JRC SCIENCE FOR POLICY REPORT

JEC Well-to-Tank report v5

Well-to-Wheels analysis of
future automotive fuels
and powertrains in the
European context

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Centre

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Contents

Abstract

The JEC consortium is a long-standing collaboration among the European Commission's Joint Research Centre (EC-JRC), EUCAR (the European council for Automotive Research and development) and Concawe (the scientific body of the European Refiners' Association for environment, health and safety in refining and distribution).

The consortium periodically updates their joint evaluation of the Well-to-Wheels (WTW) energy use and greenhouse gas (GHG) emissions, for a wide range of potential future powertrains and fuels options, within the European context. The present Well-To-Tank report belongs to a series of JEC WTW related reports where the process of producing, transporting, manufacturing and distributing a number of fuels suitable for road transport powertrains is described. The JEC WTT v5 assesses the incremental emissions (marginal approach) associated with the production of a unit of alternative fuel, with respect to the current status of production.

Foreword

Notes on version number:

This is version 5 of this report replacing version 4a published in January 2014. The main changes and additions to this version from version 4a are numerous and described in Appendix 3. Some of the most relevant are:

- The base year for this Well-to-Tank evaluation is 2015 with a time horizon of 2025+;
- Updated in CNG and LNG fuel composition based on the supply to Europe, including upgraded biogas;
- The energy and GHG values of crude oil extraction, transport and refining have updated based on the recent data and literature;
- Updated natural gas pathways, including the addition of an LNG pathway and several pathways for biogas from organic waste and synthetic natural gas (section 3.2);
- New alternative fuels have been included (e.g. pyrolysis-based and additional pathways for potential diesel substitutes) with an ad-hoc new section on Power-to-X fuels (section 3.9).
- Updated production data for biofuel pathways based on best available information from bio-industry consultations. The Transport and distribution of the final fuels have significantly changed based on the assumptions in the RED II pathways. (section 2.10);
- Reviewed and updated the EU electricity mix based, adding a 2030 mix in additional to the current one (section 3.4);
- Updated references have been cross-referenced to specific pathways or to sections of this report (section References);
- Investigated costs information on liquid biofuels pathways.

Acknowledgements

This JEC Consortium WTT study was carried out jointly by experts from the JRC (EU Commission's Joint Research Centre), EUCAR (the European Council for Automotive R&D), and Concawe (the scientific body of the European Refiners' Association for environment, health and safety in refining and distribution), assisted by experts (e.g. Weindorf W.) from Ludwig-Bölkow-Systemtechnik GmbH (LBST).

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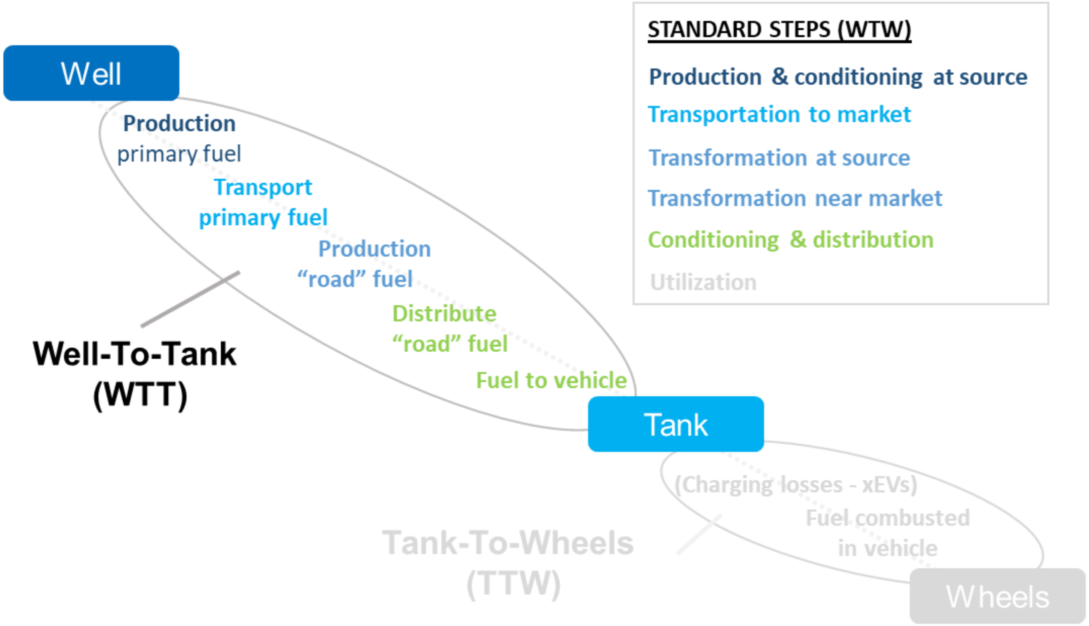
Executive summary

1. *What is the scope of the JEC WTT analysis?*

The JEC consortium is a long-standing collaboration among the European Commission's **J**oint Research Centre (EC-JRC), **E**UCAR (the European council for Automotive Research and development) and **C**oncawe (the scientific body of the European Refiners' Association for environment, health and safety in refining and distribution).

The consortium periodically updates their joint evaluation of the **Well-to-Wheels (WTW) energy** use and **greenhouse gas (GHG) emissions**, for a wide range of potential future powertrains and fuels options, within the European context. The present Well-To-Tank report belongs to a series of JEC WTW related reports where the process of **producing, transporting, manufacturing and distributing a number of fuels suitable for road transport powertrains is described**.

Figure 1. Well-To-Tank analysis (WTT) - Scope



The main objective of this report is to assist the reader and guide stakeholders in answering questions about:

- possible alternative pathways to produce a certain fuel and which of these offer the best performance in terms of energy/GHG emissions.
- initial prospects on alternative uses for a given resource, looking at how it can best be used to produce the final fuel, in terms of both energy requirement and GHG emissions

The JEC WTT v5 assesses the **incremental emissions** (**marginal approach**) associated with the production of a unit of alternative fuel, with respect to the current status of production (Section 2.3). This marginal approach has been chosen as instrumental to:

- guide judgements on the potential benefits of substituting conventional fuels/vehicles with a specific alternative.
- for future fuels: understand where the additional energy resource would come from.

As in previous versions, the **marginal approach** has been applied to refining of fossil crude, natural gas and biofuel processing pathways while average emissions have been estimated as a proxy for EU electricity and crops cultivation (since estimating incremental increases in crop output is challenging and controversial, Section 3.7). In all the cases, the report is also forward-looking and considers state-of-the-art technology to support future choices. Note that, for fuels from biomass origin, the GHG balance figures presented do not include emissions caused by land use change. Despite the potential impact it may have on the final values, both direct and indirect land use changes (DLUC and ILUC) have not been accounted for in this exercise, mainly because of the high uncertainties in the methodology for estimation (a wide discussion about this issue is available in Appendix 5).

Additionally, results from JEC WTT v5 are different from the values contained in the Renewable Energy Directive recast (2018/2011/EU) (See section 2.10). Although JEC WTT v5 shares the input dataset for biomass-related pathways, which have been provided by EC-JRC, the methodology is different. In particular for the co-products, Renewable Energy Directive (RED) recast values used energy allocation for administrative convenience. Thus, the RED recast values cannot be directly compared with the ones presented in this report.

- To complement the analysis, this JEC WTT v5 report includes a detailed section comparing attributional and consequential CO_2 allocation methods to refining products (focus on gasoline and diesel). This to invite JEC readers and LCA practitioner not to directly apply JEC results without taking into consideration the methodological approach chosen. In JEC v5, the different experiences from automotive and petroleum/refining industries have been put into value. As a general conclusion, a study conducted by an external party confirmed that **both modelling principles, attributional and consequential, are scientific sound in its domain of validity and applicability**. Therefore, **carbon intensities of fuels** can be calculated by following attributional or consequential modelling principles, depending on the specific goal & scope defined and decision context being applied, see ISO 14040/44 and European Commission's ILCD Handbook. In this context, due to the scope of the JEC WTW analysis, JEC WTT data is based on a consequential approach and the following table x2 aims to illustrate how results can be affected by different methodological allocation choices:

Table 1. Summary. Refinery allocation results based on extended literature review[1]

	Consequential "Marginal" (g CO_{2eq}/MJ)			**Attributional "Average" (g CO_{2eq}/MJ)**			
	JEC (Concawe)		JRC paper (2017)	Aramco paper (4)		JRC paper	Sphera (2020)
	JEC v4 (1)	**JEC v5 (3)**	JRC (2)	Standard Mass allocation	Customized allocation (4)*	EN (2)	Mass & Energy
Gasoline	7	**5.5**	5.8	10.2	7.6	5.7 - 5.8	9.6
Diesel	8.6	**7.2**	7.2	5.4	6.8	5.8 – 6	3.4

It is of utmost important to remark that, while the JEC-WTT (and the derived WTW) values follow a consequential approach, for A-LCA average values shall be used. It is thus fundamental, before using the data provided in JEC, to consider the goal and scope of the analysis carefully.

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[1] Sources: (1) JEC WTW studies (2014) Version 4; (2) Moretti, C et al. (2017) (JRC) Analysis of standard and innovative methods for allocating upstream and refinery GHG emissions to oil product; (3) JEC WTW studies (2019) version 5; (4) Gordillo, V et al. (2018) Customizing CO_2 allocation using a new non-iterative method to reflect operational constraints in complex EU refineries; (4)* Customized reallocation, influencing Hydrogen production from catalytic reforming and vacuum distillation; (5) Sphera values [EUCAR 2020]

Finally, the values in this report, even though they apply a forward-looking approach through the marginal approach, remain focused on a product-basis comparison and do not include detailed modelling of possible scale-driven consequences or market-mediated effects on other sectors of the economy. Therefore, the results should not be intended to be made for large-scale, strategic policy decisions[2].

2. Which pathways have been included in JEC WTT v5?

Extending the previous content of JEC WTT v4, the JEC WTT v5 contains many fuel categories: fossil derived fuels, biofuels from vegetable oil, ethers, hydrogen, etc. The JEC WTT v5 dataset is contained in 9 excel workbooks, structured per energy carrier categories, namely: **oil, natural gas, biogas, ethanol, biodiesel, hydrotreated vegetable oils (HVO), synthetic fuels (including different final fuels), hydrogen, electricity and heat**. Within each fuel category, a wide number of potential conversion pathways have been analysed: for instance, ethanol produced from wheat, sugar beet, barley, etc., biodiesel obtained from different vegetable oils like rapeseed, soy, sunflower, palm, etc.

The fuel matrix (**Table 2**) illustrates the different possible feedstock (resources) to final fuel pathway combinations.

The updated JEC WTT v5 contains:

- **252 energy carrier pathways** in total (including heat and power in **Appendix 4**). Energy demand and GHG emissions data of almost all the pathways in version 4 (v4) have been updated based on recent literature review or additional data (e.g. for conventional fuels, the energy and GHG data for crude oil extraction and refining have been updated according to the recent data from Exergia et al. 2015 and a Concawe internal report 2017). The energy and GHG emissions of all the biofuel pathways changed significantly, because the latest version implemented the basic assumptions outlined in RED II for forestry residue collection, short rotation forestry, wood chips storage (seasoning), biomass transport and transport and distribution for the final fuels. These, among many others, are the significant/apparent changes compared to version 4.
- **78 new pathways** to better represent the current state-of-the-art of the sector. Some of the new pathways represent additional features in the existing fuel production facilities (e.g. Carbon Capture & Storage (CCS) at gasoline production, high octane petrol, etc.), while others represent novel feedstock and innovative production technologies (e.g. sugar beet based ETBE, synthetic fuels from waste and farmed wood, biogas to hydrogen, etc.). There is a completely new section on Power-to-fuels. Additionally, this report investigates the possibilities for using high-octane gasoline for higher energy efficiency in conventional petrol vehicles sector. Therefore, three different high RON gasoline (RON 100, RON 102/E5eq & RON102/E10eq) pathways have been included.
- **54 Synthetic fuel pathways** are available in this version, of which 35 are new ones. Within the synthetic fuels, two new subcategories have been added: Pyrolysis fuels and Oxymethylene dimethyl ether (OME). In addition, the production of synthetic methane, methanol and Dimethyl ether (DME) from renewable electricity have also been included. Furthermore, ethanol based ED95 fuel pathways for diesel-like engines (modelled as mixture of ethanol, lubricants, i-butanol, polyethylene glycol, etc.) is another interesting addition to version 5. Considering that some production pathways are technologically and commercially more mature than others, in order to complement the analysis, in this version the Technological (TRL) and market/commercial (CRL) maturity levels have been introduced (Section 2.8).

3. What are the main results in terms of WTT Energy expended and GHG emissions?

The analysis performed in this version shows the high variability among the more than 250 modelled pathways, both in terms of WTT energy expended for production and resulting GHG emissions. Specific conversion pathways and feedstock/resources have a strong impact on the results. A specific comparison section has been introduced, in order to summarize the detailed results in terms of:

a) Fuel comparison – Conversion routes –This comparison aims to show the **WTT Energy expended and GHG range per type of fuel** (e.g. fossil, CNG, DME, etc) including the range (min/max) and a representative pathway for each of the conversion routes modelled.

b) Resource to fuels – This section allows to compare the impact of using **different feedstock/resource** options to produce a specific fuel.

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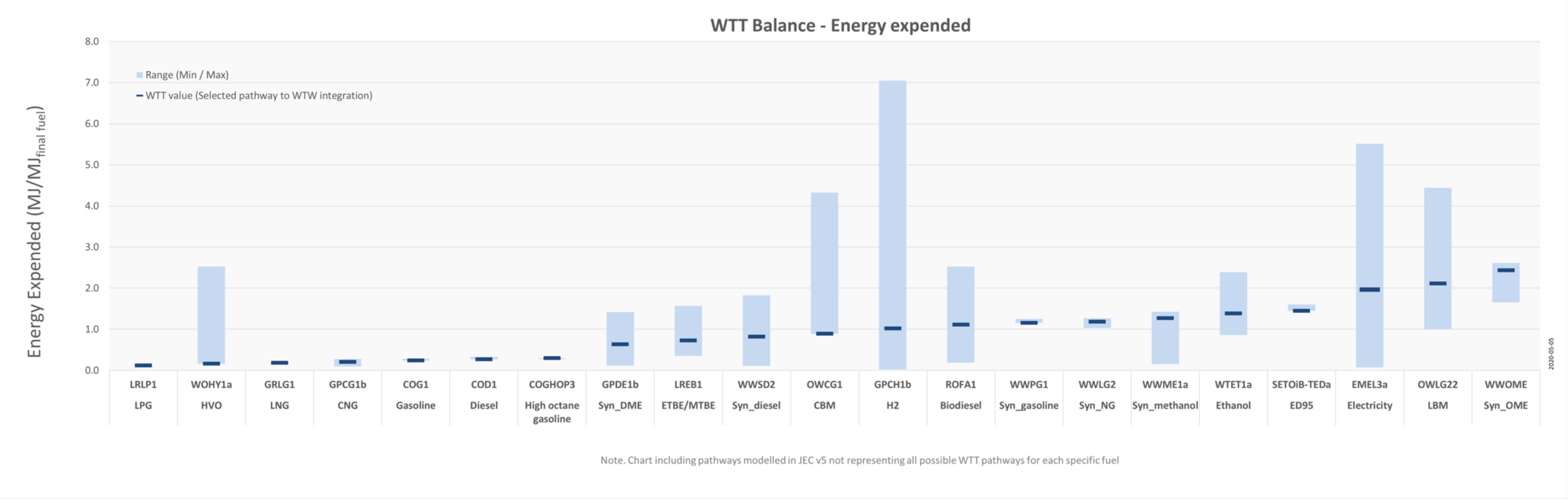
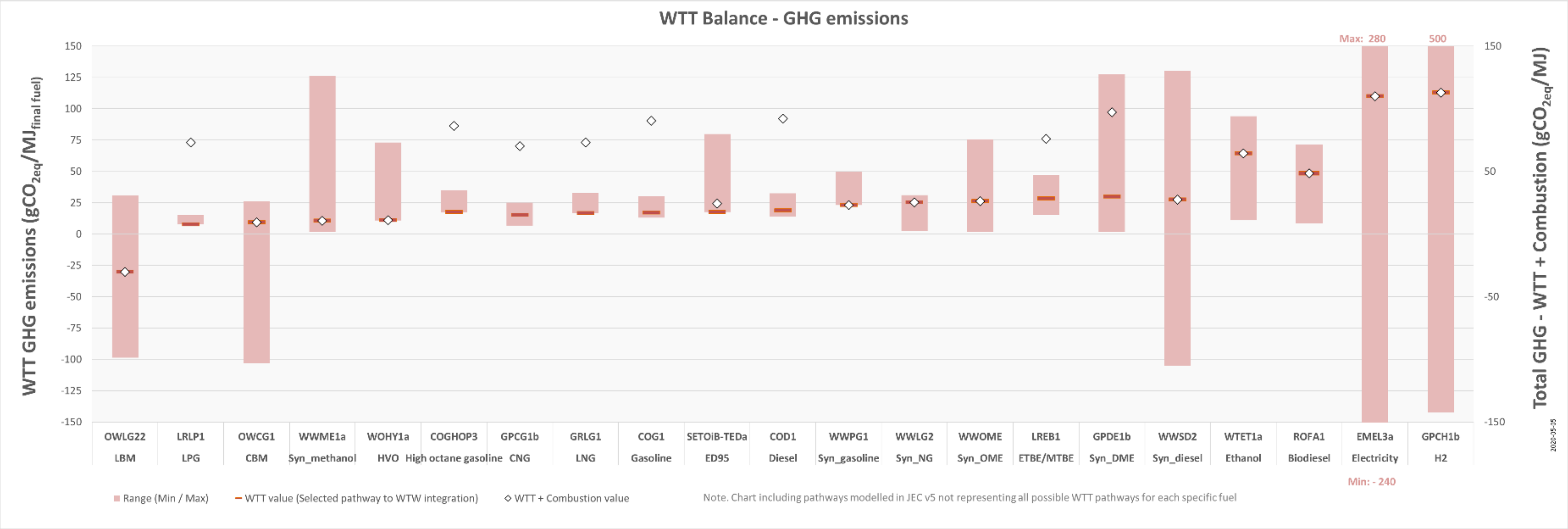
[2] see https://ec.europa.eu/jrc/en/science-update/life-cycle-assessment-environmental-impacts-bioeconomy

The comparison among the WTT values for the explored fuel production pathways is presented in **Figure 2** (energy expended and GHG emissions). For each specific final fuel, the minimum and maximum values represent the variability within the existing production pathways. The most "representative" pathway has been selected on the base of techno-economical evaluations; these representative pathways are those used for the WTW integration (Selection criteria are detailed in section 5 – Comparative analysis):

Figure 2. Comparison among the WTT values (Energy expenditure and GHG emissions) for some investigated fuel production pathways



Note. Chart including pathways modelled in JEC v5 not representing all possible WTT pathways for each specific fuel



Notes

(1) For each fuel, the width of the bar represents the minimum and maximum values from the pathways modelled in this JEC WTT v5. Within the range, the thick line represents the pathway selected as representative of the specific fuel – consistent with the JEC WTW v5 report (Code included above as a reference). For the high octane gasoline pathways the wheat-to-ethanol pathway WTET5 (biogas from DDGS for internal energy supply) instead of the representative wheat-to-ethanol pathway WTET1a (NG boiler) has been used for admixture. The difference for the WTW GHG balance for high octane gasoline pathway COGHOP3 (variant with the highest ethanol share) amounts to about 2%.

(2) The WTT figures included in this JEC WTT report reflect the net energy requirement and related emissions required for the production of 1 MJ of fuel (See chapter 2.9.4). In case of bio-based feedstocks, the bio-credits will be taken into consideration into the WTW calculations (where the impact of the combustion of the fuel in a specific engine is assessed).

(3) Due to the consequential nature of the LCA approach applied according to goal and scope of JEC WTT v5 the values shall not be used in attributional LCA context.

(4) The report includes representative pathways / routes but additional technologies (not included in this version 5) are already in development. Therefore, the comparison of various WTT routes has been conducted among the modelled JEC pathways which differ depending on the type of fuels and the routes to produce them. E.g. whereas we have considered a very extensive range of primary energy sources for some fuels/energy carriers (eg. electricity, hydrogen), for others, only some initial examples of potential sources/pathways have been chosen for illustrative purposes (e.g. DME). This issue should be factored in when comparing the ranges for different fuels.

(5) In case of electricity negative GHG emissions occur for electricity from biogas from liquid manure due to credits for avoided CH4 and N2O emissions from avoided storage of untreated liquid manure

From the analysis of the results, the following general conclusions can be drawn:

- In terms of WTT energy required for fuel production, among fossil based fuels, the representative pathways for LPG, LNG and CNG resulted in more energy efficient routes than conventional crude oil based ones.
- Among the pathways with high-energy input, the most WTT energy-intensive pathways are the electricity (when EU mix is considered), liquefied bio-methane (LBM) and synthetic OME.
- A number of pathways offer the possibility to achieve negative WTT emissions: LBM/CBM (liquefied/compressed bio-methane) and electricity and hydrogen, when produced from biogas due to the avoided CH_4 and N_2O emissions[3], and production of synthetic diesel from biomass when coupled with CCS processes (a portion of CO_2 absorbed from the crops is not released but permanently stored in underground geologic formation- see section 3.5).

  It is important to point out that for biomethane, negative emissions are results as a reduction of GHG emissions compared to a reference use (e.g. avoided CH4 emissions). In case of bio-CCS, if CO_2 is permanently sequestered, then that pathway is actually increasing the C-sink and it is actively removing carbon from the atmosphere. Both pathways actively mitigate climate change with the difference that, while one is reducing emissions, the other is increasing a sink.
- It is worth noting that the wide variability, observed in some pathways such as for HVO, CBM/LBM, H_2 and electricity, is heavily depending on the conversion route/feedstock chosen which have a significant impact on the final expended energy and GHG emissions.
- Additionally, it is important to highlight that general conclusions about the most favourable routes, both in terms of GHG emissions and energy consumption minimisation, can be derived only when the whole WTW analysis is taken into account, as the powertrain efficiency strongly impact the results (expressed in terms of g CO_{2eq}/km, including the efficiency of the different powertrains). As an initial proxy, the total GHG emissions including combustion is also included in the WTT related chart.
- Within each of the categories and when the WTT energy and GHG emissions are compared:
  - **Fossil**: A number of "representative" fossil based pathways such as CNG/LNG or high octane gasoline can offer lower GHG emissions routes than conventional gasoline and diesel, while lower energy intensities are mainly reached by the gaseous fossil fuels.

    It is worth to remark, that results for gasoline and diesel are based on the consequential LCA methodology used in JEC. The Concawe refinery model calculates marginal CO_2 intensities induced by a marginal change, e.g. demand in petroleum products, around the European refinery operations calibrated for the reference year (2010) in terms of refinery configuration, price of crude oil, other feedstocks supply, petroleum product demand and specifications, as well as processing capacities. Due to the consequential nature of the LCA approach applied according to goal and scope of JEC WTT v5 the values shall not be used in a pure attributional LCA context. An attributional LCA approach follows other modelling criteria. This is why this JEC WTT v5 report includes a detailed section comparing attributional and consequential CO_2 allocation methods [section 2.3.2].
  - **Crop derived fuels**: the newly added bio-ETBE route involving ethanol and isobutene from sugar beet shows interestingly low GHG emissions, when compared to Ethanol from other sources than sugar beet (wheat except WTET4a/b, barley, and corn) or HVO/Biodiesel routes, but with higher energy demand. Compared to the associated ethanol pathway the GHG emissions for the ETBE route are higher.
  - **Wood**: selected pathways for synthetic diesel, DME and hydrogen derived from wood are the ones with the potentially lowest WTT GHG emissions[4]. Negative emissions can be achieved in the pathways implementing CCS.
  - **Biogas**: interestingly, biogas from manure as feedstock for hydrogen production shows lower WTT emissions than CBM (Compressed BioMethane) or LBM (Liquefied BioMethane) pathways, but with significantly higher energy requirements. Significant negative emissions can be derived from routes involving biogas from manure due to the avoided CH_4 emissions. This is the reason why biogas to

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[3] It has to be noted that the negative GHG emissions for biomethane from manure only can be taken into account as long as there are farms where storage of untreated manure is applied.

[4] Impacts on forest C-stocks and sinks is not included in this analysis.

hydrogen routes involving biogas from manure show lower WTT GHG emissions than the CBM and LBM ones although the energy requirement is higher. It is important to note that this substitution approach is valid under the current assumption that the methane would be released to the atmosphere if not used as fuel. Alternative technologies could also reduce the fugitive methane emissions and, thus, for comparisons to such a case, the current pathway calculations would have to be adjusted accordingly.

- **Electricity and H_2**: regarding electricity and Hydrogen, it is worth noticing that they should be primarily considered as energy carriers, with environmental performances determined by the primary source used for their production. More precisely, the use of electrical energy in the transport sector is, in terms of GHG emissions saving, determined by the pathway of power production. At least for the transitional phase (out of the scope of this JEC study), towards road electrification, when power for vehicles is taken from the grid, this can lead to an increase in emissions, if the system reacts to this increased demand by **increasing** the production from fossil source (e.g. coal); these issues are country specific and time specific (as production is a non-steady process by definition). On the other end, a substantial uptake of electrical energy for the road sector may act as a driver for increasing the share of renewable energies in the EU mix. Similarly and from a mere GHG reduction perspective, the use of hydrogen fuel cells may not lead to any advantages, if electricity used is not from a carbon-neutral source.
- **e-fuels**: as e-fuels production is based on electricity, the above-mentioned considerations can be extended to these cases. As detailed in section 3.9, this route is an **example** of *Carbon Capture and Utilisation* (CCU) in a highly energy and capital intensive process with high CO_2 abatement potential versus their equivalent fossil-based fuels.

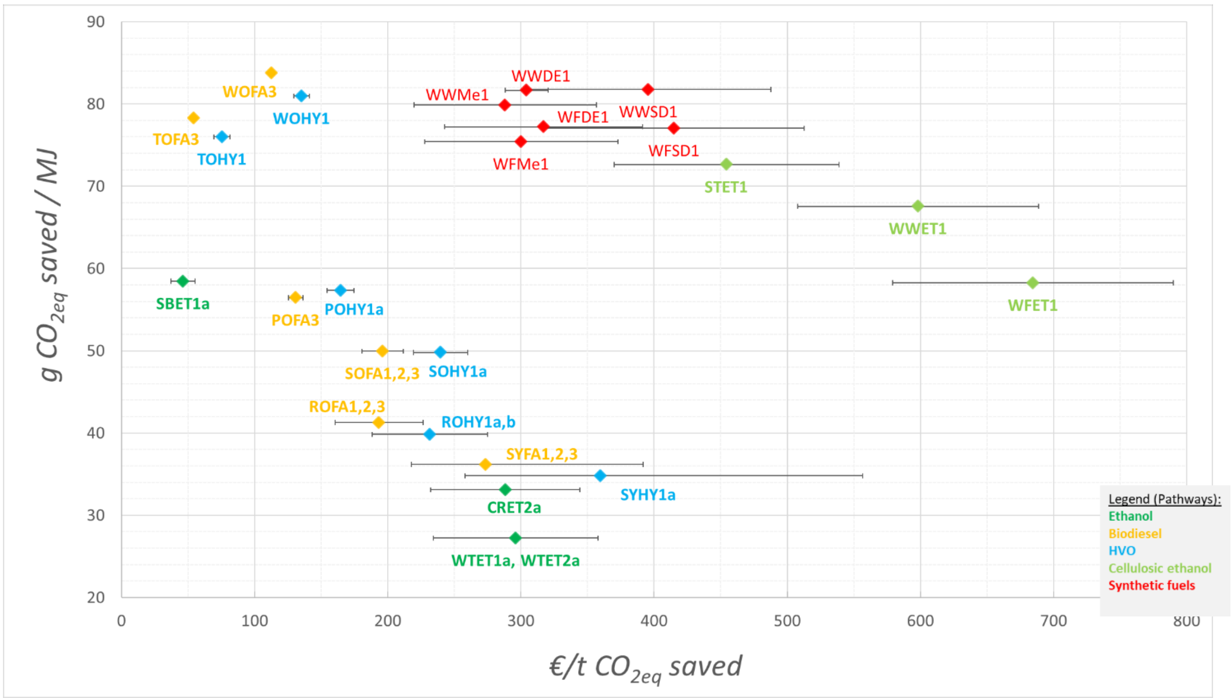
General conclusions about the most favourable routes, both in terms of GHG emissions and energy consumption minimisation, can be derived only when the whole WTW analysis is taken into account, as the powertrain efficiency strongly impacts the results (expressed in terms of g $CO_{2eq/km}$, including the efficiency of the different powertrains).

4. *What is the cost of replacing conventional road fuels with different alternative fuels?*

The JEC WTT v5 analyses and quantifies the production and the related GHG savings costs for the main conventional and advanced biofuels, produced in Europe. The evaluation process considers data from the period 2014-2016, but it includes scenarios for 2030, based on different crude oil prices. The method implemented in the analysis for conventional and advanced biofuel production consists of estimating the cost to the EU (not including taxes and subsidies), following the same principles developed in the JEC-WTW v2 (2007) report, but limiting the focus to the 'well-to-tank' part. Therefore, commodity prices, costs for plants and equipment required for the fuel production and the cost of energy, have been defined on all EU basis.

Focusing the analysis on the pure cost of saved CO_2, **Figure 3** shows that using biofuels is today a more expensive solution with respect to fossil fuels, if compared with other mitigation options (e.g. EU-ETS).

Figure 3. Cost of GHG savings for the investigated production pathways in 2014-2016



Note 1. Synthetic fuels included in the WTW integration refer to BTL (Biomass-To-Fuels) pathways.
Note 2. The total production costs are simply given by the sum of capital costs (CAPEX), cost of feedstocks and operational costs (OPEX). A capital charge rate of 12% has been used, representing a return on investment of about 8% without accounting for a profit tax, which returns to the EU. A 20% uncertainty range on the capital investment was also applied.

1 Introduction

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

Being an energy carrier, a fuel must originate from a form of primary energy, which can be either contained in a fossil feedstock (hydrocarbons of fissile material) or converted from solar energy (biomass or wind power). Generally, a fuel can be produced from a number of different primary energy sources. In this study have been included all fuels and primary energy sources considered as relevant, within the selected timeframe. The main objective of this report is to provide the reader and guide stakeholders in answering the questions about possible alternative pathways to produce a certain fuel, and which of these offer the best performance in terms of energy/GHG emissions.

Primary focus of the study is to establish the energy and greenhouse gas (GHG) balances for the different production pathways. The methodology used is based on the description of each individual process, which is discreet steps composing the pathway. Given this approach, additional combinations maybe relevant in the future, can be easily included.

JEC study is forward-looking and considers state-of-the-art technology, with the aim to support stakeholder in their future choices. It worth noticing that existing production plant using older technology may not achieve the same efficiency.

Given the complexity of the task, many assumptions have been chosen by experts in preparing this report: all the relevant choices and decisions have been carefully reported in the workbooks, and described in the individual pathways.

In the Well-To-Tank pathways, in order to give comparable results with the past, the energy or GHG emissions associated with construction or decommissioning of fuel production and transportation facilities have not been considered. This choice is based on the high uncertainty in the available data and the expected minor impact of these additional energy requirements, on the total pathway balance. In order to verify this important assumption, in version 5 it has been decided to evaluate the potential impact on the final results, for some of the most relevant pathways; results are given in **Appendix 7**.

It is worth noticing that for fuels from biomass origin, the GHG presented figures, do not include emissions caused by land use change, either direct or indirect. Despite the potential impact it may have on the final values, both direct and indirect land use changes (DLUC and ILUC) have not been accounted in this exercise, because of the high uncertainties in the methodology for estimation; nevertheless, a wide discussion about this issue is available in **Appendix 5**. The WTT modelling work has been conducted by LBST[5] under Concawe supervision.

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[5] Ludwig-Bölkow-Systemtechnik, Germany

Relation with data used by the EU’s Renewable Energy Directive Recast (RED II)

In November 2016, the European Commission published its ‘Clean Energy for all Europeans’[6] initiative. As part of this package, the Commission adopted a legislative proposal for a recast of the Renewable Energy Directive. In the context of the co-decision procedure, in December 2018 the revised renewable energy directive 2018/2001/EU[7] entered into force.

It is worth noticing that, for pathways from biomass feedstock, JEC study uses the same input dataset than the one used for defining the RED II ‘default values’[8].

It is worth remarking that, despite the data used are the same, the Commission’s calculations applied a different methodology from the one used in this report, and therefore results cannot be directly compared.

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[6] https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans

[7] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG

[8] These input data have been assessed and validated by European Commission’s JRC: http://data.jrc.ec.europa.eu/collection/id-0082

2 Scope, Methodology, Definitions, Structure

2.1 Scope

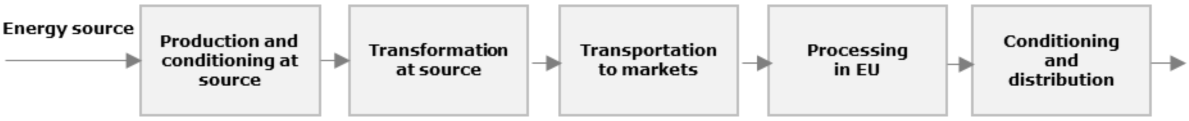
Scope of the WTT study is to evaluate the environmental performance of the various alternative fuels production pathways. The ultimate goal of this study is to supply evidence to guide those who have to evaluate the potential benefits of substituting conventional fuels by alternatives.

2.2 Investigated pathways

A number of existing and potential road transport **fuels** have been identified, in association with existing and/or future powertrains, both for Passenger Cars and for freight transport. Each final fuel can be produced from a single or several **resources** (source of primary energy), through an appropriate conversion process. The combination of steps necessary to turn a resource into a fuel, up to vehicle tank, is defined as a **Well-to-Tank pathway (WTT)**.

Each pathway is described in terms of **process** steps, required to convert the feedstock into the final fuel for the vehicles. A complete pathway is a combination and succession of processes, many of which are common to several pathways (i.e. conditioning, blending, etc.). A process can be characterised by means of a main input and a main output, secondary inputs, co-products as well as factors for energy consumption and greenhouse gas (GHG) emissions.

In order to present results from various, different, pathways in a form, which allows for comparison, the final values are aggregated in five main categories:



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

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

Transportation to EU is relevant to energy carriers which are produced outside the EU (i.e. crude oil) and need to be transported over long distances.

Transformation in EU includes the processing and transformation that takes place near the market place, in order to produce a final fuel according to agreed specifications (e.g. oil refineries or steam reforming plants for hydrogen production).

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

The **Table 2** summarises the pathways considered in this study, in terms of resources used and final produced fuels:

Table 2. Fuels and resources

		Fuel																							
		Gasoline, Diesel (2017 quality)	Gasoline E10 / Gasoline High octane	Synthetic gasoline (Pyrolysis-based Naptha)	Diesel B7 (2017 market blend)	Synthetic gasoline	Synthetic diesel	Synthetic diesel (Pyrolisis-based diesel)	DME	OME	Ethanol	Methanol	MTBE/ETBE	ED95	Pure vegetable oil	FAME / FAEE	HVO	CNG	CBG	SNG	LNG	LPG	Hydrogen (Comp., liquid)	Electricity	Heat
Resource																									
Crude Oil		X (1)	X (1)																					X (5	X (6)
Coal							X		X			X											X	X	
Natural gas	Piped						X		X	X		X						X					X (1	X	
	Remote						X (1)		X (1)			X						X (1)			X (1)		X	X	
Shale gas																		X							
LPG	Remote (3)												X									X			
Biomass	Sugar beet										X		X (10)												
	Wheat										X		X	X											
	Barley/rye										X														
	Maize (Corn)										X (4)								X (2)		X (2)			X (2)	
	Wheat straw										X			X											
	Sugar cane										X														
	Rapeseed															X	X								
	Sunflower															X	X								
	Soy beans															X	X								
	Palm fruit															X	X								
	Double crooping																		X (2)		X (2)				
	Wood waste (8)			X			X (9)	X (1)	X (9	X	X	X (9)								X (7	X (7)		X (9	X (9	X
	Farmed wood (poplar)			X			X	X (1)	X	X	X	X								X (7	X (7)		X	X	X
	Waste veg oils															X	X								
	Tallow															X	X								
	Palm oil mill effluent																X								
	Municipal organic waste																		X (2)					X	X
	Manure																		X (2)		X (2)			X	X
	Sewage sludge																		X (2)		X (2)				
Renewable electricity (Wind)							X			X										X	X		X	X	
Nuclear																							X	X	
Electricity mix																							X	X	

Note.
(1) With / Without CCS
(2) Biogas
(3) Associated with natural gas production
(4) EU and US sources
(5) Heavy Fuel Oil
(6) Heating oil / Diesel
(7) Bio-SNG or bio-LNG
(8) Forestry residue
(9) Black liquor pathway included
(10) Via isobutylene and ethanol from sugar beet via the process from Global Bioenergies

In the various analysed pathways, electricity is considered either as a "fuel" or as a resource, depending whether it is part of the conversion process inputs; clearly, as electricity is not a primary energy source, EU mix and/or other sources have been considered case-by-case. For instance, hydrogen pathways involving electrolysis are therefore the combination of one electricity production route and of the electrolytic conversion.

ED95 contains ethanol (about 90.3% based on the LHV) from wheat or straw and polyethylene glycol (4.6% based on the LHV) from crude oil. Furthermore, ED95 contains small fractions of MTBE, i-butanol, and lubricants which are not considered in the fuels and technology matrix.

Table 3. Fuels and technologies

Technology		Gasoline, Diesel (2017 quality)	Gasoline E10 / Gasoline High octane	Synthetic gasoline (Pyrolysis-based Naptha)	Diesel B7 (2017 market blend)	Synthetic diesel	Synthetic diesel (Pyrolisis-based diesel)	DME	OME	Ethanol	Methanol	MT/ETBE	ED95	FAME / FAEE	HVO	CNG	CBG	SNG	LNG	LPG	Hydrogen (Comp., liquid)	Electricity	Heat
Crude oil extraction		X	X		X								X									X (5)	X (6)
Crude oil refining		X	X		X								X									X (5)	X (6)
NG extraction & processing				X	X	X	X	X	X		X	X (3)		X	X	X			X	X (3)	X	X	X
Anaerobic digestion for biogas generation																	X		X (2)			X	X
Pressing and solvent extraction of vegetable oil					X									X	X								
Plant oil refining					X									X									
Esterification					X									X									
Saccharification of lignocellulosic biomass										X													
Fermentation to produce ethanol			X							X		X	X	X									
Fermentation to produce bio-isobutylene												X											
Gasification						X		X	X		X							X	X (7)		X	X	
Pyrolysis				X			X																
Steam reforming of NG				X			X								X						X (1)		
Partial oxidation of NG						X (1)																	
Combined reforming of NG					X			X (1	X		X	X		X									
Hydrocracking						X																	
Hydrotreating				X		X	X								X								
Oligomerization						X																	
Methanation																		X	X (7)				
Synthesis	Methanol				X	X			X		X	X		X									
	DME					X		X															
	Olefin					X																	
	Fischer-Tropsch					X																	
	Formaldehyde								X														
	Methylal								X														
	Trioxane								X														
	OME								X														
	MTBE											X											
	ETBE											X											
Liquefaction	Hydrogen																				X		
	Methane																		X				
	LPG																			X			
Power station	Wind, PV, hydro					X			X									X	X		X	X	
	Thermal power																				X	X	
	Nuclear power																				X	X	
CHP plant																					X	X	X
Heating plant																							X
Water electrolysis	Low temperature (AEL/PEMEL)					X			X									X			X		
	High temperature (SOEC)					X																	
Direct air capture of CO2						X																	

Note.
(1) With / Without CCS
(2) Biogas
(3) Associated with natural gas production
(4) EU and US sources
(5) Heavy Fuel Oil
(6) Heating oil / Diesel
(7) Bio-SNG or bio-LNG

The main calculations have been carried by the software tool E3database (developed by LBST[9]) and which combines a dataset for all input data and their references with an algorithm for the rigorous calculation of the total energy and GHG associated with a given pathway, including feedback loops[10].

2.3 Incremental approach: conventional fuel substitution.

2.3.1 General concept

The aim of this study is to provide scientific based evidence on assessing the difference in emissions between the use of an alternative fuel/vehicle against a baseline based on conventional fossil fuels/ICE vehicles. With this clear goal, the JEC WTT is not a full LCA analysis: JEC WTT allows estimating GHG emissions related to fossil, and bio-derived to fuel pathways, from the production of the fuel up to the tank of the vehicle.

Shifting a certain amount of energy from conventional to alternative fuels implies to affect the production chains, on both sides: a reduction in the traditional fossil-based industry and an increment in the demand for the alternative fuels production sector. The difference with respect to the *Business As Usual* case is thus incremental emissions to be considered (either positive or negative with respect to the BAU).

For refinery emissions of fossils, the ISO-14044 LCA guidelines have been followed, by establishing a physical causality between the outputs of different products and refinery emissions. This provides the marginal emissions associated with each product or co-product.

Similarly, following ISO-14044, for biomass derived pathways emissions the boundaries of the analysis are extended to cover the alternative production routes of co-products.

For many fuels that are not currently on the market, the incremental emissions are the same as the average emissions for the new fuels, because they will be made in new factories, so not implying significant change on the traditional production facilities. Similarly, the emissions for making more vehicles of a particular type can be approximated to emissions per car for the existing production. However, use of conventional biofuels require incremental increases in crop output (compared with a fossil-fuelled baseline), and these are likely to have an emission intensity higher than the average of the baseline crop output[11]. However, estimating such higher intensities for extra-crop production is challenging and controversial, so average crop emissions have been used in this study **as a proxy**, whilst admitting that this probably significantly underestimates the emissions intensity of the incremental crop.

2.3.2 CO_2 allocation in an oil-based refinery: "marginal" and "average" allocation approach

Life Cycle Assessment (LCA) offers an established and globally standardized methodology to help quantifying the environmental impact of products, processes, and services along the supply chain by following ISO 14040/44.

The European Commission has identified the strategic and practical value of LCA and implemented several approaches, guidelines and tools to support the usage of LCA. For instance, the European Commission Joint Research Centre (JRC) has developed the "*International Reference Life Cycle Data System (ILCD)*" and its related ILCD-Handbook[12], a detailed guidance document for LCA practitioners, highly accepted in the LCA community and widely used. The ILCD-Handbook in co-junction with the ISO 14040/44 standards can be seen as internationally accepted and applied reference documents for LCA.

Over the years, the attributional LCA, often following an "average" approach, was supplemented by an alternative way to model LCA systems: the consequential LCA where "marginal" modelling principles are used.

In its various industries applications, LCA serves to different goals and scopes. This has led to different approaches in using LCA tools, by sector experts. In JEC, the different experiences from automotive and petroleum/refining industries have been put into value, to complement the previous version 4, with additional

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[9] E3database by Ludwig-Bölkow-Systemtechnik, Germany

[10] A feedback loop occurs when part of the output energy of a pathway is used in the pathway itself (e.g. in an electricity generation pathway some of the electricity generated can be used to supply power to the equipment used in the pathway). In such cases a recursive calculation is used to determine the total input energy required to produce a unit of output energy.

[11] Because of the need to either use new land, which is likely to be less fertile than the land already chosen by the world's farmers, or to increase yields on the existing land beyond the historical increase that would be expected in the fossil-fuel baseline. There, one faces diminishing yield returns to increases in inputs, generally resulting in a higher emissions intensity for the extra crop.

[12] https://eplca.jrc.ec.europa.eu/ilcdHandbook.html

clarification on the best way to use WTT results. In particular, differences in “consequential” and “attributional” approaches have been clarified, with the final aim to guide on the appropriate way to use the provided data.

The refining process is one of the main steps responsible for differences between the CO_2 intensities of automotive fuels (gasoline and diesel). Estimating CO_2 emissions associated with production of a specific oil-derived product is a challenging task, as refinery outputs are produced simultaneously through a combination of interrelated processes[13]. In this “interrelated production system”, the total refinery released CO_2 emissions constitute all emissions of the full set of outputs (products) simultaneously, and the challenge is to find the most appropriate way to distribute them among the outputs.

In JEC v5, Concawe utilise a refinery’s model representative of the European production system to produce a consistent set of CO_2 intensities for all refinery products. Concawe methodology is based on the specific features of the Linear Programming (LP) technique. The CO_2 emission and energy intensity of refining products, such as LPG, gasoline, diesel or heavy fuel oil, have been modelled based on the allocation methodology developed by Concawe in 2017 [Concawe 2017].

In this section, a methodology overview of different LCA modelling principles (consequential and attributional), explaining the differences in the intended goal, usage and impacts on GHG inventories in life cycle modelling (such is the JEC study), is presented.

This overview resulted from an independent assessment commissioned by EUCAR to perform a critical review of existing fuel datasets including the investigation of inventories calculated by Concawe and Sphera’s (as owners of the GaBi software of common use by the automotive industry) [EUCAR 2020; Concawe 2017]. As a result of this external assessment, this section summarizes the key findings, conclusions and recommendations for the proper usage of the data.

2.3.2.1 Definitions: attributional and consequential modelling principles

- The **attributional life cycle inventory modelling principle** is also referred to as "accounting”, “book-keeping”, “retrospective”, “descriptive” or sometimes and potentially confusing: “*average*” or “non-marginal”.

  It depicts the potential environmental impacts that can be attributed to a system (e.g. a product) over its life cycle, i.e. upstream along the supply-chain and downstream following the system's use and end-of-life value chain.

  Attributional modelling is the LCA modelling frame that inventories the inputs and output flows of all processes of a system as they occur. Modelling processes along an existing supply-chain is of this type.

  The attributional approach is therefore applied in situations, were:

  - the focus of the study is on a clearly defined functional unit and its core supply chain. An enlargement/ dilution of effects via system expansion is to be avoided, as the main goal is to assess the options related to the core system under study (and rather not the effects on its alternatives and background system behaviour).
  - the result (variations) are aimed to be linked to technical options rather than to potential economic market reactions in the future.
  - not all background processes can be traced back to specific suppliers (retrospectively due to supply via “stock/resource” markets or prospectively if a potential future supplier of a material is not yet known).

  Most studies in industry, R&D or design are based on attributional LCA (A-LCA), as the own “product” (responsibility) and its related supply chain in a micro-economic perspective.

- The **consequential life cycle inventory modelling principle** is also called “change-oriented”, "effect-oriented", "decision-based", “market-based” and “*marginal*” or “prospective”.

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[13] The same problem is faced in cost-accounting of refining and other multi-product processes, and has been intensely studied by economists, such as A.T.N. Moghaddam & C. Michelot; A contribution to the linear programming approach to joint cost allocation: Methodology and application.

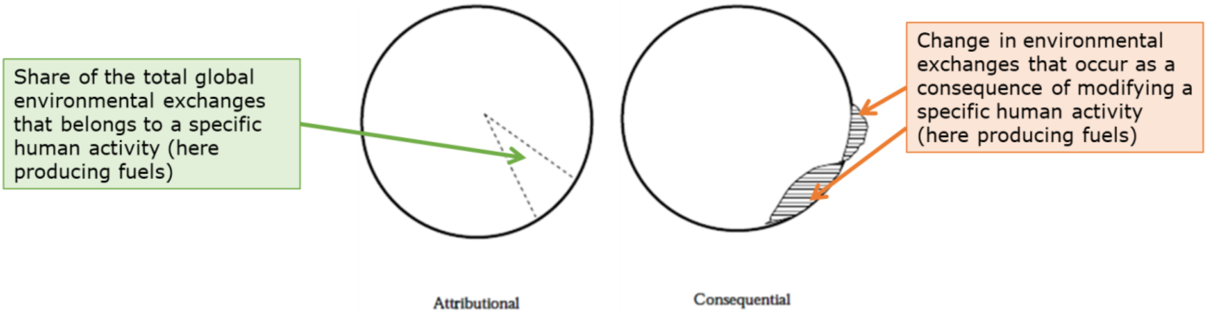
It aims at identifying the consequences that a decision in the foreground system has for other processes and systems of the economy, both in the analysed system's background system and on other systems. It models the analysed system around these consequences.

The consequential life cycle model is hence not reflecting the actual (or forecasted) specific or average supply-chain, but a hypothetic generic supply-chain is modelled that is prognosticated along market-mechanisms, and potentially including political interactions and consumer behaviour changes.

Consequential modelling is mostly applied by LCA researchers, industry experts or policy makers in a macro-economic decision context as the LCI modelling principle identifies and models all processes in the background system of a system in consequence of decisions made in the foreground system.

Table 4a. Comparison between attributional (A-LCA) and consequential (C-LCA) approaches

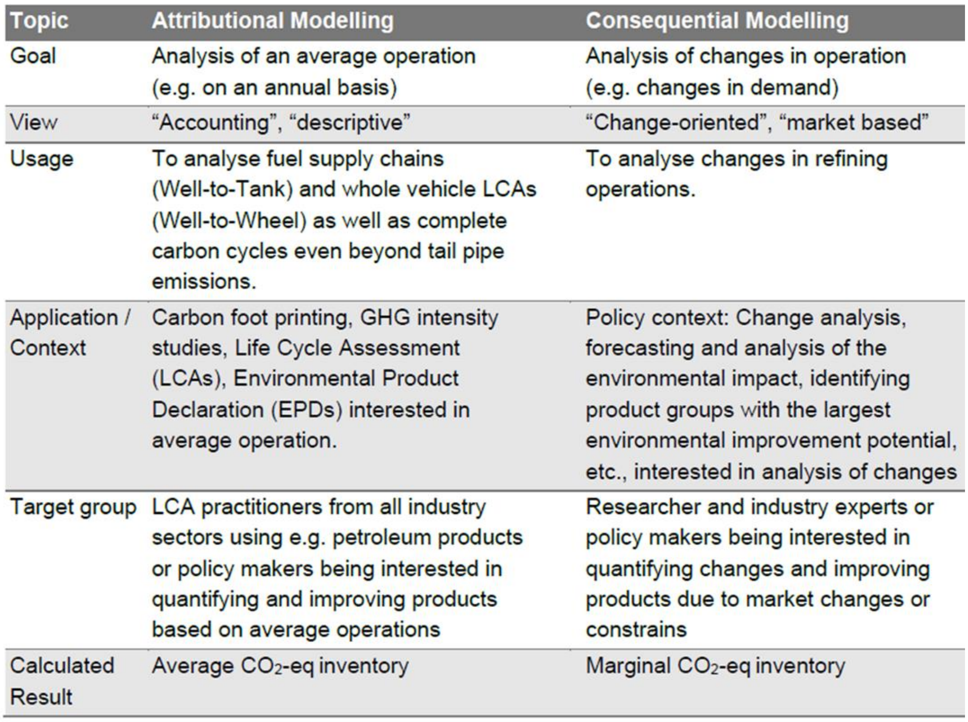
	A-LCA	**C-LCA**
Goal and scope	Assessment of goods and services	Assessment of a change (e.g. policy implementation)
Technical system	Energy and material flow physically linked to the product system	Energy and material flows affected by marginal changes
Dealing with Multi-functionality	Mass, energy or economic allocation, substitution	System expansion
Data requirements	Average data	Marginal data (Site-, process-, product-specific)



Share of the total global environmental exchanges that belongs to a specific human activity (here producing fuels)

Change in environmental exchanges that occur as a consequence of modifying a specific human activity (here producing fuels)

Table 4b. Summary of allocation principles [EUCAR 2020].



Topic	Attributional Modelling	Consequential Modelling
Goal	Analysis of an average operation (e.g. on an annual basis)	Analysis of changes in operation (e.g. changes in demand)
View	"Accounting", "descriptive"	"Change-oriented", "market based"
Usage	To analyse fuel supply chains (Well-to-Tank) and whole vehicle LCAs (Well-to-Wheel) as well as complete carbon cycles even beyond tail pipe emissions.	To analyse changes in refining operations.
Application / Context	Carbon foot printing, GHG intensity studies, Life Cycle Assessment (LCAs), Environmental Product Declaration (EPDs) interested in average operation.	Policy context: Change analysis, forecasting and analysis of the environmental impact, identifying product groups with the largest environmental improvement potential, etc., interested in analysis of changes
Target group	LCA practitioners from all industry sectors using e.g. petroleum products or policy makers being interested in quantifying and improving products based on average operations	Researcher and industry experts or policy makers being interested in quantifying changes and improving products due to market changes or constrains
Calculated Result	Average CO$_2$-eq inventory	Marginal CO$_2$-eq inventory

JEC context: a "marginal" (consequential) approach

The main objective of JEC study is to assist the reader and guide stakeholders in answering questions about:

- possible alternative pathways to produce a certain fuel and which of these offer the best performance in terms of energy/GHG emissions;
- initial prospects on alternative uses for a given resource, looking at how it can best be used to produce the final fuel, in terms of both energy requirement and GHG emissions.

According to these goals, and the different LCA methodological approaches previously introduced, JEC study WTT v5 assesses the incremental emissions (**marginal approach**) associated with the production of an unit of alternative fuel, with respect to the current status of production (Section 2.3). To be fully consistent with the JEC methodology, the same consequential approach has also applied to the production of fossil fuels in the refining stage. This approach has been chosen as instrumental to:

- guide judgements on the potential benefits of substituting conventional fuels/vehicles with a specific alternative;
- for future fuels: understand where the additional energy resource would come from.
- As JEC is based on a consequential approach, the results of this study are suitable for being used under the same conceptual framework.

2.3.2.2 Well-to-Tank GHG emissions of gasoline and diesel

Estimating carbon intensity of refinery products is a challenging task, given the complexity of the system and the iterations among the various streams of energy and materials.

Due to the possibility to use different criteria to allocated emissions, there is no single LCA value for gasoline and diesel in the literature as different allocation criteria can potentially be chosen to distribute emissions on the various refinery streams leading to different results. For instance, gasoline related values -available in literature - ranges from 5.8 [Moretti et al. 2017] to 10.2 [Gordillo et al. 2018] gCO_{2e}/MJ, and for diesel from 5.4 [Gordillo et al. 2018] to 10.3 [AV(2) table] gCO_{2e}/MJ.

As introduced earlier in the text, JEC WTT results are based on consequential allocation and, for different goals and scopes, attributional "average" allocations can be considered. As for automotive industry average approach is relevant in many applications (consistent with other analyses), a comparison with JEC values has been conducted. The results are provided in the table 5a.

It is important to note that the JEC values are from JEC WTT study v5, while Sphera's values refer to the GaBi databases 2020 (detailed explanation in the full assessment [EUCAR 2020]). The JEC-WTT refinery values are based on Concawe's consequential LCA approach that provides marginal values, while Sphera's refinery values are based on an attributional LCA approach that provides average values. As a consequence, on the different approaches chosen, the results obtained for GHG emissions in g CO_{2eq} per MJ of fuel delivered, at tank, for fuels produced in Europe are different.

Table 5a. JEC and Sphera GHG emissions in g CO_2 equivalent (CO_{2eq}) per MJ of fuel delivered, at tank, for fuels produced in Europe.

gCO_{2eq}/MJ fuel	**Gasoline**		**Diesel**	
	JEC WTT v5	Sphera GaBi 2020	JEC WTT v5	Sphera GaBi 2020
Crude oil supply	10.6	6.4	10.8	6.5
Another feedstock supply	-	1	-	0.4
Refinery	5.5	9.6	7.2	3.4
Conditioning and distribution	1	0.6	0.9	0.6
TOTAL	**17**	**17.6**	**18.9**	**10.9**

Note 1. The GHG emissions are expressed in g CO_2 equivalent (CO_{2eq}) per MJ of fuel delivered, at tank. The table refers to IPCC characterisation factors, taken from the 4th Assessment Report (AR4), 2007 in order to be in line with the methodology used in the JEC WtW studies.
Note 2. These datasets do not consider any bio-components blended to the finished refined product (That means, the data refer to 100% fossil fuels).

In order to show how results can be affected by different methodological allocation choices, the **Table 5b** below expands the comparison above by including a summary of results from other various sources:

Table 5b. Summary. Refinery allocation results based on extended literature review[14]

	Consequential "Marginal" (g CO_{2eq}/MJ)			**Attributional "Average" (g CO_{2eq}/MJ)**			
	JEC (Concawe)		JRC paper (2017)	Aramco paper (4)		JRC paper	Sphera (2020)
	JEC v4 (1)	**JEC v5 (3)**	JRC (2)	Standard Mass allocation	Customized allocation (4)*	EN (2)	Mass & Energy
Gasoline	7	**5.5**	5.8	10.2	7.6	5.7 - 5.8	9.6
Diesel	8.6	**7.2**	7.2	5.4	6.8	5.8 - 6	3.4

It is of utmost important to remark that, while the JEC-WTT (and the derived WTW) values follow a consequential approach, for A-LCA, "average" values shall be used. It is thus fundamental, before using the data provided in JEC, to consider the goal and scope of the analysis carefully.

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[14] Sources: (1) JEC WTW studies (2014) Version 4; (2) Moretti, C et al. (2017) (JRC) Analysis of standard and innovative methods for allocating upstream and refinery GHG emissions to oil product; (3) JEC WTW studies (2019) version 5; (4) Gordillo, V et al. (2018) Customizing CO_2 allocation using a new non-iterative method to reflect operational constraints in complex EU refineries; (4)* Customized reallocation showing the impact from, Hydrogen production from catalytic reforming allocation and vacuum distillation; (5) Sphera values [EUCAR 2020]

2.3.2.3 Main take-aways

As described thorough this section:

- **Both modelling principles, attributional and consequential, are scientific sound**, in its domain of validity and applicability under a differently defined goal & scope and in a different decision context, so serving **different aims[15] [EUCAR 2020]:**
    - The **attributional approach** describes the environmental impacts that can be attributed to a particular system or product with the core foreground system in specific focus.
        - The attributional modelling principle analyses a specifically defined or average operation, e.g. on an annual basis.
        - These CO_{2eq} inventories are intended to be used by LCA practitioners and users from all industry sectors using petroleum products or policy makers being interested in average GHG emission data based on average operations, used in micro-economic decision contexts with the core operation and supply chain in focus.
    - The **consequential approach** describes the environmental impacts induced by a product on an economic system that surrounds it (like background processes, alternative product supplies and constraint processes due to the change).
        - The consequential modelling principle, analyses impacts due to marginal changes or constraints (most often) implied by the market (e..g changes in operation) or a new policy, (e.g. changes in diesel demand in comparison with the base year 2010) and its impact on refining operation from a refiner's point of view.
        - It is applied by research, industry and policy makers in a macro-economic decision context, including effects on the economic system in the background and effects on alternative, avoided or constraint products that relate to the assessed product in the foreground.
- **Carbon intensities of fuels** can be calculated by following attributional or consequential modelling principles, depending on the specific goal & scope defined and decision context being applied, see ISO 14040/44 and European Commission's ILCD Handbook.

  In other words, attributional CO_{2eq} describe the average impact to produce diesel or gasoline, while consequential CO_{2eq} describes the impact released to deliver more (or less) diesel or gasoline (e.g. due to a new policy motivating the use of alternative fuels in the transport sector).
- Given the specific aims of each approach, **JEC WTT is based on a consequential approach,** as it aims to be relevant for policy making.
    - Data provided by JEC are based on a consequential approach, with marginal allocation for the refinery stage. Due to this approach and in order to guarantee consistency in the findings, the use JEC WTT (and WTW) results should be carefully considered, especially when considered in attributional contexts.
    - The fulfilment of an additivity criterion within the consequential modelling principle (by re-attributing process-related emissions) relates to necessities or implications within consequential modelling but does not qualify the results to be used in an attributional context (especially if CO_{2eq} values for refinery products are negative or zero).
    - **In light of all the elements provided, JEC Consortium recommends to not directly use C-LCA results in pure A-LCA analyses (See Table 4b).**

2.4 Methodology for co-products accounting

Many processes produce not only the desired product but also other streams or "co-products". This is the case for biofuels from traditional crops such as biodiesel from rapeseed, where a large amount of proteins for feed sector are made available from rapeseed production. In line with the philosophy described above, in this study is endeavoured to represent the incremental impact of these co-products. This implies that the modelled scenario must include either an existing process able to generate the same quantity of co-product, or considering another product being realistically able to replace the co-product.

This logic is reflected in the following methodological approaches (**Figure 4**):

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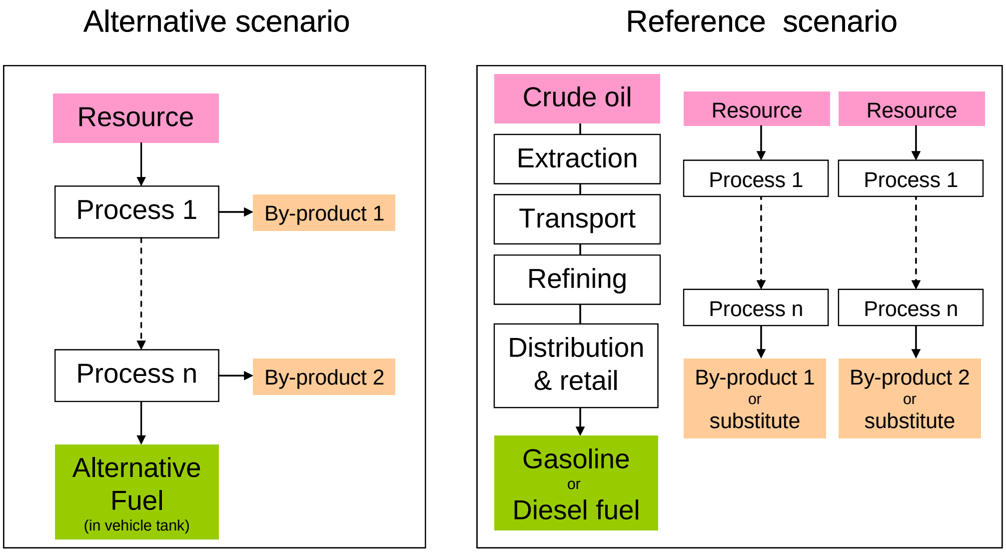
[15] As indicated in European Commission's ILCD-Handbook: https://eplca.jrc.ec.europa.eu/ilcdHandbook.html

- all energy and emissions generated by the process are allocated to the main or desired product of that process.
- the co-product generates an energy and emission credit equal to the energy and emissions saved by not producing the material that the co-product is most likely to displace.

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

For the purpose of policy[16] support analysis, this method attempts to model the complexity of real market interactions, by tracking the emissions consequences of the likely disposition of co-products. Some other studies have used "allocation" methods whereby energy and emissions from a process are allocated to the various products according to e.g. mass, energy content, “exergy” content or monetary value. The method proposed and used for calculating results in JEC WTT (representing an “expansion of system boundaries”) is the preferred methodology in the ILCD handbook [ILCD 2010].

Figure 4. Co-product credit methodology



This substitution methodology attempts to estimate the energy and emissions in the current economy, which result from a particular fuel pathway, including the use of co-products[17]. Indeed, there is not a univocal way to describe the use of a co-product, as in most cases it can conceivably be used in a variety of ways. Different routes can have very different implications in terms of energy, GHG or cost and it must be realised that economics rather than energy use or GHG balance, are likely to dictate which routes are the most popular in real life. In JEC study, all the available sectorial information has been used to guide the selection.

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[16] As for the callout of the 2008 Renewable Energy Directive

[17] Note that, in the event of a pathway generating electricity, it is assumed that that additional generation replaces electricity from a power station which uses the same type of fuel (State-of-the-art technologies used for the generation units). E.g. if an ethanol plant uses NG CHP for heat supply the excess electricity replaces electricity from a NG fuelled CCGT.

As an example, the manufacture of FAME (biodiesel) produces glycerine as a co-product. Amongst other options, the glycerine could replace synthetic (pharmaceutical) glycerine or be used as animal feed, replacing wheat grain. Making 1 MJ synthetic glycerine requires about 13 MJ of fossil energy. Making 1 MJ of wheat takes about 0.16 MJ. Clearly much more fossil carbon emissions will be saved in the first option than in the second. The “allocation” approaches based on energy or mass give exactly the same energy credits for both these potential uses of glycerine.

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

Electricity produced from biomass could substitute a range of other electricity production pathways, including coal or natural gas. However, this is the case whether that quantity of bio-electricity was produced by a free-standing bioelectricity generator independently of the biofuels process, or a co-product in a biofuel plant. It is clear that to get a balance which pertains only to the biofuel output, it is needed in some way to subtract the bioelectricity part of the process. In JEC it has been done by using a dedicated biomass-to-electricity process, in the reference scenario, so that the difference between the alternative and reference scenarios is only related to the production of biofuel. This approach ensures that the benefits of using the raw material for biofuel production can be clearly seen. The way the credit for electricity export is calculated is explained in each individual pathway.

2.5 Managing uncertainties

As already presented in the introduction, the analysis of a certain process or pathway requires choices to be made and figures to be adopted on the basis of criteria that, even if logical and documented, always remain somewhat judgmental. Industry generally uses a range of processes which, at least historically, have not been selected based solely on their energy efficiency but mainly on economic grounds. So established production paths display a range of variability.

Whenever major contributions were at stake, different pathways have been created to directly show the effect of a particular option or view (e.g. the origin of natural gas has a strong influence on the total pathways through the transport contribution).

Moreover, as JEC study also deals with the future production and consumption of fuels and vehicles, and with new processes or improved existing ones, the future performances are necessarily somewhat speculative. As a result, each step in a pathway carries a certain variability range, representing the combination of the range of performance of the future installations and the uncertainty attached to the expected technical developments. Based on the quality of the available data, the degree of development of the process and any other relevant parameter, a judgement has been made as to the level of uncertainty attached to each figure as well as the probability distribution within the range. A Gaussian distribution has been used as default but also a “double-triangle” for asymmetrical ranges and an equal-probability or “square” distribution when there is reason to believe that all values in the range are equally probable.

In order to combine all uncertainties in a pathway and arrive at a plausible range of variation for the total pathway, the traditional Monte Carlo approach has been widely utilised; subsequent calculations have been carried out with the resulting figures.

2.6 Miscellaneous assumptions

In the following paragraph are described a set of common assumptions, widely used in the modelling exercise.

2.6.1 GHG coefficients

The CO_2 equivalence is applied to the non-CO_2 greenhouse gases according to the 100 year conversion coefficients recommended by the fourth assessment report of the Inter-governmental Panel for Climate Change AR4 [IPCC 2007a] in line with the European *Renewable Energy Directive* (RED II).

Table 6. Global Warming Potential (GWP) values for 100-year time horizon

Greenhouse gas	t CO_{2eq} / t
CO_2	1
Methane (CH_4)	25
Nitrous oxide (N_2O)	298

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

2.6.2 Energy content

All energy contents used are on LHV basis. For materials containing water (crops, animal feed, wood, manure, etc.), energy for drying has been considered.

2.6.3 Shipping

Many pathways include long-distance shipping of gases or liquids. In all such case published data have been used for a type of ship, consistent with the length of the envisaged trip and the material being carried. Such ships normally return empty and the corresponding fuel consumption has been taken into account through the so-called “Admiralty formula” according to which the fuel consumption of a ship is proportional to the cubic root of the water displacement. Details of shipping processes are given in sections 3.1.2, 3.2.2 and the associated workbooks.

For biofuel shipping, such as import of oilseeds, vegetable oils or ethanol from South America, ships are known to be partially loaded on the return trip. The same assumptions on the % loading on outward and return trips have been used as in the calculations as for the EU Renewable Energy Directive, which result in a somewhat higher overall loading than the average for such ships reported by the International Maritime Organization.

2.7 Time horizon

The time horizon of the study is likely to significantly impact on the results, especially referring to the considered assumptions made for medium-term; in the case of JEC WTT v5, the chosen time horizon is 2017-2025+. The technologies considered are those that have the potential to become commercially available in that time frame, although we added some new promising pathways, with a lower Technology Readiness Level (e.g. Power-to-fuel ones).

Since this study is forward-looking, we have assumed that new production facilities would use state-of-the-art technology to deliver the best technically feasible efficiency. Where efficiency is influenced by different design (and cost) choices, we have shown the effect of these choices through different scenarios. The figures may not reflect the performance of existing production facilities built using older technology. Statistical data are from 2016 for European electricity production and from 2017 for natural gas production.

2.8 Technology and Commercial Readiness Levels

The JEC WTT v5 explores the potential impact on both energy and GHG of a wide range of different commercially available as well as emerging/promising fuel pathways. To help the reader understand the current technology and market deployment of each of them, the present version of the JEC WTT v5 incorporates two new parameters for each individual pathway: the Technology Readiness Levels (TRL) and the Commercial Readiness Levels (CRL), reported at the beginning of each specific fuel/energy carrier sections.

2.8.1 Technology Readiness Levels

The Technology Readiness Level (TRL) is a parameter used to describe the estimated **maturity level** of a particular technology, which typically is used from tracking progress and supporting development through the early stages of the technology development chain (lower TRLs) to the final demonstration, and the subsequent commercial deployment (Higher TRLs). Initially developed by NASA in 1974, the 9-grade scale derived from the initial definition[18] applied in the H2020 Work programme 2014-2015 is used in the present JEC WTT report:

Technology Readiness Level: a 9-grade scale

(based on H2020 WP 2014/2015)

- TRL 1 – Basic principles observed.
- TRL 2 – Technology concept formulated.
- TRL 3 – Experimental proof of concept.
- TRL 4 – Technology validated in lab.
- TRL 5 – Technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies).
- TRL 6 – Technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies).
- TRL 7 – System prototype demonstration in operational environment.
- TRL 8 – System complete and qualified.
- TRL 9 – Actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space).

Based on this, different TRLs have been assigned to each individual pathway modelled by the JEC.

2.8.2 Commercial Readiness Levels

The Technology Readiness Level provides a good understanding of the technology risk, associated with the development of a certain technology and also for already developed technologies for which there is an intrinsic risk related to their commercial deployment. Among the analysed pathways, some could remain in the higher demonstration or deployment levels without being able to deliver fuels to the market, due to many of the multiple barriers (e.g. capital cost) encountered during the commercialization process.

In order to capture this uncertainty, the TRL of each specific pathway has been complemented with a 6-level scale additional index: The *Commercial Readiness Level* (CRL). CRL provides a picture of the current commercial deployment of a certain technology, based on the methodology developed by ARENA[19] [ARENA 2014].

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[18] https://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf

[19] https://arena.gov.au/assets/2014/02/Commercial-Readiness-Index.pdf

Commercial Readiness Level: a 6-grade scale

(based on ARENA 2014)

- CRL 1 – **Hypothetical commercial proposition**: Technically ready – commercially untested and unproven. Commercial proposition driven by technology advocates with little or no evidence of verifiable technical or financial data to substantiate claims.
- CRL 2 – **Commercial trial: Small scale**, first of a kind project funded by equity and government project support. Commercial proposition backed by evidence of verifiable data typically not in the public domain.
- CRL 3 – **Commercial scale up** occurring driven by specific policy and emerging debt finance. Commercial proposition being driven by technology proponents and market segment participants – publically discoverable data driving emerging interest from finance and regulatory sectors.
- CRL 4 – **Multiple commercial applications** becoming evident locally although still subsidised. Verifiable data on technical and financial performance in the public domain driving interest from variety of debt and equity sources however still requiring government support. Regulatory challenges being addressed in multiple jurisdictions.
- CRL 5 – **Market competition driving widespread deployment** in context of long-term policy settings. Competition emerging across all areas of supply chain with commoditisation of key components and financial products occurring.
- CRL 6 – "**Bankable" grade asset class** driven by same criteria as other mature energy technologies. Considered as a "Bankable" grade asset class with known standards and performance expectations. Market and technology risks not driving investment decisions. Proponent capability, pricing and other typical market forces driving uptake.

2.8.3 Integration: TRL and CRL

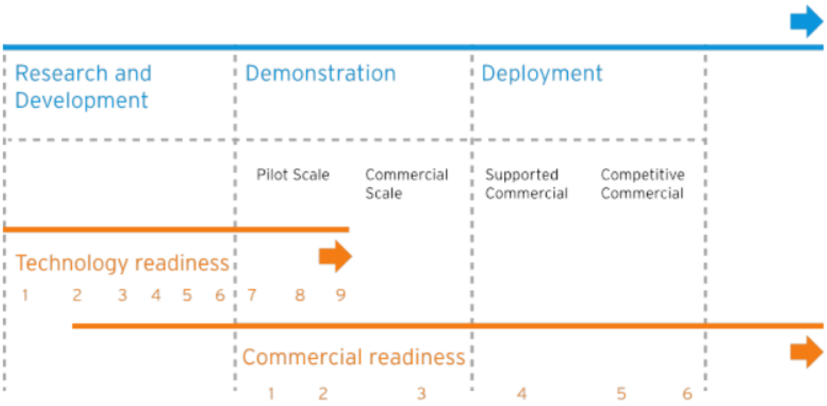
Both indexes offer a complementary and comprehensive view of the level of technical and commercial maturity for each specific technology pathway. However, the scales are not completely independent as technologies at the higher levels of technical development may already have some initial penetration in the market.

The following table summarizes the considered overlaps between TRL and CRL, to be used as a guidance to understand the *Technology Development Chain* that maps each individual pathway at the beginning of each specific fuel/energy carrier sections in this JEC WTT report:

Table 7. JEC WTT. TRL and CRL overlaps

TRL		CRL	
1	Basic principles observed.	N/A	
2	Technology concept formulated.	1	Hypothetical commercial proposition.
3	Experimental proof of concept.		
4	Technology validated in lab.		
5	Technology validated in relevant environment.		
6	Technology demonstrated in relevant environment.		
7	System prototype demonstration in operational environment.		
8	System complete and qualified.	2	Commercial trial, small-scale.
9	Actual system proven in operational environment.	3	Commercial scale-up.
		4	Multiple commercial applications.
		5	Market competition driving widespread development.
		6	Bankable asset class.

Figure 5. *Technology Development Chain* map



2.9 Results presentation

2.9.1 Where to find what in this report

The narrative part of this report is divided into two sections:

- Section 3 "*From resource to fuel*" where the answered question is "which fuel can be made from a given resource?" Here the steps or processes necessary to transform a resource into a number of final fuels are discussed, indicating the relevant assumptions and choices.
- Section 4 "*Final fuels*" where the answered question is "how can a given fuel be made?" The merits of the different routes from the points of view of energy and GHG balance are compared.

WTT_Appendixes

Complementing the main text, different detailed Appendixes have been created:

- Appendix 1. WTT individual workbooks (ZIP).
- Appendix 2. Conversion factors, fuel properties and input data.
- Appendix 3. Comparison versus JEC WTT v4.
- Appendix 4. Heat & Power. Inputs and Energy / GHG results.
- Appendix 5. ILUC/DLUC.
- Appendix 6. Contribution of construction materials.
- Appendix 7. Cost analysis on liquid biofuel pathways.

In **Appendix 1**, a series of Excel-based workbooks have been created: each pathway is described in detail including overall and stepwise energy and GHG balances and relevant processes with basic data input and literature references.

2.9.2 Units and conventions

The energy figures are presented as total primary energy expended, regardless of its origin, to produce one MJ_f of the finished fuel under study (LHV basis). The figures exclude the heat content of the fuel itself (i.e. 1 MJ/MJ_f means that as much energy is required to produce the fuel as is available to the final user) but include both fossil and renewable energy. As such, they describe the energy efficiency of the pathway. For fuels of renewable origin or including renewable elements (e.g. electricity) the total energy is based on the energy in the feedstock (wheat, oilseeds, wood etc). Fossil (and nuclear) energy expended in the pathway has also been evaluated, illustrating the fossil energy saving potential of that pathway compared to conventional fossil alternatives.

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

By contrast, input data indicated for each **process** generally are per **MJ of output of that process** which is only the finished fuel for the final process in the chain of the pathway. These figures are therefore not additive.

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

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

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

2.9.3 References

A complete list of references used in the study is included at the end of this document (Section 6). As far as possible, references are cited in their proper context in relation to a specific process and specific input data in the pathway workbooks rather than in the main text of this report.

2.9.4 Interpretation of WTT results

For illustrative purposes and through a selected example, the **Figure 6** summarises the calculations presented in this WTT report (fuel focus) and their integration with the TTW figures (powertrains) to produce the final WTW values.

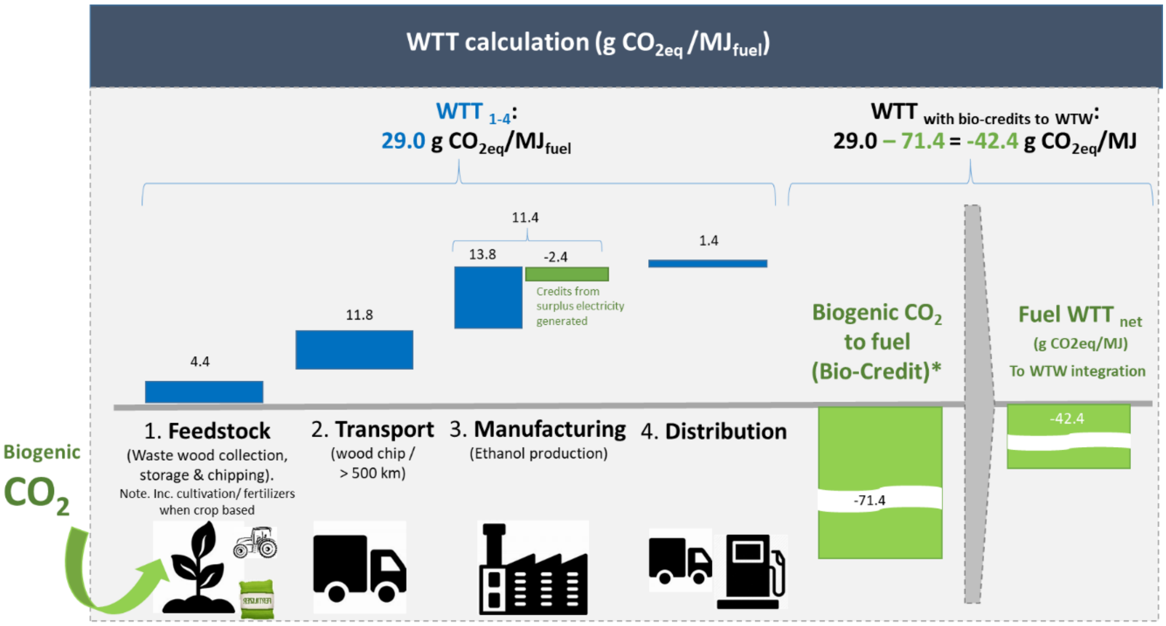
In JEC-WTT the emission associated with fuel production, all along the chain, are evaluated. For bio-derived feedstock, they encompass feedstock production, transport, pre-treating, fuel conversion and distribution, up to the tank of the vehicle.

Referring to the example in **Figure 6**, the WTT emissions account for 27 gCO_2/MJ of fuel. **These emissions represent the net emissions associated with the energy needed for the production of 1 MJ of such fuel**. Referring to the use stage, if this MJ of fuel were fully oxidised (burned with a theoretical 100% conversion efficiency), the CO_2 released would be equal to the CO_2 captured during the plant growth, and the net emission associated to this ideal combustion would result zero. This can be taken into account by defining a credit (e.g. referring to **Figure 6**: -71.4 gCO_{2e}/MJfuel), numerically equal to the CO_2 captured during the plant life.

As the real situation for fuel use is far from this theoritical case, when this MJ is used into a combustion engine, the vehicle conversion efficiency has to be taken into account.

From a numerical point of view, the credit is added to the net WTT emission, to have a suitable number for WTW integration e.g. referring to **Figure 6**: -44.5 gCO_{2e}/MJfuel). The conversion efficnecy in terms of MJ/100km is used to define the fuel (energy) needed per km. On the base of this consumption, it is calculated the CO_2 released from the all chain (WTT+TTW), considering the credit. The resulting emissions in WTW represent the sum of the emissions associated to the fuel production and distribution (WTT) plus the emissions of the conversion into the vehicle (TTW), by appliyng the credit for the CO_2 absorbed by the biomass feedstock (further details in the JEC WTW v4 report).

Figure 6. Schematic representation of JEC WTT GHG intensity calculation for fuel pathways and its use in the JEC WTW integration. Example. Wood based pathway (Ethanol – WWET1b)



(*) CO_2 released back to the atmosphere when 1 MJ of the fuel is totally combusted. Equivalent to the amount of CO_2 initially captured by the tree during the photosynthesis process (zero net effect)

Note. As explained, the WTT figures included in this JEC WTT report reflect the net energy requirement and related emissions required for the production of 1 MJ of fuel (WTT_{1-4} of the example above). In case of bio-based feedstocks, the bio-credits will be taken into consideration into the WTW calculations (where the impact of the combustion of the fuel in a specific engine is assessed).

2.10 RED II and JEC WTT

In November 2016, the European Commission published its 'Clean Energy for all Europeans' initiative. As part of this package, the Commission adopted a legislative proposal for a recast of the Renewable Energy Directive. During the co-decision procedure, a final compromise text among the EU institutions was agreed in June 2018. In December 2018, the revised Renewable Energy Directive 2018/2001/EU (RED II) entered into force.

It is worth noticing that, for pathways from biomass feedstock, the JEC WTT v5 study uses almost entirely the same input dataset used for defining the RED II 'default values'. The input data have been collected by EC-JRC and are available in the following link: http://data.jrc.ec.europa.eu/collection/id-0082.

- RED II - OVERALL TARGET

  In RED II, the overall EU target for Renewable Energy Sources consumption by 2030 has been raised to 32%. The Commission's original proposal did not include a transport sub-target, which has been introduced by co-legislators in the final agreement: Member States must require fuel suppliers to supply a minimum of 14% of the energy consumed in road and rail transport by 2030 as renewable energy.

- SUSTAINABILITY CRITERIA

  RED II includes a set of sustainability and GHG emission saving criteria that biofuels, bioliquids and biogas used in transport must comply with to be counted towards the overall 14% target and to be eligible for financial support by public authorities. Some of these criteria are the same as in the original RED, while others are new or reformulated. In particular, RED II introduces sustainability for forestry feedstocks as well as GHG emission saving criteria for solid and gaseous biomass fuels.

  Default GHG emission values and calculation rules are provided in Annex V (for liquid biofuels) and Annex VI (for solid and gaseous biomass for power and heat production) of RED II. The Commission can revise and update the default values of GHG emissions when technological developments make it necessary. Economic operators have the option to either use default GHG intensity values provided in RED II or to calculate actual values for their pathway.

Table 8. Greenhouse gas savings thresholds in RED II

Greenhouse gas savings thresholds in RED II			
Plant operation start date	Transport biofuels	Transport renewable fuels of non-biological origin	Electricity, heating and cooling
Before October 2015	50%	-	-
After October 2015	60%	-	-
After January 2021	65%	70%	70%
After January 2026	65%	70%	80%

Sustainability criteria include criteria protecting land with high biodiversity value and land with high-carbon stock resulting from direct land use change, but do not cover the issue of indirect land-use change (ILUC). The ILUC issue refers to the global market-mediated agricultural area expansion in response to the increased biofuel demand. If crops grown on existing arable land are used to make biofuels and are diverted from food and feed production, then the gap in the food supply will be partly filled by the expansion of cropland, because of the necessity to replace the food production. This is referred to as **indirect land use change (ILUC)**. The expansion may happen in areas with high carbon stock such as forests, wetlands and peatlands. The magnitude of ILUC emissions is capable of negating some or all greenhouse gas emissions savings of individual biofuels, bioliquids or biomass fuels. In order to address the ILUC issue, RED II sets limits for the share of biofuels, bioliquids, and biomass fuels produced from food and feed crops (maximum 7% of final consumption in the road and rail transport sector in a Member State). In addition, the share of high ILUC-risk biofuels, bioliquids or biomass fuels produced from food and feed crops for which a significant expansion of the production area into land with high-carbon stock is observed shall not exceed the level of consumption of such fuels in that Member State in 2019 (for the period 2021-2023), which will gradually decrease from the end of 2023 to zero by 2030. Exemptions from these limits apply for certified low ILUC-risk biofuels, bioliquids or biomass fuels.

For the implementation of this approach, as required by the directive, the Commission has adopted the Delegated Regulation (EU) 2019/807, and published an accompanying report [COM(2019)142] on the status of production expansion of relevant food and feed crops worldwide, based on the best available scientific data. The delegated act sets out specific criteria both for:

- determining the high ILUC-risk feedstock for which a significant expansion of the production area into land with high carbon stock is observed; and
- certifying low ILUC-risk biofuels, bioliquids and biomass fuels.

