for vehicle manufacturers to provide reliable information regarding the expected operating range.

RULES CONCERNING THE ALLOWED TANK FILLING PRESSURE SHOULD BE HARMONISED WITHIN THE EU.

(3) Equipment standards at the filling station

Gas filling stations which lack sufficiently sophisticated equipment, or are unable to provide high enough filling pressures, may, although operating 'within the law' fail to meet customer expectations concerning mass of gas filled into empty tanks. Having settled issue (2) above, it would be desirable that public filling stations are able to deliver expected pressures.

DEMANDS REGARDING THE CAPACITY AND SOPHISTICATION OF PUBLIC GAS FILLING STATIONS SHOULD BE HARMONISED WITHIN THE EU.

(4) Gas filling operations and use of adaptors

For cars and light commercial vehicles NGV-1 tank filling connectors have become the standard in almost all countries. In Italy (and to a small extent in other European countries) with a long established CNG market another type of connector has long been used. This raises the question on how to deal with Italian vehicles wishing to refill in other countries (and vice versa). Should the vehicle users be allowed to fit adaptors themselves when filling gas abroad? This question may not be an issue in countries where gas is always filled by gas station attendants only, but the current European development goes in the direction of self-service stations for all kinds of transportation fuels.

HARMONISED RULES CONCERNING THE USE OF ADAPTORS SHOULD BE SET WITHIN THE EU.

(5) Purity of dispensed gas

Modern car engines with sophisticated engine and emission control equipment represent a much more demanding technology than simple gas burners. It is crucial that the gas is free of oil, moisture and impurities in order to protect the engine and the fuel system components. The gas delivered at filling stations should meet minimum standards in these regards. A significant share of hydrocarbons with a comparatively high boiling point (e.g. butane and pentane) could potentially also cause driveability problems at low ambient temperatures.

COMMON EU STANDARDS AND CONTROL SYSTEMS SHOULD BE SET CONCERNING GAS CONTENTS WHICH POTENTIALLY COULD DAMAGE ENGINES AND FUEL SYSTEMS, OR DURING ADVERSE CLIMATIC CONDITIONS HAVE A NEGATIVE IMPACT ON THE ENGINE PERFORMANCE.

(6) Gas composition

The heating value, or calorific content, of a gas determines the amount of energy available for an engine. A high portion of inert gas could have a negative impact on vehicle performance and fuel economy since it limits the room for the mixture of useful fuel and air in the engine cylinders. What demands could be raised on consumer information concerning dispensing of gas with a high share of inert gas (so called L-gas)?

EU RULES SHOULD BE DEVELOPED FOR CONSUMER INFORMATION WHEN THE GAS DISPENSED AT A FILLI NG STATION HAS A 'BELOW PAR' CHEMICAL COMPOSITION.

(7) Gas pricing

Customers are used to a payment system where the price is related to the actual value of the purchased commodity. The fairly wide range of offered natural gas qualities means that the energy content of a cubic metre, or (to a lesser extent) a kilogram of gas can vary significantly. Even at the same dispensing unit the gas quality could sometimes vary considerably over time. A sensible European billing unit transparent for vehicle users should therefore be developed. This billing unit should allow a fair price comparison with other transportation fuels.

A HARMONISED EU MEASUREMENT UNIT SHOULD BE SET FOR METHANE GAS USED AS A VEHICLE FUEL. A HARMONISED FUEL PRICE PRESENTATION SHOULD BE DEVELOPED WHICH ALLOWS TRANSPARENT PRICE COMPARISONS WITH PETROL AND DIESEL FUEL.

(8) Official fuel consumption figures

The European legislation requires that the official fuel consumption values must be stated in all sales literature. For methane gas used in cars and light commercial vehicles the official unit is expressed as cubic metres at 15 degrees centigrade of methane gas in a gas containing 96,25 % methane and balance inert gas. This unit, however, is completely unfamiliar to the vehicle users. They normally pay on the basis of the weight (in kg) of methane gas, or normal cubic metres (0 degrees centigrade). It would be desirable to reach an agreement on a billing unit to be used commercially (and legally) all across Europe.

THE OFFICIAL EUROPEAN FUEL CONSUMPTION RESULTS SHOULD BE EXPRESSED IN A UNIT EASILY UNDERSTANDABLE FOR THE CONSUMERS.

(9) Vehicle tank capacity

The actual amount of useful energy stored in a gas tank is affected by two factors - how well the filled mass corresponds to the target of achieving a settled maximum working pressure of 200 bars, and the actual chemical composition of the gas. Expectations concerning the effective operating range of a vehicle are, of course, influenced by both factors. In a fast-filling operation with insufficiently sophisticated equipment the mass filled will be lower than in a slow-filling operation. Life would become simpler if fuel consumption measurements and tank capacity calculations could be based on the most common quality, so called H-gas with over 98 % methane content. That some gas qualities have a higher energy content (thus giving a longer range), consumers would be prepared to accept. They might also be able to reluctantly accept the worsened performance and reduced range on so called L-gas, as long as stations delivering this quality clearly inform the consumer about the low energy content.

The owner of a car demanding 98 RON petrol would in the same manner not expect normal performance if the available petrol quality is below 90 RON.

VEHICLE TANK CAPACITY FIGURES SHOULD BE BASED ON A COMMONLY AGREED 'NORMAL' FUEL COMPOSITION (>98 % METHANE), AND THE ASSUMPTION THAT EACH PUBLIC EUROPEAN FILLING STATION IS ABLE TO SUPPLY GAS AT A PRESSURE WHICH WILL LEAD TO A SETTLED WORKING PRESSURE INSIDE THE TANKS OF 200 BARS.

