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JEC Well-to-Tank report v5: **Annexes**

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

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Appendix 1. JEC WTT v5

Individual Spreadsheets

(Inputs & Energy and GHG balance of individual pathways)

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1 Introduction

Extending the previous in JEC WTT v4, the JEC-WTT report v5 contains many fuel categories: fossil derived fuels, biofuels from vegetable oil, ethers, hydrogen, etc. JEC-WTT dataset is made of 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 updated JEC WTT v5 report contains:

- **252 energy carrier pathways** in total (including heat and power). 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 framed 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, out 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 this 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 (CRL) maturity levels have been introduced (Section 2.9.3).

This appendix includes the individual workbooks where all the information regarding individual pathways can be found. The results workbook is also attached which summarizes the Energy and GHG results including the figures built for the purpose of the main WTT v5 report.

As a new element, the related WTT v5 workbooks also include pivot table to facilitate the comparison of different pathways to the reader.

2 Individual workbooks

WTT v5a pathways
1-Oil and Gas_Jan202

WTT v5 pathways
2-CBM_Jan2020.xlsx

WTT v5 pathways
3-Ethanol_Jan2020.

WTT v5 pathways
4-Biodiesel_Jan2020

WTT v5a pathways
5-Synfuels_Jan2020.

WTT v5 pathways
6-Electricity_Jan202

WTT v5 pathways
7-Heat and Power_J

WTT v5 pathways
8-H2_Jan2020.xlsx

WTT v5 pathways
9-Electrolysis_Jan20

3 Results and comparison workbook

WTT v5a Results
31012020.xlsx

4 References

See section 6 in the main report for the complete list of references.

Appendix 2. JEC WTT v5

Conversion factors, fuel properties and list of detailed input data

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1 Introduction

This appendix contains all the conversion factors, fuel properties and input data used to support the modelling exercise conducting within the scope of the JEC WTT v5 analysis.

2 Description of individual processes and detailed input data

The inputs to the JEC WTT pathways are stored in the LBST's E_3 database and that software was used to calculate the energy and GHG balances of the pathways. This appendix provides full detail of the input data. It consists in two elements:

- A series of tables giving input data to each process,
- A textual description and justification of each process.

The information has been split into logical sections each incorporating the processes involved in a number of related pathways. The changes versus JEC WTT v4 are described in detail in the Appendix 3 of the present JEC WTT v5 report.

In this appendix both energy and GHG figures are shown per unit energy content of the output of the particular process (MJ), i.e. NOT of the output of the total pathway (e.g. the energy required for wheat farming is shown per MJ of wheat grain, rather than MJ of ethanol). This has to be kept in mind when comparing figures in the appendix with those in the main report where figures pertaining to each step of a pathway are expressed per MJ of the final fuel.

The energy figures are expressed as net total energy expended (MJ_{xt}) in each process (i.e. *excluding* the energy transferred to the final fuel) per unit energy content of the output of the process (MJ). Where fuels or intermediate energy sources (e.g. electricity) are used in a process the total primary energy (MJ_p) is allocated to the process including the energy necessary to make the fuel or the electricity.

Example:

- If a process requires 0.1 MJ of electricity per MJ output, the expended energy is expressed as 0.1 MJ_x/MJ.
- If electricity is generated with a 33% efficiency, the primary energy associated to 1 MJ of electricity is 3 MJ_p.
- The total primary energy associated to the process is then 3 x 0.1 = 0.3 MJ_p/MJ.

All energy is accounted for regardless of the primary energy source, i.e. including renewable energy. This is necessary to estimate the energy footprint of each process and each pathway. The share of fossil energy in each complete pathway is shown in the overall pathway energy balance (*see* ***WTT Appendix 1***).

The CO_2 figures represent the actual emissions occurring during each process. When CO_2 emissions stem from biomass sources only the net emissions are counted i.e. excluding CO_2 emitted when burning the biomass.

The figures used in this study and described in this appendix are generally based on literature references as given. In a number of cases, particularly with regards to oil-based pathways, we have used figures considered as typical in the industry and generally representing the combined views of a number of experts. Where no specific reference is given, the figures are the result of standard physical calculations based on typical parameters. This is the case for instance for CNG or hydrogen compression energy.

3 Useful conversion factors and calculation methods

3.1 General

1 kWh = 3.6 MJ = 3412 Btu
1 Mtoe = 42.6 PJ
1 MW = 1 MJ/s = 28.8 PJ/a (8000 h)
1 t crude oil ~ 7.4 bbl
1 Nm^3 of EU-mix NG ~ 0.78 kg ~ 36 MJ

(i.e. 1 Nm3 of NG has approximately the same energy content as 1 kg of crude oil)

3.2 Factors for individual fuels

Gases							
	NG EU-mix piped						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	77.8	1868	623	100
GJ/d	0.0116		0.333	0.901	21.6	7.2	1.16
TJ/a (8000 h)	0.035	3.00		2.70	64.8	21.6	3.47
kg/h	0.013	1.11	0.370		24.0	8.0	1.28
kg/d		0.046	0.015			0.333	0.053
t/a (8000 h)		0.139	0.046	0.125	3.00		0.160
Nm^3/h		0.866	0.289	0.780	18.7	6.24	
	NG EU-mix 2016						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	77.3	1855	618	99
GJ/d	0.0116		0.333	0.894	21.5	7.2	1.14
TJ/a (8000 h)	0.035	3.00		2.68	64.4	21.5	3.43
kg/h	0.013	1.12	0.373		24.0	8.0	1.28
kg/d		0.047	0.016			0.333	0.053
t/a (8000 h)		0.140	0.047	0.125	3.00		0.160
Nm^3/h		0.874	0.291	0.782	18.8	6.25	
	NG EU-mix H gas 2016						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	75.1	1801	600	97
GJ/d	0.0116		0.333	0.869	20.8	6.9	1.12
TJ/a (8000 h)	0.035	3.00		2.61	62.5	20.8	3.36
kg/h	0.013	1.15	0.384		24.0	8.0	1.29
kg/d		0.048	0.016			0.333	0.054
t/a (8000 h)		0.144	0.048	0.125	3.00		0.161
Nm^3/h		0.892	0.297	0.775	18.6	6.20	
	Russian NG quality						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	73.2	1757	586	101
GJ/d	0.0116		0.333	0.847	20.3	6.8	1.17
TJ/a (8000 h)	0.035	3.00		2.54	61.0	20.3	3.50
kg/h	0.014	1.18	0.393		24.0	8.0	1.38
kg/d		0.049	0.016			0.333	0.057
t/a (8000 h)		0.147	0.049	0.125	3.00		0.172
Nm^3/h		0.857	0.286	0.727	17.4	5.81	
	LNG EU mix						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	73.3	1759	586	92
GJ/d	0.0116		0.333	0.848	20.4	6.8	1.06
TJ/a (8000 h)	0.035	3.00		2.55	61.1	20.4	3.19
kg/h	0.014	1.18	0.393		24.0	8.0	1.25
kg/d		0.049	0.016			0.333	0.052
t/a (8000 h)		0.147	0.049	0.125	3.00		0.157
Nm^3/h		0.941	0.314	0.798	19.2	6.39	
	Hydrogen						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	30.0	720	240	333
GJ/d	0.0116		0.333	0.347	8.3	2.8	3.86
TJ/a (8000 h)	0.035	3.00		1.04	25.0	8.3	11.58
kg/h	0.033	2.88	0.960		24.0	8.0	11.11
kg/d		0.120	0.040			0.333	0.463
t/a (8000 h)		0.360	0.120	0.125	3.00		1.389
Nm^3/h		0.259	0.086	0.090	2.2	0.72	

	Methane						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	72.0	1728	576	101
GJ/d	0.0116		0.333	0.833	20.0	6.7	1.17
TJ/a (8000 h)	0.035	3.00		2.50	60.0	20.0	3.50
kg/h	0.014	1.20	0.400		24.0	8.0	1.40
kg/d		0.050	0.017			0.333	0.058
t/a (8000 h)		0.150	0.050	0.125	3.00		0.175
Nm^3/h		0.857	0.286	0.714	17.1	5.71	
	NG EU-mix 2030						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	76.9	1846	615	98
GJ/d	0.0116		0.333	0.890	21.4	7.1	1.14
TJ/a (8000 h)	0.035	3.00		2.67	64.1	21.4	3.41
kg/h	0.013	1.12	0.374		24.0	8.0	1.28
kg/d		0.047	0.016			0.333	0.053
t/a (8000 h)		0.140	0.047	0.125	3.00		0.160
Nm^3/h		0.879	0.293	0.782	18.8	6.26	
	NG EU-mix H gas 2030						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	75.0	1800	600	97
GJ/d	0.0116		0.333	0.868	20.8	6.9	1.12
TJ/a (8000 h)	0.035	3.00		2.60	62.5	20.8	3.36
kg/h	0.013	1.15	0.384		24.0	8.0	1.29
kg/d		0.048	0.016			0.333	0.054
t/a (8000 h)		0.144	0.048	0.125	3.00		0.161
Nm^3/h		0.893	0.298	0.775	18.6	6.20	
	Upgraded biogas (biomethane)						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	78.1	1873	624	104
GJ/d	0.0116		0.333	0.903	21.7	7.2	1.20
TJ/a (8000 h)	0.035	3.00		2.71	65.0	21.7	3.61
kg/h	0.013	1.11	0.369		24.0	8.0	1.33
kg/d		0.046	0.015			0.333	0.055
t/a (8000 h)		0.138	0.046	0.125	3.00		0.166
Nm^3/h		0.832	0.277	0.752	18.0	6.01	
	Liqefied biomethane (LBM)						
	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	Nm^3/h
MW (MJ/s)		86.4	28.8	72.0	1728	576	101
GJ/d	0.0116		0.333	0.833	20.0	6.7	1.16
TJ/a (8000 h)	0.035	3.00		2.50	60.0	20.0	3.49
kg/h	0.014	1.20	0.400		24.0	8.0	1.40
kg/d		0.050	0.017			0.333	0.058
t/a (8000 h)		0.150	0.050	0.125	3.00		0.175
Nm^3/h		0.859	0.286	0.716	17.2	5.73	

Liquids

Gasoline	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	83.4	2000	667	2.69
GJ/d	0.012		0.33	0.96	23.2	7.72	0.031
TJ/a (8000 h)	0.035	3		2.89	69.5	23.2	0.093
kg/h	0.012	1.04	0.35		24.0	8.00	0.032
kg/d		0.043	0.014			0.333	
t/a (8000 h)		0.130	0.043	0.125	3.00		
m^3/d		32.1	10.7	31.0	743	248	

Diesel	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	83.5	2003	668	2.41
GJ/d	0.012		0.33	0.97	23.2	7.73	0.028
TJ/a (8000 h)	0.035	3		2.90	69.6	23.2	0.084
kg/h	0.012	1.04	0.35		24.0	8.00	0.029
kg/d		0.043	0.014			0.333	
t/a (8000 h)		0.129	0.043	0.125	3.00		
m^3/d		35.9	12.0	34.7	832	277	

ED95	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	141.7	3402	1134	4.15
GJ/d	0.012		0.33	1.64	39.4	13.12	0.048
TJ/a (8000 h)	0.035	3		4.92	118.1	39.4	0.144
kg/h	0.007	0.61	0.20		24.0	8.00	0.029
kg/d		0.025	0.008			0.333	
t/a (8000 h)		0.076	0.025	0.125	3.00		
m^3/d		20.8	6.9	34.2	820	273	

Methanol	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	180.7	4336	1445	5.47
GJ/d	0.012		0.33	2.09	50.2	16.73	0.063
TJ/a (8000 h)	0.035	3		6.27	150.5	50.2	0.190
kg/h	0.006	0.48	0.16		24.0	8.00	0.030
kg/d		0.020	0.007			0.333	
t/a (8000 h)		0.060	0.020	0.125	3.00		
m^3/d		15.8	5.3	33.0	793	264	

LPG	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	78.2	1876	625	3.41
GJ/d	0.012		0.33	0.90	21.7	7.24	0.039
TJ/a (8000 h)	0.035	3		2.71	65.2	21.7	0.118
kg/h	0.013	1.11	0.37		24.0	8.00	0.044
kg/d		0.046	0.015			0.333	
t/a (8000 h)		0.138	0.046	0.125	3.00		
m^3/d		25.3	8.4	22.9	550	183	

FT diesel	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	81.8	1964	655	2.52
GJ/d	0.012		0.33	0.95	22.7	7.58	0.029
TJ/a (8000 h)	0.035	3		2.84	68.2	22.7	0.087
kg/h	0.012	1.06	0.35		24.0	8.00	0.031
kg/d		0.044	0.015			0.333	
t/a (8000 h)		0.132	0.044	0.125	3.00		
m^3/d		34.3	11.4	32.5	780	260	

DME	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	126.6	3039	1013	4.54
GJ/d	0.012		0.33	1.47	35.2	11.72	0.052
TJ/a (8000 h)	0.035	3		4.40	105.5	35.2	0.157
kg/h	0.008	0.68	0.23		24.0	8.00	0.036
kg/d		0.028	0.009			0.333	
t/a (8000 h)		0.085	0.028	0.125	3.00		
m^3/d		19.0	6.3	27.9	670	223	

OME	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	187.9	4509	1503	4.23
GJ/d	0.012		0.33	2.17	52.2	17.40	0.049
TJ/a (8000 h)	0.035	3		6.52	156.6	52.2	0.147
kg/h	0.005	0.46	0.15		24.0	8.00	0.023
kg/d		0.019	0.006			0.333	
t/a (8000 h)		0.057	0.019	0.125	3.00		
m^3/d		20.4	6.8	44.4	1067	356	

Ethanol	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	134.3	3223	1074	4.06
GJ/d	0.012		0.33	1.55	37.3	12.44	0.047
TJ/a (8000 h)	0.035	3		4.66	111.9	37.3	0.141
kg/h	0.007	0.64	0.21		24.0	8.00	0.030
kg/d		0.027	0.009			0.333	
t/a (8000 h)		0.080	0.027	0.125	3.00		
m^3/d		21.3	7.1	33.1	794	265	

Crude	MW	GJ/d	TJ/a	kg/h	kg/d	t/a	m^3/d
MW (MJ/s)		86.4	28.8	85.7	2057	686	2.51
GJ/d	0.01		0.33	0.99	23.8	7.94	0.03
TJ/a (8000 h)	0.03	3		2.98	71.4	23.8	0.09
kg/h	0.01	1.01	0.34		24	8	0.03
kg/d		0.04	0.01			0.333	
t/a (8000 h)		0.13	0.04	0.13	3		
m_3/d		34.4	11.5	34.2	820	273	

Solids

Hard Coal	MW	GJ/d	TJ/a	kg/h	kg/d	t/a
MW (MJ/s)		86.4	28.8	135.8	3260	1087
GJ/d	0.01		0.33	1.57	37.7	12.58
TJ/a (8000 h)	0.03	3		4.72	113.2	37.7
kg/h	0.01	0.64	0.21		24	8
kg/d		0.03	0.01			0.333
t/a (8000 h)		0.08	0.03	0.13	3	

Wood	MW	GJ/d	TJ/a	kg/h	kg/d	t/a
MW (MJ/s)		86.4	28.8	189.5	4547	1516
GJ/d	0.01		0.33	2.19	52.6	17.54
TJ/a (8000 h)	0.03	3		6.58	157.9	52.6
kg/h	0.01	0.46	0.15		24	8
kg/d		0.02	0.01			0.333
t/a (8000 h)		0.06	0.02	0.13	3	

3.3 GHG calculations

CO_2-equivalence coefficients [IPPC 2007]

Methane 25

Nitrous oxide 298

CO_2 emissions from combustion (assuming total combustion)

1 kg of a fuel with C% carbon emits:

1 x C% / 100 / 12 x 44 = (0.0367 x C%) kg of CO_2

1 MJ of a fuel with λ MJ/kg (LHV) and C% carbon emits:

1 / λ x C% / 100 / 12 x 44 = (0.0367 / λ x C%) kg of CO_2

4 Fuels properties

4.1 Standard properties of fuels

Gases		**NG EU mix**						**NG (Rus)**	**Biomethane**		**Methane**		**Hydrogen**	**LPG***
		Piped	**2016**	**2030**	**H gas 2016**	**H gas 2030**	**LNG**		**as CNG**	**as LNG**				
LHV	MJ/kg	46.3	46.6	46.8	48.0	48.0	49.1	49.2	46.1	50.0	50		120.0	46.0
	kg/kWh	0.078	0.077	0.077	0.075	0.075	0.073	0.073	0.078	0.072	0.072		0.030	0.078
	kWh/kg	12.85	12.94	13.00	13.32	13.34	13.64	13.66	12.81	13.89	13.89		33.32	12.79
	kWh/Nm^3	10.02	10.12	10.17	10.33	10.33	10.89	9.92	9.63	9.95	9.92		3.00	29.18
MM	g/mol	17.5	17.5	17.5	17.4	17.4	17.9	16.3	16.8	16.0	16.0		2.0	51.1
C content	m/m	70.8%	71.3%	71.7%	73.5%	73.5%	75.6%	73.9%	71.3%	74.9%	75.0%		0.0%	82.2%
CO2 emission factor (assuming total combustion)														
	g CO_2/MJ	56.1	56.2	56.2	56.2	56.2	56.4	55.1	56.7	54.9	55.0			
	kg CO_2/kg	2.60	2.62	2.63	2.69	2.70	2.77	2.71	2.61	2.75	2.75			
	kg CO_2/Nm^3	3.33	3.35	3.36	3.48	3.48	3.47	3.73	3.48	3.83	3.85			
* LPG at gaseous state (before compression/liquefaction)														
Liquids		**Crude**	**Gasoline**	**Diesel**	**HFO**	**Syn diesel**	**Methanol**	**DME**	**OME**	**Ethanol**	**ED95**	**FAME**	**MTBE**	**ETBE**
Density	kg/m^3	820	743	832	970	780	793	670	1067	794	820	890	745	750
LHV	MJ/kg	42.0	43.2	43.1	40.5	44.0	19.9	28.4	19.2	26.8	25.4	37.2	35.1	36.3
	kg/kWh	0.086	0.083	0.083	0.089	0.082	0.181	0.127	0.188	0.134	0.142	0.097	0.103	0.099
	kWh/kg	11.67	12.00	11.98	11.25	12.22	5.54	7.90	5.32	7.45	7.06	10.33	9.75	10.07
C content	m/m	86.5%	86.4%	86.1%	89.0%	85.0%	37.5%	52.2%	43.5%	52.2%	49.4%	77.3%	68.2%	70.6%
CO2 emission factor (assuming total combustion)														
	g CO_2/MJ	75.5	73.4	73.2	80.6	70.8	68.9	67.3	83.3	71.4	71.3	76.2	71.2	71.4
	kg CO_2/kg	3.17	3.17	3.17	3.26	3.12	1.37	1.91	1.60	1.91	1.81	2.83	2.50	2.59
Solids		**Hard coal**	**Wood**	**Wheat grain**	**Sugar beet**	**Rapeseed**	**Sunflower seed**	**SB pulp**	**SB slops**	**Wheat straw**	**DDGS**	**DDGS (corn)**	**Sugar cane**	**Corn**
Moisture content	m/m		30.0%	13.5%	76.5%	9.0%	9.0%	9.0%	9.0%	13.5%	10.0%	10.0%	72.5%	14.0%
LHV (dry matter)	MJ/kg	26.5	19.0	17.0	16.3	27.0	27.2	16.1	15.6	17.2	18.1	19.2	19.6	17.3
	kg/kWh	0.136	0.189	0.212	0.221	0.133	0.132	0.224	0.231	0.209	0.199	0.187	0.184	0.208
	kWh/kg	7.36	5.28	4.72	4.53	7.49	7.57	4.47	4.33	4.78	5.03	5.34	5.44	4.81
C content	m/m	69.4%	50.0%											
CO2 emission factor (assuming total combustion)														
	g CO_2/MJ	96.0	96.5											
	kg CO_2/kg	2.54	1.83											

4.2 Detailed composition of natural gas per source

NATURAL GAS – EU MIX (CURRENT): PIPED NG

Origin	CIS (Russia)	NL	UK	Norway	Algeria	EU-mix	
						% v/v	% m/m
Share in EU-mix	34.2%	13.0%	10.1%	24.9%	6.6%		
H_2	0.0%	0.0%	0.5%	0.5%	0.8%	0.3%	0.0%
C1	98.4%	81.5%	86.0%	86.0%	92.1%	90.6%	83.0%
C2	0.4%	2.8%	8.8%	8.8%	1.0%	4.1%	7.1%
C3	0.2%	0.4%	2.3%	2.3%	0.0%	1.0%	2.6%
C4	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.3%
C5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CO_2	0.1%	1.0%	1.5%	1.5%	0.0%	0.8%	2.0%
N_2	0.8%	14.2%	0.8%	0.8%	6.1%	3.1%	5.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
MM (g/mol)	16.3	18.5	18.4	18.4	16.8	17.5	
Density (kg/Nm^3)	0.727	0.827	0.820	0.820	0.750	0.780	
LHV (MJ/Nm^3)	35.7	31.4	38.6	38.6	33.7	36.1	
LHV (GJ/t)	49.2	38.0	47.1	47.1	44.9	46.26	
MON (CARB)	138.2	132.9	122.3	122.3	138.0	126.4	
Methane number (MWM)	95.0	87.0	74.0	74.0	94.0	84.0	
Methane number (DK)	96.6	93.3	75.7	75.7	98.3		
%C m/m	73.9					70.8	
CO_2 emission factor, g CO_2/MJ	55.1					56.1	

Notes:

- LHV: The formula proposed for the calculation of LHV is empirical and based on best fit of available data (main source: CRC Physics and Chemistry databook
- Natural gas composition: The data used by LBST in previous studies has been taken over without changes. Although survey of other data available from CONCAWE members showed a fair amount of dispersion, the weighted average did not differ appreciably from the composition proposed by LBST. The numbers can also be found in the actual version of GEMIS [GEMIS 2016]

NATURAL GAS - EU MIX (CURRENT): PIPED NG + LNG

Origin	CIS (Russia)	NL	UK	Norway	Algeria	LNG	EU-mix	
							% v/v	% m/m
Share in EU-mix	30.8%	11.7%	9.1%	22.4%	5.9%	10.0%		
H_2	0.0%	0.0%	0.5%	0.5%	0.8%	0.0%	0.2%	0.0%
C1	98.4%	81.5%	86.0%	86.0%	92.1%	90.3%	90.5%	82.7%
C2	0.4%	2.8%	8.8%	8.8%	1.0%	6.3%	4.4%	7.5%
C3	0.2%	0.4%	2.3%	2.3%	0.0%	2.1%	1.2%	2.9%
C4	0.1%	0.1%	0.1%	0.1%	0.0%	0.9%	0.2%	0.6%
C5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CO_2	0.1%	1.0%	1.5%	1.5%	0.0%	0.0%	0.7%	1.7%
N_2	0.8%	14.2%	0.8%	0.8%	6.1%	0.4%	2.8%	4.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
MM (g/mol)	16.3	18.5	18.4	18.4	16.8	17.9	17.5	
Density (kg/Nm³)	0.727	0.827	0.820	0.820	0.750	0.798	0.782	
LHV (MJ/Nm³)	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	
Methane number (DK)	96.6	93.3	75.7	75.7	98.3	96.6		
%C m/m	73.9					75.6	71.3	
CO_2 emission factor, g CO_2/MJ	55.1						56.2	

Notes:

- LNG composition calculated based on [GIIGNL 2017]
- The LHV value is highly dependent on the regional values. As a reference, the average measured value (2016) seems to be close to the 47.5 MJ/kg for the EU mix – CNG & LNG in [NVGA 2017], [Exergia 2015]

H-CNG (NATURAL GAS - EU MIX CURRENT): PIPED NG without NL + LNG

Origin	CIS (Russia)	NL	UK	Norway	Algeria	LNG	EU-mix	
							% v/v	% m/m
Share in EU-mix (H-CNG)	39.4%	0.0%	11.6%	28.6%	7.6%	12.8%		
H_2	0.0%	0.0%	0.5%	0.5%	0.8%	0.0%	0.3%	0.0%
C1	98.4%	81.5%	86.0%	86.0%	92.1%	90.3%	91.9%	84.7%
C2	0.4%	2.8%	8.8%	8.8%	1.0%	6.3%	4.6%	7.9%
C3	0.2%	0.4%	2.3%	2.3%	0.0%	2.1%	1.3%	3.2%
C4	0.1%	0.1%	0.1%	0.1%	0.0%	0.9%	0.2%	0.6%
C5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CO_2	0.1%	1.0%	1.5%	1.5%	0.0%	0.0%	0.6%	1.6%
N_2	0.8%	14.2%	0.8%	0.8%	6.1%	0.4%	1.2%	1.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
MM (g/mol)	16.3	18.5	18.4	18.4	16.8	17.9	17.4	
Density (kg/Nm³)	0.727	0.827	0.820	0.820	0.750	0.798	0.775	
LHV (MJ/Nm³)	35.7	31.4	38.6	38.6	33.7	39.2	37.2	
LHV (GJ/t)	49.2	38.0	47.1	47.1	44.9	49.1	47.96	
MON (CARB)	138.2	132.9	122.3	122.3	138.0	121.5		
Methane number (MWM)	95.0	87.0	74.0	74.0	94.0	73.0	82.0	
Methane number (DK)	96.6	93.3	75.7	75.7	98.3	96.6		
%C m/m	73.9						73.5	
CO_2 emission factor, g CO_2/MJ							56.2	

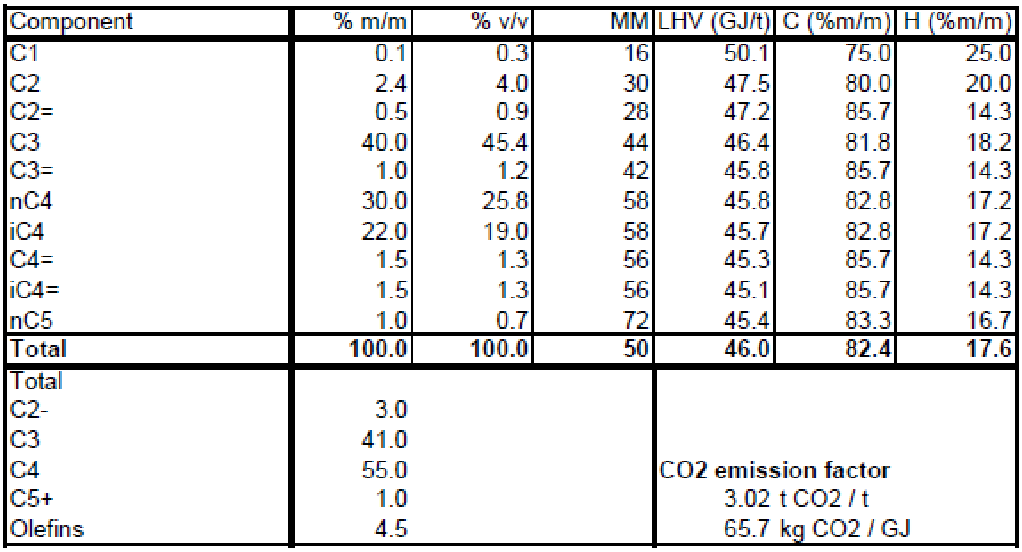
NATURAL GAS - EU MIX (2030): PIPED NG + LNG + BIOGAS

Origin	Piped NG	LNG	BIOGAS		
	EU mix (2.1)			% v/v	% m/m
Share in EU-mix	77.7%	18.9%	3.4%		
H_2	0.3%	0.0%	0.0%	0.2%	0.0%
C1	90.6%	90.3%	97.0%	90.7%	82.9%
C2	4.1%	6.3%	0.0%	4.4%	7.5%
C3	1.0%	2.1%	0.0%	1.2%	3.0%
C4	0.1%	0.9%	0.0%	0.2%	0.8%
C5	0.0%	0.0%	0.0%	0.0%	0.0%
C6	0.0%	0.0%	0.0%	0.0%	0.0%
C7	0.0%	0.0%	0.0%	0.0%	0.0%
CO_2	0.8%	0.0%	3.0%	0.7%	1.8%
N_2	3.1%	0.4%	0.0%	2.5%	4.0%
	100.0%	100.0%	100.0%	100.0%	100.0%
MM (g/mol)	17.5	17.9	16.8	17.5	
Density (kg/Nm^3)	0.780	0.798	0.752	0.782	
LHV (MJ/Nm^3)	36.1	39.2	34.7	36.6	
LHV (GJ/t)	46.3	49.1	46.1	46.81	
MON (CARB)	126.4	121.5	128.5	125.4	
Methane number (MWM)	84.0	73	102	82.0	
Methane number (DK)					
%C m/m	70.8	75.6	71.3	71.7	
CO_2 emission factor, g CO_2/MJ			56.65	56.19	

H-CNG (NATURAL GAS - 2030 EU MIX): PIPED NG without NL + LNG

Origin	Piped NG	LNG	BIOGAS		
	EU mix (H-piped NG)			% v/v	% m/m
Share in EU-mix	77.7%	18.9%	3.4%		
H_2	0.3%	0.0%	0.0%	0.22%	0.0%
C1	92.3%	90.3%	97.0%	92.11%	84.9%
C2	4.2%	6.3%	0.0%	4.44%	7.7%
C3	1.1%	2.1%	0.0%	1.26%	3.2%
C4	0.1%	0.9%	0.0%	0.23%	0.8%
C5	0.0%	0.0%	0.0%	0.00%	0.0%
C6	0.0%	0.0%	0.0%	0.00%	0.0%
C7	0.0%	0.0%	0.0%	0.00%	0.0%
CO_2	0.7%	0.0%	3.0%	0.66%	1.7%
N_2	1.3%	0.4%	0.0%	1.08%	1.7%
	100.0%	100.0%	100.0%	100.0%	100.0%
MM (g/mol)	17.2	17.9	16.8	17.4	
Density (kg/Nm^3)	0.770	0.798	0.752	0.775	
LHV (MJ/Nm^3)	36.8	39.2	34.7	37.2	
LHV (GJ/t)	47.8	49.1	46.1	48.01	
MON (CARB)					
Methane number (MWM)		73	102	82.0	
Methane number (DK)					
%C m/m	73.1			73.5	
CO_2 emission factor, g CO_2/MJ				56.16	

4.3 Deemed composition of LPG



Component	% m/m	% v/v	MM	LHV (GJ/t)	C (%m/m)	H (%m/m)
C1	0.1	0.3	16	50.1	75.0	25.0
C2	2.4	4.0	30	47.5	80.0	20.0
C2=	0.5	0.9	28	47.2	85.7	14.3
C3	40.0	45.4	44	46.4	81.8	18.2
C3=	1.0	1.2	42	45.8	85.7	14.3
nC4	30.0	25.8	58	45.8	82.8	17.2
iC4	22.0	19.0	58	45.7	82.8	17.2
C4=	1.5	1.3	56	45.3	85.7	14.3
iC4=	1.5	1.3	56	45.1	85.7	14.3
nC5	1.0	0.7	72	45.4	83.3	16.7
Total	**100.0**	**100.0**	**50**	**46.0**	**82.4**	**17.6**

Total		
C2-	3.0	
C3	41.0	
C4	55.0	**CO2 emission factor**
C5+	1.0	3.02 t CO2 / t
Olefins	4.5	65.7 kg CO2 / GJ

5 Common processes

5.1 Crude Oil and natural gas

Process code	*Step*	*Common process*	*Input*		*Range*		*Distribution*	*Source*
Generic fuel provision								
F1	**Diesel provision**							Pathway COD1
	Crude oil + others		MJ/MJ_{diesel}	0.26				
	CO_{2eq} emissions		g/MJ_{diesel}	18.9				
F2	**HFO provision**							CONCAWE internal
	Crude oil		MJ/MJ_{HFO}	0.0666				
	CO_{2eq} emissions		g/MJ_{HFO}	5.7				
EU-mix electricity 2016								[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.83				
	CO_{2eq} emissions		g/MJe	105.4				
EMMa	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.86				
	CO_{2eq} emissions		g/MJe	106.3				
EMLa	**Electricity (EU-mix, LV)**							
	Energy (mixed sources)		MJ/MJe	2.96				
	CO_{2eq} emissions		g/MJe	110.1				
EU-mix electricity 2030								[JRC 2017]
EMHb	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.2				
	CO_{2eq} emissions		g/MJe	70.6				
EMMb	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.3				
	CO_{2eq} emissions		g/MJe	71.2				
EMLb	**Electricity (EU-mix, LV)**							
	Energy (mixed sources)		MJ/MJe	2.3				
	CO_{2eq} emissions		g/MJe	73.7				
Transport processes								
T1	**Road truck (40 t)**							
	(includes return trip)							[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81				
	CH_4 emissions		g/t.km	0.0034				
	N_2O emissions		g/t.km	0.0015				
T3c	**Sea-going tanker 50 kt**							[Oeko Inventar 1996]
	HFO	*F2*	MJ/t.km	0.124	0.112	0.136	Square	
T3g	**LPG carrier (84 km^3)**							[Mann B&W 2003], [Kawasaki 2000]
	(Includes return voyage)							
	HFO	*F2*	MJ/t.km	0.132	0.126	0.139	Square	
T2	**Rail transport**							[GEMIS 2011]
	Electricity (EU-mix MV)	*EMMa*	MJ/t.km	21				
Processes relating to other pathways								
GHI	**NG-fired boiler (large scale)**							
	See e.g. pathway GPHT1a							

5.2 Biogas and synthetic methane

Process code	*Step*	*Common process*	*Input*		*Range*	*Distribution*	*Source*
Generic fuel provision							
F1	**Diesel provision**						Pathway COD1
	Crude oil + others		MJ/MJ_{diesel}	0.26			
	CO_{2eq} emissions		g/MJ_{diesel}	18.9			
F2	**HFO provision**						CONCAWE internal
	Crude oil		MJ/MJ_{HFO}	0			
	CO_{2eq} emissions		g/MJ_{HFO}	5.1			
F3	**Marginal NG provision (piped 4000km)**						
	Natural gas		MJ/MJ_{NG}	0.14			
	CO_{2eq} emissions		g/MJ_{NG}	12.7			
EU-mix electricity 2016							[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.83			
	CO_{2eq} emissions		g/MJe	105.4			
EMMa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.86			
	CO_{2eq} emissions		g/MJe	106.3			
EMLa	**Electricity (EU-mix, LV)**						
	Energy (mixed sources)		MJ/MJe	2.96			
	CO_{2eq} emissions		g/MJe	110.1			
Transport processes							
T1	**Road truck (40 t)**						
	(includes return trip)						[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81			
	CH_4 emissions		g/t.km	0.0034			
	N_2O emissions		g/t.km	0.0015			
Processes relating to other pathways							
KO1	**Hard coal supply (EU-mix)**						
	See pathway KOEL1						

5.3 Ethanol

Process code	Step	Common process	Input		Range		Distribution	Source
Generic fuel provision								
F1	**Diesel provision**							Pathway COD1
	Crude oil + others		MJ/MJ_{diesel}	0.26				
	CO_{2eq} emissions		g/MJ_{diesel}	18.9				
F2	**HFO provision**							CONCAWE internal
	Crude oil		MJ/MJ_{HFO}	0.07				
	CO_{2eq} emissions		g/MJ_{HFO}	5.7				
F3	**Marginal NG provision (piped 4000km)**							
	Natural gas		MJ/MJ_{NG}	0.14				
	CO_{2eq} emissions		g/MJ_{NG}	12.7				
EU-mix electricity 2016								[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.83				
	CO_{2eq} emissions		g/MJe	105.4				
EMMa	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.86				
	CO_{2eq} emissions		g/MJe	106.3				
EMLa	**Electricity (EU-mix, LV)**							
	Energy (mixed sources)		MJ/MJe	2.96				
	CO_{2eq} emissions		g/MJe	110.1				
Transport processes								
T1	**Road truck (40 t)**							
	(includes return trip)							[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81				
	CH_4 emissions		g/t.km	0.0034				
	N_2O emissions		g/t.km	0.0015				
T3a	**Inland/Coastal tanker 1.2 kt**							[Oeko Inventar 1996]
	Diesel	*F2*	MJ/t.km	0.5040				
	CH_4 emissions		g/t.km	0.0300				
T3d	**Sea-going tanker 12.6 kt (ethanol transport from Brazil and USA)**							JRC internal
	HFO	*F2*	MJ/t.km	0.1151				
T3h	**Sea-going bulk carrier Handysize (26 kt, for wood chips)**							JRC internal
	HFO	*F2*	MJ/t.km	0.1961				
T3j	**Sea-going product tanker 12.6 kt (distribution of ethanol)**							JRC internal
	HFO	*F2*	MJ/t.km	0.1691				
T3g	**LPG carrier (84 km^3)**							
	(Includes return voyage)							[Mann B&W 2003], [Kawasaki 2000]
	HFO	*F2*	MJ/t.km	0.1321	0.12564	0.1386	Square	
T2	**Rail transport**							[GEMIS 2011]
	Electricity (EU-mix MV)	*EMMa*	MJ/t.km	21.00				
Processes relating to other pathways								
KO1	**Hard coal supply (EU-mix)**							
	See pathway KOEL1							
GG1	**NG extraction and processing**							
	See e.g. pathway GCG1a							
GGe	**Electricity generation (NG-fired CCGT)**							
	See e.g. pathway GRCG1							
GHI	**NG-fired boiler (large scale)**							
	See e.g. pathway GPHT1a							
Processes relating to chemicals provision								
Z1	**Coke**							[GEMIS 2016]
	Coal		MJ/MJ	1.4298				
	Electricity EU-mix, MV		MJ/MJ	0.0050				
	Heat in	*Z1a*	MJ/MJ	0.2660				
	Heat out	*GHI*	MJ/MJ	-0.1140				
	(subsitutes heat from NG-fired boiler)							
	CH_4 emissions		g/MJ	0.0000				
Z1a	**Heat from coke oven gas**							[GEMIS 2011]
	Efficiency			85.0%				
	CO_2 emissions		g/MJ	51.31				
	CH_4 emissions		g/MJ	0.0025				
	N_2O emissions		g/MJ	0.0015				
Z2	**Hydrogen via steam reforming (NG)**							[Foster Wheeler 1996]
	NG	*F3*	MJ/MJ	1.3150				
	CO_2 emissions		g/MJ	72.42				
	CH_4 emissions		g/MJ	0.0016				

5.4 Biodiesel

Process code	Step	Common process	Input		Range	Distribution	Source
Generic fuel provision							
F1	**Diesel provision**						Pathway COD1
	Crude oil + others		MJ/MJ_{diesel}	0.26			
	CO_{2eq} emissions		g/MJ_{diesel}	18.9			
F2	**HFO provision**						CONCAWE internal
	Crude oil		MJ/MJ_{HFO}	0.0666			
	CO_{2eq} emissions		g/MJ_{HFO}	5.7			
F3	**Marginal NG provision (piped 4000km)**						
	Natural gas		MJ/MJ_{NG}	0.14			
	CO_{2eq} emissions		g/MJ_{NG}	12.7			
EU-mix electricity 2016							[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.83			
	CO_{2eq} emissions		g/MJe	105.4			
EMMa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.86			
	CO_{2eq} emissions		g/MJe	106.3			
EMLa	**Electricity (EU-mix, LV)**						
	Energy (mixed sources)		MJ/MJe	2.96			
	CO_{2eq} emissions		g/MJe	110.1			
Transport processes							
T1	**Road truck (40 t)**						
	(includes return trip)						[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81			
	CH_4 emissions		g/t.km	0.0034			
	N_2O emissions		g/t.km	0.0015			
T3b	**Inland/Coastal bulk carrier (8.8 kt)**						[Oeko Inventar 1996]
	Diesel	*F2*	MJ/t.km	0.3240			
	CH_4 emissions		g/t.km	0.0930			
	N_2O emissions		g/t.km	0.0004			
T3a	**Inland/Coastal tanker 1.2 kt**						[Oeko Inventar 1996]
	Diesel	*F1*	MJ/t.km	0.5040			
	CH_4 emissions		g/t.km	0.0300			
T3e	**Sea-going tanker 23 kt**						JRC internal
	HFO	*F2*	MJ/t.km	0.1031			
Processes relating to other pathways							
KO1	**Hard coal supply (EU-mix)**						
	See pathway KOEL1						
GGe	**Electricity generation (NG-fired CCGT)**						
	See e.g. pathway GRCG1						
GHI	**NG-fired boiler (large scale)**						
	See e.g. pathway GPHT1a						
Processes relating to chemicals provision							
Z1	**Coke**						
	Coal		MJ/MJ	1.4298			[GEMIS 2016]
	Electricity EU-mix, MV		MJ/MJ	0.0050			
	Heat in	*Z1a*	MJ/MJ	0.2660			
	Heat out	*GHI*	MJ/MJ	-0.1140			
	(subsitutes heat from NG-fired boiler)						
	CH_4 emissions		g/MJ	0.0018			
Z1a	**Heat from coke oven gas**						
	Efficiency			85.0%			[GEMIS 2011]
	CO_2 emissions		g/MJ	51.31			
	CH_4 emissions		g/MJ	0.0025			
	N_2O emissions		g/MJ	0.0015			
Z2	**Hydrogen via steam reforming (NG)**						
	NG	*F3*	MJ/MJ	1.3150			[Foster Wheeler 1996]
	CO_2 emissions		g/MJ	72.42			
	CH_4 emissions		g/MJ	0.0016			

5.5 Synthetic fuel

Process code	*Step*	*Common process*	*Input*		*Range*		*Distribution*	*Source*
Generic fuel provision								
F1	**Diesel provision**							Pathway COD1
	Crude oil + others		MJ/MJ_{diesel}	0.26				
	CO_{2eq} emissions		g/MJ_{diesel}	18.9				
F2	**HFO provision**							CONCAWE internal
	Crude oil		MJ/MJ_{HFO}	0.0666				
	CO_{2eq} emissions		g/MJ_{HFO}	5.1				
F3	**Marginal NG provision (piped 4000km)**							
	Natural gas		MJ/MJ_{NG}	0.14				
	CO_{2eq} emissions		g/MJ_{NG}	12.7				
EU-mix electricity 2016								[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.83				
	CO_{2eq} emissions		g/MJe	105.4				
EMMa	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.86				
	CO_{2eq} emissions		g/MJe	106.3				
EMLa	**Electricity (EU-mix, LV)**							
	Energy (mixed sources)		MJ/MJe	2.96				
	CO_{2eq} emissions		g/MJe	110.1				
Transport processes								
T1	**Road truck (40 t)**							
	(includes return trip)							[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81				
	CH_4 emissions		g/t.km	0.0034				
	N_2O emissions		g/t.km	0.0015				
T3h	**Sea-going bulk carrier Handysize (26 kt, for wood chips)**							JRC internal
	HFO	*F2*	MJ/t.km	0.1961				
T3i	**Sea-going product tanker 13.1 kt (distribution of biomass derived methanol, and FT diesel)**							
	HFO	*F2*	MJ/t.km	0.1637				JRC internal
T3a	**Inland/Coastal tanker 1.2 kt**							
	Diesel							
	CH_4 emissions							
	N_2O emissions							
T3c	**Sea-going tanker 50 kt**							[Oeko Inventar 1996]
	HFO	*F2*	MJ/t.km	0.1238				
T3g	**LPG carrier (84 km^3)**							[Mann B&W 2003], [Kawasaki 2000]
	HFO	*F2*	MJ/t.km	0.1321	0.12564	0.1386	Square	
T3k	**Sea-going LPG carrier 22 km3**							[China Shibuilding 2014]
	HFO	*F2*	MJ/t.km	0.2278				
T3l	**Inland/Coastal LPG carrier 2000 m^3**							[MARIC 2003]
	Diesel	*F1*	MJ/t.km	0.8804				
T2	**Rail transport**							[GEMIS 2011]
	Electricity (EU-mix MV)	*EMMa*	MJ/t.km	21				
Processes relating to other pathways								
KO1	**Hard coal supply (EU-mix)**							
	See pathway KOEL1							
GGe	**Electricity generation (NG-fired CCGT)**							
	See e.g. pathway GRCG1							
GE1C	**Electricity generation (NG firedd CCGT) with CCS**							
	See e.g. pathway GRCG1C							
GHI	**NG-fired boiler (large scale)**							
	See e.g. pathway GPHT1a							
Processes relating to chemicals provision								
Z1	**Coke**							[GEMIS 2016]
	Coal		MJ/MJ	1.4298				
	Electricity EU-mix, MV		MJ/MJ	0.0050				
	Heat in	*Z1a*	MJ/MJ	0.2660				
	Heat out	*GHI*	MJ/MJ	-0.1140				
	(subsitutes heat from NG-fired boiler)							
	CH_4 emissions		g/MJ	0.0018				
Z1a	**Heat from coke oven gas**							[GEMIS 2011]
	Efficiency			85.0%				
	CO_2 emissions		g/MJ	51.31				
	CH_4 emissions		g/MJ	0.0025				
	N_2O emissions		g/MJ	0.0015				
Z2	**Hydrogen via steam reforming (NG)**							[Foster Wheeler 1996]
	NG	*F3*	MJ/MJ	1.3150				
	CO_2 emissions		g/MJ	72.42				
	CH_4 emissions		g/MJ	0.0016				
EU-mix electricity 2030								[JRC 2017]
EMHb	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.24				
	CO_{2eq} emissions		g/MJe	70.6				
EMMb	**Electricity (EU-mix, MV)**							
	Energy (mixed sources)		MJ/MJe	2.26				
	CO_{2eq} emissions		g/MJe	71.2				
EMLb	**Electricity (EU-mix, LV)**							
	Energy (mixed sources)		MJ/MJe	2.33				
	CO_{2eq} emissions		g/MJe	73.7				

5.6 Electricity

Process code	*Step*	*Common process*	*Input*		*Range*	*Distribution*	*Source*
Generic fuel provision							
F1	**Diesel provision**						Pathway COD1
	Crude oil + others		MJ/MJ$_{diesel}$	0.26			
	CO_{2eq} emissions		g/MJ$_{diesel}$	18.9			
F2	**HFO provision**						CONCAWE internal
	Crude oil		MJ/MJ$_{HFO}$	0			
	CO_{2eq} emissions		g/MJ$_{HFO}$	5.1			
F3	**Marginal NG provision (piped 4000km)**						
	Natural gas		MJ/MJ$_{NG}$	0.14			
	CO_{2eq} emissions		g/MJ$_{NG}$	12.7			
EU-mix electricity 2016							[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.83			
	CO_{2eq} emissions		g/MJe	105.4			
EMMa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.86			
	CO_{2eq} emissions		g/MJe	106.3			
EMLa	**Electricity (EU-mix, LV)**						
	Energy (mixed sources)		MJ/MJe	2.96			
	CO_{2eq} emissions		g/MJe	110.1			
Transport processes							
T1	**Road truck (40 t)**						
	(includes return trip)						[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81			
	CH_4 emissions		g/t.km	0.0034			
	N_2O emissions		g/t.km	0.0015			
T3f	**Sea-going bulk carrier**						
	HFO	*F2*	MJ/t.km	0.0810			
Processes relating to other pathways							
KO1	**Hard coal supply (EU-mix)**						
	See pathway KOEL1						

5.7 Heat and Power

Process code	*Step*	*Common process*	*Input*		*Range*	*Distribution*	*Source*
Generic fuel provision							
F1	**Diesel provision**						Pathway COD1
	Crude oil + others		MJ/MJ$_{diesel}$	0.26			
	CO_{2eq} emissions		g/MJ$_{diesel}$	18.9			
F2	**HFO provision**						CONCAWE internal
	Crude oil		MJ/MJ$_{HFO}$	0.0666			
	CO_{2eq} emissions		g/MJ$_{HFO}$	5.7			
F3	**Marginal NG provision (piped 4000km)**						
	Natural gas		MJ/MJ$_{NG}$	0.14			
	CO_{2eq} emissions		g/MJ$_{NG}$	12.7			
EU-mix electricity 2016							[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.83			
	CO_{2eq} emissions		g/MJe	105.4			
EMMa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.86			
	CO_{2eq} emissions		g/MJe	106.3			
EMLa	**Electricity (EU-mix, LV)**						
	Energy (mixed sources)		MJ/MJe	2.96			
	CO_{2eq} emissions		g/MJe	110.1			
Transport processes							
T1	**Road truck (40 t)**						
	(includes return trip)						[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81			
	CH_4 emissions		g/t.km	0.0034			
	N_2O emissions		g/t.km	0.0015			
Other processes							
KO1	**Hard coal supply (EU-mix)**						
	See pathway KOEL1						

5.8 Hydrogen

Process code	*Step*	*Common process*	*Input*		*Range*	*Distribution*	*Source*
Generic fuel provision							
F1	**Diesel provision**						Pathway COD1
	Crude oil + others		MJ/MJ$_{diesel}$	0.26			
	CO$_{2eq}$ emissions		g/MJ$_{diesel}$	18.9			
F2	**HFO provision**						CONCAWE internal
	Crude oil		MJ/MJ$_{HFO}$	0.0666			
	CO$_{2eq}$ emissions		g/MJ$_{HFO}$	5.1			
F3	**Marginal NG provision (piped 4000km)**						
	Natural gas		MJ/MJ$_{NG}$	0.14			
	CO$_{2eq}$ emissions		g/MJ$_{NG}$	12.7			
EU-mix electricity 2016							[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.83			
	CO$_{2eq}$ emissions		g/MJe	105.4			
EMMa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.86			
	CO$_{2eq}$ emissions		g/MJe	106.3			
EMLa	**Electricity (EU-mix, LV)**						
	Energy (mixed sources)		MJ/MJe	2.96			
	CO$_{2eq}$ emissions		g/MJe	110.1			
Transport processes							
T1	**Road truck (40 t)**						
	(includes return trip)						[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81			
	CH$_4$ emissions		g/t.km	0.0034			
	N$_2$O emissions		g/t.km	0.0015			
T3c	**Sea-going tanker 50 kt**						[Oeko Inventar 1996]
	HFO	*F2*	MJ/t.km	0.1238			
T3h	**Sea-going bulk carrier Handysize (26 kt, for wood chips)**						JRC internal
	HFO	*F2*	MJ/t.km	0.1961			
T2	**Rail transport**						[GEMIS 2011]
	Electricity (EU-mix MV)	*EMMa*	MJ/t.km	21			
Processes relating to other pathways							
GGe	**Electricity generation (NG-fired CCGT)**						
	See e.g. pathway GRCG1						

5.9 Electrolysis

Process code	*Step*	*Common process*	*Input*		*Range*	*Distribution*	*Source*
Generic fuel provision							
F1	**Diesel provision**						Pathway COD1
	Crude oil + others		MJ/MJ_{diesel}	0.26			
	CO_{2eq} emissions		g/MJ_{diesel}	18.9			
F2	**HFO provision**						CONCAWE internal
	Crude oil		MJ/MJ_{HFO}	0.0666			
	CO_{2eq} emissions		g/MJ_{HFO}	5.1			
F3	**Marginal NG provision (piped 4000km)**						
	Natural gas		MJ/MJ_{NG}	0.14			
	CO_{2eq} emissions		g/MJ_{NG}	12.7			
EU-mix electricity 2016							[JRC 2017], [EEA 2018]
EMHa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.83			
	CO_{2eq} emissions		g/MJe	105.4			
EMMa	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.86			
	CO_{2eq} emissions		g/MJe	106.3			
EMLa	**Electricity (EU-mix, LV)**						
	Energy (mixed sources)		MJ/MJe	2.96			
	CO_{2eq} emissions		g/MJe	110.1			
EU-mix electricity 2030							
EMHb	**Electricity (EU-mix, MV)**						[JRC 2017]
	Energy (mixed sources)		MJ/MJe	2.24			
	CO_{2eq} emissions		g/MJe	70.6			
EMMb	**Electricity (EU-mix, MV)**						
	Energy (mixed sources)		MJ/MJe	2.26			
	CO_{2eq} emissions		g/MJe	71.2			
EMLb	**Electricity (EU-mix, LV)**						
	Energy (mixed sources)		MJ/MJe	2.33			
	CO_{2eq} emissions		g/MJe	73.7			
Transport processes							
T1	**Road truck (40 t)**						
	(includes return trip)						[EMEP/EEA 2012]
	Diesel	*F1*	MJ/t.km	0.81			
	CH_4 emissions		g/t.km	0.0034			
	N_2O emissions		g/t.km	0.0015			
T3f	**Sea-going bulk carrier**						[Kawasaki 2002] [Reischauer 2002]
	HFO	*F2*	MJ/t.km	0.0810			
Processes relating to other pathways							
KO1	**Hard coal supply (EU-mix)**						
GGe	**Electricity generation (NG-fired CCGT)**						
	See e.g. pathway GRCG1						

6 Crude oil – based fuels provision

6.1 Diesel fuel (COD1)

Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), typical EU distribution and retail.

Process code	Step	Common processes	Input		Range	Distribution	Source
	Production & conditioning at source						
CO1	Crude oil production						[Exergia et al. 2015]
	Crude oil		MJ/MJ$_{crude}$	0.1152		Normal	
			g CO2/MJ$_{crude}$	8.41			
	CH4 emissions		g/MJ$_{crude}$	0.0244			
	Total emissions		g CO2eq/MJ$_{crude}$	9.02		Normal	
	Transformation at source						
	NA						
	Transportation to market						
CO2	Crude oil transport						[Exergia et al. 2015]
	Crude oil (primary energy)		MJ/MJ$_{crude}$	0.0081		Normal	
			g CO2eq/MJ$_{crude}$	0.7000			
	Transformation near market						
CD1a	Crude refining, marginal diesel (EU)						CONCAWE internal
	Refinery fuel		MJ/MJ$_{diesel}$	0.1070		Normal	
			g CO2/MJ$_{diesel}$	7.20			
	Conditioning & Distribution						
CD2	Diesel fuel distribution (long distance)						[TOTAL 2002]
	Barge, 1200t (20%)						
	Distance		km	500			
	Diesel fuel		MJ/t.km	0.50			[Ecoinvent 1996]
	CH4 emissions		g/t.km	0.03			
	Rail (20%)						
	Distance	*T2*	km	250			
	Pipeline (60%)						
	Electricity (EU-mix MV)	*EMLa*	MJ/MJ$_{diesel}$	0.0002			
LF1	Liquid fuel depot						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{diesel}$	0.00084			
LF2	Liquid fuel local distribution						[TOTAL 2002]
	Standard road tanker	*T1*					
	Payload / tank mass		t/t	26/28			
	Distance		km	150			
LF3	Liquid fuel dispensing at retail site						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{diesel}$	0.0034			

6.1.1 CO1. Crude oil production

Figures include all energy and GHG emissions associated with crude oil production and conditioning at or near the wellhead (such as dewatering and associated gas separation). The total CO_{2eq} figure includes an element of flaring and emissions of GHGs other than combustion CO_2.

Production conditions for conventional crude oil vary considerably between producing regions, fields and even between individual wells and it is only meaningful to give typical or average energy consumption and GHG emission figures for the wide range of crudes relevant to Europe, hence the wide variability range indicated. These figures are best estimates for the basket of crude oils available to Europe.

Substantial deposits of heavier oils also exist, notably in Canada and Venezuela. The process of extracting and processing these oils is more energy intensive than for conventional crude oil. The very large reserves mean that these resources may become more important in the future, however most of the current production is used within the Americas, and we expect little or none of it to reach Europe in the period to 2020. The marginal crude available to Europe is likely to be of a similar quality and overall GHG footprint to the overwhole basket (see also *section 3.1* of the ***WTT report***).

6.1.2 CO2. Crude oil transport

Crude oil is mostly transported by ship. The type of ship used depends on the distance to be covered. The bulk of the Arab Gulf crude is transported 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. The developing regions of the Caspian basin will rely on one or several new pipelines to be built to the Black Sea. Crude from central Russia is piped to the Black Sea as well as directly to Eastern European refineries through an extensive pipeline network.

The majority of EU refineries are located at coastal locations with direct access to a shipping terminal. Those that are inland are generally supplied via one of several pipelines such as from the Mediterranean to North Eastern France and Germany, from the Rotterdam area to Germany and from Russia into Eastern and Central Europe.

Here again, there is a wide diversity of practical situations. The figures are based on data in [Exergia et al. 2015] and represent the crude oil mix supplied to the EU. [Exergia et al. 2015] indicates the GHG emissions. It has been assumed that the GHG emissions are from the combustion of heavy fuel oil which is made from crude oil. Note that that require shorter transport distances such as North Sea or North African crudes or those that can be transported by pipeline (e.g. Russian crude) would command somewhat smaller figures.

6.1.3 CD1a. Crude refining, marginal diesel (EU)

This represents the energy and GHG emissions that can be saved, in the form of crude oil, by not producing a marginal amount of diesel in Europe, starting from a 2010 “business-as-usual” base case (see also *section 3.1.3* and *Appendix 6* of the ***WTT report***).

6.1.4 CD2. Diesel fuel distribution (long distance)

Road fuels are transported from refineries to depots via a number of transport modes. We have included water (inland waterway or coastal), rail and pipeline (1/3 each). The energy consumption and distance figures are typical averages for EU. Barges and coastal tankers are deemed to use a mixture of marine diesel and HFO. Rail transport consumes electricity. The consumption figures are typical.

6.1.5 LF1. Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

6.1.6 LF2. Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

6.1.7 LF3. Liquid fuel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

6.2 Diesel fuel with CCS (COD1C)

Crude oil from typical EU supply, transport by sea, refining in EU (marginal production) with CCS, typical EU distribution and retail.

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
CO1	Crude oil production							[Exergia et al. 2015]
	Crude oil		MJ/MJ$_{crude}$	0.1152			Normal	
			g CO2/MJ$_{crude}$	8.41				
	CH4 emissions		g/MJ$_{crude}$	0.0244				
	Total emissions		g CO2eq/MJ$_{crude}$	9.02			Normal	
	Transformation at source							
	NA							
	Transportation to market							
CO2	Crude oil transport							[Exergia et al. 2015]
	Crude oil (primary energy)		MJ/MJ$_{crude}$	0.0081			Normal	
			g CO2eq/MJ$_{crude}$	0.7000				
	Transformation near market							
CD1b	Crude refining, marginal diesel (EU) with CCS							
	Refinery fuel		MJ/MJ$_{diesel}$	0.1070			Normal	CONCAWE internal
	Electricity for CO2 capture		MJ/MJ$_{diesel}$	0.0037				[RECCS 2007]
	Steam for CO2 capture		MJ/MJ$_{diesel}$	0.0272				[RECCS 2007]
			g CO2/MJ$_{diesel}$	0.72				[RECCS 2007], CONCAWE internal
	Conditioning & Distribution							
CD2	Diesel fuel distribution (long distance)							[TOTAL 2002]
	Barge, 1200t (20%)							
	Distance		km	500				
	Diesel fuel		MJ/t.km	0.50				[Ecoinvent 1996]
	CH4 emissions		g/t.km	0.03				
	Rail (20%)							
	Distance	*T2*	km	250				
	Pipeline (60%)							
	Electricity (EU-mix MV)	*EMLa*	MJ/MJ$_{diesel}$	0.0002				
LF1	Liquid fuel depot							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{diesel}$	0.00084				
LF2	Liquid fuel local distribution							[TOTAL 2002]
	Standard road tanker	*T1*						
	Payload / tank mass		t/t	26/28				
	Distance		km	150				
LF3	Liquid fuel dispensing at retail site							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{diesel}$	0.0034				

These processes are the same as for diesel fuel except from the CD1 phase, including CCS in this process.

6.2.1 CD1b. Crude refining, marginal diesel (EU) with CCS

This represents the energy and GHG emissions that can be saved, in the form of crude oil, by not producing a marginal amount of diesel in Europe, starting from a 2010 “business-as-usual” base case (see also section 3.1.3 and Appendix 6 of the WTT report). For CCS it has been assumed that 90% of the CO_2 is captured. The electricity and steam requirement have been derived from [RECCS 2007] where CO_2 separation from flue gas for post combustion CCS is described.

6.3 Gasoline (COG1)

Crude oil from typical EU supply, transport by sea, refining in EU (marginal production), typical EU distribution and retail.

Process code	Step	Common processes	Input		Range	Distribution	Source
	Production & conditioning at source						
CO1	Crude oil production						[Exergia et al. 2015]
	Crude oil		MJ/MJ_{crude}	0.1152		Normal	
			$g CO2/MJ_{crude}$	8.41			
	CH4 emissions		$g CO2eq/MJ_{crude}$	0.0244			
	Total emissions		$g CO2eq/MJ_{crude}$	9.02		Normal	
	Transformation at source						
	NA						
	Transportation to market						
CO2	Crude oil transport						[Exergia et al. 2015]
	Crude oil (primary energy)		MJ/MJ_{crude}	0.0081		Normal	
			$g CO2eq/MJ_{crude}$	0.7000			
	Transformation near market						
CG1a	Crude refining, marginal gasoline (EU)						CONCAWE internal
	Refinery fuel		$MJ/MJ_{gasoline}$	0.0820		Normal	
			$g CO2/MJ_{gasoline}$	5.50			
	Conditioning & Distribution						
CG2	Gasoline distribution (long distance)						[TOTAL 2002]
	Barge, 1200t (20%)						
	Distance		km	500			
	Gasoline		MJ/t.km	0.50			
	CH4 emissions		g/t.km	0.03			
	Rail (20%)						
	Distance	T2	km	250			
	Evaporation losses(1)		$MJ/MJ_{gasoline}$	0.0004			
	Pipeline (60%)						
	Electricity (EU-mix LV)	EMLa	$MJ/MJ_{gasoline}$	0.0002			
LF1	Liquid fuel depot						[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	$MJ/MJ_{gasoline}$	0.00084			
LF2	Gasoline local distribution						[TOTAL 2002]
	Standard road tanker	T1					
	Payload / tank mass		t/t	26/28			
	Distance		km	150			
	Evaporation losses(1)		$MJ/MJ_{gasoline}$	0.0004			
LF3	Gasoline dispensing at retail site						[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	$MJ/MJ_{gasoline}$	0.0034			
	Evaporation losses(1)		$MJ/MJ_{gasoline}$	0.0008			

(1) CO_2 emissions from degradation of non-methane VOC evaporative losses were not taken into account in previous versions.

These processes are essentially the same as for diesel with some specific adjustments for the gasoline case, mostly of evaporation losses.

6.4 Gasoline with CCS (COG1C)

Crude oil from typical EU supply, transport by sea, refining in EU (marginal production) with CCS, typical EU distribution and retail.

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
CO1	Crude oil production							[Exergia et al. 2015]
	Crude oil		MJ/MJ_{crude}	0.1152			Normal	
			$g CO2/MJ_{crude}$	8.41				
	CH4 emissions		$g CO2eq/MJ_{crude}$	0.0244				
	Total emissions		$g CO2eq/MJ_{crude}$	9.02			Normal	
	Transformation at source							
	NA							
	Transportation to market							
CO2	Crude oil transport							[Exergia et al. 2015]
	Crude oil (primary energy)		MJ/MJ_{crude}	0.0081			Normal	
			$g CO2eq/MJ_{crude}$	0.7000				
	Transformation near market							
CG1b	Crude refining, marginal gasoline (EU) with CCS							
	Refinery fuel		$MJ/MJ_{gasoline}$	0.0820			Normal	CONCAWE internal
	Electricity for CO2 capture		$MJ/MJ_{gasoline}$	0.0028				[RECCS 2007]
	Steam for CO2 capture		$MJ/MJ_{gasoline}$	0.0208				[RECCS 2007]
			$g CO2/MJ_{gasoline}$	0.55				[RECCS 2007], CONCAWE internal
	Conditioning & Distribution							
CG2	Gasoline distribution (long distance)							[TOTAL 2002]
	Barge, 1200t (20%)							
	Distance		km	500				
	Gasoline		MJ/t.km	0.50				
	CH4 emissions		g/t.km	0.03				
	Rail (20%)							
	Distance	T2	km	250				
	Evaporation losses(1)		$MJ/MJ_{gasoline}$	0.0004				
	Pipeline (60%)							
	Electricity (EU-mix LV)	EMLa	$MJ/MJ_{gasoline}$	0.0002				
LF1	Liquid fuel depot							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	$MJ/MJ_{gasoline}$	0.00084				
LF2	Gasoline local distribution							[TOTAL 2002]
	Standard road tanker	T1						
	Payload / tank mass		t/t	26/28				
	Distance		km	150				
	Evaporation losses(1)		$MJ/MJ_{gasoline}$	0.0004				
LF3	Gasoline dispensing at retail site							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	$MJ/MJ_{gasoline}$	0.0034				
	Evaporation losses(1)		$MJ/MJ_{gasoline}$	0.0008				

(1) CO_2 emissions from degradation of non-methane VOC evaporative losses were not taken into account in previous versions.

These processes are the same as for gasoline fuel except from the CG1b phase, including CCS in this process.

6.4.1 CG1b. Crude refining, marginal gasoline (EU) with CCS

This represents the energy and GHG emissions that can be saved, in the form of crude oil, by not producing a marginal amount of gasoline in Europe, starting from a 2010 “business-as-usual” base case (see also section 3.1.3 and Appendix 6 of the WTT report). For CCS it has been assumed that 90% of the CO_2 is captured. The electricity and steam requirement have been derived from [RECCS 2007] where CO_2 separation from flue gas for post combustion CCS is described.

One CCS project in a crude oil refinery has been implemented at a Sinopec oil refinery in He’Nan Province in China. In this crude oil refinery, the CO_2 from the flue gas from a fluid catalytic cracking (FFC) unit has been captured. The capture capacity has been indicated with 300 t of CO2 per day (12.5 t of CO_2 per hour) [Zhang et al. 2017]. Another project is located at Sturgeon Refinery in Alberta, Canada [NEB 2018].

6.5 Lubricants (COL1)

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.

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
CO1	Crude oil production							[Exergia et al. 2015]
	Crude oil		MJ/MJ_{crude}	0.1152			Normal	
			$g\ CO2/MJ_{crude}$	8.41				
	CH4 emissions		$g\ CO2eq/MJ_{crude}$	0.0244				
	Total emissions		$g\ CO2eq/MJ_{crude}$	9.02			Normal	
	Transformation at source							
	NA							
	Transportation to market							
CO2	Crude oil transport							[Exergia et al. 2015]
	Crude oil (primary energy)		MJ/MJ_{crude}	0.0081			Normal	
			$g\ CO2eq/MJ_{crude}$	0.7000				
	Transformation near market							
CL1	Crude refining, marginal lubricants (EU)							CONCAWE internal
	Refinery fuel		$MJ/MJ_{lubricants}$	1.1130			Normal	
			$g\ CO2/MJ_{lubricants}$	14.10				
	Conditioning & Distribution							
CL2	Lubricant distribution (long distance)							[TOTAL 2002]
	Rail							
	Distance	T2	km	250				
LF1	Liquid fuel depot							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	$MJ/MJ_{lubricants}$	0.00084				
LF2	Lubricants local distribution							[TOTAL 2002]
	Standard road tanker	T1						
	Payload / tank mass		t/t	26/28				
	Distance		km	150				
LF3	Lubricants dispensing at retail site							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	$MJ/MJ_{lubricants}$	0.0034				

These processes are essentially the same as for diesel with some specific adjustments for lubricants.

6.6 Polyethylene glycol (COPEG1)

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.

Process code	Step	Common processes	Input		Range	Distribution	Source
	Production & conditioning at source						
CO1	Crude oil production						[Exergia et al. 2015]
	Crude oil		MJ/MJ$_{crude}$	0.1152		Normal	
			g CO2/MJ$_{crude}$	8.41			
	CH4 emissions		g CO2eq/MJ$_{crude}$	0.0244			
	Total emissions		g CO2eq/MJ$_{crude}$	9.02		Normal	
	Transformation at source						
	NA						
	Transportation to market						
CO2	Crude oil transport						[Exergia et al. 2015]
	Crude oil (primary energy)		MJ/MJ$_{crude}$	0.0081		Normal	
			g CO2eq/MJ$_{crude}$	0.7000			
	Transformation near market						
CN1	Crude refining, marginal naphtha (EU)						CONCAWE internal
	Refinery fuel		MJ/MJ$_{naphtha}$	0.1000		Normal	
			g CO2/MJ$_{naphtha}$	6.40			
CPEG11	Ethylene production via steam cracking of naphtha						[GEMIS 2014]
	Naphtha		MJ/MJ$_{ethylene}$	1.98			
	Crude oil		MJ/MJ$_{ethylene}$	-0.41			
	Heat out		MJ/MJ$_{ethylene}$	0.22			
	Emissions		g CO2/MJ$_{ethylene}$	45.03			
			g CH4/MJ$_{ethylene}$	0.0018			
			g N2O/MJ$_{ethylene}$	0.0012			
CPEG12	Ethylene oxide production						[Ecoinvent 2007]
	Ethylene		MJ/MJ$_{ethylene\ oxide}$	1.44			
	Liquid O2		kg/MJ$_{ethylene\ oxide}$	0.02			
	Electricity EU-mix, MV	EMMa	MJ/MJ$_{ethylene\ oxide}$	0.04			
			g CO2/MJ$_{ethylene\ o}$	7.76			
			g CH4/MJ$_{ethylene\ o}$	0.03			
CPEG13	Ethylene glycol production						[Ecoinvent 2007]
	Ehylene oxide		MJ/MJ$_{ethylene\ glycol}$	1.12			
	Electricity EU-mix, MV	EMMa	MJ/MJ$_{ethylene\ glycol}$	0.08			
CPEG14	Liquid O2 production						[GEMIS 2002]
	Electricity EU-mix, MV	EMMa	MJ/kg$_{LO2}$	2.02			
CPEG15	Polyethylene glycol (PEG) production						
	Ethylene glycol		MJ/MJ$_{PEG}$	0.11			
	Ethylene oxide		MJ/MJ$_{PEG}$	0.98			
CPEG2	Polyethylene glycol (PEG) distribution (long distance)						
	Rail	T1					
	Distance		km	250			
LF1PEG	PEG depot						[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{PEG}$	0.00154			
LF2PEG	Standard road tanker	T1					
	Payload / tank mass		t/t	26/28			
	Distance		km	150			
LF3PEG	PEG dispensing at retail site						[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ$_{PEG}$	0.0062			

Some of these processes are essentially the same as for diesel with some specific adjustments for polyethylene glycol.

6.6.1 CN1 Crude refining, marginal naphtha (EU)

This represents the energy and GHG emissions that can be saved, in the form of crude oil, by not producing a marginal amount of gasoline in Europe, starting from a 2010 "business-as-usual" base case (see also section 3.1.3 and Appendix 6 of the WTT report).

6.6.2 CPEG11 Ethylene production via steam cracking of naphtha

Ethylene is produced via steam cracking of naphtha. Products are ethylene, propylene, and benzene. In [GEMIS 2014] the inputs are allocated by mass to the various products. The mass related data in [GEMIS 2014] have been converted to energy related data based on the lower heating value (LHV).

6.6.3 CPEG12 Ethylene oxide production

Ethylene oxide is produced via oxidation of ethylene with pure oxygen. The mass related data in [Ecoinvent 2007] have been converted to energy related data based on the lower heating value (LHV).

6.6.4 CPEG13 Ethylene glycol production

Ehtylene glycol is produced from ethylene oxide and water.

6.6.5 CPEG14 Liquid O2 production

Oxygen is separated from air via liquefaction (Linde process).

6.6.6 CPEG15 Polyethylene glycol (PEG) production

Polyethylene glycol (PEG) is synthesized from ethylene oxide and ethylene glycol via the reaction:

HOCH2CH2OH + (n-1) (CH2CH2O) => HO(CH2CH2O)nH.

For ED95 supply PEG with n = 9 has been assumed. It is also called PEG 400 because the molar mass amounts to about 400 g/mol (PEG with n =9: 414.49 g/mol)

6.6.7 CPEG2 Polyethylene glycol (PEG) distribution (long distance)

It has been assumed that the PEG is transported to a depot via road tankers over a distance of 150 km. The payload of the road tanker amounts to 26 t.

6.6.8 LF1PEG PEG depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations. The value for diesel indicated by [Total 2002] has been adjusted to the lower LHV of PEG.

6.6.9 LF2PEG Standard road tanker

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

6.6.10 LF3PEG PEG dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The value for diesel indicated by [Total 2002] has been adjusted to the lower LHV of PEG. The pathway for the supply of PEG is combined with the supply of ethanol, i-butanol, MTBE, and lubricants as indicated in [SEKAB 2018].

6.7 I-butanol (COiB1)

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.

Process code	Step	Common processes	Input		Range	Distribution	Source
	Production & conditioning at source						
CO1	Crude oil production						[Exergia et al. 2015]
	Crude oil		MJ/MJ$_{crude}$	0.1152		Normal	
			g CO2/MJ$_{crude}$	8.41			
	CH4 emissions		g/MJ$_{crude}$	0.0244			
	Total emissions		g CO2eq/MJ$_{crude}$	9.02		Normal	
	Transformation at source						
	NA						
	Transportation to market						
CO2	Crude oil transport						[Exergia et al. 2015]
	Crude oil (primary energy)		MJ/MJ$_{crude}$	0.0081		Normal	
			g CO2eq/MJ$_{crude}$	0.7000			
	Transformation near market						
CN1	Crude refining, marginal naphtha (EU)						CONCAWE internal
	Refinery fuel		MJ/MJ$_{naphtha}$	0.1000		Normal	
CB11	Propylene via steam cracking of naphtha		g CO2/MJ$_{naphtha}$	6.40			[GEMIS 2011]
	Naphtha		MJ/MJ$_{propene}$	2.04			
	Crude oil		MJ/MJ$_{propene}$	-0.42			
	Heat out		MJ/MJ$_{propene}$	0.23			
	CO2 emissions		g CO2/MJ$_{propene}$	46.33			
	CH4 emissions		g CH4/MJ$_{propene}$	0.0019			
	N2O emissions		g N2O/MJ$_{propene}$	0.0013			
CB12	CO (LHV) / Gasfication of heavy fuel oil via POX						
	Electricity		MJ/MJ$_{CO}$	0.13			[Ecoinvent 2007], [Scholz 1992]
	Heavy fuel oil		MJ/MJ$_{CO}$	2.65			[Ecoinvent 2007]
	H2 output		MJ/MJ$_{CO}$	0.83			[Ecoinvent 2007]
	CO2 emissions		g/MJ$_{CO}$	57.66			
	CH4 emissions		g/MJ$_{CO}$	0.03			[Ecoinvent 2007], [Scholz 1992]
CB13	i-butanol via oxo synthesis						[Ecoinvent 2007]
	CO (LHV)		MJ/MJ$_{i\text{-}butanol}$	0.12			
	Coal		MJ/MJ$_{i\text{-}butanol}$	0.06			
	Diesel		MJ/MJ$_{i\text{-}butanol}$	0.01			
	Electricity		MJ/MJ$_{i\text{-}butanol}$	0.02			
	Heavy fuel oil		MJ/MJ$_{i\text{-}butanol}$	0.04			
	Hydrogen		MJ/MJ$_{i\text{-}butanol}$	0.10			
	Natural gas		MJ/MJ$_{i\text{-}butanol}$	0.10			
	Propylene		MJ/MJ$_{i\text{-}butanol}$	0.78			
	CO2 emissions		g/MJ$_{I\text{-}butanol}$	15.17			
	Conditioning & Distribution						
CB2	i-butanol distribution (long distance)						
	Rail						
	Distance	T2	km	250			
LF1B	Liquid fuel depot						[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{i\text{-}butanol}$	0.00084			
LF2B	Standard road tanker	T1					
	Payload / tank mass		t/t	26/28			
	Distance		km	150			
LF3B	Liquid fuel dispensing at retail site						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{i\text{-}butanol}$	0.0034			

6.8 MTBE (GRMB1)

MTBE in remote plant near gas field

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ$_{NG}$	0.0798				
LR1	**LPG extraction and processing**							[ETSU 1996]
	Energy as NG		MJ/MJ$_{LPG}$	0.0529	0.0500	0.0700	Square	
	CH_4 emissions		g/MJ$_{LPG}$	0.0152				
	Transformation at source							
NM1	**NG to methanol plant**							[Larsen 1998]
	Efficiency			68.3%	67.3%	69.4%	Square	
	CH_4 emissions		g/MJ$_{Meth}$	0.000083				
LB1b	**LPG to isobutene**							
	LPG		MJ/MJ$_{Isobutene}$	1.0490				
	Hydrogen production		MJ/MJ$_{Isobutene}$	-0.0960				
	Energy as NG		MJ/MJ$_{Isobutene}$	0.1127	0.1125	0.1129	Normal	
	(inc. credit for hydrogen used a							
	CH_4 emissions		g/MJ$_{Isobutene}$	0.0004				
	N_2O emissions		g/MJ$_{Isobutene}$	0.0002				
MB1	**MTBE synthesis plant**							
	Isobutene		MJ/MJ$_{MTBE}$	0.8160				
	Methanol		MJ/MJ$_{MTBE}$	0.2066				
	Electricity	*GGe*	MJ/MJ$_{MTBE}$	0.0012				
	Energy as NG		MJ/MJ$_{MTBE}$	0.0290				
MB2	**MTBE depot (remote)**							
	Electricity (EU-mix, LV)	*GGe*	MJ/MJ$_{MTBE}$	0.00084				
	Transportation to market							
MB3	**MTBE long-distance sea transport**							
	Distance	*T3c*	Nautical miles	5500				
	Transformation near market							
	NA							
	Conditioning & Distribution							
LF1	**MTBE depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{MTBE}$	0.00084				
MB4	**MTBE distribution (long distance)**							
	Barge, 1200t (20%)							
	Distance		km	500				
	Diesel fuel		MJ/t.km	0.5040				
	CH_4 emissions		g/t.km	0.0300				
	Rail (20%)							
	Distance	*T2*	km	250				
	Pipeline (60%)							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ$_{MTBE}$	0.0002				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{MTBE}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Standard road tanker	*T1*						
	Payload / tank mass		t/t	26/28				
	Distance		km	150				
LF3	**Liquid fuel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{MTBE}$	0.0034				

6.8.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H_2S as well as separate inert gases, particularly CO_2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

6.8.2 LR1 LPG extraction and processing

It is assumed here that LPG is produced as part of the heavier hydrocarbons (condensate) associated with natural gas. 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.

6.8.3 NM1 NG to methanol plant

The plant energy efficiency selected here corresponds to a current state-of-the-art installation. The upper value (29.64 GJ/t of methanol) is the value guaranteed by the manufacturer, the lower value (28.74 GJ/t of methanol) is a measured value for the methanol plant located in Tjeldbergodden in Norway.

This process is applicable to both a remote plant and a large “central” plant located in Europe.

6.8.4 LB1b LPG to isobutene

Mixed butanes are isomerised into isobutane which is in turns dehydrogenated into isobutene. Hydrogen is released which is assumed to be used as fuel (as there is normally no specific requirement for hydrogen at such a remote gas plant).

6.8.5 MB1 MTBE synthesis plant

This represents a typical large-scale plant. MTBE is synthesised from isobutene and methanol.

6.8.6 MB2 MTBE depot (remote)

MTBE is stored in a depot near the production plant prior to shipping. Electricity is from the local power plant.

6.8.7 MB3 MTBE long-distance sea transport

Typical distance from the Middle East to EU. The ship is a 50 kt liquid carrier.

6.8.8 LF1 MTBE depot

MTBE is stored at the import EU port.

6.8.9 MB4 MTBE distribution (long distance)

Long distance distribution modes and distances are the same as for gasoline and diesel.

6.8.10 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

6.8.11 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

6.8.12 LF3 Liquid fuel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

6.9 LPG (LRLP1)

LPG from remote natural gas field, purification and liquefaction at source, long-distance sea transport, distribution by road to retail point.