See also **Appendix 5** for more details. Results from JEC WTT v5 cannot be directly compared to the values published in the Renewable Energy Directive recast (2018/2011/EU, RED II). Despite the JEC WTTv5 study substantially shares the input data used for RED II, as provided by EC-JRC, some methodological approaches strongly differ, such as the co-products allocation.

3 From Resource to Fuel: production routes

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

3.1 Crude oil pathways

(See also workbook WTT v5 pathways 1-Oil and gas)

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

Summary

Changes vs Version 4

Significant update on the existing fuel pathways (Crude oil)

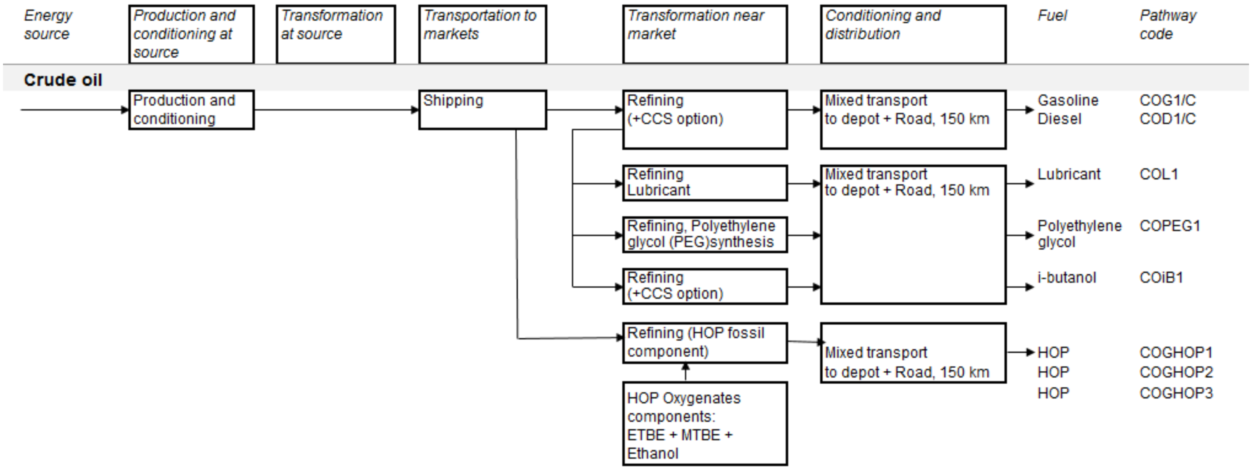
COD1 & COG1 - *Updated literature/data source* The energy and GHG values of crude oil extraction and transport have been updated based on the recent data and literature ([ICCT 2014], [Exergia et al. 2015]). The energy and GHG values for crude oil refineries for the production of gasoline and diesel have been updated based on recent data and literature [Concawe 2017].

Newly added fuel categories and pathways

Lubricant (COL1), PEG (COPEG1) and Oxo i-butanol (COiB1) which are admixtures to Ethanol in ED95 production.
COD1C & COG1C - *Additional feature* CCS addition to the conventional diesel and gasoline production (C indicates CCS).
New High Octane gasoline (*HOP*) pathways: COGHOP1 (HOP 100 / 3.4% bioenergy (E5eq), COGHOP2 (3.4% bioenergy (E5eq)), COGHOP3 (HOP 102 / 6.5% bioenergy (E10eq)).

Addition of TRL and CRL

Figure 7. Conventional fossil fuels pathways (crude oil based)



Summary (Cont.)

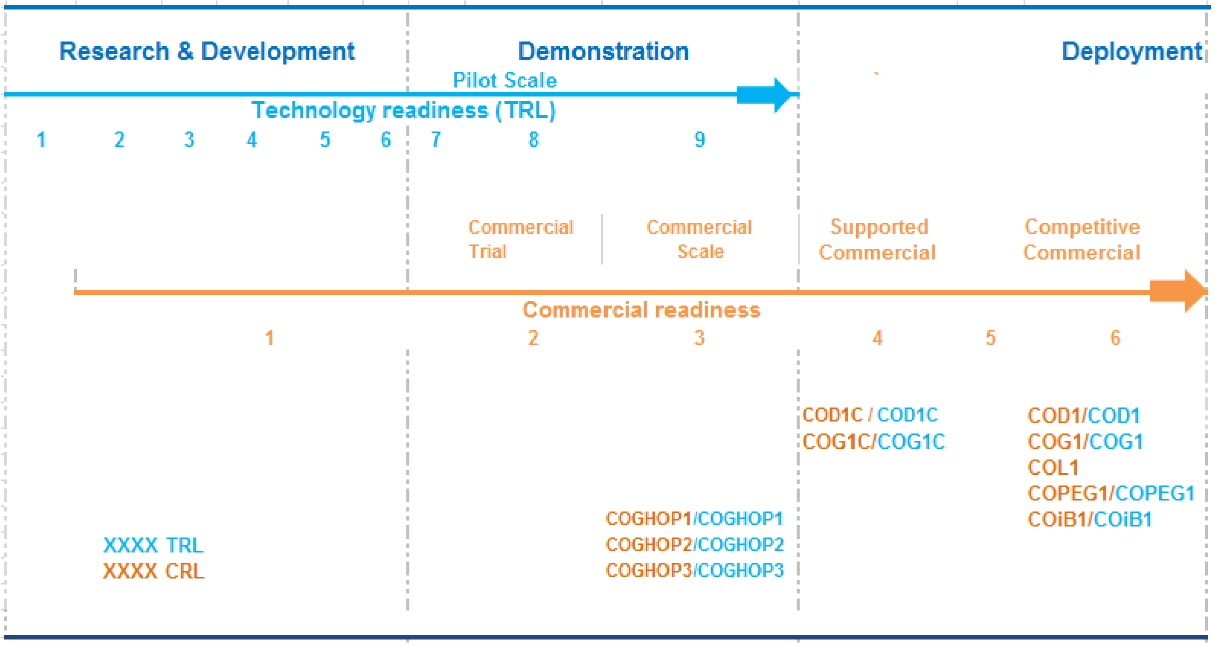


Figure 8. Fossil fuels Pathways TRL/CRL

3.1.1 Crude oil production and conditioning at source

a) The regional component

Crude oil is a worldwide commodity. Although most grades are traded on a wide geographical basis, consuming regions tend, for logistic and geopolitical reasons, to have preferred supply sources. The favourable geographic location of Europe in relation to light and sweet crude producing regions (North Sea, North and West Africa) has resulted in a fairly light crude diet in the past two to three decades.

Crude oil is generally extracted under the natural pressure of the underground reservoir. In some, mostly older, fields it may be necessary to boost the reservoir pressure by gas injection. In most cases oil is associated with gases and needs to be stabilised before shipment. Water separation is also sometimes required. Significant flaring still occurs in certain producing countries, and satellite data estimates from 2015 [World Bank] show that Russia, Iraq, Iran, the United States, Venezuela, Algeria, and Nigeria are the seven largest flaring countries, contributing to 59% of the world's total flaring. Based on the US Energy Information Agency (EIA), 4306 billion cubic meters (bcm) of gas was produced from gas fields and oil fields (associated gas) in 2014 (latest available data) from which around 145 bcm flared. Overall, the EIA estimates that, in 2012 (latest data available), 15% of associated gas production was flared or vented, 58% re-injected and 27% utilized (EIA) for both natural gas and oil reservoirs. At each production site, flared gas is often of relatively small volume and with an unstable production profile, making its use difficult. However, Worldwide, flaring represents around 4% of the total gas produced and several international programmes such as the *Zero routine flaring by 2030* initiative introduced by the World Bank (WB) aim to bring together governments, oil companies, and development institutions to cooperate to eliminate routine flaring in Upstream activities no later than 2030.

As alternative uses for the associated gas, the WB list a number of potential options depending on the regional circumstances of each oil/natural gas field: re-inject the flared gas into the oil reservoir to enhance oil recovery (EOR), use it for on-site electricity self-generation or convert/transport it as a fuel (either as LNG after liquefaction or after conversion into liquid fuels (e.g. synthetic oil, diesel, methanol, DME by using gas-to-liquid (GTL) technologies).

Regarding the origin of the oil, conventional oil sources are expected to meet all of Europe’s crude oil needs during the period covered by this study. In Europe, production in Norway is expected to increase to 2025 mainly due to the giant Johan Sverdrup field but afterwards, it will not be enough to offset a general decline in the European oil production [IEA WEO 2018]. However, new sources of **offshore oil** are expected to come to production in the coming years. As mentioned by the International Energy Agency [WEO 2018], new discoveries of deepwater fields, especially in the areas of Brazil and Mexico, are expecting to come to production around 2020. Enhance oil recovery (EOR) technologies are also foreseen as opportunities to increase production in mature basins, expected to rise slowly to 2025 and accelerate afterwards [IEA 2018].

Regarding unconventional oils, **tight oil production** in the United States is expected to double by 2025 but reaching a plateau in the min-2020s, declining afterwards. However, this trend is partially offset by tight oil growth outside mainly in countries such as Argentina, Russia, Canada and Mexico [IEA WEO 2018].

Substantial deposits of **heavier oils** also exist, notably in Canada and Venezuela. Canada's reserves of oil sands are large and situated almost entirely in Alberta (170 billion barrels of crude oil reserves where oil sands represent the main part), already being exploited, almost exclusively for the US and Canadian markets, either by mining or *in situ* projects. Multiple new projects have been approved in Canada although there is some uncertainty of whether additional pipeline capacity will be available at the end of the 2035 period. If these constrains are overcome, the total oil production is expected to increase to 5.6 Mbbl/d by 2035 (oil sands production accounting for 75% reaching 4.2 Mbbl/d by 2035 compared to 2.6 Mbbl/d in 2017) [CAPP 2018]. Venezuela is also a relevant oil producer with the world's largest crude oil reserves (~300 billion bbl) [OPEC 2017] most of which (~>85% depending on different scenarios) are linked to very large deposits of heavy oils. These are located at depths where surface mining techniques are not practical, and so far they have not been developed in a major way.

In Canada, **oil sands** are concentrated in the Athabasca region of northern Alberta and can be exploited in two ways. Firstly, bitumen, which exists in solid or semi-solid state can be extracted in-situ using steam or solvents. Alternatively, the oil-containing sand can be extracted by surface mining, followed by treatment to separate the oil and treat it in a coker or hydrotreater to produce a light synthetic crude. Some of this is further processed locally, but much is distributed by pipeline to refineries in Canada, the USA and further afield. Oil sand exploitation is contentious because of the effects of large scale mining, and concerns about air and water pollution as well as the large energy inputs and associated GHG emissions needed to produce and process the fuel. Efforts are continuing to reduce the environmental impact. Whether bitumen is separated from sand in-situ or the oil-sands are mined and processed together, the combined process of extraction and processing is more energy intensive than for conventional crude oil. Heavier oils tend to contain more carbon as a percentage than conventional fuels, so processing to a similar product slate requires more hydrogen. In Canada, most of the energy input is in the form of natural gas. Electricity may either be imported or produced on-site, and may include co-generation producing an excess of electricity for export.

Figures for **Venezuelan** unconventional oil reserves are expected to be broadly similar, but will depend on the details of the extraction and processing processes. Where the oils are more fluid, extraction will be easier and heating may not be needed in all cases, which would reduce energy needs. Venezuela has extensive natural gas reserves, so the GHG figures should also be similar to those for Canada (around 23.74 g CO_{2eq}/MJ estimated for Venezuela unconventional extra heavy crude oils (Petrozuata) vs 23.83 g CO_{2eq}/MJ for bitumen from Alberta oil sands (based on the Oil Production Greenhouse gas Emissions Estimator [OPGEE] from Stanford University). Large amounts of oil also exist in shale rock formations, and US reserves alone could be as much as the world conventional oil resources. However, recovery of the oil is energy intensive and so far these resources have been less widely exploited.

b) New approach: WTT v5 (OPGEE model)

As described above, the upstream contribution to the WTW intensity of conventional (fossil-based) gasoline or diesel could range from **5 up to 10**%. However, the difficulty of estimating numbers related to the upstream emissions is high due to two major issues:

- Data availability at oil field:

  The lack of reliable public information per individual oil field is significant and assuming one single number representative of the whole country is misleading since the efficiency of the operations and the behaviour of the oil field could significantly impact the CO_2 intensity of the crude oil extraction and production processes.

- Variety of the diet of crude oil per refinery (diet potentially based on a trading scheme including both permanent contracts as well as on-the-spot operations depending on the specific refinery).

Due to these factors, this version of the JEC WTT report uses average numbers for the crude oils being processed in Europe based on a detailed study conducted by ICCT together with the Stanford University, Energy Redefined and Defense Terre [ICCT 2014]. The aim of the EU COM led project was to estimate the *Upstream Emissions of Fossil Fuel Feedstocks for Transport Fuels* and the final paper presents the results of several studies on the EU crude oil market, a model for lifecycle analysis of crude oil extraction (OPGEE model) and provides an estimate of the carbon intensity of oil supplied to the European Union in 2010 (latest consistent data set available).

The centrepiece of the project is the ‘***Oil Production GHG Emissions Estimator’***, or OPGEE model which is an open-source, fully public engineering-based model of GHG emissions from oil production operations.

The model OPGEE initially developed by Stanford University is a predictive tool which allows estimation of the *carbon intensity* (CI) and energy consumption associated with the production of oil in a certain reservoir. It is based on the publicly available data per individual oilfield using as inputs both the characteristics or the reservoir (e.g. age, field depth, oil production volumes) and the field operation. Regarding the latter, OPGEE models the production, processing and transport of crude petroleum considering seven process stages:

- Exploration, drilling and development.
- Oil production and extraction including fluid production and injection, bitumen mining, maintenance and workovers (Flaring, venting and other fugitive emissions are also reported/estimated per oil field as part the crude oil production operation).
- Surface processing (crude separation and handling, crude storage, bitumen upgrading or dilution) waste treatment and disposal.
- And the final transport of the crude to the refineries.

Table 9. Public data sources currently referenced in OPGEE Model [ICCT 2014].

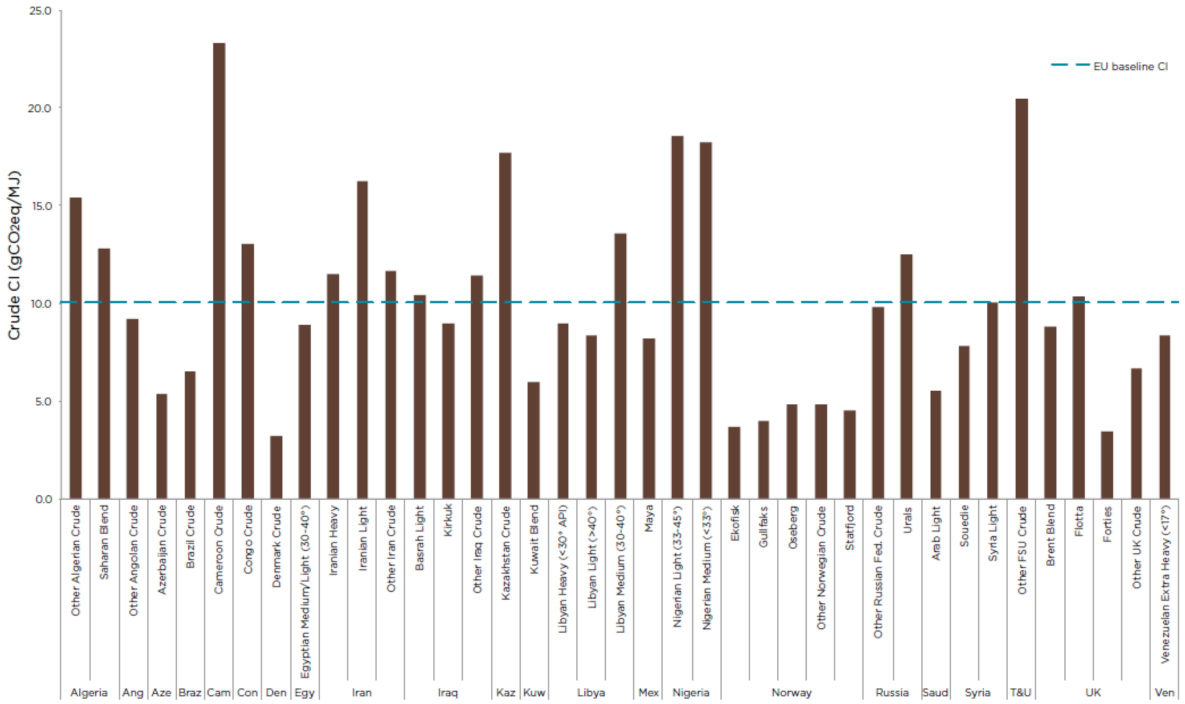
SOURCE	REFERENCED INFORMATION
GREET	Emissions Factors: Boilers/Heaters, Turbines, Reciprocating Engines, and Flaring with 0.2% Non-combustion
	Fuel Cycles and Displaced Systems for Natural Gas
	Ocean Tanker/Pipeline Transport
	Fuel Specifications (Liquid Fuel Heating Values)
Caterpillar, Inc.	Technical Sheets for Oil and Gas Engines
General Electric (GE)	Technical Sheets for Electric Motors
EIA	Country-Specific Crude Oil Production
NOAA	Country-Specific Flaring Volumes

Note. The user guide, with the description of the main input parameters, can be found in the following link: https://www.arb.ca.gov/regact/2011/lcfs2011/opgee_userguide.pdf

In order to determine the average energy/CO_2eq intensity value of crude oils used in Europe, the list of crudes consumed in Europe published by DG Energy (2010) is used as the starting point. For each field, based on location, API and information from the *Crude Information Management System* (CIMS) database, every crude stream is allocated to the field which would most likely be feeding from (with important caveats around this assumption as it is not possible to directly determine from the DG Energy data exactly which fields have supplied Europe). Then the average carbon intensity of the EU baseline is calculated from the field specific carbon intensities (OPGEE tool):

- Firstly, each oilfield in the Baseline is associated with a particular crude from the DG Energy reporting.
- Having assigned CIs to each individual crude, these are used to estimate the average carbon intensity of crude supplied in Europe in 2010 overall. This is done by taking the average CI across all DG Energy identified crudes (calculated by OPGEE based on some key parameters of every single oilfield, assuming default values when unknown), weighted by their contribution to the EU crude slate.

Figure 9. Crude carbon intensities grouped by country compared to EU baseline [ICCT 2014]



However, due to the lack of information available per oil field, some default values are assumed in order to calculate the CI value for the field and they highlight that any change in those default parameters may have a huge impact on the energy consumption and GHG intensity. Despite having analysed 265 fields all over the world, it is explicitly noted in the report that "*additional consultation and data collection from industry would allow this result to be confirmed, or the value to be improved and made more representative of the actual crude used in European refineries. […] While the emissions are still relatively high in all cases, there is substantial uncertainty about the precise value. […] Within a* regulatory *framework, a hybrid reporting system (or other system allowing data reporting) would enable producers to provide data and ensure that they would not be unduly penalized because the OPGEE defaults did not reflect their fields. […]*".

Despite the limitations on the data available and the OPGEE model, most likely overestimating the energy consumption associated to the EU average crude slate, the JEC have decided to align our results to the ones published in this study based on the most up-to-date available data. Therefore, the updated oil upstream value (without including the oil transport stage) is **9.0 g CO_{2e}/MJ crude**.

This value is used in all related pathways of the present JEC WTT v5 study as the intensity for the oil production stage (also aligned to what a DG CLIMA-led consortium presented as inputs for their *Study on actual GHG emissions for diesel, gasoline, kerosene and natural gas [COM Upstream 2015]*).

3.1.2 Crude oil transportation to markets

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

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

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

According to [Exergia et al. 2015] for the transport of crude oil to crude oil refineries in the EU the primary energy use is indicated with about 0.008 MJ per MJ of transported crude oil, corresponding to about 0.7 g CO_{2eq}/MJ.

3.1.3 Crude oil refining

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

An oil refinery is a complex combination of process plants, the objective of which is to turn crude oil into marketable products of the right quality and in the right quantities simultaneously from a single feedstock. This entails

- Physical separation of the crude components.
- Treating to remove such compounds as sulphur.
- Conversion of mainly heavy molecules into lighter ones to match the production slate to the market demand.

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

Refinery operation is characterized by multiple real constraints arising from feedstock supply, product demand (quantity and quality) and process unit limitations. Yet, there are multiple options of adjusting the operation and the refining scheme within the given constraints to supply a certain demand with the maximum profit or minimum costs. The tool used by refiners worldwide to optimize the complex system is a mathematical technique known as Linear Programming (LP).

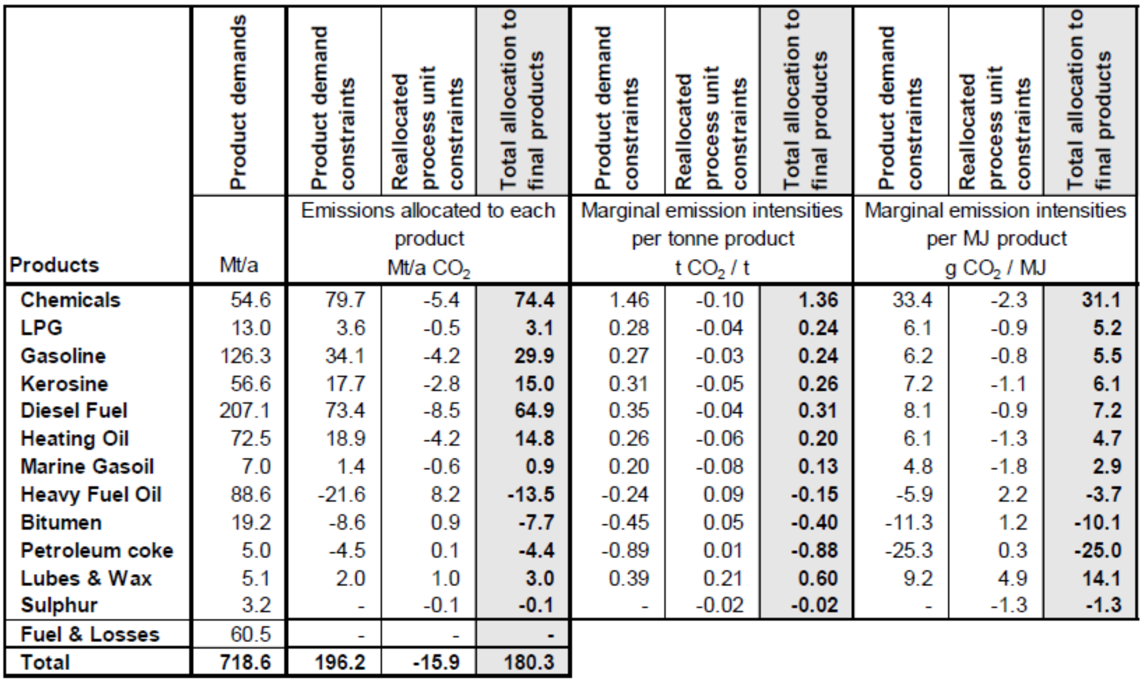
Whereas the total amount of energy (and other resources) used by refineries is well documented, there is no simple, non-controversial way to allocate energy, emissions or cost to a specific product as they are produced simultaneously through a combination of interrelated processes. Distributing the resources used in refining amongst the various products invariably involves the use of allocation rules that can have a major influence on the results. Although allocation methods are often used for lack of better tools, in order to better account for the complex interactions, constraints and synergies within a refinery and also between the different refineries in a certain region we have used an integrated regional refinery model to capture these interactions.

In order to estimate the savings from substituting conventional fuels, the question to consider is what primary energy and GHG can be saved by using less conventional fuels rather than how much energy/GHG emissions are associated with producing fuels today. In the context of this study, we thus considered that the energy and GHG emissions associated with the production and use of conventional fuels should be representative of how the EU refineries would have to adapt to a marginal reduction in demand. Such figures were obtained through modelling of the EU-wide refining system and a new methodology developed by Concawe [Concawe 2017] that utilises the specific features of the Linear Programming (LP) technique to model refineries to produce a consistent set of CO_2 intensities for all refinery products (see more details in in Concawe report 1/17).

As part of the LP model solution, a marginal emission value (in tonnes of CO_2 per unit of each constrain) is generated for any constrain that has a bearing on CO_2 emissions. By design of the LP model, the sum of all marginal emission values multiplied by the value of each respective constraint is equal to the total tonnes of refinery CO_2 emissions, thereby fulfilling the additivity criterion required for *Life Cycle Assessments*. The model can be adapted for the purpose of this study in such a way that the only constraining variables are product demand and process unit capacities allowing a unique allocation of CO_2 emissions associated with process unit capacities to final products. In this way, the new methodology captures differences in refining CO_2 intensities between products due to the level of processing for each product type (e.g. more conversion or more stringent quality specifications) ensuring at the same time that the sum of all CO_2 emissions related to each individual refining product will be exactly equal to the total emissions of the EU refining system.

The full set of product CO_2 intensities is summarized in the following table:

Table 10. Marginal emission intensities (g CO_2) per MJ products used in the JEC WTT v5 report [Concawe 2017]



	Product demands	Product demand constraints	Reallocated process unit constraints	Total allocation to final products	Product demand constraints	Reallocated process unit constraints	Total allocation to final products	Product demand constraints	Reallocated process unit constraints	Total allocation to final products
Products	Mt/a	Emissions allocated to each product Mt/a CO_2			Marginal emission intensities per tonne product t CO_2 / t			Marginal emission intensities per MJ product g CO_2 / MJ		
Chemicals	54.6	79.7	-5.4	**74.4**	1.46	-0.10	**1.36**	33.4	-2.3	**31.1**
LPG	13.0	3.6	-0.5	**3.1**	0.28	-0.04	**0.24**	6.1	-0.9	**5.2**
Gasoline	126.3	34.1	-4.2	**29.9**	0.27	-0.03	**0.24**	6.2	-0.8	**5.5**
Kerosine	56.6	17.7	-2.8	**15.0**	0.31	-0.05	**0.26**	7.2	-1.1	**6.1**
Diesel Fuel	207.1	73.4	-8.5	**64.9**	0.35	-0.04	**0.31**	8.1	-0.9	**7.2**
Heating Oil	72.5	18.9	-4.2	**14.8**	0.26	-0.06	**0.20**	6.1	-1.3	**4.7**
Marine Gasoil	7.0	1.4	-0.6	**0.9**	0.20	-0.08	**0.13**	4.8	-1.8	**2.9**
Heavy Fuel Oil	88.6	-21.6	8.2	**-13.5**	-0.24	0.09	**-0.15**	-5.9	2.2	**-3.7**
Bitumen	19.2	-8.6	0.9	**-7.7**	-0.45	0.05	**-0.40**	-11.3	1.2	**-10.1**
Petroleum coke	5.0	-4.5	0.1	**-4.4**	-0.89	0.01	**-0.88**	-25.3	0.3	**-25.0**
Lubes & Wax	5.1	2.0	1.0	**3.0**	0.39	0.21	**0.60**	9.2	4.9	**14.1**
Sulphur	3.2	-	-0.1	**-0.1**	-	-0.02	**-0.02**	-	-1.3	**-1.3**
Fuel & Losses	60.5	-	-	**-**						
Total	**718.6**	**196.2**	**-15.9**	**180.3**						

Note
(1) The negative CO_2 intensity values for heavy products are due to the marginal nature of the methodology reflecting the fact that demand for heavy products reduces the need for conversion of the original crude oil barrel to lighter products (See more details in Concawe report 1/17).
(2) It has to be noted that:

- The figures generated through this method are strictly only valid for the given set of base conditions (Base scenario) defined in the Concawe 1/17 report. Different base cases would correspond to different distribution of marginal CO_2 intensities between products. For the same reasons, the figures generated for the EU system as a whole cannot be applied to individual refineries with specific configuration, feedstocks and product demands. This is a generic statement regardless the marginal or average methods chosen.
- Since this methodology is based on a marginal analysis, the resulting marginal CO_2 intensity figures for refining should only be used in consequential LCAs.

It is important to remark that this methodology is consistent with the substitution methodology used for accounting for co-products in other pathways. Both arise from the over-arching principle of a marginal calculation which estimates the difference in emissions between a reference scenario and one with a small change in output of the fuel in question. In the case of the oil refinery calculation, the production of co-products has been kept constant. This means that no substitutions need to be made for co-products, because they cancel out when we take the difference between the two scenarios. The only changes we assume are the diesel (or gasoline) output, and the inputs of crude oil, gas and electricity.

To be noted that this set of data was based on a study case representing EU refining in 2010 in terms of refinery capacities, refinery energy intensity, feedstock availability, import/export opportunities, product demand and total CO_2 emissions. Further changes to the EU refining environment are expected beyond 2010 related to quality changes of non-road fuels (mostly marine fuels) and changes in the global EU demand which will impact on future EU refining constrains. However, the European system is expected to be able to further adapt and de-constrain future bottlenecks in the system and, therefore, for the purpose of this study, the same set of CO_2 intensity values have been considered across the whole timeframe of the analysis (2025/2030) acknowledging that, significantly different base cases and model constrains would correspond to different total CO_2 emissions and different distributions of marginal CO_2 intensities between products.

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

3.1.4 Gasoline and diesel fuel distribution

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

The total average figure for Europe is estimated at 20 kJ and just over 1 g CO_{2eq} per MJ of delivered fuel. These figures can reasonably be assumed to be independent of the volumes concerned.

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

3.1.5 High octane gasoline (HOP)

In this version of the JEC WTT report, the production of different gasoline grades with higher RON within the European refining system has been explored based on an about-to-be-published Concawe report. Three different pathways are presented in our WTT report:

1. **COGHOP1**: 100 RON gasoline: 3.4 energy% equivalent[20] to an average E5 grade.
2. **COGHOP2**: 102 RON gasoline with lower oxygenates level equivalent to E5 as (1).
3. **COGHOP3**: 102 RON gasoline with higher oxygenate levels, 7.3 energy% equivalent to E10 grade.

The cases explored are summarized below:

Table 11. Details of HOP cases included in JEC WTT v5 report

Composition, % energy eq vs E5 / E10 grade	***ETBE***	***MTBE***	***Ethanol***	***Fossil gasoline***
COGHOP1	2.3%	3.2%	2.5%	92.0%
COGHOP2	2.3%	5.4%	2.5%	89.8%
COGHOP3	2.3%	0.9%	5.7%	91.1%

- HOP would be a blend of fossil gasoline and diferent proportions of oxygenates (ETBE, MTBE and Ethanol).
- For comparision purposes, conventional (fossil based) gasoline and its related CO_2 intensity have been used as detailed in the Crude Oil refining section (Section 3.1.3).
- As an illustrative case, a 2030 case has been explored where 50% of the demand of gasoline is satisfed by High Octane gasoline (HOP) while the remaining 50% being RON 95 grade.

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[20] Ethanol content in 95/98 grades in EU: Concawe estimate based on Wood Mackenzie data, elaborated from Eurostat (2018).

Therefore, the final HOP carbon and energy intensity value would be the mix between its different components.

(a) Fossil gasoline component:

Through the Linear Programming (LP) techique, the impact of the production of in terms of total CO_2 emissions for the EU refining system have been estimated when producing each grade of gasoline (to be blended with oxygenates to produce the final HOP). The changes in the CO_2 refining-related emissions are directly allocated to the fossil gasoline component to the different HOP cases. The Crude oil well-to-gate component as well as the transport of the gasoline-to-gate intensities have been assumed to be the same as the regular gasoline (COG1 pathway).

(b) Oxygenate pathways considered for the HOP:

- ETBE pathway based on bio-ethanol (**LRBE1** - ETBE from *wheat ethanol*).
  No 100% bio-ETBE considered for the purpose of this study as bio isobutene may be available in the long term but in a limited quantity for the timeframe of this study.
- MTBE: **GRMB1** from natural gas as representative of non-bio oxgygenates.
- Ethanol: **WTET5** from wheat has been chosen for consistency with the EBTE pathway.

3.2 Natural gas pathways

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

Natural gas (NG) is the most plentiful fossil fuel after coal. It is available in most regions of the globe although there are a few very large producing regions such as Russia and, potentially, the Middle East. Only a relatively small part of the known reserves of natural gas is currently exploited. This is partly the result of the relative difficulty to bring natural gas to market when it originates from isolated areas. The exploitation of a natural gas field requires a heavy associated infrastructure in the form of either pipelines or liquefaction equipment and LNG ships. The real availability is therefore limited more by the realisation of projects to develop new fields and transportation systems than by the physical reserves. In recent years the option of turning natural gas into liquids (such as methanol, DME or Fischer-Tropsch fuels) has become a potentially viable option particularly for the most remote locations and new related pathways have been added to this WTT v5 to compare them versus other alternatives.

Summary

Changes vs Version 4

Natural gas pathways

Significant update on the existing fuel pathways (Natural gas)

GPCG1a - Change in assumptions and updated literature. The significant change originates from the transport to the market stage, because the assumed transport distance of gas from western Siberia has changed significantly from the previous version. According to actual GEMIS data the transport distance for natural gas transported via pipeline amounts to 5000 km from the natural gas fields in Siberia to central EU. According to [Thinkstep 2017] the distance for natural gas transport via pipeline amounts to about 4300 km from natural gas fields to EU border (average of 3 corridors to the EU border). Therefore, it has been assumed that the natural gas is transported over a distance of 4300 km to the EU border, from there over a distance of 700 km to central EU where the natural gas is distributed over a distance of 500 km via the high pressure pipeline grid, and then distributed via the local pipeline grid (10 km) to the fuel refuelling stations.

GRCG1, GRCG1C, GRCG2 & GRLG1 - Updated literature. The inventory data for transformation at source (i.e. Liquefaction) and long distance sea transportation have been updated based on recent literature sources. The distance for maritime LNG transport has changed from 5,500 nautical miles to 4,000 nautical miles based on data from NVGA (mix of transport distances for LNG delivered to the EU). For the natural gas liquefaction plant the electricity consumption indicated in [Ott et al. 2015] for state-of-the art plants has been used.

Newly added fuel categories and pathways

GMCG2a - EU-mix natural gas supply including 10% LNG (mix of pathway GMCG1 and GRCG1 – See description of the pathways in Section 4.5.2.1).

GMCG2b - EU-mix natural gas supply including 18.9% LNG and 3.4% bio-CH4, 40% of the bio-CH4 is derived from organic waste, 20% from manure, and 40% from energy crops.

Addition of TRL and CRL

Natural gas to fuel pathways (Hydrogen)

Significant update on the existing fuel pathways (Natural gas)

GMCH1: EU-mix piped natural gas supply, transport to EU by pipeline over a distance of 1900 km to EU border + 500 km inside EU.

GPCH1a, GPCH2a: The significant change originates from the transport to the market stage, because the assumed transport distance of gas from western Siberia has changed significantly from the previous version. According to actual GEMIS data the transport distance for natural gas transport via pipeline amounts to 5000 km from the natural gas fields in Siberia to central EU. According to [Thinkstep 2017] the distance for natural gas transport via pipeline amounts to about 4300 km from natural gas fields to EU border (average of 3 corridors to the EU border). Therefore, it has been assumed that the natural gas is transported over a distance of 4300 km to the EU border, from there over a distance of 700 km to central EU where the natural gas is distributed over a distance of 500 km via the high pressure pipeline grid (in case of onsite steam reforming (GPCH1a) 10 km via the local natural gas grid).

Summary (Cont.)

Changes vs Version 4

GRCH1, GRCH2, GRCH3: The inventory data for transformation at source (i.e. Liquefaction) and long distance sea transportation have been updated based on recent literature sources. The distance for maritime LNG transport has changed from 5,500 nautical miles to 4,000 nautical miles based on data from NVGA (mix of transport distances for LNG delivered to the EU). For the natural gas liquefaction plant, the electricity consumption indicated in [Ott et al. 2015] for state-of-the art plants has been used.

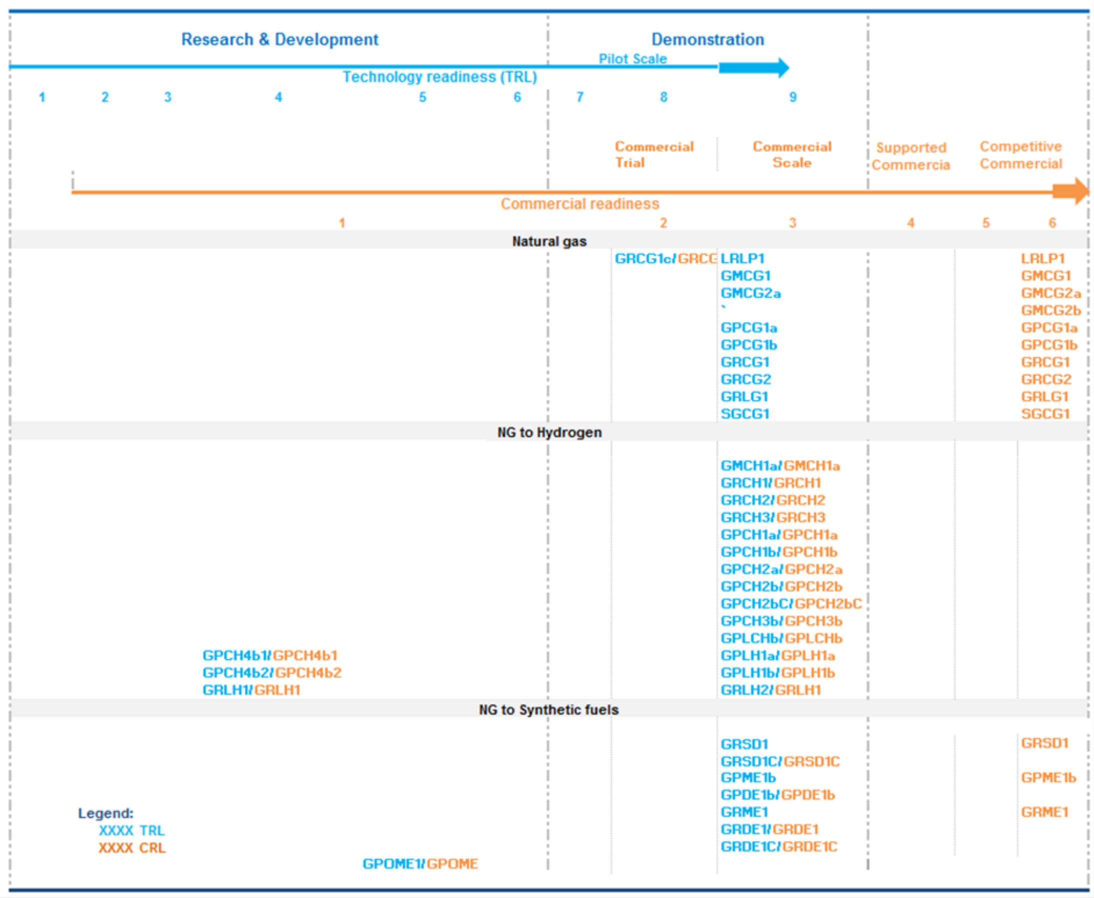
Newly added fuel categories and pathways

Hydrogen: GPCH4b1, GPCH4b2 (Methane cracking: liquid metal route / Pyrolysis).

Synthetic fuels: GPOME (OME from NG).

Addition of TRL and CRL

Figure 10. Natural gas Pathways TRL/CRL



So far NG has been almost exclusively used in stationary applications, mainly in domestic heating, industrial fuel and electricity production. Use of NG as road fuel (in the form of compressed natural gas or CNG) has been limited to specific markets although different recent papers foreseen a more relevant role [NGVA webpage]. NG use for power generation has increased in the EU and when used in a Combined Cycle Gas Turbine (CCGT), power plant NG can produce electricity with a much higher efficiency than using solid or liquid fuels. This factor combined with the favourable C/H ratio of natural gas compared to coal or oil, makes attractive to replace coal or heavy fuel oil by natural gas when targeting CO_2 emissions.

The sections below address the use of natural gas as fuel. More details regarding natural gas for heating or electricity generation can be found in **Appendix 4)**.

3.2.1 Natural gas supply in the EU

The EU is a significant gas producer, mainly from the Netherlands and the UK (North Sea) with smaller productions in Denmark, Germany, Italy and Romania (Note. UK included in this version of the JEC as part of Europe as figures were calculated before Brexit). Demand, however, far outstrips domestic production leading to substantial imports. Domestic production has been declining and is set to continue shrinking so that imports represent an ever increasing proportion of total consumption. Imports are mostly from Norway, Russia and North Africa via long-distance pipelines.

In recent years, LNG imports have become significant opening opportunities for new supply sources in Africa and the Middle East.

Table 12. EU-27 Natural gas balance (bcm, billion m^3)

Year	2005	2011	2017
Gross domestic consumption	511	466	483
Domestic production	218	161	124
Net Import	293	305	359
% of consumption	*57%*	*65%*	*74%*

Source: [Eurostat 2007]; [Eurostat 2014; [Eurostat 2019] Energy balances.

Note. See section 1.1.5. for more details regarding the current and future European mix (including imports and LNG contribution).

The current statistics show how the share of NG imports has increased in the latest years. Therefore, in the second and third decades of this century, we have assumed that any extra supplies to Europe will most likely come from either the Middle East or the FSU. Bringing this gas to Europe will involve either new pipelines or LNG schemes. We have therefore considered two main options:

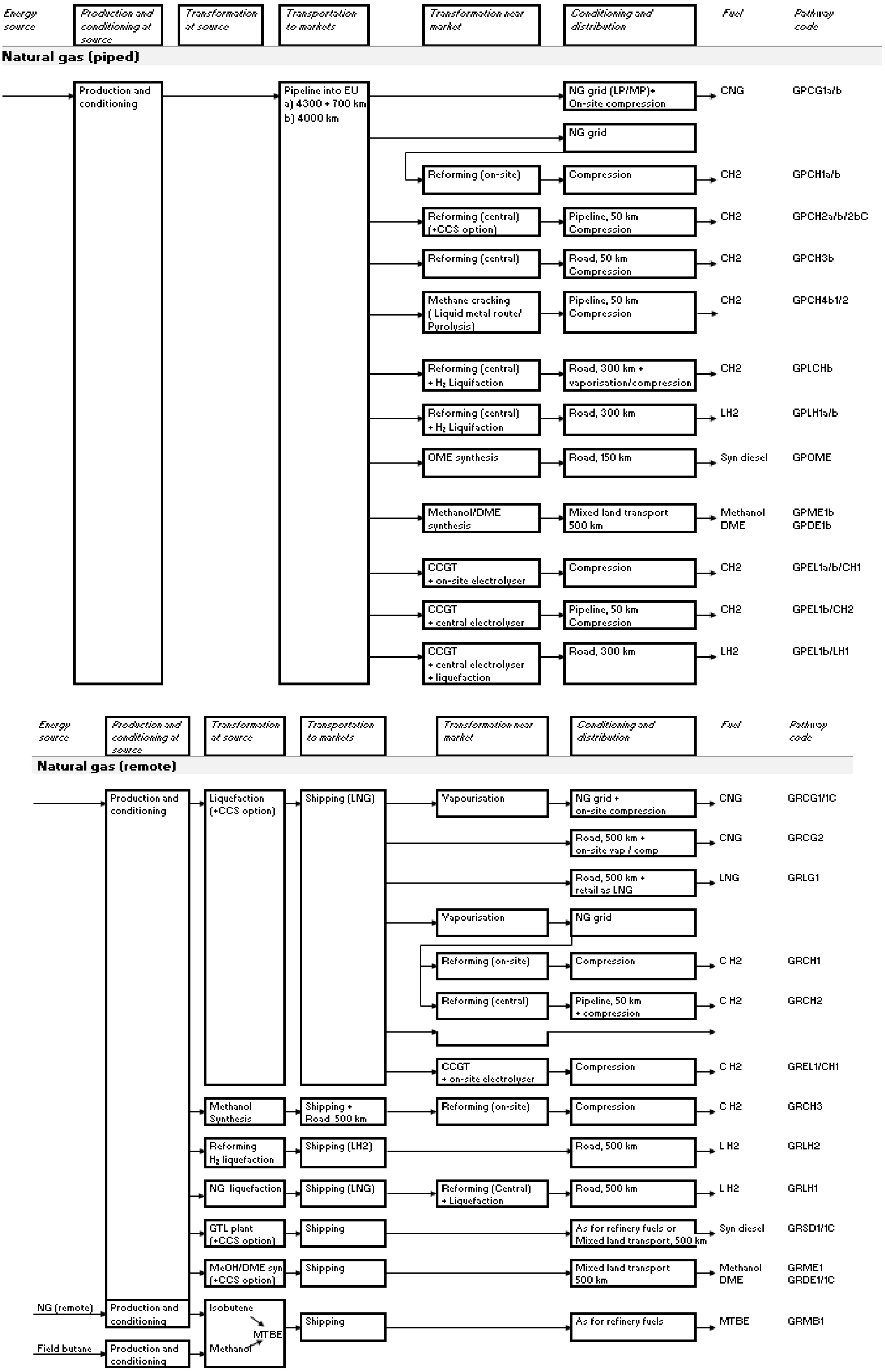
- “Piped” gas transported to Europe via long-distance pipeline. In practice this represents additional availability from the FSU or new sources from Central Asia.
- “Remote” gas from various world producing regions (particularly the Arabian Gulf) either shipped into Europe as LNG or transformed at source into liquid fuels.

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

Figure 11. Natural gas (shale gas) pathway

Natural gas to fuel pathways detailed in the figure below:

Figure 12. Natural gas (piped) to fuel pathways



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

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

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

Inert gases are not normally separated except for some fields where the CO_2 content is high. In a limited number of cases, the separated CO_2 is re-injected into the wells and this may become more common in the future. Unless this is the case, this CO_2 ends up in the atmosphere either at the processing plant or at the end consumer. The CO_2 content of the typical gas sources available to Europe is generally in the region of 1% v/v or less. In order to account for this CO_2 in a simple way in all pathways concerned, we have included a 1% v/v CO_2 venting at the production stage.

The energy associated with extraction and processing varies considerably with the producing region. This reflects different gas qualities, practices and climatic conditions. For extraction, most of the energy is supplied directly in the form of natural gas (typically through an on-site power plant). Processing can take place near the wellhead or, as is common in Russia, at a central location where light hydrocarbons can be readily used as chemical feedstocks. In such a case the energy supply may be mixed and include various hydrocarbon fuels as well as electricity from the local grid. Based on the various sources of information available we have used a median figure of 2% of the processed gas energy with a range of 1 to 4%. We have not included any term for associated condensates, postulating that their production and use would globally be energy/GHG neutral (compared to alternative sources). In addition to the GHG emissions from energy use we have included 1% volume venting as CO_2 and 0.4% volume of methane losses are also included.

Transportation accounts for the largest part of the energy requirement because of the large distances involved. Western Siberian fields are about 5000 km from Europe (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) whereas typical future South West Asian locations may be 4000 km away. For the supply of marginal piped natural gas a transport distance of 4000 km has been assumed representing typical future South West Asian locations.

Table 13. Actual EU mix composition of piped NG included in JEC WTT v5 [Thinkstep 2017]

	% Share
Netherlands	13.0%
UK	10.1%
Other EU	9.4%
Norway	24.9%
FSU (Former Soviet Union)	34.18%
Algeria	6.56%
Others	1.89%

Note. EU mix estimated including UK as part of Europe (figures calculated before *Brexit*).

Pipelines require compression stations at regular intervals, typically powered by a portion of the transported gas. The specific energy requirement therefore increases with distance as the larger the distance the more gas has to be transported initially to obtain a unit of delivered gas. The actual energy consumption figures may vary considerably from one pipeline to another depending on the design and operation parameters (size vs. throughput, compressors and drivers' efficiency etc.). The energy consumption is very sensitive to the pressure at which the pipeline is operated. Existing pipelines operate at pressures of 6 to 8 MPa. New pipelines may be designed to operate at significantly higher pressures which, at constant diameter and throughput, could cut energy requirements by a factor 2 to 3.

There is however a trade-off between energy consumption (i.e. operating costs) and pipeline diameter (i.e. capital cost). In order to represent the diversity of current or possible future situations we have used median and maximum values corresponding to today's operations with, as a potential future improvement, a minimum value corresponding to a 50% pressure increase. In this study we assume that the compression power comes from a proportion of the transported gas. For the 4000 km case for instance we have used a median value of 9.6% of the delivered gas with a range of 3.2 to 10.7%.

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

Improved estimates of pipeline transport and inclusion of CO_2 venting slightly increase the energy use and GHG emission for today's European piped natural gas mix compared with version 4 of this study. In addition, in version 5 we have conducted a detailed revision of the distances per each pathway. The improved pipeline distance has now been estimated of 2400 km (1900 km to EI border and 700 km inside EU) based on data from [Thinkstep 2017] commissioned by NGVA for the EU-mix piped natural gas.

3.2.3 LNG

Liquefied Natural Gas (LNG) provides an alternative to pipelines where these are not practical or when distances are very large. LNG production and long distance shipping is a well-established route widely used throughout the world. Regarding the use in marine, in 2017, the first LNG bunkering vessel started its operation in Europe [GIIGNL 2018].

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

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

Transport takes place in dedicated ships. Heat exchange with the environment during transport is compensated for by evaporation of a portion of the gas which is typically used as fuel by the ship, the balance being provided by standard residual bunker fuel.

The average distance has been taken as 4000 nautical miles, based on the average for the supply of LNG to EU derived from [Gerini 2017]. The LNG is imported from Algeria, Norway, Nigeria, and Qatar.

LNG could play a significant role in future freight transport (heavy duty trucks, ships) in Europe. LNG imported into Europe is most likely to be vaporised and mixed into the natural gas grid. As the number of terminals increases LNG will become more accessible as such and the possibility to deliver it by road directly to refuelling stations can also be envisaged. This option has a theoretical advantage from an energy point of view as compression and vaporisation can be combined. We have included this case in the analysis.

Liquefaction of natural gas requires energy to be spent near the gas fields, essentially in the form of electricity. This may provide an opportunity for CO_2 capture and storage (CCS, see *section 3.5*).

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

Regarding the LNG properties, a major update has been also conducted in the current WTT v5 version. The new set of properties (LHV and CO_2 emissions) for the supply of LNG to Europe have been calculated based on a detailed analysis per country considering both the individual quality of (domestic / imported) LNG per region and the share of each of them in the final European LNG mix.

Table 14. Details per country used to estimate LNG EU mix properties in WTT v5 (see **Appendix 2** for more details regarding fuel properties)

Country	*LHV* *MJ/Nm3*	*EF* *g CO2/MJ*	*Share EU supply* *%*
Algeria-Arznew	39.62	56.4	5.5%
Algeria-Bethioua-1	39.48	56.5	5.5%
Algeria-Bethioua-2	37.78	55.8	5.5%
Algeria-Skikda	37.87	55.9	5.5%
Libya	41.91	57.2	0.0%
Nigeria	39.69	56.4	15.0%
Qatar	39.53	56.4	56.0%
Norway (assumption)	39.53	56.4	7.0%

3.2.4 Role of Biogas in the NG grid

Biogas is gaining traction in the last years as an opportunity to reduce the carbon intensity of the natural gas grid. It is important to highlight that, in order to ensure that that quality of biogas meets the natural gas standards, an upgrading process will need to be conducted:

- Dehydration to remove water.
- Desulfuration to eliminate H_2S, avoiding corrosion.
- Decarbonation in order to remove the CO_2 content (maximum 2.5-6% allowed in Europe).

Note. To be used in vehicles, biomethane needs to meet gas quality specifications: European standard EN 16723-1 for grid injection or standard EN 16723-2, to be used as BioCNG or BioLNG in road transport.

However, there is a significant uncertainty around to what extent this biogas will be consumed locally or effectively injected in the natural gas grid as it will be competing with other local uses such as electricity and heat production.

Currently, in Germany where a large fraction of European biogas plants is located the biogas derived methane share is only about 1%. Most of the biogas is used for electricity generation via gas engines installed onsite the fermenter. Only in Sweden, the share of biogas derived methane is currently higher (low natural gas consumption lead to a higher share of bio-methane).

The European Biogas Association (EBA) reported a total of 17662 plants, of which 10.849 in Germany, 1555 in Italy and 873 in France, for a total installed capacity close to 10 GWe [EBA, 2017]. It is worth noting that, unlike other renewable energy plants (i.e. solar or wind), biogas installations have reached high availability (capacity factor), that allow for relevant energy production in kWh/yr per installed kW (Prussi et al. 2019). Various estimations of biomethane potential have been carried out in recent years [i.e. van Grinsven et al. 2017]; according to EBA (EBA, 2017), in 2016 Europe biomethane plants were 513, with an estimated production of 17264 GWh of biomethane per year (1.48 Mtoe/yr <> 11.6 kWh/kg oil equivalent). Prussi [Prussi et al. 2019] carried out an analysis of the current state of play of the biogas upgrading sector; The total number of commercial initiatives in Europe is about 465, in 2017; with Germany leading the scene. Upgrading technologies are mainly based on three techniques: Pressure Swing Adsorption (PSA), Water Scrubbing (WSC) and Chemical Scrubbing (CSC). The estimated current production potential resulted of about 1.9 billion m^3 of biomethane per year (18905 GWh/yr or 1.63 Mtoe/yr). For future, new biogas plants will likely be equipped with biogas separation units, which allow fostering costs reduction and a parallel consolidation of the operation plants availability.

Regarding the **future outlook**, different recent studies assess the potential to increase the biogas production in Europe up to 2030 and estimate that around 30 to 40 Mtoe [IFP 2017] could be obtained from the digestion of different type of waste and wood materials (see also section 4.5.2 on Biogas from Wood and Waste). The European Commission also published a recent report ('*Optimal use of biogas from waste streams – An assessment of the potential of biogas from digestion in the EU beyond 2020'* [COM Biogas 2016]) where different 2020/2030 scenarios are compared: biogas production (including biomethane) vary from 28.8 to 40.2 Mtoe depending on the scenarios considered. In this study, the scenario 3 (*Biomethane to grid*) defines a future situation where the main driver/reasoning behind the biogas development is the potential use of the biogas to replace fossil fuels in applications such as heating in the built environment and industry (via the natural gas grid) and use as a transport fuel, to replace diesel. [EBA 2016] also estimate a total potential of 48 bcm pretty aligned with the accelerated scenario explored by the EU Commission.

Therefore, for the purpose of this study, we have explored a pathway looking into the current and potential future contribution of biogas to the natural gas grid. In this context and keeping in mind the competing uses, for future natural gas supply in 2030 a pathway has been modelled where a moderate **3.4%** potential for upgraded biogas injection is included. The upgraded biogas modelled consists of biogas from municipal organic waste (40%), manure (20%), and energy crops (40%) [COM Biogas 2016]:

Table 15. Current feedstock use and potentials for 2030 reference scenario (JEC estimate based on EU COM data)

Biogas mix (PJ)	Current use (2016)	Reference 2030	% mix (2016)	% mix (Reference 2030)
Solid manure	0	70	0%	7%
Liquid manure (OWXG2X)	49	120	10%	13%
Energy crops (OWXGX)	325	325	63%	34%
Agricultural residues	0	50	0%	5%
Organic waste (OWXG1)	80	350	16%	37%
Sludge (OWXG3)	60	30	12%	3%
	514	945		

Regarding the properties associated to this biogas, it is worth of note the fact that LNG from biogas assume pure methane as the amount of CO_2 in the biogas (assumed ~3%) will be removed during the liquefaction process and only some traces of N_2 will remain. However, in the case of CNG from upgraded biogas, a LHV of 56.7 g/MJ will be used in our model.

3.2.5 European NG mix

Based on the pathways detailed above, natural gas pathways representing today's EU mix and future EU mix including LNG and upgraded biogas have been modelled informed by discussions with different experts in the field (see **Tables 16** and **17** below). In line with the marginal approach, we do not consider this as a valid case for assessment of the future potential of natural gas pathways and it has been included in WTT v5 only for illustrative purposes to provide a reference to the reader versus current gas use.

Figure 13. Natural gas EU mix pathways

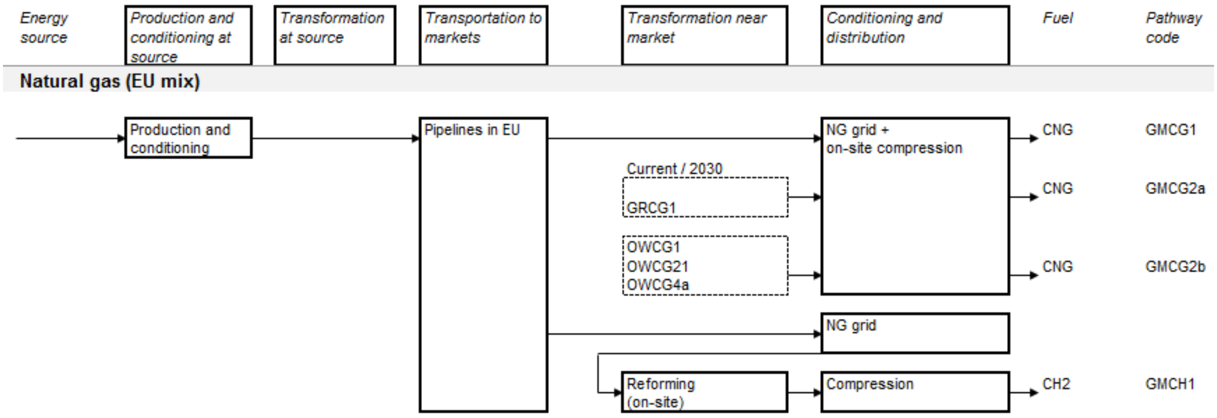


Table 16. Current EU Mix composition

		Share NG total 2015	Share piped gas (Except LNG)
Local production	Germany	1.9%	2%
	Denmark	1.0%	1%
	Netherlands	11.7%	13%
	Poland	1.3%	1%
	Hungary	0.4%	0%
	Italy	1.5%	2%
	Romania	2.4%	3%
	UK	9.1%	10%
Transport by pipeline	Russia	30.8%	34%
	Norway	22.4%	25%
	Algeria	5.9%	7%
	Libya	1.7%	2%
LNG transported by marine vessels	Algeria	2.2%	
	Norway	0.7%	
	Nigeria	1.5%	
	Qatar	5.6%	

Source: [IEA 2016] [NVGA/Thinkstep report 2017].

Note. EU mix estimated including UK as part of Europe (figures calculated before *Brexit*).

Table 17. 2030 NG EU mix composition

	2030 Total production Share	*bcm (billion m^3)*	*Source*
Piped Natural Gas	77.7%	412	Concawe / IHS/ Platts
LNG	18.9%	100	IHS / Platts
Biogas	3.4%	18	EBA / GreenGasGrids
Total		**530**	**IHS / Platts**

Source: JEC own projections based on [Platts 2017]; [HIS 2016]; [EBA 2014]; [Gastechnology.org 2012]; [GreenGasGrids.eu 2012].

3.2.6 Shale gas in Europe

Despite shale gas exploitation has been recognized to be potential associated with relevant environmental impact, its production can be performed in a way able to reduced direct GHG emissions, which are the ones ultimately captured by this study.

Based on data in [AEA 2012] the energy use and GHG emissions for production of shale gas in Europe are very similar to those for conventional gas sources based on a hypothetical analysis for shale gas production in Europe using best available technologies. Note that in line with our general approach we have excluded energy and emissions related to site preparation, construction and drilling. **Table 18** shows the inputs and GHG emissions for shale gas production.

Table 18. Assumptions for **shale gas** extraction and processing based on [AEA 2012] related to the shale gas leaving the gas processing stage

		Base	High productivity	Worst case
General				
Well productivity over lifetime	Million Nm^3	56.6	84.9	28.3
Transport distance for material transport via truck*	km	100	100	500
Well completion emissions flared		15%	15%	0%
Well completion emissions vented		85%	85%	100%
Hydraulic fracturing				
Diesel for stationary engines	$MJ/MJ_{shale\ gas}$	0.00299	0.00199	0.00597
CO_2 from diesel combustion	$g/MJ_{shale\ gas}$	0.219	0.146	0.438
HCl	$kg/MJ_{shale\ gas}$	0.0000105	0.0000070	0.0000211
Distance	$tkm/MJ_{shale\ gas}$	0.001032	0.000688	0.010318
Well completion				
CO_2 emissions	$g/MJ_{shale\ gas}$	0.109	0.073	0.145
CH_4 emissions	$g/MJ_{shale\ gas}$	0.0756	0.0504	0.2143

		Base	High productivity	Worst case
Waste water treatment				
Electricity	$MJ/MJ_{\text{shale gas}}$	0.0000630	0.0000420	0.0001259
Distance	$tkm/MJ_{\text{shale gas}}$	0.001695	0.001130	0.016951
Gas processing				
CO_2 emissions	$g/MJ_{\text{shale gas}}$	0.700	0.700	0.700
CH_4 emissions	$g/MJ_{\text{shale gas}}$	0.0300	0.0300	0.0300

* Delivery of fracking fluid, transport of filter mud

The diesel input is connected with the supply of diesel, the input of hydrochloric acid (HCl) is connected with the supply of HCL, and the transport service (distance) is connected with a 40 t truck which consumes about 0.81 MJ per tkm. The energy requirement for shale gas processing is met by combustion of shale gas. **Table 19** shows the GHG emissions from shale gas extraction and processing based on data in [AEA 2012].

Table 19. GHG emissions from shale gas extraction and processing based on [AEA 2012]

	CO_2 (g/MJ)	CH_4 (g/MJ)	N_2O (g/MJ)	CO_2 equivalent (g/MJ)
Base case				
Hydraulic fracturing	0.36	0.000	0.000	0.36
Well completion	0.11	0.076	0.000	2.00
Waste water treatment	0.04	0.000	0.000	0.04
Gas processing	0.70	0.030	0.000	1.45
Total	1.21	0.106	0.000	3.85
High productivity				
Hydraulic fracturing	0.24	0.000	0.000	0.24
Well completion	0.07	0.050	0.000	1.33
Waste water treatment	0.03	0.000	0.000	0.03
Gas processing	0.70	0.030	0.000	1.45
Total	1.04	0.081	0.000	3.05
Worst case				
Hydraulic fracturing	1.33	0.000	0.000	1.34
Well completion	0.14	0.214	0.000	5.50
Waste water treatment	0.36	0.000	0.000	0.37
Gas processing	0.70	0.030	0.000	1.45
Total	2.53	0.245	0.000	8.66

We have assumed that the gas produced will be injected directly into the European high pressure distribution grid, avoiding the need for long distance transport and associated greenhouse gas emissions. However, there is a large uncertainty concerning emissions of CH_4 from the production of shale gas. In the USA, high amount of CH_4 has been measured in regions where shale gas is extracted [Frankenberg et al. 2016], [EU COM 2015].

3.2.7 NG distribution in Europe

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

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

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

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

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

Natural gas from the network can be used to supply CNG refuelling stations. For more details on CNG see *section 4.5.1.*

3.2.8 NG to fuels

3.2.8.1 NG to hydrogen

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

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

For plants located in Europe we have considered two configurations:

- A “central” plant with a capacity of 200 MW (as hydrogen), equivalent to 5.8 PJ/a of hydrogen (just under 50 kt/a). A minimum of 3.4 MPa feed gas pressure is required which is available from the industrial grid (4-6 MPa). The estimated efficiency is 76% and includes the generation of auxiliary electricity.
- A small-scale “distributed” hydrogen plant serving a single refuelling station (onsite), typically fed from the natural gas domestic grid, with a capacity of 1 to 2 MW (as hydrogen). A minimum of 1.6 MPa feed gas pressure is required. Therefore, an additional compressor is required if the pressure from the natural gas grid is lower. This smaller plant would have a lower estimated efficiency of 69%, the difference being mainly due to the fact that use of waste heat would not be practical at that scale. Furthermore, some auxiliary electricity is required.

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

Thermodynamically, the reforming reaction is favoured by lower pressures. The effect is relatively small and the actual pressure at which a plant will deliver the hydrogen has more to do with design considerations and the pressure of the gas supply. Large plants generally deliver the hydrogen at a fairly high pressure, between 3 and 4 MPa. For small “distributed” plants most of the actual or conceptual designs described in the literature indicate a pressure of about 1.5 MPa. To be consistent with the CNG pathways, we have assumed the gas to be available at the plant inlet at 0.5 MPa (abs). The chain then includes a gas compression step to 1.6 MPa (absolute) for the natural gas inserted into the steam reforming plant.

Hydrogen production with natural gas involves full decarbonisation of the fuel and production of concentrated CO_2, making it an attractive proposition for CCS (see also *section 3.5.1*).

For a discussion of hydrogen transport and distribution refer to *section 3.6.3.*

3.2.8.2 NG to synthetic liquid fuels

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

- Synthetic hydrocarbons via the Fischer-Tropsch route.
- Methanol (including H_2 via methanol and MTBE).
- DME.
- Poly(oxymethylene) dimethyl ethers (OME).

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

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

a) Synthetic diesel fuel (Fischer-Tropsch)

Production of liquid hydrocarbons from syngas via the Fischer-Tropsch (FT) process has been known for many years and the subject of many variations and improvements. The first commercial plant was the Shell Middle Distillate Synthesis (SMDS) plant in Malaysia. A much larger plant is operating in Qatar. This is capable of producing 140,000 bpd of GTL products. In this study we assume the synthetic fuels to be saturated i.e. the process scheme to include a hydrocracker to cut and hydrogenate the long chains to the desired fuel type. In earlier versions of this study, the assumed FT plant was based on SMDS with an overall efficiency (including syngas generation from natural gas) in the range of 61 to 65%. This excludes any potential synergy with upstream or adjacent complexes which could add a few percent points. The theoretical efficiency is about 78% and, with the considerable R&D effort going into these processes at the moment, it is reasonable to believe that higher efficiencies could be achieved in the future. A lot can be achieved through improved heat integration, particularly in the syngas production step and, with rising energy cost, the extra capital investment required is likely to be easier to justify. To reflect these developments, the mean efficiency figure for future plants in this study has been retained at the slightly higher figure of 65%, with a range of 63-67%.

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

The process scheme is essentially the same for all products that can be therefore considered as “co-products”. There is no technical basis for arguing that more or less energy and emissions are associated to specific products so that, in this case, allocation on the basis of energy content is justified (i.e. that all products are produced with the same energy efficiency). We have taken this view which led us to consider that all products and their disposition are independent of each other and so simply compare the energy and GHG emissions of GTL production with the marginal figures for fossil diesel.

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

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

In the GTL process CO_2 is produced and separated from the syngas upstream of the Fischer-Tropsch synthesis. This provides an opportunity for CCS (see *section 4.6.2*).

b) Methanol

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

- NG to hydrogen via methanol

Methanol synthesised from remote natural gas could potentially be used as an energy vector instead of compressed or liquefied gas. Distributed into Europe it could be reformed locally to hydrogen. A separate pathway has been included to represent this option.

- MTBE

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

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

c) DME

Di-methyl ether or DME has attractive characteristics as a fuel for diesel vehicles. However, it is volatile and must be kept under moderate pressure (similar to LPG) so would require specially adapted vehicles. There is, however, no commercial experience with its direct production from natural gas (via synthesis gas). Present commercial manufacture of DME is via methanol and not for fuel purposes. There have been various reports of large plants planned for Iran and particularly China, mainly for domestic fuel. We have used data available from Haldor Topsoe, scaled to a notional plant with the same gas intake as its methanol equivalent. As mentioned for synthetic diesel, development of such processes at a large scale would likely lead to process improvements and higher energy efficiency in the long run.

Note. In the DME synthesis process CO_2 is produced and separated from the syngas upstream of the synthesis step. This provides an opportunity for CCS (see *section 4.6.3*).

d) OME

Poly(oxymethylene) dimethyl ethers (OME) are suggested as blending agent and as neat fuel for diesel engines to reduce the emission of particulate matter (PM). Tests show that the PM emissions significantly decrease if OME instead of conventional diesel is used. The reason for the lower PM emission is the oxygen content. The chemical formula is $H_3CO(CH_2O)_nCH_3$. Typical mixtures are OME with n = 3, 4 and 5.

Today, OME is produced from methanol via formaldehyde, methylal[21], and trioxane[22] as intermediate products. At first, a part of the methanol has to be converted into formaldehyde via partial oxidation. A part of formaldehyde is converted to methylal by reaction with methanol. The other part of the formaldehyde stream is converted to trioxane. Then, the methylal and the trioxane is converted to OME.

Formaldehyde is gaseous at room temperature. However, mixing formaldehyde with water leads to a polymethylene glycol solution, also called an aqueous formaldehyde solution [Jacob & Maus 2017]. In this way the formaldehyde loses its high reactivity. The presence of water disturbs the production of OME via oligomerization of CH_2O. Therefore, energy intensive dewatering of the aqueous formaldehyde solution is required via conversion to a trimer of formaldehyde, the trioxane ($C_3H_6O_3$) [Jacob & Maus 2017].

At room temperature the trioxane is solid. The melting point is 62°C. Trioxane is well soluble in water, alcohol, and ether. The problem is that at a pressure of 0.1 MPa trioxane, formaldehyde, and water forms an azeotrope consisting of 69 % (mass) trioxane, 5 % (mass) formaldehyde, and 26 % (mass) water [Siegert et al. 2009]. In case of the conventional production of trioxane chlorine containing solvents (e.g. 1,2-dichloroethane) are used which leads to a very complex process [Siegert et al. 2009], [Schmitz et al. 2016]. Furthermore, the use of chlorine containing solvents is not wanted for environmental reasons, health and safety. Therefore, a new process for the production of trioxane has been developed based on several patents since 2005. The new process has less process stages, is simpler and more economic than the conventional process for trioxane production. The technical feasibility has been proved via several pilot plants [Schmitz et al. 2016]. Therefore, in [Schmitz et al. 2016] the new process has been assumed. The new process involves a trioxane separation via pressure swing distillation which achieves a trioxane purity of 99.9%.

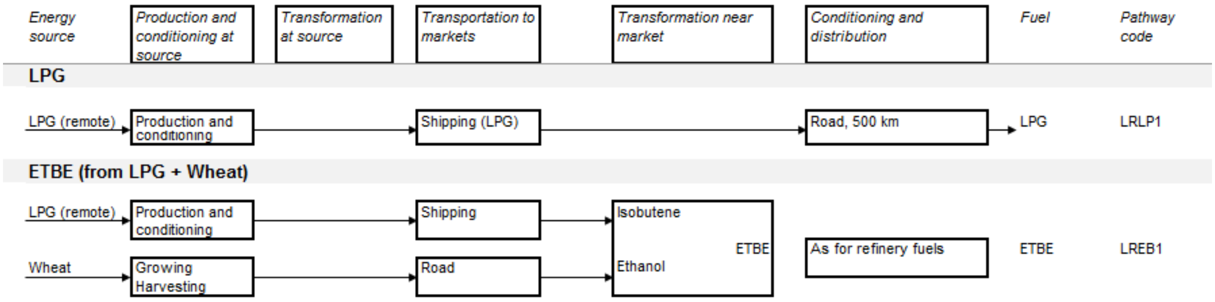
3.2.9 LPG

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

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

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

Figure 14. LPG from gas field



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[21] also called dimethoxymethane (IUPAC name), Formal, Dimethylformal (DMFL), Formaldehyde dimethylacetal or Methylene dimethyl ether

[22] IUPAC name: 1,3,5-Trioxane

3.3 Coal to fuel pathways

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

Summary

Changes vs Version 4

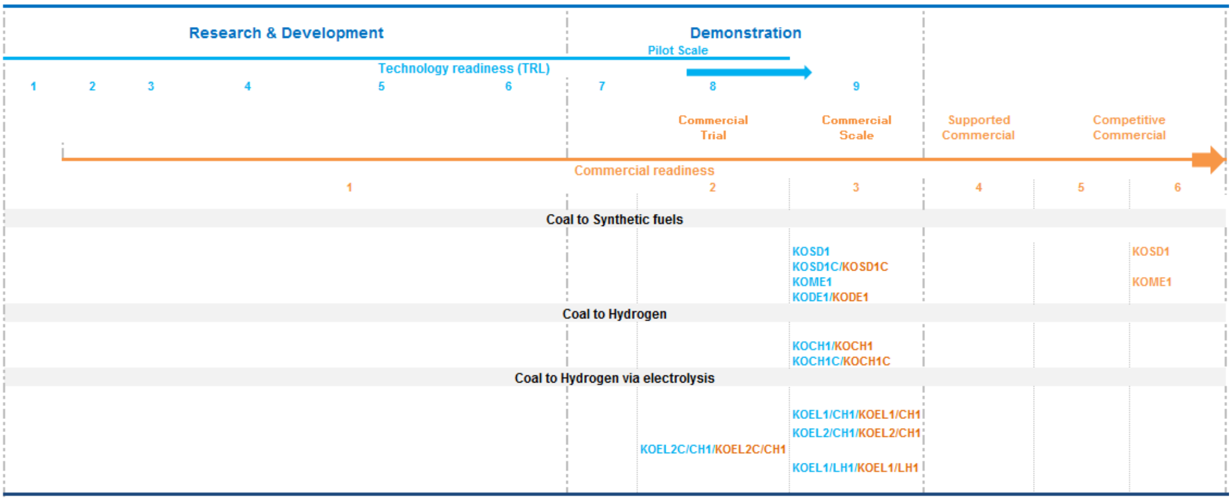
Significant update on the existing fuel pathways (Coal)

Electrolysis pathways involving coal (KOEL1/CH1, KOEL2/CH1, KOEL1/LH1): The losses for electricity transport and distribution have been updated.

No significant changes in the pathways related to synthetic fuels and direct hydrogen production.

Addition of TRL and CRL

Figure 15. Coal to fuel pathways TRL/CRL



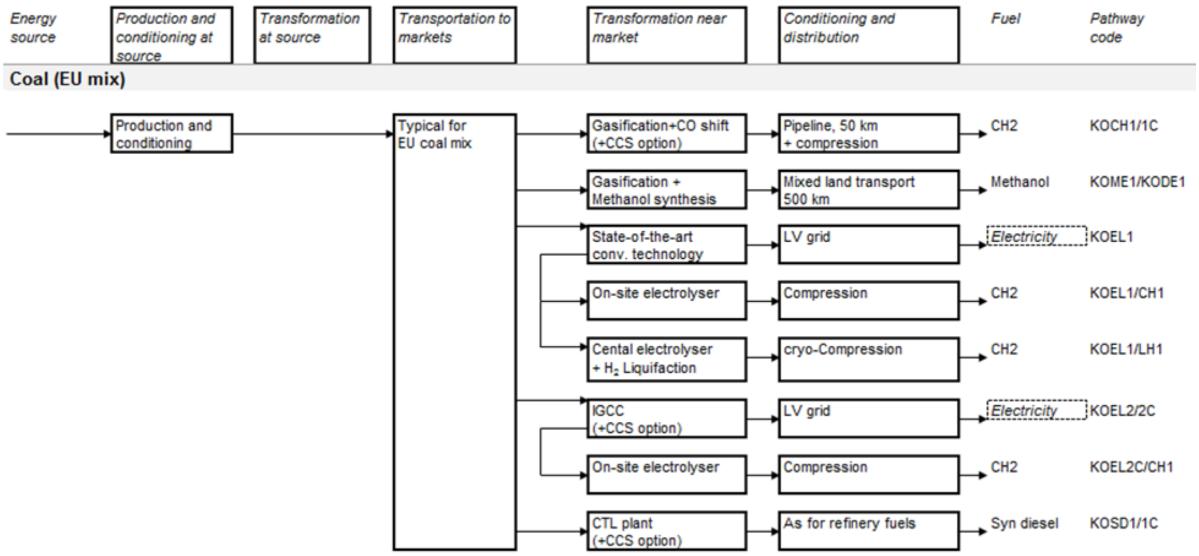
Although not fashionable in today's carbon-conscious world, coal still plays an important role in the world and even in Europe's energy supply, essentially for power generation. After a steady decline over many years, EU consumption has reached around 240 Mtoe in 2016 [Eurostat 2018]. It is, however growing in some other parts of the world, e.g. in India. "Clean coal" technologies such as gasification followed by electricity generation through combined cycle (Integrated Gasification and Combined Cycle or IGCC) and advanced flue gas treatment schemes can resolve most of the air pollution issues while offering high thermal efficiencies. Gasification can also be followed by synthesis of methanol or by a Fischer-Tropsch plant to produce liquid hydrocarbons (Coal-To-Liquids or CTL). CO_2 capture and storage (CCS) further offers the vision of low-carbon electricity or hydrogen production from coal and could also reduce the carbon emissions footprint of synthetic fuels (see also *section 3.5*).

We have included a number of coal-based pathways representing processing of the current EU hard coal mix into hydrogen, methanol, synthetic diesel and electricity (both conventional boiler + steam turbine and IGCC). We have derived energy efficiency figures from the literature: 51% for hydrogen [Foster Wheeler 1996], 57% for methanol (51% if the net electricity requirement is met by a biomass fuelled IGCC) [Katofsky 1993] and 40% for syn-diesel (54% for the sum of FT products and net electricity export) [Gray 2001], Gray 2005]. The coal to electricity pathways are further described in *section 4.10.1.1*.

We have also included the option of CCS for the hydrogen, synthetic diesel and electricity IGCC pathways to illustrate the potential of this technology.

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

Figure 16. Coal pathways



3.4 Electricity production

(See also workbooks WTT v5.0 pathways 6-Electricity/7-Heat & Power)

Electricity is the power source for Electric Vehicles (EV) and also for Plug In Hybrid Electric Vehicle (PHEV). Electricity is also an intermediate source of energy for the production of hydrogen via electrolysis as well as being used as an input in the production of other fuels. It is in any case of interest to establish the energy and GHG balance of the main electricity generation pathways as electricity in effect competes with other fuels for primary energy sources.

Calculating generating efficiency for different forms of primary energy

With reference to the conventions explained in *section* 2.9.2. it is necessary here to clarify some points affecting both the calculation of efficiency and primary energy input.

For electricity generation pathways “efficiency” is the ratio between the electric energy generated in output and the total primary energy consumed in input. However, electricity can be generated from different energy forms and the appropriate calculation needs to be considered carefully for each one.

For electricity generating plants based on combustion of fossil fuel, primary energy input is calculated from the thermal energy content (LHV) of the fuel.

For renewable energy sources (wind, solar, hydrological and geothermal) and for nuclear energy, the amount of energy in the input of power plants cannot be calculated by using the LHV, as in the case of combustible fuels. For these energy sources, LCA studies often define an equivalent primary energy value. These values have been calculated from the gross electric energy produced in output of the power plants (IEA data), multiplying it by an input–output ratio or efficiency.

For nuclear power plants, energy efficiency is not related to the energy content of the raw material (e.g. uranium) used, but to a conventional thermal efficiency of the power plant which, following convention, we have assumed to be 33%.

For renewable energy sources, as the raw material is considered unlimited, the energy efficiency is considered to be (conventionally) 100%, whatever the efficiency of the turbine for wind power and the losses arising during the electricity conversion.

These conventions allow the total energy inputs to be calculated, however it is also valuable to separate the different types of primary energy (fossil, nuclear and renewable).

3.4.1 Electricity generation pathways

Electricity can be produced from virtually any energy source. We have selected a range of pathways covering the most practical options namely natural gas, heavy fuel oil, coal, biomass (in the form of wood), biogas, wind and nuclear. As for the other fuel pathways in this study, these are 'forward-looking' pathways that represent the state-of-the-art and hence what could be expected from a new power station using the selected fuel.

For comparison purposes we have also described the EU-mix generation as a discreet pathway. However, this uses a different methodology and reflects the reported performance of EU electricity generation as it exists today, including power plants of varying ages which may not match state-of-the-art efficiency.

Summary

Changes vs Version 4

Significant update on the existing fuel pathways (Electricity)

Waste wood and farmed wood pathways (WWEL1, WFEL1, WWEL2, WFEL2, WWEL3, WFEL3, WWEL4, WFEL4) and the black liquor pathway (BLEL1): The energy consumption and GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for forestry residue collection, short rotation forestry, wood chips storage (seasoning), biomass transport. Pathways involving waste wood uses forestry residue.

Biogas pathways involving **municipal organic waste** (OWEL1a, OWEL1b): The energy and GHG inventory of the fermentation process have been updated based on the recent data and literature (Giuntoli et al. 2017). The N credit has been removed. Biogas pathways involving **liquid manure** (OWEL21a, OWEL21b, OWEL22a, OWEL22b): Firstly, the Methane emissions credit at the production & conditioning stage of these pathways are significantly changed based on the recent study from JRC (Giuntoli et al, 2017). In addition, the energy and GHG emissions data associated to the fermentation (both closed and open digestate storage) and the distribution of end fuel have been updated to the latest available data.

Pathways for the **EU electricity mix at high voltage** (HV), **medium voltage (MV), and low voltage (LV) level** (EMEL1a, EMEL2a, EMEL3a): The EU electricity mix has been changed from EU electricity mix from 2009 to EU electricity mix from 2016.

Natural gas-to-electricity involving **natural gas from Russia** (GPEL1a): The significant change originates from the transport to the market stage, because the assumed transport distance of gas from western Siberia has changed significantly from the previous version. According to actual GEMIS data the transport distance for natural gas transport via pipeline amounts to 5000 km from the natural gas fields in Siberia to central EU. According to [Thinkstep 2017] the distance for natural gas transport via pipeline amounts to about 4300 km from natural gas fields to EU border (average of 3 corridors to the EU border). Therefore, it has been assumed that the natural gas is transported over a distance of 4300 km to the EU border, from there over a distance of 700 km to central EU where the natural gas is distributed over a distance of 500 km via the high pressure pipeline grid. The losses for electricity transport and distribution has been updated.

Electricity from imported LNG (GREL1): The inventory data for transformation at source (i.e. Liquefaction) and long distance sea transportation have been updated based on recent literature sources. The distance for maritime LNG transport has changed from 5,500 nautical miles to 4,000 nautical miles based on data from NVGA (mix of transport distances for LNG delivered to the EU). For the natural gas liquefaction plant the electricity consumption indicated in [Ott et al. 2015] for state-of-the art plants has been used.

The losses for electricity transport and distribution have been updated in all pathways.

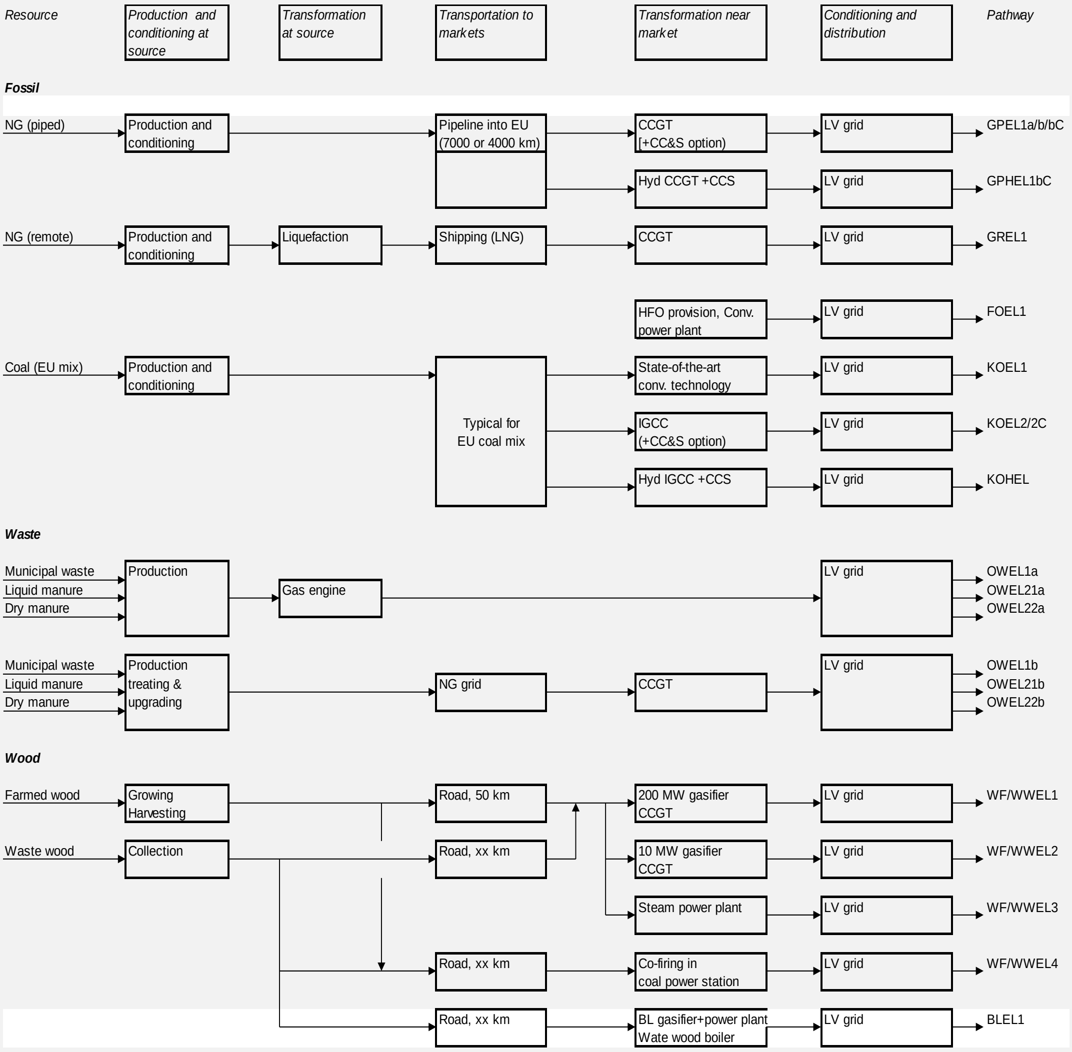
Newly added fuel categories and pathways: 2030 EMEL1b, EMEL2b, EMEL3b

Addition of TRL and CRL

Summary (Cont.)