ANNEX 4

INVESTMENT FOR A HYDROGEN ECONOMY IN TRANSPORT

(1) Scenarios and assumptions for the development of a hydrogen infrastructure in Europe

The industrial partners co-operating in HyNet have estimated the overall cost of a European hydrogen infrastructure that could support a hydrogen vehicle fleet that would create a fuel demand consistent with the European Commission targets for alternative fuels by 2020. Different scenarios regarding the hydrogen vehicle population, the number of filling stations and different production pathways allow specifying a range for the necessary investment on a well to tank base.

The following assumptions concerning the demand side have been made:

- Hydrogen vehicle population in 2020: 2 to 9 million
  (reflects roughly 1 to 5% of the total European car population)
- Average hydrogen amount per refuelling: 5.5 kg for a range of 500 km
  (based on a FCV/ H_2-ICE Mix in the fleet)
- Average Mileage per vehicle and year: 15,000 km

As potential hydrogen generation pathways for the timeframe until 2020 natural gas and electricity have been considered, either as on-site generation for compressed gaseous hydrogen (CGH_2) storage systems or central generation with liquid distribution for both liquid hydrogen (LH_2) and CGH_2 vehicle storage systems.

The following assumptions concerning the hydrogen infrastructure have been made:

- Number of hydrogen stations in 2020: 5,000/ 10,000
  (50% LH_2, 50% CGH_2 supplying 70 MPa vehicle tanks)
- Fuel sales at rated capacity per year: 4.78 GWh (LH_2/ CGH_2)
- Average cost per LH_2/ CGH_2 system: 250-300 k€
  (without H_2 generation)
- Central LH_2: 8,000 full load hours per year,
  0.30 kWh_{el}/kWh_{H2} energy input
- On-Site CGH_2: 6,000 full load hours per year
  (steam reformer & electrolyser)

The average investment for standardized equipment that will be produced in 5,000 respectively 10,000 units has been calculated by using a learning curve. LBST (Ludwig Bölkow Systemtechnik GmbH) has proposed following formula for determining the investment I of the n^{th} plant,

$$I = a \bullet n^{-b}$$

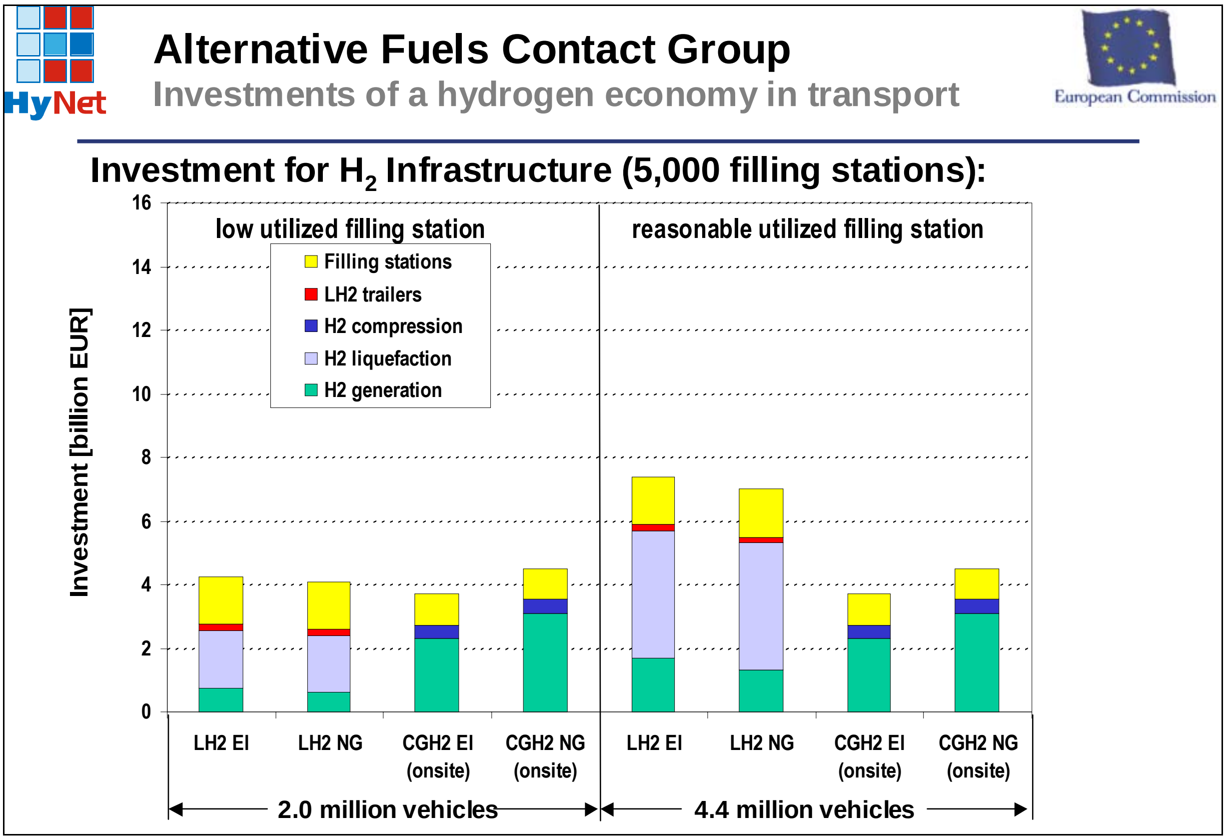
where a is the investment for the 1^{st} plant and the parameter b has been given the value of 0.1 due to comparative studies of the economies of scale in the field of chemical and process engineering.