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
LR1	**LPG extraction and processing**							[ETSU 1996]
	Energy as NG		MJ/MJ_{LPG}	0.0529	0.0500	0.0700	Square	
	CH_4 emissions		g/MJ_{LPG}	0.0152				
	Transformation at source							
LR2	**LPG liquefaction**							[ETSU 1996]
	Electricity (on-site generation)	*GGe*	MJ/MJ_{LNG}	0.0028				
	Transportation to market							
LR3	**LPG long-distance sea transport**							
	Distance	*T3g*	Nautical miles	5500				
	Transformation near market							
	NA							
	Conditioning & Distribution							
LR4	**LPG distribution**							
	Standard road tanker	*T1*						
	Payload / tank mass		t/t	18.5/8.6				
	Distance		km	500				
LR5	**LPG dispensing at retail site**							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LPG}	0.0034				

6.9.1 LR1 LPG extraction and processing

It is assumed here that LPG is produced as part of the heavier hydrocarbons (condensate) associated with natural gas. 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.

6.9.2 LR2 LPG liquefaction

Liquefaction requires electricity assume to be generated on site with an NG-fired CCGT.

6.9.3 LR3 LPG long-distance sea transport

Representative of a typical LPG carrier.

6.9.4 LR4 LPG distribution

The road tanker figures pertain to a notional truck transporting 18.5 t of LPG in a 8.6 t tank. The return trip is taken into account in the figures.

6.9.5 LR5 LPG dispensing at retail site

Retail stations require energy, essentially as electricity, for lighting, pumping etc.

7 Natural gas (NG) provision (including CNG)

7.1 CNG (GMCG1)

EU-mix piped 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, compression to CNG at retail point.

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0236	0.0136	0.0436	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.0798				
	Transformation at source							
	NA							
	Transportation to market							
GG2	**NG long-distance pipeline transport to EU border**							
	Compression specific energy		MJ/t.km	0.300	0.269	0.330	Equal	[GEMIS 2016]
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
GG2/19	Distance		km	1900				
	CH_4 emissions (losses)		g/MJ_{NG}	0.0610				[Thinkstep 2017]
GG3	**NG pipeline transport inside EU (same as for distribution)**							
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
	Distance		km	500				
	CH_4 emissions (losses)		g/MJ_{NG}	0.0006				
	Transformation near market							
	NA							
	Conditioning & Distribution							
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ_{NG}	0.0006				
GG4	**NG local distribution (low pressure)**							[Ruhrgas 2003]
	No contribution							
GG5	**Compression and CNG dispensing at retail site**							[LBST internal]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{CNG}	0.0220	0.014	0.027	2-triangle	
	CH_4 emissions		g/MJ_{CNG}	0.0001				

7.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H_2S as well as separate inert gases, particularly CO_2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

7.1.2 GG2 NG long-distance pipeline transport to EU border

With reference to section 3.2 of the WTT report, we have used as a proxy for the EU-mix a pipeline transportation distance of about 2400 km (1900 km to EU border and 500 km inside EU) which results in energy and emissions similar to the actual piped natural gas mix.

7.1.3 GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/t.km is typical of European networks. Gas losses are reportedly very small.

7.1.4 GG4 NG local distribution (low pressure)

The low-pressure networks are fed from the high-pressure trunk lines and supply small commercial and domestic customers. No additional energy is required for these networks, the pressure energy from the trunk lines being more than adequate for the local transport.

Various pressure levels are used in different countries and even within countries. Although some local networks are still at very low pressure (<100 mbar(g)) the modern European standard is 0.4 MPa(g) (with pressure reduction at the customer boundary). Very low-pressure networks also need to be fed by higher pressure systems at regular intervals (e.g. 0.7 MPa in the UK). As a result, it is reasonable to assume that, as long as a gas network is present in the area, a supply at a few bars pressure will be available for CNG refuelling stations in the vast majority of cases. Pressures up to 2 MPa are also available in some areas and may be available to some sites, particularly fleet refuelling stations. We have assumed that the typical refuelling station will be supplied at 0.4 MPa.

Significant methane losses have been reported for these local networks. They appear, however, to be based on overall gas accounting and therefore include measurement accuracy. Some losses are associated with purging operations during network maintenance. It is difficult to believe that local networks would have sizeable continuous losses. In any case all such losses would be related to the extent of the network rather than the throughput. NG used for road transport would only represent a modest increase of the total amount transported in the network and would therefore not cause significant additional losses.

7.1.5 GG5 Compression and CNG dispensing at retail site

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

7.2 CNG (GMCG2a)

EU-mix natural gas supply including 10% LNG (mix of pathway GMCG1 and GRCG1, see chapter 7.1 and chapter 7.5)

7.3 CNG (GMCG2b)

EU-mix natural gas supply including 18.9% LNG and 3.4% bio-CH4 (mix of pathway GMCG1, GRCG1, OWCG1, OWCG21, OWCG4a, see chapter 7.1, chapter 7.5, and chapter 8.1). 40% of the bio-CH4 is derived from organic waste (OWCG1), 20% from manure (OWCG21), and 40% from energy crops.

7.4 CNG (GPCG1a/b)

Natural gas from Russia, 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 gas high pressure trunk lines and low-pressure grid, compression to CNG at retail point

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ$_{NG}$	0.0798				
	Transformation at source							
	NA							
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ$_{fuel}$	0.0084				
	N_2O emissions		g/MJ$_{fuel}$	0.0026				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				[Thinkstep 2017]
	Compression specific energy		MJ/t.km	0.360	0.120	0.400	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ$_{NG}$	0.1398				[GEMIS 2016]
GG2/07	**NG pipeline transport inside EU for NG import from Russia**							
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				[GEMIS 2016]
	CH_4 emissions		g/MJ$_{fuel}$	0.0042				
	N_2O emissions		g/MJ$_{fuel}$	0.0025				[GEMIS 2016]
	GPCG1a (Russia)							
	Distance		km	700				
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ$_{NG}$	0.0009				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ$_{NG}$	0.1057				[Wuppertal 2004]
	Transformation near market							
	NA							
	Conditioning & Distribution							
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ$_{fuel}$	0.0042				
	N_2O emissions		g/MJ$_{fuel}$	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ$_{NG}$	0.0006				
GG4	**NG local distribution (low pressure)**							[Ruhrgas 2003]
	No contribution							
GG5	**Compression and CNG dispensing at retail site**							[LBST internal]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{CNG}$	0.0220	0.014	0.027	2-triangle	
	CH_4 emissions		g/MJ$_{CNG}$	0.0001				

7.4.1 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2016], the range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

7.5 CNG (GRCG1 and GRCG1C)

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.

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ$_{NG}$	0.08				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ$_{LNG}$	0.0113	0.0025	0.0200	Square	[FfE 1996]
	CH_4 emissions		g/MJ$_{LNG}$	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency		%	58%	57%	59%	Normal	
	CH_4 emissions		g/MJ$_{elec}$	0.0054				
	N_2O emissions		g/MJ$_{elec}$	0.0043				
GGeC	**On-site electricity generation (NG fired CCGT) with CCS**							[Rubin 2004]
	Efficiency			47%	46%	48%		
	CH_4 emissions		g/MJ$_{elec}$	0.0075				
	N_2O emissions		g/MJ$_{elec}$	0.0021				
	Transportation to market							
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ$_{LNG}$	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ$_{LNG}$	0.0222				[Mitsubishi 2000]
	CH_4 emissions		g/MJ$_{LNG}$	0.00013				[GEMIS 2001]
	N_2O emissions		g/MJ$_{LNG}$	0.00009				[GEMIS 2001]
	Transformation near market							
	NA							
	Conditioning & Distribution							
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GR5	**LNG vaporisation**							LBST internal
	Heat as NG		MJ/MJ$_{NG}$	0.0194				
	NG to pump drive (gas engine)		MJ/MJ$_{NG}$	0.0012	0.0009	0.0014	Square	
	CH_4 emissions		g/MJ$_{NG}$	0.000004	0.000004	0.000005		
	N_2O emissions		g/MJ$_{NG}$	0.000005	0.000004	0.000007		
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ$_{fuel}$	0.0042				
	N_2O emissions		g/MJ$_{fuel}$	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ$_{NG}$	0.0006				
GG4	**NG local distribution (low pressure)**							[Ruhrgas 2003]
	No contribution							
GG5	**Compression and CNG dispensing at retail site**							[LBST internal]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{CNG}$	0.0220	0.014	0.027	2-triangle	
	CH_4 emissions		g/MJ$_{CNG}$	0.0001				

7.5.1 GR1 NG liquefaction

The energy required for the liquefaction process is well documented and not subject to a large uncertainty. It is assumed here that the electrical power for the compressors is supplied by a gas fired on-site combined cycle gas fired power plant (see process GGe).

Some off gas is flared for which estimates vary widely in the literature hence the wide range used. There are also small methane losses.

A significant amount of natural gas is used to generate the electrical energy required for liquefaction. The corresponding CO_2 could be captured (see process CGeC). The proximity of gas and possibly oil field where the CO_2 could be injected would enhance the feasibility of such a scheme.

7.5.2 GR2 LNG loading terminal

A small amount of electricity is required for the operation of the terminals. In addition, the evaporation losses (estimated at 1%) are flared resulting in CO_2 emissions. The electricity is deemed to be produced by the on-site gas-fired power plant (process GGe).

7.5.3 GGe On-site electricity generation (NG-fired CCGT)

In all gas transformation schemes requiring significant amounts of electricity, we have assumed the latter is produced on-site by a state-of-the-art gas-fired combined cycle gas turbine (CCGT) with a typical efficiency of 55% (52-58%). The high end of the range represents potential future improvements to the technology that are thought to be achievable in the next ten years.

7.5.4 GGeC On-site electricity generation (NG fired CCGT) with CCS

In this process CO_2 would be scrubbed out of the gas turbine flue gases. Oxy-firing of turbine is assumed in order to obtain a concentrated CO_2 flue gas stream. As a result, there are no appreciable N_2O emissions. It has been estimated that some 88% of the CO_2 could be recovered. The energy penalty is sizeable, the overall efficiency being reduced by about 8 percentage points.

7.5.5 GR3 LNG long-distance sea transport

LNG is transported in specially designed cryogenic carriers. Heat ingress is compensated by gas evaporation. The evaporation rate is estimated at 0.15% per day, the number of days being based on an average speed of 19.5 knots. The average distance has been taken as 4000 nautical miles, based on the average for the supply of LNG to EU. The LNG is imported from Algeria, Norway, Nigeria, and Qatar.

The evaporated gas is used as fuel for the ship, the balance being provided by standard marine bunker fuel (HFO). This practice is also valid for the return voyage inasmuch as the LNG tanks are never completely emptied in order to keep them at low temperature (required for metallurgical reasons). The figures include an allowance for the return trip in accordance with the “admiralty formula” (see process Z4: LNG carriers have a typical gross tonnage of 110,000 t, including a payload of 135,000 m3 or 57,000 t [Hanjin 2000] [Mitsubishi 2000]. This results in a ratio of 0.8 between the full and empty ship).

The figures include provision for return trip.

7.5.6 GR4 LNG unloading terminal

The terminal electricity requirement is deemed to be the same as for the loading terminal (see process GR2). The electricity, however, is now assumed to be supplied by the EU grid. If LNG is vaporised on receipt no evaporation losses are included; if LNG is further transported as such, the same figures as for the loading terminal are used. A small additional electricity consumption (0.0007 to 0.0010 MJ/MJ of LNG) is added for the LNG terminal. The road tanker loading and unloading is carried out by a truck mounted LNG pump. The additional diesel requirement for the LNG pump is very low (approximately 0.0002 MJ/MJ of LNG).

7.5.7 GR5 LNG vaporisation

If it is to be used in the gas distribution grid, LNG needs to be vaporised and compressed. Although small amounts can be vaporised with heat taken from the atmosphere, this is impractical for large evaporation rates and heat at higher temperature must be supplied. The figures used here assume compression (as liquid) to 4 MPa followed by vaporisation and heating of the gas from -162 to 15°C.

7.6 CNG (GRCG2)

Remote natural gas liquefied at source, LNG sea transport, distribution by road as LNG, compression/vaporisation to CNG at retail point.

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.08				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ_{LNG}	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ_{LNG}	0.0113	0.0025	0.0200	Square	[FfE 1996]
	CH_4 emissions		g/MJ_{LNG}	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ_{LNG}	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ_{LNG}	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency		%	58%	57%	59%	Normal	
	CH_4 emissions		g/MJ_{elec}	0.0054				
	N_2O emissions		g/MJ_{elec}	0.0043				
	Transportation to market							
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ_{LNG}	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ_{LNG}	0.0222				[Mitsubishi 2000]
	CH_4 emissions		g/MJ_{LNG}	0.00013				[GEMIS 2001]
	N_2O emissions		g/MJ_{LNG}	0.00009				[GEMIS 2001]
	Transformation near market							
	NA							
	Conditioning & Distribution							
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ_{LNG}	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ_{LNG}	0.0100				[Total 2001]
GR6	**LNG distribution**							[Messer 1998]
	Standard road tanker							
	Payload / tank mass		t/t	19/9				
	Distance		km	500				
	CH_4 emissions		g/MJ_{LNG}	0.1000				
GR7	**Vaporisation/compression and CNG dispensing at retail site**							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{CNG}	0.0034				[Messer 1998]
	LNG for heat		MJ/MJ_{CNG}	0.0194				LBST internal

7.6.1 GR6 LNG distribution

This process assumes road transport of LNG from the import terminal directly to a local storage at the refuelling station (diesel truck carrying 19 t of LNG and 9 t of steel, see also process Z2).

7.6.2 GR7 Vaporisation/compression and CNG dispensing at retail site

LNG needs to be vaporised and compressed into CNG at 25 MPa (at the refuelling station). This can be done in and energy-efficient manner by pumping the liquid to the required pressure followed by vaporisation. Methane emissions are negligible. No further compression energy is required. We have assumed that the vaporisation and reheating energy has to be provided by an auxiliary heat source (electricity) as ambient air would not provide sufficient heat flow for the rates of vaporisation required. The total electricity requirement of 0.0228 MJ/MJ includes 0.0032 for pumping [Messer 1998]. It is assumed that the vaporization and reheating is carried out by a water bath heat exchanger. The electricity requirement is 0.0118 MJ/MJ for vaporisation and 0.0078 MJ/MJ for reheating (100% efficiency).

7.7 LNG (GRLG1)

Remote natural gas liquefied at source, LNG sea transport, distribution by road as LNG, use as LNG in vehicle.

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.08				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ_{LNG}	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ_{LNG}	0.0113	0.0025	0.0200	Square	[FfE 1996]
	CH_4 emissions		g/MJ_{LNG}	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ_{LNG}	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ_{LNG}	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency		%	58%	57%	59%	Normal	
	CH_4 emissions		g/MJ_{elec}	0.0054				
	N_2O emissions		g/MJ_{elec}	0.0043				
	Transportation to market							
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ_{LNG}	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ_{LNG}	0.0222				[Mitsubishi 2000]
	CH_4 emissions		g/MJ_{LNG}	0.00013				[GEMIS 2001]
	N_2O emissions		g/MJ_{LNG}	0.00009				[GEMIS 2001]
	Transformation near market							
	NA							
	Conditioning & Distribution							
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ_{LNG}	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ_{LNG}	0.0100				[Total 2001]
GR6	**LNG distribution**							[Messer 1998]
	Standard road tanker							
	Payload / tank mass		t/t	19/9				
	Distance		km	500				
	CH_4 emissions		g/MJ_{LNG}	0.1000				
GR8	**LNG filling station**							[Messer 1998]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LNG}	0.00005				
	LNG losses			0.001%				

7.7.1 LNG filling station

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm^3 of natural gas per day and bus.

7.8 CNG (SGCG1)

Shale gas (EU).

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
SG1	**Extraction (Fracking)**							[Perks 2012]
	Diesel		MJ/MJ_{gas}	0.0038	0.0028	0.0064	2-triangle	
	HCl	*Ecoinvent 2007*	g/MJ_{gas}	0.0104	0.0069	0.0217	2-triangle	
SG2	**Well completion**							[Perks 2012]
	CO_2 emissions		g/MJ_{gas}	0.1078				
	CH_4 emissions		g/MJ_{gas}	0.0744	0.0497	0.2114	2-triangle	
SG3	**Waste water treatment**							[Perks 2012]
	Diesel		MJ/MJ_{gas}	0.00038	0.00038	0.00025	2-triangle	
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ_{gas}	0.00006	0.00004	0.00012	2-triangle	
SG4	**Gas processing**							[Perks 2012]
	NG (own gas)		MJ/MJ_{gas}	0.0143				
	CH_4 emissions		g/MJ_{gas}	0.0300				
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
	NA							
	Conditioning & Distribution							
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ_{NG}	0.0006				
GG4	**NG local distribution (low pressure)**							[Ruhrgas 2003]
	No contribution							
GG5	**Compression and CNG dispensing at retail site**							[LBST internal]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{CNG}	0.0220	0.014	0.027	2-triangle	
	CH_4 emissions		g/MJ_{CNG}	0.0001				

The data is from a recent study for the EU Commission by AEA Technology [Perks 2012]. Note that in line with our general approach we have excluded energy and emissions related to site preparation, construction etc.

7.8.1 SG1 Extraction (Fracking)

"Shale"" gas is extracted by fracturing the shale rock in which the gas is trapped (a process known as ""fracking""). This requires energy in the form of diesel for machinery and transport of material and equipment.

7.8.2 SG2 Well completion

Some gas is released as methane and some is flared.

7.8.3 SG3 Waste water treatment

Water treatment requires diesel (for transport of waste water) and electricity in the treatment plant.

7.8.4 SG4 Gas processing

A small amount of the produced gas is used as energy for gas processing. Some is released as methane.

8 Biogas and Synthetic Methane

Three sources of organic waste are considered namely municipal waste and "liquid" manure. Furthermore, energy crops such as maize and double cropping have been considered. The process is described in the main ***WTT report***. The anaerobic fermentation produces raw biogas that, depending on the intended use, may need to be treated (to remove contaminants such as sulphur) and/or upgraded (to remove CO2). The electricity is supplied by the EU electricity mix (LV level), the heat is supplied by biogas.

Data for biogas from municipal waste, liquid manure, and maize whole plant silage fermentation are from [Giuntoli et al. 2017] and [GEMIS 2007]. The data for biogas from sewage sludge are from [Boisen 2005] (electricity), [Giuntoli et al. 2017] (feedstock input, assumption: same as for liquid manure) and [Haberkern 2008] (heat). The data for the fermentation of whole plant silage from double cropping are from [Agostini 2012] and [GEMIS 2007].

When left untreated, stored manure produces methane that is vented to the atmosphere. This is particularly so for liquid manure where the right conditions for anaerobic fermentation are met. Using manure for biogas production therefore offers a credit for avoided "field" methane emissions. This should be larger for liquid manure than solid, but we only have an average figure.

8.1 Compressed biomethane (CBM) from biogas

8.1.1 Upgraded biogas from municipal organic waste as CMG closed digestate storage (OWCG1)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
BG3.1	**Fermenter (closed digestate storage)**							[Giuntoli et al. 2017]
	Raw gas yield		MJ/MJ$_{waste}$	0.7073	0.7445	0.6736	Square	
	Heat to process		MJ/MJ$_{\text{raw gas}}$	0.0976	0.0927	0.1024	Square	
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/MJ$_{\text{raw gas}}$	0.0293	0.0278	0.0307	Square	
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ$_{heat}$	0.0056				
	N_2O emissions		g/MJ$_{heat}$	0.0011				
BG4.1	**Upgrading**							
	Upgraded gas yield		MJ/MJ$_{\text{raw gas}}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{gas}$	0.0300				[Schulz 2004], JRC internal
	RED methodology							
	No credit for N fertilizer							
	Conditioning & Distribution							
	Local distribution (low pressure)							
	No contribution							
GG5	**Compression and dispensing**							
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{CBG}$	0.0220	0.0140	0.0270	2-triangle	[LBST internal]
	CH_4 emissions		g/MJ$_{CBG}$	0.0001				

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

8.1.1.1 BG3.1 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a "digester" in a batch process that can take several days. The gas produced is collected and sent to the treating section. The conversion level of the organic matter is typically 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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. (version 3 of this study assumed a gas engine supplying both heat and electricity but we have modified this to ensure consistency amongst all CMG pathways). Some methane losses are incurred as well as some N_2O emissions.

8.1.1.2 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be "upgraded" i.e. treated to remove contaminants such as H_2S and CO_2 to supply biomethane.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H_2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas).

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.1.1.3 GG5 Compression and dispensing

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement.

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

8.1.2 Upgraded biogas from wet manure as CBM. Digestate storage closed (21) or open (22) (OWCG21/2)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
BG1.1	**GHG emissions credit from avoided manure storage**							[Guintoli et al. 2017]
	CH_4 emissions		g/MJ_{manure}	-1.4700				
	N_2O emissions		g/MJ_{manure}	-0.0279				
	Transformation at source							
	NA							
	Transportation to market							
BG2.2	**Manure transport (Road)**							
	Distance	*F1*	km	10				
	Transformation near market							
BG3.21	**Fermenter (closed digestate storage)**							JRC internal
OWCG21	Raw gas yield		MJ/MJ_{manure}	0.4620				
	Heat to process		MJ/$MJ_{raw\ gas}$	0.0909				
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/$MJ_{raw\ gas}$	0.0182				
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ_{heat}	0.0056				
	N_2O emissions		g/MJ_{heat}	0.0011				
BG3.22	**Fermenter (open digestate storage)**							JRC internal
OWCG22	Raw gas yield		MJ/MJ_{manure}	0.4200				
	Heat to process		MJ/$MJ_{raw\ gas}$	0.1000				
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/$MJ_{raw\ gas}$	0.0200				
	CH_4 emissions		g/$MJ_{raw\ gas}$	2.00				
	N_2O emissions		g/$MJ_{raw\ gas}$	0.0660				
BG4.1	**Upgrading**							
	Upgraded gas yield		MJ/$MJ_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	RED methodology							
	No CH_4 field emission credit							
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GG5	**Compression and dispensing**							
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{CBG}	0.0220	0.0140	0.0270	2-triangle	[LBST internal]
	CH_4 emissions		g/MJ_{CBG}	0.0113				

8.1.2.1 BG1.1 GHG emissions credit from avoided manure storage

If unused or stored, wet manure would produce CH4 and N2O from naturally occurring anaerobic digestion. These emissions are avoided by controlling this process and collecting the gas produced.

8.1.2.2 BG2.2 Manure transport (Road)

Manure has to be transported over a short distance from the farm to the biogas plant. Road transport is assumed by a standard road truck according to process Z2.

8.1.2.3 BG3.21 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. In case of manure the conversion level of the organic matter is typically about 46% (closed digestate storage with CH4 capture and use). Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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.

8.1.2.4 BG3.22 Fermenter (open digestate storage)

This variant is presented to illustrate the impact of letting all methane from digestate escape to atmosphere.

8.1.2.5 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.1.2.6 GG5 Compression and dispensing

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement.

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

8.1.3 Upgraded biogas from sewage sludge as CBM closed digestate storage (OWCG3)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
BG3.5	**Fermenter for biogas from sewage sludge (closed digestate storage)**							
	Raw gas yield		MJ/MJ_{sludge}	0.4620	0.4863	0.4400	Equal	[Giuntoli et al. 2017]
	Heat to process		MJ/MJ_{sludge}	0.4767				[Haberkern 2008]
	Electricity (EU-mix, LV) to process	*EMLa*	$MJ/MJ_{raw\ gas}$	0.0688				[Boison 2005]
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ_{heat}	0.0056				
	N_2O emissions		g/MJ_{heat}	0.0011				
BG4.1	**Upgrading**							
	Upgraded gas yield		$MJ/MJ_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	RED methodology							
	No credit for N fertilizer							
	Conditioning & Distribution							
	Local distribution (low pressure)							
	No contribution							
GG5	**Compression and dispensing**							
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{CBG}	0.0220	0.0140	0.0270	2-triangle	[LBST internal]
	CH_4 emissions		g/MJ_{CBG}	0.0001				

8.1.3.1 BG3.5 Fermenter for biogas from sewage sludge (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. It has been assumed that the conversion level of the organic matter is the same as for manure (46% in case of closed digestate storage with CH4 capture and use). Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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. (version 3 of this study assumed a gas engine supplying both heat and electricity but we have modified this to ensure consistency amongst all CBM pathways). Some methane losses are incurred as well as some N2O emissions.

8.1.3.2 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas).

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.1.3.3 GG5 Compression and dispensing

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement.

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

8.1.4 Upgraded biogas from maize (whole plant) as CBM closed digestate storage (OWCG4)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
BG1.4	**Maize cultivation**							[Giuntoli et al. 2017]
	Agricultural inputs							
	Fertilizers		g/MJ$_{\text{maize}}$					
	N (as N)	*FN*		0.26				
	P (as P2O5)	*FP*		0.16				
	K (as K2O)	*FK*		0.10				
	CaO	*CA*		0.65				
	Pesticides	*PE*		0.03				
	Seeding material	*SCR*		0.10				
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{\text{maize}}$	0.0155				
	CH4 emissions (from diesel)		g/MJ$_{\text{maize}}$	0.0000198				
	CO2 emissions from soil neutralisation			0.257				
	Field emissions (N2O)		g/MJ$_{\text{maize}}$	0.0193	0.0044	0.0969	2-triangle	[IPCC 2006], [Giuntoli et al. 2017]
	Ensiling							[Giuntoli et al. 2017]
	Losses			10%				
	Diesel			0.00375				
	CH4 emissions diesel			0.00000479				
	N2O emissions from diesel			0.00001180				
	Transformation at source							
	NA							
	Transportation to market							
BG2.4	**Maize transport (Road)**							[Giuntoli et al. 2017]
	Distance	*T1*	km	20				
	Transformation near market							
BG3.4	**Fermenter (closed digestate storage)**							JRC internal
	Raw gas yield		MJ/MJ$_{\text{maize}}$	1.3978				
	Heat to process		MJ/MJ$_{\text{raw gas}}$	0.0978				[GEMIS 2007]
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/MJ$_{\text{raw gas}}$	0.0245				[IEA Biogas Handbook 2013]; [Boulamanti
BG4.1	**Upgrading**							
	Upgraded gas yield		MJ/MJ$_{\text{raw gas}}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{\text{gas}}$	0.0300				[Schulz 2004], JRC internal
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GG5	**Compression and dispensing**							
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{\text{CBG}}$	0.0220	0.0140	0.0270	2-triangle	[LBST internal]
	CH_4 emissions		g/MJ$_{\text{CBG}}$	0.0246				

8.1.4.1 BG1.4 Maize cultivation

The maize variety grown for the purpose of producing biogas (maximum biomass) is assumed to be different from standard maize cultivated for grain (such as used in e.g. pathway CRET2).

The yield of maize whole crop (40.76 t of fresh substance per ha and year @ a dry matter content of 35%) and the use of fertilizers is calculated as an average over the EU-27 based on FAOSTAT data for the years 2011 and 2010. The amount of synthetic fertilizer applied accounts already for the application of other organic fertilizers such as manure and digestate (the residue of the anaerobic digestion) [Giuntoli et al. 2017].

8.1.4.2 BG2.4 Maize transport (Road)

Maize is transported by road over a short distance. We assumed a standard truck as described in common process T1.

8.1.4.3 BG3.4 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. In case of maize whole plant silage, the conversion level of the organic matter is typically about 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

8.1.4.4 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be "upgraded" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.1.4.5 GG5 Compression and dispensing

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement.

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to

2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

8.1.5 Upgraded biogas from double cropping (barley/maize) as CBM closed digestate storage (OWCG5)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
BG1.4	**Double cropping (barley/maize)**							[GEMIS 2005], [Grass 2001]
	Agricultural inputs							
	N Fertilizer (as N)		g/MJ_{crop}	0.25				
	Seeding material (barley/corn)	*SBA/SCR*	g/MJ_{crop}	0.37				
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{maize}	0.0260				
	CH4 emissions (from diesel)		g/MJ_{maize}	0.0002				
	CO2 emissions from soil neutralisation			2.01				
	Field emissions (N2O)		g/MJ_{maize}	0.0053	0.0011	0.0253	2-triangle	[IPCC 2006]
	Transformation at source							
	NA							
	Transportation to market							
BG2.4	**Crop transport (Road)**							
	Distance	*T1*	km	20				
	Transformation near market							
BG3.4	**Fermenter (closed digestate storage)**							JRC internal
	Raw gas yield		MJ/MJ_{crop}	1.3978				
	Heat to process		MJ/$MJ_{raw\ gas}$	0.0978				[GEMIS 2007]
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/$MJ_{raw\ gas}$	0.0245				
BG4.1	**Upgrading**							
	Upgraded gas yield		MJ/$MJ_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GG5	**Compression and dispensing**							
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{CBG}	0.0220	0.0140	0.0270	2-triangle	[LBST internal]
	CH_4 emissions		g/MJ_{CBG}	0.0246				

8.1.5.1 BG1.4 Double cropping (barley/maize)

Two crops are grown sequentially on the same land and within a single, the whole plant being harvested perhaps before it reaches maturity. In European conditions, maize and barley appear to be the best crops for this purpose where the objective is simply to maximise the amount of biomass produced.

8.1.5.2 BG2.4 Crop transport (Road)

The crops are transported by road over a short distance. We assumed a standard truck as described in common process T1.

8.1.5.3 BG3.4 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. The conversion level of the organic matter is typically 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

8.1.5.4 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.1.5.5 GG5 Compression and dispensing

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement.

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

8.2 Compressed biomethane (CBM) from synthetic methane (SNG)

8.2.1 Synthetic methane (as CBM) via gasification of waste wood and methanation (WWCG2)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
FRC	**Forestry residue collection**							
	Diesel	*F1*	MJ/MJ_{wood}	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindholm 201
W2	**Forestry residue chipping**							
	Diesel	*F1*	MJ/MJ_{wood}	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WW3b	**Waste wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
	Transformation near market							
WG	**Synthetic natural gas (SNG) from wood**							
	Efficiency			66.4%				[DBFZ 2009], [Kaltschmitt 2001]
	Electricity	*EMMa*	MJ/MJ_{SNG}	0.0649				[DBFZ 2009]
	RME		MJ/MJ_{SNG}	0.0410				[DBFZ 2009]
	LPG		MJ/MJ_{SNG}	0.0454				[DBFZ 2009]
	Heat surplus		MJ/MJ_{SNG}	-0.0268				[DBFZ 2009]
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GG5	**Compression and dispensing**							
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{CBG}	0.0220	0.0140	0.0270	2-triangle	[LBST internal]
	CH_4 emissions		g/MJ_{CBG}	0.0246				

8.2.1.1 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

8.2.1.2 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Guintoli et al. 2017].

8.2.1.3 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

8.2.1.4 WW3b Waste wood transport (regional, 500 km)

For large plants a transport distance of 500 km has been assumed if the wood is derived from regions inside the EU.

8.2.1.5 WG Synthetic natural gas (SNG) from wood

A large plant with a capacity of 380 MW of synthetic natural gas (SNG) has been assumed as described in [DBFZ 2009] as long-term technology. An indirectly heated fast Internally circulating fluidized bed (FICFB) gasifier has been used to convert the wood chips into synthesis gas.

The synthesis gas leaving the gasifier is purified by a precoat filter, scrubbing with rapeseed methylester (RME), scrubbing with an alkaline scrubbing agent, and then adsorption by a ZnO bed. The RME is used as scrubbing agent for tar removal, the scrubbing with an alkaline scrubbing agent with downstream ZnO bed to remove sulphur. The purified synthesis gas is sent to methanation.

The methane rich gas leaving the methanation step is upgraded using amines as scrubbing agent for to remove residual CO2. NH3 is removed by a separate scrubber. Then the gas is dried using triethyleneglycol (TEG). Unreacted hydrogen is separated via membranes and sent back to the methanation reactor. The plant also includes compression of the synthetic methane to a pressure of 7 MPa [DBFZ 2009].

Methanation of gas mixtures consisting of CO, H2 and CO_2 is a mature technology. A lignite-to-SNG has been operated at the Great Plains Synfuel Plant in the USA since 1984. Syngas from biomass gasification can contain ethylene (C2H4) which tends to form carbon whiskers on nickel catalysts in fixed bed reactors. Therefore, fluidized bed methanation has been applied for the biomass-to-SNG pilot plant in Güssing [Schildhauer & Biollaz 2009]. There are several biomass-to-SNG pilot plants, e.g. in Güssing in Austria (1 MW SNG) [Schildhauer & Biollaz 2009] and in Göteborg in Sweden (GoBiGas: 20 MW SNG) [Larsson 2017].

8.2.1.6 GG5 Compression and dispensing

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement.

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

8.2.2 Synthetic methane (as CBM) via gasification of wood chips from short rotation forestry and methanation (WFCG2)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation**							
	Agricultural inputs							
	Fertilizers	*FN*	g/MJ$_{wood}$					
	N (as N)			0.00				JRC internal
	Pesticides	*PE*	g/MJ$_{wood}$	0.015				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000161				
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000397				
	N_2O field emissions		g/MJ$_{wood}$	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3b	**Farmed wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
	Transformation near market							
WG	**Synthetic natural gas (SNG) from wood**							
	Efficiency			66.4%				[DBFZ 2009], [Kaltschmitt 2001]
	Electricity	*EMMa*	MJ/MJ$_{SNG}$	0.0649				[DBFZ 2009]
	RME		MJ/MJ$_{SNG}$	0.0410				[DBFZ 2009]
	LPG		MJ/MJ$_{SNG}$	0.0454				[DBFZ 2009]
	Heat surplus		MJ/MJ$_{SNG}$	-0.0268				[DBFZ 2009]
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GG5	**Compression and dispensing**							
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{CBG}$	0.0220	0.0140	0.0270	2-triangle	[LBST internal]
	CH_4 emissions		g/MJ$_{CBG}$	0.0246				

8.2.2.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

8.2.2.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

8.2.2.3 WF3b Farmed wood transport (regional, 500 km)

For large plants a transport distance of 500 km has been assumed if the wood is derived from regions inside the EU.

8.2.2.4 WG Synthetic natural gas (SNG) from wood

A large plant with a capacity of 380 MW of synthetic natural gas has been assumed as described in [DBFZ 2009] as long-term technology. An indirectly heated fast Internally circulating fluidized bed (FICFB) gasifier has been used to convert the wood chips into synthesis gas.

The synthesis gas leaving the gasifier is purified by a precoat filter, scrubbing with rape seed methylester (RME), scrubbing with an alkaline scrubbing agent, and then adsorption by a ZnO bed. The RME is used as scrubbing agent for tar removal, the scrubbing with an alkaline scrubbing agent with downstream ZnO bed to remove sulphur. The purified synthesis gas is sent to methanation.

The methane rich gas leaving the methanation step is upgraded using amines as scrubbing agent for to remove residual CO_2. NH3 is removed by a separate scrubber. Then the gas is dried using triethyleneglycol (TEG). Unreacted hydrogen is separated via membranes and sent back to the methanation reactor. The plant also includes compression of the synthetic methane to a pressure of 7 MPa [DBFZ 2009].

Methanation of gas mixtures consisting of CO, H2 and CO2 is a mature technology. A lignite-to-SNG has been operated at the Great Plains Synfuel Plant in the USA since 1984. Syngas from biomass gasification can contain ethylene (C2H4) which tends to form carbon whiskers on nickel catalysts in fixed bed reactors. Therefore, fluidized bed methanation has been applied for the biomass-to-SNG pilot plant in Güssing [Schildhauer & Biollaz 2009]. There are several biomass-to-SNG pilot plants, e.g. in Güssing in Austria (1 MW SNG) [Schildhauer & Biollaz 2009] and in Göteborg in Sweden (GoBiGas: 20 MW SNG) [Larsson 2017].

8.2.2.5 GG5 Compression and dispensing

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement.

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

8.2.3 Synthetic methane (as CNG) from renewable electricity and CO_2 from flue gases (RECG1)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
WD1	**Wind turbine**							[GEMIS 2000]
	No expended energy or emissions							
	Transformation at source							
	NA							
	Transportation to market							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
	NA							
	Transformation near market							
YH1	**Hydrogen via electrolysis (large plant)**							
	Electricity		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
CA1	**CO_2 absorption (from flue gases)**							[Socolow 2011]
	Electricity (wind)		MJ/kg	0.0334				
	Heat		MJ/kg	4.2998				
CC1	**CO_2 compression**							
	Electricity (wind)		MJ/kg	0.1454				
HG1	**Methane synthesis**							[Breyer 2011]
	CO_2		kg/MJ_{CH4}	0.0550				
	Hydrogen		MJ/MJ_{CH4}	1.1998				
	Heat surplus		MJ/MJ_{CH4}	-0.1998				
	Conditioning & Distribution							
	Local distribution (low pressure)							
	No contribution							
GG5	**Compression and dispensing**							
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{CBG}	0.0220	0.0140	0.0270	2-triangle	[LBST internal]
	CH_4 emissions		g/MJ_{CBG}	0.0001				

8.2.3.1 WD1 Wind turbine

Electricity from wind turbine is energy and emission - free (as we do not consider energy and emissions related to construction and maintenance).

8.2.3.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report

8.2.3.3 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

8.2.3.4 YH1 Hydrogen via electrolysis (large plant)

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPa_g electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].
- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].
- McPhy indicates an electricity consumption of 4.5 kWh/Nm^3 at nominal flow rate for its 800 Nm^3/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPa_g [McPhy 2017].

Several sources of data are available, giving figures for both for small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depends on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPa$_g$ [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh$_e$/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 68% (4.8 to 5.4 kWhe/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

8.2.3.5 CA1 CO_2 absorption (from flue gases)

CO_2 is assumed to be recovered from the flue gases of e.g. a power station. It is extracted from the flue gas stream via scrubbing with monoethanolamine (MEA). The regeneration of the scrubbing agent is carried out to a large extent with the heat from the methanation process.

8.2.3.6 CC1 CO_2 compression

CO_2 is available at or near atmospheric pressure and needs to be compressed to about 0.5 MPa.

8.2.3.7 HG1 Methane synthesis

Hydrogen reacts with CO_2 in the methanation reaction:

4 H2 + CO2 => CH4 + 2 H2O

The reaction is exothermic. About 83% of the LHV of the hydrogen is recovered in the methane. The catalytic methanation process is carried out at a temperature of 200 to 400°C and a pressure of 0.5 MPa. Alternatively, the methanation can be carried out biologically in-situ a fermenter of a biogas plant. But this variant has not been considered in this study.

For power-to-methane plants new fixed bed plate reactors have been developed which can quicker load changes than conventional fixed bed reactors. As a result, a smaller H2 buffer storage is sufficient to operate the plant in combination with fluctuating renewable energy sources such as wind power and solar. In contrast to biomass-to-SNG plants no ethylene occurs in the feed gas stream and no formation of carbon whiskers on the catalyst can occur. In June 2018, 12 power-to-methane plants are operated in the EU (thereof 10 in Germany, 1 in Denmark, 1 in Netherlands), 3 power-to-methane plant are under construction (1 in Germany, 1 in Italy, 1 in Sweden), and another 3 power-to-methane plants are planned (2 in Germany, 1 in France). One example is the Audi e-gas plant in Werlte in Germany with a capacity of about 3.2 MW of synthetic methane. In Werlte, the CO_2 has been derived from biogas upgrading.

8.2.3.8 GG5 Compression and dispensing

Synthetic methane is available at the plant outlet at a pressure level which is considered adequate for joining the grid without any further energy requirement.

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [Greenfield 2002] the methane emissions during NG compression can be lowered to virtually zero.

8.3 Liquefied biomethane (LBM) from biogas

8.3.1 Upgraded biogas from municipal organic waste as liquefied biomethane (LBM) closed digestate storage (OWLG1)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
BG3.1	**Fermenter (closed digestate storage)**							[Giuntoli et al. 2017]
	Raw gas yield		MJ/MJ$_{waste}$	0.7073	0.7445	0.6736	Square	
	Heat to process		MJ/MJ$_{raw\ gas}$	0.0976	0.0927	0.1024	Square	
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/MJ$_{raw\ gas}$	0.0293	0.0278	0.0307	Square	
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ$_{heat}$	0.0056				
	N_2O emissions		g/MJ$_{heat}$	0.0011				
BG4.1	**Upgrading**							
	Upgraded gas yield		MJ/MJ$_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{gas}$	0.0300				[Schulz 2004], JRC internal
	RED methodology							
	No credit for N fertilizer							
	Conditioning & Distribution							
	Local distribution (low pressure)							
	No contribution							
GL1	**Liquefaction of upgraded biogas onsite refueling station**							[Galileo 2013]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{LBG}$	0.06048				
	LPG		MJ/MJ$_{LBG}$	0.00013				
	Lubricants		g/MJ$_{LBG}$	0.0041				
GR8	**Dispensing**							[Messer 1998]
	Losses			0.001%				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{LBG}$	0.0001				

8.3.1.1 BG3.1 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a "digester" in a batch process that can take several days. The gas produced is collected and sent to the treating section. The conversion level of the organic matter is typically 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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. (Version 3 of this study assumed a gas engine supplying both heat and electricity but we have modified this to ensure consistency amongst all LBM pathways). Some methane losses are incurred as well as some N2O emissions.

8.3.1.2 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be "upgraded" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas).

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.3.1.3 GL1 Liquefaction of upgraded biogas onsite refueling station

The data for decentralized CH4 liquefaction have been derived from model 'CRYOBOX' offered by Galileo [Galileo 2013]. The electricity consumption is indicated with 420 kW per 500 kg of liquefied methane. Additionally, small amounts of lubricant (0.12 kg/h) and propane (0.07 kg/h) is required.

8.3.1.4 GR8 Dispensing

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm^3 of natural gas per day and bus.

8.3.2 Upgraded biogas from wet manure as liquefied biomethane (LBM). Digestate storage closed (21) or open (22) (OWLG21/2)

Process code	*Step*	*Common processes*		*Input*	*Range*	*Distribution*	*Source*
	Production & conditioning at source						
BG1.1	**GHG emissions credit from avoided manure storage**						[Guintoli et al. 2017]
	CH_4 emissions		g/MJ$_{manure}$	-1.4700			
	N_2O emissions		g/MJ$_{manure}$	-0.0279			
	Transformation at source						
	NA						
	Transportation to market						
BG2.2	**Manure transport (Road)**						
	Distance	*F1*	km	10			
	Transformation near market						
BG3.21	**Fermenter (closed digestate storage)**						JRC internal
OWCG21	Raw gas yield		MJ/MJ$_{manure}$	0.4620			
	Heat to process		MJ/MJ$_{raw\ gas}$	0.0909			
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/MJ$_{raw\ gas}$	0.0182			
	Internal heat generation using own raw gas						[GEMIS 2007]
	Efficiency		%	90.0%			
	CH_4 emissions		g/MJ$_{heat}$	0.0056			
	N_2O emissions		g/MJ$_{heat}$	0.0011			
BG3.22	**Fermenter (open digestate storage)**						JRC internal
OWCG22	Raw gas yield		MJ/MJ$_{manure}$	0.4200			
	Heat to process		MJ/MJ$_{raw\ gas}$	0.1000			
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/MJ$_{raw\ gas}$	0.0200			
	CH_4 emissions		g/MJ$_{raw\ gas}$	2.00			
	N_2O emissions		g/MJ$_{raw\ gas}$	0.0660			
BG4.1	**Upgrading**						
	Upgraded gas yield		MJ/MJ$_{raw\ gas}$	0.9700			JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{gas}$	0.0300			[Schulz 2004], JRC internal
	RED methodology						
	No CH_4 field emission credit						
	Conditioning & Distribution						
GG4	**Local distribution (low pressure)**						
	No contribution						
GL1	**Liquefaction of upgraded biogas onsite refueling station**						[Galileo 2013]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{LBG}$	0.06048			
	LPG		MJ/MJ$_{LBG}$	0.00013			
	Lubricants		g/MJ$_{LBG}$	0.0041			
GR8	**Dispensing**						[Messer 1998]
	Losses			0.001%			
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{LBG}$	0.0001			

8.3.2.1 BG1.1 GHG emissions credit from avoided manure storage

If unused or stored, wet manure would produce CH4 and N2O from naturally occurring anaerobic digestion. These emissions are avoided by controlling this process and collecting the gas produced.

8.3.2.2 BG2.2 Manure transport (Road)

Manure has to be transported over a short distance from the farm to the biogas plant. Road transport is assumed by a standard road truck according to process Z2.

8.3.2.3 BG3.21 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a "digester" in a batch process that can take several days. The gas produced is collected and sent to the treating section. In case of manure the conversion level of the organic matter is typically about 46% (closed digestate storage with CH4 capture and use). Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

8.3.2.4 BG3.22 Fermenter (open digestate storage)

This variant is presented to illustrate the impact of letting all methane from digestate escape to atmosphere.

8.3.2.5 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the "in-house" power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.3.2.6 GL1 Liquefaction of upgraded biogas onsite refueling station

The data for decentralized CH4 liquefaction have been derived from model 'CRYOBOX' offered by Galileo [Galileo 2013]. The electricity consumption is indicated with 420 kW per 500 kg of liquefied methane. Additionally, small amounts of lubricant (0.12 kg/h) and propane (0.07 kg/h) is required.

8.3.2.7 GR8 Dispensing

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm^3 of natural gas per day and bus.

8.3.3 Upgraded biogas from sewage sludge as liquefied biomethane (LBM) closed digestate storage (OWLG3)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
BG3.5	**Fermenter for biogas from sewage sludge (closed digestate storage)**							
	Raw gas yield		MJ/MJ_{sludge}	0.4620	0.4863	0.4400	Equal	[Giuntoli et al. 2017]
	Heat to process		MJ/MJ_{sludge}	0.4767				[Haberkern 2008]
	Electricity (EU-mix, LV) to process	*EMLa*	$MJ/MJ_{raw\ gas}$	0.0688				[Boison 2005]
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ_{heat}	0.0056				
	N_2O emissions		g/MJ_{heat}	0.0011				
BG4.1	**Upgrading**							
	Upgraded gas yield		$MJ/MJ_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	RED methodology							
	No credit for N fertilizer							
	Conditioning & Distribution							
	Local distribution (low pressure)							
	No contribution							
GL1	**Liquefaction of upgraded biogas onsite refueling station**							[Galileo 2013]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LBG}	0.06048				
	LPG		MJ/MJ_{LBG}	0.00013				
	Lubricants		g/MJ_{LBG}	0.0041				
GR8	**Dispensing**							[Messer 1998]
	Losses			0.001%				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LBG}	0.0001				

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

8.3.3.1 BG3.5 Fermenter for biogas from sewage sludge (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a "digester" in a batch process that can take several days. The gas produced is collected and sent to the treating section. It has been assumed that the conversion level of the organic matter is the same as for manure (46% in case of closed digestate storage with CH4 capture and use). Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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. (version 3 of this study assumed a gas engine supplying both heat and electricity but we have modified this to ensure consistency amongst all LBM pathways). Some methane losses are incurred as well as some N2O emissions.

8.3.3.2 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the "in-house" power plant. Typical water consumption is 10-20 m3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas).

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.3.3.3 GL1 Liquefaction of upgraded biogas onsite refueling station

The data for decentralized CH4 liquefaction have been derived from model 'CRYOBOX' offered by Galileo [Galileo 2013]. The electricity consumption is indicated with 420 kW per 500 kg of liquefied methane. Additionally, small amounts of lubricant (0.12 kg/h) and propane (0.07 kg/h) is required.

8.3.3.4 GR8 Dispensing

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm³ of natural gas per day and bus.

8.3.4 Upgraded biogas from maize (whole plant) as liquefied biomethane (LBM) closed digestate storage (OWLG4)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
BG1.4	**Maize cultivation**							[Giuntoli et al. 2017]
	Agricultural inputs							
	Fertilizers		g/MJ$_{maize}$					
	N (as N)	*FN*		0.26				
	P (as P2O5)	*FP*		0.16				
	K (as K2O)	*FK*		0.10				
	CaO	*CA*		0.65				
	Pesticides	*PE*		0.03				
	Seeding material	*SCR*		0.10				
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{maize}$	0.0155				
	CH4 emissions (from diesel)		g/MJ$_{maize}$	0.0000198				
	CO2 emissions from soil neutralisation			0.257				
	Field emissions (N2O)		g/MJ$_{maize}$	0.0193	0.0044	0.0969	2-triangle	[IPCC 2006], [Giuntoli et al. 2017]
	Ensiling							[Giuntoli et al. 2017]
	Losses			10%				
	Diesel			0.00375				
	CH4 emissions diesel			0.00000479				
	N2O emissions from diesel			0.00001180				
	Transformation at source							
	NA							
	Transportation to market							
BG2.4	**Maize transport (Road)**							[Giuntoli et al. 2017]
	Distance	*T1*	km	20				
	Transformation near market							
BG3.4	**Fermenter (closed digestate storage)**							JRC internal
	Raw gas yield		MJ/MJ$_{maize}$	1.3978				
	Heat to process		MJ/MJ$_{raw\ gas}$	0.0978				[GEMIS 2007]
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/MJ$_{raw\ gas}$	0.0245				[IEA Biogas Handbook 2013]; [Boulamanti et al. 2013]
BG4.1	**Upgrading**							
	Upgraded gas yield		MJ/MJ$_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{gas}$	0.0300				[Schulz 2004], JRC internal
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GL1	**Liquefaction of upgraded biogas onsite refueling station**							[Galileo 2013]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{LBG}$	0.06048				
	LPG		MJ/MJ$_{LBG}$	0.00013				
	Lubricants		g/MJ$_{LBG}$	0.0041				
GR8	**Dispensing**							[Messer 1998]
	Losses			0.001%				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{LBG}$	0.0001				

8.3.4.1 BG1.4 Maize cultivation

The maize variety grown for the purpose of producing biogas (maximum biomass) is assumed to be different from standard maize cultivated for grain (such as used in e.g. pathway CRET2).

The yield of maize whole crop (40.76 t of fresh substance per ha and year @ a dry matter content of 35%) and the use of fertilizers is calculated as an average over the EU-27 based on FAOSTAT data for the years 2011 and 2010. The amount of synthetic fertilizer applied accounts already for the application of other organic fertilizers such as manure and digestate (the residue of the anaerobic digestion) [Giuntoli et al. 2017].

8.3.4.2 BG2.4 Maize transport (Road)

Maize is transported by road over a short distance. We assumed a standard truck as described in common process T1.

8.3.4.3 BG3.4 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. In case of maize whole plant silage, the conversion level of the organic matter is typically about 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

8.3.4.4 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.3.4.5 GL1 Liquefaction of upgraded biogas onsite refueling station

The data for decentralized CH4 liquefaction have been derived from model 'CRYOBOX' offered by Galileo [Galileo 2013]. The electricity consumption is indicated with 420 kW per 500 kg of liquefied methane. Additionally, small amounts of lubricant (0.12 kg/h) and propane (0.07 kg/h) is required.

8.3.4.6 GR8 Dispensing

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm^3 of natural gas per day and bus.

8.3.5 Upgraded biogas from double cropping (barley/maize) as liquefied biomethane (LBM) closed digestate storage (OWLG5)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
BG1.4	**Double cropping (barley/maize)**							[GEMIS 2005], [Grass 2001]
	Agricultural inputs							
	N Fertilizer (as N)		g/MJ_{crop}	0.25				
	Seeding material (barley/corn)	*SBA/SCR*	g/MJ_{crop}	0.37				
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{maize}	0.0260				
	CH4 emissions (from diesel)		g/MJ_{maize}	0.0002				
	CO2 emissions from soil neutralisation			2.01				
	Field emissions (N2O)		g/MJ_{maize}	0.0053	0.0011	0.0253	2-triangle	[IPCC 2006]
	Transformation at source							
	NA							
	Transportation to market							
BG2.4	**Crop transport (Road)**							
	Distance	*T1*	km	20				
	Transformation near market							
BG3.4	**Fermenter (closed digestate storage)**							JRC internal
	Raw gas yield		MJ/MJ_{crop}	1.3978				
	Heat to process		$MJ/MJ_{raw\ gas}$	0.0978				[GEMIS 2007]
	Electricity (EU-mix, LV) to process	*EMLa*	$MJ/MJ_{raw\ gas}$	0.0245				
BG4.1	**Upgrading**							
	Upgraded gas yield		$MJ/MJ_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GL1	**Liquefaction of upgraded biogas onsite refueling station**							[Galileo 2013]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LBG}	0.06048				
	LPG		MJ/MJ_{LBG}	0.00013				
	Lubricants		g/MJ_{LBG}	0.0041				
GR8	**Dispensing**							[Messer 1998]
	Losses			0.001%				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LBG}	0.0001				

8.3.5.1 BG1.4 Double cropping (barley/maize)

Two crops are grown sequentially on the same land and within a single, the whole plant being harvested perhaps before it reaches maturity. In European conditions, maize and barley appear to be the best crops for this purpose where the objective is simply to maximise the amount of biomass produced.

8.3.5.2 BG2.4 Crop transport (Road)

The crops are transported by road over a short distance. We assumed a standard truck as described in common process T1.

8.3.5.3 BG3.4 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a "digester" in a batch process that can take several days. The gas produced is collected and sent to the treating section. The conversion level of the organic matter is typically 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

8.3.5.4 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO_2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the "in-house" power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

8.3.5.5 GL1 Liquefaction of upgraded biogas onsite refueling station

The data for decentralized CH4 liquefaction have been derived from model 'CRYOBOX' offered by Galileo [Galileo 2013]. The electricity consumption is indicated with 420 kW per 500 kg of liquefied methane. Additionally, small amounts of lubricant (0.12 kg/h) and propane (0.07 kg/h) is required.

8.3.5.6 GR8 Dispensing

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm^3 of natural gas per day and bus.

8.4 Synthetic natural gas (SNG) as liquefied biomethane (LBM) and synthetic liquefied natural gas (LSNG)

8.4.1 Synthetic natural gas as LBM via gasification of waste wood and methanation (WWLG2)

Process code	*Step*	*Common processes*		*Input*	*Range*	*Distribution*	*Source*
	Production & conditioning at source						
FRC	**Forestry residue collection**						
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0120			[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038			[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**						
	Losses			5.0%			[Hamelinck 2005], [Kofman 2012], [Lindholm 2010]
W2	**Forestry residue chipping**						
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0034			[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011			[EMEP/EEA 2013]
	Losses			2.5%			[JRC 2013], [Sikkema et al. 2010]
	Transformation at source						
	NA						
	Transportation to market						
	Wood moisture content			30%			
WW3b	**Waste wood transport (regional, 500 km)**						JRC internal
	Road truck	*T1*					
	Distance		km	500			
	Transformation near market						
WG	**Synthetic natural gas (SNG) from wood**						
	Efficiency			66.4%			[DBFZ 2009], [Kaltschmitt 2001]
	Electricity	*EMMa*	MJ/MJ$_{SNG}$	0.0649			[DBFZ 2009]
	RME		MJ/MJ$_{SNG}$	0.0410			[DBFZ 2009]
	LPG		MJ/MJ$_{SNG}$	0.0454			[DBFZ 2009]
	Heat surplus		MJ/MJ$_{SNG}$	-0.0268			[DBFZ 2009]
	Conditioning & Distribution						
GG4	**Local distribution (low pressure)**						
	No contribution						
GL1	**Liquefaction of upgraded biogas onsite refueling station**						[Galileo 2013]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{LBG}$	0.06048			
	LPG		MJ/MJ$_{LBG}$	0.00013			
	Lubricants		g/MJ$_{LBG}$	0.0041			
GR8	**Dispensing**						[Messer 1998]
	Losses			0.001%			
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{LBG}$	0.0001			

8.4.1.1 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

8.4.1.2 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Giuntoli et al. 2017].

8.4.1.3 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

8.4.1.4 WW3b Waste wood transport (regional, 500 km)

For large plants a transport distance of 500 km has been assumed if the wood is derived from regions inside the EU.

8.4.1.5 WG Synthetic natural gas (SNG) from wood

A large plant with a capacity of 380 MW of synthetic natural gas has been assumed as described in [DBFZ 2009] as long-term technology. An indirectly heated fast. Internally circulating fluidized bed (FICFB) gasifier has been used to convert the wood chips into synthesis gas.

The synthesis gas leaving the gasifier is purified by a precoat filter, scrubbing with rape seed methylester (RME), scrubbing with an alkaline scrubbing agent, and then adsorption by a ZnO bed. The RME is used as scrubbing agent for tar removal, the scrubbing with an alkaline scrubbing agent with downstream ZnO bed to remove sulphur. The purified synthesis gas is sent to methanation.

The methane rich gas leaving the methanation step is upgraded using amines as scrubbing agent for to remove residual CO_2. NH3 is removed by a separate scrubber. Then the gas is dried using triethyleneglycol (TEG). Unreacted hydrogen is separated via membranes and sent back to the methanation reactor. The plant also includes compression of the synthetic methane to a pressure of 7 MPa [DBFZ 2009].

Methanation of gas mixtures consisting of CO, H2 and CO_2 is a mature technology. A lignite-to-SNG has been operated at the Great Plains Synfuel Plant in the USA since 1984. Syngas from biomass gasification can contain ethylene (C2H4) which tends to form carbon whiskers on nickel catalysts in fixed bed reactors. Therefore, fluidized bed methanation has been applied for the biomass-to-SNG pilot plant in Güssing [Schildhauer & Biollaz 2009]. There are several biomass-to-SNG pilot plants, e.g. in Güssing in Austria (1 MW SNG) [Schildhauer & Biollaz 2009] and in Göteborg in Sweden (GoBiGas: 20 MW SNG) [Larsson 2017].

8.4.1.6 GL1 Liquefaction of upgraded biogas onsite refueling station

The data for decentralized CH4 liquefaction have been derived from model 'CRYOBOX' offered by Galileo [Galileo 2013]. The electricity consumption is indicated with 420 kW per 500 kg of liquefied methane. Additionally, small amounts of lubricant (0.12 kg/h) and propane (0.07 kg/h) is required.

8.4.1.7 GR8 Dispensing

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm^3 of natural gas per day and bus.

8.4.2 Synthetic natural gas (as LBM) via gasification of wood chips from short rotation forestry and methanation (WFLG2)

Process code	*Step*	*Common processes*		*Input*	*Range*	*Distribution*	*Source*
	Production & conditioning at source						
WF1	**Wood plantation**						
	Agricultural inputs						
	Fertilizers	*FN*	g/MJ_{wood}				
	N (as N)			0.00			JRC internal
	Pesticides	*PE*	g/MJ_{wood}	0.015			JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"						
	Diesel	*F1*	MJ/MJ_{wood}	0.0126			JRC internal
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.0000161			
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.0000397			
	N_2O field emissions		g/MJ_{wood}	0.0067			JRC internal
WS	**Wood storage (seasoning)**						
	Losses			12.0%			JRC internal
	Transformation at source						
	NA						
	Transportation to market						
	Wood moisture content			30%			
WF3b	**Farmed wood transport (regional, 500 km)**						JRC internal
	Road truck	*T1*					
	Distance		km	500			
	Transformation near market						
WG	**Synthetic natural gas (SNG) from wood**						
	Efficiency			66.4%			[DBFZ 2009], [Kaltschmitt 2001]
	Electricity	*EMMa*	MJ/MJ_{SNG}	0.0649			[DBFZ 2009]
	RME		MJ/MJ_{SNG}	0.0410			[DBFZ 2009]
	LPG		MJ/MJ_{SNG}	0.0454			[DBFZ 2009]
	Heat surplus		MJ/MJ_{SNG}	-0.0268			[DBFZ 2009]
	Conditioning & Distribution						
GG4	**Local distribution (low pressure)**						
	No contribution						
GL1	**Liquefaction of upgraded biogas onsite refueling station**						[Galileo 2013]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LBG}	0.06048			
	LPG		MJ/MJ_{LBG}	0.00013			
	Lubricants		g/MJ_{LBG}	0.0041			
GR8	**Dispensing**						[Messer 1998]
	Losses			0.001%			
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LBG}	0.0001			

8.4.2.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

8.4.2.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12% dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

8.4.2.3 WF3b Farmed wood transport (regional, 500 km)

For large plants a transport distance of 500 km has been assumed if the wood is derived from regions inside the EU.

8.4.2.4 WG Synthetic natural gas (SNG) from wood

A large plant with a capacity of 380 MW of synthetic natural gas has been assumed as described in [DBFZ 2009] as long-term technology. An indirectly heated fast Internally circulating fluidized bed (FICFB) gasifier has been used to convert the wood chips into synthesis gas.

The synthesis gas leaving the gasifier is purified by a precoat filter, scrubbing with rape seed methylester (RME), scrubbing with an alkaline scrubbing agent, and then adsorption by a ZnO bed. The RME is used as scrubbing agent for tar removal, the scrubbing with an alkaline scrubbing agent with downstream ZnO bed to remove sulphur. The purified synthesis gas is sent to methanation.

The methane rich gas leaving the methanation step is upgraded using amines as scrubbing agent for to remove residual CO_2. NH3 is removed by a separate scrubber. Then the gas is dried using triethyleneglycol (TEG). Unreacted hydrogen is separated via membranes and sent back to the methanation reactor. The plant also includes compression of the synthetic methane to a pressure of 7 MPa [DBFZ 2009].

Methanation of gas mixtures consisting of CO, H2 and CO_2 is a mature technology. A lignite-to-SNG has been operated at the Great Plains Synfuel Plant in the USA since 1984. Syngas from biomass gasification can contain ethylene (C2H4) which tends to form carbon whiskers on nickel catalysts in fixed bed reactors. Therefore, fluidized bed methanation has been applied for the biomass-to-SNG pilot plant in Güssing [Schildhauer & Biollaz 2009]. There are several biomass-to-SNG pilot plants, e.g. in Güssing in Austria (1 MW SNG) [Schildhauer & Biollaz 2009] and in Göteborg in Sweden (GoBiGas: 20 MW SNG) [Larsson 2017].

8.4.2.5 GL1 Liquefaction of upgraded biogas onsite refueling station

The data for decentralized CH4 liquefaction have been derived from model 'CRYOBOX' offered by Galileo [Galileo 2013]. The electricity consumption is indicated with 420 kW per 500 kg of liquefied methane. Additionally, small amounts of lubricant (0.12 kg/h) and propane (0.07 kg/h) is required.

8.4.2.6 GR8 Dispensing

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm^3 of natural gas per day and bus.

8.4.3 Synthetic natural gas (as SLNG) from renewable electricity (RELG1) RELG1a: CO_2 from flue gases. RELG1b: CO2 from biogas upgrading

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WD1	**Wind turbine**							[GEMIS 2000]
	No expended energy or emissions							
	Transformation at source							
	NA							
	Transportation to market							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
	NA							
	Transformation near market							
YH1	**Hydrogen via electrolysis (large plant)**							
	Electricity		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
CA1	**CO_2 absorption (from flue gases)**							[Socolow 2011]
	Electricity (wind)		MJ/kg	0.0334				
	Heat		MJ/kg	4.2998				
CC1	**CO_2 compression**							
	Electricity (wind)		MJ/kg	0.1454				
HG1	**Methane synthesis**							[Breyer 2011]
	CO_2		kg/MJ_{CH4}	0.0550				
	Hydrogen		MJ/MJ_{CH4}	1.1998				
	Heat surplus		MJ/MJ_{CH4}	-0.1998				
	Conditioning & Distribution							
	Local distribution (low pressure)							
	No contribution							
GL1	**Liquefaction of upgraded biogas onsite refueling station**							[Galileo 2013]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LBG}	0.06048				
	LPG		MJ/MJ_{LBG}	0.00013				
	Lubricants		g/MJ_{LBG}	0.0041				
GR8	**Dispensing**							[Messer 1998]
	Losses			0.001%				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{LBG}	0.0001				

8.4.3.1 WD1 Wind turbine

Electricity from wind turbine is energy and emission - free (as we do not consider energy and emissions related to construction and maintenance)

8.4.3.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.5 of the WTT report

8.4.3.3 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.5 of the WTT report.

8.4.3.4 YH1 Hydrogen via electrolysis (large plant)

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPa_g electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].
- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].

- McPhy indicates an electricity consumption of 4.5 kWh/Nm³ at nominal flow rate for its 800 Nm³/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPa_g [McPhy 2017].

Several sources of data are available, giving figures for both small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm³) at a current density of 1.5 A/cm² leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm² the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depends on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm³/h (HyLYZER 100-30), 400 Nm³/h (HyLYZER 400-30), and 3000 Nm³/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm³ or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPa_g [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm³/h with an electricity consumption of 4.8 kWh/Nm³ or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm³ or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh_e/Nm³ of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 68% (4.8 to 5.4 kWh_e/Nm³ of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

8.4.3.5 CA1 CO_2 absorption (from flue gases)

CO_2 is assumed to be recovered from the flue gases of e.g. a power station. It is extracted from the flue gas stream via scrubbing with monoethanolamine (MEA). The regeneration of the scrubbing agent is carried out to a large extent with the heat from the methanation process.

8.4.3.6 CC1 CO_2 compression

CO_2 is available at or near atmospheric pressure and needs to be compressed to about 5 bars.

8.4.3.7 HG1 Methane synthesis

Hydrogen reacts with CO_2 in the methanation reaction:

4 H2 + CO_2 => CH4 + 2 H2O

The reaction is exothermic. About 83% of the LHV of the hydrogen is recovered in the methane. The catalytic methanation process is carried out at a temperature of 200 to 400°C and a pressure of 0.5 MPa. Alternatively, the methanation can be carried out biologically in-situ a fermenter of a biogas plant. But this variant has not been considered in this study.

For power-to-methane plants new fixed bed plate reactors have been developed which can quicker load changes than conventional fixed bed reactors. As a result, a smaller H2 buffer storage is sufficient to operate the plant in combination with fluctuating renewable energy sources such as wind power and solar. In contrast to biomass-to-SNG plants no ethylene occurs in the feed gas stream and no formation of carbon whiskers on the catalyst can occur. In June 2018, 12 power-to-methane plants are operated in the EU (thereof 10 in Germany, 1 in Denmark, 1 in Netherlands), 3 power-to-methane plant are under construction (1 in Germany, 1 in Italy, 1 in Sweden), and another 3 power-to-methane plants are planned (2 in Germany, 1 in France). One example is the Audi e-gas plant in Werlte in Germany with a capacity of about 3.2 MW of synthetic methane. In Werlte, the CO_2 has been derived from biogas upgrading.

8.4.3.8 GL1 Liquefaction of upgraded biogas onsite refueling station

The data for decentralized CH4 liquefaction have been derived from model 'CRYOBOX' offered by Galileo [Galileo 2013]. The electricity consumption is indicated with 420 kW per 500 kg of liquefied methane. Additionally, small amounts of lubricant (0.12 kg/h) and propane (0.07 kg/h) is required.

8.4.3.9 GR8 Dispensing

For dispensing of LNG only small amounts of electricity for pumping is required. The electricity consumption has been derived from a refueling station for city buses. According to [Messer 1998] about 2000 kWh of electricity is required per year for a refueling station which supplies 100 buses which consume 100 Nm^3 of natural gas per day and bus.

9 Ethanol

As general notes:

- Farming processes

Original sources mostly give agricultural input data per hectare with reference to a certain yield. However, the yield basis varies between sources which can lead to confusion. As a result, we show the data per MJ of the crop (grain). The figures are considered valid for the range of yield typically found in Europe.

As explained in the WTT report, our GHG balances figures refer to annual farming emissions, and do not take account of any land use change emissions, which should be considered separately. However, when we calculate N2O emissions, we take into account that soil emits "background" N2O even if it is not cultivated (which are low according to IPCC). As explained in the WTT report, the best of a limited range of options is to choose "unfertilized grass" as the land-cover for the calculation of background emissions.

N2O field emissions are calculated according to the JRC methodology described in section 3.7.2 of the WTT report.

All figures are related to the Lower Heating Value (i.e. excluding the heat of condensation of water vapour formed during combustion) and to the dry matter (i.e. water-free) of the biomass products. In our convention, this arises only from the hydrogen content of the dry-matter. However, some other workers (for example, in the Netherlands) include also the energy for evaporating water from moist materials. The heat of vaporization is not recovered in the flue gas, so this gives a lower LHV than ours. We do not do this because it causes problems: wood apparently increases in heating value during storage, sewage sludge apparently has a negative LHV, and in the "Dutch" convention energy is not conserved in processes whenever the water content of the products differs from those of the feedstocks. Of course, we take the water content into account when calculating the weight of biomass transported.

Generally, only best estimate figures are shown. It is not worth including a range of energy inputs, because the impact on the whole chain is small. The main source of uncertainty is in the GHG emissions, caused by the field N2O emissions.

- Conversion of biomass to biofuel

The range of energy and emissions reported by different authors for processing biomass into 'conventional biofuels' is much smaller than the uncertainty in farming emissions. Therefore, we do not attempt to indicate an uncertainty range. Where there are significantly different processes, we have made separate calculations for the two processes. Large variations in the energy and emissions reported in the literature are due to different treatment of co-products, as discussed in the WTT report.

The method for calculating the credit for co-products used as animal feed is based on balancing protein and digestible energy requirements of animal feeds. This is detailed in WTT report section 3.7.4.

Co-products often require drying before they can be used conveniently as animal feed, and this can consume more energy than the credit for the feedstocks replaced. Usually, however, waste heat from the process can be used.

Ethanol production

Ethanol is produced by hydrolysis of the grain's starch and subsequent fermentation. CO_2 is released in the process but it is not taken into account in the GHG balance as the carbon is from biomass origin. The process requires energy in the form of mainly heat to distil out the ethanol and some electricity to operate pumps and other ancillary equipment.

Heat and electricity can be provided in a number of different ways which can have a significant impact on the overall energy and GHG balance. For each of the feedstocks, we have considered a number of alternatives.

9.1 Ethanol

9.1.1 EU sugar beet to ethanol. Pulp to animal feed (a/b). Pulp to fuel (c). Slops not used (a) or used as feed for biogas (b/c) (SBET1a/b/c)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Dist.*	*Source*
	Production & conditioning at source							
SB1	**Sugar beet cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{SB}					
	N (as N)	*FN*		0.35				JRC internal
	P (as P_2O_5)	*FP*		0.15				JRC internal
	K (as K_2O)	*FP*		0.26				JRC internal
	CaO	*CA*		0.61				JRC internal
	Pesticides	*PE*	g/MJ_{SB}	0.05				[Capri 2012], [FfE 1998]
	Seeding material	*SSB*	g/MJ_{SB}	0.01				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							[Capri 2012], [FfE 1998]
	Diesel	*F1*	MJ/MJ_{SB}	0.0105				[EMEP/EFA 2013]
	CH_4 emissions		g/MJ_{SB}	0.000013				
	CO_2 from soil neutralisation		g/MJ_{SB}	0.00				
	N_2O field emissions		g/MJ_{SB}	0.0126	0.0101	0.0151	Normal	JRC internal
SB2	**Sugar beet storage and handling**							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SB}	0.0000				JRC internal
	Transformation at source							
	NA							
	Transportation to market							
SB3	**Sugar beet transport**							JRC internal
	Road truck	*T1*						
	Distance		km	30				
	Transformation near market							
SB4	**Ethanol production**							
	Ethanol yield		$kg_{EtOH}/kg_{SB\ @76.5\%}$	0.0777				[Kaltschmitt 1997]
	Pulp yield (@ 9% moisture)		$kg_{Pulp}/kg_{SB\ @76.5\%}$	0.058				[FfE 1998]
	Ethanol plant							[Kaltschmitt 1997]
SB4a	Slops not used							
	Heat to process	*GHI*	MJ/MJ_{EtOH}	0.2806				
	Electricity to process	*EMMa*	MJ/MJ_{EtOH}	0.0345				
SB4b	Slops to biogas (used as fuel in plant)							
	Net heat to process	*GHI*	MJ/MJ_{EtOH}	0.1043				
	Electricity to process	*EMMa*	MJ/MJ_{EtOH}	0.0398				
	Credit for Pulp							
	Animal feed substitution							
	1 kg Pulp substitutes:							
	Wheat grain (13.5% moisture)		kg/kg_{Pulp}	*-0.866*				
	Soya meal (10% moisture)		kg/kg_{Pulp}	*-0.013*				
SB4c	Pulp to fuel, slops to biogas							[Kaltschmitt 1997]
	Electricity surplus		MJ/MJ_{EtOH}	-0.0404				
	Credit based on EU-mix, MV							
	RED methodology							
	Allocation between ethanol and pulp on energy content basis							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	*T3j*						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{EtOH}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{EtOH}	0.0034				

9.1.1.1 SB1 Sugar beet cultivation

Fertiliser inputs are based on the weighted average of national fertiliser inputs for countries with sugar-beet ethanol production.

We assume that the sugar beet leaves are ploughed back into the soil after harvest, which is the usual practice.

9.1.1.2 SB2 Sugar beet storage and handling

A small amount of energy is consumed to handle and store sugar beets mainly in the form of electricity. In practice storage may occur after transportation and is already taken into account at the ethanol production stage. Therefore, the electricity requirement is set to zero.

9.1.1.3 SB3 Sugar beet transport

Sugar beets are typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.1.4 SB4 Ethanol production

Following [LBST 2002] we chose a conventional fermentation plant, not integrated with a sugar refinery, as analysed by [FfE 1998]. The main steps in the basic process are cleaning, slicing, sieving out the pulp by-product, syrup pasteurisation, fermentation, distillation, and final purification. These steps use electricity (from the grid) and heat which we assume is supplied by a natural gas boiler with 90% efficiency. Distillation and final ethanol purification (drying with zeolite) consumes most of the energy.

Sugar factories using beet do not work all year round because sugar beet have to be processed quickly after harvest to avoid sugar loss in storage (see SB1 farming pathway). Beet processing "campaigns" typically last between 60 days (Poland) and 150 days (Britain). Average for EU-25 is about 90 days (also the German figure). However, it is possible to keep the ethanol part of the plant working continuously by storing pasteurised syrup. The size of the plant is not very important for efficiency, but has a large effect on costs. [FfE 1998] made a cost analysis on a hypothetical 59 MW (ethanol) plant.

There are two by-products: sugar beet pulp sieved from the syrup and the slops filtered from the fermented. Both beet by-products contain initially 35-40% water, and have to be dried to about 9% water [FfE 1998], [NRC 1998]. In addition, there is a small amount of electricity required for the blowers.

In variant a and b, the pulp is used for animal feed. We have assumed that it is dried evaporatively using waste heat which considerably reduces the overall energy requirement and GHG emissions compared to conventional drying using natural gas generated heat. The pulp substitutes a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production.

The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.

In variant a, the slops are not used. In variant b, slops are fed to an anaerobic digester to produce biogas, providing some of the plant energy needs, and reducing natural gas consumption. Electricity consumption increases slightly to power the biogas plant. We assume 1 MJ biogas substitutes 1 MJ natural gas. The waste from the biomass fermenter would probably be used as fertilizer. However, the quantity is much smaller than the uncertainty in fertilizer use in the sugar beet farming process, so we do not account for this.

In variant c the sieved pulp mash is burned in a boiler and the slops continue to produce biogas. Both are used in a CHP plant to produce electricity and heat with an electrical efficiency of 20% (typical for a small-scale steam turbine). This is sufficient to fully meet the needs of the plant. There is excess electricity and heat. The former is exported and produces a credit, while the surplus heat is considered to have no value.

9.1.1.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.1.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.1.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.1.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.2 EU wheat to ethanol. Production energy provided by as heat from NG-fired boiler and grid electricity (WTET1a/b)

DDGS (Dried Distillers Grains with Solubles) to animal feed (a) or to electricity production (b).

Process code	Step	Common processes		Input	Range		Dist.	Source
	Production & conditioning at source							
WT1a	**Wheat cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{grain}$					
	N (as N)	FN		1.34				JRC internal
	P (as P_2O_5)	FP		0.26				JRC internal
	K (as K_2O)	FP		0.21				[EFMA 2008]
	CaO	CA		1.44				JRC internal
	Pesticides	PE	g/MJ$_{grain}$	0.07				[CAPRI 2012]
	Seeding material	SWH	g/MJ$_{grain}$	0.42				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ$_{grain}$	0.0384				[CAPRI 2012]
	CH_4 emissions		g/MJ$_{grain}$	0.000049				
	CO_2 from soil neutralisation		g/MJ$_{grain}$	0.00				
	N_2O field emissions		g/MJ$_{grain}$	0.045	0.040	0.049	Normal	JRC internal
WT2	**Wheat grain drying, storage and handling**							
	Wheat grain drying							
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{grain}$	0.000048				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	F1	MJ/MJ$_{grain}$	0.00029				
	NG	F3	MJ/MJ$_{grain}$	0.00029				
	Wheat grain handling and storage							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{grain}$	0.000392				[Kaltschmitt 1997]
	Transformation at source							
	NA							
	Transportation to market							
WT3a	**Wheat grain transport (road)**							
	Road truck	T1						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
WT4	**Ethanol production**							
	Ethanol yield		kg$_{EtOH}$/kg$_{grain\ @3\%}$	0.295				[ADEME 2010], [Crop Energies 2016], [Lywood 2010], [Power et al. 2008], [Stölken 2009]
	DDGS yield (@10% moisture)		kg$_{DDGS}$/kg$_{EtOH}$	0.362				[Crop Energies 2016]
	NH_3	C8	g/MJ$_{EtOH}$	0.20				
	NaOH	C6	g/MJ$_{EtOH}$	0.47				
	H_2SO_4	C7	g/MJ$_{EtOH}$	0.45				
	Alpha-amylase	C9	g/MJ$_{EtOH}$	0.05				
	Gluco-amylase	C10	g/MJ$_{EtOH}$	0.06				
	Heat to process		MJ/MJ$_{EtOH}$	0.3737				
WTET1a	Electricity to process (EU-mix, MV)	EMMa	MJ/MJ$_{EtOH}$	0.0491				
WTET1b	Electricity surplus from DDGS		MJ/MJ$_{EtOH}$	-0.1745				
WT41	**NG-fired steam boiler**	F3						
	Efficiency			90.0%	85.0%	95.0%	Normal	
	Electricity (EU-mix, MV)	EMMa	MJe/MJ$_{heat}$	0.0200				
	CH_4 emissions		g/MJ$_{heat}$	0.0028				
	N_2O emissions		g/MJ$_{heat}$	0.0011				
	Credit for DDGS							
WTET1a	*Animal feed substitution*							*JRC internal*
	1 kg DDGS substitutes:							
	Wheat grain (13% moisture)		*kg/kg$_{DDGS}$*	*-0.766*				
	Soya meal (11% moisture)		*kg/kg$_{DDGS}$*	*-0.303*				
WTET1b	*DDGS used as fuel to produce electricity (substitutes EU-mix, MV)*	*EMMa*						
	Efficiency			*30%*				
	RED methodology							
	Allocation between ethanol and DDGS on energy content basis							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	T1						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	T3j						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	T3a						
	Distance		km	153				
	Rail (4.4%)	T2						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ$_{EtOH}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{EtOH}$	0.0034				

9.1.2.1 WT1a Wheat cultivation

Wheat is the highest-yielding cereal crop, but it also takes the highest inputs. This process represents conventional wheat grain farming for ‘soft wheat’, which accounts for most of EU production, gives the highest yield, and has the highest fermentable content. Straw use is discussed in the main WTT report.

9.1.2.2 WT2 Wheat grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity, diesel, and natural gas.

9.1.2.3 WT3a Wheat grain transport (road)

Grain is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.2.4 WT41 NG-fired steam boiler

Heat is supplied by a conventional natural gas fired boiler and electricity is imported from the grid. This can be considered as representative of some of the earlier existing installations and is also by far the cheapest solution. The boiler consumes a small amount of electricity and emits small quantities of CH4 and N2O.

The residual material after fermentation is known as DGS ("Distiller's Grain and Solubles") or DDGS after drying. This co-product is assumed to be used in one of two ways:

- In alternative a DDGS is used as animal feed and is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production. The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.
- In alternative b DDGS is used on site as fuel for the production of electricity. For such a biomass product, efficiency is assumed to be fairly low at 30%. This is assumed to be exported to the grid thereby generating a credit corresponding to the EU-mix electricity (MV level).

9.1.2.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.2.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.2.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.2.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.3 EU wheat to ethanol. Production energy provided by a NG-fired CHP plant (WTET2a).

DDGS to animal feed (a) or to electricity production (b).

