International Energy Agency

PRODUCTION COSTS OF ALTERNATIVE TRANSPORTATION FUELS

Influence of Crude Oil Price and Technology Maturity

FEATURED INSIGHT

Pierpaolo Cazzola, Geoff Morrison, Hiroyuki Kaneko, François Cuenot, Abbas Ghandi and Lewis Fulton

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International Energy Agency

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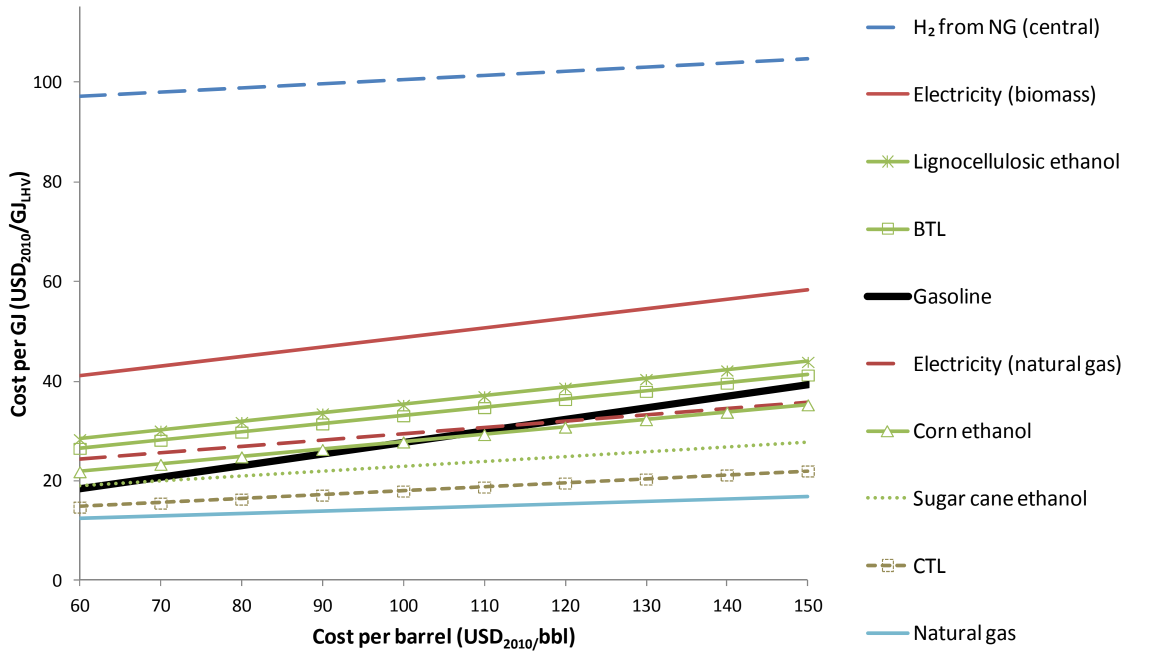
Executive Summary

This study examines the production costs of a range of transport fuels and energy carriers under varying crude oil price assumptions and technology market maturation levels. It uses an engineering "bottom-up" approach to estimate the effect of both the input cost of oil and various technological assumptions on the finished price of these fuels. In total, the production costs of 20 fuels were examined for crude oil prices between USD 60 per barrel of oil (USD/bbl) and USD 150/bbl (USD 60/bbl was the reference point as a long-term series of data were linked to low oil prices, which only increased in the last decade or so).

The paper used data from a range of sources, collected as part of the International Energy Agency (IEA) Mobility Model (MoMo) project (Fulton, Cazzola and Cuenot, 2009). The estimates presented here constitute one of the sources that feed into IEA analyses, such as the IEA *Energy Technology Perspectives 2012* (IEA, 2012a), and are part of a wider range of inputs unrepresentative of official IEA estimates. This working paper is intended both to show the results of specific IEA analysis, and solicit comments on the methodology and data used. The fuel cost estimates take into account the costs of feedstock procurement and transportation; feedstock conversion to fuel; and fuel transportation and distribution (including costs of constructing infrastructure and dispensing stations). Specific attention is paid to the transmission and distribution (T&D) costs of hydrogen (H_2), bio-synthetic natural gas (bio-SNG), and electricity for electric vehicles (EVs), as these fuels' infrastructures are the least developed of the pathways currently considered.

Figure 1 • Cost of fuel production versus oil price for select fuels in Current Technology Scenario



Note: BTL = biomass-to-liquids; CTL = coal-to-liquids; NG = natural gas; USD_{2010}/bbl = 2010 nominal USD per barrel of oil; USD_{2010}/GJ_{LHV} = 2010 nominal USD per gigajoule using lower heating value. Fuel production costs in this figure are extrapolated from their USD 60/bbl value using an arithmetical average of the two methods (Petroleum Intensity and Historic Trend) are discussed below (see Chapter "Results").

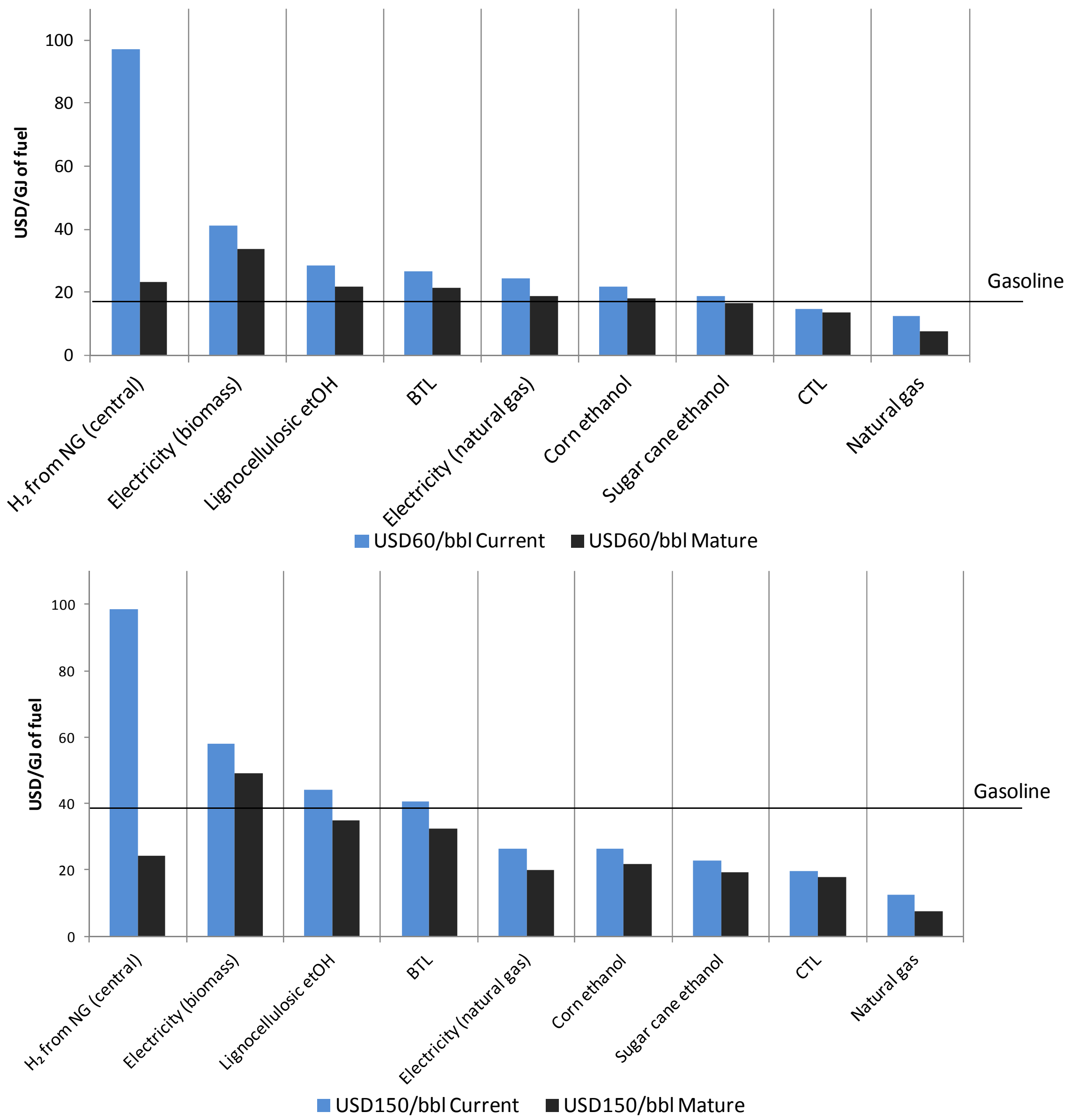
Source: unless otherwise stated, all material in figures and tables derive from IEA data and analysis.

For the feedstock and procurement stage, two separate procedures were used to estimate how changes in oil prices affect fuel production costs. The first procedure, the Petroleum Intensity Method, estimates the quantity of petroleum used to produce and transport each feedstock. As the oil price increases, feedstocks with the highest petroleum intensity incur the highest rises in cost. The second procedure, the Historical Trend Method, relies on the historical bivariate relationship between the price of oil and the average global price of a given feedstock. As the oil price increases, the cost of a given feedstock changes according to this relationship. Results from both procedures are presented, and represent what is considered as the two extremes of the influence of oil price on transportation fuel costs.

Fuel production costs are estimated for today's market environment (Current Technology Scenario) in which emerging technologies have not fully benefited from economies of scale or know-how (Figure 1).

Future fuel costs are also estimated for a situation in which a fully mature supply chain exists independently for each fuel using a Mature Technology Scenario (Figure 2). For some emerging energy pathways, such as electricity (and electric transport), technological maturity may not be achieved before 2020, and in a few cases (*e.g.* H_2) it may not be until 2030 or later. However, the main purpose of this Scenario's analysis is to find a set of parameters that enable comparability of energy for transportation and quantification of the effect of higher crude oil prices on the production costs of fuels.

Figure 2 • Cost of fuel for Current Technology Scenario versus Mature Technology Scenario for USD 60/bbl (top) and USD 150/bbl (bottom)



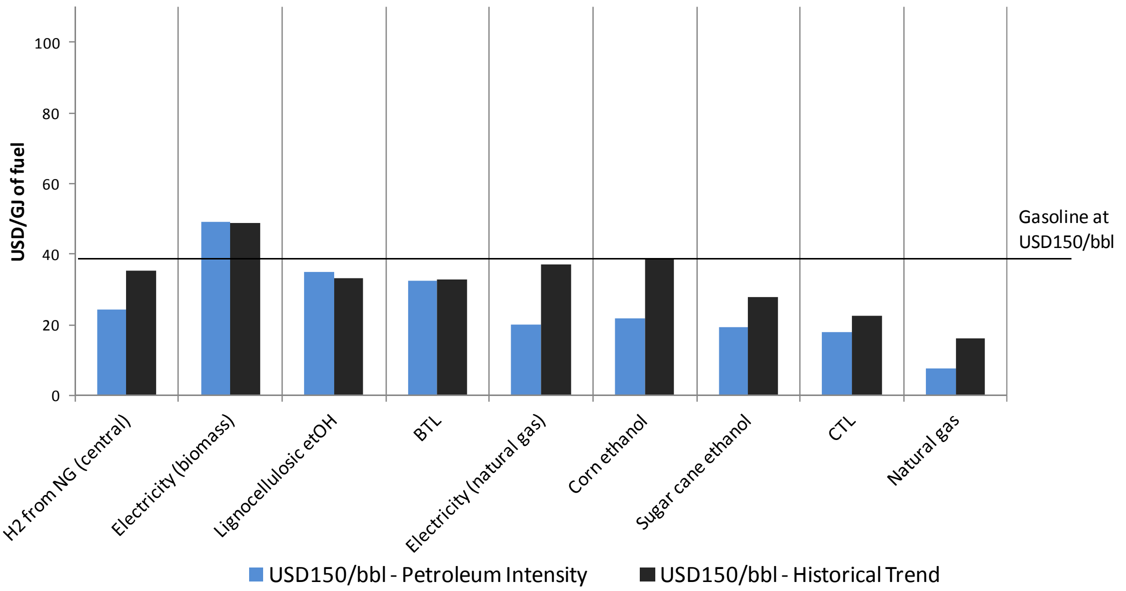
Note: USD/GJ = USD per gigajoule, etOH = ethanol.

There are two methods for estimating fuel costs:

- linking the cost of production to the quantity of petroleum products used in production (Petroleum Intensity Method);
- linking the inputs to production to the historical relationships between input commodities and the fuel of interest (Historical Trend Method).

The Petroleum Intensity Method accounts for direct effects and uses energy input-output co-efficients from the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model (Wang, 2007). The Historical Trend Method accounts for both the direct and indirect effects. When using the two methods for mature technology with oil priced at USD 150/bbl, the Historical Trend Method yields slightly higher estimated costs than the Petroleum Intensity Method (Figure 3).

Figure 3 • Cost of fuel for Petroleum Intensity Method and Historical Trend Method (USD150/bbl)



This report will be useful to policy makers and practitioners seeking to understand how and why transport fuels are sensitive to crude oil price fluctuations, and how the cost-competitiveness of different fuels may change with these fluctuations. It also should be of use to energy providers who seek to minimise their exposure to future oil price volatility.

Nine main results and recommendations were drawn from this analysis:

- **Policy makers should not assume that in a future with higher oil prices, non-petroleum transportation fuels will be economically competitive.** Rather, because most production processes of alternative transportation fuels rely on petroleum these alternatives will likely face increasing costs as oil prices increase.
  - **Feedstock prices play a major role in the final (untaxed) costs of alternative fuels.** Since feedstock prices can vary considerably, they should be carefully accounted for in the cost-benefit analysis of different fuel options.
  - **Several fuels could compete with gasoline if high gasoline prices are compared to a fuel cost estimate that assumed low crude oil prices.** This underscores the importance of clearly stating the oil price assumptions in techno-economic analyses, and using this assumption when developing cost assumptions for other fuels.
- **Alternative transportation fuels vary in sensitivity towards oil price changes.** A 1% increase in the oil price leads to a 0.0% to 0.68% increase in the production cost of fuels in the Current

Technology Scenario. The fuels with production costs least sensitive to oil price changes include bio-SNG, sugarcane ethanol and H_2 from coal gasification. On the other hand, corn or lignocellulosic ethanol, biodiesel, BTL, and gas-to-liquids (GTL) have the largest production cost changes as the oil price fluctuates. Considering the impact of changing oil prices on other feedstocks, first and second generation biofuels such as corn ethanol, lignocellulosic ethanol and BTL tend not to achieve levels of cost-competitiveness that are comparable with other alternative energy pathways.