(2) Investment for a European hydrogen infrastructure

The necessary investment for a European hydrogen infrastructure has been estimated for two cases using a static approach. The first case assumes a network of 5,000 stations which could be capable of serving 4.4 million vehicles at full utilisation assuming 12 hours of operation per day for a dispenser. The second case assumes a network of 10,000 stations allowing to serve roughly 9 million hydrogen cars at full utilisation.

Since the central LH_2 pathways allow a flexible, demand oriented build up of the centralised hydrogen generation capacities and the related distribution system, there is a difference if the 5,000/ 10,000 stations are running on full capacity or if less hydrogen vehicles need to be supplied. In order to examine this effect, besides the scenario of a "reasonable utilised filling station" also a scenario of a "low utilised filling station" (roughly half the maximum utilisation) has been computed.

In contradiction to the central pathways the on-site generation requires to install the full capacity of all locations at the beginning which leads to the same investment for the "low" and the "high" utilisation scenarios. The results for 5,000 stations are seen in the figure below.

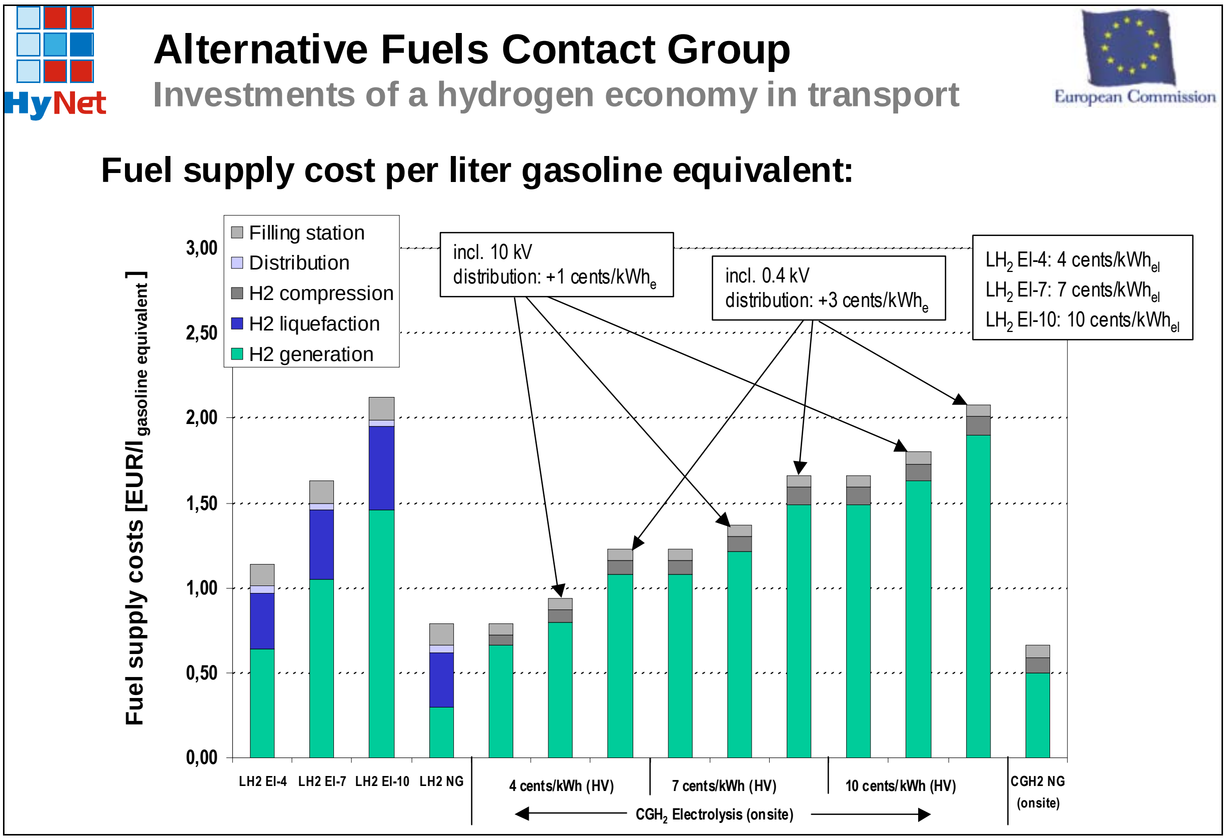


(3) Hydrogen Supply Cost

The hydrogen supply costs are strongly influenced by the necessary infrastructure investment, the energy cost and the utilisation. In order to consider the key factors and to keep the numbers of scenarios at a manageable level following settings have been combined:

- LH_2 and CGH_2 refuelling,
- Low and high utilisation of the hydrogen stations,
- Different electricity prices of 11, 19, 28 €/GJ (4, 7 and 10 cent/kWh) at 110 kV off-take) reflecting the range from grid-power to renewable power,
- For on-site electrolyser pathways besides the 110 kV off-take additional Third-Party Access (TPA) fees for 10 kV respectively 0.4 kV off-take have been considered.

The capital cost has been calculated with an interest rate of 12% reflecting a 15 years life time of equipment and capital cost of 8%. The supply cost of hydrogen at the station excluding tax lies in a range between 22 and 66 €/GJ (0.7 and 2.1 € per litre gasoline equivalent) which is roughly two to seven times more than the corresponding value for gasoline (also excluding tax) today as seen from the figure below.