Process code	*Step*	*Common processes*		*Input*	*Range*		*Dist.*	*Source*
	Production & conditioning at source							
WT1a	**Wheat cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{grain}					
	N (as N)	FN		1.34				JRC internal
	P (as P_2O_5)	FP		0.26				JRC internal
	K (as K_2O)	FP		0.21				[EFMA 2008]
	CaO	CA		1.44				JRC internal
	Pesticides	PE	g/MJ_{grain}	0.07				[CAPRI 2012]
	Seeding material	SWH	g/MJ_{grain}	0.42				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ_{grain}	0.0384				[CAPRI 2012]
	CH_4 emissions		g/MJ_{grain}	0.000049				
	CO_2 from soil neutralisation		g/MJ_{grain}	0.00				
	N_2O field emissions		g/MJ_{grain}	0.045	0.040	0.049	Normal	JRC internal
WT2	**Wheat grain drying, storage and handling**							
	Wheat grain drying							
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{grain}	0.000048				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	F1	MJ/MJ_{grain}	0.00029				
	NG	F3	MJ/MJ_{grain}	0.00029				
	Wheat grain handling and storage							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{grain}	0.000392				[Kaltschmitt 1997]
	Transformation at source							
	NA							
	Transportation to market							
WT3a	**Wheat grain transport (road)**							
	Road truck	T1						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
WT4	**Ethanol production**							
	Ethanol yield		$kg_{EtOH}/kg_{grain\ @3\%}$	0.295				[ADEME 2010], [Crop Energies 2016], [Lywood 2010], [Power et al. 2008], [Stölken 2009]
	DDGS yield (@10% moisture)		kg_{DDGS}/kg_{EtOH}	0.362				[Crop Energies 2016]
	NH_3	C8	g/MJ_{EtOH}	0.20				
	NaOH	C6	g/MJ_{EtOH}	0.47				
	H_2SO_4	C7	g/MJ_{EtOH}	0.45				
	Alpha-amylase	C9	g/MJ_{EtOH}	0.05				
	Gluco-amylase	C10	g/MJ_{EtOH}	0.06				
	Heat to process		MJ/MJ_{EtOH}	0.3737				
WTET2a	Electricity to process (EU-mix, MV)	EMMa	MJ/MJ_{EtOH}	0.0491				
WTET2b	Electricity surplus from DDGS		MJ/MJ_{EtOH}	-0.1745				
WT42	**NG-fired CHP**							[Dienhardt 1999]
	Natural gas consumption	F3	MJ/MJ_{heat}	2.3867				
	Electricity production		MJ/MJ_{heat}	0.7900				
	CH_4 emissions		g/MJ_{heat}	0.0100				
	N_2O emissions		g/MJ_{heat}	0.0024				
	Electricity surplus from CHP		MJ/MJ_{EtOH}	-0.2462				
	Credit for surplus electricity from CHP based on alternative generation in state-of-the-art NG-fired CCGT							
	Generic process	GGe						[GEMIS 2011]
	Efficiency			*58.1%*	*57.0%*	*59.3%*	*Normal*	
	CH_4 emissions		g/MJ_e	*0.0054*				
	N_2O emissions		g/MJ_e	*0.0043*				
	Credit for DDGS							
WTET2a	*Animal feed substitution*							*JRC internal*
	1 kg DDGS substitutes:							
	Wheat grain (13% moisture)		*kg/kg_{DDGS}*	*-0.766*				
	Soya meal (11% moisture)		*kg/kg_{DDGS}*	*-0.303*				
WTET2b	*DDGS used as fuel to produce electricity (substitutes EU-mix, MV)*	EMMa						
	Efficiency			*30%*				
	RED methodology							
	Allocation between ethanol and DDGS on energy content basis, between heat and electricity from CHP on exergy content basis							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	T1						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	T3j						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	T3a						
	Distance		km	153				
	Rail (4.4%)	T2						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ_{EtOH}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{EtOH}	0.0034				

9.1.3.1 WT1a Wheat cultivation

Wheat is the highest-yielding cereal crop, but it also takes the highest inputs. This process represents conventional wheat grain farming for 'soft wheat', which accounts for most of EU production, gives the highest yield, and has the highest fermentable content. Straw use is discussed in the main WTT report.

9.1.3.2 WT2 Wheat grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity, diesel, and natural gas.

9.1.3.3 WT3a Wheat grain transport (road)

Grain is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.3.4 WT42 NG-fired CHP

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

This alternative is energy efficient but also complex and expensive to build and operate compared to a simple steam boiler and electricity import from the grid.

The residual material after fermentation is known as DGS ("Distiller's Grain and Solubles") or DDGS after drying. This co-product is assumed to be used in one of two ways:

- In alternative a DDGS is used as animal feed and is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production. The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.
- In alternative b DDGS is used on site as fuel for the production of electricity. For such a biomass product, efficiency is assumed to be fairly low at 30%. This is assumed to be exported to the grid thereby generating a credit corresponding to the EU-mix electricity (MV level).

9.1.3.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.3.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.3.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.3.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.1 EU wheat to ethanol. Production energy provided by a lignite-fired CHP plant (WTET3a/b).

DDGS to animal feed (a) or to electricity production (b).

Process code	*Step*	*Common processes*		*Input*	*Range*		*Dist.*	*Source*
	Production & conditioning at source							
WT4	**Wheat cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{grain}$					
	N (as N)	*FN*		1.34				JRC internal
	P (as P_2O_5)	*FP*		0.26				JRC internal
	K (as K_2O)	*FP*		0.21				[EFMA 2008]
	CaO	*CA*		1.44				JRC internal
	Pesticides	*PE*	g/MJ$_{grain}$	0.07				[CAPRI 2012]
	Seeding material	*SWH*	g/MJ$_{grain}$	0.42				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{grain}$	0.0384				[CAPRI 2012]
	CH_4 emissions		g/MJ$_{grain}$	0.000049				
	CO_2 from soil neutralisation		g/MJ$_{grain}$	0.00				
	N_2O field emissions		g/MJ$_{grain}$	0.045	0.040	0.049	Normal	JRC internal
WT2	**Wheat grain drying, storage and handling**							
	Wheat grain drying							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{grain}$	0.000048				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	*F1*	MJ/MJ$_{grain}$	0.00029				
	NG	*F3*	MJ/MJ$_{grain}$	0.00029				
	Wheat grain handling and storage							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{grain}$	0.000392				[Kaltschmitt 1997]
	Transformation at source							
	NA							
	Transportation to market							
WT3a	**Wheat grain transport (road)**							
	Road truck	*T1*						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
WT1a	**Ethanol production**							
	Ethanol yield		kg$_{EtOH}$/kg$_{grain\ @3\%}$	0.295				[ADEME 2010], [Crop Energies 2016], [Lywood 2010], [Power et al. 2008], [Stölken 2009]
	DDGS yield (@10% moisture)		kg$_{DDGS}$/kg$_{EtOH}$	0.362				[Crop Energies 2016]
	NH_3	*C8*	g/MJ$_{EtOH}$	0.20				
	NaOH	*C6*	g/MJ$_{EtOH}$	0.47				
	H_2SO_4	*C7*	g/MJ$_{EtOH}$	0.45				
	Alpha-amylase	*C9*	g/MJ$_{EtOH}$	0.05				
	Gluco-amylase	*C10*	g/MJ$_{EtOH}$	0.06				
	Heat to process		MJ/MJ$_{EtOH}$	0.3737				
WTET3a	Electricity to process (EU-mix, MV)	*EMMa*	MJ/MJ$_{EtOH}$	0.0491				
WTET3b	Electricity surplus from DDGS		MJ/MJ$_{EtOH}$	-0.1745				
WT43	**Lignite-fired CHP**							[GEMIS 2014]
	Lignite consumption		MJ/MJ$_{heat}$	1.4049				
	Electricity production		MJ/MJ$_{heat}$	0.2222				
	CH_4 emissions		g/MJ$_{heat}$	0.0020				
	N_2O emissions		g/MJ$_{heat}$	0.0042				
	Electricity surplus from CHP		MJ/MJ$_{EtOH}$	-0.0340				
	Credit for surplus electricity from CHP based on alternative generation in state-of-the-art lignite-fired power station							*[GEMIS 2014]*
	Efficiency			*43.0%*				
	CH_4 emissions		g/MJ$_e$	*0.0036*				
	N_2O emissions		g/MJ$_e$	*0.0073*				
	Credit for DDGS							
WTET3a	*Animal feed substitution*							*JRC internal*
	1 kg DDGS substitutes:							
	Wheat grain (13% moisture)		*kg/kg$_{DDGS}$*	*-0.766*				
	Soya meal (11% moisture)		*kg/kg$_{DDGS}$*	*-0.303*				
WTET3b	*DDGS used as fuel to produce electricity (substitutes EU-mix, MV)*	*EMMa*						
	Efficiency			*30%*				
	RED methodology							
	Allocation between ethanol and DDGS on energy content basis, between heat and electricity from CHP on exergy content basis							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	*T3j*						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{EtOH}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{EtOH}$	0.0034				

9.1.1.1 WT4 Wheat cultivation

Wheat is the highest-yielding cereal crop, but it also takes the highest inputs. This process represents conventional wheat grain farming for ‘soft wheat’, which accounts for most of EU production, gives the highest yield, and has the highest fermentable content. Straw use is discussed in the main WTT report.

9.1.1.2 WT2 Wheat grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity, diesel, and natural gas.

9.1.1.3 WT3a Wheat grain transport (road)

Grain is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.1.4 WT43 Lignite-fired CHP

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

The residual material after fermentation is known as DGS ("Distiller's Grain and Solubles") or DDGS after drying. This co-product is assumed to be used in one of two ways:

- In alternative a DDGS is used as animal feed and is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production. The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.
- In alternative b DDGS is used on site as fuel for the production of electricity. For such a biomass product, efficiency is assumed to be fairly low at 30%. This is assumed to be exported to the grid thereby generating a credit corresponding to the EU-mix electricity (MV level).

9.1.1.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.1.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.1.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.1.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.2 EU wheat to ethanol. Production energy provided by a wood-fired CHP plant.

DDGS to animal feed (a) or to electricity production (b).

Process code	*Step*	*Common processes*		*Input*	*Range*		*Dist.*	*Source*
	Production & conditioning at source							
WT1a	**Wheat cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{grain}					
	N (as N)	*FN*		1.34				JRC internal
	P (as P_2O_5)	*FP*		0.26				JRC internal
	K (as K_2O)	*FP*		0.21				[EFMA 2008]
	CaO	*CA*		1.44				JRC internal
	Pesticides	*PE*	g/MJ_{grain}	0.07				[CAPRI 2012]
	Seeding material	*SWH*	g/MJ_{grain}	0.42				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{grain}	0.0384				[CAPRI 2012]
	CH_4 emissions		g/MJ_{grain}	0.000049				
	CO_2 from soil neutralisation		g/MJ_{grain}	0.00				
	N_2O field emissions		g/MJ_{grain}	0.045	0.040	0.049	Normal	JRC internal
WT2	**Wheat grain drying, storage and handling**							
	Wheat grain drying							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{grain}	0.000048				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	*F1*	MJ/MJ_{grain}	0.00029				
	NG	*F3*	MJ/MJ_{grain}	0.00029				
	Wheat grain handling and storage							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{grain}	0.000392				[Kaltschmitt 1997]
	Transformation at source							
	NA							
	Transportation to market							
WT3a	**Wheat grain transport (road)**							
	Road truck	*T1*						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
WT4	**Ethanol production**							
	Ethanol yield		$kg_{EtOH}/kg_{grain\ @3\%}$	0.295				[ADEME 2010], [Crop Energies 2016], [Lywood 2010], [Power et al. 2008], [Stölken 2009]
	DDGS yield (@10% moisture)		kg_{DDGS}/kg_{EtOH}	0.362				[Crop Energies 2016]
	NH_3	*C8*	g/MJ_{EtOH}	0.20				
	NaOH	*C6*	g/MJ_{EtOH}	0.47				
	H_2SO_4	*C7*	g/MJ_{EtOH}	0.45				
	Alpha-amylase	*C9*	g/MJ_{EtOH}	0.05				
	Gluco-amylase	*C10*	g/MJ_{EtOH}	0.06				
	Heat to process		MJ/MJ_{EtOH}	0.3737				
WTET4a	Electricity to process (EU-mix, MV)	*EMMa*	MJ/MJ_{EtOH}	0.0491				
WTET4b	Electricity surplus from DDGS		MJ/MJ_{EtOH}	-0.1745				
WT44	**Wood-fired CHP**							
	Wood consumption		MJ/MJ_{heat}	2.1322				[LowCVP 2004]
	Electricity production		MJ/MJ_{heat}	0.3612				[LowCVP 2004]
	CH_4 emissions		g/MJ_{heat}	0.0008				[GEMIS 2011]
	N_2O emissions		g/MJ_{heat}	0.0043				[Vitovec 1999]
	Electricity surplus from CHP		MJ/MJ_{EtOH}	-0.0859				
	Credit for surplus electricity from CHP based on alternative generation in state-of-the-art wood-fired power station							
	Efficiency			*32.0%*				*[JOPP 1999]*
	CH_4 emissions		g/MJ_e	*0.0826*				*[GEMIS 2005]*
	N_2O emissions		g/MJ_e	*0.0063*				*[Vitovec 1999]*
	Credit for DDGS							
WTET4a	*Animal feed substitution*							*JRC internal*
	1 kg DDGS substitutes:							
	Wheat grain (13% moisture)		*kg/kg_{DDGS}*	*-0.766*				
	Soya meal (11% moisture)		*kg/kg_{DDGS}*	*-0.303*				
WTET4b	*DDGS used as fuel to produce electricity (substitutes EU-mix, MV)*	*EMMa*						
	Efficiency			*30%*				
	RED methodology							
	Allocation between ethanol and DDGS on energy content basis, between heat and electricity from CHP on exergy content basis							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	*T3j*						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{EtOH}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{EtOH}	0.0034				

9.1.2.1 WT1a Wheat cultivation

Wheat is the highest-yielding cereal crop, but it also takes the highest inputs. This process represents conventional wheat grain farming for 'soft wheat', which accounts for most of EU production, gives the highest yield, and has the highest fermentable content. Straw use is discussed in the main WTT report.

9.1.2.2 WT2 Wheat grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity, diesel, and natural gas.

9.1.2.3 WT3a Wheat grain transport (road)

Grain is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.2.4 WT44 Wood-fired CHP

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

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

The residual material after fermentation is known as DGS ("Distiller's Grain and Solubles") or DDGS after drying. This co-product is assumed to be used in one of two ways:

- In alternative a DDGS is used as animal feed and is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production. The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.
- In alternative b DDGS is used on site as fuel for the production of electricity. For such a biomass product, efficiency is assumed to be fairly low at 30%. This is assumed to be exported to the grid thereby generating a credit corresponding to the EU-mix electricity (MV level).

9.1.2.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.2.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.2.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.2.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.3 EU wheat to ethanol. DDGS used as internal fuel to produce electricity via biogas (WTET5)

Process code	Step	Common processes		Input	Range		Dist.	Source
	Production & conditioning at source							
WT1a	**Wheat cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{grain}$					
	N (as N)	*FN*		1.34				JRC internal
	P (as P_2O_5)	*FP*		0.26				JRC internal
	K (as K_2O)	*FP*		0.21				[EFMA 2008]
	CaO	*CA*		1.44				JRC internal
	Pesticides	*PE*	g/MJ$_{grain}$	0.07				[CAPRI 2012]
	Seeding material	*SWH*	g/MJ$_{grain}$	0.42				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{grain}$	0.0384				[CAPRI 2012]
	CH_4 emissions		g/MJ$_{grain}$	0.000049				
	CO_2 from soil neutralisation		g/MJ$_{grain}$	0.00				
	N_2O field emissions		g/MJ$_{grain}$	0.045	0.040	0.049	Normal	JRC internal
WT2	**Wheat grain drying, storage and handling**							
	Wheat grain drying							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{grain}$	0.000048				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	*F1*	MJ/MJ$_{grain}$	0.00029				
	NG	*F3*	MJ/MJ$_{grain}$	0.00029				
	Wheat grain handling and storage							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{grain}$	0.000392				[Kaltschmitt 1997]
	Transformation at source							
	NA							
	Transportation to market							
WT3a	**Wheat grain transport (road)**							
	Road truck	*T1*						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
WT4	**Ethanol production**							
	Ethanol yield		kg$_{EtOH}$/kg$_{grain\ @3\%}$	0.295				[ADEME 2010], [Crop Energies 2016], [Lywood 2010], [Power et al. 2008], [Stölken 2009]
	DDGS yield (@10% moisture)		kg$_{DDGS}$/kg$_{EtOH}$	0.362				[Crop Energies 2016]
	NH_3	*C8*	g/MJ$_{EtOH}$	0.20				
	NaOH	*C6*	g/MJ$_{EtOH}$	0.47				
	H_2SO_4	*C7*	g/MJ$_{EtOH}$	0.45				
	Alpha-amylase	*C9*	g/MJ$_{EtOH}$	0.05				
	Gluco-amylase	*C10*	g/MJ$_{EtOH}$	0.06				
WT45	**Ethanol plant (DDGS used internally for electricity via biogas)**							[Kaltschmitt 1997], [Kaltschmitt 2001]
	NG	*F3*	MJ/MJ$_{EtOH}$	0.2382				
	Electricity surplus		MJ/MJ$_{EtOH}$	-0.1662				
	Credit for electricity based on alternative generation in NG CCGT	*GGe*						
	Credit for fertilisers (residue from biogas production)		*g/MJ $_{EtOH}$*					
	N (as N)			*2.49*				
	P (as P2O5)			*0.98*				
	K (as K2O)			*0.61*				
	CaO			*0.08*				
	RED methodology							
	NA							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	*T3j*						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{EtOH}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{EtOH}$	0.0034				

9.1.3.1 WT1a Wheat cultivation

Wheat is the highest-yielding cereal crop, but it also takes the highest inputs. This process represents conventional wheat grain farming for ‘soft wheat’, which accounts for most of EU production, gives the highest yield, and has the highest fermentable content. Straw use is discussed in the main WTT report.

9.1.3.2 WT2 Wheat grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity, diesel, and natural gas.

9.1.3.3 WT3a Wheat grain transport (road)

Grain is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.3.4 WT45 Ethanol plant (DDGS used internally for electricity via biogas)

DDGS is not released as a product but rather used internally (without drying) to produce biogas. The biogas is fed to a CHP plant providing all the energy required for the plant as well as a surplus of electricity which is exported, thereby generating a credit. We assume that surplus heat cannot be used and so does not generate a credit.

9.1.3.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.3.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.3.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.3.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.4 EU mix barley/rye grain 50/50 ethanol. Production energy provided by a NG-fired CHP plant. DDGS to animal feed.

Process code	*Step*	*Common processes*		*Input*	*Range*		*Dist.*	*Source*
	Production & conditioning at source							
BR1	**Cultivation (barley/rye)**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{grain}$					JRC internal
	N (as N)	*FN*		1.44/1.22				
	P (as P_2O_5)	*FP*		0.36/0.3				
	K (as K_2O)	*FP*		0.36/0.32				
	CaO	*CA*		2.03/3.51				
	Pesticides	*PE*	g/MJ$_{grain}$	0.06/0.03				[CAPRI 2012], [FAOSTAT 2016]
	Seeding material	*SBA*	g/MJ$_{grain}$	2.98/3.35				[FE 2016], [FAOSTAT 2016]
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{grain}$	0.05/0.06				[CAPRI 2012], [FAOSTAT 2016]
	CH_4 emissions		g/MJ$_{grain}$	0.00006/0.00007				[EMEP/EFA 2013]
	CO_2 from soil neutralisation		g/MJ$_{grain}$	0.47/1.65				
	N_2O field emissions		g/MJ$_{grain}$	0.044/0.037	0.037/0.026	0.05/0.048	Normal	JRC internal
BR2	**Grain drying, storage, and handling**							[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Grain drying							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{grain}$	0.00003/0.00006				
	Diesel	*F1*	MJ/MJ$_{grain}$	0.00018/0.00034				
	NG	*F3*	MJ/MJ$_{grain}$	0.00018/0.00034				
	Grain storage and handling							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)			0.00039/0.00039				[Kaltschmitt 1997]
	Transformation at source							
	NA							
	Transportation to market							
BR3	**Grain transport (road)**							
	Road truck	*T1*						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
BR4	**Ethanol production (barley/rye)**							
	Ethanol yield		kg$_{EtOH}$/kg$_{grain\ @13.5\%}$	0.26/0.27				[ADEME 2010], [Crop Energies 2016], [Kaltschmitt 2001], [Lywood 2010], [Power et al. 2008], [Stölken 2009]
	DDGS yield (dry matter)		kg$_{DDGS}$/kg$_{EtOH}$	1.49/1.36				JRC internal
	NH_3	*C8*	g/MJ$_{EtOH}$	0.2/0.2				[ADEME 2010], [Crop Energies 2016]
	NaOH	*C6*	g/MJ$_{EtOH}$	0.47/0.47				
	H_2SO_4	*C7*	g/MJ$_{EtOH}$	0.45/0.45				
	Alpha-amylase	*C9*	g/MJ$_{EtOH}$	0.05/0.05				
	Gluco-amylase	*C10*	g/MJ$_{EtOH}$	0.06/0.06				
	Heat to process		MJ/MJ$_{EtOH}$	0.3737				
	Electricity to process		MJ/MJ$_{EtOH}$	0.0491				
	NG-fired GT CHP							[Dienhardt 1999]
	Natural gas consumption	*F3*	MJ/MJ$_{heat}$	2.3867				
	Electricity production		MJ/MJ$_{heat}$	0.7900				
	CH_4 emissions		g/MJ$_{heat}$	0.0100				
	N_2O emissions		g/MJ$_{heat}$	0.0024				
	Electricity surplus from CHP		MJ/MJ$_{EtOH}$	-0.2462				
	Credit for surplus electricity from CHP based on alternative generation in state-of-the-art NG-fired CCGT							
	Generic process	*GGe*						[GEMIS 2011]
	Efficiency			*58.1%*	*57.0%*	*59.3%*	*Normal*	
	CH_4 emissions		g/MJ$_e$	*0.0054*				
	N_2O emissions		g/MJ$_e$	*0.0043*				
	Credit for DDGS							
	Animal feed substitution							*JRC internal*
	1 kg DDGS substitutes:							
	Wheat grain (13% moisture)		*kg/kg$_{DDGS}$*	*-0.766*				
	Soya meal (11% moisture)		*kg/kg$_{DDGS}$*	*-0.303*				
	RED methodology							
	Allocation between ethanol and DDGS on energy content basis, between heat and electricity from CHP on exergy content basis							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	*T3j*						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{EtOH}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{EtOH}$	0.0034				

9.1.4.1 BR1 Cultivation (barley/rye)

This pathway is presented to describe an alternative to wheat with other cereals typically grown in Europe. Comparison with pathway WTET2a shows that the difference is relatively small.

9.1.4.2 BR2 Grain drying, storage, and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity, diesel, and natural gas.

9.1.4.3 BR3 Grain transport (road)

Grain is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.4.4 BR4 Ethanol production (barley/rye)

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

This alternative is energy efficient but also complex and expensive to build and operate compared to a simple steam boiler and electricity import from the grid.

The residual material after fermentation is known as DGS ("Distiller's Grain and Solubles") or DDGS after drying. DDGS is used as animal feed and is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production.

The detailed principles and mechanisms of animal feed credit calculations are discuss in the main WTT report chapter 3.4.4.

9.1.4.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.4.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.4.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.4.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.5 Corn (maize) (average used in EU) to ethanol. Production energy provided by a NG-fired CHP plant. DDGS to animal feed.

Process code	Step	Common processes		Input	Range		Dist.	Source
	Production & conditioning at source							
CR1	**Cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{grain}					JRC internal
	N (as N)	*FN*		1.06				
	P (as P_2O_5)	*FP*		0.28				
	K (as K_2O)	*FP*		0.26				
	CaO	*CA*		0.70				
	Pesticides	*PE*	g/MJ_{grain}	0.07				[CAPRI 2016]
	Seeding material	*SRY*	g/MJ_{grain}	0.46				[CAPRI 2016], [FAOSTAT 2016]
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{grain}	0.0312				[CAPRI 2016], [FAOSTAT 2016]
	CH_4 emissions		g/MJ_{grain}	0.000040				[EMEP/EFA 2013]
	CO_2 from soil neutralisation		g/MJ_{grain}	0.000				
	N_2O field emissions		g/MJ_{grain}	0.042	0.036	0.049	Normal	JRC internal
CR2	**Grain drying, storage and handling**							
	Grain drying							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{grain}	0.0015				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	*F1*	MJ/MJ_{grain}	0.0089				
	NG	*F3*	MJ/MJ_{grain}	0.0089				
	Grain storage and handling							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{grain}	0.00039				[Kaltschmitt 1997]
	Transformation at source							
	NA							
	Transportation to market							
CR3	**Grain transport (road)**							
	Road truck	*T1*						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
CR4	**Ethanol production**							
	Ethanol yield		MJ_{EtOH}/MJ_{corn}	0.608				[GREET 2014], [KTBL 2006], [Pannonia, 2015]
	DDGS yield (7%)		kg_{DDGS}/MJ_{EtOH}	0.030				[GREET 2014], [Pannonia, 2015]
	NH_3	*C8*	g/MJ_{EtOH}	0.23				[ADEME 2010], [MacLean et al., 2009], [GREET 2014]
	NaOH	*C6*	g/MJ_{EtOH}	0.38				
	CaO	*C16*	g/MJ_{EtOH}	0.10				
	H_2SO_4	*C7*	g/MJ_{EtOH}	0.12				
	Urea	*C19*	g/MJ_{EtOH}	0.04				
	Alpha-amylase	*C9*	g/MJ_{EtOH}	0.06				
	Gluco-amylase	*C10*	g/MJ_{EtOH}	0.09				
	Heat to process		MJ/MJ_{EtOH}	0.3302				
	Electricity to process		MJ/MJ_{EtOH}	0.0359				
	NG-fired GT CHP							[Dienhardt 1999]
	Natural gas consumption	*F3*	MJ/MJ_{heat}	2.3867				
	Electricity production		MJ/MJ_{heat}	0.7900				
	CH_4 emissions		g/MJ_{heat}	0.0100				
	N_2O emissions		g/MJ_{heat}	0.0024				
	Electricity surplus from CHP		MJ/MJ_{EtOH}	-0.2250				
	Credit for surplus electricity from CHP based on alternative generation in state-of-the-art NG-fired CCGT							
	Generic process	*GGe*						[GEMIS 2011]
	Efficiency			*58.1%*	*57.0%*	*59.3%*	*Normal*	
	CH_4 emissions		g/MJ_e	*0.0054*				
	N_2O emissions		g/MJ_e	*0.0043*				
	Credit for DDGS							
	Animal feed substitution							*JRC internal*
	1 kg DDGS substitutes:							
	Wheat grain (13% moisture)		*kg/kg_{DDGS}*	*-0.813*				
	Soya meal (11% moisture)		*kg/kg_{DDGS}*	*-0.262*				
	RED methodology							
	Allocation between ethanol and DDGS on energy content basis, between heat and electricity from CHP on exergy content basis							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	*T3j*						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{EtOH}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{EtOH}	0.0034				

9.1.5.1 CR1 Cultivation

A weighted average of corn cultivated in EU and USA imported to EU has been used.

9.1.5.2 CR2 Grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity, diesel, and natural gas.

9.1.5.3 CR3 Grain transport (road)

Corn is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.5.4 CR4 Ethanol production

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

This alternative is energy efficient but also complex and expensive to build and operate compared to a simple steam boiler and electricity import from the grid.

The residual material after fermentation is known as DGS ("Distiller's Grain and Solubles") or DDGS after drying. DDGS is used as animal feed and is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production.

The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.

9.1.5.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.5.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.5.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.5.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.6 Corn (USA) to ethanol. Ethanol produced in USA and exported to EU.

DDGS as animal feed.

Process code	Step	Common processes		Input	Range		Dist.	Source
	Production & conditioning at source							
CRus1	**Cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{grain}					JRC internal
	N (as N)	FN		1.18				
	P (as P_2O_5)	FP		0.36				
	K (as K_2O)	FP		0.42				
	CaO	CA		0.88				
	Pesticides	PE	g/MJ_{grain}	0.014				[GREET 2011]
	Seeding material	SRY	g/MJ_{grain}	0.011				[GREET 2011]
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ_{grain}	0.025				[GREET 2011]
	CH_4 emissions		g/MJ_{grain}	0.000032				[EMEP/EFA 2013]
	CO_2 from soil neutralisation		g/MJ_{grain}	0.196				
	N_2O field emissions		g/MJ_{grain}	0.034	0.031	0.038	Normal	JRC internal
CR2	**Grain drying, storage and handling**							
	Grain drying							
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{grain}	0.0015				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	F1	MJ/MJ_{grain}	0.0089				
	NG	F3	MJ/MJ_{grain}	0.0089				
	Grain storage and handling							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{grain}	0.00039				[Kaltschmitt 1997]
CRus2	**Corn local transport**							
	Standard road truck	T1						
	Distance		km	56				
	Transformation at source							
CRus3	**Ethanol production**							
	Ethanol yield		MJ_{EtOH}/MJ_{corn}	0.602				[GREET 2011]
	DGS yield (57% moisture)		kg_{DDGS}/MJ_{EtOH}	0.012				[GREET 2011]
	DDGS yield (7% moisture)		kg_{DDGS}/MJ_{EtOH}	0.029				[GREET 2011]
	Corn oil yield		kg_{oil}/MJ_{EtOH}	0.000069				[GREET 2011]
	NH_3	C8	g/MJ_{EtOH}	0.20				[GREET 2011]
	NaOH	C6	g/MJ_{EtOH}	0.50				[McLean 2009]
	CaO	C16	g/MJ_{EtOH}	0.12				[McLean 2009]
	Alpha-amylase	C9	g/MJ_{EtOH}	0.08				[McLean 2009]
	Gluco-amylase	C10	g/MJ_{EtOH}	0.11				[McLean 2009]
	NG	F3	MJ/MJ_{EtOH}	0.3126				[GREET 2011]
	Coal	KO1	MJ/MJ_{EtOH}	0.0423				[GREET 2011]
	Credit for DGS/DDGS							
	Animal feed substitution							
	1 kg DDGS substitutes:							
	Wheat grain (13% moisture)		*kg/kg_{DDGS}*	*-0.813*				*[BOA 2000],*
	Soya meal (11% moisture)		*kg/kg_{DDGS}*	*-0.262*				*[Univ. Minnesota 2008]*
	Credit for corn oil based on sunflower oil sunstitution (1 for 1)							
	Transportation to market							
CRus4	**Ethanol rail transport**							
	Distance		km	1000				
	Diesel consumption		MJ/MJ_{EtOH}	0.2500				[GEMIS 2011]
	CH_4 emissions		g/MJ_{EtOH}	0.0050				
	N_2O emissions		g/MJ_{EtOH}	0.0010				
CRus5	**Ethanol sea transport**	T3d						
	Distance		km	6800				
CRus6	**Ethanol depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{EtOH}	0.00084				
	Transformation near market							
	NA							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	T1						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.6	T3j						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	T3a						
	Distance		km	153				
	Rail (4.4%)	T2						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ_{EtOH}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{EtOH}	0.0034				

9.1.6.1 CRus1 Cultivation

Data is typical US, as advised by [Edwards 2016]

9.1.6.2 CR2 Grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity. We account for it at this point in the pathway although in practice storage may occur after transportation.

9.1.6.3 CRus2 Corn local transport

Corn is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.1.6.4 CRus3 Ethanol production

Data is typical US, including a combination of natural gas and coal consumption [GREET 2011].

DDGS (and DGS after drying) is used as animal feed and is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production.

The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.

A small amount of corn oil is produced, assumed to substitute sunflower oil.

9.1.6.5 CRus4 Ethanol rail transport

Ethanol has to be transported by rail from the production plant to a loading port. Data is typical US, from [GEMIS 2011].

9.1.6.6 CRus5 Ethanol sea transport

Ethanol has to be further transported by ship to Europe. A 12.6 kt tanker is assumed as per process T3d.

9.1.6.7 CRus6 Ethanol depot

A small amount of energy is consumed in the receiving depot in EU mainly in the form of electricity for pumping operations.

9.1.6.8 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.6.9 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.6.10 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.6.11 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.7 Brazilian sugar cane to ethanol.

Excess bagasse used for electricity production.

Process code	Step	Common processes		Input	Range		Dist.	Source
	Production & conditioning at source							
SC1	**Sugar cane cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{SC}$					
	N (as N)	*FN*		0.17				JRC internal
	P (as P_2O_5)	*FP*		0.06				JRC internal
	K (as K_2O)	*FP*		0.19				JRC internal
	$CaCO_3$ (as CaO)	*CA*		0.19				JRC internal
	Pesticides	*PE*	g/MJ$_{SC}$	0.01				JRC internal
	Seeding material	*SSC*	g/MJ$_{SC}$	6.16				JRC internal
	Vinasse		g/MJ$_{SC}$	210.52				JRC internal
	Filter mud cake		g/MJ$_{SC}$	1.76				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{SC}$	0.0104				[Macedo 2004, 2008]
	(inc. vinasse and mud cake filter provision)							
	CO_2 from soil neutralisation		g/MJ$_{SC}$	0.650				JRC internal
	N_2O field emissions		g/MJ$_{SC}$	0.007	0.005	0.009	Normal	JRC internal
	CH_4 emissions (trash burning)		g/MJ$_{SC}$	0.043				
SC2	**Sugar cane local transport**							
	Distance		km	20				
	Diesel consumption	*F1*	MJ/t.km	0.81				
	Transformation at source							
SC3	**Ethanol production**							
	Ethanol yield		kg$_{EtOH}$/t$_{SC\ @72.5\%}$	68.5				[Macedo 2008]
	H_2SO_4	*C7*	g/MJ$_{EtOH}$	0.43				[Macedo 2008]
	Cyclohexane	*C18*	g/MJ$_{EtOH}$	0.03				[Macedo 2008]
	CaO	*C16*	g/MJ$_{EtOH}$	0.51				[Macedo 2004, 2008]
	CH_4 emissions		g/MJ$_{EtOH}$	0.0028				[GEMIS 2009]
	N_2O emissions		g/MJ$_{EtOH}$	0.0014				[GEMIS 2009]
	Electricity surplus		MJe/MJ$_{EtOH}$	-0.0180				[Macedo 2008]
	Credit for electrcity based on EU Mix MV	*EMMa*						
	RED methodology							
	No credit for electricity surplus							
	Transportation to market							
SC4	**Ethanol long-distance transport**							
	Road transport							
	Distance		km	700				
	Diesel consumption	*F1*	MJ/t.km	0.81				
SC5	**Ethanol depot (loading port)**							
	Electricity	*EMMa*	MJ$_e$/MJ$_{EtOH}$	0.0008				
SC6	**Ethanol sea transport**							
	Distance	*T3d*	Nm	5500				
	Ethanol depot (loading port)							
	Electricity	*EMLa*	MJ$_e$/MJ$_{EtOH}$	0.0008				
	Transformation near market							
	NA							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	*T3j*						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{EtOH}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{EtOH}$	0.0034				

9.1.7.1 SC1 Sugar cane cultivation

Figures are derived from data in the thorough LCA study by [Macedo 2004] and [Macedo 2008] which describes best-current-practice in the Centre-South region, where 85% of Brazil's sugar cane is grown, and where it is claimed there is still plenty of grazing land which could be planted to increase the supply if there is a market. It is a very long way from any rainforest. Some sugar cane is also produced in NE Brazil, near some areas of surviving Atlantic rainforest, but the conditions are much less suitable there, so that production needed subsidies, and is unlikely to increase. The input of synthetic fertilizer and soil N2O emissions has been derived from the Global Nitrous Oxide Calculator (GNOC) developed by JRC.

There are usually 5 harvests over a 6-year period, with an average yield of 87.1 t/ha (moist), so the annualized yield is 72.6 t/ha/a. Macedo gives inputs per tonne of moist cane. We converted these to figures per MJ (LHV) dry cane using 72.5% water content of harvested sugar cane [Kaltschmitt 2001] and LHV heat content of 19.6 MJ per kg dry matter [Dreier 2000] (Macedo also describes the process per tonne of cane, so these conversion factors cancel out in the overall calculation). To keep the pathway comparable with other crops, we used our usual chemical processes to calculate the energy and emissions from producing the agricultural inputs, not the values used by Macedo.

In this best-practice scenario, the solid “filter mud cake” and liquid “vinasse” residue from the distillation process (equivalent of wet DDGS in the wheat-to-ethanol process) are sent to the closer fields to recycle the water and much of the minerals. The figures represent a weighted average of nearer and more distant fields. The average nitrogen rate over 5 years is about 85 kg/ha.

The farming emissions include CO_2, methane and nitrous oxide from burning the foliage to make manual harvesting easier. This is still the most common practice, although it is banned near towns. We used Macedo’s calculation of N2O, CH4 and CO_2 emissions from burning.

Nitrous oxide emissions were calculated from the nitrogen fertilizer additions together (in this version) with the nitrogen content of the vinasse and filter cake using IPCC default coefficients. Fortunately, they are low, so the related uncertainty is acceptable in this case.

Sugar cane resembles more a perennial biomass crop like miscanthus than it does an arable crop. Unlike arable crops in Europe, planting sugar cane on grazing land is believed to actually increase the soil carbon stocks. The risk of soil erosion (a major concern in Brazil) is heightened in the first year of establishment, compared to grazing land, but not in subsequent years.

9.1.7.2 SC2 Sugar cane local transport

Ethanol factories are normally in the immediate vicinity of sugar cane plantations.

9.1.7.3 SC3 Ethanol production

Data for this process were taken from the comprehensive life-cycle analysis by [Macedo 2004] and [Macedo 2008], adopting his “scenario 2” which describes best-current-practice in the Centre-South region of Brazil, where 85% Brazilian ethanol is produced. His analysis also takes into account the energy for plant construction and some minor inputs which we neglected to be consistent with our calculations for other processes.

The data refer to the production of anhydrous ethanol. Cyclohexane is used in the drying process. The yield corresponds to 86.3 litres ethanol per tonne of moist cane [Macedo 2008]. Inputs were converted from quantities per-tonne-of-cane to per-MJ-ethanol using the same LHV and water content for sugar cane as used in the sugar cane farming process, and standard values for ethanol (see section 1.2).

Plant capacity is 120,000 litres ethanol per day, operating for 180 days per year. A very important factor is that the bagasse is used to raise steam which provides all the process heat, and electricity via a steam turbine. In fact, modern plants have a surplus of electricity. For the calculation of the energy requirement and GHG emissions it has been assumed that the surplus electricity replaces electricity from a bagasse fueled steam turbine power plant with an efficiency of 25%.

9.1.7.4 SC4 Ethanol long-distance transport

Ethanol is first transported by road to a Brazilian sea port, then shipped to Europe.

9.1.7.5 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.7.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.7.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.7.8 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.8 EU farmed (WF) or waste (WW) wood to ethanol (WW/WFET1).

Process code	Step	Common processes		Input	Range		Dist.	Source
	Production & conditioning at source							
WF1	**Wood plantation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{wood}					
	N (as N)	FN		0.00				JRC internal
	Pesticides	PE		0.015				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ_{wood}	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.0000161				
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.0000397				
	N_2O field emissions		g/MJ_{wood}	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	F1	MJ/MJ_{wood}	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindholm
W2	**Forestry residue chipping**							
	Diesel	F1	MJ/MJ_{wood}	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3b	**Farmed wood transport (regional, 500 km)**							JRC internal
	Road truck	T1						
	Distance		km	500				
WF3c	**Farmed wood transport (regional, >500 km)**							JRC internal
WF3c1	Road truck	T1						
	Distance		km	250				
WF3c2	Bulk carrier (Handysize)	T3h						
	Distance		km	2000				
WW3b	**Waste wood transport (regional, 500 km)**							JRC internal
	Road truck	T1						
	Distance		km	500				
WW3c	**Waste wood transport (regional, >500 km)**							JRC internal
WW3c1	Road truck	T1						
	Distance		km	250				
WW3c2	Bulk carrier (Handysize)	T3h						
	Distance		km	2000				
	Transformation near market							
W4	**Ethanol production (SSCF)**							[Wooley 1999]
	Ethanol yield		MJ_{EtOH}/MJ_{wood}	0.3356	0.3553	0.3180	Square	
	Diesel	F1	MJ/MJ_{EtOH}	0.0357				
	H_2SO_4	C7	g/MJ_{EtOH}	3.54				
	NH_3	C8	g/MJ_{EtOH}	2.71				
	$(NH_4)_2SO_4$	C21	g/MJ_{EtOH}	0.74				
	Antifoam		g/MJ_{EtOH}	0.43				
	Corn Steep Liquor		g/MJ_{EtOH}	3.75				
	CaO	C16	g/MJ_{EtOH}	1.36				
	N_2O emissions		g/MJ_{EtOH}	0.00015				
	Electricity surplus		MJ/MJ_{EtOH}	-0.0987				
	Credit for surplus electricity based on biomass-fuelled power station							
	Efficiency			*32.0%*				*[JOPP 1999]*
	CH_4 emissions		g/MJ_e	*0.0826*				*[GEMIS 2005]*
	N_2O emissions		g/MJ_e	*0.0063*				*[Vitovec 1999]*
	RED methodology							
	Allocation between ethanol, heat, and electricity on exergy content basis							
	Conditioning & Distribution							
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	T1						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	T3j						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	T3a						
	Distance		km	153				
	Rail (4.4%)	T2						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ_{EtOH}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{EtOH}	0.0034				

9.1.8.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

9.1.8.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12% dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

9.1.8.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

9.1.8.4 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Guintoli et al. 2017].

9.1.8.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

9.1.8.6 WF3b Farmed wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

9.1.8.7 WF3c Farmed wood transport (regional, >500 km)

A transport distance of 250 km via truck plus a transport distance of 2000 km has been assumed if the wood chips are imported from regions outside the EU e.g. Russia or Ukraine.

9.1.8.8 WW3b Waste wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

9.1.8.9 WW3c Waste wood transport (regional, >500 km)

A transport distance of 250 km via truck plus a transport distance of 2000 km has been assumed if the wood chips are imported from regions outside the EU e.g. Russia or Ukraine.

9.1.8.10 W4 Ethanol production (SSCF)

This corresponds to the “base case” of the detailed study by NERL [Wooley 1999] on wood-to-ethanol via SSCF (Simultaneous Saccharification and Co-Fermentation). The base case combined the best equipment and processes which were had been demonstrated in 1999. Our “best case” is the ”best of industry” case in [Wooley 1999], which incorporates the technical advances which could be foreseen to flow from laboratory developments known in 1999. It was not considered that NREL’s more futuristic projections fitted in the time-frame of this study.

Wood consists principally of hemicellulose, cellulose and lignin. Wood chips are ground, steamed and then hydrolysed in dilute sulphuric acid to release the sugars from the hemicellulose. The product is neutralised and detoxified, and part goes to breed enzyme-producing aerobic bacteria with the aid of additional nutrients (such as corn steep liquor). The bacteria-rich stream then joins the main stream in the main fermenter, where enzymatic breakdown of cellulose (saccharification) occurs simultaneously with fermentation of the different sugars released. After several days, the “beer” is sent for distillation. The slops (including lignin) are dried and burnt to raise steam, along with biogas from the waste water treatment. Surplus steam goes to turbine to make electricity.

The NREL process has an excess of electricity. Like the other wood conversion processes, our process is made electricity-neutral by giving a wood credit for the electricity produced. Since this is not a gasifier-based process, we calculated the credit using a conventional wood-fired steam turbine condensing power station, based on LBST data from the plant at Altenstadt, Germany (see wood-to-electricity processes).

The processes to make the input chemicals are described above (section 1.10: chemicals), with two exceptions, for which we could find no quantitative data: corn steep liquor (CSL) and antifoam. CSL is a by-product from corn syrup manufacture, used as a culture medium for bacteria, and as animal feed. Usually it is neglected in LCA studies. To check if it could be significant, we gave it a (MJ primary energy input)/ (MJ digestible energy) ratio the same as wheat. This confirmed that it could have been neglected. Antifoam is a simple silicone compound. Instead of neglecting it a priori we attributed a primary energy per kg typical of a process chemical, which showed it to be of no unimportant in the energy balance.

9.1.8.11 ET1 Ethanol transport

Ethanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.1.8.12 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.8.13 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.8.14 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.1.9 EU wheat straw to ethanol (STET1)

Process code	Step	Common processes		Input	Range	Dist.	Source
	Production & conditioning at source						
ST1	**Straw collection**						
	Diesel	F1	MJ/MJ_{straw}	0.0096			[GEMIS 2005]
	Fertilizer debit		g/MJ_{straw}				[Kaltschmitt 1997]
	P (as P_2O_5)	FP		0.13			
	K (as K_2O)	FK		0.71			
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"						
	Transformation at source						
	NA						
	Transportation to market						
ST2	**Straw transport**						JRC internal
	Road truck	T1					
	Distance		km	500			
	Transformation near market						
ST3	**Ethanol production (Biochemtex)**						
	Ethanol yield		MJ_{EtOH}/MJ_{straw}	0.283			[Biochemtex 2015], [Kaltschmitt 2001]
	Diammonium phosphate ($(NH_4)_2HPO_4$)	C20	g/MJ	0.306			[Johnson 2016]
	Ammonium sulfate ($(NH_4)_2SO_4$)	C21		0.162			[Johnson 2016]
	$CaCl_2$	C22		0.047			[Johnson 2016]
	CaO	C16		1.93			[Johnson 2016]
	Corn Steep Liquor (CSL)			3.78			[Johnson 2016]
	Monopotassium phosphate (KH_2PO_4)	C23		0.23			[Johnson 2016]
	$MgSO_4$	C24		0.03			[Johnson 2016]
	NaOH	C6		4.85			[Johnson 2016]
	NH_3	C8		0.42			[Johnson 2016]
	Propylene glycol	C15		0.70			[Johnson 2016]
	SO_2	C25		0.05			[Johnson 2016]
	CH4 emissions			0.0000			
	N2O emissions			0.0000			
	Electricity surplus		MJ/MJ	0.403			[Biochemtex 2015]
	Credit for surplus electricity based on straw-fuelled power station						
	Efficiency		*MJe/MJ*	*0.3150*			*[Baro 2003]*
	CH_4 emissions		*g/MJe*	*0.0085*			*[GEMIS 2009]*
	N_2O emissions			*0.0017*			*[GEMIS 2009]*
	RED methodology						
	No fertilizer debit, allocation between ethanol, heat, and electricity on exergy content basis						
	Conditioning & Distribution						
ET1	**Ethanol transport**						JRC internal
	Road truck (13.2%)	T1					
	Distance		km	305			
	Sea-going product tanker 12.6 kt (31.6%	T3j					
	Distance		km	1118			
	Barge 1.2 kt (50.8%)	T3a					
	Distance		km	153			
	Rail (4.4%)	T2					
	Distance		km	381			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ_{EtOH}	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	T1					
	Distance		km	150			
LF3	**Ethanol dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{EtOH}	0.0034			

9.1.9.1 ST1 Straw collection

Removal of a portion of the straw that would normally be ploughed back deprives the land from some P/K fertiliser. This is accounted for through a small debit.

9.1.9.2 ST2 Straw transport

Locally collected straw is transported over a short distance to the ethanol plant. Road transport is assumed by a standard road truck according to process T1.

9.1.9.3 ST3 Ethanol production (Biochemtex)

Data for a straw-to-ethanol plant was supplied by [Biochemtex]. A biomass credit is given for electricity export again based on the straw-burning power station at Sanguesa in Spain.

9.1.9.4 ET1 Ethanol transport

Analogous to the pathways for RED II the straw bales are transported via truck over a distance of 500 km.

The three following processes are common to all liquid fuels.

9.1.9.5 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.1.9.6 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.1.9.7 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.2 ETBE

9.2.1 EU sugar beet to ETBE. Pulp to animal feed, Slops used as feed for biogas, ethanol and isobutene for ETBE from sugar beet (SBBE1b)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Dist.*	*Source*
	Production & conditioning at source							
SB1	**Sugar beet cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{SB}$					
	N (as N)	*FN*		0.35				JRC internal
	P (as P_2O_5)	*FP*		0.15				JRC internal
	K (as K_2O)	*FP*		0.26				JRC internal
	CaO	*CA*		0.61				JRC internal
	Pesticides	*PE*	g/MJ$_{SB}$	0.05				[Capri 2012], [FfE 1998]
	Seeding material	*SSB*	g/MJ$_{SB}$	0.01				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							[Capri 2012], [FfE 1998]
	Diesel	*F1*	MJ/MJ$_{SB}$	0.0105				[EMEP/EFA 2013]
	CH_4 emissions		g/MJ$_{SB}$	0.000013				
	CO_2 from soil neutralisation		g/MJ$_{SB}$	0.00				
	N_2O field emissions		g/MJ$_{SB}$	0.0126	0.0101	0.0151	Normal	JRC internal
SB2	**Sugar beet storage and handling**							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{SB}$	0.0000				JRC internal
	Transformation at source							
	NA							
	Transportation to market							
SB3	**Sugar beet transport**							JRC internal
	Road truck	*T1*						
	Distance		km	30				
	Transformation near market							
SB4	**Ethanol production**							
	Ethanol yield		kg$_{EtOH}$/kg$_{SB\ @76.5\%}$	0.0777				[Kaltschmitt 1997]
	Pulp yield (@ 9% moisture)		kg$_{Pulp}$/kg$_{SB\ @76.5\%}$	0.058				[FfE 1998]
	Ethanol plant							[Kaltschmitt 1997]
SB4b	Slops to biogas (used as fuel in plant)							
	Net heat to process	*GHI*	MJ/MJ$_{EtOH}$	0.1043				
	Electricity to process	*EMMa*	MJ/MJ$_{EtOH}$	0.0398				
	Credit for Pulp							
	Animal feed substitution							
	1 kg Pulp substitutes:							
	Wheat grain (13.5% moisture)		*kg/kg$_{Pulp}$*	*-0.866*				
	Soya meal (10% moisture)		*kg/kg$_{Pulp}$*	*-0.013*				
SB4c	Pulp to fuel, slops to biogas							[Kaltschmitt 1997]
	Electricity surplus		MJ/MJ$_{EtOH}$	-0.0404				
	Credit based on EU-mix, MV							
	RED methodology							
	Allocation between ethanol and pulp on energy content basis							
SB5	**Isobutene production**							[FfE 1998], [GBE 2015], [GBE 2018], [Kaltschmitt 1997]
	i-butene yield		kg/kg$_{SB\ @75\%\ H2O}$	0.1455				
	Pulp yield (9% H2O)		kg/kg$_{SB\ @75\%\ H2O}$	0.0580				
SB5b1	**Isobutene plant**							
	Slops to biogas (used as fuel in plant)							[GBE 2018], [Kaltschmitt 1997]
	Heat to process	*GHI*	MJ/MJ$_{i\text{-}butene}$	0.0255				
	Electricity to process	*EMMa*	MJ/MJ$_{i\text{-}butene}$	0.1864				
	Natural gas	*F3*	MJ/MJ$_{i\text{-}butene}$	0.0114				
	Various process chemicals		g/MJ$_{i\text{-}butene}$	1.47				
	Credit for Pulp							
	Animal feed substitution							
	1 kg Pulp substitutes:							
	Wheat grain (13.5% moisture)		*kg/kg$_{Pulp}$*	-0.866				
	Soya meal (10% moisture)		*kg/kg$_{Pulp}$*	*-0.013*				
	Credit for heat surplus based on heat from NG							
EB1	**ETBE synthesis plant**							CONCAWE internal
	Isobutene		MJ/MJ$_{ETBE}$	0.6807				
	Ethanol		MJ/MJ$_{ETBE}$	0.3329				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{ETBE}$	0.0010				
	Energy as NG	*F3*	MJ/MJ$_{ETBE}$	0.0240				
	Conditioning & Distribution							
EB4	**ETBE distribution (long distance)**							[TOTAL 2001]
	Barge, 1200 t (20%)							
	Distance		km	500				
	Diesel fuel	*F1*	MJ/t.km	0.5040				
	CH_4 emissions		g/t.km	0.0300				
	Rail (20%)							
	Distance	*T2*	km	250				
	Pipeline (60%)							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ$_{ETBE}$	0.0002				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{ETBE}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{ETBE}$	0.0034				

9.2.1.1 SB1 Sugar beet cultivation

Fertiliser inputs are based on the weighted average of national fertiliser inputs for countries with sugar-beet ethanol production.

We assume that the sugar beet leaves are ploughed back into the soil after harvest, which is the usual practice.

9.2.1.2 SB2 Sugar beet storage and handling

A small amount of energy is consumed to handle and store sugar beets mainly in the form of electricity. In practice storage may occur after transportation and is already account at the ethanol production stage. Therefore, the electricity requirement is set to zero.

9.2.1.3 SB3 Sugar beet transport

Sugar beets are typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.2.1.4 SB4 Ethanol production

Following [LBST 2002] we chose a conventional fermentation plant, not integrated with a sugar refinery, as analysed by [FfE 1998]. The main steps in the basic process are cleaning, slicing, sieving out the pulp by-product, syrup pasteurisation, fermentation, distillation, and final purification. These steps use electricity (from the grid) and heat which we assume is supplied by a natural gas boiler with 90% efficiency. Distillation and final ethanol purification (drying with zeolite) consumes most of the energy.

Sugar factories using beet do not work all year round because sugar beet have to be processed quickly after harvest to avoid sugar loss in storage (see SB1 farming pathway). Beet processing “campaigns” typically last between 60 days (Poland) and 150 days (Britain). Average for EU-25 is about 90 days (also the German figure). However, it is possible to keep the ethanol part of the plant working continuously by storing pasteurised syrup. The size of the plant is not very important for efficiency, but has a large effect on costs. [FfE 1998] made a cost analysis on a hypothetical 59 MW (ethanol) plant.

There are two by-products: sugar beet pulp sieved from the syrup and the slops filtered from the fermented. Both beet by-products contain initially 35-40% water, and have to be dried to about 9% water [FfE 1998], [NRC 1998]. In addition, there is a small amount of electricity required for the blowers.

In variant a and b the pulp is used for animal feed. We have assumed that it is dried evaporatively using waste heat which considerably reduces the overall energy requirement and GHG emissions compared to conventional drying using natural gas generated heat. The pulp substitutes a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production. The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.

In variant a, the slops are not used. In variant b slops are fed to an anaerobic digester to produce biogas, providing some of the plant energy needs, and reducing natural gas consumption. Electricity consumption increases slightly to power the biogas plant. We assume 1 MJ biogas substitutes 1 MJ natural gas. The waste from the biomass fermenter would probably be used as fertilizer. However, the quantity is much smaller than the uncertainty in fertilizer use in the sugar beet farming process, so we do not account for this.

In variant c the sieved pulp mash is burned in a boiler and the slops continue to produce biogas. Both are used in a CHP plant to produce electricity and heat with an electrical efficiency of 20% (typical for a small-scale steam turbine). This is sufficient to fully meet the needs of the plant. There is excess electricity and heat. The former is exported and produces a credit, while the surplus heat is considered to have no value.

9.2.1.5 SB5 Isobutene production

In 21 July 2015, Global Bioenergies (GBE) announced to build and operate the first full-scale Bio-Isobutene commercial plant 'IBN-One' together with Cristal Union to convert sugar beets into 50,000 tonnes of bio-isobutene by 2018 [GBE, 21 July 2015].

Sugar beet is used as feedstock. Some 3.84 t of sugar are required per t of isobutene [GBE, 29 July 2015]. 0.168 kg of sugar can be extracted per kg of moist sugar beet [Kaltschmitt 1997]. The heat and electricity requirement for the extraction of sugar from sugar beet and the pulp yield have been derived from data for a sugar beet-to-ethanol plant described in [Kaltschmitt 1997]. Data for the isobutene plant other than sugar beet processing have been derived from [GBE 2018].

9.2.1.6 EB1 ETBE synthesis plant

This represents a typical large dedicated ETBE plant located in EU. ETBE is synthesised from isobutene and ethanol.

9.2.1.7 EB4 ETBE distribution (long distance)

Long distance distribution modes and distances are the same as for gasoline and diesel. The three following processes are common to all liquid fuels.

9.2.1.8 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.2.1.9 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.2.1.10 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.2.2 ETBE from wheat ethanol and isobutene (LREB)

Process code	Step	Common processes		Input	Range		Dist.	Source
	Production & conditioning at source							
WT1a	**Wheat cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{grain}$					
	N (as N)	*FN*		1.34				JRC internal
	P (as P_2O_5)	*FP*		0.26				JRC internal
	K (as K_2O)	*FP*		0.21				[EFMA 2008]
	CaO	*CA*		1.44				JRC internal
	Pesticides	*PE*	g/MJ$_{grain}$	0.07				[CAPRI 2012]
	Seeding material	*SWH*	g/MJ$_{grain}$	0.42				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{grain}$	0.0384				[CAPRI 2012]
	CH_4 emissions		g/MJ$_{grain}$	0.000049				
	CO_2 from soil neutralisation		g/MJ$_{grain}$	0.00				
	N_2O field emissions		g/MJ$_{grain}$	0.045	0.040	0.049	Normal	JRC internal
WT2	**Wheat grain drying, storage and handling**							
	Wheat grain drying							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{grain}$	0.000048				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	*F1*	MJ/MJ$_{grain}$	0.00029				
	NG	*F3*	MJ/MJ$_{grain}$	0.00029				
	Wheat grain handling and storage							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{grain}$	0.000392				[Kaltschmitt 1997]
LR1	**LPG extraction and processing**							[ETSU 1996]
	Energy as NG		MJ/MJ$_{LPG}$	0.0529	0.0500	0.0700	Square	
	CH_4 emissions		g/MJ$_{LPG}$	0.0152				
	Transformation at source							
LR2	**LPG liquefaction**							[ETSU 1996]
	Electricity (on-site generation)	*GGe*	MJ/MJ$_{LNG}$	0.0028				
	Transportation to market							
WT3a	**Wheat grain transport (road)**							
	Road truck	*T1*						
	Distance		km	100				
	Losses			1.0%				
LR3	**LPG long-distance sea transport**							
	Distance	*T3g*	Nautical miles	5500				
	Transformation near market							
WT4	**Ethanol production**	*According to WTET2a, process WT42*						
ET1	**Ethanol transport**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	*T3j*						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LB1	**LPG to isobutene**							CONCAWE internal
	LPG		MJ/MJ$_{Isobutene}$	1.0490				
	Hydrogen production		MJ/MJ$_{Isobutene}$	-0.0960				
	Energy as NG *(inc. credit for hydrogen used as chemical)*	*GG1*	MJ/MJ$_{Isobutene}$	0.0258				
	Electricity (EU-mix, MV)	*EMMa*		0.0082				
	CH_4 emissions *(inc. credit for hydrogen used as chemical)*		g/MJ$_{Isobutene}$	-0.0011				
	N_2O emissions		g/MJ$_{Isobutene}$	0.0002				
EB1	**ETBE synthesis plant**							CONCAWE internal
	Isobutene		MJ/MJ$_{ETBE}$	0.6807				
	Methanol		MJ/MJ$_{ETBE}$	0.3329				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{ETBE}$	0.0010				
	Energy as NG	*F3*	MJ/MJ$_{ETBE}$	0.0240				
	Conditioning & Distribution							
EB4	**ETBE distribution (long distance)**							[TOTAL 2001]
	Barge, 1200 t (20%)							
	Distance		km	500				
	Diesel fuel	*F1*	MJ/t.km	0.5040				
	CH_4 emissions		g/t.km	0.0300				
	Rail (20%)							
	Distance	*T2*	km	250				
	Pipeline (60%)							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ$_{ETBE}$	0.0002				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{ETBE}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{ETBE}$	0.0034				

9.2.2.1 WT1a Wheat cultivation

Wheat is the highest-yielding cereal crop, but it also takes the highest inputs. This process represents conventional wheat grain farming for 'soft wheat', which accounts for most of EU production, gives the highest yield, and has the highest fermentable content. Straw use is discussed in the main WTT report.

9.2.2.2 WT2 Wheat grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity. We account for it at this point in the pathway although in practice storage may occur after transportation.

9.2.2.3 LR1 LPG extraction and processing

It is assumed here that LPG is produced as part of the heavier hydrocarbons (condensate) associated with natural gas. 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.

9.2.2.4 LR2 LPG liquefaction

Liquefaction requires electricity assume to be generated on site with an NG-fired CCGT.

9.2.2.5 WT3a Wheat grain transport (road)

Grain is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.2.2.6 LR3 LPG long-distance sea transport

Representative of a typical LPG carrier.

9.2.2.7 LB1 LPG to isobutene

Mixed butanes are isomerised into isobutane which is in turns dehydrogenated into isobutene. As this plant can reasonable be assumed to be part of a petrochemical complex, the hydrogen released is assumed to be used as feedstock to other hydrogen consuming process, generating a credit based on alternative hydrogen production by NG reforming.

9.2.2.8 EB1 ETBE synthesis plant

This represents a typical large dedicated ETBE plant located in EU. ETBE is synthesised from isobutene and ethanol.

9.2.2.9 EB4 ETBE distribution (long distance)

Long distance distribution modes and distances are the same as for gasoline and diesel.

9.2.2.10 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.2.2.11 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.2.2.12 LF3 Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

9.3 ED95

9.3.1 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

		Wheat	Ethanol	DDGS	PEG	MTBE	i-butanol	Lubricants	ED 95
Density	kg/m^3		794		1126	745	802	873	820
Typical moisture content	% m	13.5%		10.0%					
LHV (dry matter)	MJ/kg	17.0	26.8	18.1	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	g CO$_2$/MJ		71.4		80.8	71.2	71.6	73.5	71.3
(assuming total combustion)	kg CO$_2$/kg		1.91		1.90	2.50	2.37	3.13	1.81

Pathway code	Pathway	Common processes		Input	Range		Dist.	Source	
	WETOiB-TED							SEKAB 2018	
WTET2a/b	Ethanol from wheat		MJ/MJ$_{ED95}$	0.903					
COPEG1	Polyethylene glycol from crude oil		MJ/MJ$_{ED95}$	0.046					
GRMB1	MTBE from natural gas		MJ/MJ$_{ED95}$	0.030					
COiB1	i-butanol from crude oil		MJ/MJ$_{ED95}$	0.006					
COL1	Lubricants from crude oil		MJ/MJ$_{ED95}$	0.016					
	WETBiB-TED							SEKAB 2018	
WTET2a/b	Ethanol from wheat		MJ/MJ$_{ED95}$	0.903					
COPEG1	Polyethylene glycol from crude oil		MJ/MJ$_{ED95}$	0.046					
GRMB1	MTBE from natural gas		MJ/MJ$_{ED95}$	0.030					
MtiBa	i-butanol from corn (maize)		MJ/MJ$_{ED95}$	0.006					
COL1	Lubricants from crude oil		MJ/MJ$_{ED95}$	0.016					

9.3.2 Wheat straw to ethanol. Mixed with polyethylene glycol (PEG), MTBE, i-butanol, and lubricants to ED95 for diesel engines (SETOiB-TED).

SETOiB-TED: i-butanol from crude oil

a) straw transport 50 km

b) straw transport 500 km

Input data

Physical properties of products and intermediates relevant to this pathway

		Wheat	Ethanol	DDGS	PEG	MTBE	i-butanol	Lubricants	ED 95
Density	kg/m^3		794		1126	745	802	873	820
Typical moisture content	% m	13.5%		10.0%					
LHV (dry matter)	MJ/kg	17.0	26.8	18.1	23.5	35.1	33.2	42.6	24.9
Carbon content	% m		52.2%		51.8%	68.2%	64.8%	85.3%	49.1%
CO$_2$ emission factor	g CO$_2$/MJ		71.4		80.8	71.2	71.6	73.5	72.3
(assuming total combustion)	kg CO$_2$/kg		1.91		1.90	2.50	2.37	3.13	1.80

Pathway code	Pathway	Common processes		Input	Range		Dist.	Source	
	SETOiB-TED							SEKAB 2018	
STET1	Ethanol from wheat straw		MJ/MJ$_{ED95}$	0.903					
COPEG1	Polyethylene glycol from crude oil		MJ/MJ$_{ED95}$	0.046					
GRMB1	MTBE from natural gas		MJ/MJ$_{ED95}$	0.030					
COiB1	i-butanol from crude oil		MJ/MJ$_{ED95}$	0.006					
COL1	Lubricants from crude oil		MJ/MJ$_{ED95}$	0.016					

9.4 i-butanol

9.4.1 Corn (maize) (average used in EU) to i-butanol. Production energy provided by a biogas fueled CHP plant (MTiBA).

DDGS to animal feed.

Process code	Step	Common processes		Input	Range		Dist.	Source
	Production & conditioning at source							
CR1	**Cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{grain}					JRC internal
	N (as N)	FN		1.06				
	P (as P_2O_5)	FP		0.28				
	K (as K_2O)	FP		0.26				
	CaO	CA		0.70				
	Pesticides	PE	g/MJ_{grain}	0.07				[CAPRI 2016]
	Seeding material	SRY	g/MJ_{grain}	0.46				[CAPRI 2016], [FAOSTAT 2016]
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ_{grain}	0.0312				[CAPRI 2016], [FAOSTAT 2016]
	CH_4 emissions		g/MJ_{grain}	0.000040				[EMEP/EFA 2013]
	CO_2 from soil neutralisation		g/MJ_{grain}	0.000				
	N_2O field emissions		g/MJ_{grain}	0.042	0.036	0.049	Normal	JRC internal
CR2	**Grain drying, storage and handling**							
	Grain drying							
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{grain}	0.0015				[CAPRI 2016], [Kaltschmitt 2001], [KTBL 2006], [UBA 1999]
	Diesel	F1	MJ/MJ_{grain}	0.0089				
	NG	F3	MJ/MJ_{grain}	0.0089				
	Grain storage and handling							
	Storage losses			0.8%				[Kenkel 2009]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{grain}	0.00039				[Kaltschmitt 1997]
	Transformation at source							
	NA							
	Transportation to market							
CR3	**Grain transport (road)**							
	Road truck	T1						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
CR5	**i-butanol production**							
	i-butanol yield		MJ_{EtOH}/MJ_{corn}	0.5752				[EPA 2016]
	DDGS yield (7%)		kg_{DDGS}/MJ_{EtOH}	0.0348				[Lund 2013]
	Biogas (from waste)			0.2842				[EPA 2016]
	Electricity surplus from biogas CHP		MJ/MJ_{EtOH}	-0.0050				[EPA 2016]
	Credit for surplus electricity from CHP based on electricity mix (MV)							
	Credit for DDGS							
	Animal feed substitution							*JRC internal*
	1 kg DDGS substitutes:							
	Wheat grain (13% moisture)		*kg/kg_{DDGS}*	*-0.813*				
	Soya meal (11% moisture)		*kg/kg_{DDGS}*	*-0.262*				
	RED methodology							
	Allocation between ethanol and DDGS on energy content basis, between heat and electricity from CHP on exergy content basis							
	Conditioning & Distribution							
BT1	**i-butanol transport**							JRC internal
	Road truck (13.2%)	T1						
	Distance		km	305				
	Sea-going product tanker 12.6 kt (31.	T3j						
	Distance		km	1118				
	Barge 1.2 kt (50.8%)	T3a						
	Distance		km	153				
	Rail (4.4%)	T2						
	Distance		km	381				
LF1B	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{EtOH}	0.00084				
LF2B	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3B	**Ethanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{EtOH}	0.0034				

9.4.1.1 CR1 Cultivation

A weighted average of corn cultivated in EU and USA imported to EU has been used.

9.4.1.2 CR2 Grain drying, storage and handling

A small amount of energy is consumed to handle and store grain mainly in the form of electricity, diesel, and natural gas.

9.4.1.3 CR3 Grain transport (road)

Corn is typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

9.4.1.4 CR5 i-butanol production

The assumptions for the corn-to-i-butanol plant are based on the Gevo Luverne facility in Minnesota in the USA where an ethanol plant is converted to an i-butanol plant. The process energy is supplied by biogas leading to excess electricity. The biogas is derived from off-site landfills or other waste digesters [EPA 2016]. About 2.2 gal i-butanol (1 US gal = 3.785 l) and 17.0 lb of DDGS (1 kb = 0,4531 kg) are produced per bushel of corn [Lund 2013] (1 bushel = 56 lb = 25.4 kg). For this study it has been assumed that the biogas is derived from municipal organic waste.

About 2.5 million gal (9460 m^3) of i-butanol are produced per year [GEVO 2014].

The residual material after fermentation is known as DGS ("Distiller's Grain and Solubles") or DDGS after drying. DDGS is used as animal feed and is assumed to substitute a mixture of wheat grain and soya meal representing a similar level of protein and digestible energy. The level of credit is based on production figures for these alternative materials. For wheat the figures are the same as in process WT1a. The calculation is more complex for soya meal as it is itself a co-product of soya oil production.

The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report chapter 3.4.4.

9.4.1.5 BT1 i-butanol transport

i-butanol has to be transported from the production plant to a conventional fuel depot via maritime ship, inland ship, rail, and truck.

The three following processes are common to all liquid fuels.

9.4.1.6 LF1B Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

9.4.1.7 LF2B Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

9.4.1.8 LF3B Ethanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

10 Biodiesel

As general notes:

- Farming processes

Original sources mostly give agricultural input data per hectare with reference to a certain yield. However, the yield basis varies between sources which can lead to confusion. As a result, we show the data per MJ of the crop. The figures are considered valid for the range of yield typically found in Europe.

As explained in the WTT report, our GHG balances figures refer to annual farming emissions, and do not take account of any land use change emissions, which should be considered separately. However, when we calculate N2O emissions, we take into account that soil emits "background" N2O even if it is not cultivated (which are low according to IPCC). As explained in the WTT report, the best of a limited range of options is to choose "unfertilized grass" as the land-cover for the calculation of background emissions.

N2O field emissions are calculated according to the JRC methodology described in section 3.7.2 of the WTT report.

All figures are related to the Lower Heating Value (i.e. excluding the heat of condensation of water vapour formed during combustion) and to the dry matter (i.e. water-free) of the biomass products. In our convention, this arises only from the hydrogen content of the dry-matter. However, some other workers (for example, in the Netherlands) include also the energy for evaporating water from moist materials. The heat of vaporization is not recovered in the flue gas, so this gives a lower LHV than ours. We do not do this because it causes problems: wood apparently increases in heating value during storage, sewage sludge apparently has a negative LHV, and in the "Dutch" convention energy is not conserved in processes whenever the water content of the products differs from those of the feedstocks. Of course, we take the water content into account when calculating the weight of biomass transported.

Generally, only best estimate figures are shown. It is not worth including a range of energy inputs, because the impact on the whole chain is small. The main source of uncertainty is in the GHG emissions, caused by the field N2O emissions.

We call seeds "seeding materials" to avoid confusion with oilseeds as a crop.

- Conversion of biomass to biofuel

The range of energy and emissions reported by different authors for processing biomass into 'conventional biofuels' is much smaller than the uncertainty in farming emissions. Therefore, we do not attempt to indicate an uncertainty range. Where there are significantly different processes, we have made separate calculations for the two processes. Large variations in the energy and emissions reported in the literature are due to different treatment of co-products, as discussed in the WTT report.

The method for calculating the credit for co-products used as animal feed is based on balancing protein and digestible energy requirements of animal feeds. This is detailed in WTT report section 3.7.4.

Co-products often require drying before they can be used conveniently as animal feed, and this can consume more energy than the credit for the feedstocks replaced. Usually, however, waste heat from the process can be used.

10.1 Biodiesel

10.1.1 Rapeseed to biodiesel (Rapeseed Methylester) (ROFA)

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)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Dist.*	*Source*
	Production & conditioning at source							
RO1	**Rapeseed cultivation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{Rapeseed}$					
	N (as N)	*FN*		1.84				[FAOSTAT 2016], [FE 2016]
	P (as P_2O_5)	*FP*		0.41				[FE 2016]
	K (as K_2O)	*FK*		0.56				[FE 2016]
	$CaCO_3$ (as CaO)	*CA*		2.27				JRC internal
	Pesticides	*PE*	g/MJ$_{Rapeseed}$	0.09				[CAPRI 2012], [FAOSTAT 2016],
	Seeding material	*SRO*	g/MJ$_{Rapeseed}$	0.36				[FAOSTAT 2016]
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{Rapeseed}$	0.039				[CAPRI 2012]
	CH_4 emissions		g/MJ$_{Rapeseed}$	0.000049				[EMEP/EFA 2013]
	CO_2 from soil neutralisation		g/MJ$_{Rapeseed}$	0.000				
	N_2O field emissions		g/MJ$_{Rapeseed}$	0.0573	0.0430	0.0717	Normal	JRC internal
RO2	**Rapeseed drying, storage and handling**							[JRC internal], [UBA 1999]
	Diesel	*F1*	MJ/MJ$_{Rapeseed}$	0.0062				
	NG	*F3*	MJ/MJ$_{Rapeseed}$	0.0062				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Rapeseed}$	0.0030				
	Transformation at source							
	NA							
	Transportation to market							
RO3	**Rapeseed transport**							[Rous 2008]
	Road truck	*T1*						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
RO4	**Raw oil production**							[EBB 2009]
	Raw oil yield		MJ$_{oil}$/MJ$_{seed}$	0.633				
RO4a	**Meal export**							
	Rape meal yield		kg/MJ$_{oil}$	0.036				
	Heat to process	*GHI*	MJ/MJ$_{oil}$	0.0433				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{oil}$	0.0097				
	n-Hexane	*C11*	MJ/MJ$_{oil}$	0.0023				
	CO_2 emissions (from n-hexane)		g/MJ$_{oil}$	0.155				
	Credit for meal							
ROFA 1/2/3/5	*Animal feed substitution*							
	1 kg meal substitutes:							
	Wheat grain (13% moisture)		*kg/kg$_{Meal}$*	*-0.479*				
	Soya meal (11% moisture)		*kg/kg$_{Meal}$*	*-0.382*				
RO4b	**Meal to biogas**							
	Heat surplus		MJ/MJ$_{oil}$	-0.0784				
	Electricity surplus		MJ/MJ$_{oil}$	-0.1068				
	n-Hexane	*C11*	MJ/MJ$_{oil}$	0.0023				
	CO_2 emissions		g/MJ$_{oil}$	0.155				
	No credit for heat surplus							
	Electricity credit based on EU-mix MV							
	N-fertilizer credit							
	N-fertilizer		*gN/MJ$_{oil}$*	*-0.0023*				
RO5	**Oil refining**							[EBB 2009]
	Refined oil yield		MJ/MJ	0.976				
	Heat to process	*GHI*	MJ/MJ$_{oil}$	0.0040				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{oil}$	0.0009				
	H_3PO_4	*C12*	g/MJ$_{oil}$	0.000032				
	NaOH	*C6*	g/MJ$_{oil}$	0.000088				
BO1	**Biodiesel (RME) production**							[EBB 2009]
	RME yield		MJ$_{Biodiesel}$/MJ$_{oil}$	0.999				
	Methanol (feed)		MJ/MJ$_{Biodiesel}$	0.051				
	CO_2 emissions (fossil carbon in methanol)		g/MJ$_{Biodiesel}$	3.518				
	Methanol production							[Larsen 1998]
	NG		MJ/MJ$_{Methanol}$	1.463	1.4406	1.4857	Normal	
	CH_4 emissions		g/MJ$_{Methanol}$	0.000083				
BO1a	**Glycerine export**							[EBB 2009]
ROFA 1/2	Glycerine yield		kg/MJ$_{Biodiesel}$	0.0027				
	Heat to process	*GHI*	MJ/MJ$_{Biodiesel}$	0.0330				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{Biodiesel}$	0.0040				
	HCl	*C13*	g/MJ$_{oil}$	0.00010				
	$Na(CH_3O)$	*C14*	g/MJ$_{oil}$	0.00011				
BO1b	**Glycerine to fuel (biogas)**							
ROFA3/4	Heat surplus		MJ/MJ$_{Biodiesel}$	-0.0056	-0.00702	-0.00422	Normal	[EBB 2009], [BioChemTechEngi
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{Biodiesel}$	0.0040				[EBB 2009]
	HCl	*C13*	g/MJ$_{oil}$	0.00010				[EBB 2009]
	$Na(CH_3O)$	*C14*	g/MJ$_{oil}$	0.00011				[EBB 2013]
BO1c	**Glycerine to hydrogen**							
ROFA5	Hydrogen yield		MJ/MJ$_{Biodiesel}$	0.0351				[EBB 2009], [Linde 2011]
	Heat to process	*GHI*	MJ/MJ$_{Biodiesel}$	0.0354				[EBB 2009], [Linde 2011]
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{Biodiesel}$	0.0044				[EBB 2009], [Linde 2011]
	HCl	*C13*	g/MJ$_{oil}$	0.00010				[EBB 2009]
	$Na(CH_3O)$	*C14*	g/MJ$_{oil}$	0.00011				[EBB 2013]
	Credit for glycerine							
ROFA1	*Propylene glycol*	*C15*	*kg/kg$_{Glycerine}$*	*-1.00*				
ROFA2	*Animal feed*							
	Wheat grain (13% moisture)		*kg/kg$_{Glycerine}$*	*-1.18*				
ROFA5	*Hydrogen produced by NG steam reforming*							
	RED methodology							
	Allocation between oil and meal and biodiesel and glycerine on energy content basis							
	Conditioning & Distribution							
BD1	**Biodiesel transport**							
	Road truck	*T1*						
	Distance		km	150				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{Biodiesel}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Biodiesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Biodiesel}$	0.0034				

10.1.1.1 RO1 Rapeseed cultivation

Rape gives the highest oil yield in the Northern half of Europe. However, it still has much lower yield than cereals: it is typically grown as a low-input break crop, to rest the soil between more profitable cereal crops. The rape straw is invariably ploughed back into the soil, because it contains most of the nitrogen and minerals taken up by the crop and is needed to improve the organic content of the soil.

10.1.1.2 RO2 Rapeseed drying, storage and handling

A small amount of energy is consumed to handle and store seeds. We account for it at this point in the pathway although in practice storage may occur after transportation.

10.1.1.3 RO3 Rapeseed transport

Oil seeds are typically transported by road. The distance taken into account reflects average EU practice. We assumed a standard truck as described in common process T1.

10.1.1.4 RO4 Raw oil production

Rapeseed is crushed and the oil is extracted with the aid of n-hexane solvent and heat. Hexane is a refinery product made almost entirely from crude oil. n-hexane lost to the atmosphere or to the waste water is assumed to be eventually oxidised hence the small amount of CO_2 emissions. In all conversion processes, we assume process heat or steam is supplied by a NG boiler working at 90% efficiency.

10.1.1.5 RO4a Meal export

In alternative 1/2/3/5 the rapeseed meal is used as animal feed, substituting a mix of soy bean and feed wheat.

The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report section 3.7.4.

10.1.1.6 RO4b Meal to biogas

In alternative 4 the rapeseed meal is used to generate biogas which provides all the heat and a large part of the electricity for the process, improving the energy and GHG balance.

10.1.1.7 RO5 Oil refining

The refining step purifies the plant oil so it is ready for esterification.

10.1.1.8 BO1 Biodiesel (RME) production

The process is the same for rapeseed, sunflower, soy and palm oils. Plant oil consists of 3 fatty acid chains on a 3-carbon backbone. 3 molecules of methanol combine with the fatty acids to make 3 molecules of fatty acid methyl ester (biodiesel), leaving their three alcohol groups bonded to the 3-carbon backbone to form glycerine.

Methanol is assumed to be produced from natural gas (with a small amount of methane emissions). CO_2 emissions from methanol combustion are added here so that the resulting biodiesel can be considered to be 100% renewable.

Three alternatives are explored for use of glycerine.

10.1.1.9 BO1a Glycerine export

In alternative 1/2 glycerine is assumed to be exported and substitute either a similar chemical product (1) or be used as animal feed (2). Propylene glycol differs from glycerine only by 1 oxygen atom and is one of many chemicals which glycerine might displace. It uses much less primary energy than synthetic glycerine, presumably because the data for the latter includes energy for distilling a pharmaceutical-quality product. If used as animal feed, glycerine is assumed to replace wheat. We know that glycerine is easily digestible by cattle: we assumed that its digestible energy content is 95% of the LHV: the same fraction as for wheat. Then glycerine replaces wheat 1:1 on an LHV basis; we can use our wheat-farming process to calculate the credit.