Changes vs Version 4

Figure 17. Electricity pathways



Summary (Cont.)

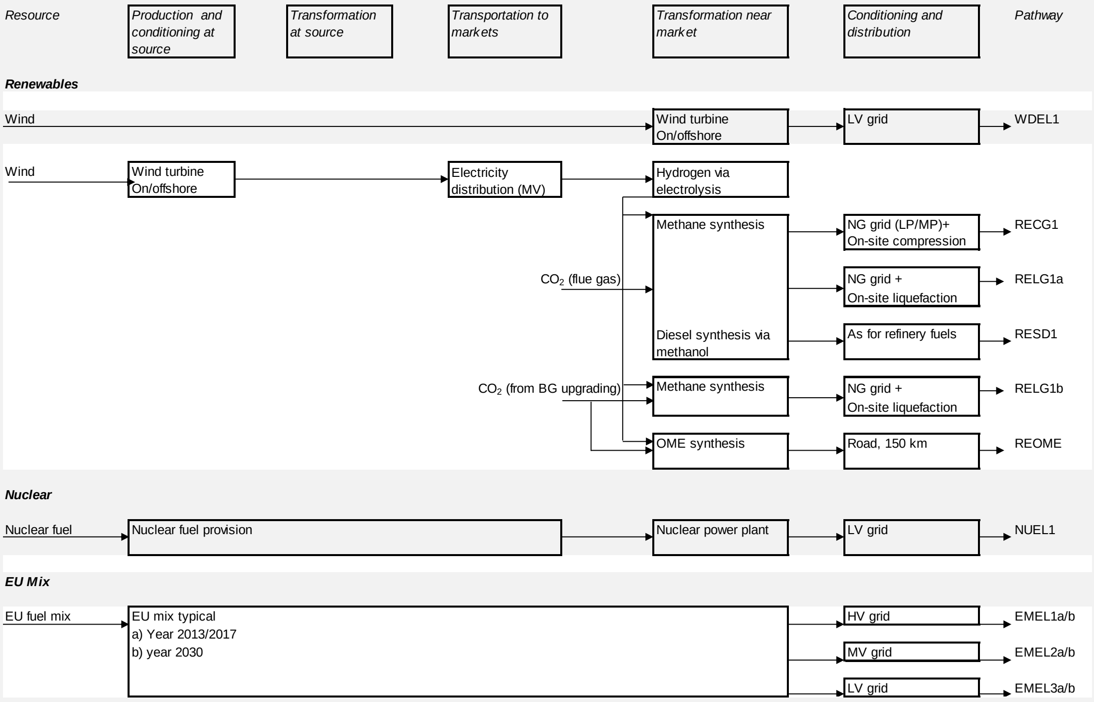
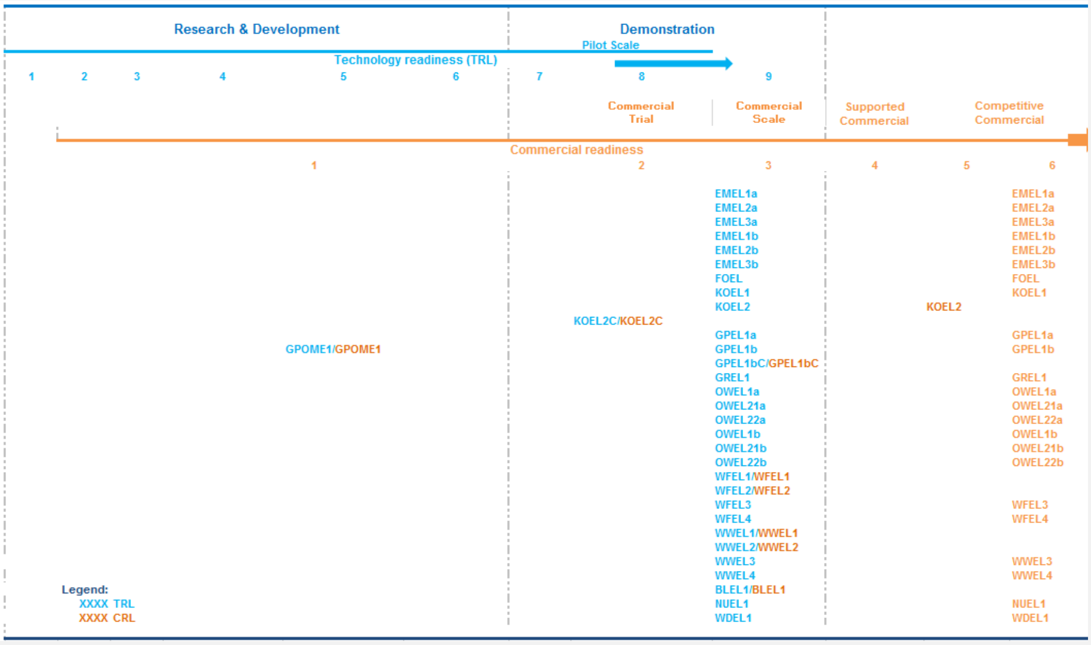
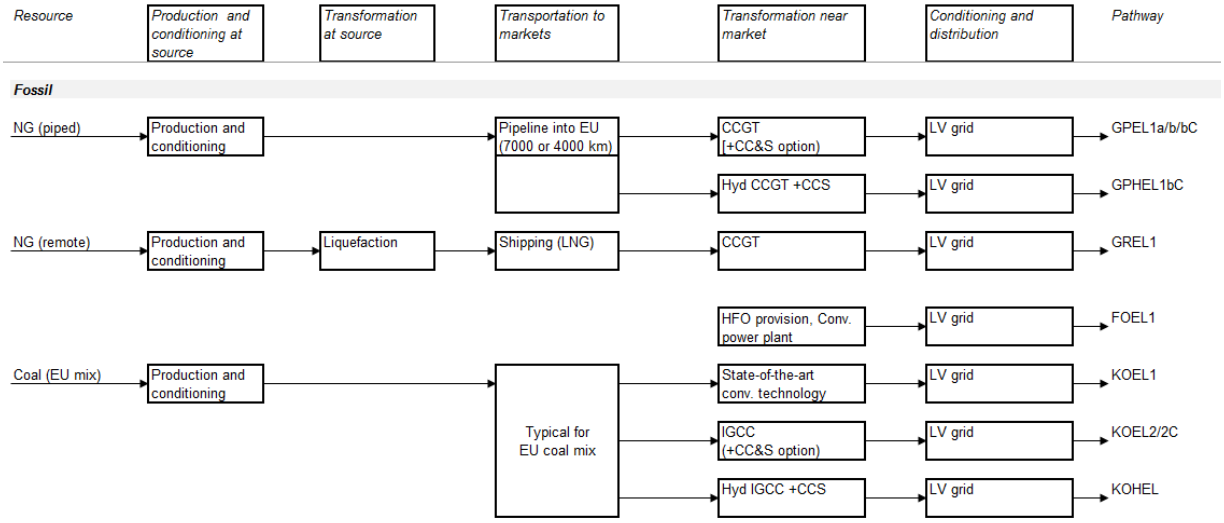


Figure 18. Electricity pathways TRL/CRL



3.4.1.1 Fossil resources

Figure 19. Fossil resources to electricity pathways



3.4.1.1.1 Natural gas

Natural gas is already extensively used for power generation. Its use is expected to increase strongly in the coming years where gas will replace some nuclear and coal generation as well as cover the bulk of the increasing demand.

Although gas is used in conventional thermal steam cycles, virtually all new large-scale capacity is and will be based on the CCGT concept (combined cycle gas turbine) which has a much better efficiency (we have assumed 58%). We have also included a CCS option for this process (see *section 3.5*. Note, however, that such high efficiency can only be reached in a new state-of-the-art plant. A simple "switch to gas" in an existing installation will only marginally improve efficiency.

The above process has been used in the calculations for specific pathways involving NG-based electricity (such as LNG, see *section 3.2.3*) with and without CCS as appropriate. We have also included full NG-to-electricity pathways for three sources of natural gas namely piped gas (5000 and 4000 km) and LNG as well as a CCS option for the 4000 km piped gas case.

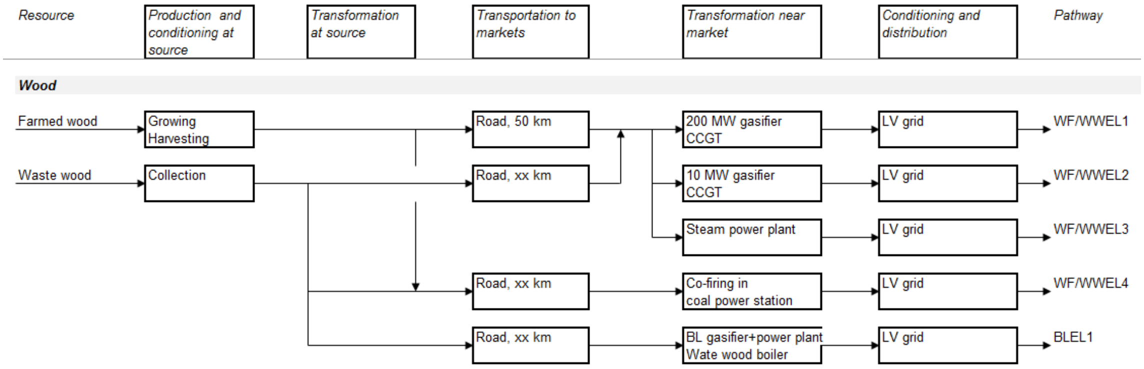
3.4.1.1.2 Coal

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

3.4.1.2 Wood

Wood can be used in a simple boiler + steam turbine configuration or in a more sophisticated scheme involving gasification and CCGT. The expected efficiency is much higher in the latter case although costs will also be higher. Both large and small scale gasifiers and gas turbines can be envisaged. The black liquor route also offers an attractive alternative for efficiently producing electricity from waste wood (see also *section 4.10.1*). Where a boiler + steam turbine is used, large centralised plants can usually attain higher efficiency than smaller local installations.

Figure 20. Wood to electricity pathways



3.4.1.3 Organic waste via biogas

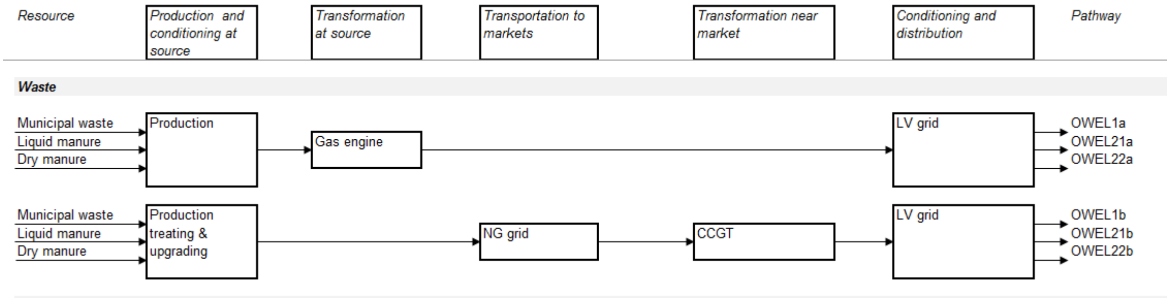
Waste material can be used to produce biogas, and electricity generation, either on-site or via export of biogas to the gas grid is one way of using the product. These biogas/biomethane pathways are described in *section 3.7.9.2.*

Regarding the associated electricity generation through biogas, two scenarios can be envisaged:

- Small scale plant where the raw biogas is used directly in a local CHP plant using a gas engine, with the heat used in the biogas production process.
- Larger scale installation where upgraded gas is exported to the grid and subsequently used in a large power plant.

In the second case, the gas must be upgraded before being accepted in the grid and this offsets the higher generation efficiency in larger power plants.

Figure 21. Waste to electricity pathways

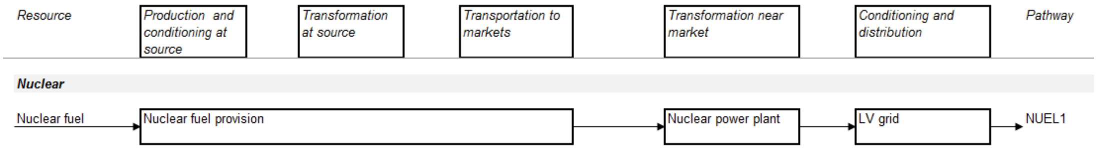


3.4.1.4 Nuclear

The resource in this case is uranium and more precisely the U_{235} isotope of which there are large reserves. However, the future of nuclear fission as a major power source is a societal issue that goes far beyond the scope of this study and will not be further discussed.

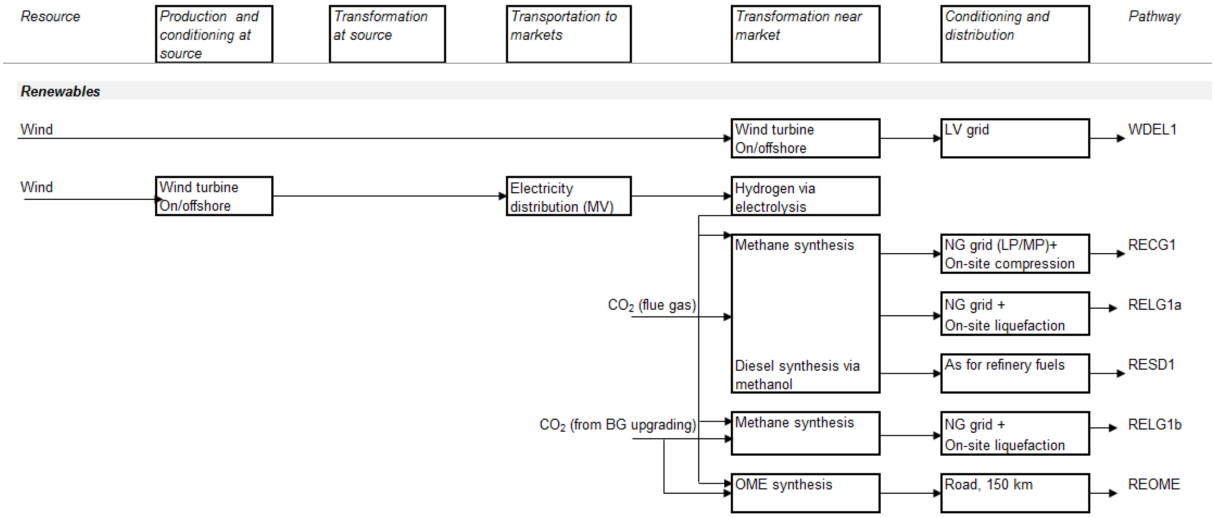
Although nuclear electricity is not strictly renewable, it is virtually carbon-free, the only significant sources of CO_2 emissions being associated with fossil fuel energy used in mining, transport and enrichment of the uranium as well as maintenance of the power plants.

Figure 22. Renewable energy to nuclear pathway



3.4.1.5 Renewables

Figure 23. Renewable energy to electricity pathways



3.4.1.5.1 Wind

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

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

Wind power is growing rapidly, but because it starts from a very low base will take many years to have a significant impact. In 2016 wind electricity contributed about 10% of the total net electricity generation in the EU [Eurostat 2018]. The IEA expects that wind electricity will contribute about 20% of total electricity generation in 2030 [IEA WEO 2017] (IEA New Policies Scenario (2030). The European Commission expects that wind electricity will contributed about 26% by 2030 [EU COM 2018] (baseline scenario in European Commission's Long-Term Strategy). Once installed, wind power causes virtually no GHG emissions.

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

3.4.1.5.2 Solar

In 2016 photovoltaic electricity contributed about 3% of the total net electricity generation in the EU [Eurostat 2018] reaching about 4% of the total in 2018 according to [Agora & Sandbag 2019]. The European Commission expects about 11% in the baseline scenario in European Commission's Long-Term Strategy [EU COM 2018]. Wind and solar temporally and seasonally complements one another. The availability of wind power generally is high in periods with low solar irradiation and vice versa. It has not been considered as a separate pathway in this study.

3.4.1.5.3 Hydropower

In 2016, hydroelectricity currently represented the largest portion of Europe's renewable electricity generation (about 11% in 2016 [Eurostat 2018]. There are, however, very few sites still available and capacity is not expected to grow substantially. It has not been considered as a separate pathway in this study.

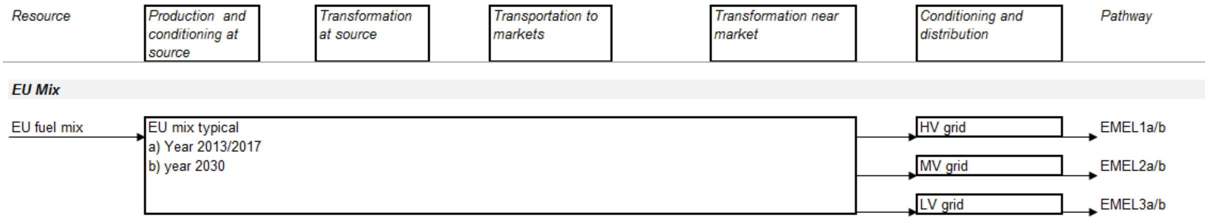
Hydroelectric power plants have a very important role in an electric system, not only because of the low cost of the fuel used (water) and the lack of GHG emissions. Their quick response to power control systems and the opportunity to store energy in case of plants using a reservoir (e.g. dams) make them ideal for peak load supply. When there is a surplus of energy (e.g. during the night), water can be pumped in the reservoir and be then used to satisfy next demand peaks. Notwithstanding the power losses for pumping, hydropower is currently the cheapest way to store electric energy. Unfortunately, hydro-power production potential is reaching its limits and a future increase in the hydropower capacity in EU28 countries is therefore not envisaged. Between 2012 and 2016 the share of electric energy generated from hydropower on the gross electric energy generated in EU has ranged between 11 and 13% depending on the rainfall.

3.4.1.6 The "EU-mix"

Electricity in the EU is produced from different energy sources including coal, gas, nuclear, hydro etc. The combination of all them in the 'so-called' EU-mix, although not corresponding to a single pathway, is used in this study to represent the typical electricity supply. EU-mix electricity is used to calculate credits in some pathways where surplus electricity is exported to the grid and as the notional electricity source for ancillary electricity consumption.

The specific fuel pathways described in this study include a representative case of the current EU-mix as well as look forward to the 2020-2030 timeframe, presenting figures for state-of-the-art technology that would be used for new fuel production commissioned in this period.

Figure 24. EU mix electricity pathways



For the determination of the ***current* EU-mix,** statistical data were used as provided in a JRC study of current EU electricity generation performance [Moro & Lonza 2018] for 2013 updated with 2016 data from the European Environment Agency [EEA 2018]. National statistics are generally based on the demand for primary fuels. Therefore, current figures in version 5 result from a detailed country-by-country analysis of electricity production (energy input and output) including both combustion and upstream emissions to estimate weighted efficiencies per type of fuel [Moro & Lonza, 2018]. The methodology for the calculation of the average carbon intensity of grid electricity *consumed* in each member states is available in [Moro & Lonza 2018].

Upstream emissions occur before the gates of the power plant and result from the production and transport of the fuel. Upstream emission factors are shown in the table below. They refer to the fuel input to the power plants (While combustion emissions result from the combustion of the fuel in power plants for the production of electricity based on [IPCC 2006]).

Table 20. Upstream Emission factors (kg CO_{2eq}/GJ)

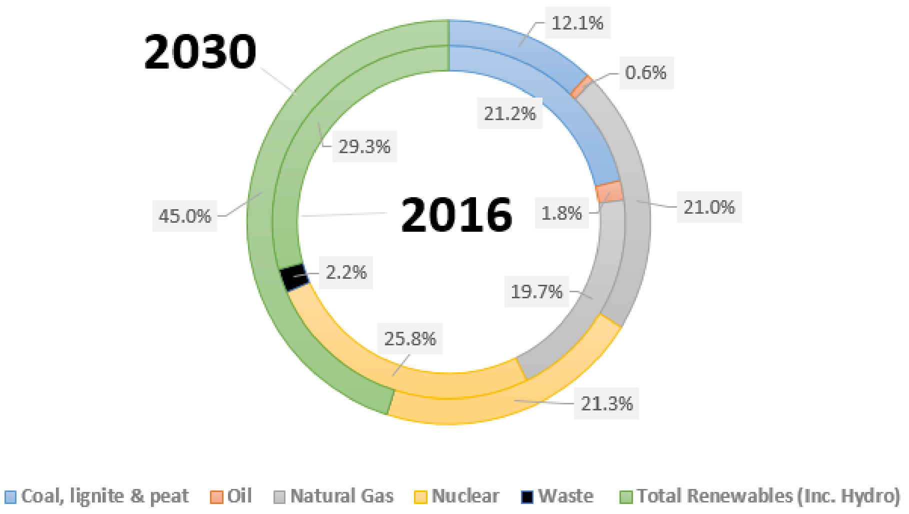
Hard coal	Brown Coal	Peat	Coal gases	Pet. Products	NG	Solid biofuels	Liquid biofuels	Industrial Waste	Municipal waste	Biogases	Nuclear
16.0	1.7	0	0	10.7	12.8	0.7	46.8	0	0	14.9	1.4

An improvement factor was applied to the 2013 carbon intensity of electricity consumed in EU28. According to [EEA 2018], the EU electricity generating emissions fell from 334 gCO_2/kWh in 2013 to 296 gCO_2/kWh in 2016; a fall of ≈11.5%. The input of fuels has been adjusted via factors derived from [EEA 2018].

Prediction of an **EU-mix electricity** for a **future** period is difficult, because it requires a knowledge of what generating capacity and efficiency gains per technology will be in place at a future date. In version 5, we have used as a reference the 2030 electricity mixed defined by IEA in their New Policies Scenario [IEA WEO 2017]. Existing combustion power plants are expected to improve their energy efficiency within this timeframe so we have estimated efficiency gains based on the historical level of improvement using 2009 and 2013 statistical data as the starting point.

The share of the electricity production sources reported in [*Moro & Lonza, 2018*] adjusted via factors derived from [EEA 2018] as well as the assumptions from IEA NPC scenario [IEA WEO 2017] are shown in the following figure.

Figure 25/ Table 21. EU electricity production mix (2016 data and projections for 2030)



% share	*2016*	*2030*
Source	**EEA 2018**	**IEA NPS (2030) – WEO 2017**
Coal, lignite	21.2 %	12.1 %
Oil	1.8 %	0.6 %
Natural Gas	19.7 %	21.0 %
Nuclear	25.8 %	21.3 %
Hydro	10.8 %	11.8 %
Wind	9.4 %	19.7 %
Solar	3.5 %	5.3 %
Other non-renewable fuels	2.2 %	-
Other renewables	5.6 %	8.2 %

Note. These figures are for the shares of electricity from different sources. The shares of the fuels used are different because of different efficiencies of the power plants. To be distinguished between the renewable energy share of the renewable primary inputs included in the WTT spreadsheets and the renewable energy share of the electricity generated (Figure above). The numbers related to the input and related to the origin of electricity output in the case of the EU Mix are different due to the efficiency for hydro, wind, and PV is set to 100%, the efficiency of nuclear power to 33%, and of thermal power stations to below 60% depending on the technology.

The efficiencies of the different power generation technologies based on 2016 data and the supply of the fuels for power generation leads to the primary energy input shown in **Table 22**.

Table 22. Primary energy input for electricity generation based on 2016 data and projections for 2030 without transport and distribution

PRIMARY ENERGY SOURCE	2016 (KWH/KWH$_{E}$)	2030 (KWH/KWH$_{E}$)
COAL	0.369	0.188
LIGNITE	0.233	0.108
PEAT	0.016	0.007
CRUDE OIL	0.065	0.014
NATURAL GAS	0.443	0.450
BIOMASS	0.245	0.096
WASTE	0.047	0.043
NUCLEAR	1.087	0.845
HYDRO	0.107	0.124
GEOTHERMAL	0.020	0.044
SOLAR	0.035	0.051
WIND	0.093	0.207
TOTAL	2.758	2.176

The total energy input needed to generate 1 MJ of net electricity is about 2.76 MJ at the power stations including the primary fuels and deliver them to the power stations (upstream losses), and including the electricity used for the power station itself. For 2030 the primary energy consumption to generate 1 MJ of net electricity decreases to about 2.18 MJ at the power stations.

Transmission losses in the High Voltage system are about 2.6%, while losses for Medium Voltage distribution add 0.9% and Low Voltage distribution a further 3.4%. The figures are summarised in **Table 23** and **24**.

Table 23. EU-mix electricity primary energy use and GHG emissions (2016 data)

	MJ/MJe	g CO2eq/kWhe	g CO2eq/MJe
Net electricity generation including primary fuel provision and pumping losses	2.758	369	103
Delivered HV electricity including distribution	2.833	379	105
Delivered MV electricity including distribution	2.859	383	106
Delivered LV electricity including distribution	2.959	396	110

Table 24. EU-mix electricity primary energy use and GHG emissions (2030) based on IEA NPS - New policies scenario (2030) + Energy Efficiency Improvement for combustion power plants

	MJ/MJe	g CO2eq/kWhe	g CO2eq/MJe
Net electricity generation including primary fuel provision and pumping losses	2.176	250	69
Delivered HV electricity including distribution	2.235	257	71
Delivered MV electricity including distribution	2.256	259	72
Delivered LV electricity including distribution	2.334	268	75

3.4.2 Electricity production, transmission and distribution

3.4.2.1 Main conventional energy sources

Nuclear energy satisfies one fourth (26%) of the primary electric energy needs in the EU [EEA 2018]. Due to their technical characteristics and relative low fuel cost per energy output, nuclear power plants are used only for base load. They have relatively low operating costs and are practically carbon free, but because of issues related to safety and very high initial investments, their long term future remains unclear. This may affect the EU-mix in the longer term but will not have a significant effect for the 2030 EU electricity mix.

Coal fuels (including also lignite and coal gases) provided in 2016 about 21% of the EU primary energy transformed in electricity [EEA 2018]. Coal is an abundant fossil fuel, with large reserves placed in politically stable countries. Being a cheap primary energy source for generating electricity, coal power plants are typically used to provide base load. However, because it is a high carbon fuel, coal can produce higher GHG emissions than competing technologies. Emissions from coal power plants can be mitigated by Carbon Capture and Sequestration (CCS) technology, which transports CO_2 to a storage site where it will not enter the atmosphere, normally in an underground geological formation. However, capturing CO_2 in turn requires energy and this reduces the overall efficiency of the plants.

Conventional thermal electric power plants (e.g. coal plants using the Rankine thermodynamic cycle) produce only electric energy. The 2016 average efficiency of a hard coal power plant representative of the production in EU 28 is in the order of 40% (weighted). Higher efficiencies can be achieved if the coal is gasified and used in a combined cycle (IGCC), however this process is not commercially used in Europe today. Some recent power plants are designed to use some of the waste heat of the thermal cycle for heating purposes, but this depends on a suitable use for the heat. Where Combined Heat and Power (CHP) plants can be achieved they present a higher efficiency, reaching 60%.

Natural gas (NG) represents 16% of the primary energy used to produce electricity in the EU in 2016 (input for electricity generation/total primary energy input for electricity generation). NG power plants commonly use a Brayton (gas turbine) cycle with a typical efficiency of 40%. By using the exhaust steam in a steam turbine, the overall efficiency can be increased up to 60% (e.g. Irsching in Bavaria). This configuration is referred to as a Combined-Cycle gas turbine (CCGT) and is widely used in Europe. Emissions of GHG from gas power stations are lower than emissions from coal or oil power plants, because of the lower carbon content of NG and because of the higher efficiency from the CCGT cycle. Small-scale NG plants rate well in terms of efficiency, and are suitable for distributed generation systems. NG can be provided at a relatively low cost, has good environmental performances compared to coal and its availability is expected to grow (as piped gas but also as LNG), including shale gas as this becomes available.

3.4.2.2 Transmission

Once produced, electric energy is distributed through transmission grids for consumption normally located far away from the place of production Power losses in transmission are proportional to the square of the current transmitted due to the Joule effect. Since power is the product of the voltage by the current, electricity is transformed to high voltage (220-380 kV), so (for the same power transmitted) the current can be lower and the power losses reduced. This is conventionally done with electric systems using Alternate Current (AC) and employing electric transformers. Power losses in the 2013 EU transmission system accounted for 2.6% of the total power produced.

3.4.2.3 Distribution

After long distance transmission, electric energy is delivered to the specific places of consumption, such as urban districts, buildings, factories, etc. This is done after having transformed the electricity to Medium Voltage (MV). Typically, big commercial and industrial users are supplied at MV, and are responsible for designing, acquiring and maintaining their own MV/LV (Low Voltage) transformers and LV electric wirings. The energy supplier provides LV electric energy to individual private users. The energy losses due to MV and LV distribution are in the order of 7% in the 2013 EU system.

It is worth noting that limited power is available to the individual private users to charge electric vehicles at home. This limit is, theoretically, the power limit guaranteed by contract from the energy provider (e.g. 3 kW) but, practically, the power that can be used for a specific load is lower. This limitation is typically due to physical constraints of the electric wiring, which is unlikely to be designed for bearing high currents for a long time (the charging time of an Electric Vehicle at home can be 8-10 hours). These safety limitations should be considered together with the simultaneous electricity demand of the user and the need to have a "reserve power" for supplying other loads while charging the EV.

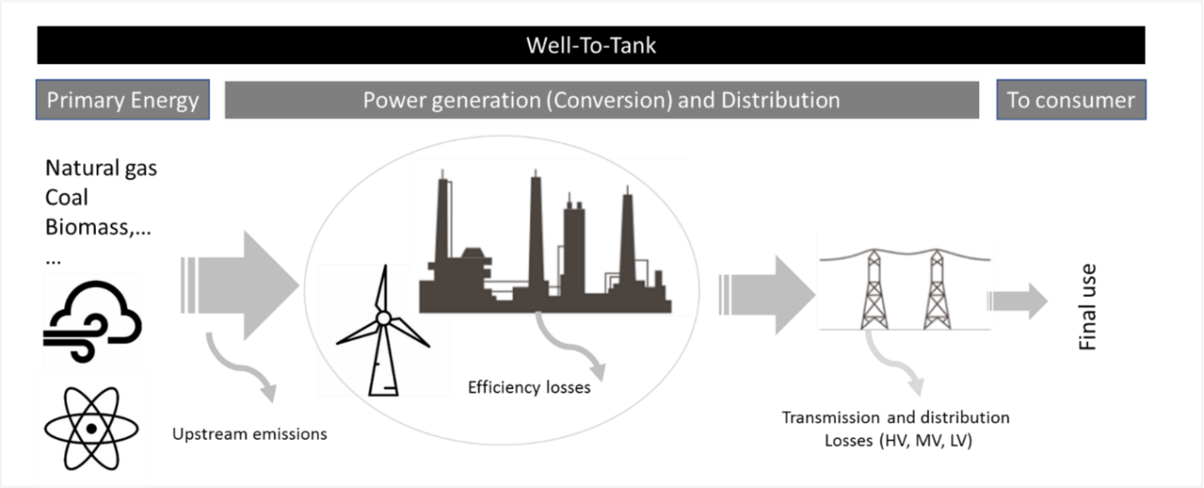
3.4.3 2016 EU electricity mix and 2030 WTW calculations

JEC WTT Version 5 calculations on the EU electric energy mix used at Low Voltage include all the energy losses and GHG emissions incurred at the different stages of its production, transmission and distribution. On the basis of the latest available data for year 2016, in the EU28 one kWh of electricity consumed at LV was responsible for GHG emission of 396 gCO_{2eq}/kWh (110 gCO_{2eq}/MJ, see pathway EMEL 3a).

In a 2030 perspective, we can imagine that the GHG emissions from the EU28 electric mix will decrease significantly. Based on the IEA - New policies scenario plus assumed energy efficiency improvement for combustion power plants the GHG emissions for one kWh of electricity consumed at LV decrease to about 268 g CO_{2eq}/kWh in 2030 (75 g CO_{2eq}/MJ, see pathway EMEL3b).

The **Figure 26** and **Table 25** synthesise the approach followed in JEC WTT v5 calculations:

Figure 26. Summary of steps and losses and emissions considered in JEC WTT v5



Primary energy	**Power plant**		**Transmission**	**Power to household**
WTT JEC v5 **(Individual spreadsheets)**	Conversion efficiency: Hydro, wind, and PV → set to 100% Nuclear power → 33% Geothermal → 10% Thermal power stations < 60%, depending on the technology	**Gross electricity energy**	Transmission losses: HV ~2.6% MV: + ~0.9% LV: + ~3.4%.	EU-Mix (Output) (% RES: 29% in 2016)
Primary energy input for electricity generation based on 2016 data and projections for 2030 (w/o transmission)			Energy including transmission	EU Mix (*)

(*) % RES in the final power to household is modelled as 45% in 2030 (268 g CO2eq/kWeq (LHV)

Table 25. Summarize of energy expended and g CO_{2eq}/MJ calculations in the JEC WTT v5

Code	**Description**	Energy expended (MJ/MJ final fuel) Primary energy					WTT GHG emitted (g CO_{2eq}/MJ final fuel)
		Total	Fossil	Nuclear	Renewable	*Fract renew*	
EMEL1a	EU-mix high 2016 mix) - HV	**1.83**	0.76	0.72	0.35	*19.0%*	**105.4**
EMEL1b	EU-mix high (2030 mix) - HV	**1.24**	0.45	0.48	0.31	*25.0%*	**71.3**
EMEL2a	EU-mix medium 2016 mix) - MV	**1.86**	0.77	0.73	0.35	*19.0%*	**106.3**
EMEL2b	EU-mix medium (2030 mix) - MV	**1.26**	0.45	0.49	0.31	*25.0%*	**72.0**
EMEL3a	EU-mix low (2016 mix) - LV	**1.96**	0.82	0.77	0.37	*19.0%*	**110.1**
EMEL3b	EU-mix low (2030 mix) - LV	**1.33**	0.48	0.52	0.33	*25.0%*	**74.5**

Note. The % of renewable in the EU-mix is higher than in the Energy expended figures included in the table above (due to the fact that the latter includes all the energy losses detailed in previous sections). More details regarding the different electricity pathways are reported in Section 4.10. Results. Electricity pathways.

3.4.3.1 Technology Neutrality

Throughout our study, we have tried to use the 'incremental approach' (*section 2.3*) wherever possible. In the case where use of electric vehicles results in a significant increase in electricity demand, we would really like to know how this incremental electricity would be produced and use this in evaluating the impact of increased EV use on energy and GHG emissions. In practice, electricity generation and distribution is complex with the instantaneous power mix varying in response to demand and (in the case of hydro, wind, and solar energy) weather conditions and there is no practical way to deduce an 'incremental' electrical energy source in 2030+.

In evaluating the performance of electric vehicles, we present figures based on a range of different electricity pathways, however there is no reason to believe that electric vehicles will run exclusively on one particular energy source. To do so would arbitrarily bias the results in favour of or against electric vehicles. In the absence of a reliable estimate of the incremental electricity source, the EU-mix provides an objective metric of performance.

3.4.3.2 Data uncertainty / Data consistency

Drawing data from a variety of sources each characterised by specific assumptions is likely to increase the uncertainty and reduce the robustness of the WTW analyses. This is particularly true if data projections affect only one part of the energy system (e.g. the electricity sector), as noted in *section 3.4.3* on transmission lines.

Uncertainty in data projections. The case of photovoltaic:

The case of photovoltaic (PV) electrical power provides a good example of possible discrepancies when comparing different data projections each surrounded by comparable level of uncertainty. Recent scenario studies elaborated by different authors foresee, for the year 2015, installed PV powers ranging from 60 GW to 234 GW [Jaeger-Waldau et al. 2013]. Considering that installed capacity in 2015 was 97 GW in the EU (2016: 103 GW), it is easy to understand why the range of uncertainty can distort WTT results substantially. Variability across data projections is sometimes motivated by the limited robustness of techno-economic development assumptions used by key actors in the private and the public sector alike, including wish-lists for and back-casting from previously identified targets/objectives. On the other hand, many organizations e.g. the International Energy Agency (IEA) have regularly underestimated the penetration of photovoltaic power [Fraunhofer ISE 2019]. In [WEO 2017] (New Policies Scenario) the share of photovoltaic power for 2030 amounts to about 5%, in [EU COM 2018] the share of photovoltaic power amounts to about 11% (baseline). As a result, the electricity mix used for 2030 in this study based on IEA scenarios in [WEO 2017] can be considered as conservative. The penetration of renewable energy strongly depends on regulatory frame conditions (e.g. an emission cap for greenhouse gases, CO_2 price or taxes, feed-in tariffs for renewable electricity).

3.4.3.3 Development of the EU electricity mix

Power plants are expensive and electric power plants are renewed quite slowly (the time of life of a power plant is in the order of 30-60 years), so the penetration rate of new technologies is relatively slow. On the other hand, most of the coal and nuclear power stations are older than 30 years. EU28 data [EUROSTAT 2018] on the share of the electric energy produced from Renewable Energy Sources (RES) in year 2000 (13%) compared with the same data source for 2016 (30%) indicate a 17% variation.

Government schemes supporting RES were implemented prior to 2008, but the level of support per KWhe has been steadily decreasing. On the other hand, specific cost of renewable electricity is also steadily decreasing.

On the technology side integration of RES in the traditional network is a solved problem. Smart grids (consisting of e.g. voltage regulated distribution transformers, battery systems for electricity storage and grid control[23], cellular grid architecture) meanwhile are at the demonstration level. Only adequate regulatory frame conditions and operating regimes still have to be introduced. Therefore, significant changes of the EU electricity mix can be expected for the future and IEA's New Policies Scenario has been used as the basis for our analysis (as detailed at the beginning of the section).

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[23] 70 to 80% share of fluctuating renewable electricity can be integrated in the electricity grid using battery systems for electricity storage and grid control. Exceeding 70 to 80% share of fluctuating renewable electricity generation requires long-term (several days to several weeks) electricity storage e.g. via hydrogen.

3.5 CO_2 Capture and Storage (CCS)

3.5.1 CO_2 Capture and Storage (CCS). The concept

a) General

The concept of capturing the CO_2 produced by combustion or other conversion processes and storage of it - for instance by injecting it into suitable geological formations - has been gaining credibility in the last few years. This pathway to avoid the release of CO_2 into the atmosphere has been gaining momentum, especially after the Conference of the Parties (COP 21) in December 2015, where the need of deep-cut CO_2 technologies such as Carbon Capture and Storage (CCS) has been emphasized in order to pursue efforts to limit the increase of the global average temperature to 1.5 degrees C above pre-industrial levels.

This key role of CCS is portrayed by different stakeholders – including the European Commission in the recent long-term strategy publication ("*A* Clean *Planet for all*" [EU COM 2018]) - as one technology (besides renewable energy) to reduce CO_2 emissions across various sectors of the economy including the production of carbon-free hydrogen as well as energy intensive industries.

Carbon Capture from concentrated streams (e.g. industrial sites) and subsequent Storage is not the only way to deal with this problem. Carbon dioxide (CO_2) can theoretically also be recovered directly from air (Direct Air Capture), but the high energy required, due to the low CO_2 concentration, makes this option economically not attractive at the moment. Regarding the accessibility to storage locations, there are many such structures available in most areas of the globe from depleted gas and oil fields to salt domes and aquifers where CO_2 could be storage in the long-term (alternatively, CO_2 recovery and injection schemes can also be used to enhanced and prolonged production from ageing oil and gas fields). CCS storage capacity potential for Europe varies between sources. From 300 $GtCO_2$ estimated by GCCSI [GCCSI 2019] to a more conservative estimate [GeoCapacity 2009] of about 117 Gt CO_2, thereof 96 Gt CO_2 in deep saline aquifers, 20 Gt CO_2 in hydrocarbon fields, and 1 Gt CO_2 in coal fields. [Oei et al. 2014] indicates a storage capacity of about 94 Gt CO_2, thereof 71 Gt in saline aquifers (onshore and offshore) and 23 Gt CO_2 in depleted gas fields.

As examples, CCS is being undertaken in industries such as natural gas processing, fertilizer production, hydrogen production, coal gasification and iron and steel production worldwide. Globally, 43 large-scale CCS facilities globally – 18 in commercial operation, 5 under construction and 20 in various stages of development – are reported around the world [GCCSI 2018]. Pilot projects are also already in operation in the oil and gas industry. In terms of the CO_2 savings, the world's 18 large-scale facilities are already capturing almost 40 Mt/y of CO_2, and the same GCCSI reports indicates that a total of over 230 Mt of CO_2 has been safely injected underground to date.

In Europe, there are currently two operating CCS large-scale sites both in Norway [Sleipner and Snovhit] and some other projects are in development in the UK, Netherlands and Norway:

- The Porthos project in the Port of Rotterdam aims to establish a common infrastructure to collect CO_2 captured from a variety of industrial facilities in the area (2-5 Mt CO_2/y).
- The Norwegian full-scale project aims to develop common CO_2 capture and storage infrastructure for Europe. It will collect CO_2 from industrial point sources across Europe and store it offshore. The project will also include two industrial capture projects at a cement and waste-to-energy plant.
- In the Netherlands, H2M project aims to convert a CCGT (Combined Cycle Gas Turbine) power plant into hydrogen-powered plant by 2023 where the hydrogen production is combined with a CCS scheme (storage offshore in underground storage off Norway).

Alternatively, to this storage route, once CO_2 is captured either from a concentrated or directly from air, it can be used as a feedstock for the production of fuels, carbonates, or other chemicals; this possibility is referred as Carbon Capture and Utilisation (CCU). The CCU related pathways are further detailed in section 3.9 of the present report (Power-to-fuel section).

b) CO_2 capture technology

CO_2 capture is a process that involves the separation of CO_2 from other gases, compression and liquefaction, transport (by pipeline or ships) to the point of injection and injection under pressure.

Separation of CO_2 from other gases can be made by various technologies, and among them some are based on already well-established processes (TRL7). A relevant technology for CO_2 separation consists in scrubbing the CO_2-containing gas mixture with a solvent or a physical absorbent. In combustion applications using air, scrubbing CO_2 out of the flue gases is feasible although very large equipment is required because of the large gas volumes. Oxy-combustion is more favourable from this point of view as it delivers virtually pure CO_2, although additional energy needs to be expended in the air separation unit. Reforming and gasification processes deliver CO/hydrogen/CO_2 mixtures or mostly hydrogen/CO_2 after the shift reaction. In these cases, CO_2 scrubbing is more straightforward. In some cases, for example before syngas is fed to a Fischer-Tropsch reactor, CO_2 scrubbing is required irrespective of the CCS option.

The gas streams could include, but are not limited to, combustion flue gases, process off-gases (i.e. tail gases from steam methane reforming and various refinery processes), syngas (i.e. synthesis gas produced from coal gasification) or natural gas (i.e. from natural gas processing).

CO_2 separation and compression require some energy, the amount depending on the composition of the gas to be scrubbed and of the process used. Processes using a chemical solvent such as Monoethanolamine (MEA), and Methyl Di-Ethanol Amine (MDEA) are more energy-intensive than absorption processes because of the heat needed to regenerate the solvent.

c) Modelling approach in the JEC WTT v5

In many cases the energy effort for CO_2 capture cannot be easily separated from the rest of the plant. E.g. in case of the production of transportation fuel via gasification of coal and biomass with downstream Fischer-Tropsch (FT synthesis downstream the gasifier the CO_2 has to be separated in any case because the FT reactors need synthesis gas with low CO_2 content. The main difference between a FT plant with and without CCS is the compression of CO_2 for transport and injection into the CO_2 repository. The input and output data for the complete plant for the production of liquid transportation fuels from coal via gasification and Fischer-Tropsch synthesis with and without CCS have derived from [Gray 2001; Gray 2005]. The input and output data for the production of liquid transportation fuels from wood via gasification and FT synthesis with CCS have been derived from [Kreutz et al. 2008]. **Table 26** shows the production of FT products such a synthetic diesel from coal as an example.

Table 26. Synthetic diesel via gasification of coal with downstream FT synthesis with and without CCS based on [Gray 2001] and [Gray 2005]

	Unit	Without CCS	With CCS	Comment
Input				
Coal	$MJ/MJ_{FT\ products}$	2.47	2.44	Coal input: 16400 t/d; 27.47 MJ/kg FT products: 33200 bbl/d (w/o CCS); 33570 bbl/d (w CCS); 34.54 MJ/l
Output				
FT products	MJ	1	1	
Electricity	$MJ/MJ_{FT\ products}$	0.33	0.24	697 MW (w/o CCS) 511 MWe (w CCS)
CO_2	$g/MJ_{FT\ products}$	166.7	14.9	

The coal input with and without CCS is approximately the same. The reason for the small difference for coal input probably are differences in the overall process layout. The main difference between with and without CCS is the electricity requirement mainly for CO_2 compression leading to a significantly lower electricity export in case of CCS.

In contrast to processes involving FT synthesis for hydrogen and electricity production the separation of CO_2 from the gas stream leads to additional natural gas and coal requirements. The plants described in [Foster Wheeler 1996] are self-sufficient concerning electricity. No electricity is imported, no electricity is exported. In case of the production of pure hydrogen from natural gas steam reforming without CCS the synthesis gas is at first sent to a CO shift reactor and then directly to a pressure swing adsorption (PSA) plant. The tail gas including the CO_2 from the PSA plant is sent to the reformer burner. If CCS is applied, the CO_2 is removed after the CO shift stage via scrubbing with e.g. MDEA leading to additional electricity and heat requirement besides electricity for CO_2 compression.

For hydrogen from natural gas via steam reforming and hydrogen from coal gasification with and without CCS, the input and output data directly have been derived from [Foster Wheeler 1996]. For hydrogen production from coal without CCS the coal input amounts to about 1.97 MJ per MJ of hydrogen based on the LHV. For hydrogen from coal with CCS the coal input amounts to 2.30 MJ per MJ of hydrogen based on the LHV. The capture rate for the coal-to-hydrogen plant with CCS modelled by Foster Wheeler is rather high leading to CO_2 emissions of about 5.6 g per MJ of hydrogen compared to 189.2 g per MJ of hydrogen without CCS. For hydrogen from natural gas via steam reforming the difference is lower (1.32 MJ of natural gas per MJ of hydrogen for steam reforming without CCS and 1.37 MJ natural gas per MJ of hydrogen for steam reforming with CCS). The CO_2 emissions for the steam reforming plant with CCS amount to about 11.9 g per MJ of hydrogen compared to 72.4 g per MJ of hydrogen without CCS. The CO_2 capture rate is lower in case of steam reforming (about 85% instead of about 97% for coal) because the CO_2 in the flue gas of the reformer burner is not captured. The higher CO_2 recovery for the coal case compared with the natural gas case is due to the fundamental difference that all coal input is gasified within the process and CO_2 captured in-situ. The natural gas case involves a separate natural gas input into the reformer burner and some slippage of methane occurs within the process. Both these factors reduce capture efficiency.

The input and output data for complete plants with CCS instead of adding the energy effort for CO_2 capture also have been applied for electricity generation because of integration of CCS concerning heat supply. For electricity from natural gas two variants have been assessed. One variant with post-combustion CCS based on data in [Rubin 2004] and [Rubin 2005] and one variant with pre-combustion CCS based on data in [SSE 2005]. The data in [SSE 2005] are based on a CCGT power plant project with pre-combustion CCS in Peterhead which was stopped in 2007 [BBC 2007] (A succession project at Peterhead with post-combustion CCS instead of pre-combustion CCS was stopped in 2015 [Cotton et al. 2017]). In case of post combustion CCS, the CO_2 is captured from the flue gas of the gas turbine, in case of pre-combustion CCS hydrogen is generated via steam reforming upstream the gas turbine. For coal electricity only pre-combustion CCS in combination with an integrated gasification combined cycle (IGCC) power plant has been taken into account based on data in [ENEA et al. 2004].

In case of a crude oil refinery where CO_2 is separated from the flue gas form combustion processes mainly for heat and steam supply the energy effort for CO_2 capture can be derived from the CO_2 released by the refinery. The electricity consumption amounts to about 0.159 kWh per kg of CO_2 (CO_2 capture: 0.049 kWh per kg of CO_2 captured; CO_2 compression: 0.110 kWh per kg of CO_2 captured). The steam consumption for CO_2 capture amounts to 4.2 MJ per kg of CO_2 captured [REECS 2007, p. 140, 144]. A capture rate of 90% has been assumed. The CO_2 capture technology is based on scrubbing with monoethanolamine (MEA).

The concept can in principle be applied to many schemes. As illustration of its potential, we have included a CCS variant in the following cases:

- Diesel (crude oil based) produced in a refinery coupled with CCS (New).
- Gasoline (crude oil based) produced in a refinery coupled with CCS (New).
- Electricity from natural gas (CCGT) and coal (IGCC).
- LNG: CO_2 from the power plant associated to the liquefaction plant.
- Hydrogen from NG and coal: Process CO_2 after shift reaction.
- GTL, CTL, and BTL diesel: Process CO_2 after reforming / partial oxidation / gasification.
- DME from NG: Process CO_2 after reforming.

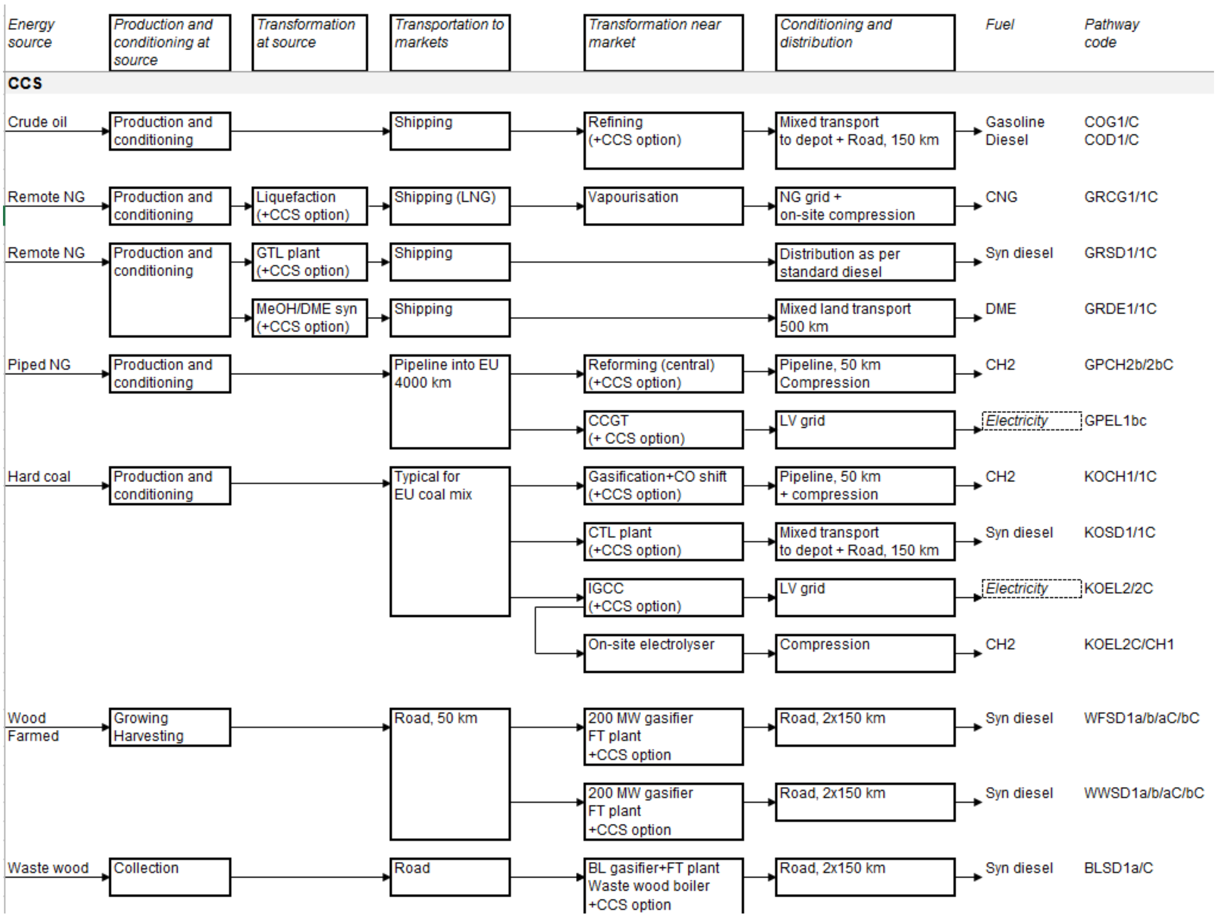
In attempting to assess the CO_2 benefit and energy requirement of CCS in these different cases we found many literature references. In particular we were guided by a study conducted by the IEA's Greenhouse gas R&D programme [IEA 2005]. These do not always include details of the envisaged flow schemes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

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

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

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

Figure 27. Summary of pathways with CCS option



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

3.5.2 Bioenergy with CO_2 Capture and Storage (BECCS). The concept

In the IPCC Fourth Assessment Report by the *Intergovernmental Panel on Climate Change* (IPCC) and also in the COM long-term strategy document mentioned in the section above [EU COM 2018], BECCS was indicated as a key technology for reaching effective negative CO_2 emissions and clearly stated as one of the relevant pathways to pursue net zero emissions in the second half of the century. On the other hand, large-scale deployment of BECCS would imply significant impacts on many Earth system components besides atmospheric CO_2 concentrations such as fresh water use and lead to further transgression of the planetary boundaries for land-system change, biosphere integrity, and biogeochemical flows [Heck et al. 2018].

The idea behind this is that when the CO_2 emitted in sustainable biofuel processes is captured and stored (CCS), carbon-negative value chains are attained as CO_2 sequestered from air as biomass grow is not returned to atmosphere [IEA CCS 2015]. Overall, more CO_2 is withdrawn from the atmosphere than emitted from the tailpipe potentially contributing to a low-CO_2 transport future.

There are different combination of technologies included in the present JEC WTT report where these BECCS schemes, and therefore, negative CO_2 emissions, could be achieved:

- Electric power plants using biomass as energy source.
- Heat power plants, combusting biofuels for heat generation purposes.
- Ethanol production, through routes such as fermentation of biomass.
- Second generation biofuels produced by the gasification of woody biomass associated with CO_2 capture (Fisher-Tropsch with CO_2 capture).
- Biogas upgrading process, where CO_2 is separated from methane to increase the quality of the biogas.

As an illustration of its potential, we have included a BECCS variant in the following cases:

- Fisher-Tropsch diesel from wood residue or farmed wood, coupled with CCS.
- Fischer-Tropsch diesel from black liquor, coupled with CCS.

The energy streams (wood input, output of synthetic gasoline and diesel, electricity export) for Fischer-Tropsch diesel from wood coupled with CCS have been derived from [Kreutz et al. 2008]. The plant consists of air separation for O_2 supply, biomass gasification, purification of synthesis gas, Fischer-Tropsch syntheses, upgrading of crude FT products to gasoline and diesel, power generation via steam turbines, and CO_2 compression to 15 MPa for the transport of CO_2 via pipeline.

Table 27. Synthetic gasoline and diesel via gasification of biomass and Fischer-Tropsch synthesis without and with CCS

Parameter (Input)	Without CCS	With CCS	Comment
Wood chips	2.22	2.22 $MJ/MJ_{FT\ products}$	3044 t dry substance/d; 17.5 MJ/(kg dry)
Output			
FT gasoline and diesel	1 MJ	1 MJ	278 MW (LHV)
Electricity	0.124	0.087 $MJ/MJ_{FT\ products}$	Net electricity export: 34.42 MW (w/o CCS); 24.23 MW (wCCS)
CO_2	-	-115.2 g CO_2/ $MJ_{FT\ products}$	

The input and output data for synthetic gasoline and diesel from black liquor have been derived from [Berglin et al. 1999; Berglin 2006; Ekbom et al. 2005; Landälv 2007; Pettersson 2011]. Black liquor occurs in pulp mills and is generally used for internal heat and electricity supply using a recovery boiler. If the black liquor is used for the production of transportation fuel additional wood is required to meet the heat and electricity demand of the pulp mill.

Table 28. Synthetic gasoline and diesel via gasification of black liquor and Fischer-Tropsch synthesis in a pulp mill with CCS

Parameter	Magnitude	Reference/comment
Input		
Round wood	3.69 $MJ/MJ_{FT\ products}$	2.05 t dry roundwood/(Adt pulp); 10.55 GJ FT products/(Adt pulp) [Berglin et al. 1999; Ekbom et al. 2005; Landälv 2007; LHV (dry roundwood) = 19 MJ/kg
Wood chips	1.06 $MJ/MJ_{FT\ products}$	Shortfall in electricity: 3.59 GJ/(ADt pulp); Extra forest residues for mill: 1.11 GJ/(ADt pulp); Output FT products: 10.55 GJ/(ADt pulp); Efficiency electricity generation: 40% [Ekbom et al. 2005]; Electricity for CCS: 10 MW_e/(244 MW FT products) [Berglin 2006];
Output		
FT gasoline and diesel	1 MJ	
Pulp	0.095 $kg/MJ_{FT\ products}$	[Ekbom et al. 2005]; 1 t Adt pulp/(10.55 GJ FT products)
CO_2	-99.6 g CO_2/ $MJ_{FT\ products}$	[Berglin 2006; Landälv 2007; Pettersson 2011] 87,500 kg CO_2 captured/h per 244 MW of FT products

ADt: Air dry ton

The exported pulp replaces pulp from a pulp mill with a conventional black liquor recovery boiler without CCS. As a result, the requirement of extra forest residues (calculated as wood chips) and all CO_2 captured reallocated to the FT products.

3.6 Transport and distribution

3.6.1 Feedstock transport

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

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

Local transport vectors for crops and intermediates from outside Europe (e.g. soy beans in Argentina, Brazil, USA, vegetable oils in Malaysia) are based on advice from stakeholders and have also been assumed for the calculation of the typical and default values in the recast of the Renewable Energy Directive (RED II).

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

Table 29. Transport vectors for feedstocks

	Local	**To EU**	**Within EU**
Maize to biogas (whole plant)	NA	NA	Road, 20 km
Double crop to biogas	NA	NA	Road, 20 km
Manure to biogas	NA	NA	Road, 5 km
Sugar beet	NA	NA	Road, 30 km
Other EU crops	NA	NA	Road, 100 km
Soy beans Import to EU	Road, 517 km Rail, 179 km Inland bulk carrier (8.8 kt), 615 km	Bulk carrier (Panamax), 9381 km	NA
Soy beans processed at source	Road, 517 km Rail, 179 km	NA	NA
Vegetable oil from soybeans processed at source	Inland tanker (1.2 kt), 562 km	Tanker (23 kt), 11107 km	NA
Fresh fruit bunches /FFB from oil palm	Road, 50 km	NA	NA
Palm oil	Road, 120 km	Tanker (23 kt), 16287 km	NA
Carcass	NA	NA	Road, 30 km
Tallow	NA	NA	Road, 150 km

3.6.2 Biofuels and Synthetic fuels transport and distribution

(See also workbooks WTT v5 pathways 2-CBM/3-Ethanol/4-Biodiesel/5-Synfuels)

3.6.2.1 Liquid fuels

Long-distance transportation

Fuels from a remote plant will be transported by ships appropriate to the type of product. Synthetic hydrocarbons can be transported in conventional product carriers. Ethanol and biodiesel do not have specific requirements either but are likely to be transported in smaller ships because of the volumes involved and/or the capacity of loading ports. Large methanol ships already exist today.

Distribution within Europe

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

For biodiesel manufactured in Europe, we have assumed blending with conventional fuels is more likely to occur down the distribution chain. Accordingly, we have used two standard road transport vectors of 150 km each representing trips from the plant to a blending depot (or a refinery) and from the depot to the filling station.

We have assumed that synthetic diesel manufactured in Europe in large plants (CTL) would necessarily go through blending in a refinery and we have used the standard transport vector for conventional fuels followed by the 150 km road transport for final distribution (pipeline/rail/water, see *section 3.1.4*). Imported synthetic diesel from a remote location would be available at an EU entry port and in case of blending with refinery products (the most likely use) the conventional fuels transport vector would apply.

Ethanol cannot generally be transported in standard multiproduct pipelines so a mixed transport using ships, trucks, and rail has been assumed analogous to the RED II pathways. For methanol, DME, and synthetic diesel from wood also a mixed transport using ships, trucks, and rail has been assumed.

Methanol cannot be mixed with conventional fuels. Its introduction in the existing multi-product pipeline infrastructure is not technically feasible. It would therefore require a specific distribution system. A dedicated methanol pipeline network is unlikely to be built at least as long as the market remains limited. For bulk imports, distribution of 500 km from a coastal import terminal was therefore assumed on the basis that bulk products would be distributed over a wide area. Intermediate depots may be involved but the associated extra energy consumption would be insignificant.

For methanol from biomass we assumed a single road transportation leg of 150 km, recognising the fact that the plants would be of limited size and serving the local market. For methanol from wood a mixed transport using ships, trucks, and rail has been assumed analogous to the RED II pathways.

3.6.2.2 DME

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

In case of biomass derived DME a mixed transport using ships, trucks, and rail has been assumed analogous to the RED II pathways.

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

3.6.2.3 Biogas

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

Table 30. Transport vectors for fuels

	To EU	Within EU	
		To depot*	To filling stations
Crude oil based gasoline and diesel, Syn-diesel from coal	NA	Inland barge (9 kt), 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
Ethanol produced within EU	NA	Road, 305 km (13.2%); sea-going product tanker, 1118 km (31.6%); inland barge, 153 km (50.8%); Rail, 381 km (4.4%)	Road, 150 km
FAME produced within EU	NA	Road, 150 km	Road, 150 km
Ethanol bulk imports (Brazil)	Road, 700km Tanker (13 kt), 5,500 nautical miles	Road, 305 km (13.2%); sea-going product tanker, 1118 km (31.6%); inland barge, 153 km (50.8%); Rail, 381 km (4.4%)	Road, 150 km
MTBE (remote)	Tanker (50 kt), 5,500 nautical miles	Inland barge (9 kt), 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
ETBE		Inland barge (9 kt), 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
Syn-diesel from biomass (BtL)	NA	Road, 305 km (13.2%); sea-going product tanker, 1118 km (31.6%); inland barge, 153 km (50.8%); Rail, 381 km (4.4%)	Road, 150 km
Syn-diesel from remote NG	Tanker (50 kt), 5,500 nautical miles	Inland barge (9 kt), 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
Methanol from remote NG	Tanker (50 kt), 5,500 nautical miles	NA	Rail, 250 km Road, 250 km
DME from remote NG	LPG carrier (84 km^3), 5,500 nautical miles	NA	Rail, 250 km Road, 250 km
Methanol or DME from biomass	NA	Road, 305 km (13.2%); sea-going product tanker, 1118 km (31.6%); inland barge, 153 km (50.8%); Rail, 381 km (4.4%)	Road, 150 km
LPG (remote)	LPG carrier (84 km^3), 5,500 nautical miles	NA	Road, 500 km

3.6.3 Hydrogen transport and distribution

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

Compressed hydrogen from a central plant can be transported either in pipelines at moderate pressures (2-4 MPa) or at high pressure (20-30 MPa) in cylinders loaded on a road truck. In the case of a large central plant, the average distribution distance has been taken as 50 km. Generally the pressure available at the plant outlet is considered sufficient to carry the hydrogen through a 50 km pipeline without the need for additional energy input. A residual pressure of 2 to 3 MPa has been assumed at the refuelling site, depending on the type of plant. Hydrogen from small on-site steam reforming plants will generally be available at a somewhat lower pressure of typically 1.5 MPa. Hydrogen from small on-site electrolysis plants can supply hydrogen at a pressure of 3.0 MPa.

Gaseous hydrogen reaching the refuelling station needs to be compressed to the high pressure required to store sufficient fuel on-board. The current “state-of-the-art” is 35 MPa although tests are already underway for 70 MPa storage tanks. In practice, this requires a compressor discharge pressure of 45 MPa or 88 MPa to ensure an adequate filling time. The 70 MPa level is required to allow an acceptable vehicle range. For this reason, it is expected to become the standard and we have calculated the pathways for that case (this is also consistent with the assumptions made for the on-board storage in the *Tank-to-Wheels report*). The compression process includes precooling at -40°C.

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

Long-distance transport of liquid hydrogen from a remote plant would require special ships for which only design concepts and lab-scale experiments (e.g. [Maekawa et al 2017]) exist today. The LH2 carrier is the critical process for pathways involving long-distance LH2 transport concerning the technical readiness level (TRL). The TRL is set to 4. A prototype LH_2 carrier is planned until 2020 in Japan [Nishimura 2018]. If this project is successful the TRL will increase to 6 or higher. Liquid hydrogen would be further transported by road from the EU entry port directly to the service stations (assumed distance 500 km). Liquid hydrogen from an EU plant would also be transported by road albeit along a somewhat lower average distance (assumed 300 km) as it can be surmised that the plant would be better located to serve the market.

Hydrogen can be stored in the vehicle in either compressed or liquid form. In recent years the “cryo-compression” alternative has been suggested, whereby liquid hydrogen is pumped into the vehicle tank and compressed at a maximum of 35 MPa or 50 MPa [Ahluwalia et al. 2018]. A super-insulated cryo-tank is used that can also withstand these pressures. The main advantage is to allow a longer "dormancy period” i.e. the time that the vehicle can be left idle without losing too much fuel by evaporation. Under 30% of the maximum tank capacity no hydrogen loss occurs even after long periods of time without operating the vehicle.

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

3.7 Biomass pathways

(See also workbooks WTT v5 pathways 2-CBM/3-Ethanol/4-Biodiesel/5-Synfuels/6-Electricity/7-Heat & Power)

Biofuels have been proposed as a way to reduce the global warming effect of transport fuels as well as helping to diversify their sources of supply. In the energy sector biomass can also play the role of grid balancer, as storable solid, liquid and gaseous energy vectors can be produced from it.

Despite these potential advantages, if not properly managed, significant reduction in environmental benefits may occur. The availability of biomass and the production of fuels from it is a complex question intimately tied to the cost, because of the diversity of agricultural conditions in EU and beyond. We have endeavoured to include all sources of biomass which have the potential to produce biofuels to substitute a significant amount of transport fuel in the EU i.e. farmed crops such as sugar beet, wheat and oil seeds and woody biomass either in the form of waste or purpose-grown. “Wood farming” also represents perennial grasses such as miscanthus or switch grass.

We do not attempt to calculate *Direct Land Use Change* (DLUC) and Indirect Land Use Change (ILUC) emissions in this report, because the subject is still controversial and we lack the appropriate tools. However, we do consider these emissions essential for accounting the climate change effects of biofuels. However, Appendix 5 (*Potential effects of DLUC and ILUC on biomass based pathways*) explores potential effects on the GHG performance of biomass based alternative fuel production, and use (as mentioned, not included in the scope of the JEC WTT analysis).

3.7.1 Carbon Debt and Credit

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

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

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

Forest residues are branches, tops and sometimes leaves and stumps, which are traditionally left in the forest at harvest, but which can also be collected for energy use. They would rot if left in the forest, but this process can take up to 20 years, so there is a temporary carbon debt. If consistently removed, there is also a small reduction in the long-term soil carbon stock in the forest, which can be considered like a land use change emission. Nevertheless, forest residues represent a low-emission source of energy [Bellassen and Luyssaert][24].

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

3.7.2 Nitrous oxide emissions

3.7.2.1 Background

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

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

3.7.2.2 Sources of N_2O emissions

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

- a direct pathway

  i.e. directly from the soils to which the nitrogen is added/released, and:

- two indirect pathways[25]:

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[24] https://www.nature.com/news/carbon-sequestration-managing-forests-in-uncertain-times-1.14687

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

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

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

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

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

3.7.2.3 Methodology

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

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

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

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

In version 3 of this study we applied a tier 3 approach, estimating N_2O using a soils chemistry model applied to the extensive local data available for sites growing particular crops in the EU15 in the LUCAS land-cover survey. Unfortunately, the same approach was impossible for crops grown outside EU because there was not enough input data available; in these cases, we were obliged to fall back on IPCC tier 1, with its high uncertainty.

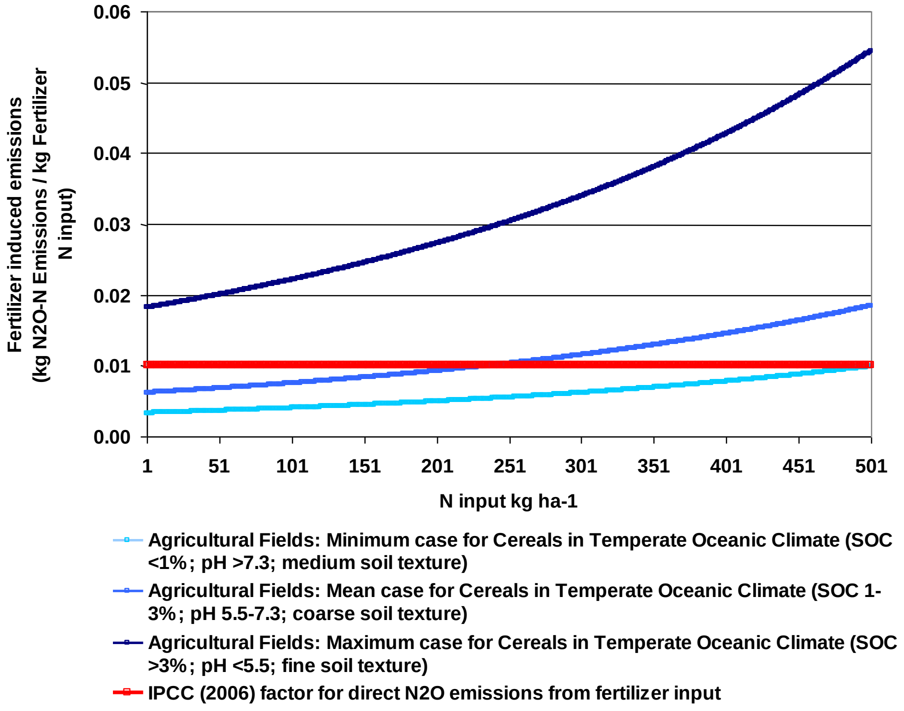
In this version, we use the same N_2O emissions as calculated by JRC for the "typical" and "default" emissions in Annex V of the recast of the Renewable Energy Directive, 2018. an IPCC "tier 2" approach, because it requires less detailed input data than tier 3, and could thus be applied equally to crops grown both inside and outside EU. Furthermore, although a tier 3 soils model should give a more accurate prediction of emissions on a particular field if all the input data is known, we fear that inaccuracies in the soils chemistry model may lead to systematic errors in the *average* of emissions for a particular crop. This is avoided in our new approach.

The tier 2 methodology used in this version was developed by the Climate Change Unit of JRC's Institute for Environment and Sustainability (IES), and called 'Global crop and site specific Nitrous Oxide emission

Calculator (GNOC)'. It is available as on-line tool which will enable estimates to be made of N_2O emissions for any crop in any place in the world, using estimated or specified input parameters: http://gnoc.jrc.ec.europa.eu/.

Example output from the model is shown in **Figure 28**. The mean line is close to the IPCC generic figure, but takes account of fertiliser input rates. The GNOC models the effect of soil organic carbon and pH, and the impact can be seen by the minimum and maximum cases. Even with this improved discrimination, there remains a large uncertainty in the estimates.

Figure 28. Nitrous oxide emissions from the GNOC calculator for temperate climates



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

The GNOC tool was already used to calculate N_2O emissions in version 4 of the WTW study, but in version 5 we have updated the nitrogen inputs per crop using 2016 data from Fertilizers Europe, whilst the crop yields are the average of FAO yields for 2009-2014. The significance of field N_2O emissions in the overall WTT calculation is illustrated by these example figures for the main EU crops considered in the study and shown in **Table 31.** Note that the total WTT GHG emissions may be less than the cultivation emissions after co-product credits are taken into account.

Table 31. N_2O contribution to GHG emissions for the main biofuels crops

Final fuel	**Crop**	**Pathway code**	**GHG emitted (g CO_{2eq}/MJ final fuel)**			
			WTT	**Cultivation**		
			Total	**Total**	***of which N_2O***	
Ethanol	**EU crops**					
	Sugar Beet	SBET1a	32.6	13.3	*7.4*	*56%*
	Wheat	WTET1a	65.4	45.8	*26.9*	*59%*
	Barley/Rye	BRET2a	65.1	55.3	*28.2*	*51%*
	Maize	CRET2a	57.5	36.1	*22.4*	*62%*
	Wood	WFET1a	32.4	11.1	*6.7*	*60%*
	Straw	STET1a	18.4	4.5	*0.0*	*0%*
Biodiesel	**EU crops**					
	Rapeseed	ROFA1	48.7	50.5	*30.1*	*60%*
	Sunflower	SOFA3	42.7	39.1	*20.2*	*52%*
	Imported crops					
	Soya	SYFA3a	56.5	61.8	*38.4*	*62%*
	Soya	SYFA3b	59.4	61.8	*38.4*	*62%*
	Palm Oil	POFA3a	51.2	28.8	*17.9*	*62%*
	Palm Oil	POFA3b	32.0	28.8	*17.9*	*62%*

Rapeseed has high emissions because it is grown in the Northern half of Europe, where soils generally have a higher organic content. Sunflower, grown in the drier South, has lower emissions per ha, which the low yield does not entirely compensate. It also has the lowest contribution from “indirect” emissions from leached nitrogen, which reduces the error range. The high yield of sugar beet, and the fact that it cannot be grown on badly-drained soil, brings its emissions below that of the other grain/seed crops. Farmed wood and straw have the lowest N_2O emissions.

3.7.2.4 Top-Down estimates

Calculation of N_2O emissions remains challenging and there is considerable uncertainty in the results. Top-down estimates have suggested these 'bottom-up' calculations may significantly underestimate the real emissions of N_2O from agriculture [Crutzen 2007; Davidson 2009]. They compare the known emissions of N_2O to the levels actually found in the atmosphere. Taking into account the mechanisms that slowly remove N2O from the atmosphere over time, they estimate that N_2O emissions from agriculture may be as much as three times higher than those produced by 'bottom up' calculations as used in our study. They also comment on the implications for biofuels. Such higher N_2O emissions would obviously reduce the GHG savings from biofuels, and could even lead to GHG increases, even without considering ILUC emissions.

However, [Crutzen 2007] attributed all emissions only to fertilizer application; the discrepancy is smaller if one includes nitrogen from manure and crop residues in the IPCC tier 1 estimates. Nevertheless, it seems that N_2O emissions from nitrogen that is removed from the field by leaching and run-off may have been under-estimated in the 2006 IPCC guidelines that we are using to estimate that part of the emissions.

3.7.3 Farming inputs and yields

In this version of JEC WTT v5, the input data describing the inputs and emissions for cultivation, and the crop yields, are taken from the JRC's assessed input data used for the "typical" and "default" emissions calculations for biofuels, bioliquids, solid biomass and biogas in annex V of the recast of the EU's Renewable Energy Directive, directive 2001/2018. The data and a detailed explanation is available on-line [JRC 2019]. This also documents the two rounds of consultations with stakeholders (in 2013 and 2016), including their comments, and the updates made.

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

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

Nitrogen is the main fertiliser input. Potassium and phosphorous fertilizer rates vary greatly according to geography, but hardly correlate with yield. For EU, we took the average fertilizer use per hectare for different crops from Fertilizers Europe 2016; for other countries, we took data from the International Fertilizer association 2013. These were the latest data available at the time. The fertilizer use is based on sales data, with fertilizer attributed to different crops by fertilizer experts. We consider these figures to be more reliable than those derived from limited farm surveys.

Unlike other biofuel feedstock crops, sugar beet is not traded over long distances, but processed very locally. Therefore, it is appropriate to use the yield data for the countries where ethanol is produced from these crops, rather than EU-average data.

Where straw is collected, fertilizers should be added to compensate for the lost minerals, but the effect of this on the calculations for straw pathways is minor. We do not assume that more nitrogen must be added to compensate for the nitrogen removed in the straw, because the decomposition of the straw also consumes nitrogen from the soil.

Nitrogen fertilizer causes soil acidification. Since version 4 we calculate how much CO_2 is emitted when this acid is neutralized, either by applied agricultural lime (aglime) or by carbonates that are naturally present in the soil. However, responding to stakeholder comments, in version 5 we use the acidification-induce emissions recommended by Fertilizers Europe [JRC 2019].

Production emissions for agricultural lime (aglime) ignore the contribution of calcined limestone (CaO or $Ca(OH)_2$), as almost all aglime used these days is ground carbonate rock.

We exploit the GIS capabilities of JRC's GNOC model to calculate aglime use and emissions per crop, as detailed in [JRC 2019]. Starting with our best estimate of aglime use per country, GNOC distributes on a GIS basis, proportional to recommendations for aglime use as a function of the soil type and.pH. Then we calculate the emissions from that aglime reacting with soil acidity. According to IPCC guidelines, one should assume that all the CO_2 content of aglime is released; however, we applied a more sophisticated calculation which indicates that on neutral soils (pH > 6.4) only about 18% of the aglime's CO_2 content is released. To avoid double-counting, the local CO_2 emissions attributed to N fertilizer acidification are subtracted from the local aglime CO_2 emissions, so that remaining emissions attributed to aglime application are for where it is applied to counter natural acidity in the soil.

3.7.4 Credits for animal feed co-products

At present the main co-products of biofuel manufacture are rapeseed meal from biodiesel and *Distiller's Dried Grain with Solubles* (DDGS) from cereals-ethanol. These are rich in protein, but not as rich as soybean meal, the main protein concentrate feed in EU. Therefore, they substitute a mix of soybean meal and carbohydrate feeds. In practice, a wide range of animal feed products are substituted in EU. However, many of these (such as gluten feed, which is compositionally closest to DDGS) are themselves co-products of another process, so their supply hardly reacts to changes in biofuel production. The main *marginal* source of carbohydrate feed is cereals, which we represent by EU feed-wheat, whilst the main marginal source of protein is clearly soybean meal. We consider soybean meal from a weighted mix of soybeans from EU, Argentina, Brazil, and USA.

3.7.4.1 The animal-feed substitution calculation

Our calculation is made assuming that the co-products are eaten by cattle. Although some feed may be consumed by pigs and poultry, cattle are the largest consumers of animal feed and are also more suited to this purpose than pigs and poultry. This is because cattle are relatively less efficient at digesting soybean meal, and are not troubled by the high fibre content of some co-products. To find the maximum proportion of soybean meal substituted, one should ideally balance all the essential amino acids as well as the overall metabolizable protein and digestible energy. Furthermore, depending on what else is fed to the animals, some co-products may improve the weight-gain per tonne of feed ("feed efficiency") more (or less) than indicated by the digestible energy ratio. However, that would be a complex task to take these effects into account for all products and feed combinations. For simplicity we balance only digestible energy and total metabolizable protein. However, this over-estimates the fraction replaced by soybean meal, because it does not take into account differences in protein quality. For example, largely DDGS inherits the amino acid mix in cereals, but animals that are already fed cereals are particularly short of certain essential amino acids that are more concentrated in soybean meal, so less soybean protein is needed than DDGS-protein to balance the diet. Furthermore, in some cases the local over-supply of DDGS, especially wet DDGS in USA, means that more is fed to animals than they need just to get enough protein, so extra DDGS production merely provides digestible energy, substituting mainly corn. These effects are considered in more detail in WTT spreadsheets.

3.7.5 Agro-chemicals production

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

The main types of nitrogen fertilizer are urea and nitrates, such as ammonium nitrate. Urea is made from ammonia and CO_2. However, the CO_2 is released when it is applied to the soil, so we do not count its use as a negative emission (unlike in ECOINVENT, for example). For ammonia and urea production, we use the data on natural gas and other energy inputs from Fertilizers Europe (the results on emissions are slightly different from Fertilizers Europe because with use different upstream emissions, and consider also imported products used in EU).

Nitrate fertilizers use nitric acid, which is also made from ammonia, but releases N_2O from the plant. In WTWv4, we assumed linear progress between the last-reported emissions and 2020 emissions baseline of the Emissions Trading Scheme (ETS). However, in this version we recognise that the industry already exceeded its 2020 emissions reduction target, so we use the last-reported emissions.

For crops grown outside EU, emissions from N fertilizer production are probably higher in general, but we assume the same emissions as for EU consumption.

3.7.6 Other environmental effects of biofuels

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

- **Soil quality/erosion**

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

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

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

On the other hand, there are initiatives trying to promote the recovery of already degraded soils (i.e. marginal land in Spain) by producing biofuels (e.g. BIO4A[26]) but still cost feasibility has to be demonstrated at large scale.

- **Eutrophication and acidification**

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

- **Biodiversity**

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

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

- **Impact on water table**

The increased growth of crops requiring extensive irrigation in arid areas will put pressure on water resources. For example, sugar beet cultivation in Spain and Greece has a very high percentage of irrigated area (76 and 99% respectively as reported by Eurostat). In Italy it is lower but still over a third of the area compared with 6% for durum wheat and 7% for sunflower. Water use per tonne of dry matter is around 200 litres for sugar beet and 300 litres for wheat.

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

- **Introduction of non-native species and GMOs**

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

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

3.7.7 Biomass transportation

The energy and GHG emissions for biomass transportation to the processing plants are a very minor part of all pathways. The modes of transport and distances considered are summarised in *section 3.7*.

The following sections includes more details on how different biofuel pathways have been modelled. A detailed comparison of the pathways updated and newly added in the present report (v5) versus WTT v4 is included in **Appendix 3**.

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[26] https://www.bio4a.eu/

3.7.8 Crop based pathways

3.7.8.1 Ethanol

Summary

Changes vs Version 4

Significant update on the existing fuel pathways (Ethanol)

SBET1a/b/c, CRET2a , CRETus - The GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for cultivation, fertilizers, harvesting, etc., and partly adapted similar assumptions to RED II for transport and distribution of the final fuel.

STET1 - The inventory for ethanol production process has been updated based on the latest literature / site-specific data.

WFET1a, WWET1a, WFET1b, WWET1b: The energy consumption and GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for forestry residue collection, short rotation forestry, wood chips storage (seasoning), biomass transport, and are partly adapted similar assumptions to RED II for transport and distribution of the final fuel. New variants have been introduced with different transport distance and modes for the transport of wood chips (a: truck, 500 km; b: truck, 250 km, ship, 2000 km). Pathways involving waste wood uses forestry residue.