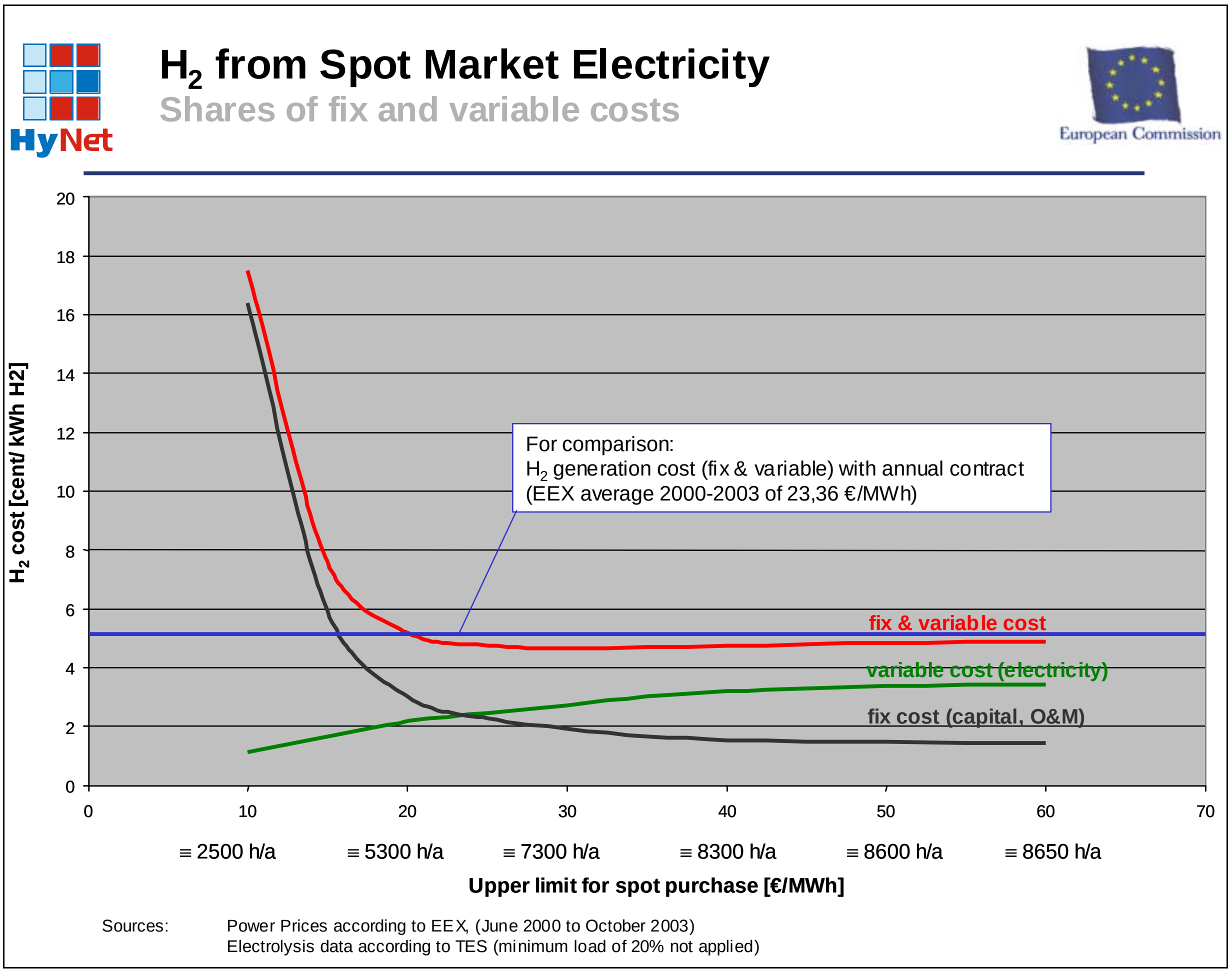


In addition to the fixed electricity prices another analysis has been performed on the influence of purchasing cheaper “excess” power on the exchange market in low demand situations. For a first estimate following model was set up:

- Flexible operation of the electrolyser between 0 and 100% load
- TES High pressure electrolyser (approx. 400 €/kW_{el}, 67% efficiency (lower heating value)
- Interest rate 12%, operation and maintenance 6% of the invest
- Electricity prices according to European Energy Exchange (EEX) hourly data (from June 2000 to October 2003)
- No TPA fees included

For the purchase of power a variable upper limit was set between 3 and 17 €/GJ (10 and 60 €/MWh) and the possible amount of hydrogen that could be produced per year was calculated by using the hourly data from the EEX for each upper limit. A low upper limit of 3 €/GJ (10 €/MWh) for the power purchase is leading on the one hand to low variable costs, on the other hand the low utilisation rate in the order of 2,500 full load hours per year is leading to high fix costs which are determined by the investment and the O&M share. With an investment of approximately 400 €/kW_{el} installed electrolyser capacity the minimal hydrogen costs are achieved at an upper limit of 8 €/GJ (30 €/MWh) and the total hydrogen generation cost fall only just below the level which could be achieved by an annual power supply contract. For this base-load operation an average electricity purchase price of 6 €/GJ (23,36 €/MWh) can be calculated with the historical EEX data for the time frame 2001 to 2003.

The graphs for the total hydrogen generation costs as well as the variable and fix costs are shown in the figure below.