10.1.1.10BO1b Glycerine to fuel (biogas)

In alternative 3/4 glycerine is used to produce biogas, significantly reducing the energy input into the process. The biogas is used internally to generate heat (steam) for the plant.

10.1.1.11BO1c Glycerine to hydrogen

In alternative 5 glycerine is used to produce hydrogen by steam reforming. Hydrogen is assumed to be exported and substitute hydrogen produced by steam reforming of natural gas.

10.1.1.12BD1 Biodiesel transport

Biodiesel has to be transported from the production plant to a conventional fuel depot. Road transport is assumed by a standard road truck according to process T1.

The three following processes are common to all liquid fuels.

10.1.1.13LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.1.1.14LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

10.1.1.15LF3 Biodiesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

10.1.2 Rapeseed to biodiesel (Rapeseed Ethylester) (ROFE)

Meal export (animal feed). Glycerine to internal biogas

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distr.*	*Source*
	Production & conditioning at source							
RO1	**Rapeseed cultivation**							
	Agricultural inputs							
	Fertilizers		g/$MJ_{Rapeseed}$					
	N (as N)	FN		1.84				[FAOSTAT 2016], [FE 2016]
	P (as P_2O_5)	FP		0.41				[FE 2016]
	K (as K_2O)	FK		0.56				[FE 2016]
	$CaCO_3$ (as CaO)	CA		2.27				JRC internal
	Pesticides	PE	g/$MJ_{Rapeseed}$	0.09				[CAPRI 2012], [FAOSTAT 2016], [FE 2016]
	Seeding material	2.152	g/$MJ_{Rapeseed}$	0.36				[FAOSTAT 2016]
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/$MJ_{Rapeseed}$	0.039				[CAPRI 2012]
	CH_4 emissions		g/$MJ_{Rapeseed}$	0.000049				[EMEP/EFA 2013]
	CO_2 from soil neutralisation		g/$MJ_{Rapeseed}$	0.000				
	N_2O field emissions		g/$MJ_{Rapeseed}$	0.0573	0.0430	0.0717	Normal	JRC internal
RO2	**Rapeseed drying, storage and handling**							[JRC internal], [UBA 1999]
	Diesel	F1	MJ/$MJ_{Rapeseed}$	0.0062				
	NG	F3	MJ/$MJ_{Rapeseed}$	0.0062				
	Electricity (EU-mix, LV)	EMLa	MJ/$MJ_{Rapeseed}$	0.0030				
	Transformation at source							
	NA							
	Transportation to market							
RO3	**Rapeseed transport**							[Rous 2008]
	Road truck	T1						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
RO4a	**Raw oil production (meal export)**							[EBB 2009]
	Raw oil yield		MJ_{oil}/MJ_{seed}	0.633				
	Rape meal yield		kg/MJ_{oil}	0.036				
	Heat to process	GHI	MJ/MJ_{oil}	0.0433				
	Electricity (EU-mix, MV)	EMMa	MJ/MJ_{oil}	0.0097				
	n-Hexane	C11	MJ/MJ_{oil}	0.0023				
	CO_2 emissions (from n-hexane)		g/MJ_{oil}	0.155				
	Credit for meal							
	Animal feed substitution							
	1 kg meal substitutes:							
	Wheat grain (13% moisture)		*kg/kg_{Meal}*	*-0.479*				
	Soya meal (11% moisture)		*kg/kg_{Meal}*	*-0.382*				
RO5	**Oil refining**							[EBB 2009]
	Refined oil yield		MJ/MJ	0.976				
	Heat to process	GHI	MJ/MJ_{oil}	0.0040				
	Electricity (EU-mix, MV)	EMMa	MJ/MJ_{oil}	0.0009				
	H_3PO_4	C12	g/MJ_{oil}	0.000032				
	NaOH	C6	g/MJ_{oil}	0.000088				
BO1d	**Biodiesel (REE) production, glycerine to fuel (biogas)**							
	REE yield		$MJ_{Biodiesel}$/MJ_{oil}	1.039				
	Ethanol (feed, see pathway WTET2)		MJ/$MJ_{Biodiesel}$	0.1100	0.1045	0.1155	Normal	
	Heat surplus		MJ/$MJ_{Biodiesel}$	-0.0107	-0.0121	-0.0093	Normal	[EBB 2009], [BioChemTechEngineering 2012]
	Electricity (EU-mix, MV)	EMMa	MJ/$MJ_{Biodiesel}$	0.0041				[EBB 2009]
	HCl	C13	g/MJ_{oil}	0.00010				[EBB 2009]
	Na(CH_3O)	C14	g/MJ_{oil}	0.00047				[EBB 2009]
	RED methodology							
	N/A							
	Conditioning & Distribution							
BD1	**Biodiesel transport**							
	Road truck	T1						
	Distance		km	150				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/$MJ_{Biodiesel}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3	**Biodiesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/$MJ_{Biodiesel}$	0.0034				

10.1.2.1 RO1 Rapeseed cultivation

Rape gives the highest oil yield in the Northern half of Europe. However, it still has much lower yield than cereals: it is typically grown as a low-input break crop, to rest the soil between more profitable cereal crops. The rape straw is invariably ploughed back into the soil, because it contains most of the nitrogen and minerals taken up by the crop and is needed to improve the organic content of the soil.

10.1.2.2 RO2 Rapeseed drying, storage and handling

A small amount of energy is consumed to handle and store seeds. We account for it at this point in the pathway although in practice storage may occur after transportation.

10.1.2.3 RO3 Rapeseed transport

Oil seeds are typically transported by road. The distance taken into account reflects average EU practice. We assumed a standard truck as described in common process T1.

10.1.2.4 RO4a Raw oil production (meal export)

Rapeseed is crushed and the oil is extracted with the aid of n-hexane solvent and heat. Hexane is a refinery product made almost entirely from crude oil. n-hexane lost to the atmosphere or to the waste water is assumed to be eventually oxidised hence the small amount of CO_2 emissions. In all conversion processes, we assume process heat or steam is supplied by a NG boiler working at 90% efficiency.

The rapeseed cake is used as animal feed, substituting a mix of soy bean and feed wheat. The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report section 3.7.4.

10.1.2.5 RO5 Oil refining

The refining step purifies the plant oil so it is ready for esterification.

10.1.2.6 BO1d Biodiesel (REE) production, glycerine to fuel (biogas)

Plant oil consists of 3 fatty acid chains on a 3-carbon backbone. 3 molecules of ethanol combine with the fatty acids to make 3 molecules of fatty acid ethyl ester (biodiesel), leaving their three alcohol groups bonded to the 3-carbon backbone to form glycerine.

Ethanol is assumed to be produced from wheat according to pathway WTET2a. As this is renewable ethanol, combustion CO_2 emissions are not added.

Glycerine is used to produce biogas, significantly reducing the energy input into the process. The biogas is used internally to generate heat (steam) for the plant.

10.1.2.7 BD1 Biodiesel transport

Biodiesel has to be transported from the production plant to a conventional fuel depot. Road transport is assumed by a standard road truck according to process T1.

The three following processes are common to all liquid fuels.

10.1.2.8 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.1.2.9 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

10.1.2.10LF3 Biodiesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

10.1.3 Sunflower to biodiesel (Sunflower seed Methylester) (SOFA)

Meal export (animal feed). Glycerine to internal biogas

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distr.*	*Source*
	Production & conditioning at source							
SO1	**Sunflower seed cultivation**							
	Agricultural inputs							
	Fertilizers		$g/MJ_{Sunf\ seed}$					JRC internal
	N (as N)	*FN*		1.03				
	P (as P_2O_5)	*FP*		0.61				[ADEME 2010]
	K (as K_2O)	*FK*		0.46				[ADEME 2010]
	$CaCO_3$ (as CaO)	*CA*		1.23				
	Pesticides	*PE*	$g/MJ_{Sunf\ seed}$	0.05				[CAPRI 2012]
	Seeding material	*SSO*	$g/MJ_{Sunf\ seed}$	0.35				[ADEME 2010], [FAOSTAT 2016]
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	$MJ/MJ_{Sunf\ seed}$	0.0694				[CAPRI 2012]
	CH_4 emissions		$g/MJ_{Sunf\ seed}$	0.000089				[EMEP/EFA 2013]
	CO_2 from soil neutralisation		$g/MJ_{Sunf\ seed}$	0.0000				
	N_2O field emissions		$g/MJ_{Sunf\ seed}$	0.0397	0.0338	0.0457	Normal	JRC internal
SO2	**Sunflower seed drying, storage and handling**							[JRC internal], [UBA 1999]
	Diesel	*F1*	$MJ/MJ_{Sunf\ seed}$	0.00615				
	NG	*F3*	$MJ/MJ_{Sunf\ seed}$	0.00615				
	Electricity (EU-mix, LV)	*EMLa*	$MJ/MJ_{Sunf\ seed}$	0.0030				
	Transformation at source							
	NA							
	Transportation to market							
SO3	**Sunflower seed transport**							
	Road truck	*T1*						
	Distance		km	100				
	Losses			1.0%				
	Transformation near market							
SO4a	**Raw oil production (meal export)**							[EBB 2009]
	Raw oil yield		MJ_{oil}/MJ_{seed}	0.655				
	Rape meal		kg/MJ_{oil}	0.033				
	Heat to process	*GHI*	MJ/MJ_{oil}	0.0339				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ_{oil}	0.0112				
	n-Hexane	*C11*	MJ/MJ_{oil}	0.0029				
	CO_2 emissions		g/MJ_{oil}	0.196				
	Credit for meal							
	Animal feed substitution							
	1 kg meal substitutes:							*JRC internal*
	Wheat grain (13% moisture)		*kg/kg_{Meal}*	*-0.556*				
	Soya meal (11% moisture)		*kg/kg_{Meal}*	*-0.215*				
SO5	**Oil refining**							[EBB 2009]
	Refined oil yield		MJ/MJ	0.975				
	Heat to process	*GHI*	MJ/MJ_{oil}	0.0058				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ_{oil}	0.0023				
	H_3PO_4	*C12*	g/MJ_{oil}	0.000012				
	NaOH	*C6*	g/MJ_{oil}	0.000069				
	Losses (winterization)			1.0%				
BO1b	**Biodiesel (SME) production, glycerine as fuel (biogas)**							[Larsen 1998]
	SME yield		$MJ_{Biodiesel}/MJ_{oil}$	0.999				
	Methanol (feed)		$MJ/MJ_{Biodiesel}$	0.051				
	CO_2 emissions (fossil carbon in methanol)		$g/MJ_{Biodiesel}$	3.518				
	Methanol production							[Larsen 1998]
	NG		$MJ/MJ_{Methanol}$	1.463	1.4406	1.4857	Normal	
	CH_4 emissions		$g/MJ_{Methanol}$	0.000083				
	Heat surplus		$MJ/MJ_{Biodiesel}$	-0.0056	-0.00702	-0.00422	Normal	[EBB 2009], [BioChemTechEngineering 2012]
	Electricity (EU-mix, MV)	*EMMa*	$MJ/MJ_{Biodiesel}$	0.0040				[EBB 2009]
	HCl	*C13*	g/MJ_{oil}	0.00010				[EBB 2009]
	$Na(CH_3O)$	*C14*	g/MJ_{oil}	0.00011				[EBB 2013]
	RED methodology							
	Allocation between oil and meal and biodiesel and glycerine on energy content basis							
	Conditioning & Distribution							
BD1	**Biodiesel transport**							
	Road truck	*T1*						
	Distance		km	150				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	$MJ/MJ_{Biodiesel}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Biodiesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	$MJ/MJ_{Biodiesel}$	0.0034				

10.1.3.1 SO1 Sunflower seed cultivation

In the drier parts of Europe where rape does not grow well, sunflower is grown in rather the same way, in rotation with cereals, although average yields are lower. We assume the straw is ploughed in the soil, which is the usual practice.

10.1.3.2 SO2 Sunflower seed drying, storage and handling

A small amount of energy is consumed to handle and store seeds. We account for it at this point in the pathway although in practice storage may occur after transportation.

10.1.3.3 SO3 Sunflower seed transport

Oil seeds are typically transported by road. The distance taken into account reflects average EU practice. We assumed a standard truck as described in common process T1.

10.1.3.4 SO4a Raw oil production (meal export)

The process is similar to rapeseed oil extraction. The sunflower oil yield is slightly higher than for rapeseed, so less kg of cake are produced per MJ. However, the sunflower seed cake contains less protein (30% dry matter), so the credit for replacing soy beans meal and wheat is smaller.

Sunflower seeds are crushed and the oil is extracted with the aid of n-hexane solvent and heat. Hexane is a refinery product made almost entirely from crude oil. n-hexane lost to the atmosphere or to the waste water is assumed to be eventually oxidised hence the small amount of CO_2 emissions. In all conversion processes, we assume process heat or steam is supplied by a NG boiler working at 90% efficiency.

The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report section 3.7.4.

10.1.3.5 SO5 Oil refining

The refining step purifies the plant oil so it is ready for esterification. However, winterisation is required in the case of sunflower oil leading to a 1% loss on LHV basis.

10.1.3.6 BO1b Biodiesel (SME) production, glycerine as fuel (biogas)

The process is the same for rapeseed, sunflower, soy and palm oils. Plant oil consists of 3 fatty acid chains on a 3-carbon backbone. 3 molecules of methanol combine with the fatty acids to make 3 molecules of fatty acid methyl ester (biodiesel), leaving their three alcohol groups bonded to the 3-carbon backbone to form glycerine.

Methanol is assumed to be produced from natural gas (with a small amount of methane emissions). CO_2 emissions from methanol combustion are added here so that the resulting biodiesel can be considered to be 100% renewable.

The glycerine co-product is assumed to be used to produce biogas, significantly reducing the energy input into the process. The biogas is used internally to generate heat (steam) for the plant.

10.1.3.7 BD1 Biodiesel transport

Biodiesel has to be transported from the production plant to a conventional fuel depot. Road transport is assumed by a standard road truck according to process T1.

The three following processes are common to all liquid fuels.

10.1.3.8 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.1.3.9 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

10.1.3.10LF3 Biodiesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

10.1.4 Soy beans to biodiesel (Soy Methylester) (SYFA)

Meal export (animal feed). Mix of till and no till, oil imported into EU, glycerine to internal biogas(a). Mix of till and no till, beans imported into EU, glycerine to internal biogas (b). Allocation between soya oil and soya meal by market value (d).

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distr.*	*Source*
	Production & conditioning at source							
	(mixed source Argentina, Brazil, USA)							
SY1	**Soy cultivation**							JRC internal
Agricultural inputs								
	Fertilizers		g/MJ$_{\text{Soy bean}}$					
	N (as N)	*FN*		0.08				
	P (as P_2O_5)	*FP*		0.71				
	K (as K_2O)	*FK*		0.69				
	$CaCO_3$ (as CaO)	*CA*		4.16				
	Pesticides	*PE*	g/MJ$_{\text{Soy bean}}$	0.06				
	Seeding material	*SRO*	g/MJ$_{\text{Soy bean}}$	1.33				
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{\text{Soy bean}}$	0.031				
	CH_4 emissions		g/MJ$_{\text{Soy bean}}$	0.000040				[EMEP/EFA 2013]
	CO_2 from soil neutralisation		g/MJ$_{\text{Soy bean}}$	3.094				
	N_2O field emissions		g/MJ$_{\text{Soy bean}}$	0.0428	0.0330	0.0528	Normal	
SY2a	**Beans to locaol oil mill: Soy beans drying (13%), storage and handling**							JRC internal
	Diesel	*F1*	MJ/MJ$_{\text{Soy bean}}$	0.0010				
	NG	*F3*	MJ/MJ$_{\text{Soy bean}}$	0.0010				
	LPG (LRLP1)		MJ/MJ$_{\text{Soy bean}}$	0.0004				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{\text{Soy bean}}$					
SY2b	**Beans to EU: Soy beans drying (13%), storage and handling**							JRC internal
	Diesel	*F1*	MJ/MJ$_{\text{Soy bean}}$	0.0006				
	NG	*F3*	MJ/MJ$_{\text{Soy bean}}$	0.0011				
	LPG (LRLP1)		MJ/MJ$_{\text{Soy bean}}$	0.0006				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{\text{Soy bean}}$	0.00023				
SY3	**Soy beans local transport**							
	Road							
	Standard road truck	*T1*						
	Distance		km					
SYFA3b/d	Beans to EU			517				
SYFA3a	Beans to local oil mill			517				
	Losses			1.0%				
	Rail							[Da Silva 2010]
	Distance		km					
SYFA3b/d	Beans to EU			179				
SYFA3a	Beans to local oil mill			179				
	Diesel consumption (inc. return trip)		MJ/km	0.25				[GEMIS 2011]
	CO2 emissions		g/tkm	18.31				[GEMIS 2011]
	CH4 emissions		g/tkm	0.0050				[GEMIS 2011]
	N2O emissions		g/tkm	0.0010				[GEMIS 2011]
SYFA3a	**Transformation at source**							
SY4	**Soy beans drying (13 to 11%)**							
	NG	*F3*	MJ/MJ$_{\text{Soy bean}}$	0.0029				
SY5	**Raw oil production (meal export)**							
	Raw oil yield		MJ$_{\text{oil}}$/MJ$_{\text{seed}}$	0.348				[FIDEOL 2013]
	Soya meal		kg/MJ$_{\text{oil}}$	0.110				[Ecoinvent 2009]
	Heat to process	*GHI*	MJ/MJ$_{\text{oil}}$	0.082	0.078	0.086	Square	[FIDEOL 2013]
	Electricity (EU-mix, MV)		MJ/MJ$_{\text{oil}}$	0.015				[FIDEOL 2013]
	n-Hexane	*C11*	MJ/MJ$_{\text{oil}}$	0.004				[FIDEOL 2013]
	CO_2 emissions (from n-hexane)		g/MJ$_{\text{oil}}$	0.248				
	Credit for meal							
	Animal feed substitution							*JRC internal*
	1 kg meal substitutes:							
	Dry corn		*kg/kg$_{\text{Meal}}$*	*-0.976*				
	Transportation to market							
SY6a	**Soy oil long distance transport**							
SYFA 3a	Inland/coastal tanker (1.2 kt)	*T3a*						
	Distance		km	562				
	Sea-going tanker (23 kt)	*T3e*						
	Distance		km	11107				
SY6b	**Soy beans long distance transport**							
SYFA 3b/d	Inland ship	*T3b*						
	Distance		km	615				
	Sea-going product carrier (Panamax)							
	Distance		km	9381				
	HFO	*F2*	MJ/t.km	0.0078				
	Transformation near market							
SYFA3b/d	**Raw oil production (meal export)**							
	See SY4 and SY5							
SO5	**Oil refining**							[EBB 2009]
	Refined oil yield		MJ/MJ	0.975				
	Heat to process	*GHI*	MJ/MJ$_{\text{oil}}$	0.0058				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{\text{oil}}$	0.0023				
	H_3PO_4	*C12*	g/MJ$_{\text{oil}}$	0.000012				
	NaOH	*C6*	g/MJ$_{\text{oil}}$	0.000069				
BO1b	**Biodiesel (SoyME) production, glycerine as fuel (biogas)**							[Larsen 1998]
	SME yield		MJ$_{\text{Biodiesel}}$/MJ$_{\text{oil}}$	0.999				
	Methanol (feed)		MJ/MJ$_{\text{Biodiesel}}$	0.051				
	CO_2 emissions (fossil carbon in methanol)		g/MJ$_{\text{Biodiesel}}$	3.518				
	Methanol production							[Larsen 1998]
	NG		MJ/MJ$_{\text{Methanol}}$	1.463	1.4406	1.4857	Normal	
	CH_4 emissions		g/MJ$_{\text{Methanol}}$	0.000083				
	Heat surplus		MJ/MJ$_{\text{Biodiesel}}$	-0.0056	-0.00702	-0.00422	Normal	[EBB 2009], [BioChemTechEngineering 2012]
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{\text{Biodiesel}}$	0.0040				[EBB 2009]
	HCl	*C13*	g/MJ$_{\text{oil}}$	0.00010				[EBB 2009]
	Na(CH_3O)	*C14*	g/MJ$_{\text{oil}}$	0.00011				[EBB 2013]
	RED methodology							
	Allocation between oil and meal and biodiesel and glycerine on energy content basis							
	Conditioning & Distribution							
BD1	**Biodiesel transport**							
	Road truck	*T1*						
	Distance		km	150				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{\text{Biodiesel}}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Biodiesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{\text{Biodiesel}}$	0.0034				

10.1.4.1 SY1 Soy cultivation

Soy bean meal is the main protein-rich animal feed in Europe. South America (Argentina and Brazil) is the main exporter of soy beans to EU although anomalies in biofuels subsidies between US and EU have recently created a boom of US soy bean-biodiesel. The cultivation figures are weighted averages assuming a 56.0/26.3/17.7 distribution between Argentina/Brazil/USA for imported beans and 59.4/16.2/24.5 for imported oil.

Field N2O emissions are from [IPCC 2006] default values, but the nitrogen content of the below-ground biomass was corrected as described in the main WTT report section 3.7.2.

10.1.4.2 SY2b Beans to EU: Soy beans drying (13%), storage and handling

A small amount of energy is consumed to handle and store soy beans. Drying is assumed to occur in two stages, down to 13% moisture before transportation and down to 11% moisture immediately prior to oil production (see SY4).

10.1.4.3 SY3 Soy beans local transport

Local transport is by a combination of road and rail (the latter only for Brazil). Typical distances are used for each assumed country of origin. The share of sourcing for each country is slightly different depending on the fate of the beans. The resulting distances are the weighted averages. Road transport is assumed to be by standard truck as described in common process T1. Rail transport energy and emissions is from a Brazilian source [Da Silva 2010].

10.1.4.4 SY4 Soy beans drying (13 to 11%)

See SY2

10.1.4.5 SY5 Raw oil production (meal export)

Soy beans only yield about 20 %m/m of oil, the balance being meal. As a result, when applying a substitution methodology, the fate of the meal as a co-product becomes overwhelming in the energy and GHG balance of the oil. Finding a substitute for the meal is difficult since soy bean meal itself is considered the swing source of protein for animal feed.

The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report section 3.7.4.

10.1.4.6 SY6a Soy oil long distance transport

Oil is transported to Europe by inland waterways and sea.

10.1.4.7 SY6b Soy beans long distance transport

Beans are transported to Europe by inland and sea-going ship. Distances are weighted averages for the three beans/oil sources.

10.1.4.8 SO5 Oil refining

The refining step purifies the plant oil so it is ready for esterification.

10.1.4.9 BO1b Biodiesel (SoyME) production, glycerine as fuel (biogas)

The process is the same for rapeseed, sunflower, soy and palm oils. Plant oil consists of 3 fatty acid chains on a 3-carbon backbone. 3 molecules of methanol combine with the fatty acids to make 3 molecules of fatty acid methyl ester (biodiesel), leaving their three alcohol groups bonded to the 3-carbon backbone to form glycerine.

Methanol is assumed to be produced from natural gas (with a small amount of methane emissions). CO_2 emissions from methanol combustion are added here so that the resulting biodiesel can be considered to be 100% renewable.

Glycerine is used to produce biogas, significantly reducing the energy input into the process. The biogas is used internally to generate heat (steam) for the plant.

10.1.4.10BD1 Biodiesel transport

Biodiesel has to be transported from the production plant to a conventional fuel depot. Road transport is assumed by a standard road truck according to process T1.

The three following processes are common to all liquid fuels.

10.1.4.11LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.1.4.12LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

10.1.4.13LF3 Biodiesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

10.1.5 Palm oil to biodiesel (Palm oil Methylester) (POFA)

Meal export (animal feed). No CH4 emissions recovery, heat credit (oil mill), glycerine to internal biogas (a). CH4 emissions recovery, heat credit, glycerine to internal biogas (b). No CH4 emissions recovery, no heat credit, glycerine to internal biogas (c).

Process code	Step	Common processes		Input	Range		Distr.	Source
	Production & conditioning at source							
PO1	**Palm cultivation (Fresh Fruit Bunch)**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{FFB}$					JRC internal
	N (as N)	FN		0.32				
	P (as P_2O_5)	FP		0.10				[IFA 2013], [FAPRI 2012]
	K (as K_2O)	FK		0.58				
	$CaCO_3$ (as CaO)	CA		0.00				
	Pesticides	PE	g/MJ$_{Soy\ bean}$	0.05				[Coo 2011], [Coo 2013]
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ$_{FFB}$	0.0054				[Coo 2011]
	CH_4 emissions		g/MJ$_{FFB}$	0.1206				[EMEP/EFA 2013]; [JRC 2018]
	CO_2 from soil neutralisation		g/MJ$_{FFB}$	0.000				
	N_2O field emissions		g/MJ$_{FFB}$	0.0298	0.0268	0.0328	Normal	JRC internal
PO2	**Palm FFB local transportation**							
	12 t Road truck							
	Distance		km	50				
	Diesel	F1	MJ/t.km	2.24				[Lastauto Omnibus Katalog 2010]
	Transformation at source							
PO3	**Palm oil production (meal export)**							[Coo 2011]
	Oil yield		MJ/MJ$_{FFB}$	0.5228				
	Palm kernel meal yield		kg/MJ$_{oil}$	0.0035				
POFA3a/b	Heat (surplus)		MJ/MJ$_{oil}$	-0.1186				
	Diesel	F1	MJ/MJ$_{oil}$	0.0040				
	Electricity (inc. EU MV losses)	EMMa	MJ/MJ$_{oil}$	0.0001				
	CO2 emissions		g/MJ$_{oil}$	0.29				
POFA3a/c	No recovery			0.8789				
POFA3b	With recovery			0.1318				
	Credit for heat surplus based on diesel-fired heating plant							
	Efficiency			*92.0%*				
	Credit for meal							JRC internal
	Animal feed substitution							
	1 kg meal substitutes:							
	Wheat grain (13% moisture)		*kg/kg$_{Meal}$*	*-0.710*				
	Soya meal (11% moisture)		*kg/kg$_{Meal}$*	*-0.118*				
	Transportation to market							
PO4	**Oil transport**							
	Road truck	T1						
	Distance		km	120				
PO5	**Oil depot**							
	Electricity (inc. EU LV losses)	EMLa	MJ/MJ$_{oil}$	0.00084				
PO6	**Oil long distance transport**							
	Sea-going tanker (23 kt)	T3e						
	Distance		km	16287				
PO5	**Oil depot** (see above)							
	Transformation near market							
RO5	**Oil refining**							[EBB 2009]
	Refined oil yield		MJ/MJ	0.976				
	Heat to process	GHI	MJ/MJ$_{oil}$	0.0040				
	Electricity (EU-mix, MV)	EMMa	MJ/MJ$_{oil}$	0.0009				
	H_3PO_4	C12	g/MJ$_{oil}$	0.000032				
	NaOH	C6	g/MJ$_{oil}$	0.000088				
BO1b	**Biodiesel (SoyME) production, glycerine as fuel (biogas)**							[Larsen 1998]
	SME yield		MJ$_{Biodiesel}$/MJ$_{oil}$	0.999				
	Methanol (feed)		MJ/MJ$_{Biodiesel}$	0.051				
	CO_2 emissions (fossil carbon in methanol)		g/MJ$_{Biodiesel}$	3.518				
	Methanol production							[Larsen 1998]
	NG		MJ/MJ$_{Methanol}$	1.463	1.4406	1.4857	Normal	
	CH_4 emissions		g/MJ$_{Methanol}$	0.000083				
	Heat surplus		MJ/MJ$_{Biodiesel}$	-0.0056	-0.00702	-0.00422	Normal	[EBB 2009], [BioChemTechEngineering 2012]
	Electricity (EU-mix, MV)	EMMa	MJ/MJ$_{Biodiesel}$	0.0040				[EBB 2009]
	HCl	C13	g/MJ$_{oil}$	0.00010				[EBB 2009]
	Na(CH_3O)	C14	g/MJ$_{oil}$	0.00011				[EBB 2013]
	RED methodology							
	Allocation between oil and meal and biodiesel and glycerine on energy content basis							
	Conditioning & Distribution							
BD1	**Biodiesel transport**							
	Road truck	T1						
	Distance		km	150				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ$_{Biodiesel}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3	**Biodiesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{Biodiesel}$	0.0034				

10.1.5.1 PO1 Palm cultivation (Fresh Fruit Bunch)

Fresh fruit bunches (FFB, 34% dry matter [Teoh 2004]) are processed in the oil mill. After processing the empty fruit bunches (EFB) are returned to the oil palm plantations (approx. 224 kg EFB per t of FFB) [Schmidt 2007]. The input of synthetic N fertilizer and the N2O soil emissions are based on the Global Nitrous Oxide Calculator (GNOC) developed by the JRC. The inputs of K and P fertilizers have been derived from statistics supplied by the International Fertilizer Association [IFA 2013] and the FAPRI world agricultural outlook database [FAPRI 2012], the input of diesel for farming machines has been derived from [Choo, Y.M. et al 2011]. The share of peat soil has been assumed to be 14%. CH4 is formed by degradation of empty fruit bunches (EFB) which is used as fertilizer. About 6.46 g CO2 equivalent per MJ of crude palm oil (CPO) are emitted which has been traced back to crop (FFB) by division with the FFB input per MJ of CPO (2.1427 MJ per MJ of CPO without palm kernel oil) and by 25 g CO2 equivalent per g of CH4.

10.1.5.2 PO2 Palm FFB local transportation

FFBs are typically transported by road over a short distance. We assumed a standard truck as described in common process T1.

10.1.5.3 PO3 Palm oil production (meal export)

The oil yield form FFB processing is around 22.4% oil (90% of which is from the flesh, 10% from the kernel). The composition of the two oils is different, but they can both be used to make biofuels. In addition, a small amount of palm kernel meal is produced (about 2.9% of the FFB by mass). This is given credit as animal feed using a mix of soy meal and wheat. Because there is a large amount of residual biomass, the heat and electricity mill can be powered from this source. Empty fruit bunches are returned to nearby plantations and used as mulch. Methane emissions from waste are assumed to be collected in this process.

Figures for yield, heat output from mesocarp fibre and shell, and palm kernel meal are taken from [Schmidt 2007] (palm oil), [Choo et al. 2011] (palm kernel oil, mesocarb fibre and nut shells), and [Chin 1991] (palm kernel meal).

Waste material from palm oil production can produce significant quantities of methane if stored in anaerobic conditions. There are still differences between the best and worst practices, and even with the best care some emissions from wastewater ponds will occur. We have estimated emissions from wastewater for current best practice using figures from oil industry sources. Without methane capture 11.94 kg methane per tonne of effluent are emitted, whereas with methane capture this is reduced by 85%.

Palm biomass provides sufficient energy to meet most of the needs of the crushing plant (small amounts of electricity and diesel are imported). In addition, there is an excess that can be exported to provide local heat where opportunities exist. The input of electricity and diesel is based on [Choo et al. 2011].

The detailed principles and mechanisms of animal feed credit calculations are discussed in the main WTT report section 3.7.4.

10.1.5.4 PO4 Oil transport

Palm oil is first transported over a short distance by road (standard road truck according to standard process T1).

10.1.5.5 PO5 Oil depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.1.5.6 PO6 Oil long distance transport

Oil is transported to Europe by sea.

10.1.5.7 RO5 Oil refining

The refining step purifies the plant oil so it is ready for esterification and is assumed to be the same as for rape oil.

10.1.5.8 BO1b Biodiesel (SoyME) production, glycerine as fuel (biogas)

The process is the same for rapeseed, sunflower, soy and palm oils. Plant oil consists of 3 fatty acid chains on a 3-carbon backbone. 3 molecules of methanol combine with the fatty acids to make 3 molecules of fatty acid methyl ester (biodiesel), leaving their three alcohol groups bonded to the 3-carbon backbone to form glycerine.

Methanol is assumed to be produced from natural gas (with a small amount of methane emissions). CO2 emissions from methanol combustion are added here so that the resulting biodiesel can be considered to be 100% renewable.

Glycerine is used to produce biogas, significantly reducing the energy input into the process. The biogas is used internally to generate heat (steam) for the plant.

10.1.5.9 BD1 Biodiesel transport

Biodiesel has to be transported from the production plant to a conventional fuel depot. Road transport is assumed by a standard road truck according to process T1.

The three following processes are common to all liquid fuels.

10.1.5.10 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.1.5.11 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

10.1.5.12 LF3 Biodiesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

10.1.6 Waste cooking oil to biodiesel (WOFA)

Glycerine to internal biogas

Process code	*Step*	*Common processes*		*Input*	*Range*	*Dist.*	*Source*
	Production & conditioning at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
	NA						
	Transformation near market						
WO1	**Biodiesel production**						[EWEBA & BDI 2017], [BioChemTechEngineering 2012]
	Biodiesel yield		$MJ_{Biodiesel}/MJ_{oil}$	0.965			
	Methanol (feed)		$MJ/MJ_{Biodiesel}$	0.056			
	CO_2 emissions (fossil carbon in methanol)		$g/MJ_{Biodiesel}$	3.889			
	Electricity (EU-mix, MV)		$MJ/MJ_{Biodiesel}$	0.0068			
	NG		$MJ/MJ_{Biodiesel}$	0.0471			
	H_3PO_4		$g/MJ_{Biodiesel}$	0.047			
	KOH		$g/MJ_{Biodiesel}$	0.427			
	H_2SO_4		$g/MJ_{Biodiesel}$	0.295			
	Heat surplus (used in process)		$MJ/MJ_{Biodiesel}$	-0.032			
	K fertiliser production		$g/MJ_{Biodiesel}$	-0.381			
	K fertiliser credit based on alternative mainstream production						
	Methanol production						[Larsen 1998]
	NG		$MJ/MJ_{Methanol}$	1.463	1.4406 1.4857	Normal	
	CH_4 emissions		$g/MJ_{Methanol}$	0.000083			
	RED methodology						
	Allocation between biodiesel and glycerine on energy content basis, no credit for fertilizer						
	Conditioning & Distribution						
BD1	**Biodiesel transport**						
	Road truck	*T1*					
	Distance		km	150			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	$MJ/MJ_{Biodiesel}$	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	*T1*					
	Distance		km	150			
LF3	**Biodiesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	$MJ/MJ_{Biodiesel}$	0.0034			

10.1.6.1 WO1 Biodiesel production

The esterification of waste cooking oil and animal fat is similar to that of virgin vegetable oil but the amounts of in and outputs are slightly different and it is overall more energy-intensive. One reason for this is the presence of free fatty acids which need to be turned into alkyl esters prior to the main esterification step.

10.1.6.2 BD1 Biodiesel transport

Biodiesel has to be transported from the production plant to a conventional fuel depot. Road transport is assumed by a standard road truck according to process T1.

The three following processes are common to all liquid fuels.

10.1.6.3 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.1.6.4 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

10.1.6.5 LF3 Biodiesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

10.1.7 Tallow oil to biodiesel

Glycerine to internal biogas

Process code	Step	Common processes		Input	Range	Dist.	Source
	Production & conditioning at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
TO1	**Carcass transport**						JRC internal
	Road truck	*T1*					
	Distance		km	30			
	Transformation near market						
TO2	**Tallow production (rendering plant)**						[DE CAMILLIS et al. 2010], [EFPRA 2015], [Notarnicola et al. 2011], [NRA 2018]; [JRC internal]
	Tallow yield		$kg/kg_{dry\ carcass}$	0.2865			
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ_{tallow}	0.0029			
	HFO	*F2*	MJ/MJ_{tallow}	0.0064			
	NG	*F3*	MJ/MJ_{tallow}	0.0521			
TO3	**Tallow transport**						JRC internal
	Road truck	*T1*					
	Distance		km	150			
WO1	**Biodiesel production**						[EWEBA & BDI 2017], [BioChemTechEngineering 2012]
	Biodiesel yield		$MJ_{Biodiesel}/MJ_{oil}$	0.965			
	Methanol (feed)		$MJ/MJ_{Biodiesel}$	0.056			
	CO_2 emissions (fossil carbon in methanol)		$g/MJ_{Biodiesel}$	3.889			
	Electricity (EU-mix, MV)		$MJ/MJ_{Biodiesel}$	0.0068			
	NG		$MJ/MJ_{Biodiesel}$	0.0471			
	H_3PO_4		$g/MJ_{Biodiesel}$	0.047			
	KOH		$g/MJ_{Biodiesel}$	0.427			
	H_2SO_4		$g/MJ_{Biodiesel}$	0.295			
	Heat surplus (used in process)		$MJ/MJ_{Biodiesel}$	-0.032			
	K fertiliser production		$g/MJ_{Biodiesel}$	-0.381			
	K fertiliser credit based on alternative mainstream production						
	Methanol production						[Larsen 1998]
	NG		$MJ/MJ_{Methanol}$	1.463	1.4406 1.4857	Normal	
	CH_4 emissions		$g/MJ_{Methanol}$	0.000083			
	RED methodology						
	Allocation between biodiesel and glycerine on energy content basis, no credit for fertilizer						
	Conditioning & Distribution						
BD1	**Biodiesel transport**						
	Road truck	*T1*					
	Distance		km	150			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	$MJ/MJ_{Biodiesel}$	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	*T1*					
	Distance		km	150			
LF3	**Biodiesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	$MJ/MJ_{Biodiesel}$	0.0034			

10.1.7.1 TO1 Carcass transport

Carcasses need to be transported to the rendering plant, typically by road (standard road truck according to process T1).

10.1.7.2 TO2 Tallow production (rendering plant)

Tallow is a product of the rendering process.

10.1.7.3 TO3 Tallow transport

Tallow oil is typically transported by road. We assumed a standard truck as described in common process T1.

10.1.7.4 WO1 Biodiesel production

The esterification of waste cooking oil and animal fat is similar to that of virgin vegetable oil but the amounts of in and outputs are slightly different and it is overall more energy-intensive. One reason for this is the presence of free fatty acids which need to be turned into alkyl esters prior to the main esterification step.

10.1.7.5 BD1 Biodiesel transport

Biodiesel has to be transported from the production plant to a conventional fuel depot. Road transport is assumed by a standard road truck according to process T1.

The three following processes are common to all liquid fuels.

10.1.7.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.1.7.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

10.1.7.8 LF3 Biodiesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

10.2 HVO

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distr.*	*Source*
	Production & conditioning at source							
	See specific crop cultivation local transport and drying steps							
	Transformation at source							
	See relevant oil production processes (soy and palm)							
	Transportation to market							
	See relevant seed or oil transport processes							
	Transformation near market							
	See relevant oil production processes (rape, sunflower, soy)							
	Where relevant, pathways shown in full assumes meal to animal feed							
HY1a	**HVO production (NexBTL)**							[IFEU 2006]
	HVO yield		MJ/MJ_{oil}	0.9767				
	Hydrogen		MJ/MJ_{HVO}	0.0848	0.07336	0.09331	Square	
	H_3PO_4		g/MJ_{HVO}	0.0169				
	NaOH		g/MJ_{HVO}	0.0270				
	Electricity surplus		MJ/MJ_{HVO}	-0.0016				
	Heat surplus		MJ/MJ_{HVO}	-0.0079				
	Credit for electricity surplus based on EU-mix, MV							
	Credit for heat surplus based on alternative generation with NG @ 90% efficiency							
HY1b	**HVO production (UOP)**							[Shonnard 2007]
	HVO yield		MJ/MJ_{oil}	1.0989				
	Hydrogen		MJ/MJ_{HVO}	0.1100				
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ_{HVO}	0.0050				
	Steam		MJ/MJ_{HVO}	0.0130				
	HFO		MJ/MJ_{HVO}	0.0130				
POME	**Oil from palm oil mill effluent (POME)**							[Kuusisto 2017]
	Diesel		MJ/MJ_{oil}	0.00000676				
	Electricity		MJ/MJ_{oil}	0.00346				
	RED methodology							
	Allocation between oil and meal on energy content basis							
	Conditioning & Distribution							
HY2	**HVO transport**							
	Standard road truck	*T1*						
	Distance		km	150				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	$MJ/MJ_{Biodiesel}$	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Biodiesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	$MJ/MJ_{Biodiesel}$	0.0034				

10.2.1.1 HY1a HVO production (NexBTL)

The data for the NexBTL process, from [IFEU 2006], a study sponsored by Neste Oil. The process as described produces only diesel. The very small naphtha production is neglected. Lighter products are used to internally produce electricity and heat of which there is a surplus. In this case a credit is granted to the heat surplus as this is likely to be usable in an oil refinery environment where such plants would normally be located.

The UOP data was obtained directly from UOP on the basis of an unpublished report. The process as described produces diesel as well as small quantities of naphtha and lighter hydrocarbons. In line with what we did for GTL (see section 6.1, process GD1), we allocated the inputs according to the energy content of the products. This results in a higher hydrogen import compared to NexBTL but a lower plant oil consumption.

10.2.1.2 POME Oil from palm oil mill effluent (POME)

Even at the most efficient palm oil mills there is a tiny share of residual oil in the waste water. The process for residual oil extraction consists of:

- Skimming/pumping from the pond
- Heating, filtering
- Liquid storage depot

10.2.1.3 HY2 HVO transport

HVO has to be transported from the production plant to a conventional fuel depot. Road transport is assumed by a standard road truck according to process T1.

The three following processes are common to all liquid fuels.

10.2.1.4 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

10.2.1.5 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

10.2.1.6 LF3 Biodiesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11 Synthetic fuels

11.1 Syndiesel

11.1.1 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 (GRSD).

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.08				
	Transformation at source							
SD1	**GTL plant (large scale)**							[Shell 2007]
	Efficiency			65.0%	63.0%	67.0%	Normal	
SD1C	**GTL plant (large scale) with CCS**							[IEA 2005]
	Efficiency			62.0%	65.3%	59.0%	Normal	
SD2	**Syndiesel depot**							[TOTAL 2002]
	Electricity (NG CCGT)	GGe	MJ/MJ_{SD}	0.0008				
	Transportation to market							
SD3	**Syndiesel long distance sea transport**							
	50 kt liquid carrier	T3c						
	Distance		km	5500	5000	6000	Square	
SD2	**Syndiesel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{SD}	0.0008				
	Transformation near market							
	NA							
	Conditioning & Distribution							
CD2	**Syndiesel distribution (long distance)**							[TOTAL 2002]
	Barge, 1200t (20%)							
	Distance	T3a	km	500				
	Diesel fuel		MJ/t.km	0.5040				[Ecoinvent 1996]
	CH_4 emissions		g/t.km	0.0300				
	Rail (20%)							
	Distance	T2	km	250				
	Pipeline (60%)							
	Electricity (EU-mix LV)	EMLa	MJ/MJ_{SD}	0.0002				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{SD}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3	**Diesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{SD}	0.0008				

11.1.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

11.1.1.2 SD1 GTL plant (large scale)

This is the so-called GTL process including NG reforming or partial oxidation followed by the Fischer-Tropsch (FT) synthesis. The plant also includes hydrocracking of the FT product. GTL is a relatively new technology, and we can expect that with continued development the process efficiency will improve. We expect plants designed in the next few years to have a typical overall efficiency of 65%. This means that 100 MJ of NG in will deliver 65 MJ of combined product, 35 MJ being expended in the process. The selectivity of the process for a specific product can be adjusted to a large degree, notably with a hydrocracking step after the FT synthesis. The maximum practically achievable diesel yield (including the kerosene cut) is considered to be around 75% of the total product, the remainder being mainly naphtha and some LPG. In this case we assume that the plant is built for the primary purpose of producing diesel. Many future plants will not produce any specialties such as base oils and waxes as these markets will soon be saturated.

Naphtha and LPG are also potential automotive fuels. The energy required to produce them from refineries is of the same order of magnitude as diesel. The GTL process produces all these products simultaneously but, contrary to the refinery case, there is no technical argument for allocating proportionally more or less energy to one product than to the others (a yield change between e.g. naphtha and diesel would not significantly affect the overall energy balance of the process). We have therefore considered that allocation on energy content basis between the different co-products is a reasonable simplifying assumption if this case and assumed that all products are produced independently with the same energy efficiency.

11.1.1.3 SD1C GTL plant (large scale) with CCS

The "chemical" CO2 from the reforming or partial oxidation reactions and the CO-shift reaction (required to adjust the hydrogen/CO ratio) is scrubbed from the syngas feed to the FT process. The solvent absorption processes commonly used for this purpose produce a virtually pure CO2 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 CO2 can be re-injected. For FT liquids from NG there is not literature source where a NG FT plant with and without CCS is compared. FT plants are very complex. The layout differs from licensor to licensor and this can have a large impact on the energy penalty for CCS. [IEA 2005] suggests an energy efficiency penalty of 3%. We have used this figure as a basis for our calculation, starting from an overall plant efficiency of 65% in the base case. The CO2 generated in the auxiliary power plant is not recovered in this scheme, so that the CO2 recovery is relatively low at around 75%.

11.1.1.4 SD3 Syndiesel long distance sea transport

Large GTL plants have been and are likely to be built near large gas reserves, typically in the Middle East. Transport distance to Europe is between 5000 and 6000 nautical miles. The assume ship is a 50kt liquid carrier as per process T3c.

11.1.1.5 SD2 Syndiesel depot

This is a standard liquid fuel depot located at the EU import port.

11.1.1.6 CD2 Syndiesel distribution (long distance)

Road fuels are transported from refineries to depots via a number of transport modes. We have included water (inland waterway or coastal), rail and pipeline (1/3 each). The energy consumption and distance figures are typical averages for EU. Barges and coastal tankers are deemed to use a mixture of marine diesel and HFO. Rail transport consumes electricity. The consumption figures are typical.

11.1.1.7 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.1.1.8 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.1.1.9 LF3 Diesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.1.2 EU-mix hard coal to: Syndiesel (CTL) with / without CCS, Methanol, DME (KOSD/ME/DE)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
KO1	**Hard coal supply (EU-mix)**							[El Cerrejon 2002], [DOE 20
	Hard coal (primary)		MJ/MJ_{Coal}	1.0266				0
	Brown coal (primary)		MJ/MJ_{Coal}	0.0016				0
	Crude oil		MJ/MJ_{Coal}	0.0375				0
	Natural gas (primary)		MJ/MJ_{Coal}	0.0100				0
	Hydro power		MJ/MJ_{Coal}	0.0010				0
	Nuclear		MJ/MJ_{Coal}	0.0109				
	Waste		MJ/MJ_{Coal}	0.0018				
	CO_2 emissions		g/MJ_{Coal}	6.27				
	CH_4 emissions		g/MJ_{Coal}	0.3852				
	N_2O emissions		g/MJ_{Coal}	0.0003				
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
KD1	**CTL plant**							[GEMIS 2005], [Gray 2001-2005]
	Efficiency			40.5%	38.5%	42.6%	Square	
	Electricity surplus		MJ/MJ_{Meth}	-0.3300				
	Credit for electricity surplus based on alternative generation in coal-fired IGCC (see workbook WTT v40 6- Electricity, process KE2.2)							
KD1C	**CTL plant with CCS**							[GEMIS 2005], [Gray 2001-2005]. [Winslow 2004]
	Efficiency			40.9%	39.0%	43.1%	Square	
	Electricity surplus		MJ/MJ_{Meth}	-0.2390				
	CO_2 emissions		$g/MJ_{Meth/DME}$	14.92				
	Credit for electricity surplus based on alternative generation in coal-fired IGCC with CCS (see workbook WTT v40 6- Electricity, process KE2.2C)							
KMD	**Coal to methanol or DME plant**							[Katofsky 1993]
	Efficiency			59.7%	56.8%	62.8%	Square	
	Electricity (EU-mix, MV)	*EMMa*	$MJ/MJ_{Meth/DME}$	0.0294				
	CH_4 emissions		$g/MJ_{Meth/DME}$	0.0069				
SD2	**Syndiesel depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{SD}	0.00084				
	Transformation near market							
	NA							
	Conditioning & Distribution							
	KOSD							
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Diesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0008				
	KOME/KODE							
NMD4a	**Methanol/DME distribution**							
	Rail	*T2*						
	Distance		km	250				
	Road truck	*T1*						
	Distance		km	250				
	Payload / tank mass		t/t					
	Methanol			26/28				
	DME			20/28				
NM6	**Methanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034				
ND6	**DME dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034				

11.1.2.1 KO1 Hard coal supply (EU-mix)

These figures approximate the average primary energy associated to the production and provision of hard coal to Europe.

11.1.2.2 KD1 CTL plant

This is the "CTL" (Coal-to-Liquids) process, including coal gasification and Fischer-Tropsch synthesis.

11.1.2.3 KD1C CTL plant with CCS

This the same plant as above, now with CO2 capture after preparation of the syngas. Both configurations are described in a consistent manner in [Gray 2001-2005].

The Shenhua 100 kta CCS Demonstration Project in the Erdos Basin in China has been commissioned in December 2010 [Shenhua 2012]. Tests with injection of CO2 into a saline aquifer started in 2010 and ended in 2015 [Xiaochun Li et al. 2016]. The plant has two trains using Shell gasifiers and has a capacity of 1 Mt of diesel and gasoline per year. 100 kt of CO2 are captured per year [Mills 2012].

11.1.2.4 KMD Coal to methanol or DME plant

This process is similar to CTL but with methanol or DME synthesis rather than Fischer-Tropsch. As the synthesis process for methanol and DME are very similar. The same reference was used for both products.

11.1.2.5 SD2 Syndiesel depot

This is a standard liquid fuel depot located at the EU import port.

11.1.2.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.1.2.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.1.2.8 LF3 Diesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.1.2.9 NMD4a Methanol/DME distribution

A mixture of rail and road is assumed for a total distance of 500 km.

NM6 Methanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

ND6 DME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.1.3 Wood to Syndiesel (SD), Methanol (ME), DME (DE) (WxSD/ME/DE)

WWxx1: Waste wood to gasification/synthesis plant

WFxx1: Farmed to gasification/synthesis plant

BLxx1: Waste wood via black liquor

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
WF1	**Wood plantation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{wood}					
	N (as N)	*FN*		0.00				JRC internal
	Pesticides	*PE*	g/MJ_{wood}	0.015				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{wood}	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.0000161				
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.0000397				
	N_2O field emissions		g/MJ_{wood}	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	*F1*	MJ/MJ_{wood}	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindholm 2010]
W2	**Forestry residue chipping**							
	Diesel	*F1*	MJ/MJ_{wood}	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3b	**Farmed wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
WF3c	**Farmed wood transport (regional, >500 km)**							JRC internal
WF3c1	Road truck	*T1*						
	Distance		km	250				
WF3c2	Bulk carrier (Handysize)	*T3h*						
	Distance		km	2000				
WW3b	**Waste wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
WW3c	**Waste wood transport (regional, >500 km)**							JRC internal
WW3c1	Road truck	*T1*						
	Distance		km	250				
WW3c2	Bulk carrier (Handysize)	*T3h*						
	Distance		km	2000				
RW1	**Roundwood transport (BLxx1)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
	Transformation near market							
WSD1	**Wood to syndiesel plant**							[Tijmensen et al. 2002]
	Efficiency			48.2%	46.1%	50.8%	2-triangle	
	NaOH	*C6*	g/MJ_{SD}	0.00880				[Hamelinck 2004]
	Dolomite	*C17*	g/MJ_{SD}	5.0511				[Hamelinck 2004]
WSD1C	**Wood to syndiesel plant with CCS**							
	Efficiency			45.1%				[Kreutz et al. 2008]
	Electricity surplus		MJ/MJ_{SD}	-0.0827				[Kreutz et al. 2008]
	NaOH	*C6*	g/MJ_{SD}	0.00940				[Hamelinck 2004]
	Dolomite	*C17*	g/MJ_{SD}	5.3985				[Hamelinck 2004]
	CO_2 emissions		g/MJ_{SD}	-115.17				
WMD	**Wood to Methanol/DME plant**							[Katofsky 1993]
	Efficiency			51.1%	46.1%	57.2%	Square	[Atrax 1999]
WSD2	**Forestry residue to syndiesel via black liquor**							[Berglin et al. 1999]; [Landälv 2007]
	Efficiency (related to roundwood input)			27.1%				
	Additional wood chips		MJ/MJ_{SD}	0.9559				[Ekbom et al. 2005]
	Pulp output		g/MJ_{SD}	94.79				[Ekbom et al. 2005]
WSD2C	**Forestry residue to syndiesel via black liquor with CCS**							
	Efficiency (related to roundwood input)			27.1%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		MJ/MJ_{SD}	1.0584				[Ekbom et al. 2005]
	Pulp output		g/MJ_{SD}	94.79				[Berglin 2006], [Ekbom et al. 2005]; [Pettersson 2011]
	CO_2 emissions		g/MJ_{SD}	-99.61				[Berglin 2006], [Ekbom et al. 2005]; [Pettersson 2011]
WM1	**Forestry residue to methanol via black liquor**							
	Efficiency (related to roundwood input)			30.2%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		$MJ/MJ_{methanol}$	0.9856				[Ekbom et al. 2005]
	Pulp output		$g/MJ_{methanol}$	84.89				[Ekbom et al. 2005]
WD1	**Residual wood to DME via black liquor**							
	Efficiency (related to roundwood input)			30.5%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		MJ/MJ_{DME}	0.9566				[Ekbom et al. 2005]
	Pulp output		g/MJ_{DME}	84.25				[Ekbom et al. 2005]
	Credit for pulp based on puld from pulp mill without black liquor gasification							

	Conditioning & Distribution						
SD4b	**Syndiesel distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{SD}	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	*T1*					
	Distance		km	150			
LF3	**Diesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0008			
NM4b	**Methanol distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
NM2	**Methanol depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0018			
ND4b	**DME distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	20/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
ND2	**DME depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0013			
NM5/ND6	**Local methanol/DME distribution**						
	Road truck	*T1*					
	Distance		km	150			
	Payload / tank mass		t/t				
	Methanol			26/28			
	DME		t/t	20/28			
NM6	**Methanol dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034			
ND6	**DME dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034			

11.1.3.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

11.1.3.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

11.1.3.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

11.1.3.4 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Giuntoli et al. 2017].

11.1.3.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

11.1.3.6 WF3b Farmed wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.1.3.7 WF3c Farmed wood transport (regional, >500 km)

A transport distance of 250 km via truck plus a transport distance of 2000 km has been assumed if the wood chips are imported from regions outside the EU e.g. Russia or Ukraine.

11.1.3.8 WW3b Waste wood transport (regional, 500 km).

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.1.3.9 WW3cWaste wood transport (regional, >500 km)

A transport distance of 250 km via truck plus a transport distance of 2000 km has been assumed if the wood chips are imported from regions outside the EU e.g. Russia or Ukraine.

11.1.3.10WSD1 Wood to syndiesel plant

Our “best estimate” is based on the study by [Tijmensen et al. 2002] and [Hamelink 2004]. In the variant we chose, syngas from the BCL gasifier (the same as in the 200 MW_{th} hydrogen process) passes cold gas cleaning, a reformer and shift-reactor as in the hydrogen process. An amine process removes the CO2 and the rest of the syngas enters a fixed-bed Fischer-Tropsch reactor, which builds alkanes from reacting CO and hydrogen on the surface of the catalyst. The reaction conditions are adjusted to maximize the direct production of liquids (gasoil, kerosene and naphtha), which are condensed from the off-gas. Co-products are unreacted gas, LPG vapour and wax. The wax is hydrocracked to make more diesel and naphtha. In our chosen variant, which maximizes diesel yield, up to 2/3 of the unreacted gas (+LPG) is recycled to pass the FT reactor again. The LPG in the recycle does not react: once the alkyl chain is terminated, it cannot be re-opened by the FT catalyst.

The off-gas that is not recycled in our variant is burnt in a condensing combined cycle for process heat and electricity. This produces an excess of electricity, for which we give a wood credit, using process W3i: electricity from BCL gasifier. This simulates an electricity-neutral process as explained above.

The process yield, efficiency and the product mix depend on the performance of the FT catalyst, which determines the chain growth probability (CGP). [Tijmensen 2002] took a range of likely CGP values, because the catalyst performance is difficult to predict. We took their average CGP (0.85) for our best-estimate case.

The composition of the FT liquids condensed after the reactor has to be found from figure 2 of [Tijmensen 2002]: about 35% m/m naphtha and 65% m/m middle distillates (= gasoil + kerosene). To this should be added the products of wax cracking. The mass of wax produced is 19% of the FT liquids, and if cracked so as to maximize gasoil, yields 15% of its mass in naphtha and 85% diesel. Bearing in mind also that naphtha has slightly higher LHV than diesel (44.5 vs. 44.0 MJ/kg) the overall product mix turns out to be 68% diesel and 32% naphtha in energy terms.

For our worst-case we took the lowest CGP (0.8) considered by [Tijmensen 2002]. Then we calculated the overall product mix is 57% diesel and 43% naphtha in LHV terms. There is a wood credit for electricity as before.

For our best case, no variant in [Tijmensen 2002] can match the yield and efficiency (51%) claimed by [CHOREN 2003] for a projected biomass-to-liquid plant. The CHOREN process is electrically neutral. They project 100% diesel product. That means all the non-diesel components, which are an inevitable product of the FT reaction, have to be fed back to the gasifier (the FT reactor cannot grow chains which are already terminated). For calculations we chose a triangular probability distribution drawn between the three cases. The wood-to-FT products (gasoline and diesel) efficiency of about 42% indicated in [dena 2006] is close to the best case in [Tijmensen et al. 2002] and [Hamelink 2004] for a CGP of 0.9.

11.1.3.11 WSD2C Forestry residue to syndiesel via black liquor with CCS

If carbon capture and storage (CCS) is applied the yield of FT product does not change but the amount of electricity export decreases do the electricity demand for CO2 compression. For CO2 capture no additional energy is required because the CO2 is removed from the synthesis gas stream before feeding into the FT synthesis both for the case without and with CCS.

11.1.3.12 WMD Wood to Methanol/DME plant

Our “best-case” process is based on [Katofsky 1993], using the BCL indirectly-heated gasifier with wet gas cleaning and reforming of higher hydrocarbons. The rest of the process is similar to methanol synthesis from natural gas. A conventional, fixed bed methanol reactor is used. With all fuel synthesis routes, it might be possible to improve efficiency by using slurry reactors or hot gas cleaning. However, neither has been demonstrated for synthesis from bio-syngas: there are question marks about gas quality [Tijmensen 2002]. Furthermore, the use of conventional processes enables us to compare all routes on a fair basis.

Our “worst case” is based on oxygen-blowing the Värnamo autothermal pressurized fluidized bed gasifier, modelled by [Atrax 1999]. Although this is a state-of-the art gasifier, it is not as sophisticated and expensive as the BCL gasifier. The process uses the hot gas filtration demonstrated at Värnamo to allow the gas to go hot into the 950°C steam reformer, where some tar is also decomposed. However, after the shift water-gas shift reactor (to boost the H2/CO ratio), it is still necessary to use a scrubbing process to remove impurities (including HCl, H2S…) before the gas is pure enough for synthesis. In the Altrax process the purification is combined with CO2 removal by scrubbing with methanol (Rectisol Process).

DME can be thought of as dehydrated methanol: the only difference between the synthesis processes is in the final catalyst reactor so that the efficiencies are more or less the same. The DME synthesis process (by Haldor Topsoe A/S) is similar to that in the 200 MW plant. The efficiency is lower than the BCL-gasifier process because of the energy consumption by the oxygen separation plant, and because the H2/CO ratio in the raw syngas is lower.

11.1.3.13 WSD2 Forestry residue to syndiesel via black liquor

A pulp mill consumes 2.05 kg per dry t of pulp. Alternatively, some or all of the black liquor can be gasified instead of burnt in the recovery boiler. Various fuels: methanol, DME or Fischer-Tropsch products mix (naphtha, kerosene, diesel) can be made from the gas. Here we use data on the CHEMREC oxygen-blown black liquor gasification process. Some 10.55 GJ of FT liquids (naphtha, kerosene, diesel) can be generated per t of pulp [Berglin, N. et al. 1999], [Landälv 2007].

In a conventional pulp mill the black liquor is used for heat and electricity supply. So extra biomass in the form of forest residuals is required to make the plant self-sufficient in heat and electricity. Based on data in [Ekbom et al. 2005] about 8.98 GJ of extra forest residues per t of dry pulp are required for electricity supply and about 1.11 GJ of extra forest residues are required per t of dry pulp are required for heat supply.

For the calculation a pulp mill with black liquor gasification has been modelled which generates FT liquids and pulp. The pulp is exported and replaces pulp from a conventional pulp mill with black liquor boiler leading to a net increment input of wood. The inputs of the pulp mill are round wood and extra forest residues as wood chips.

11.1.3.14 WM1/WD1 Waste wood to methanol/DME via black liquor

A pulp mill consumes 2.05 kg per dry t of pulp. Alternatively, some or all of the black liquor can be gasified instead of burnt in the recovery boiler. Various fuels: methanol, DME or Fischer-Tropsch products mix (naphtha, kerosene, diesel) can be made from the gas. Here we use data on the CHEMREC oxygen-blown black liquor gasification process. Some 11.78 GJ of methanol or 11.87 GJ can be generated per t of pulp [Berglin, N. et al. 1999], [Landälv 2007].

In a conventional pulp mill the black liquor is used for heat and electricity supply. So extra biomass in the form of forest residuals is required to make the plant self-sufficient in heat and electricity. Based on data in [Ekbom et al. 2005] about 6.05 GJ of extra forest residues per t of dry pulp are required for electricity supply and about 5.56 GJ of extra forest residues are required per t of dry pulp are required for heat supply in case of methanol. In case of DME about 5.98 GJ of extra forest residues per t of dry pulp are required for electricity supply and about 5.38 GJ of extra forest residues are required per t of dry pulp are required for heat supply

For the calculation a pulp mill with black liquor gasification has been modelled which generates methanol and pulp or DME and pulp. The pulp is exported and replaces pulp from a conventional pulp mill with black liquor boiler leading to a net increment input of wood. The inputs of the pulp mill are round wood and extra forest residues as wood chips.

11.1.3.15 SD4b Syndiesel distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived synthetic diesel.

11.1.3.16 NM4b/ND4b Methanol and DME distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived methanol and DME.

11.1.3.17 NM5/ND6 Local methanol/DME distribution

From the depot the final fuel is transported via truck over a distance of 150 km (one way).

11.1.3.18 NM6 Methanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.1.3.19 ND6 DME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.1.4 Renewable electricity to Syndiesel via methanol (CO_2 from flue gases) (RESD1)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WD1	**Wind turbine**							[GEMIS 2000]
	No expended energy or emissions							
	Transformation at source							
	NA							
	Transportation to market							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
	NA							
	Transformation near market							
YH1	**Hydrogen via electrolysis (large plant)**							JEC internal
	Electricity (wind)		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
CA1	**CO_2 absorption (from flue gases)**							[Socolow 2011]
	Electricity (wind)		MJ/kg_{CO2}	0.0334				
	Heat		MJ/kg_{CO2}	4.2998				
HM1	**Methanol synthesis from hydrogen and CO_2**							[Van-Dal & Bouallou 2013]
	CO_2		$kg/MJ_{methanol}$	0.0745				
	Electricity (wind)		$MJ/MJ_{methanol}$	0.0539				
	Hydrogen		$MJ/MJ_{methanol}$	1.2281				
	Surplus heat		$MJ/MJ_{methanol}$	0.0863				
MSD	**Syndiesel from methanol**							[Liebner 2004]
	Methanol		MJ/MJ_{SD}	1.1130				
	Hydrogen		MJ/MJ_{SD}	0.0245				
	Electricity surplus (used internally)		MJ/MJ_{SD}	0.0500				
	CO_2 emissions		g/MJ_{SD}	5.92				
	Conditioning & Distribution							
CD2	**Syndiesel distribution (long distance)**							[TOTAL 2002]
	Barge, 1200t (20%)							
	Distance	T3g	km	500				
	Diesel fuel		MJ/t.km	0.5040				[Ecoinvent 1996]
	CH_4 emissions		g/t.km	0.0300				
	Rail (20%)							
	Distance	T2	km	250				
	Pipeline (60%)							
	Electricity (EU-mix LV)	EMLa	MJ/MJ_{SD}	0.0002				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{SD}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	T1						
	Distance		km	150				
LF3	**Diesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{SD}	0.0008				

11.1.4.1 WD1 Wind turbine

Electricity from wind turbine is energy and emission - free (as we do not consider energy and emissions related to construction and maintenance)

11.1.4.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.1.4.3 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.1.4.4 YH1 Hydrogen via electrolysis (large plant)

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPa_g electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].

- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].
- McPhy indicates an electricity consumption of 4.5 kWh/Nm^3 at nominal flow rate for its 800 Nm^3/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPa$_g$ [McPhy 2017].

Several sources of data are available, giving figures for both for small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depends on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPa$_g$ [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh$_e$/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 63% (4.8 to 5.4 kWh$_e$/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

11.1.4.5 CA1 CO2 absorption (from flue gases)

CO2 is assumed to available from the flue gases of e.g. a power station. It is extracted from the flue gas stream via scrubbing with monoethanolamine (MEA). The regeneration of the scrubbing agent is carried out to a large extent with the heat from the methanation process.

11.1.4.6 HM1 Methanol synthesis from hydrogen and CO_2

Hydrogen reacts with CO_2 to form methanol according to the reaction:

$3 H_2 + CO_2 \Rightarrow CH_3OH + H_2O$

The reaction is exothermic.

11.1.4.7 MSD Syndiesel from methanol

Methanol is converted to synthetic diesel via olefin synthesis (with DME synthesis as an intermediate step), olefin oligomerization, hydrogenation, and product separation. Lurgi has developed such a methanol to synfuels process which is commercially available as “MtSynfuels process”.

The following reactions occur:

- 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: $C_nH2_n + H_2 \Rightarrow C_nH_{2n+2}$

11.1.4.8 CD2 Syndiesel distribution (long distance)

Road fuels are transported from refineries to depots via a number of transport modes. We have included water (inland waterway or coastal), rail and pipeline (1/3 each). The energy consumption and distance figures are typical averages for EU. Barges and coastal tankers are deemed to use a mixture of marine diesel and HFO. Rail transport consumes electricity. The consumption figures are typical.

11.1.4.9 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.1.4.10LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.1.4.11LF3 Diesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.1.5 Renewable electricity to Syndiesel high temperature (HT) electrolysis based on SOEC and FT route (CO2 from flue gases, biogas upgrading, and direct air capture) (RESD2x)

RESD2a_ CO2 from flue gas

RESD2c: CO2 from biogas upgrading

RESD2d: CO2 from direct air capture

Process code	Step	Common processes		Input	Range	Distribution	Source
	Production & conditioning at source						
WD1	**Wind turbine**						[GEMIS 2000]
	No expended energy or emissions						
	Transformation at source						
	NA						
	Transportation to market						
EDH	**Electricity distribution HV**						[JRC 2017]
	Losses		%	2.6%			
	Transformation near market						
YH2	**Hydrogen via high temperature electrolysis via SOEC**						[Sunfire 2018]
	Electricity (wind)		MJ/MJ$_{H2}$	1.2500			
	Heat		MJ/MJ$_{H2}$	0.2468			
CA1	**CO_2 absorption (from flue gases)**						[Socolow 2011]
	Electricity (wind)		MJ/kg$_{CO2}$	0.0334			
	Heat		MJ/kg$_{CO2}$	4.2998			
CA2	**Direct CO2 capture from air via temperature swing adsorption**						[Climeworks 2015]
	Electricity (wind)		MJ/kg$_{CO2}$	0.9000			
	Heat		MJ/kg$_{CO2}$	6.3000			
CL1	**CO2 liquefaction (for purification and storage)**						[Brinkdöpke 2014]
	Electricity (wind)		MJ/kg$_{CO2}$	0.7412			
RWGS	**CO production from CO2 and H2 via reverse water gas shift (RWGS)**						LBST internal
	H2		MJ/MJ$_{CO}$	0.8546			
	CO_2		kg/MJ$_{CO}$	0.1555			
	Steam		MJ/MJ$_{CO}$	0.1454			
HC1	**H2 compression from 1.0 MPa to 2.5 MPa**						LBST internal
	Electricity (wind)		MJ/MJ$_{H2}$	0.0156			
HFT1	**Fischer-Tropsch synthesis**						[Backer et al. 1997], [Senden et al. 1996]
	H2		MJ/MJ$_{syncrude}$	0.8738			
	CO		MJ/MJ$_{syncrude}$	0.5113			
	Electricity surplus (used internally)		MJ/MJ$_{syncrude}$	-0.0556			
	Steam surplurs		MJ/MJ$_{syncrude}$	-0.2748			
	CO_2 emissions		g/MJ$_{syncrude}$	8.41			
HCU	**Upgrading to gasoline and diesel**						
	Syncrude		MJ/MJ$_{SD}$	1.0027			[Backer et al. 1997]
	Electricity (wind)		MJ/MJ$_{SD}$	0.0030			[Hedden 1994]
	H2		MJ/MJ$_{SD}$	0.0127			[Backer et al. 1997]
	Steam		MJ/MJ$_{SD}$	0.0258			[Hedden 1994]
	CO_2 emissions		g/MJ$_{SD}$	0.47			
	Conditioning & Distribution						
CD2	**Syndiesel distribution (long distance)**						[TOTAL 2002]
	Barge, 1200t (20%)						
	Distance	T3g	km	500			
	Diesel fuel		MJ/t.km	0.5040			[Ecoinvent 1996]
	CH_4 emissions		g/t.km	0.0300			
	Rail (20%)						
	Distance	T2	km	250			
	Pipeline (60%)						
	Electricity (EU-mix LV)	EMLa	MJ/MJ$_{SD}$	0.0002			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{SD}$	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	T1					
	Distance		km	150			
LF3	**Diesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{SD}$	0.0008			

11.1.5.1 WD1 Electricity (wind)

Electricity from wind turbine is energy and emission - free (as we do not consider energy and emissions related to construction and maintenance).

11.1.5.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.1.5.3 YH2 Hydrogen via high temperature electrolysis via SOEC

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. Heat is required to generate steam. The heat is supplied by heat 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 electrolysers (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 Nm³ of hydrogen per hour. The hydrogen purity is 99.999% and the hydrogen pressure amounts to 1 MPa.

11.1.5.4 CA1 CO2 absorption (from flue gases)

CO2 is assumed to available from the flue gases of e.g. a power station. It is extracted from the flue gas stream via scrubbing with monoethanolamine (MEA). The regeneration of the scrubbing agent is carried out to a large extent with the heat from the methanation process.

11.1.5.5 CA2 Direct CO2 capture from air via temperature swing adsorption

The Swiss company Climeworks ((an ETH Zurich spinoff) has developed a technology for the separation of CO2 from air based on an adsorption/desorption cycle. The process can also be referred to as a temperature swing adsorption (TSA) process. The regeneration of the sorbent is carried out at low temperatures (95°C) [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.

11.1.5.6 CL1 CO2 liquefaction (for purification and storage)

For CO2 purification and CO2 storage a CO2 liquefaction plant has been applied. Today, such plants are installed at ethanol plants if the CO2 should be exported as pure substance. The purity is 99.999%. CO2 becomes liquid at elevated pressure and/or at low temperatures. At the plant described in [Brinkdöpke 2014] the CO2 is stored at a temperature of -25°C.

11.1.5.7 RWGS CO production from CO2 and H2 via reverse water gas shift (RWGS)

For Fischer-Trosch synthesis carbon monoxide (CO) is required. Therefore, the CO2 has to be converted to CO via reverse water gas shift (RWGS) according to the reaction:

$CO_2 + H_2 => CO + H_2O$

The reaction is endothermal if the water is kept gaseous and slightly exothermal if the water becomes liquid. Since the reaction is carried out at a temperature 900°C [König et al. 2015] heat the water is gaseous and heat is required to run the process.

11.1.5.8 HC1 H2 compression from 1.0 MPa to 2.5 MPa

The hydrogen pressure at the outlet of the SOEC amounts to 1 MPa. The Fischer-Tropsch synthesis is carried out at 2.5 MPa. Therefore, hydrogen compression is required.

11.1.5.9 HFT1 Fischer-Tropsch synthesis

Hydrogen reacts with CO to form liquid hydrocarbons according to the reaction:

$2\ H_2 + CO => -CH_2- + H_2O$

The reaction is exothermic.

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 H2 is fed recycled. The pressure is 2.5 MPa [Backer et al. 1997], [Senden et al. 1996]. It has been assumed that 90% of the Fischer-Tropsch products are liquid (i.e. C5 and above). The gases are used for electricity generation via a combined cycle gas turbine (CCGT) with an efficiency of 50%. The heat from the Fischer-Tropsch reaction is used for steam generation for the high temperature electrolysis.

11.1.5.10HCU Upgrading to gasoline and diesel

The syncrude leaving the Fischer-Tropsch reactor is sent to a hydrocracking unit where the heavier products such as wax is hydrocracked to the desired products naphtha, kerosene, and diesel. According to [Senden et al. 1996] the product split consists of 15% naphtha, 25% kerosene, and 60% gas oil (= diesel) if the plant is operated at 'gas oil mode'. If the plant is operated at 'kerosene mode' the product split consists of 25% naphtha, 50% kerosene, and 25% diesel.

The syncrude input and the hydrogen consumption has been derived from [Backer et al. 1997], the heat and steam requirement from [Hedden 1994].

11.1.5.11 CD2 Syndiesel distribution (long distance)

Road fuels are transported from refineries to depots via a number of transport modes. We have included water (inland waterway or coastal), rail and pipeline (1/3 each). The energy consumption and distance figures are typical averages for EU. Barges and coastal tankers are deemed to use a mixture of marine diesel and HFO. Rail transport consumes electricity. The consumption figures are typical.

11.1.5.12 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.1.5.13 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.1.5.14 LF3 Diesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.2 OME

11.2.1 Piped natural gas (4000 km) to oxymethylene ether (OME) via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis (GPOME)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.08				
	Transformation at source							
	NA							
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ_{fuel}	0.0084				
	N_2O emissions		g/MJ_{fuel}	0.0026				
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ_{NG}	0.1057				[Wuppertal 2004]
	Transformation near market							
NM1	**NG to methanol plant**							[Larsen 1998]
	Efficiency			68.3%	67.3%	69.4%	Square	
	CH_4 emissions		g/MJ_{Meth}	0.0001				
MF	**Methanol to formaldehyde**							[Renner 2013]
	Methanol		MJ/MJ_{CH2O}	1.4252				
	Heat		MJ/MJ_{CH2O}	0.0596				
	Electricity surplus		MJ/MJ_{CH2O}	-0.0027				
	Steam surplus		MJ/MJ_{CH2O}	-0.2116				
	CO2 emissions		g/MJ_{CH2O}	13.30				
FMM	**Formaldehyd and methanol to Methylal**							[Renner 2013]
	Formaldehyde		MJ/MJ_{C3H8O2}	0.3120				
	Methanol		MJ/MJ_{C3H8O2}	0.7419				
	Electricity		MJ/MJ_{C3H8O2}	0.0078				
	Heat		MJ/MJ_{C3H8O2}	0.2347				
	CO2 emissions		g/MJ_{C3H8O2}	3.0				
FTR	**Formaldehyde to trioxane**							
	Formaldehyde		MJ/$MJ_{trioxane}$	1.1125				[NIST 2017], [Renner 2013]
	Electricity		MJ/$MJ_{trioxane}$	0.0116				[Renner 2013], [Schmitz et al. 2016]
	Heat		MJ/$MJ_{trioxane}$	0.3515				[Renner 2013], [Schmitz et al. 2016]
MTRO	**Methylal and trioxane to OME**							[Burger 2012]
	Methylal		MJ/MJ_{OME}	0.5869				
	Trioxane		MJ/MJ_{OME}	0.4178				
	Steam		MJ/MJ_{OME}	0.0701				
	CO2 emissions		g/MJ_{OME}	0.0469				
	Conditioning & Distribution							
OME2	**OME distribution (transport to depot)**							
	Road truck	*T1*						
	Distance		km	150				
LF1OME	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{OME}	0.0019				
LF2OME	**Liquid fuel local distribution**							
	Road truck	*T1*						
	Distance		km	150				
LF3OME	**OME dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{OME}	0.0034				

11.2.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

11.2.1.2 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of the Near/Middle East (4000 km), being the most likely source of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

11.2.1.3 NM1 NG to methanol plant

The plant energy efficiency selected here corresponds to a current state-of-the-art installation. The upper value (29.64 GJ/t of methanol) is the value guaranteed by the manufacturer, the lower value (28.74 GJ/t of methanol) is a measured value for the methanol plant located in Tjeldbergodden in Norway.

This process is applicable to both a remote plant and a large “central” plant located in Europe.

11.2.1.4 MF Methanol to formaldehyde

Methanol is converted to formaldehyde (CH_2O) according to reaction:

$CH_3OH + 0.5\ O_2 \Rightarrow CH_2O + H_2O$

The reaction is exothermal.

The technical data are from the German company INEOS.

11.2.1.5 FMM Formaldehyde and methanol to Methylal

Methylal can be considers as OME with n = 1.

Methylal is produced from formaldehyde and methanol according to reaction:

$2\ CH_3OH + CH_2O \Rightarrow C_3H_8O_2 + H_2O$.

The technical data are from the German company INEOS which offer chemical plants.

11.2.1.6 FTR Formaldehyde to trioxane

For the synthesis of longer chain OME the formaldehyde has to be converted to trioxane according to reaction:

$3\ CH_2O \Rightarrow C_3H_6O_3$

Analogous to [Schmitz et al. 2016] it has been assumed that the same heat and electricity per kg as for methylal is required.

11.2.1.7 MTRO Methylal and trioxane to OME

Longer chain OME is generated from methylal and trioxane. The chemical formula of OME is $H_3CO(CH_2O)_nCH_3$. For the use in diesel engines n ranges between 3 and 5. The synthesis of OME with n = 4 occurs according to reaction:

$C_3H_8O_2 + C_3H_6O_3 => C_6H_{14}O_5$

11.2.1.8 OME2 OME distribution (transport to depot)

Form the OME plant the OME is transported via truck to a depot over a distance of 150 km.

11.2.1.9 LF2OME Liquid fuel local distribution

From the depot the OME is transported via truck to a depot over a distance of 150 km.

11.2.1.10LF3OME OME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.2.2 Wood to oxymethylene ether (OME) via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis (WxOME)

WWxx1: Waste wood to gasification/synthesis plant

WFxx1: Farmed to gasification/synthesis plant

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{wood}$					
	N (as N)	*FN*		0.00				JRC internal
	Pesticides	*PE*	g/MJ$_{wood}$	0.02				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.00002				
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000				
	N_2O field emissions		g/MJ$_{wood}$	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindholm 20
W2	**Forestry residue chipping**							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content		%	30%				
WF3b	**Farmed wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
WW3b	**Waste wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
	Transformation near market							
WMD	**Wood to Methanol plant**							[Katofsky 1993]
	Efficiency			51.1%	46.1%	57.2%	Square	[Atrax 1999]
MF	**Methanol to formaldehyde**							[Renner 2013]
	Methanol		MJ/MJ$_{CH2O}$	1.4252				
	Heat		MJ/MJ$_{CH2O}$	0.0596				
	Electricity surplus		MJ/MJ$_{CH2O}$	-0.0027				
	Steam surplus		MJ/MJ$_{CH2O}$	-0.2116				
	CO2 emissions		g/MJ$_{CH2O}$	13.30				
FMM	**Formaldehyd and methanol to Methylal**							[Renner 2013]
	Formaldehyde		MJ/MJ$_{C3H8O2}$	0.3120				
	Methanol		MJ/MJ$_{C3H8O2}$	0.7419				
	Electricity		MJ/MJ$_{C3H8O2}$	0.0078				
	Heat		MJ/MJ$_{C3H8O2}$	0.2347				
	CO2 emissions		g/MJ$_{C3H8O2}$	3.0				
FTR	**Formaldehyde to trioxane**							
	Formaldehyde		MJ/MJ$_{trioxane}$	1.1125				[NIST 2017], [Renner 2013]
	Electricity		MJ/MJ$_{trioxane}$	0.0116				[Renner 2013], [Schmitz et al. 2016]
	Heat		MJ/MJ$_{trioxane}$	0.3515				[Renner 2013], [Schmitz et al. 2016]
MTRO	**Methylal and trioxane to OME**							[Burger 2012]
	Methylal		MJ/MJ$_{OME}$	0.5869				
	Trioxane		MJ/MJ$_{OME}$	0.4178				
	Steam		MJ/MJ$_{OME}$	0.0701				
	CO2 emissions		g/MJ$_{OME}$	0.0469				
	Conditioning & Distribution							
OME2	**OME distribution (transport to depot)**							
	Road truck	*T1*						
	Distance		km	150				
LF1OME	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{OME}$	0.0019				
LF2OME	**Liquid fuel local distribution**							
	Road truck	*T1*						
	Distance		km	150				
LF3OME	**OME dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{OME}$	0.0034				

11.2.2.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

11.2.2.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

11.2.2.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

11.2.2.4 FRS Forestry residue seasoning

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

11.2.2.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

11.2.2.6 WF3b Farmed wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.2.2.7 WW3b Waste wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.2.2.8 WMD Wood to Methanol plant

'Our "best-case' process is based on [Katofsky 1993], using the BCL indirectly-heated gasifier with wet gas cleaning and reforming of higher hydrocarbons. The rest of the process is similar to methanol synthesis from natural gas. A conventional, fixed bed methanol reactor is used. With all fuel synthesis routes, it might be possible to improve efficiency by using slurry reactors or hot gas cleaning. However, neither has been demonstrated for synthesis from bio-syngas: there are question marks about gas quality [Tijmensen 2002]. Furthermore, the use of conventional processes enables us to compare all routes on a fair basis.