  - **Fuels with the greatest sensitivity to input parameters include H_2 pathways, electricity from solar photovoltaic (PV), and lignocellulosic ethanol.** The fuels with the least sensitivity to future costs include corn ethanol and CTL.
  - **The most sensitive input parameters used to estimate production costs in this analysis vary by fuel type.** The conversion efficiency from primary to secondary energy, the price of oil, and the feedstock acquisition cost (that are linked to the oil price, as assumed in the Historical Trend Method), however, are generally the most sensitive parameters.

- **Refuelling infrastructure costs can significantly impact the introduction of a number of alternative fuels, depending on their specific characteristics.** This effect is much stronger in immature markets, where the ratio of infrastructure to the amount of fuel sold may be relatively high.
- **In the Current Technology Scenario, few alternative fuels are likely to compete with oil below USD 90/bbl.** On an energy basis, only natural gas and CTL enjoy lower production costs. For natural gas, this result is heavily dependent on the rate of usage of the refuelling infrastructure. On a per kilometre basis, natural gas, CTL and all electricity pathways have lower production costs, the latter thanks to the much higher efficiency of electric motors compared to internal combustion engines.
  - **Many alternative fuels can compete with a USD 100/bbl in the Mature Technology Scenario.** Only fuels that can be mixed with oil would immediately reduce the overall driving costs. Other fuels that need alternative powertrain technologies (such as gaseous fuels, electricity that need substantial retrofits and ethanol-based fuels that need slight retrofit to make the vehicle compatible with those fuels) will require important lead times to have a significant market share. They also need ambitious infrastructure deployment programmes that focus on fuel costs, which are not considered in this analysis. Of the cheaper options, CTL is only readily available for the existing vehicle fleet.

Introduction

The estimation of production costs for transportation fuels has been the subject of major research (NAS, 2004; Parker, 2004; Yousif *et al*., 2011; Fornell, Berntsson and Asblad, 2012) in recent years. Such estimations are used by energy stakeholders to determine the economic viability of a particular fuel technology or conversion process. However, a missing component in nearly all these analyses has been the discussion about the effect of oil price changes on production costs. This paper attempts to fill this research gap by evaluating global "well-to-tank" supply chain costs for 20 transportation energy pathways[1] at oil price levels between USD 60/bbl and USD 150/bbl in current technological conditions (Current Technology Scenario), and a condition in which a fully developed supply chain exists independently for each fuel alternative (Mature Technology Scenario).

Working on a global average is clearly too simplified and the aim of this analysis is not to address specific regional situations or "break-even" prices with crude oil. Its purpose is rather to highlight structural linkages between the cost of crude oil and the production costs of alternatives, and investigate whether an increase in crude oil price could potentially prevent various options from becoming cost-competitive.

The cost of a particular fuel or energy carrier can be broken into three general categories:

- The input stream cost, which includes the procurement of the primary energy feedstock and the transportation of the feedstock to the conversion facility. Feedstock storage and preparation (*e.g.* biomass pelletisation) costs are not covered here.
- The production cost, which includes levellised capital costs and the operation and maintenance (O&M) costs of the conversion facility. This includes refineries, gas processing units, gasifiers, etc.
- The fuel transport/T&D costs, which include capital and infrastructure needed to transport the fuel/energy carrier from the refinery and dispense it to end-users. Specific attention is given to the costs of fuels with extremely low current market penetration (*i.e.* H_2 and electricity for transportation).

A large technical manual is used to estimate each of these three costs for the 20 transportation energy pathways. All costs are given in 2010 USD. Unit costs are given in USD per gigajoule using lower heating value (USD/GJ_{LHV}), USD per litre of gasoline-equivalent using low heating value (USD/lge_{LHV}), or USD per kilometre travelled (USD/km). This analysis considers relevant energy pathways (Table 1). Though many potentially important emerging pathways are omitted, the breadth of pathways across different primary energy sources enables a number of conclusions to be drawn about the effect of oil price on production costs.

For ease of presentation, all data tables and discussion in this report concern results at USD 60/bbl and USD 150/bbl. The average price of crude oil was USD 39.2/bbl from 1985 to 2010, in real 2010 USD, and an average of USD 72.2/bbl from 2005 to 2010.

The IEA assumes that oil prices will rise steadily, reaching prices of USD 145/bbl and USD 125/bbl, respectively, in 2035 (IEA, 2012b). Only in the 450 parts per million of carbon dioxide scenario, do oil prices stay near the 2011 levels of USD 100/bbl (IEA, 2012b). For this analysis, USD 60 and USD 150/bbl have been selected as reasonable low and high oil prices to reflect the wide range of possibilities.

As engine efficiencies differ between different energy types (*i.e.* electric motors are more efficient than spark-ignition engines), a further analysis is conducted to estimate the cost per kilometre travelled for each energy pathway. This provides another perspective about the viability of different energy options.

[1] Here, an energy pathway is defined as a particular feedstock and conversion process. An example energy pathway is BTL production using woody forest residue in a fixed-bed gasifier. The analysis stops at this level of detail (*i.e.* does not discuss the specific type of farming equipment, biomass pre-treatment process, etc.) since the focus is to identify the broad relationship between the crude oil price and production costs.

Table 1 • Energy pathways considered

Primary energy source	Final energy type	Process
Crude oil	Gasoline* Diesel fuel**	Oil refining
Natural gas	Middle distillates (GTL) Compressed natural gas H_2 Electricity	Gasification and Fischer-Tropsch conversion Processing, compression Reforming, compression Gas turbine (50% efficiency assumed)
Coal	Middle distillates (CTL) H_2 Electricity	Gasification and Fischer-Tropsch conversion Coal gasification Integrated gasification combined cycle
Nuclear energy	H_2 Electricity	Water splitting Fission
Oil-seed crops	Biodiesel (rapeseed)	Transesterification, hydrogenation
Grain crops	Ethanol (corn)	Biochemical conversion
Cane crops	Ethanol (sugarcane)	Fermentation
Biomass from crops and/or waste products	Biodiesel (BTL) Lignocellulosic ethanol Bio-SNG H_2 Electricity	Gasification and Fischer-Tropsch conversion Biochemical conversion Biomass gasification Electricity generation from power plants (co-firing and dedicated) and point-of-use electrolysis Direct combustion (dedicated)
Solar energy	Electricity	PV cells
Hydroelectric energy	Electricity	Large hydroelectric turbines

* Reference fuel.

** Assumed the same cost per gigajoule as gasoline.

The cost estimates in this study were based on a set of technical and economic parameters such as conversion efficiency, energy density of feedstocks, scaling factors, lifetime of infrastructure and conversion facilities, interest rate, historical cost movements and others outlined below. To understand the importance of each of these input parameters to the final cost estimate, a sensitivity analysis was performed for each fuel.

As is usual with this type of study, a number of caveats deserve mention. The cost estimates here reflect the "global average delivery cost to consumers" located reasonably close to conversion plants. These costs will inevitably differ from estimations at regional or local levels, from those considering particularly long transportation distances from the point of final consumption/distribution of the fuels and/or from estimations with particularly long transportation distances for the feedstocks in each pathway (except for natural gas), where transportation costs are assumed to be included in the feedstock price). Global studies have gone a long way to combine cost estimates. However, the spatial design of the supply chain, the endowment of resources within a region, the cost of a region's labour force, exchange rates, costs of the long-distance transportation of energy carriers and their required feedstocks, as well as differing regional policies implemented, could shift supply chain costs away from the estimates given here. The average cost to producers also differs from the consumer price, which can vary owing to market-mediated effects. Another caveat is that technological advancement is uncertain and will likely be heterogeneous across energy pathways. This report details production costs, not market prices (except for oil as an input). Additionally, this analysis does not consider the time lag between oil price changes and changes to production costs. Rather, all estimations assume that energy, capital, and labour markets have readjusted to the new stable oil price. Finally, this analysis does not estimate vehicle costs, which will likely be an important factor in the expansion of emerging energy technologies as much as fuel costs.

Description of Main Analysis and Key Assumptions

This section describes the three main components of cost – input streams, production, and transportation and distribution – in greater detail. Information about the drive-train efficiency assumptions used to estimate the cost per kilometre for each fuel is useful (Table 10). Additional details are also of interest (Annexes A to F).

Input stream costs

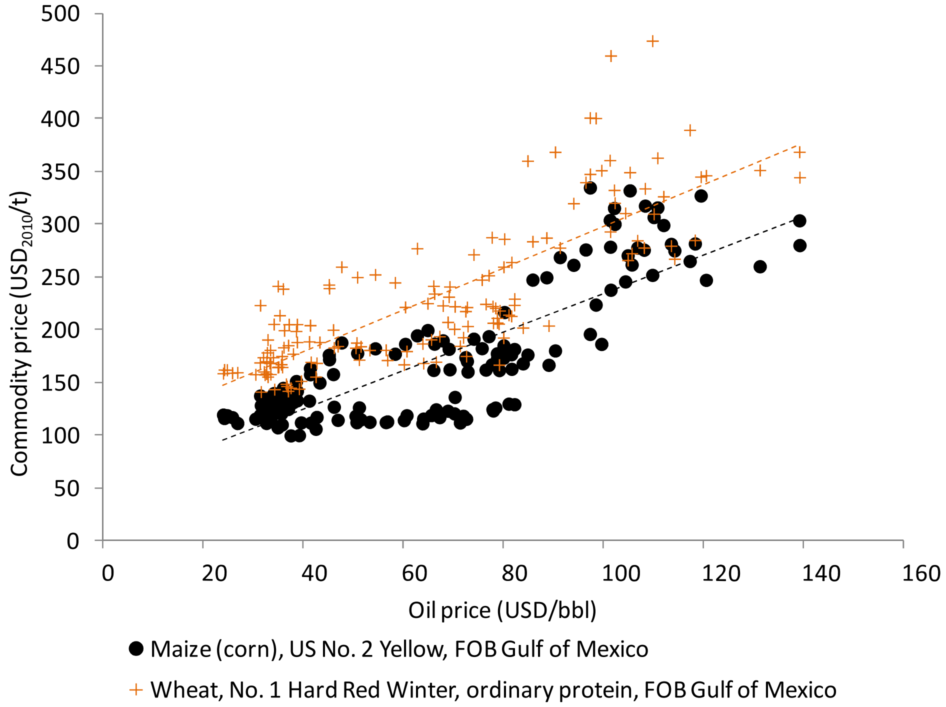
Input streams include all physical inputs to the refining/conversion process including the primary feedstock, chemicals and electricity. In this analysis, input stream costs also include the transportation from the points of extraction/harvest to the conversion facility. The costs of the feedstock represent one of the largest overall costs in the production of fuels (Yousif *et al.*, 2011). The linkage between input stream costs and crude oil price reflects a number of "direct effects" *e.g.* oil used in fertiliser production, for farm tractors, biomass transport, etc. (Table 2). The linkage between input stream costs and crude oil price also reflects "indirect effects"(*e.g.* as oil prices increase, the attractiveness of natural gas or biofuel use increases and places an upward pressure on natural gas or bio-energy feedstock prices) are mainly related to the market relationships of feedstock prices (Figure 4).

Table 2 • Direct effects of petroleum energy used

Primary energy source	Final energy type	Petroleum intensity of energy source (megajoule of oil/gigajoule of final energy)	
		Production	Transportation
Natural gas	GTL	3.99	0.00
	H_2 (central production)	3.99	0.00
	Electricity	3.99	0.00
Coal	CTL	11.3	19.4
	H_2 (gasification)	11.3	19.4
	Electricity	11.3	19.4
Nuclear energy	H_2	3.98	0.00
	Electricity	3.98	0.00
Oil-seed crops	Biodiesel (rapeseed)	29.8	22.7
Grain crops	Ethanol (corn)	20.1	25.7
Sugar crops	Ethanol (sugarcane)	15.6	9.19
Biomass from crops and/or waste products	BTL (forest residues)	40.5	49.9
	Lignocellulosic ethanol (corn stover)	39.6	24.7
	Biogas (landfill)	0.00	0.00
	H_2 (corn stover)	39.6	24.7
	Electricity (forest residues)	40.5	49.9
Solar energy	Electricity (PV)	0.00	0.00
Hydroelectric energy	Electricity	0.00	0.00

In the Petroleum Intensity Method, using the GREET model, the quantity of petroleum used in the production of each commodity (*i.e.* only capturing the direct effects) was estimated. The Petroleum Intensity Method (the amount of megajoules of petroleum used to produce 1 gigajoule of final fuel) established a base price of USD 60/bbl. Subsequent changes from USD 60 were based on the commodity's petroleum intensity (see Annex A for a sample calculation). In all tables and figures showing both the Petroleum Intensity Method and Historical Trend Method, the costs of production at USD 60/bbl are equal for the two methods. As oil prices exceed USD 150/bbl, the two methods give slightly different results. The reader must decide which method is preferable.

Figure 4 • Energy feedstock commodities and oil price, 2000-10



Note: USD_{2010}/t = 2010 nominal USD per tonne; FOB = free on board; US = United States.
Sources: IMF, 2013; BLS, 2012.

Table 3 • Comparison between Petroleum Intensity Method and Historical Trend Method for estimating input stream costs under variable oil prices, Current Technology Scenario

Primary energy source	Final energy type	Amortised input stream costs (USD/GJ)			
		Petroleum Intensity Method		Historical Trend Method	
		USD 60/bbl	USD 150/bbl	USD 60/bbl	USD 150/bbl
Natural gas	GTL	10.97	9.94	10.97	24.71
	Gaseous (for CNG)	5.42	4.82	5.42	13.39
	H_2 (central production)	9.15	8.32	9.15	20.21
	Electricity	10.84	9.65	10.84	26.77
Coal	CTL	7.27	9.78	7.27	14.34
	H_2 (gasification)	6.27	8.34	6.27	20.21
	Electricity	6.39	9.24	6.39	14.41
Nuclear energy	H_2	1.62	1.62	1.62	1.62
	Electricity	2.38	2.38	2.38	2.38
Oil-seed crops	Biodiesel (rapeseed)	26.80	31.59	26.80	52.97
Grain crops	Ethanol (corn)	19.58	21.02	19.58	41.56
Sugar crops	Ethanol (sugarcane)	13.38	14.16	13.38	24.06
Biomass from crops and/or waste products	BTL (forest residues)	10.80	15.27	10.80	16.12
	Lignocellulosic ethanol (corn stover)	16.32	22.19	16.32	24.55
	Biogas (landfill)	8.43	11.82	8.43	12.25
	H_2 (agricultural residues)	9.97	14.03	9.97	14.80
	Electricity (forest residues)	10.53	16.05	10.53	15.85
Solar energy	Electricity (PV)	0.00	0.00	0.00	0.00
Hydroelectric energy	Electricity	0.00	0.00	0.00	0.00

Note: Excludes carbon capture and storage technologies.