ANNEX 5

BIOMASS TO LIQUID (BTL) FUELS PRODUCTION AND FEEDSTOCK

5.1. Synthetic Fuels from biomass

BTL fuels can be used the following ways:

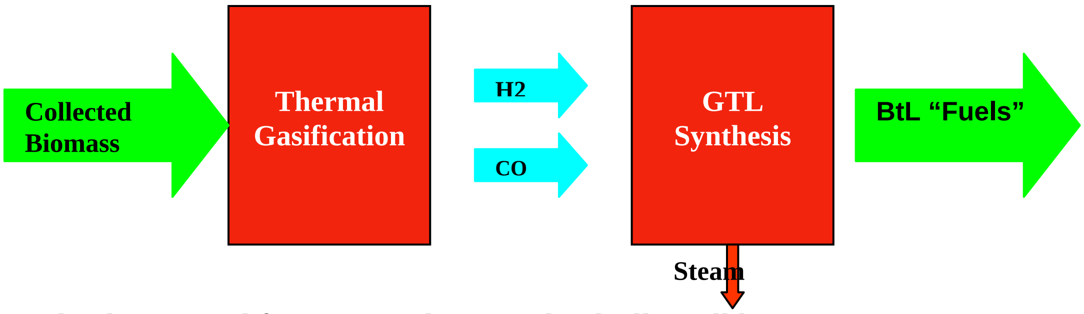
- Directly, in "state of the art" Diesel engines (FT BTL); either in pure form or in blending with crude based fuels, avoiding thus the need for any specific distribution infrastructure.
- In specifically adapted Diesel engines in the case of Di-Methyl Ether., using a distribution network equivalent to or revamped from that of LPG.
- At medium terms, such FT BTL fuels could provide a key element to the low polluting "Homogeneous Combustion" strategy for gasoline-Diesel engines.
- At longer terms, all of these sulphur-free, low aromatics, synthetic fuels should be the "best in class" hydrogen carriers for reformers in Fuel Cells vehicles

5.2. Production processes

The production of these BTL fuels must resolve several issues related to the main steps:

a) Feedstock availability, collection and logistics.

b) Conversion of feedstock into liquid fuels in 2 steps : Gasification (1) and GTL synthesis (2)



The technologies used for step 1 and 2 are individually well known:

- Gasification IGCC plants have been developed for the simultaneous production of power and heat, from wood in Nordic countries, from coal and natural gas in Germany, from industrial and municipal waste everywhere in Europe. Nevertheless, a noticeable margin of industrial improvement remains open to the R & D

- DME synthesis is available from methanol synthesis suppliers

- Fischer-Tropsch synthetic fuels production plants are currently operated, primarily fed with natural gas or coal, in South Africa and Malaysia. Other plants are projected in Qatar, Egypt, Australia and North America. After final hydro-cracking, under feasible conditions (SHELL SMDS) the final product of such process can be: 60% Diesel fuel, 25 % kerosene, 15% naphtha and LPG. These "GTL" fuels are substantially equivalent to those which can be produced from biomass.

The challenge, now, is to solve the logistical, technical and economical issues raised by the integration of these processes. In Germany, Sweden, France, Finland and UK, intensive R&D activities are in progress to optimise the industrial processes for the conversion of biomass into these fuels. Imperial College of London (UK), the "Commissariat à l'Energie Atomique" (F), TU Eberswalde (Germany) have carefully assessed the potentials in terms of feedstock resource and process yields.

Nowadays, one pilot plant has started production of BTL fuels: CHOREN Industries GmbH in Freiberg (Germany). Others are planned in Sweden, such as CHEMREC AB., using the by-product "Black liquor" of pulp and paper mills to generate synthesis gas, planned to be converted into Methanol and DME. Major European car manufacturers such as Daimler-Chrysler, Volkswagen, Volvo and Renault devote a sensible activity to this topic.

5.2.1. Conversion: Energy efficiency and Yields:

Orders of magnitude:

Fuel	Density ton / m3	LHV (GJ/ton)
Diesel	0.835	43.0
FT Diesel	0.78	44,0
Naphtha	0.72	43,7
D.M.E.	0,67	28,4
Methanol	0,79	19,8
Wood *	0,85	15,5

<u>Wood</u> *:

For optimal efficiency in the conversion, the rate of humidity, in the feedstock, must be 15 % by weight. The LHV here-mentioned refer to such "Wood*"

<u>Units</u>:
1 toe (oil equiv.): 42 GJ
1 ton Diesel : 43 GJ
1 ton "Wood*" : 15.5 GJ
1 ton dry wood: 18.2 GJ

For easier handling of the evaluations, we shall, indistinctly, globalise Diesel and kerosene (jet fuel) under the name of Diesel.

<u>Energy efficiency</u> is defined as: ratio, in equivalent energy units, of the transport fuel produced to the energy (feedstock <u>and</u> added power, renewable and fossil) fed in the process.

<u>Conversion yield</u>: is defined as the quantity of transport fuel produced (in GJ or toe 'tons of oil equivalent") per ton of feedstock (biomass) or per unit of exploited surface (ha).