Our 'worst case' is based on oxygen-blowing the Värnamo autothermal pressurized fluidized bed gasifier, modelled by [Atrax 1999]. Although this is a state-of-the art gasifier, it is not as sophisticated and expensive as the BCL gasifier. The process uses the hot gas filtration demonstrated at Värnamo to allow the gas to go hot into the 950°C steam reformer, where some tar is also decomposed. However, after the shift water-gas shift reactor (to boost the H2/CO ratio), it is still necessary to use a scrubbing process to remove impurities (including HCl, H2S…) before the gas is pure enough for synthesis. In the Altrax process the purification is combined with CO2 removal by scrubbing with methanol (Rectisol Process).

11.2.2.9 MF Methanol to formaldehyde

Methanol is converted to formaldehyde (CH_2O) according to reaction:

$CH_3OH + 0.5\ O_2 \Rightarrow CH_2O + H_2O$

The reaction is exothermal.

The technical data are from the German company INEOS.

11.2.2.10FMM Formaldehyde and methanol to Methylal

Methylal can be considers as OME with n = 1.

Methylal is produced from formaldehyde and methanol according to reaction:

$2\ CH_3OH + CH_2O \Rightarrow C_3H_8O_2 + H_2O$.

The technical data are from the German company INEOS which offer chemical plants.

11.2.2.11FTR Formaldehyde to trioxane

For the synthesis of longer chain OME the formaldehyde has to be converted to trioxane according to reaction:

$3\ CH_2O \Rightarrow C_3H_6O_3$

Analogous to [Schmitz et al. 2016] it has been assumed that the same heat and electricity per kg as for methylal is required.

11.2.2.12MTRO Methylal and trioxane to OME

Longer chain OME is generated from methylal and trioxane. The chemical formula of OME is $H_3CO(CH_2O)_nCH_3$. For the use in diesel engines n ranges between 3 and 5. The synthesis of OME with n = 4 occurs according to reaction:

$C_3H_8O_2 + C_3H_6O_3 \Rightarrow C_6H_{14}O_5$

11.2.2.13OME2 OME distribution (transport to depot)

Form the OME plant the OME is transported via truck to a depot over a distance of 150 km.

11.2.2.14LF2OME Liquid fuel local distribution

From the depot the OME is transported via truck to a depot over a distance of 150 km.

11.2.2.15LF3OME OME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.2.3 Renewable electricity to oxymethylene ether (OME) via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis (CO2 from biogas upgrading) (REOME)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WD1	**Wind turbine**							[GEMIS 2000]
	No expended energy or emissions							
	Transformation at source							
	NA							
	Transportation to market							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
	NA							
	Transformation near market							
YH1	**Hydrogen via electrolysis (large plant)**							JEC internal
	Electricity (wind)		MJ/MJ$_{H2}$	1.5380	1.6000	1.4760	Normal	
HM1	**Methanol synthesis from hydrogen and CO_2**							[Van-Dal & Bouallou 2013]
	CO_2		kg/MJ$_{methanol}$	0.0745				
	Electricity (wind)		MJ/MJ$_{methanol}$	0.0539				
	Hydrogen		MJ/MJ$_{methanol}$	1.2281				
	Surplus heat		MJ/MJ$_{methanol}$	0.0863				
MF	**Methanol to formaldehyde**							[Renner 2013]
	Methanol		MJ/MJ$_{CH2O}$	1.4252				
	Heat		MJ/MJ$_{CH2O}$	0.0596				
	Electricity surplus		MJ/MJ$_{CH2O}$	-0.0027				
	Steam surplus		MJ/MJ$_{CH2O}$	-0.2116				
	CO2 emissions		g/MJ$_{CH2O}$	13.30				
FMM	**Formaldehyd and methanol to Methylal**							[Renner 2013]
	Formaldehyde		MJ/MJ$_{C3H8O2}$	0.3120				
	Methanol		MJ/MJ$_{C3H8O2}$	0.7419				
	Electricity		MJ/MJ$_{C3H8O2}$	0.0078				
	Heat		MJ/MJ$_{C3H8O2}$	0.2347				
	CO2 emissions		g/MJ$_{C3H8O2}$	3.0				
FTR	**Formaldehyde to trioxane**							
	Formaldehyde		MJ/MJ$_{trioxane}$	1.1125				[NIST 2017], [Renner 2013]
	Electricity		MJ/MJ$_{trioxane}$	0.0116				[Renner 2013], [Schmitz et al. 2016]
	Heat		MJ/MJ$_{trioxane}$	0.3515				[Renner 2013], [Schmitz et al. 2016]
MTRO	**Methylal and trioxane to OME**							[Burger 2012]
	Methylal		MJ/MJ$_{OME}$	0.5869				
	Trioxane		MJ/MJ$_{OME}$	0.4178				
	Steam		MJ/MJ$_{OME}$	0.0701				
	CO2 emissions		g/MJ$_{OME}$	0.0469				
	Conditioning & Distribution							
OME2	**OME distribution (transport to depot)**							
	Road truck	*T1*						
	Distance		km	150				
LF1OME	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{OME}$	0.0019				
LF2OME	**Liquid fuel local distribution**							
	Road truck	*T1*						
	Distance		km	150				
LF3OME	**OME dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{OME}$	0.0034				

11.2.3.1 WD1 Wind turbine

Electricity from wind turbine is energy and emission - free (as we do not consider energy and emissions related to construction and maintenance)

11.2.3.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.2.3.3 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.2.3.4 YH1 Hydrogen via electrolysis (large plant)

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPa_g electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].
- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].
- McPhy indicates an electricity consumption of 4.5 kWh/Nm^3 at nominal flow rate for its 800 Nm^3/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPag [McPhy 2017].

Several sources of data are available, giving figures for both small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depend on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPag [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh_e/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 63% (4.8 to 5.4 kWh_e/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

11.2.3.5 HM1 Methanol synthesis from hydrogen and CO2

Hydrogen reacts with CO_2 to form methanol according to the reaction:

$3\ H_2 + CO_2 \Rightarrow CH_3OH + H_2O$

The reaction is exothermic.

11.2.3.6 MF Methanol to formaldehyde

Methanol is converted to formaldehyde (CH_2O) according to reaction:

$CH_3OH + 0.5\ O_2 \Rightarrow CH_2O + H_2O$

The reaction is exothermal.

The technical data are from the German company INEOS.

11.2.3.7 FMM Formaldehyde and methanol to Methylal

Methylal can be considers as OME with n = 1.

Methylal is produced from formaldehyde and methanol according to reaction:

2 CH_3OH + CH_2O => $C_3H_8O_2$+ H_2O.

The technical data are from the German company INEOS which offer chemical plants.

11.2.3.8 FTR Formaldehyde to trioxane

For the synthesis of longer chain OME the formaldehyde has to be converted to trioxane according to reaction:

3 CH_2O => $C_3H_6O_3$

Analogous to [Schmitz et al. 2016] it has been assumed that the same heat and electricity per kg as for methylal is required.

11.2.3.9 MTRO Methylal and trioxane to OME

Longer chain OME is generated from methylal and trioxane. The chemical formula of OME is $H_3CO(CH_2O)_nCH_3$. For the use in diesel engines n ranges between 3 and 5. The synthesis of OME with n = 4 occurs according to reaction:

$C_3H_8O_2$ + $C_3H_6O_3$ => $C_6H_{14}O_5$

11.2.3.10OME2 OME distribution (transport to depot)

Form the OME plant the OME is transported via truck to a depot over a distance of 150 km.

11.2.3.11LF2OME Liquid fuel local distribution

From the depot the OME is transported via truck to a depot over a distance of 150 km

11.2.3.12LF3OME OME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.3 Pyrolysis-based gasoline and diesel

11.3.1 Farmed wood to pyrolysis gasoline (WFPG1) and diesel (WFPD1)

Process code	Step	Common processes		Input	Range	Distribution	Source
WF1	**Wood plantation**						
	Agricultural inputs						
	Fertilizers						
	N (as N)	*FN*	g/MJ_{wood}	0.00			JRC internal
	Pesticides	*PE*	g/MJ_{wood}	0.02			JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"						
	Diesel	*F1*	MJ/MJ_{wood}	0.0126			JRC internal
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.0000			
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.0000			
	N_2O field emissions		g/MJ_{wood}	0.0067			JRC internal
WS	**Wood storage (seasoning)**						
	Losses			12.0%			JRC internal
FRC	**Forestry residue collection**						
	Diesel	*F1*	MJ/MJ_{wood}	0.0120			[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000009			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000038			[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**						
	Losses			5.0%			[Hamelinck 2005], [Kofman 2012], [Lindholm 2010]
W2	**Forestry residue chipping**						
	Diesel	*F1*	MJ/MJ_{wood}	0.0034			[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000003			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000011			[EMEP/EEA 2013]
	Losses			2.5%			[JRC 2013], [Sikkema et al. 2010]
	Transformation at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
	Wood moisture content		%	30%			
WF3b	**Farmed wood transport (regional, 500 km)**						JRC internal
	Road truck	*T1*					
	Distance		km	500			
WW3b	**Waste wood transport (regional, 500 km)**						JRC internal
	Road truck	*T1*					
	Distance		km	500			
WPG1/D1	**Wood to gasoline and diesel via pyrolysis & hydrotreating**						[Jones et al. 2015]
	Efficiency			61.6%			
	Electricity (EU-mix, MV)	*EMMa*	$MJ/MJ_{G\&D}$	0.0359			
	NG		$MJ/MJ_{G\&D}$	0.1583			
	Dimethyl sulfoxide		$g/MJ_{G\&D}$	0.02311			
	HCl	*C13*	$g/MJ_{G\&D}$	0.00003			
	Inorganic chemicals	*C26*	$g/MJ_{G\&D}$	0.00012			
	NaOH	*C6*	$g/MJ_{G\&D}$	0.00004			
	Zeolithe	*C27*	$g/MJ_{G\&D}$	0.03306			
SD4b	**Biomasss derived gasoline, diesel, and FT diesel distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	*T1*					
	Distance		km	150			
LF3	**Diesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0008			

11.3.1.1 General

Fast pyrolysis is performed under a range of temperatures around 500°C and short residence times (few seconds) in the reactor to maximize the pyrolysis oil yield. Liquid fuels from the upgrading of pyrolysis oil, which is a mixture of naphtha-range products (gasoline blend stock) and diesel-range products (diesel blend stock), do not have infrastructure or engine compatibility concerns. The co-products of the fast pyrolysis process can be used as process inputs to satisfy various energy needs. For example, excess fuel gas and biochar can be combusted to generate electricity, which can be used to grind biomass to a required particle size, while any surplus electricity can be exported to the grid. Alternatively, excess biochar can be exported from the plant and used as a soil amendment, while fuel gas (a mix of CO2 and C1-C4 gases) can be used to supply process heat or reformed to produce hydrogen for the upgrading processes.

11.3.1.2 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

11.3.1.3 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

11.3.1.4 WF3b Farmed wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.3.1.5 WPG1/D1 Wood to gasoline and diesel via pyrolysis & hydrotreating

The plant consists of:

- fast pyrolysis
- NG steam reforming
- 3-step hydrotreating
- Product separation

Products are gasoline and diesel. The allocation between gasoline and energy has been carried out on energy basis.

11.3.1.6 SD4b Biomass derived gasoline, diesel, and FT diesel distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived synthetic diesel.

11.3.1.7 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.3.1.8 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.3.1.9 LF3 Diesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.3.2 Waste wood to pyrolysis gasoline (WWPG1) and diesel (WWPD1)

Process code	*Step*	*Common processes*		*Input*	*Range*	*Distribution*	*Source*
WF1	**Wood plantation**						
	Agricultural inputs						
	Fertilizers						
	N (as N)	*FN*	g/MJ$_{wood}$	0.00			JRC internal
	Pesticides	*PE*	g/MJ$_{wood}$	0.02			JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"						
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0126			JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000			
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000			
	N_2O field emissions		g/MJ$_{wood}$	0.0067			JRC internal
WS	**Wood storage (seasoning)**						
	Losses			12.0%			JRC internal
FRC	**Forestry residue collection**						
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0120			[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038			[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**						
	Losses			5.0%			[Hamelinck 2005], [Kofman 2012], [Lindholm 2010]
W2	**Forestry residue chipping**						
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0034			[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011			[EMEP/EEA 2013]
	Losses			2.5%			[JRC 2013], [Sikkema et al. 2010]
	Transformation at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
	Wood moisture content		%	30%			
WF3b	**Farmed wood transport (regional, 500 km)**						JRC internal
	Road truck	*T1*					
	Distance		km	500			
WW3b	**Waste wood transport (regional, 500 km)**						JRC internal
	Road truck	*T1*					
	Distance		km	500			
WPG1/D1	**Wood to gasoline and diesel via pyrolysis & hydrotreating**						[Jones et al. 2015]
	Efficiency			61.6%			
	Electricity (EU-mix, MV)	*EMMa*	MJ/MJ$_{G\&D}$	0.0359			
	NG		MJ/MJ$_{G\&D}$	0.1583			
	Dimethyl sulfoxide		g/MJ$_{G\&D}$	0.02311			
	HCl	*C13*	g/MJ$_{G\&D}$	0.00003			
	Inorganic chemicals	*C26*	g/MJ$_{G\&D}$	0.00012			
	NaOH	*C6*	g/MJ$_{G\&D}$	0.00004			
	Zeolithe	*C27*	g/MJ$_{G\&D}$	0.03306			
SD4b	**Biomasss derived gasoline, diesel, and FT diesel distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{SD}$	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	*T1*					
	Distance		km	150			
LF3	**Diesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{SD}$	0.0008			

11.3.2.1 General

Fast pyrolysis is performed under a range of temperatures around 500°C and short residence times (few seconds) in the reactor to maximize the pyrolysis oil yield. Liquid fuels from the upgrading of pyrolysis oil, which is a mixture of naphtha-range products (gasoline blend stock) and diesel-range products (diesel blend stock), do not have infrastructure or engine compatibility concerns. The co-products of the fast pyrolysis process can be used as process inputs to satisfy various energy needs. For example, excess fuel gas and biochar can be combusted to generate electricity, which can be used to grind biomass to a required particle size, while any surplus electricity can be exported to the grid. Alternatively, excess biochar can be exported from the plant and used as a soil amendment, while fuel gas (a mix of CO_2 and C1-C4 gases) can be used to supply process heat or reformed to produce hydrogen for the upgrading processes.

11.3.2.2 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

11.3.2.3 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Guintoli et al. 2017].

11.3.2.4 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

11.3.2.5 WW3b Waste wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.3.2.6 WPG1/D1 Wood to gasoline and diesel via pyrolysis & hydrotreating

The plant consists of:

- fast pyrolysis
- NG steam reforming
- 3-step hydrotreating
- Product separation

Products are gasoline and diesel. The allocation between gasoline and energy has been carried out on energy basis.

11.3.2.7 SD4b Biomass derived gasoline, diesel, and FT diesel distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived synthetic diesel.

11.3.2.8 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.3.2.9 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.3.2.10LF3 Diesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.4 HTL-based diesel

Wood to diesel via hydrothermal liquefaction (HTL) and upgrading.

11.4.1 Farmed wood to diesel, hydrothermal liquefaction (HTL) and upgrading

Process code	Step	Common processes		Input	Range	Distribution	Source
	Production & conditioning at source						
WF1	**Wood plantation**						
	Agricultural inputs						
	Fertilizers		g/MJ$_{wood}$				
	N (as N)	*FN*		0.00			JRC internal
	Pesticides	*PE*	g/MJ$_{wood}$	0.015			JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"						
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0126			JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000161			
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000397			
	N_2O field emissions		g/MJ$_{wood}$	0.0067			JRC internal
WS	**Wood storage (seasoning)**						
	Losses			12.0%			JRC internal
FRC	**Forestry residue collection**						
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0120			[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038			[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**						
	Losses			5.0%			[Hamelinck 2005], [Kofman 2012], [Lindholm 201
W2	**Forestry residue chipping**						
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0034			[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011			[EMEP/EEA 2013]
	Losses			2.5%			[JRC 2013], [Sikkema et al. 2010]
	Transformation at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
	Wood moisture content			30%			
WF3b	**Farmed wood transport (regional, 500 km)**						JRC internal
	Road truck	*T1*					
	Distance		km	500			
WW3b	**Waste wood transport (regional, 500 km)**						JRC internal
	Road truck	*T1*					
	Distance		km	500			
	Transformation near market						
HTL	**HTL and upgrading plant**						[Jensen et al. 2018]
	Efficiency			83.9%			
	Electricity	*EMMa*	MJ/MJ$_{diesel}$	0.0721			
	Hydrogen	*Z2*	MJ/MJ$_{diesel}$	0.1361			
	LNG		MJ/MJ$_{diesel}$	0.0051			
	K_2CO_3	*C28*	g/MJ$_{diesel}$	0.70			
	NaOH	*C6*	g/MJ$_{diesel}$	1.63			
	Conditioning & Distribution						
SD4b	**Syndiesel distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{SD}$	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	*T1*					
	Distance		km	150			
LF3	**Diesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{SD}$	0.0008			

11.4.1.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

11.4.1.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

11.4.1.3 WF3b Farmed wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.4.1.4 HTL HTL and upgrading plant

Wood chips are converted to a synthetic crude oil at supercritical water conditions with temperatures up to 450 °C and pressures of 35 MPa, generally called hydrothermal liquefaction (HTL). A pilot plant with a capacity of 30 kg of synthetic crude oil (slurry) per hour is operated in Aalborg in Denmark by the Danish-Canadian company Steeper Energy. Steeper Energy calls its HTL process 'Hydrofaction'. The pilot plant has been commissioned in 2013. The Pilot plant has completed more than 4000 h of hot operation, including 1200 oil production hours [Jensen et al. 2017]. December 2017, Steeper Energy announced to build an industrial-scale demonstration plant at a former pulp mill located in Tofte in Norway together with the Norwegian-Swedish joint venture Silva Green Fuel.

The slurry is converted to diesel via hydroprocessing. In the process described in [Jensen et al. 2018] the products are diesel and marine fuel (heavy fuel oil).

11.4.1.5 SD4b Syndiesel distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived synthetic diesel.

11.4.1.6 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.4.1.7 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.4.1.8 LF3 Diesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.4.2 Wood waste to diesel, hydrothermal liquefaction (HTL) and upgrading (WWSD2)

Process code	Step	Common processes		Input	Range	Distribution	Source
	Production & conditioning at source						
WF1	**Wood plantation**						
	Agricultural inputs						
	Fertilizers		g/MJ$_{wood}$				
	N (as N)	FN		0.00			JRC internal
	Pesticides	PE	g/MJ$_{wood}$	0.015			JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"						
	Diesel	F1	MJ/MJ$_{wood}$	0.0126			JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000161			
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000397			
	N_2O field emissions		g/MJ$_{wood}$	0.0067			JRC internal
WS	**Wood storage (seasoning)**						
	Losses			12.0%			JRC internal
FRC	**Forestry residue collection**						
	Diesel	F1	MJ/MJ$_{wood}$	0.0120			[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038			[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**						
	Losses			5.0%			[Hamelinck 2005], [Kofman 2012], [Lindholm 201
W2	**Forestry residue chipping**						
	Diesel	F1	MJ/MJ$_{wood}$	0.0034			[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003			[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011			[EMEP/EEA 2013]
	Losses			2.5%			[JRC 2013], [Sikkema et al. 2010]
	Transformation at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
	Wood moisture content			30%			
WF3b	**Farmed wood transport (regional, 500 km)**						JRC internal
	Road truck	T1					
	Distance		km	500			
WW3b	**Waste wood transport (regional, 500 km)**						JRC internal
	Road truck	T1					
	Distance		km	500			
	Transformation near market						
HTL	**HTL and upgrading plant**						[Jensen et al. 2018]
	Efficiency			83.9%			
	Electricity	EMMa	MJ/MJ$_{diesel}$	0.0721			
	Hydrogen	Z2	MJ/MJ$_{diesel}$	0.1361			
	LNG		MJ/MJ$_{diesel}$	0.0051			
	K_2CO_3	C28	g/MJ$_{diesel}$	0.70			
	NaOH	C6	g/MJ$_{diesel}$	1.63			
	Conditioning & Distribution						
SD4b	**Syndiesel distribution (long distance)**						JRC internal
	Road truck (13.2%)	T1					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	T3h					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	T3a					
	Distance		km	153			
	Rail (4.4%)	T2					
	Distance		km	381			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ$_{SD}$	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	T1					
	Distance		km	150			
LF3	**Diesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{SD}$	0.0008			

11.4.2.1 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

11.4.2.2 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Giuntoli et al. 2017].

11.4.2.3 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

11.4.2.4 WW3b Waste wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.4.2.5 HTL HTL and upgrading plant

Wood chips are converted to a synthetic crude oil at supercritical water conditions with temperatures up to 450 °C and pressures of 35 MPa, generally called hydrothermal liquefaction (HTL). A pilot plant with a capacity of 30 kg of synthetic crude oil (slurry) per hour is operated in Aalborg in Denmark by the Danish-Canadian company Steeper Energy. Steeper Energy calls its HTL process 'Hydrofaction'. The pilot plant has been commissioned in 2013. The Pilot plant has completed more than 4000 h of hot operation, including 1200 oil production hours [Jensen et al. 2017]. December 2017, Steeper Energy announced to build a industrial-scale demonstration plant at a former pulp mill located in Tofte in Norway together with the Norwegian-Swedish joint venture Silva Green Fuel.

The slurry is converted to diesel via hydroprocessing. In the process described in [Jensen et al. 2018] the products are diesel and marine fuel (heavy fuel oil).

11.4.2.6 SD4b Syndiesel distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived synthetic diesel.

11.4.2.7 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.4.2.8 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.4.2.9 LF3 Diesel dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.5 Methanol

11.5.1 Piped natural gas (4000 km) to methanol, synthesis plant in EU (GPME1b)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.08				
	Transformation at source							
	NA							
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ_{fuel}	0.0084				
	N_2O emissions		g/MJ_{fuel}	0.0026				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				[Thinkstep 2017]
	Compression specific energy		MJ/t.km	0.360	0.120	0.400	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.1398				[GEMIS 2016]
GG2/07	**NG pipeline transport inside EU**							
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				[GEMIS 2016]
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				[GEMIS 2016]
	GPCG1a (Russia)							
	Distance		km	700				
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.0009				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ_{NG}	0.1057				[Wuppertal 2004]
	Transformation near market							
NM1	**NG to methanol plant**							[Larsen 1998]
	Efficiency			68.3%	67.3%	69.4%	Square	
	CH_4 emissions		g/MJ_{Meth}	0.0001				
ND1	**NG to DME plant**							[Hansen 2001]
	Efficiency			71.3%	69.9%	72.7%	Square	
	Electricity	*GGe*	MJ/MJ_{DME}	0.0043	0.4%	0.4%	Square	
	Heat surplus		MJ/MJ_{DME}	-0.0022				
	CH_4 emissions		g/MJ_{DME}	0.0035				
	Credit for heat surplus based on alternative generation with NG @ 90% efficiency							
	Conditioning & Distribution							
NMD4a	**Methanol/DME distribution**							
	Rail	*T2*						
	Distance		km	250				
	Road truck	*T1*						
	Distance		km	250				
	Payload / tank mass		t/t					
	Methanol			26/28				
	DME			20/28				
NM6	**Methanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034				
ND6	**DME dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034				

11.5.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the

gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

11.5.1.2 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

11.5.1.3 NM1 NG to methanol plant

The plant energy efficiency selected here corresponds to a current state-of-the-art installation. The upper value (29.64 GJ/t of methanol) is the value guaranteed by the manufacturer, the lower value (28.74 GJ/t of methanol) is a measured value for the methanol plant located in Tjeldbergodden in Norway.

This process is applicable to both a remote plant and a large “central” plant located in Europe.

11.5.1.4 NMD4a Methanol/DME distribution

A mixture of rail and road is assumed for a total distance of 500 km.

11.5.1.5 NM6 Methanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.5.2 Remote natural gas to methanol, synthesis plant near gas field (GRME1)

Remote natural gas to Methanol: Synthesis plant near gas field.

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.08				
	Transformation at source							
NM1	**NG to methanol plant**							[Larsen 1998]
	Efficiency			68.3%	67.3%	69.4%	Square	
	CH_4 emissions		g/MJ_{Meth}	0.0001				
NM2	**Methanol depot**							[TOTAL 2002]
	Electricity	GGe	MJ/MJ_{SD}	0.0018				
ND1	**NG to DME plant**							[Hansen 2001]
	Efficiency			71.3%	69.9%	72.7%	Square	
	Electricity	GGe	MJ/MJ_{DME}	0.0043	0.4%	0.4%	Square	
	Heat surplus		MJ/MJ_{DME}	-0.0022				
	CH_4 emissions		g/MJ_{DME}	0.0035				
	Credit for heat surplus based on alternative generation with NG @ 90% efficiency							
ND1C	**NG to DME plant with CCS**							[IEA 2005]
	Efficiency		%	70.2%	68.9%	71.4%	Square	
	Electricity surplus	GE1C	MJ/MJ_{DME}	-0.0022	0.0%	0.0%		
	CO_2 emissions		g/MJ_{DME}	0.58				
	Credit for electricity surplus based on alternative generation in a state-of-the-art CCGT with CCS							
ND2	**DME depot**							[TOTAL 2002]
	Electricity	GGe	MJ/MJ_{SD}	0.0013				
	Transportation to market							
NM3	**Methanol long-distance sea transport**							
	50 kt liquid carrier	T3c						
	Distance		Nautical miles	5500	5000	6000	Square	
NM2	**Methanol depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{Meth}	0.0018				
ND3	**DME long-distance sea transport**							
	84 km^3 LPG carrier	T3g						
	Distance		Nautical miles	5500				
ND2	**DME depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	EMLa	MJ/MJ_{SD}	0.0013				
	Transformation near market							
	NA							
	Conditioning & Distribution							
NMD4a	**Methanol/DME distribution**							
	Rail	T2						
	Distance		km	250				
	Road truck	T1						
	Distance		km	250				
	Payload / tank mass		t/t					
	Methanol			26/28				
	DME			20/28				
NM6	**Methanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{Meth}	0.0034				
ND6	**DME dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{Meth}	0.0034				

11.5.2.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO_2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

11.5.2.2 NM1 NG to methanol plant

The plant energy efficiency selected here corresponds to a current state-of-the-art installation. The upper value (29.64 GJ/t of methanol) is the value guaranteed by the manufacturer, the lower value (28.74 GJ/t of methanol) is a measured value for the methanol plant located in Tjeldbergodden in Norway.

This process is applicable to both a remote plant and a large “central” plant located in Europe (typically 600 MW in terms of methanol, equivalent to about 100 t/h).

11.5.2.3 NM2 Methanol depot

A small amount of electricity is required for the operation of loading and unloading depot and terminal facilities. The figure used for gasoline/diesel has been prorated to remain the same per tonne of product.

11.5.2.4 NM3 Methanol long-distance sea transport

Large remote methanol plants are likely to be built near large gas reserves, typically in the Middle East. Transport distance to Europe is between 5 and 6000 Nm. The assume ship is a 50kt liquid carrier as per process T3c.

11.5.2.5 NMD4a Methanol/DME distribution

A mixture of rail and road is assumed for a total distance of 500 km.

11.5.2.6 NM6 Methanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.5.3 Wood to methanol, waste wood, farmed wood, and waste wood via black liquor gasification/synthesis plant (WxME1/BLME1)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation**							
	Agricultural inputs							
	Fertilizers		g/MJ_{wood}					
	N (as N)	*FN*		0.00				JRC internal
	Pesticides	*PE*	g/MJ_{wood}	0.015				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{wood}	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.0000161				
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.0000397				
	N_2O field emissions		g/MJ_{wood}	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	*F1*	MJ/MJ_{wood}	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindholm 2010]
W2	**Forestry residue chipping**							
	Diesel	*F1*	MJ/MJ_{wood}	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3b	**Farmed wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
WF3c	**Farmed wood transport (regional, >500 km)**							JRC internal
WF3c1	Road truck	*T1*						
	Distance		km	250				
WF3c2	Bulk carrier (Handysize)	*T3h*						
	Distance		km	2000				
WW3b	**Waste wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
WW3c	**Waste wood transport (regional, >500 km)**							JRC internal
WW3c1	Road truck	*T1*						
	Distance		km	250				
WW3c2	Bulk carrier (Handysize)	*T3h*						
	Distance		km	2000				
RW1	**Roundwood transport (BLxx1)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
	Transformation near market							
WSD1	**Wood to syndiesel plant**							[Tijmensen et al. 2002]
	Efficiency			48.2%	46.1%	50.8%	2-triangle	
	NaOH	*C6*	g/MJ_{SD}	0.00880				[Hamelinck 2004]
	Dolomite	*C17*	g/MJ_{SD}	5.0511				[Hamelinck 2004]
WSD1C	**Wood to syndiesel plant with CCS**							
	Efficiency			45.1%				[Kreutz et al. 2008]
	Electricity surplus		MJ/MJ_{SD}	-0.0827				[Kreutz et al. 2008]
	NaOH	*C6*	g/MJ_{SD}	0.00940				[Hamelinck 2004]
	Dolomite	*C17*	g/MJ_{SD}	5.3985				[Hamelinck 2004]
	CO_2 emissions		g/MJ_{SD}	-115.17				
WMD	**Wood to Methanol/DME plant**							[Katofsky 1993]
	Efficiency			51.1%	46.1%	57.2%	Square	[Atrax 1999]
WSD2	**Forestry residue to syndiesel via black liquor**							[Berglin et al. 1999]; [Landälv 2007]
	Efficiency (related to roundwood input)			27.1%				
	Additional wood chips		MJ/MJ_{SD}	0.9559				[Ekbom et al. 2005]
	Pulp output		g/MJ_{SD}	94.79				[Ekbom et al. 2005]
WSD2C	**Forestry residue to syndiesel via black liquor with CCS**							
	Efficiency (related to roundwood input)			27.1%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		MJ/MJ_{SD}	1.0584				[Ekbom et al. 2005]
	Pulp output		g/MJ_{SD}	94.79				[Berglin 2006], [Ekbom et al. 2005]; [Pettersson 2011]
	CO_2 emissions		g/MJ_{SD}	-99.61				[Berglin 2006], [Ekbom et al. 2005]; [Pettersson 2011]
WM1	**Forestry residue to methanol via black liquor**							
	Efficiency (related to roundwood input)			30.2%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		MJ/$MJ_{methanol}$	0.9856				[Ekbom et al. 2005]
	Pulp output		g/$MJ_{methanol}$	84.89				[Ekbom et al. 2005]
WD1	**Residual wood to DME via black liquor**							
	Efficiency (related to roundwood input)			30.5%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		MJ/MJ_{DME}	0.9566				[Ekbom et al. 2005]
	Pulp output		g/MJ_{DME}	84.25				[Ekbom et al. 2005]
	Credit for pulp based on puld from pulp mill without black liquor gasification							

	Conditioning & Distribution						
SD4b	**Syndiesel distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{SD}$	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	*T1*					
	Distance		km	150			
LF3	**Diesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{SD}$	0.0008			
NM4b	**Methanol distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
NM2	**Methanol depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Meth}$	0.0018			
ND4b	**DME distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	20/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
ND2	**DME depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{SD}$	0.0013			
NM5/ND6	**Local methanol/DME distribution**						
	Road truck	*T1*					
	Distance		km	150			
	Payload / tank mass		t/t				
	Methanol			26/28			
	DME		t/t	20/28			
NM6	**Methanol dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Meth}$	0.0034			
ND6	**DME dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Meth}$	0.0034			

11.5.3.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

11.5.3.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

11.5.3.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

11.5.3.4 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Guintoli et al. 2017].

11.5.3.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

11.5.3.6 WF3b Farmed wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.5.3.7 WF3c Farmed wood transport (regional, >500 km)

A transport distance of 250 km via truck plus a transport distance of 2000 km has been assumed if the wood chips are imported from regions outside the EU e.g. Russia or Ukraine.

11.5.3.8 WW3b Waste wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.5.3.9 WW3c Waste wood transport (regional, >500 km)

A transport distance of 250 km via truck plus a transport distance of 2000 km has been assumed if the wood chips are imported from regions outside the EU e.g. Russia or Ukraine.

11.5.3.10 WMD Wood to Methanol plant

"Our “best-case” process is based on [Katofsky 1993], using the BCL indirectly-heated gasifier with wet gas cleaning and reforming of higher hydrocarbons. The rest of the process is similar to methanol synthesis from natural gas. A conventional, fixed bed methanol reactor is used. With all fuel synthesis routes, it might be possible to improve efficiency by using slurry reactors or hot gas cleaning. However, neither has been demonstrated for synthesis from bio-syngas: there are question marks about gas quality [Tijmensen 2002]. Furthermore, the use of conventional processes enables us to compare all routes on a fair basis.

Our “worst case” is based on oxygen-blowing the Värnamo autothermal pressurized fluidized bed gasifier, modelled by [Atrax 1999]. Although this is a state-of-the art gasifier, it is not as sophisticated and expensive as the BCL gasifier. The process uses the hot gas filtration demonstrated at Värnamo to allow the gas to go hot into the 950°C steam reformer, where some tar is also decomposed. However, after the shift water-gas shift reactor (to boost the H2/CO ratio), it is still necessary to use a scrubbing process to remove impurities (including HCl, H2S…) before the gas is pure enough for synthesis. In the Altrax process the purification is combined with CO2 removal by scrubbing with methanol (Rectisol Process).

11.5.3.11 WM1 Waste wood to methanol via black liquor

A pulp mill consumes 2.05 kg per dry t of pulp. Alternatively, some or all of the black liquor can be gasified instead of burnt in the recovery boiler. Various fuels: methanol, DME or Fischer-Tropsch products mix (naphtha, kerosene, diesel) can be made from the gas. Here we use data on the CHEMREC oxygen-blown black liquor gasification process. Some 11.78 GJ of methanol or 11.87 GJ can be generated per t of pulp [Berglin, N. et al. 1999], [Landälv 2007].

In a conventional pulp mill the black liquor is used for heat and electricity supply. So extra biomass in the form of forest residuals is required to make the plant self-sufficient in heat and electricity. Based on data in [Ekbom et al. 2005] about 6.05 GJ of extra forest residues per t of dry pulp are required for electricity supply and about 5.56 GJ of extra forest residues are required per t of dry pulp are required for heat supply in case of methanol. In case of DME about 5.98 GJ of extra forest residues per t of dry pulp are required for electricity supply and about 5.38 GJ of extra forest residues are required per t of dry pulp are required for heat supply.

For the calculation a pulp mill with black liquor gasification has been modelled which generates methanol and pulp or DME and pulp. The pulp is exported and replaces pulp from a conventional pulp mill with black liquor boiler leading to a net increment input of wood. The inputs of the pulp mill are round wood and extra forest residues as wood chips.

11.5.3.12 NM4b/ND4b Methanol/DME distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived methanol.

11.5.3.13 NM5 Local methanol distribution

From the depot the final fuel is transported via truck over a distance of 150 km (one way).

11.5.3.14 NM6 Methanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.5.4 Renewable electricity to methanol

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WD1	**Wind turbine**							[GEMIS 2000]
	No expended energy or emissions							
	Transformation at source							
	NA							
	Transportation to market							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
	NA							
	Transformation near market							
YH1	**Hydrogen via electrolysis (large plant)**							JEC internal
	Electricity (wind)		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
CA1	**CO_2 absorption (from flue gases)**							[Socolow 2011]
	Electricity (wind)		MJ/kg_{CO2}	0.0334				
	Heat		MJ/kg_{CO2}	4.2998				
HM1	**Methanol synthesis from hydrogen and CO_2**							[Van-Dal & Bouallou 2013]
	CO_2		$kg/MJ_{methanol}$	0.0745				
	Electricity (wind)		$MJ/MJ_{methanol}$	0.0539				
	Hydrogen		$MJ/MJ_{methanol}$	1.2281				
	Surplus heat		$MJ/MJ_{methanol}$	0.0863				
	Conditioning & Distribution							
WM2	**Methanol distribution (long distance)**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Payload / tank mass							
	Syndiesel/methanol		t/t	26/28				
	Sea-going product tanker (31.6%)	*T3h*						
	Distance		km	1118				
	Inland/Coastal tanker (50.8%)	*T3a*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Road truck	*T1*						
	Distance		km	150				
LF3	**Diesel dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0008				

11.5.4.1 WD1 Wind turbine

Electricity from wind turbine is energy and emission - free (as we do not consider energy and emissions related to construction and maintenance).

11.5.4.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.5.4.3 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.5.4.4 YH1 Hydrogen via electrolysis (large plant)

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPag electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].

- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].
- McPhy indicates an electricity consumption of 4.5 kWh/Nm^3 at nominal flow rate for its 800 Nm^3/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPag [McPhy 2017].

Several sources of data are available, giving figures for bote and large PEM electrolyzers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depends on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPag [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh$_e$/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 63% (4.8 to 5.4 kWh$_e$/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

11.5.4.5 CA1 CO2 absorption (from flue gases)

CO2 is assumed to available from the flue gases of e.g. a power station. It is extracted from the flue gas stream via scrubbing with monoethanolamine (MEA). The regeneration of the scrubbing agent is carried out to a large extent with the heat from the methanation process.

11.5.4.6 HM1 Methanol synthesis from hydrogen and CO2

Hydrogen reacts with CO_2 to form methanol according to the reaction:

$3 H_2 + CO_2 \Rightarrow CH_3OH + H_2O$

The reaction is exothermic.

11.5.4.7 WM2 Methanol distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived methanol.

11.5.4.8 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.5.4.9 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.5.4.10LF3 Methanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

11.6 DME

11.6.1 Piped natural gas (4000 km) to DME, synthesis plant in EU (GPDE1b)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.08				
	Transformation at source							
	NA							
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ_{fuel}	0.0084				
	N_2O emissions		g/MJ_{fuel}	0.0026				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				[Thinkstep 2017]
	Compression specific energy		MJ/t.km	0.360	0.120	0.400	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.1398				[GEMIS 2016]
GG2/07	**NG pipeline transport inside EU**							
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				[GEMIS 2016]
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				[GEMIS 2016]
	GPCG1a (Russia)							
	Distance		km	700				
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.0009				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ_{NG}	0.1057				[Wuppertal 2004]
	Transformation near market							
NM1	**NG to methanol plant**							[Larsen 1998]
	Efficiency			68.3%	67.3%	69.4%	Square	
	CH_4 emissions		g/MJ_{Meth}	0.0001				
ND1	**NG to DME plant**							[Hansen 2001]
	Efficiency			71.3%	69.9%	72.7%	Square	
	Electricity	*GGe*	MJ/MJ_{DME}	0.0043	0.4%	0.4%	Square	
	Heat surplus		MJ/MJ_{DME}	-0.0022				
	CH_4 emissions		g/MJ_{DME}	0.0035				
	Credit for heat surplus based on alternative generation with NG @ 90% efficiency							
	Conditioning & Distribution							
NMD4a	**Methanol/DME distribution**							
	Rail	*T2*						
	Distance		km	250				
	Road truck	*T1*						
	Distance		km	250				
	Payload / tank mass		t/t					
	Methanol			26/28				
	DME			20/28				
NM6	**Methanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034				
ND6	**DME dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034				

11.6.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO_2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

11.6.1.2 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

11.6.1.3 ND1 NG to DME plant

There is limited data available on DME and there are no full-scale commercial plants on the ground at the moment. The data used here is from Haldor Topsoe, the main proponent of DME. This process is applicable to both a remote plant and a large “central” plant located in Europe. In both cases electricity is deemed to be produced by a dedicated gas-fired power plant (CCGT, see process GG2).

11.6.1.4 NMD4a Methanol/DME distribution

A mixture of rail and road is assumed for a total distance of 500 km.

11.6.1.5 NM6 Methanol dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.6.1.6 ND6 DME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.6.2 Remote natural gas to DME, synthesis plant near gas field, with CCS (GRDE1/1C)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ$_{NG}$	0.08				
	Transformation at source							
NM1	**NG to methanol plant**							[Larsen 1998]
	Efficiency			68.3%	67.3%	69.4%	Square	
	CH_4 emissions		g/MJ$_{Meth}$	0.0001				
NM2	**Methanol depot**							[TOTAL 2002]
	Electricity	*GGe*	MJ/MJ$_{SD}$	0.0018				
ND1	**NG to DME plant**							[Hansen 2001]
	Efficiency			71.3%	69.9%	72.7%	Square	
	Electricity	*GGe*	MJ/MJ$_{DME}$	0.0043	0.4%	0.4%	Square	
	Heat surplus		MJ/MJ$_{DME}$	-0.0022				
	CH_4 emissions		g/MJ$_{DME}$	0.0035				
	Credit for heat surplus based on alternative generation with NG @ 90% efficiency							
ND1C	**NG to DME plant with CCS**							[IEA 2005]
	Efficiency		%	70.2%	68.9%	71.4%	Square	
	Electricity surplus	*GE1C*	MJ/MJ$_{DME}$	-0.0022	0.0%	0.0%		
	CO_2 emissions		g/MJ$_{DME}$	0.58				
	Credit for electricity surplus based on alternative generation in a state-of-the-art CCGT with CCS							
ND2	**DME depot**							[TOTAL 2002]
	Electricity	*GGe*	MJ/MJ$_{SD}$	0.0013				
	Transportation to market							
NM3	**Methanol long-distance sea transport**							
	50 kt liquid carrier	*T3c*						
	Distance		Nautical miles	5500	5000	6000	Square	
NM2	**Methanol depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Meth}$	0.0018				
ND3	**DME long-distance sea transport**							
	84 km^3 LPG carrier	*T3q*						
	Distance		Nautical miles	5500				
ND2	**DME depot**							[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ$_{SD}$	0.0013				
	Transformation near market							
	NA							
	Conditioning & Distribution							
NMD4a	**Methanol/DME distribution**							
	Rail	*T2*						
	Distance		km	250				
	Road truck	*T1*						
	Distance		km	250				
	Payload / tank mass		t/t					
	Methanol			26/28				
	DME			20/28				
NM6	**Methanol dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Meth}$	0.0034				
ND6	**DME dispensing at retail site**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Meth}$	0.0034				

11.6.2.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO_2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

11.6.2.2 ND1 NG to DME plant

There is limited data available on DME and there are no full-scale commercial plants on the ground at the moment. The data used here is from Haldor Topsoe, the main proponent of DME. This process is applicable to both a remote plant and a large “central” plant located in Europe. In both cases electricity is deemed to be produced by a dedicated gas-fired power plant (CCGT, see process GG2).

11.6.2.3 ND1C NG to DME plant with CCS

This is a rough estimate of the impact of applying CCS in the DME plant. There is, however, no literature source providing a direct comparison of two consistent plant configurations.

11.6.2.4 ND2 DME depot

A small amount of electricity is required for the operation of loading and unloading depot and terminal facilities. The figure used for gasoline/diesel has been prorated to remain the same per tonne of product.

11.6.2.5 ND3 DME long-distance sea transport

Large remote methanol plants are likely to be built near large gas reserves, typically in the Middle East. Transport distance to Europe is between 5 and 6000 Nm. The assume ship is an 84km3 LPG carrier as per process T3g.

11.6.2.6 NMD4a Methanol/DME distribution

A mixture of rail and road is assumed for a total distance of 500 km.

11.6.2.7 ND6 DME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.6.3 Wood to DME, waste wood, farmed wood, and waste wood via black liquor in gasification/synthesis plant (WxDE1/BLDE1)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{wood}$					
	N (as N)	FN		0.00				JRC internal
	Pesticides	PE	g/MJ$_{wood}$	0.015				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ$_{wood}$	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000161				
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000397				
	N_2O field emissions		g/MJ$_{wood}$	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	F1	MJ/MJ$_{wood}$	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindholm 2010]
W2	**Forestry residue chipping**							
	Diesel	F1	MJ/MJ$_{wood}$	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3b	**Farmed wood transport (regional, 500 km)**							JRC internal
	Road truck	T1						
	Distance		km	500				
WF3c	**Farmed wood transport (regional, >500 km)**							JRC internal
WF3c1	Road truck	T1						
	Distance		km	250				
WF3c2	Bulk carrier (Handysize)	T3h						
	Distance		km	2000				
WW3b	**Waste wood transport (regional, 500 km)**							JRC internal
	Road truck	T1						
	Distance		km	500				
WW3c	**Waste wood transport (regional, >500 km)**							JRC internal
WW3c1	Road truck	T1						
	Distance		km	250				
WW3c2	Bulk carrier (Handysize)	T3h						
	Distance		km	2000				
RW1	**Roundwood transport (BLxx1)**							JRC internal
	Road truck	T1						
	Distance		km	500				
	Transformation near market							
WSD1	**Wood to syndiesel plant**							[Tijmensen et al. 2002]
	Efficiency			48.2%	46.1%	50.8%	2-triangle	
	NaOH	C6	g/MJ$_{SD}$	0.00880				[Hamelinck 2004]
	Dolomite	C17	g/MJ$_{SD}$	5.0511				[Hamelinck 2004]
WSD1C	**Wood to syndiesel plant with CCS**							
	Efficiency			45.1%				[Kreutz et al. 2008]
	Electricity surplus		MJ/MJ$_{SD}$	-0.0827				[Kreutz et al. 2008]
	NaOH	C6	g/MJ$_{SD}$	0.00940				[Hamelinck 2004]
	Dolomite	C17	g/MJ$_{SD}$	5.3985				[Hamelinck 2004]
	CO_2 emissions		g/MJ$_{SD}$	-115.17				
WMD	**Wood to Methanol/DME plant**							[Katofsky 1993]
	Efficiency			51.1%	46.1%	57.2%	Square	[Atrax 1999]
WSD2	**Forestry residue to syndiesel via black liquor**							[Berglin et al. 1999]; [Landälv 2007]
	Efficiency (related to roundwood input)			27.1%				
	Additional wood chips		MJ/MJ$_{SD}$	0.9559				[Ekbom et al. 2005]
	Pulp output		g/MJ$_{SD}$	94.79				[Ekbom et al. 2005]
WSD2C	**Forestry residue to syndiesel via black liquor with CCS**							
	Efficiency (related to roundwood input)			27.1%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		MJ/MJ$_{SD}$	1.0584				[Ekbom et al. 2005]
	Pulp output		g/MJ$_{SD}$	94.79				[Berglin 2006], [Ekbom et al. 2005]; [Pettersson 2011]
	CO_2 emissions		g/MJ$_{SD}$	-99.61				[Berglin 2006], [Ekbom et al. 2005]; [Pettersson 2011]
WM1	**Forestry residue to methanol via black liquor**							
	Efficiency (related to roundwood input)			30.2%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		MJ/MJ$_{methanol}$	0.9856				[Ekbom et al. 2005]
	Pulp output		g/MJ$_{methanol}$	84.89				[Ekbom et al. 2005]
WD1	**Residual wood to DME via black liquor**							
	Efficiency (related to roundwood input)			30.5%				[Berglin et al. 1999]; [Landälv 2007]
	Additional wood chips		MJ/MJ$_{DME}$	0.9566				[Ekbom et al. 2005]
	Pulp output		g/MJ$_{DME}$	84.25				[Ekbom et al. 2005]
	Credit for pulp based on puld from pulp mill without black liquor gasification							

	Conditioning & Distribution						
SD4b	**Syndiesel distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
LF1	**Liquid fuel depot**						[TOTAL 2002]
	Electricity (EU-mix, MV)	*EMLa*	MJ/MJ_{SD}	0.00084			
LF2	**Liquid fuel local distribution**						[TOTAL 2002]
	Road truck	*T1*					
	Distance		km	150			
LF3	**Diesel dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0008			
NM4b	**Methanol distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	26/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
NM2	**Methanol depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0018			
ND4b	**DME distribution (long distance)**						JRC internal
	Road truck (13.2%)	*T1*					
	Distance		km	305			
	Payload / tank mass						
	Syndiesel/methanol		t/t	20/28			
	Sea-going product tanker (31.6%)	*T3h*					
	Distance		km	1118			
	Inland/Coastal tanker (50.8%)	*T3a*					
	Distance		km	153			
	Rail (4.4%)	*T2*					
	Distance		km	381			
ND2	**DME depot**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0013			
NM5/ND6	**Local methanol/DME distribution**						
	Road truck	*T1*					
	Distance		km	150			
	Payload / tank mass		t/t				
	Methanol			26/28			
	DME		t/t	20/28			
NM6	**Methanol dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034			
ND6	**DME dispensing at retail site**						[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{Meth}	0.0034			

11.6.3.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

11.6.3.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

11.6.3.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

11.6.3.4 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Guintoli et al. 2017].

11.6.3.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

11.6.3.6 WF3b Farmed wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.6.3.7 WF3c Farmed wood transport (regional, >500 km)

A transport distance of 250 km via truck plus a transport distance of 2000 km has been assumed if the wood chips are imported from regions outside the EU e.g. Russia or Ukraine.

11.6.3.8 WW3b Waste wood transport (regional, 500 km)

A transport distance of up to 500 km is assumed if the wood chips are derived from regions inside the EU.

11.6.3.9 WW3cWaste wood transport (regional, >500 km)

A transport distance of 250 km via truck plus a transport distance of 2000 km has been assumed if the wood chips are imported from regions outside the EU e.g. Russia or Ukraine. WMD Wood to DME plant

Our “best-case” process is based on [Katofsky 1993], using the BCL indirectly-heated gasifier with wet gas cleaning and reforming of higher hydrocarbons. The rest of the process is similar to methanol synthesis from natural gas. A conventional, fixed bed methanol reactor is used. With all fuel synthesis routes, it might be possible to improve efficiency by using slurry reactors or hot gas cleaning. However, neither has been demonstrated for synthesis from bio-syngas: there are question marks about gas quality [Tijmensen 2002]. Furthermore, the use of conventional processes enables us to compare all routes on a fair basis.

Our “worst case” is based on oxygen-blowing the Värnamo autothermal pressurized fluidized bed gasifier, modelled by [Atrax 1999]. Although this is a state-of-the art gasifier, it is not as sophisticated and expensive as the BCL gasifier. The process uses the hot gas filtration demonstrated at Värnamo to allow the gas to go hot into the 950°C steam reformer, where some tar is also decomposed. However, after the shift water-gas shift reactor (to boost the H2/CO ratio), it is still necessary to use a scrubbing process to remove impurities (including HCl, H2S…) before the gas is pure enough for synthesis. In the Altrax process the purification is combined with CO2 removal by scrubbing with methanol (Rectisol Process).

DME can be thought of as dehydrated methanol: the only difference between the synthesis processes is in the final catalyst reactor so that the efficiencies are more or less the same. The DME synthesis process (by Haldor Topsoe A/S) is similar to that in the 200 MW plant. The efficiency is lower than the BCL-gasifier process because of the energy consumption by the oxygen separation plant, and because the H2/CO ratio in the raw syngas is lower.

11.6.3.10WM1/WD1 Waste wood to methanol/DME via black liquor

A pulp mill consumes 2.05 kg per dry t of pulp. Alternatively, some or all of the black liquor can be gasified instead of burnt in the recovery boiler. Various fuels: methanol, DME or Fischer-Tropsch products mix (naphtha, kerosene, diesel) can be made from the gas. Here we use data on the CHEMREC oxygen-blown black liquor gasification process. Some 11.78 GJ of methanol or 11.87 GJ can be generated per t of pulp [Berglin, N. et al. 1999], [Landälv 2007].

In a conventional pulp mill the black liquor is used for heat and electricity supply. So extra biomass in the form of forest residuals is required to make the plant self-sufficient in heat and electricity. Based on data in [Ekbom et al. 2005] about 6.05 GJ of extra forest residues per t of dry pulp are required for electricity supply and about 5.56 GJ of extra forest residues are required per t of dry pulp are required for heat supply in case of methanol. In case of DME about 5.98 GJ of extra forest residues per t of dry pulp are required for electricity supply and about 5.38 GJ of extra forest residues are required per t of dry pulp are required for heat supply.

For the calculation a pulp mill with black liquor gasification has been modelled which generates methanol and pulp or DME and pulp. The pulp is exported and replaces pulp from a conventional pulp mill with black liquor boiler leading to a net increment input of wood. The inputs of the pulp mill are round wood and extra forest residues as wood chips.

11.6.3.11ND4b DME distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived methanol and DME.

11.6.3.12NM5/ND6 Methanol/DME distribution

From the depot the final fuel is transported via truck over a distance of 150 km (one way).

11.6.3.13ND6 DME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc. The figure is considered to be independent of the fuel energy density hence the same figure on energy basis is used for all fuels.

11.6.4 Renewable electricity to DME

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WD1	**Wind turbine**							[GEMIS 2000]
	No expended energy or emissions							
	Transformation at source							
	NA							
	Transportation to market							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
	NA							
	Transformation near market							
YH1	**Hydrogen via electrolysis (large plant)**							JEC internal
	Electricity (wind)		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
CA1	**CO_2 absorption (from flue gases)**							[Socolow 2011]
	Electricity (wind)		MJ/kg_{CO2}	0.0334				
	Heat		MJ/kg_{CO2}	4.2998				
HM1	**Methanol synthesis from hydrogen and CO_2**							[Van-Dal & Bouallou 2013]
	CO_2		$kg/MJ_{methanol}$	0.0745				
	Electricity (wind)		$MJ/MJ_{methanol}$	0.0539				
	Hydrogen		$MJ/MJ_{methanol}$	1.2281				
	Surplus heat		$MJ/MJ_{methanol}$	0.0863				
MD1	**Methanol to DME**							LBST internal
	Methanol		MJ/MJ_{DME}	1.0264				
	Steam		MJ/MJ_{DME}	1.0264				
	Conditioning & Distribution							
WD2	**DME distribution (long distance)**							JRC internal
	Road truck (13.2%)	*T1*						
	Distance		km	305				
	Payload / tank mass							
	DME		t/t	20/28				
	Sea-going LPG carrier 22 km3 (31.6%)	*T3k*						
	Distance		km	1118				
	Inland/Coastal LPG carrier 2000 m³ (50.8%)	*T3l*						
	Distance		km	153				
	Rail (4.4%)	*T2*						
	Distance		km	381				
WD3	**DME depot**							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0013				
WD4	**DME local distribution**							
	Road truck	*T1*						
	Distance		km	150				
WD5	**DME dispensing at retail site**							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{SD}	0.0034				

11.6.4.1 WD1 Wind turbine

Electricity from wind turbine is energy and emission-free (as we do not consider energy and emissions related to construction and maintenance).

11.6.4.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.6.4.3 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is discussed in section 3.4 of the WTT report.

11.6.4.4 YH1 Hydrogen via electrolysis (large plant)

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPa_g electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].

- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].
- McPhy indicates an electricity consumption of 4.5 kWh/Nm^3 at nominal flow rate for its 800 Nm^3/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPag [McPhy 2017].

Several sources of data are available, giving figures for both small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depends on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPa$_g$ [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh$_e$/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 63% (4.8 to 5.4 kWh$_e$/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

11.6.4.5 CA1 CO2 absorption (from flue gases)

CO_2 is assumed to available from the flue gases of e.g. a power station. It is extracted from the flue gas stream via scrubbing with monoethanolamine (MEA). The regeneration of the scrubbing agent is carried out to a large extent with the heat from the methanation process.

11.6.4.6 HM1 Methanol synthesis from hydrogen and CO_2

Hydrogen reacts with CO_2 to form methanol according to the reaction:

$3\ H_2 + CO_2 \Rightarrow CH_3OH + H_2O$

The reaction is exothermic.

11.6.4.7 MD1 Methanol to DME

"Methanol reacts to DME:

$2\ CH_3OH \Rightarrow CH_3OCH_3 + H_2O$

The conversion efficiency has assumed to be 95%

11.6.4.8 WD2 DME distribution (long distance)

Analogous to the pathways for the recast of the EU Renewable Energy Directive (RED II pathways) the transport to the depot is carried out via a mix of road, maritime ship, inland ship, and rail for biomass derived methanol and DME.

11.6.4.9 WD3 DME depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

11.6.4.10 WD4 DME local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

11.6.4.11 WD5 DME dispensing at retail site

Dispensing at retail stations requires energy, essentially as electricity, for lighting, pumping etc.

12 Electricity

12.1 EU-mix

12.1.1 EU-mix electricity (High, Medium and Low voltage) 2016 mix (a) and 2030 mix (b) (EMEL)

Process code	Step	Common processes	Input		Range	Distribution	Source
	Production & conditioning at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
	NA						
	Transformation near market						
EMa	**Mixed supply 2016**						[JRC 2017], [EEA 2018]
	Hard coal (primary)		MJ/MJ_e	0.3685			
	Brown coal (source)		MJ/MJ_e	0.2329			
	Crude oil (primary)		MJ/MJ_e	0.0652			
	NG (primary)		MJ/MJ_e	0.4433			
	Hydropower		MJ/MJ_e	0.1073			
	Nuclear		MJ/MJ_e	1.0857			
	Biomass (primary)		MJ/MJ_e	0.2449			
	Peat		MJ/MJ_e	0.0155			
	Geothermal		MJ/MJ_e	0.0199			
	Solar		MJ/MJ_e	0.0348			
	Wind		MJ/MJ_e	0.0928			
	Waste		MJ/MJ_e	0.0473			
	Total		MJ/MJ_e	2.7581			
	CO_2 emissions		g/MJ_e	102.59			
	CH_4 emissions		g/MJ_e	0.0000			
	N_2O emissions		g/MJ_e	0.0000			
EMb	**Mixed supply 2030**						[JRC 2017]
	Hard coal (primary)		MJ/MJ_e	0.1882			
	Brown coal (source)		MJ/MJ_e	0.1078			
	Crude oil (primary)		MJ/MJ_e	0.0135			
	NG (primary)		MJ/MJ_e	0.4497			
	Hydropower		MJ/MJ_e	0.1239			
	Nuclear		MJ/MJ_e	0.8454			
	Biomass (primary)		MJ/MJ_e	0.0956			
	Peat		MJ/MJ_e	0.0067			
	Geothermal		MJ/MJ_e	0.0436			
	Solar		MJ/MJ_e	0.0514			
	Wind		MJ/MJ_e	0.2073			
	Waste		MJ/MJ_e	0.0430			
	Total		MJ/MJ_e	2.1761			
	CO_2 emissions		g/MJ_e	68.73			
	CH_4 emissions		g/MJ_e	0.0000			
	N_2O emissions		g/MJ_e	0.0000			
	Conditioning & Distribution						
EDH	**Electricity distribution HV**						[JRC 2017]
	Losses			2.6%			
EDM	**Electricity distribution MV**						[JRC 2017]
	Losses			0.9%			
EDL	**Electricity distribution LV**						[JRC 2017]
	Losses			3.4%			

12.1.1.1 EMa Mixed supply 2016

A description of the estimation of the EU-mix electricity supply is included section 3.4.2 of the WTT report with reference to [JRC 2018] and [EEA 2018]. Upstream GHG emissions for the supply of fuels for electricity generation have been taken into account. The GHG emissions includes non-$_{CO2}$ greenhouse gases such as CH4 and N2O.

12.1.1.2 EMb Mixed supply 2030

A description of the estimation of the EU-mix electricity supply is included section 3.4.4 of the WTT report with reference to [JRC 2018]. The electricity mix 2030 based on IEA scenarios. Upstream GHG emissions for the supply of fuels for electricity generation have been taken into account. The GHG emissions includes non-CO_2 greenhouse gases such as CH4 and N2O.

12.1.1.3 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

12.1.1.4 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

12.1.1.5 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

12.2 HFO

12.2.1 Electricity from heavy fuel oil (HFO) (FOEL)

Conventional power plant (state-of-the-art)

Process code	*Step*	*Common processes*	*Input*		*Range*	*Distribution*	*Source*
	Production & conditioning at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
	NA						
	Transformation near market						
	HFO provision						
	Efficiency	F2					
FO1	**Conventional HFO power plant (state-of-the-art)**						[GEMIS 2011]
	Efficiency			41.5%			
	CH_4 emissions		g/MJ$_e$	0.0084			
	N_2O emissions		g/MJ$_e$	0.0063			
	Conditioning & Distribution						
EDH	**Electricity distribution HV**						[JRC 2017]
	Losses		%	2.6%			
EDM	**Electricity distribution MV**						[JRC 2017]
	Losses		%	0.9%			
EDL	**Electricity distribution LV**						[JRC 2017]
	Losses		%	3.4%			

12.2.1.1 FO1 Conventional HFO power plant (state-of-the-art)

This represents a modern conventional power plant (boiler/condensing steam turbine configuration) burning high sulphur heavy fuel oil (HFO) and equipped with flue gas desulphurisation. HFO provision is according to generic process F2.

12.2.1.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.2.1.3 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.2.1.4 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.3 Hard coal

12.3.1 Hard coal in conventional power plant or IGCC (with/without CCS) (KOEL)

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
KO1	**Hard coal provision**							[El Cerrejon 2002], [DOE 2002], [Eurostat 2001], [GEMIS 2002], [IDEAM 2001], [IEA 2000]
	Hard coal (primary)		MJ/MJ_{coal}	1.0266				
	Brown coal (primary)		MJ/MJ_{coal}	0.0016				
	Crude oil		MJ/MJ_{coal}	0.0375				
	Natural gas (primary)		MJ/MJ_{coal}	0.0100				
	Hydro power		MJ/MJ_{coal}	0.0010				
	Nuclear		MJ/MJ_{coal}	0.0109				
	Waste		MJ/MJ_{coal}	0.0018				
	CO_2 emissions		g/MJ_{coal}	6.27				
	CH_4 emissions		g/MJ_{coal}	0.3852				
	N_2O emissions		g/MJ_{coal}	0.0003				
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
KE2.1	**State-of-the-art conventional coal power plant**							[Dienhart 1999]
	Efficiency			43.5%	40.0%	50.0%	2-triangle	
	CO_2 emissions		g/MJ_e	220.62				
	CH_4 emissions		g/MJ_e	0.0041				
	N_2O emissions		g/MJ_e	0.0114				
KE2.2	**IGCC**							[Dienhart 1999]
	Efficiency			48.0%	45.0%	51.5%	Square	
	CO_2 emissions		g/MJ_e	199.94				
	CH_4 emissions		g/MJ_e	0.0088				
	N_2O emissions		g/MJ_e	0.0021				
KE2.2C	**IGCC with CCS**							[ENEA 2004]
	Efficiency			41.0%	38.3%	44.1%	Square	
	CO_2 emissions		g/MJ_e	23.33				
	CH_4 emissions		g/MJ_e	0.0102				
	N_2O emissions		g/MJ_e	0.0024				
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses		%	3.4%				

12.3.1.1 KO1 Hard coal provision

These figures approximate the average primary energy associated to the production and provision of hard coal to Europe.

12.3.1.2 KE2.1 State-of-the-art conventional coal power plant

This represents a modern boiler/ condensing turbine configuration. The efficiency of 43.5% is assumed to be achievable over the life time of the plant (45% for a new plant).

12.3.1.3 KE2.2 IGCC

In the IGCC process (Integrated Gasification Combined Cycle), the coal feed is gasified and the syngas burnt in a gas turbine. Electricity is generated directly by the gas turbine while steam raised from the flue gases generates extra electricity through condensing steam turbines. Overall the process is more efficient than conventional schemes.

Several coal-fired IGCC power plants are operated since more than 10 years. A pilot coal and petroleum coke fired IGCC power plant has been built in 1998 in Puertollano in Spain with a capacity of 335 MW_e [García-Peña 2011], another one in Japan (Nakoso IGCC plant: 250 MW_e) [Mills 2012]. Commercial coal fired IGCC power plants exist e.g. in Indiana in the USA (Edwardsport: 618 MW_e) and in Florida in the USA (Polk IGCC Power Station: 250 MW_e). The technology readiness level (TRL) can be assumed to be 9. The Polk IGCC power station project has been awarded by the U.S. Department of Energy (DOE). Other IGCC power plant projects also have been granted. Therefore, the commercial readiness level (CRL) has been assumed to be 5 [TECO 2018].

12.3.1.4 KE2.2C IGCC with CCS

The IGCC process is well suited to CO_2 capture: syngas is 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 reference used here is from a pre-feasibility study. There is no commercial-scale plant in operation.

2010 to 2011, experiments with CO_2 capture have been carried out at the IGCC power plant in Puertollano in Spain [García-Peña 2011]. For CO_2 capture a CO shift reactor has been installed to convert CO to CO_2 and H2 and a CO_2 scrubber using aMDEA. For the production of pure hydrogen e.g. for hydrogen fueled FCEV vehicles a pressure swing adsorption PSA) plant has been installed. A part of the hydrogen rich gas stream is sent to the gas turbine, the other part to the PSA plant. Another pilot plant with a capacity of 524 MW_e has been built at Kemper County, Mississippi in the USA. The whole gasification and CO_2 capture process was successfully tested in 2016. 65% of the CO_2 is captured. However, the plant has been shut down in 2017 due to low natural gas prices and problems with the gasifier [Lockwood 2017]. About US$ 7.5 billion have been invested in the Kemper IGCC power plant [Swartz 2017]. Now, natural gas is used as fuel for the gas turbines.

12.3.1.5 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.3.1.6 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.3.1.7 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.4 Natural Gas

12.4.1 Electricity from imported natural gas (7000 and 4000 km) and LNG in state-of-the-art CCGT (GxEL)

Natural gas: CCGT

GPEL1: 4300 km to EU border and 700 km inside EU (Russia) (a), 4000 km pipeline (Middle East) (b), with CCS (bC)

GREL1: LNG

Process code	*Step*	*Common processes*	*Input*		*Range*		*Distribution*	*Source*
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0200	0.0200	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.0798				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ_{LNG}	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ_{LNG}	0.0113				[FfE 1996]
	CH_4 emissions		g/MJ_{LNG}	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ_{LNG}	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ_{LNG}	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency			58%	57%	59%		[GEMIS 2011]
	CH_4 emissions		g/MJ_{elec}	0.0054				
	N_2O emissions		g/MJ_{elec}	0.0043				
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ_{fuel}	0.0278				
	N_2O emissions		g/MJ_{fuel}	0.0085				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.1398				[GEMIS 2016]
GG2/07	Additional NG trunk distribution for NG import from Russia							
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				[GEMIS 2016]
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				[GEMIS 2016]
	Distance		km	700				
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.0009				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ_{NG}	0.1057				[Wuppertal 2004]
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ_{LNG}	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ_{LNG}	0.0222				[Mitsubishi 2000]
	CH_4 emissions		g/MJ_{LNG}	0.000131				[GEMIS 2001]
	N_2O emissions		g/MJ_{LNG}	0.000094				[GEMIS 2001]
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	EMMa	MJ/MJ_{LNG}	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ_{LNG}	0.0100				[Total 2001]
GR5	**LNG vaporisation**							LBST internal
	Heat as NG		MJ/MJ_{NG}	0.0194				
	NG to pump drive (gas engine)		MJ/MJ_{NG}	0.0012	0.0009	0.0014	Square	
	CH_4 emissions		g/MJ_{NG}	0.0000044	0.0000035	0.0000052		
	N_2O emissions		g/MJ_{NG}	0.0000055	0.0000044	0.0000065		
GG3	**NG distribution (high pressure)**							
	Compression specific energy		MJ/t.km	0.2690				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0135				
	N_2O emissions		g/MJ_{fuel}	0.0081				
	Other CH_4 emissions		g/MJ_{NG}	0.0006				
	Distance		km	500				
	Transformation near market							
GGe	**State-of-the-art NG-Fired CCGT**							[GEMIS 2011]
	Efficiency		%	58.1%	57.0%	59.3%	Normal	
	CH_4 emissions		g/MJ_e	0.0054				
	N_2O emissions		g/MJ_e	0.0043				
GE1C	**State-of-the-art NG-Fired CCGT with CCS**							[Rubin 2005]
	Efficiency		%	47.1%	44.8%	49.6%	Normal	
	CH_4 emissions		g/MJ_e	0.0075				
	N_2O emissions		g/MJ_e	0.0021				
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses		%	3.4%				

12.4.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

12.4.1.2 GR1 NG liquefaction

The energy required for the liquefaction process is well documented and not subject to a large uncertainty. It is assumed here that the electrical power for the compressors is supplied by a gas fired on-site combined cycle gas fired power plant (see process GGe).

Some off gas is flared for which estimates vary widely in the literature hence the wide range used. There are also small methane losses.

A significant amount of natural gas is used to generate the electrical energy required for liquefaction. The corresponding CO2 could be captured (see process CGeC). The proximity of gas and possibly oil field where the CO2 could be injected would enhance the feasibility of such a scheme.

12.4.1.3 GR2 LNG loading terminal

A small amount of electricity is required for the operation of the terminals. In addition, the evaporation losses (estimated at 1%) are flared resulting in CO2 emissions. The electricity is deemed to be produced by the on-site gas-fired power plant (process GGe).

12.4.1.4 GGe GPCG1b (Middle East)

In all gas transformation schemes requiring significant amounts of electricity, we have assumed the latter is produced on-site by a state-of-the-art gas-fired combined cycle gas turbine (CCGT) with a typical efficiency of 58% (57-59%). The high end of the range represents potential future improvements to the technology that are thought to be achievable in the next ten years.

12.4.1.5 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per

1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

12.4.1.6 GR3 LNG long-distance sea transport

LNG is transported in specially designed cryogenic carriers. Heat ingress is compensated by gas evaporation. The evaporation rate is estimated at 0.15% per day, the number of days being based on an average speed of 19.5 knots. The average distance has been taken as 4000 nautical miles, based on the average for the supply of LNG to EU. The LNG is imported from Algeria, Norway, Nigeria, and Qatar.

The evaporated gas is used as fuel for the ship, the balance being provided by standard marine bunker fuel (HFO). This practice is also valid for the return voyage inasmuch as the LNG tanks are never completely emptied in order to keep them at low temperature (required for metallurgical reasons). The figures include an allowance for the return trip in accordance with the “admiralty formula” (see process Z4: LNG carriers have a typical gross tonnage of 110,000 t, including a payload of 135,000 m3 or 57,000 t [Hanjin 2000] [Mitsubishi 2000]. This results in a ratio of 0.8 between the full and empty ship).

The figures include provision for return trip.

12.4.1.7 GR4 LNG unloading terminal

The terminal electricity requirement is deemed to be the same as for the loading terminal (see process GR2). The electricity, however, is now assumed to be supplied by the EU grid. If LNG is vaporised on receipt no evaporation losses are included; if LNG is further transported as such, the same figures as for the loading terminal are used. A small additional electricity consumption (0.0007 to 0.0010 MJ/MJ of LNG) is added for the LNG terminal. The road tanker loading and unloading is carried out by a truck mounted LNG pump. The additional diesel requirement for the LNG pump is very low (approximately 0.0002 MJ/MJ of LNG).

12.4.1.8 GR5 LNG vaporisation

If it is to be used in the gas distribution grid, LNG needs to be vaporised and compressed. Although small amounts can be vaporised with heat taken from the atmosphere, this is impractical for large evaporation rates and heat at higher temperature must be supplied. The figures used here assume compression (as liquid) to 4 MPa followed by vaporisation and heating of the gas from -162 to 15°C.

12.4.1.9 GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/(t.km) are typical of European networks. Gas losses are reportedly very small.

12.4.1.10 GGe State-of-the-art NG-Fired CCGT

This process represents the now standard route for efficient and cost-effective production of electricity from gas i.e. a combined cycle gas turbine complex. Electricity is generated directly by the natural gas -fired gas turbine while steam raised from the flue gases generates extra electricity through condensing steam turbines. The overall efficiency of 58.1% is typical of modern state-of-the-art plants.

12.4.1.11 GE1C State-of-the-art NG-Fired CCGT with CCS

The CCGT uses two GE7FA gas turbines and 3-pressure reheat HRSG. The CO2 is captured from the flue gas of the gas turbine (post-combustion CCS). The CO2 is captured via amine scrubbing. The extracted CO2 is compressed to a pressure of 13.7 MPa for injection into a CO2 pipeline (assumed length: 161 km). The electricity requirement for CO2 compression is taken into account.

12.4.1.12 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.4.1.13 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.4.1.14 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.5 Biogas

12.5.1 Biogas from municipal waste and manure, on-site generation or export to large scale power plant (OWEL)

Biogas: (a) small scale CHP, (b) co-firing in large gas CCGT

OWEL1: Municipal waste, closed digestate storage

OWEL21: Wet manure, closed digestate storage

OWEL22: Wet manure, open digestate storage

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
BG1.1	**CH_4 field emissions credit**							
	CH_4 emissions		$\text{g/MJ}_{\text{manure}}$	-1.4700				[Guintoli et al. 2017]
	Transformation at source							
	NA							
	Transportation to market							
BG2.2	**Manure transport (Road)**							
	Distance	*F1*	km	5				
	Transformation near market							
BG3.1	**Fermenter (Municipal waste, closed digestate storage)**							[Giuntoli et al. 2017]
	Raw gas yield		$\text{MJ/MJ}_{\text{waste}}$	0.7073	0.7445	0.6736	Square	
	Heat to process		$\text{MJ/MJ}_{\text{rawgas}}$	0.0976	0.0927	0.1024	Square	
	Electricity to process		$\text{MJ/MJ}_{\text{rawgas}}$	0.0293	0.0278	0.0307	Square	
	Heat and electricity supply to all fermenters							
	Option a: heat and electricity generated internally via small scale CHP, see BG5a below							
	Option b: heat generated internally, electricity imported from grid (EU-mix, LV)							
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		$\text{g/MJ}_{\text{heat}}$	0.0056				
	N_2O emissions		$\text{g/MJ}_{\text{heat}}$	0.0011				
BG3.21	**Fermenter (Manure, closed digestate storage)**							JRC internal
	Raw gas yield		$\text{MJ/MJ}_{\text{manure}}$	0.4620				
	Heat to process		$\text{MJ/MJ}_{\text{raw gas}}$	0.0909				
	Electricity to process		$\text{MJ/MJ}_{\text{raw gas}}$	0.0182				
BG3.22	**Fermenter (Manure, open digestate storage)**							JRC internal
	Raw gas yield		$\text{MJ/MJ}_{\text{manure}}$	0.4200				
	Heat to process		$\text{MJ/MJ}_{\text{raw gas}}$	0.1000				
	Electricity to process		$\text{MJ/MJ}_{\text{raw gas}}$	0.0200				
	CH_4 emissions		$\text{g/MJ}_{\text{raw gas}}$	1.9998				
BG4.1	**Upgrading**							
	Biogas yield		MJ/MJrawgas	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ	0.0300	0.0200	0.0400	Square	[Schulz 2004], JRC internal
BG5a	**Small scale CHP (gas engine)**							[Dienhart 1999], [GEMIS 2004]
	Efficiency		%	40.0%	38.2%	42.0%	2-triangle	
	CH_4 emissions		g/MJ_{e}	0.85				
	N_2O emissions		g/MJ_{e}					
GGe	**State-of-the-art NG-Fired CCGT**							[GEMIS 2011]
	Efficiency		%	58.1%	57.0%	59.3%	Normal	
	CH_4 emissions		g/MJ_{e}	0.0054				
	N_2O emissions		g/MJ_{e}	0.0043				
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses		%	3.4%				

12.5.1.1 BG1.1 CH4 field emissions credit

If unused or stored, wet manure would produce CH4 from naturally occurring anaerobic digestion. These emissions are avoided by controlling this process and collecting the gas produced.

12.5.1.2 BG2.2 Manure transport (Road)

Manure has to be transported over a short distance from the farm to the biogas plant. Road transport is assumed by a standard road truck according to process Z2.

12.5.1.3 BG3.1 Fermenter (Municipal waste, closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. The conversion level of the organic matter is typically 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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. (version 3 of this study assumed a gas engine supplying both heat and electricity but we have modified this to ensure consistency amongst all CBM pathways). Some methane losses are incurred as well as some N2O emissions.

12.5.1.4 BG3.21 Fermenter (Manure, closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. In case of manure with closed digestate storage the conversion level of the organic matter is typically 46%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

12.5.1.5 BG3.22 Fermenter (Manure, open digestate storage)

This variant is presented to illustrate the impact of letting all methane from digestate escape to atmosphere.

12.5.1.6 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas).

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

12.5.1.7 BG5a Small scale CHP (gas engine)

For electricity and heat generation within the biogas plant, a gas engine is assumed in which raw biogas can be used. The engine is assumed to produce all required electricity and heat for the plant. There is no credit for any heat surplus.

12.5.1.8 GGe State-of-the-art NG-Fired CCGT

This process represents the now standard route for efficient and cost-effective production of electricity from gas i.e. a combined cycle gas turbine complex. Electricity is generated directly by the natural gas -fired gas turbine while steam raised from the flue gases generates extra electricity through condensing steam turbines. The overall efficiency of 58.1% is typical of modern state-of-the-art plants.

12.5.1.9 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.5.1.10 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.5.1.11 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.6 Wood

12.6.1 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 (WxEL)

Wood (F: Farmed, W: Waste)

WxEL: IGCC (200 MWth (1), 10 MWth (2)), Conventional (small-scale) (3), co-firing in conventional coal power plant (4)

BLEL1: Waste wood via Black Liquor

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation, harvesting & chipping**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{wood}$					
	N (as N)	FN		0.00				JRC internal
	Pesticides	PE	g/MJ$_{wood}$	0.015				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ$_{wood}$	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000161				
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000397				
	N_2O field emissions		g/MJ$_{wood}$	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	F1	MJ/MJ$_{wood}$	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindholm 2
W2	**Forestry residue chipping**							
	Diesel		MJ/MJ$_{wood}$	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3a	**Farmed wood transport (local, 50 km, WFEL2)**							
	Road truck	T1						
	Distance		km	50				
WF3b	**Farmed wood transport (regional, 500 km, WFEL1, WFEL3)**							JRC internal
	Road truck	T1						
	Distance		km	500				
WW3a	**Waste wood transport (local, 50 km, WWEL2)**							
	Road truck	T1						
	Distance		km	50				
WW3b	**Waste wood transport (regional, 500 km, WWEL1, WWEL3, WWEL4, BLEL1)**							JRC internal
	Road truck	T1						
	Distance		km	500				
	Transformation near market							
WE1	**Wood IGCC (200 MW$_{th}$)**							[Sydcraft 2001]
	Efficiency			48.2%	46.0%	50.0%	2-triangle	
	CH_4 emissions		g/MJ$_e$	0.0261				
	N_2O emissions		g/MJ$_e$	0.0025				
WE2	**Wood IGCC (10 MW$_{th}$)**							[Oeko Institut 1999]
	Efficiency			35.4%	34.2%	36.7%	2-triangle	
	CH_4 emissions		g/MJ$_e$	0.0356				
	N_2O emissions		g/MJ$_e$	0.0033				
WE3	**Conventional biomass power plant (boiler/turbine, small scale)**							
	Efficiency			32.0%	30.5%	33.7%	2-triangle	[Jopp 1999]
	CH_4 emissions		g/MJ$_e$	0.0828				[GEMIS 2005]
	N_2O emissions		g/MJ$_e$	0.0063				[Vitovec 1999]
WE4	**Wood co-firing in coal power plant**							[Dienhart 1999]
	Efficiency			43.5%	40.0%	50.0%	2-triangle	
	CH_4 emissions		g/MJ$_e$	0.0041				
	N_2O emissions		g/MJ$_e$	0.0114				
BL1	**Black liquor gasifier / Power plant**							[Berglin 1999]
	Efficiency		%	90.0%	94.7%	85.7%	Square	
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses			2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses			0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses			3.4%				

12.6.1.1 WF1 Wood plantation, harvesting & chipping

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

12.6.1.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

12.6.1.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

12.6.1.4 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Giuntoli et al. 2017].