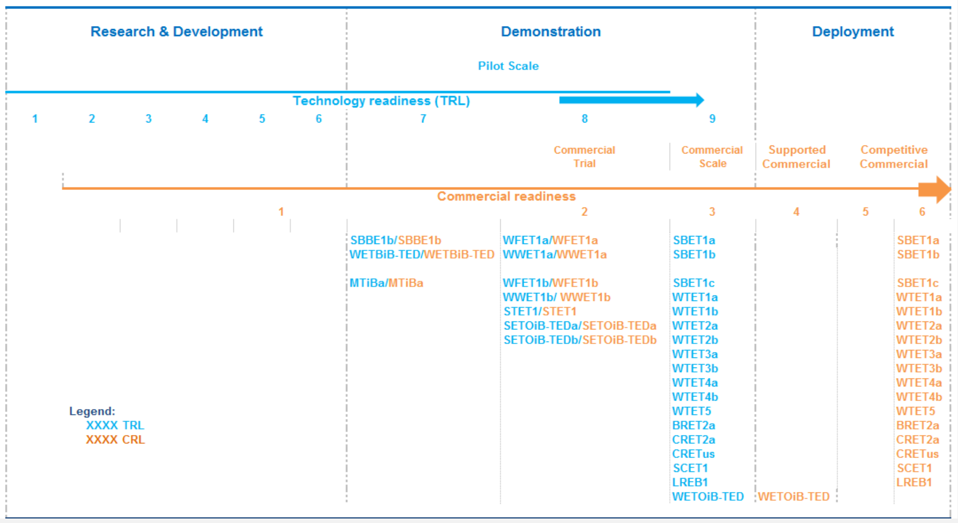
STET1: Transport of straw via truck over a distance of 500 km similar as in RED II. The energy consumption and GHG inventory of ethanol plant has significantly changed as this version uses basic assumptions in RED II for the input and output data. The transport and distribution of the final fuel are also adapted to similar assumptions in RED II.

Newly added fuel categories and pathways

ETBE - SBBE1b **ED95** - *WETOiB -TED, WETBiB -TED, SETOiB - TEDa, SETOiB –* TEDb

Addition of TRL and CRL

Figure 29. Ethanol pathways TRL/CRL



3.7.8.1.1 Sugar beet to ethanol

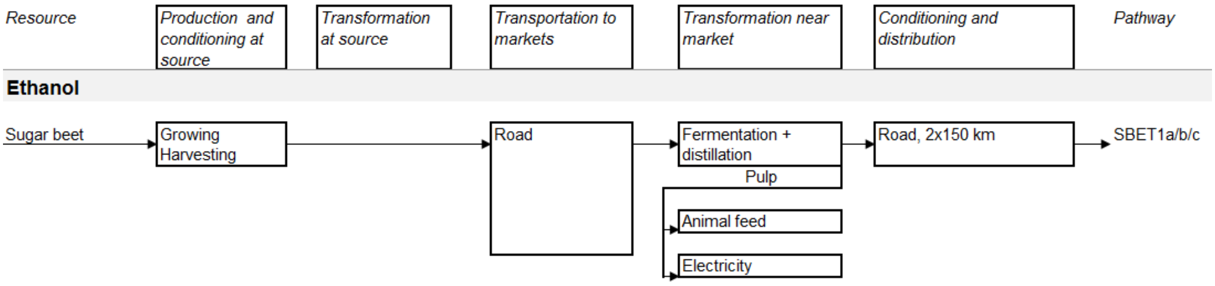
Sugar beet is a high yield crop. It produces carbohydrate already in the form of sugar and is easily crushed and mashed for fermentation which makes the processing into alcohol rather cheap. The economics of its cultivation are highly distorted by the CAP.

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

To improve the yield of ethanol, the pulp could, in principle, be treated by a SSCF-type process (Simultaneous Saccharification and Co-Fermentation) to break down the cellulose and hemicellulose.

We have therefore considered 3 sugar-beet-to-ethanol pathways as shown below. SBET1a/b consider use of pulp for animal feed with the slops either not used or added to the biogas digester, while SBET1c uses pulp as fuel and slops for biogas production both of which are used for co-generation of electricity and heat.

Figure 30. Sugar beet to ethanol pathways



3.7.8.1.2 Wheat to ethanol

Ethanol can be produced from wheat grain by hydrolysis and fermentation. The process is more complex and therefore more expensive than with sugar beet. Milling and distilling are the most energetically expensive parts of the wheat-to-ethanol pathway. These processes require some electricity but mostly heat. This makes the scheme well suited for supplying the energy required with a combined heat and power scheme (CHP). We chose wheat-to-ethanol to illustrate the effects of choosing different fuel and CHP options; not all these variants exist in commercial practice.

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

Energy supply options

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

- WTET1: Conventional natural gas boiler

  Heat is supplied by a conventional natural gas fired boiler and electricity is imported. This can be considered as representative of the vast majority of existing installations and is also by far the cheapest solution. In this WTW version, we slightly amended the inputs for this plant after checking the data against other sources - see [JRC 2019] for details.

- WTET2: Combined cycle gas turbine

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

- WTET3: Lignite boiler CHP

  High pressure steam is produced in a lignite (brown-coal) boiler. A back-pressure turbo-generator produces electricity and low pressure steam for the process. Here again the plant is assumed to be sized and operated to produce the heat required for ethanol manufacture but it nevertheless generates an electricity surplus. Lignite is a cheap and abundant fuel used for electricity production in certain parts of Europe, but we are not aware that a wheat-ethanol plant using lignite as fuel exists at the moment: the pathways is there as an illustration.

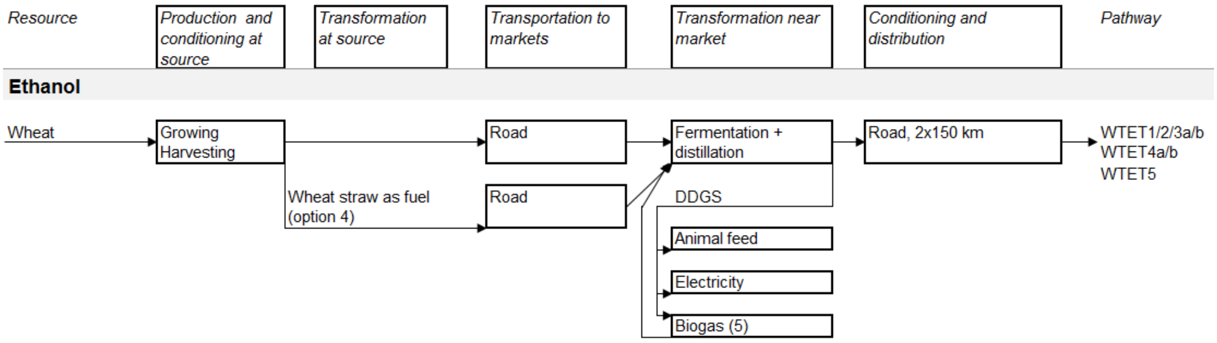
- WTET4: Wood chip fired boiler CHP

  Wheat cultivation produces large amounts of straw. Some studies have considered straw as a co-product, but in most of the EU it should be ploughed back to maintain the water-retention properties of the soil. In practice straw use should only be proposed where there is little water stress, a high density of cereals production and a low density of livestock. This scheme is similar to the previous case but straw in used instead of lignite. The main advantage of this scheme is to use a renewable source of energy to drive the process. However, analogous to the pathways calculated for the recast of the EU Renewable Energy Directive wood has been used instead of straw for the CHP plant.

- WTET5: DDGS to biogas

  This pathway considers use of the DDGS to produce biogas, which is then used to produce heat and electricity to supply all the heat and most of the electricity needs of the ethanol plant. The residue from the biogas digester still has value as a fertiliser and generates a credit for the overall process.

Figure 31. Wheat grain to ethanol pathways



DDGS

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

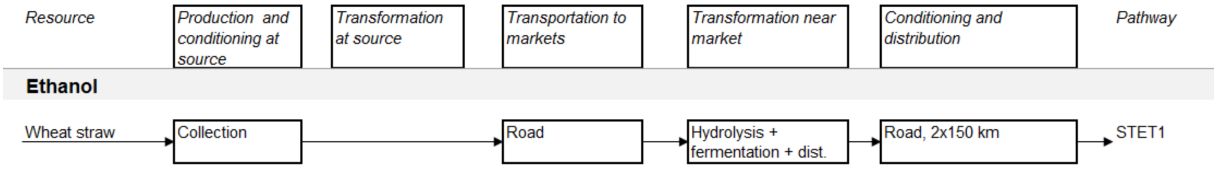
An alternative use of the DDGS is also modelled, to produce electricity and heat in the ethanol plant via a boiler and steam turbine.

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

3.7.8.1.3 Straw to ethanol

The SSCF (*Simultaneous Saccharification and Co-Fermentation*) process that turns cellulosic material like straw into sugars that can then be fermented to ethanol. If the cellulosic material is not diverted from use for food or animal feed, then this is a *second-generation* process for ethanol. We have taken the example of wheat-straw as a feedstock. Vast resources have been put into subsidizing the construction of several innovative plants, (especially in the USA), but as far as we are aware the only commercial production from “cellulosic material” is from corn cobs; however, it is unclear how much of the ethanol produced actually comes from the cellulose, and how much from the starch content of the cobs.

Figure 32. Wheat straw to ethanol pathways



3.7.8.1.4 Ethanol from sugar cane (Brazil)

Sugar cane is an excellent biomass crop from almost every point of view, but cannot practically be grown in Europe. Production of ethanol from sugar cane has been pioneered in Brazil and we have used Brazilian data to represent this pathway. Sugar cane resembles more a permanent biomass crop like miscanthus than it does an arable crop. In Brazil, there are usually 5 harvests, with very high annualized yields of about 63 t/ha/a (moist). Each tonne yields 86 litres (1.83 GJ) anhydrous ethanol at a conservative estimate. Yields may be much lower in areas that do not benefit from Brazil’s favourable combination of warm temperatures and abundant rainfall.

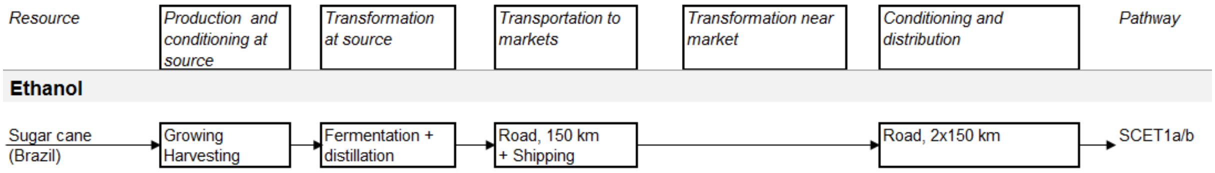
Brazil is the by far the world’s largest producer, and has the greatest potential to expand production. The main growing area is in the South of the country, around Sao Paulo province. Expansion of sugar cane growing would occur in this and neighbouring regions, mostly at the expense of rough grazing land. There is a small amount of sugar cane production in the coastal areas of the northeast, nearer some patches of Atlantic rainforest. However, new production areas in Mato Grosso and Mato Grosso del Sur impinge on natural Cerado (savannah-type) land-cover, either directly, or indirectly through displaced ranching. Cerado has high biodiversity, but does not store as much carbon as rainforest.

Unlike arable crops in Europe, planting sugar cane on grazing land may increase soil carbon stocks, although some studies still show significant land change effects. The risk of soil erosion (a major concern in Brazil) is only heightened in the first year of establishment. The plant has low fertilizer and water requirements and has low levels of minerals in the foliage.

A major benefit of the sugar cane to ethanol process is that the process electricity and heat is entirely provided by the bagasse. The vinasse from the fermentation vats is nowadays recycled to the fields. The emissions calculation takes into account that sometimes the foliage is burned to allow easier harvesting. There is a small surplus of bagasse which can provide fuel for a neighbouring food-processing plant (for example, orange juice production), generating a credit for saved fuel oil. There is also an initiative by Sao Paulo province to encourage co-generation of excess electricity to replace imported electricity from other provinces. We have considered that making use of this excess bagasse will become the norm and have shown the case where electricity is produced.

We have taken most of our input data from Macedo et al. [Macedo 2008], with the exception of fertilizer use, as explained in *section 3.7*.

Figure 33. Sugar cane to ethanol pathway



3.7.8.1.5 Ethanol to ETBE

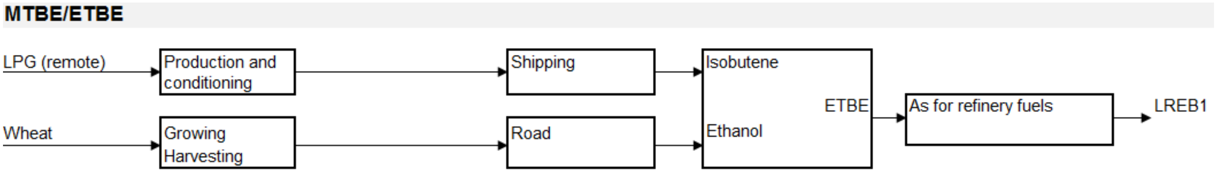
As an alternative to using ethanol directly as a gasoline blending component, ethanol can be converted to ETBE (Ethyl-Tertiary-Butyl Ether). ETBE is a high-octane component with very similar properties to MTBE but with a somewhat lower solubility in water. The main advantage of ETBE over ethanol as a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

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

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

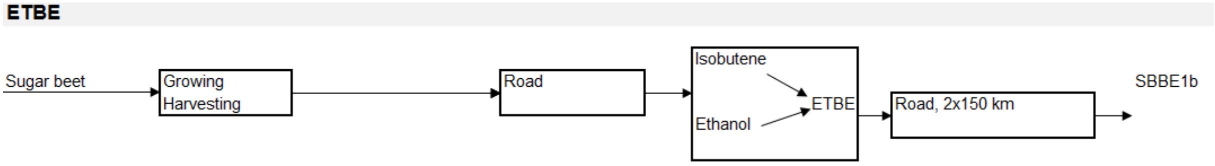
Should more ETBE be required it would have to be made from isobutene produced by isomerisation and dehydrogenation of normal butane. We have represented this pathway with the assumption that the marginal butane required is imported from gas fields.

Figure 34. Wheat-ethanol to ETBE pathway



Meanwhile a process has been developed by Global Energies where the isobutene can be derived from biomass [GBE 2018]. This novel pathway has been modelled in this WTT v5 where both the ethanol and isobutene have been produced from sugar beet leading to a fully bio-ETBE pathway:

Figure 35. Wheat-ethanol and Sugar beet ethanol to ETBE pathways



3.7.8.1.6 Ethanol admixture to ED95

ED95 is a mixture of ethanol, ignition improver (modelled as polyethylene glygol (PEG)), MTBE, i-butanol and lubricants [SCANIA/SEKAB 2018] to produce a fuel suitable for dedicated compression ignition (diesel-like) engines.

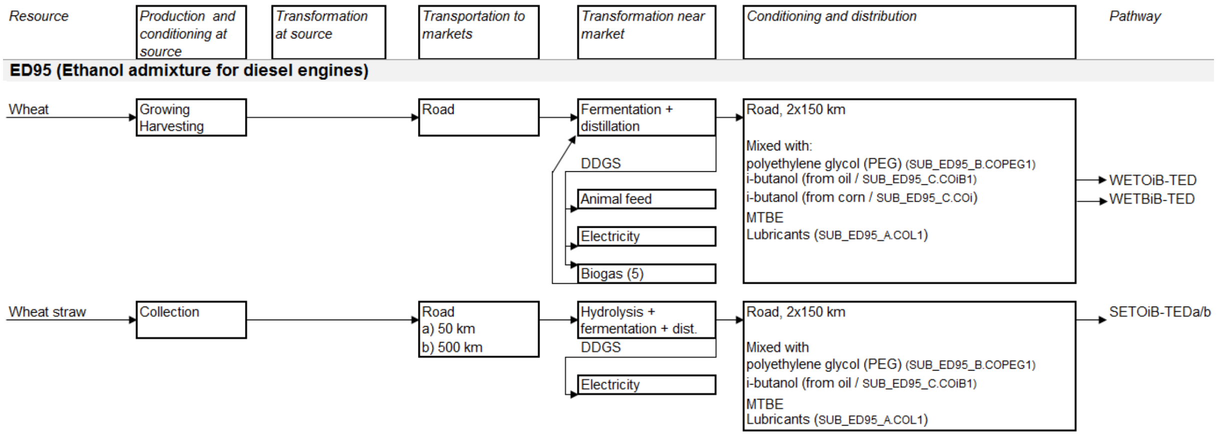
Table 32. ED95 composition modelled in JEC WTT v5 based on SEKAB 2018 (%-mass)

	Ethanol	Ignition improver PEG (n 8.7)	MTBE	I-butanol	Lubricants
ED95	**91.46%***	**4.97%**	**2.14%**	**0.43%**	**1%**

*The ethanol includes some water (6.25% by mass)

As representative examples of this new type of fuel, we have selected a conventional ethanol pathway based on wheat and a second-generation ethanol pathway based on straw as feedstock and modelled the other components as detailed below:

Figure 36. Wheat and Wheat straw ethanol admixture to ED95



In the wheat-based ethanol cases, the main i-butanol route modelled is through the processing of crude oil-based naphtha being refined in Europe with downstream steam cracking, followed by the production of final i-butanol via oxo synthesis ready to be mixed for ED95 supply [GEMIS 2016] (propene via steam cracking of naphtha), [Ecoinvent 2007] (i-butanol from propene, carbon monoxide, and hydrogen via oxo-synthesis; carbon monoxide from heavy fuel oil). Besides this, a more optimistic alternative route to produce i-butanol from corn has also been included, via the technology used in the Gevo Luverne facility where the energy demand is met by biogas from land fill [EPA 2017; Lund 2013]. Due to the small share of i-butanol in the ED95 mix, the total impact in terms of GHG savings is limited.

3.7.8.2 Biodiesel & HVO from Vegetable Oils

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

Pure vegetable oils are unsuitable for a direct use in modern reciprocating engines, because of its high viscosity and gum content. Although special engine modifications have been proposed to run on pure oils in limited applications, the oil generally needs to undergo processing to produce a free-flowing fuel that is miscible with conventional diesel to obtain a fuel which respects the technical specifications set by engine manufacturers.

The most common process is esterification i.e. the reaction of the organic acid functions with an alcohol. However, a rival process producing hydrotreated vegetable oil is becoming increasingly important (see section 3.7.8.2.2). Esterification is an essential step to ensure the resulting fuel is stable. Vegetable oil can be thought of as three fatty acid "ribs" attached to glycerol (propane-1,2,3-triol) "backbone". The "trans-esterification" process consists of replacing the glycerol with three methanol molecules, so that three separate fatty-acid methyl ester (FAME) molecules are formed from each molecule of plant oil. The processing is relatively straightforward, cheap, and does not require a lot of energy.

Today methanol is used as it is abundantly available and cheap, however ethanol can be used instead. We have included this option in combination with rapeseed to show the impact of using bio-ethanol on the overall energy and GHG balance (to produce a fatty acid ETHYL ester (FAEE). In representing this option, we assumed the same energy input as for FAME for the esterification process, the benefit coming from the use of a partially renewable alcohol. This has the advantage of exploiting the GHG savings of bioethanol whilst replacing diesel, which eases the imbalance in the refining industry. However, if there is no economic advantage in improving the GHG performance of biodiesel beyond an already-attainable threshold, FAEE is unlikely to be produced extensively in practice.

Summary

Changes vs Version 4

Significant update on the existing fuel pathways (Biodiesel and HVO)

Rapeseed oil, Sunflower oil, Soybean oil, palm oil, waste oil and tallow oil-based pathways (ROFA1, ROFA2, ROFA3, ROFA4, ROFA5, SOFA3, SYFA3a, SYFA3b, SYFA3d, POFA3a, POFA3b, POFA3c, WOFA3, TOFA3, ROHY1a, ROHY1b, ROHY4, SOHY1a, SYHY1a, POHY1a, WOHY3, TOHY3). The energy consumption and GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for cultivation, fertilizers, harvesting, etc. and partly adapted similar assumptions to RED II for transport and distribution of the final fuel.

Newly added fuel categories and pathways

SYHY1b (soybeans with imported beans), **POHY1b** (palm oil with CH_4 recovery), **POHY1c** (Palm oil without CH4 nor heat credit) & **PWHY** (Extraction of oil from palm oil effluent).

Addition of TRL and CRL

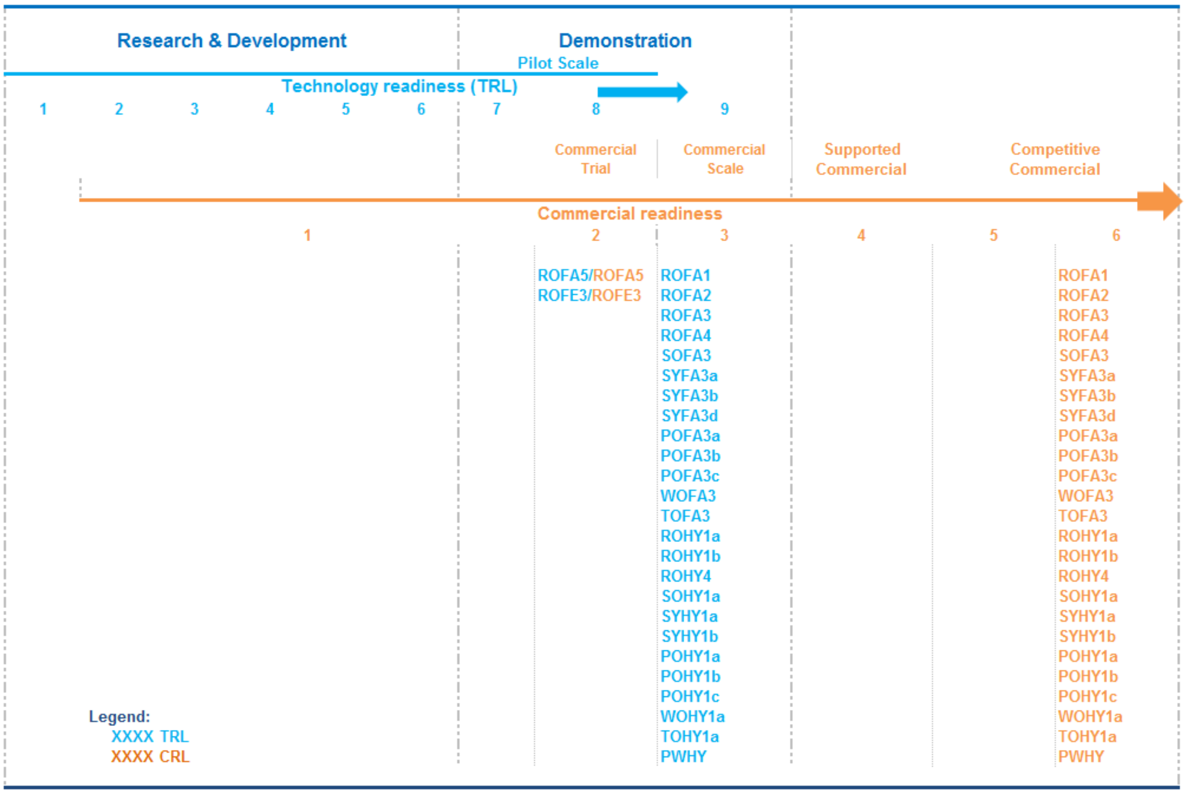
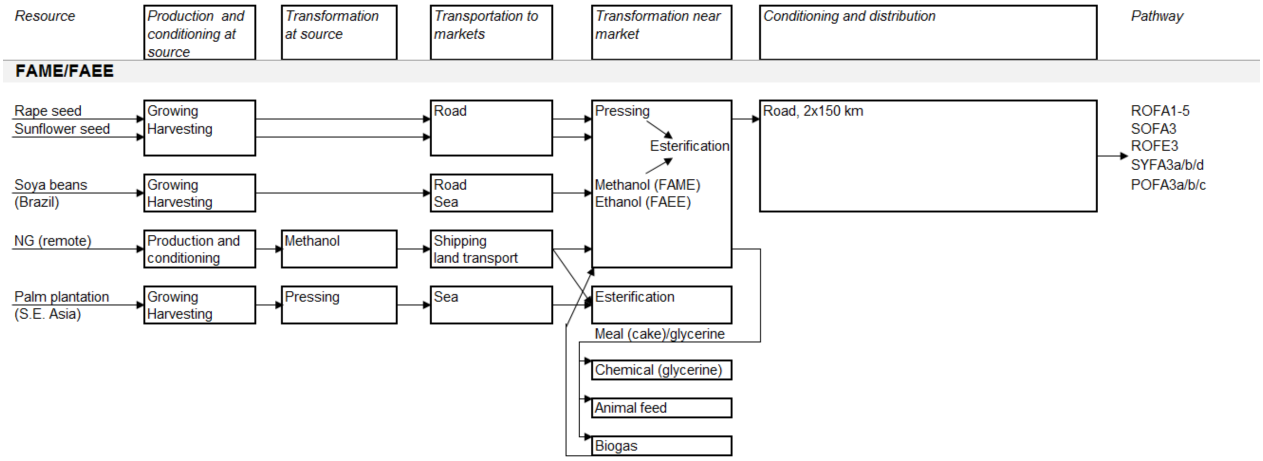


Figure 37. Oil crops to biodiesel and HVO pathways TRL / CRL

3.7.8.2.1 Oil crops to biodiesel (FAME/FAEE) pathways

The amount of FAME that can be added to conventional diesel fuel is limited to maintain acceptable fuel quality and compatibility with the vehicles in the market. In addition, the trans-esterification process leaves the basic backbone of the molecule unchanged, so the fuel properties depend to some extent on the type of oil or fat used in the process. Where the oil or fat contains many double bonds, stability may be a problem and conversely if the chains are long and saturated it may be difficult to meet cold flow requirements. Three different type of vegetable oils have been modelled based on rape and sunflower seed, soya beans and palm plantation as described below:

Figure 38. Oil crops to biodiesel pathways



a) Rapeseed processing

In the oil mill, the rapeseed is crushed, and oil extracted by steam and hexane. The co-product is rapeseed meal, a high-protein animal feed which can substitute soy bean meal. The production of soy bean meal also involves soy oil as co-product. In this version of we have calculated the credit for this based on sunflower oil because this is compositionally more similar than the rapeseed oil substitution used in earlier versions. Rapeseed meal could also in principle be burned as a fuel, much in the same way as DDGS, although its high value as animal feed discourages this approach and we have not developed a pathway to cover this. However, consideration is being given to using it as a source of biogas and we have modelled this option.

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

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

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

Most non-biodiesel glycerine produced today is a co-product of soap-making from fats and oils and the supply will hardly change if more is produced from biodiesel. Therefore, a large increase in supply can only be accommodated by finding other uses, at a lower price. Crude glycerine is already used as animal feed. This gives a much lower energy and emissions credit compared with pharmaceutical use.

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

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

- ROFA1: meal exported as animal feed, glycerine used as chemical.
- ROFA2: meal and glycerine exported as animal feed.
- ROFA3: meal exported as animal feed, glycerine used to internally produce biogas used for process heat and electricity.

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

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

b) Sunflower

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

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

c) Oil seed imports

Europe is short of vegetable oil. Historically the trade pattern has been to import the raw materials (oil seeds) rather than vegetable oil. Perhaps this was because there was a ready and profitable market for the animal-feed co-products in the EU. However, there has been a growing trend to import vegetable oil or biodiesel from low-cost producers, such as Malaysia, Indonesia, Argentina or USA.

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

d) Soy beans

Almost all soy production in tropical regions is no-till, based on GM varieties, whereas tillage is still needed in more temperate zones (where the crop residues take longer to decay, and shade the growth of the seedlings of the next crop).

While oil is the main product from most oil seeds, soy beans yield considerably more meal than oil (about 75% by mass, or 35-40% by value). As a result, the net footprint of soy oil is very sensitive to the meal credit. The choice of substitution for soy meal is especially difficult because soy meal is itself the main "swing-provider" of protein in animal feed. Therefore, we show the results for several variants.

Beans can be either crushed to oil and meal near the production area or exported as beans. Soy products are imported into Europe either as beans or separately as oil and meal. EU imports about 90% of its soy-oil as beans.

According to the data available up to the time of fixing the input data for RED recast calculations, South America (Argentina and Brazil) was the main exporter of soy beans to EU. However, recently there has been a huge increase in the proportion from USA, due to the US-China trade dispute. We have not taken this into account. So, the cultivation figures are weighted averages for a mix of 10% EU, 20% Argentina, 46% Brazil, and 24% US production [JRC 2019].

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

The soybean crushing mill data originates from a review of 7 mills by Ecoinvent, whilst for biofuel processing, EU data for recent plant was used, originating from the European Biofuels Board and Prolea.

In SYFA3a we have included a mix of no-till and conventional agriculture, bean crushing near production and import of **oil** into Europe. The extra soy meal left in the local market has the effect of reducing protein feed prices, with the result that in the end livestock will eat a greater proportion of protein feed in their diets. We assume this is in replacement of cereals: in Brazil, principally maize. The amount of maize-farming in the credit is estimated on the basis of equivalent digestible energy.

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

SYFA3d has the same features as SYFA3b but with allocation between soybean oil and soybean meal by market value.

e) Palm oil

Oil palms offer a very high oil yield: typically 3-4 t/ha of palm oil [Khathun 2017] and recycling of other biomass from the palms reduces fertilizer requirements and makes it an energy-efficient pathway.

Two countries, Indonesia and Malaysia, account for 80% of EU palm oil imports (Eurostat data).

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

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

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

We assume palm kernel meal is used as animal feed, although its high fibre content and a toxin limit its value[27]. We model the case where palm oil is then shipped to Europe where it is converted to FAME in the same way as for other oil feeds. Pure palm oil methyl ester (POME) has too high cloud-point to meet transport fuel specifications, but can be blended with other biodiesels. It can also be used in stationary applications (as can pure palm oil), and can be processed to diesel specification by deep hydrogenation (see next section).

The operation of the palm plantation and crushing facilities can significantly influence the GHG emissions. We have assumed that empty fruit bunches (EFBs) are returned to the land. However, in the usual practice, the decomposition is partially anaerobic, generating methane, which has a higher global warming potential than CO_2. We know this because there are documented projects in the UN's Clean Development Mechanism that profit from avoiding these emissions by aerobically composting them or treating them in a closed anaerobic digestor with methane recovery. The projects have to prove that anaerobic digestion is the "only credible alternative scenario" for the disposition of EFBs, and in 2016 the projects accounted for only 17% of Malaysian production, and probably less in the rest of the world. So, in this version, we have included the methane emissions that the CDM projects claim to avoid. They amount to 6.46g CO_2e/MJ of crude palm oil.

We have assumed the mill is heated using part of the nut shells and palm fibre. In an efficient mill, there is a surplus of biomass, and sometimes, where transport is easy, the excess nut shells are exported for heating elsewhere. We model two alternatives: either no credit, or a credit based on fossil heat replaced. The water/slurry effluent from the mill is sent to a treatment pond where anaerobic decomposition occurs. In the best case, the methane emissions are recovered; but in present practice they are usually released from open ponds. We have modelled both alternatives.

Hence, we have modelled three pathways representing different combinations of the above options:

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

In all cases the meal is exported as animal feed and the glycerine used to produce biogas internally. In the above pathways, glycerine from the biodiesel plant is assumed to be used to produce internal biogas.

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

Emissions from Tropical Peat Loss are <u>not</u> included in Our Results for Palm Oil

There is about twice as much carbon stored in peat as in the forests of the world, and tropical peatland contains about 96% of tropical carbon. For this reason, one can see why losing only a small part of this peatland can result in very large consequences in terms of GHG emissions.

Only plantations need deep drainage

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

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

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

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

This means the peat oxidation emissions are in fact an *annual* emission which could be added in to the direct emissions calculation. However, traditionally, they have been treated along with once-off land-use-change emissions. Estimates of the average annual CO_2 emissions from drained peat have converged in recent years, to an average figure of around 106 tonnes CO_2 per ha per year spread over 20 years *[Page et al. 2011]*. That corresponds to about 700 gCO_2/MJ of palm oil from peat-land (at 4 tonnes/ha palm oil yield) and a similar addition to the emissions per MJ of biodiesel. These figures take into account the initial high rate of carbon loss the first 5 years after drainage, whereas the long-term rate of carbon emissions from drained peat swamp forest falls to about 73 tonnes CO_2/ha/y [Page et al. 2011].

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

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

*About 23% of **new** palm oil plantations are on peat*

In estimating ILUC emissions, the important number is the fraction of *new* oil palm plantations which are established on peat. EU report COM(2019)142 reviews the literature, concluding that about 23% of world oil-palm expansion is on tropical peat.

3.7.8.2.2 Hydrotreated Vegetable Oils (HVO)

The main advantage of HVO over transesterification, is that it can more easily cope with a wide range of feedstock, including impure used cooking oils and animal fats, as well as palm oil and oil from other seeds.

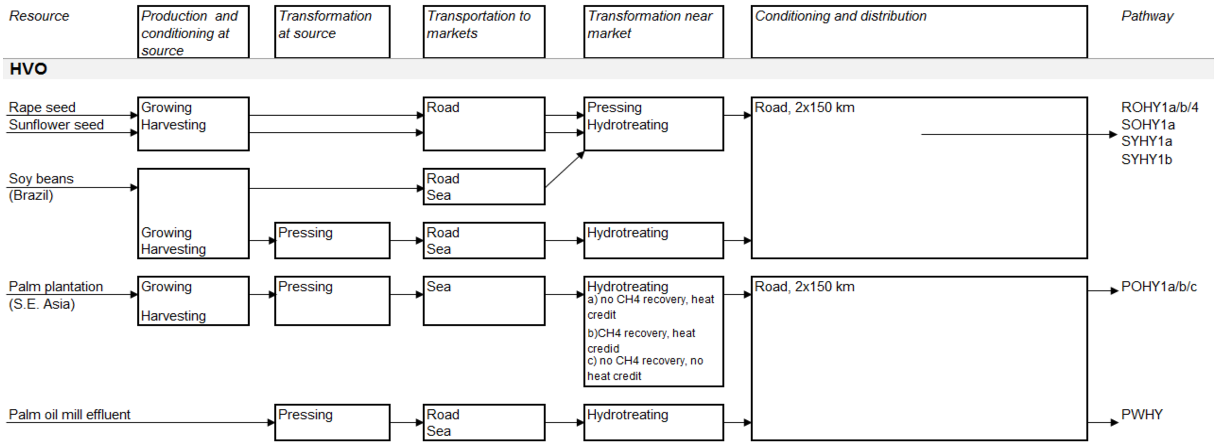
As an alternative to trans-esterification the pure oil can be hydrotreated. This removes double bonds and oxygen from the molecule, yielding a paraffinic fuel similar in properties to Fischer-Tropsch diesel. This can either be used alone or blended into conventional diesel, and the final fuel properties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

The Neste process (NExBTL®) [IFEU 2006], [Neste 2015], [GREENEA 2017] [REG 2017] (for HVO from waste cooking oil and tallow) is the first to be used in commercial production, and we have modelled this process using rapeseed, sunflower, soy and palm oils. Similar processes are being developed by a number of other companies, and for comparison a process from UOP has been included, using rapeseed oil.

We fully report HVO pathways covering rape, sunflower, soy and palm with meal to animal feed as well as a new pathway based on the extraction of oil from palm oil effluent, all of them based on the Neste process. In addition, we show alternatives with rape, with the UOP process and meal used as fuel:

- ROHY1a: Rapeseed to HVO, meal to animal feed, Neste hydrotreating process.
- ROHY1b: Rapeseed to HVO, meal to animal feed, UOP hydrotreating process.
- ROHY4: Rapeseed to HVO, meal to biogas for heat/power, Neste hydrotreating process.
- SOHY1:Sunflower to HVO, meal to animal feed, Neste hydrotreating process.
- SYHY1a: Soya to HVO, mix of no till and conventional culture, local mill, meal export to animal feed, oil transport to EU, Neste hydrotreating process.
- SYHY1b: Soya to HVO, mix of no till and conventional culture, bean import into Europe, oil mill in Europe, and meal credit based on substitution of EU wheat, Neste hydrotreating process.
- POY1a: Palm to HVO, kernel meal export to animal feed, no CH_4 recovery from waste storage, heat credit from residue use as fuel, oil transport to EU, Neste hydrotreating process.
- POY1b: Palm to HVO, kernel meal export to animal feed, CH_4 recovery from waste storage, heat credit from residue use as fuel, oil transport to EU, Neste hydrotreating process.
- POY1c: Palm to HVO, kernel meal export to animal feed, no CH_4 recovery from waste storage, heat credit from residue use as fuel, oil transport to EU, Neste hydrotreating process.
- PWHY: Extraction of oil from palm oil effluent (POME) – wastewater, Neste hydrotreating process.
- WOHY: Waste oil to HVO, Neste hydrotreating process.
- TOHY: Tallow from rendering plants to HVO, Neste hydrotreating process.

Figure 39. HVO from vegetable oil pathways



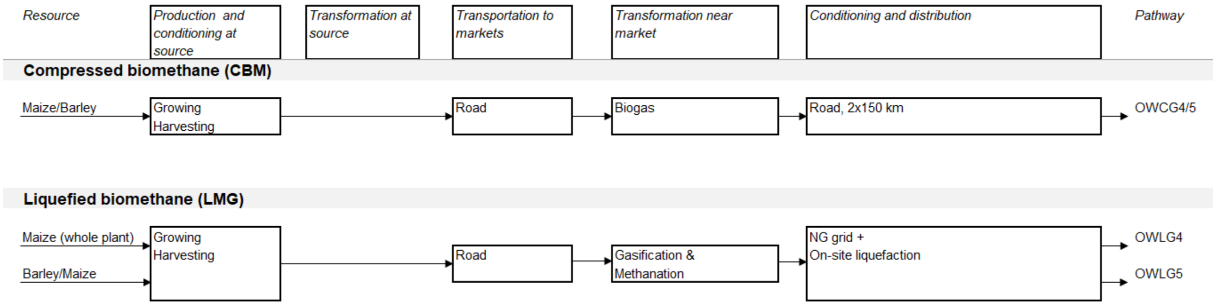
Note. Palm oil mill effluent is a waste water included in this chapter for comparison purposes.

3.7.8.3 Biomethane

Purpose-grown crops can of course also be used in principle to produce biogas although this has so far received limited attention. Perhaps as a result of the relatively high cost of biogas plants per unit of gas produced, the process appears to be more attractive for (cheap) wastes than for expensive crops. However, traditional fermentation processes to produce ethanol can use only the cereal grain, whereas production of biogas has the advantage that the whole plant including the straw can be used, and hence improve yield. In addition, there is a trend in Germany for intensive *non-food* crops to be planted on grassland to provide feedstock for biogas plants supplying the electricity and gas grids. We have therefore included pathways for both Compressed (CBM) and liquefied (LBM) biomethane.

- OWCG/LG4: Whole plant maize.
- OWCG/LG5: Double cropping of barley and maize[28].

Figure 40. Farmed crops to biomethane pathways



Additional details about biomethane pathways can be found in section "*Organic material*" to biomethane (3.7.9.2.2).

3.7.9 Waste

Summary

Changes vs Version 4

Significant update on the existing fuel pathways (Waste based)

Waste to FAME / HVO

Waste oil and tallow oil-based pathways (WOFA3, TOFA3, WOHY1a, TOHY1a) - The energy consumption and GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for cultivation, fertilizers, harvesting, etc., and partly adapted similar assumptions to RED II for transport and distribution of the final fuel.

Organic waste to Biogas

OWCG1 - Updated literature/data source. The energy and GHG inventory of the fermentation process have been updated based on the recent data and literature (Giuntoli et al. 2017). The N credit has been removed.

OWCG21 & OWCG22 - Updated literature/data source. Firstly, the Methane emissions credit at the production & conditioning stage of these pathways are significantly changed based on the recent study from JRC [Giuntoli et al, 2017]. In addition, the energy and GHG emissions data associated to the fermentation (both closed and open digestate storage) and the distribution of end fuel have been updated to the latest available data.

Newly added fuel categories and pathways

Compressed biomethane (CBM): OWCG3 (biogas from sewage plant) and **Liquid biomethane** (LBM): OWLG1, OWLG21, OWLG22, OWLG3,

Addition of TRL and CRL

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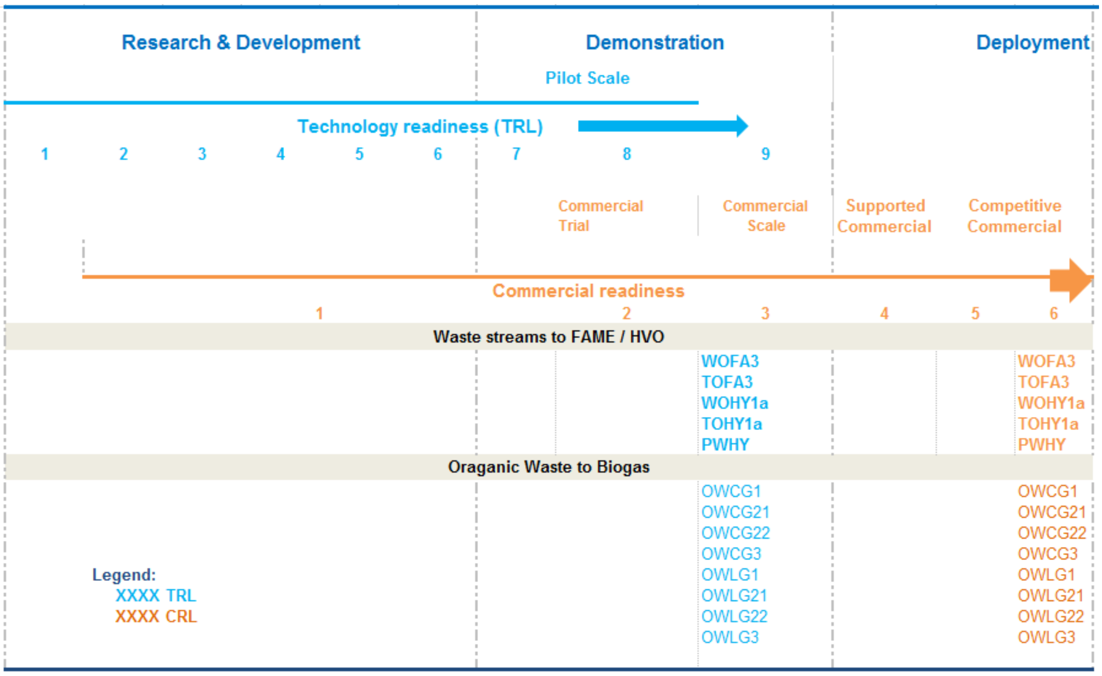
[28] In European conditions, maize and barley appear to be the best crops where the objective is simply to maximise the amount of biomass produced.

Figure 41. Waste streams to biodiesel and HVO pathways TRL / CRL

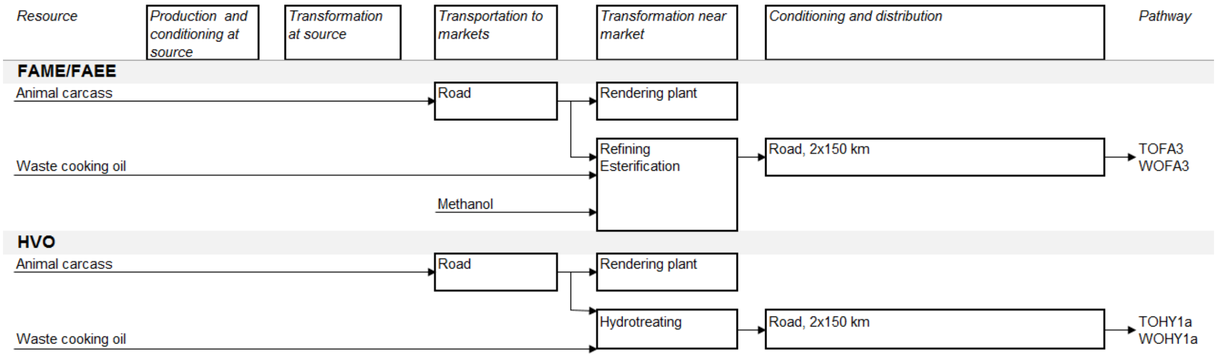


3.7.9.1 Biodiesel & HVO

Biodiesel can also be produced from a number of waste streams, notably used cooking oils and produced animal fat, loosely called tallow, which is one of the products of rendering animal carcasses from slaughterhouses.

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

Figure 42. Waste streams to biodiesel and HVO



Note. Palm oil mill effluent (PWHY) is a wastewater included in the vegetable oil related chapter for comparison purposes.

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

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

The energy consumption for the esterification of waste cooking oil is higher than that for the esterification of rapeseed oil. This is because these materials usually contain free fatty acids, which are saponified by homogeneous alkali catalysts, leading to a depletion of the catalysts as well as to increased purification costs.

Generally, the problem can be overcome by an esterification pretreatment of the free fatty acids to alkyl esters in the presence of an acid catalyst.

In this version of JEC-WTW we have updated the transesterification and also HVO processing of both animal fats and used cooking oil, using data from stakeholders. We added some sea transport to cooking oil, as ~20% is being imported [EWABA 2014].

3.7.9.2 Biomethane

3.7.9.2.1 Municipal Solid Waste

Despite the numerous initiatives and the large efforts in promoting recycling and advance waste management practices, Municipal Solid Wastes (MSW) are still widely available. MSW contain an organic fraction, which can be used to produce renewable energy or fuel. In spite of this possibility, the strong variability in the composition is a relevant issue, when MSW are considered for supplying advanced processes. It is worth noticing that MSW composition varies between and inside countries. The organic fraction of MSW can be used to supply thermochemical conversion processes, such as gasification or HTL. After a sorting stage, MSW can be separated in the so-called Refuse Derived Fuel (RDF) and other recyclable materials. This additional production of recyclable materials constitutes an added value of the production of biofuels from MSW, and can be credited or supported by specific national or international scheme (e.g. feed-in-tariff for electrical energy or biomethane production in several EU countries). Currently there are initiatives proposing the use of MSW for biofuel production, among the others: Enerkem[29], Fulcrum[30], Velocys[31], etc. Despite the advance status of some pilot plants, still this technology can hardly be defined as mature: final product quality and cost effectiveness still have to be demonstrated at commercial scale. This technological pathway has already been described for waste wood supply.

Similarly, **HTL** (hydrothermal liquefaction) appears to be an interesting technology to convert MSW into fuels, but these conversion pathways need further development to each commercial stage. This technological pathway has already been described for waste wood supply (*Wood to synthetic liquid fuels*).

On the contrary, **biological conversion** processes, supplied with MSW, already shown to be market ready; biogas production and potential upgrade to biomethane is described in the following section.

3.7.9.2.2 Organic material to biomethane

The anaerobic fermentation of organic matter produces a gaseous mixture, known as "biogas", consisting mainly of methane and CO_2 (typically 60/40 % v/v although the actual composition varies significantly depending on the type of feedstock used). However, after the upgrading process, most of the CO_2 content is leading to the properties of compressed biogas as shown in the *fuel properties/natural gas* sections of this report.

Biogas also contains small amounts of other substances, such as H_2 (0-1%), N_2 (0-7%), H_2S (0-1%) and traces of NH_3, as well as water vapour (in case of landfill gas also small amounts of halogenated compounds can occur).

Following sterilisation of the feedstock, if needed, the process consists of a hydrolysis step, formation of organic acids and of methane. In case of glucose (a saccharide) the methane formation reaction is:

$$C_6H_{12}O_6 \Rightarrow 3\ CH_4 + 3\ CO_2$$

A suitable feedstock is biomass which contains components such as carbohydrates (i.e. saccharides such as glucose), fatty acids and proteins. Cellulose and hemicellulose are converted to saccharides via hydrolysis. Lignin cannot be decomposed via anaerobic fermentation but only via aerobic processes which do not generate methane. The process requires inputs of heat and electricity, the latter mainly for mixing the reactor.

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

In this study we are primarily concerned with pathways representing biomethane used as a motor fuel, which include supply of the feedstock, biogas production, biogas treatment and upgrading, biomethane distribution

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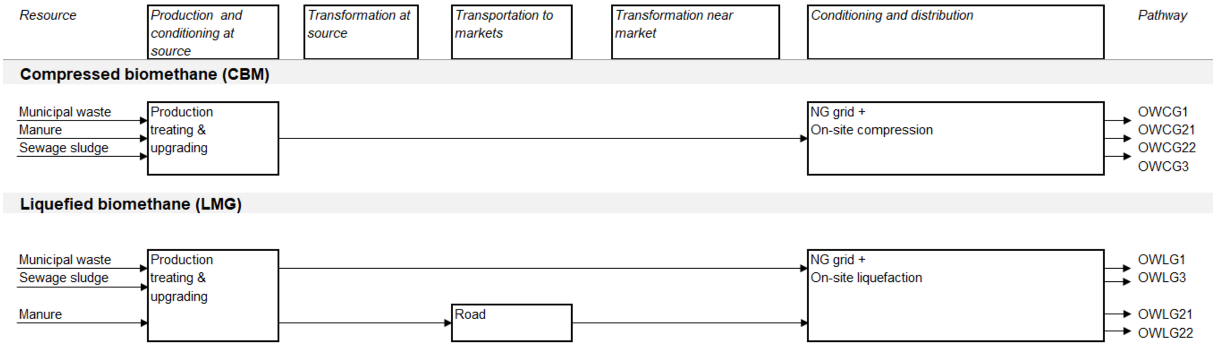
[29] https://enerkem.com/biofuels-and-green-chemicals/biofuels/
[30] fulcrum-bioenergy.com
[31] https://www.velocys.com/

and finally compression to 25 MPa to refuel a vehicle. For comparison purposes we have also included biogas-to-electricity pathways representing either local small-scale usage or export to the grid and use in a large-scale power plant and biogas to heat pathways at small or medium scale.

Many feedstocks could in principle be used to produce either compressed (OWCG) or liquefied (OWLG) biogas (including purpose grown crops covered in previous section 3.7.8.3), however we have included three waste feedstocks currently of most interest:

- OWCG1 / OWLG1:Organic municipal waste.
- OWCG2 / OWLG2:Wet manure[32].
- OWCG3 / OWLG3:Sewage sludge.

Figure 43. Organic waste to biomethane pathways



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

Small, often farm-size installations designed to capture this gas have been used for many years. In this case the "raw" biogas is used directly to produce heat and occasionally power e.g. in a dedicated gas engine. Larger scale installations are now becoming more widespread, driven both by environmental concerns and, in the case of municipal waste, increasing disposal constraints. It is particularly advantageous for wet feedstocks, since drying is not required.

In the larger installations, biogas can be used to produce electricity which provides power and heat for the biogas plant and surplus electricity for export to the grid (See electricity section 4.10.1.6). In suitable locations additional waste heat may be used off-site, perhaps through a district heating scheme.

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

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

Mixed Feedstock

The economies of scale mean that large biomass plants have lower capital costs per unit of output than small ones, and can thus provide biogas more cheaply. This is especially true if purification and compression is to be

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

built into the same plant. Large biogas plants use all the feedstock available within an economic transport distance. Thus, they typically use a mixture of animal slurry from local intensive animal farms, concentrated organic waste from the food processing industry, and sometimes municipal organic waste. There is also some synergy in mixing the feeds to optimise the C/N ratio. This point is important in the costs and availability calculation.

3.7.10 Wood based pathways

3.7.10.1 General

Two wood feedstocks are considered in this analysis: forest residues and short-rotation forestry. The input data for these pathways is now aligned with that used for the calculation of default values for the re-cast of the Renewable Energy Directive.

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

The most efficient way to make biofuels from forest residues is to use them inside a pulp mill, to substitute the burning of black liquor for process heat, freeing black liquor to be gasified and converted to transport fuel (BLSD1a/aC). This leads to a separate pathway for the “black liquor route”, which is essentially limited to the forest residues associated with pulp-wood (see specific section below). If the felling residues and thinning are left in the forest, they initially add to the stock of carbon in the forest litter, but they rot away at a rate of about 10% per year (see fig. 5 in [Liski et al. 2005]). That means the GHG emissions saved by collecting the residues are delayed compared to those saved by substituting fossil fuel.

Summary

Changes vs Version 4

Significant update on the existing fuel pathways (Wood based)

Wood to H_2: Waste wood and farmed wood pathways (WFCH1, WWCH1, WFCH2, WWCH2, BLCH1, WFLH1): The energy consumption and GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for forestry residue collection, short rotation forestry, wood chips storage (seasoning), biomass transport, and are partly adapted similar assumptions to RED II for transport and distribution of the final fuel. Transport modes and distanes for the transport of wood chips has partly been modified (WFCH1, WWCH1: truck, 50 km; WFCH2, WFLH, BLCH1: truck, 500 km; WWCH2: truck, 250 km, ship, 2000 km). Pathways involving waste wood uses forestry residue. The black liquor pathways also use forestry residue as feedstock.

Wood to synthetic fuels: Waste wood and farmed wood pathways (WWSD1, WFSD1, WWME1, WFME1, WWDE1, WFDE1) and black liqor pathways (BLSD1a, BLME1a, BLDE1a): The energy consumption and GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for forestry residue collection, short rotation forestry, wood chips storage (seasoning), biomass transport, and are partly adapted similar assumptions to RED II for transport and distribution of the final fuel. New variants have been introduced with different transport distance and modes for the transport of wood chips (a: truck, 500 km; b: truck, 250 km, ship, 2000 km). Pathways involving waste wood uses forestry residue. The black liquor pathways also use forestry residue as feedstock. The basic data for pulp mill is the same as used for the RED II pathways. However, the substitution method has been applied instead of allocation by energy.

Summary (cont)

The reference for the wood-to-synthetic diesel process has been changed from [Hamelinck 2004] to [Kreutz et al. 2008] to be consistent with the variant with CCS used in newly added pathways WWSD1aC, WWSD1bC, WFSD1aC, and WFSD1bC.

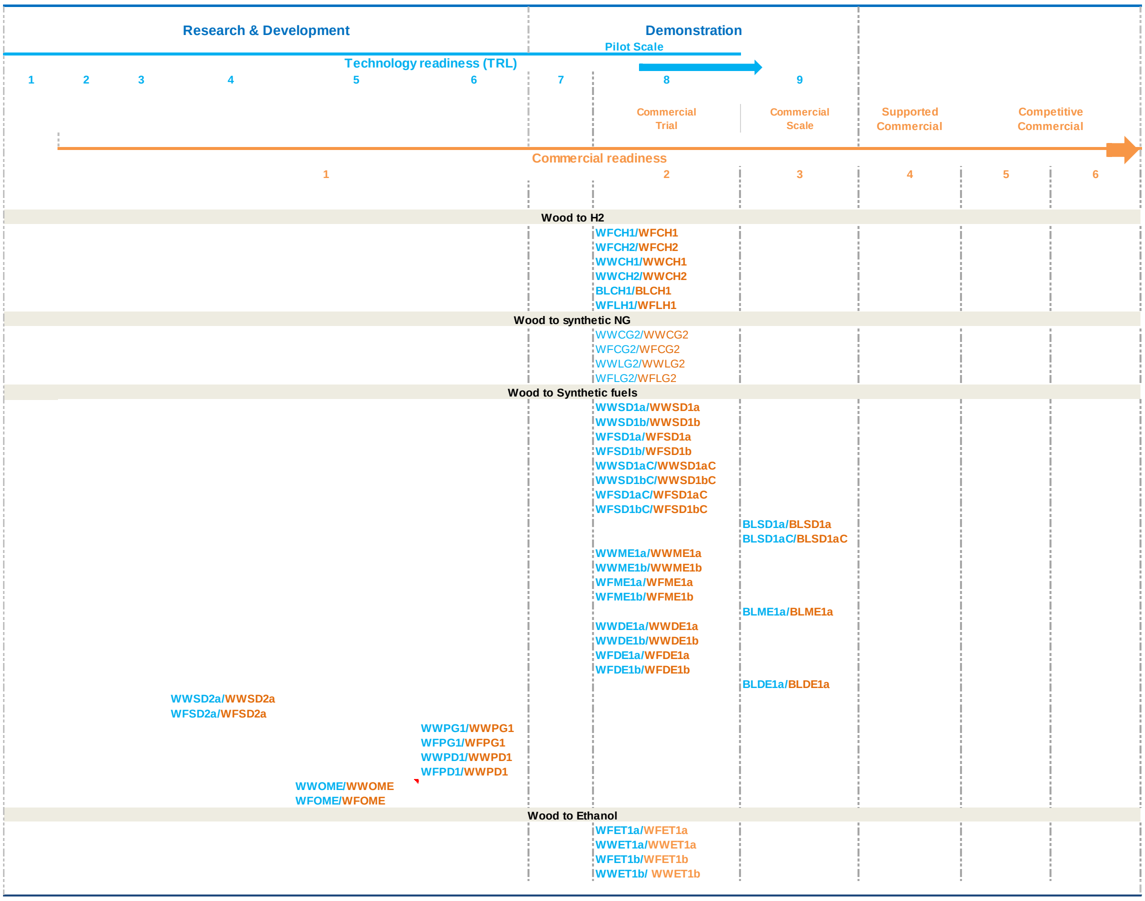
Wood to Ethanol: WFET1a, WWET1a, WFET1b, WWET1b: The energy consumption and GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for forestry residue collection, short rotation forestry, wood chips storage (seasoning), biomass transport, and are partly adapted similar assumptions to RED II for transport and distribution of the final fuel. New variants have been introduced with different transport distances and modes for the transport of wood chips (a: truck, 500 km; b: truck, 250 km, ship, 2000 km). Pathways involving waste wood use forestry residue.

Newly added fuel categories and pathways

Wood to synthetic liquid fuels: Synthetic diesel (WWSD1aC, WWSD1bC, WFSD1aC, WFSD1bC, BLSD1aC, WWSD2a, WFSD2a), Pyrolisis based gasoline and diesel (WWPG1, WFPG1, WWPD1, WGPD1), OME (WWOME, WFOME).

Wood to synthetic NG: SNG (WWCG2, WFCG2) & SLNG (WWLG2, WFLG2).

Figure 44. TRL/CRL. Wood to fuel pathways



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

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

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

There is also the nitrogen balance to consider. Removing residues removes some fixed nitrogen from the forest which may have to be made up by artificial fertilizer. This would generate N_2O emissions in the forest soils, but these are only about the same as those from the decomposition of the forest residues. Overall, we think the effects on the GHG balance are small, and we did not include them.

Use of Stemwood for Energy

The commercial forests in EU grow slightly more than is harvested each year, so there is potential to increase the sustainable supply of stem-wood (as well as residues) in EU, for energy purposes. The pulp, paper and woodworking industry is understandably concerned about subsidized competition for their feedstock, both stem-wood and wood chips. This is not to be ignored, because life cycle analyses almost all agree that wood saves more greenhouse gas when made into durable products than when burnt for energy. Another reason not to consider stem-wood as a sustainable source of energy is the carbon debt problem [Agostini 2013].

Compared to the hydrocarbon of fossil fuel, wood is partially oxidized, so it has a lower energy content per tonne of carbon, and poorer combustion efficiency. Furthermore, already cutting the wood leads to the release of carbon from decomposition of the stump, roots and the finer residue (leaves etc.) that is left on the ground. This initial burst of additional emissions is not recovered by increased sequestration of carbon in the forest for a time of the order of several decades to a century. In the mean-time global warming may have become irreversible.

Newly-replanted forest grows at first slower than a mature stand, but after some decades the growth rate increases, but then the rate slows down as the stand ages. So, there is a certain optimum frequency for felling forest to maximize time-averaged wood yield and carbon sequestration. Cutting trees more frequently would result in a lower sequestration. So, the only way cutting wood more frequently can give a higher rate of carbon sequestration, even after very long times, is if the trees were not otherwise being cut often enough to maximize time-averaged wood yield.

However, even in this best-case scenario, a present increase in cutting rate will not be matched by an increase in forest carbon sequestration for around a century (for boreal forests), or many decades (for tropical forests). In the meantime, cutting the extra trees increases global warming. Even if the forest as a whole is still sequestering carbon, increasing the frequency of cutting will lead to *less* sequestration until the carbon debt is paid off.

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

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

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

Wheat + straw as a bio-energy crop

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

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

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

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

3.7.10.2 Details of wood to fuel pathways

Besides the update of existing pathways, we have included **new pathways** either from farmed wood (Code WF) or waste wood (Code WW) as follows:

a) Farmed wood pathways (Code WF)

- WFCG2/LG2: Farmed wood to compressed or liquefied natural gasví gasification and methanation routesand on-site compression/liquefaction.
- WFSD1a: Farmed wood to synthetic diesel (Fischer-Tropsch process), wood chips transport via road, 500 km.
- WFSD1b: Farmed wood to synthetic diesel (Fischer-Tropsch process), wood chips transport via road, 250 km plus ship, 2000 km.
- WFSD2: Farmed wood to diesel via via hydrothermal liquefaction (HTL) and upgrading.
- WFPG1/D1: Farmed wood to gasoline and diesel via pyrolysis and upgrading.
- WFME1a: Farmed wood to Methanol, wood chips transport via road, 500 km.
- WFME1b: Farmed wood to Methanol, wood chips transport via road, 250 km plus ship, 2000 km.
- WFDE1a: Farmed wood to DME, wood chips transport via road, 500 km.
- WFDE1b: Farmed wood to DME, Farmed wood to Methanol, wood chips transport via road, 250 km plus ship, 2000 km.

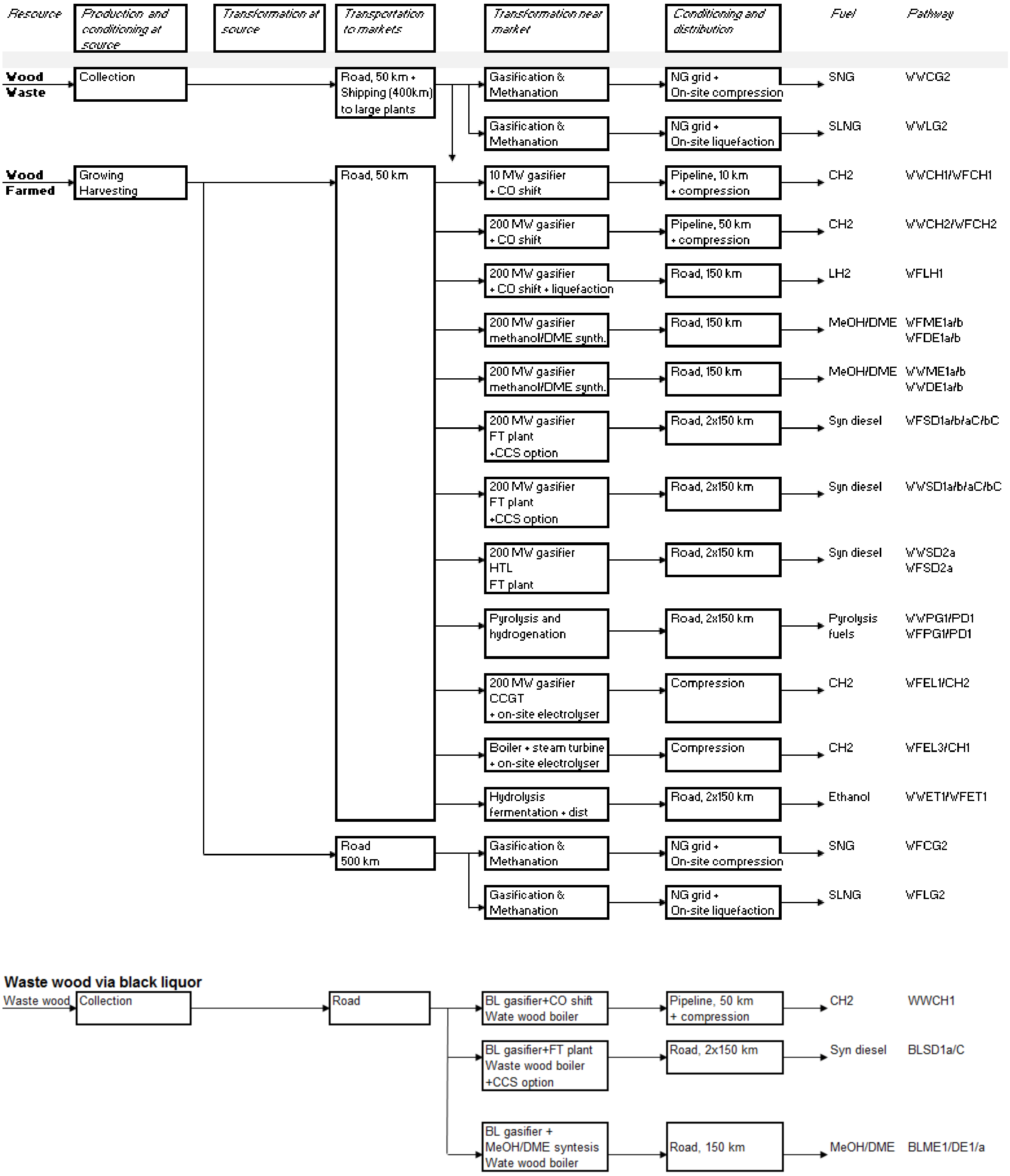
b) Waste wood pathways (Code WW):

- WWCG2/LG2: Waste wood to compressed or liquefied natural gas ví gasification and methanation routesand on-site compression/liquefaction.
- WWSD1a: Waste wood to synthetic diesel (wood chips transport via road, 500 km).
- WWSD1b: Waste wood to synthetic diesel (wood chips transport via road, 250 km plus ship, 2000 km).
- WWSD2: Waste wood to diesel via hydrothermal liquefaction (HTL) and upgrading.

- WWPG1/D1: Waste wood to gasoline and diesel via pyrolysis and upgrading.
- BLSD1: Waste wood to synthetic diesel via black liquor gasfication in pulp mill (round wood and wood chips transport via road, 500 km).
- WWME1a: Waste wood to methanol (wood chips transport via road, 500 km).
- WWME1b: Waste wood to methanol diesel (wood chips transport via road, 250 km plus ship, 2000 km).
- BLME1: Waste wood to methanol via black liquor gasification in pulp mill (round wood and wood chips transport via road, 500 km).
- WWDE1a: Waste wood to DME (wood chips transport via road, 500 km).
- WWDE1b: Waste wood to DME (Waste wood to synthetic diesel (wood chips transport via road, 250 km plus ship, 2000 km).
- BLDE1: Waste wood to DME via black liquor gasification in pulp mill (round wood and wood chips transport via road, 500 km).

The various wood pathways considered are illustrated in the figure below. Equivalent electricity pathways are described in *section 3.4.1*.2.

Figure 45. Wood pathways



3.7.10.2.1 Wood to hydrogen

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

For production of hydrogen and other fuels via gasification, it is important that the syngas is not diluted by nitrogen from air-blowing. Gasifiers carry out two reactions: partial oxidation, which is exothermic, and steam reforming (to make hydrogen) which is endothermic. Simple auto-thermal gasifiers carry out the two reactions simultaneously, and would need oxygen separation systems, which are expensive at these comparatively small scales and prohibitive at the 10 MW scale. Therefore, thermal (externally heated) gasifiers are preferred for small plants. The absorption enhanced reforming (AER) process developed by a consortium consisting of scientific research institutions (e.g. the Solar Energy and Hydrogen Research (ZSW) Stuttgart/Ulm and the Vienna University of Technology) and companies (GE Jenbacher and Biomasse-Kraftwerk Güssing GmbH & Co KG) is an example for a gasification concept which works well at 10 MW biomass input. The layout of the gasification process is similar to the existing biomass gasification plant in Güssing in Austria which has been operated successfully for several years. The Güssing plant consists of a circulating fluidized bed reactor for gasification and a circulating fluidized bed combustion stage to heat up the heat carrier which transfers the heat to into the gasification section. The process is also called fast internal circulating fluidised bed (FICFB) gasification. In the AER process a different bed material is used which captures the CO_2 to elevate the hydrogen content of the product gas by reaction with CaO to form $CaCO_3$. The $CaCO_3$ is sent to the combustion chamber together with the formed bio-coke where the $CaCO_3$ is regenerated back to CaO. This process only consists of the gasification stage and the pressure swing adsorption (PSA) plant and does not include a CO-shift step. It requires therefore a relatively large amount of biomass. This leads to surplus of energy that is turned into both heat and electricity. We have accounted for an electricity credit based on electricity only production with wood but have taken no credit for surplus heat.

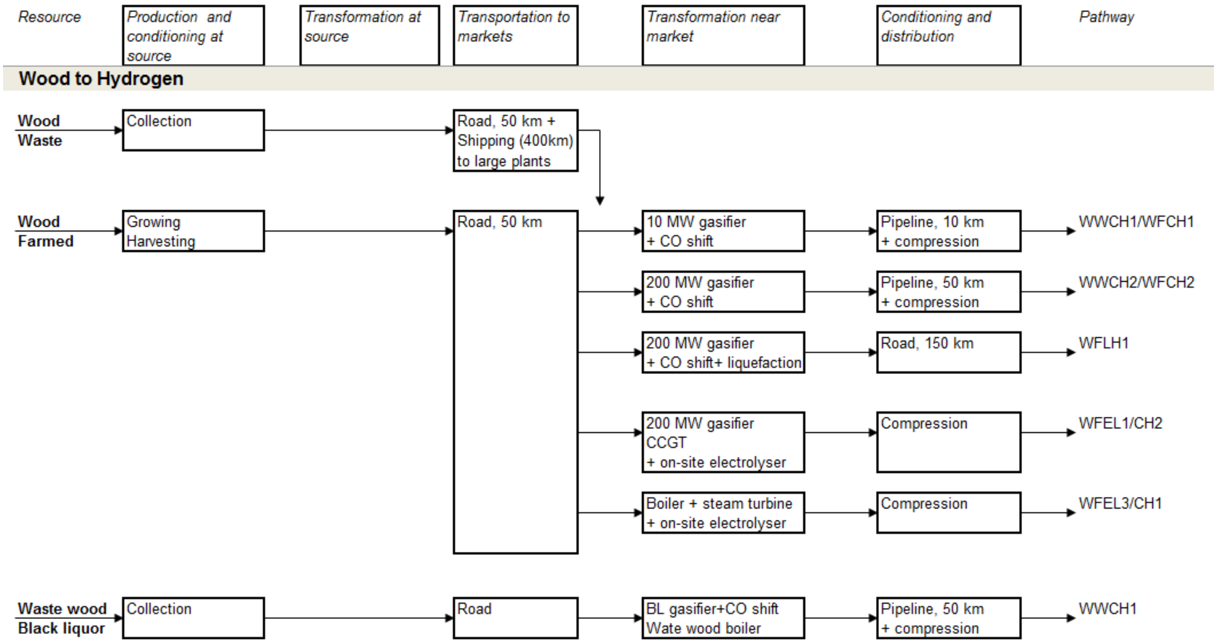
Various gasification plants using woody biomass have been installed in the last 20 years. Gasifiers employing the technology used in Güssing have been commissioned in Senden in Germany (14 MWt), in the GoBiGas plant in Gothenburg in Sweden (20 MWt), and in Nongbua in Thailand. There is also a gasification plant under construction in Wajima in Japan (8 MWt) [Repotec 2019; GP Energy 2019]. Most of the gasification plants are used for the generation of syngas for electricity and heat production. The GoBiGas gasification plant generates syngas which is sent to methanation [Göteborg Energi 2019]. Technologies for the production of pure hydrogen from syngas such as CO shift reactors and pressure swing adsorption (PSA) are commercially available. Therefore, the technology readiness level (TRL) for hydrogen from woody biomass gasification is set to 8.

For the 200 MW variant a similar gasification process (also indirectly heated dual circulating fluidised bed) based on the BCL gasifier has been used which also consists of a circulating fluidized bed to transfer heat between the two processes. However, the BCL process is rather designed for larger gasification plants (> 50 MW) and includes additional processes such as a methane steam reforming stage for converting the methane fraction in the product gas stream leaving the gasifier and a CO shift stage to maximize the hydrogen output. This leads to additional electricity consumption to the extent that some import is required.

Both the AER process and the BCL gasifier are operated at near atmospheric pressure because long year experience has led to the conclusion that reliable operation of pressurized biomass gasification is too challenging (inserting solid feedstock which sometimes is contaminated with stones, nails, screws, etc. into a pressurized gasification process).

A relatively large plant based on the BCL technology with a biomass input of 200 to 400 t/d has been operated in the USA between 1998 and 2002 in Burlington in Vermont [Ahrenfeldt et al. 2010]. Planned projects were stopped mainly due to economic reasons, not due to technical reasons. The developers of the Güssing plants also can built larger plants a customer would order one. Therefore, a TRL of 8 has also been assumed for larger gasification plants using wood chips as feedstock.

Figure 46. Wood to hydrogen pathways

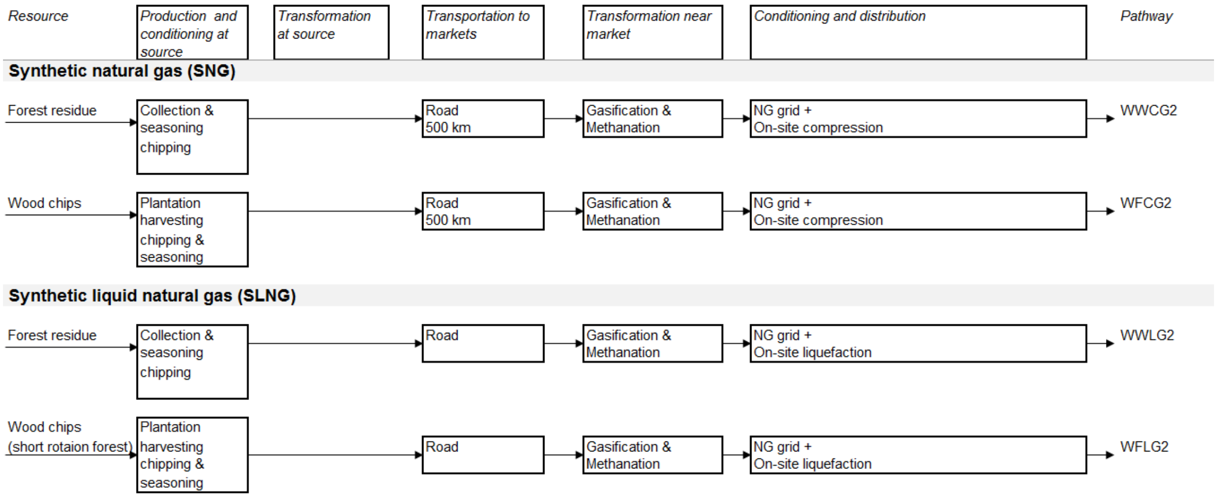


3.7.10.2.2 Wood to synthetic natural gas

The syngas leaving the gasification plant can be converted to methane (synthetic natural gas) via methanation. Experiments for the production of synthetic natural gas (SNG) have been carried out at the gasification plant in Güssing in Austria. The capacity of the SNG plant amounts to about 1 MW of SNG [Ahrenfeldt et al. 2010]. In [DBFZ 2009] large biomass-to-SNG plants with a capacity of up to 380 MW of SNG (572 MW of wood chips input) have been modelled. A transport distance of 500 km to the gasification plant has been assumed both for farmed wood and wood chips from forestry residue.

In the current version of the report, the pathways to synthetic liquefied natural gas have also been included for comparative purposes (same on-site liquefaction process as in the conventional LNG pathways):

Figure 47. Wood to synthetic natural gas pathways



3.7.10.2.3 Wood to synthetic liquid fuels

We have included one pathway for biomass-to-liquid (Fischer-Tropsch) fuel based on farmed wood. This can be considered fairly generic and representative of other biomass resources including perennial grasses like miscanthus. We used a process analysis based on a dry-fed, oxygen/steam-blown fluidized-bed gasifier operating at 29.9 bar.gasifier as described in [Kreutz et al. 2008]. The efficiency of this process depends strongly on the performance of the FT catalyst. For our "best estimate" we used the data in [Kreutz et al. 2008] to be consistent with the variant with CCS.

The wood-to-FT products (gasoline and diesel) efficiency of about 42% indicated in [dena 2006] is close to the best csse in [Tijmensen et al. 2002] and [Hamelink 2004] for a hydrocarbon chain growth probability of 0.9. From the data in [Kreutz et al. 2008] a wood-to-FT products (gasoline and diesel) efficiency of about 45% can be calculated (calculated on dry LHV basis, wet LHV basis: 46%) plus some excess electricity. We assumed an efficiency of 45% based on data in [Kreutz et al. 2008] to be consistent with the variant with VCCS with uncertainty of ±5%.

If carbon capture and storage (CCS) is applied the yield of FT product does not change but the amount of electricity export decreases due to the electricity demand for CO_2 compression. For CO_2 capture no additional energy is required because the CO_2 is removed from the synthesis gas stream before feeding into the FT synthesis both for the case without and with CCS.

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

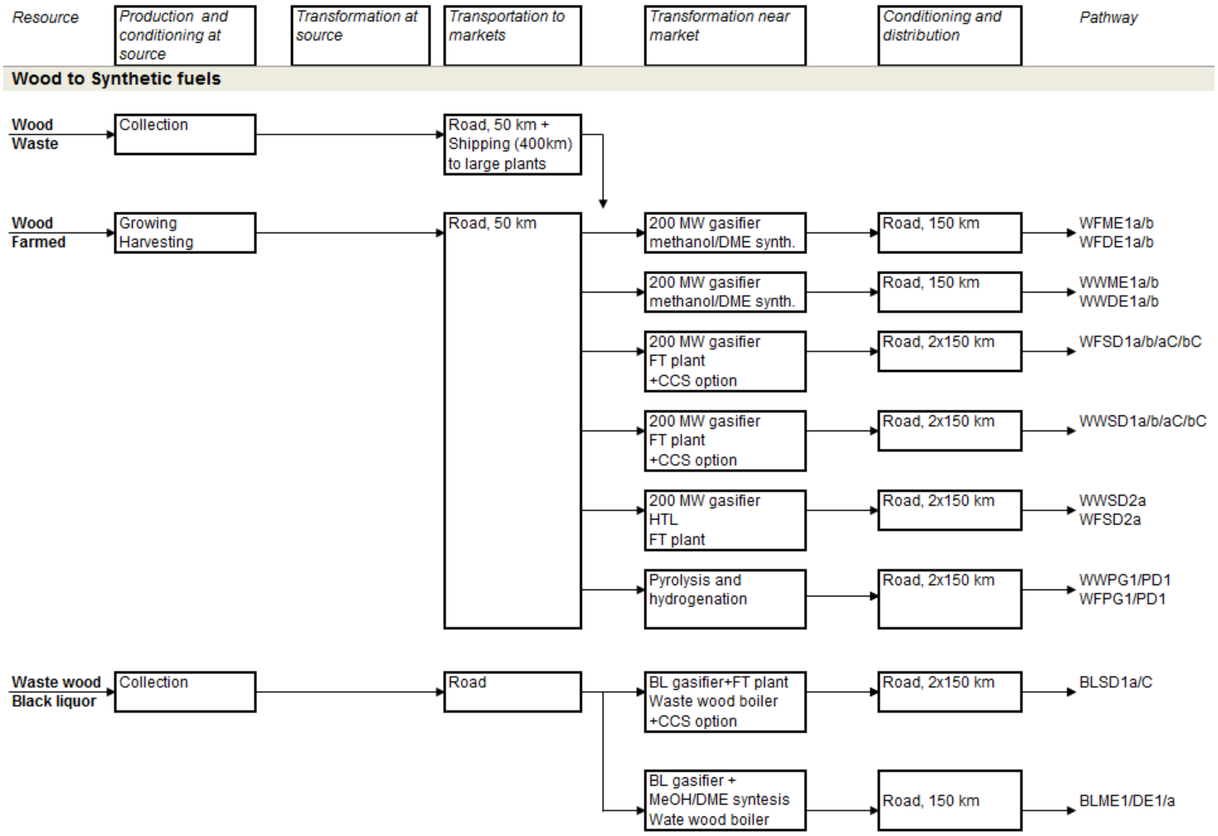
Lurgi developed an alternative to Fischer-Tropsch first producing methanol as an intermediate step in the production of syndiesel. The outcome in terms of energy use and GHG emissions is close to the FT case [dena 2006] so we have not represented this separately.

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

Other processes for conversion of wood (or waste) to liquids are described in the literature such as fast pyrolysis [Han 2011] or the HTU process (a process based on hydrothermal liquefaction). Fast-pyrolysis of wood produces products that cannot be used directly as road fuels, but can be fed to a gasifier in the same way as black liquor or can be upgraded by adding hydrogen. Thus, fast pyrolysis is a sort of pre-treatment step as far a road-fuel production is concerned. It may be a viable process for making other chemical products, but the capital cost of two processing plants in series is likely to present a major hurdle.

The HTU process has been under bench-scale development for some time. It converts the feedstock to a mix of solid and liquid products in superheated water. The liquid fraction has to be upgraded to hydrocarbon fuel by hydrogenation (Hydro-De-Oxygenation - HDO). The proposed process has changed greatly since it was included in [LBST 2002]. Today, the Danish company Steeper Energy offers a hydrothermal liquefaction process called 'Hydrofaction' for the production of diesel and jet fuels from wood chips [Steeper Energy 2008]. The hydrothermal liquefaction (HTL) process is operated at supercritical conditions (above 374°C and 22.1 MPa). At test facility with a capacity of 30 kg of slurry per hour (about 320 kW related to the LHV of the slurry) is located in Alborg in Denmark which has been commissioned in 2013. The process is described in detail in [Jensen et al. 2018]. In case of the plant described in [Jensen et al. 2018] the products are diesel and marine fuel (heavy fuel oil). The yield of transportation fuel amounts to about 84% per MJ of wood. Additional inputs are hydrogen (about 0.14 MJ per MJ of final fuel) for upgrading and electricity (about 0.07 MJ per MJ of final fuel).

Figure 48. Wood to synthetic liquid fuels pathways

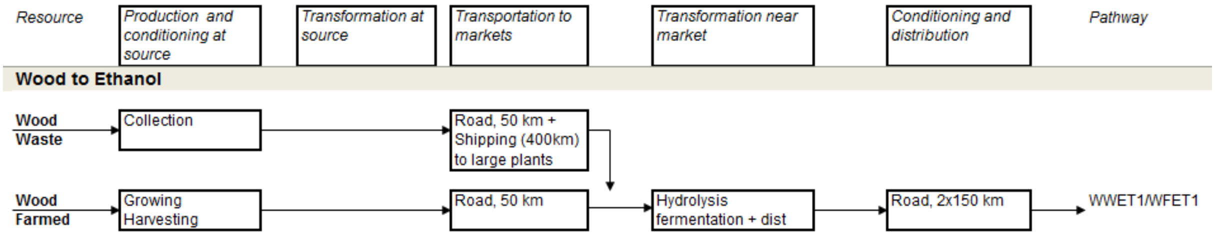


3.7.10.2.4 Wood to ethanol

Iogen's demonstration plant has been producing cellulosic ethanol from wheat straw since 2004, and a demonstrator was built in Canada by Woodland Biofuels in 2012. A commercial plant has been built in Brazil (Costa Pinto Project) [Iogen 2015]. NREL have made detailed studies of an SSCF process for converting wood and other biomass to ethanol (see also wheat straw to ethanol in section 3.4.8.3). We have selected their "base case" as our "worst case": it is the design for a plant using the state-of the art technology available in 1999. For our "best cast" we selected their "best of industry" plant, which already anticipates advances which are still at the laboratory stage.

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

Figure 49. Wood to ethanol pathways



3.7.10.2.5 Accounting for co-production of electricity

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

3.7.10.2.6 Waste wood in combination with black liquor gasification

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

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

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

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

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

Of course, this efficiency improvement can only come about through a substantial investment in a black liquor gasifier and fuel synthesis plant. The gasifier is expensive because of the need to resist corrosion by the very high sulphur and salt content of the syngas. The high costs of converting pulp mills for biofuel production using this process seem to have halted the application of this technology for several years, but research on more economic variants continues.

In [Ekbom 2003] the generation of methanol and DME from black liquor has been investigated within the BLGMF (Black Liquor Gasification to Motor Fuels) project. In version 5, we have included these new pathways as well as pathways to synthetic diesel and hydrogen inferred from the methanol and DME data. We have also included the electricity pathway as it will be the reference against which mill operators will judge the attractiveness of fuel manufacture.

3.8 Hydrogen via electrolysis pathways

(See also workbooks ***WTT v5 pathways 9-Electrolysis)***

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

Summary

Changes vs Version 4

Significant update on the existing fuel pathways (H_2 / Electrolysis)

Waste wood and farmed wood pathways (WFEL1/CH2, WFEL3/CH1, WFEL1/LH1): The energy consumption and GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for forestry residue collection, short rotation forestry, wood chips storage (seasoning), biomass transport. Pathways involving waste wood uses forestry residue.

Electrolysis pathways involving the EU electricity mix (EMEL1/CH1a, EMEL1/CH2a, EMEL1/LH1a): The EU electricity mix has been changed from EU electricity mix from 2009 to EU electricity mix from 2013.