Forest residues, which require a large quantity of petroleum in their collection and transportation to the biorefinery, are the most sensitive feedstock costs to changes in oil price in this paper. On the other hand, the least oil price-sensitive feedstocks are biogas from landfill, electricity from solar, and electricity from hydroelectric plants which, according to the GREET model, require 0 megajoules of petroleum to collect and transport to the conversion facility.

The other method for estimating input stream costs for different crude oil price levels is to use the Historical Trend Method. Using nominal data for 2012 from both the International Monetary Fund (IMF) and the consumer price index (CPI) of the United States from the Bureau of Labor Statistics (BLS), real corn and wheat commodity prices from Mexico changed significantly in relation to the oil price from 2000 to 2010 (Figure 4). Certainly, the oil price is not the only important determinant of historical commodity price fluctuations. However, for most energy commodities, the oil price's explanatory power is very high and provides a straightforward approach to modelling cost changes. Annex A provides further details on this method.

The costs of production and transportation of feedstocks at USD 60/bbl are the same for the Petroleum Intensity Method and the Historic Trend Method (Table 3). However, as oil prices rise from USD 60/bbl to USD 150/bbl, the Petroleum Intensity Method cost is generally lower than the Historical Trend Method cost.

Differences between the Current Technology Scenario and the Mature Technology Scenario

Adjustments in costs from the Current Technology Scenario to the Mature Technology Scenario are made using assumptions on crop yield increases, increasing efficiencies of conversions and changing transportation distances from the point of extraction/harvest to the conversion facility. It should be noted that in already well-developed pathways (*e.g.* corn ethanol), the marginal improvement is small (Figures 2 and 3).

Capital costs, O&M costs, co-products

Capital costs include the cost of construction, interest payments, insurance, licensing, contingencies, and royalties. O&M costs include the labour costs for workers and supervisors and the costs for conducting routine maintenance on the facility. Lastly, some agricultural feedstocks generate co-product revenue.

For each energy pathway (*e.g.* wood waste to BTL), multiple literature sources were used to estimate an average total capital cost of the fuel production facility. As some sources report regarding levellised costs for both small pilot plants and large-scale plants, effort was taken to resize plants to equal sizes using the equation in Annex B. See also Annex C for details on the assumptions retained for the energy efficiency of the plants. The fuel production plant capacities were determined considering medium- to large-scale production facilities (Table 4). The increase in size from the Current Technology Scenario to the Mature Technology Scenario depends on the current maturity of the industry and how large a conversion facility will become following the corresponding energy pathway's successful large-scale exploitation. The resulting assumption also includes the effects of pathway-specific limiting factors (such as the concentrated sparse nature of the feedstocks, which leads to much lower scales for plants using biomass feedstocks, in comparison with those relying on fossil fuels or nuclear energy).

To estimate the effects of crude oil price on capital costs, a refinery cost index from IHS Cambridge Energy Research Associates (CERA) is used. This index tracks the costs of equipment, facilities, materials, and personnel used in the construction of over 30 refining and petrochemical construction projects (IHS, 2012) and, for power generation, the costs of building coal, gas, wind, and nuclear power plants. It is similar to the CPI and aims to provide a clear benchmark for tracking investment costs. This index increases with rising oil prices (Figure 5). In this analysis, the oil price has been assumed to be the driver that determines changes of the IHS CERA indices over the years. While this is clearly a simplification, it helps give a sense of small changes in the capital and O&M costs of the price of oil.[2] As with other studies, the O&M costs in this analysis are assumed to be 10% of the levellised capital costs.

Table 4 • Summary of sizes of production facilities (expressed as annual output) for Current Technology Scenario and Mature Technology Scenario

Primary energy source	Final energy type	Current Technology Scenario (GJ_{LHV}/yr)	Mature Technology Scenario (GJ_{LHV}/yr)
Natural gas	GTL	57 000 000	140 000 000
	H_2 (central production)	28 000 000	50 000 000
	Electricity	5 200 000	9 400 000
Coal	CTL	57 000 000	140 000 000
	H_2 (gasification)	22 000 000	33 500 000
	Electricity	9 400 000	17 000 000
Nuclear energy	H_2	28 000 000	33 500 000
	Electricity	6 700 000	12 000 000
Oil-seed crops	Biodiesel (rapeseed)	2 500 000	6 300 000
Grain crops	Ethanol (corn)	2 500 000	6 300 000
Sugar crops	Ethanol (sugarcane)	2 500 000	6 300 000
Biomass from crops and/or waste products	BTL (forest residues)	2 500 000	6 300 000
	Lignocellulosic ethanol (corn stover)	2 500 000	6 300 000
	Biogas (landfill)	2 500 000	6 300 000
	H_2 (biomass)	4 000 000	24 000 000
	Electricity (forest residues)	1 100 000	2 000 000
Solar energy	Electricity (PV)	2 500 000	4 000 000
Hydroelectric energy	Electricity	17 000 000	17 000 000

Note: GJ_{LHV}/yr = gigajoules using lower heating value per year.

Capital and O&M costs evaluated at USD 60/bbl and USD 150/bbl show a significant cost reduction potential for all fuels (Tables 5 and 6). An interest rate of 10% and an average lifetime of 25 years for production facilities were assumed in the calculations.

For all energy pathways, except electricity, these estimates result from the combination of the information collected from relevant literature on capital costs (see Annex B for a detailed description of the relevant sources) and those derived from the normalised IHS CERA Downstream index (IHS, 2012).[3] For power generation, this analysis relies on the IHS CERA Power Capital Costs Index for North America, with and without nuclear (IHS, 2012).

[2] Since the majority of sources found in literature for investment costs refer to a period where oil prices were in the range of USD 40/bbl to USD 50/bbl, the information has been corrected using the IHS CERA indexes to match the oil price assumptions selected here (USD 60/bbl and USD 150/bbl, depending on the case). This reassessment was made without applying a factor to the original cost information that equals the normalised IHS CERA downstream index evaluated at the average oil price that corresponded to the relevant time period for the selected literature source (USD 60/bbl or USD 150/bbl, depending on the case).

[3] Since the IHS CERA index is associated with real prices, it has been normalised using the US CPI, published by the Organisation for Economic Co-operation and Development (OECD). Additionally, the IHS CERA downstream index refers to projects that are in the downstream oil sector and not in other alternative fuel production sectors. Nevertheless, it was applied here to all processes except for power generation.

Figure 5 • Relationship between downstream IHS CERA index and historical real crude price

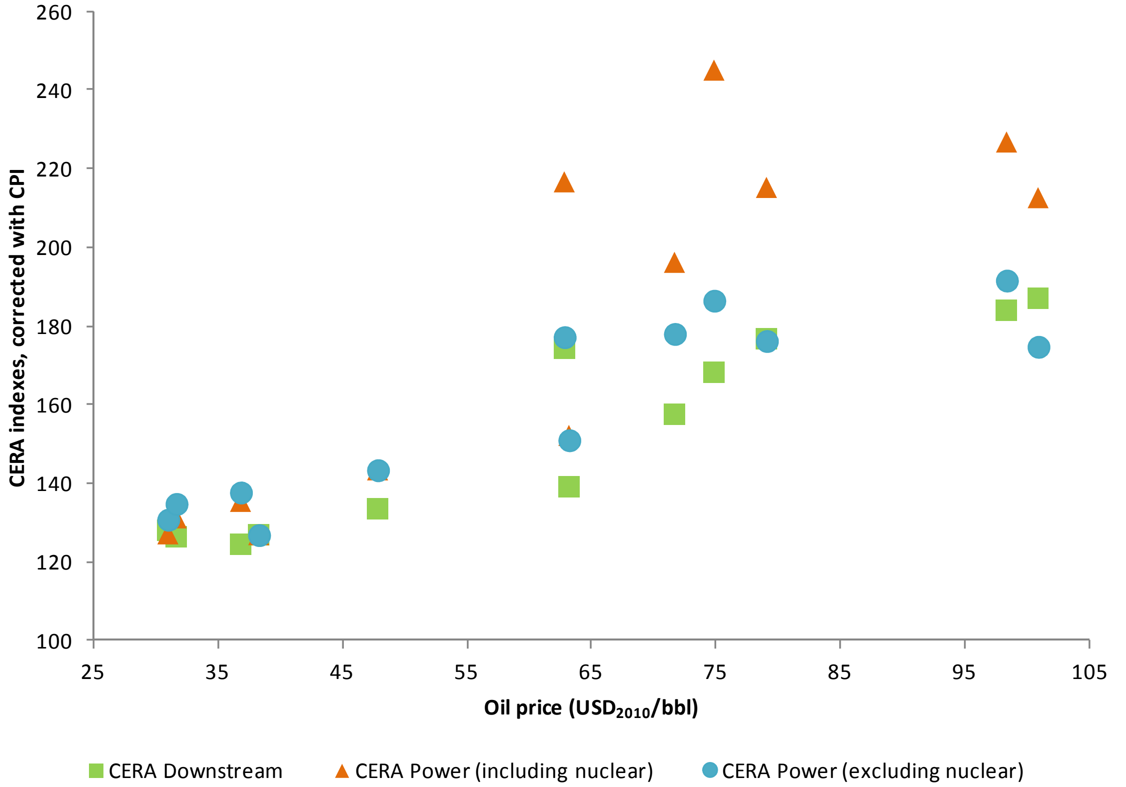


Table 5 • Investment cost components for different energy pathways (USD 60/bbl)

Primary energy source	Final energy type	Amortised costs (USD_{2010}/GJ_{LHV})					
		Current Technology Scenario			Mature Technology Scenario		
		Total fixed costs	Capital costs	O&M costs	Total fixed costs	Capital costs	O&M costs
Natural gas	GTL	7.18	6.60	0.58	5.70	5.24	0.46
	H_2	2.78	2.44	0.34	1.59	1.34	0.25
	Electricity	3.08	2.76	0.33	2.64	2.36	0.28
Coal	CTL	4.03	3.70	0.33	2.91	2.67	0.24
	H_2	3.70	3.19	0.51	1.51	1.31	0.21
	Electricity	8.26	7.38	0.87	7.71	6.89	0.82
Nuclear energy	H_2	12.46	11.31	1.14	7.46	6.75	0.70
	Electricity	17.55	13.37	4.17	15.72	11.99	3.74
Oil-seed crops	Biodiesel	2.31	2.12	0.19	1.61	1.48	0.13
Grain crops	Ethanol	3.33	3.06	0.27	2.44	2.24	0.20
Sugar crops	Ethanol	3.00	2.75	0.24	1.98	1.82	0.16
Biomass from crops and/or waste products	BTL	13.96	12.84	1.12	10.01	9.27	0.74
	Lignocellulosic ethanol	13.35	12.27	1.08	10.66	9.80	0.86
	Biogas	9.22	8.47	0.74	7.62	7.00	0.61
	H_2	6.31	5.51	0.79	5.04	4.35	0.69
	Electricity	18.71	16.73	1.98	16.95	15.16	1.79
Solar energy	Electricity	43.75	39.13	4.63	19.40	17.35	2.05
Hydroelectric energy	Electricity	15.33	13.71	1.62	14.15	12.66	1.50

Table 6 • Investment cost components for different energy pathways (USD 150/bbl)

Primary energy source	Final energy type	Amortised costs (USD_{2010}/GJ_{LHV}) Current Technology Scenario: Total fixed costs	Current Technology Scenario: Capital costs	Current Technology Scenario: O&M costs	Mature Technology Scenario: Total fixed costs	Mature Technology Scenario: Capital costs	Mature Technology Scenario: O&M costs
Natural gas	GTL	11.463	10.883	0.580	9.090	8.630	0.460
	H_2	3.796	3.457	0.339	2.456	2.209	0.247
	Electricity	4.677	4.351	0.326	4.009	3.729	0.279
Coal	CTL	6.432	6.098	0.334	4.633	4.393	0.240
	H_2	5.767	5.262	0.505	2.357	2.151	0.207
	Electricity	12.528	11.655	0.873	11.693	10.878	0.815
Nuclear energy	H_2	19.784	18.642	1.143	11.830	11.128	0.702
	Electricity	25.286	21.115	4.171	22.659	18.921	3.738
Oil-seed crops	Biodiesel	3.683	3.497	0.186	2.576	2.446	0.130
Grain crops	Ethanol	5.311	5.042	0.269	3.892	3.695	0.197
Sugar crops	Ethanol	4.781	4.539	0.242	3.155	2.996	0.160
Biomass from crops and/or waste products	BTL	22.271	21.153	1.118	16.016	15.272	0.744
	Lignocellulosic. ethanol	21.300	20.223	1.077	17.010	16.150	0.860
	Biogas	14.706	13.962	0.744	12.156	11.541	0.615
	H_2	9.879	9.085	0.794	7.853	7.162	0.692
	Electricity	28.397	26.417	1.980	25.724	23.931	1.793
Solar energy	Electricity	66.398	61.769	4.629	29.441	27.388	2.052
Hydroelectric energy	Electricity	23.266	21.644	1.622	21.476	19.979	1.497

Fuel transport, distribution and refuelling infrastructure costs

The costs for the various fuels' transportation, distribution, and refuelling infrastructure give each fuel group specific characteristics (Tables 7 and 8).