The conversion process can be autothermal or "allothermal"[5]. The autothermal integrated process is a process in which all the energy needed for the conversion is obtained from the biomass itself. The "allothermal" process, in which a non negligible quantity of energy or chemicals is fed from external sources are investigated too. The most established process, now, are autothermal:

a) Autothermal:

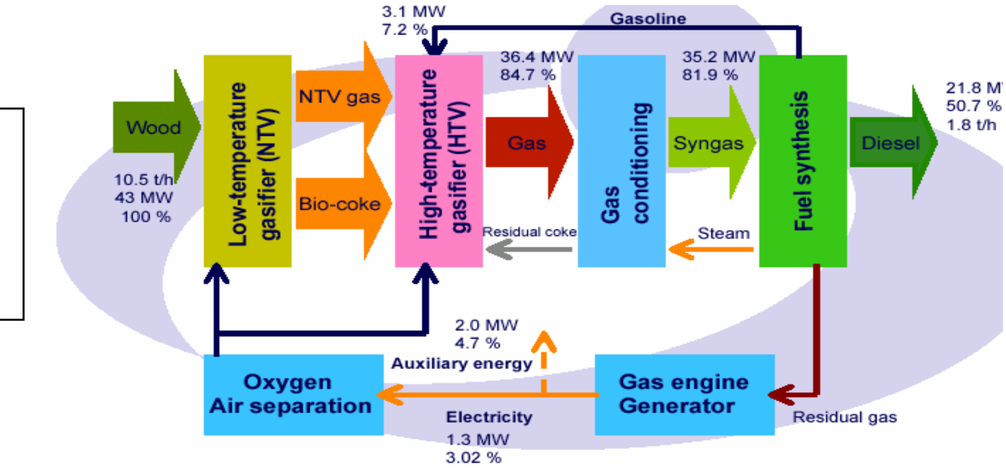
- BTL Diesel from biomass — Theory assessment — Imperial Coll. (UK)
- DME from forest wood — Theory assessment — Atrax Energi (S)
- BTL Diesel from biomass — Theory assessment — CEA Grenoble (F)
- BTL Diesel from biomass — Pilot production — CHOREN Industries (D)

[5] Although such process would be more appropriately referred to as "with external energy input", for simplicity, we shall keep the name of "Allothermal".

- DME / 'Black Liquor" (paper mills) Project of production CHEMREC AB (S)

CHOREN Process

Overall Energy balance



Depending on the size of the plant, on the local conditions, nature of the fuel synthesised and technologies, the resulting figures vary, remaining globally coherent, where atypical values can be explained:

Autothermal process	Main Fuel	Production (t.o.e. / y.)	Energy efficiency	Conver. Yield (t.o.e. / ton)
Imperial College	DIESEL	76 500	42,0%	0,14
ATRAX Energi A.B.	D.M.E.	127 000	49,0%	0,19
CEA Grenoble	DIESEL	n.a.	40,0%	0,14 to 0,20
CHOREN Industries	DIESEL	50 000	50,7%	0,18
CHEMREC A.B.**	D.M.E.	98 500	64,0%	0,28

In the Imperial College assessment neither electric power output, generated in the process, nor kerosene and naphtha are credited for; only FT road fuel is considered as valuable product ex-feedstock. CHEMREC A.B.**[6] derives benefit of the pulp and paper mill process, in which the by-produced "Black Liquor" can be profitably converted into BTL fuel. This "Black Liquor" is the caustic liquid (which extracts the lignin from the primary wood feedstock), carrying a LHV of 12.4 GJ / ton. Today, the energy of the black liquor is used to feed the process with power and heat by boiler. This "Black Liquor" can profitably be substituted by low grade biomass with high conversion efficiency. The size of the paper mill considered here is 1 000 tons/day paper pulp production.

The size of the production plants ranges from 50 to 130 ktoe fuel / year, which can be considered as coherent, in order of magnitude, for comparable efficiencies. The feedstock input ranges from 40 to 104 ton / hour, which seems perfectly realistic as usual paper mills consume about 100 tons/hour, 300 days / year.

b) Process with external energy input.

Alternative conversion processes are under investigation. In these processes, beyond the biomass feedstock, external energy is introduced, either as power, or as chemicals (hydrogen). The target is to increase the energy efficiency, but, mainly, to maximise the quantity of transport fuel which could be produced from the available biomass.

[6] "Feasability & market potential of Black Liquor" gasification with production of renewable motor fuel" T. Ekbom, N. Berglin, M. Lindblom at ISAF IV Conference , November 2002

Such processes have been assessed independently by CHOREN Industries (D) and the CEA laboratory of Grenoble (F):

Process with external input	Main Fuel	Energy efficiency	Conver. Yield (t.o.e. / ton)
CHOREN Industries	F-T Diesel	53,0%	0,39
ATRAX Energi	DME	63,0%	0,54
CEA Grenoble	F-T Diesel	43 to 64 %	0,35 to 0,55

CHOREN adds renewable power via an electrolyser to supply oxygen to the gasification step and hydrogen to the syngas composition tuning step.

CEA adds either non-fossil power to supply the gasification energy in a plasma system or external hydrogen instead of an internal “shift” reaction.

As a partial conclusion on autothermal conversion of biomass into BTL fuels, one can note, in orders of magnitude:

- a credible conversion energy efficiency can be approximated as 50 % +/- 12 %
- the production of 1 toe BTL fuel needs 5 (+/- 2) ton feedstock (wood at 15 % moisture)
- The feedstock supply logistics remains feasible for 100 ktoe fuel / year per plant
- Several European countries support the concept

Processes with external energy inputs are under investigation. Subject the origin of these inputs remain compatible with the global target, these process should bring promisingly increased fuel yields from the available biomass resource.