Electrolysis pathways involving natural gas from Russia (GPEL1a/CH1): The significant change originates from the transport to the market stage, because the assumed transport distance of gas from western Siberia has changed significantly from the previous version. According to actual GEMIS data the transport distance for natural gas transported via pipeline amounts to 5000 km from the natural gas fields in Siberia to central EU. According to [Thinkstep 2017] the distance for natural gas transport via pipeline amounts to about 4300 km from natural gas fields to EU border (average of 3 corridors to the EU border). Therefore, it has been assumed that the natural gas is transported over a distance of 4300 km to the EU border, from there over a distance of 700 km to central EU where the natural gas is distributed over a distance of 500 km via the high-pressure pipeline grid.

Electrolysis pathways involving piped gas transported over a distance of 4000 km (GPEL1b/CH1, GPEL1b/CH2, GPEL1b/LH1): The losses for electricity transport and distribution has been updated.

Electrolysis pathways involving imported LNG (GREL1/CH1, GREL1/LH1): The inventory data for transformation at source (i.e. Liquefaction) and long-distance sea transportation have been updated based on recent literature sources. The distance for maritime LNG transport has changed from 5,500 nautical miles to 4,000 nautical miles based on data from NVGA (mix of transport distances for LNG delivered to the EU). For the natural gas liquefaction plant the electricity consumption indicated in [Ott et al. 2015] for state-of-the art plants has been used.

The losses for electricity transport and distribution have been updated.

Newly added fuel categories and pathways

EMEL1/CH1b, EMEL1/CH2b, EMEL1/LH1b

Addition of TRL and CRL

Summary

Figure 50. Hydrogen via electrolysis pathways

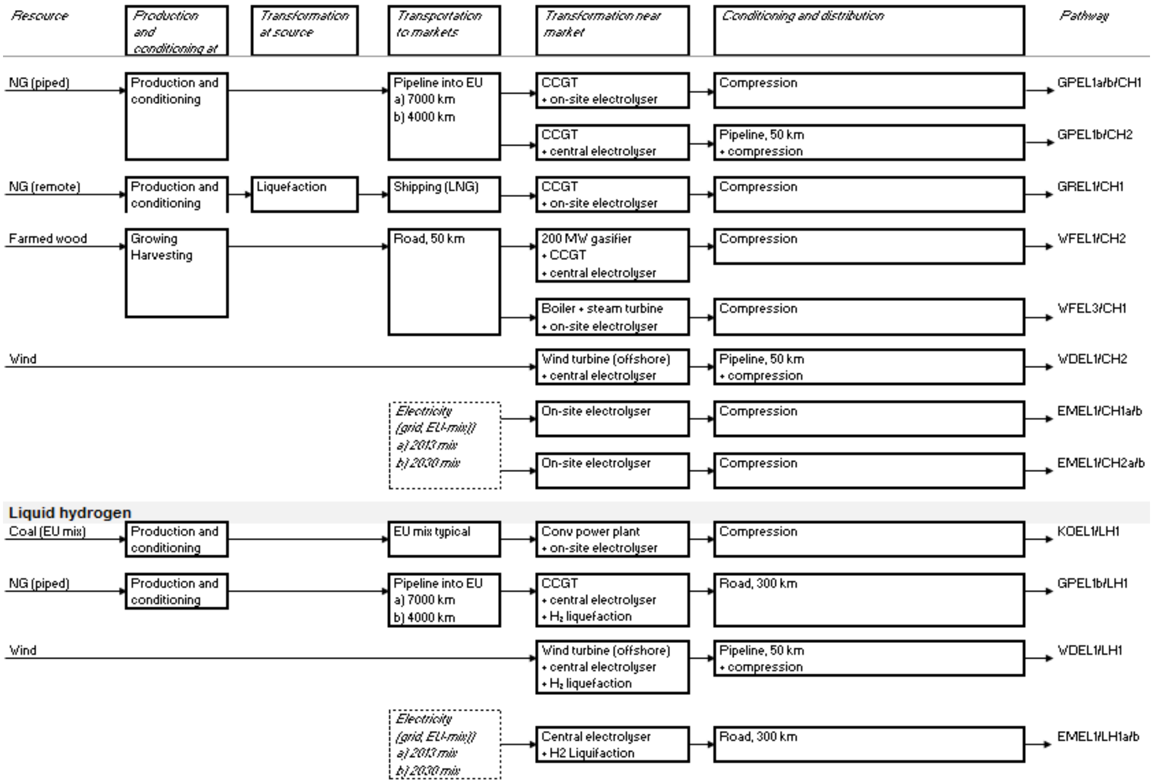
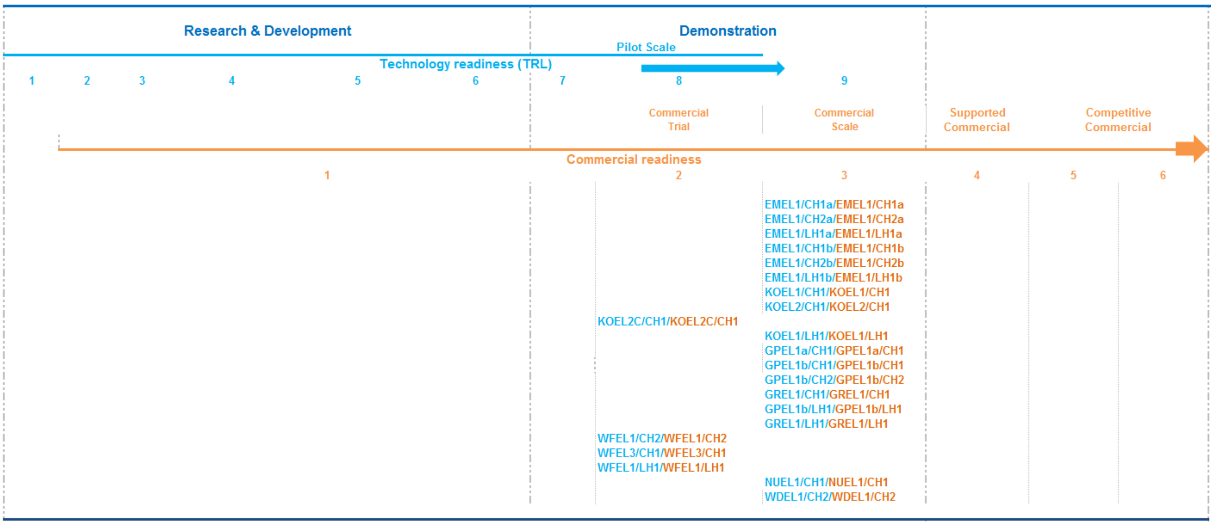


Figure 51. Hydrogen via electrolysis pathways TRL/CRL



Several sources of data are available, giving figures for both small and large (alkaline) electrolysers with and without auxiliaries. Including the latter most figures fall into the 58 to 67% bracket (related to hydrogen LHV, equivalent to 4.5 to 5.2 kWhe/Nm^3 of hydrogen produced), with no clear size effect [Hydrogenics 2009; Hydrogenics 2017; McPhy 2017; NEL 2012; NEL 2015]. Recently large electrolyzers employing proton exchange membranes (PEM) are commercially available or in the early state of commercialization. PEM electrolyzers achieve about 56 to 63% (4.8 to 5.4 kWhe/Nm^3 of hydrogen) [Areva 2016; Giner 2012; Hydrogenics 2017].

Many studies e.g. [DLR et al. 2015] expect an improvement in efficiency for hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries) versus the conventional technology while [Anglower & Dreier 1999] assume a far higher efficiency for the hydrogen generation via electrolysis (up to 77% related to the LHV and up to 91% related to the HHV including all auxiliaries).

The efficiency increases at part load. In combination with fluctuating renewable electricity sources such as wind power and photovoltaic the electrolysis plants are often operated at part load. We have therefore represented all electrolysis cases with a single process. On balance we have considered that a figure of 65% with a range of 63 to 68%, irrespective of the size and technology (alkaline, PEM), is a reasonable representation of the available data.

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

For the production of synthetic methane and synthetic liquid fuels from electricity high temperature electrolysis is an option. High temperature electrolysis based on solid oxide electrolysis cells (SOEC) splits steam instead of liquid water. The electricity consumption for splitting water steam is lower than that for the splitting of liquid water. According to [Sunfire 2018] the electricity consumption amounts to about 3.75 kWh per Nm^3 of hydrogen leading to an efficiency of about 80% related to the hydrogen LHV. Heat is required to generate steam (about 0.25 MJ per MJ of hydrogen). The heat is supplied by heat e.g. released by the downstream Fischer-Tropsch synthesis. As a result, the overall efficiency for the production of liquid fuels is higher than in case of using low temperature electrolyzers (PEM, alkaline).

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

One important issue is the pressure at which the hydrogen is available at the electrolyser outlet. Current and foreseeable technology at the 2030 horizon allows about 3 MPa. Higher pressures may be possible in the longer term but this is still somewhat speculative and we have not taken it into account. Furthermore, higher pressures lead to higher specific investment requirements. Hydrogen from a central electrolyser will need to be transported. If this is done through a pipeline network this pressure will be sufficient and a remaining pressure of 2 MPa has been assumed at the refuelling station compressor inlet. For the on-site electrolyser, no hydrogen transport is necessary and the whole 3 MPa outlet pressure is available.

Refer to Sections 3.2.8.1 and 3.7.10.2.1 for more details regarding Natural gas and Wood to Hydrogen pathways.

3.9 Power-to-fuel pathways

*(See also workbooks **WTT v5 pathways 5-Synfuels)***

3.9.1 Power-to-fuels. Carbon *Capture and Utilization* (CCU) pathways.

3.9.1.1 Approach.

In recent years, alternative routes to produce synthetic fuels as a way to increase the penetration of renewable energy in transport have been explored. One promising route in terms of Green House Gases (GHG) reduction is the concept of e-fuels also mentioned in the literature as *Electrofuels* (e-fuels) or Power-to-Gas (PtG) / Power-to-Liquid (PtL). The e-fuels production route is an example of Carbon Capture and Utilization (CCU) technologies as it combines the use of renewable electricity to produce “green” hydrogen through the electrolysis of water with CO_2 captured either from a concentrated source (flue gases from an industrial site, for example) or eventually from the air.

The main advantages of these e-fuels are:

- High CO_2 abatement potential versus their equivalent fossil-based fuels (≈ 85-96% WTT CO_2 reduction).
- high energy density, enabling their potential use as an alternative in segments such as long distance heavy duty, aviation and shipping.

- good storability, offering a means of storing renewable energy in a stable and transportable form (allowing to compensate seasonal supply fluctuations offering both short and long-term energy storage solutions) for grid balancing.
- drop-in fuels with similar properties to conventional fuels (e.g. green H_2, e-methane to natural gas and e-liquid fuels to conventional gasoline and diesel).
- the possibility to use the existing fuel infrastructure (for example, gas transport networks, liquid fuels distribution infrastructure –pipelines, filling stations, energy storage facilities) in some of the cases (e.g. diesel, gasoline, kerosene) without requiring any engine modification.

Whilst these technologies and their potential to produce low GHG intensive fuels used in conventional engines have been successfully demonstrated at pilot plant and demo scale, the main drawback is that whole conversion process for the production of liquid fuels is **highly energy and capital intensive** (mainly due to the water electrolysis, the potential CO_2 capture from the air scheme as well as the synthesis process itself) with low efficiencies that can vary between 35% to 53% ($MJ_{fuel}/MJ_{primary\ energy}$), depending on the integrated design and the technology selection.

Therefore, scalability and accessibility to a low cost and continuous source of renewable electricity are the main future challenges behind the e-fuels routes. Addressing both factors are essential for further development of the technology and potential deployment of the production of e-fuels in the medium and short term – specially in certain locations where favourable conditions can be found. These framework conditions are key elements to boost their use as one of the alternatives to reduce GHG emissions across all transport sectors especially in segments such as maritime and aviation where energy-dense fuels are required and less low carbon alternatives are foreseen to be available in the future. These power-to-fuels (PtL/PtG) technologies are also recognized as one of the elements to achieve 1.5° scenarios in the European Commission long-term strategy [EU COM 2018]. Due to the increasing interest on the subject, some selected e-fuel pathways are included for the first time in our JEC study:

- RESD1: Renewable electricity to e-diesel via methanol (CO_2 from flue gases).
- RESD2a/b/c: Renewable electricity to e-diesel high temperature electrolysis based on SOEC and FT route (a. CO_2 from flue gases; b. biogas upgrading; c. direct air capture).
- REME1a: Renewable electricity to methanol (CO_2 from flue gases).
- REDE1a: Renewable electricity to DME (CO_2 from flue gases).
- REOME: Renewable electricity to OME via methanol synthesis, formaldehyd synthesis, methylal synthesis, trioxane synthesis, and OME synthesis (CO_2 from biogas upgrading).

As examples of commercial and demonstration projects, some selected projects for the synthesis of efuels through chemical conversion processes are emerging in Europe, still with low-maturity in terms of commercial readiness level [Nova 2019]:

CCU fuels								
Company	Headquarter	Scale	Production site				Start date	End product
			City	Country	Status	Capacity		
Chemical CO_2 conversion processes								
Carbon Recycling International	Iceland	commercial	Grindavik	Iceland	in operation	4,000 t/a	2011	methanol
Nordic Blue Crude AS	Norway	commercial	Herøya	Norway	under construction	8,000 t/a	2020	diesel, kerosene naphtha, wax
Sunfire GmbH	Germany	demonstration	Dresden	Germany	in operation	>3 t/a	2014	

3.9.1.2 Power-to-fuel pathways.

Summary

Changes vs Version 4

Newly added fuel categories and pathways (Power-to-fuels – synthetic fuels)

e-diesel (syndiesel): RESD1, RESD2a/b/c; e-Methanol: REME1a; e-OME: REOME; e-DME: REDE1a

Addition of TRL and CRL

Figure 52. Power-to-fuel pathways

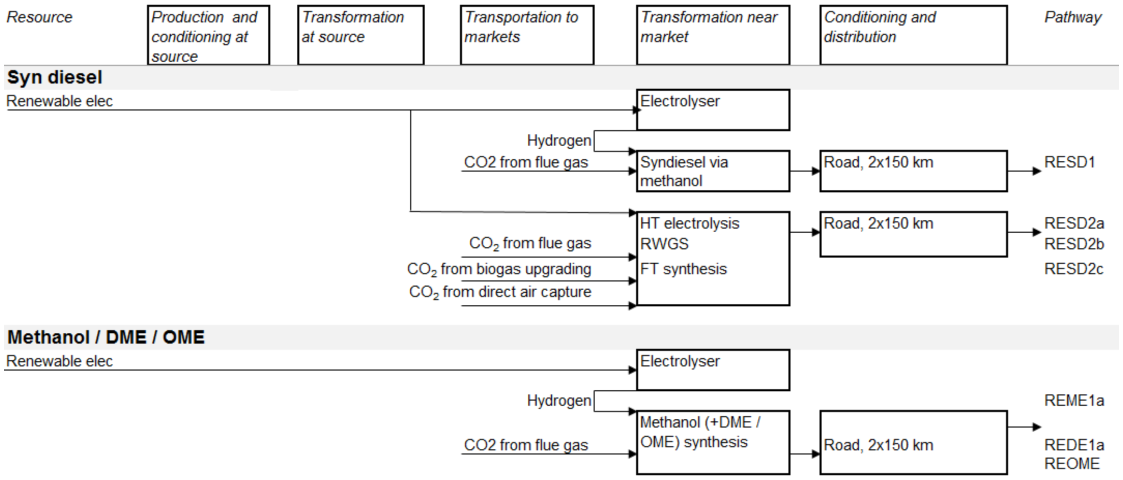
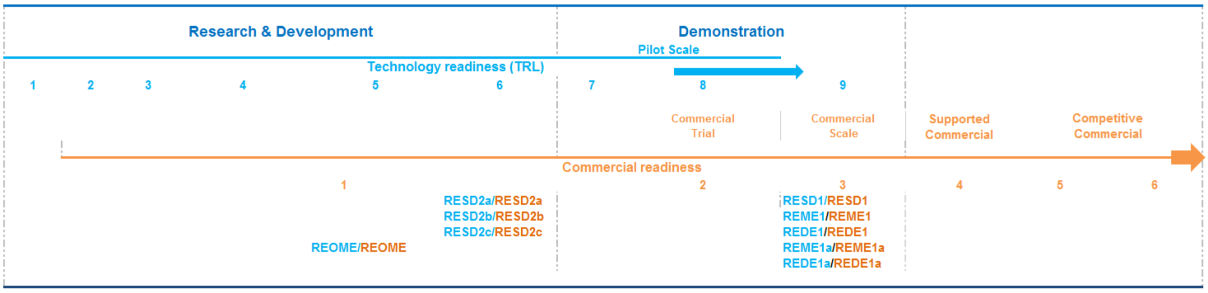


Figure 53. Power-to-fuel pathways TRL/CRL



In the present report, four type of synthetic e-fuels have been modelled as illustrative examples of Power-to-fuel pathways: **e-diesel** (through both Methanol and Fisher-Tropsch routes), **e-Methanol**, **e-DME** (e-Dimethyl ether) and **e-OME** (e-oxymethyl ether).

3.9.1.2.1 Feedstocks: CO_2 and “green H_2” from water electrolysis

- CO_2 from flue gases.

  CO_2 is the main feedstocks for these CCU conversion processes and the same technology as for additional CCS pathways has been considered for these pathways (See CCS section 3.5). For the purpose of this report, CO_2 is assumed to be available from flue gases and it is extracted via scrubbing with monoethanolamine (MEA) as the main agent. Besides this, one e-diesel pathway (*RESD2d*) explores the WTT impact of using CO_2 captured from the air via swing adsorption.

- Hydrogen produced via water electrolysis (see more details in Section 3.8 “Hydrogen via electrolysis”).

  Hydrogen is produced through water electrolysis using renewable electricity as the energy source (*Wind power plant* pathway selected for the modelling followed by electricity distribution from high to medium voltage assuming an efficiency of 65% irrespective of the size as a reasonable representation of the available data).

3.9.1.2.2 Fuel conversion processes

(See also *Natural gas to synthetic fuel pathways* in Section 3.2.8.2)

a) e-Methanol (REME1a)

e-Methanol is produced directly from the feedstocks mentioned above through the exothermic reaction: $3\ H_2 + CO_2 \Rightarrow CH3OH + H_2O$ and transported afterwards to the depot via a mix of road, maritime ship, inland ship, and rail for biomass derived methanol in an analogous way to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways).

b) e-OME (REOME) & e-DME (REDE1a)

The e-DME and e-OME pathways follow the e-Methanol route described above and add subsequent conversion processes to produce the related ethers following the reactions described below:

e-DME: $2\ CH_3OH \Rightarrow CH_3OCH_3 + H_2O$

e-OME MeOH to Formaldehyd

→ Formaldehyd & MeOH to Methylal
→ Formaldehyd to Trixane

Methylal + Trioxane → OME

c) e-diesel (RESD1, RESD2a/b/c)

The production of ediesel from CO_2 and Hydrogen could follow different routes. For illustrative purposes, two relevant pathways have been modelled in the present report:

i. **RESD1.** Syndiesel (e-diesel) via **methanol route** with the CO_2 and Hydrogen production as described above (a).

The starting point for this route is the e-methanol/DME one described above where Methanol is converted to e-diesel via olefin synthesis (with DME synthesis as an intermediate step), olefin oligomerization, hydrogenation, and product separation. For the modelling exercise, the commercially available “*MtSynfuels process*” [Liebner & Schlichting 2005] has been used where the methanol-to-synthetic-fuel process occurs through the following reactions:

DME-Synthesis: $2\ CH_3OH \Rightarrow CH_3\text{-}O\text{-}CH_3 + H_2O$

Olefin synthesis: $CH_3\text{-}O\text{-}CH_3 \Rightarrow (CH_2)_2 + 2\ H_2O$

Oligomerization: $0.5\ n\ (CH_2)_2 \Rightarrow C_nH_{2n}$

Hydrogenation: $C_nH_{2n} + H_2 \Rightarrow CnH_{2n+2}$

Table 33. Input and output data of the MtSynfuels process [Liebner & Schlichting 2005]

	t/d	MW_{LHV}
	Inputs	
Methanol	19200	4429
Hydrogen	70	97
	Outputs	
Kerosene/Diesel	6961	3475
Gasoline	877	439
LPG	741	398

ii. **RESD2.** e-diesel with a high temperature electrolysis (SOEC) and **Fischer-Tropsch route** and CO_2 from various sources (RESD2a. flue gases; RESD2c. biogas upgrading; RESD2d direct air capture):

- Feedstocks:
  - Hydrogen production via SOEC.

    These pathways explore alternative routes to produce Hydrogen via high temperature electrolysis using solid oxide electrolysis cells (SOEC) which splits steam instead of liquid water with lower energy requirements. The integration with the downstream Fischer-Tropsch conversion process (exothermic) maximizes the synergies with the electrolysis process as it makes use of the heat released during the synthesis stage. As a result, the overall efficiency for the production of liquid fuels is higher than in case of using low temperature electrolyzers (PEM, alkaline). The electricity and heat demand of the SOEC have been derived from the German manufacturer Sunfire [Sunfire 2018] based on a SOEC plant with a capacity of 40 Nm^3 of high purity hydrogen per hour.
  - CO_2 sources.

    Besides the CO_2 absorption process from flue gases used for the previous pathways (RESD2a), two alternative CO_2 sources are also explored in this case: RESD2c with CO_2 emitted in a biogas upgrading plant and RESD2d where a Direct CO_2 Capture (DAC) process is modelled. Regarding the DAC technology, the process developed by the Swiss company Climeworks (an ETH Zurich spinoff) has being applied. This technology capture CO_2 from air based on an adsorption/desorption cycle. [Climeworks 2015]. The process has been applied at Sunfire’s power-to-liquid plant in Dresden, which uses high-temperature electrolysis with downstream Fischer-Tropsch synthesis.
- Fischer-Tropsch synthesis.

The final step of the conversion process is the Fischer-Tropsch where carbon monoxide (CO) is required for the synthesis (see also Section 3.2.8.2 on natural gas to synthetic fuels):

Step 1. Reverse Water gas shift reaction

CO_2 has to be converted to CO via reverse water gas shift (RWGS) according to the exothermic reaction [König et al. 2015]:

$$CO_2 + H_2 => CO + H_2O$$

Hydrogen reacts with CO to form liquid hydrocarbons as follows: (exothermic reaction)
$2\ H_2 + CO => -CH_2- + H_2O$

Step 2. Compressed H_2 + FT synthesis

The reaction conditions of the Fischer-Tropsch reactor are adjusted to maximize the direct production of liquids (naphtha, kerosene, diesel, wax) and to minimize the share of gases (C1-C4). Unreacted CO and H_2 is fed recycled and it has been assumed that 90% of the Fischer-Tropsch products are liquid (i.e. C5 and above).

Step 3. Upgrading to gasoline and diesel

The “syn-crude” leaving the Fischer-Tropsch reactor is sent to a hydrocracking unit where the heavier products such as wax is hydrocracked to the desired products e-naphtha, e-kerosene and e-diesel. According to [Senden et al. 1996] the product split consists of 15% naphtha, 25% kerosene, and 60% gasoil/diesel if the plant is operated at 'gas oil mode'.

The input and output data for the conversion of hydrogen and CO_2 to synthetic gasoline, kerosene, and diesel including Fischer-Tropsch synthesis, reverse water gas shift (RWGS), upgrading and all auxiliaries has been derived from [König et al. 2015].

4 Final fuels: Energy and GHG balance

In this section we report and compare the energy and GHG balance of each pathway. In order to illustrate the relative importance of the different stages of a given pathway, we include detailed results according to the 5 generic steps defined in *section 2.1 (*From *production* to *conditioning and distribution)*. The actual figures with additional details for each pathways are listed in *the relevant workbooks (***Appendix 1***)*.

In the generic presentation of results, we focus on total energy expended, i.e. all the energy, regardless of its origin, that needs to be used to produce the desired fuel, *after discounting the energy content of the fuel itself*. The unit used is MJ expended total energy per MJ finished fuel (LHV basis). For example, a figure of 0.5 $MJ/MJ_{final\ fuel}$ means that making the fuel requires 50% of the energy that it can produce when burned. This total energy figure gives a truly comparable picture of the various pathways in terms of their ability to use energy efficiently.

For fuels derived from renewable resources it is also of interest to report the fossil energy used in the pathway, particularly by comparison with the energy content of the final fuel. This is reported and discussed separately as MJ *expended fossil energy* per MJ *finished fuel.* The reported WTT GHG figures **exclude CO_2 emissions associated with the combustion** of the final fuel.

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

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

4.1 Gasoline, diesel fuels. ED95 components and Adblue

This section explores different routes to produce gasoline and diesel fuels including oil-based pathways as well as some selected examples of alternative gasoline and diesel routes modelled in the present JEC WTT v5 from different feedstocks (synthetic diesel from bio/waste, pyrolysis diesel and gasoline and e-fuels routes). As complementing information, some details regarding the Adblue production pathway, especially important for air quality control in diesel engine trucks, have been also included. At the end of the section, the main results are summarized and compared versus conventional oil-based gasoline and diesel.

4.1.1 Oil based Gasoline and diesel

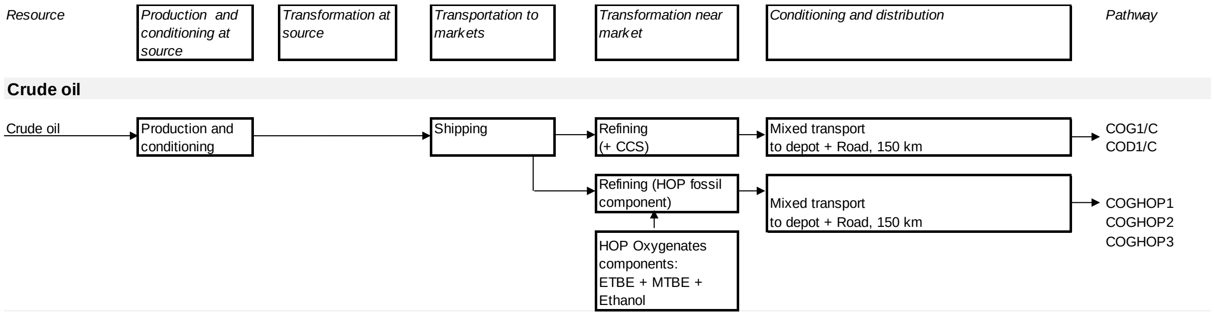
(see also workbook WTT v5 pathways 1- Oil & Gas in Appendix 1)

Gasoline and diesel fuel from conventional crude oil supply the bulk of road transport needs today. As noted in *section 3.1.1* non-conventional sources of crude oil, although of growing importance in North America, are not expected to impact the European market significantly in the time frame of this study.

The energy and GHG "cost" of introducing alternative fuels needs to be measured against the savings related to "not-providing" the conventional equivalents. The energy and GHG balance that we need to be concerned with here pertain, therefore, to the effect of marginally reducing the production of conventional fuels compared to a "business-as-usual" case. The following figures reflect this approach (see also *section 3.1.3* and *WTT Appendix 1).*

A new set of pathways couple with CCS (Carbon Capture and Storage) schemes have been added to the conventional gasoline and diesel pathways.

Figure 54. Key to pathway codes (section 3.1)



Code	*Final fuel*	*Description*
COD1	Diesel fuel	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), typical EU distribution and retail.
COD1C		Crude oil from typical EU supply, transport by sea, refining in EU (marginal production) with CCS, typical EU distribution and retail.
COG1	Gasoline	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), typical EU distribution and retail.
COG1C		Crude oil from typical EU supply, transport by sea, refining in EU (marginal production) with CCS, typical EU distribution and retail.

Figure 55. WTT total expended energy balance for crude oil based fuels

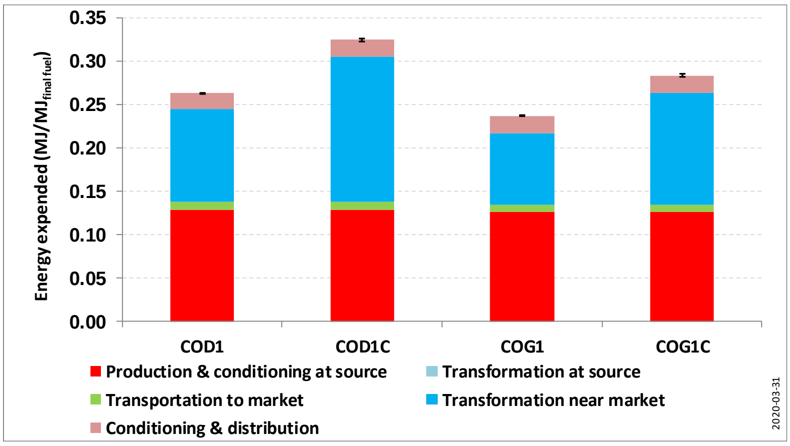
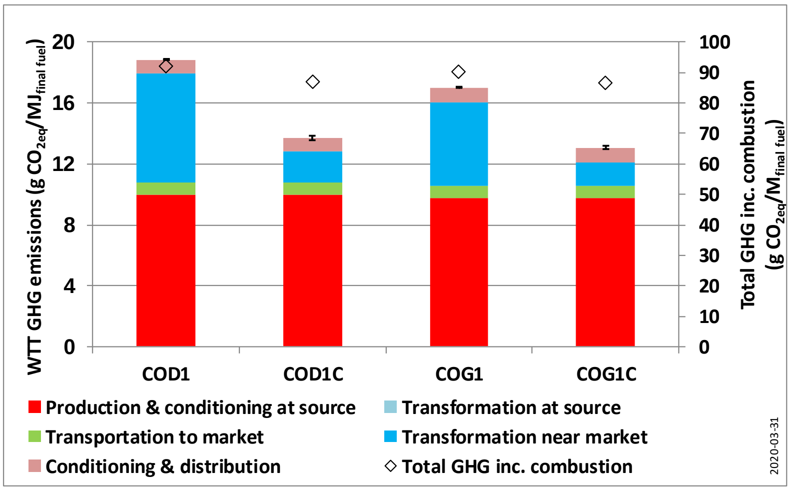


Figure 56. WTT GHG emissions balance for crude oil based



General:

Based on the assumptions detailed in Section 3.1, diesel conversion routes are more energy and GHG intensive than the equivalent gasoline ones.

Carbon capture and storage (CCS) schemes applied to the refinery emissions have the potential to reduce ~30% the GHG WTT balance with some additional energy expended in the process.

The black dots on the top shows the uncertainty bars which are very small in case of crude oil based fuels.

Steps:

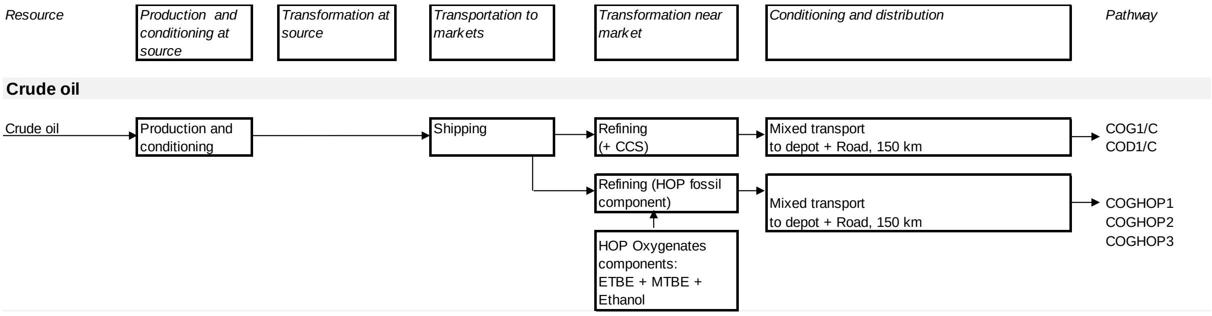
In all the cases, the production of the fossil oil represents from ~50% (w/o CCS) of the total GHG emissions increasing up to ~70% when the CO_2 coming from the refining process is partially captured and storage.

The refining process is energy intensive representing 15-30% of the total GHG emissions but up to 35-50% of the total WTT energy consumption (diesel routes being ~10% more energy intensive than gasoline ones.

4.1.2 Oil based High Octane Gasoline

The following figures summarize both the Energy expended and GHG emissions balance for the high-octane gasoline pathways modelled in the present JEC WTT v5 study:

Figure 57. Key to pathway codes (section 3.1)



Code	*Final fuel*	*Description*
COGHOP	Gasoline High octane	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), typical EU distribution and retail. COGHOP1 - HOP 100 RON / 3.4% bioenergy (avg. E5) - 'Light Oxygenate' Pathway COGHOP2 - HOP 102 RON / 3.4% bioenergy (avg. E5) - 'Light Oxygenate' Pathway COGHOP3 - HOP 102 RON / 6.5% bioenergy (avg. E10)

Figure 58. WTT total expended energy balance for HOP pathways

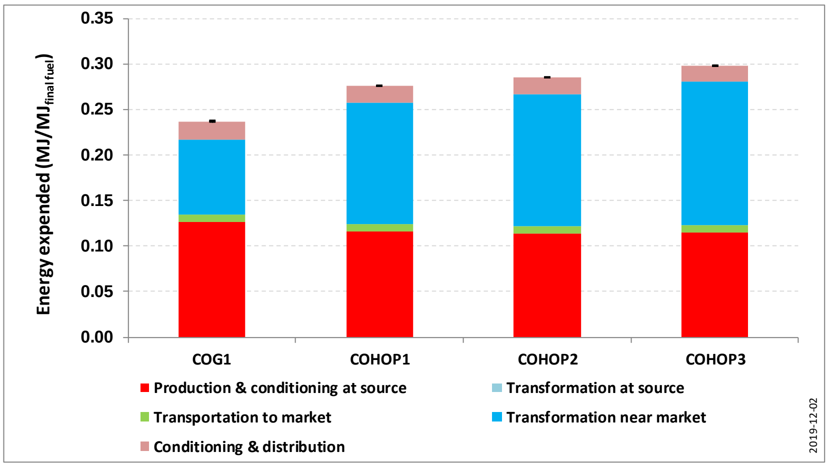
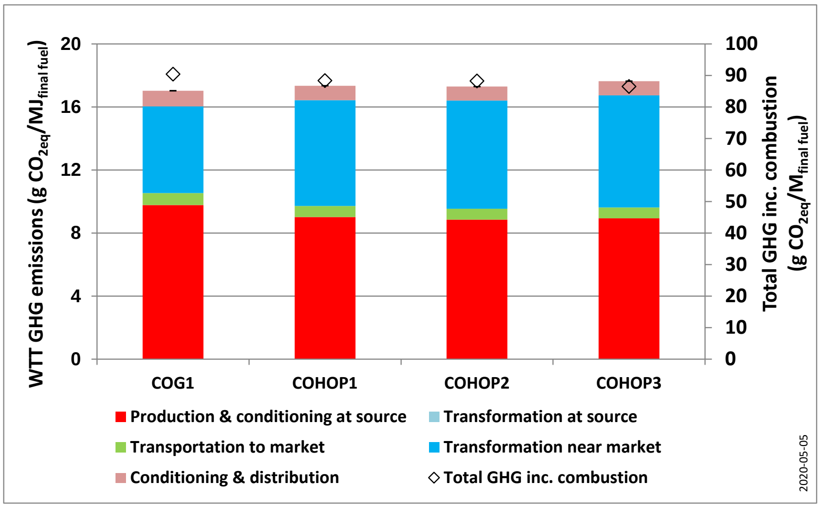


Figure 59. WTT GHG emissions balance comparing gasoline (crude oil based) and HOP pathways



General:

The routes modelled in JEC WTT v5 as examples of potential pathways to produce high octane gasoline (through blending with other oxygenates / high octane components) are more energy (delta ~15-25%) and less GHG intensive (including combustion ~2-4%) than the conventional gasoline ones (w/o CCS).

COHOP3 (102 RON route with 6.5%eq bioenergy) is presented as the less GHG and more energy intensive route.

Steps:

In both cases, due to the addition of blending components, the energy consumed in the *Transformation near market* step increases up to ~90% in the higher case, reducing at the same time the WTT + combustion emissions due to the less GHG intensive oxygenate routes considered (up to ~4%) versus the conventional gasoline route.

Note that these figures apply to Europe as a result of the specific situation prevailing in the region. The situation will be different in other parts of the world and a similar assessment would have to be made taking into account the local parameters and leading to different figures and conclusions. Note also that, at this stage, there is no credible prospect for naphtha to be used as an automotive fuel and it has therefore not been included in this version.

4.2 Synthetic Fischer-Tropsch diesel (GTL, BTL, CTL and Power-To-Diesel)

4.2.1 Pathways

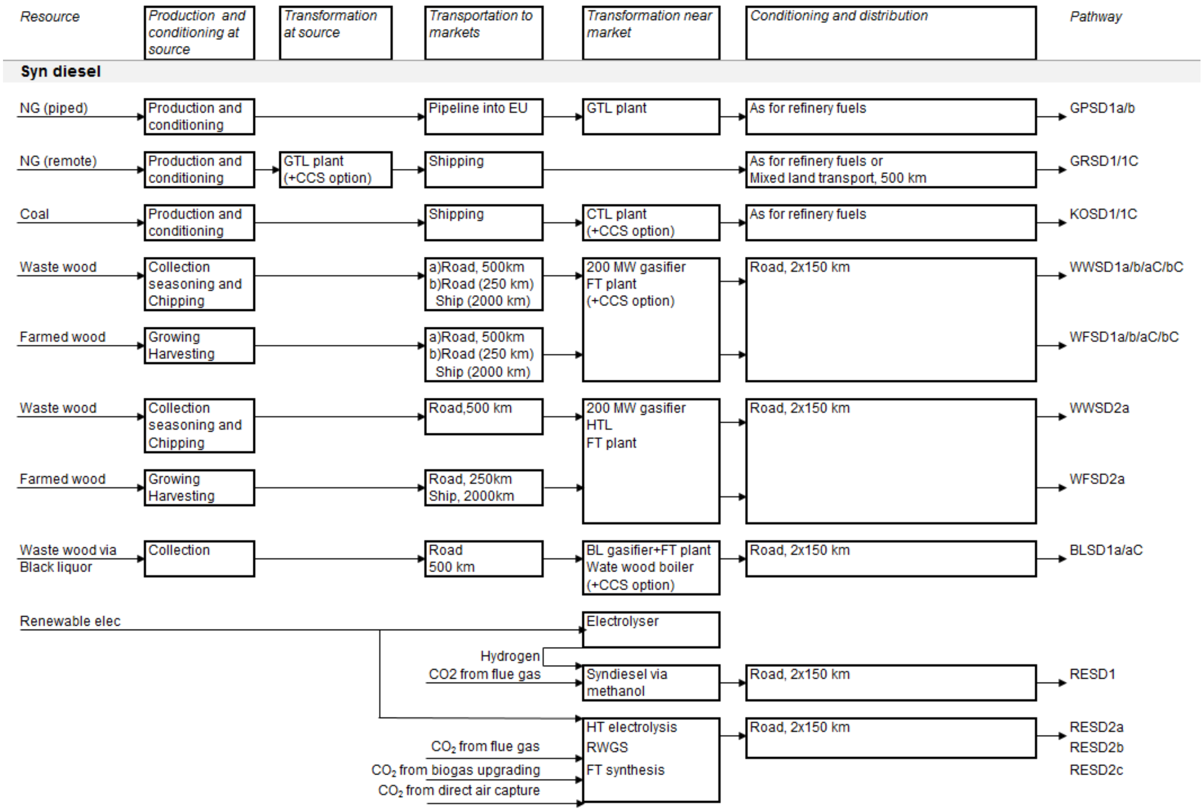
(See also workbook WTT v5 pathways 5-Synfuels in Appendix 1)

The manufacturing of synthetic fuels relies on steam reforming or partial oxidation of a fossil hydrocarbon or organic feedstock to produce syngas which is, in turn, converted into the desired fuel using the appropriate process. In other words, the fuel is reduced to smaller molecular components (CO, H_2) from which new products can be built.

Natural gas is the most likely feedstock for these processes because of its widespread availability, particularly as stranded (and therefore cheap) gas in remote locations and also because of the relative simplicity of the steam reforming and/or partial oxidation process compared to heavier feedstocks. Coal can also be used although the complexity and cost of the required plant are much higher. Both coal and gas lend themselves to large scale facilities which are beneficial in terms of cost. Cost considerations also mean that these facilities tend to be located near to the natural resource, to avoid or minimise shipping of raw materials.

Biomass, most likely in the form of wood or perennial grasses, is also being actively considered as a source of such fuels. Our generic wood pathway based on farmed wood (poplar) represents this group of feedstocks. An alternative option for producing liquid fuels from waste wood would be the so-called Black Liquor route (see *section 3.7.10.2.6*). Fischer-Tropsch routes will produce a diesel-like fuel which can in principle be used alone or blended as a component of normal diesel fuel and used in conventional vehicles.

Figure 60. Key to pathway codes (Fischer-Tropsch diesel section)



Code	*Final fuel*	*Description*
GRSD1/1C	Syndiesel	Remote natural gas to Syndiesel (GTL): GTL plant near remote gas field with/without CCS (C), Syndiesel imported into Europe and incorporated into diesel pool.
KOSD1/1C		EU-mix hard coal to: Syndiesel (CTL) with / without CCS.
WxSD1/BLSD1		Wood to Syndiesel, waste wood (WWxx1), farmed wood (WFxx1), and waste wood via black liquor gasification/synthesis plant (BLxx1) considering two subcases: Distance travelled ((a) 500 km distance travelled, (b) >500 km) and with CCS schemes (code as "xC").
RESD1		Renewable electricity to Syndiesel via methanol (CO_2 from flue gases).
RESD2		Renewable electricity to Syndiesel high temperature electrolysis based on SOEC and FT route (CO_2 from flue gases, biogas upgrading, and direct air capture).

The main properties for the syndiesel considered in the study are summarized below:

Table 34. Physical properties – Syndiesel

Density	kg/m^3	780
LHV	MJ/kg	44.0
C content	% m	85.0%
CO_2 emission factor (assuming total combustion)	g CO_2/MJ	70.8
	kg CO_2/kg	3.12

4.2.2 CCS in syndiesel production

Steam reforming and/or partial oxidation is the first step towards production synthetic diesel from natural gas or coal. However, CO_2 has to be removed upstream of the synthesis step because CO_2 is not desired in the gas stream entering the synthesis reactor. The solvent absorption processes commonly used produce a virtually pure CO_2 stream so that only compression is required for potential transport and eventual storage. Most GTL plants will be built near gas or oil fields where the CO_2 can be re-injected.

For GTL there is no literature source where a plant with and without CCS is compared. GTL plants are very complex. The layout differs from licensor to licensor and this can have a large impact on the energy penalty for CCS. We have used a literature estimate of 3% energy efficiency penalty as a basis for our calculation, starting from an overall plant efficiency of 65% in the base case. The CO_2 generated in the auxiliary power plant is not recovered in this scheme, so that the CO_2 recovery is relatively low at around 80%. For coal-to-liquid we used a literature source giving a direct comparison of base and CCS cases summarized below:

Table 35. Syndiesel production with/without CCS

Feedstock		***Natural Gas***		***Coal***	
Case		***Base***	***With CCS***	***Base***	***With CCS***
Code		***GRSD1***	***GRSD1C***	***KOSD1***	***KOSD1C***
Natural gas well-to-tank	MJ/MJ SD	0.62	0.70		
Coal well-to-tank	MJ/MJ SD			0.94	1.02
Energy Efficiency GTL and CTL plant*		65%	62%	40%	41%
Excess electricity GTL and CTL plant	MJ/MJ SD	-	-	0.33	0.24
CO_2 removal efficiency			80%		90%
Net GHG emissions well-to-tank	g CO_{2eq}/MJ SD	23.2	13.1	130.3	40.2

(*) LHV (output of FT products)/LHV (natural gas or coal); without taking into account excess electricity

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

4.2.3 WTT Energy and GHG emissions balance

WTT Energy use and GHG emissions for the synthetic diesel pathways are shown in **Figures 61** and **62**. Making synthetic diesel is an energy-intensive endeavour. The combination of steam reforming, partial oxidation and Fischer-Tropsch synthesis result in overall efficiencies within a broad range of 45 to 65% depending mostly on the feedstock and to a lesser extent the process scheme.

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

Coal-based processes (CTL) can achieve coal to synthetic liquid fuel efficiencies of about 40% and overall efficiencies in the region of up to 55% including exported electricity. The biomass to liquid fuel efficiencies of wood-based processes are expected to be 38 to 45% depending on the assumed hydrocarbon chain growth probability α (0.85 to 0.90) and the overall efficiencies including exported electricity are expected to be up to 50%. Solid fuels require a more complex gasification process than NG and because solid residues are formed, the syngas must be cleaned before further processing. In the case of wood processing, the plants are likely to be much smaller and less optimised in energy terms. This is also the main reason why wood processes are less favourable than CTL from this point of view. Future developments may improve the performance of these processes.

Although the total energy use for the pathways based on wood is fairly high, this is almost entirely renewable energy and the fossil inputs are very low. The black liquor route, where this process can be applied, uses less energy than the Fischer-Tropsch pathway due to efficiency gains from the integration into a pulp mill and replacing the less efficient recovery boiler. The differences between farmed and waste wood are small in energy terms.

Syndiesel produced from wind electricity and flue gas CO_2 as described in *section 3.9*, is essentially carbon-free, the only potential emissions being related to distribution of the finished fuel. The energy expended, although mostly renewable, is relatively large due to the efficiency of the electrolysis and the energy requirement of the synthesis process.

Figure 61. WTT total expended energy balance for syndiesel pathways (Fischer-Tropsch)

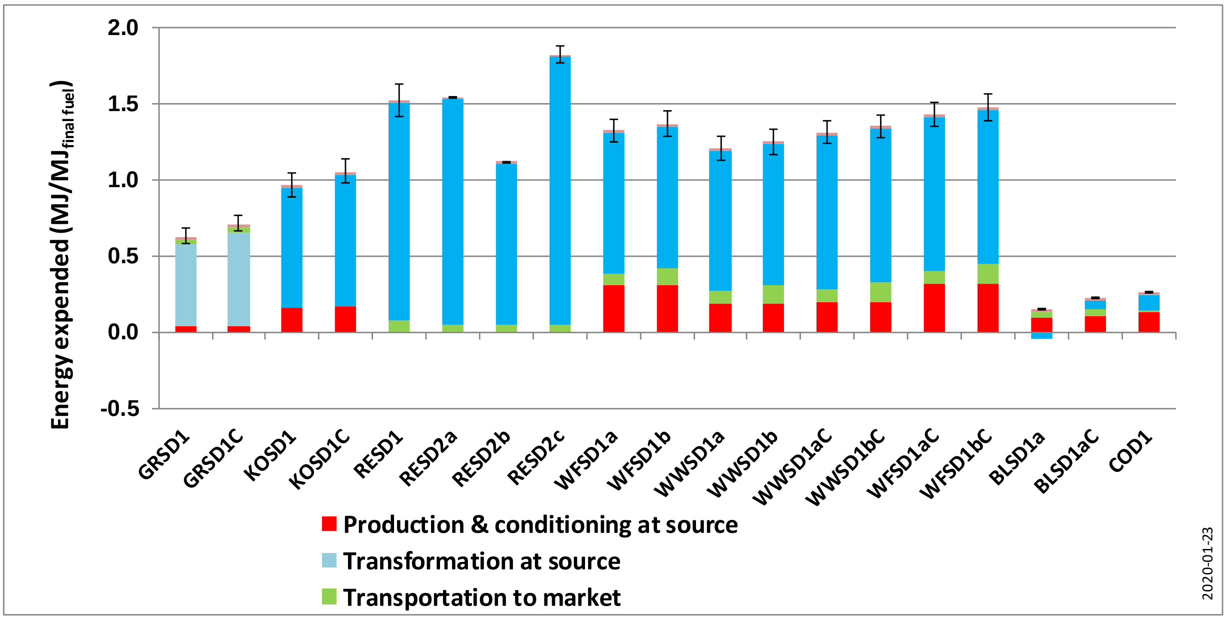
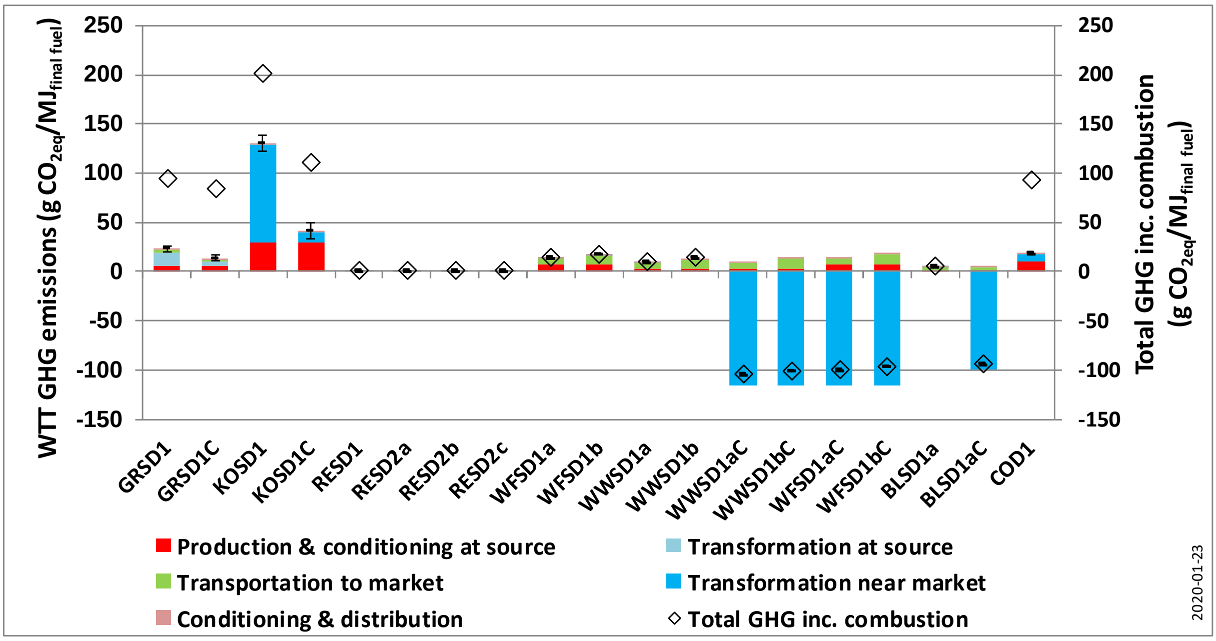


Figure 62. WTT GHG emissions for syndiesel pathways (Fischer-Tropsch)



General:

The different synthetic routes modeled from natural gas, coal or biogas show more energy intensive pathways than their comparable oil-based diesel route with the only exception of the black liquor pathways where the results are similar.

As in previous figures, **Figure 62** shows the GHG emissions at each stage of fuel production as stacked bars and in addition the total GHG emission including the combustion emissions as diamond symbols. The picture is more favourable for renewable electricity (RESx) and waste based pathways with the potential to reduce the GHG emissions significantly (around half of the WTT diesel GHG intensity for the wood-based routes reaching almost neutrality in the case of the Power-To-Diesel (e-diesel) ones). For the e-diesel pathways, the Fischer-Tropsch route with a High Temperature electrolyzer offers a pathway to improve efficiency versus the methanol route (using state-of-the-art electrolyzer). When the High Temperature electrolyzers are combined with methanol routes, both methanol and Fischer-Tropsch routes offer comparable results (slightly better in the methanol case).

When natural gas and coal are compared, the GHG balance is more favourable for natural gas as the energy involved is less carbon-intensive (the GTL process is in effect a carbon concentration process and a large fraction of the expended energy is in the form of hydrogen). Regarding the value including combustion (diamond symbol), it has to be noted that besides the WTT pathways, the combustion of syndiesel has lower CO_2 emissions than fossil diesel because of the lower C/H ratio.

Using coal, however, results in very large GHG emissions reflecting both the higher energy inputs and the high C/H ratio of coal. For wood, GHG emissions are mainly incurred for wood growing and collection/transport and since the combustion CO_2 is considered as renewable, the overall GHG emission is very low.

CCS offers an opportunity for substantial reductions of CO_2 emissions. For CTL the reduction is much more dramatic (>50%) because of the much larger amount of CO_2 emitted during the CTL process. With CCS, emissions for CTL are still almost twice the ones obtained for fossil diesel from crude oil. As these processes develop, higher CO_2 recovery may be possible. When applied to wood pathways, CCS offers a potential route to achieve negative emissions (See section 3.5.2 where the concept of Bio-energy Carbon Capture is further detailed).

Steps:

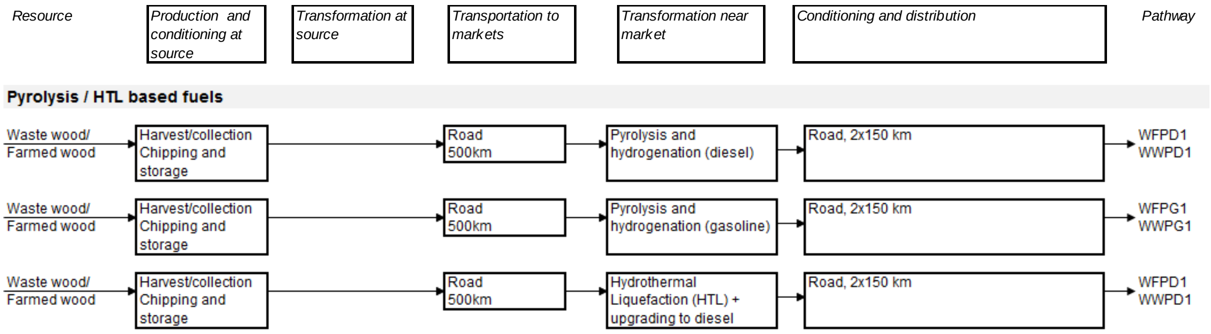
Regarding the individual steps, the transformation process is the one where the energy is mainly expended due to the gasification and synthesis process which occurs near the market.

4.3 Pyrolysis / HTL based gasoline and diesel

(See also workbook WTT v5 pathways 5-Synfuels in Appendix 1)

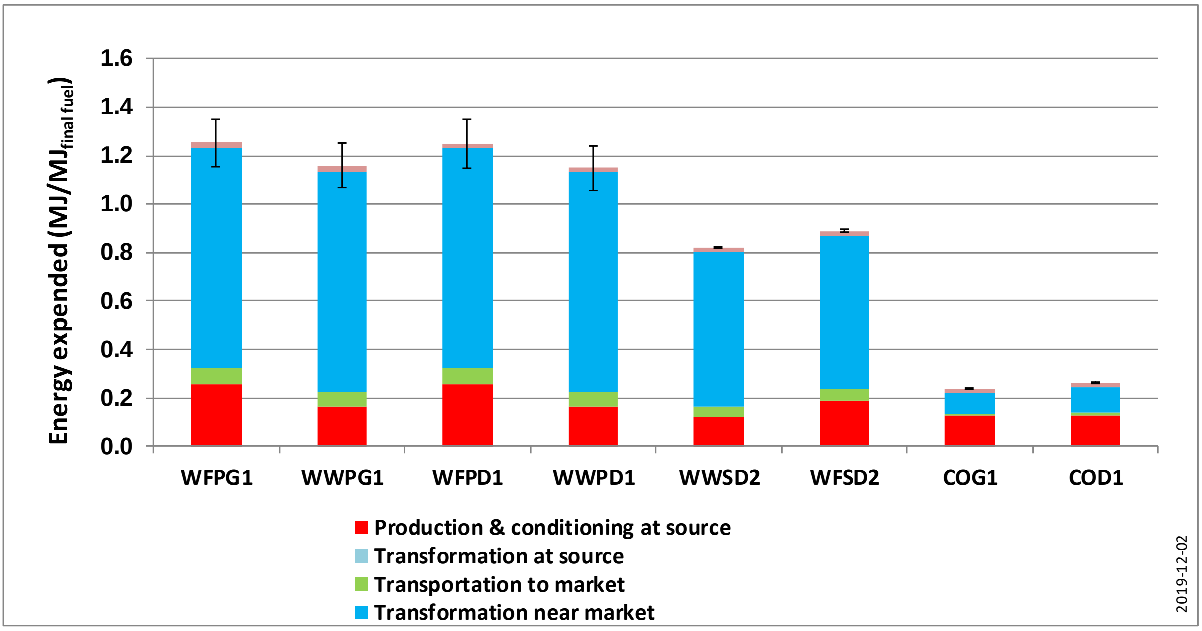
Alternative routes to the synthetic routes described in the previous sections can also be foreseen. Conversion pathways based on pyrolysis and hydrothermal liquefaction (HTL) have been modelled in the JEC WTT v5 as follows:

Figure 63. Key to pathway codes (Pyrolysis/HTL routes)



Code	*Final fuel*	*Description*
WFPG1	Pyrolysis-based gasoline	Farmed wood to pyrolysis-based fuel
WWPG1		Waste wood to pyrolysis-based fuel
WFPD1	Pyrolysis-based diesel	Farmed wood to pyrolysis-based fuel
WWPD1		Waste wood to pyrolysis-based fuel
WWSD2	HTL-based diesel	Wood waste to diesel, hydrothermal liquefaction (HTL) and upgrading
WFSD2		Farmed wood to diesel, hydrothermal liquefaction (HTL) and upgrading

Figure 64. WTT expended energy balance for pyrolysis and HTL based fuels pathways (Gasoline and diesel)

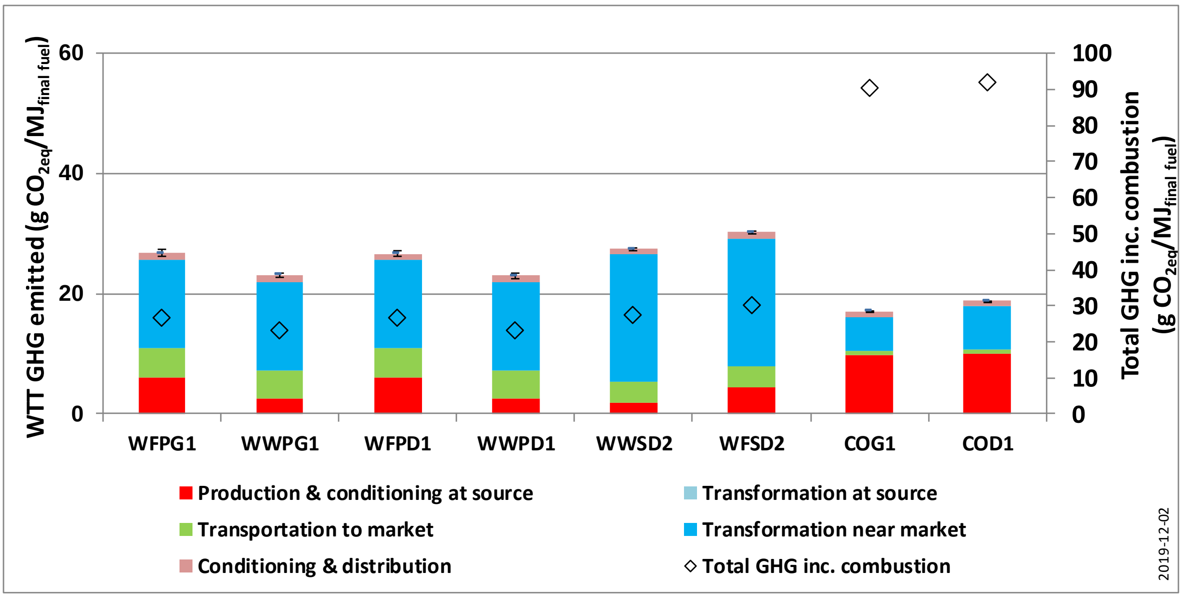


General:

All the routes to process wood through either **pyrolysis** (Pyrolysis of chips followed by hydrogenation) or **HTL** (Synthesis at supercritical water conditions and hydroprocessing) expend 4 to 6 times more energy than their equivalent fossil gasoline or diesel.

The higher efficiency of the HTL process (~84%) vs ~62% of the pyrolysis route together with the lower energy requirement in the whole conversion process reduces significantly (~40%) the total energy expended for the HTL route (TRL 4).

Figure 65. WTT GHG emissions balance for pyrolysis based fuels pathways



General:

All the pathways investigated present a higher WTT GHG intensity (from 15% up to ~40%) when compared with conventional (oil-based) diesel or gasoline depending on the conversion chosen.

Despite of the higher energy expended, the pyrolysis routes end up with lower GHG intensity fuels heavily affected by the different energy sources used to meet the energy requirements: mainly natural gas in the pyrolysis one vs electricity and hydrogen in the HTL. As the electricity and hydrogen mix evolve towards renewables, the picture would likely change favoring the HTL route.

4.4 Adblue

The GHG emissions and energy use from Adblue supply (per kg of urea/water solution with 32.5% urea) have been included in this version in the event that some Heavy Duty vehicles may require the injection of a certain amount of Adblue to reduce NO_x emissions in vehicles.

After comparing different sources, the BASF related pathway has been chosen for the WTW integration. Further details regarding the GHG and Energy balances explored from different sources are presented below:

Table 36. Adblue pathways (CO_{2eq}/kg adblue). Summary

	Emissions	Energy		
	CO2eq	Total	Non-renewable	Renewable
Source	g/kg	MJ/kg	MJ/kg	MJ/kg
AdBlue based on FE data from 2014 (EU and import)	645	10.74	10.74	0.00
AdBlue via CO2-Stripping-Verfahren SKW Piesteritz GmbH Lutherstadt Wittenberg)	489	7.98	7.98	0.00
AdBlue via NH3-Stripping-Verfahren (Hydro Agri GmbH Brunsbüttel)	484	7.90	7.90	0.00
AdBlue via Solution Recycle Urea Process (BASF AG Ludwigshafen) (*)	502	8.21	8.21	0.00

Note. Chosen average pathway (link to TTW)

The total GHG emissions for the supply and use (combustion) account for about 502 g CO_2 equivalent per kg of Adblue. Thereof, 264 g CO_2 equivalent per kg are emitted during supply (WTT) and 238 g CO_2 per kg are emitted during combustion (TTW).

4.5 CNG, LNG, CBM (Compressed Biomethane), LBG (Liquefied biomethane), Synthetic natural gas (SNG / SLNG) and LPG

4.5.1 Pathways to CNG and LNG

(See also workbook WTT v5 pathways 1-Oil & Gas in Appendix 1)

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

4.5.1.1 Composition

Gas sent down the pipelines from various sources still contains some light hydrocarbons and some inerts so that its composition varies between producing regions. In the case of LNG, practically all heavier hydrocarbons have been removed in the liquefaction process and the gas is virtually pure methane. These differences in composition result in a range of volumetric heating values as well as significant differences in combustion characteristics as measured by the methane or octane number. In spite of these variations, the current European gas grid is estimated to deliver a minimum *Motor Octane Number* (MON) of 115, which is sufficient to allow the use of dedicated CNG vehicles with higher compression ratio. In the current version, we have also included a H-CNG composition including only H-gas qualities in the mix value to assess the potential impact on TTW (especially for Heavy Duty) of this dedicated grade.

In previous versions of this study, we calculated a notional composition of the standard gas available in the EU distribution network and that would be available for use as road fuel. This composition and quality is used as input to the Tank-to-Wheels part of the study for CNG vehicles.

Table 37. Notional composition of NG distributed in the EU (Current)

Origin	Piped NG					LNG	Notional EU-mix (Current)
	CIS (Russia)	NL	UK	Norway	Algeria		
Notional share in EU-mix (%v/v)	30.8%	11.7%	9.1%	22.4%	5.9%	10.0%	100%
H_2	0.0%	0.0%	0.5%	0.5%	0.8%	0.000%	0.22%
Methane	98.4%	81.5%	86.0%	86.0%	92.1%	90.3%	90.5%
Ethane	0.4%	2.8%	8.8%	8.8%	1.0%	6.3%	4.355%
Propane	0.2%	0.4%	2.3%	2.3%	0.0%	2.1%	1.160%
Butane and heavier	0.10%	0.09%	0.08%	0.08%	0.02%	0.87%	0.17%
CO_2	0.1%	1.0%	1.5%	1.5%	0.0%	0.000%	0.6%
N_2	0.8%	14.2%	0.8%	0.8%	6.1%	0.45%	2.6%
MM (g/mol)	16.3	18.5	18.4	18.4	16.8	17.9	17.5
Density (kg/Nm^3)	0.727	0.827	0.820	0.820	0.750	0.798	0.782
LHV (MJ/Nm^3)	35.7	31.4	38.6	38.6	33.7	39.2	36.4
LHV (GJ/t)	49.2	38.0	47.1	47.1	44.9	49.1	46.59
MON (CARB)	138.2	132.9	122.3	122.3	138.0	121.5	125.8
Methane number (MWM)	95.0	87.0	74.0	74.0	94.0	73.0	82.0

Notes.

i. *Methane number* calculated with *MWM methane number calculator*: http://www.euromot.eu/media_and_events/publications/mn
ii. *LNG composition* calculated based on GIIGNL report [2017]
iii. LHV value for the EU mix highly dependent on the regional values. As a reference, the average measured value (2016) is close to the one estimated in our WTT study (EU mix - CNG & LNG: LHV value, 47.5 MJ/kg from [NVGA 2017, Exergia report 2016]).
iv. Nm^3 is gas at 0°C = 273.15 K and 0.1013 MPa
v. Note that a similar H-CNG mix composition has been estimated by removing the share of NL in the piped NG mix (LHV of H-CNG Eu mix is 47.96 GJ/t).
vi. MON means "Motor Octane Number"
vii. The piped natural gas properties defined by the composition detailed in the table above are included here for information:

Properties	Piped NG EU-mix (Current)
MM (g/mol)	17.5
Density (kg/Nm3)	0.780
LHV (MJ/Nm3)	36.1
LHV (GJ/t)	46.3
MON (CARB)	126.4
Methane number (MWM)	84.0
CO_2 emission factor, g CO_2/MJ	56.1

In the present version 5, we have attempted to estimate a notional 2030 EU-mix including a certain penetration of biogas to explore the differences versus the current natural gas pathways. The detailed composition and share in the 2030 EU-mix presented are shown in the table below:

Table 38. Notional composition of NG distributed in the EU (2030)

Origin	Piped NG EU mix (2.1)	LNG	Biogas	Notional NG EU-mix (2030)
Notional share in EU-mix (%v/v)	77.7%	18.9%	3.4%	
H_2	0.3%	0.0%	0.0%	0.20%
C1	90.6%	90.3%	97.0%	90.7%
C2	4.1%	6.3%	0.0%	4.4%
C3	1.0%	2.1%	0.0%	1.2%
Butane and heavier	0.1%	0.9%	0.0%	0.23%
CO_2	0.8%	0.0%	3.0%	0.71%
N_2	3.1%	0.4%	0.0%	2.5%
MM (g/mol)	17.5	17.9	16.8	17.5
Density (kg/Nm3)	0.780	0.798	0.752	0.782
LHV (MJ/Nm3)	36.1	39.2	34.7	36.6
LHV (GJ/t)	46.3	49.1	46.1	46.8
MON (CARB)	126.4	121.5	128.5	125.4
Methane number (MWM)	84	73	102	82
%C m/m	70.8	75.6	71.3	71.7

To be noted that, as in the current notional EU mix, a H-CNG 2030 mix composition has been estimated by removing the share of NL in the piped NG mix (LHV of H-CNG 2030 notional EU mix is 48.01 GJ/t).

4.5.1.2 Pathways

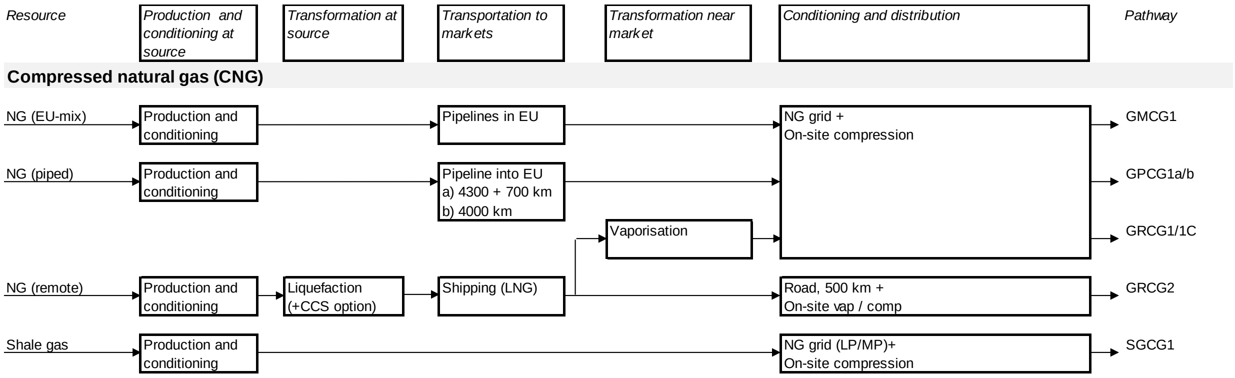
After reaching the refuelling station the gas needs to be compressed to a sufficient pressure to ensure fast refuelling. For on-board tanks at 20 MPa maximum a pressure of 25 MPa is required. Compression is an energy-intensive process, the energy consumption being strongly dependent on the outlet to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

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

In the case of direct LNG distribution, the liquid is pumped to the appropriate pressure while the heat of vaporisation has to be supplied by an external source (atmospheric evaporation, although feasible, is unlikely to be fast enough to allow acceptable refuelling times). The total energy requirement is still less than in the compression case. In this version, we have added a further option for a vehicle able to accept liquid NG fuel. In this case, the energy cost of vaporisation and compression is avoided although some additional energy will need to be used in the vehicle.

The pathways selected to represent CNG provision reflect the various supply routes available, i.e. medium and long-distance pipeline or the mix including LNG and biogas as detailed in the composition above or in section 3.2.5. We have also included a pathway representing shale gas produced in the EU. In the case of LNG a CCS option is also presented.

Figure 66. CNG pathways



Key to pathway codes:

Table 39. WTT codes. NG related pathways.

Code	*Final fuel*	*Description*
GMCG1	CNG	EU-mix natural gas, transport to EU by pipeline (1900 km to EU border, 500 km inside EU), distribution through gas trunk lines and low pressure grid, compression to CNG at retail point.
GMCG2a	CNG	EU-mix natural gas (pathway GMCG1) including 10% LNG (pathway GRCG1).
GMCG2b	CNG	EU-mix natural gas supply including 18.9% LNG and 3.4% bio-CH4 (mix of pathway GMCG1, GRCG1, OWCG1, OWCG21, OWCG4a). 40% of the bio-CH4 is derived from organic waste (OWCG1), 20% from manure (OWCG21), and 40% from energy crops (OWCG4a).
GPCG1a/b	CNG	Imported natural gas, transport to EU by pipeline (a, 4300 km to EU border, 700 km inside EU) or Middle East (b, 4000 km), distribution through gas high pressure trunk lines and low pressure grid, compression to CNG at retail point.
GRCG1/1C	CNG	Remote natural gas liquefied at source, LNG sea transport, vaporisation at import terminal, distribution through gas high pressure trunk lines and low pressure grid, compression to CNG at retail point. Pathway **GRCG1C includes CCS** at the liquefaction power plant.
GRCG2	CNG	Remote natural gas liquefied at source, LNG sea transport, distribution by road as LNG, compression/vaporisation to CNG at retail point.
GRLG1	LNG	Remote natural gas liquefied at source, LNG sea transport, distribution by road as LNG, use as LNG in vehicle.
SGCG1	CNG	Shale gas (EU).

4.5.1.3 CCS in CNG/LNG production

The carbon in the CNG molecules is mostly carried to the end-user. In the case of power generation or hydrogen production there are opportunities for CO_2 to be captured as the fuel is used. These opportunities do not exist so far where the CNG is used in dispersed applications such as domestic buildings or road vehicles. However, in the case of LNG, the smaller amount of CNG consumed in generating electrical power for liquefaction does offer some potential for CO_2 capture. Similar possibilities occur in the production of synthetic fuels and are discussed in *sections 3.7*.

In all gas transformation schemes requiring significant amounts of electricity, we have assumed that power is produced on-site by a gas-fired combined cycle gas turbine (CCGT). In this process CO_2 would be scrubbed out of the gas turbine flue gases. It is estimated that some 88% of the CO_2 could be recovered. The energy penalty is sizeable, the overall efficiency of power generation being reduced by about 8 percentage points (from 58% to 47%), but the effect on the overall pathway is much less (as shown in **Table 40** and **Figures 67/68 (GRCG1C)**).

Table 40. LNG production with/without CCS (LNG plant including CCGT)

Feedstock Case		Natural gas	
		Base GRCG1	With CCS GRCG1C
Natural gas (*)	MJ/MJ LNG	1.055	1.065
Energy efficiency		94.8%	93.9%
Net GHG emissions at plant ste	g CO_2/MJ LNG	2.95	0.91
	g CO_{2eq}/MJ LNG	3.84	1.78
CO_2 removal efficiency for total LNG plant including CCGT with CCS (**)	-	-	69.2%

Note. (*) including the NG bound in the LNG; (**) CCGT plant with CCS alone: 90%
Figure refer to a LNG plant (without upstream and downstream processes)

Compared to version 4 the electricity consumption for natural gas liquefaction has been decreased from 0.036 MJ per MJ of KNG to about 0.025 MJ per MJ of LNG.

4.5.1.4 WTT CNG Energy and GHG balance

Figures 67 and **68** illustrate the contribution of the various steps to the total energy and GHG balance. The most important components of the balance are:

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

For piped gas, the transport distance plays a crucial role and as a reference changing the length of the pipeline from 7000 to 4000 km reduces both energy requirement and GHG emissions by over 40%. Note that, as detailed in Section 3.2.7, the transport distance has been significantly updated and version 5 considers 5000 km as the transport distance for natural gas via pipeline from the natural gas fields to EU border (average of 3 corridors).

Pathway GMCG1 represents the notional EU-Mix and as explained in Section 3.2.5 and 3.4.1.6 is not representative of future marginal gas supplies. As such, it is included for reference only. The marginal selected pathway for CNG route is the ***piped gas for Russia*** which will be used for the WTW integration. For LNG the liquefaction energy is compensated by the relatively low energy required for shipping over the typical distance of around 7400 km, so that the total balance is close to that of a 5000 km long-distance pipeline. The long-distance transport energy is avoided in the case of EU shale gas.

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

There is little difference between the case where LNG is vaporised into the gas distribution network (GRCG1) and the alternative where LNG as such is trucked to a refuelling station and vaporised/compressed locally (GRCG2). The latter is marginally more energy-efficient because compression is more efficient when starting from the liquid state. Slightly higher GHG emissions in distribution of LNG to the service station mean that the overall GHG emissions are similar for the two options. We consider that these differences are not significant and therefore view both options as equivalent. Both energy and emissions are somewhat reduced if LNG can be directly fed to the vehicle (GRLG1) although, as mentioned above, the vaporisation energy then needs to be supplied inside the vehicle which may in turns increase emissions (unless it is in the form of waste heat).

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

Figure 67. WTT total expended energy balance for CNG/LNG pathways

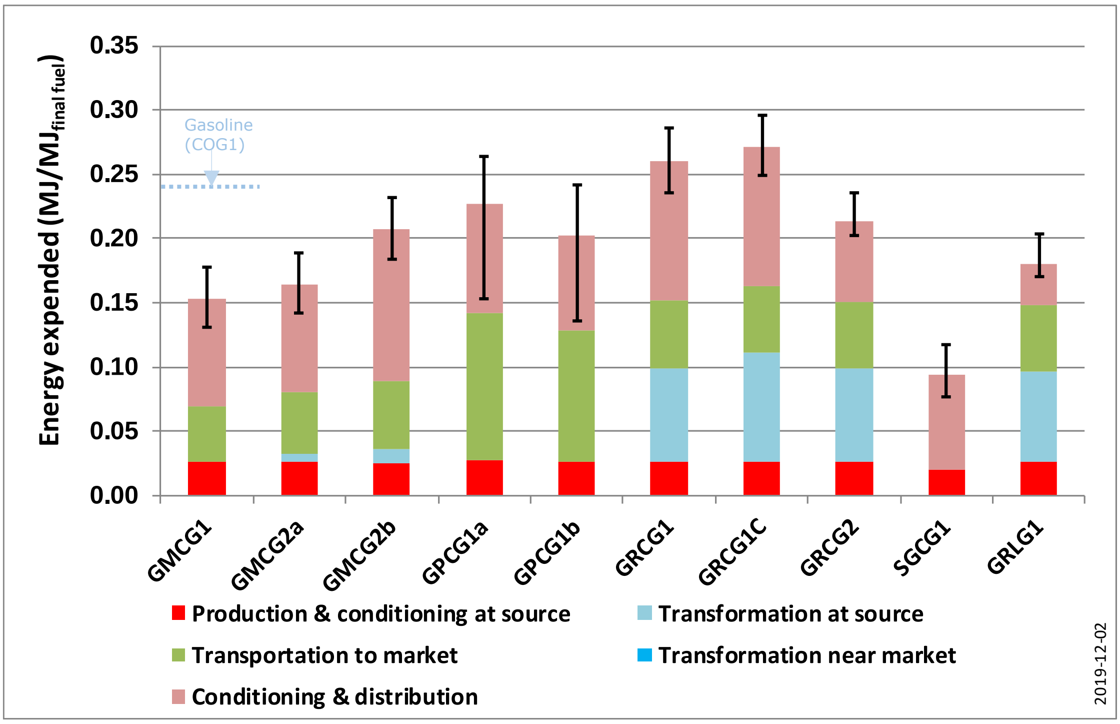
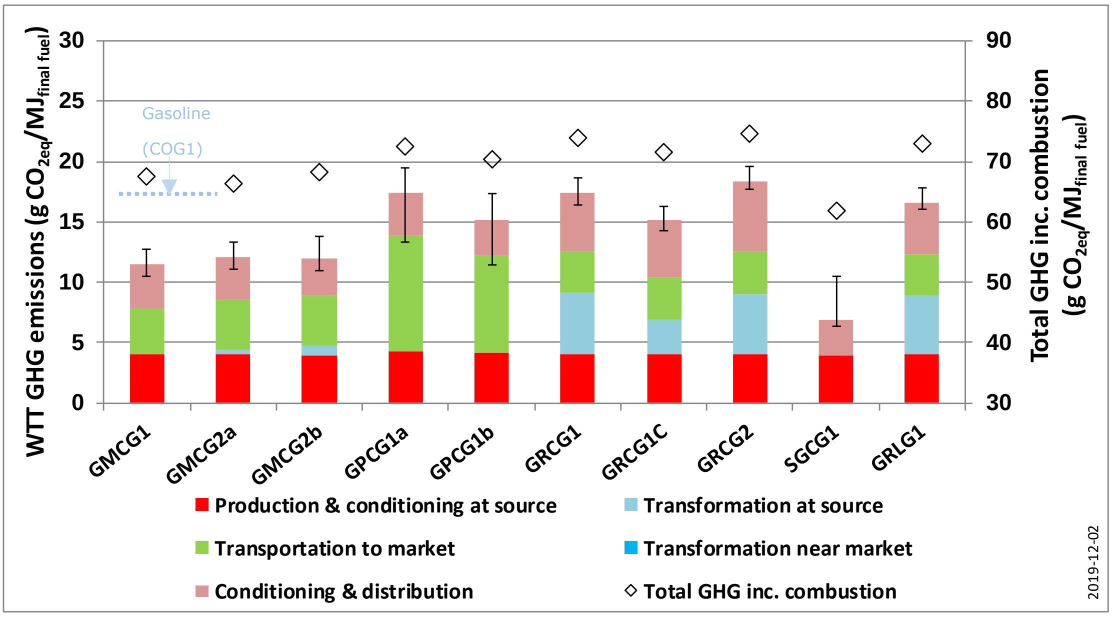


Figure 68. WTT GHG emissions balance for CNG/LNG pathways



General:

On an energy content basis, CNG from imported marginal gas supply (GPCG1a) is slightly less energy-intensive (~5%) than conventional fuels when it is transported to Europe by pipeline. LNG routes, where liquefaction occurs at source and natural gas is then transported to Europe as LNG by sea being vaporized upon arrival at the port terminal, can range from more energy intensive pathways (~8% higher than conventional gasoline) when the distribution of the natural gas is conducted through low pressure pipelines to lower values when the distribution is by road as LNG (and then re-compressed at retail point). The LNG route and final use of the fuel as such in a LNG vehicle offers some potential savings in terms of energy efficiency and similar results in terms of WTT GHG savings than the marginal GPCG1a route.

The EU shale gas production is modelled as the least energy intensive CNG route (~60% reduction vs the GPCG1a route). Shale gas production in Europe is in its infancy, so the estimates presented here are provisional. In reality, the shale gas supply to Europe is expected to come from increasingly remote sources with a significant impact on the total energy attached, which is expected to increase in the future.

An estimate of the EU CNG mix (current and 2030) is also presented in the chart (section 3.2.5). Although it comes out better (~35% reduction in energy content) than the marginal route (GPCG1a), we stress the fact that such a pathway do not exist in reality and any displacement of a conventional fossil liquid fuel will likely follow the marginal routes represented instead of this notional EU-mix included only for informative purposes.

The same trends can be observed in the GHG intensity chart. It is worthy of mentioning that a true comparison of NG options with conventional gasoline or diesel is only possible on a WTW basis because of the different carbon contents of these fuels and efficiency (*JEC TTW* and *WTW report v5*).

Steps:

Direct methane emissions account for a significant share of the total GHG emissions in the CNG chains. For the pipeline cases (e.g. CMCG1), they stem mainly from natural gas extraction and transport and are responsible for up to a third of the total GHG emissions. For LNG the proportion is smaller mainly because methane evaporation during shipping is fully recovered, although there is some loss if LNG is transported to the service station by truck. Of course the evaluation of such emissions is partly speculative inasmuch as they correspond to losses occurring in different parts of a very large and complex supply system and that are not always well documented. This, however, illustrates the fact that failure to tightly control methane losses could lead to a serious degradation of the GHG balance of natural gas chains.

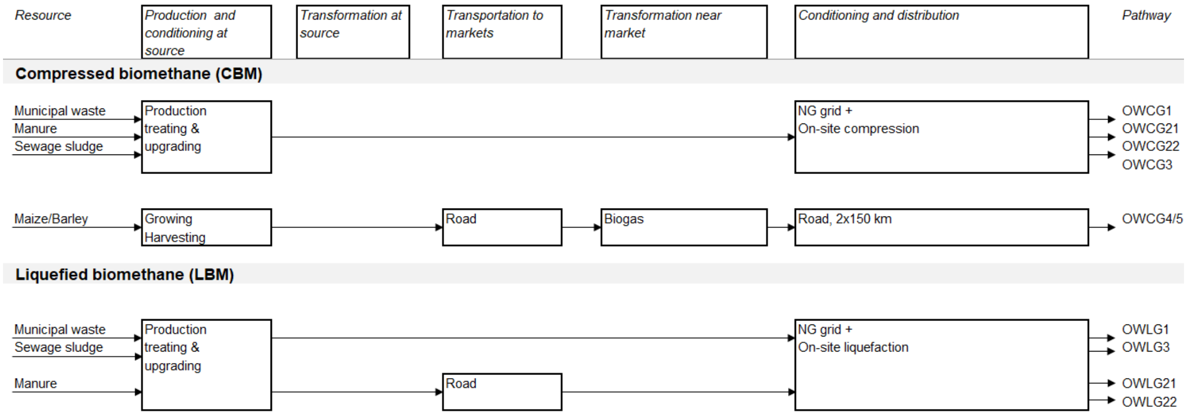
Note. Besides potential changes in LNG composition, modification of the GHG emissions from NG extraction and processing, the electricity requirement for NG liquefaction, the transport distance for the transport of LNG, and of CH_4 losses over the supply chain (NG extraction, processing, liquefaction, transport, refueling station) would lead to far larger variations of the life cycle GHG emissions for LNG supply and use.

4.5.2 Compressed and Liquified Biomethane (CBM and LBM)

(See also workbook WTT v5 pathways 2-CBM in Appendix 1)

The pathways considered here illustrate the impact of producing biomethane through different routes. To that end, parameters have been kept constant as far as possible with different options represented by the individual pathways. Biogas is typically obtained from waste organic material in which case little fossil energy is involved. We have also included pathways for biogas sourced from purpose-grown crops. In these cases, there will be fossil energy inputs to produce the crop. The pathways are described in *section 3.7.9.2.2*.