Table 7 • Cost of transport, distribution and refuelling infrastructure for energy pathways (USD 60/bbl)

Energy carrier	Amortised costs (USD_{2010}/GJ_{LHV}) Current Technology Scenario: Total costs	Current Technology Scenario: Transport costs	Current Technology Scenario: Storage and refuelling costs	Mature Technology Scenario: Total costs	Mature Technology Scenario: Transport costs	Mature Technology Scenario: Storage and refuelling costs
CTL, BTL, GTL	3.266	3.198	0.068	3.260	3.198	0.061
Ethanol	3.522	3.412	0.110	3.511	3.412	0.099
Biodiesel	1.719	1.641	0.079	1.711	1.641	0.071
Natural gas, bio-SNG	7.675	3.152	4.523	2.687	1.367	1.320
Centralised H_2	86.457	70.898	15.559	13.820	4.191	9.629
Electricity	13.168	2.173	10.996	8.440	1.965	6.475

Table 8 • Cost of transport, distribution and refuelling infrastructure for energy pathways (USD 150/bbl)

Energy carrier	Amortised costs (USD_{2010}/GJ_{LHV})					
	Current Technology Scenario			Mature Technology Scenario		
	Total costs	Transport costs	Storage and refuelling costs	Total costs	Transport costs	Storage and refuelling costs
CTL, BTL, GTL	3.609	3.534	0.075	3.602	3.534	0.068
Ethanol	3.892	3.771	0.121	3.880	3.771	0.109
Biodiesel	1.900	1.813	0.087	1.891	1.813	0.078
Natural gas, bio-SNG	7.675	3.152	4.523	2.687	1.367	1.320
Centralised H_2	86.457	70.898	15.559	13.820	4.191	9.629
Electricity	13.643	2.648	10.996	8.867	2.392	6.475

Liquid fuels

All cases accounted for the levellised cost of liquid fuel transported, distributed and dispatched through refuelling stations. As a result, these costs were higher for liquid fuels with a lower energy density. Ethanol transport and refuelling costs entail the transportation costs from the biorefinery to the dispensing station, as well as the costs of holding tanks, gasoline blending systems, rail modifications, contingencies and dispensing stations. Ethanol infrastructure requirements are considerably less than other emerging transportation fuels. Ethanol is primarily blended with gasoline, which leads to relatively low fuel storage and refuelling station costs. The cost of transporting ethanol fuel from biorefineries to dispensing stations can be higher than other liquid fuels, particularly because biorefineries are often far from large demand centres. Differences between the Current Technology Scenario and the Mature Technology Scenario ethanol infrastructure costs are taken from a study (Morrow, Griffin and Matthews, 2006).

Hydrogen

H_2 can be transmitted and distributed in a gaseous pipeline, liquid truck, or gaseous trucks. For centrally produced H_2, the lowest cost delivery method depends on the distance between the production facility and distribution point as well as the distance between the distribution point to the dispensing station (Yang and Ogden, 2008). Here, we combined the method suggested in Yang and Ogden (2008) with vehicle and population projections from the IEA MoMo project.

The costs characterising the Current Technology Scenario correspond to a situation with few stations (mainly located in large cities and motorways), the lack of H_2 use in transport and in other end-uses, and a transmission and yet-to-be-built distribution networks. Under these circumstances, the estimated cost of H_2 transport and distribution costs from centralised production facilities is so high that centralised H_2 production is more expensive than distributed production from electrolysis. This confirms the conclusions of one of a number of studies (IEA, 2005). The transport and distribution costs used in the Mature Technology Scenario reflect a reality with many stations, a very high number of cars per station, and established T&D networks whose exploitation is shared with other end-uses. In this context, centralised production of H_2 becomes cheaper than distributed production from electrolysis. More information on the calculation of H_2 transport and distribution costs is included (Annex E).

Natural gas and bio-SNG

The current infrastructure for natural gas, bio-SNG T&D is more developed than it is for H_2, but still less developed than it is for transportation fuels. In 2009, only 3% of transportation fuel worldwide consisted of natural gas and 2.1% of this was used in five countries: Pakistan, Argentina, Iran, Brazil and India. Other sectors used natural gas more ubiquitously. Some 40% of residential households had access to natural gas and 21% of electric power generation uses natural gas as the primary energy feedstock (IEA, 2011). Thus, natural gas T&D infrastructure exists in most regions for industry but its use in the transportation sector is more limited.

In the Current Technology Scenario, fuel transport and distribution costs combine with few vehicles and a limited number of stations located in large cities and on main motorways. The assumed widespread use of methane in other end-uses (*e.g.* buildings), and a subsequently well-developed T&D network, assumes that transport and distribution costs in this Scenario are still relatively high with a fuel station usage rate approaching 50%.

In the Mature Technology Scenario, many stations accommodate a very high number of vehicles and have much lower fuel transport and distribution costs along with a highly developed T&D pipeline network.

Electricity

Two main infrastructure requirements are necessary for making electricity available to vehicles:

- transmitting electricity from the generation facility to the vehicle recharging location;
- equipment and systems to control, monitor and safely transfer electricity to the vehicle.

According to some research, T&D losses in 2007 accounted for about 7% of the electricity generated in OECD member countries (IEA, 2012c). This value has been used throughout this analysis.[4] If smart metering is used, the recharging infrastructure requires an advanced system that interacts with the grid to control charging times, rates, etc., and to allow the use of vehicles as electricity storage units for grid stabilisation purposes.

Three main types of recharging infrastructure are considered in this analysis:

- slow residential;
- slow public (parking lot/roadside);
- fast public charging devices.

In the Current Technology Scenario, these costs are based on the current costs of available components, often at low volumes. In the Mature Technology Scenario, these costs are assumed to be less than today's costs owing to economies of scale. The estimates are associated with a given set of average charger usage patterns that depend primarily on home recharging. The price of crude oil is not assumed to affect electricity T&D to transportation.

Infrastructure costs for charging depend on the investment required for the charging device (the charger and the control/safety systems associated with it) and the amount of electricity associated with the recharging operation of a given charger (because this is the basis upon which the charger's costs will be paid). This second cost, in turn, depends on vehicle efficiency, energy storage capacity and daily travel patterns.

It draws on information collected from other research and includes a differentiated estimation for usage patterns and costs that correspond to an initial deployment phase and to a situation where the market is already established. Assumptions of the cost of the electricity recharging infrastructure per kilowatt hour (USD 0.04 per kilowatt hour [USD/kWh] per vehicle in the Current

[4] This average value may result in some misallocations because of the ignored effects associated with intermittent electricity sources and decentralised production. Intermittent sources such as onshore or offshore wind are likely to need backup capacity or the coupling with energy storage units (*e.g.* with hydroelectric plants capable of pumped storage), and the use of storage units leads to higher losses.

Technology Scenario and USD 0.023/kWh in the Mature Technology Scenario) and the annual costs of charging infrastructure per vehicle or per unit energy that are associated to each type of charger are also presented (Table 9).[5]

Table 9 • Assumptions on the characteristics of recharging infrastructure for plug-in hybrid electric vehicles (PHEVs) and EVs, and resulting cost estimates

	Current Technology Scenario			Mature Technology Scenario		
	Slow home	Slow public	Fast	Slow home	Slow public	Fast public
Maximum power of chargers (kW or kVA)	4.00	4.60	47.0	4.00	4.60	47.0
Investment cost (USD/plug)	650	6 600	33 000	460	5 500	24 000
Annualised cost (USD/plug)	85	870	4 300	60	720	3 200
Frequency of use (charges/yr)	312	52	52.0	312	52	52.0
Average refill time (minutes/charge)	104	107	10.0	104	107	10.0
Assumed charger occupancy rate (% of time)	6.00	54.0	27.0	7.00	77.0	33.0
Charger ratio to vehicles (%)	100	2.00	0.40	83.0	1.40	0.30
Infrastructure: total costs per unit electricity output (USD/kWh or USD/GJ)	0.04 or 11.1			0.02 or 6.57		

Notes: kVA = kilovolt ampere; kW = kilowatt; USD/plug = USD per recharging plug for EVs/PHEVs; minutes/charge = minutes per full charge of vehicle; charges/yr = number of full vehicle charges per year. Other assumptions include 15 000 kilometres (km) travelled per vehicle per year, 150 km range per charge and 30 kilowatt hours (kWh) of energy at full charge.

Source: Kaneko, Cazzola and Fulton, 2011.

In order to deliver electricity at the same cost per kilowatt hour, fast chargers require an occupancy rate of roughly 30%. This value increases to roughly 50% to 80% for slow public chargers. Losses are assumed to range from 4% for decentralised production, to 7% for centralised generation plants.

Travel cost assumptions

In addition to estimating the cost of fuel production in units of USD/GJ, an attempt is made to estimate driving costs in USD per kilometre for each fuel after accounting for differences in engine efficiency levels. Also, an attempt is made to account for how efficiencies improve over time because of hybridisation, weight reductions and government-imposed fuel consumption standards. Fuel consumption data sets in the Current Technology Scenario and Mature Technology Scenario are taken from the MoMo (Table 10). The Current Technology Scenario costs use the 2010 fleet average fuel consumption while the long-term costs use the 2050 fleet average fuel consumption.

Several engine technologies are more efficient than gasoline engines. In particular, electric motors and H_2 vehicles vastly outperform gasoline engines.

[5] Costs in Table 9 reflect the utilisation rates and electricity throughput at the recharging stations described in Annex F. The same Annex contains a detailed description of the key sources of information used for this evaluation. If the recharging infrastructure is used less often prices would rise accordingly. For example, in a situation where many fast chargers are installed around a city early on, but are rarely used in the first few years, the costs could be considerably higher. If they were used one fifth of the times assumed here, the cost per kWh would increase fivefold, as also explained in Annex F.

Table 10 • Fuel economy assumptions for Current Technology Scenario and Mature Technology Scenario used to estimate travel cost (USD/km) by fuel options, for the typical fleet average passenger light duty vehicle

Final energy type	Fuel economy (lge/100 km)	
	Current Technology Scenario	Mature Technology Scenario
GTL	9.63	6.85
Natural gas	8.84	7.16
H_2 (natural gas, central)	5.36	3.94
Electricity (natural gas)	1.84	1.51
CTL	9.63	6.85
H_2 (coal)	5.36	3.94
Electricity (coal)	1.84	1.51
H_2 (nuclear energy)	5.36	3.94
Electricity (nuclear energy)	1.84	3.94
Biodiesel (rapeseed)	8.95	6.18
Corn ethanol	9.63	6.85
Sugar cane ethanol	9.63	6.85
BTL	9.63	6.85
Lignocellulosic ethanol	9.63	6.85
Bio-SNG	8.84	7.16
H_2 (biomass)	5.36	3.94
Electricity (biomass)	1.84	1.51
Electricity (solar PV)	1.84	1.51
Electricity (hydroelectric energy)	1.84	1.51
Diesel*	8.95	6.18
Gasoline	**9.63**	**6.85**

* Diesel fuel is included to give another comparison to gasoline costs (Table 12). In the results section below, diesel is included in the comparison of travel costs. A full techno-economic analysis has not been conducted for diesel. Its production cost is assumed to be equal to gasoline in USD/GJ. However, as shown in the results section, because diesel vehicle efficiencies are higher than those of gasoline, the cost per kilometre is lower for diesel.

Notes: lge/100 km = litres of gasoline-equivalent per 100 kilometres. Bold means gasoline is the reference fuel.

Source: IEA, 2009.

Results

The results section presents cost estimates at USD 60/bbl for the Current Technology Scenario and USD 150/bbl for the Mature Technology Scenario. Fuel costs per 100 km travelled are then derived for each vehicle-fuel combination. Driving cost is always imperative for the vehicle user.

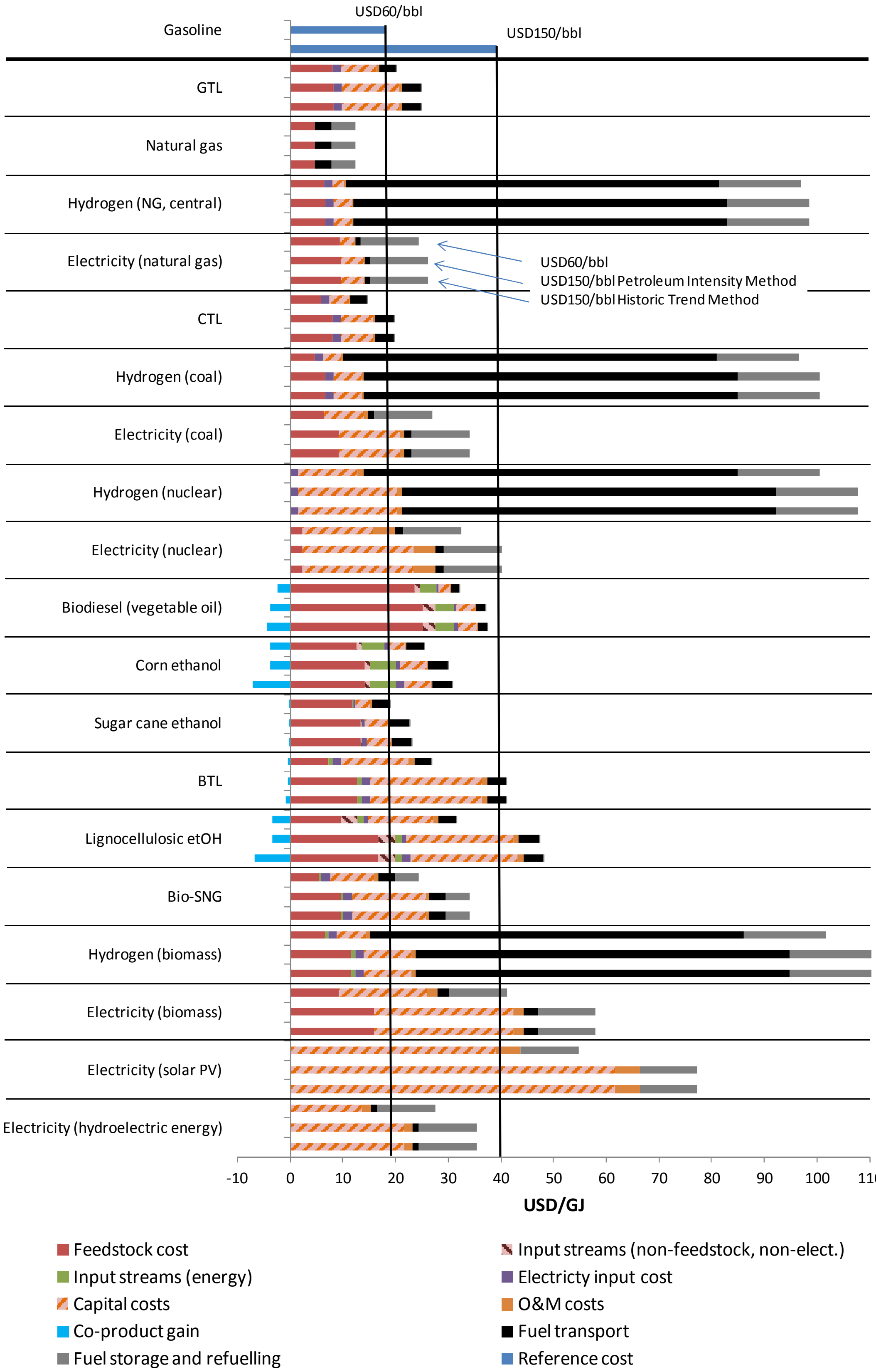
Disaggregated cost for the 20 energy pathways compared to gasoline under different oil price assumptions does not always lead to the same conclusions in terms of cost-competitiveness for the different energy production pathways considered. At USD 60/bbl the cost of the reference fuel – gasoline – is USD 18.4/GJ, while at USD 150/bbl the cost of gasoline is USD 45.9/GJ.