5.2.2. Feedstock: Availability and Yields, fuel potential:

The feedstock considered here includes any renewable carbonaceous stuff, subject it is not necessary to human industrial activity or food, such as:

- Agricultural residues
    - crop harvest residues and manure
- Forest residues
    - felling residues, sawmills and paper mills by-products
    - end-of-life already collected woods (construction, pallets …etc)
- Municipal waste
- Energy plantations
    - Forests
    - short rotation coppice and herbaceous

Several research organisms have, independently, undertaken to assess tentatively such figures at the European (EU 15) level: LBST (D), Kaltschmidt and IfE (D), more recently: STFI (S) and Imperial College (UK). If these studies converge on the conversion energy efficiency, less homogeneous boundaries and range bring, for the evaluated resource, some more random figures:

SOURCES Unit (PJ)	IfE U. WAGNER (2) MINI.	 MAXI	R. WURSTER (LBST)	VW -DC at VDA Konf. Conservative	 Ambitious	Imperial College
Wood residues	1 000	1 800	2 000	Surface : 5 % of agri. area. 10 t./ha.	Surface : 10 % of agri. area. 20 t./ha.	5 000
Agricultural straws	600	1 000	1 300			3 000
SUB TOTAL:	1 600	2 800	3 300			8 000
Recoverable (50 % or 25%):	800	1 400	1 650	-		2 000
Energy plantations	400	1 000	1 000	1 085	4 340	2 200
TOTAL (PJ)	1 200	2 400	2 650	1 085	4 340	4 200
Equivalent wood (Mtons / y.)	77,4	154,8	171,0	70,0	280,0	271,0
BtL fuel potential in (Mtoe / year)	**14**	**29**	**32**	**13**	**52**	**50**
Fuel substitution potential at year 2010-2020	4,6%	9,2%	10,2%	4,2%	16,7%	16,1%

For energy plantations, although more promising forestry yields are being claimed, the value considered here was conservatively limited at 10 tonnes wood* (15 % moisture) per ha over a supposed dedicated surface representing 5% of cropland, forest and woodland (Imperial College).

Beyond these pathways, the most recent one of converting the “Black Liquor” of pulp and paper mills provides a potential of 6.6 Mtoe BTL fuels from the 432 PJ/y of “Black Liquor” produced in Europe (STFI –CHEMREC A.B.) If the energy converter for biomass is a standard boiler, the black liquor used for this purpose has to be substituted with biomass at an efficiency rate of about 65% (produced fuel per added biomass).

The different estimates on the biomass feedstock potential give a large range for the market share of motor fuel substitution, depending on assumptions, with an upper limit of 16% for EU-15.

5.2.3. Logistics: feedstock and BTL fuel

The feedstock collecting range around a conversion plant is one of the key issues of the economical and environmental equation in the process, the energy dedicated to the transport (by truck) of that feedstock having to remain minimal compared to the fuel produced in the conversion plant. The majority of the studies on that aspect consider a possible radius of 50 km. But, if a realistic forest yield has been stated at 10 tons/ha, geographical regions are not often fully covered with such dense forest and a minimal geographic average forest yield has to be established as a success criterion.

In the case of a “classical” (gasification – synthesis) plant producing 100 000 toe fuel/year, the feedstock need is 500 000 tons/year. Over a collecting basin 25 km in radius, the average forest yield should be, at least 4 tons/ha a favourable yield of 8 t/ha would reduce the radius to 17 km.

In the specific case of the “Black Liquor” process, (STFI & Chemrec)[7] have established that a typical mill producing 185 000 tons paper pulp / year would be correctly supplied with a basin of 180 000 ha of forest land. When the mill is extended to generate also BTL, the production would correspond to 100 000 tons/year of methanol or DME. To achieve this, additional biomass is needed. According to this investigation, the area quoted can generate additional 1.3 tons of wood/ha. This would satisfy 85% of the biomass needed to produce the 100 000 tons/y of methanol/DME.

[7] “Feasability & market potential of Black Liquor” gasification with production of renewable motor fuel” T. Ekbom, N. Berglin, M. Lindblom at ISAF IV Conference , November 2002

5.2.4. Investment, pay-back, cost

Feedstock supply from residues is usually considered on a "no cost" basis. Farmed wood feedstock (pellets) is considered as a profitable business at a price of 50 (S) – 78 (UK) € / ton.

The assessments for conversion plants obtained for a BTL DME plant[6], for a "Black Liquor" based Methanol plant, and the financial business plan communicated by CHOREN for BTL diesel give indicative orders of magnitude, taking into account the specificity of each process:

Data Source	Main Fuel	Production (t.o.e. / y.)	Invest. (Meuros)	Redemption (years)
CHOREN Industries	BtL Diesel	50.000	140	20
ATRAX Energi A.B.	BtL D.M.E.	127.000	330 to 440	15
CHEMREC A.B.**	BtL Methanol	98.500	70 to 80	4
IFP / CEA Grenoble	BtL Diesel	100.000	150,00	-

Investment for a conversion plant capacity of 100 000 toe/year is estimated around 250 – 300 M€.

The economic profitability of such a conversion plant remains an issue. Usual economic standards in the oil industry claim as profitable a refinery producing 2 Mtoe fuel/year. The SHELL experimental BTL plant BIG FiT aims at profitability at a capacity of 0.2 Mtoe / year.

For logistics reasons, a 0.1 Mtoe/y plant has been taken as example matching the dimension of feedstock base and supply rate of 1500 – 2000 tons/day usual for paper mills.

A special case is BTL fuel produced from paper mills "Black Liquor", in which a part of the production system is already operated and paid by the main product, while the investment borne by the fuel is limited to the Black Liquor circuit updating, the fuel synthesis unit and the addition of a biomass boiler with around 80 M€ / plant.