Figure 69. CBM and LBM pathways



Key to pathway codes:

Table 41. WTT codes: CBM and LBM

Code	*Final fuel*	*Description*
OWCG1	CBM	Upgraded biogas from municipal organic waste as CBM. Closed digestate storage.
OWCG21/2		Upgraded biogas from wet manure as CBM Digestate storage closed (21) or open (22)
OWCG3		Upgraded biogas from sewage sludge as CBM. Closed digestate storage
OWCG4		Upgraded biogas from maize (whole plant) as CBM. Closed digestate storage.
OWCG5		Upgraded biogas from double cropping (barley/maize) as CBM. Closed digestate storage.
OWLG1	LBM	Upgraded biogas from municipal organic waste as LBM. Closed digestate storage.
OWLG21/2		Upgraded biogas from wet manure as LBM Digestate storage closed (21) or open (22)
OWLG3		Upgraded biogas from sewage sludge as liquefied biomethane (LBM). Closed digestate storage
OWLG4		Upgraded biogas from maize (whole plant) as LBM. Closed digestate.
OWLG5		Upgraded biogas from double cropping (barley/maize) as LBM. Closed digestate storage.

Figure 70. WTT total expended energy balance for CBM and LBM pathways

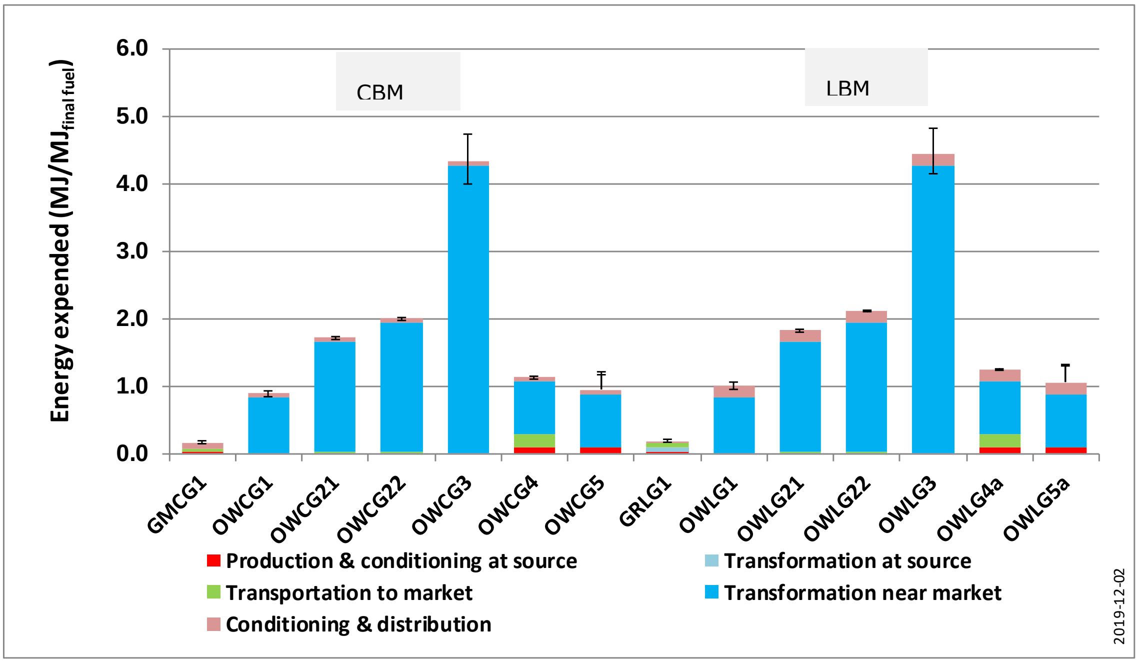
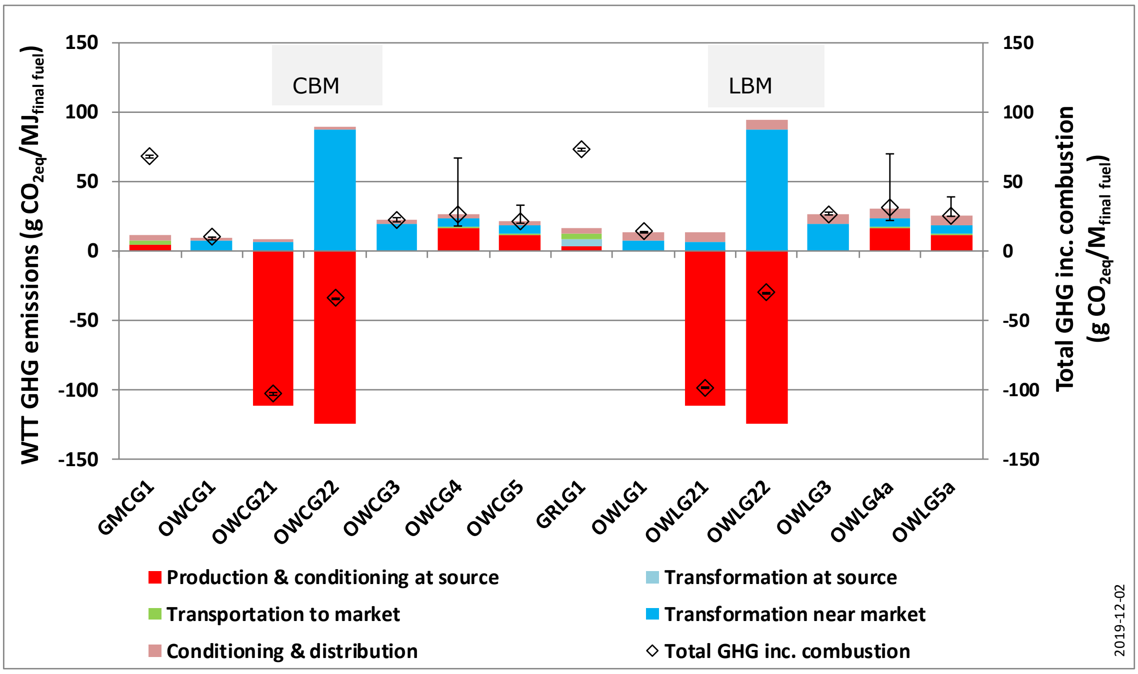


Figure 71. WTT GHG balance for CBM and LBN pathways



General:

In terms of energy intensity, both CBM and LBM pathways expend more energy per MJ final fuel than the conventional (fossil based) CNG and LNG routes described in the previous section (GMCG1 included for comparison). The energy intensity can range from a minimum of 5 times higher when biogas is upgraded biogas from municipal waste in closed digestate storage (OWCG1) to more than 20 in the case of sewage sludge (OWCG3) due to the fermentation and upgrading required.

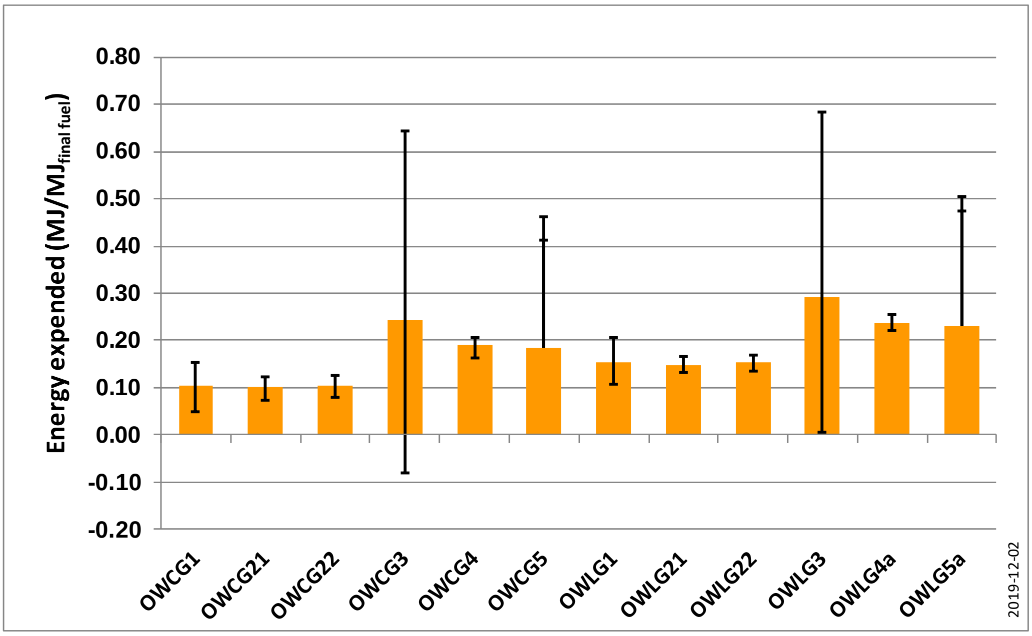
For GHG emissions (**Figure 71**), the diamond symbols show the overall emissions in producing the fuel. The balance is very favourable, the more so in the case of manure because large emissions of methane from the raw manure are avoided in the process (the credit has been given at the collection stage). Collecting liquid manure and using it for biogas production in itself prevents some GHG emissions to the atmosphere. Note that this is essentially the result of bad farming practices which should be avoided in any case. For sewage sludge, maize and double cropping, the GHG emissions are slightly higher, but lower to those for production of CNG, and better than most of the wheat to ethanol pathways.

Steps:

In all the pathways, the most energy intensive steps are related to the fermentation and further processing of the feedstocks. In the most energy intensive pathway (OWCG3/OWLG3) where biogas is obtained through fermentation of sewage sludge, the process requires heat and electricity (the latter mostly for rotating equipment). This is assumed to be supplied by an on-site boiler fired with own raw biogas while electricity is imported from the grid. Some methane losses are incurred as well as some N_2O emissions.

In terms of the GHG emissions, the credits (negative GHG emissions) come from the renewable origin of the feedstocks used.

Figure 72. WTT expended fossil energy balance for CBM and LBM pathways



The fossil energy share for the municipal waste and municipal waste options is in the order of ~0.10 $\mathrm{MJ/MJ_{f}}$. Note that these figures result from the decision to limit the on-site energy generation from biogas to the process heat requirement, which means that the electricity requirement comes from the grid. For maize and double cropping, the fossil energy input is higher, ~0.2-0.25 $\mathrm{MJ/MJ_{f}}$ (similar to the sewage sludge route) reflecting the energy used in crop production and transport to the processing plant. The bandwidth shows the total energy including renewable energy

Bandwidth is related to total energy input including renewable (biomass) input.

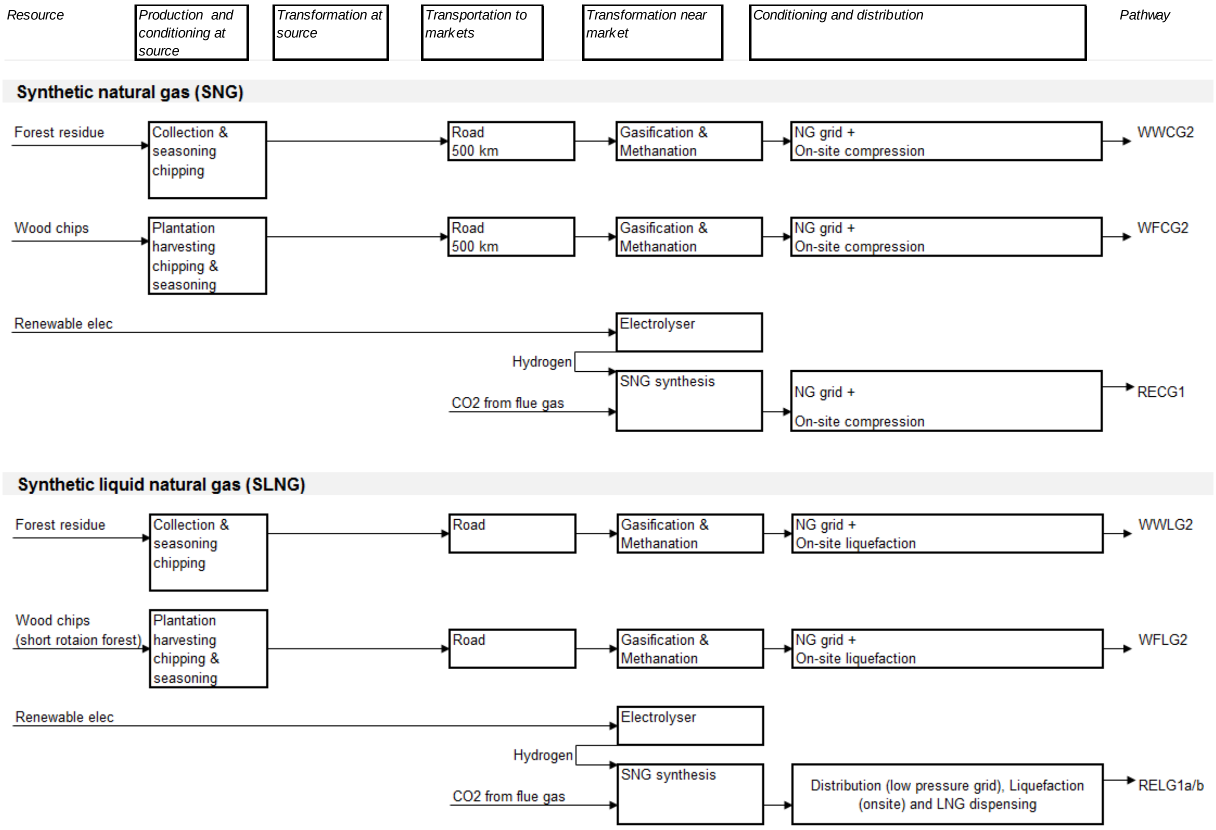
4.5.3 Synthetic Natural Gas (SNG / SLNG)

(See also workbook WTT v5 pathways 2-CBM in Appendix 1)

In the current JEC WTT v5, new synthetic natural gas pathways have been modelled to show the state-of-the art of additional low-GHG emission routes from either wood or renewable electricity as potential alternatives to their fossil based equivalents (See sections: Power-to-Fuels (Section 3.9) and Biomass / Wood based pathways (Section 3.7.1.0)).

The synthetic routes via the methanation process from different feedstocks are summarized as follows:

Figure 73. SNG and SLNG pathways



Key to pathway codes:

Table 42. WTT codes. SNG and SLNG (and comparison)

WWCG2	SNG	Synthetic methane (as CNG) via gasification of waste wood and methanation
WFCG2		Synthetic methane (as CNG) via gasification of wood chips from short rotation forestry and methanation
RECG1		eCNG: Synthetic methane (as CNG) from renewable electricity and CO2 from flue gases
WWLG2	SLNG	Synthetic methane (as LNG) via gasification of waste wood and methanation
WFLG2		Synthetic methane (as LNG) via gasification of wood chips from short rotation forestry and methanation
RELG1a/b		eLNG: Synthetic methane (as LNG) from renewable electricity, CO_2 from flue gases (a) or CO_2 from biogas upgrading (b).

Note. The Power-To-Gas pathways (RECG1/RELG1a/b are essentially carbon-free, the major potential emissions being related to gas compression or liquefaction at the service station.

Figure 74. WTT total expended energy balance for SNG and SLNG pathways

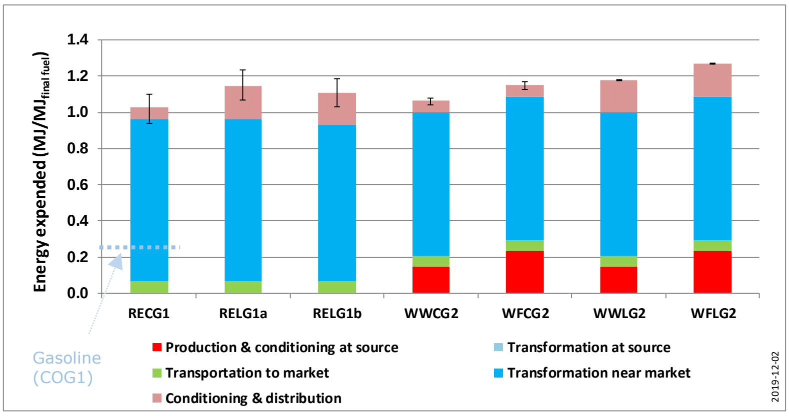
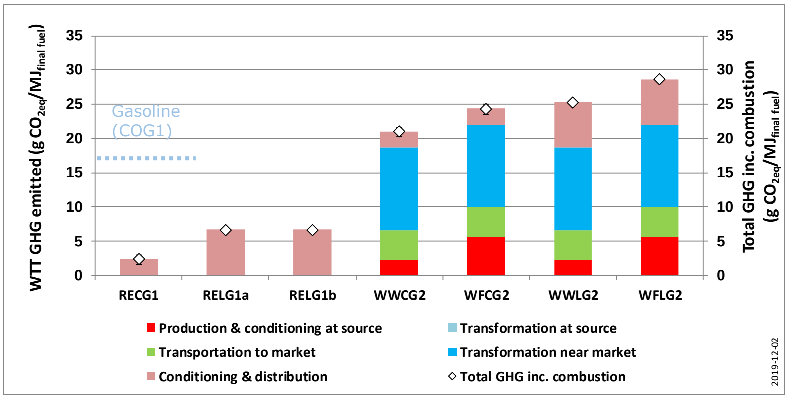


Figure 75. WTT GHG balance for SNG and SLNG pathways



General:

The energy expended is relatively large due to the efficiency of the electrolysis and the energy requirement of the synthesis process (Synthetic routes >10 times more energy intensive than their equivalent fossil based natural gas routes and ~5 times more than conventional gasoline).

In the Power-To-Gas pathways (RECG/RELG), most of the energy expended comes from renewable sources leading to a significant lower GHG emissions when compared with a fossil-based gasoline route (e-CNG ~15% and e-LNG ~40% of the total GHG intensity versus fossil gasoline).

Steps:

In the SNG and SLNG routes, the transformation near market step is the most energy intensive one as it comprises:

- Power-To-Gas: the electricity requirement to produce hydrogen via electrolysis as well as the SNG/SLG synthesis (with no GHG emissions as renewable electricity is considered).
- the gasification and methanation process in the wood-based routes.

The conditioning steps are the second source of GHG emissions in these pathways due to the compression / liquefaction steps (major source of GHG emissions in the REX routes).

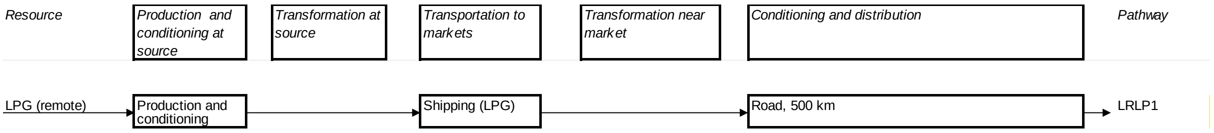
4.5.4 Liquefied Petroleum Gas (LPG)

(See also workbook WTT v5 pathways 1-Oil & Gas in Appendix 1)

As explained in *section 3.2.9*, we have considered only the marginal LPG imported to Europe from natural gas field condensate.

As the marginal route, it is assumed that LPG is produced as part of the heavier hydrocarbons (condensate) associated with natural gas and the energy is required for cleaning the gas and separating the C3 and C4 fractions. Reliable data is scarce in this area and this should only be regarded as a best estimate.

Figure 76. LPG pathway



Key to pathway codes:

Table 43. WTT codes. LPG (and comparison)

Code	*Final fuel*	*Description*
COG1	Gasoline	Conventional gasoline
GMCG1	CNG	EU-mix natural gas, transport to EU by pipeline (1900 km to EU border, 500 km inside EU), distribution through gas trunk lines and low pressure grid, compression to CNG at retail point.
GRLG1	LNG	Remote natural gas liquified at source, LNG sea transport, distribution by road as LNG, use as LNG in vehicle.
LRLP1	LPG	LPG from remote natural gas field, purification and liquefaction at source, long-distance sea transport, distribution by road to retail point.

In the following figures, the energy and GHG emissions balances are compared to those for gasoline and CNG/LNG:

Figure 77. WTT GHG emissions balance for LPG pathway

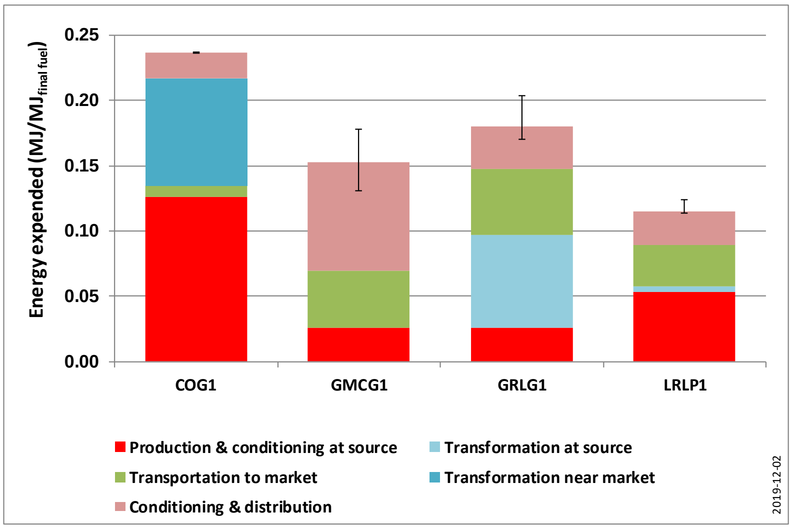
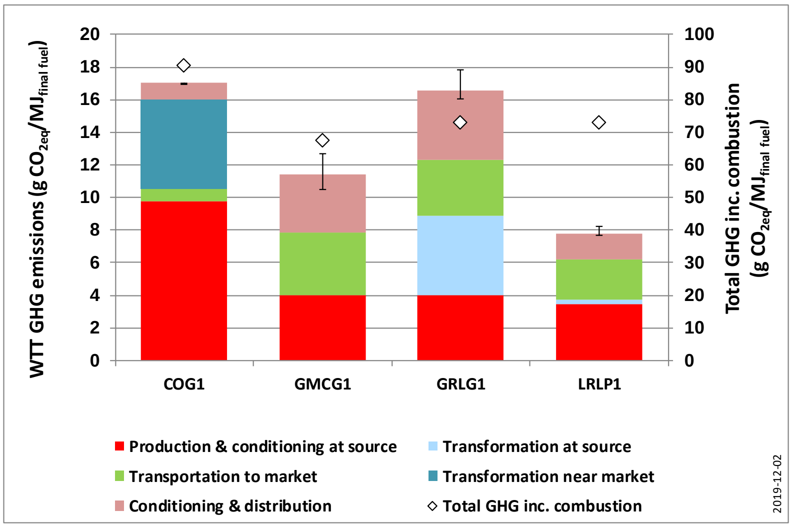


Figure 78. WTT GHG emissions balance for LPG pathway



General:

The LPG pathway is less energy and GHG intensive than the conventional gasoline (~35% less energy and ~half GHG emissions per MJ$_{fuel}$) with little energy expended in the transformation processes.

One of the main reasons for the lower GHG emissions when compared with fossil gasoline is the fact that the energy required at source is in the form of natural gas or other light hydrocarbons and is therefore less carbon-intensive than the case for crude oil.

Steps:

A large proportion of the total energy required relates to separation, treatment and liquefaction near the gas field being the reason for more energy expended in the process when compared with CNG marginal routes. Long-distance transport is more onerous than crude oil because of the smaller dedicated ships used. The same applies to distribution. The main differences with the LNG route (GRLG1) can be linked to the energy required in the liquefaction process which is more than 10 times less energy intensive in the case of the LPG due to its heavier components.

4.6 Ethanol

(See also workbook WTT v5 pathways 3-Ethanol in Appendix 1)

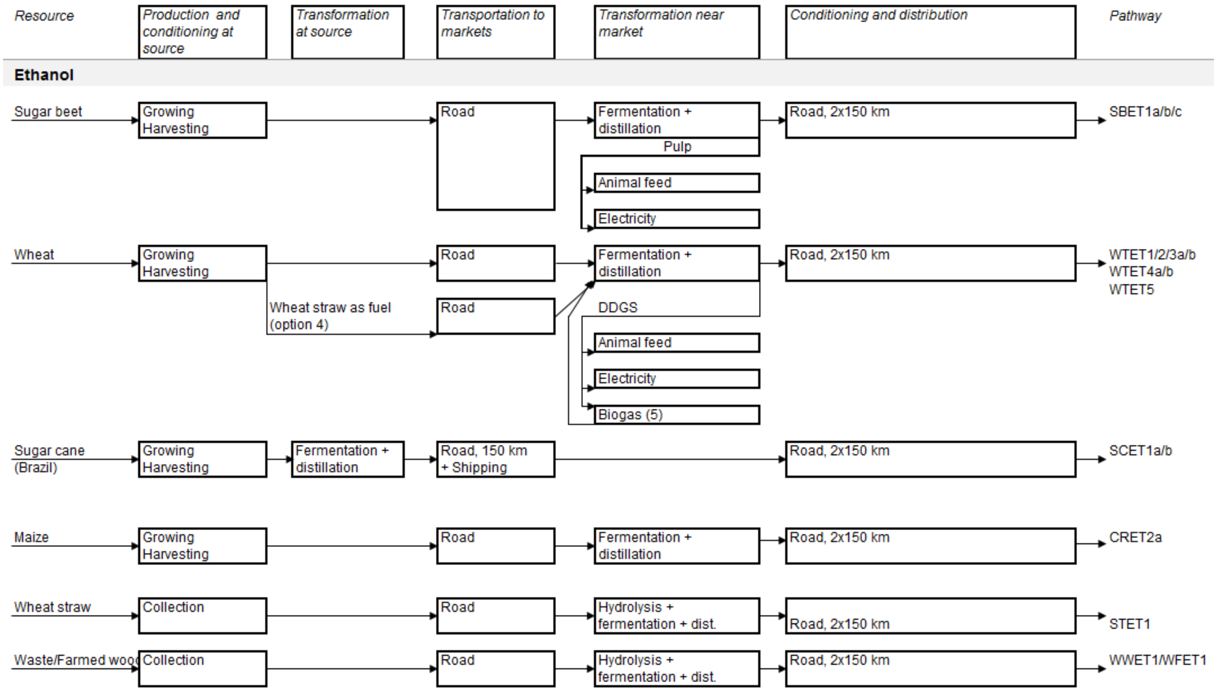
4.6.1 Ethanol pathways

Ethanol can be produced by traditional fermentation methods from a variety of crops. We have represented the most common in Europe i.e. sugar beet and wheat. For each of these crops a number of options are available depending on the use of co-products and the way the energy for the manufacturing process is generated (see *section 3.4.4/3.7.8.1*). In this version of the study we have in addition included pathways for European crops of a barley/rye mixture and of maize.

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

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

Figure 79. Ethanol pathways

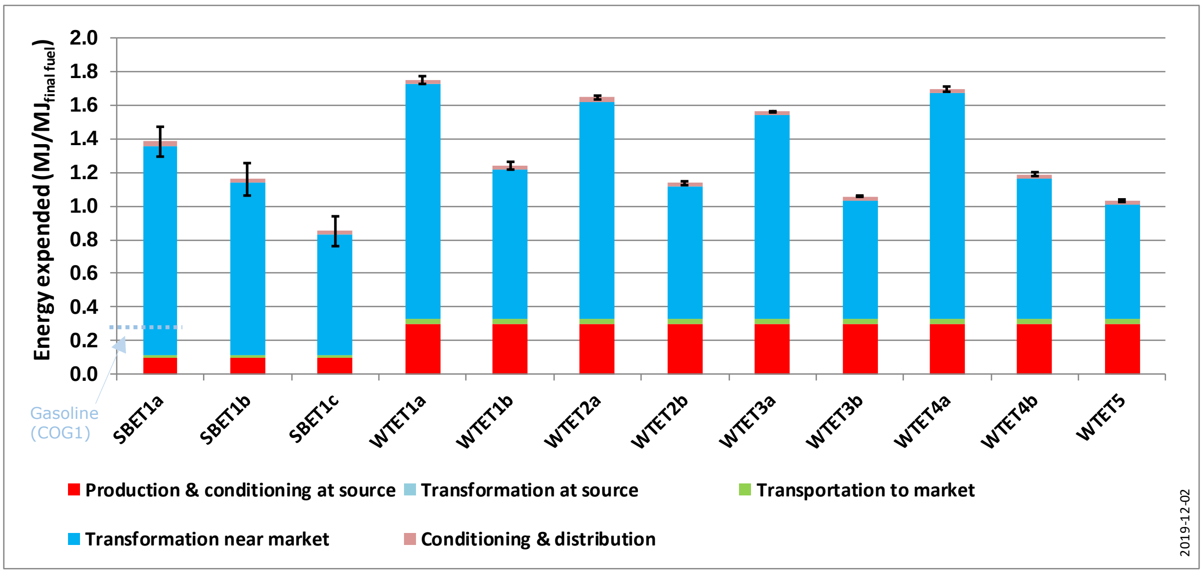


4.6.2 Ethanol WTT energy balance

4.6.2.1 Total energy

Figures 80 and **81** show the total energy build-up along the different stages of the more conventional pathways to bio-ethanol. In this case "total" energy includes the energy content of the bio-feedstock used (e.g. wheat grain) as well as the energy content of any biomass used as a fuel at any stage of the pathway. As explained in *section 2.9.2*, this is the energy "expended" i.e. it excludes the energy content of the ethanol produced.

Figure 80. WTT total expended energy balance for sugar beet and wheat ethanol pathways



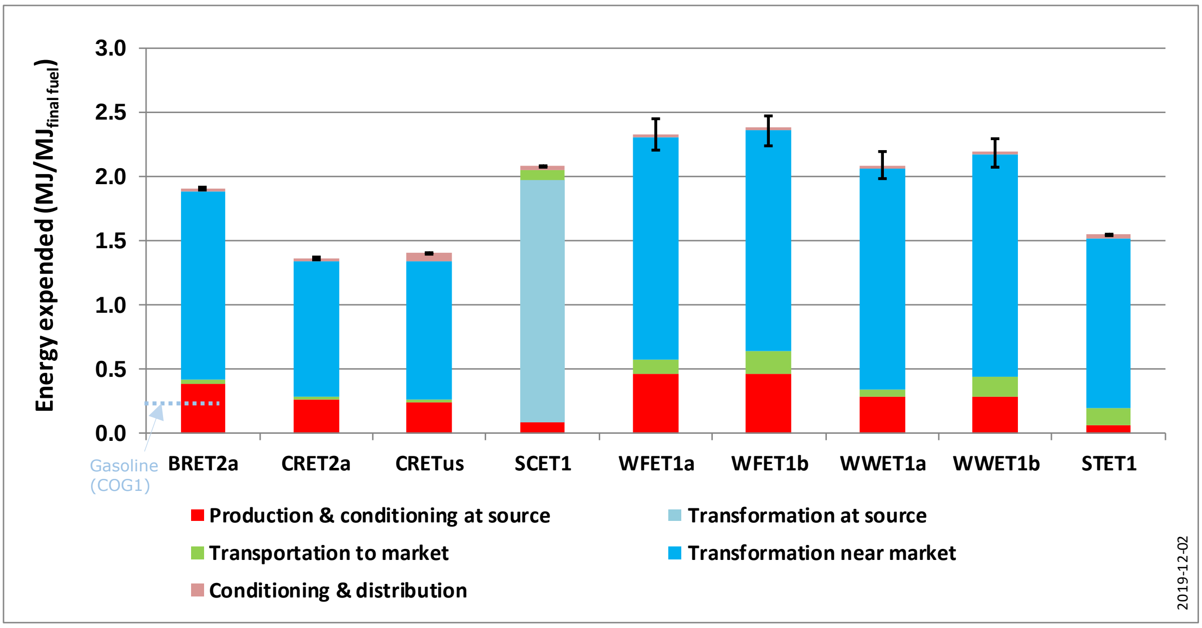
General:

Most of this energy is expended during ethanol manufacturing and to a lesser extent for growing the crop (a large portion of the latter energy stemming from fertilisers).

The energy balance is critically dependent on the specific pathway, particularly with regards to the fate of co-products. As a result of the energy credits generated, the more co-products are used for energy purposes, the better the energy balance (compare e.g. SBET1b to SBET1c, WTET1a to WTWT1b and WTET2a to WTET2b where using the process residue to produce electricity saves more energy than using it as animal feed).

The way energy for the manufacturing process is produced has also an impact on the energy balance. The ethanol plant requires heat for distillation and drying of the ethanol: in WTET2a the use of a natural gas fired gas turbine CHP scheme reduces the energy requirement by about 15%, because it is more efficient than the more conventional scheme used in WTET1a. For WTET3/4, although CHP is also used the relatively low efficiency of solids burning compared to gas reduces the energy gain to insignificance.

Figure 81. WTT total expended energy balance for other ethanol pathways



General:

Figure 81 shows the total energy balance for other advanced biomass-to-ethanol pathways. The overall energy balance for barley/rye and maize grown in Europe is slightly higher than the equivalent wheat pathway (WTET2a). The overall energy balance for US-produced corn ethanol is very similar, long distance marine transportation being energy efficient.

The more advanced cellulosic ethanol routes based on waste or farmed wood or straw do not offer much from a total energy point of view. Their interest resides in their potential to save fossil energy and therefore to reduce GHG emissions (see WTT GHG results in Section 4.6.2.3).

Steps:

In all the pathways, the ethanol production is the most GHG intensive step occurring near market except for the SCET1 pathway (Brazilian sugar cane) where the production of ethanol has been allocated to the *transformation at source* step prior to long distance transport to Europe.

4.6.2.2 Energy breakdown by source

Figures 82 and **83** show a breakdown of fossil, nuclear and renewable (i.e. biomass) energy, as a measure of the "renewability" of the pathways. For ethanol, this is in effect the WTW fossil energy (as no additional fossil energy is expended in the vehicle). To compare to gasoline, we would have to add the combustion energy. This is in effect a WTW comparison and reference is made to the ***JEC WTW report***.

Figure 82. WTT expended energy breakdown by source for sugar beet and wheat ethanol pathways

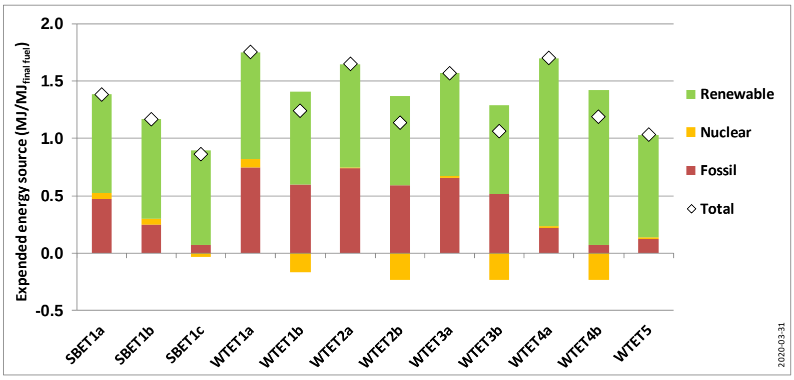
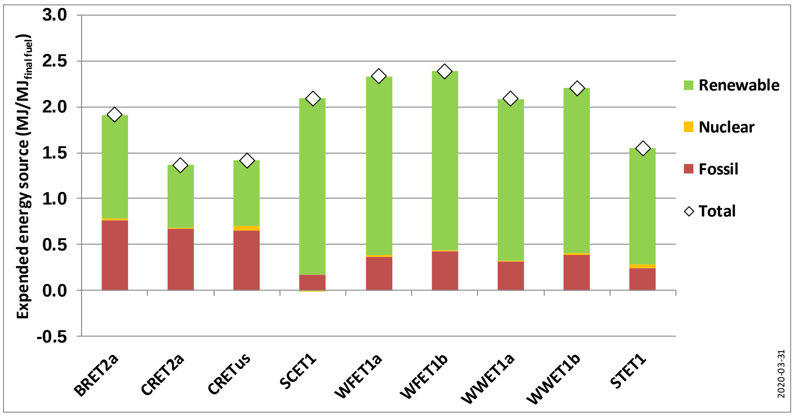


Figure 83. WTT expended energy breakdown by source for other ethanol pathways



General:

The impact of using co-products for energy purposes and/or using bio-energy for fuelling the production process appears very clearly in this case. As an example, SBET1a uses grid gas and electricity to meet the heat and power needs of the plan. SBET1b uses slops to produce biogas, this reducing the amount of grid energy needed. SBET1c in addition uses the pulp as a heat source for the plant, so that the demand for grid energy is much reduced. For the more conventional pathways, this does not, however, generally correspond to either common practice or economic optimum (see also *section 2.4*).

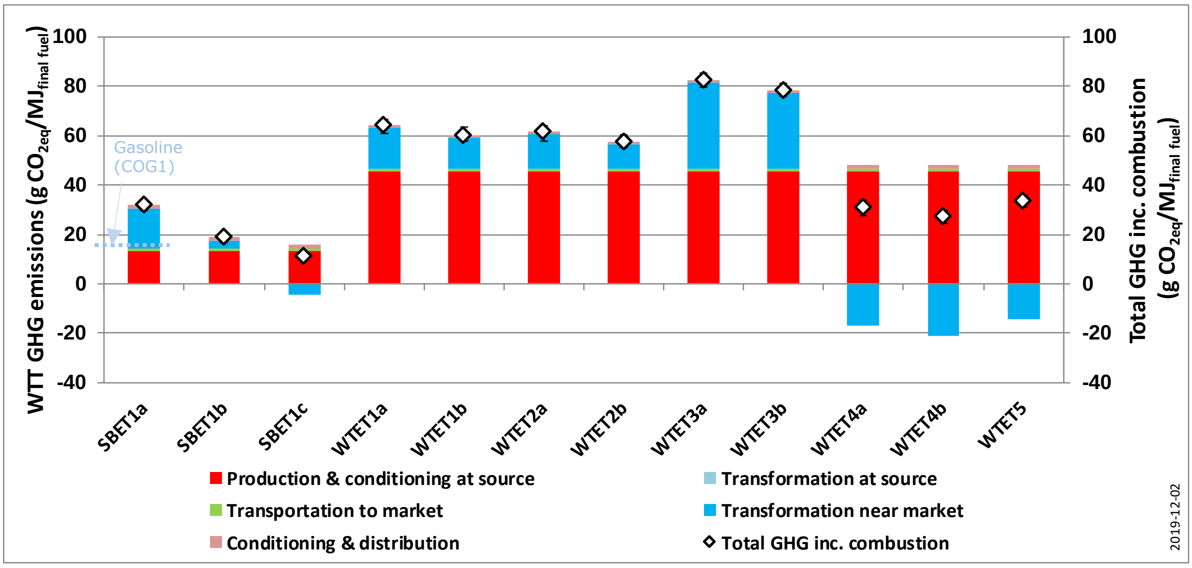
Sugar cane and **advanced cellulosic ethanol** pathways use a lot less fossil energy because the processes used allow usage of biomass for the major energy requirements. Using bagasse to fuel the sugar cane ethanol manufacturing plant is a well-established practice (a credit for additional fuel oil saving further reduce the net fossil energy used in SCET1). In pathways using wood or straw a significant proportion of the energy used is also of renewable origin, coming from the non-fermentable part of the cellulosic feed material. Note that using wheat straw induces a small penalty as additional fertilisers have to be used in order to replace the nutrient contained in the straw.

4.6.2.3 Ethanol WTT GHG balance

Figures 84 and **85** show the total GHG build-up along the different stages of the pathways. As in previous figures, for reference, the gasoline WTT GHG emission figure is 17 g CO_{2eq}/MJ and adding the combustion CO_2 to make the GHG figures comparable gives 90.4 g CO_{2eq}/MJ.

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

Figure 84. GHG emissions balance for sugar beet and wheat ethanol pathways



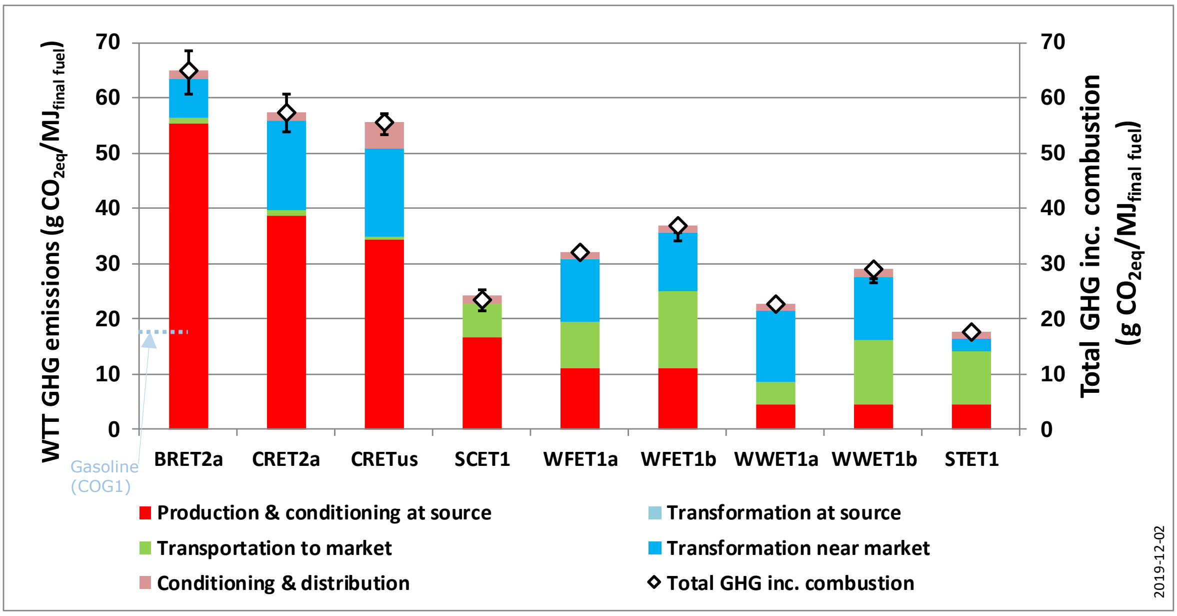
General:

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

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

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

Figure 85. GHG emissions balance for other ethanol pathways



General:

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

The wood-based pathways yield a very favourable GHG balance as very little fossil energy is involved in the process, energy coming from the non-fermentable portion of the feedstock. The straw option is less favourable because of the increased farming inputs required to compensate for removing the straw from the land (additional energy for fertiliser production and additional N_2O emissions from the fields). Comparison with gasoline is discussed in the *WTW report*.

Using co-products as animal feed gives an ILUC credit

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

4.6.3 ED95 pathway (Ethanol based)

(See also workbook WTT v5 pathways 3-Ethanol and 1-Oil&Gas in Appendix 1)

As described in section 3.7.8.1.6, ED95 is a fuel produced as a result of the blending of different bio and oil-based components:

Table 44. ED95 composition modelled in JEC WTT v5 based on SEKAB 2018

	Ethanol	**Ignition improver PEG (n 8.7)**	**MTBE**	**I-butanol**	**Lubricants**
ED95 (%w)	**91.46%***	**4.97%**	**2.14%**	**0.43%**	**1%**
ED95 (%energy)	**90.3%**	**4.6%**	**3%**	**0.6%**	**1.6%**

*The ethanol includes some water (6.25% by mass)

The following subsections summarize the energy and GHG balances for both the admixture oil-based components (PEG, lubricants and ibutanol) as well as the bio-components (Ethanol from either wheat or wheat straw and bio i-butanol from maize). In order to allow comparison between different routes, as examples of potential pathways, three combinations have been explored for ED95 in JEC WTT v5:

1) **Bio ethanol and fossil i-butanol**: EU wheat to ethanol but crude oil based i-butanol.
2) **Bio ethanol and bio i-butanol**: EU wheat to ethanol and corn based i-butanol.
3) **Advanced bio ethanol and fossil i-butanol**: Wheat straw to ethanol and oil based i-butanol.

The physical properties of products and intermediates relevant to this pathway are described below:

Table 45. Physical properties ED95 admixture

		Wheat	Ethanol	PEG	MTBE	i-butanol	Lubricants	ED95
Density	kg/m^3		794	1126	745	802	873	820
Typical moisture content	% m	13.5%						
LHV (dry matter)	MJ/kg	17.0	26.8	23.5	35.1	33.2	42.6	25.4
Carbon content	% m		52.2%	51.8%	68.2%	64.8%	85.3%	49.4%
CO_2 emission factor (assuming total combustion)	g CO_2/MJ		71.4	80.8	71.2	71.6	73.5	71.3
	kg CO_2/kg		1.91	1.90	2.50	2.37	3.13	1.81

4.6.3.1 ED95 components (non-ethanol)

The individual WTT balances of the oil-based ED95 components have been included in this section for information purposes despite of not being final fuels but minor admixtures to the final product. The WTT expended energy and GHG emission balances for the integrated ED95 pathway as a whole are presented in Section 1.5.2:

Key to pathway codes:

Table 46. ED95 oil based components.

Code	*Final fuel*	*Description*
COL1	Lubricants	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), admixture to ethanol for ED95 supply, typical EU distribution and retail.
COPEG1	PEG	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), steam cracking, ethylene oxide production, ethylene glycol production, polyethylene glycol production, admixture to ethanol for ED95 supply, typical EU distribution and retail.
COiB1	i-butanol (oil)	Crude oil from typical EU supply, transport by sea, refining in EU (marginal naphtha production) with downstream steam cracking, i-butanol via oxo synthesis, admixture to ethanol for ED95 supply, typical EU distribution and retail.
MTiBa	i-butanol (bio)	Corn (maize) (average used in EU) to i-butanol for ED95 supply. Production energy provided by a biogas fueled CHP plant. DDGS to animal feed.

Figure 86. ED95 pathways (oil based components)

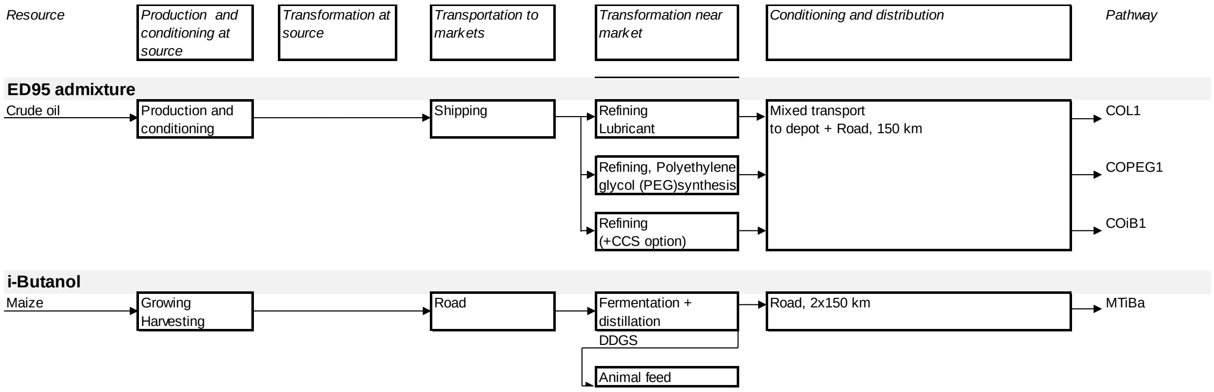


Figure 87. WTT total expended energy balance of crude oil based ED95 components

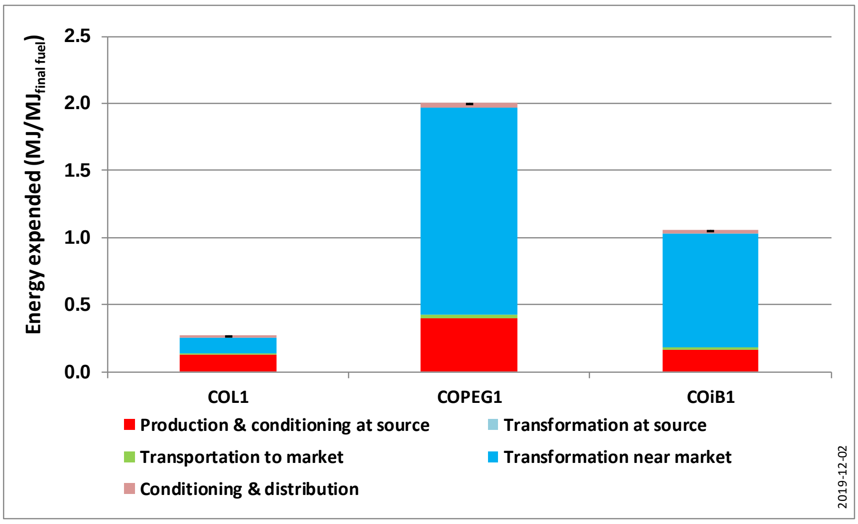
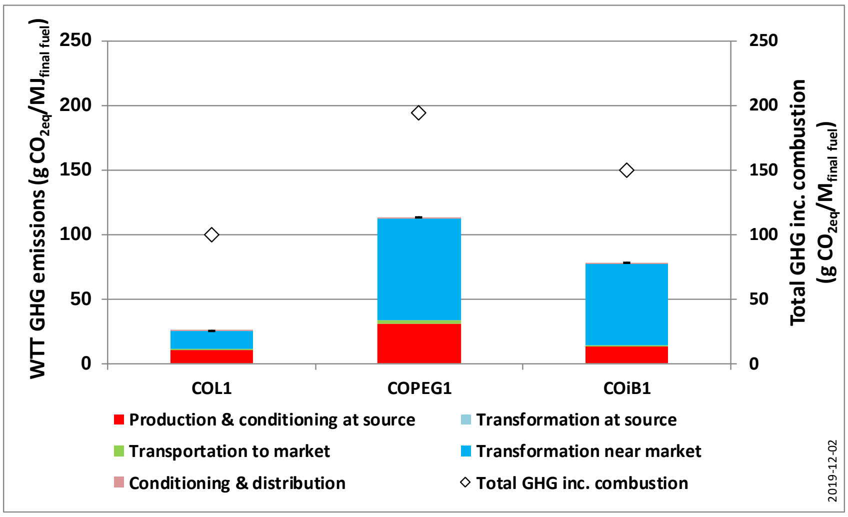


Figure 88. WTT GHG emissions balance of crude oil based ED95 components



General:

The ignition improver (PEG) as polyethylene glycol admixture to ED95 is the more energy and GHG intensive of the oil components to ED95.

Steps:

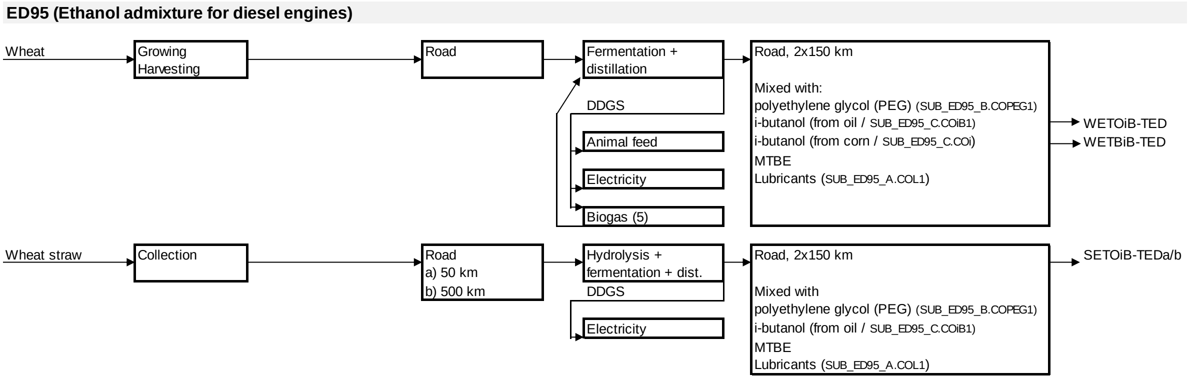
The transformation of oil into the final PEG through refining, steam cracking processing and ethylene oxide production are the most energy and GHG intensive steps representing up to ~75% of the total energy consumption (of which the PEG synthesis represents more than a half).

Regarding the other components, the *transformation near market* step is the highest contributor to both the energy and GHG balances, especially for the i-butanol route where the production via the Oxo synthesis is as equally GHG and energy intensive as the refining and steam cracking sub-steps.

4.6.3.2 ED95 – Admixture

This sections summarizes the results of the three ED95 pathways modelled as selected examples of the potential routes to produce this alternative fuel. For comparison purposes, the energy and GHG values for fossil-based gasoline and one selected pathway from ethanol (WTET1a / EU wheat) are also included in the WTT results:

Figure 89. Key to pathway codes. ED95 admixture.



Code	*Final fuel*	*Description*
WETXxX-TED	ED95	**EU wheat to ethanol**. Production energy provided by a NG-fired CHP plant. Mixed with polyethylene glycol (PEG), MTBE, i-butanol, and lubricants to ED95 for diesel engines. DDGS to animal feed WETOiB-TED: **i-butanol from crude oil** WETBiB-TED: **i-butanol from corn**
SETOiB-TED		**Wheat straw to ethanol**. Mixed with polyethylene glycol (PEG), MTBE, i-butanol, and lubricants to ED95 for diesel engines (Options: (a) straw transport 50 km, (b) straw transport 500 km) SETOiB-TED: i-butanol from crude oil

Figure 90. WTT total expended energy balance for ED95 pathways

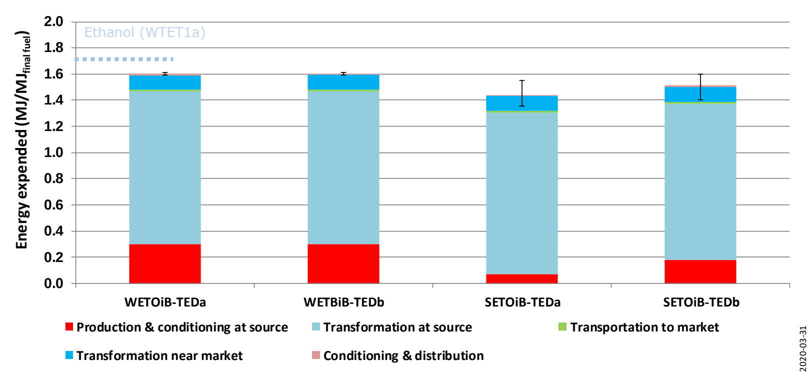
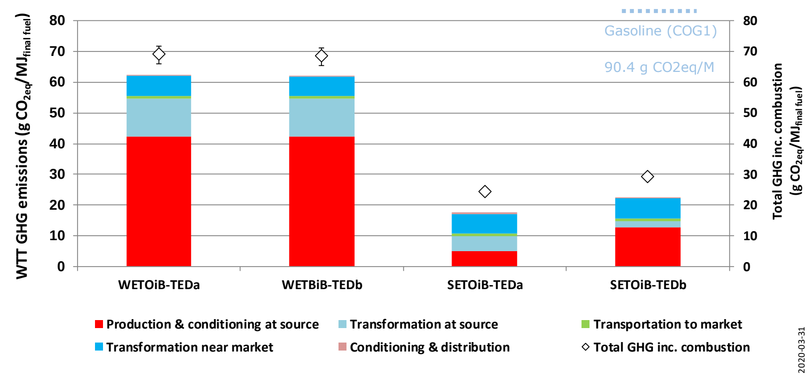


Figure 91. GHG emissions balance for ED95 pathways



General:

The ED95 pathways offers a way to reduce both energy and GHG emissions when compared versus an equivalent pure ethanol pathway (wheat) (~10% less energy and ~3% less GHG intensive). Due to the small proportion of i-butanol into the final admixture, its oil or bio origin has little impact on the final results. As expected, using wheat straw as the main feedstock for ethanol is deemed to achieve the lowest GHG intensive values.

Steps:

In terms of energy content, the ethanol production is the most energy intensive step representing above ~70% of the total energy expended across the different pathways although some credits are generated due to surplus electricity generation and animal food (DDGS).

Figure 91 shows a different picture regarding the contribution of the different steps as the relevance of the wheat cultivation increases in the WETx pathways (representing more than half of the WTT GHG emissions). In the straw-based pathways, the straw baling and collection (including fertilizers) included in the Production step together with the supply of PEG (transformation near market) are the main steps responsible for the vast majority of the WTT GHG emissions.

4.7 FAME, FAEE and Hydrotreated Vegetable Oils (HVO)

(See also workbook WTT v5 pathways 4-Biodiesel in Appendix 1)

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

An alternative processing option is to hydrotreat the plant oils, either alone or mixed with petroleum products to produce HVO (hydrotreated vegetable oil). This has the advantage that it produces a high-quality diesel fuel, but requires an additional energy input for the hydrotreating process (see *section 3.7.9.1*). We have included HVO pathways from rapeseed, sunflower, soya and palm as well as other feedstocks such as waste cooking oil, tallow and the extraction of oil from palm oil mill effluent (POME) and compared them with the equivalent FAME processes. As in previous sections, the diesel WTT GHG emission figure is also included in the GHG emissions valance figures for comparison purposes (18.9 g CO_{2eq}/MJ WTT value and adding the combustion CO_2 gives 92.1 g CO_{2eq}/MJ).

4.7.1 Biodiesel (FAME/FAEE) pathways

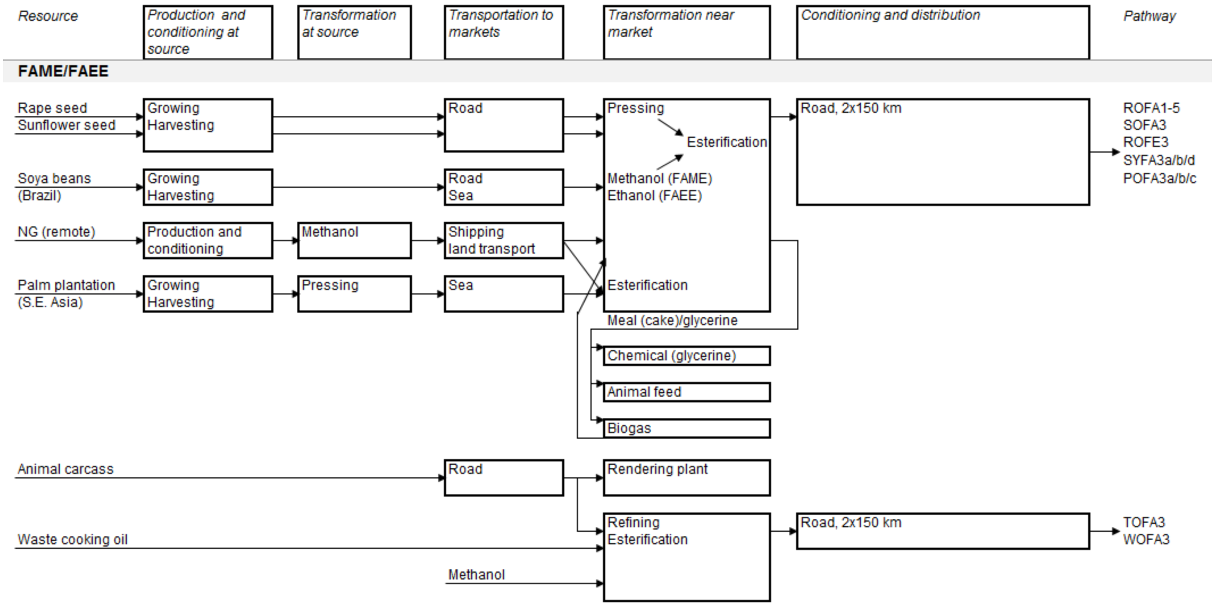
As described in section 3.7.8.2.1, FAME/FAEE is a blending component of conventional diesel (see physical properties applied across the whole JEC WTW study below):

Table 47. Physical properties of products and intermediates relevant to these pathways

		Rapeseed	**Rape meal**	**Rape oil**	**Glycerine**	**Methanol**	**Biodiesel**
Density	kg/m^3			920		793	890
Typical moisture content	% m	9.0%	12.8%				
LHV (dry matter)	MJ/kg	27.0	18.4	37.0	16.0	19.9	37.2
Carbon content	% m					37.5%	77.3%
CO_2 emission factor (assuming total combustion)	g CO_2/MJ					68.9	76.2
	kg CO_2/kg					1.37	2.83

As mentioned in the introduction, different pathways / feedstocks have been modelled:

Figure 92. Biodiesel (FAME/FAEE) pathways

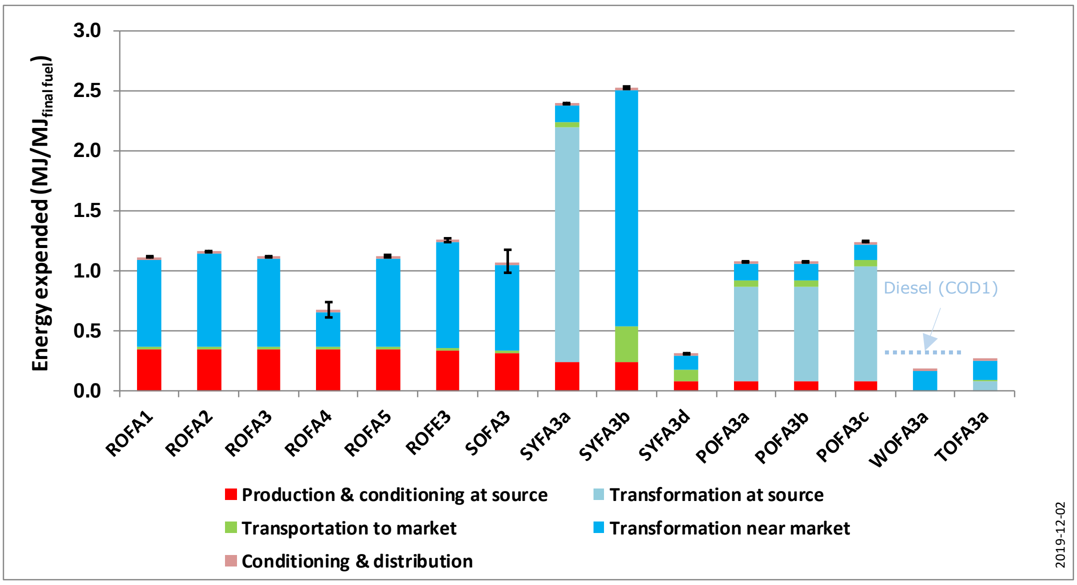


Code	*Final fuel*	*Description*
ROFA1-5	Biodiesel	Rapeseed to biodiesel (Rapeseed Methylester) Meal export (animal feed) (1/2/3/5), to internal biogas (4) Glycerine export to chemical (1), to animal feed (2), to internal biogas (3/4), to hydrogen (5)
ROFE3		Rapeseed to biodiesel (Rapeseed Ethylester) Meal export (animal feed) Glycerine to internal biogas
SOFA3		Sunflower to biodiesel (Sunflower seed Methylester) Meal export (animal feed) Glycerine to internal biogas
SYFA3 a-c		Soy beans to biodiesel (Soy Methylester) Meal export (animal feed) (a) Oil imported into EU, glycerine to internal biogas (b) Beans imported into EU, glycerine to internal biogas (c) Oil imported into EU, Allocation between soya oil and soya meal by market value (not used in version 5) (d) Beans imported into EU, allocation between soya oil and soya meal by market value
POFA3 a-c		Palm oil to biodiesel (Palm oil Methylester) Meal export (animal feed) (a) No CH4 emissions recovery, heat credit (oil mill), glycerine to internal biogas (b) CH4 emissions recovery, heat credit, glycerine to internal biogas (c) No CH4 emissions recovery, no heat credit, glycerine to internal biogas
WOFA3a		Waste cooking oil to biodiesel Glycerine to internal biogas
TOFA3a		Tallow oil to biodiesel Glycerine to internal biogas

4.7.1.1 Biodiesel WTT energy balance

Figure 93 shows the total energy build-up along the different stages for selected conventional biodiesel (FAME) pathways. For comparison, the production energy for fossil diesel including the combustion energy has been included. This simple comparison works because conventional and biodiesel are used in the same vehicles delivering the same energy efficiency. For the biodiesel, "total" energy includes the energy content of the oil seeds as well as the energy content of any biomass used as a fuel at any stage of the pathway. As explained in *section 2.9.2*, this is the energy "expended" i.e. it excludes the energy content of the biodiesel produced.

Figure 93. WTT total expended energy balance for conventional biodiesel pathways



General:

Except for Soy, biodiesel consumes about the same amount of energy in its production (WTT) and use as fossil diesel fuel. Its advantage lies in the extent to which this energy comes from non-fossil sources and reduces WTW GHG emissions. When only the WTT part is considered, the total energy expended is significantly higher in all the crop-based cases with notable differences depending on the feedstocks used.

Soy has the highest total energy use (~10 times the WTT one from oil-based diesel), although this deserves some explanation. Unlike other crops, soy yields more than 4 times as much meal as it does oil. Following the substitution method, all energy use for cultivation and processing is allocated to the oil. The credit recovered from the meal for substituting Brazilian corn does not fully compensate. The effect is exacerbated in this case because the alternative use of meal as animal feed saves relatively little energy. For comparison purposes, the case SYFA3d is included where the allocation between soya oil and soya meal is conducted based on their market value.

Using ethanol instead of methanol for trans-esterification slightly increases the required total energy. Use of glycerine as a chemical or animal feed has only a marginal impact; however, use of meal and glycerine for energy production (ROFA4) reduces the overall energy requirement considerably. The POFA cases show a similar energy expended balance when compared to the ROFx routes.

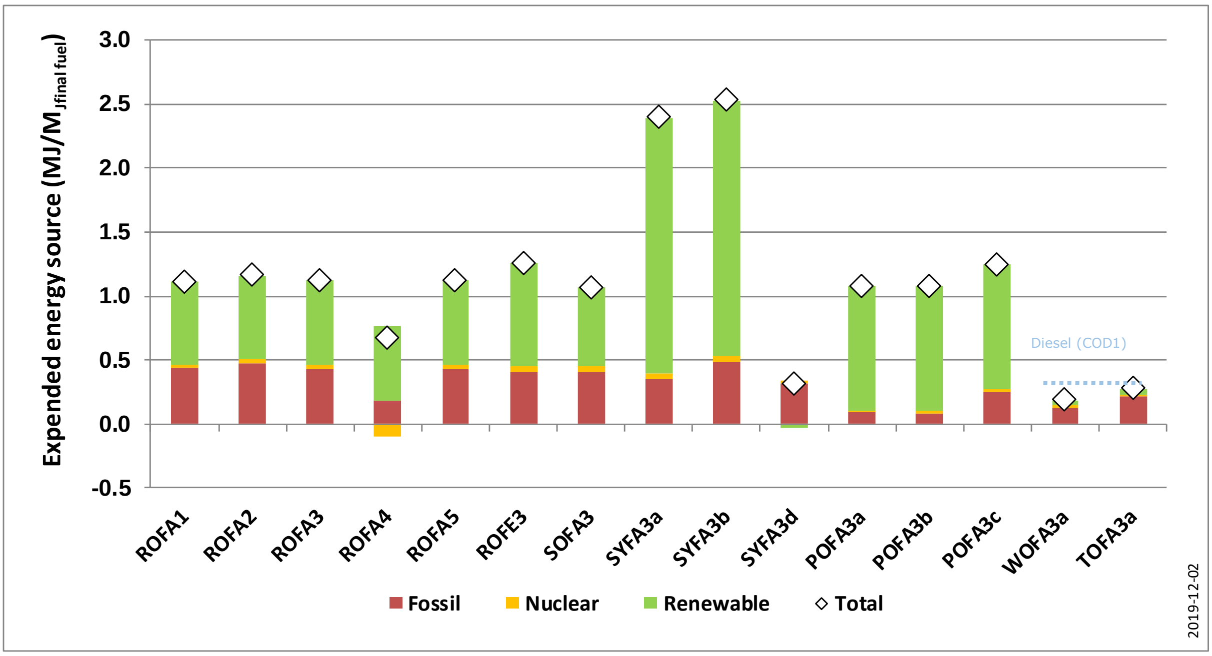
The pathways using waste cooking oil or tallow are the ones offering the most energy efficient routes with energy consumption similar or even lower than the equivalent oil-based diesel route.

Steps:

In the rapeseed, sunflower routes and soybeans, the most energy intensive step is the *Transformation near market* where the rapeseed oil and biodiesel production take place (Except for the case of imported biodiesel from soy oil – SYFA3a). In the case of POFAx, most of the energy is expended *at source* due to the transport of the fresh fruit bunch and further palm oil production.

Figure 94 shows a breakdown of fossil, nuclear and renewable energy as a measure of the "renewability" of the pathways. For biodiesel, this is in effect the WTW fossil energy (as no additional fossil energy is expended in the vehicle). To compare to conventional diesel, we would have to add the combustion energy, which as noted above gives a total of 1.26 MJ/MJ final fuel. This is in effect a WTW comparison and reference is made to the ***JEC WTW report***.

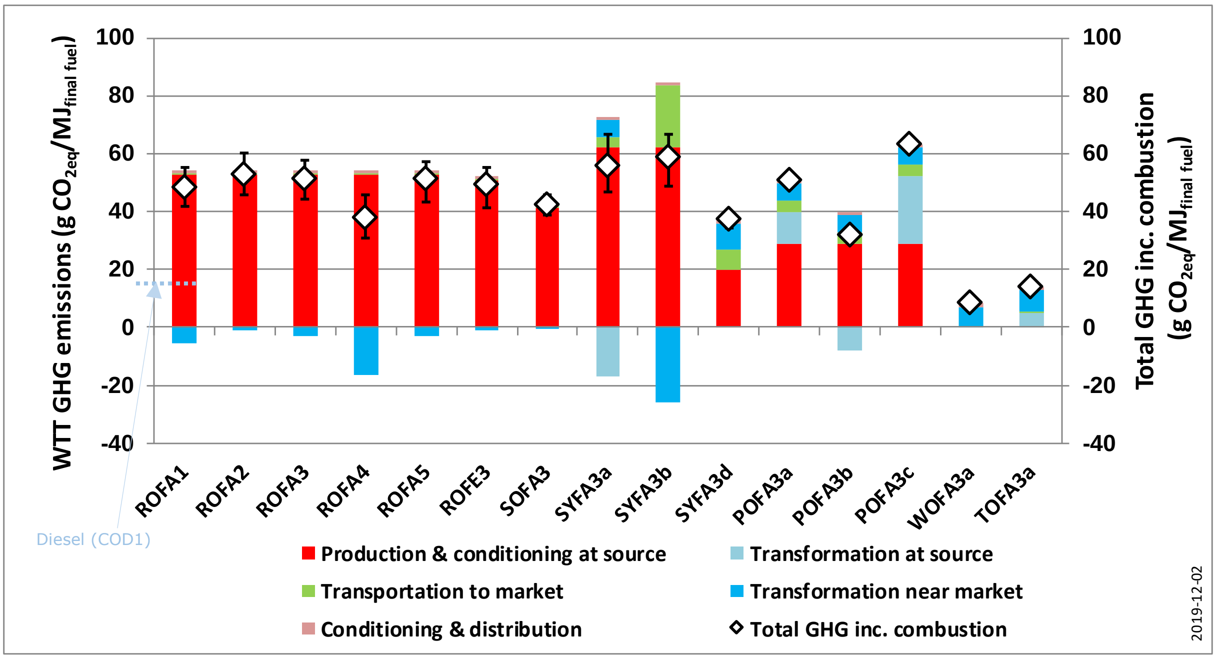
Figure 94. WTT expended energy breakdown by source for conventional biodiesel pathways



4.7.1.2 Biodiesel WTT GHG balance

Figure 95 shows the total GHG build-up along the different stages of the pathways. For comparison, the fossil diesel balance including the combustion CO_2 is 92.1 g CO_{2eq}/MJ final fuel.

Figure 95. WTT GHG emissions balance for conventional biodiesel pathways



General:

As in the energy expended balance, here again soy shows the highest values, although the difference from the rapeseed cases is relatively small, following the fossil energy figures more closely than the total energy figures. The negative numbers shown for the "transformation" stage are the result of fossil energy credits for co-products including the residue from pressing the oil seeds and the glycerine produced by the esterification process. Alternative uses of glycerine do not have a big impact, although switching the larger amount of meal from animal feed to energy production does reduce the overall direct GHG emissions, although it would increase ILUC emissions if these were included (see *Appendix 5 on ILUC*). Note that our results from palm oil do not include the large emissions from oxidation of tropical peat (see text box in *section 3.7.8.2.1).*

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

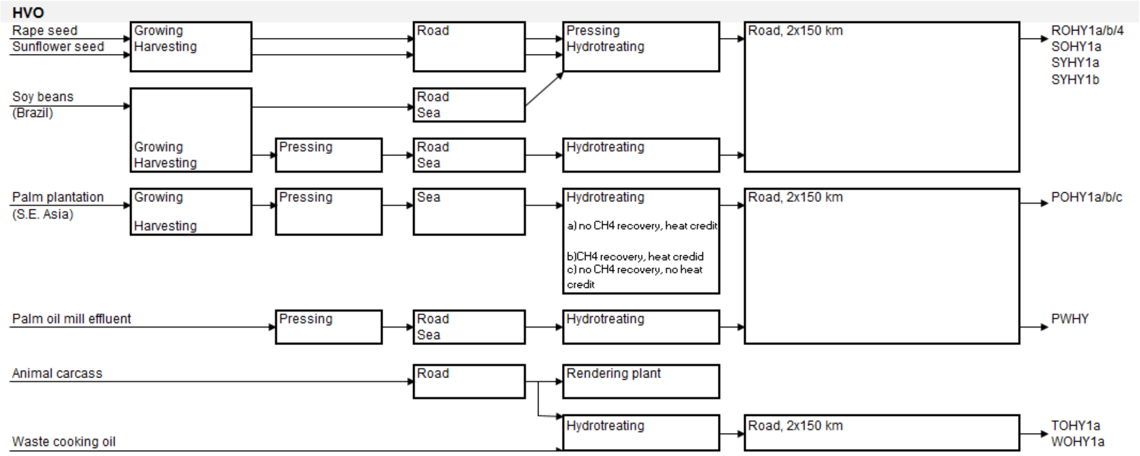
Steps.

The GHG emissions are dominated by the seed production step, mostly through N_2O emissions. This is largely due to the fact that oil seed crops, and particularly rape, require a lot of nitrogen fertiliser. The uncertainty attached to these emissions is also responsible for the large error bars.

4.7.2 Hydrotreated Vegetable Oils (HVO)

As outlined in *section 3.7.8.2.2*, deep-hydrotreating of rapeseed oil, sunflower, soy oil, palm oil, waste cooking oil, tallow and POME have been evaluated. In the figures that follow, the energy and GHG balances of these pathways are compared with the corresponding FAME pathways for the three feedstocks.

Figure 96. HVO pathways

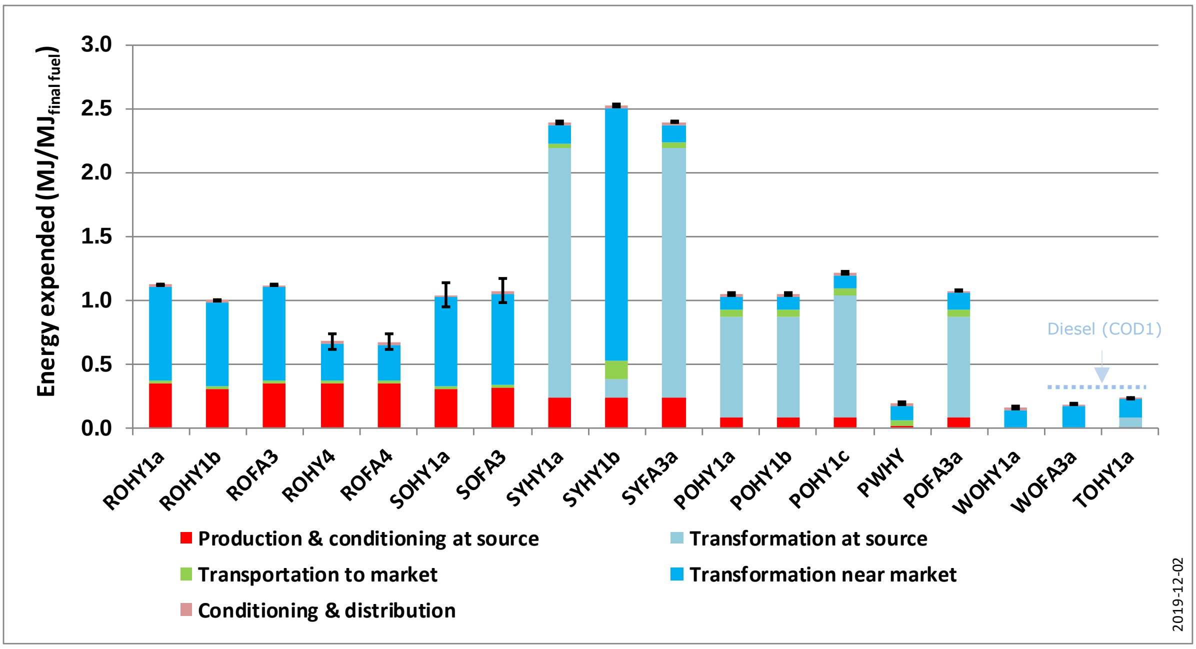


Code	*Final fuel*	*Description*
ROHY1a/b	HVO	Rape seed, meal export to animal feed, NexBTL / UOP.
ROHY4		Rape seed, meal to internal biogas, NexBTL.
SOHY1a		Sunflower seed, meal export to animal feed, NexBTL.
SYHY1a/b		Soybeans as feedstock with two variants: (a) soybeans, mix of till and no till, oil EU import, Nex BTL. (b) soybeans, mix of till and no till, beans EU import, NexBTL.
POHY1a-c		Palm oil as feedstock with three variants: (a) Palm oil, no CH4 recovery, heat credit, NexBTL. (b) POHY1b: Palm oil, CH4 recovery, heat credit, NexBTL. (c) Palm oil, no CH4 recovery, no heat credit, NexBTL.
WOHY1a		Waste cooking oil.
TOHY1a		Tallow.
PWHY		Extraction of oil from palm oil mill effluent (POME), NexBTL.

Note. A selection of the biodiesel pathways is shown in detail in the HVO variant i.e. where esterification is replaced by hydrotreating. All except ROY4 (meal to biogas) assume meal export as animal feed. For other combinations only the overall energy and GHG balances are shown in a separate table. The pathway coding is consistent with the corresponding biodiesel pathway. The front end of the pathways (up to and including raw oil production) is the same. The hydrotreating process is the same for all oils and results in a single HVO product considered to be equivalent to syndiesel (Fisher-Tropsch). However, two variants of the process are shown with rape oil: NexBTL (ROHY1a) and UOP (ROHY1b). All other pathways use the Neste process.

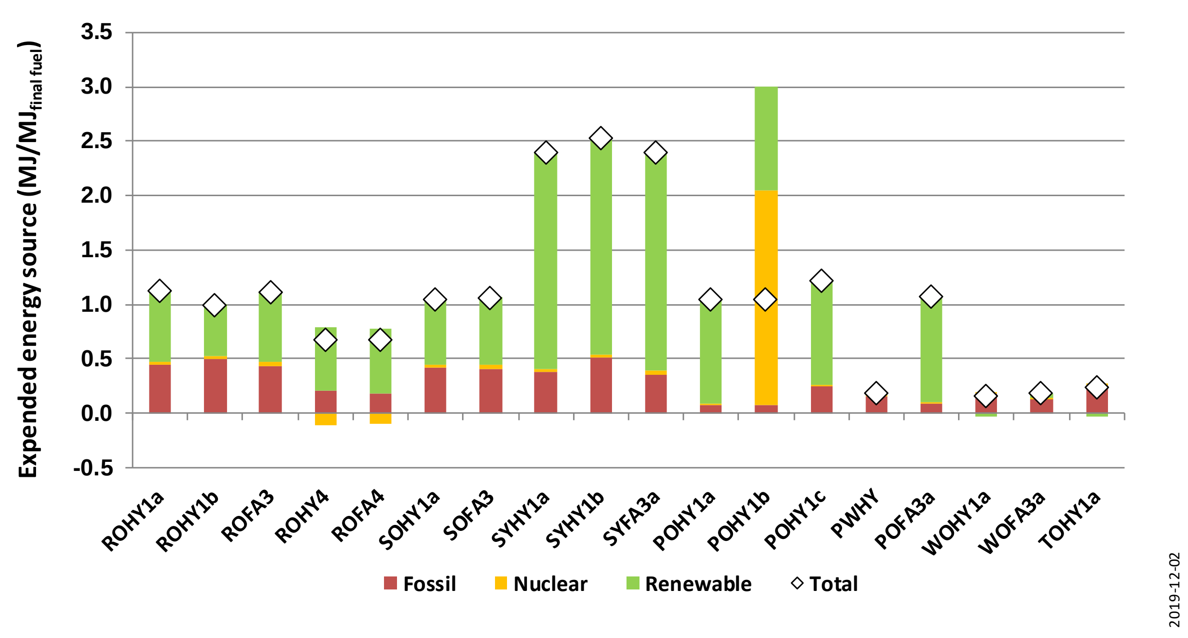
Figure 97 shows the HVO pathways for rapeseed, sunflower, soya, palm oil, waste cooking oil and compares them with the equivalent FAME pathway. The POME pathway has been included in this case as a potential additional route. The main conclusion is that, overall energy consumption is very similar, whether HVO or FAME is produced.

Figure 97. WTT total expended energy balance for HVO pathways and comparison with equivalent FAME pathways



Note. **xHx** <> HVO pathways while **xFx** <> FAME routes.

Figure 98. WTT expended energy breakdown by source for HVO pathways and comparison with equivalent FAME pathways



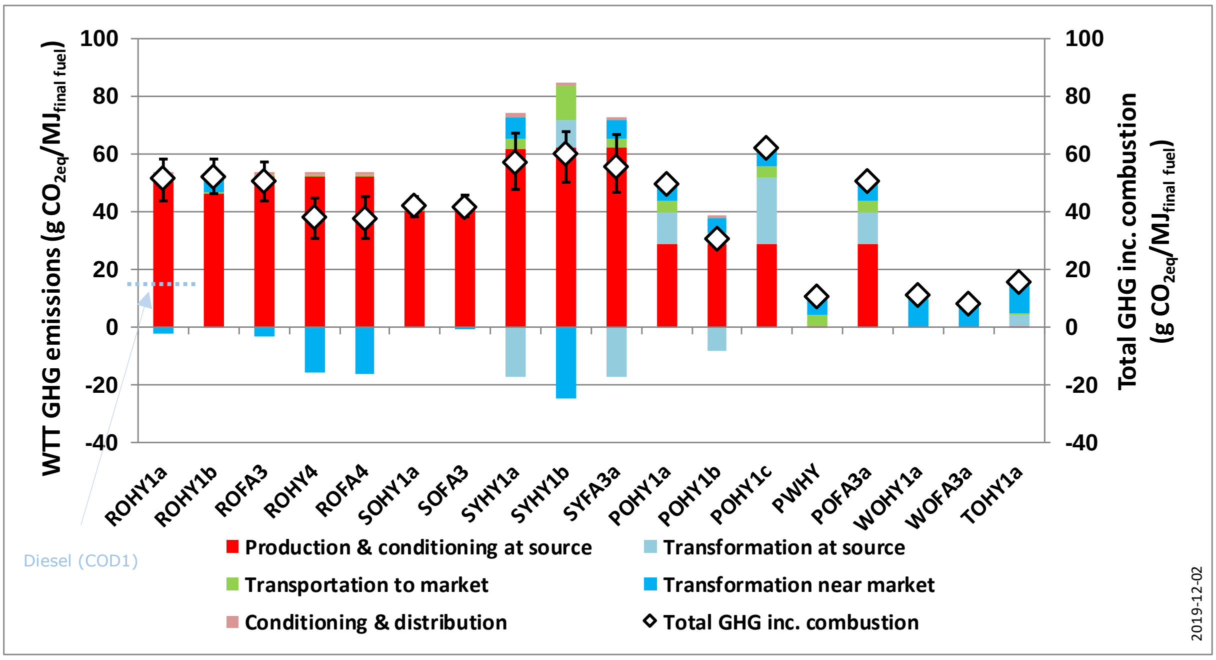
General:

When focussing on fossil energy, the ratio to fossil diesel is in the region of 0.4 for rape, i.e. a net fossil energy saving of about 60% compared to fossil diesel. Again, sunflower is slightly more favourable than rape. Obviously, the use of bio-ethanol instead of fossil-based methanol results in a small decrease of the total fossil energy requirement. Using co-products for energy production (ROFA4) displaces fossil fuels otherwise needed for heat and electricity generation and so reduces the WTT fossil fuel needs (but increases ILUC: see ***Appendix 5***). Again, we do not include the large emissions from oxidation of tropical peat in the palm oil results see text box in *section 3.7.8.2.1*).