A rising oil price tends to result in higher alternative fuel production costs than those calculated when oil price rises are not considered. For example, the production cost of BTL with oil at USD 60/bbl (top BTL line) is less than the estimates obtained with oil at USD 150/bbl. In the first case, BTL is cost-competitive with petroleum fuels (whose price reference at USD 150/bbl is represented by the right black vertical line on the right), if its cost is estimated with a constant oil price of USD 60/bbl, but this is not the case for the cost estimates obtained with the Petroleum Intensity Method and the Historical Trend Method, both centred on USD 150/bbl. Similar results are found for conventional biodiesel, lignocellulosic ethanol and a few electricity generation pathways. In the first two cases, the gap is mainly due to increasing feedstock costs, while in the case of electricity it depends primarily on changing capital costs. According to the Historical Trend Method, options like corn ethanol and GTL fuels are not cost-competitive with gasoline at USD 150/bbl, while they remain cost-competitive according to the Petroleum Intensity Method. A similar profile characterises natural gas in the Current Technology Scenario (Figure 6). For liquid fuels, the difference results mainly from larger increases in feedstock costs that are generally associated with the Historical Trend Method. For natural gas, this effect is combined with the estimates stemming from the assumptions characterising fuel transport, distribution and refuelling. A number of alternatives, including all centralised H_2 pathways and sole electricity generation technologies, are always more expensive in terms of cost per unit energy of the energy carrier than oil-based fuels (mainly because of the transport and distribution costs of H_2 as detailed in certain research [IEA, 2012a]). Options like CTL fuels and sugarcane ethanol remain cost-competitive with all the methods, and in all the circumstances, considered.

In a mature market (Mature Technology Scenario), few options (CTL fuels, natural gas, and sugarcane ethanol) are competitive with petroleum fuels at USD 60/bbl (Figure 7). These options remain cost-competitive with liquid petroleum fuels under all circumstances. For natural gas, this is partly due to the more optimistic assumption on transport and refuelling costs in the Mature Technology Scenario. This is also the case for centralised H_2 production pathways, which become much cheaper but remain above gasoline prices once they are evaluated with oil at USD 60/bbl. Estimating the fuel production costs with the Petroleum Intensity and Historical Trend methods highlights that a growth in the oil price (*e.g.* to USD 150/bbl) can compromise the cost-competitiveness of alternative fuels (such as biodiesel from vegetable oil, lignocellulosic ethanol, BTL and bio-SNG) that would be cheaper than petroleum fuels if their cost is estimated with a constant oil price. The Historical Trend Method leads to similar conclusions for corn ethanol and GTL fuels, which are unaffected by oil price increases when analysed with the Petroleum Intensity Method because of the low oil use in its production, transport, distribution and refuelling processes.

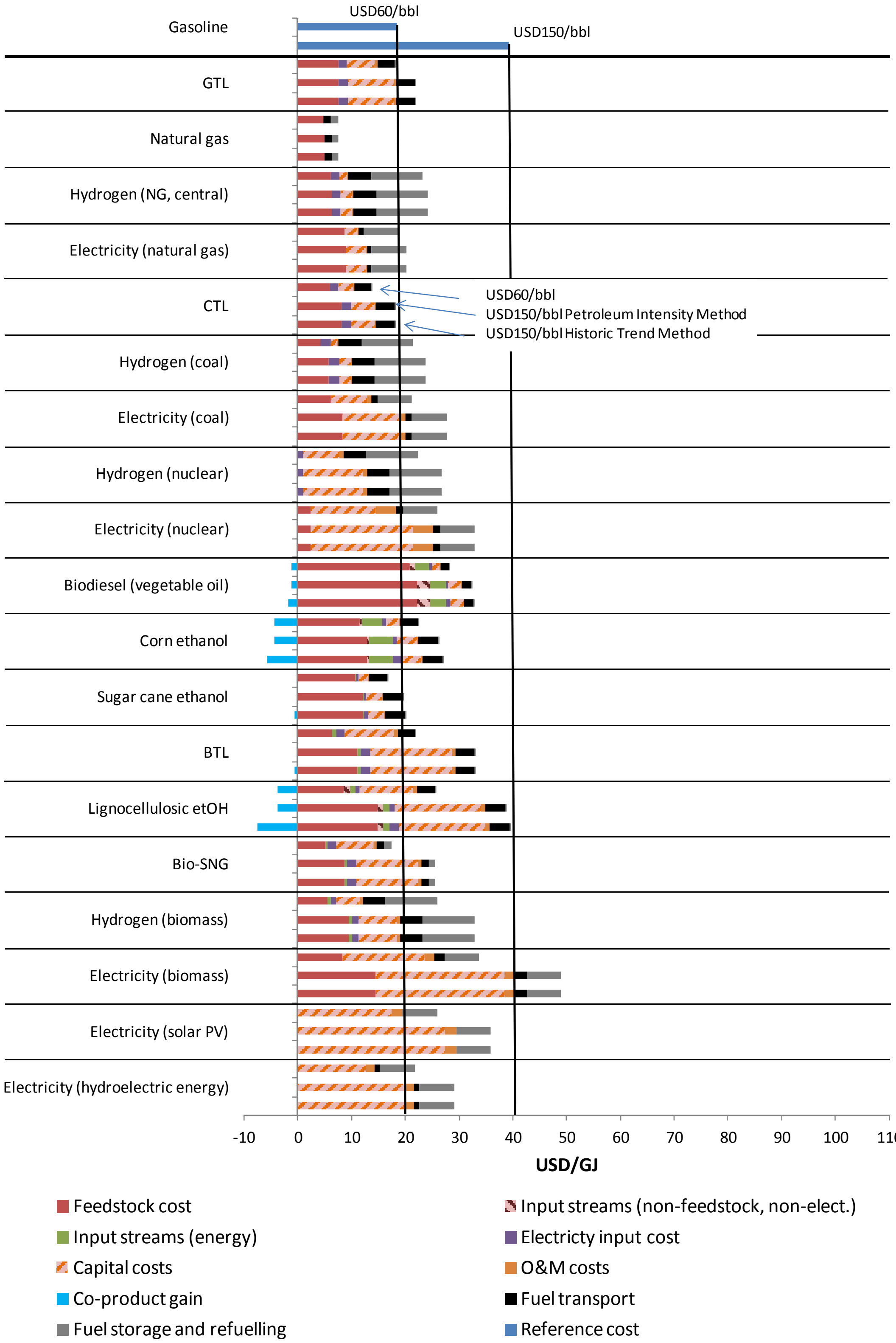
Using the engine efficiency values (Table 10) and the production costs of fuels (Figures 6 and 7), cost per kilometre of driving is derived and expressed in USD per 100 km (USD/100 km) (Table 11).

Figure 6 • Cost of fuel production in Current Technology Scenario



Notes: for each fuel, three cost estimates are shown: the cost at USD 60/bbl, the cost at USD 150/bbl when using the Petroleum Intensity Method for predicting input prices and the cost at USD 150/bbl when using input prices based on the Historical Trend Method with oil price. The black vertical lines represent the gasoline price when crude oil price is USD 60/bbl (left line) and USD 150/bbl (right line). Fuels with co-products are shifted left to reflect cost reductions with co-product credits.

Figure 7 • Cost of fuel production in Mature Technology Scenario



In the Current Technology Scenario, pathways with lower costs than liquid petroleum fuels (gasoline and diesel fuel) when the crude price is USD 60/bbl include all electricity generation options (mainly because of the high efficiency of electric motors), natural gas, CTL fuels and sugarcane cane ethanol. For H_2 pathways, the better fuel efficiency of vehicles is not enough to compensate for the high costs per unit of energy of fuel (including transport, distribution and refuelling resulting from aforementioned assumptions). At USD 150/bbl, options such as GTL, corn ethanol and conventional biodiesel, have lower costs per kilometre than petroleum fuels if costs are estimated with the Petroleum Intensity Method, but not with the Historical Trend Method. Interestingly, bio-SNG is affected the least by changes in the estimation method, but it is also heavily influenced by the assumptions made on refuelling costs of gaseous fuels. If natural gas prices remain coupled with oil prices, GTL is unlikely to be competitive (Historical Trend Method). In the Mature Technology Scenario, most of the alternative fuel options have a lower cost per kilometre than petroleum fuels when crude price is at USD 60/bbl. H_2 pathways, in particular, have far more optimistic assumptions for transport, distribution and refuelling costs per unit of energy. Significant exceptions include conventional biodiesel, lignocellulosic ethanol, BTL and bio-SNG. As most fuels have costs per kilometre that are consistently lower or comparable with those of petroleum fuels, the results are similar with oil at USD 150/bbl. In this case, however, biofuels such as lignocellulosic ethanol, BTL, conventional biodiesel and bio-SNG are among the least-competitive options with respect to petroleum fuels, while the performance of GTL fuels depends strongly on the evolution of natural gas and oil prices.

Table 11 • Driving costs of fuels calculated for Current Technology Scenario and Mature Technology Scenario when crude oil is at USD 60/bbl and USD 150/bbl

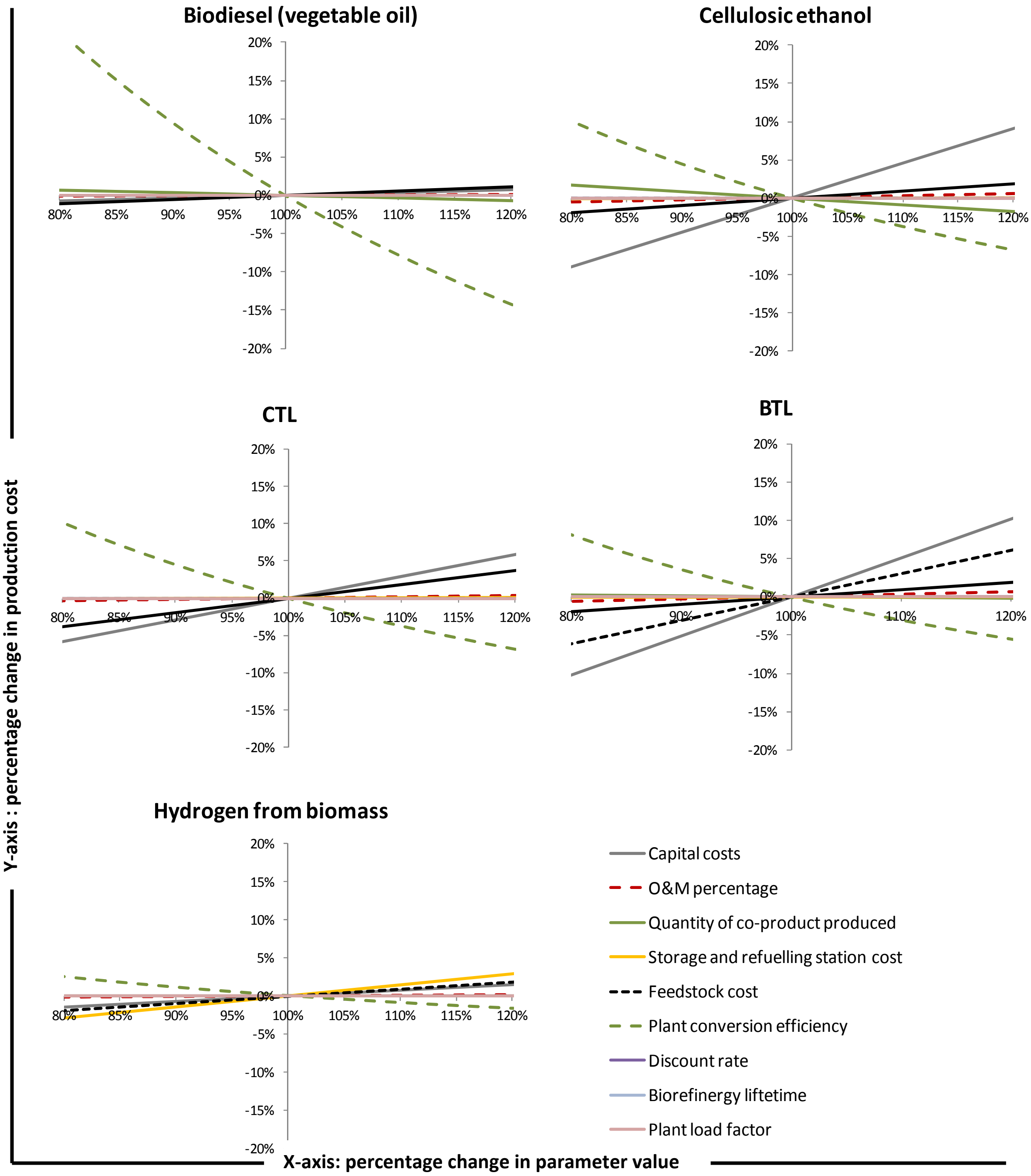
Final energy type	Driving costs (USD/100 km)					
	Current Technology Scenario			Mature Technology Scenario		
	USD 60/bbl	USD 150/bbl (Petroleum Intensity Method)	USD 150/bbl (Historical Trend Method)	USD 60/bbl	USD 150/bbl (Petroleum Intensity Method)	USD 150/bbl (Historical Trend Method)
Gasoline	6.05	15.13	15.13	4.31	10.76	10.76
Diesel	**5.63**	**14.06**	**14.06**	**3.88**	**9.71**	**9.71**
GTL	7.75	15.61	**13.38**	**4.56**	**7.41**	**8.44**
Natural gas (natural gas)	**4.04**	**5.35**	**6.50**	**2.03**	**1.88**	**4.02**
H_2 (natural gas, central)	18.65	20.72	20.68	**3.31**	**3.66**	**4.85**
Electricity (natural gas)	**1.67**	**2.61**	**2.86**	**1.05**	**1.27**	**1.95**
CTL	**5.44**	**12.12**	**8.20**	**3.21**	**5.42**	**5.40**
H_2 (coal)	18.35	21.46	19.53	**2.92**	**3.60**	**3.71**
Electricity (coal)	**1.72**	**3.59**	**2.55**	**1.11**	**2.08**	**1.72**
H_2 (nuclear energy)	19.12	24.20	20.19	**3.06**	**5.29**	**3.67**
Electricity (nuclear energy)	**2.09**	**4.36**	**2.59**	**3.58**	**7.65**	**4.53**
Biodiesel (rapeseed)	10.40	21.49	16.95	5.54	**7.27**	**10.62**
Corn ethanol	9.78	17.75	14.73	4.45	**6.12**	**9.34**
Sugarcane ethanol	6.91	**14.01**	**10.95**	**4.09**	**5.39**	**6.69**
BTL	10.10	26.34	**13.88**	5.36	11.63	**7.89**
Lignocellulosic ethanol	11.82	29.43	**14.51**	5.50	12.41	**7.96**
Bio-SNG	8.45	18.75	**10.69**	**4.51**	**9.44**	**6.50**
H_2 (biomass)	19.66	25.13	20.80	3.67	5.60	4.60
Electricity (biomass)	**2.73**	6.59	3.72	1.84	3.94	2.58
Electricity (solar PV)	**3.52**	**9.24**	**4.97**	**1.36**	**3.45**	**1.89**
Electricity (hydroelectric energy)	**1.77**	**3.78**	**2.28**	**1.15**	**2.67**	**1.53**