12.6.1.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

12.6.1.6 WF3a Farmed wood transport (local, 50 km, WFEL2)

In case of the smaller 10 MW_{th} plant wood farming is assumed to occur within a small distance from the plant, hence the 50 km toad transport.

12.6.1.7 WF3b Farmed wood transport (regional, 500 km, WFEL1, WFEL3)

For large plants a transport distance of 500 km has been assumed if the wood is derived from regions inside the EU.

12.6.1.8 WW3a Waste wood transport (local, 50 km, WWEL2)

In case of the smaller 10 MW_{th} plant wood farming is assumed to occur within a small distance from the plant, hence the 50 km toad transport.

12.6.1.9 WW3b Waste wood transport (regional, 500 km, WWEL1, WWEL3, WWEL4, BLEL1)

For large plants a transport distance of 500 km has been assumed if the wood is derived from regions inside the EU.

12.6.1.10 WE1 Wood IGCC (200 MW_{th})

The large gasifier power station is taken from the study of an IGCC based on the Värnamo pressurized fluidized bed gasifier, using a state-of-the-art GTX 100 gas turbine with flue gas condensation (140 MW_{th}). This configuration maximizes the electrical efficiency. The lower efficiency limit is for the existing turbine at Värnamo, whilst the upper limit projects a further 2% in gas turbine efficiency by 2010. We selected this power station because the Värnamo gasifier is the only one which has been demonstrated to work with hot gas filtration, which gives a significant improvement in efficiency since the syngas enters hot into the turbine, and will surely become the norm for future IGCC power stations.

12.6.1.11 WE2 Wood IGCC (10 MWth)

Data are from the Oeko-Institut's EM generic database, which also supplies cost data. We consider 5% uncertainty in the LHV efficiency. Gasifiers give higher electrical efficiency and can cope with varying fuel quality. But the investment cost is higher: not worth it if one can use the waste heat for district heating.

12.6.1.12 WE3 Conventional biomass power plant (boiler/turbine, small scale)

The small conventional plant is based on LBST data for the 11.5 MW fluidized-bed condensing steam-turbine power plant at Altenstadt, Germany. Fluidized bed combustors cope better with the varying quality of fuel from wood chips than conventional grate boilers.

12.6.1.13 WE4 Wood co-firing in coal power plant

The power plant is state-of-the-art, as used in pathway KOEL1. When co-fired with coal wood the same efficiency is assumed to be achieved for both fuel.

12.6.1.14 BL1 Black liquor gasifier / Power plant

Instead of using the output of the gasifier in a BLGMF plant for motor-fuel synthesis (section 14.4), one can burn the syngas for electricity cogeneration. Again, the heat balance of the plant is restored by burning additional biomass in the hog boiler. In the same way that [Ekbom 2003] analysed fuel-producing BLGMF [Berglin 1999] analysed different options for electricity production by replacing the black liquor recovery boiler with an oxygen-blown gasifier. The efficiency of electricity production is found by dividing the increased electricity production by the increased biomass consumption, compared to the reference mill. A little confusingly, [Berglin 1999] adopts a modern integrated pulp/paper mill as the reference mill, instead of the modern pulp-only-mill in [Ekbom 2003]. However, the changes are all in the pulp section, this should not affect the results (Berglin does this to demonstrate that the extra electricity produced could be sufficient to make the whole paper mill self-sufficient on energy, instead of consuming electricity, as at present).

The syngas is cleaned, and burnt in a combined cycle of back-pressure steam turbine, condensing steam turbine and gas turbine. Berglin discusses many different options, including three ways to remove the H2S from the syngas. We chose the variant ("case 6", table 7 in [Berglin 1999]) which produces the highest electricity export, though not at the highest incremental efficiency. It removes H2S from the syngas by reabsorbing it in the white liquor. That means it uses more lime, but the lime is regenerated in a closed cycle as part of the system, so the energy implications are fully taken into account. The gas turbine assumed in this variant has an input temperature of 1430ºC, with a pressure ratio 20, and the maximum steam temperature is 530ºC. The gasifier operates at 3.7 MPa.

The plant produces electricity from biomass (bark or forest residuals) at an incremental efficiency of 90%, because it benefits from the reduction in stack losses and increased thermal capacity in the paper mill.

12.6.1.15 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

12.6.1.16 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.6.1.17 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

12.7 Nuclear

12.7.1 Nuclear power plant (NUEL)

Process code	*Step*	*Common processes*	*Input*		*Range*		*Distribution*	*Source*
	Production & conditioning at source							
NU1.1	**Uranium ore extraction and processing (Canada)**							
	Diesel*	*F1*	MJ/MJ$_{fuel}$	0.00008				[GEMIS 2005],
NU1.2	**Uranium fuel ore extraction and processing (France)**							
	Electricity (EU-mix, HV)	*EMHa*	MJ/MJ$_{fuel}$	0.00002				[GEMIS 2005]
	Transformation at source							
	NA							
	Transportation to market							
NU2	**U_3O_8 sea transport**							
	Distance	*T3f*	km	6000				[GEMIS 2002]
	Transformation near market							
NU3	**Nuclear fuel production**							
NU3a	**UF6 production**							[GEMIS 2011]
	Efficiency			90.0%				
	Electricity (EU-mix, HV)	*EMHa*	MJ/MJ$_{UF6}$	0.00001				
NU3b	**Enrichment**							[GEMIS 2002]
	Electricity (EU-mix, HV)	*EMHa*	MJ/MJ$_{fuel}$	0.00800	0.0076	0.0084	Normal	
NU3c	**Nuclear fuel rod production (France)**							[GEMIS 2009, 2010]
	Efficiency			95.0%				
	Heat		MJ/MJ$_{fuel}$	0.0010				
	Electricity (EU-mix, HV)		MJ/MJ$_{fuel}$	0.0010				
NU4	**Nuclear power plant**							[GEMIS 2002]
	Efficiency			33.0%				
	Diesel*	*F1*	MJ/MJ$_{fuel}$	0.0033				[GEMIS 2002]
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses			2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses			0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses			3.4%				

12.7.1.1 NU1.1 Uranium ore extraction and processing (Canada)

Uranium ore is extracted in open cast mines.

12.7.1.2 NU1.2 Uranium fuel ore extraction and processing (France)

Uranium ore is extracted in open deep mines. The pathway assumes 50% ore from Canada and 50% from France.

12.7.1.3 NU2 U3O8 sea transport

Uranium ore (Canada) is transported to EU by ship. The shipping process (T3f) represents and large bulk carrier.

12.7.1.4 NU3 Nuclear fuel production

This consists of three steps: Conversion of Uranium oxide into hexafluoride (UF6), enrichment and final fuel production.

12.7.1.5 NU4 Nuclear power plant

The nuclear plant consumes its own power and a small amount of diesel.

12.7.1.6 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.7.1.7 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.7.1.8 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2013].

12.8 Wind

12.8.1 Wind turbine (WDEL)

Process code	Step	Common processes	Input		Range	Distribution	Source
	Production & conditioning at source						
	NA						
	Transformation at source						
	NA						
	Transportation to market						
	NA						
	Transformation near market						
WD1	**Wind turbine**						[GEMIS 2000]
	No expended energy or emissions						
	Conditioning & Distribution						
EDH	**Electricity distribution HV**						[JRC 2017]
	Losses			2.6%			
EDM	**Electricity distribution MV**						[JRC 2017]
	Losses			0.9%			
EDL	**Electricity distribution LV**						[JRC 2017]
	Losses			3.4%			

12.8.1.1 WD1 Wind turbine

Electricity from wind turbine is energy and emission - free (as we do not consider energy and emissions related to construction and maintenance)

12.8.1.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.8.1.3 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

12.8.1.4 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13 Heat and Power

13.1 Heat only

13.1.1 Diesel (COHT)

Heat from fossil diesel-fired boiler. (1) small scale domestic boiler, (2) large scale industrial boiler

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
CO1	**Crude oil production**							[Exergia et al. 2015]
	Crude oil		MJ/MJ_{crude}	0.1152				
			g CO_2/MJ_{crude}	8.41				
	CH_4 emissions		g/MJ_{crude}	0.0244				
	Total emissions		g CO_{2eq}/MJ_{crude}	9.02				
	Transformation at source							
	NA							
	Transportation to market							
CO2	**Crude oil transport**							[Exergia et al. 2015]
	Heavy Fuel Oil		MJ/MJ_{crude}	0.0081				
	Transformation near market							
CD1a	**Crude refining, marginal diesel (EU)**							CONCAWE internal
	Refinery fuel		MJ/MJ_{diesel}	0.1070				
			g CO_2/MJ_{diesel}	7.20				
CD2	**Diesel fuel distribution (long distance)**							
	Barge, 1200t (20%)							
	Distance		km	500				
	Diesel fuel	*F1*	MJ/t.km	0.5040				
	CH_4 emissions		g/t.km	0.0300				
	Rail (20%)							
	Distance		km	250				
	Electricity (EU-mix MV)	*EMMa*	MJ/t.km	0.21				
	Pipeline (60%)							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ_{diesel}	0.0002				
LF1	**Liquid fuel depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{diesel}	0.00084				
LF2	**Liquid fuel local distribution**							[TOTAL 2002]
	Standard road tanker	*T1*						
	Payload / tank mass		t/t	26/28				
	Distance		km	150				
CHD	**Diesel-fired boiler (small scale domestic)**							[GEMIS 2002]
	Efficiency			90.0%	87.5%	92.5%	Square	
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{heat}	0.020				
	CH_4 emissions		g/MJ_{heat}	0.0028				
	N_2O emissions		g/MJ_{heat}	0.0021				
CHI	**Diesel-fired boiler (large scale industrial)**							[GEMIS 2005]
	Efficiency		%	90.0%	87.5%	92.5%	Square	
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{heat}	0.025				
	CH_4 emissions		g/MJ_{heat}	0.0028				
	N_2O emissions		g/MJ_{heat}	0.0021				
	Conditioning & Distribution							
	NA							

13.1.1.1 CO1 Crude oil production

Figures include all energy and GHG emissions associated with crude oil production and conditioning at or near the wellhead (such as dewatering and associated gas separation). The total CO2eq figure includes an element of flaring and emissions of GHGs other than combustion CO2.

Production conditions for conventional crude oil vary considerably between producing regions, fields and even between individual wells and it is only meaningful to give typical or average energy consumption and GHG emission figures for the wide range of crudes relevant to Europe, hence the wide variability range indicated. These figures are best estimates for the basket of crude oils available to Europe.

Substantial deposits of heavier oils also exist, notably in Canada and Venezuela. The process of extracting and processing these oils is more energy intensive than for conventional crude oil. The very large reserves mean that these resources may become more important in the future, however most of the current production is used within the Americas, and we expect little or none of it to reach Europe in the period to 2020. The marginal crude available to Europe is likely to be of a similar quality and overall GHG footprint to the overwhole basket (see also section 3.1.1 of the WTT report).

13.1.1.2 CO2 Crude oil transport

Crude oil is mostly transported by ship. The type of ship used depends on the distance to be covered. The bulk of the Arab Gulf crude is transported 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. The developing regions of the Caspian basin will rely on one or several new pipelines to be built to the Black Sea. Crude from central Russia is piped to the Black Sea as well as directly to Eastern European refineries through an extensive pipeline network.

The majority of EU refineries are located at coastal locations with direct access to a shipping terminal. Those that are inland are generally supplied via one of several pipelines such as from the Mediterranean to North Eastern France and Germany, from the Rotterdam area to Germany and from Russia into Eastern and Central Europe.

Here again, there is a wide diversity of practical situations. The figures are based on data in [Exergia et al. 2015] and represent the crude oil mix supplied to the EU. [Exergia et al. 2015] indicates the GHG emissions. It has been assumed that the GHG emissions are from the combustion of heavy fuel oil which is made from crude oil. The energy is supplied in the form of HFO, the normal ship's fuel. Note that that require shorter transport distances such as North Sea or North African crudes or those that can be transported by pipeline (e.g. Russian crude) would command somewhat smaller figures.

13.1.1.3 CD1a Crude refining, marginal diesel (EU)

This represents the energy and GHG emissions that can be saved, in the form of crude oil, by not producing a marginal amount of diesel in Europe, starting from a 2010 "business-as-usual" base case (see also section 2.3.2 and Appendix 6 of the WTT report).

13.1.1.4 CD2 Diesel fuel distribution (long distance)

Road fuels are transported from refineries to depots via a number of transport modes. We have included water (inland waterway or coastal), rail and pipeline (1/3 each). The energy consumption and distance figures are typical averages for EU. Barges and coastal tankers are deemed to use a mixture of marine diesel and HFO. Rail transport consumes electricity. The consumption figures are typical.

13.1.1.5 LF1 Liquid fuel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations.

13.1.1.6 LF2 Liquid fuel local distribution

From the depots, road fuels are transported to the retail stations by road tankers (notionally 26 t payload).

13.1.1.7 CHD Diesel-fired boiler (small scale domestic)

Typical small-scale boiler, 90% efficiency.

13.1.1.8 CHI Diesel-fired boiler (large scale industrial)

Typical large-scale boiler, 90% efficiency.

13.1.2 Natural gas (GPHT)

Heat from natural gas-fired boiler. (1) small scale domestic boiler, (2) large scale industrial boiler, GPHTx: 4300 km + 700 km pipeline (Russia) (a), 4000 km pipeline (Middle East) (b)

Heat from natural gas-fired boiler. LNG **(GRHT1)**

Process code	*Step*	*Common processes*	*Input*		*Range*		*Distribution*	*Source*
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0200	0.0200	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ$_{NG}$	0.0798				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ$_{LNG}$	0.0113				[FfE 1996]
	CH_4 emissions		g/MJ$_{LNG}$	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency			58.1%	57.0%	59.3%		[GEMIS 2011]
	CH_4 emissions		g/MJ$_{elec}$	0.0054				
	N_2O emissions		g/MJ$_{elec}$	0.0043				
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ$_{fuel}$	0.0278				
	N_2O emissions		g/MJ$_{fuel}$	0.0085				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ$_{NG}$	0.1398				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ$_{NG}$	0.1057				[Wuppertal 2004]
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ$_{LNG}$	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ$_{LNG}$	0.0222				[Mitsubishi 2000]
	CH_4 emissions		g/MJ$_{LNG}$	0.00013				[GEMIS 2001]
	N_2O emissions		g/MJ$_{LNG}$	0.00009				[GEMIS 2001]
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GR5	**LNG vaporisation**							LBST internal
	Heat as NG		MJ/MJ$_{NG}$	0.0194				
	NG to pump drive (gas engine)		MJ/MJ$_{NG}$	0.0012	0.0009	0.0014	Square	
	CH_4 emissions		g/MJ$_{NG}$	0.000004	0.000004	0.000005		
	N_2O emissions		g/MJ$_{NG}$	0.000005	0.000004	0.000007		
GG3	**NG distribution (high pressure)**							
	Compression specific energy		MJ/t.km	0.2690				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ$_{fuel}$	0.0135				
	N_2O emissions		g/MJ$_{fuel}$	0.0081				
	Other CH_4 emissions		g/MJ$_{NG}$	0.0006				
	Distance		km	500				
GG4	**NG local distribution (low pressure)**							[Ruhrgas 2003]
	No contribution							
	Transformation near market							
GHD	**NG-fired boiler (small scale domestic)**							[GEMIS 2005]
	Efficiency			100.0%				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{heat}$	0.016				
	CH_4 emissions		g/MJ$_{heat}$	0.0011				
	N_2O emissions		g/MJ$_{heat}$	0.0003				
GHI	**NG-fired boiler (large scale industrial)**							[GEMIS 2005]
	Efficiency			90.0%				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{heat}$	0.020				
	CH_4 emissions		g/MJ$_{heat}$	0.0028				
	N_2O emissions		g/MJ$_{heat}$	0.0011				
GGe	**State-of-the-art NG-fired CCGT**							[GEMIS 2011]
	Efficiency			58.1%	57.0%	59.3%	Normal	
	CH_4 emissions		g/MJ$_e$	0.0054				
	N_2O emissions		g/MJ$_e$	0.0043				
	Conditioning & Distribution							
	NA							

13.1.2.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

13.1.2.2 GR1 NG liquefaction

The energy required for the liquefaction process is well documented and not subject to a large uncertainty. It is assumed here that the electrical power for the compressors is supplied by a gas fired on-site combined cycle gas fired power plant (see process GGe).

Some off gas is flared for which estimates vary widely in the literature hence the wide range used. There are also small methane losses.

A significant amount of natural gas is used to generate the electrical energy required for liquefaction. The corresponding CO2 could be captured (see process CGeC). The proximity of gas and possibly oil field where the CO2 could be injected would enhance the feasibility of such a scheme.

13.1.2.3 GR2 LNG loading terminal

A small amount of electricity is required for the operation of the terminals. In addition, the evaporation losses (estimated at 1%) are flared resulting in CO2 emissions. The electricity is deemed to be produced by the on-site gas-fired power plant (process GGe).

13.1.2.4 GGe On-site electricity generation (NG-fired CCGT)

In all gas transformation schemes requiring significant amounts of electricity, we have assumed the latter is produced on-site by a state-of-the-art gas-fired combined cycle gas turbine (CCGT) with a typical efficiency of 58% (57-59%). The high end of the range represents potential future improvements to the technology that are thought to be achievable in the next ten years.

13.1.2.5 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per

1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

13.1.2.6 GR3 LNG long-distance sea transport

LNG is transported in specially designed cryogenic carriers. Heat ingress is compensated by gas evaporation. The evaporation rate is estimated at 0.15% per day, the number of days being based on an average speed of 19.5 knots. The average distance has been taken as 4000 nautical miles, based on the average for the supply of LNG to EU. The LNG is imported from Algeria, Norway, Nigeria, and Qatar.

The evaporated gas is used as fuel for the ship, the balance being provided by standard marine bunker fuel (HFO). This practice is also valid for the return voyage inasmuch as the LNG tanks are never completely emptied in order to keep them at low temperature (required for metallurgical reasons). The figures include an allowance for the return trip in accordance with the “admiralty formula” (see process Z4: LNG carriers have a typical gross tonnage of 110,000 t, including a payload of 135,000 m3 or 57,000 t [Hanjin 2000] [Mitsubishi 2000]. This results in a ratio of 0.8 between the full and empty ship).

The figures include provision for return trip.

13.1.2.7 GR4 LNG unloading terminal

The terminal electricity requirement is deemed to be the same as for the loading terminal (see process GR2). The electricity, however, is now assumed to be supplied by the EU grid. If LNG is vaporised on receipt no evaporation losses are included; if LNG is further transported as such, the same figures as for the loading terminal are used. A small additional electricity consumption (0.0007 to 0.0010 MJ/MJ of LNG) is added for the LNG terminal. The road tanker loading and unloading is carried out by a truck mounted LNG pump. The additional diesel requirement for the LNG pump is very low (approximately 0.0002 MJ/MJ of LNG).

13.1.2.8 GR5 LNG vaporisation

If it is to be used in the gas distribution grid, LNG needs to be vaporised and compressed. Although small amounts can be vaporised with heat taken from the atmosphere, this is impractical for large evaporation rates and heat at higher temperature must be supplied. The figures used here assume compression (as liquid) to 4 MPa followed by vaporisation and heating of the gas from -162 to 15°C.

13.1.2.9 GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/(t.km) are typical of European networks. Gas losses are reportedly very small.

13.1.2.10GG4 NG local distribution (low pressure)

The low-pressure networks are fed from the high-pressure trunk lines and supply small commercial and domestic customers. No additional energy is required for these networks, the pressure energy from the trunk lines being more than adequate for the local transport.

Various pressure levels are used in different countries and even within countries. Although some local networks are still at very low pressure (<100 mbar(g)) the modern European standard is 0.4 MPa(g) (with pressure reduction at the customer boundary). Very low-pressure networks also need to be fed by higher pressure systems at regular intervals (e.g. 0.7 MPa in the UK). As a result, it is reasonable to assume that, as long as a gas network is present in the area, a supply at a few bars pressure will be available for CNG refuelling stations in the vast majority of cases. Pressures up to 2 MPa are also available in some areas and may be available to some sites, particularly fleet refuelling stations. We have assumed that the typical refuelling station will be supplied at 0.4 MPa.

Significant methane losses have been reported for these local networks. They appear, however, to be based on overall gas accounting and therefore include measurement accuracy. Some losses are associated with purging operations during network maintenance. It is difficult to believe that local networks would have sizeable continuous losses. In any case all such losses would be related to the extent of the network rather than the throughput. NG used for road transport would only represent a modest increase of the total amount transported in the network and would therefore not cause significant additional losses.

13.1.2.11 GHD NG-fired boiler (small scale domestic)

This is small scale (domestic) condensing boiler with 100% average efficiency.

13.1.2.12 GHI NG-fired boiler (large scale industrial)

This is standard industrial scale gas boiler with and efficiency of 90%.

13.1.3 Farmed/Waste wood (WxHT)

Heat from wood-fired boiler (F Farmed, W Waste). (1) small scale domestic boiler (2) large scale industrial boiler

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation, harvesting & chipping**							
	Agricultural inputs							
	Fertilizers		g/MJ_{wood}					
	N (as N)	FN		0.00				JRC internal
	Pesticides	PE	g/MJ_{wood}	0.02				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ_{wood}	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.0000				
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.0000				
	N_2O field emissions		g/MJ_{wood}	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	F1	MJ/MJ_{wood}	0.0120				[Lindholm et al. 2010], [Sikkema et al. 201
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindho
W2	**Forestry residue chipping**							
	Diesel		MJ/MJ_{wood}	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3a	**Farmed wood transport (local, 50 km, pathway WFHT2)**							
	Road truck	T1						
	Distance		km	50				
WF3b	**Farmed wood transport (regional, 500 km, pathway WFHT1)**							JRC internal
	Road truck	T1						
	Distance		km	500				
WW3a	**Waste wood transport (local, 50 km, pathway WWHT2)**							
	Road truck	T1						
	Distance		km	50				
WW3b	**Waste wood transport (regional, 500 km, pathway WWHT1)**							JRC internal
	Road truck							
	Distance	T1	km	500				
	Transformation near market							
WHD	**Wood pellet fired boiler (small scale domestic)**							[GEMIS 2007]
	Efficiency			90.0%	85.5%	95.0%	Square	
	Electricity (EU-mix MV)	EMLa	MJ/MJ_{heat}	0.030				
	CH_4 emissions		g/MJ_{heat}	0.0033				
	N_2O emissions		g/MJ_{heat}	0.0013				
WHI	**Wood chips fired boiler (large scale industrial)**							[GEMIS 2002]
	Efficiency			85.0%	81.0%	90.0%	Square	
	Electricity (EU-mix MV)	EMLa	MJ/MJ_{heat}	0.020				
	CH_4 emissions		g/MJ_{heat}	0.0029				
	N_2O emissions		g/MJ_{heat}	0.0006				
	Conditioning & Distribution							
	NA							

13.1.3.1 WF1 Wood plantation, harvesting & chipping

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

13.1.3.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

13.1.3.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

13.1.3.4 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Guintoli et al. 2017].

13.1.3.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

13.1.3.6 WF3b Farmed wood transport (regional, 500 km, pathway WFHT1)

In the wood pathways for the recast of the EU Renewable Directive (RED II pathways) several transport distances and transport modes are suggested. Pellet production plants are generally large central plants. For pathways involving wood pellet production a transport via truck over a distance of 500 km has been assumed.

13.1.3.7 WW3b Waste wood transport (regional, 500 km, pathway WWHT1)

In the wood pathways for the recast of the EU Renewable Directive (RED II pathways) several transport distances and transport modes are suggested. Pellet production plants are generally large central plants. For pathways involving wood pellet production a transport via truck over a distance of 500 km has been assumed.

13.1.3.8 WHD Wood pellet fired boiler (small scale domestic)

This represents a small-scale wood pellet fired domestic boiler.

13.1.3.9 WHI Wood chips fired boiler (large scale industrial)

This represents a medium scale wood chip fired industrial boiler (10 MW$_{th}$)

13.1.4 Heat from biogas from waste (OWHT)

Heat from biogas-fired boiler (small scale)

OWHT1a/b: Municipal waste, closed digestate storage

OWHT21a/b: Wet manure, closed digestate storage

OWHT22a/b: Wet manure, open digestate storage

a: domestic condensing boiler; b: commercial boiler

Process code	*Step*	*Common processes*	*Input*		*Range*		*Distribution*	*Source*
	Production & conditioning at source							
BG1.1	**CH_4 field emissions credit**							
	CH_4 emissions		g/MJ$_{manure}$	-1.4700				0
	Transformation at source							
	NA							
	Transportation to market							
BG2.2	**Manure transport (Road)**							
	Distance	*T1*	km	10				
	Transformation near market							
BG3.1	**Fermenter (Municipal waste, closed digestate storage)**							[Giuntoli et al. 2017]
	Raw gas yield		MJ/MJ$_{waste}$	0.7073	0.7445	0.6736	Square	
	Heat to process		MJ/MJ$_{raw\ gas}$	0.0976	0.0927	0.1024	Square	
	Electricity to process		MJ/MJ$_{raw\ gas}$	0.0293	0.0278	0.0307	Square	
	Heat and electricity supply to all fermenters							
	Heat generated internally, electricity imported from grid (EU-mix, LV)							
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ$_{heat}$	0.0056				
	N_2O emissions		g/MJ$_{heat}$	0.0011				
BG3.21	**Fermenter (Manure, closed digestate storage)**							JRC internal
	Raw gas yield		MJ/MJ$_{manure}$	0.4620				
	Heat to process		MJ/MJ$_{raw\ gas}$	0.0909				
	Electricity to process		MJ/MJ$_{raw\ gas}$	0.0182				
BG3.22	**Fermenter (Manure, open digestate storage)**							JRC internal
	Raw gas yield		MJ/MJ$_{manure}$	0.4200				
	Heat to process		MJ/MJ$_{raw\ gas}$	0.1000				
	Electricity to process		MJ/MJ$_{raw\ gas}$	0.0200				
	CH_4 emissions		g/MJ$_{raw\ gas}$	1.9998				
BG4.1	**Upgrading**							
	Biogas yield		MJ/MJrawgas	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ	0.0300	0.0200	0.0400	Square	[Schulz 2004],
GHD	**NG-fired condensing boiler (small scale domestic)**							[GEMIS 2005]
	Efficiency			100.0%				
	Electricity (EU-mix LV)	*EMLa*	MJ/MJ	0.016				
	CH_4 emissions		g/MJ$_e$	0.0011				
	N_2O emissions		g/MJ$_e$	0.0003				
GHI	**NG-fired boiler (large scale commercial)**							[GEMIS 2005]
	Efficiency			90%				
	Electricity (EU-mix LV)	*EMLa*	MJ/MJ	0.0200				
	CH_4 emissions		g/MJ$_e$	0.0028				
	N_2O emissions		g/MJ$_e$	0.0011				
	Conditioning & Distribution							
	NA							

13.1.4.1 BG1.1 CH4 field emissions credit

If unused or stored, wet manure would produce CH4 from naturally occurring anaerobic digestion. These emissions are avoided by controlling this process and collecting the gas produced.

13.1.4.2 BG2.2 Manure transport (Road)

Manure has to be transported over a short distance from the farm to the biogas plant. Road transport is assumed by a standard road truck according to process Z2.

13.1.4.3 BG3.1 Fermenter (Municipal waste, closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane and CO2. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield.

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. (version 3 of this study assumed a gas engine supplying both heat and electricity but we have modified this to ensure consistency amongst all CBG pathways). Some methane losses are incurred as well as some N2O emissions.

13.1.4.4 BG3.21 Fermenter (Manure, closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane and CO2. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. In case of wet manure, the conversion level of the organic matter is typically about 40%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield.

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 N2O emissions.

13.1.4.5 BG3.22 Fermenter (Manure, open digestate storage)

This variant is presented to illustrate the impact of letting all methane from digestate escape to atmosphere.

13.1.4.6 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m3 per 100 Nm3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas).

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

13.1.4.7 GHD NG-fired condensing boiler (small scale domestic)

This is small scale (domestic) condensing boiler with 100% average efficiency.

13.1.4.8 GHI NG-fired boiler (large scale commercial)

This is a large-scale commercial boiler with 90% efficiency. The efficiency lower than that of the domestic condensing boiler because the heat from condensation of water is not used in the commercial boiler.

13.2 Combined Heat and Power (CHP)

13.2.1 Natural gas (GPEH1a)

Piped gas (a: 4300 km + 700 km, b: 4000 km) into large scale state-of-the-art gas turbine CHP plant. Heat as exported co-product.

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0200	0.0200	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.0798				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ_{LNG}	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ_{LNG}	0.0113				[FfE 1996]
	CH_4 emissions		g/MJ_{LNG}	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ_{LNG}	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ_{LNG}	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency			58%	57%	59%		
	CH_4 emissions		g/MJ_{elec}	0.0054				
	N_2O emissions		g/MJ_{elec}	0.0043				
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency		%	30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ_{fuel}	0.0278				
	N_2O emissions		g/MJ_{fuel}	0.0085				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.1398				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ_{NG}	0.1057				[Wuppertal 2004]
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ_{LNG}	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ_{LNG}	0.0222				[Mitsubishi 2000]
	CH_4 emissions		g/MJ_{LNG}	0.00013				[GEMIS 2001]
	N_2O emissions		g/MJ_{LNG}	0.00009				[GEMIS 2001]
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ_{LNG}	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ_{LNG}	0.0100				[Total 2001]
GR5	**LNG vaporisation**							LBST internal
	Heat as NG		MJ/MJ_{NG}	0.0194				
	NG to pump drive (gas engine)		MJ/MJ_{NG}	0.0012	0.0009	0.0014	Square	
	CH_4 emissions		g/MJ_{NG}	0.000004				
	N_2O emissions		g/MJ_{NG}	0.000005				
GG3	**NG distribution (high pressure)**							
	Compression specific energy		MJ/t.km	0.2690				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0135				
	N_2O emissions		g/MJ_{fuel}	0.0081				
	Other CH_4 emissions		g/MJ_{NG}	0.0006				
	Distance		km	500				
	Transformation near market							
GEH	**Large scale state-of-the-art gas turbine CHP (electricity as main product)**							[GEMIS 2005]
	NG		MJ/MJ_e	2.328	2.222	2.434	Square	[TAB 1999]
	Heat surplus		MJ/MJ_e	-1.095				[SWM 2006]
	CH_4 emissions		g/MJ_e	0.0097				
	N_2O emissions		g/MJ_e	0.0006				
GxEH	*Credit for surplus heat based on*							
GHI	***NG-fired boiler (large scale industrial)***							[GEMIS 2005]
	Efficiency		%	90.0%				
	Electricity		MJ/MJ_{heat}	0.020				
	CH_4 emissions		g/MJ_{heat}	0.0028				
	N_2O emissions		g/MJ_{heat}	0.0011				
GxHE	*Credit for surplus electricity based on*							
GGe	***State-of-the-art NG-fired CCGT***							[GEMIS 2011]
	Efficiency			*58.1%*	*57.0%*	*59.3%*	*Normal*	
	CH_4 emissions		*g/MJ_e*	*0.0054*				
	N_2O emissions		*g/MJ_e*	*0.0043*				
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses		%	3.4%				

13.2.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

13.2.1.2 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

13.2.1.3 GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/(t.km) are typical of European networks. Gas losses are reportedly very small.

13.2.1.4 GEH Large scale state-of-the-art gas turbine CHP (electricity as main product)

This process represents a large-scale gas-fired CHP plant. Electricity is generated directly by the natural gas-fired gas turbine while steam raised from the flue gases generates extra electricity through back-pressure steam turbines from which medium pressure steam is recovered. The overall thermal efficiency is 90%.

In GxEH electricity is the primary product and surplus heat is assumed to be exported, substituting heat generated by a standard natural gas boiler (GH1).

IN GxHT heat is the primary product and is assumed to be used in a district heating scheme. The electricity surplus substitutes that generated by a state-of-the-art gas-fired CCGT (GE1).

13.2.1.5 GHI NG-fired boiler (large scale industrial)

This is standard industrial scale gas boiler with and efficiency of 90%.

13.2.1.6 GGe State-of-the-art NG-fired CCGT

This process represents the now standard route for efficient and cost-effective production of electricity from gas i.e. a combined cycle gas turbine complex. Electricity is generated directly by the natural gas -fired gas turbine while steam raised from the flue gases generates extra electricity through condensing steam turbines. The overall efficiency of 58.1% is typical of modern state-of-the-art plants.

13.2.1.7 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.1.8 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.1.9 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.2 Natural gas (GREH1)

LNG into large scale state-of-the-art gas turbine CHP plant. Heat as exported co-product.

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0200	0.0200	2-triangle	
	CO$_2$ venting		%v/v	1.0%				
	CH$_4$ losses		g/MJ$_{NG}$	0.0798				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ$_{LNG}$	0.0113				[FfE 1996]
	CH$_4$ emissions		g/MJ$_{LNG}$	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency			58%	57%	59%		
	CH$_4$ emissions		g/MJ$_{elec}$	0.0054				
	N$_2$O emissions		g/MJ$_{elec}$	0.0043				
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency		%	30%	35%	22%	2-triangle	
	CH$_4$ emissions		g/MJ$_{fuel}$	0.0278				
	N$_2$O emissions		g/MJ$_{fuel}$	0.0085				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	2-triangle	[GEMIS 2016]
	CH$_4$ emissions (losses)		g/MJ$_{NG}$	0.1398				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ$_{NG}$	0.1057				[Wuppertal 2004]
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ$_{LNG}$	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ$_{LNG}$	0.0222				[Mitsubishi 2000]
	CH$_4$ emissions		g/MJ$_{LNG}$	0.00013				[GEMIS 2001]
	N$_2$O emissions		g/MJ$_{LNG}$	0.00009				[GEMIS 2001]
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	EMMa	MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GR5	**LNG vaporisation**							LBST internal
	Heat as NG		MJ/MJ$_{NG}$	0.0194				
	NG to pump drive (gas engine)		MJ/MJ$_{NG}$	0.0012	0.0009	0.0014	Square	
	CH$_4$ emissions		g/MJ$_{NG}$	0.000004				
	N$_2$O emissions		g/MJ$_{NG}$	0.000005				
GG3	**NG distribution (high pressure)**							
	Compression specific energy		MJ/t.km	0.2690				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH$_4$ emissions		g/MJ$_{fuel}$	0.0135				
	N$_2$O emissions		g/MJ$_{fuel}$	0.0081				
	Other CH$_4$ emissions		g/MJ$_{NG}$	0.0006				
	Distance		km	500				
	Transformation near market							
GEH	**Large scale state-of-the-art gas turbine CHP (electricity as main product)**							[GEMIS 2005]
	NG		MJ/MJ$_e$	2.328	2.222	2.434	Square	[TAB 1999]
	Heat surplus		MJ/MJ$_e$	-1.095				[SWM 2006]
	CH$_4$ emissions		g/MJ$_e$	0.0097				
	N$_2$O emissions		g/MJ$_e$	0.0006				
GxEH	*Credit for surplus heat based on*							
GHI	***NG-fired boiler (large scale industrial)***							[GEMIS 2005]
	Efficiency		%	90.0%				
	Electricity		MJ/MJ$_{heat}$	0.020				
	CH$_4$ emissions		g/MJ$_{heat}$	0.0028				
	N$_2$O emissions		g/MJ$_{heat}$	0.0011				
GxHE	*Credit for surplus electricity based on*							
GGe	***State-of-the-art NG-fired CCGT***							[GEMIS 2011]
	Efficiency			*58.1%*	*57.0%*	*59.3%*	*Normal*	
	CH$_4$ emissions		*g/MJ$_e$*	*0.0054*				
	N$_2$O emissions		*g/MJ$_e$*	*0.0043*				
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses		%	3.4%				

13.2.2.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

13.2.2.2 GR1 NG liquefaction

The energy required for the liquefaction process is well documented and not subject to a large uncertainty. It is assumed here that the electrical power for the compressors is supplied by a gas fired on-site combined cycle gas fired power plant (see process GGe).

Some off gas is flared for which estimates vary widely in the literature hence the wide range used. There are also small methane losses.

A significant amount of natural gas is used to generate the electrical energy required for liquefaction. The corresponding CO2 could be captured (see process CGeC). The proximity of gas and possibly oil field where the CO2 could be injected would enhance the feasibility of such a scheme.

13.2.2.3 GR2 LNG loading terminal

A small amount of electricity is required for the operation of the terminals. In addition, the evaporation losses (estimated at 1%) are flared resulting in CO2 emissions. The electricity is deemed to be produced by the on-site gas-fired power plant (process GGe).

13.2.2.4 GGe On-site electricity generation (NG-fired CCGT)

In all gas transformation schemes requiring significant amounts of electricity, we have assumed the latter is produced on-site by a state-of-the-art gas-fired combined cycle gas turbine (CCGT) with a typical efficiency of 58% (57-59%). The high end of the range represents potential future improvements to the technology that are thought to be achievable in the next ten years.

13.2.2.5 GR3 LNG long-distance sea transport

LNG is transported in specially designed cryogenic carriers. Heat ingress is compensated by gas evaporation. The evaporation rate is estimated at 0.15% per day, the number of days being based on an average speed of 19.5 knots. The average distance has been taken as 4000 nautical miles, based on the average for the supply of LNG to EU. The LNG is imported from Algeria, Norway, Nigeria, and Qatar.

13.2.2.6 GR4 LNG unloading terminal

The terminal electricity requirement is deemed to be the same as for the loading terminal (see process GR2). The electricity, however, is now assumed to be supplied by the EU grid. If LNG is vaporised on receipt no evaporation losses are included; if LNG is further transported as such, the same figures as for the loading terminal are used. A small additional electricity consumption (0.0007 to 0.0010 MJ/MJ of LNG) is added for the LNG terminal. The road tanker loading and unloading is carried out by a truck mounted LNG pump. The additional diesel requirement for the LNG pump is very low (approximately 0.0002 MJ/MJ of LNG).

13.2.2.7 GR5 LNG vaporisation

If it is to be used in the gas distribution grid, LNG needs to be vaporised and compressed. Although small amounts can be vaporised with heat taken from the atmosphere, this is impractical for large evaporation rates and heat at higher temperature must be supplied. The figures used here assume compression (as liquid) to 4 MPa followed by vaporisation and heating of the gas from -162 to 15°C.

13.2.2.8 GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/(t.km) are typical of European networks. Gas losses are reportedly very small.

13.2.2.9 GEH Large scale state-of-the-art gas turbine CHP (electricity as main product)

This process represents a large-scale gas-fired CHP plant. Electricity is generated directly by the natural gas -fired gas turbine while steam raised from the flue gases generates extra electricity through back-pressure steam turbines from which medium pressure steam is recovered. The overall thermal efficiency is 90%.

In GxEH electricity is the primary product and surplus heat is assumed to be exported, substituting heat generated by a standard natural gas boiler (GH1).

IN GxHT heat is the primary product and is assumed to be used in a district heating scheme. The electricity surplus substitutes that generated by a state-of-the-art gas-fired CCGT (GE1).

13.2.2.10 GHI NG-fired boiler (large scale industrial)

This is standard industrial scale gas boiler with and efficiency of 90%.

13.2.2.11 GGe State-of-the-art NG-fired CCGT

This process represents the now standard route for efficient and cost-effective production of electricity from gas i.e. a combined cycle gas turbine complex. Electricity is generated directly by the natural gas -fired gas turbine while steam raised from the flue gases generates extra electricity through condensing steam turbines. The overall efficiency of 58.1% is typical of modern state-of-the-art plants.

13.2.2.12 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.2.13 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.2.14 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.3 Natural gas (GPHE1b)

Piped gas (4000 km) into large scale state-of-the-art gas turbine CHP plant. Electricity as exported co-product.

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0200	0.0200	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ$_{NG}$	0.0798				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ$_{LNG}$	0.0113				[FfE 1996]
	CH_4 emissions		g/MJ$_{LNG}$	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency			58%	57%	59%		
	CH_4 emissions		g/MJ$_{elec}$	0.0054				
	N_2O emissions		g/MJ$_{elec}$	0.0043				
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency		%	30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ$_{fuel}$	0.0278				
	N_2O emissions		g/MJ$_{fuel}$	0.0085				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ$_{NG}$	0.1398				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ$_{NG}$	0.1057				[Wuppertal 2004]
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ$_{LNG}$	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ$_{LNG}$	0.0222				[Mitsubishi 2000]
	CH_4 emissions		g/MJ$_{LNG}$	0.00013				[GEMIS 2001]
	N_2O emissions		g/MJ$_{LNG}$	0.00009				[GEMIS 2001]
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GR5	**LNG vaporisation**							LBST internal
	Heat as NG		MJ/MJ$_{NG}$	0.0194				
	NG to pump drive (gas engine)		MJ/MJ$_{NG}$	0.0012	0.0009	0.0014	Square	
	CH_4 emissions		g/MJ$_{NG}$	0.000004				
	N_2O emissions		g/MJ$_{NG}$	0.000005				
GG3	**NG distribution (high pressure)**							
	Compression specific energy		MJ/t.km	0.2690				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ$_{fuel}$	0.0135				
	N_2O emissions		g/MJ$_{fuel}$	0.0081				
	Other CH_4 emissions		g/MJ$_{NG}$	0.0006				
	Distance		km	500				
	Transformation near market							
GEH	**Large scale state-of-the-art gas turbine CHP (electricity as main product)**							[GEMIS 2005]
	NG		MJ/MJ$_e$	2.328	2.222	2.434	Square	[TAB 1999]
	Heat surplus		MJ/MJ$_e$	-1.095				[SWM 2006]
	CH_4 emissions		g/MJ$_e$	0.0097				
	N_2O emissions		g/MJ$_e$	0.0006				
GxEH	*Credit for surplus heat based on*							
GHI	***NG-fired boiler (large scale industrial)***							[GEMIS 2005]
	Efficiency		%	90.0%				
	Electricity		MJ/MJ$_{heat}$	0.020				
	CH_4 emissions		g/MJ$_{heat}$	0.0028				
	N_2O emissions		g/MJ$_{heat}$	0.0011				
GxHE	*Credit for surplus electricity based on*							
GGe	***State-of-the-art NG-fired CCGT***							[GEMIS 2011]
	Efficiency			*58.1%*	*57.0%*	*59.3%*	*Normal*	
	CH_4 emissions		*g/MJ$_e$*	*0.0054*				
	N_2O emissions		*g/MJ$_e$*	*0.0043*				
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses		%	3.4%				

13.2.3.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

13.2.3.2 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

13.2.3.3 GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/(t.km) are typical of European networks. Gas losses are reportedly very small.

13.2.3.4 GEH Large scale state-of-the-art gas turbine CHP (electricity as main product)

This process represents a large-scale gas-fired CHP plant. Electricity is generated directly by the natural gas - fired gas turbine while steam raised from the flue gases generates extra electricity through back-pressure steam turbines from which medium pressure steam is recovered. The overall thermal efficiency is 90%.

In GxEH electricity is the primary product and surplus heat is assumed to be exported, substituting heat generated by a standard natural gas boiler (GH1).

IN GxHT heat is the primary product and is assumed to be used in a district heating scheme. The electricity surplus substitutes that generated by a state-of-the-art gas-fired CCGT (GE1).

13.2.3.5 GHI NG-fired boiler (large scale industrial)

This is standard industrial scale gas boiler with and efficiency of 90%.

13.2.3.6 GGe State-of-the-art NG-fired CCGT

This process represents the now standard route for efficient and cost-effective production of electricity from gas i.e. a combined cycle gas turbine complex. Electricity is generated directly by the natural gas -fired gas turbine while steam raised from the flue gases generates extra electricity through condensing steam turbines. The overall efficiency of 58.1% is typical of modern state-of-the-art plants.

13.2.3.7 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.3.8 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.3.9 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.4 Farmed/Waste wood (WFWWEH1)

Farmed or waste wood into medium scale boiler/back-pressure turbine CHP. Heat as exported co-product

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation, harvesting & chipping**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{wood}$					
	N (as N)	FN		0.00				JRC internal
	Pesticides	PE	g/MJ$_{wood}$	0.02				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	F1	MJ/MJ$_{wood}$	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000				
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000				
	N_2O field emissions		g/MJ$_{wood}$	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	F1	MJ/MJ$_{wood}$	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindhol
W2	**Forestry residue chipping**							
	Diesel		MJ/MJ$_{wood}$	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transportation to market				`			
	Wood moisture content			30%				
WF3a	**Farmed wood transport (local, 50 km)**							
	Road truck	T1						
	Distance		km	50				
WW3a	**Waste wood transport (local, 50 km)**							
	Road truck	T1						
	Distance		km	50				
	Transformation near market							
WEH	**Wood CHP**							[Wittkopf 2005]
	Wood		MJ/MJ$_e$	4.450	4.230	4.670	Normal	[BMU 2004]
	Heat surplus		MJ/MJ$_e$	-2.500				[Scheuermann 2003]
	CH_4 emissions		g/MJ$_e$	0.0101				[GEMIS 2005]
	N_2O emissions		g/MJ$_e$	0.0004				
WxEH	*Credit for surplus heat based on*							
WHI	***Biomass-fired boiler***							*[GEMIS 2002]*
	Efficiency		*%*	*85.0%*	*81.0%*	*90.0%*	*Square*	
	Electricity		*MJ/MJ$_{heat}$*	*0.020*				
	CH_4 emissions		*g/MJ$_{heat}$*	*0.0029*				
	N_2O emissions		*g/MJ$_{heat}$*	*0.0006*				
WxHE	*Credit for surplus electricity based on*							
WE3	***Conventional biomass power plant (boiler/turbine, small scale)***							*0*
	Efficiency		*%*	*32.0%*	*30.5%*	*33.7%*	*2-triangle*	
	CH_4 emissions		*g/MJ$_e$*	*0.0828*				
	N_2O emissions		*g/MJ$_e$*	*0.0063*				
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
EDL	**Electricity distribution LV**							[JRC 2017]
	Losses		%	3.4%				

13.2.4.1 WF1 Wood plantation, harvesting & chipping

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

13.2.4.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

13.2.4.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

13.2.4.4 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation.

13.2.4.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

13.2.4.6 WF3a Farmed wood transport (local, 50 km)

Wood chips for relatively small plants (< 50 MW) are generally produced locally. Therefore, a transport distance of 50 km instead of 500 km has been assumed.

13.2.4.7 WW3a Waste wood transport (local, 50 km)

Wood chips for relatively small plants (< 50 MW) are generally produced locally. Therefore, a transport distance of 50 km instead of 500 km has been assumed.

13.2.4.8 WEH Wood CHP

This represents a small to medium scale conventional wood fired boiler / back pressure turbine installation based on the Pfaffenhofen plant in Germany.

13.2.4.9 WHI Biomass-fired boiler

This represents a small to medium scale conventional wood fired boiler / condensing turbine installation.

13.2.4.10 WE3 Conventional biomass power plant (boiler/turbine, small scale)

The small conventional plant is based on LBST data for the 11.5 MW fluidized-bed condensing steam-turbine power plant at Altenstadt, Germany. Fluidized bed combustors cope better with the varying quality of fuel from wood chips than conventional grate boilers.

13.2.4.11 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.4.12 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.4.13 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.5 Farmed/Waste wood (WFWWHE1)

Farmed or waste wood into medium scale boiler/back-pressure turbine CHP. Electricity as exported co-product

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation, harvesting & chipping**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{wood}$					
	N (as N)	*FN*		0.00				JRC internal
	Pesticides	*PE*	g/MJ$_{wood}$	0.02				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0126				JRC internal
	CH$_4$ emissions (from diesel use)		g/MJ$_{wood}$	0.0000				
	N$_2$O emissions (from diesel use)		g/MJ$_{wood}$	0.0000				
	N$_2$O field emissions		g/MJ$_{wood}$	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010
	CH$_4$ emissions (from diesel use)		g/MJ$_{wood}$	0.000009				[EMEP/EEA 2013]
	N$_2$O emissions (from diesel use)		g/MJ$_{wood}$	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindhol
W2	**Forestry residue chipping**							
	Diesel		MJ/MJ$_{wood}$	0.0034				[Lindholm et al. 2010]
	CH$_4$ emissions (from diesel use)		g/MJ$_{wood}$	0.000003				[EMEP/EEA 2013]
	N$_2$O emissions (from diesel use)		g/MJ$_{wood}$	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3a	**Farmed wood transport (local, 50 km)**							
	Road truck	*T1*						
	Distance		km	50				
WW3a	**Waste wood transport (local, 50 km)**							
	Road truck	*T1*						
	Distance		km	50				
	Transformation near market							
WEH	**Wood CHP**							[Wittkopf 2005]
	Wood		MJ/MJ$_e$	4.450	4.230	4.670	Normal	[BMU 2004]
	Heat surplus		MJ/MJ$_e$	-2.500				[Scheuermann 2003]
	CH$_4$ emissions		g/MJ$_e$	0.0101				[GEMIS 2005]
	N$_2$O emissions		g/MJ$_e$	0.0004				
WxEH	*Credit for surplus heat based on*							
WHI	***Biomass-fired boiler***							*[GEMIS 2002]*
	Efficiency		*%*	*85.0%*	*81.0%*	*90.0%*	*Square*	
	Electricity		*MJ/MJ$_{heat}$*	*0.020*				
	CH$_4$ emissions		*g/MJ$_{heat}$*	*0.0029*				
	N$_2$O emissions		*g/MJ$_{heat}$*	*0.0006*				
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	Efficiency		*%*	*32.0%*	*30.5%*	*33.7%*	*2-triangle*	
	CH$_4$ emissions		*g/MJ$_e$*	*0.0828*				
	N$_2$O emissions		*g/MJ$_e$*	*0.0063*				
	Conditioning & Distribution							
EDH	**Electricity distribution HV**							[JRC 2017]
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13.2.5.1 WF1 Wood plantation, harvesting & chipping

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Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

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13.2.5.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

13.2.5.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

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13.2.5.9 WHI Biomass-fired boiler

This represents a small to medium scale conventional wood fired boiler / condensing turbine installation.

13.2.5.10 WE3 Conventional biomass power plant (boiler/turbine, small scale)

The small conventional plant is based on LBST data for the 11.5 MW fluidized-bed condensing steam-turbine power plant at Altenstadt, Germany. Fluidized bed combustors cope better with the varying quality of fuel from wood chips than conventional grate boilers.

13.2.5.11 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.5.12 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

13.2.5.13 EDL Electricity distribution LV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

14 Hydrogen by thermal processes

Compressed hydrogen

14.1 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 (GMCH1).

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0236	0.0136	0.0436	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.0798				
	Transformation at source							
	NA							
	Transportation to market							
GG2	**NG long-distance pipeline transport to EU border**							
	Compression specific energy		MJ/t.km	0.300	0.269	0.330	Equal	[GEMIS 2016]
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
GG2/19	Distance		km	1900				
	CH_4 emissions (losses)		g/MJ_{NG}	0.0610				[Thinkstep 2017]
GG3	**NG pipeline transport inside EU (same as for distribution)**							
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
	Distance		km	500				
	CH_4 emissions (losses)		g/MJ_{NG}	0.0006				
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ_{NG}	0.0006				
GG4	**NG local distribution (low pressure)**							[Ruhrgas 2003]
	No contribution							
	Transformation near market							
GH1	**NG compression (1.6 Mpa)**							JEC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{NG}	0.0059				
GH2a	**NG on-site steam reforming**							[Haldor Topsoe 1998]
	NG		MJ/MJ_{H2}	1.4406	1.4118	1.4494	Normal	
	CH_4 emissions (losses)		g/MJ_{H2}	0.0208				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0161				
	Conditioning & Distribution							
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
HC4a	On-site reformer (1.5 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0917	0.0871	0.0963	Normal	
	Hydrogen losses			2.0%				

14.1.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the

gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

14.1.1.2 GG2 NG long-distance pipeline transport to EU border

With reference to section 3.2 of the WTT report, we have used as a proxy for the EU-mix a pipeline transportation distance of 2400 km (1900 km to EU border and 500 km inside EU) which results in energy and emissions similar to the actual piped natural gas mix.

14.1.1.3 GG3 NG pipeline transport inside EU (same as for distribution)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/t.km is typical of European networks. Gas losses are reportedly very small.

14.1.1.4 GG4 NG local distribution (low pressure)

The low-pressure networks are fed from the high-pressure trunk lines and supply small commercial and domestic customers. No additional energy is required for these networks, the pressure energy from the trunk lines being more than adequate for the local transport.

Various pressure levels are used in different countries and even within countries. Although some local networks are still at very low pressure (<100 mbar(g)) the modern European standard is 0.4 MPa(g) (with pressure reduction at the customer boundary). Very low-pressure networks also need to be fed by higher pressure systems at regular intervals (e.g. 0.7 MPa in the UK). As a result, it is reasonable to assume that, as long as a gas network is present in the area, a supply at a few bars pressure will be available for CNG refuelling stations in the vast majority of cases. Pressures up to 2 MPa are also available in some areas and may be available to some sites, particularly fleet refuelling stations. We have assumed that the typical refuelling station will be supplied at 0.4 MPa.

Significant methane losses have been reported for these local networks. They appear, however, to be based on overall gas accounting and therefore include measurement accuracy. Some losses are associated with purging operations during network maintenance. It is difficult to believe that local networks would have sizeable continuous losses. In any case all such losses would be related to the extent of the network rather than the throughput. NG used for road transport would only represent a modest increase of the total amount transported in the network and would therefore not cause significant additional losses.

14.1.1.5 GH1 NG compression (1.6 MPa)

NG needs to be compressed from 0.5 to 1.6 MPa in order to be fed into the reformer.

14.1.1.6 GH2a NG on-site steam reforming

This represents a small-scale steam reformer installed at the retail site, with an efficiency of about 69%.

14.1.1.7 HC4 Hydrogen compression and dispensing at retail site

Hydrogen is available at 1.5 MPa at the reformer outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The compression process includes precooling at -40°C.

14.2 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 (GPCHx)

- 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

- GPCH4b2: Compressed Hydrogen via methane cracking (BASF process), hydrogen pipeline, compression to 88 MPa at retail station

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.0798				
	Transformation at source							
	NA							
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ_{fuel}	0.0084				
	N_2O emissions		g/MJ_{fuel}	0.0026				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				[Thinkstep 2017]
	Compression specific energy		MJ/t.km	0.360	0.120	0.400	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.1398				[GEMIS 2016]
GG2/07	**NG pipeline transport inside EU**							
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				[GEMIS 2016]
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				[GEMIS 2016]
	GPCG1a (Russia)							
	Distance		km	700				
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.0009				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ_{NG}	0.1057				[Wuppertal 2004]
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ_{NG}	0.0006				
GG4	**NG local distribution (low pressure)**							[Ruhrgas 2003]
	No contribution							
	Transformation near market							
GH1	**NG compression (1.6 MPa)**							JEC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{NG}	0.0059				
GH2a	**NG on-site steam reforming**							[Haldor Topsoe 1998]
	NG		MJ/MJ_{H2}	1.4406	1.4118	1.4494	Normal	
	CH_4 emissions (losses)		g/MJ_{H2}	0.0208				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0161				
GH2b	**NG central reformer**							[Foster Wheeler 1996]
	NG		MJ/MJ_{H2}	1.3150	1.2890	1.3410	Normal	
	CH_4 emissions (losses)		g/MJ_{H2}	0.0159				
GH2bC	**NG central reformer with CCS**							[Foster Wheeler 1996]
	NG		MJ/MJ_{H2}	1.3650	1.3380	1.3920	Normal	
	CO_2 emissions		g/MJ_{H2}	11.86				
	CH_4 emissions (losses)		g/MJ_{H2}	0.0159				
GH3a	**CH4 cracking (liquid metal route)**							[Postels et al. 2016]
	NG		MJ/MJ_{H2}	2.1708				
	Electricity		MJ/MJ_{H2}	0.0502				
	Coke export		MJ/MJ_{H2}	1.0674				
	CO2 emissions		g/MJ_{H2}	0.02				
GH3b	**CH4 cracking (BASF process)**							[Machhammer et al. 2016]
	NG		MJ/MJ_{H2}	1.6580				
	Electricity		MJ/MJ_{H2}	0.2169				
	Coke export		MJ/MJ_{H2}	0.8133				
	CO2 emissions		g/MJ_{H2}	0.00				
HL1	**Hydrogen liquefaction**							[Le Breton 2002], [Tomforde 2004]
	Electricity	GGe	MJ/MJ_{H2}	0.3000	0.2100	0.3900	Square	
	Conditioning & Distribution							
HC1	**Hydrogen pipeline**							
	Distance		km	55				
	No contribution							
HC2	**Hydrogen compression for road transport (3.0 to 50.0 MPa)**							LBST internal
	Electricity (EU-mix, LV)	EMLa	MJ/MJ_{H2}	0.0537	0.051	0.0567	Normal	
HC3	**C-H2 road transport**							
	Distance	*T1*	km	50				
	Payload / tank mass		t/t	0.955/28				
HL4	**L-H2 road transport**							
	Distance	*T1*	km	300				
	Payload / tank mass		t/t	3.5/27.5				
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
HC4a	On-site reformer (1.5 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0917	0.0871	0.0963	Normal	
HC4b	Central reformer (2.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0864	0.0821	0.0907	Normal	
HC4c	C-H2 road transport (50.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0528	0.0502	0.0554	Normal	
	Hydrogen losses			2.0%				
HL6	**L-H2 vaporisation compression and dispensing**							[Linde 2001]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJH2	0.0513				

14.2.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

14.2.1.2 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

14.2.1.3 G2/07 NG pipeline transport inside EU

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/t.km is typical of European networks. Gas losses are reportedly very small.

14.2.1.4 GG4 NG local distribution (low pressure)

The low-pressure networks are fed from the high-pressure trunk lines and supply small commercial and domestic customers. No additional energy is required for these networks, the pressure energy from the trunk lines being more than adequate for the local transport.

Various pressure levels are used in different countries and even within countries. Although some local networks are still at very low pressure (<100 mbar(g)) the modern European standard is 0.4 MPa(g) (with pressure reduction at the customer boundary). Very low-pressure networks also need to be fed by higher pressure systems at regular intervals (e.g. 0.7 MPa in the UK). As a result, it is reasonable to assume that, as long as a gas network is present in the area, a supply at a few bars pressure will be available for CNG refuelling stations in the vast majority of cases. Pressures up to 2 MPa are also available in some areas and may be available to some sites, particularly fleet refuelling stations. We have assumed that the typical refuelling station will be supplied at 0.4 MPa.

Significant methane losses have been reported for these local networks. They appear, however, to be based on overall gas accounting and therefore include measurement accuracy. Some losses are associated with purging operations during network maintenance. It is difficult to believe that local networks would have sizeable continuous losses. In any case all such losses would be related to the extent of the network rather than the throughput. NG used for road transport would only represent a modest increase of the total amount transported in the network and would therefore not cause significant additional losses.

14.2.1.5 GH1 NG compression (1.6 MPa)

NG needs to be compressed from 0.5 to 1.6 MPa in order to be fed into the reformer.

14.2.1.6 GH2a NG on-site steam reforming

This represents a small-scale steam reformer installed at the retail site, with an efficiency of about 69%. There are some methane losses.

14.2.1.7 GH2b NG central reformer

This represents a medium to large scale steam reformer, with an efficiency of about 76%. There are some methane losses.

14.2.1.8 GH2bC NG central reformer with CCS

CO2 capture causes a loss of efficiency of about 3%.

14.2.1.9 GH3a CH4 cracking (liquid metal route)

This represents a process where methane is cracked into hydrogen and solid carbon via a cracking process based on liquid metal technology. The process has been developed by the Institute for Advanced Sustainability Studies (IASS) in collaboration with the Karlsruhe Institute of Technology (KIT) and tested in experiments at laboratory scale. The reactor consists of quartz tubes filled with liquid tin (76.2 vol.-%) and a quartz packed bed (23.8 vol.-%). The liquid tin fills the spaces in the solid quartz packed bed. The methane bubbles rise by buoyancy from the bottom to the top of the reactor. In the liquid-metal reactor, methane is converted to gaseous hydrogen and solid carbon at temperatures up to 1200°C. The produced carbon accumulated above the liquid tin surface, without blocking the reactors operation. The heat required for methane cracking is supplied by combustion of a part of the hydrogen leaving the hydrogen separation plant which is based on a membrane.

14.2.1.10 GH3b CH4 cracking (BASF process)

This represents a process where methane is cracked into hydrogen and solid carbon via pyrolysis. The heat required for pyrolysis is supplied by electricity. The process has been developed by BASF and is tested at laboratory scale.

14.2.1.11 HL1 Hydrogen liquefaction

Liquefaction is a highly energy intensive process. Energy requirement figures vary within a wide range. One reason for this is that many of the existing liquefaction plants were not built with the objective of maximum energy efficiency as they are mostly relatively small and making hydrogen as a premium product for the chemical industry. Figures in the region of 0.35-0.40 MJ_e/MJ are not uncommon but experts agree that much lower figures down nearly 0.2 can be achieved [LBST 2001], [Quack 2001/1], [Quack 2001/2] have therefore taken a wide range with a square probability distribution. Note that this process refers to process GGe i.e. assumes electricity is produced in a dedicated natural gas CCGT.

14.2.1.12 HC1 Hydrogen pipeline

Hydrogen is available at a sufficient pressure at the reformer outlet to compensate for the pressure drop in the pipeline (55 km). No additional energy is required.

14.2.1.13 HC2 Hydrogen compression for road transport (3.0 to 50.0 MPa)

Hydrogen is compressed to 50 MPa for road transport.

14.2.1.14 HC3 C-H2 road transport

Road transport assumes a standard truck with a 28 t tank transporting 0.955 ton of compressed hydrogen.

14.2.1.15 HL4 L-H2 road transport

Road transport assumes a standard truck with a 24 t tank transporting 3.5 ton of liquid hydrogen.

14.2.1.16 HC4 Hydrogen compression and dispensing at retail site

For on-site reformers, hydrogen is available at 1.5 MPa at the reformer outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The inlet pressure is slightly higher with a central reformer and pipeline system (2.0 MPa). If hydrogen is transported by road it is already compressed to 50.0 MPa. The compression process includes precooling at -40°C.

14.2.1.17 HL6 L-H2 vaporisation compression and dispensing

Hydrogen delivered in liquid form to the refuelling station has to be vaporised and compressed if the vehicles require compressed hydrogen. This process is less energy-intensive than compression of gaseous hydrogen, essentially as the liquid can be pumped to the required pressure before vaporisation [BOC 1997], [Linde 2001].

14.3 Remote natural gas liquified at source, LNG sea transport, vaporisation at import terminal, distribution through gas high pressure trunk lines (GRCHx)

- 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.

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0100	0.0400	2-triangle	
	CO$_2$ venting		%v/v	1.0%				
	CH$_4$ losses		g/MJ$_{NG}$	0.08				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ$_{LNG}$	0.0113	0.0025	0.0200	Square	[FfE 1996]
	CH$_4$ emissions		g/MJ$_{LNG}$	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
NM1	**NG to methanol plant**							[Larsen 1998]
	Efficiency			68.3%	67.3%	69.4%	Square	
	CH$_4$ emissions		g/MJ$_{methanol}$	0.000083				
NM2	**Methanol depot**							[TOTAL 2002]
	Electricity		MJ/MJ$_{methanol}$	0.0018				
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency		%	58%	57%	59%	Normal	
	CH$_4$ emissions		g/MJ$_{elec}$	0.0054				
	N$_2$O emissions		g/MJ$_{elec}$	0.0043				
	Transportation to market							
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ$_{LNG}$	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ$_{LNG}$	0.0222				[Mitsubishi 2000]
	CH$_4$ emissions		g/MJ$_{LNG}$	0.00013				[GEMIS 2001]
	N$_2$O emissions		g/MJ$_{LNG}$	0.00009				[GEMIS 2001]
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GR5	**LNG vaporisation**							LBST internal
	Heat as NG		MJ/MJ$_{NG}$	0.0194				
	NG to pump drive (gas engine)		MJ/MJ$_{NG}$	0.0012	0.0009	0.0014	Square	
	CH$_4$ emissions		g/MJ$_{NG}$	0.000004	0.000004	0.000005		
	N$_2$O emissions		g/MJ$_{NG}$	0.000005	0.000004	0.000007		
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH$_4$ emissions		g/MJ$_{fuel}$	0.0042				
	N$_2$O emissions		g/MJ$_{fuel}$	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ$_{NG}$	0.0006				
GG4	**NG local distribution (low pressure)**							[Ruhrgas 2003]
	No contribution							
NM3	**Methanol long-distance sea transport**							
	50 kt liquid carrier	*T3c*						
	Distance		nautical miles	5500	5000	6000	Square	
NM2	**Methanol depot**							[TOTAL 2002]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{Meth}$	0.0018				
NMD4a	**Methanol/DME distribution**							
	Rail	*T2*						
	Distance		km	250				
	Road truck	*T1*						
	Distance		km	250				
	Payload / tank mass		t/t					
	Methanol			26/28				
	DME			20/28				
	Transformation near market							
GH1	**NG compression (1.6 MPa)**							JEC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{NG}$	0.0059				
GH2a	**NG on-site steam reforming**							[Haldor Topsoe 1998]
	NG		MJ/MJ$_{H2}$	1.4406	1.4118	1.4494	Normal	
	CH$_4$ emissions (losses)		g/MJ$_{H2}$	0.0208				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0161				
GH2b	**NG central reformer**							[Foster Wheeler 1996]
	NG		MJ/MJ$_{H2}$	1.3150	1.2890	1.3410	Normal	
	CH$_4$ emissions (losses)		g/MJ$_{H2}$	0.0159				
MH1	**Methanol steam reforming**							[Moore 1996]
	Methanol			1.1896				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0065				
	Conditioning & Distribution							
HC1	**Hydrogen pipeline**							
	Distance		km	55				
	No contribution							
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
GH2a	On-site NG reformer (1.5 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0917	0.0871	0.0963	Normal	
HC4b	Central NG and on-site methanol reformer (2.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0864	0.0821	0.0907	Normal	

14.3.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

14.3.1.2 GR1 NG liquefaction

The energy required for the liquefaction process is well documented and not subject to a large uncertainty. It is assumed here that the electrical power for the compressors is supplied by a gas fired on-site combined cycle gas fired power plant (see process GGe).

Some off gas is flared for which estimates vary widely in the literature hence the wide range used. There are also small methane losses.

A significant amount of natural gas is used to generate the electrical energy required for liquefaction. The corresponding CO2 could be captured (see process CGeC). The proximity of gas and possibly oil field where the CO2 could be injected would enhance the feasibility of such a scheme.

14.3.1.3 GR2 LNG loading terminal

A small amount of electricity is required for the operation of the terminals. In addition, the evaporation losses (estimated at 1%) are flared resulting in CO2 emissions. The electricity is deemed to be produced by the on-site gas-fired power plant (process GGe).

14.3.1.4 NM1 NG to methanol plant

The plant energy efficiency selected here corresponds to a current state-of-the-art installation. The upper value (29.64 GJ/t of methanol) is the value guaranteed by the manufacturer, the lower value (28.74 GJ/t of methanol) is a measured value for the methanol plant located in Tjeldbergodden in Norway.

This process is applicable to both a remote plant and a large “central” plant located in Europe (typically 600 MW in terms of methanol, equivalent to about 100 t/h).

14.3.1.5 NM2 Methanol depot

A small amount of electricity is required for the operation of loading and unloading depot and terminal facilities. The figure used for gasoline/diesel has been prorated to remain the same per tonne of product.

14.3.1.6 GGe On-site electricity generation (NG-fired CCGT)

In all gas transformation schemes requiring significant amounts of electricity, we have assumed the latter is produced on-site by a state-of-the-art gas-fired combined cycle gas turbine (CCGT) with a typical efficiency of 55% (52-58%). The high end of the range represents potential future improvements to the technology that are thought to be achievable in the next ten years.

14.3.1.7 GR3 LNG long-distance sea transport

LNG is transported in specially designed cryogenic carriers. Heat ingress is compensated by gas evaporation. The evaporation rate is estimated at 0.15% per day, the number of days being based on an average speed of 19.5 knots. The average distance has been taken as 4000 nautical miles, based on the average for the supply of LNG to EU. The LNG is imported from Algeria, Norway, Nigeria, and Qatar.

The evaporated gas is used as fuel for the ship, the balance being provided by standard marine bunker fuel (HFO). This practice is also valid for the return voyage inasmuch as the LNG tanks are never completely emptied in order to keep them at low temperature (required for metallurgical reasons). The figures include an allowance for the return trip in accordance with the “admiralty formula” (see process Z4: LNG carriers have a typical gross tonnage of 110,000 t, including a payload of 135,000 m3 or 57,000 t [Hanjin 2000] [Mitsubishi 2000]. This results in a ratio of 0.8 between the full and empty ship).

The figures include provision for return trip.

14.3.1.8 GR4 LNG unloading terminal

The terminal electricity requirement is deemed to be the same as for the loading terminal (see process GR2). The electricity, however, is now assumed to be supplied by the EU grid. If LNG is vaporised on receipt no evaporation losses are included; if LNG is further transported as such, the same figures as for the loading terminal are used. A small additional electricity consumption (0.0007 to 0.0010 MJ/MJ of LNG) is added for the LNG terminal. The road tanker loading and unloading is carried out by a truck mounted LNG pump. The additional diesel requirement for the LNG pump is very low (approximately 0.0002 MJ/MJ of LNG).

14.3.1.9 GR5 LNG vaporisation

If it is to be used in the gas distribution grid, LNG needs to be vaporised and compressed. Although small amounts can be vaporised with heat taken from the atmosphere, this is impractical for large evaporation rates and heat at higher temperature must be supplied. The figures used here assume compression (as liquid) to 4 MPa followed by vaporisation and heating of the gas from -162 to 15°C.

14.3.1.10GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/(t.km) are typical of European networks. Gas losses are reportedly very small.

14.3.1.11GG4 NG local distribution (low pressure)

The low-pressure networks are fed from the high-pressure trunk lines and supply small commercial and domestic customers. No additional energy is required for these networks, the pressure energy from the trunk lines being more than adequate for the local transport.

Various pressure levels are used in different countries and even within countries. Although some local networks are still at very low pressure (<100 mbar(g)) the modern European standard is 0.4 MPa(g) (with pressure reduction at the customer boundary). Very low-pressure networks also need to be fed by higher pressure systems at regular intervals (e.g. 0.7 MPa in the UK). As a result, it is reasonable to assume that, as long as a gas network is present in the area, a supply at a few bars pressure will be available for CNG refuelling stations in the vast majority of cases. Pressures up to 2 MPa are also available in some areas and may be available to some sites, particularly fleet refuelling stations. We have assumed that the typical refuelling station will be supplied at 0.4 MPa.

Significant methane losses have been reported for these local networks. They appear, however, to be based on overall gas accounting and therefore include measurement accuracy. Some losses are associated with purging operations during network maintenance. It is difficult to believe that local networks would have sizeable continuous losses. In any case all such losses would be related to the extent of the network rather than the throughput. NG used for road transport would only represent a modest increase of the total amount transported in the network and would therefore not cause significant additional losses.

14.3.1.12NM3 Methanol long-distance sea transport

Large remote methanol plants are likely to be built near large gas reserves, typically in the Middle East. Transport distance to Europe is between 5 and 6000 Nm. The assume ship is a 50kt liquid carrier as per process T3c.

14.3.1.13NMD4a Methanol/DME distribution

A mixture of rail and road is assumed for a total distance of 500 km.

14.3.1.14HC1 Hydrogen pipeline

Hydrogen is available at a sufficient pressure at the reformer outlet to compensate for the pressure drop in the pipeline (55 km). No additional energy is required.

14.3.1.15HC4 Hydrogen compression and dispensing at retail site

For on-site NG reformers, hydrogen is available at 1.5 MPa at the reformer outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The inlet pressure is slightly higher with a central NG reformer and pipeline system or for a methanol on-site reformer (2.0 MPa). The compression process includes precooling at -40°C.

14.4 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, liquefied hydrogen road transport to retail station, hydrogen cryo- compression in to vehicle tank (35 MPa) (GPLHx)

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ_{NG}	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ_{NG}	0.0798				
	Transformation at source							
	NA							
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ_{fuel}	0.0084				
	N_2O emissions		g/MJ_{fuel}	0.0026				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				[Thinkstep 2017]
	Compression specific energy		MJ/t.km	0.360	0.120	0.400	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.1398				[GEMIS 2016]
GG2/07	**NG pipeline transport inside EU**							
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				[GEMIS 2016]
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				[GEMIS 2016]
	GPCG1a (Russia)							
	Distance		km	700				
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ_{NG}	0.0009				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ_{NG}	0.1057				[Wuppertal 2004]
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ_{fuel}	0.0042				
	N_2O emissions		g/MJ_{fuel}	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ_{NG}	0.0006				
	Transformation near market							
GH2b	**NG central reformer**							[Foster Wheeler 1996]
	NG		MJ/MJ_{H2}	1.3150	1.2890	1.3410	Normal	
	CH_4 emissions (losses)		g/MJ_{H2}	0.0159				
HL1	**Hydrogen liquefaction**							[Le Breton 2002], [Tomforde 2004]
	Electricity	*GGe*	MJ/MJ_{H2}	0.3000	0.2100	0.3900	Square	
	Conditioning & Distribution							
HL4	**Liquid hydrogen road transport**							
	Distance	*T1*	km	300				
	Payload / tank mass		t/t	3.5/27.5				
	Losses			0.5%				
HL5	**Liquid hydrogen dispensing (cryo-compression)**							[Brunner 2011], [Kampitsch 2012]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0100				

14.4.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the

gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

14.4.1.2 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

14.4.1.3 GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/t.km is typical of European networks. Gas losses are reportedly very small.

14.4.1.4 GH2b NG central reformer

This represents a medium to large scale steam reformer, with an efficiency of about 76%. There are some methane losses.

14.4.1.5 HL1 Hydrogen liquefaction

Liquefaction is a highly energy intensive process. Energy requirement figures vary within a wide range. One reason for this is that many of the existing liquefaction plants were not built with the objective of maximum energy efficiency as they are mostly relatively small and making hydrogen as a premium product for the chemical industry. Figures in the region of 0.35-0.40 MJ_e/MJ are not uncommon but experts agree that much lower figures down nearly 0.2 can be achieved [LBST 2001], [Quack 2001/1], [Quack 2001/2] have therefore taken a wide range with a square probability distribution. Note that this process refers to process GGe i.e. assumes electricity is produced in a dedicated natural gas CCGT.

14.4.1.6 HL4 Liquid hydrogen road transport

Road transport assumes a standard truck with a 24 t tank transporting 3.5 ton of liquid hydrogen.

14.4.1.7 HL5 Liquid hydrogen dispensing (cryo-compression)

Liquefied hydrogen is pumped into the vehicle tank and compressed at a maximum of 35 MPa. The electricity requirement is about 1% of the dispensed hydrogen [Kampitsch 2012]. 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 [Ahluwalia 2018].

14.5 Remote natural gas (GRLHx)

- 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).

14.6 EU-mix hard coal without/with CCS, hydrogen pipeline transport, compression at retail site (KOCH).

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
KO1	**Hard coal supply (EU-mix)**							[El Cerrejon 2002], [DOE 2002],
	Hard coal (primary)		MJ/MJ_{Coal}	1.0266				0
	Brown coal (primary)		MJ/MJ_{Coal}	0.0016				0
	Crude oil		MJ/MJ_{Coal}	0.0375				0
	Natural gas (primary)		MJ/MJ_{Coal}	0.0100				0
	Hydro power		MJ/MJ_{Coal}	0.0010				0
	Nuclear		MJ/MJ_{Coal}	0.0109				
	Waste		MJ/MJ_{Coal}	0.0018				
	CO_2 emissions		g/MJ_{Coal}	6.27				
	CH_4 emissions		g/MJ_{Coal}	0.3852				
	N_2O emissions		g/MJ_{Coal}	0.0003				
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
KH1	**Coal gasification to hydrogen**							[Foster Wheeler 1996]
	Hard coal		MJ/MJ_{H2}	1.967				
KH1C	**Coal gasification to hydrogen with CCS**							[Foster Wheeler 1996]
	Hard coal		MJ/MJ_{H2}	2.303				
	CO_2 emissions		g/MJ_{H2}	5.64				
	Conditioning & Distribution							
HC1	**Hydrogen pipeline**							
	Distance		km	55				
	No contribution							
HC4	**Hydrogen compression and dispensing at retail site**							[Angloher 1999]
HC4b	Central coal gasification (2.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0864	0.0821	0.0907	Normal	

14.6.1.1 KO1 Hard coal supply (EU-mix)

These figures approximate the average primary energy associated to the production and provision of hard coal to Europe.

14.6.1.2 KH1 Coal gasification to hydrogen

This represents the total process from coal gasification through CO shift, PSA etc.

14.6.1.3 KH1C Coal gasification to hydrogen with CCS

Same as above with additional capture of CO2. The figures for both cases (with and without capture) are based on a conceptual plant design described in [Foster Wheeler 1996].

14.6.1.4 HC1 Hydrogen pipeline

Hydrogen is available at a sufficient pressure at the reformer outlet to compensate for the pressure drop in the pipeline (55 km). No additional energy is required.

14.6.1.5 HC4 Hydrogen compression and dispensing at retail site

Hydrogen is available at 2.0 MPa from the pipeline and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The compression process includes precooling at -40°C.

14.7 Wood (WF: farmed, WW: waste) (WxCH)

- 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.

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation, harvesting & chipping**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{wood}$					
	N (as N)	*FN*		0.00				JRC internal
	Pesticides	*PE*	g/MJ$_{wood}$	0.015				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000161				
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000397				
	N_2O field emissions		g/MJ$_{wood}$	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
FRC	**Forestry residue collection**							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0120				[Lindholm et al. 2010], [Sikkema et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000009				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000038				[EMEP/EEA 2013]
FRS	**Forestry residue seasoning**							
	Losses			5.0%				[Hamelinck 2005], [Kofman 2012], [Lindholm 2010]
W2	**Forestry residue chipping**							
	Diesel		MJ/MJ$_{wood}$	0.0034				[Lindholm et al. 2010]
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.000003				[EMEP/EEA 2013]
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.000011				[EMEP/EEA 2013]
	Losses			2.5%				[JRC 2013], [Sikkema et al. 2010]
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content			30%				
WF3a	**Farmed wood transport (local, 50 km, WFCH1)**							
	Road truck	*T1*						
	Distance		km	50				
WF3b	**Farmed wood transport (regional, 500 km, WFCH2)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
WW3a	**Waste wood transport (local, 50 km, WWCH1)**							
	Road truck	*T1*						
	Distance		km	50				
WW3b	**Waste wood transport (regional, 500 km, BLCH2)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
WW3c	**Waste wood transport (regional, >500 km, WWCH2)**							JRC internal
WW3c1	Road truck	*T1*						
	Distance		km	250				
WW3c2	**Bulk carrier (Handysize)**	*T3h*						
	Distance		km	2000				
	Transformation near market							
WH1	**Wood to hydrogen small scale (AER process)**							[ZSW 2008]
	Wood chips		MJ/MJ$_{H2}$	1.5764	1.7848	1.3399	Square	
	Heat surplus (no credit)		MJ/MJ$_{H2}$	-0.1441				
WH2	**Wood to hydrogen large scale (BCL gasifier)**							[FfE 1998], [Katofsky 1993], [Paisley 2001], [Sydcraft 2002]
	Wood chips		MJ/MJ$_{H2}$	1.6553	1.9199	1.4850	Normal	
WH3	**Forestry residue to hydrogen via black liquor**							[Ekbom 2003], [Ekbom 2005]
	Wood chips		MJ/MJ$_{H2}$	1.2410	1.3030	1.1790	Square	
	Conditioning & Distribution							
HC1	**Hydrogen pipeline**							
	Distance		km	55				
	No contribution							
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
HC4b	Central NG and on-site methanol reformer (2.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0864	0.0821	0.0907	Normal	

14.7.1.1 WF1 Wood plantation, harvesting & chipping

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

14.7.1.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

14.7.1.3 FRC Forestry residue collection

The process includes stump harvesting. Moreover, various logistic choices that are being developed, especially in Scandinavian countries, are considered, including the use of bundled and loose residues. The process of forestry residue collection includes forwarding, bundling/lifting, forestry machinery transport, and loading/unloading [Giuntoli et al. 2017].