The high total energy use for soy-derived FAME has been mentioned above; however, most of this energy is contained in the soya beans themselves and hence appears as renewable energy. The fossil energy use in this calculation is comparable to or slightly lower than for rapeseed. Palm oil has lower fossil energy use than rapeseed, because waste biomass from the oil extraction is used for heat generation in the production process. The newly added POME pathway (PWHY) offer an alternative low energy expended route similar to the waste cooking oil or tallow routes.

Comparing **Figures 97** and **98,** the UOP process uses slightly less total energy than the NExBTL® process, but more fossil energy, probably because the latter makes use of cracking products from the bio feedstock as fuel for the process.

Figure 99. WTT GHG emissions balance for hydrotreated plant oil pathways



In terms of GHG emissions, **Figure 99** there is little difference between FAME and hydrotreated plant oils when similar plant energy provisions are compared.

4.8 Methanol

(See also workbook WTT v5 pathways 5-Synfuels in Appendix 1)

In section 3, we referred to the different routes to produce synthetic routes, some one of which involve methanol in the production process. In this section, the WTT Energy use and GHG emissions for the methanol pathways including coal, natural gas, wood or renewable electricity (e-methanol) have been modelled and the results are presented in **Figures 101** and **102.**

In principle methanol could be used as a blend component in gasoline and its use as marine fuel is gaining attention in the last years as the International Maritime Organization (IMO) pursue efforts to reduce the GHG emissions of this sector. Although out of the scope of the study, consideration would need to be given to its toxicity and water solubility. Neat methanol has also been proposed as a fuel for on-board reforming to hydrogen for fuel cell vehicles although this technology is no longer considered promising for road transport, at least in the medium term and has not been included in the TTW part of this study.

Besides the pure methanol pathways as potential fuel for road transport, the methanol derived fuels (ETBE, MTBE, DME, OME) are also detailed in section 4.9. Ethers.

Figure 100. Methanol pathways

Code	*Final fuel*	*Description*
GPME1b	Methanol	Piped natural gas (4000 km) to methanol, synthesis plant in EU
GRME1		Remote natural gas to methanol, synthesis plant near gas field
WxME1/BLME1		Wood to methanol, waste wood, farmed wood, and waste wood via black liquor gasification/synthesis plant
REME1		Renewable electricity to methanol (CO_2 from flue gases)

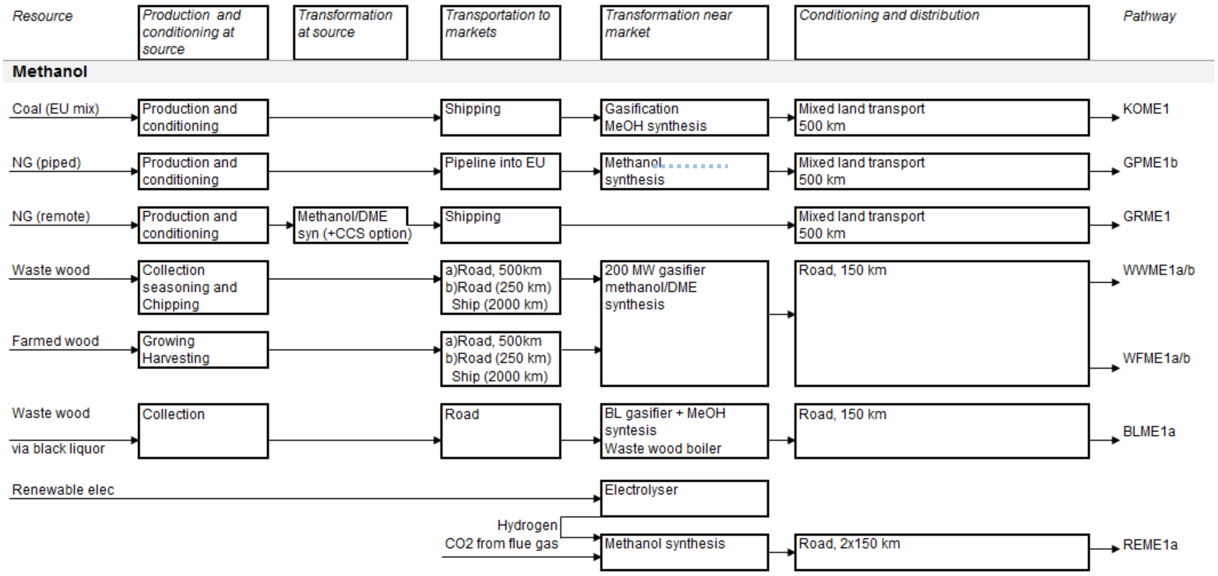


Figure 101. WTT total expended energy balance for methanol pathways

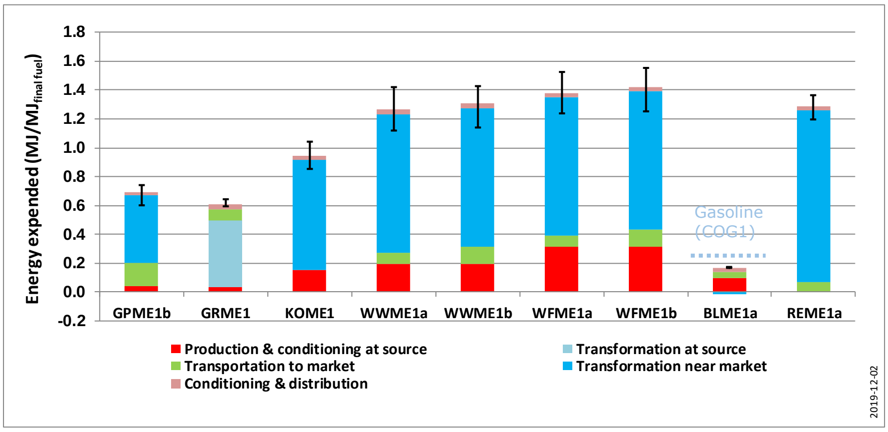
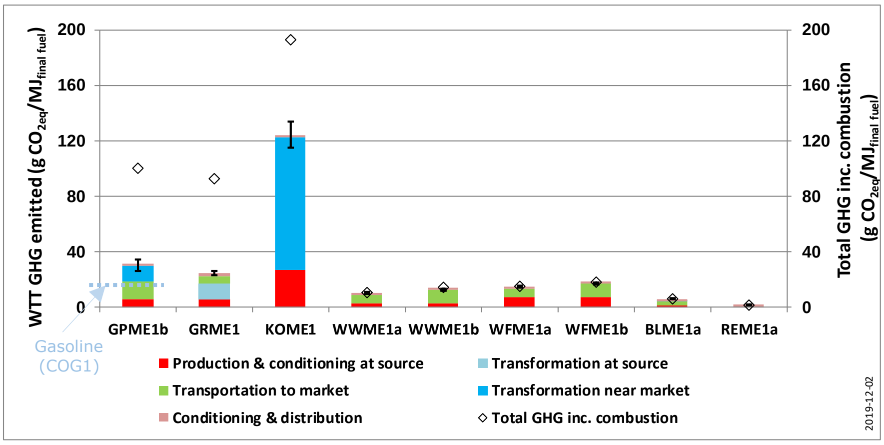


Figure 102. WTT GHG emissions balance for methanol



General:

Methanol from wood is much less energy-efficient than other routes but virtually all the energy used comes from the wood itself, resulting in a very favourable fossil energy balance. The black liquor route offers a substantial energy efficiency improvement when using wood, and the overall energy use and final GHG emissions are the lowest ones with the exception of the Power-To-Methanol route (REME1a). In terms of WTT emissions, both the wood and the renewable electricity pathways are less GHG although more energy intensive than the equivalent gasoline route (fossil based).

Figures including combustion CO_2 have not been included in this case, because the potential uses of methanol are still unclear.

4.9 Ethers

4.9.1 MTBE / ETBE

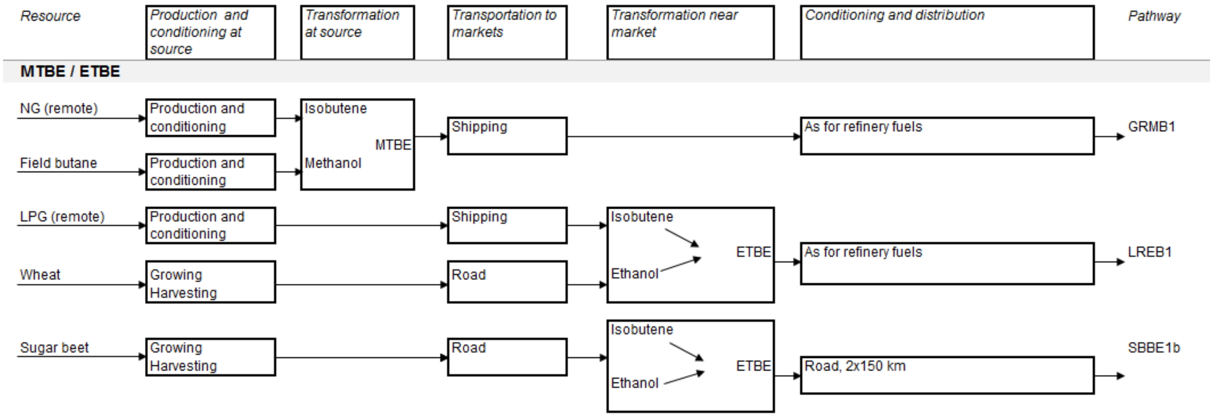
(See also workbooks WTT v5 pathways 1-Oil&Gas/3-Ethanol/ in Appendix 1)

As explained in *section 3.7.8.1.5*, ETBE is currently manufactured by some European oil refineries in purpose-built ETBE plants or, much more frequently, in plants that used to produce MTBE. The isobutene feed is a co-product of the catalytic cracking process and is only available in limited quantities. Should more ETBE be required it would have to be made from isobutene produced by isomerisation and dehydrogenation of normal butane. We have represented this pathway with the assumption that the marginal butane required is imported from gas fields. We compare a base case where ethanol is used as such and MTBE is produced in refineries, to the alternative where ethanol is turned into ETBE in replacement of MTBE.

Pathway GRMB1 represents marginal MTBE produced from natural gas and associated butane in a remote plant located near a gas field (see *section 3.2.5*). Pathway LREB1 represents a case where ETBE would be produced in Europe from imported butane and bio-ethanol (from wheat according to pathway WTET2a, see *section 3.4.8.2).*

Besides this more conventional pathways the results of a new route to produce bio-ETBE (SBEE1b) are also presented.

Figure 103. MTBE and ETBE pathways



Code	Final fuel	Description
GRMB1	MTBE	MTBE in remote plant near gas field
LREB1 b/c	ETBE	ETBE from wheat ethanol and isobutene, from FCC (b) or steam cracking (c)
SBBE1	Bio-ETBE	EU sugar beet to ETBE. Pulp to animal feed, Slops used as feed for biogas, ethanol and isobutene for ETBE from sugar beet

The energy and GHG balances are shown in **Figures 104** and **105.**

Figure 104. WTT total expended energy balance for MTBE and ETBE pathways

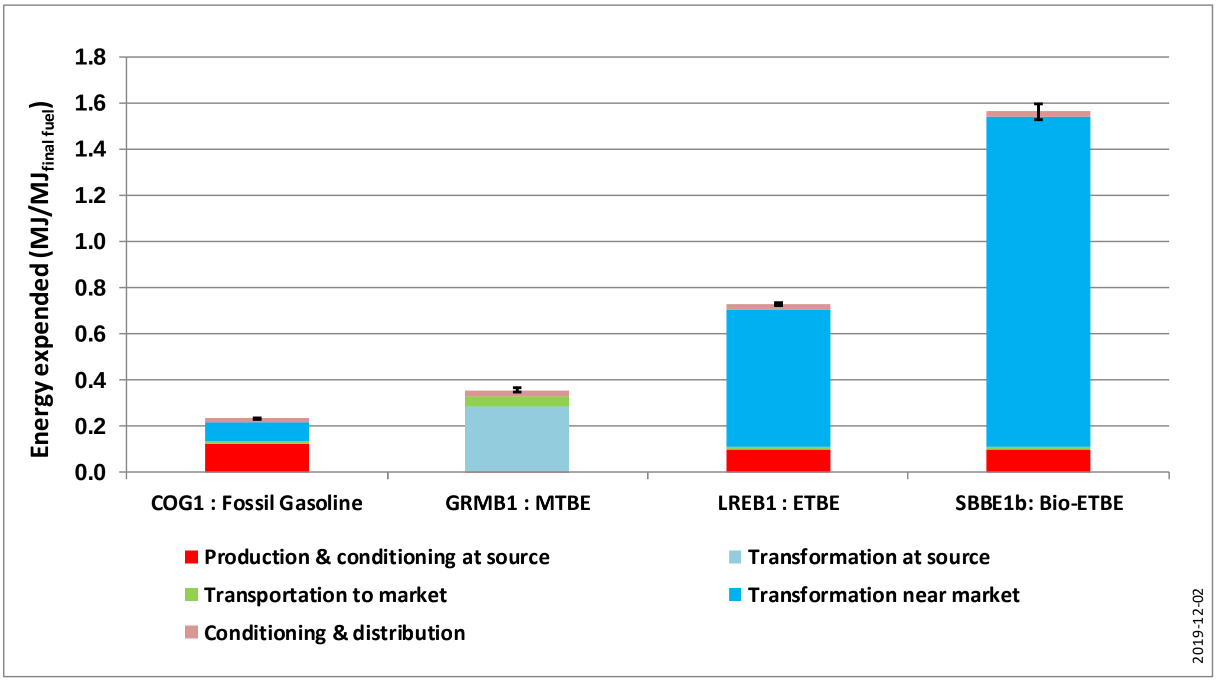
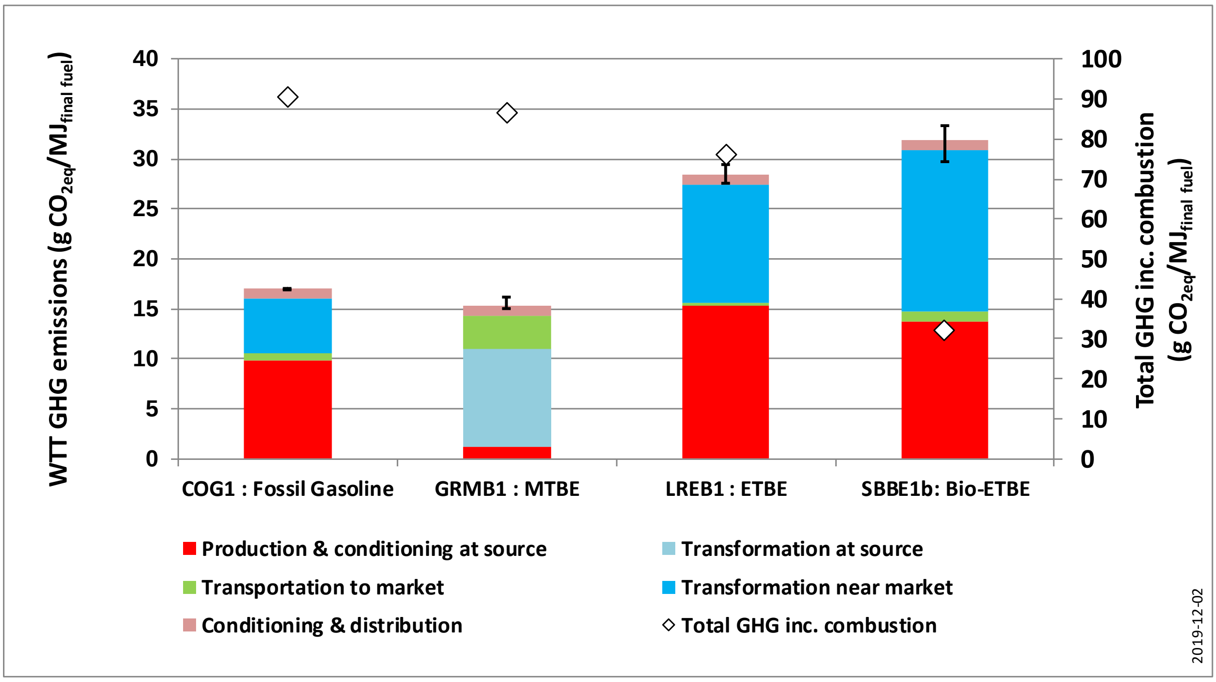


Figure 105. WTT GHG balance for MTBE and ETBE pathways



General:

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

ETBE's energy footprint is much higher, partly because of the high energy demand for bio-ethanol. Part of that energy is renewable though and this is taken into account when calculating GHG emissions. ETBE is itself partly renewable so that, to compare GHG emissions with purely fossil pathways, only the non-renewable part of the CO_2 combustion emissions (2/3) has to be factored in (ETBE has 6 carbon atoms, 2 of which come from ethanol hence 33% of the combustion CO_2 emissions are renewable).

The new bio-ETBE pathway is worthy of an additional note as, despite their higher energy and WTT GHG intensity (more than 8 times in terms of energy and twice the WTT GHG emission balance), due to the renewable content of the products, the total GHG emissions including combustions are the lowest ones (~60% less than the conventional fossil gasoline).

4.9.2 DME / OME

In section 3.2.8.2, we referred to the different routes to produce synthetic routes, some one of them involving methanol and their derived fuels Di-Methyl Ether (DME) and Oxy-methyl Ether (DME) potentially comparable with oil-based and Fisher-Tropsch diesel routes.

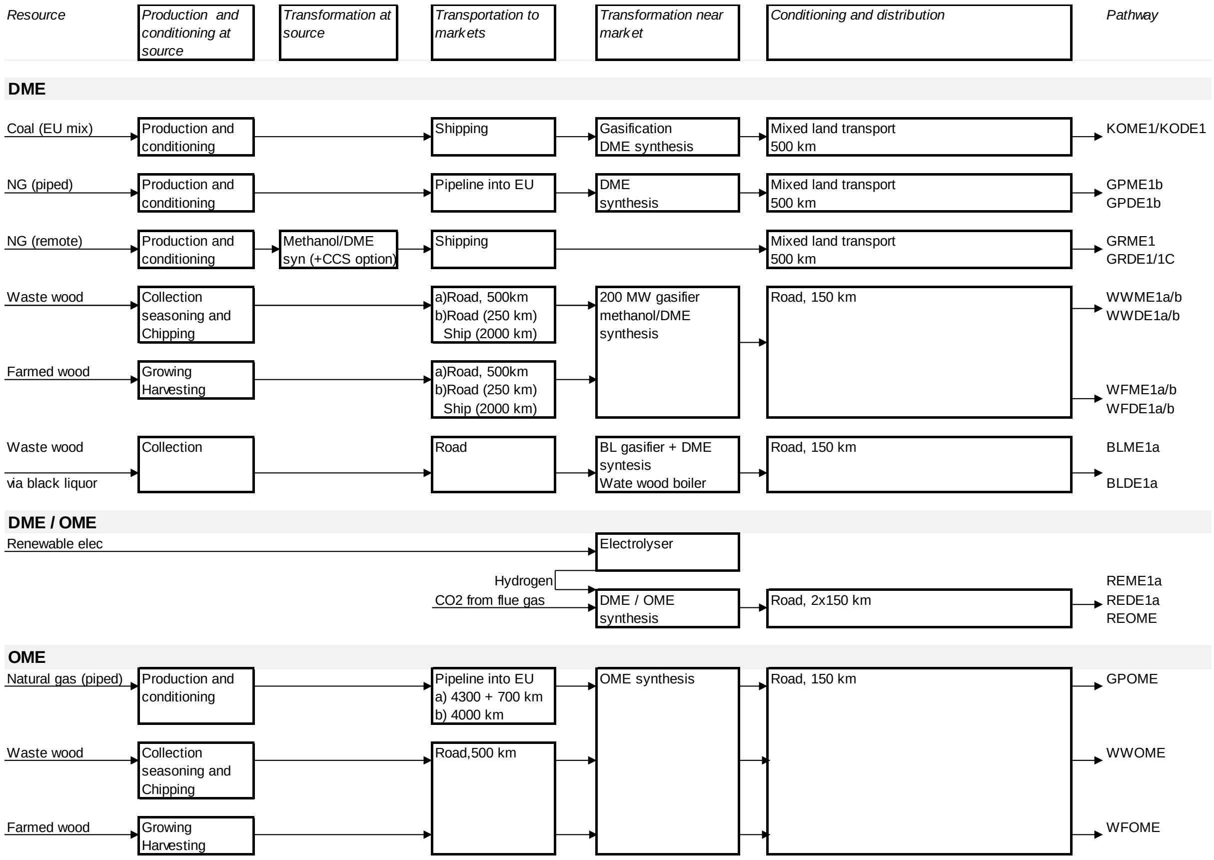
DME has some attractive characteristics as a fuel for diesel engines although the fact that it is gaseous at ambient conditions means it can only be used in vehicle specially designed for the purpose (See details of the physical properties in the table below):

Table 48. Physical properties of products and intermediates relevant to these pathways

		Hydrogen	**Methanol**	**DME**	**OME**
Density	kg/m^3		793	670	1067
LHV	MJ/kg	120	19.9	28.4	19.2
Molar mass	g/mol	2.0			
C content	% m	0	37.5%	52.2%	43.5%
CO_2 emission factor (assuming total combustion)	g CO_2/MJ	0	68.9	67.3	83.3
	kg CO_2/kg	0	1.37	1.91	1.60

Different pathways have been modelled in the current JEC WTT v5 including coal, natural gas wood and renewable electricity (See section 3.9 on Power-To-Fuels) routes. The summary is included below:

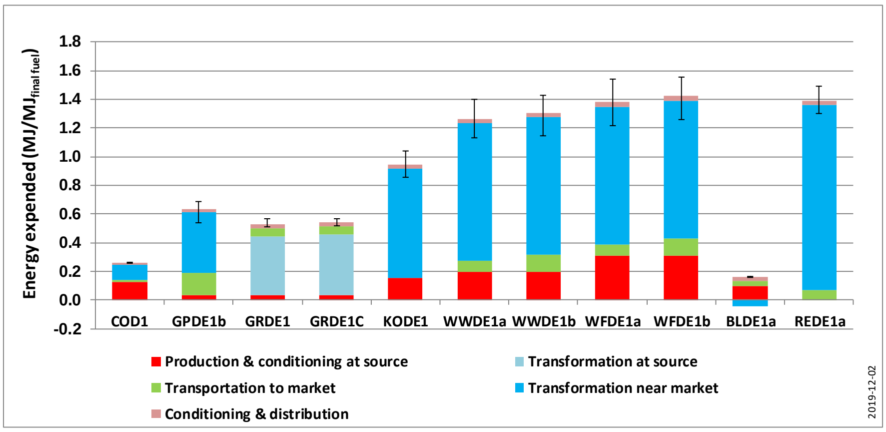
Figure 106. DME and OME pathways



Code	*Final fuel*	*Description*
GPOME	OME	Piped natural gas (4000 km) to OME via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis.
WxOME		Wood to OME via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis, waste and farmed wood in gasification/synthesis plants.
REOME		Renewable electricity to OME via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis (CO_2 from biogas upgrading).
GPDE1b	DME	Piped natural gas (4000 km) to DME, synthesis plant in EU.
GRDE1/1C		Remote natural gas to methanol, synthesis plant near gas field, without/with CCS.
WxDE1/BLDE1		Wood to DME, waste wood, farmed wood, and waste wood via black liquor in gasification/synthesis plant.
REDE1		Renewable electricity to DME (CO_2 from flue gases).

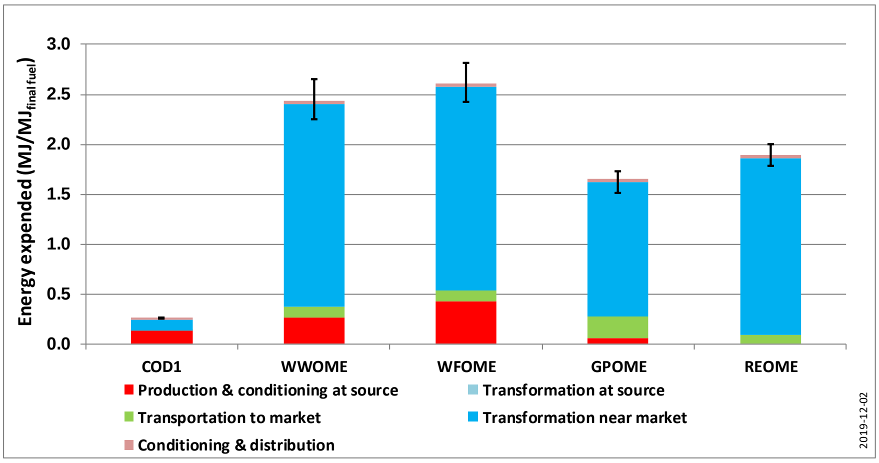
WTT Energy use and GHG emissions for the DME pathways are shown in **Figures 107** and **108.** The synthesis of DME is a more efficient than that of FT diesel, resulting is a more favourable energy balance (compare GRSD1 and REDE1 in **Figure 107**).

Figure 107. WTT total expended energy balance for DME pathways



Note. As a reference, FT Diesel Energy intensities (MJ/MJfuel): 0.63 (GRSD1 - GTL) and 0.53 (REDE1 – PTL)

Figure 108. WTT total expended energy balance for OME pathways



Note. The OME pathways are considerable more energy intensive than the equivalent DME ones due to the additional pathways required in the conversion (from 25% more energy intensive in the Power-To-X route (REx) up to x4 times higher in the piped natural gas routes (GPx)).

General:

DME from wood is much less energy-efficient but virtually all the energy used comes from the wood itself, resulting in a very favourable fossil energy balance (with lower GHG emissions associated).

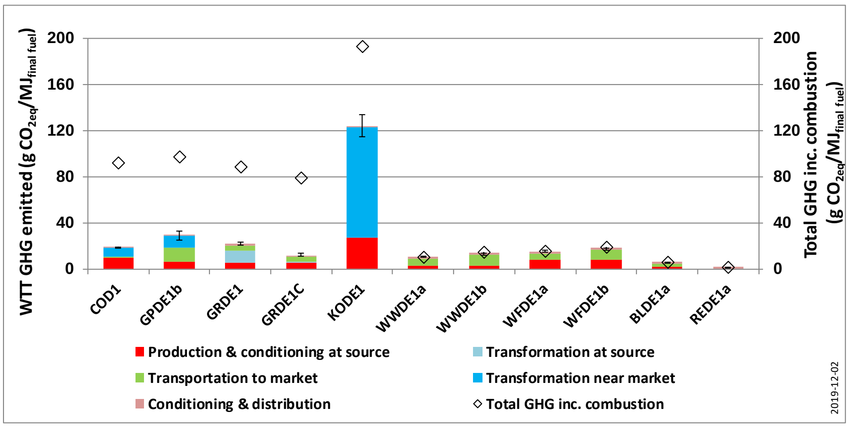
The black liquor route offers a substantial energy efficiency improvement when using wood, and the overall energy use is more than three times less energy intensive than the NG route with half of the energy requirements than the oil-based diesel.

The eDME route (REDE1a) is x7 times more energy intensive than fossil diesel but the electricity is expected to come from renewable sources with a lower GHG emissions associated.

When compared with another synthetic fuel routes such as the Fischer-Tropsch diesel ones, DME is more energy intensive with the exception of the remote natural gas to ethanol pathways (GRDx) where the results are comparable.

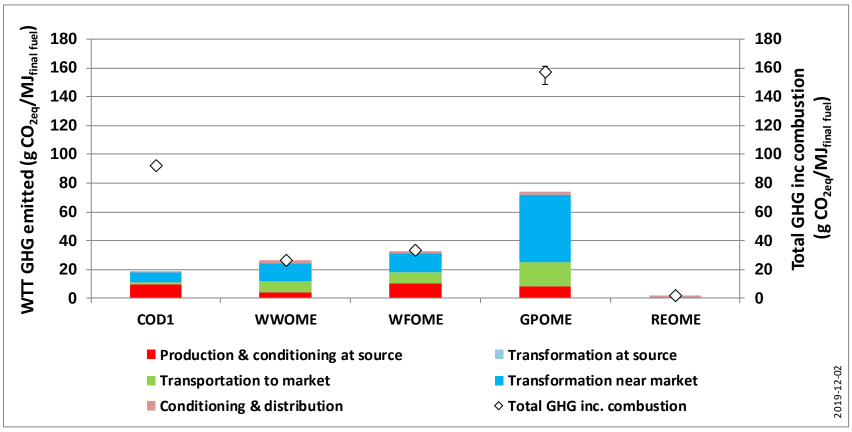
Total GHG emissions including combustion are again shown. This is appropriate since DME can be used in diesel-type engines, albeit specially designed ones, so will be burned with much the same efficiency as fossil diesel fuel.

Figure 109. WTT GHG emissions balance for DME pathways



Note. As a reference, FT Diesel GHG intensities (MJ/MJfuel):23.2 (GRSD1 - GTL) and 1.7 (REDE1 – PTL)

Figure 110. WTT GHG emissions balance for OME pathways



General:

Manufacturing of DME near a remote natural gas source is one of the most credible scenarios as DME can be transported in liquid form by simple compression, much like LPG, avoiding the need for expensive LNG installations. For this route DME is on a par with conventional diesel in terms of GHG emissions.

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

The renewable electricity pathway offers additional routes to produce nearly-zero GHG emissions fuels.

As with energy, OME offers no GHG emissions savings when compared versus their equivalent DME routes.

Note. CCS in DME production

DME production is similar to syndiesel in that there is an opportunity to capture CO_2 from the syngas. In such a scheme, WTT GHG emissions could be cut by a factor of nearly two for a relatively small energy penalty, making DME somewhat more GHG-efficient than fossil diesel.

There is limited information available on DME and there are no full-scale commercial plants on the ground at the moment. The data used here are from Haldor Topsoe [Haldor Topsoe 2002], the main proponent of DME. This process is applicable to both a remote plant and a large “central” plant located in Europe. In both cases electricity is deemed to be produced by a dedicated gas-fired CCGT power plant.

Table 49. DME production with/without CCS

Feedstock		Natural gas	
Case		Based GRDE1	With CCS GRDE1C
Natural gas well-to-tank	MJ/MJ DME	0.52	3
Energy Efficiency DME plant (*)	%	71.3%	70.2%
Net GHG emissions well-to-tank	g CO_{2eq}/MJ DME	21.6	11.6
CO_2 removal efficiency at plant site	%		94.8%

Note. (*) LHV (DME) / LHV (natural gas); without electricity import or export

4.10 Electricity

(See also workbooks WTT v5 pathways 6-Electricity in Appendix 1)

4.10.1 Electricity generation pathways

The pathways to electricity are included here as a reference against other fuels with which electricity competes for primary resources. Electricity is also used as intermediate stage for electrolysis pathways to hydrogen (see *section 3.8*). Electricity is also a road fuel for electric vehicles which are described in the version of this study. For a diagrammatic description of the pathways considered, refer to **Figure 111*.***

The routes to produce electricity modelled in WTT JEC v5 include fossil, waste, wood, renewable, and nuclear sources. The pathways represent power generation from specific primary energy sources **using state-of-the-art technology**. Older power plants already in production may not achieve state-of-the-art efficiency so the current EU-mix is also represented only as a reference (see *sections 3.4.1.6/3.4.3* for a detailed discussion).

4.10.1.1 Energy and GHG balance for electricity pathways

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

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

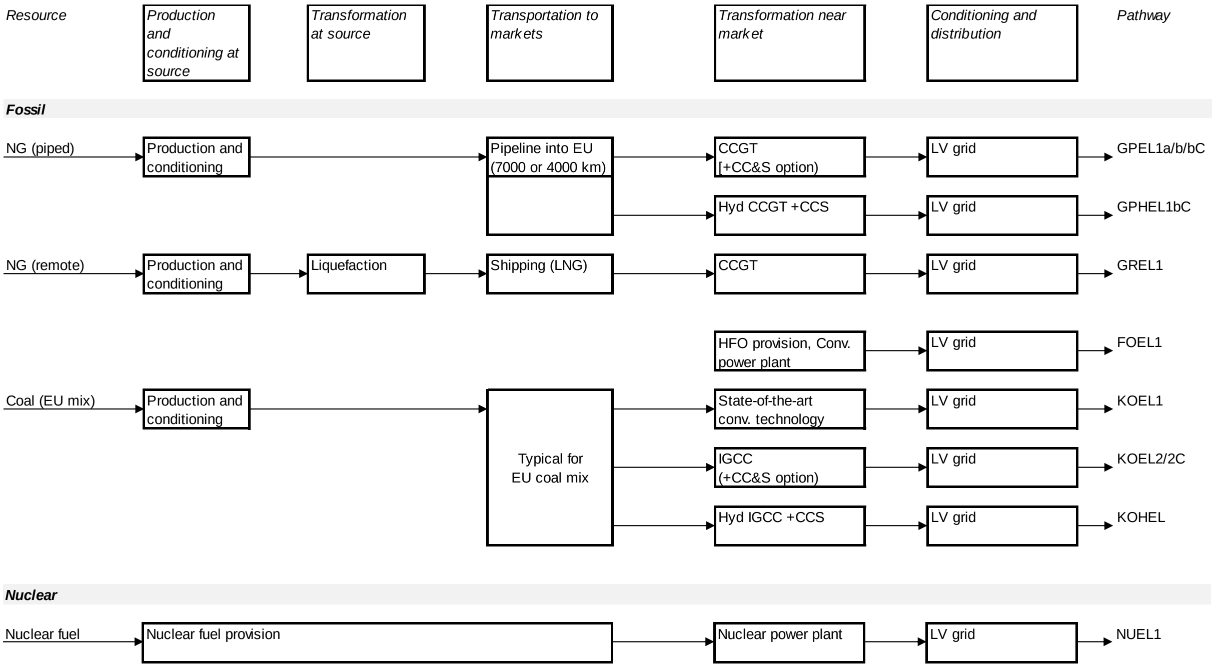
The overall efficiency of the power generation process through resource extraction, power station and distribution is then given by

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

Note that the figures shown assume distribution to LV (low voltage) level.

4.10.1.2 Electricity from fossil and nuclear sources

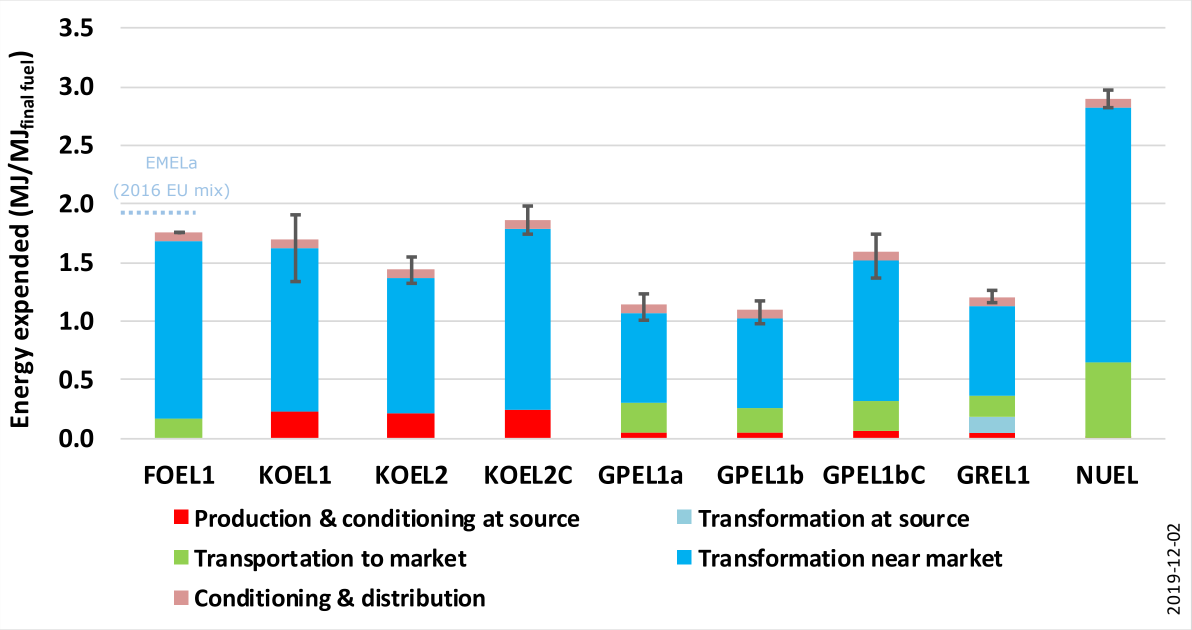
Figure 111. WTT electricity pathways: Fossil and nuclear

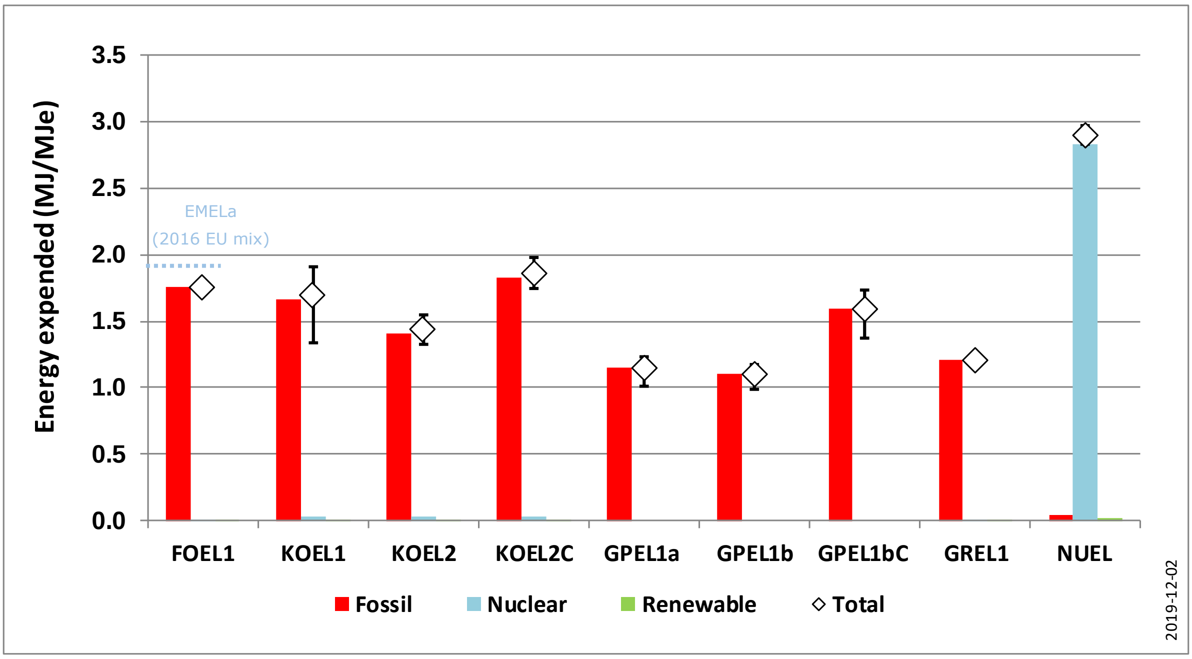


Code	*Feedstock*	*Description*
EMEL	EU-mix	EU-mix electricity (High, Medium and Low voltage) 2016 mix (a) and 2030 mix (b).
FOEL	HFO	Electricity from heavy fuel oil (HFO) Conventional power plant (state-of-the-art) .
KOEL	Hard coal	Hard coal in conventional power plant or IGCC (with/without CCS).
GxEL	NG	Electricity from imported natural gas (5000 and 4000 km) and LNG in state-of-the-art CCGT.
OWEL	Biogas	Biogas from municipal waste and manure, on-site generation or export to large scale power plant.
WxEL	Wood	Farmed and waste wood in 4 different power plants (large/small scale IGCC, conventional, co-firing in large coal plant) plus waste wood through black liquor.
NUEL	Nuclear	Nuclear power plant.
WDEL	Wind	Wind turbine.

Energy and GHG emission figures for fossil and nuclear electricity are shown in **Figures 112** and **113**.

Figure 112. Total expended energy balance for fossil and nuclear electricity pathways (excluding final electrical energy)

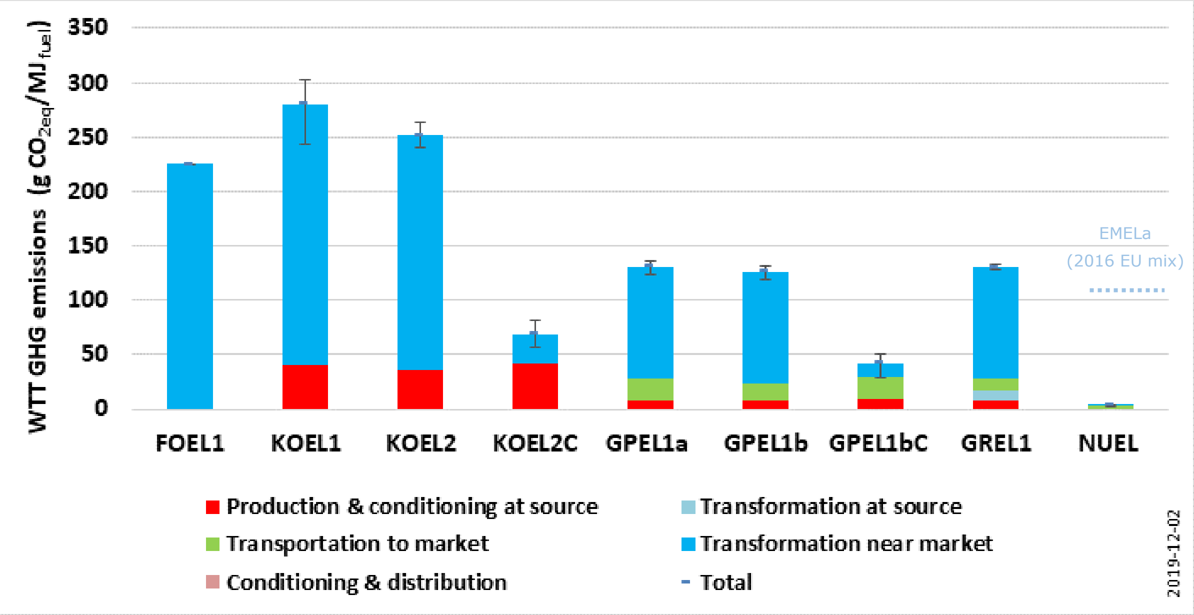




General:

In terms of total energy, the very efficient gas-fired CCGT (combined cycle gas turbine) fares best amongst fossil fuels. Coal is significantly more energy-intensive, although new coal plants can achieve efficiency over 40%. We have used efficiencies of 58% for natural gas fuelled CCGT and 43.5% for a conventional coal fuelled steam turbine power plant, representative of state-of-the-art technology. Where the energy source is biomass, the efficiency of electricity generation depends on the scale of the operation. For a large scale IGCC the efficiency is 48.0%, whereas a smaller scale IGCC may only achieve 35.2%, which is little better than a conventional small-scale steam turbine at 32%. Wind energy is effectively considered 100% efficient. Efficiencies are estimated for the lifetime of the plant and may be higher when the plant is new.

Figure 113. *GHG emissions balance for fossil and nuclear electricity pathways*



General:

Defining conventional coal electricity as a benchmark, introduction of IGCC provides relatively small reductions in energy use and GHG emission reductions, because the IGCC efficiency is less than can be achieved with a gas powered CCGT. Electricity production from natural gas benefits both from generating efficiency and the lower carbon content of gas, so that GHG emissions are about half those of coal, even when the gas is sourced through a long-distance pipeline or as LNG.

It is common practice to calculate the efficiency of a nuclear power plant as the fraction of the energy transferred to the steam that is turned into electricity which explains the fairly high energy use figures, since the efficiency of the steam turbine is around 33%. Extraction and upgrading of nuclear fuel also require a significant amount of energy. However, nuclear power draws on a different source of energy than fossil hydrocarbon sources and has very low GHG emissions.

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

4.10.1.3 CCS in electricity generation

For natural gas two different routes for CCS can be envisaged. The so-called "post-combustion" route involves scrubbing flue-gases of a standard power plant using an amine absorption process. Alternatively, the "pre-combustion" route includes reforming NG into hydrogen and separating CO_2 before burning the hydrogen in an adapted CCGT.

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

The coal IGCC process is well suited to CO_2 capture, since syngas can be converted, via the shift reaction, to hydrogen and virtually pure CO_2 upstream of the gas turbine. This is, however at a significant energy cost. The calculations are based on a pre-feasibility study since there is no commercial-scale plant in operation. Results are shown in the figures above, and summarised in **Table 50**.

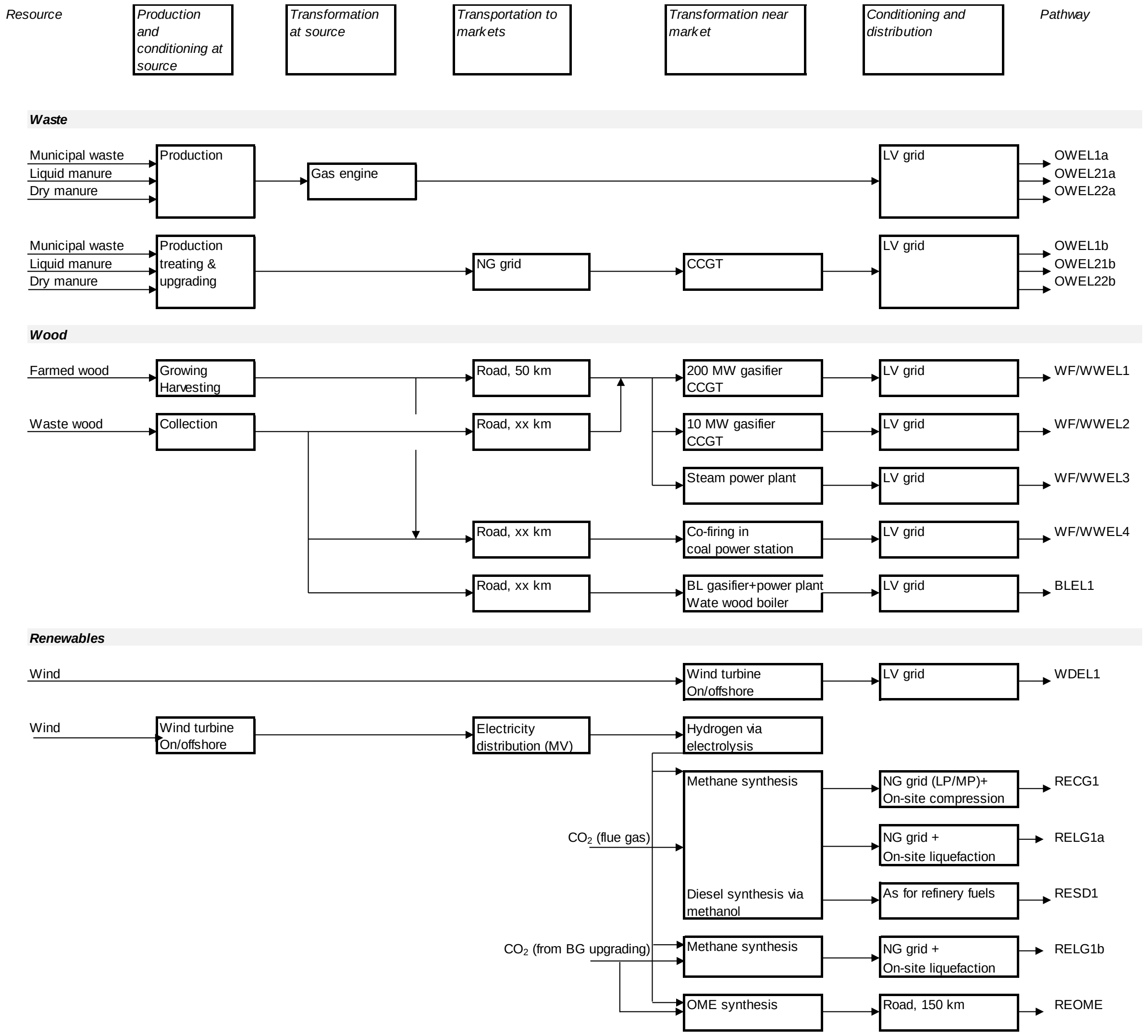
Table 50. Electricity production with/without CCS

Feedstock		Natural gas		Coal	
Case		Based GPEL1b	With CCS GPEL1bC	Base KOEL2	With CCS KOEL2C
Natural gas well-to-tank	MJ/MJe	1.10	1.59		
Coal well-to-tank	MJ/MJe			1.44	1.86
Energy Efficiency power plant (*)	%	58.1%	47.1%	43.5%	41.0%
Net GHG emissions well-to-tank	g CO_{2eq}/MJe	126.7	42.6	251.7	68.6
CO_2 removal efficiency at plant site	%		90%		90%

(*) State-of-the-art; without upstream energy use i.e. the supply of fuel for electricity generation.

4.10.1.4 Electricity from waste and renewable sources

Figure 114. WTT Electricity pathways: waste, wood and renewables

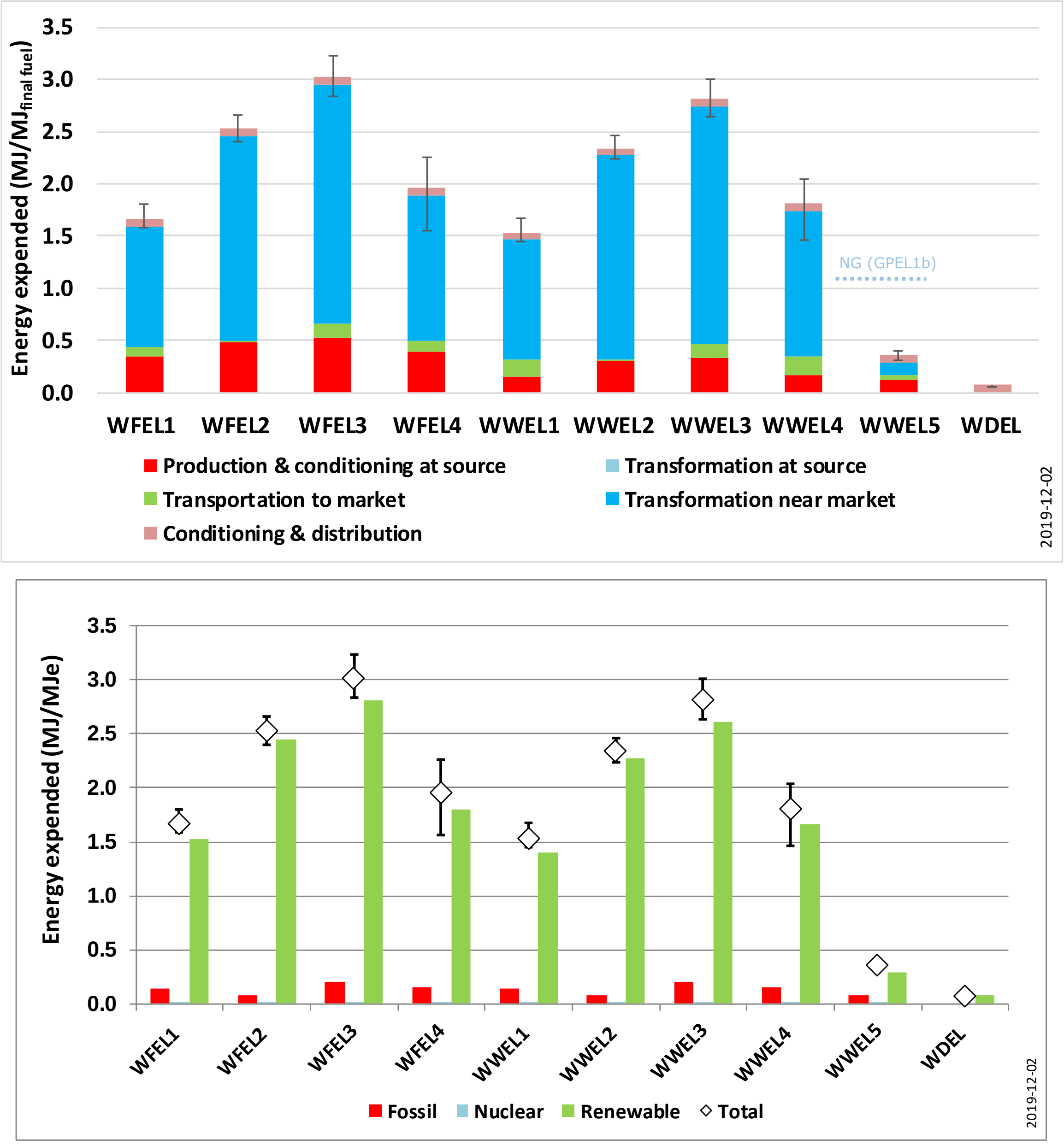


Code	*Feedstock*	*Description*
OWEL	Biogas	Biogas from municipal waste and manure, on-site generation or export to large scale power plant
WxEL	Wood	Farmed and waste wood in 4 different power plants (large/small scale IGCC, conventional, co-firing in large coal plant) plus waste wood through black liquor
WDEL	Wind	Wind turbine

4.10.1.5 *Energy and GHG balances: wood and renewable sources*

Energy and GHG emission figures for electricity produced from wood and wind are shown in **Figures 115** and **116**. Note that, for comparison purposes, the comparison with one example of the natural gas based electricity routes is also included (GPEL1b).

Figure 115. Total expended energy balance for wood and wind to electricity pathways (excluding final electrical energy)

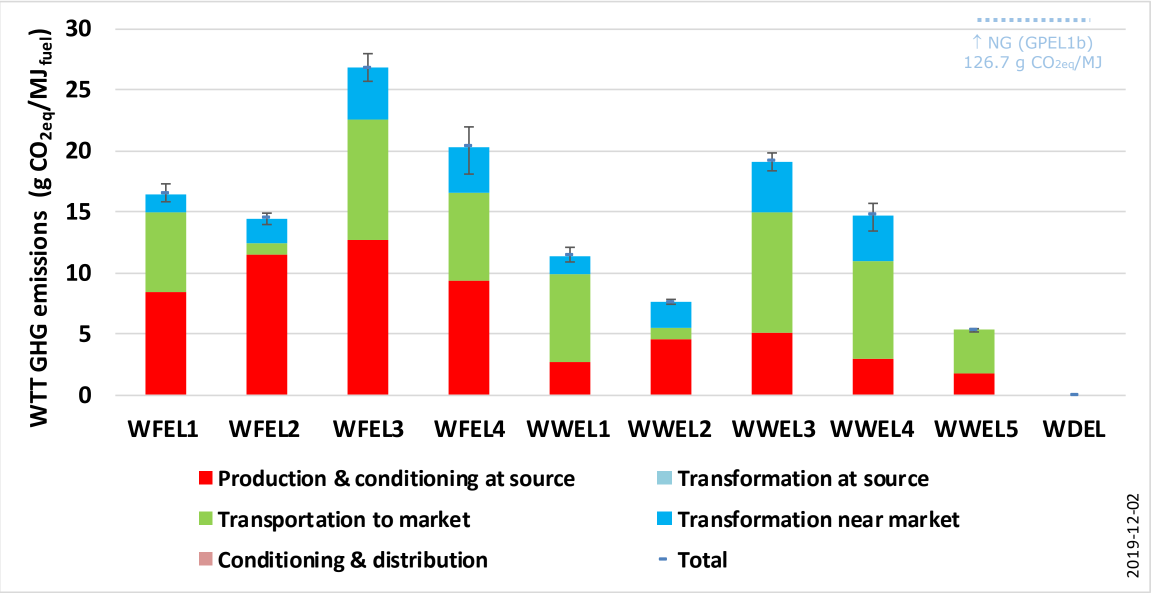


General:

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

For the other wood pathways, overall energy efficiency depends on the scale. Efficiency comes close to gas in the case of a large gasifier associated to a CCGT but other schemes such as small gasifiers or conventional steam plants are much less efficient. Electricity produced by the black liquor route achieves remarkably high energy efficiency due to its synergy with the requirements of the paper mill. Most of the energy consumed comes from the wood itself, so the fossil energy use and GHG emissions are very low for all the pathways.

Figure 116. GHG emissions balance for wood and wind to electricity pathways



General:

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

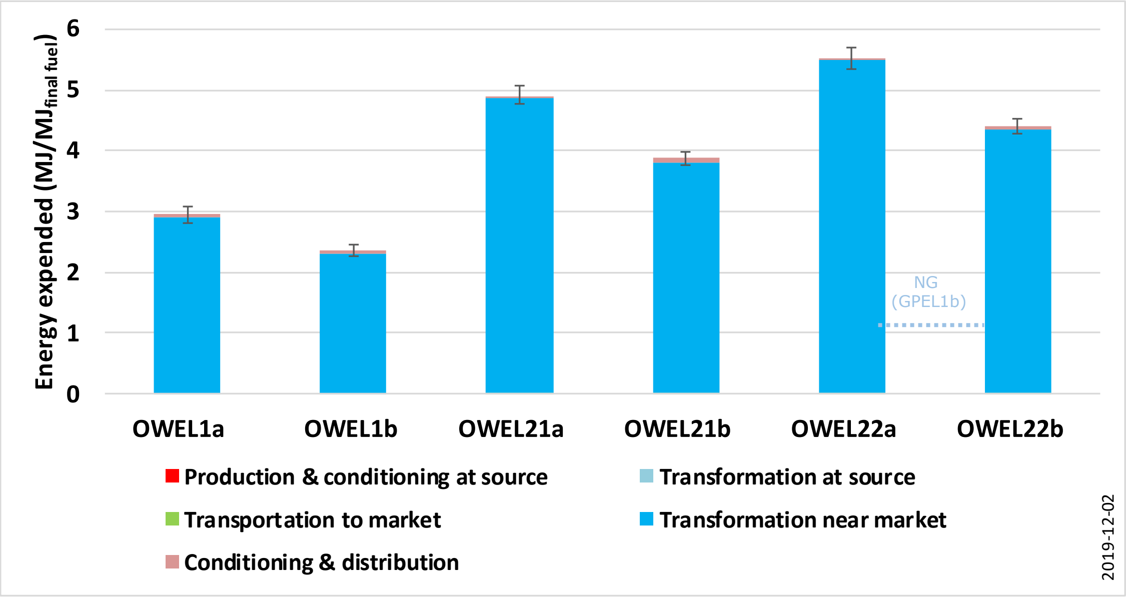
4.10.1.6 Energy and GHG balances: biogas

Where biogas is produced from waste materials there are benefits both in using an energy source that might otherwise be discarded and in avoiding GHG emissions from disposal of the material. Electricity production provides one way of using the biogas and the figures shown here may be compared with those for biomethane as a road fuel in *section 4.5.2.*

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

Results for electricity produced from biogas are shown in **Figures 117** and **118.**

Figure 117. Total expended energy balance for biogas to electricity pathways (excluding final electrical energy)



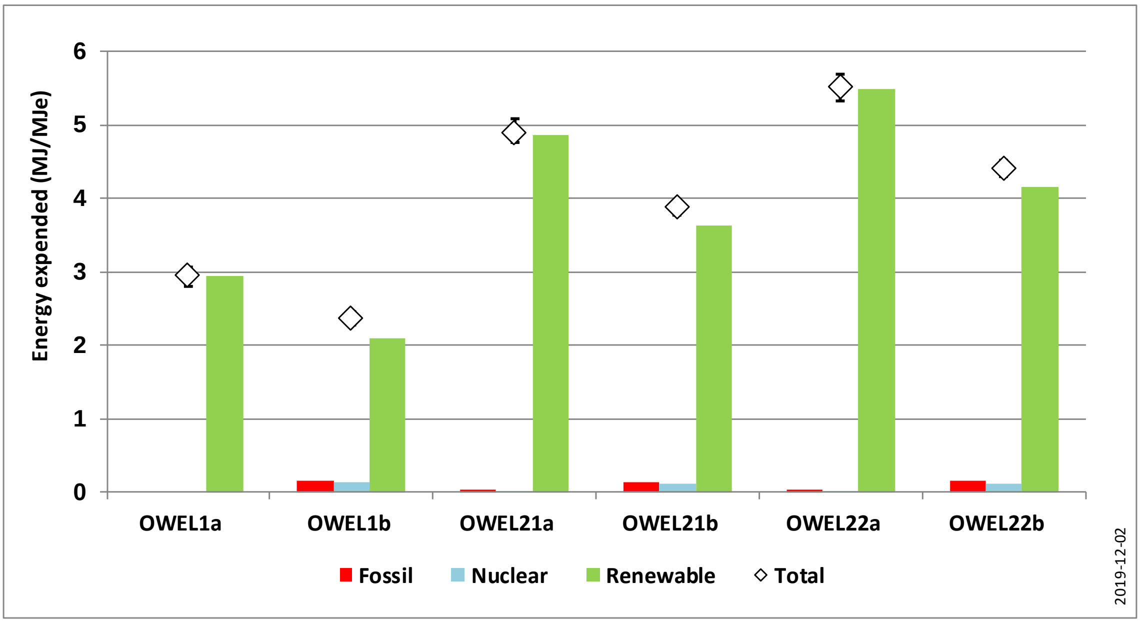
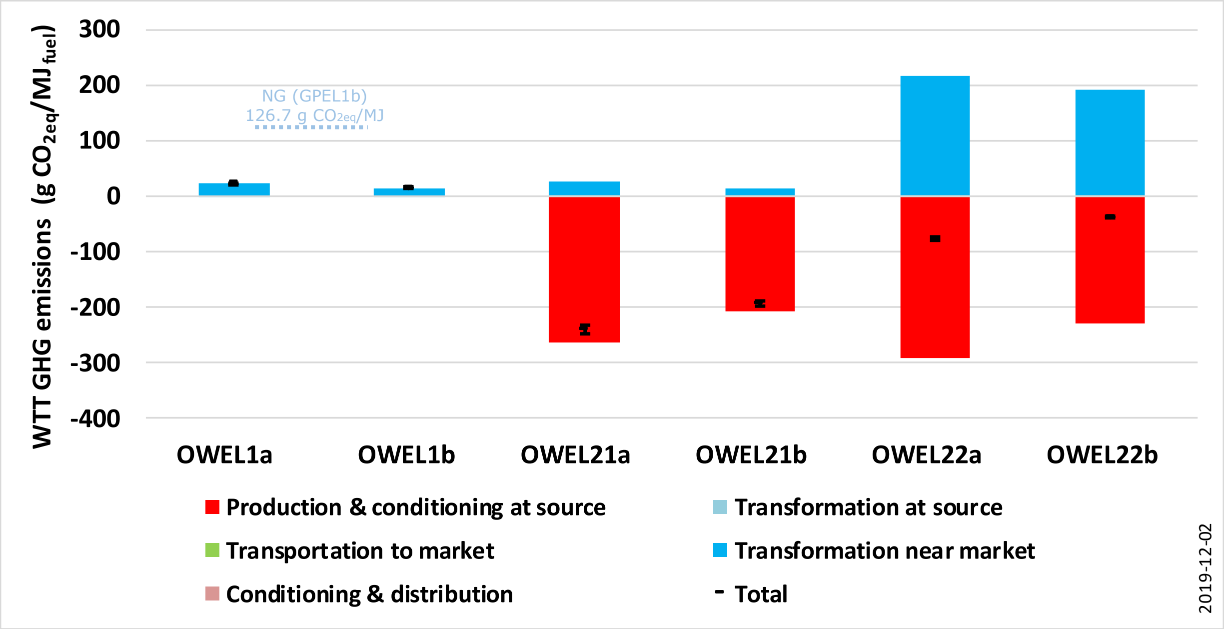


Figure 118. GHG emissions balance for biogas to electricity pathways



General

Waste material:

Since most of the energy comes from the waste material, the overall energy figures are of less interest in this case. In all cases the fossil energy use is low. Pathway OWEL1a has a negative fossil energy, because of a credit for N fertilizer. Pathway OWEL1b also has that credit but there is some fossil energy involved in upgrading that more than cancels out the credit. For municipal waste, exporting gas to a CCGT uses less total energy than electricity generation in the plant, so more electricity is produced from a given amount of waste material. On the other hand, more fossil energy is consumed by this route. GHG emissions for biogas electricity from municipal waste are low (note the different scales between **Figures 117** and **118**.

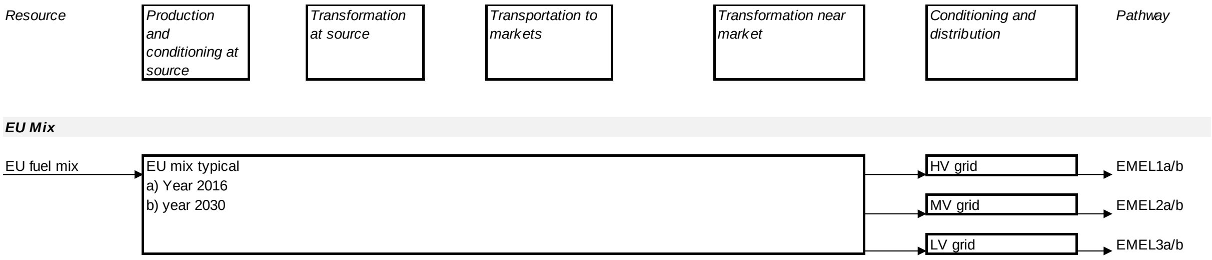
Wet manure:

For the pathways based on wet manure, a credit has been given for the uncontrolled methane emissions that might otherwise occur. While this is essentially the result of bad farming practices which should be avoided in any case, it is introduced here for comparability with the road fuel pathways presented in *section 4.5.2*. With this credit GHG emissions are negative, however comparison of the pathways shows that this benefit is eroded if open digestate storage is used, allowing some methane to escape to the atmosphere. The benefit is greater for the on-site gas engine than for exported gas burned in a CCGT, but this is largely a reflection of the higher efficiency of the latter process, because the results are presented per MJ of electricity produced rather than per MJ of energy input.

4.10.1.7 The “EU-mix”

As described at the beginning of this section, the state-of-the-art technologies have been considered when estimating the credits due to a surplus electricity generation. In order to capture the impact that non-efficient plants may have, the EU mix is also modelled for comparison purposes with two timeframes: 2016 and 2030.

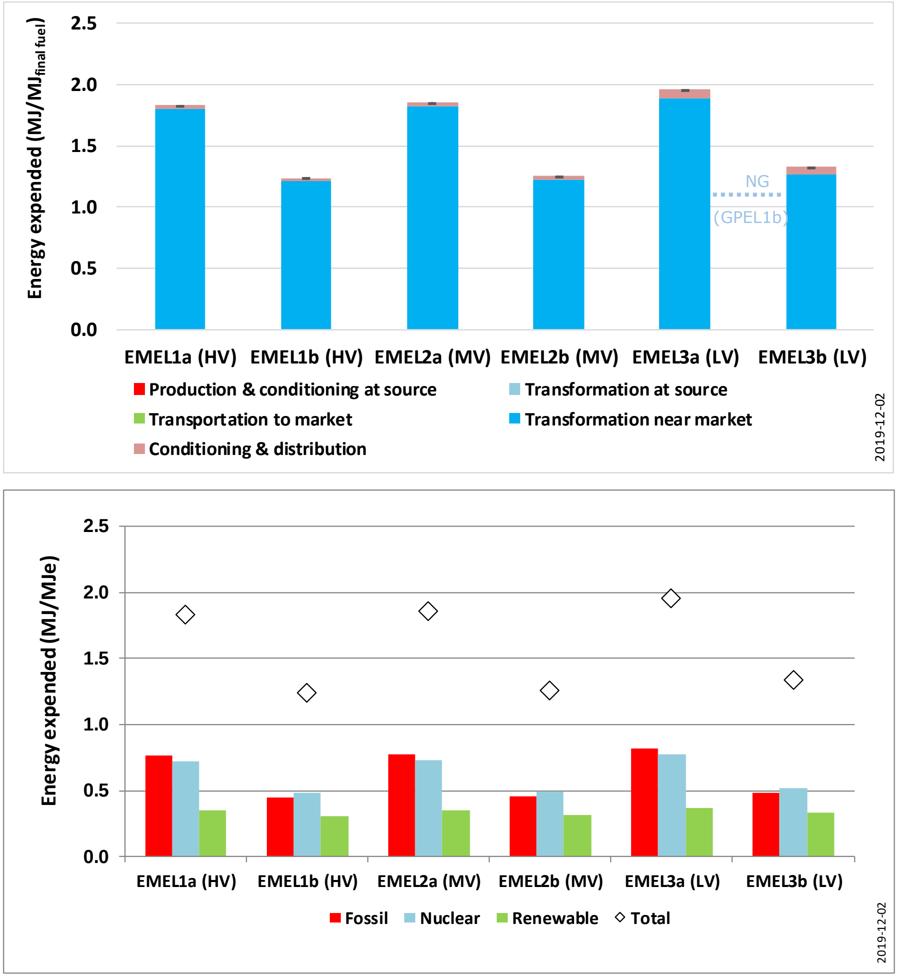
Figure 119. WTT pathways: EU electricity mix



Code	*Feedstock*	*Description*
EMEL	EU-mix	EU-mix electricity supply (based on actual averages) (1) High voltage (2) Medium voltage (3) Low voltage (a): 2016 mix; (b): 2030 mix

Figures 120 and **121** show the energy and GHG balance of the current EU-mix (based on 2016) as described in detail in *section 3.5.1 and the EU-mix 2030*. The energy use and GHG emissions include the upstream GHG emissions for the supply of fuels for electricity generation (e.g. coal, natural gas, nuclear fuel). All three voltage levels are shown.

Figure 120. Total expended energy balance for the EU-mix electricity (excluding final electrical energy)

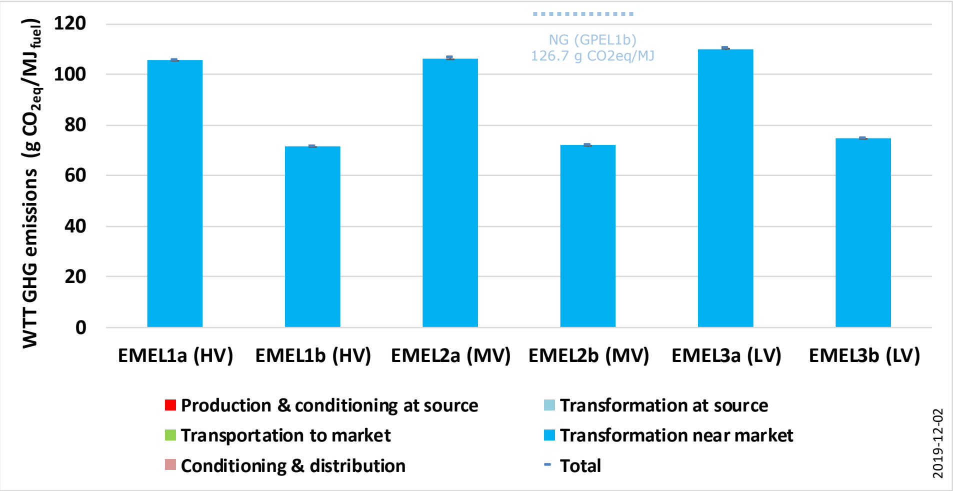


General

The primary energy expended in the 2016 EU mix is ~70% more energy intensive than the state-of-the-art CCGT route (GPEL1b) without CCS. In the 2030 case, due to the higher share of renewables with higher efficiency, the energy expended is reduced and reaches similar levels.

Mainly due to the share of nuclear in the EU mix (with no GHG related emissions), the GHG intensity does not follow the energy expended picture with results which are similar to the CCGT route in the 2016 EU mix, achieving levels of reduction of ~45% in the 2030 scenario (subject to the increasing penetration of renewables in the electricity mix)

Figure 121. GHG emissions balance for the EU-mix electricity



4.11 Hydrogen

(See also workbook WTT v5 pathways 8-H2 and 9-Electrolysis in Appendix 1)

4.11.1 Pathways to hydrogen

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

The different hydrogen production routes are described in section 3.2.8.1 for natural gas, section 3.3 for coal, section 3.7 for biomass and section 3.8 for electricity (electrolysis).

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

Figure 122. Liquid hydrogen pathways

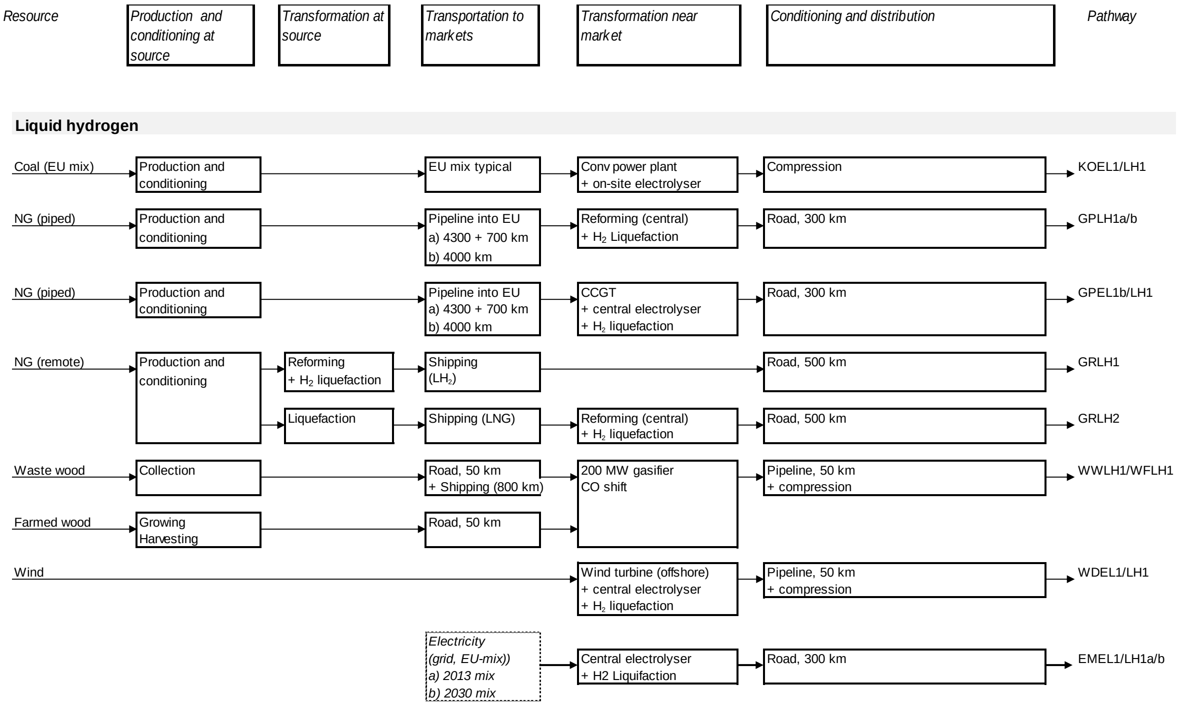
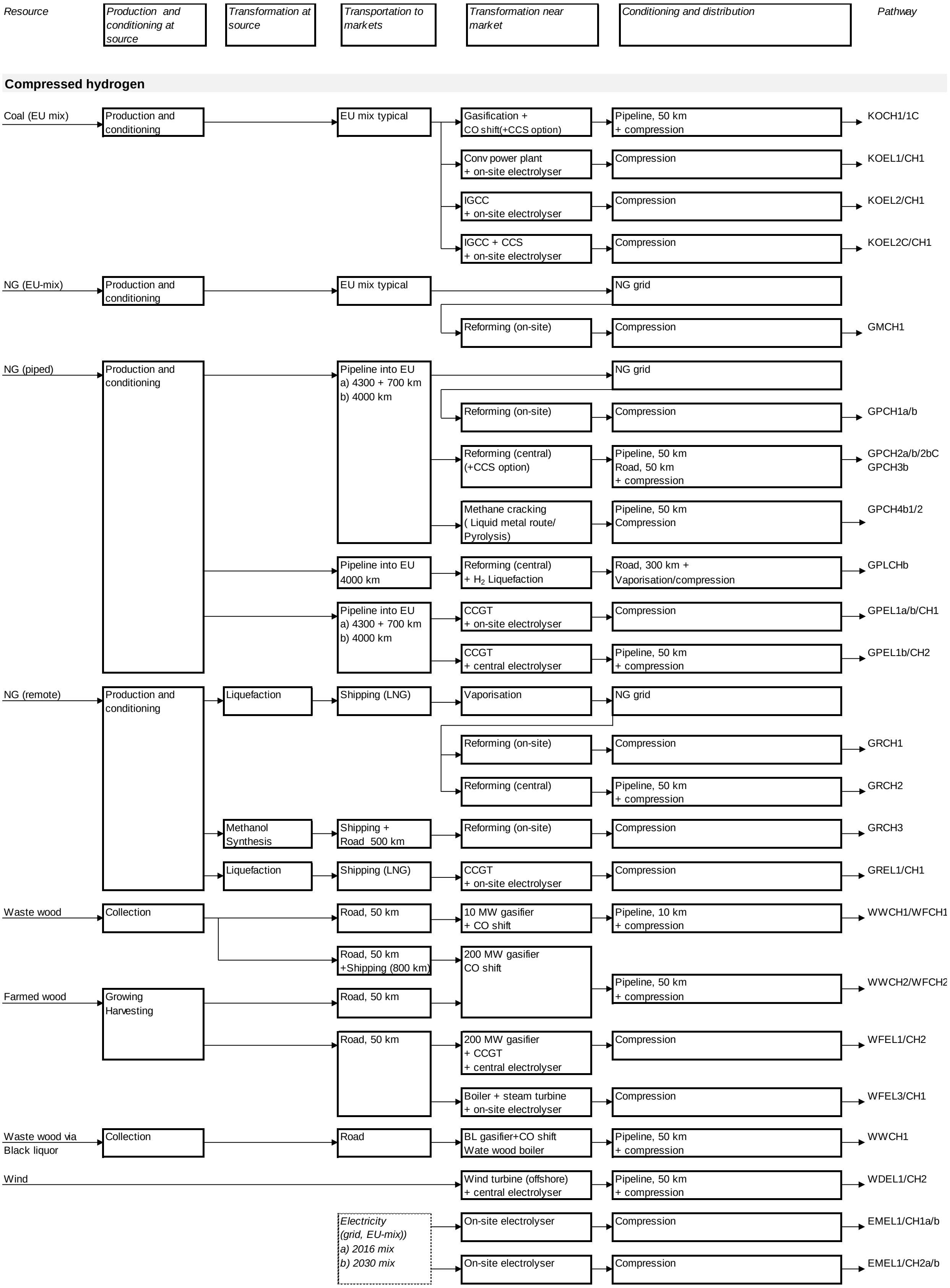


Figure 123. Compressed hydrogen pathways



4.11.2 CCS in hydrogen production from gas or coal

Hydrogen is produced from natural gas via steam reforming followed by CO-shift. The hydrogen-rich gas, including CO_2 is then commonly routed to a pressure swing adsorption (PSA) plant to separate the bulk of the hydrogen. The same scheme applies to coal, replacing steam reforming by partial oxidation (gasification). The tail gas of the PSA is fed to a boiler to provide heat for the endothermic steam reforming reaction or electricity for the air separation plant that provides pure oxygen for coal gasification. CO_2 capture involves an additional scrubbing process between CO-shift and PSA followed by compression / liquefaction of CO_2 to 15 MPa.

CCS is thus a very attractive option for hydrogen because all carbon is turned into CO_2 during the process. There is a small energy cost which in practice will depend on the process scheme used in the base case.

We have based our figures for steam reforming start-of-the-art technology on a conceptual plant design [*Foster Wheeler 1996*]. The study includes base case (no CCS) and CCS case for both natural gas and coal. In the CCS cases, CO_2 is extracted chemically with activated MDEA as solvent. Heat and electricity are required for the regeneration of the solvent and CO_2 compression.

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

Table 51. Hydrogen production with/without CCS

Feedstock		Natural gas		Coal	
Case / Pathway code		Based CPCH2	With CCS CPCH2b	Base KOCH1	With CCS KOCH1C
Natural gas well-to-tank	MJ/MJe	0.78	0.84		
Coal well to tank	MJ/MJe			1.44	1.82
Energy Efficiency H_2 plant (*)	%	76.0%	73.3%	50.8%	43.4%
Net GHG emissions well-to-tank	g CO_{2eq}/MJe	100.8	39.7	234.8	53.3
CO_2 removal efficiency at plant site	%	-	85%	-	97%

Note. (*) LHV (hydrogen) / (LHV natural gas or coal input)

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

4.11.3 Compressed Hydrogen

4.11.3.1 Compressed hydrogen from NG.

The following pathways have been modelled using natural gas as the main feedstock:

Table 52. WTT pathways: Compressed Hydrogen from natural gas

Code	*Final fuel*	*Description*
GMCH1	C-H_2 (Compressed H_2)	EU-mix natural gas supply, transport to EU by pipeline (1900 km), transport inside EU (500 km), distribution through high pressure trunk lines and low pressure grid, steam reforming at retail station, compression to 88 MPa.
GPCHx		Piped natural gas supply, transport to EU by pipeline (a, 4300 km to EU border and 700 km inside EU) or Southern Asia / Middle East (b, 4000 km), distribution through high pressure trunk lines. - GPCH1: distribution in low pressure grid, steam reforming at retail station, compression to 88 MPa. - GPCH2: central large scale reformer, hydrogen pipeline, compression to 88 MPa at retail station. CCS option for GPCH2b. - GPCH3: central large scale reformer, hydrogen compression to 50 MPa and road transport, compression to 88 MPa at retail station. - GPLCHb: central large scale reformer, hydrogen liquefaction, road transport, vaporisation / compression to 88 MPa at retail station. - GPCH4b1: compressed Hydrogen via methane cracking (Liquid metal route), hydrogen pipeline, compression to 88 MPa at retail station. The by-product coke replaces coke from coal. - GPCH4b2: compressed Hydrogen via methane cracking (BASF process), hydrogen pipeline, compression to 88 MPa at retail station. The by-product coke replaces coke from coal.
GRCHx		Remote natural gas liquefied at source, LNG sea transport, vaporisation at import terminal, distribution through gas high pressure trunk lines. - GRCH1: distribution in low pressure grid, steam reforming at retail station, compression to 88 MPa. - GRCH2: central large scale reformer, hydrogen pipeline, compression to 88 MPa at retail station. - GRCH3: Remote Natural gas to methanol at source, methanol transport to EU retail station, on-site methanol steam reforming, hydrogen compression to 88 MPa.