Note: bold means costs are lower than gasoline.

Sensitivity Analysis and Discussion

In addition to crude oil prices, other parameters can significantly affect the total estimated cost of a fuel. A sensitivity analysis was undertaken using a simple methodology in which each parameter was altered in the range of ± 20% and the resulting change in total price was plotted on the Y-axis (Figure 8).

Figure 8 • Sensitivity analysis for selected alternative fuels evaluated at USD 150/bbl in Current Technology Scenario



Conclusions from the sensitivity analysis are categorised by fuel group. For biomass-related fuels, the most sensitive parameter tends to be plant conversion efficiency. Bio-SNG and BTL are also sensitive to capital cost assumptions and gasoline price. In addition, other biofuels are sensitive to feedstock procurement costs. It is noteworthy that CTL and GTL are sensitive to conversion efficiencies, gasoline price, the IHS CERA Index and capital costs, while CNG is most sensitive to distribution costs, gasoline price and feedstock costs. H_2 pathways tend to be most sensitive to fuel transportation costs (*e.g.* pipelines and trucks), gasoline price, and conversion efficiencies. Electricity pathways tend to be most sensitive to capital costs, the IHS CERA Index and gasoline prices.

The most sensitive parameters tend to have elasticities between ± 0.5 and ± 0.9 (Figure 8). This means that a 1% change results in a 0.5% to 0.9% change in the production cost of the most oil price-sensitive fuel. Among all of the fuels analysed, the largest effect observed was the efficiency of conversion for rapeseed oil, which resulted in a 0.9% increase in cost for every 1% decrease in efficiency.[6] Future research should focus on estimating ranges of production costs based on a range on input parameters. There is no large difference in the magnitude of sensitivities between the Current Technology Scenario and Mature Technology Scenario.

The 11 results in this research paper are mainly consistent with energy providers' current investment choices:

- Considering the price of the feedstock, sugarcane ethanol is cost-competitive when oil is at USD 150/bbl. The cost-competeviness at lower oil prices depends heavily on the sugarcane price under consideration (cane price accounts for about 60% of the fuel's production cost). In Brazil, sugarcane and ethanol mills historically rely on lower cane prices and very high cane yields, and take advantage of larger unit sizes than those assumed here (and therefore lower costs per unit of fuel).
- Corn ethanol is not as cost-competitive with petroleum fuels when the oil price is close to USD 60/bbl. With oil prices close to USD 150/bbl, its cost-competitiveness depends on corn prices.
- Few CTL plants exist today. They are often located in coal-rich areas such as South Africa and China. The increasing cost-competitiveness of CTL for an oil price above USD 60/bbl justifies recent interest in the technology, especially in coal-rich areas of the world. On the other hand, CTL fuels are associated with extremely high greenhouse gas emissions, making investment risky under potential future carbon pricing.
- Natural gas is currently promoted in many countries as a transport fuel. The near-term hurdles related to the cost of installing refuelling stations are generally offset by subsidies, such as differentiated taxation. Countries that promote the use of natural gas as a transport fuel have large resources of natural gas. Natural gas is also promoted in countries with poor air quality. Countries having limited availability of oil and more robust fuel diversification policies constitute a third group.
- Bio-SNG can build on the experience of biogas plants, but it would need to surpass its current state to compete with gasoline price. Initial applications of bio-SNG may not be relevant for transport, but rather for power generation. If the introduction of natural gas as a transport fuel proves successful and bio-SNG can exploit the natural gas T&D network then bio-SNG will likely be suitable for large-scale deployment in the transport sector. One major advantage of bio-SNG as a transport fuel is its relative immunity to increases in oil price.
- Second generation liquid biofuels are currently facing obstacles to achieving cost parity with gasoline, even with the implementation of policies for renewable fuels and additional technological improvements will be needed to allow their large-scale adoption. Under mature market conditions, they can achieve cost-competitiveness with gasoline. This may not be the case if market effects not included in our rather simplistic model come into play.

[6] As efficiency is already in percentages, a 10% decrease in efficiency refers to the percentage as a whole and not percentage points (*e.g.* 10% of 45% efficiency is 4.5%).

- Biodiesel derived from vegetable oil requires relatively little capital investment and its production is based on well-established industrial processes, with limited process-related cost reductions ahead. Nevertheless, as a derivative of vegetable oil, conventional biodiesel is characterised by relatively low yields per unit of land compared to other biofuels. Additionally, some biodiesel feedstocks (*e.g.* palm oil) are coupled with environmental problems such as deforestation and the subsequent eutrophication of water bodies. These issues may preclude their use on the large scale. To date, the development of conventional biodiesel has been associated with mandates or other supportive programmes, such as tax incentives. Based on the above results, biodiesel is highly sensitive to increases in oil price, even under a fully mature market condition.
- Under a mature market, centralised H_2 production pathways are expected to be cheaper than gasoline on a per kilometre basis, but not per unit of energy.
- If measured in USD/GJ, electricity production options are more expensive than most other fuels. The much higher efficiency of electric motors (more than double) compared to internal combustion engines, however, makes the cost of using EVs comparatively lower than conventional cars. The challenge of electrified transport expansion probably lies in the vehicle cost gap.
- For transport, the incremental costs associated with the need to recharge vehicles using *ad hoc* recharging infrastructure have been estimated to be close to USD 0.04/kWh if the cost is entirely linked to the electricity needed to load the vehicles, and well below USD 0.01/kWh (about one-tenth as less) if the cost of the recharging infrastructure is spread over all the electricity sales.

Conclusions

This research quantifies how shifts in oil prices affect the production costs of alternative transport fuels. One major finding of this report is that several fuels could be cost-competitive with gasoline if the impact of high oil prices on alternative fuel costs is not taken into account. This finding underscores the importance of clearly stating input assumptions in techno-economic analyses. Indeed, many biofuels would be fully cost-competitive with gasoline at high oil prices if the price of feedstock commodities such as cereals, sugarcane and biomass was unaffected by an increase in the price of oil. However, if rising oil prices affect feedstock costs, the anticipated competitive gain for biofuels may not materialise.

While the oil price is not the most sensitive input parameter for the fuels investigated here, it ranks among the top two or three most important (out of the ones examined) parameters for all fuels. A 1% increase in the gasoline price leads from nil to a 0.48% increase in production cost across the fuels examined. Transport fuels that use biomass as a feedstock, particularly petroleum intensive biomass such as forest residue, will likely be the most sensitive to shifts in crude oil price. Fuels such as nuclear electricity, hydro electricity, PV electricity, and H_2 from coal exhibit the least sensitivity towards changes in crude price because few places in their supply chains require the use of petroleum and the primary feedstocks used for these energy carriers are more distantly related to crude markets than other primary feedstocks.

This analysis shows that few alternative fuels are likely to be competitive on an energy basis with oil in the near term. Only sugarcane ethanol, very large CTL plants, GTL and natural gas are close to being fully cost-competitive with gasoline and diesel if the oil price is at USD 60/bbl.

In the longer term (or in established market conditions, beyond an initial development), several options may achieve a competitive position on an energy basis, even with an oil price of USD 60/bbl. As the oil price increases from this lower price, more fuels become competitive, including some electricity generation pathways. When compared on a per kilometre basis, nearly all fuels (with the important exception of some biofuel options) have lower costs than gasoline in the Mature Scenario when crude is at USD 150/bbl.

Refuelling infrastructure costs can also have a significant impact on the introduction of alternative fuels. This issue merits scrutiny in the case of electricity and gaseous fuels (including natural gas and H_2), and this is extremely relevant in the deployment phase of technologies. In particular, accounting for the costs associated with the infrastructure development will likely add a cost of close to USD 0.04/kWh for electricity, both in a market development and mature market phase.

Annexes

Annex A • Description of input stream cost methods

The following sections describe the reasoning that underpins the hypotheses taken on the variation of primary energy market prices with respect to oil prices.

Petroleum Intensity Method

This method links the changes in input stream cost from USD 60/bbl using the following formula:

$$\text{input stream cost}_i = B_i + (P_i * C_p * K)$$

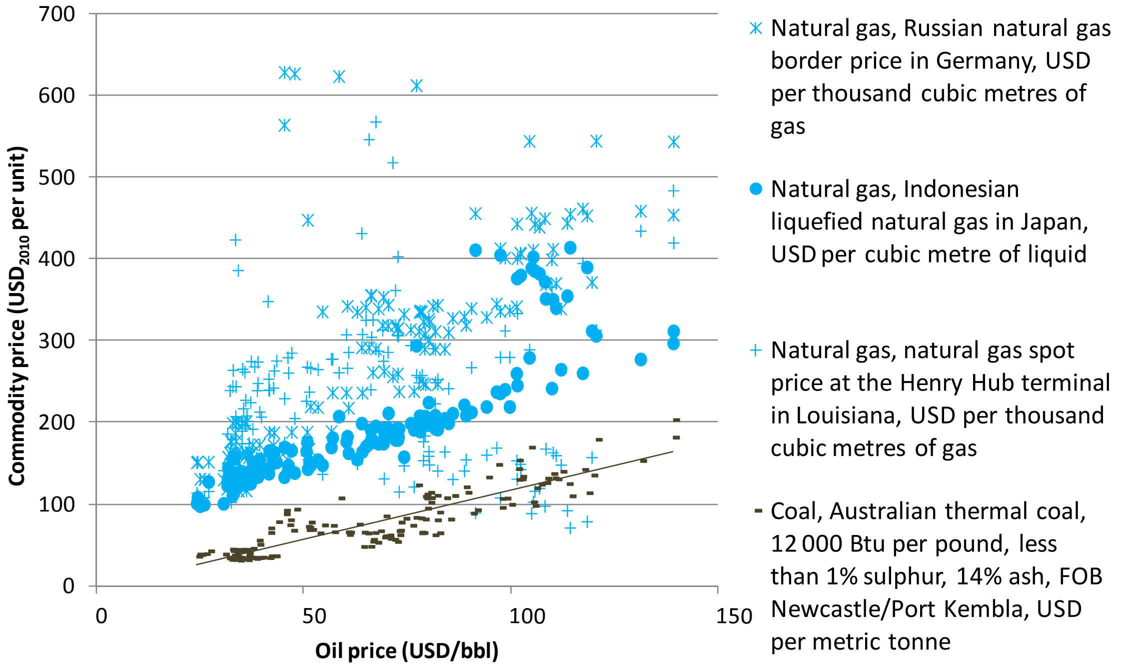
Where B_i is the base cost of commodity i, at USD 60/bbl in USD/GJ of feedstock (using the average real cost for oil of USD 60/bbl for the years 2000-10 [IMF, 2013]). P_i is the petroleum intensity of feedstock expressed in megajoules of petroleum per gigajoule of feedstock (using GREET [Wang, 2007]. C_p is the cost of petroleum in USD per megajoule and K is the change in the price of oil away from USD 60/bbl (*e.g.* for USD 100/bbl, the value of K is USD 40).

Historical Trend Method

Fossil fuels

Some of the representative prices of coal and natural gas have evolved as a function of the oil price (Figure 9).

Figure 9 • Monthly coal and natural gas prices as a function of the oil price, January 2000 to October 2012



Note: Btu = British thermal unit.
Sources: IMF, 2013; BLS, 2012.

Coal

Inevitably, when we assume a linkage between the price of oil and the price of coal we simplify the actual dynamics of each market considered. A direct substitute between coal and petroleum can only be achieved in the long run (*i.e.* engines and boilers cannot generally switch between coal and oil without major machinery changes). One study (Ellerman, 1995) suggests that coal is now a globally traded commodity whose long-term price fluctuations are primarily caused by changes in productivity of energy, labour, capital and materials.

Historically, coal prices increased by 74% when oil prices doubled. This figure was derived from the variation of monthly oil spot prices averaged across the year and the corresponding Australian coal export prices from 2000 to 2010 (IMF, 2013).