14.7.1.4 FRS Forestry residue seasoning

It includes open air seasoning at roadside with the residues covered from rain. Storage is usually for a period of 3-8 months. Moisture of the wood is considered to be lowered from 50% to 30%. About 5% of the dry matter is lost due to degradation [Giuntoli et al. 2017].

14.7.1.5 W2 Forestry residue chipping

Average of energy consumption between a mobile (diesel) chopper for roadside operation and an electrical central chopper.

14.7.1.6 WF3a Farmed wood transport (local, 50 km, WFCH1)

In case of the smaller 10 MW_{th} plant wood farming is assumed to occur within a small distance from the plant, hence the 50 km toad transport.

14.7.1.7 WF3b Farmed wood transport (regional, 500 km, WFCH2)

For large plants a transport distance of 500 km has been assumed if the wood is derived from regions inside the EU.

14.7.1.8 WW3a Waste wood transport (local, 50 km, WWCH1)

In case of the smaller 10 MW_{th} plant wood farming is assumed to occur within a small distance from the plant, hence the 50 km toad transport.

14.7.1.9 WW3b Waste wood transport (regional, 500 km, BLCH2)

For large plants a transport distance of 500 km has been assumed if the wood is derived from regions inside the EU.

14.7.1.10 WW3c Waste wood transport (regional, >500 km, WWCH2)

Because of more limited availability, waste wood is assumed to be transported over longer distances in a combination of road and inland waterways. In [Giuntoli 2017] a combination of road (250 km) and ship (2000 km) is indicated for wood import e.g. from Russia.

14.7.1.11 WH1 Wood to hydrogen small scale (AER process)

This represents the absorption enhanced reforming (AER) process 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. In the AER process a different bed material is used which captures the CO2 to elevate the hydrogen content of the product gas by reaction with CaO to form CaCO3. The CaCO3 is sent to the combustion chamber together with the formed bio-coke where the CaCO3 is regenerated back to CaO.

14.7.1.12 WH2 Wood to hydrogen large scale (BCL gasifier)

We took the detailed description of a wood-to-hydrogen plant based on the Battelle Columbus Gasifier (BCL) in [Katofsky 1993]. It includes gasification, gas clean up, CO shift and pressure swing adsorption (PSA). The plant described in [Katofsky 1993] has a net electricity input. It has been assumed that the net electricity demand is met by a wood chip fueled integrated gasification combined cycle (IGCC) power plant with an efficiency of 42.5% based on data in [Paisley 2001] and [Sydcraft 2002]. In [Katofsky 1993] the energy related data are based on the higher heating value (HHV). The ratio between LHV and HHV of wood chips has been derived from the LHV of wood indicated in [FfE 1998].

14.7.1.13 WH3 Forestry residue to hydrogen via black liquor

For the production of hydrogen via black liquor gasification we took the detailed description of the BLGMF plant in [Ekbom 2003] and considered what modifications would be needed to make hydrogen instead of methanol. The methanol synthesis and distillation are not needed, but a larger CO shift reactor is required, coupled to a pressure swing absorption (PSA) to purify the hydrogen.

The hydrogen process starts from stream 4 in Figure 14.4. All this goes to the CO-shift instead of only half for the methanol plant. Therefore, more steam is required for the CO shift reactor, but on the other hand the outlet of the CO shift contains more steam, because more is formed in the reaction. The net amount of steam compared with the methanol plant depends on whether the shift reaction is exothermic or endothermic. If we calculate this starting from steam, it is slightly exothermic, but if we include the energy for generating the steam from water, it is slightly endothermic. In practice, one could find a source of steam, but a little less heat would be recovered. Thus, the difference in steam requirements is approximately zero.

The CO2 absorption (Abs 2) is not required because CO2 is anyway removed downstream in the PSA. The pressure at the outlet of the CO shift reactor (2.9 MPa; [Ekbom 2003]) is sufficient to drive the PSA process. Hydrogen recovery is assumed to be 86%; the tail-gases can be burnt for steam and electricity.

Compared to the reference pulp mill, the BGLF-hydrogen process produces 247 MW H2 and 108.3 MW of the other gases. Thus, 1MJ extra biomass would produce 0.594 MJ hydrogen and leave 0.261 MJ in the tail-gas. If the tail gas is added to the boiler of the existing condensing steam-turbine generator, it will save the same energy input of biomass. Therefore only 0.839 MJ biomass are needed to 0.594 MJ hydrogen by itself. Thus, the efficiency to hydrogen is 81% and 1.24 MJ biomass are needed to make 1 MJ hydrogen.

14.7.1.14 HC1 Hydrogen pipeline

Hydrogen is available at a sufficient pressure at the reformer outlet to compensate for the pressure drop in the pipeline (55 km). No additional energy is required.

14.7.1.15 HC4 Hydrogen compression and dispensing at retail site

Hydrogen is available at 2.0 MPa from the gasifier and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The compression process includes precooling at -40°C.

14.8 Upgraded biogas from municipal organic waste sent to onsite SMR, Hydrogen compression to 88 MPa at retail site (OWCH1)

Closed digestate storage

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
BG3.1	**Fermenter (closed digestate storage)**							[Giuntoli et al. 2017]
	Raw gas yield		MJ/MJ$_{\text{waste}}$	0.7073	0.7445	0.6736	Square	
	Heat to process		MJ/MJ$_{\text{raw gas}}$	0.0976	0.0927	0.1024	Square	
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/MJ$_{\text{raw gas}}$	0.0293	0.0278	0.0307	Square	
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ$_{\text{heat}}$	0.0056				
	N_2O emissions		g/MJ$_{\text{heat}}$	0.0011				
BG4.1	**Upgrading**							
	Upgraded gas yield		MJ/MJ$_{\text{raw gas}}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{\text{gas}}$	0.0300				[Schulz 2004], JRC internal
	RED methodology							
	No credit for N fertilizer							
	Conditioning & Distribution							
	Local distribution (low pressure)							
	No contribution							
GH1	**CH_4 compression (1.6 MPa)**							JEC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{\text{NG}}$	0.0059				
GH2a	**CH_4 on-site steam reforming**							[Haldor Topsoe 1998]
	Upgraded biogas		MJ/MJ$_{H2}$	1.4406	1.4118	1.4494	Normal	
	CH_4 emissions (losses)		g/MJ$_{H2}$	0.0208				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0161				
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
HC4a	On-site reformer (1.5 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0917	0.0871	0.0963	Normal	
	Hydrogen losses			2.0%				

14.8.1.1 BG3.1 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. The conversion level of the organic matter is typically 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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. (version 3 of this study assumed a gas engine supplying both heat and electricity but we have modified this to ensure consistency amongst all CBG pathways). Some methane losses are incurred as well as some N2O emissions.

14.8.1.2 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m3 per 100 Nm3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas).

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

14.8.1.3 GH1 CH4 compression (1.6 MPa)

The biomethane needs to be compressed from 0.5 to 1.6 MPa in order to be fed into the reformer.

14.8.1.4 GH2a CH4 on-site steam reforming

This represents a small-scale steam reformer installed at the retail site, with an efficiency of about 69%.

14.8.1.5 HC4 Hydrogen compression and dispensing at retail site

Hydrogen is available at 1.5 MPa at the reformer outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The compression process includes precooling at -40°C.

14.9 Upgraded biogas from wet manure sent to onsite SMR (OWCH2)

Digestate storage closed (21) or open (22)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
BG1.1	**GHG emissions credit from avoided manure storage**							[Guintoli et al. 2017]
	CH_4 emissions		g/MJ_{manure}	-1.4700				
	N_2O emissions		g/MJ_{manure}	-0.0279				
	Transformation at source							
	NA							
	Transportation to market							
BG2.2	**Manure transport (Road)**							
	Distance	*F1*	km	5				
	Transformation near market							
BG3.21	**Fermenter (closed digestate storage)**							JRC internal
OWCG21	Raw gas yield		MJ/MJ_{manure}	0.4620				
	Heat to process		MJ/$MJ_{raw\ gas}$	0.0909				
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/$MJ_{raw\ gas}$	0.0182				
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ_{heat}	0.0056				
	N_2O emissions		g/MJ_{heat}	0.0011				
BG3.22	**Fermenter (open digestate storage)**							JRC internal
OWCG22	Raw gas yield		MJ/MJ_{manure}	0.4200				
	Heat to process		MJ/$MJ_{raw\ gas}$	0.1000				
	Electricity (EU-mix, LV) to process	*EMLa*	MJ/$MJ_{raw\ gas}$	0.0200				
	CH_4 emissions		g/$MJ_{raw\ gas}$	2.00				
	N_2O emissions		g/$MJ_{raw\ gas}$	0.0660				
BG4.1	**Upgrading**							
	Upgraded gas yield		MJ/MJ_{rawgas}	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	RED methodology							
	No CH_4 field emission credit							
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GH1	**CH_4 compression (1.6 MPa)**							JEC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{NG}	0.0059				
GH2a	**CH_4 on-site steam reforming**							[Haldor Topsoe 1998]
	Upgraded biogas		MJ/MJ_{H2}	1.4406	1.4118	1.4494	Normal	
	CH_4 emissions (losses)		g/MJ_{H2}	0.0208				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0161				
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
HC4a	On-site reformer (1.5 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0917	0.0871	0.0963	Normal	
	Hydrogen losses			2.0%				

14.9.1.1 BG1.1 GHG emissions credit from avoided manure storage

If unused or stored, wet manure would produce CH4 and N2O from naturally occurring anaerobic digestion. These emissions are avoided by controlling this process and collecting the gas produced.

BG2.2 Manure transport (Road)

Manure has to be transported over a short distance from the farm to the biogas plant. Road transport is assumed by a standard road truck according to process Z2.

14.9.1.2 BG3.21 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a "digester" in a batch process that can take several days. The gas produced is collected and sent to the treating section. In case of manure the conversion level of the organic matter is typically about 46% (closed digestate storage with CH4 capture and use). Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

14.9.1.3 BG3.22 Fermenter (open digestate storage)

This variant is presented to illustrate the impact of letting all methane from digestate escape to atmosphere.

14.9.1.4 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m3 per 100 Nm3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

14.9.1.5 GH1 CH4 compression (1.6 MPa)

NG needs to be compressed from 0.5 to 1.6 MPa in order to be fed into the reformer.

14.9.1.6 GH2a CH4 on-site steam reforming

This represents a small-scale steam reformer installed at the retail site, with an efficiency of about 69%.

14.9.1.7 HC4 Hydrogen compression and dispensing at retail site

Hydrogen is available at 1.5 MPa at the reformer outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The compression process includes precooling at -40°C.

14.10 Upgraded biogas from sewage sludge sent to onsite SMR (OWCH3)

Closed digestate storage

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
BG3.5	**Fermenter for biogas from sewage sludge (closed digestate storage)**							
	Raw gas yield		MJ/MJ_{sludge}	0.4620	0.4863	0.4400	Equal	[Giuntoli et al. 2017]
	Heat to process		MJ/MJ_{sludge}	0.4767				[Haberkern 2008]
	Electricity (EU-mix, LV) to process	*EMLa*	$MJ/MJ_{raw\ gas}$	0.0688				[Boison 2005]
	Internal heat generation using own raw gas							[GEMIS 2007]
	Efficiency		%	90.0%				
	CH_4 emissions		g/MJ_{heat}	0.0056				
	N_2O emissions		g/MJ_{heat}	0.0011				
BG4.1	**Upgrading**							
	Upgraded gas yield		$MJ/MJ_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	RED methodology							
	No credit for N fertilizer							
	Conditioning & Distribution							
	Local distribution (low pressure)							
	No contribution							
GH1	**CH_4 compression (1.6 MPa)**							JEC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{NG}	0.0059				
GH2a	**CH_4 on-site steam reforming**							[Haldor Topsoe 1998]
	Upgraded biogas		MJ/MJ_{H2}	1.4406	1.4118	1.4494	Normal	
	CH_4 emissions (losses)		g/MJ_{H2}	0.0208				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0161				
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
HC4a	On-site reformer (1.5 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0917	0.0871	0.0963	Normal	
	Hydrogen losses			2.0%				

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

14.10.1.1 BG3.5 Fermenter for biogas from sewage sludge (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. It has been assumed that the conversion level of the organic matter is the same as for manure (46% in case of closed digestate storage with CH4 capture and use). Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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. (version 3 of this study assumed a gas engine supplying both heat and electricity but we have modified this to ensure consistency amongst all CBG pathways). Some methane losses are incurred as well as some N2O emissions.

14.10.1.2 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m3 per 100 Nm3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas).

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

14.10.1.3 GH1 CH4 compression (1.6 MPa)

NG needs to be compressed from 0.5 to 1.6 MPa in order to be fed into the reformer.

14.10.1.4 GH2a CH4 on-site steam reforming

This represents a small-scale steam reformer installed at the retail site, with an efficiency of about 69%.

14.10.1.5 HC4 Hydrogen compression and dispensing at retail site

Hydrogen is available at 1.5 MPa at the reformer outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The compression process includes precooling at -40°C.

14.11 Upgraded biogas from maize (whole plant) sent to SMR (OWCH4)

Closed digestate storage

Process code	*Step*	*Common processes*		*Input*	*Range*		*Distribution*	*Source*
	Production & conditioning at source							
BG1.4	**Maize cultivation**							[Giuntoli et al. 2017]
	Agricultural inputs							
	Fertilizers		g/MJ_{maize}					
	N (as N)	*FN*		0.26				
	P (as P2O5)	*FP*		0.16				
	K (as K2O)	*FK*		0.10				
	CaO	*CA*		0.65				
	Pesticides	*PE*		0.03				
	Seeding material	*SCR*		0.10				
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{maize}	0.0155				
	CH4 emissions (from diesel)		g/MJ_{maize}	0.0000198				
	CO2 emissions from soil neutralisation			0.257				
	Field emissions (N2O)		g/MJ_{maize}	0.0193	0.0044	0.0969	2-triangle	[IPCC 2006], [Giuntoli et al. 201
	Ensiling							[Giuntoli et al. 2017]
	Losses			10%				
	Diesel			0.00375				
	CH4 emissions diesel			0.00000479				
	N2O emissions from diesel			0.00001180				
	Transformation at source							
	NA							
	Transportation to market							
BG2.4	**Maize transport (Road)**							[Giuntoli et al. 2017]
	Distance	*T1*	km	20				
	Transformation near market							
BG3.4	**Fermenter (closed digestate storage)**							JRC internal
	Raw gas yield		MJ/MJ_{maize}	1.3978				
	Heat to process		$MJ/MJ_{raw\ gas}$	0.0978				[GEMIS 2007]
	Electricity (EU-mix, LV) to process	*EMLa*	$MJ/MJ_{raw\ gas}$	0.0245				[IEA Biogas Handbook 2013]; [E
BG4.1	**Upgrading**							
	Upgraded gas yield		$MJ/MJ_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GH1	**CH_4 compression (1.6 MPa)**							JEC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{NG}	0.0059				
GH2a	**CH_4 on-site steam reforming**							[Haldor Topsoe 1998]
	Upgraded biogas		MJ/MJ_{H2}	1.4406	1.4118	1.4494	Normal	
	CH_4 emissions (losses)		g/MJ_{H2}	0.0208				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0161				
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
HC4a	On-site reformer (1.5 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0917	0.0871	0.0963	Normal	
	Hydrogen losses			2.0%				

14.11.1.1 BG1.4 Maize cultivation

The maize variety grown for the purpose of producing biogas (maximum biomass) is assumed to be different from standard maize cultivated for grain (such as used in e.g. pathway CRET2).

The yield of maize whole crop (40.76 t of fresh substance per ha and year @ a dry matter content of 35%) and the use of fertilizers is calculated as an average over the EU-27 based on FAOSTAT data for the years 2011 and 2010. The amount of synthetic fertilizer applied accounts already for the application of other organic fertilizers such as manure and digestate (the residue of the anaerobic digestion) [Giuntoli et al. 2017].

14.11.1.2 BG2.4 Maize transport (Road)

Maize is transported by road over a short distance. We assumed a standard truck as described in common process T1.

14.11.1.3 BG3.4 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. In case of maize whole plant silage, the conversion level of the organic matter is typically about 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

14.11.1.4 BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m3 per 100 Nm3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

14.11.1.5 GH1 CH4 compression (1.6 MPa)

NG needs to be compressed from 0.5 to 1.6 MPa in order to be fed into the reformer.

14.11.1.6 GH2a CH4 on-site steam reforming

This represents a small-scale steam reformer installed at the retail site, with an efficiency of about 69%.

14.11.1.7 HC4 Hydrogen compression and dispensing at retail site

Hydrogen is available at 1.5 MPa at the reformer outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The compression process includes precooling at -40°C.

14.12 Upgraded biogas from double cropping (barley/maize) sent to SMR (OWCH5)

Closed digestate storage

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
BG1.4	**Double cropping (barley/maize)**							[GEMIS 2005], [Grass 2001]
	Agricultural inputs							
	N Fertilizer (as N)		g/MJ_{crop}	0.25				
	Seeding material (barley/corn)	*SBA/SCR*	g/MJ_{crop}	0.37				
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{maize}	0.0260				
	CH4 emissions (from diesel)		g/MJ_{maize}	0.0002				
	CO2 emissions from soil neutralisation			2.01				
	Field emissions (N2O)		g/MJ_{maize}	0.0053	0.0011	0.0253	2-triangle	[IPCC 2006]
	Transformation at source							
	NA							
	Transportation to market							
BG2.4	**Crop transport (Road)**							
	Distance	*T1*	km	20				
	Transformation near market							
BG3.4	**Fermenter (closed digestate storage)**							JRC internal
	Raw gas yield		MJ/MJ_{crop}	1.3978				
	Heat to process		$MJ/MJ_{raw\ gas}$	0.0978				[GEMIS 2007]
	Electricity (EU-mix, LV) to process	*EMLa*	$MJ/MJ_{raw\ gas}$	0.0245				
BG4.1	**Upgrading**							
	Upgraded gas yield		$MJ/MJ_{raw\ gas}$	0.9700				JRC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{gas}	0.0300				[Schulz 2004], JRC internal
	Conditioning & Distribution							
GG4	**Local distribution (low pressure)**							
	No contribution							
GH1	**CH_4 compression (1.6 MPa)**							JEC internal
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{NG}	0.0059				
GH2a	**CH_4 on-site steam reforming**							[Haldor Topsoe 1998]
	Upgraded biogas		MJ/MJ_{H2}	1.4406	1.4118	1.4494	Normal	
	CH_4 emissions (losses)		g/MJ_{H2}	0.0208				
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0161				
HC4	**Hydrogen compression and dispensing at retail site**							LBST internal
HC4a	On-site reformer (1.5 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0917	0.0871	0.0963	Normal	
	Hydrogen losses			2.0%				

14.12.1.1BG1.4 Double cropping (barley/maize)

Two crops are grown sequentially on the same land and within a single, the whole plant being harvested perhaps before it reaches maturity. In European conditions, maize and barley appear to be the best crops for this purpose where the objective is simply to maximise the amount of biomass produced.

14.12.1.2BG2.4 Crop transport (Road)

The crops are transported by road over a short distance. We assumed a standard truck as described in common process T1.

14.12.1.3BG3.4 Fermenter (closed digestate storage)

The fermenting process is the anaerobic digestion of biomass by bacteria, producing mostly methane. The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. The conversion level of the organic matter is typically 70%. Accepted good practice is to enclose the digestate storage to capture the bulk of the methane arising from continued fermentation. The closed digestate storage is also called 'post fermenter'. The captured methane contributes to the biogas yield. A small amount of remaining methane emissions is assumed.

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 N2O emissions.

14.12.1.4BG4.1 Upgrading

If the biogas is to be exported for use either in the gas grid or as vehicle fuel as CNG, it needs to be ""upgraded"" i.e. treated to remove contaminants such as H2S and CO2.

H2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m3 per 100 Nm3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH4/MJ treated biogas)

This consumes a small amount of electricity. Some 3% of the gas is lost and assumed to be burnt (no CH4 emissions to atmosphere). Upgraded gas is essentially pure methane. For consistency with CNG pathways, Russian gas quality is assumed.

14.12.1.5GH1 CH4 compression (1.6 MPa)

NG needs to be compressed from 0.5 to 1.6 MPa in order to be fed into the reformer.

14.12.1.6GH2a CH4 on-site steam reforming

This represents a small-scale steam reformer installed at the retail site, with an efficiency of about 69%.

14.12.1.7HC4 Hydrogen compression and dispensing at retail site

Hydrogen is available at 1.5 MPa at the reformer outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa). The compression process includes precooling at -40°C.

14.13 Farmed wood, large scale gasifier and hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa) (WFLH)

Process code	Step	Common processes		Input	Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation, harvesting & chipping**							
	Agricultural inputs							
	Fertilizers		g/MJ$_{wood}$					
	N (as N)	*FN*		0.00				JRC internal
	Pesticides	*PE*	g/MJ$_{wood}$	0.02				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ$_{wood}$	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ$_{wood}$	0.0000161				
	N_2O emissions (from diesel use)		g/MJ$_{wood}$	0.0000397				
	N_2O field emissions		g/MJ$_{wood}$	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content		%	30%				
WF3b	**Farmed wood transport**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
	Transformation near market							
WH2	**Wood to hydrogen large scale (BCL gasifier)**							[FfE 1998], [Katofsky 1993], [Paisley 2001], [Sydcraft 2002]
	Wood chips		MJ/MJ$_{H2}$	1.6553	1.9199	1.4850	Normal	
HL1	**Hydrogen liquefaction**							[Le Breton 2002], [Tomforde 2004]
	Electricity	*GGe*	MJ/MJ$_{H2}$	0.3000	0.2100	0.3900	Square	
	Conditioning & Distribution							
HL4	**Liquid hydrogen road transport**							
	Distance	*T1*	km	300				
	Payload / tank mass		t/t	3.5/27.5				
	Losses			0.5%				
HL5	**Liquid hydrogen dispensing (cryo-compression)**							[Brunner 2011], [Kampitsch 2012]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0100				

14.13.1.1 WF1 Wood plantation, harvesting & chipping

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

14.13.1.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

14.13.1.3 WF3b Farmed wood transport

As for Sydiesel it has been assumed that the wood chips are transported via truck over a distance of 500 km.

14.13.1.4 WH2 Wood to hydrogen large scale (BCL gasifier)

We took the detailed description of the BLGMF plant in [Ekbom 2003] and considered what modifications would be needed to make hydrogen instead of methanol. The methanol synthesis and distillation are not needed, but a larger CO shift reactor is required, coupled to a pressure swing absorption (PSA) to purify the hydrogen.

The hydrogen process starts from stream 4 in Figure 14.4. All this goes to the CO-shift instead of only half for the methanol plant. Therefore, more steam is required for the CO shift reactor, but on the other hand the outlet of the CO shift contains more steam, because more is formed in the reaction. The net amount of steam compared with the methanol plant depends on whether the shift reaction is exothermic or endothermic. If we calculate this starting from steam, it is slightly exothermic, but if we include the energy for generating the steam from water, it is slightly endothermic. In practice, one could find a source of steam, but a little less heat would be recovered. Thus, the difference in steam requirements is approximately zero.

The CO2 absorption (Abs 2) is not required because CO2 is anyway removed downstream in the PSA. The pressure at the outlet of the CO shift reactor (2.9 MPa; [Ekbom 2003]) is sufficient to drive the PSA process. Hydrogen recovery is assumed to be 86%; the tail-gases can be burnt for steam and electricity.

Compared to the reference pulp mill, the BGLF-hydrogen process produces 247 MW H2 and 108.3 MW of the other gases. Thus, 1MJ extra biomass would produce 0.594 MJ hydrogen and leave 0.261 MJ in the tail-gas. If the tail gas is added to the boiler of the existing condensing steam-turbine generator, it will save the same energy input of biomass. Therefore only 0.839 MJ biomass are needed to 0.594 MJ hydrogen by itself. Thus, the efficiency to hydrogen is 81% and 1.24 MJ biomass are needed to make 1 MJ hydrogen.

14.13.1.5 HL4 Liquid hydrogen road transport

Road transport assumes a standard truck with a 24 t tank transporting 3.5 ton of liquid hydrogen.

14.13.1.6 HL5 Liquid hydrogen dispensing (cryo-compression)

Liquefied hydrogen is pumped into the vehicle tank and compressed at a maximum of 35 MPa. The electricity requirement is about 1% of the dispensed hydrogen [Kampitsch 2012]. 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 [Ahluwalia 2018].

15 Hydrogen from electrolysis

15.1 EU-mix electricity supply (based on actual averages)

(1) High voltage

(2) Medium voltage

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).

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
EMa	**Mixed supply 2016**							[JRC 2017], [EEA 2018]
	Hard coal (primary)		MJ/MJ_e	0.3685				
	Brown coal (source)		MJ/MJ_e	0.2329				
	Crude oil (primary)		MJ/MJ_e	0.0652				
	NG (primary)		MJ/MJ_e	0.4433				
	Hydropower		MJ/MJ_e	0.1073				
	Nuclear		MJ/MJ_e	1.0857				
	Biomass (primary)		MJ/MJ_e	0.2449				
	Peat		MJ/MJ_e	0.0155				
	Geothermal		MJ/MJ_e	0.0199				
	Solar		MJ/MJ_e	0.0348				
	Wind		MJ/MJ_e	0.0928				
	Waste		MJ/MJ_e	0.0473				
	Total		MJ/MJ_e	2.7581				
	CO_2 emissions		g/MJ_e	102.6				
	CH_4 emissions		g/MJ_e	0.00				
	N_2O emissions		g/MJ_e	0.000				
EMb	**Mixed supply 2030**							
	Hard coal (primary)		MJ/MJ_e	0.1882				
	Brown coal (source)		MJ/MJ_e	0.1078				
	Crude oil (primary)		MJ/MJ_e	0.0135				
	NG (primary)		MJ/MJ_e	0.4497				
	Hydropower		MJ/MJ_e	0.1239				
	Nuclear		MJ/MJ_e	0.8454				
	Biomass (primary)		MJ/MJ_e	0.0956				
	Peat		MJ/MJ_e	0.0067				
	Geothermal		MJ/MJ_e	0.0436				
	Solar		MJ/MJ_e	0.0514				
	Wind		MJ/MJ_e	0.2073				
	Waste		MJ/MJ_e	0.0430				
	Total		MJ/MJ_e	2.1761				
	CO_2 emissions		g/MJ_e	68.7				
	CH_4 emissions		g/MJ_e	0.00				
	N_2O emissions		g/MJ_e	0.000				
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses			2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses			0.9%				
YH1	**Hydrogen via electrolysis**							JEC internal
	Efficiency (electricity)		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
HL1	**Hydrogen liquefaction**							[Le Breton 2002], [Tomforde 2004]
	Electricity (EU-mix, HV)	*EMHa*	MJ/MJ_{H2}	0.3000	0.2100	0.3900	Square	
	Conditioning & Distribution							
HC1	**Hydrogen pipeline**							
	Distance		km	55				
	No contribution							
HC4b	**Hydrogen compression and dispensing at retail site**							
	H2 delivery via pipeline (2.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0864	0.0821	0.0907	Normal	
	Losses			2.0%				
HC4d	**Hydrogen compression and dispensing at retail site**							LBST internal
	On-site electrolyser (3.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)		MJ/MJ_{H2}	0.0789	0.075	0.0828	Normal	
	Losses			2.0%				
HL4	**Liquid hydrogen road transport**							
	Distance	*T1*	km	300				
	Payload / tank mass		t/t	3.5/27.5				
	Losses			0.5%				
HL5	**Liquid hydrogen dispensing (cryo-compression)**							[Brunner 2011], [Kampitsch 2012]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0100				

15.1.1.1 EMa Mixed supply 2016

A description of the estimation of the EU-mix electricity supply is included section 3.4.2 of the WTT report with reference to [JRC 2013] and [EEA 2018].

15.1.1.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.1.1.3 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.1.1.4 YH1 Hydrogen via electrolysis

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPa$_g$ electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].
- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].
- McPhy indicates an electricity consumption of 4.5 kWh/Nm^3 at nominal flow rate for its 800 Nm^3/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPa$_g$ [McPhy 2017].

Several sources of data are available, giving figures for both small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depends on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPa$_g$ [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh$_e$/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 63% (4.8 to 5.4 kWh$_e$/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

15.1.1.5 HL1 Hydrogen liquefaction

Liquefaction is a highly energy intensive process. Energy requirement figures vary within a wide range. One reason for this is that many of the existing liquefaction plants were not built with the objective of maximum energy efficiency as they are mostly relatively small and making hydrogen as a premium product for the chemical industry. Figures in the region of 0.35-0.40 MJ_e/MJ are not uncommon but experts agree that much lower figures down nearly 0.2 can be achieved [LBST 2001], [Quack 2001/1], [Quack 2001/2] have therefore taken a wide range with a square probability distribution.

15.1.1.6 HC1 Hydrogen pipeline

Hydrogen is available at a sufficient pressure at the reformer outlet to compensate for the pressure drop in the pipeline (55 km). No additional energy is required.

15.1.1.7 HC4b Hydrogen compression and dispensing at retail site

Hydrogen is available at 2.0 MPa at the pipeline and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa).

15.1.1.8 HC4d Hydrogen compression and dispensing at retail site

Hydrogen is available at 3.0 MPa at the electrolyser outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa).

15.1.1.9 HL4 Liquid hydrogen road transport

Road transport assumes a standard truck with a 24 t tank transporting 3.5 ton of liquid hydrogen.

15.1.1.10HL5 Liquid hydrogen dispensing (cryo-compression)

Liquefied hydrogen is pumped into the vehicle tank and compressed at a maximum of 35 MPa. The electricity requirement is about 1% of the dispensed hydrogen [Kampitsch 2012]. 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 [Ahluwalia 2018].

15.2 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.
- LH1: central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
KO1	**Hard coal provision**							[El Cerrejon 2002], [DOE 2002], [Eurostat 2001], [GEMIS 2002], [IDEAM 2001], [IEA 2000]
	Hard coal (primary)		MJ/MJ$_{coal}$	1.0266				
	Brown coal (primary)		MJ/MJ$_{coal}$	0.0016				
	Crude oil		MJ/MJ$_{coal}$	0.0375				
	Natural gas (primary)		MJ/MJ$_{coal}$	0.0100				
	Hydro power		MJ/MJ$_{coal}$	0.0010				
	Nuclear		MJ/MJ$_{coal}$	0.0109				
	Waste		MJ/MJ$_{coal}$	0.0018				
	CO_2 emissions		g/MJ$_{coal}$	6.27				
	CH_4 emissions		g/MJ$_{coal}$	0.3852				
	N_2O emissions		g/MJ$_{coal}$	0.0003				
	Transformation at source							
	NA							
	Transportation to market							
	NA							
	Transformation near market							
KE2.1	**State-of-the-art conventional coal power plant**							[Dienhart 1999]
	Efficiency			43.5%	40.0%	50.0%	2-triangle	
	CO_2 emissions		g/MJ$_e$	220.62				
	CH_4 emissions		g/MJ$_e$	0.0041				
	N_2O emissions		g/MJ$_e$	0.0114				
KE2.2	**IGCC**							[Dienhart 1999]
	Efficiency		%	48.0%	45.0%	51.5%	Square	
	CO_2 emissions		g/MJ$_e$	199.94				
	CH_4 emissions		g/MJ$_e$	0.0088				
	N_2O emissions		g/MJ$_e$	0.0021				
KE2.2C	**IGCC with CCS**							[ENEA 2004]
	Efficiency			41.0%	38.3%	44.1%	Square	
	CO_2 emissions		g/MJ$_e$	23.33				
	CH_4 emissions		g/MJ$_e$	0.0102				
	N_2O emissions		g/MJ$_e$	0.0024				
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses			2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses			0.9%				
YH1	**Hydrogen via electrolysis**							JEC internal
	Efficiency (electricity)		MJ/MJ$_{H2}$	1.5380	1.6000	1.4760	Normal	
HL1	**Hydrogen liquefaction**							[Le Breton 2002], [Tomforde 2004]
	Electricity		MJ/MJ$_{H2}$	0.3000	0.2100	0.3900	Square	
	Conditioning & Distribution							
HC4d	**Hydrogen compression and dispensing at retail site**							LBST internal
	On-site electrolyser (3.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)		MJ/MJ$_{H2}$	0.0789	0.075	0.0828	Normal	
	Losses			2.0%				
HL4	**Liquid hydrogen road transport**							
	Distance	T1	km	300				
	Payload / tank mass		t/t	3.5/27.5				
	Losses			0.5%				
HL5	**Liquid hydrogen dispensing (cryo-compression)**							[Brunner 2011], [Kampitsch 2012]
	Electricity (EU-mix, LV)	EMLa	MJ/MJ$_{H2}$	0.0100				

15.2.1.1 KO1 Hard coal provision

These figures approximate the average primary energy associated to the production and provision of hard coal to Europe.

15.2.1.2 KE2.1 State-of-the-art conventional coal power plant

This represents a modern boiler/ condensing turbine configuration. The efficiency of 43.5% is assumed to be achievable over the life time of the plant (45% for a new plant).

15.2.1.3 KE2.2 IGCC

In the IGCC process (Integrated Gasification Combined Cycle), the coal feed is gasified and the syngas burnt in a gas turbine. Electricity is generated directly by the gas turbine while steam raised from the flue gases generates extra electricity through condensing steam turbines. Overall the process is more efficient than conventional schemes.

15.2.1.4 KE2.2C IGCC with CCS

The IGCC process is well suited to CO2 capture: syngas is converted, via the shift reaction, to hydrogen and virtually pure CO2 upstream of the gas turbine. This is, however at a significant energy cost. The reference used here is from a pre-feasibility study. There is no commercial-scale plant in operation.

2010 to 2011, experiments with CO2 capture have been carried out at the IGCC power plant in Puertollano in Spain [García-Peña 2011]. For CO2 capture a CO shift reactor has been installed to convert CO to CO2 and H2 and a CO2 scrubber using aMDEA. For the production of pure hydrogen e.g. for hydrogen fueled FCEV vehicles a pressure swing adsorption PSA) plant has been installed. A part of the hydrogen rich gas stream is sent to the gas turbine, the other part to the PSA plant. Another pilot plant with a capacity of 524 MW_e has been built at Kemper County, Mississippi in the USA. The whole gasification and CO2 capture process was successfully tested in 2016. 65% of the CO2 is captured. However, the plant has been shut down in 2017 due to low natural gas prices and problems with the gasifier [Lockwood 2017]. About US$ 7.5 billion have been invested in the Kemper IGCC power plant [Swartz 2017]. Now, natural gas is used as fuel for the gas turbines.

15.2.1.5 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.2.1.6 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.2.1.7 HL1 Hydrogen liquefaction

Liquefaction is a highly energy intensive process. Energy requirement figures vary within a wide range. One reason for this is that many of the existing liquefaction plants were not built with the objective of maximum energy efficiency as they are mostly relatively small and making hydrogen as a premium product for the chemical industry. Figures in the region of 0.35-0.40 MJ_e/MJ are not uncommon but experts agree that much lower figures down nearly 0.2 can be achieved [LBST 2001], [Quack 2001/1], [Quack 2001/2] have therefore taken a wide range with a square probability distribution.

15.2.1.8 HC4d Hydrogen compression and dispensing at retail site

Hydrogen is available at 3.0 MPa at the electrolyser outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa).

15.2.1.9 HL4 Liquid hydrogen road transport

Road transport assumes a standard truck with a 24 t tank transporting 3.5 ton of liquid hydrogen.

15.2.1.10HL5 Liquid hydrogen dispensing (cryo-compression)

Liquefied hydrogen is pumped into the vehicle tank and compressed at a maximum of 35 MPa. The electricity requirement is about 1% of the dispensed hydrogen [Kampitsch 2012]. 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 [Ahluwalia 2018].

15.3 Natural gas: CCGT

GPEL1: 7000 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.
- LH1: central reforming, hydrogen liquefaction, liquid hydrogen road transport to retail site, hydrogen cryo- compression in to vehicle tank (35 MPa).

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
GG1	**NG extraction and processing**							[Shell 2002]
	Energy as NG		MJ/MJ$_{NG}$	0.0200	0.0100	0.0400	2-triangle	
	CO_2 venting		%v/v	1.0%				
	CH_4 losses		g/MJ$_{NG}$	0.08				
	Transformation at source							
GR1	**NG liquefaction**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0246				[Ott et al. 2015]
	Flared NG		MJ/MJ$_{LNG}$	0.0113	0.0025	0.0200	Square	[FfE 1996]
	CH_4 emissions		g/MJ$_{LNG}$	0.0340				[Masake 1997]
GR2	**LNG loading terminal**							
	Electricity (on-site generation)		MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency		%	58%	57%	59%	Normal	
	CH_4 emissions		g/MJ$_{elec}$	0.0054				
	N_2O emissions		g/MJ$_{elec}$	0.0043				
	Transportation to market							
GG2	**NG long-distance pipeline transport**							
	Compressors powered by GT fuelled by NG							[GEMIS 2016]
	Efficiency			30%	35%	22%	2-triangle	
	CH_4 emissions		g/MJ$_{fuel}$	0.0084				
	N_2O emissions		g/MJ$_{fuel}$	0.0026				
GG2/43	GPCG1a (Russia)							
	Distance		km	4300				[Thinkstep 2017]
	Compression specific energy		MJ/t.km	0.360	0.120	0.400	2-triangle	[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ$_{NG}$	0.1398				[GEMIS 2016]
GG2/07	**NG pipeline transport inside EU**							
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				[GEMIS 2016]
	CH_4 emissions		g/MJ$_{fuel}$	0.0042				
	N_2O emissions		g/MJ$_{fuel}$	0.0025				[GEMIS 2016]
	GPCG1a (Russia)							
	Distance		km	700				
	Compression specific energy		MJ/t.km	0.269				[GEMIS 2016]
	CH_4 emissions (losses)		g/MJ$_{NG}$	0.0009				[GEMIS 2016]
GG2/4	GPCG1b (Middle East)							
	Distance		km	4000				
	Compression specific energy		MJ/t.km	0.3600	0.1200	0.4000	Square	[GEMIS 2016]
	CH4 emissions (losses)		g/MJ$_{NG}$	0.1057				[Wuppertal 2004]
GR3	**LNG long-distance sea transport**							
	Distance		Nautical miles	4000				[Gerini 2017]
	NG evaporation		MJ/MJ$_{LNG}$	0.0263				[Hanjin 2000],
	Heavy Fuel Oil		MJ/MJ$_{LNG}$	0.0222				[Mitsubishi 2000]
	CH_4 emissions		g/MJ$_{LNG}$	0.00013				[GEMIS 2001]
	N_2O emissions		g/MJ$_{LNG}$	0.00009				[GEMIS 2001]
GR4	**LNG unloading terminal**							
	Electricity (EU-mix MV)	*EMMa*	MJ/MJ$_{LNG}$	0.0009				[FfE 1996]
	Energy as NG		MJ/MJ$_{LNG}$	0.0100				[Total 2001]
GR5	**LNG vaporisation**							LBST internal
	Heat as NG		MJ/MJ$_{NG}$	0.0194				
	NG to pump drive (gas engine)		MJ/MJ$_{NG}$	0.0012	0.0009	0.0014	Square	
	CH_4 emissions		g/MJ$_{NG}$	0.000004	0.000004	0.000005		
	N_2O emissions		g/MJ$_{NG}$	0.000005	0.000004	0.000007		
GG3	**NG distribution (high pressure)**							[GEMIS 2016]
	Compression specific energy		MJ/t.km	0.269				
	Compressors powered by GT fuelled by NG							
	Efficiency			31%				
	CH_4 emissions		g/MJ$_{fuel}$	0.0042				
	N_2O emissions		g/MJ$_{fuel}$	0.0025				
	Distance		km	500				
	CH4 emissions (losses)		g/MJ$_{NG}$	0.0006				
	Transformation near market							
GGe	**On-site electricity generation (NG-fired CCGT)**							[GEMIS 2011]
	Efficiency		%	58.1%	57.0%	59.3%	Normal	
	CH_4 emissions		g/MJ$_{elec}$	0.0054				
	N_2O emissions		g/MJ$_{elec}$	0.0043				
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses		%	2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses		%	0.9%				
YH1	**Hydrogen via electrolysis**							JEC internal
	Efficiency (electricity)		MJ/MJ$_{H2}$	1.5380	1.6000	1.4760	Normal	
HL1	**Hydrogen liquefaction**							[Le Breton 2002], [Tomforde 2004]
	Electricity	*GGe*	MJ/MJ$_{H2}$	0.3000	0.2100	0.3900	Square	
	Conditioning & Distribution							
HC1	**Hydrogen pipeline**							
	Distance		km	55				
	No contribution							
HC4b	**Hydrogen compression and dispensing at retail site**							
	H2 delivery via pipeline (2.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*		0.0864	0.0821	0.0907	Normal	
	Losses			2.0%				
HC4d	**Hydrogen compression and dispensing at retail site**							LBST internal
	On-site electrolyser (3.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)		MJ/MJ$_{H2}$	0.0789	0.075	0.0828	Normal	
	Losses			2.0%				
HL4	**Liquid hydrogen road transport**							
	Distance	*T1*	km	300				
	Payload / tank mass		t/t	3.5/27.5				
	Losses			0.5%				
HL5	**Liquid hydrogen dispensing (cryo-compression)**							[Brunner 2011], [Kampitsch 2012]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ$_{H2}$	0.0100				

15.3.1.1 GG1 NG extraction and processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H2S as well as separate inert gases, particularly CO2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO2 reflects the low CO2 content of the gas sources typically available to Europe. For sources with higher CO2 content, it is assumed that re-injection will be common at the 2015-20 and beyond horizon. 0.4% methane losses are included.

15.3.1.2 GR1 NG liquefaction

The energy required for the liquefaction process is well documented and not subject to a large uncertainty. It is assumed here that the electrical power for the compressors is supplied by a gas fired on-site combined cycle gas fired power plant (see process GGe).

Some off gas is flared for which estimates vary widely in the literature hence the wide range used. There are also small methane losses.

A significant amount of natural gas is used to generate the electrical energy required for liquefaction. The corresponding CO2 could be captured (see process CGeC). The proximity of gas and possibly oil field where the CO2 could be injected would enhance the feasibility of such a scheme.

15.3.1.3 GR2 LNG loading terminal

A small amount of electricity is required for the operation of the terminals. In addition, the evaporation losses (estimated at 1%) are flared resulting in CO2 emissions. The electricity is deemed to be produced by the on-site gas-fired power plant (process GGe).

15.3.1.4 GGe On-site electricity generation (NG-fired CCGT)

In all gas transformation schemes requiring significant amounts of electricity, we have assumed the latter is produced on-site by a state-of-the-art gas-fired combined cycle gas turbine (CCGT) with a typical efficiency of 58.1% (57-59%). The high end of the range represents potential future improvements to the technology that are thought to be achievable in the next ten years.

15.3.1.5 GG2 NG long-distance pipeline transport

As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [LBST 1997/1] [LBST 1997/2], [GEMIS 2002]. The range used represents the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures are unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (4300 km to EU border, which represents a mix of three corridors, and 700 km inside EU) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe.

Methane losses associated with long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [LBST 1997/1], [LBST 1997/2], [GEMIS 2002] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [Wuppertal 2004] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

15.3.1.6 GR3 LNG long-distance sea transport

LNG is transported in specially designed cryogenic carriers. Heat ingress is compensated by gas evaporation. The evaporation rate is estimated at 0.15% per day, the number of days being based on an average speed of 19.5 knots. The average distance has been taken as 4000 nautical miles, based on the average for the supply of LNG to EU. The LNG is imported from Algeria, Norway, Nigeria, and Qatar.

The evaporated gas is used as fuel for the ship, the balance being provided by standard marine bunker fuel (HFO). This practice is also valid for the return voyage inasmuch as the LNG tanks are never completely emptied in order to keep them at low temperature (required for metallurgical reasons). The figures include an allowance for the return trip in accordance with the “admiralty formula” (see process Z4: LNG carriers have a typical gross tonnage of 110,000 t, including a payload of 135,000 m3 or 57,000 t [Hanjin 2000] [Mitsubishi 2000]. This results in a ratio of 0.8 between the full and empty ship).

The figures include provision for return trip.

15.3.1.7 GR4 LNG unloading terminal

The terminal electricity requirement is deemed to be the same as for the loading terminal (see process GR2). The electricity, however, is now assumed to be supplied by the EU grid. If LNG is vaporised on receipt no evaporation losses are included; if LNG is further transported as such, the same figures as for the loading terminal are used. A small additional electricity consumption (0.0007 to 0.0010 MJ/MJ of LNG) is added for the LNG terminal. The road tanker loading and unloading is carried out by a truck mounted LNG pump. The additional diesel requirement for the LNG pump is very low (approximately 0.0002 MJ/MJ of LNG).

15.3.1.8 GR5 LNG vaporisation

If it is to be used in the gas distribution grid, LNG needs to be vaporised and compressed. Although small amounts can be vaporised with heat taken from the atmosphere, this is impractical for large evaporation rates and heat at higher temperature must be supplied. The figures used here assume compression (as liquid) to 4 MPa followed by vaporisation and heating of the gas from -162 to 15°C.

15.3.1.9 GG3 NG distribution (high pressure)

The European gas distribution systems consist of high-pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high-pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/(t.km) are typical of European networks. Gas losses are reportedly very small.

15.3.1.10GGe On-site electricity generation (NG-fired CCGT)

This process represents the now standard route for efficient and cost-effective production of electricity from gas i.e. a combined cycle gas turbine complex. Electricity is generated directly by the natural gas -fired gas turbine while steam raised from the flue gases generates extra electricity through condensing steam turbines. The overall efficiency of 58.1% is typical of modern state-of-the-art plants.

15.3.1.11EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

15.3.1.12EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.3.1.13YH1 Hydrogen via electrolysis

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPa$_g$ electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].
- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].
- McPhy indicates an electricity consumption of 4.5 kWh/Nm^3 at nominal flow rate for its 800 Nm^3/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPa$_g$ [McPhy 2017].

Several sources of data are available, giving figures for both small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depends on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPa$_g$ [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh$_e$/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 63% (4.8 to 5.4 kWh$_e$/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

15.3.1.14HL1 Hydrogen liquefaction

Liquefaction is a highly energy intensive process. Energy requirement figures vary within a wide range. One reason for this is that many of the existing liquefaction plants were not built with the objective of maximum energy efficiency as they are mostly relatively small and making hydrogen as a premium product for the chemical industry. Figures in the region of 0.35-0.40 MJ$_e$/MJ are not uncommon but experts agree that much lower figures down nearly 0.2 can be achieved [LBST 2001], [Quack 2001/1], [Quack 2001/2] have therefore taken a wide range with a square probability distribution. Note that this process refers to process GGe i.e. assumes electricity is produced in a dedicated natural gas CCGT.

15.3.1.15 HC1 Hydrogen pipeline

Hydrogen is available at a sufficient pressure at the reformer outlet to compensate for the pressure drop in the pipeline (55 km). No additional energy is required.

15.3.1.16 HC4d Hydrogen compression and dispensing at retail site

Hydrogen is available at 3.0 MPa at the electrolyser outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa).

15.3.1.17 HL4 Liquid hydrogen road transport

Road transport assumes a standard truck with a 24 t tank transporting 3.5 ton of liquid hydrogen.

15.3.1.18 HL5 Liquid hydrogen dispensing (cryo-compression)

Liquefied hydrogen is pumped into the vehicle tank and compressed at a maximum of 35 MPa. The electricity requirement is about 1% of the dispensed hydrogen [Kampitsch 2012]. 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 [Ahluwalia 2018].

15.4 Wood (Farmed): WFEL1 IGCC (200 MW_{th}, 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).

Process code	Step	Common processes	Input		Range		Distribution	Source
	Production & conditioning at source							
WF1	**Wood plantation**							
	Agricultural inputs							
	Fertilizers							
	N (as N)	*FN*	g/MJ_{wood}	0.00				JRC internal
	Pesticides	*PE*	g/MJ_{wood}	0.02				JRC internal
	Data relative to the provision of agricultural inputs are shown in sheet "Agri inputs"							
	Diesel	*F1*	MJ/MJ_{wood}	0.0126				JRC internal
	CH_4 emissions (from diesel use)		g/MJ_{wood}	0.00002				
	N_2O emissions (from diesel use)		g/MJ_{wood}	0.0000				
	N_2O field emissions		g/MJ_{wood}	0.0067				JRC internal
WS	**Wood storage (seasoning)**							
	Losses			12.0%				JRC internal
	Transformation at source							
	NA							
	Transportation to market							
	Wood moisture content		%	30%				
WF3b	**Farmed wood transport (regional, 500 km)**							JRC internal
	Road truck	*T1*						
	Distance		km	500				
	Transformation near market							
WE1	**Wood IGCC (200 MW_{th})**							[Sydcraft 2001]
	Efficiency			48.2%	46.0%	50.0%	2-triangle	
	CH_4 emissions		g/MJ_e	0.0261				
	N_2O emissions		g/MJ_e	0.0025	0.0000	0.0050	2-triangle	
WE3	**Conventional biomass power plant (boiler/turbine, small scale)**							
	Efficiency			32.0%	30.5%	33.7%	2-triangle	[Jopp 1999]
	CH_4 emissions		g/MJ_e	0.0828				[GEMIS 2005]
	N_2O emissions		g/MJ_e	0.0063				[Vitovec 1999]
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses			2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses			0.9%				
YH1	**Hydrogen via electrolysis**							JEC internal
	Efficiency (electricity)		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
HL1	**Hydrogen liquefaction**							[Le Breton 2002], [Tomforde 2004]
	Electricity	*WE1*	MJ/MJ_{H2}	0.3000	0.2100	0.3900	Square	
	Conditioning & Distribution							
HC1	**Hydrogen pipeline**							
	Distance		km	55				
	No contribution							
HC4b	**Hydrogen compression and dispensing at retail site**							LBST internal
	H2 delivery via pipeline (2.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)		MJ/MJ_{H2}	0.0864	0.0821	0.0907	Normal	
	Losses			2.0%				
HC4d	**Hydrogen compression and dispensing at retail site**							LBST internal
	On-site electrolyser (3.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)		MJ/MJ_{H2}	0.0789	0.075	0.0828	Normal	
	Losses			2.0%				
HL4	**Liquid hydrogen road transport**							
	Distance	*T1*	km	300				
	Payload / tank mass		t/t	3.5/27.5				
	Losses			0.5%				
HL5	**Liquid hydrogen dispensing (cryo-compression)**							[Brunner 2011], [Kampitsch 2012]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0100				

15.4.1.1 WF1 Wood plantation

This represents Short-Rotation Forestry (SRF) on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizers, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with miscanthus [Scurlock 1999] indicates a realistic yield similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in Europe at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming. Our data on wood farming (short rotation forestry) are from [Giuntoli et al. 2017] whereas the variant with organic fertilizer input (manure) has been selected. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, the soil N2O emissions have been estimated using the procedure based on IPCC guidelines described in [IPCC 2006], for the 80 kg/ha nitrogen rate from manure input reported by [Franke et al. 2012] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 14 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 19 GJ/ dry tonne.

15.4.1.2 WS Wood storage (seasoning)

The most common harvesting technique for SRC at present is a combined harvester and chipper, so the wood chips need to be stored. During storage period the moisture of the woodchips decreases from 50% to 30%. The wood chips are stored at a central terminal in a closed environment without artificial ventilation, but with good natural ventilation. The storage is usually for a period of 3 to 8 months. 12 % dry matter losses are considered. Emissions of methane from storage are considered to be negligible in these conditions [Giuntoli et al. 2017].

15.4.1.3 WF3b Farmed wood transport (regional, 500 km)

Wood farming is assumed to occur within a small distance from the power plant, hence the 50 km toad transport.

15.4.1.4 WE1 Wood IGCC (200 MW_{th})

The large gasifier power station is taken from the study of an IGCC based on the Värnamo pressurized fluidized bed gasifier, using a state-of-the-art GTX 100 gas turbine with flue gas condensation (140 MW_{th}). This configuration maximizes the electrical efficiency. The lower efficiency limit is for the existing turbine at Värnamo, whilst the upper limit projects a further 2% in gas turbine efficiency by 2010. We selected this power station because the Värnamo gasifier is the only one which has been demonstrated to work with hot gas filtration, which gives a significant improvement in efficiency since the syngas enters hot into the turbine, and will surely become the norm for future IGCC power stations.

15.4.1.5 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018]

15.4.1.6 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.4.1.7 YH1 Hydrogen via electrolysis

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPa_g electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].

- NEL Hydrogen indicates an electricity consumption of 4.9 kWh/Nm^3 for a 60 Nm^3/h electrolysis (61.2% efficiency) for a hydrogen purity of 99.9% (NEL P60) [NEL 2012]. For a 30.000 Nm^3/h plant the electricity consumption is indicated with 4.5 kWh/Nm^3 leading to an efficiency of 66.7% based on the LHV of the delivered hydrogen [NEL 2015].
- McPhy indicates an electricity consumption of 4.5 kWh/Nm^3 at nominal flow rate for its 800 Nm^3/h electrolyser leading to an efficiency of 66.7%. The hydrogen pressure is 3 MPa$_g$ [McPhy 2017].

Several sources of data are available, giving figures for both small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depend on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPa$_g$ [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh$_e$/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 63% (4.8 to 5.4 kWh$_e$/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

15.4.1.8 HL1 Hydrogen liquefaction

Liquefaction is a highly energy intensive process. Energy requirement figures vary within a wide range. One reason for this is that many of the existing liquefaction plants were not built with the objective of maximum energy efficiency as they are mostly relatively small and making hydrogen as a premium product for the chemical industry. Figures in the region of 0.35-0.40 MJe/MJ are not uncommon but experts agree that much lower figures down nearly 0.2 can be achieved [LBST 2001], [Quack 2001/1], [Quack 2001/2] have therefore taken a wide range with a square probability distribution.

15.4.1.9 HC1 Hydrogen pipeline

Hydrogen is available at a sufficient pressure at the reformer or electrolysis plant outlet to compensate for the pressure drop in the pipeline (55 km). No additional energy is required.

15.4.1.10HC4d Hydrogen compression and dispensing at retail site

Hydrogen is available at 3.0 MPa at the electrolyser outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa).

15.4.1.11 HL4 Liquid hydrogen road transport

Road transport assumes a standard truck with a 24 t tank transporting 3.5 ton of liquid hydrogen.

15.4.1.12 HL5 Liquid hydrogen dispensing (cryo-compression)

Liquefied hydrogen is pumped into the vehicle tank and compressed at a maximum of 35 MPa. The electricity requirement is about 1% of the dispensed hydrogen [Kampitsch 2012]. 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 [Ahluwalia 2018].

15.5 Electricity from nuclear energy

Electrolysis: on retail site, hydrogen compression to 88 MPa.

Process code	*Step*	*Common processes*	*Input*		*Range*		*Distribution*	*Source*
	Production & conditioning at source							
NU1.1	**Uranium ore extraction and processing (Canada)**							
	Diesel*	*F1*	MJ/MJ_{fuel}	0.00008				[GEMIS 2005]
NU1.2	**Uranium ore extraction and processing (France)**							
	Electricity (EU-mix, HV)	*EMHa*	MJ/MJ_{fuel}	0.00002				[GEMIS 2005]
	Transformation at source							
	NA							
	Transportation to market							
NU2	**U_3O_8 sea transport**							
	Distance	*T3f*	km	6000				[GEMIS 2002]
	Transformation near market							
NU3	**Nuclear fuel production**							
NU3a	**UF6 production**							[GEMIS 2011]
	Efficiency			90.0%				
	Electricity (EU-mix, HV)	*EMHa*	MJ/MJ_{UF6}	0.00001				
NU3b	**Enrichment**							[GEMIS 2002]
	Electricity (EU-mix, HV)	*EMHa*	MJ/MJ_{fuel}	0.00800	0.0076	0.0084	Normal	
NU3c	**Nuclear fuel rod production (France)**							[GEMIS 2009, 2010]
	Efficiency			95.0%				
	Heat		MJ/MJ_{fuel}	0.0010	0.00095	0.00105	Normal	
	Electricity (EU-mix, HV)		MJ/MJ_{fuel}	0.0010	0.00095	0.00105	Normal	
NU4	**Nuclear power plant**							[GEMIS 2002]
	Efficiency			33.0%				
	Diesel*	*F1*	MJ/MJ_{fuel}	0.0033				
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses			2.6%				
EDM	**Electricity distribution MV**							[JRC 2017]
	Losses			0.9%				
YH1	**Hydrogen via electrolysis**							JEC internal
	Efficiency (electricity)		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
	Conditioning & Distribution							
HC4d	**Hydrogen compression and dispensing at retail site**							LBST internal
	On-site electrolyser (3.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)		MJ/MJ_{H2}	0.0789	0.075	0.0828	Normal	
	Losses			2.0%				

15.5.1.1 NU1.1 Uranium ore extraction and processing (Canada)

Uranium ore is extracted in open cast mines

NU1.2 Uranium ore extraction and processing (France)

Uranium ore is extracted in open deep mines. The pathway assumes 50% ore from Canada and 50% from France.

15.5.1.2 NU2 U3O8 sea transport

Uranium ore (Canada) is transported to EU by ship. The shipping process (T3f) represents and large bulk carrier.

15.5.1.3 NU3 Nuclear fuel production

This consists of three steps: Conversion of Uranium oxide into hexafluoride (UF6), enrichment and final fuel production.

15.5.1.4 NU4 Nuclear power plant

The nuclear plant consumes its own power and a small amount of diesel.

15.5.1.5 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.5.1.6 EDM Electricity distribution MV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.5.1.7 HC4d Hydrogen compression and dispensing at retail site

Hydrogen is available at 3.0 MPa at the electrolyser outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa).

15.6 Electricity from wind energy

Electrolysis:

- CH2: central electrolysis, 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).

Process code	*Step*	*Common processes*	*Input*		*Range*		*Distribution*	*Source*
	Production & conditioning at source							
	NA							
	Transformation at source							
	NA							
	Transportation to market							
	Nuclear fuel ore sea transport							
	NA							
	Transformation near market							
WD1	**Wind turbine**							[GEMIS 2000]
	No expended energy or emissions							
EDH	**Electricity distribution HV**							[JRC 2017]
	Losses			2.6%				
YH1	**Hydrogen via electrolysis**							JEC internal
	Efficiency (electricity)		MJ/MJ_{H2}	1.5380	1.6000	1.4760	Normal	
HL1	**Hydrogen liquefaction**							[Le Breton 2002], [Tomforde 2004]
	Electricity	*WD1*	MJ/MJ_{H2}	0.3000	0.2100	0.3900	Square	
	Conditioning & Distribution							
HC1	**Hydrogen pipeline**							
	Distance		km	55				
	No contribution							
HC4b	**Hydrogen compression and dispensing at retail site**							LBST internal
	H2 delivery via pipeline (2.0 to 88.0 MPa)							
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0864	0.0821	0.0907	Normal	
	Losses			2.0%				
HL4	**Liquid hydrogen road transport**							
	Distance	*T1*	km	300				
	Payload / tank mass		t/t	3.5/27.5				
	Losses			0.5%				
HL5	**Liquid hydrogen dispensing (cryo-compression)**							[Brunner 2011], [Kampitsch 2012]
	Electricity (EU-mix, LV)	*EMLa*	MJ/MJ_{H2}	0.0100				

15.6.1.1 WD1 Wind turbine

Electricity from wind turbine is energy and emission - free (as we do not consider energy and emissions related to construction and maintenance)

15.6.1.2 EDH Electricity distribution HV

The way typical EU electricity distribution losses have been estimated is described in detail in section 3.4.3 of the WTT report and in [JRC 2018].

15.6.1.3 YH1 Hydrogen via electrolysis

Several sources of data are available, giving figures for both small and large alkaline electrolysers including all auxiliaries:

- Hydrogenics (former Stuart Energy, former Hydrogen Systems) offers a 100 Nm^3/h, 1.0 MPag electrolyser (HySTAT 100-10) with an electricity consumption of 5.0 to 5.2 kWh/Nm^3 or an efficiency of 57.7 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV [Hydrogenics 2017]. For a hydrogen purity of 99.9% the electricity consumption is indicated with 4.9 kWh/Nm^3 leading to an efficiency of 61.2%. [Hydrogenics 2009].
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Several sources of data are available, giving figures for both small and large PEM electrolysers including all auxiliaries:

- Giner indicates an electricity consumption of 54.0 kWh per kg of hydrogen (4.86 kWh/Nm^3) at a current density of 1.5 A/cm^2 leading to an efficiency of 61.7% based on the LHV including hydrogen purification via deOxo drier. At a higher current density of 1.75 A/cm^2 the electricity consumption increases to 54.2 kWh per kg of hydrogen leading to an efficiency of 61.5% [Giner 2012]. The efficiency depends on the current density which is applied to the electrolysis stack. The lower the current density the higher the efficiency.
- Hydrogenics offers PEM electrolysers with capacities of 100 Nm^3/h (HyLYZER 100-30), 400 Nm^3/h (HyLYZER 400-30), and 3000 Nm^3/h (HyLYZER 3000-30) with an electricity consumption of 5.0 to 5.4 kWh/Nm^3 or 55.6 to 60.0% for a hydrogen purity of 99.998% based on hydrogen LHV. The pressure of the hydrogen amounts to 3 MPa_g [Hydrogenics 2017].
- Areva offers PEM electrolysers up to a capacity of 120 Nm^3/h with an electricity consumption of 4.8 kWh/Nm^3 or an efficiency of 62.5% based on the LHV for a hydrogen purity of more than 99.9% (without auxiliaries: 4.4 kWh/Nm^3 or 68.2%). At part load the efficiency is higher (above 70%) [Areva 2016].

Many studies e.g. [DLR et al. 2015] expect a higher efficiency for or the hydrogen generation via electrolysis in the future (72% related to the LHV and 84% related to the HHV including all auxiliaries. [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 of commercially available pressurized alkaline electrolysers ranges between 58 and 67% related to the LHV of the delivered hydrogen (or 4.5 to 5.2 kWh_e/Nm^3 of hydrogen) [NEL 2012], [Hydrogenics 2017]. Membrane electrolysers achieve about 56 to 63% (4.8 to 5.4 kWh_e/Nm^3 of hydrogen) [Areva 2016], [Hydrogenics 2017].

The efficiency of an electrolyser does not vary significantly with size. Furthermore, the efficiency increases 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, is a reasonable representation of the available data.

The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3.1 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage.

15.6.1.4 HL1 Hydrogen liquefaction

Liquefaction is a highly energy intensive process. Energy requirement figures vary within a wide range. One reason for this is that many of the existing liquefaction plants were not built with the objective of maximum energy efficiency as they are mostly relatively small and making hydrogen as a premium product for the chemical industry. Figures in the region of 0.35-0.40 MJ_e/MJ are not uncommon but experts agree that much lower figures down nearly 0.2 can be achieved [LBST 2001], [Quack 2001/1], [Quack 2001/2] have therefore taken a wide range with a square probability distribution.

15.6.1.5 HC1 Hydrogen pipeline

Hydrogen is available at a sufficient pressure at the reformer outlet to compensate for the pressure drop in the pipeline (55 km). No additional energy is required.

15.6.1.6 HC4b Hydrogen compression and dispensing at retail site

Hydrogen is available at 3.0 MPa at the electrolyser outlet and needs to be compressed from 88 MPa for dispensing (max vehicle tank pressure 70 MPa).

15.6.1.7 HL4 Liquid hydrogen road transport

Road transport assumes a standard truck with a 24 t tank transporting 3.5 ton of liquid hydrogen.

15.6.1.8 HL5 Liquid hydrogen dispensing (cryo-compression)

Liquefied hydrogen is pumped into the vehicle tank and compressed at a maximum of 35 MPa. The electricity requirement is about 1% of the dispensed hydrogen [Kampitsch 2012]. 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 [Ahluwalia 2018].

16 References

See section 6 in the main report for the complete list of references

Appendix 3. JEC WTT v5

Changes versus the JEC WTT v4

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1 Fuel properties

For pathway GMCG2a and GMCG2b new natural gas mixtures including a share of CNG from imported LNG and CNG from upgraded biogas has been used (see chapter 3.4).

For LNG the actual composition of LNG supplied to the EU has been used based on the LNG mix in [Thinkstep 2017] and the properties of LNG from various regions indicated in [GIIGNL 2017]. Compressed biomethane (CBM) has slightly different properties as CNG (from natural gas). In contrast to CBM, liquefied biomethane (LBM) consists of almost pure methane because the CO_2 is completely removed during the liquefaction process. Synthetic liquefied natural gas (SLNG) and synthetic natural gas (SNG) from renewable electricity also consists of pure methane.

Table 1 shows the fuel properties used in version 4 and version 5.

Table 1. Fuel properties

Final fuel	Pathway code	Version 4 (g CO_2/MJ)	Version 5 (g CO_2/MJ)
CNG	GMCG1	56.2	56.1
CNG	GMCG2a	N/A	56.2
CNG	GMCG2b	N/A	56.2
CNG	GPCG1a	55.1	55.1
CNG	GPCG1b	55.1	55.1
CNG	GRCG1	55.1	56.4
CNG	GRCG1C	55.1	56.4
CNG	GRCG2	55.1	56.4
LNG	GRLG1	55.1	55.1
CNG	SGCG1	55.1	55.1
CBM	OWCG1	55.1	56.7
CBM	OWCG21	55.1	56.7
CBM	OWCG22	55.1	56.7
CBM	OWCG3	N/A	56.7
CBM	OWCG4	55.1	56.7
CBM	OWCG5	55.1	56.7
SNG	WWCG2	N/A	56.7
SNG	WFCG2	N/A	56.7
SNG	RECG1	55.0	55.0
LBM	OWLG1	N/A	55.0
LBM	OWLG21	N/A	55.0
LBM	OWLG22	N/A	55.0
LBM	OWLG3	N/A	55.0
LBM	OWLG4	N/A	55.0
LBM	OWLG5	N/A	55.0
SLNG	WWLG2	N/A	55.0
SLNG	WFLG2	N/A	55.0
SLNG	RELG1a	N/A	55.0
SLNG	RELG1b	N/A	55.0

N/A: not applicable

2 Oil pathways

2.1 Gasoline and diesel from crude oil (COD1 & COG1)

The energy and GHG values of crude oil extraction and transport have updated based on the recent data and literature [Exergia et al. 2015].

According to [Exergia et al. 2015] the GHG emissions from crude oil extraction and transport for the crude oil mix supplied to the EU amount to 9.72 g of CO_2 equivalent per MJ crude oil. Crude oil transport leads to about 0.7 g CO_2 equivalent per MJ of crude oil. As a result, crude oil extraction alone leads to about 9.02 g CO_2 equivalent per MJ of crude oil. The 9.02 g CO_2 equivalent have been traced back to CO_2 and CH_4 assuming that the CH_4 emissions amount to 0.0244 g of CH_4 per MJ of crude oil as in version 4. The energy use includes flaring. In [Exergia et al. 2015] no data for the energy use are indicated. Therefore, the energy use (0.115 MJ per MJ of crude oil without the energy bound in the crude oil itself) has been derived from the CO_2 emissions. It has been assumed that 73 g of CO_2 are emitted per MJ of crude oil. Error! Not a valid bookmark self-reference. shows the input and output data for crude oil extraction assumed in version 4 and in version 5.

Table 2. Input and output data for crude oil extraction

		Version 4	Version 5
Input			
Crude oil in ground	MJ/MJ_{crude}	1.07*	1.12*
Output			
Crude oil extracted	MJ	1.00	1.00
Emissions			
CO_2	g/MJ_{crude}	3.64	8.41
CH_4	g/MJ_{crude}	0.024	0.024
CO_2 equivalent	g/MJ_{crude}	4.25	9.02

* Includes the energy bound in the delivered crude oil

The crude oil transport has been updated based on [Exergia et al. 2015]. In version 4 GHG emissions of 0.881 g CO_2 equivalent per MJ of crude oil (0.952 g CO_2 equivalent per MJ of gasoline or e.g. 0.969 g CO_2 equivalent per MJ of diesel), in version 5 GHG emissions of 0.700 g CO_2 equivalent per MJ of crude oil (0.758 g CO_2 equivalent of gasoline or 0.775 g CO_2 equivalent per MJ of diesel) has been assumed.

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]. **Table 3** shows the input and output data for crude oil refining for version 4 and version 5.

Table 3. Crude oil refining (gasoline and diesel)

		Version 4		Version 5	
		Gasoline	Diesel	Gasoline	Diesel
Input					
Crude oil*	MJ/MJ_{crude}	1.080	1.100	1.082	1.107
Output					
Gasoline or diesel	MJ	1.000	1.000	1.000	1.000
Emissions					
CO_2 equivalent	g/MJ_{crude}	7.0	8.6	5.5	7.2

* Includes the energy bound in the delivered crude oil

2.2 Heavy fuel oil from crude oil (COFO)

The energy and GHG values of crude oil extraction and transport have updated based on the recent data and literature [Exergia et al. 2015] (see above). The input and output data for the refinery (**Table 4**) have been changed based on recent data in [CONCAWE 2017].

Table 4. Crude oil refining (heavy fuel oil)

		Version 5
Input		
Crude oil*	MJ/MJ_{crude}	0.95**
Output		
Heavy fuel oil (HFO)	MJ	1.000
Emissions		
CO_2 equivalent	g/MJ_{crude}	-3.7

* Includes the energy bound in the delivered crude oil; ** Lower than 1 because the energy input without the energy bound in the final fuel is negative (-0.055 MJ per MJ of HFO) according to [CONCAWE 2017]

Based on data in [EUROPIA 2011] the HFO is transported to the consumer partly via train over a distance of 250 km (45%), partly via ship over a distance of 250 km (50%), and partly via truck over a distance of 250 km (5%).

As a result, the GHG emissions from the supply of crude oil amounts to about 6.37 g CO_2 equivalent per MJ of crude oil (version 4: 6.64 g CO_2 equivalent per MJ of HFO). In version 4 only data for a summarized number for the GHG emissions from HFO supply were available.

2.3 Newly added pathways

2.3.1 COD1C & COG1C

In version 5 crude oil refineries for the production of gasoline and diesel with carbon capture and storage (CCS) have been introduced.

2.3.2 SUB_ED95_A.COL1, SUB_ED95_B.COPEG1, SUB_ED95_C.COiB1

The newly added transportation fuel ED 95 consists of ethanol and a small fraction of lubricants, polyethylene glycol (PEG), and i-butanol. The lubricants and PEG are derived from crude oil. In one variant also the i-butanol is derived from crude oil.

3 NG pathways

3.1 GMCG1

The average distance for the transport of natural gas via pipeline has been modified in version 5 based on recent references. An average distance of1900 km to EU border based on the NG mix indicated in [Thinkstep 2017] has been assumed. From there the natural gas is transported over a distance of 500 km to central EU (total 2400 km). As in version 4 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 refuelling stations.

In the previous version (version 4) a transport distance of 2500 km has been assumed, from there 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 refuelling stations.

3.2 GPCG1a

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. In version 4 the transport distance from natural gas fields in Siberia to the central EU was assumed to be 7000 km. According to actual GEMIS data [GEMIS 2016] the transport distance for natural gas transport via pipeline amounts to 5000 km from the natural gas fields in Siberia to central EU (2000 km less than in version 4).

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 refuelling stations.

3.3 GRCG1, GRCG1C, GRCG2 & GRLG1

The inventory data for transformation at source (i.e. natural gas 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 different 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 have been used.

The natural gas losses from natural liquefaction (flaring and CH_4 emissions) still have been derived from [FfE 1996] and [Masake 1997]. However, for version 5 the electricity consumption has been derived from [Ott et al. 2015]. **Table 5** shows the input and output data for a large natural gas liquefaction plant assumed in version 4 and version 5.

Table 5. Large-scale natural gas liquefaction plant

	Unit	Version 4 ([FfE 1996], [Masake 1997)	Version 5 ([FfE 1996], [Masake 1997], **[Ott et al. 2015]**)
Input			
Natural gas	MJ/MJ_{LNG}	1.013	1.013
Electricity	MJ/MJ_{LNG}	0.036	**0.025**
Output			
LNG	MJ	1	1
Emissions			
CO_2	g/MJ_{LNG}	0.62	0.62
CH_4	g/MJ_{LNG}	0.034	0.034

3.4 Newly added pathways (GMCG2a, GMCG2b)

From existing and updated natural gas pathways and compressed upgraded biomethane (CBM) pathways new pathways have been derived.

GMCG2a: EU-mix natural gas supply including

- 90% CNG from piped natural gas (pathway GMCG1)
- 10% CNG from imported LNG (pathway: GRCG1)

GMCG2b: EU-mix natural gas supply including

- 77.7% CNG from piped natural gas (pathway GMCG1)
- 18.9% CNG from imported LNG (pathway GRCG1)
- 3.4% CBM, thereof 40% of the bio-CH4 is derived from organic waste (pathway OWCG1), 20% from manure (OWCG21), and 40% from energy crops (OWCG4a)

4 Compressed upgraded biomethane (CBM)

4.1 OWCG1

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. **Table 6** shows the input and output data for biomethane from municipal organic waste in version 4 and version 5.

Table 6. Biomethane from municipal organic waste

	Unit	Version 4	Version 5
Input			
Municipal organic waste	$MJ/MJ_{biomethane}$	1.43	1.41
Electricity	$MJ/MJ_{biomethane}$	0.062	0.029
Heat	$MJ/MJ_{biomethane}$	0.086	0.098
Output			
Biogas	MJ	1.0	1.0
Fertilizer N	$kg/MJ_{biomethane}$	0.00054	-
Emissions			
CH4	$g/MJ_{biomethane}$	0	0
N2O	$g/MJ_{biomethane}$	0	0

The heat is supplied by a biogas fueled boiler with an efficiency of 90% (LHV). The electricity is supplied by the EU electricity mix at low voltage (0.4 kV) level. The electricity mix and the losses from electricity transport and distribution have been updated base on recent references. The EU electricity mix from 2013 has been used instead of that from 2009 in the previous version.

4.2 OWCG21 & OWCG22

Many significant changes have been observed in the pathways for the supply of CBM from wet manure. We have two variants for biogas generation, biogas from a biogas plant with closed digestate storage and zero CH_4 emissions, and biogas from biogas plants with open digestate storage as worst case. The numbers are from [Giuntoli et al 2017]. The pathways described in [Giuntoli 2017] are used for the typical and default values in the Annex of the re-cast of the Renewable Energy Directive (RED II). **Table 7** shows the input and output data for the biogas plant using wet manure as feedstock.

Table 7. Biomethane from wet manure

	Unit	Version 4		Version 5	
		Closed DS	Open DS	Closed DS	Open DS
Input					
Wet manure	$MJ/MJ_{biomethane}$	2.38	2.5	2.16	2.38
Electricity	$MJ/MJ_{biomethane}$	0.019	0.02	0.018	0.02
Heat	$MJ/MJ_{biomethane}$	0.096	0.10	0.091	0.1
Output					
Biogas	MJ	1	1	1	1
Emissions					
CH_4	$g/MJ_{biomethane}$	0	1.000	0	2.0
N_2O	$g/MJ_{biomethane}$	0	0	0	0.066

The heat is supplied by a biogas fuelled boiler with an efficiency of 90% (LHV). The electricity is supplied by the EU electricity mix at low voltage (0.4 kV) level. The EU electricity mix from 2013 has been used instead of that from 2009 in the previous version.

Although open digestate storage is not realistic because it is not allowed in many EU countries, it is included in the RED II pathways.

4.3 OWCG4a

Energy and emissions in the Production and conditioning stage have been updated based on the latest JRC source. Additionally, “Ensiling” has been added in the feedstock supply chain. **Table 8** shows the inputs and emissions for maize whole plant cultivation in version 4 and in version 5.

Table 8. Input and output data for maize whole plant cultivation

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ_{crop}	0.00094	0.00065
Diesel	MJ/MJ_{crop}	0.016	0.015
K_2O fertilizer	kg/MJ_{crop}	0.00085	0.000099
N fertilizer	kg/MJ_{crop}	0.00058	0.00026
P_2O_5 fertilizer	kg/MJ_{crop}	0.00031	0.16
Pesticides	kg/MJ_{crop}	0.000029	0.000028
Seeding material	kg/MJ_{crop}	0.000093	0.00010
Emissions			
CO_2	g/MJ_{crop}	1.19	1.39
CH_4	g/MJ_{crop}	0.000029	0.000020
N_2O	g/MJ_{crop}	0.029	0.019

$CaCO_3$ expressed as CaO

In version 4 the CO_2 emissions from neutralization and other soil acidity were 0.002 g per MJ of crop. In version 5 the CO_2 emissions from neutralization and other soil acidity amounts to 0.28 g per MJ of crop.

The input of fertilizers, pesticides, and diesel is connected with upstream process to supply these materials and energy sources. The energy use and GHG emissions from the supply of N fertilizer, K2O fertilizer, and P2O fertilizer has been changed based on recent references.

In contrast to version 4, in version 5 losses and diesel requirement for ensiling have been taken into account. From 18 field studies a dry matter loss of 10% can be derived [Kohler 2013] which has also been assumed in [Giuntoli 2017]. The diesel requirement amounts to 0.0037 per MJ of crop [Giuntoli et al. 2018].

In version 5, the maize whole plant is transported via truck to the biogas plant over a distance of 20 km (one way) compared to version 4 where a transport distance of 50 km has been assumed.

The input and output data of the biogas plant (fermenter) have significantly changed based on recent references (**Table 9**). The maize whole plant input in [Giuntoli et al. 2017] used in version 5 is based on [IEA Biogas Handbook 2013]; [Boulamanti et al. 2013].

Table 9. Biomethane from maize whole plant, closed digestate storage

	Unit	Version 4	Version 5
Input			
Maize whole plant	$MJ/MJ_{biomethane}$	1.61	1.40
Electricity	$MJ/MJ_{biomethane}$	0.024	0.024
Heat	$MJ/MJ_{biomethane}$	0.098	0.098
Output			
Biogas	MJ	1.0	1.0
Emissions			
CH_4	$g/MJ_{biomethane}$	0	0
N_2O	$g/MJ_{biomethane}$	0	0

The heat is supplied by a biogas fuelled boiler with an efficiency of 90% (LHV). The electricity is supplied by the EU electricity mix at low voltage (0.4 kV) level. The EU electricity mix from 2013 has been used instead of that from 2009 in the previous version.

4.4 Newly added pathways in the existing fuel category

4.4.1 CBM from biogas from sewage sludge (OWCG3)

Pathway OWCG3 describes the supply of compressed upgraded biomethane from sewage sludge.

Table 10. Biomethane from sewage sludge

	Unit	Version 5	Reference
Input			
Sewage sludge	$MJ/MJ_{biomethane}$	2.16	[Giuntoli et al. 2017]
Electricity	$MJ/MJ_{biomethane}$	0.067	[Boisen 2005]
Heat	$MJ/MJ_{biomethane}$	0.48	[Bösch 2005], [Haberkern 2008]
Output			
Biogas	MJ	1.0	
Emissions			
CH_4	$g/MJ_{biomethane}$	0	[Giuntoli et al. 2017]
N_2O	$g/MJ_{biomethane}$	0	[Giuntoli et al. 2017]

According to [Haberkern 2008] about 900,000 MWh of heat are required per 2.3 million t of dry sludge. According to [Bösch 2005] the biogas yield amounts to 300 Nm^3 per t of dry organic substance. The organic fraction amounts to 45.6% of dry sewage sludge. It has been assumed that the CH_4 content of the biogas amounts to 60%.