Figure 124 and **125** summarize the Energy and GHG emissions balance for the pathways mentioned above:

Figure 124. WTT total expended energy balance for selected NG to compressed hydrogen pathways

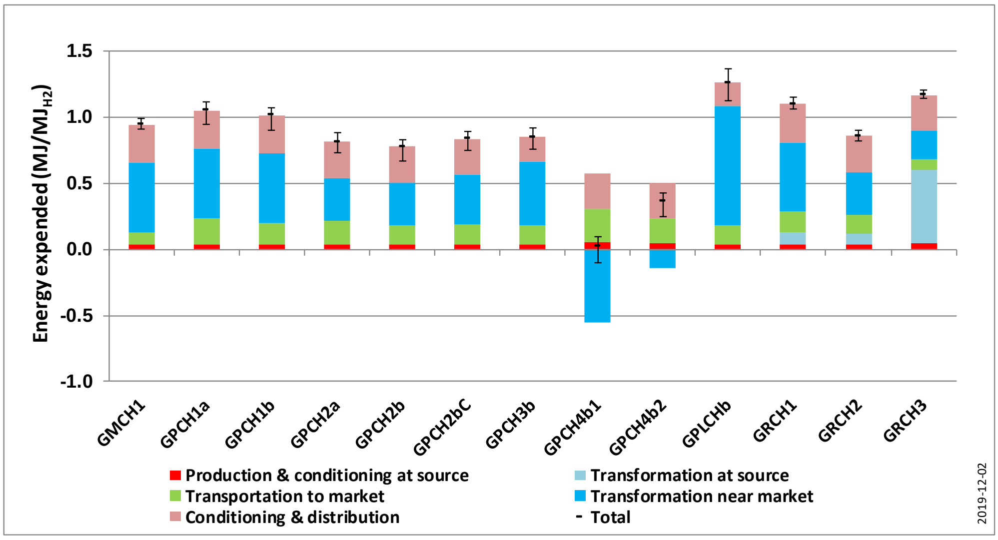
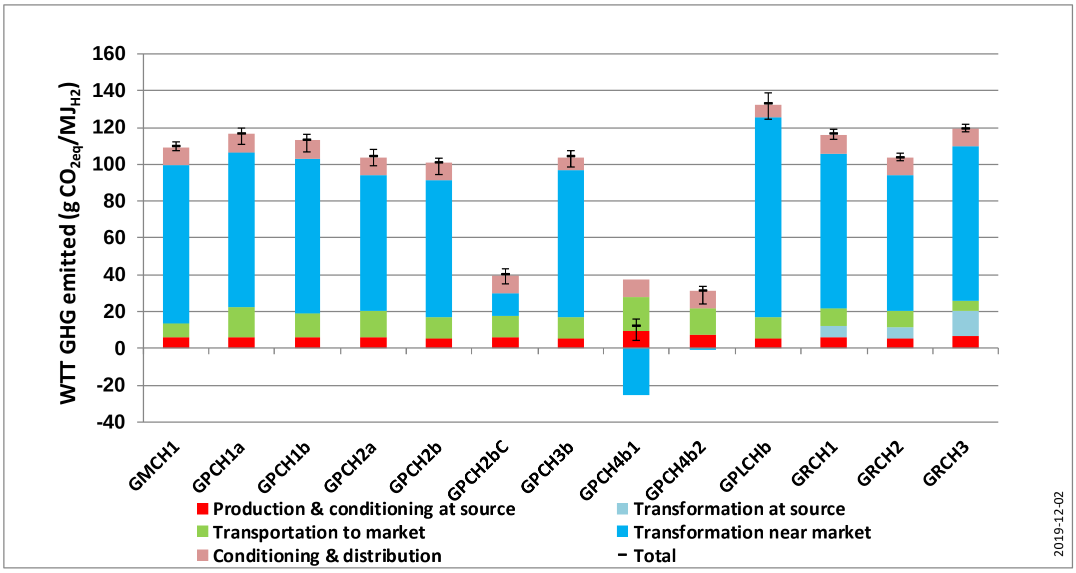


Figure 125. WTT GHG emissions balance for selected NG to compressed hydrogen pathways



General:

For a given transport distance, central reforming is more efficient (because of the better waste heat recovery potential of a large plant), irrespective of mode of transport to the delivery point (GPCH1/2/3b). Although it could be quite attractive from an economic point of view especially in the early stages of development, the option of transporting hydrogen in liquid form is not energy-efficient (GPLCHb ~30% more energy intensive than an equivalent compressed hydrogen route - GPCH3b).

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

The newly modelled routes via methane cracking (GPCH4b1/2) appear as the most efficient and less GHG intensive routes due to the credits generated when the by-product coke replaces coke from coal (Note that in these processes tested at lab scale so far, methane is converted into gaseous hydrogen and solid carbon at high temperatures). These routes, especially the liquid metal one, show a potential to reach WTT GHG emissions as low as ~10 g CO2/MJ (10 times lower than an equivalent NG one (GPCH3b).

Steps:

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

In subsequent graphs of this *section 4.9* we have repeated pathway **GPCH2b** as a common reference for easy comparison.

4.11.3.2 Compressed hydrogen from coal, wood and biogas.

The following pathways have been modelled:

Table 53. WTT pathways: Hydrogen from biogas, coal and wood (Compressed and Liquid)

Code	*Final fuel*	*Description*
KOCH	C-H_2 (Compressed H_2)	EU-mix hard **coal** without (KOCH1) / with CCS (KOCH1C), hydrogen pipeline transport, compression at retail site.
WxCH		**Wood** (WF: farmed, WW: waste): - WxCH1: small scale gasifier in retail site - WxCH2: central reformer, hydrogen pipeline - BLCH1: Waste wood via black liquor, pipeline Hydrogen compression to 88 MPa at retail site.
BLCH1		**Wood** - BLCH1: Waste wood via black liquor, pipeline Hydrogen compression to 88 MPa at retail site.
OWCH1		Upgraded **biogas** from municipal organic waste sent to onsite SMR, Hydrogen compression to 88 MPa at retail site. Closed digestate storage
OWCH2		Upgraded **biogas** from wet manure sent to onsite SMR (retail site) Digestate storage closed (21) or open (22)
OWCH3		Upgraded **biogas** from sewage sludge sent to onsite SMR (retail site) Closed digestate storage
OWCH4		Upgraded **biogas** from maize (whole plant) sent to SMR (retail site) Closed digestate storage
OWCH5		Upgraded **biogas** from double cropping (barley/maize) sent to SMR (retail site). Closed digestate storage

Figure 126. Total expended energy balance for biogas, coal and wood to compressed hydrogen pathways

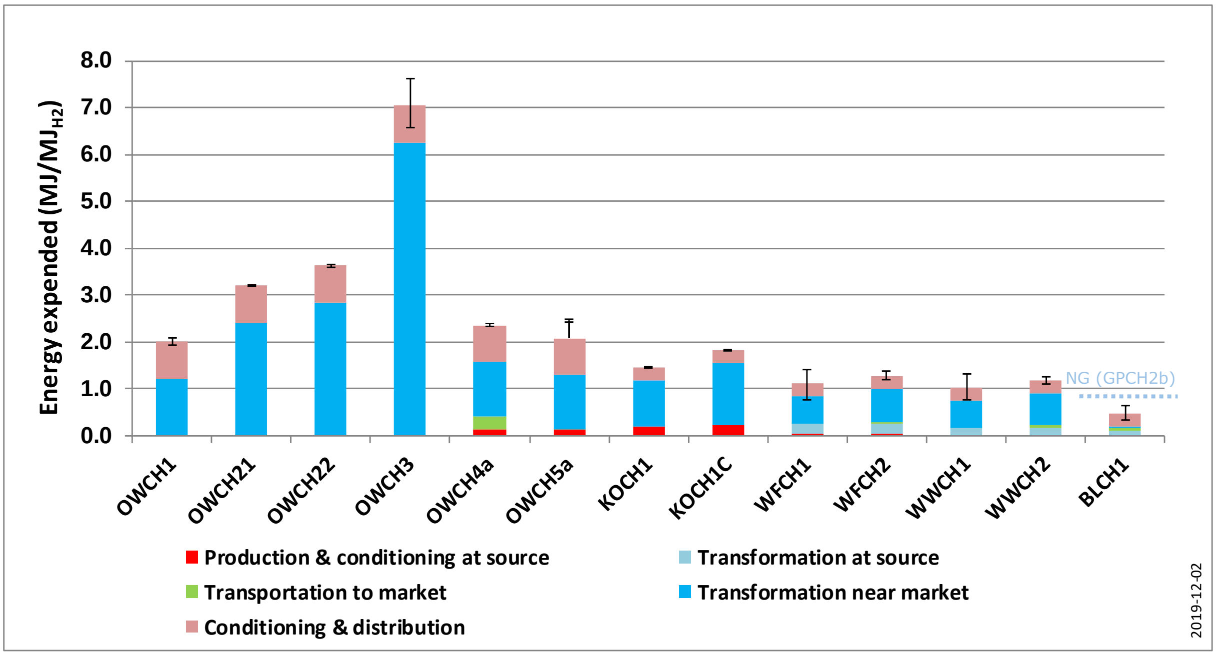
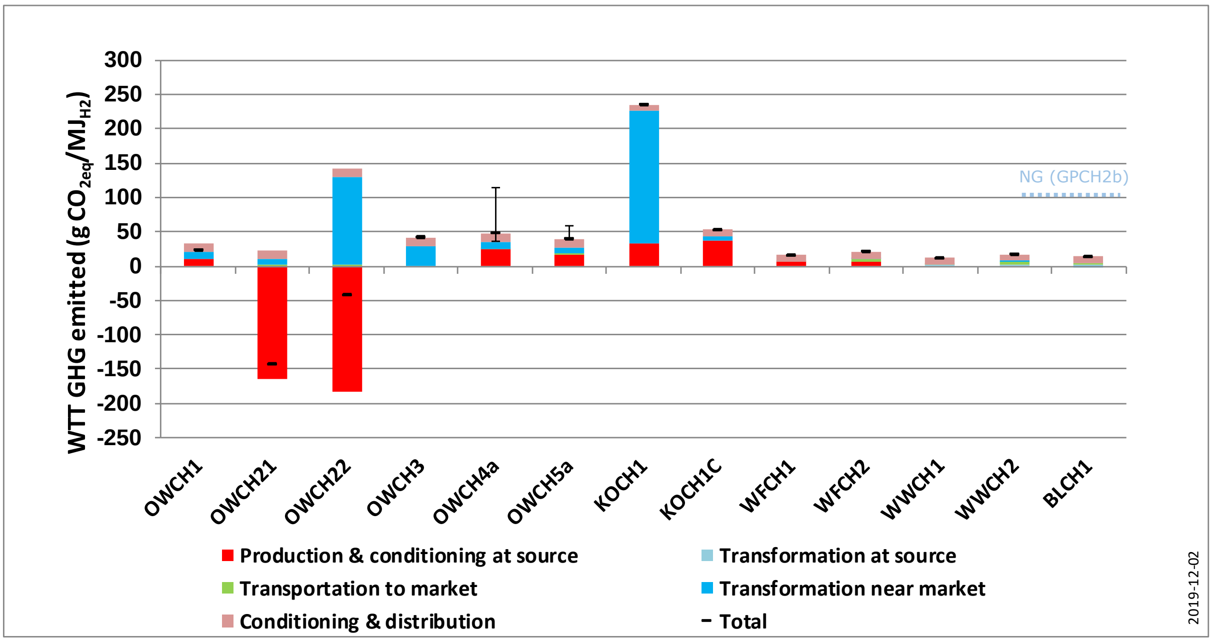


Figure 127. GHG emissions balance for coal and wood to compressed hydrogen pathways



General:

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

Wood gasification is also less efficient than gas. Somewhat surprisingly, the small scale scheme comes out as slightly more efficient than the large scale. This is due to a major difference in concept between the two schemes whereby the small scale system produces surplus heat and electricity whereas the large scale system is optimised for maximum hydrogen production. There is, however, a large uncertainty range for the small scale gasifier. The black liquor route is more energy efficient as would have been expected. The GHG emission figures are of course very small as the main conversion process uses nothing but wood as energy source.

The biogas routes, despite being more energy intensive than the other routes (including the gas one), have the potential to achieve negative GHG emissions when wet manure is used as feedstock (~3 times lower in the case of using close digestate storage versus the open one). The fermentation routes using other feedstocks, such as the sewage sludge, to produce biogas and then hydrogen offer less attractive GHG emissions savings when compared with waste wood or crop based routes.

It is important to note that this substitution approach is valid under the current assumption that the methane is released to the atmosphere if not used as fuel. Alternative technologies could also reduce the fugitive methane emissions and, thus, for comparisons to such a case, the current pathway calculations would have to be adjusted accordingly.

Steps:

The transformation near market step is the most energy intensive in all the pathways (e.g. due to the gasification process for coal and wood based routes).

4.11.3.3 Compressed hydrogen via electrolysis.

This section includes the comparison of different electricity sources to produce electrolytic hydrogen. Coal, natural gas, wood and renewable electricity are compared including a notional EU-mix (2016) for comparison purposes.

Table 54. WTT pathways: Compressed hydrogen from electrolysis

Code	*Final fuel*	*Description*
EMELx/xHx	C-H_2 (Compressed)	EU-mix electricity supply ((a) 2016 (b) 203) (1) High voltage (2) Medium voltage Electrolysis: CHx: (1) on retail site, (2) central with hydrogen pipeline transport, hydrogen compression to 88 MPa.
KOELx/xH1		Hard coal (EU-mix), (1) state-of-the-art conventional power plant, (2) IGCC, (2C) IGCC with CCS. Electrolysis: CH1: on retail site, hydrogen compression to 88 MPa.
GxELx/xHx		Natural gas: CCGT GPEL1: 5000 km pipeline (Russia) (a), 4000 km pipeline (Middle East) (b), with CCS (bC) GREL1: LNG Electrolysis: CHx: (1) on retail site, (2) central with hydrogen pipeline transport, hydrogen compression to 88 MPa.
WFELx/xHx		Wood (Farmed): WFEL1 IGCC (200 MWth, WFEL3: Conventional (small-scale) Electrolysis: CHx: (1) on retail site, (2) central with hydrogen pipeline transport, hydrogen compression to 88 MPa.
NUEL1/CH1		Electricity from nuclear energy Electrolysis: on retail site, hydrogen compression to 88 MPa.
WDEL1/xHx		Electricity from wind energy Electrolysis: CH2: central electrolysis, hydrogen pipeline transport, hydrogen compression to 88 MPa.

Figure 128. Total expended energy balance for selected hydrogen via electrolysis pathways

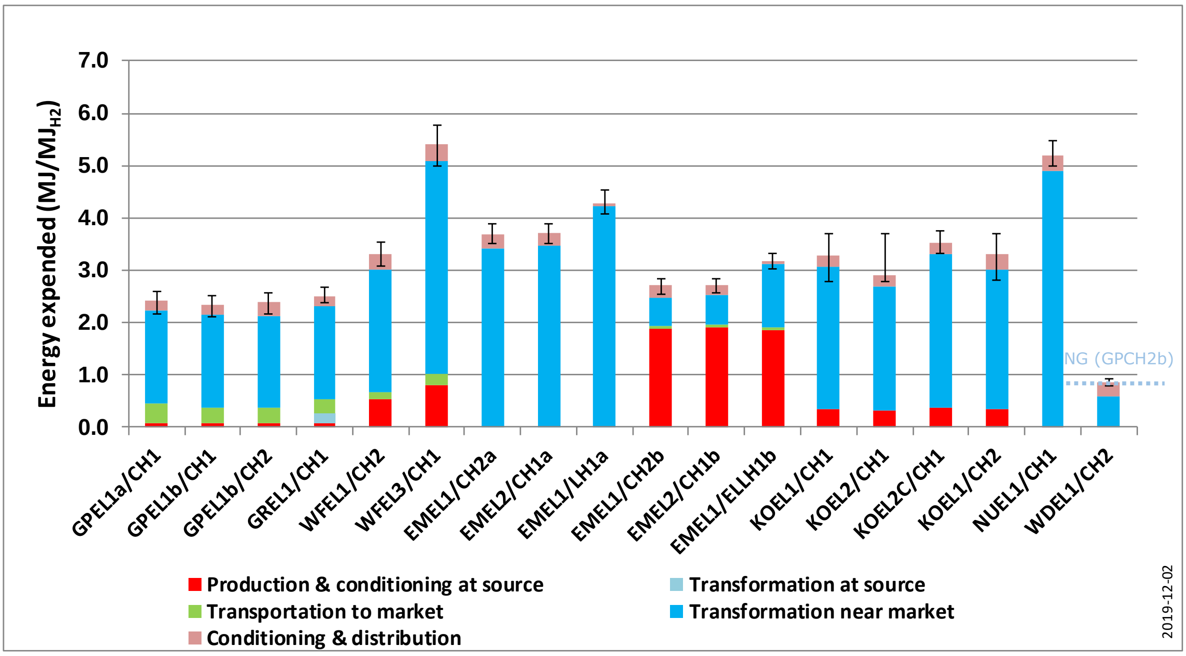
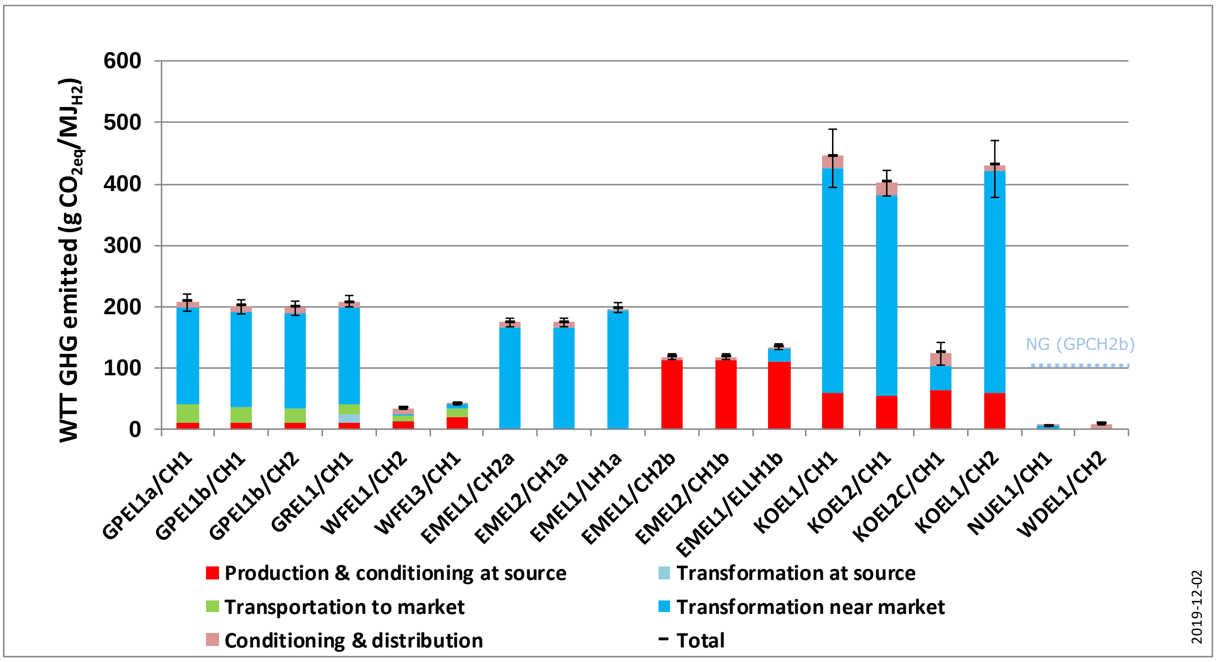


Figure 129. GHG emissions balance of selected hydrogen via electrolysis pathways



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

4.11.4 Liquid hydrogen (+ cryo-compression)

The following pathways have been modelled using natural gas as the main feedstock:

General:

For a given source of electricity, central and on-site electrolysis give nearly equal results with compressed hydrogen, the only small difference coming from the somewhat lower final compressor suction pressure in the central case (see e.g. GPEL1b/CH1/CH2). The relative merits of the different energy sources are of course the same as discussed for electricity generation in *section 4.10*.

Comparison of the straightforward NG to hydrogen pathway (GPCH2b, 100.8 gCO_{2eq}/MJ) with the comparable electrolysis pathway (GPEL1b/CH1, 201.7 gCO_{2eq}/MJ) highlights the low energy efficiency of the electrolysis route.

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

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

The 2016 EU mix (EMEL1) shows a comparable case to the direct natural gas route (GPCH2b).

Table 55. WTT pathways: Liquid Hydrogen

Code	*Final fuel*	*Description*
GPLHx	Cc-H_2 (Liquid H_2)	**Piped natural gas supply**, transport to EU by pipeline (a, 4300 km to EU border and 700 km inside EU), distribution through high pressure trunk lines, central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail station, hydrogen cryo-compression in to vehicle tank (35 MPa).
GRLHx		**Remote natural gas** - GRLH1: NG steam reforming and hydrogen liquefaction at source, liquid hydrogen sea transport - GRLH2: NG liquefaction at source, LNG sea transport, central reforming, hydrogen liquefaction Liquid hydrogen road transport to retail station, hydrogen cryo- compression in to vehicle tank (35 MPa).
WFLH		Farmed **wood**, large scale gasifier and hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).
EMELx/xHx		EU-mix electricity supply (based on actual averages) (1) High voltage (2) Medium voltage Electrolysis: LH1: central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).
KOELx/xH1		Hard coal (EU-mix), (1) state-of-the-art conventional power plant, (2) IGCC, (2C) IGCC with CCS. Electrolysis: LH1: central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).
GxELx/xHx		Natural gas: CCGT GPEL1: 5000 km pipeline (Russia) (a), 4000 km pipeline (Middle East) (b), with CCS (bC) GREL1: LNG Electrolysis: LH1: central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).
WFELx/xHx		Wood (Farmed): WFEL1 IGCC (200 MWth, WFEL3: Conventional (small-scale) Electrolysis: CHx: (1) on retail site, (2) central with hydrogen pipeline transport, hydrogen compression to 88 MPa. LH1: central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).
WDEL1/xHx		Electricity from wind energy Electrolysis: LH1: central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).

Figure 130. WTT total expended energy balance for selected cryo-compressed liquid hydrogen pathways

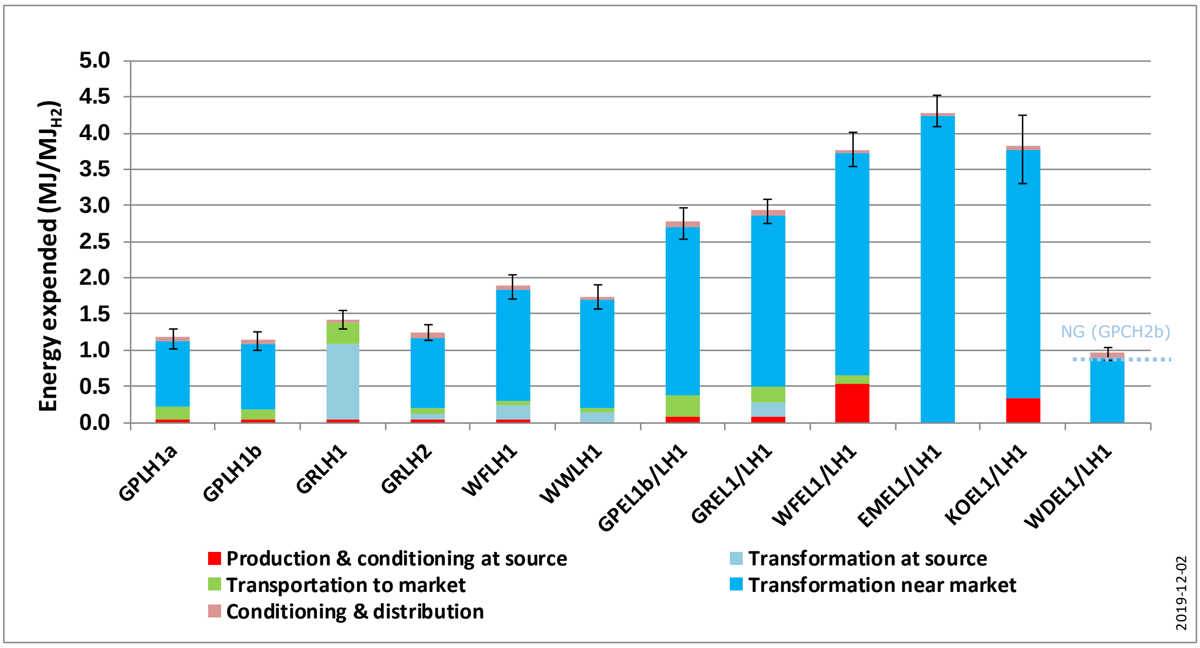
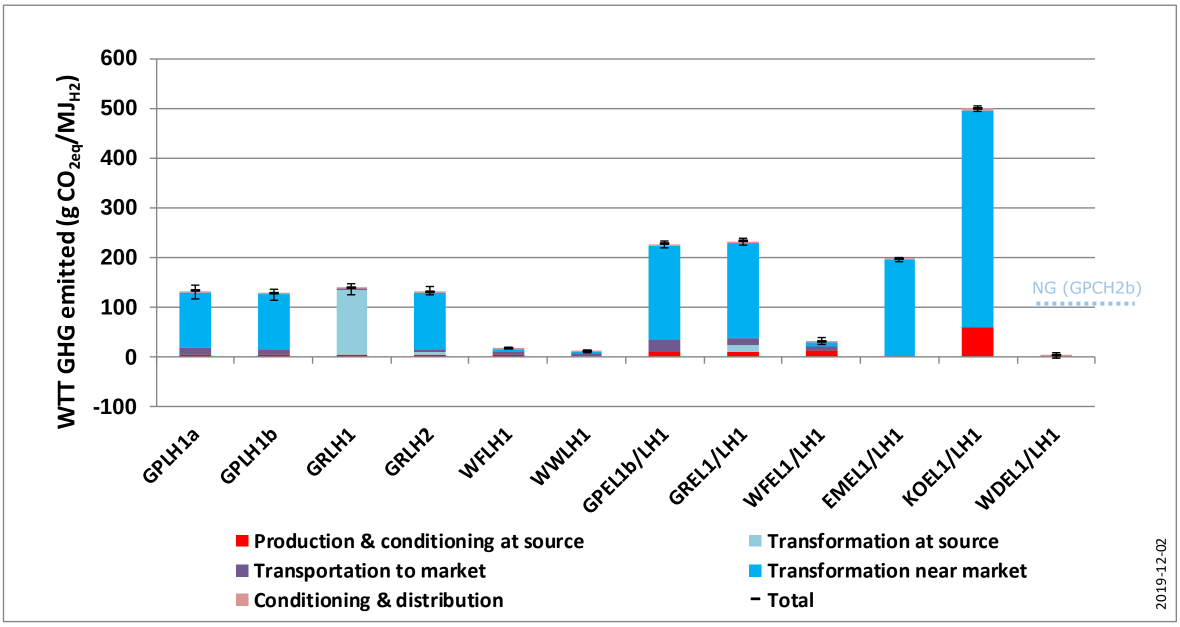


Figure 131. GHG emissions balance for selected cryo-compressed liquid hydrogen pathways



General:

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

The energy required for liquefaction penalises the liquid hydrogen option (the attractiveness of liquid hydrogen rather stems from practicality and economics considerations). The larger error bar for the liquid hydrogen pathways is mainly due to the large range of liquefaction energy (0.21 to 0.39 MJ of electricity per MJ of LH_2).

5 Comparative analysis

(See also workbook WTT v5 Results / Comparison in Appendix 1)

More than 250 different pathways have been modelled in the current JEC WTT v5 analysis, resulting in a huge variability in terms of WTT energy expended and GHG emissions when compared with conventional fuels. As shown in the specific chapters, factors such as the conversion pathways chosen and the feedstock/resource used have a strong impact on the final results.

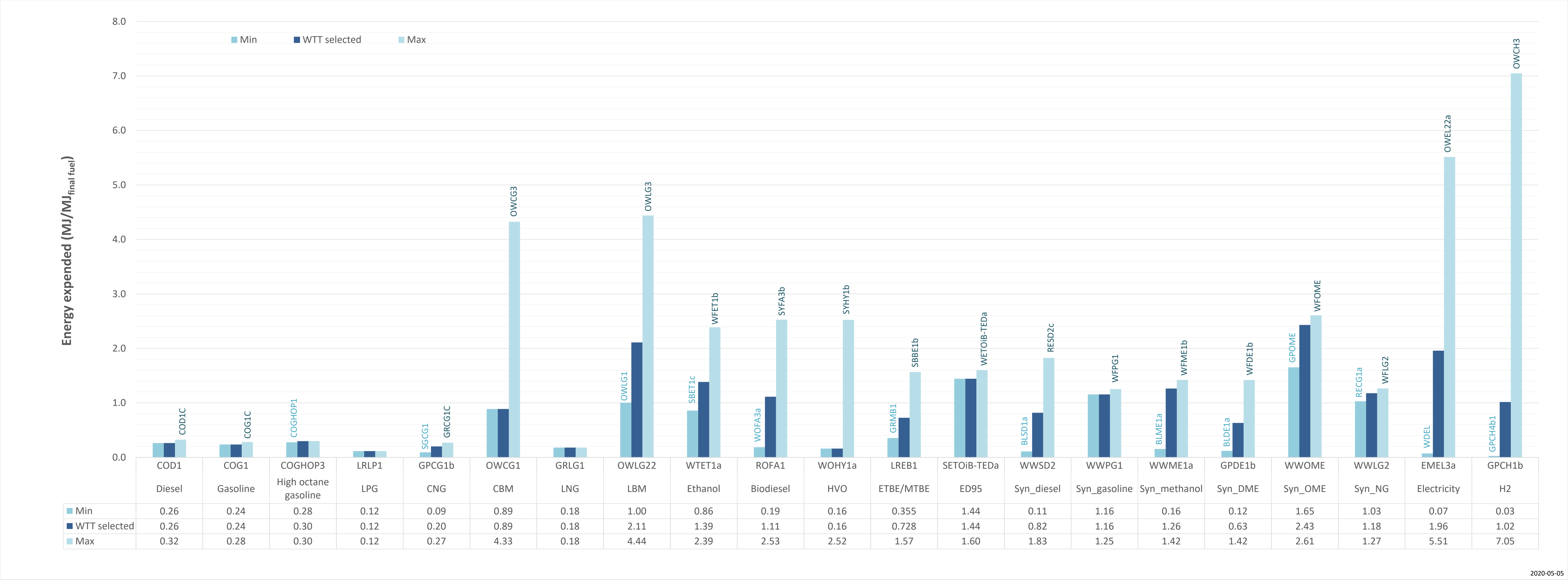
The following figures summarize the minimum and maximum values, per type of fuel and feedstock origin, obtained as the results of the modelling of the different pathways included in this version of the JEC study (variability given by illustrative examples of some current and emerging technologies, not intending to represent all the possible production pathways for each specific fuel). Besides this, a "*selected pathway*" (Details in **Table 57**) is included for each of the fuels presented:

- Fuel comparison – Range (min/max) and selected conversion routes.
- This comparison aims to show the **WTT Energy expended** and **GHG range per type of fuel** (e.g. fossil, CNG, DME, etc.), presenting **a set of selected conversion routes** for each of them (**Figure 132/133**). See Selection criteria at the end of this chapter (**Table 56**) **aligned to the ones included in the JEC WTW v5 report**. For illustrative purpose, when different from the selected route, the minimum and maximum values are also presented (and identified with the same codes as in the previous sections of the report).
- Resource to fuels comparison.
- The impact of **using different feedstocks/resources** to produce a range of fuels is explored. **Figures 134** and **135** show and overview of the most and least efficient way to convert a certain feedstock into a final fuel. Per type of fuel, the range shows the minimum and maximum values for each WTT conversion route modelled.
- WTT energy expended and expended energy ratio – Variability.
- **Figure 136, 137** and **138** show the variability within all the conversion pathways modelled in this version 5, clustered in the main fuel categories. The WTT GHG emissions versus the energy expended in each of them are presented.

Note that the aim of this comparison is to provide the reader with some useful insights and further analysis facilitating the comparison of the selected pathways and examples of relevant and emerging technologies. Additional production routes with alternative feedstocks can also be envisaged for potential consideration in future updates of this JEC report.

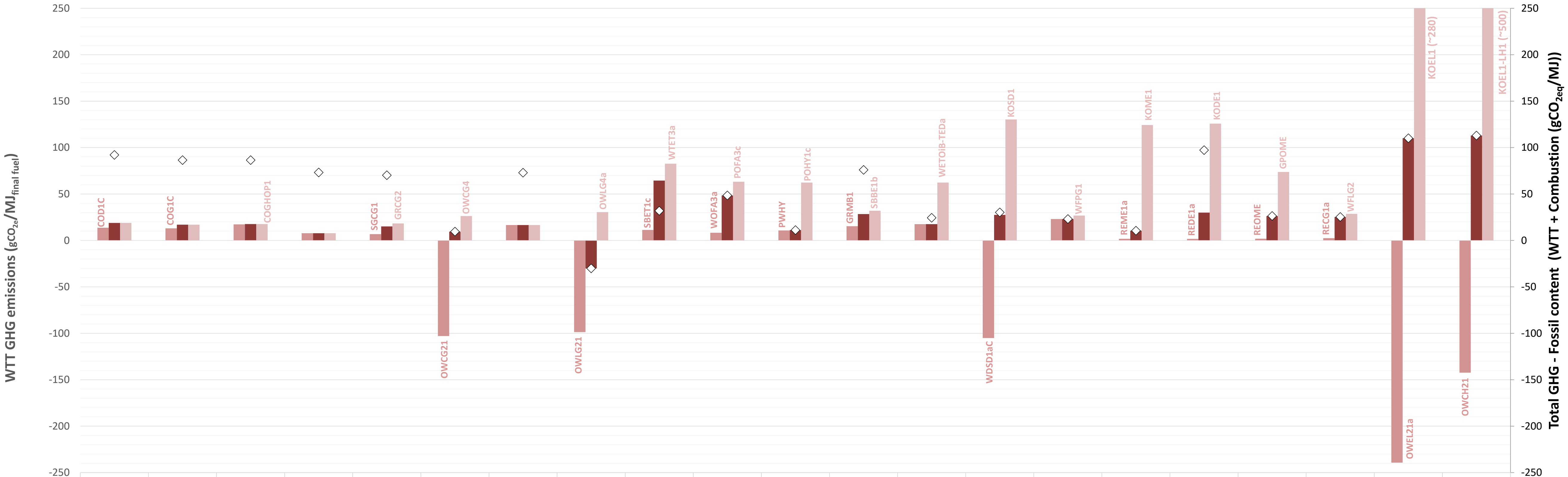
a) <u>Fuel comparison – Selected conversion routes</u>

Figure 132. WTT energy expended per type of fuel. Summary



	COD1	COG1	COGHOP3	LRLP1	GPCG1b	OWCG1	GRLG1	OWLG22	WTET1a	ROFA1	WOHY1a	LREB1	SETOiB-TEDa	WWSD2	WWPG1	WWME1a	GPDE1b	WWOME	WWLG2	EMEL3a	GPCH1b
	Diesel	Gasoline	High octane gasoline	LPG	CNG	CBM	LNG	LBM	Ethanol	Biodiesel	HVO	ETBE/MTBE	ED95	Syn_diesel	Syn_gasoline	Syn_methanol	Syn_DME	Syn_OME	Syn_NG	Electricity	H2
Min	0.26	0.24	0.28	0.12	0.09	0.89	0.18	1.00	0.86	0.19	0.16	0.355	1.44	0.11	1.16	0.16	0.12	1.65	1.03	0.07	0.03
WTT selected	0.26	0.24	0.30	0.12	0.20	0.89	0.18	2.11	1.39	1.11	0.16	0.728	1.44	0.82	1.16	1.26	0.63	2.43	1.18	1.96	1.02
Max	0.32	0.28	0.30	0.12	0.27	4.33	0.18	4.44	2.39	2.53	2.52	1.57	1.60	1.83	1.25	1.42	1.42	2.61	1.27	5.51	7.05

Figure 133. WTT GHG emissions. Summary



	COD1	COG1	COGHOP3	LRLP1	GPCG1b	OWCG1	GRLG1	OWLG22	WTET1a	ROFA1	WOHY1a	LREB1	SETOiB-TEDa	WWSD2	WWPG1	WWME1a	GPDE1b	WWOME	WWLG2	EMEL3a	GPCH1b
	Diesel	Gasoline	High octane gasoline	LPG	CNG	CBM	LNG	LBM	Ethanol	Biodiesel	HVO	ETBE/MTBE	ED95	Syn_diesel	Syn_gasoline	Syn_methanol	Syn_DME	Syn_OME	Syn_NG	Electricity	H2
▪ Min	13.7	13.1	17.3	7.8	6.8	-102.9	16.6	-98.7	11.3	8.3	10.8	15.3	17.6	-105.1	23.1	1.8	1.7	1.8	2.4	-239.3	-142.4
▪ WTT selected	18.9	17.0	17.6	7.8	15.1	9.5	16.6	-30.1	64.5	48.4	11.1	28.38	17.6	27.5	23.1	10.5	30.0	26.3	25.3	110.1	113.0
▪ Max	18.9	17.0	17.6	7.8	18.3	26.3	16.6	30.5	82.7	63.3	62.4	31.9	62.4	130.3	26.8	124.3	125.7	73.7	28.6	280.5	499.6

2020-05-05

General: In terms of WTT energy required for fuel production, among fossil based fuels, the representative pathways for LPG, LNG and CNG resulted in more energy efficient routes than conventional oil based ones. Among the pathways with high-energy inputs, the most energy-intense ones are: electricity from EU mix, LBM and synthetic OME. A number of pathways offer the possibility to achieve negative WTT emissions (e.g. LBM/CBM and electricity and hydrogen when produced from biogas due to the avoided CH_4 emissions and production of synthetic diesel when coupled with CCS processes (CO_2 absorbed from the crops is not released and storage permanently). It is worthy noticing that the wide variability, which can be observed in some pathways such for HVO, CBM/LBM, H_2 and electricity can have a significant impact on the general conclusions. Additionally, it is important to highlight that a general conclusions about the most favourable routes, both in terms of GHG emissions and energy consumption minimisation, can be derived only when the whole WTW analysis is taken into account, as the powertrain efficiency strongly impact the results (expressed in terms of g CO_{2eq}/km, including the efficiency of the different powertrains).

Note. The selection criteria for the WTT pathways presented in the previous charts follows the same rationale as for the ones selected for the WTW integration:

Table 56. Summary of WTT selected pathways based on criteria defined above

Code	Description	Selection criteria
Conventional fossil fuels		
COD1	Diesel	Current fossil fuel
COG1	Gasoline	Current fossil fuel
CNG		
GPCG1b	Pipeline 4000 km	For the supply of marginal piped natural gas a transport distance of 4000 km has been assumed representing typical future South West Asian locations. For HEV, CNG considered as alternative to the fossil diesel, currently dominating the market.
GRCG1	LNG, vap, pipe	Representative pathway of the current LNG production route in Europe.
Compressed biomethane (CBM)		
OWCG1	Municipal waste	High potential feedstock availability in 2030 supported by on-going initiatives in Europe.
LNG		
GRLG1	LNG, road	Despite the fossil source, we consider this as an alternative to the current fuel (as in CNG).
Organic waste to LBG		
OWLG22	Biomethane from organic waste (wet manure, OS) as LNG	Representative pathway of the most common production route.
OWLG21	Biogas from organic waste (wet manure, CS)	Min GHG intensive pathway according to the described selection criteria.
WWLG2	Liquefied BIO-SNG: biomass thermal gasification (wood waste)	Interesting pathway supplied by lignocellulosic/woody feedstocks.
LPG		
LRLP1	LPG (remote)	Despite the fossil source, we consider LPG as an alternative to the current diesel / gasoline conventional fuels
Ethanol		
WTET1a	Wheat, conv NG boiler, DDGs as AF	High potential feedstock availability in 2030.

Code	Description	Selection criteria
STET1	Wheat straw (500 km)	High potential feedstock availability in 2030 supported by on-going initiatives in Europe.
ED95		
SETOiB-TEDa	ED95 (EtOH from straw and i-butanol from crude oil, 50 km)	One interesting example of an alternative fuel for the sector based on industrial current trends / availability of feedstock.
Biodiesel (FAME 100)		
ROFA1	RME: Meal as AF, glycerine as chem	Selected pathway on the base of most used feedstock for the current EU production.
HVO		
WOHY1a	HWO (NExBTL), waste cooking oil	Pathway representative of the industrial trend towards more sustainable/residual feedstocks.
Syndiesel		
KOSD1	Syndiesel: CTL, diesel pool	Max GHG intensive pathway according to the described selection criteria.
RESD2a	Syndiesel: Renewable electricity via SOEC (FT route), CO2 from flue gas	Power-to-X, supplied by RES, foreseen as an interesting asset for a highly decarbonized scenario.
WWSD1aC	F-T diesel from wood residue with CCS (500 km)	Interesting pathway supplied by lignocellulosic/woody feedstocks to allow comparison with other residual feedstocks / processes and final fuels. It shows the potential for BECCS (negative emissions).
WWSD2	Syndiesel from wood residue via HTL (500 km)	Interesting thermochemical pathway supplied by lignocellulosic/woody feedstocks. Due to the wide range of the syndiesel pathways, selected as a “representative” pathway in the middle of the range.
BLSD1a	Syndiesel: W Wood via black liquor, diesel pool	Min GHG intensive pathway according to the described selection criteria.
WWPD1	Pyrolysis-based diesel: Wood (waste)	Interesting thermochemical pathway supplied by lignocellulosic/woody feedstocks.
MTBE / ETBE		
GRMB1	MTBE: remote plant	Representative pathway of the current commercial route
LREB1	ETBE: imported C4 and wheat ethanol	Representative pathway of the current commercial route
DME		
GPDE1b	DME: NG 4000 km, EU prod., rail/road	Alternative fuel based on the reference natural gas pathway selected on the base of potential market availability.
OME		
WWOME	OME: Residual wood	Interesting pathway supplied by lignocellulosic/woody feedstocks allowing comparison versus DME route.
Electricity		
EMEL3a	EU-mix low (Current mix) - LV	Electricity (energy vector) considered as an alternative "fuel" to enable comparison. Current electricity mix
Hydrogen		
GPCH1b	C-H2: NG 4000 km, O/S Ref	Compressed hydrogen (energy carrier) considered as an alternative "fuel" to enable comparison. Natural gas route chosen as a reference pathway for the current

Code	Description	Selection criteria
		production in Europe.

b) Resource to fuels comparison

From the resources point of view, a similar analysis has been conducted showing the impact of using different feedstocks/resources to produce different fuels/energy carriers. **Figures 134** and **135** show and overview of the most and least efficient way to convert a certain feedstock into a final fuel. Within the feedstock categories, and for each of the fuels, the range **reflects that there are different conversion routes from the feedstock/resources to a fuel showing lower or higher WTT GHG intensities.** For the conversion of one resources to one fuel, a different number of potential conversion pathways were modelled. Therefore the ranges vary depending on the technologies considered in these JEC WTT study. There might be conversion pathways into specific fuels showing lower or significant higher WTT energy and GHG intensities as considered in this WTT study.

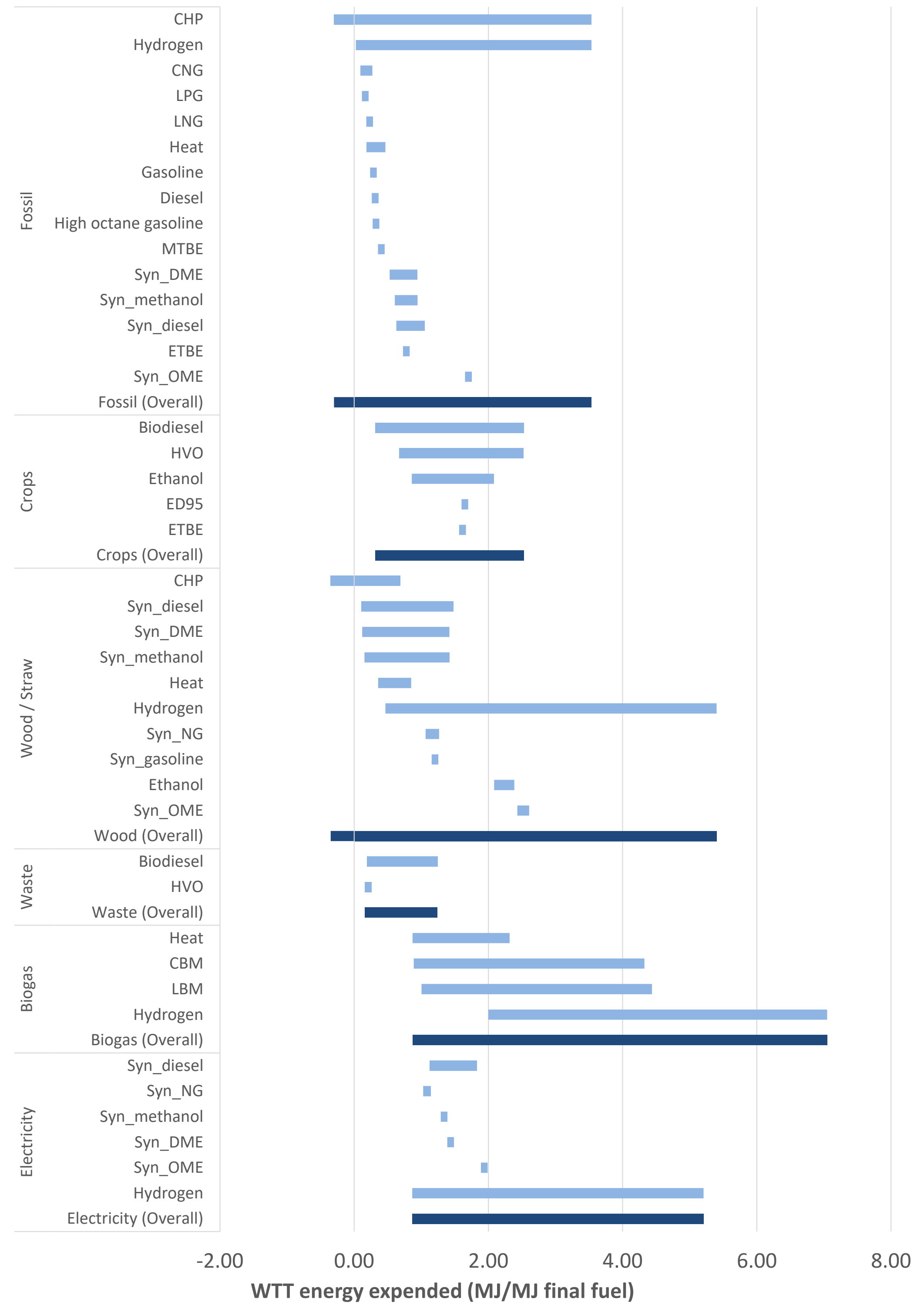
General:

The comparison within each of the feedstocks modelled in the analysis shows than conventional fossil-based fuels offer highly efficient energy routes. Within each of the categories and when the WTT energy and GHG emissions are compared; the following conclusions can be derived:

- **Fossil:** A number of "representative" fossil based pathways such as CNG/LNG or high octane gasoline can offer lower GHG emissions routes than conventional gasoline and diesel, while lower energy intensities are mainly reached by the gaseous fossil fuels.
- **Crop derived fuels:** the newly added bio-ETBE route involving ethanol and isobutene from sugar beet shows interestingly low GHG emissions, when compared to Ethanol (wheat, barley, and corn) or HVO/Biodiesel routes, but with higher energy demand. Compared to the associated ethanol pathway the GHG emissions for the ETBE route are higher.
- **Wood:** selected pathways for synthetic diesel, DME and hydrogen are the ones with the potentially lowest WTT GHG emissions. Negative emissions can be achieved in the pathways implementing CCS.
- **Biogas**: interestingly, biogas to hydrogen routes show lower WTT emissions than CBM or LBM pathways, but with significantly higher energy requirements. Significant negative emissions can be derived from these routes due to the avoided CH4 emissions.
- **Electricity and H_2:** regarding electricity and Hydrogen, it is worth noticing that they should not be considered as primary energy sources, but energy carriers. Environmental performances of fuel pathways based on electricity- either used as final fuel or as energy vector - are determined by the primary source used for its production. More precisely, the use of electrical energy in transport sector is, in terms of GHG emissions saving, determined by the pathway of power production. When power for car is taken from the grid, this can lead to an increase in emissions, if the system reacts to this increased demand by increasing the production from fossil source (e.g. natural gas); this issues are country specific and time specific (as production is a non-steady process by definition). On the other end, a relevant uptake of electrical energy for road sector may act as a driver for increasing the share of renewable energies in the EU mix.

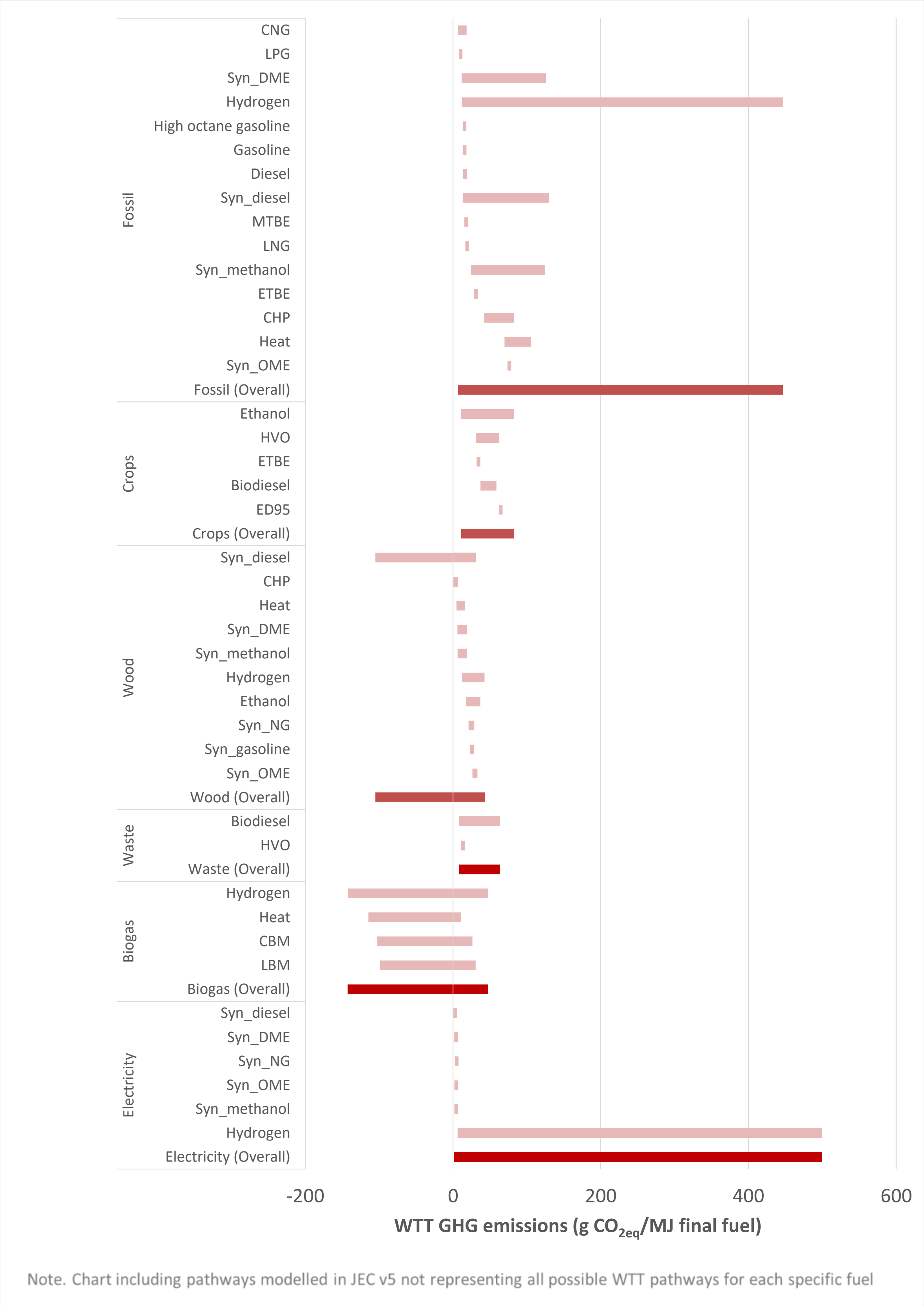
  It is also important to note that the WTT electricity related figures are *Well-to-Charging point* estimate (without accounting for the losses that occur at the charging devices when the electricity is used to recharge battery electric vehicles. These losses are considered within the TTW component of the JEC TTW and WTW reports).
- **e-fuels:** as e-fuels production is based on electricity, the above-mentioned considerations can be extended to these cases. From a mere GHG reduction perspective, the use of hydrogen fuel cells may not lead to any advantages, if electricity used is not from carbon neutral source.

Figure 134. WTT energy expended per type of feedstock/resource and its conversion in a specific fuel for the range of conversion pathways considered in the JEC WTT study.



Note. Chart including pathways modelled in JEC v5 not representing all possible WTT pathways for each specific fuel

Figure 135. WTT energy expended per type of feedstock/resource and its conversion in a specific fuel for the range of conversion pathways considered in the JEC WTT study.

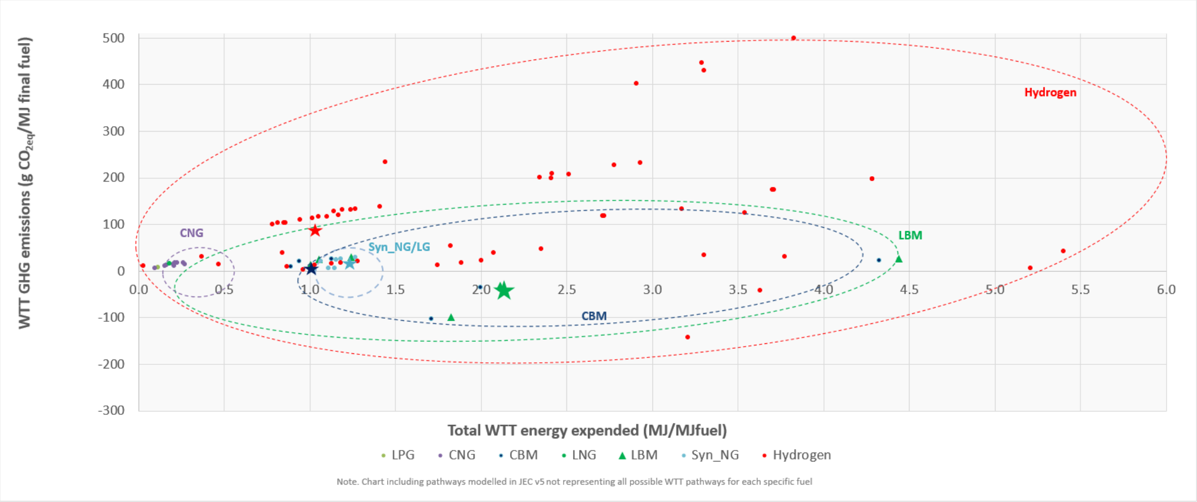


Note. Chart including pathways modelled in JEC v5 not representing all possible WTT pathways for each specific fuel

c) WTT energy expended and expended energy ratio - Variability

As presented along the JEC WTT v5 document, more than 250 different pathways have been modelled and generally with a higher WTT GHG Emissions / energy expended ratio when compared with the equivalent conventional fuels. However, not all the pathways achieve the same level of WTT GHG reduction per unit of energy expended and this huge variability among the routes is widely shown in **Figures 136, 137** and **138.**

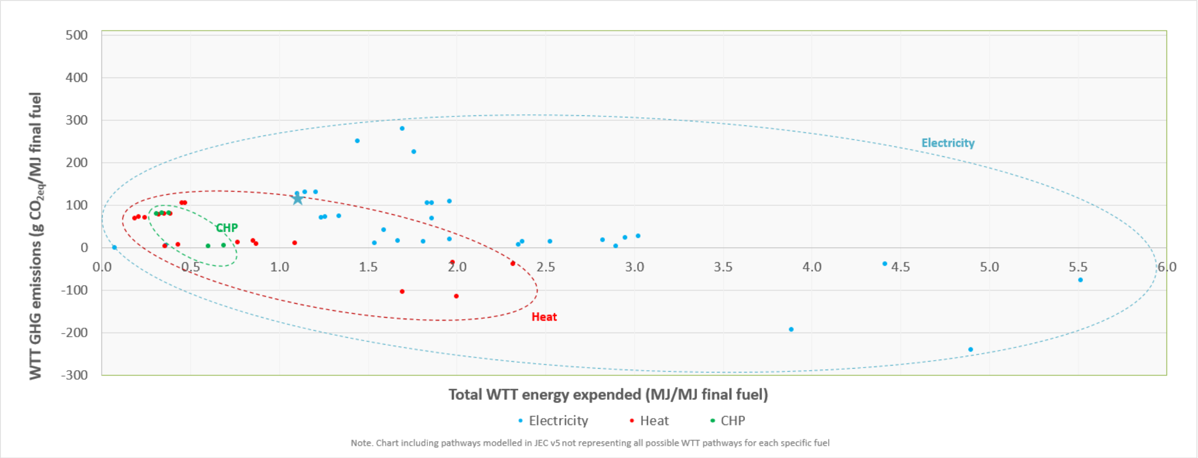
Figure 136. WTT energy expended and GHG emissions for gaseous fuel pathways



Note. Chart including pathways modelled in JEC v5 not representing all possible WTT pathways for each specific fuel

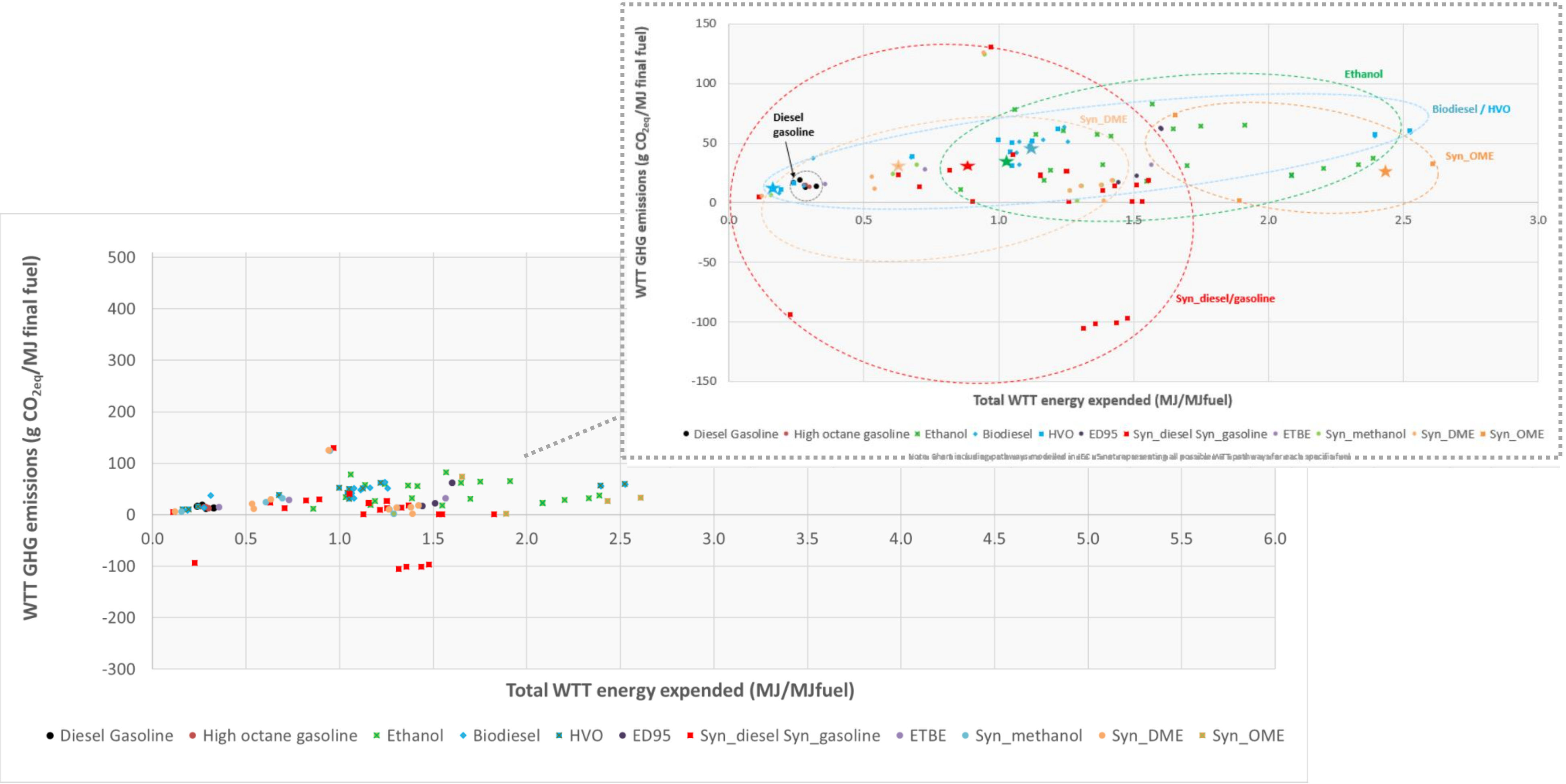
Figure 137. WTT energy expended and GHG emissions for electricity and heat & power (CHP)

Note. The WTT figure below exclude combustion



Note. Chart including pathways modelled in JEC v5 not representing all possible WTT pathways for each specific fuel

Figure 138. WTT energy expended and GHG emissions for liquid fuel pathways (Zoom in in the right hand side chart)



Note. Chart including pathways modelled in JEC v5 not representing all possible WTT pathways for each specific fuel

As general, final remarks, it is important to highlight that:

- The report includes representative pathways / routes but additional ones (not included in this version 5) are already in development.
- The comparison of various WTT routes has been conducted among the selected JEC pathways which differ depending on the type of fuels and the routes to produce them. As the JEC report is not intended to be a detailed list of all plausible pathways, there may be some variability in the number of pathways modelled for each fuel: whereas we have considered a whereas a very extensive range of primary energy sources for some fuels/energy carriers (eg. electricity, hydrogen), for others, only some initial examples of potential sources/pathways have been chosen for illustrative purposes (e.g. DME).
- When comparing different routes, TRL & CRL are key elements to be factored in, besides the WTT energy & GHG emissions.

General conclusions, about the most favourable routes, both in terms of GHG emissions and energy consumption minimisation, can be derived only when the whole WTW analysis is taken into account, as the powertrain efficiency strongly impact the results (expressed in terms of g CO_{2eq}/km, including the efficiency of the different powertrains).

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List of abbreviations and definitions

Adt	Air dry ton
API	American Petroleum Institute
BCL	Battelle Columbus Laboratory (biomass gasifier)
BCM	Billion Cubic Meters
BECCS	Bioenergy with CO_2 Capture and Storage
BLGMF	Black Liquor Gasification to Motor Fuels
BTL	Biomass-To-Liquids: denotes processes to convert biomass to synthetic liquid fuels, primarily diesel fuel
C/H	Carbon/Hydrogen (ratio)
CAP	Common Agricultural Policy (of the European Union)
CBM	Compressed Bio-Methane
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture & Storage
CCU	Carbon Capture and Utilisation
CDM	Clean Development Mechanism
CHP	Combined Heat and Power
CIMS	Crude Information Management System
CNG	Compressed Natural Gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_{2eq}	CO_2 equivalent
Concawe	the scientific body of the European Refiners' Association for environment, health and safety in refining and distribution
COP	Conference of the Parties
CRL	Commercial Readiness Levels
CSC	Chemical Scrubbing
CTL	Coal-To-Liquids
DDGS	Distiller's Dried Grain with Solubles: the residue left after production of ethanol from wheat grain
DLUC	**Direct Land Use Change**
DME	Di-Methyl-Ether
e-DME	e-Dimethyl Ether
EEA	European Environment Agency
EFBs	Empty Fruit Bunches
EIA	US Energy Information Agency
e-OME	e-Oxymethyl Ether
EOR	Enhance Oil Recovery
ETBE	Ethyl-Tertiary-Butyl Ether
ETS	Emissions Trading Scheme

EU	European Union
EUCAR	the European council for Automotive Research and development
EU-mix	European average composition of a certain resource or fuel, typically used to describe natural gas, coal and electricity
EV	Electric Vehicles
FAEE	Fatty Acid Ethyl Ester
FAME	Fatty Acid Methyl Ester
FFB	Fresh Fruit Bunch
FICFB	Fast Internal Circulating Fluidised Bed
FSU	Former Soviet Union
FT	Fischer-Tropsch: process that converts syngas to linear hydrocarbons
GEMIS	Global Emissions Model for Integrated Systems
GHG	Greenhouse Gas
GIS	Geographic Information System
GJ	Gigajoule
GMO	Genetically Modified Organism
GNOC	Global crop and site specific Nitrous Oxide emission Calculator
GTL	Gas-To-Liquids
HCl	Hydrochloric acid
HCL	Hydrogen chloride
HDO	Hydro-De-Oxygenation
HFO	Heavy Fuel Oil
HOP	High Octane gasoline
HRSG	Heat Recovery Steam Generator
HTL	Hydrothermal Liquefaction
HTU	Hydrothermal Upgrading (process unit)
HV	High Voltage
HVO	Hydrotreated Vegetable Oils
IEA	International Energy Agency
IES	Institute for Environment and Sustainability (JRC)
IGCC	Integrated Gasification and Combined Cycle
ILUC	Indirect Land Use Change
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
JEC	JRC, EUCAR, and Concawe
JRC	Joint Research Centre (of the European Commission)
LBM	Liquefied Bio-Methane
LBST	Ludwig-Bölkow-Systemtechnik GmbH
LC	Lignocellulose
LCA	Life-Cycle Assessment

LH_2	Liquid (or Liquefied) Hydrogen
LHV	Lower Heating Value (‘Lower” indicates that the heat of condensation of water is not included)
LNG	Liquefied Natural Gas
LP	Linear Programming
LPG	Liquefied Petroleum Gas
LUCAS	Land Use/Cover Area Survey
LV	Low Voltage
MDEA	Methyl Di-Ethanol Amine
MEA	Monoethanolamine
MJ	Megajoule
MON	Motor Octane Number
MPa	Mega Pascal, unit of pressure (1MPa = 10bar). Unless otherwise stated pressure figures are expressed as "gauge", i.e. over and above atmospheric pressure
MSW	Municipal Solid Waste
MTBE	Methyl-Tertiary-Butyl Ether
M_{toe}	Million tonnes oil equivalent.
MV	Medium Voltage
MW	Megawatt
N	Nitrogen
N_2O	Nitrous Oxide
NExBTL®	Neste Renewable Diesel, Proprietary technology for producing renewable diesel (Neste Oil)
NG	Natural Gas
NO_x	Nitrogen Oxides emitted from vehicles and combustion sources
NREL	National Renewable Energy Laboratory (USA)
OECD	Organisation for Economic Co-operation and Development
OME	Oxymethylene dimethyl Ether
OPGEE	Oil Production GHG Emissions Estimator
PEG	Polyethylene Glycol
PEM	Proton Exchange Membranes
pH	Measure of acidity
PHEV	Plug In Hybrid Electric Vehicle
PJ	Petajoule
PKO	Palm Kernel Oil
PM	Particulate Matter
PO	Palm Oil
POME	Palm Oil Methyl Ester
PSA	Pressure Swing Adsorption

PV	Photovoltaic
RDF	Refuse Derived Fuel
RED	Renewable Energy Directive
REE	Rapeseed Ethyl Ester
RESx	Renewable Electricity
RFS	Renewable Fuel Standard (USA)
RME	Rapeseed Methyl Ester: biodiesel derived from rapeseed oil (colza)
RWGS	Reverse Water Gas Shift
SLNG	Synthetic Liquefied Natural Gas
SMDS	Shell Middle Distillate Synthesis
SNG	Synthetic Natural Gas
SOEC	Solid Oxide Electrolysis Cells
SRF	Short Rotation Forestry
SSCF	Simultaneous Saccharification and Co-Fermentation: a process for converting cellulosic material to ethanol
TRL	Technology Readiness Levels
TTW	Tank-to-Wheels
ULCC	Ultra Large Crude Carrier
UOP	A Honeywell Company, formerly known as Universal Oil Products LLC
VLCC	Very Large Crude Carrier
WB	World Bank
WEO	World Energy Outlook
WF	Farmed Wood (Code WF)
WSC	Water Scrubbing
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
WW	Waste Wood (Code WW)
ZSW	Center for Solar Energy and Hydrogen Research Baden-Württemberg

List of codes

Code	*Final fuel / feedstock*	*Description*
Oil based Gasoline and diesel (see Section 4.1.1)		
COD1	Diesel fuel	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), typical EU distribution and retail.
COD1C		Crude oil from typical EU supply, transport by sea, refining in EU (marginal production) with CCS, typical EU distribution and retail.
COG1	Gasoline	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), typical EU distribution and retail.
COG1C		Crude oil from typical EU supply, transport by sea, refining in EU (marginal production) with CCS, typical EU distribution and retail.
Oil based High Octane Gasoline (see Section 4.1.2)		
COGHOP	Gasoline High octane	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), typical EU distribution and retail. COGHOP1 - HOP 100 RON / 3.4% bioenergy (avg. E5) - 'Light Oxygenate' Pathway COGHOP2 - HOP 102 RON / 3.4% bioenergy (avg. E5) - 'Light Oxygenate' Pathway COGHOP3 - HOP 102 RON / 6.5% bioenergy (avg. E10)
Synthetic Fischer-Tropsch diesel (GTL, BTL, CTL and Power-To-Diesel) (see Section 4.2)		
GRSD1/1C	Syndiesel	Remote natural gas to Syndiesel (GTL): GTL plant near remote gas field with/without CCS (C), Syndiesel imported into Europe and incorporated into diesel pool.
KOSD1/1C		EU-mix hard coal to: Syndiesel (CTL) with / without CCS.
WxSD1/BLSD1		Wood to Syndiesel, waste wood (WWxx1), farmed wood (WFxx1), and waste wood via black liquor gasification/ synthesis plant (BLxx1) considering two subcases: Distance travelled ((a) 500 km distance travelled, (b) >500 km) and with CCS schemes (code as “xC”).
RESD1		Renewable electricity to Syndiesel via methanol (CO_2 from flue gases).
RESD2		Renewable electricity to Syndiesel high temperature electrolysis based on SOEC and FT route (CO_2 from flue gases, biogas upgrading, and direct air capture).
Pyrolysis / HTL based gasoline and diesel (see Section 4.3)		
WFPG1	Pyrolysis-based gasoline	Farmed wood to pyrolysis-based fuel
WWPG1		Waste wood to pyrolysis-based fuel
WFPD1	Pyrolysis-based diesel	Farmed wood to pyrolysis-based fuel
WWPD1		Waste wood to pyrolysis-based fuel
WWSD2	HTL-based diesel	Wood waste to diesel, hydrothermal liquefaction (HTL) and upgrading
WFSD2		Farmed wood to diesel, hydrothermal liquefaction (HTL) and upgrading
Compressed Natural Gas and Liquefied Natural Gas (CNG and LNG) (see Section 4.5.1)		

GMCG1	CNG	EU-mix natural gas, transport to EU by pipeline (1900 km to EU border, 500 km inside EU), distribution through gas trunk lines and low pressure grid, compression to CNG at retail point.
GMCG2a	CNG	EU-mix natural gas (pathway GMCG1) including 10% LNG (pathway GRCG1).
GMCG2b	CNG	EU-mix natural gas supply including 18.9% LNG and 3.4% bio-CH4 (mix of pathway GMCG1, GRCG1, OWCG1, OWCG21, OWCG4a). 40% of the bio-CH4 is derived from organic waste (OWCG1), 20% from manure (OWCG21), and 40% from energy crops (OWCG4a).
GPCG1a/b	CNG	Imported natural gas, transport to EU by pipeline (a, 4300 km to EU border, 700 km inside EU) or Middle East (b, 4000 km), distribution through gas high pressure trunk lines and low pressure grid, compression to CNG at retail point.
GRCG1/1C	CNG	Remote natural gas liquefied at source, LNG sea transport, vaporisation at import terminal, distribution through gas high pressure trunk lines and low pressure grid, compression to CNG at retail point. Pathway **GRCG1C includes CCS** at the liquefaction power plant.
GRCG2	CNG	Remote natural gas liquefied at source, LNG sea transport, distribution by road as LNG, compression/vaporisation to CNG at retail point.
GRLG1	LNG	Remote natural gas liquefied at source, LNG sea transport, distribution by road as LNG, use as LNG in vehicle.
SGCG1	CNG	Shale gas (EU).
Compressed and Liquified Biomethane (CBM and LBM) (see Section 4.5.2)		
OWCG1	CBM	Upgraded biogas from municipal organic waste as CBM. Closed digestate storage.
OWCG21/2		Upgraded biogas from wet manure as CBM Digestate storage closed (21) or open (22)
OWCG3		Upgraded biogas from sewage sludge as CBM. Closed digestate storage
OWCG4		Upgraded biogas from maize (whole plant) as CBM. Closed digestate storage.
OWCG5		Upgraded biogas from double cropping (barley/maize) as CBM. Closed digestate storage.
OWLG1	LBM	Upgraded biogas from municipal organic waste as LBM. Closed digestate storage.
OWLG21/2		Upgraded biogas from wet manure as LBM Digestate storage closed (21) or open (22)
OWLG3		Upgraded biogas from sewage sludge as liquefied biomethane (LBM). Closed digestate storage
OWLG4		Upgraded biogas from maize (whole plant) as LBM. Closed digestate.
OWLG5		Upgraded biogas from double cropping (barley/maize) as LBM. Closed digestate storage.
Synthetic Natural Gas (SNG / SLNG) (see Section 4.5.3)		
WWCG2	SNG	Synthetic methane (as CNG) via gasification of waste wood and methanation
WFCG2		Synthetic methane (as CNG) via gasification of wood chips from short rotation forestry and methanation
RECG1		eCNG: Synthetic methane (as CNG) from renewable electricity and CO2 from flue gases
WWLG2	SLNG	Synthetic methane (as LNG) via gasification of waste wood and methanation
WFLG2		Synthetic methane (as LNG) via gasification of wood chips from short rotation

		forestry and methanation
RELG1a/b		eLNG: Synthetic methane (as LNG) from renewable electricity, CO_2 from flue gases (a) or CO_2 from biogas upgrading (b).
Liquefied Petroleum Gas (LPG) (see Section 4.5.4)		
COG1	Gasoline	Conventional gasoline
GMCG1	CNG	EU-mix natural gas, transport to EU by pipeline (1900 km to EU border, 500 km inside EU), distribution through gas trunk lines and low pressure grid, compression to CNG at retail point.
GRLG1	LNG	Remote natural gas liquified at source, LNG sea transport, distribution by road as LNG, use as LNG in vehicle.
LRLP1	LPG	LPG from remote natural gas field, purification and liquefaction at source, long-distance sea transport, distribution by road to retail point.
ED95 components (non-ethanol) (see Section 4.6.3.1)		
COL1	Lubricants	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), admixture to ethanol for ED95 supply, typical EU distribution and retail.
COPEG1	PEG	Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), steam cracking, ethylene oxide production, ethylene glycol production, polyethylene glycol production, admixture to ethanol for ED95 supply, typical EU distribution and retail.
COiB1	i-butanol (oil)	Crude oil from typical EU supply, transport by sea, refining in EU (marginal naphtha production) with downstream steam cracking, i-butanol via oxo synthesis, admixture to ethanol for ED95 supply, typical EU distribution and retail.
MTiBa	i-butanol (bio)	Corn (maize) (average used in EU) to i-butanol for ED95 supply. Production energy provided by a biogas fueled CHP plant. DDGS to animal feed.
ED95 – Admixture (see Section 4.6.3.2)		
WETXxX-TED	ED95	**EU wheat to ethanol**. Production energy provided by a NG-fired CHP plant. Mixed with polyethylene glycol (PEG), MTBE, i-butanol, and lubricants to ED95 for diesel engines. DDGS to animal feed WETOiB-TED: **i-butanol from crude oil** WETBiB-TED: **i-butanol from corn**
SETOiB-TED		**Wheat straw to ethanol**. Mixed with polyethylene glycol (PEG), MTBE, i-butanol, and lubricants to ED95 for diesel engines (Options: (a) straw transport 50 km, (b) straw transport 500 km) SETOiB-TED: i-butanol from crude oil

Biodiesel (FAME/FAEE) pathways (see Section 4.7.1)		
ROFA1-5	Biodiesel	Rapeseed to biodiesel (Rapeseed Methylester) Meal export (animal feed) (1/2/3/5), to internal biogas (4) Glycerine export to chemical (1), to animal feed (2), to internal biogas (3/4), to hydrogen (5)
ROFE3		Rapeseed to biodiesel (Rapeseed Ethylester) Meal export (animal feed) Glycerine to internal biogas
SOFA3		Sunflower to biodiesel (Sunflower seed Methylester) Meal export (animal feed) Glycerine to internal biogas
SYFA3 a-c		Soy beans to biodiesel (Soy Methylester) Meal export (animal feed) (a) Oil imported into EU, glycerine to internal biogas (b) Beans imported into EU, glycerine to internal biogas (c) Oil imported into EU, Allocation between soya oil and soya meal by market value (not used in version 5) (d) Beans imported into EU, allocation between soya oil and soya meal by market value
POFA3 a-c		Palm oil to biodiesel (Palm oil Methylester) Meal export (animal feed) (a) No CH4 emissions recovery, heat credit (oil mill), glycerine to internal biogas (b) CH4 emissions recovery, heat credit, glycerine to internal biogas (c) No CH4 emissions recovery, no heat credit, glycerine to internal biogas
WOFA3a		Waste cooking oil to biodiesel Glycerine to internal biogas
TOFA3a		Tallow oil to biodiesel Glycerine to internal biogas
Hydrotreated Vegetable Oils (HVO) (see Section 4.7.2)		
ROHY1a/b	HVO	Rape seed, meal export to animal feed, NexBTL / UOP.
ROHY4		Rape seed, meal to internal biogas, NexBTL.
SOHY1a		Sunflower seed, meal export to animal feed, NexBTL.
SYHY1a/b		Soybeans as feedstock with two variants: (c) soybeans, mix of till and no till, oil EU import, Nex BTL. (d) soybeans, mix of till and no till, beans EU import, NexBTL.
POHY1a-c		Palm oil as feedstock with three variants: (d) Palm oil, no CH4 recovery, heat credit, NexBTL. (e) POHY1b: Palm oil, CH4 recovery, heat credit, NexBTL. (f) Palm oil, no CH4 recovery, no heat credit, NexBTL.
WOHY1a		Waste cooking oil.
TOHY1a		Tallow.
PWHY		Extraction of oil from palm oil mill effluent (POME), NexBTL.
Methanol (see Section 4.8)		
GPME1b	Methanol	Piped natural gas (4000 km) to methanol, synthesis plant in EU
GRME1		Remote natural gas to methanol, synthesis plant near gas field
WxME1/BLME1		Wood to methanol, waste wood, farmed wood, and waste wood via black liquor gasification/synthesis plant
REME1		Renewable electricity to methanol (CO_2 from flue gases)
MTBE / ETBE (see Section 4.9.1)		
GRMB1	MTBE	MTBE in remote plant near gas field

LREB1 b/c	ETBE	ETBE from wheat ethanol and isobutene, from FCC (b) or steam cracking (c)
SBBE1	Bio-ETBE	EU sugar beet to ETBE. Pulp to animal feed, Slops used as feed for biogas, ethanol and isobutene for ETBE from sugar beet
DME / OME (see Section 4.9.2)		
GPOME	OME	Piped natural gas (4000 km) to OME via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis.
WxOME		Wood to OME via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis, waste and farmed wood in gasification/synthesis plants.
REOME		Renewable electricity to OME via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis (CO_2 from biogas upgrading).
GPDE1b	DME	Piped natural gas (4000 km) to DME, synthesis plant in EU.
GRDE1/1C		Remote natural gas to methanol, synthesis plant near gas field, without/with CCS.
WxDE1/BLDE1		Wood to DME, waste wood, farmed wood, and waste wood via black liquor in gasification/synthesis plant.
REDE1		Renewable electricity to DME (CO_2 from flue gases).
Electricity (see Section 4.10)		
EMEL	EU-mix	EU-mix electricity (High, Medium and Low voltage) 2016 mix (a) and 2030 mix (b).
FOEL	HFO	Electricity from heavy fuel oil (HFO) Conventional power plant (state-of-the-art) .
KOEL	Hard coal	Hard coal in conventional power plant or IGCC (with/without CCS).
GxEL	NG	Electricity from imported natural gas (5000 and 4000 km) and LNG in state-of-the-art CCGT.
OWEL	Biogas	Biogas from municipal waste and manure, on-site generation or export to large scale power plant.
WxEL	Wood	Farmed and waste wood in 4 different power plants (large/small scale IGCC, conventional, co-firing in large coal plant) plus waste wood through black liquor.
NUEL	Nuclear	Nuclear power plant.
WDEL	Wind	Wind turbine.

Compressed Hydrogen from NG (see Section 4.11.3.1)		
GMCH1	$C-H_2$ (Compressed H_2)	EU-mix natural gas supply, transport to EU by pipeline (1900 km), transport inside EU (500 km), distribution through high pressure trunk lines and low pressure grid, steam reforming at retail station, compression to 88 MPa.
GPCHx		Piped natural gas supply, transport to EU by pipeline (a, 4300 km to EU border and 700 km inside EU) or Southern Asia / Middle East (b, 4000 km), distribution through high pressure trunk lines. - GPCH1: distribution in low pressure grid, steam reforming at retail station, compression to 88 MPa. - GPCH2: central large scale reformer, hydrogen pipeline, compression to 88 MPa at retail station. CCS option for GPCH2b. - GPCH3: central large scale reformer, hydrogen compression to 50 MPa and road transport, compression to 88 MPa at retail station. - GPLCHb: central large scale reformer, hydrogen liquefaction, road transport, vaporisation / compression to 88 MPa at retail station. - GPCH4b1: compressed Hydrogen via methane cracking (Liquid metal route), hydrogen pipeline, compression to 88 MPa at retail station. The by-product coke replaces coke from coal. - GPCH4b2: compressed Hydrogen via methane cracking (BASF process), hydrogen pipeline, compression to 88 MPa at retail station. The by-product coke replaces coke from coal.
GRCHx		Remote natural gas liquefied at source, LNG sea transport, vaporisation at import terminal, distribution through gas high pressure trunk lines. - GRCH1: distribution in low pressure grid, steam reforming at retail station, compression to 88 MPa. - GRCH2: central large scale reformer, hydrogen pipeline, compression to 88 MPa at retail station. - GRCH3: Remote Natural gas to methanol at source, methanol transport to EU retail station, on-site methanol steam reforming, hydrogen compression to 88 MPa.
Compressed hydrogen from coal, wood and biogas. (see Section 4.11.3.2)		
KOCH	$C-H_2$ (Compressed H_2)	EU-mix hard **coal** without (KOCH1) / with CCS (KOCH1C), hydrogen pipeline transport, compression at retail site.
WxCH		**Wood** (WF: farmed, WW: waste): - WxCH1: small scale gasifier in retail site - WxCH2: central reformer, hydrogen pipeline - BLCH1: Waste wood via black liquor, pipeline Hydrogen compression to 88 MPa at retail site.
BLCH1		**Wood** - BLCH1: Waste wood via black liquor, pipeline Hydrogen compression to 88 MPa at retail site.
OWCH1		Upgraded **biogas** from municipal organic waste sent to onsite SMR, Hydrogen compression to 88 MPa at retail site. Closed digestate storage
OWCH2		Upgraded **biogas** from wet manure sent to onsite SMR (retail site) Digestate storage closed (21) or open (22)
OWCH3		Upgraded **biogas** from sewage sludge sent to onsite SMR (retail site) Closed digestate storage
OWCH4		Upgraded **biogas** from maize (whole plant) sent to SMR (retail site) Closed digestate storage
OWCH5		Upgraded **biogas** from double cropping (barley/maize) sent to SMR (retail site). Closed digestate storage
Compressed hydrogen from electrolysis (see Section 4.11.3.3)		
EMELx/xHx	$C-H_2$	EU-mix electricity supply ((a) 2016 (b) 203) (1) High voltage

	(Compressed)	(2) Medium voltage Electrolysis: CHx: (1) on retail site, (2) central with hydrogen pipeline transport, hydrogen compression to 88 MPa.
KOELx/xH1		Hard coal (EU-mix), (1) state-of-the-art conventional power plant, (2) IGCC, (2C) IGCC with CCS. Electrolysis: CH1: on retail site, hydrogen compression to 88 MPa.
GxELx/xHx		Natural gas: CCGT GPEL1: 5000 km pipeline (Russia) (a), 4000 km pipeline (Middle East) (b), with CCS (bC) GREL1: LNG Electrolysis: CHx: (1) on retail site, (2) central with hydrogen pipeline transport, hydrogen compression to 88 MPa.
WFELx/xHx		Wood (Farmed): WFEL1 IGCC (200 MWth, WFEL3: Conventional (small-scale) Electrolysis: CHx: (1) on retail site, (2) central with hydrogen pipeline transport, hydrogen compression to 88 MPa.
NUEL1/CH1		Electricity from nuclear energy Electrolysis: on retail site, hydrogen compression to 88 MPa.
WDEL1/xHx		Electricity from wind energy Electrolysis: CH2: central electrolysis, hydrogen pipeline transport, hydrogen compression to 88 MPa.
Liquid hydrogen (+ cryo-compression) (see Section 4.11.4)		
GPLHx	Cc-H_2 (Liquid H_2)	**Piped natural gas supply**, transport to EU by pipeline (a, 4300 km to EU border and 700 km inside EU), distribution through high pressure trunk lines, central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail station, hydrogen cryo- compression in to vehicle tank (35 MPa).
GRLHx		**Remote natural gas** - GRLH1: NG steam reforming and hydrogen liquefaction at source, liquid hydrogen sea transport - GRLH2: NG liquefaction at source, LNG sea transport, central reforming, hydrogen liquefaction Liquid hydrogen road transport to retail station, hydrogen cryo- compression in to vehicle tank (35 MPa).
WFLH		Farmed **wood**, large scale gasifier and hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).
EMELx/xHx		EU-mix electricity supply (based on actual averages) (1) High voltage (2) Medium voltage Electrolysis: LH1: central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).

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