Natural gas

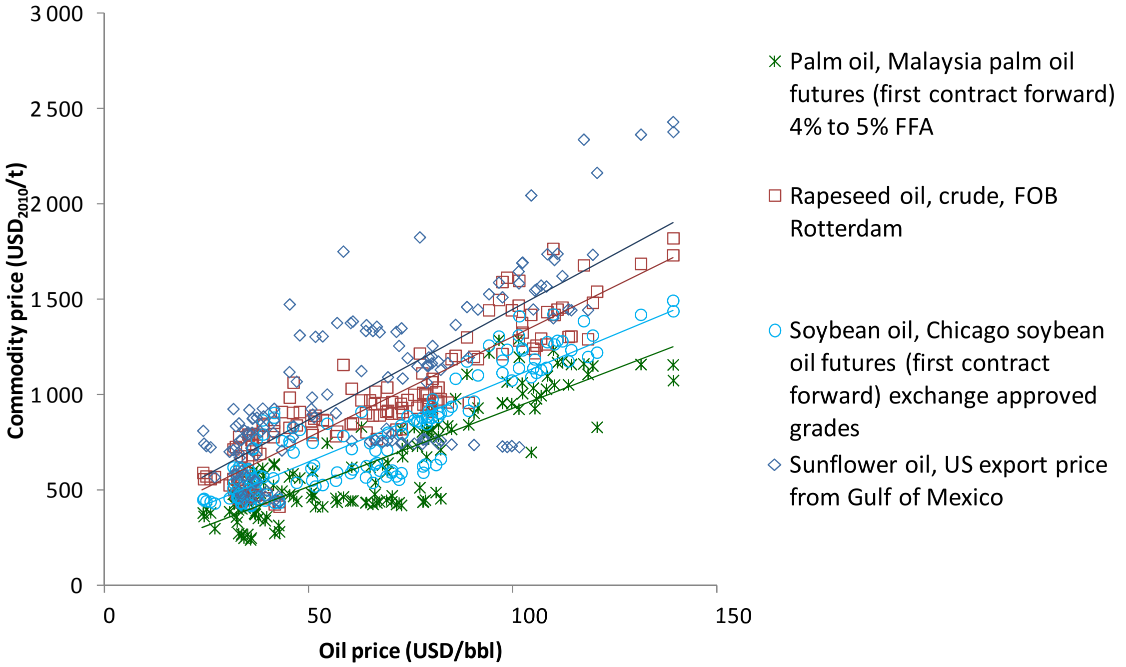
Natural gas and oil prices used to be strongly linked, although the situation is changing fast, because of the exploitation of shale gas in some regions. Regional differences can be important in the case of the gas markets. Asia, for example, actually pegs natural gas prices to the oil market whereas other regions establish region-specific markets.

Agricultural commodities

Wheat, corn, and vegetable oils

Some of the representative prices of wheat, corn and vegetable oil have changed with the oil price (Figures 4 and 10).

Figure 10 • Monthly prices of vegetable oils as a function of the oil price, January 2000 to October 2012



Note: FFA = forward freight agreement.

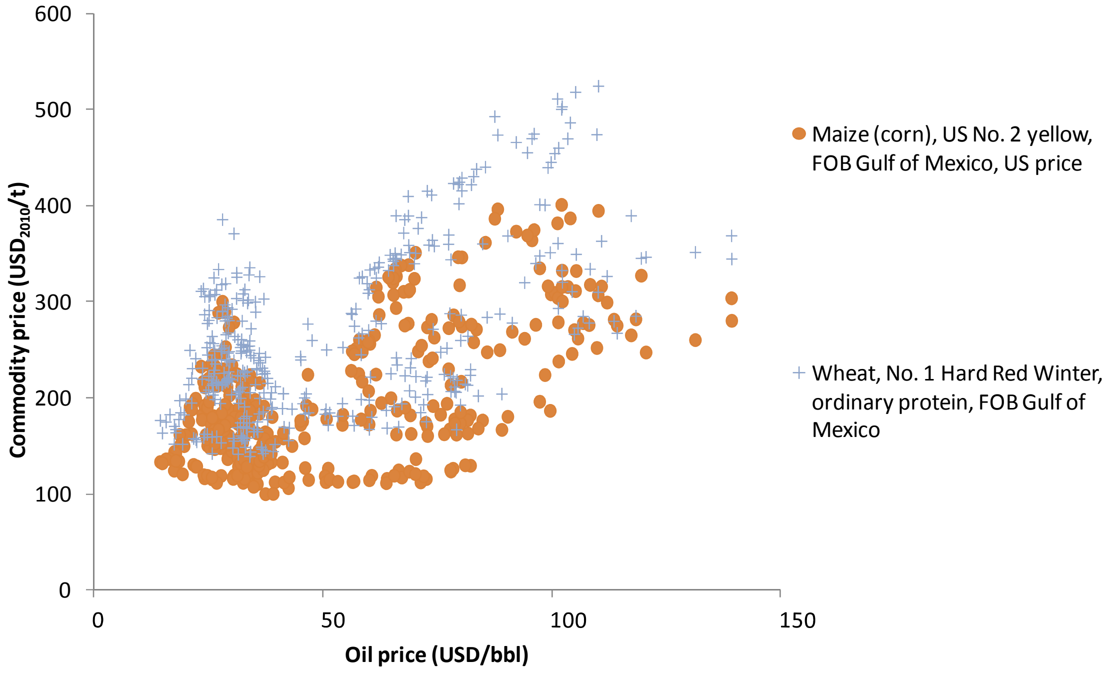
Sources: IMF, 2013; BLS, 2012.

Price trends from 2000 to 2012 show that recent oil price increases have been associated with a general increase in the price of commodities like wheat, corn, palm oil, soybean oil and sunflower oil.

In the case of agricultural commodities, the link between oil prices and the price of wheat, corn and vegetable oils is significantly weaker than that between coal and natural gas; this is because the prices of commodities that are mainly used as food or feed are subject to a wide range of other driving elements. The oil price can influence the price of food commodities through direct effects (*e.g.* via the cost of fuels needed in agriculture or via the influence on the price of fertilisers) and indirect effects (a contribution to a greater demand for wheat, corn and vegetable oil, if they are used as a feedstock for the provision of transport fuels), but cannot be considered as the main driver for the formation of these commodities' prices.

In evaluating a correlation between real oil prices and real agricultural commodity prices, on the basis of the data presented in Figures 4 and 10, we observe changes to commodity prices of 60% to 80% of the variation of oil prices. Such values may well be an approximation of the reality because of the presence of many other market drivers for agricultural prices (essentially linked to the supply and demand dynamics of their specific markets). The use of longer-time series shows that the real price of agricultural commodities actually increased more in the period 1980-2000, at a given real oil price, than was to be expected (Figures 10 and 11) .

Figure 11 • Monthly wheat and corn prices as a function of the oil price, January 1980 to October 2012



Sources: IMF, 2013; BLS,2012.

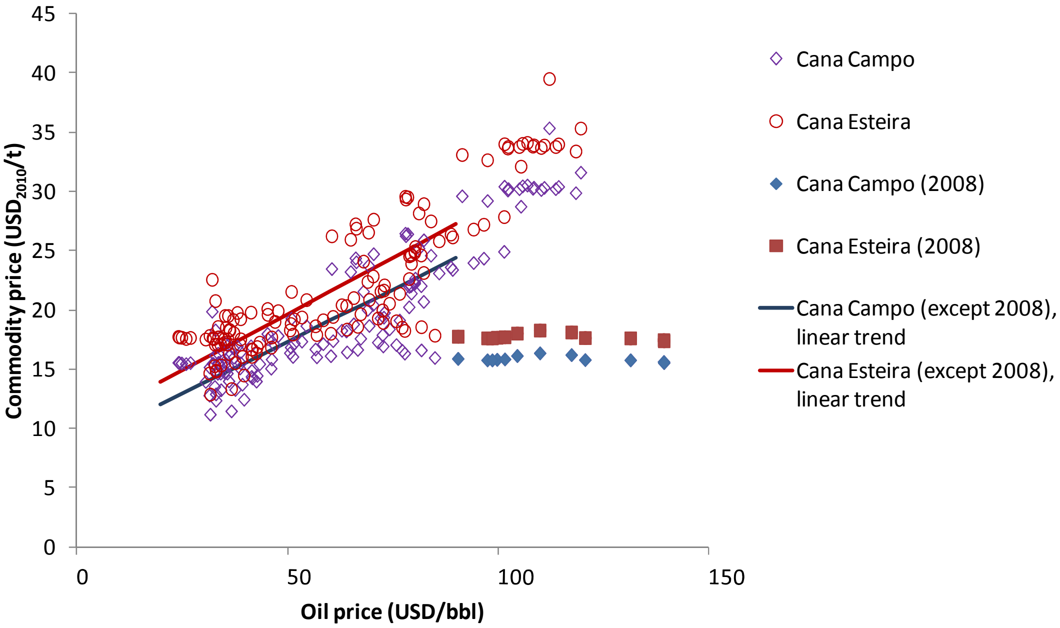
Sugarcane

Sugarcane is an increasingly important feedstock in the transport sector, notably in Brazil. Looking at Brazilian price trends from 2000 to 2012, the price of sugarcane[7] rose when oil and sugar prices increased (Figure 12). The only exception was from October 2007 to September 2008, when cane prices remained stable and relatively low.[8]

[7] This analysis refers to the Consecana price, *i.e.* the price relative to sugar cane in the Brazilian state of São Paulo – the main producer of fuel ethanol in Brazil – as was published by UDOP in 2012.

[8] This particular evolution is because of the contrast between a relatively low sugar demand growth, declining sugar exports in Brazil and, conversely, a significant growth of the sugar cane cultivation area compared to the previous year.

Figure 12 • Monthly cane price as a function of the oil price, May 2000 to October 2012



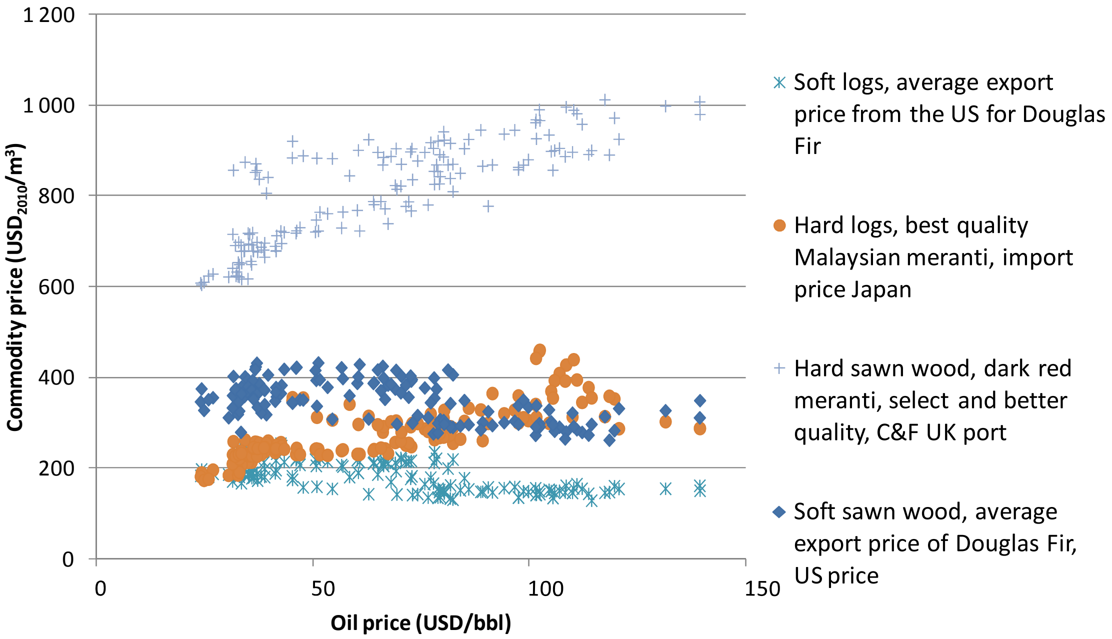
Sources: UDOP, 2012; IMF, 2013; IPEA, 2012; BLS, 2012.

Using the data published by the União dos Produtores de Bioenergia (UDOP) and excluding the 2008 data, it is possible to evaluate the prevailing trend linking oil and cane prices. This approach leads to an approximate increase in cane prices equal to 43% for each doubling of the oil price.

Wood biomass

In the case of wood biomass, the Historical Trend Method should be used with even greater caution than for the commodities above.

Figure 13 • Monthly log and sawn wood price as a function of the oil price, January 2000 to October 2012



Note: C&F = cost and freight; UK = United Kingdom.

Sources: IMF, 2013; BLS, 2012.

There were no historical price trends for wood waste, perhaps because this market is under developed or, where it is developed, highly regional. Thus, we were forced to use purpose-grown wood prices. However, these are also problematic because of the differences in trends between different types of wood (Figure 13). In the end, we averaged the historical price trends, using a USD 0.007 increase in feedstock cost per USD 1/bbl increase. This is much lower than the average USD 0.17 increase in feedstock cost per USD 1/bbl increase used for other commodities in this analysis.

Annex B • Capital costs: key sources used for the characterisation of the energy pathways

For biofuels, a large amount of information was drawn from the *Supportive Study for the OECD on Alternative Developments in Biofuel* (Smeets, Junginger, and Faaij, 2005). The cost figures and technical information in this resource were complemented by other European or North American studies, depending on the energy pathway (*e.g.* moisture content of the feedstocks, maximum ethanol theoretical yield, capital costs), and information released by the industry. The studies used for this overview were: Wright and Brown (2007); Zwart *et al.* (2006); Müller-Langer, Scholwin and Kaltschütt (2009); Shapouri, Salassi and Fairbanks (2006); McAloon *et al.* (2000); Singh *et al.* (2001); Punter *et al.* (2004); Woods *et al.* (2003); Ragwitz and Resch (2006); Edwards *et al.* (2008); Hofbauer (2007); Küsters (2009); Schmer *et al.* (2007); Brauer, Vogel and Müller-Langer (2008); and Thuneke (2006).

For H_2 fuels, the IEA report, *Prospects for Hydrogen and Fuel Cell* (IEA, 2005), was used as the primary source of information. A second important reference in this respect is Bartels and Pate (2008).

For CTL and GTL, the estimates presented rely on basic estimates presented in a lecture on the *Prospects and Potential Impact of Coal to Liquid Fuels* by Ari Geertsema (University of Kentucky, Center for Applied Energy Research, United States) at the Massachusetts Institute of Technology (Geertsema, 2005), drawing on the experience of Sasol, as well as on information released to the press on the cost and size of the Shenhua CTL project in Mongolia, the Escravos GTL project in Nigeria, the Integrated Pearl GTL project and the Oryx GTL project in Qatar (Barradas, 2008; CIAB, 2006; Green Car Congress, 2006; *Engineering News*, 2007; Reuters, 2008; and Robertson, 1999).