The expected cost of fuel has been calculated by Atrax Energi AB (S) for BioDME, by Imperial College (UK) and CHOREN Industries for FT BTL, by CHEMREC AB for methanol ex-"Black Liquor". For easier comparison, for all fuels, units have been normalised as € / litre of diesel equivalent or per toe, no consideration of taxes incentives have been accounted for. As a reference, crude based diesel is shown, for coherent comparison, without taxes.

Data Source	Main Fuel	Production (t.o.e. / y.)	Cost of fuel (Euro / lit. Diesel equiv.)	Cost of fuel (Euro / ton. Diesel equiv.)
CHOREN Industries	F-T Diesel	50 000	0,67	788
ATRAX Energi A.B.	Bio D.M.E.	127 000	0,63	741
IFP / CEA Grenoble	F-T Diesel	100 000	0,45 to 0,70	500 to 800
IMPERIAL COLLEGE	F-T Diesel	68 000	0,50 to 0,83	588 to 1000
CHEMREC A.B.**	Bio Methanol	98 500	0,28	330
SHELL (reference)	Fossil Diesel	2 000 000	0,21	247

Except in the case of the "Black Liquor" concept, where fuel is a by product of the paper mill, the production cost of BTL fuels is about 3 times that of crude based fuels, which is coherent with the situation of the "classical biofuels".

ANNEX 6

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Annex 7 Acronyms and Abbreviations

ADVISOR	A powertrain simulation model developed by the US-based National Renewable Energy Laboratory
APU	Auxiliary Power Unit: Power supply for ancillary electric appliances in vehicles
BTL	Biomass-To-Liquids: denotes processes to convert biomass to liquid fuels
CCGT	Combined Cycle Gas Turbine
CEEC-10	The 10 Central and East European Candidate countries
C-H_2	H2 Compressed hydrogen
CNG	Compressed Natural Gas
CNG BF	BF CNG/gasoline bi-fuel vehicle
CO	Carbon monoxide
CO_2	Carbon dioxide: the principal greenhouse gas
CONCAWE	The oil companies' European association for environment, health and safety in refining and distribution
DDGS	Distiller's Dried Grain with Solubles: the residue left after production of ethanol from wheat grain
DICI	An ICE using the Direct Injection Compression Ignition technology
DISI	An ICE using the Direct Injection Spark Ignition technology
DME	Di-Methyl-Ether
DPF	DPF Diesel Particulate Filter
EUCAR	EUCAR European Council for Automotive Research and Development
EU-mix	The average composition of a certain resource or fuel in Europe. Applied to natural gas, coal and electricity
FAME	FAME Fatty Acid Methyl Ester: Scientific name for biodiesel
FC	Fuel Cell
FCV	Fuel Cell Vehicle
FT	Fischer-Tropsch: the process named after its original inventors that converts syngas to hydrocarbon chains
GDP	Gross Domestic Product
GHG	Greenhouse gas
GJ	Gigajoule: 10^9 Joule: Energy unit
GTL	Gas-To-Liquids: denotes processes to convert natural gas to liquid fuels
HCCI	Homogeneous Combustion Compression Ignition
ICE	Internal Combustion Engine
IEA	International Energy Agency
IES	IES Institute for Environment and Sustainability
IFP	Institut Français du Pétrole
IGCC	IGCC Integrated Gasification and Combined Cycle
IPCC	Intergovernmental Panel for Climate Change
JRC	Joint Research Centre of the EU Commission
LBST	L-B-Systemtechnik GmbH
LCA	Life Cycle Analysis
L-H2	Liquid hydrogen
LHV	Lower Heating Value ('Lower" indicates that the heat of condensation of water is not included)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gases
ME	The Middle East
MJ	Megajoule: 10^6 Joule: Unit of energy. A litre of gasoline liberates approximately 35 MJ when burned
MPa	Mega-Pascal: Pressure unit
Mt	Megaton: 10^6 tons: Mass unit
Mtoe	Million tonnes oil equivalent. The "oil equivalent" is a notional fuel with a LHV of 42 GJ/t
N_2O	Nitrous oxide: a very potent greenhouse gas

NEDC	New European Drive Cycle
NG	Natural Gas
NGV	Natural Gas Vehicles
NOx	A mixture of various nitrogen oxides as emitted by combustion sources
OEM	Original Equipment Manufacturer
PISI	An ICE using the Port Injection Spark Ignition technology
PJ	Petajoule: 10^{15} Joule: Energy unit
PM	Particulate matter : airborne microsize particulates
PSA	Pressure Swing-Adsorption : Process for hydrogen separation from syngas
RME	Rapeseed Methyl Ester: biodiesel derived from rapeseed oil (colza)
SMDS	The Shell Middle Distillate Synthesis process
SME	Sunflower Methyl Ester: biodiesel derived from sunflower oil
SRF	Short Rotation Forestry
SUV	Sport-Utility Vehicle
Syngas	A mixture of CO and hydrogen produced by gasification or steam reforming of various feedstocks and used for the manufacture of synthetic fuels and hydrogen
TES	Transport Energy Strategy. A German consortium that worked on alternative fuels, in particular on hydrogen
TTW	Tank-To-Wheels: description of the burning of a fuel in a vehicle
VLCC	Very Large Crude Carrier
WTT	Well-To-Tank: the cascade of steps required to produce and distribute a fuel (starting from the primary energy resource), including vehicle refuelling
WTW	Well-To-Wheels: the integration of all steps required to produce and distribute a fuel (starting from the primary energy resource) and use it in a vehicle
ZEV	Zero Emission Vehicle