For electricity generation, cost estimates were largely based on the information published in the IEA *Energy Technology Perspectives* studies of 2010 and 2012 (IEA, 2010, and IEA, 2012a). T&D losses are assumed to be 7% for centralised production, as suggested by IEA statistics (IEA, 2012c), and 4% for decentralised production. Intermittency costs for some renewable sources (like wind) have been evaluated considering the need for a 50% hydroelectric spare capacity for backup.

Annex C • Plant size and scaling

In order to avoid the influence of plant size on capital costs (*i.e.* the larger the size, the lower the cost per unit produced owing to economies of scale), the capital costs for biofuel plants found in the literature sources used for this study (associated with the respective plant size) were scaled to the same representative size for all biofuels using the following exponential law, which is commonly employed to account for economies of scale:

$$\text{normalised cost} = \text{original cost}\left(\frac{\text{normalised size}}{\text{original size}}\right)^{\text{scaling exponent}}$$

The scaling exponent was assumed at 0.63 (a range of 0.6 to 0.7 is commonly cited in literature – *e.g.* by McAloon, *et al.*, 2000).

For biofuels, the plant capacities are equivalent to 75 million litres of gasoline-equivalent per year (lge/yr) in the deployment phase, and 190 million lge/yr in established market conditions. Assuming that 15 tonnes (t) of biomass per hectare can be collected each year, considering a calorific value close to 14 megajoules per kilogram and a plant efficiency of 43% (and therefore looking at plants using lignocellulosic biomass as feedstock), these sizes correspond to areas of between 17 square kilometres (km^2) and 26 km^2 of cultivated land and 50 to 135 fully loaded trucks each carrying 30 t of primary material to the transformation unit every day (not considering the seasonality of the biomass production).[9]

No attempt was made here to identify an optimised plant size (as each plant would need to be addressed on an individual basis). The normalisation was mainly intended to identify a biofuel plant size that would be compatible with current and future, expected, dimensions, taking into account the limitations associated with the relatively high costs of transporting the biomass to a large centralised unit.

Other pathways, not affected by the limitations due to the sparse nature of the biomass feedstocks, are characterised by much larger dimensions, making them comparable to small and medium refineries. This is the case with CTL, GTL and centralised H_2 production plants. Similarly, the size of future electricity plants is assumed to be comparable to the size of existing facilities. This kind of assumption means that very large investments would be needed, especially in synfuel plants (H_2 production in earlier deployment phases is expected to rely mainly on decentralised production systems, based on electrolysis).

In all cases, if the plant size in the deployment and established market phases were to be lower, the production costs of the alternative fuels concerned would benefit less from economies of scale and would ultimately be higher.

[9] The plants could (and probably should) rely on other transport means and other biomass collection systems, involving, *e.g.* torrefaction and other solutions that reduce the volume and weight of the biomass that needs to be transported. The figures given here aim to give an idea of the magnitude of the biomass transport system that would need to be associated to the assumptions considered.

Annex D • Plant efficiencies

The plant efficiencies assumed for this analysis for each energy pathway derive from the literature sources mentioned in Annex A are shown (Table 12).

Table 12 • Plant efficiencies assumed for different large-scale energy pathways

Primary energy source	Process	Plant efficiency	
		Current Technology Scenario	Mature Technology Scenario
Oil	Refining	85% to 87%	85% to 87%
Natural gas	GTL H_2 Electricity	58% 72% 50%	64% 77% 55%
Coal	Middle distillates H_2 Electricity	45% 55% 40%	45% 65% 44%
Nuclear energy	H_2 Electricity	45% 35%	56% 39%
Oil-seed crops	Biodiesel	45%	52%
Grain crops	Alcohol	38%	42%
Sugar crops	Alcohol	36%	40%
Biomass from crops and/or waste products	Biodiesel Alcohol Methane H_2 Electricity	46% 34% 62% 50% 40%	53% 39% 69% 61% 44%
Solar energy	Electricity (PV)	100%	100%
Hydroelectric energy	Electricity	100%	100%

Annex E • Gaseous fuels: key sources and explanation of the choices made for the characterisation of different cases

The transmission cost was calculated on the basis of a model of transmission (Yang and Ogden, 2008) and two key parameters affected the results:

- gaseous fuel flow;
- transmission distance.

As the share of the transport sector in the T&D of gaseous fuels (out of the total deliveries to all end-uses, including industry and buildings) may also change (Parker, 2004), this is assumed to affect the share of the infrastructure cost associated with the fuel used for transport.

Three methods of delivery were considered for centralised H_2 T&D:

- compressed gas trucks;
- cryogenic liquid trucks;
- compressed gas pipelines.

The choice of the transmission, distribution and delivery method as well as the respective T&D costs were based on H_2 demand and T&D distance, referencing the results provided in certain research (Yang and Ogden, 2008). The distribution costs were based on assumptions on city radius (representing the size of a city) and the number of refuelling stations. The total number of refuelling stations was based on assumptions on urbanisation rates, population density in urban areas and the evolution of the fuel-cell electric vehicle fleet over time (Task Force Natural Gas Vehicles, 2000; and Consorzio NGV System Italia, 2006). During infrastructure roll-out, the number of stations depends on the maximal acceptable time to reach the closest station and in a mature system, vehicle fleet per station ratios compare to the current situation with conventional refuelling stations (approximately 2 000 cars per station). The distance for H_2 transmission from the centralised plant to the city gate is assumed to be around 150 km, with one central production plant serving multiple urban areas.

For natural gas, the assumptions characterising the transport and distribution of the gaseous fuel were more optimistic than for H_2. All of the Scenarios accounted for a widespread use of natural gas for other end-uses (*e.g.* buildings). This resulted in a sharing of the transport cost per unit of energy of the natural gas amongst all end-uses. Such a repartition (leaving the transport end-use sector only a share of the total end-use – and transport cost – of close to 10% to 15%) contributes significantly to the curtailment of transport costs for natural gas.

For all gaseous fuels, refuelling costs were heavily affected by the usage rate of each refuelling point. For H_2, the number of cars per station resulted from the number of stations estimated as described above, the total fleet of fuel-cell vehicles, the average amount of H_2 per refilling (~ 5 kilograms [kg] of H_2 or 18 litres of gasoline-equivalent) and the annual H_2 use per vehicle. Utilisation rates were very low during the deployment phase (< 10%) and up to 70% in a mature market (with an average station size of 1 800 kg per day in a mature market).

For natural gas, the assumptions on the usage rate of fuel stations are based on vehicle tank capacity (equivalent to gasoline in terms of energy), refilling time and the natural gas vehicle fleet. The Current Technology Scenario assumes that the occupancy rate of the few available stations is close to 25%. While in the Mature Technology Scenario, transport and particularly refuelling costs were further reduced because of higher occupancy rates (45%) in each station and because of economies of scale due to larger scales of each station (*e.g.* the possibility to increase the refuelling points in each station).

Annex F • Electricity: key sources and explanation of the choices made for the characterisation of different cases

The investment cost of the residential charger (per plug) is an average of the investment costs suggested by a major European electricity generator (EDF, 2009), for residential chargers of one and two the cost of the residential chargers suggested by the United States Department of Energy (US DOE) (Morrow, Karner and Francfort, 2008) and the cost estimated by a private survey (IEA, 2010). For the public slow charge, the investment cost is an average of the costs given in an apartment complex for one and two plugs (EDF, 2009); a commercial facility for one and two plugs (EDF, 2009; Westminster, 2009); roadside distribution towers (evaluated using the cost of power tower system per plug, as indicated by City of Westminster, 2009); and a private survey (IEA, 2010). The fast charger cost taken into account results from the average of the estimate given for the Électricité de France (EDF) two-plug 42 kVA unit (EDF, 2009), the Tokyo Electric Power Company (TEPCO) 50 kW unit (Anegawa, 2009) and retail price of Nissan and/or Takasago direct current quick charger (Nissan Motor Company, 2010). The figures selected for the established market are taken from the same sources used for the deployment phase, but minimum price is also shown in the sources. The investment cost of chargers (per plug) has been annualised based on 15 years of service with a 10% discount rate. The most relevant parameters were also summarised (see Table 9).

Assuming that an average vehicle runs for 15 000 kilometres per year (km/yr) and that it consumes 0.2 kilowatt hours per kilometre then this results in total annual demand per vehicle of 3 000 kWh. The actual charger utilisation depends largely on the behaviour of drivers in different regions and locations (*i.e.* urban or suburban). This is crucial to evaluate future EV infrastructure cost and since little data are yet available on charging behaviour, certain assumptions must be made. Four important assumptions are included in this analysis:

- The frequency of charger use for both short and long term is assumed as 313 charges/yr (equals six days per week) for slow home and 52 charges/yr (equals once per week) for slow and fast public.
- Average recharge time for public fast chargers is based on EV drivers using the fast chargers for short periods of time to get a quick (often partial) recharge. In this analysis, on average, each EV was assumed to use a fast charger for ten minutes, which corresponds to 39 kilometres per charge (km/charge).
- For slow public charging, the average refill time per charge is assumed to be 107 minutes, which is estimated from 41 km/charge of daily average mileage.
- Since three types of charger were assumed in this analysis, the rest of the energy was charged by a slow home charger, which is calculated as 104 minutes.

From these hypotheses, the resulting share of residential charging was 72% for slow public charging and 14% for fast public charging.

The combination of these assumptions allows us to estimate the maximum possible number of vehicles that could access a recharging station in an average day, for full (100%) utilisation of each charger. Sixteen vehicles can share one slow home charger, 94 vehicles on a slow public charger, and 1 008 vehicles for a fast public charger, and the average infrastructure cost per unit electricity is USD 0.2/kWh to USD 0.21/kWh, independently on charger type.

However, 100% usage of charger is unrealistic. For example, in the case of a slow home charger, many customers would be reluctant to share their home charger with other people. In addition, some governments are deploying many public chargers to disseminate EVs and PHEVs, which may force public chargers to have relatively low usage rates in their early stages.

Considering this, this paper assumes actual number of vehicles per slow home charger is 1.0 to 1.2, which shows a low charger occupancy rate of 6% to 7% and calculated infrastructure cost per unit electricity output is USD 0.04/kWh in deployment phase and USD 0.023/kWh in established markets.[10]

These values can be used as a basis for an analysis of public charging. Since the cost per unit of electricity distributed in public charging points depends on their actual use, the significant parameter allowing calculation of the point at which they become cost-competitive with respect to residential slow charging is their occupancy rate. In the deployment phase, the assumptions retained here on costs could lead to occupancy rates of public chargers that should be as high as 54% for slow public chargers and 27% for fast chargers. In the established market, these rates could rise to 77% and 33% respectively, reflecting more optimistic cost reduction rates for slow home charging units with lower infrastructure cost.

For fast chargers, this leads to an estimation of roughly 267 vehicles per fast charger in the deployment phase and 332 in the established market. These values highlight the fact that effective management (*i.e.* balancing the need for a high usage rate, the potential waiting times required for customers and the electricity selling price required to recover costs and generate profits), the installation and use of fast chargers) will pose significant challenges.

In the case of slow public chargers, the occupancy rates required to achieve cost-competitiveness (54% in the deployment phase and 77% in the established market) are also very challenging, since chargers would require vehicle occupancy more than half of the day, including at night.

The assumptions used here are consistent with an average (unexploited) potential use of residential chargers of several vehicles (four to five), assuming that the average charger occupancy per day is eight hours. If residential chargers were improved to allow for multiple recharges (this could be achieved without either major technological improvements or incremental costs), home recharging costs would drop significantly, ultimately rendering public chargers unviable, unless their installation costs fall more than assumed here.

[10] This assumption may be conservative for the long term because more than one vehicle is actually potentially rechargeable overnight if the average approximate amount of kilometres driven every day (41 km for 15 000 km/yr and 365 days of car use) is considered.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

bio-SNG	bio-synthetic natural gas
BLS	United States Bureau of Labor Statistics
BTL	biomass-to-liquids
C&F	cost and freight
CERA	Cambridge Energy Research Associates
CNG	compressed natural gas
CPI	consumer price index
CTL	coal-to-liquids
DC	direct current
EDF	Électricité de France
etOH	ethanol
EV	electric vehicle
FFA	forward freight agreement
FOB	free on board
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model
GTL	gas-to-liquids
H_2	hydrogen
IEA	International Energy Agency
IMF	International Monetary Fund
MoMo	IEA Mobility Model
NG	natural gas
O&M	operation and maintenance
OECD	Organisation for Economic Co-operation and Development
PHEV	plug-in hybrid electric vehicle
PV	photovoltaic
T&D	transmission and distribution
TEPCO	Tokyo Electric Power Company
UK	United Kingdom
US	United States
UDOP	União dos Produtores de Bioenergia
US DOE	United States Department of Energy
USD	United States dollar

Units of measure

bbl	barrel of oil
Btu	British thermal unit
charges/yr	number of full vehicle charges per year
GJ_{LHV}/yr	gigajoules using lower heating value per year
kg	kilogram
km	kilometre
km/charge	kilometres per charge
km/yr	kilometres per year
km^2	square kilometre
kVA	kilovolt ampere

kW	kilowatt
kWh	kilowatt hour
kWh/km	kilowatt hour per kilometre
lge/100 km	litres of gasoline-equivalent per 100 kilometres
lge/yr	litres of gasoline-equivalent per year
minute/charge	minutes per full charge of vehicle
t	tonne
USD/100 km	USD per 100 kilometres
USD/bbl	USD per barrel of oil
USD/GJ	USD per gigajoule
USD/GJ_{LHV}	USD per gigajoule using low heating value
USD/km	USD per kilometre
USD/kWh	USD per kilowatt hour
USD/lge_{LHV}	USD per litre of gasoline-equivalent using low heating value
USD/plug	USD per recharging plug for EVs/PHEVs
USD_{2010}/bbl	2010 nominal USD per barrel of oil
USD_{2010}/GJ_{LHV}	2010 nominal USD per gigajoule using low heating value
USD_{2010}/t	2010 nominal USD per tonne

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