The electricity consumption has been derived from [Boisen 2005] corrected by the lower dry matter content of sewage sludge compared to that of wet manure (5% instead of 8%).

The same energy related sewage sludge input as for wet manure with closed digestate storage indicated in [Giuntoli et al. 2017] has been assumed. The same CH4 and N2O emissions as for biogas from wet manure with closed digestate storage have been assumed.

4.4.2 Synthetic natural gas (SNG): WWCG2, WFCG2

Pathways for the supply of synthetic natural gas as CNG from wood via gasification and methanation have been introduced in version 5.

4.5 Newly added fuel categories and pathways

4.5.1 Liquefied upgraded biomethane (LBM): OWLG1, OWLG21, OWLG22, OWLG3, OWLG4, OWLG5

Pathways for the supply of liquefied upgraded biomethane (LBM) have been introduced in version 5. The same feedstocks for biogas generation as for compressed upgraded biomethane (CBM) are used. The upgraded biomethane is transported to the refuelling station where it is liquefied and dispensed as LNG.

The input and output data for the liquefaction plant (**Table 11**) are based on [Galileo 2013].

Table 11. CH_4 liquefaction onsite the refuelling station

	Unit	Version 5	Comment
Input			
Natural gas	MM/MJ_{LBM}	1.000	
Electricity	MM/MJ_{LBM}	0.060	420 kWh/(500 kg LNG)
Propane	MM/MJ_{LBM}	0.00013	0.0694 kg propane/(500 kg LNG)
Lubricants	kg/MJ_{LBM}	0.0000041	0.12 l/(500 kg LNG)
Output			
LBM	MJ	1.0	
Emissions			
CO_2	kg/MJ_{LBM}	0.00083	From degradation of propane

The liquefied upgraded biomethane consists of almost pure methane because the CO_2 is removed completely by the liquefaction process.

4.5.2 Synthetic liquid natural gas (SLNG): WWLG2, WFLG2, RELG1a, RELG1b

Pathways for the supply of synthetic natural gas as LNG from wood via gasification and methanation (WWLG2, WFLG2) have been introduced in version 5.

Furthermore, analogous to the pathways RECG1a and RECG1b pathways for synthetic methane from low temperature electrolysis and methanation using renewable electricity for the supply of synthetic methane as LNG (RELG1a, RELG1b) have been introduced. The liquefaction is carried out onsite the refuelling station.

5 Ethanol pathways

5.1 Sugar beet pathways (SBET1a/b/c)

The GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for cultivation, fertilizers, harvesting, transport, and for transport and distribution of the final fuel.

Table 12 shows the inputs and output data for sugar beet cultivation used in version 4 and version 5.

Table 12. Input and output data for sugar beet cultivation

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ_{crop}	0.00108	0.00061
Diesel	MJ/MJ_{crop}	0.015	0.011
K_2O fertilizer	kg/MJ_{crop}	0.00048	0.00026
N fertilizer	kg/MJ_{crop}	0.00032	0.00035
P_2O_5 fertilizer	kg/MJ_{crop}	0.00021	0.00015
Pesticides	kg/MJ_{crop}	0.000077	0.000055
Seeding material	kg/MJ_{crop}	0.000021	0.000011
Emissions			
CO_2	g/MJ_{crop}	1.40	0.77
CH_4	g/MJ_{crop}	0.00044	0.000013
N_2O	g/MJ_{crop}	0.016	0.013

$CaCO_3$ expressed as CaO

In version 4 the CO_2 emissions from neutralization and other soil acidity for sugar beet cultivation amounted to 0.309 g per MJ of crop. In version 5 the CO_2 emissions from neutralization and other soil acidity for sugar beet cultivation have been set zero analogous to the RED II pathways. In version 5, the CH_4 emissions from farming machines have been updated based on [EMEP/EEA 2013] (in version 4 there were still older values for CH_4 from farming machines).

In version 4 the sugar beet was transported via truck over a distance of 100 km to the ethanol plant. In version 5 the transport distance has been reduced to 30 km analogous to the RED II pathways.

At the ethanol plant there are two products, the main product ethanol and the by-product sugar beet pulp. The by-product sugar beet pulp replaces animal feed from wheat and soybean meal. As a result, changes in the processes used for animal feed supply also lead to changes in the final result for ethanol supply. E.g. if the GHG emissions from wheat and/or soybean cultivation, drying, handling, storage and transport increases the GHG emissions for the production of ethanol will decrease due to a higher credit for the sugar beet pulp. The changes in the processes used for animal feed supply are described in chapter 13. Further changes in the overall results are the result of changes in the supply of fertilizers which are described in chapter 14.

The Transport and distribution of the final fuel has significantly changed based on the assumptions in the RED II pathways. In version 5, the ethanol is partly transported via truck over a distance of 305 km (13.2%), via maritime transport over a distance of 1118 km (31.6%), via inland ship over a distance of 153 km (50.8%), and via rail over a distance of 381 km (4.4%) to a depot. From there the ethanol is transported via truck over a distance of 150 km to the refuelling stations. In version 4, the ethanol was transported via truck over a distance of 150 km to the depot and from there via truck over a distance of 150 km to the refuelling stations.

5.2 Wheat pathways (WTET1a/b, WTET2a/b, WTET3a/b, WTET4a/b)

The GHG emissions inventory of these pathways changed significantly because this version uses the basic assumptions as in RED II for cultivation, fertilizers, harvesting, drying, handling, storage, conversion to ethanol, and for transport and distribution of the final fuel.

Table 13 shows the inputs and output data for wheat cultivation used in version 4 and version 5 for the supply of wheat grain for ethanol production.

Table 13. Input and output data for wheat cultivation

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ$_{crop}$	0.0014	0.0014
Diesel	MJ/MJ$_{crop}$	0.039	0.038
K_2O fertilizer	kg/MJ$_{crop}$	0.00021	0.00022
N fertilizer	kg/MJ$_{crop}$	0.0013	0.00134
P_2O_5 fertilizer	kg/MJ$_{crop}$	0.00028	0.00028
Pesticides	kg/MJ$_{crop}$	0.000070	0.000069
Seeding material	kg/MJ$_{crop}$	0.0016	0.00042
Emissions			
CO_2	g/MJ$_{crop}$	3.58	2.81
CH_4	g/MJ$_{crop}$	0.0011	0.000049
N_2O	g/MJ$_{crop}$	0.042	0.045

$CaCO_3$ expressed as CaO

In version 4 the CO_2 emissions from neutralization and other soil acidity amounted to 0.719 g per MJ of crop (there was an error in the documentation in version 5 where 3.58 g of CO_2 are indicated for CO_2 from soil neutralization). In version 5 the CO_2 emissions from neutralization and other soil acidity for wheat cultivation have been set zero analogous to the RED II pathways. In version 5, the CH_4 emissions from farming machines have been updated based on [EMEP/EEA 2013] (in version 4 there were still older values for CH4 from farming machines).

In version 5 the drying process has been modified compared to version 4 (**Table 14**).

Table 14. Energy requirement and CO_2 emissions from wheat grain drying

		Version 4	Version 5
Input			
Diesel	MJ/MJ$_{crop}$	-	0.00029
Natural gas	MJ/MJ$_{crop}$	-	0.00029
Electricity	MJ/MJ$_{crop}$	0.004944	0.000048
Emissions			
CO_2	g/MJ$_{crop}$	-	0.037

For handling and storage of wheat grain storage losses (0.8%) have been introduced in version 5 (**Table 15**).

Table 15. Input and output data from wheat grain handling and storage

	Unit	Version 4	Version 5
Input			
Wheat grain	MJ/MJ$_{crop}$	1.0	1.008
Electricity	MJ/MJ$_{crop}$	0.00039	0.00039
Output			
Wheat grain	MJ	1.0	1.0

The input and output data of the ethanol plant for the conversion of wheat grain to ethanol also have changed (**Table 16**).

Table 16. Ethanol from wheat grain

	Unit	Version 4	Version 5
Input			
Wheat grain	MJ/MJ$_{ethanol}$	1.83	1.86
Steam	MJ/MJ$_{ethanol}$	0.36	0.37
Electricity	MJ/MJ$_{ethanol}$	0.054	0.049
NH_3	kg/MJ$_{ethanol}$	0.00023	0.00020
NaOH	kg/MJ$_{ethanol}$	0.00056	0.00047
CaO	kg/MJ$_{ethanol}$	0.00013	-
H_2SO_4	kg/MJ$_{ethanol}$	-	0.00045
Alpha-amylase	kg/MJ$_{ethanol}$	0.000086	0.000047
Gluco-amylase	kg/MJ$_{ethanol}$	0.00012	0.000065
Output			
Ethanol	MJ	1.00	1.00
DDGS	kg/MJ$_{ethanol}$	0.042	0.044

At the ethanol plant there are two products, the main product ethanol and the by-product DDGS. The by-product DDGS replaces animal feed from wheat and soybean meal. As a result, changes in the processes used for animal feed supply also lead to changes in the final result for ethanol supply. E.g. if the GHG emissions from wheat and/or soybean cultivation, drying, handling, storage and transport increases the GHG emissions for the production of ethanol will decrease due to a higher credit for the DDGS. The changes in the processes used for animal feed supply are described in chapter 13. Further changes in the overall results are the result of changes in the supply of fertilizers which are described in chapter 14.

The Transport and distribution of the final fuel has significantly changed based on the assumptions in the RED II pathways. In version 5, the ethanol is partly transported via truck over a distance of 305 km (13.2%), via maritime transport over a distance of 1118 km (31.6%), via inland ship over a distance of 153 km (50.8%), and via rail over a distance of 381 km (4.4%) to a depot. From there the ethanol is transported via truck over a distance of 150 km to the refuelling stations. In version 4, the ethanol was transported via truck over a distance of 150 km to the depot and from there via truck over a distance of 150 km to the refuelling stations.

5.3 Barley and rye pathway (BRET2a)

The pathway BRET2a represents a mix of ethanol from barley and wheat. The GHG emissions inventory of this pathway changed significantly because this version uses the basic assumptions as in RED II for cultivation, fertilizers, harvesting, the conversion to ethanol, and for transport and distribution of the final fuel.

Table 17 shows the inputs and the emissions of greenhouse gases from the cultivation of barley and rye for version 4 and version 5.

Table 17. Input and output data for barley and rye cultivation

		Version 4		Version 5	
		Barley	Rye	Barley	Rye
Input					
CaO fertilizer*	kg/MJ_{crop}	0.0020	0.0035	0.0020	0.0035
Diesel	MJ/MJ_{crop}	0.050	0.064	0.049	0.056
K_2O fertilizer	kg/MJ_{crop}	0.00032	0.00041	0.00036	0.00032
N fertilizer	kg/MJ_{crop}	0.0014	0.0017	0.0014	0.0012
P_2O_5 fertilizer	kg/MJ_{crop}	0.00039	0.00055	0.00036	0.000300
Pesticides	kg/MJ_{crop}	0.000060	0.000036	0.000059	0.000032
Seeding material	kg/MJ_{crop}	0.0028	0.0012	0.003	0.0033
Emissions					
CO_2	g/MJ_{crop}	4.81	6.75	4.02	5.79
CH_4	g/MJ_{crop}	0.0015	0.0019	0.000062	0.000072
N_2O	g/MJ_{crop}	0.043	0.049	0.044	0.0370

$CaCO_3$ expressed as CaO

In version 4 the CO_2 from neutralization of other soil acidity amounts to 1.15 g per MJ of crop in case of barley and 2.09 g per MJ of crop in case of rye. In version 5 the CO_2 from neutralization of other soil acidity amounts to 0.47 g per MJ of crop in case of barley and 1.65 g per MJ of crop in case of rye.

In version 5, the CH_4 emissions from farming machines have been updated based on [EMEP/EEA 2013] (in version 4 there were still older values for CH_4 from farming machines indicated in [ETSU 1996]).

There were also changes for drying, handling and storage (**Table 18** and **Table 19**).

Table 18. Energy requirement and CO2 emissions from barley and rye grain drying

		Version 4		Version 5	
		Barley	Rye	Barley	Rye
Input					
Diesel	MJ/MJ_{crop}	-	-	0.00018	0.00034
Natural gas	MJ/MJ_{crop}	-	-	0.00018	0.00034
Electricity	MJ/MJ_{crop}	0.0033	0.0020	0.000029	0.000057
Emissions					
CO_2	g/MJ_{crop}	-	-	0.022	0.044

For handling and storage of barley and rye grain storage losses (0.8%) have been introduced in version 5 (**Table 19)**.

Table 19. Input and output data from barley and rye grain handling and storage

	Unit	Version 4		Version 5	
		Barley	Rye	Barley	Rye
Input					
Barley, rye	MJ/MJ_{crop}	1.0000	1.0000	1.0081	1.0081

Electricity	MJ/MJ$_{crop}$	0.00039	0.00039	0.00039	0.00039
Output					
Barley, rye	MJ	1.0000	1.0000	1.0000	1.0000

Slightly changes occur at the ethanol plant (**Table 20)**.

Table 20. Ethanol from barley and rye grain

	Unit	Version 4		Version 5	
		Barley	Rye	Barley	Rye
Input					
Barley, rye	MJ/MJ$_{ethanol}$	2.090	1.83	2.12	2.050
Steam	MJ/MJ$_{ethanol}$	0.36	0.36	0.37	0.37
Electricity	MJ/MJ$_{ethanol}$	0.054	0.054	0.049	0.049
NH_3	kg/MJ$_{ethanol}$	0.00026	0.00023	0.00020	0.00020
NaOH	kg/MJ$_{ethanol}$	0.00064	0.00056	0.00047	0.00047
CaO	kg/MJ$_{ethanol}$	0.00015	0.00013	-	-
H_2SO_4	kg/MJ$_{ethanol}$	-	-	0.00045	0.00045
Alpha-amylase	kg/MJ$_{ethanol}$	0.000098	0.000086	0.000047	0.000047
Gluco-amylase	kg/MJ$_{ethanol}$	0.00014	0.00012	0.000065	0.000065
Output					
Ethanol	MJ	1.00	1.00	1.00	1.00
DDGS	kg/MJ$_{ethanol}$	0.054	0.045	0.060	0.055

At the ethanol plant there are two products, the main product ethanol and the by-product DDGS. The by-product DDGS replaces animal feed from wheat and soybean meal. As a result, changes in the processes used for animal feed supply also lead to changes in the final result for ethanol supply. E.g. if the GHG emissions from wheat and/or soybean cultivation, drying, handling, storage and transport increases the GHG emissions for the production of ethanol will decrease due to a higher credit for the DDGS. The changes in the processes used for animal feed supply are described in chapter 13. Further changes in the overall results are the result of changes in the supply of fertilizers which are described in chapter 14.

The Transport and distribution of the final fuel has significantly changed based on the assumptions in the RED II pathways. In version 5, the ethanol is partly transported via truck over a distance of 305 km (13.2%), via maritime transport over a distance of 1118 km (31.6%), via inland ship over a distance of 153 km (50.8%), and via rail over a distance of 381 km (4.4%) to a depot. From there the ethanol is transported via truck over a distance of 150 km to the refuelling stations. In version 4, the ethanol was transported via truck over a distance of 150 km to the depot and from there via truck over a distance of 150 km to the refuelling stations.

5.4 Corn pathways (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, the conversion to ethanol, and for transport and distribution of the final fuel.

Table 21 shows the input data and the emissions of CO_2, CH_4, and N_2O from corn cultivation for the weighted average corn used in the EU.

Table 21. Input and output data for corn cultivation (average corn used in the EU)

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ$_{crop}$	0.00070	0.00070
Diesel	MJ/MJ$_{crop}$	0.034	0.031
K_2O fertilizer	kg/MJ$_{crop}$	0.00049	0.00026
N fertilizer	kg/MJ$_{crop}$	0.0013	0.0011
P_2O_5 fertilizer	kg/MJ$_{crop}$	0.00051	0.00028
Pesticides	kg/MJ$_{crop}$	0.000072	0.000066
Seeding material	kg/MJ$_{crop}$	0.000078	0.00046
Emissions			
CO_2	g/MJ$_{crop}$	2.82	2.29
CH_4	g/MJ$_{crop}$	0.0010	0.000040
N_2O	g/MJ$_{crop}$	0.046	0.042

$CaCO_3$ expressed as CaO

In version 4 the CO_2 from neutralization and other soil acidity amounted to about 0.43 g per MJ of crop. In version 5 the CO_2 from neutralization and other soil acidity set to zero.

The cultivation process for corn in the USA is not used in the RED II pathways. Therefore, there are only minor changes i.e. the CH_4 emissions from farming machines (**Table 22**). However, changes in upstream processes i.e. the supply of diesel, fertilizers, and pesticides influences the overall result.

Table 22. Input and output data for corn cultivation (USA)

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ$_{crop}$	0.00088	0.00088
Diesel	MJ/MJ$_{crop}$	0.025	0.025
K_2O fertilizer	kg/MJ$_{crop}$	0.00042	0.00042
N fertilizer	kg/MJ$_{crop}$	0.0012	0.0012
P_2O_5 fertilizer	kg/MJ$_{crop}$	0.00036	0.00036
Pesticides	kg/MJ$_{crop}$	0.000014	0.000014
Seeding material	kg/MJ$_{crop}$	0.000011	0.000011
Emissions			
CO_2	g/MJ$_{crop}$	2.04	2.04
CH_4	g/MJ$_{crop}$	0.00075	0.000032
N_2O	g/MJ$_{crop}$	0.034	0.034

$CaCO_3$ expressed as CaO

Both in version 4 and version 5 the CO_2 from neutralization and other soil acidity amounted to about 0.20 g per MJ of crop.

Table 23 shows the energy requirement and CO_2 emissions for corn drying both for EU and USA in version 4 and version 5.

Table 23. Energy requirement and CO_2 emissions from corn drying

		Version 4	Version 5
Input			
Diesel	MJ/MJ_{crop}	-	0.0089
Natural gas	MJ/MJ_{crop}	-	0.0089
Electricity	MJ/MJ_{crop}	0.051	0.0015
Emissions			
CO_2	g/MJ_{crop}	-	1.14

For handling and storage of wheat grain storage losses (0.8%) have been introduced in version 5 (**Table 24**).

Table 24. Input and output data from corn handling and storage

	Unit	Version 4	Version 5
Input			
Corn (maize grain)	MJ/MJ_{crop}	1.0000	1.0081
Electricity	MJ/MJ_{crop}	0.00039	0.00039
Output			
Corn (maize grain)	MJ	1.0000	1.0000

Table 25 shows the input and output data for the conversion of corn to ethanol in the EU in version 4 and version 5.

Table 25. Ethanol from corn (EU)

	Unit	Version 4	Version 5
Input			
Corn	$MJ/MJ_{ethanol}$	1.66	1.65
Steam	$MJ/MJ_{ethanol}$	0.40	0.33
Electricity	$MJ/MJ_{ethanol}$	0.049	0.036
NH_3	$kg/MJ_{ethanol}$	0.00020	0.00023
NaOH	$kg/MJ_{ethanol}$	0.00050	0.00038
CaO	$kg/MJ_{ethanol}$	0.00012	0.00010
H_2SO_4	$kg/MJ_{ethanol}$	-	0.00012
Urea	$kg/MJ_{ethanol}$	-	0.000040
Alpha-amylase	$kg/MJ_{ethanol}$	0.000077	0.000057
Gluco-amylase	$kg/MJ_{ethanol}$	0.00011	0.000089
Output			
Ethanol	MJ	1.00	1.00
DDGS	$kg/MJ_{ethanol}$	0.033	0.029

The ethanol plant data for the USA has not been changed. However, changes in upstream and downstream processes (e.g. transport and distribution of the final fuel) influence the overall result.

At the ethanol plant there are two products, the main product ethanol and the by-product DDGS. The by-product DDGS replaces animal feed from wheat and soybean meal. As a result, changes in the processes used for animal feed supply also lead to changes in the final result for ethanol supply. E.g. if the GHG emissions from wheat and/or soybean cultivation, drying, handling, storage and transport increases the GHG emissions for the production of ethanol will decrease due to a higher credit for the DDGS. The changes in the processes used for animal feed supply are described in chapter 13. Further changes in the overall results are the result of changes in the supply of fertilizers which are described in chapter 14.

The Transport and distribution of the final fuel has significantly changed based on the assumptions in the RED II pathways both for CRET2a and CRETUS. In version 5, the ethanol is partly transported via truck over a distance of 305 km (13.2%), via maritime transport over a distance of 1118 km (31.6%), via inland ship over a distance of 153 km (50.8%), and via rail over a distance of 381 km (4.4%) to a depot. From there the ethanol is transported via truck over a distance of 150 km to the refuelling stations. In version 4, the ethanol was transported via truck over a distance of 150 km to the depot and from there via truck over a distance of 150 km to the refuelling stations.

5.5 Sugar cane pathways (SCET1)

Table 26 shows the input data and the greenhouse gas emissions from the sugar cane cultivation used in version 4 and version 5.

Table 26. Input and output data for sugar cane cultivation

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ_{crop}	0.00019	0.00019
Diesel	MJ/MJ_{crop}	0.0086	0.0089
Vinasse	kg/MJ_{crop}	0.18	0.21
Filter mud cake	kg/MJ_{crop}	0.0015	0.0018
K_2O fertilizer	kg/MJ_{crop}	0.00024	0.00019
N fertilizer	kg/MJ_{crop}	0.00018	0.00017
P_2O_5 fertilizer	kg/MJ_{crop}	0.000092	0.000059
Pesticides	kg/MJ_{crop}	0.0000050	0.0000069
Seeding material	kg/MJ_{crop}	0.0054	0.0062
Emissions			
CO_2	g/MJ_{crop}	0.71	0.97
CH_4	g/MJ_{crop}	0.043	0.043
N_2O	g/MJ_{crop}	0.0079	0.0071

$CaCO_3$ expressed as CaO

In version 4 the CO_2 emissions from neutralization and other soil acidity have amounted to about 0.08 g per MJ of crop. In version 5 the CO_2 emissions from neutralization and other soil acidity amounts to about 0.32 g per MJ of crop.

The Transport and distribution of the final fuel inside EU have significantly changed based on the assumptions in the RED II pathways. In version 5, the ethanol is partly transported via truck over a distance of 305 km (13.2%), via maritime transport over a distance of 1118 km (31.6%), via inland ship over a distance of 153 km (50.8%), and via rail over a distance of 381 km (4.4%) to a depot. From there the ethanol is transported via truck over a distance of 150 km to the refuelling stations. In version 4, the ethanol was transported via truck over a distance of 150 km to the depot and from there via truck over a distance of 150 km to the refuelling stations.

5.6 Lignocellulosic ethanol from wood (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 the 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: 500 km via truck; b: 250 km via truck plus 2000 km via ship). In contrast to version 4, pathways involving waste wood uses forestry residue.

5.6.1 Forestry residue

In version 5, the diesel consumption for forestry residue collection amounts to about 0.012 MJ of diesel per MJ of wood. The collected forestry residue is stored leading to a dry matter loss of about 5%. Since industrial waste wood has been assumed in the previous version, no forestry collection and no forestry residue storage (seasoning) was taken into account in version 4.

The diesel consumption for wood chipping has only slightly changed. The chipping of the wood leads to the inputs and outputs shown in **Table 27.**

Table 27. Input and output data for the chipping of industrial residual wood (version 4) and forestry residue (version 5)

		Version 4	Version 5
		Residual industrial wood	Forestry residue
Input			
Forestry residue	$MJ/MJ_{\text{wood chips}}$	1.025	1.025
Diesel	$MJ/MJ_{\text{wood chips}}$	0.004	0.0034
Output			
Wood chips	MJ	1,000	1.000
Emissions			
CO_2	$g/MJ_{\text{wood chips}}$	0.29	0.25
CH_4	$g/MJ_{\text{wood chips}}$	0.000012	0.0000026
N_2O	$g/MJ_{\text{wood chips}}$	0.000012	0.000011

5.6.2 Short rotation forestry

The trees are fertilized with manure in version 5.

Table 28. Wood chips from short rotation forestry including plantation, harvesting and chipping

		Version 4	Version 5
Input			
Diesel	$MJ/MJ_{\text{wood chips}}$	0.0091	0.013
Synthetic N	$kg/MJ_{\text{wood chips}}$	0.00014	-
Pesticides	$kg/MJ_{\text{wood chips}}$	-	0.000015
Emissions			
CO_2	$g/MJ_{\text{wood chips}}$	0.67	0.92
CH_4	$g/MJ_{\text{wood chips}}$	0.000016	0.000016
N_2O	$g/MJ_{\text{wood chips}}$	0.0026	0.0068

In case of wood chips from short rotation forestry the storage (seasoning) leads to a dry matter loss of 12%.

5.6.3 Transport of wood chips to the lignocellulosic ethanol plant

The transport mode and transport distance have significantly changed. **Table 29** shows the transport distances and modes assumed in version 4 and version 5.

Table 29. Transport of wood chips to the lignocellulosic ethanol plant

	Version 4	Version 5	
Waste wood			
	General	Variant a	Variant b
Truck	50 km	500 km	250 km
Ship	400 km	-	2000 km
Short rotation forestry			
	General	Variant a	Variant b
Truck	50 km	500 km	250 km
Ship	-	-	2000 km

5.6.4 Distribution of final fuel

The Transport and distribution of the final fuel has significantly changed based on the assumptions in the RED II pathways. In version 5, the ethanol is partly transported via truck over a distance of 305 km (13.2%), via maritime transport over a distance of 1118 km (31.6%), via inland ship over a distance of 153 km (50.8%), and via rail over a distance of 381 km (4.4%) to a depot. From there the ethanol is transported via truck over a distance of 150 km to the refuelling stations. In version 4, the ethanol was transported via truck over a distance of 150 km to the depot and from there via truck over a distance of 150 km to the refuelling stations.

5.7 Lignocellulosic ethanol from residual straw (STET1)

In version 4 a transport distance of 50 km for the transport of residual wheat straw to the lignocellulosic ethanol plant has been assumed. In version 5 the transport distance has been increased to 500 km analogous to the RED II pathways.

The input and output data for the ethanol plant have significantly be changed. As mentioned above change of efficiency in a downstream process also influences the results for production & conditioning at source. **Table 30** shows the input and output data for the lignocellulosic ethanol plant.

Table 30. Lignocellulosic ethanol plant using wheat straw as feedstock

	Unit	Version 4 [Groves 2003]*	Version 5 [Biochemtex 2015], [Johnson 2016]
Input			
Wheat straw	$MJ/MJ_{ethanol}$	2.38	3.53
CaO	$kg/MJ_{ethanol}$	0.0024	0.0019
H_2SO_4	$kg/MJ_{ethanol}$	0.0041	-
$(NH_4)_2SO_4$	$kg/MJ_{ethanol}$	-	0.00016
NaOH	$kg/MJ_{ethanol}$	-	0.0048
$CaCl_2$	$kg/MJ_{ethanol}$	-	0.000046
$MgSO_4$	$kg/MJ_{ethanol}$	-	0.000035
$(NH_4)_2HPO_4$	$kg/MJ_{ethanol}$	-	0.00031
NH_3	$kg/MJ_{ethanol}$	-	0.00042
KH_2PO_4	$kg/MJ_{ethanol}$	-	0.00023
NaCl	$kg/MJ_{ethanol}$	-	0.00035
Propylene glycol	$kg/MJ_{ethanol}$	-	0.00070
SO_2	$kg/MJ_{ethanol}$	-	0.000048
Output			
Ethanol	MJ	1.00	1.00
Electricity	$MJ/MJ_{ethanol}$	0.052	0.40

* Based on Iogen data

The electricity replaces electricity from a straw fuelled power station with an efficiency of 31.5%. The credit for this electricity is taken into account at the ethanol plant where the electricity output of the ethanol plant is connected with a separate pathway for the supply of electricity from a straw fuelled power station.

The Transport and distribution of the final fuel has significantly changed based on the assumptions in the RED II pathways. In version 5, the ethanol is partly transported via truck over a distance of 305 km (13.2%), via maritime transport over a distance of 1118 km (31.6%), via inland ship over a distance of 153 km (50.8%), and via rail over a distance of 381 km (4.4%) to a depot. From there the ethanol is transported via truck over a distance of 150 km to the refuelling stations. In version 4, the ethanol was transported via truck over a distance of 150 km to the depot and from there via truck over a distance of 150 km to the refuelling stations.

5.8 Newly added pathways

5.8.1 ETBE from ethanol and i-butene from sugar beet (SBBE1b)

A new pathway for the supply of ETBE has been introduced where both the ethanol and the i-butene is derived from sugar beet.

5.8.2 ED95 from wheat (WETOiB -TED, WETCiB -TED)

ED95 is a fuel for diesel engines consisting of mainly of ethanol, and small amounts of polyethylene glycol (PEG), MTBE, i-butanol, and lubricants.

Table 31. Composition of ED95

Substance	m/m_{ED95}	LHV/LHV_{ED95}
PEG	91.46%	90.26%

MTBE	4.97%	4.61%
i-butanol	2.14%	2.97%
Lubricants	0.43%	0.56%

Both in pathway WETOiB –TED and pathway WETCiB –TED the ethanol is derived from wheat grain. In case of pathway WETOiB –TED the i-butanol is derived from crude oil, in case of WETCiB –TED the i-butanol is derived from corn.

5.8.3 ED95 from straw (SETOiB - TEDa, SETOiB – TEDb)

Both in pathway SETOiB - TEDa and pathway SETOiB – TEDb lignocellulosic ethanol from straw is used. The i-butanol is derived from crude oil. In case of SETOiB – TEDa the straw is transported over a distance of distance of 50 km and in case of SETOiB – TEDb the straw is transported over a distance of 500 km to the ethanol plant.

6 Biodiesel (FAME) pathways

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.

6.1 ROFA

Table 32 shows the input data and emissions of greenhouse gases for rape seed cultivation used in version 4 and version 5.

Table 32. Input and output data for rape seed cultivation

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ_{crop}	0.0023	0.0023
Diesel	MJ/MJ_{crop}	0.039	0.039
K_2O fertilizer	kg/MJ_{crop}	0.00065	0.00056
N fertilizer	kg/MJ_{crop}	0.0018	0.0018
P_2O_5 fertilizer	kg/MJ_{crop}	0.00044	0.00041
Pesticides	kg/MJ_{crop}	0.000086	0.000086
Seeding material	kg/MJ_{crop}	0.000079	0.00036
Emissions			
CO_2	g/MJ_{crop}	3.90	2.83
CH_4	g/MJ_{crop}	0.0012	0.000049
N_2O	g/MJ_{crop}	0.055	0.057

$CaCO_3$ expressed as CaO

In version 4 the CO_2 from neutralization and other soil acidity amounted to about 1.04 g per MJ of crop. In version 5 the CO_2 from neutralization and other soil acidity has been set to zero. In version 5, the CH4 emissions from farming machines have been updated based on [EMEP/EEA 2013] (in version 4 there were still older values for CH_4 from farming machines).

Furthermore, the energy requirement for drying, handling and storage and the associated GHG emissions have changed (**Table 33**).

Table 33. Energy requirement and CO_2 emissions from rape seed drying, handling and storage

		Version 4	Version 5
Input			
Diesel	MJ/MJ_{crop}	0.012	0.0062
Natural gas	MJ/MJ_{crop}	-	0.0062
Electricity	MJ/MJ_{crop}	0.0030	0.0030
Emissions			
CO_2	g/MJ_{crop}	0.91	0.79

The electricity is supplied by the EU electricity mix. For version 4 the EU electricity mix from 2009 has been used, for version 5 the electricity mix from 2013 has been used. Furthermore, the losses from electricity transport and distribution has been decreased.

At the oil extraction stage (oil mill), there are two products, the main product rape oil and the by-product rape seed meal. The by-product rapeseed meal replaces animal feed from wheat and soybean meal. As a result, changes in the processes used for animal feed supply also lead to changes in the final result. E.g. if the GHG emissions from wheat and/or soybean cultivation, drying, handling, storage and transport increases the GHG emissions for plant oil extraction will decrease due to a higher credit for the meal. The changes in the processes used for animal feed supply are described in chapter 13. Further changes in the overall results are the result of changes in the supply of fertilizers which are described in chapter 14.

Furthermore, the GHG emissions from EU electricity mix has been changed (see chapter 9.4, leading to lower GHG emissions from electricity supply and as a result to lower GHG emissions from processing), the GHG emissions from crude oil supply (see chapter 2.1, leading to higher GHG emissions for the supply of diesel for transport processes), and the fuel consumption of trucks (decrease of fuel consumption from 0.94 MJ/tkm to 0.81 MJ/tkm leading to lower GHG emissions from rapeseed transport and the distribution of final fuel). **Table 34** shows the results to changes mentioned above for the supply of FAME from rapeseed for pathways ROFA1, ROFA2, and ROFA3.

Table 34. GHG emissions from the supply of FAME from rapeseed

Code		Version 4 (g CO_{2eq}/MJ_{FAME})	Version 5 (g CO_{2eq}/MJ_{FAME})
ROFA 1	Rapeseed cultivation	55.0	50.4
	Rapeseed drying and storage	2.5	2.2
	Rapeseed transport	0.6	0.5
	Oil mill	-9.5*	-9.0*
	Esterification	3.9**	3.3**
	Distribution of final fuel	0.8	0.7
	Refueling station	0.5	0.4
	Total	**53.9**	**48.4**
ROFA2	Rapeseed cultivation	55.0	50.4
	Rapeseed drying and storage	2.5	2.2
	Rapeseed transport	0.6	0.5
	Oil mill	-9.5*	-9.0*
	Esterification	8.7***	7.7***
	Distribution of final fuel	0.8	0.7
	Refueling station	0.5	0.4
	Total	**58.7**	**52.9**
ROFA3	Rapeseed cultivation	55.0	50.4
	Rapeseed drying and storage	2.5	2.2
	Rapeseed transport	0.6	0.5
	Oil mill	-9.5*	-9.0*
	Esterification	7.0	5.9
	Distribution of final fuel	0.8	0.7
	Refueling station	0.5	0.4
	Total	**57.0**	**51.1**

* Includes credit for exported rapeseed meal (14.6 g CO_{2eq}/MJ of FAME in version 4 and 13.7 g CO_{2eq}/MJ of FAME in version 5); ** includes credit for exported glycerol as chemical (6.2 g CO_{2eq}/MJ of FAME in version 4 and 5.7 g CO_{2eq}/MJ of FAME in version 5); *** includes credit for exported glycerol as animal feed (1.3 g CO_{2eq}/MJ of FAME in version 4 and 1.2 g CO_{2eq}/MJ of FAME in version 5)

6.2 SOFA

Table 35 shows the changes for sunflower seed cultivation compared to version 5.

Table 35. Input and output data for sunflower seed cultivation

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ$_{crop}$	0.0012	0.0012
Diesel	MJ/MJ$_{crop}$	0.070	0.069
K_2O fertilizer	kg/MJ$_{crop}$	0.00036	0.00046
N fertilizer	kg/MJ$_{crop}$	0.00089	0.0010
P_2O_5 fertilizer	kg/MJ$_{crop}$	0.00049	0.00061
Pesticides	kg/MJ$_{crop}$	0.000061	0.000055
Seeding material	kg/MJ$_{crop}$	0.000064	0.00035
Emissions			
CO_2	g/MJ$_{crop}$	5.83	5.08
CH_4	g/MJ$_{crop}$	0,0021	0.0001
N_2O	g/MJ$_{crop}$	0,038	0.040

$CaCO_3$ expressed as CaO

The CO_2 from neutralization and other soil acidity initially at about 0.67 g per MJ of crop has been set to be zero for the RED II pathways and as a result also for version 5 of the JEC WTW study.

There is the main product and there is a by-product at the plant oil extraction and the esterification stage. The by-product rapeseed or sunflower meal replaces animal feed from wheat and soybean meal. As a result, changes in these processes also lead to changes in the final result. If the GHG emissions from wheat and/or soybean cultivation, drying, handling, storage and transport (see chapter 6.1) increases the GHG emissions for plant oil extraction decreases due to a higher credit for the meal.

Furthermore, the GHG emissions from the supply of N fertilizer have decreased from 5965 g CO_2 equivalent per kg of N version 4 to 4576 g CO_2 equivalent per kg of N in version 5 leading to lower GHG emissions from cultivation.

Table 36 shows the energy requirement for drying, handling and storage and the associated GHG emissions for version 4 and version 5.

Table 36. Energy requirement and CO2 emissions from sunflower seed drying, handling and storage

		Version 4	Version 5
Input			
Diesel	MJ/MJ$_{crop}$	0.013	0.0062
Natural gas	MJ/MJ$_{crop}$	-	0.0062
Electricity	MJ/MJ$_{crop}$	0.0031	0.0030
Emissions			
CO_2	g/MJ$_{crop}$	0.93	0.79

The electricity is supplied by the EU electricity mix. For version 4 the EU electricity mix from 2009 has been used, for version 5 the electricity mix from 2013 has been used. Furthermore, the losses from electricity transport and distribution has been decreased.

6.3 SYFA

In version 4 a weighed mix weighted average of soybeans from Brazil, USA, and Argentina only from no-till agriculture has been used. In version 5 a weighed mix weighted average of soybeans from Brazil, USA and Argentina from a mix of no-till and till agriculture has been used. Furthermore, in version 4 the weighted mix was different for the export of soybeans and the export of soybean oil. **Table 37** shows the inputs and the emissions of greenhouse gases for soybean cultivation used in version 4 and version 5.

Table 37. Input and output data for soybean cultivation

		Version 4		Version 5
		SYFA3a	SYFA3b	SYFAa/b
Input				
CaO fertilizer*	kg/MJ$_{crop}$	0.0016	0.0016	0.0042
Diesel	MJ/MJ$_{crop}$	0.023	0.023	0.032
K_2O fertilizer	kg/MJ$_{crop}$	0.00000064	0.00018	0.00069
N fertilizer	kg/MJ$_{crop}$	0.000046	0.000046	0.000082
P_2O_5 fertilizer	kg/MJ$_{crop}$	0.00014	0.00030	0.00071
Pesticides	kg/MJ$_{crop}$	0.000070	0.000067	0.000056
Seeding material	kg/MJ$_{crop}$	0.00085	0.0014	0.0013
Emissions				
CO_2	g/MJ$_{crop}$	2.86**	2.88**	5.40***
CH_4	g/MJ$_{crop}$	0.00069	0.00069	0.000040
N_2O	g/MJ$_{crop}$	0.047	0.047	0.043

* $CaCO_3$ expressed as CaO; ** CO_2 from neutralization and other soil acidity (1.16 g/kg of crop) included; *** CO_2 from neutralization and other soil acidity (3.09 g/kg of crop) included

For soybean cultivation the CO_2 emissions significantly have been increased due to higher CO_2 emissions from neutralization and other soil acidity.

The energy requirement and CO_2 emissions from soybean drying, handling, and storage have also changed (**Table 38**).

Table 38. Energy requirement and CO2 emissions from soybean drying, handling and storage

		Version 4		Version 5
		SYFA3a	SYFA3b	SYFAa/b
Input				
Diesel	MJ/MJ$_{crop}$	0.00043	0.00064	0.0010
Natural gas	MJ/MJ$_{crop}$	0.0013	0.0011	0.0010
LPG	MJ/MJ$_{crop}$	0.00065	0.00056	0.00042
Electricity	MJ/MJ$_{crop}$	0.00029	0.00023	0.00042
Emissions				
CO_2	g/MJ$_{crop}$	0.15	0.14	0.16

In case of SYFA3a the soybeans are transported via truck over a distance of 517 km (version 4: 373 km) and subsequently via train over a distance of 179 km (version 4: 61 km) to a soybean oil mill in Argentina, Brazil, or USA. The soybean oil is transported via inland ship over a distance of 562 km (version 4: 529 km) and subsequently via maritime transport over a distance of 11107 km (version 4: 11205 km).

In case of SYFA3b the soybeans are transported via truck over a distance of 517 km (version 4: 447 km), then via train over a distance of 179 km (version 4: 99 km), then via inland ship over a distance of 615 km (version 4: 382 km), and then via maritime transport over a distance of 9831 km (version 4: 11459 km) to a soybean oil mill in the EU.

Before inserting it into the oil mill the soybeans are further dried from 13% to 11%. The natural gas requirement for the drying from 13 to 11% amounts to about 0.00293 MJ per MJ of soybean both in version 4 and version 5.

The electricity and steam consumption of the oil mill have significantly decreased. **Table 39** shows the input and output data for the soybean oil mill.

Table 39. Soybean oil mill

		Version 4 [Ecoinvent 2007], [Ecoinvent 2009], [UBA 1999]	Version 5 **[FIDEOL 2013]**, [Ecoinvent 2007], [Ecoinvent 2009]
Input			
Soybeans	MJ/MJ_{oil}	2.94	2.88
Electricity	MJ/MJ_{oil}	0.031	0.015
n-hexane	MJ/MJ_{oil}	0.0045	0.0037
Steam	MJ/MJ_{oil}	0.14	0.082
Output			
Soybean oil	MJ	1	1
Soybean meal	kg/MJ_{oil}	0.11	0.11
Emissions			
CO_2*	g/MJ_{oil}	0.31	0.25

* From degradation of fossil n-hexane

6.4 POFA

Table 40 shows the inputs and the emission of greenhouse gases for oil palm plantation used in version 4 and version 5.

Table 40. Input and output data for oil palm plantation

		Version 4	Version 5
Input			
CaO fertilizer*	kg/MJ_{crop}	0.00032	-
Diesel	MJ/MJ_{crop}	0.0054	0.0054
K_2O fertilizer	kg/MJ_{crop}	0.00050	0.00058
N fertilizer	kg/MJ_{crop}	0.00026	0.00032
P_2O_5 fertilizer	kg/MJ_{crop}	0.000098	0.00011
Pesticides	kg/MJ_{crop}	0.00018	0.000047
Emissions			
CO_2	g/MJ_{crop}	0.53	0.39
CH_4	g/MJ_{crop}	0.00	0.12
N_2O	g/MJ_{crop}	0.031	0.030

CaCO3 expressed as CaO

It was recently noticed that there are Clean Development Mechanism (CDM) projects (including in Indonesia and Malaysia) that receive credits for avoiding methane emissions from empty fruit bunches (EFB) disposition. The methane arises because EFB decomposition in the usual practice is in fact partly anaerobic (the CDM projects avoid the methane emissions from EFB by either aerobically composting it, or treating it and burning it for electricity). The methane emissions have been attributed to the cultivation step, because the typical disposition of them is as a mulch on the plantation.

In version 5 CH_4 emissions from degradation of palm oil mill effluent (POME) which is used as fertilizer of 0.1206 g per MJ of fresh fruit bunches (FFB) are included (traced back from 6.46 g CO_2 equivalent per MJ of crude palm oil).

Table 41 shows the input and output data for the palm oil mill used in version 4 and version 5.

Table 41. Palm oil mill

		Version 4		Version 5	
Input		Open POME pond	Closed POME pond	Open POME pond	Closed POME pond
FFB	MJ/MJ_{oil}	1.91*	1.91*	1.91*	1.91*
Diesel	MJ/MJ_{oil}	0.0040	0.0040	0.0040	0.0040
Electricity	MJ/MJ_{oil}	0.000070	0.000070	0.000070	0.000070
Output					
Palm oil	MJ	1.00	1.00	1.00	1.00
Heat	MJ/MJ_{oil}	0.12	0.12	0.12	0.12
Palm oil kernel meal	kg/MJ_{oil}	0.0035	0.0035	0.0035	0.0035
Emissions					
CO_2	g/MJ_{oil}	0.29	0.29	0.29	0.29
CH_4	g/MJ_{oil}	0.88	0.12	0.88	0.13
N_2O	g/MJ_{oil}	-	-	0.00089	0.00089

* Related to crude palm oil and palm kernel oil

In case of closed POME pond the empty FFB is composted with palm oil mill effluent (POME) to avoid CH4 emissions and generate fertilizer. Changes compared to version 4 are the introduction of N2O emissions.

6.5 WOFA & TOFA

Table 42 shows the inputs and greenhouse gas emissions attributed to tallow in version 4 and version 5.

Table 42. Inputs for the extraction of tallow at a rendering plant

		Version 4	Version 5
Input			
Tallow bound in carcass	MJ/MJ_{tallow}	1.00	1.00
Electricity	MJ/MJ_{tallow}	0.018	0.0029
Natural gas	MJ/MJ_{tallow}	0.19	0.052
Heavy fuel oil	MJ/MJ_{tallow}	0.019	0.0064
Emissions			
CO_2	g/MJ_{FAME}	11.86	3.38

Table 43 shows the input and output data for combined refining and esterification of waste cooking oil and tallow used in version 4 and version 5.

Table 43. Biodiesel (FAME) from waste cooking oil and tallow via refining and esterification

		Version 4		Version 5
		WOFA	TOFA	WOFA/TOFA
Input				
Waste cooking oil, tallow	MJ/MJ_{FAME}	1.047	1.025	1.036
Electricity	MJ/MJ_{FAME}	0.0051	0.0056	0.0068
Natural gas	MJ/MJ_{FAME}	0.102	0.035	0.047
Methanol	MJ/MJ_{FAME}	0.060	0.051	0.056
$Na(CH_3O)$	kg/MJ_{FAME}	-	0.00047	-
H_3PO_4	kg/MJ_{FAME}	0.00042	0.000032	0.000047
H_2SO_4	kg/MJ_{FAME}	-	-	0.00030
NaOH	kg/MJ_{FAME}	0.000090	0.000088	-
KOH	kg/MJ_{FAME}	0.00036	-	0.00043
Output				
FAME	MJ	1.00	1.00	1.00
Steam	MJ/MJ_{FAME}	0.0014	0.033	0.032
K_2O fertilizer	kg/MJ_{FAME}	0.00038	-	0.00038
Emissions				
CO_2	g/MJ_{FAME}	9.80	5.43	6.48

In version 4 for refining the same process as for rape oil have been used (in **Table 43** summarized with esterification process and summarized with steam generation to make it comparable with the actual version 5 data). In version 5 for waste cooking oil and for tallow the same refining and esterification plant data have been used.

7 HVO pathways (WOHY & TOHY)

7.1 Significant update on the existing fuel pathways

The input and output data for hydroprocessing of waste cooking oil and tallow have changed. In version 4 for waste cooking oil the same hydrogen requirement as for rape oil has been used. In version 5 for waste cooking oil different input and output data have been used. On the other hand, for waste cooking oil the same input and output data as for tallow have been used.

Table 44 shows the input and output data for hydroprocessing of waste cooking oil and tallow used for version 4 and version 5.

Table 44. HVO from waste cooking oil and tallow

	Unit	Version 4		Version 5
		WOHY	TOHY	WOHY/TOHY
Input				
Waste cooling oil	MJ/MJ_{HVO}	1.024	1.024	0.96
Natural gas*	MJ/MJ_{HVO}	0.11**	0.086**	0.13
Electricity	MJ/MJ_{HVO}	-	-	0.0090
H_3PO_4	kg/MJ_{HVO}	0.000017	0.000017	0.000029
N_2	kg/MJ_{HVO}			0.0000060
NaOH	kg/MJ_{HVO}	0.000027	0.000027	0.000093
Output				
HVO	MJ	1	1	1
Electricity	MJ/MJ_{HVO}	0.0016	0.0016	-
Steam	MJ/MJ_{HVO}	0.0079	0.0079	-
Emissions				
CO_2	g/MJ_{HVO}	6.14	4.76	7.36

* Including natural gas for H2 generation; ** NG input SMR plant: 1.315 MJ per MJ of hydrogen

7.2 Newly added fuel categories (SYHY1b, POHY1b, POHY1c)

In case of SYHY1b the soybeans are transported to the EU instead of the soybean oil (SYFA1a) analogous to the RED II pathways.

Pathway POHY1b employs an oil mill with closed palm oil mill effluent (POME) pond leading to lower CH_4 emissions. The excess heat replaces heat from a light oil fuelled boiler. In pathway POHY1c an open POME pond is assumed and no credit for excess heat is taken into account.

7.3 Newly added pathway (PWHY)

In pathway PWHY residual oil from palm oil mill effluent is used as feedstock. Even at the most efficient palm oil mills there is a tiny share of residual oil in the waste water. The process for residual oil extraction consists of skimming/pumping from the pond, heating, filtering, and a liquid storage depot.

8 Synfuels

8.1 WWSD1, WFSD1, WWME1, WFME1, WWDE1, WFDE1, BLSD1, BLME1, BLDE1

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), wood chips transport (see chapter 5.6.1, 5.6.2, and 5.6.3). Pathways involving waste wood uses forestry residue. For the black liquor pathways, the transport distance has been increased from 50 km to 500 km.

In version 5 [Kreutz et al. 2008] instead of [Hamelinck 2004] has been introduced as reference for the wood chips to FT diesel process to be consistent with the newly introduced variant with CCS where also [Kreutz et al. 2008] has been used. The input of dolomite and NaOH still have been derived from [Hamelinck 2004] (adjusted to the specific biomass input indicated in [Kreutz et al. 2008]. Products are gasoline and diesel. Allocation by energy has been applied for allocation of the inputs and outputs to FT diesel.

Table 45. FT diesel from gasification of wood chips with downstream Fischer-Tropsch synthesis and upgrading used for pathway WWSD1 and WFSD1

	Unit	Version 4	Version 5
Input			
Wood chips	$MJ/MJ_{FT\ diesel}$	2.64	2.22
Dolomite	$g/MJ_{FT\ diesel}$	6.4	5.4
NaOH	$g/MJ_{FT\ diesel}$	0.0112	0.0094
Outputs			
FT diesel	MJ	1	1
Electricity	$MJ/MJ_{FT\ diesel}$	0.24	0.12

In version 5 for the pulp mill including black liquor gasification and downstream synthesis and upgrading the same basic data as for the RED II pathways have been used but with substitution instead of allocation by energy for the by-product pulp. The pulp mill uses round wood (which is processed inside the plant) and wood chips (which are chipped outside the plant) as feedstock, both derived from forestry residue. The by-product pulp replaces pulp from a pulp mill without employing black liquor gasification. The conventional pulp mill with conventional black liquor boiler instead of gasification used as reference system consumes about 2.05 kg (38.95 MJ) of dry round wood per kg of pulp [Berglin et al. 1999], [Landälv 2007].

Table 46 shows the input and output data for the production of synthetic diesel, methanol and DME via black liquor gasification and synthesis used in version 4 and version 5.

Table 46. FT diesel, Methanol and DME from black liquor gasification in a pulp mill

	Unit	Version 4			Version 5		
		FT diesel	Methanol	DME	FT diesel	Methanol	DME
Input							
Round wood	MJ/MJ_{fuel}	-	-		3.69	3.31	3.28
Wood chips	MJ/MJ_{fuel}	1.83*	1.52*	1.49	0.96	0.99	0.96
Output							
Final fuel	MJ	1.00	1.00		1.00	1.00	1.00
Pulp	MJ/MJ_{fuel}	-	-		0.095	0.085	0.084

* Incremental wood input (gross input – credit for replaced pulp)

The data used in version 5 lead to significantly lower incremental wood input compared to version 4 (e.g. in case of FT diesel: 3.6919 MJ round wood – 0.0948*38.95) MJ round wood + 0.9559 MJ wood chips = 0.9553 MJ). The reason is that obviously the efficiency of the combined production of pulp and transportation fuel has a higher efficiency than the production of pulp and transportation fuel in separate plants.

The Transport and distribution of the final fuel has significantly changed based on the assumptions in the RED II pathways. In version 5, the ethanol is partly transported via truck over a distance of 305 km (13.2%), via maritime transport over a distance of 1118 km (31.6%), via inland ship over a distance of 153 km (50.8%), and via rail over a distance of 381 km (4.4%) to a depot. From there the ethanol is transported via truck over a distance of 150 km to the refuelling stations. In version 4, the ethanol was transported via truck over a distance of 150 km to the depot and from there via truck over a distance of 150 km to the refuelling stations.

8.2 RESD1

Pathway RESD1 represents the supply of diesel from renewable electricity via the methanol route with CO_2 from flue gas. The process for the production of methanol from hydrogen and CO_2 has been updated based on recent literature ([Van-Dal & Bouallou 2013]) (**Table 47**).

The process derived from [Van-Dal & Bouallou 2013] includes H_2 and CO_2 compression to 7.8 MPa, methanol synthesis, methanol purification, an organic Rankine cycle (ORC) plant for electricity generation, and steam generation from purge gases. The plant consumes 88 t of CO_2 per 59.3 t of methanol. The LHV of methanol amounts to 19.93 MJ per kg leading to the CO_2 input shown in **Table 47** for version 5. The electricity input is required for the compression of CO_2 from 0.1 MPa and the hydrogen from 3 to 7.8 MPa. Some electricity is generated by the ORC plant leading to the net electricity input shown for version 5. Some CO_2 is emitted by the boiler for the combustion of purge gases.

Table 47. Methanol from hydrogen and CO2

	Unit	Version 4	Version 5
Input			
CO_2	kg/MJ_{CH3OH}	0.069	0.075
Hydrogen	MJ/MJ_{CH3OH}	1.14	1.23
Electricity (net input)	MJ/MJ_{CH3OH}	0.17	0.054
Output			
Methanol	MJ	1.00	1.00
Steam (net output)	MJ/MJ_{CH3OH}	0.078	0.086
CO_2	MJ/MJ_{CH3OH}	0.00	5.53

8.3 Newly added pathways

The following new pathways have been introduced in version 5:

- Synthetic diesel from waste wood with carbon capture and storage (CCS): WWSD1aC, WWSD1bC
- Synthetic diesel from wood from short rotation forestry with carbon capture and storage (CCS): WFSD1aC, WFSD1bC
- Synthetic diesel from black liquor with CCS (BLSD1aC)
- Diesel from waste wood via hydrothermal liquefaction (HTL): WWSD2a
- Diesel from wood from short rotation forestry via hydrothermal liquefaction (HTL): WFSD2a
- Gasoline and diesel from waste wood via pyrolysis and upgrading: WWPG1, WFPG1
- Gasoline and diesel from wood from short rotation forestry via pyrolysis and upgrading: WWPD1, WFPD1

- OME from waste wood via gasification, methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis: WWOME
- OME from wood from short rotation forestry via gasification, methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis: WFOME
- Synthetic diesel via high temperature electrolysis and FT synthesis using renewable electricity, CO2 from flue gas: RESD2a
- Synthetic diesel via high temperature electrolysis and FT synthesis using renewable electricity, CO2 from biogas upgrading: RESD2b
- Synthetic diesel via high temperature electrolysis and FT synthesis using renewable electricity, CO2 from air: RESD2c
- OME from renewable electricity via low temperature electrolysis, methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis using renewable electricity

9 Electricity

The losses for electricity transport and distribution have been updated. **Table 48** shows the efficiency for electricity transport and distribution for different voltage levels in version 4 and version 5.

Table 48. Efficiency electricity transport and distribution

	Version 4	Version 5
High voltage (HV)	98.50%	97.35%
Medium voltage (MV)	96.36%	99.09%
Low voltage (LHV)	94.02%	96.62%
Total HV, HV, LV	89.24%	93.22%

9.1 WWEL1, WFEL1, WWEL2, WFEL2, WWEL3, WFEL3, WWEL4, WFEL4, 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), wood chips transport (same as assumptions as in chapter5.6.1 and 5.6.2). Pathways involving waste wood uses forestry residue.

9.2 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 (see chapter 4.1).

9.3 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) have been updated to the latest available data (see chapter 4.2).

9.4 EMEL1a, EMEL2a, EMEL3a

In version 5 the EU electricity mix from 2016 has been used instead of 2009 leading to significantly lower GHG emissions. The renewable share of electricity has increased, the share of fossil energy input, especially coal, has decreased.

Initially, the energy use and GHG emissions for the EU electricity mix in 2013 based on IEA data have been calculated including the energy use and GHG emissions for the supply of fuels (e.g. coal, natural gas, nuclear fuel) used for electricity generation. Data from [EEA 2018] have been used to adapt the energy use and GHG emissions from the EU electricity mix in 2016. **Table 49** shows the primary energy input and the greenhouse gas emissions from electricity generation in 2016 without transport and distribution compared to the assumptions in version 4.

Table 49. Primary energy demand and GHG emissions for electricity from EU mix in 2016 without transport and distribution

		Version 4	Version 5
Input			
Hydro Power	MJ/MJ_e	0.121	0.107
Wind Power	MJ/MJ_e	0.045	0.093
Solar Power	MJ/MJ_e	0.005	0.035
Geothermal	MJ/MJ_e	0.019	0.020
Biomass source	MJ/MJ_e	0.111	0.245
Waste	MJ/MJ_e	0.037	0.047
Coal	MJ/MJ_e	0.475	0.368
Natural gas	MJ/MJ_e	0.581	0.443
Lignite	MJ/MJ_e	0.317	0.233
Crude oil	MJ/MJ_e	0.118	0.065
Nuclear	MJ/MJ_e	1.069	1.086
Peat	MJ/MJ_e	0.012	0.016
Total primary energy	MJ/MJ_e	2.911*	2.758*
Output			
Electricity	MJ	1	1
Emissions			
CO_2 equivalent	g/MJ_e	134	103

Deviation from the sum of the numbers above due to rounding errors

The GHG emissions cannot be compared with other references such as IEA where only the CO_2 emissions from electricity generation are published. The GHG emissions include CO_2, CH_4, and N_2O expressed as CO_2 equivalents, not only CO_2. Furthermore, the GHG emissions include the GHG emissions from the supply of the various fuels (biomass, biomethane, natural gas, heavy fuel oil, coal, lignite, nuclear fuel) used for electricity generation.

In version 4 the renewable energy fraction of total primary energy input is lower (10.2%) than in version 5 (14.6%). However, there was an error in version 4 in file "wtt_appendex_2_v4a.pdf' where a renewable energy fraction of 14.8 to 15.6% has been indicated. The problem is that the primary energy input without the energy content of the electricity itself is presented (= total energy input – 1). This '-1' has also to be split into the fossil, nuclear and renewable primary energy input. The error has been corrected in the associated excel sheet of version 4 but not in 'wtt_appendex_2_v4a.pdf' where accidently all the energy bound in the electricity has been subtracted from the total fossil primary energy consumption.

9.5 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 (see chapter 3.2).

9.6 GPEL1b, GPEl1bC, KOEL1, KOEL2, NUEL1, WDEL1

Only the losses for electricity transport and distribution has been updated.

9.7 GREL1

The inventory data for transformation at source (natural gas 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 different 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 have been used (see chapter 3.3).

9.8 FOEL1

The supply of heavy fuel oil has been updated (see chapter 2.2). The losses for electricity transport and distribution have been updated.

9.9 Newly added pathways (EMEL1b, EMEL2b, EMEL3b)

The pathways EMEL1b, EMEL2b, EMEL3b represents the EU electricity mix for 2030 based on IEA data at high voltage (HV), medium voltage (MV) and low voltage (LV).

10 Heat & Power

10.1 COHT1, COHT2

The energy and GHG values of crude oil extraction and transport have updated based on the recent data and literature (Exergia et al. 2015]. The energy and GHG values for crude oil refineries for the production of gasoline and diesel have been updated base on recent data and literature [CONCAWE 2017] (see chapter 2). The losses for electricity transport and distribution for the supply of auxiliary electricity have been updated.

10.2 WWHT1, WFHT1, WWHT2, WFHT2, WWEH1, WFEH1, WWHE1, WFHE1

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), wood chips transport. Pathways involving waste wood uses forestry residue (see chapter 5.6.1 and 5.6.2). The losses for electricity transport and distribution for auxiliary electricity have been updated.

10.3 OWHT1a, OWHT1b

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. The N credit has been removed (see chapter 4.1). The losses for electricity transport and distribution for auxiliary electricity have been updated.

10.4 OWHT21a, OWHT21b, OWHT22a, OWHT22b

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 (see chapter 4.2). The losses for electricity transport and distribution for auxiliary electricity have been updated.

10.5 GPHT1a, GPHT2a, GPEH1a, GPHE1a

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 (see chapter 3.2), and in case of the domestic boiler 10 km via the local natural gas grid. The losses for electricity transport and distribution for auxiliary electricity have been updated.

10.6 GPEH1b, GPHE1b

Only the losses for electricity transport and distribution have been updated.

10.7 GRHT1, GRHT2, GREH1, GRHE1

The inventory data for transformation at source (i.e. natural gas 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 have been used (see chapter 3.3). The losses for electricity transport and distribution have been updated.

11 H2 pathways

11.1 GMCH1

EU-mix piped natural gas supply, transport to EU by pipeline over a distance of 1900 km to EU border plus 500 km inside EU (see chapter 3.1).

The change of the electricity mix and the changes for electricity transport and distribution (e.g. for the electricity supply of the hydrogen refuelling station) influence the overall result.

11.2 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 (see chapter 3.2), and in case of onsite steam reforming (GPCH1a) 10 km via the local natural gas grid.

The change of the electricity mix and the changes for electricity transport and distribution (e.g. for the electricity supply of the hydrogen refuelling station) influence the overall result.

11.3 GRCH1, GRCH2, GRCH3

The inventory data for transformation at source (i.e. natural gas 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 have been used (see chapter 3.3).

11.4 WFCH1, WWCH1, WFCH2, WWCH2, BLCH1, WFLH

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), and wood chips transport (see chapter 5.6.1 and 5.6.2).

The transport modes and distances for the transport of wood chips have 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. A transport distance of 500 km has been assumed for the transport of wood chips to the pulp mill.

11.5 Newly added pathways

11.5.1 GPCH4b1, GPCH4b2,

Pathways for the supply of CGH2 via CH4 cracking have been introduced in version 5.

11.5.2 OWCH1, OWCH21, OWCH22, OWCH3, OWCH4, OWCH5

Pathways for the supply of compressed gaseous hydrogen (CGH_2) from steam reforming of biogas have been introduced in version 5. The steam reforming is carried out onsite the refuelling station. The same feedstocks for biogas generation as for CBM (chapter 4.1, 4.2, and 4.3) are used.

12 Electrolysis pathways

12.1 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), wood chips transport. Pathways involving waste wood uses forestry residue (see chapter 5.6.1 and 5.6.2).

The losses for electricity transport and distribution have been updated (see chapter 9).

12.2 EMEL2/CH1a, EMEL1/CH2a, EMEL1/LH1a

The EU electricity mix has been changed from EU electricity mix from 2009 to EU electricity mix from 2016. The losses for electricity transport and distribution have been updated (see chapter 9).

12.3 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 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 (see chapter 3.2). The losses for electricity transport and distribution have been updated (see chapter 9).

12.4 GREL1/CH1, GREL1/LH1

The inventory data for transformation at source (i.e. natural gas 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 have been used (see chapter 3.3). The losses for electricity transport and distribution have been updated (see chapter 9).

12.5 KOEL1/CH1, KOEL2/CH1, KOEL1/LH1, NUEL1/CH1, WDEL1/CH2, WDEL1/LH1

The losses for electricity transport and distribution have been updated (see chapter 9).

12.6 Newly added fuel categories and pathways

The variants EMEL2/CH1b, EMEL1/CH2b, and EMEL1/LH1b have been introduced for EU electricity mix from 2030.

13 Supply of animal feed (for credit calculation)

In various biofuel pathways there are process steps where by-products occur which can be used as animal feed (e.g. DDGS, rape seed meal, sunflower seed meal). If the GHG emissions from wheat and/or soybean cultivation, drying, handling, storage and transport increases the GHG emissions for plant oil extraction decreases due to a higher credit for the DDGS or the meal.

Table 50 and **Table 51** shows the cultivation processes for soybean and wheat for animal feed supply.

Table 50. Soybean cultivation for wheat as animal feed

		Version 4	Version 5
Input			
CaO fertilizer*	$kg/kg_{soybean}$	0.032	0.083
Diesel	$MJ/kg_{soybean}$	0.47	0.63
K_2O fertilizer	$kg/kg_{soybean}$	0.0035	0.014
N fertilizer	$kg/kg_{soybean}$	0.00092	0.0016
P_2O_5 fertilizer	$kg/kg_{soybean}$	0.0061	0.014
Pesticides	$kg/kg_{soybean}$	0.0014	0.0011
Seeding material	$kg/kg_{soybean}$	0.027	0.027
Emissions			
CO_2	$g/kg_{soybean}$	57.56**	108.05***
CH_4	$g/kg_{soybean}$	0.014	0.0008
N_2O	$g/kg_{soybean}$	0.94	0.86

* $CaCO_3$ expressed as CaO; ** CO_2 from neutralization and other soil acidity (23.2 g/kg of crop) included; *** CO_2 from neutralization and other soil acidity (61.9 g/kg of crop) included

Table 51. Wheat cultivation for wheat as animal feed (water content: 13%)

		Version 4	Version 5
Input			
CaO fertilizer*	$kg/kg_{wheat\ grain}$	0.019	0.021
Diesel	$MJ/kg_{wheat\ grain}$	0.57	0.57
K_2O fertilizer	$kg/kg_{wheat\ grain}$	0.0032	0.0032
N fertilizer	$kg/kg_{wheat\ grain}$	0.020	0.020
P_2O_5 fertilizer	$kg/kg_{wheat\ grain}$	0.0042	0.0037
Pesticides	$kg/kg_{wheat\ grain}$	0.0010	0.0010
Seeding material	$kg/kg_{wheat\ grain}$	0.023	0.0062
Emissions			
CO_2	$g/kg_{wheat\ grain}$	52.59**	41.38***
CH_4	$g/kg_{wheat\ grain}$	0.017	0.00072
N_2O	$g/kg_{wheat\ grain}$	0.62	0.66

* $CaCO_3$ expressed as CaO; ** includes CO_2 from neutralization and other soil acidity; ***CO_2 from neutralization and other soil acidity removed.

For soybean cultivation the CO_2 emissions significantly have been increased due to higher CO_2 emissions from neutralization and other soil acidity.

14 Fertilizers

The assumptions for fertilizers have been changed based on recent data. **Table 52** shows the inputs and greenhouse gas emissions from the supply of synthetic nitrogen fertilizer used in version 4 and in version 5.

Table 52. Supply of synthetic N fertilizer

	Unit	Version 4	Version 5
Input (primary energy)*			
Natural gas	MJ/kg_N	54.86	53.97
Crude oil	MJ/kg_N	0.59	0.63
Coal	MJ/kg_N	0.40	0.40
Nuclear	MJ/kg_N	0.35	0.35
Hydro	MJ/kg_N	0.12	0.12
Emissions*			
CO_2	g/kg_N	3704**	3877***
CH_4	g/kg_N	7.90	2.17
N_2O	g/kg_N	6.89	2.15

* Includes upstream energy use and GHG emissions; **Fertilizer supply: 3114 g CO_2/kg_N; Emissions from neutralization of acidity from N fertilizer oxidation after N application: 590 g CO_2/kg_N; *** Fertilizer supply: 3079 g CO_2/kg_N; Emissions from neutralization of acidity from N fertilizer oxidation after N application: 798 g CO_2/kg_N

The greenhouse gas emissions from the supply of K_2O fertilizer have been changed based on data from Fertilizers Europe [FE 2015]. The same data have been used for the RED II pathways. **Table 53** shows the inputs and greenhouse gas emissions from P_2O_5 fertilizer supply in version 4 and version 5. [FE 2015] did not supply data for the primary energy input. Therefore, the primary energy input is a rough estimate.

Table 53. Supply of K2O fertilizer

	Unit	Version 4	Version 5
Input (primary energy)*			
Natural gas	MJ/kg_{K2O}	8.67	7.56
Crude oil	MJ/kg_{K2O}	0.67	
Coal	MJ/kg_{K2O}	0.11	
Lignite	MJ/kg_{K2O}	0.07	
Nuclear	MJ/kg_{K2O}	0.25	
Waste	MJ/kg_{K2O}	0.01	
Biomass	MJ/kg_{K2O}	0.03	
Hydro	MJ/kg_{K2O}	0.03	
Wind power	MJ/kg_{K2O}	0.01	
Emissions*			
CO_2	g/kg_{K2O}	548	n. d. a.
CH_4	g/kg_{K2O}	1.60	n. d. a.
N_2O	g/kg_{K2O}	0.013	n. d. a.
Total (CO_2 equivalent)	g/kg_{K2O}	592	417

* Includes upstream energy use and GHG emissions

The greenhouse gas emissions from the supply of P_2O_5 fertilizer have been changed based on data from Fertilizers Europe [FE 2015]. The same data have been used for the RED II pathways**. Table 54** shows the inputs and greenhouse gas emissions from P_2O_5 fertilizer supply in version 4 and version 5. [FE 2015] did not supply data for the primary energy input. Therefore, the primary energy input is a rough estimate.

Table 54. Supply of P2O5 fertilizer

	Unit	Version 4	Version 5
Input (primary energy)*			
Natural gas	MJ/kg_{P2O5}	4.57	
Crude oil	MJ/kg_{P2O5}	7.00	7.2
Coal	MJ/kg_{P2O5}	1.39	
Lignite	MJ/kg_{P2O5}	0.54	
Peat	MJ/kg_{P2O5}	0.02	
Nuclear	MJ/kg_{P2O5}	1.82	
Waste	MJ/kg_{P2O5}	0.06	
Biomass	MJ/kg_{P2O5}	0.19	
Geothermal	MJ/kg_{P2O5}	0.03	
Hydro	MJ/kg_{P2O5}	0.21	
Wind power	MJ/kg_{P2O5}	0.08	
Solar	MJ/kg_{P2O5}	0.01	
Emissions*			
CO_2	g/kg_{P2O5}	988	n. d. a.
CH_4	g/kg_{P2O5}	1.40	n. d. a.
N_2O	g/kg_{P2O5}	0.053	n. d. a.
Total (CO_2 equivalent)	g/kg_{P2O5}	1039	542

* Includes upstream energy use and GHG emissions

Ca fertilizers can consist of limestone ($CaCO_3$), burnt lime (CaO), calcium hydroxide ($Ca(OH)_2$), or a mixture of these substances [Kaltschmitt & Reinhardt 1997], [Opala et al. 2018]. Modelling the RED II pathways it has been decided that $CaCO_3$ is applied to the fields instead of CaO. The supply of CaO would lead to higher CO_2 emissions than the supply of $CaCO_3$ because CO_2 is released from the conversion of $CaCO_3$ to CaO in a lime kiln. However, in literature often the application of limestone is expressed as CaO even there is no conversion of $CaCO_3$ to CaO in a lime kiln.

The changes compared to version 4 lead to a change of the overall results for all pathways involving nitrogen fertilizers.

15 References

See section 6 in the main report for the complete list of references

Appendix 4. JEC WTT v5

Heat & Combined Heat & Power (CHP)

Contents

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1 From Resource to Fuel: production routes

In this chapter of the Annex 4 the Heat & Combined Heat and Power (CHP) related pathways are described. 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 Heat & Power pathway workbooks*.

Electricity generation enters into the WTT calculations primarily as an input to the various fuel production pathways. Some pathways also include generation of electricity as part of the process, either from NG or using the co-products of road fuel production. In these cases, waste heat can often be usefully employed in the production process. For purposes of comparison, we have therefore included pathways describing typical performance of small and industrial case boilers and large scale CHP plants fed with heating oil, natural gas, biogas or wood. In CHP plants electricity is generally considered as the primary product. The results are expressed per MJ of electricity and a credit for excess heat is calculated by comparing with stand-alone heat generation using the same fuel. However, for a limited number of pathways, we have also represented the case where heat is the primary product, surplus electricity being exported to the grid.

Summary

Changes vs Version 4

Significant update on the existing fuel pathways (Heat and Combined Heat and Power)

Heat from light oil fuelled domestic and commercial boiler (COHT1, COHT2): The energy and GHG values of crude oil extraction and transport have updated based on the recent data and literature (Exergia et al. 2015). The energy and GHG values for crude oil refineries for the production of gasoline and diesel have been updated base on recent data and literature (CONCAWE 2017)

Heat from wood fuelled domestic and commercial boiler, electricity and heat from wood fuelled CHP plant wood from waste wood and farmed wood (WWHT1, WFHT1, WWHT2, WFHT2, WWEH1, WFEH1, WWHE1, WFHE1): 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. Heat from upgraded biogas fuelled domestic and commercial boiler, biogas from organic waste (OWHT1a, OWHT1b): 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.

Heat from upgraded biogas fuelled domestic and commercial boiler, biogas from liquid manure (OWHT21a, OWHT21b, OWHT22a, OWHT22b): 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.

Heat from natural gas fuelled domestic and commercial boiler, electricity and heat from CHP plant, natural gas from Russia (GPHT1a, GPHT2a, GPEH1a, GPHE1a): 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, and in case of the domestic boiler 10 km via the local natural gas grid.

Electricity and heat from CHP plants, fueled with piped natural gas transported over a distance of 4000 km (GPEH1b, GPHE1b): The losses for electricity transport and distribution has been updated.

Heat from natural gas fuelled domestic and commercial boiler, heat and electricity from CHP plant, natural gas from imported LNG (GRHT1, GRHT2, GREH1, GRHE1): 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.

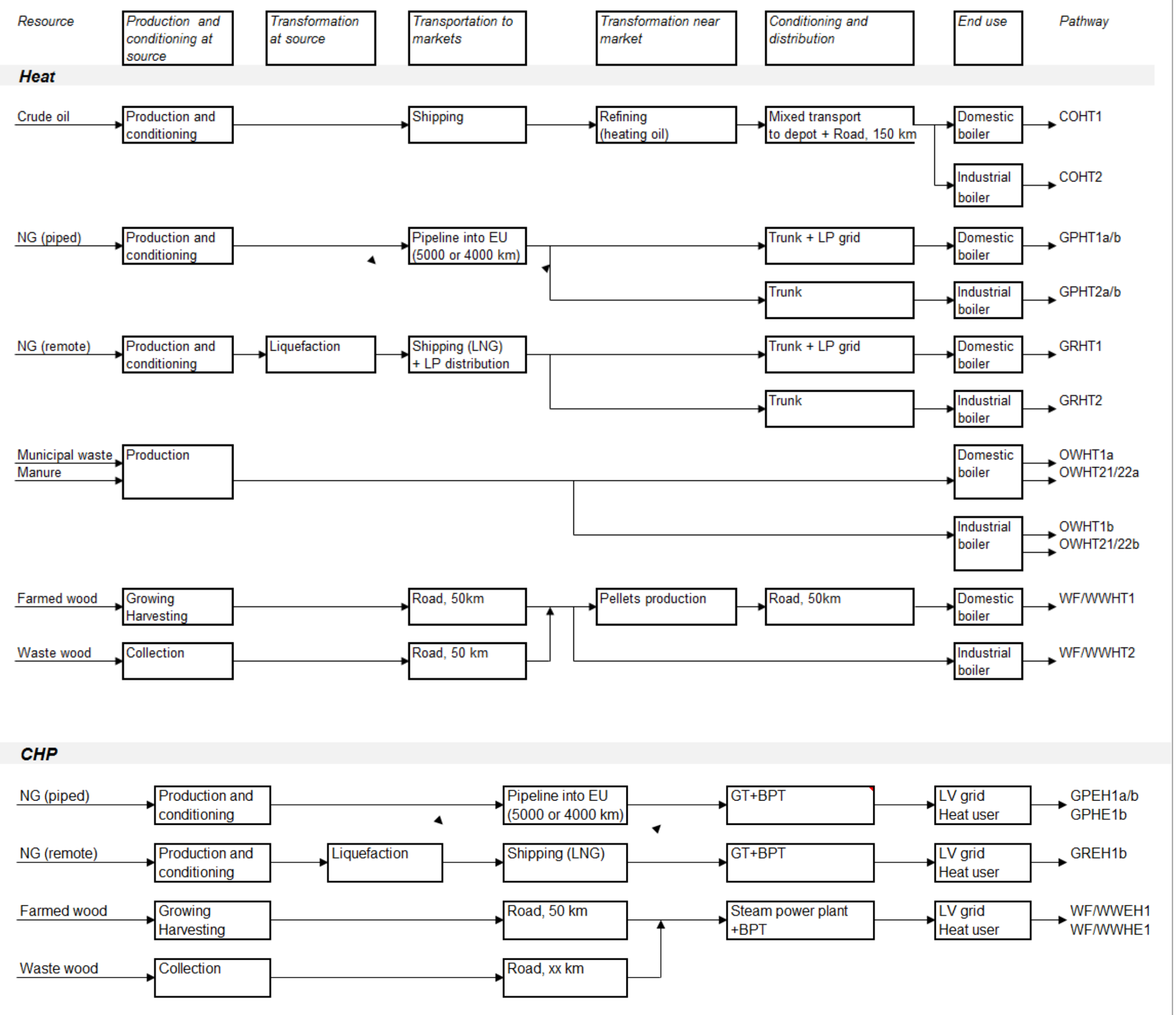
The losses for electricity transport and distribution have been updated in all related pathways.

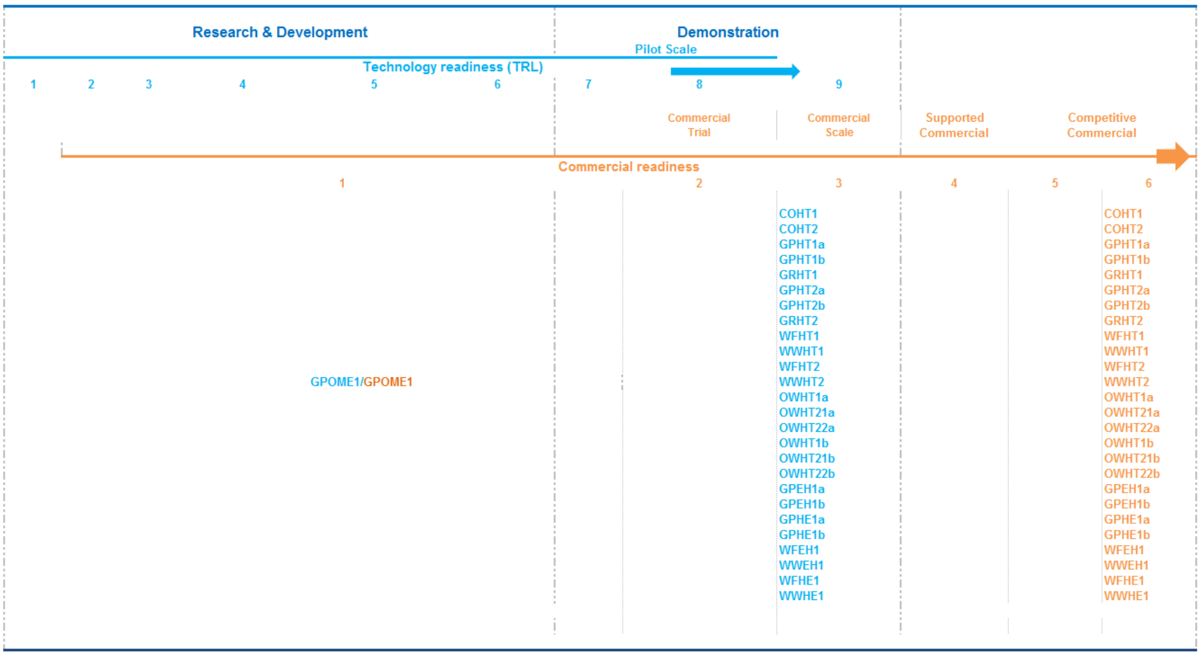
Newly added fuel categories and pathways: EMEL1b, EMEL2b, EMEL3b

Addition of TRL and CRL

Summary

Figure 1. Heat and CHP pathways





2 Energy and GHG balance

(See also workbooks WTT v5 pathways 7-Heat & Power in Appendix 4)

As in the main report, this section reports and compares the energy and GHG balance of each pathway. In order to illustrate the relative importance of the different stages of the pathway, we give detailed results according to the 5 generic steps defined in *section 2.1 (*From *production* to *conditioning and distribution)*. The actual figures with additional details for each pathway are listed in *the relevant workbooks*.

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/energy carrier, *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. The reported WTT GHG figures **exclude CO_2 emissions associated with the combustion** of the final fuel.

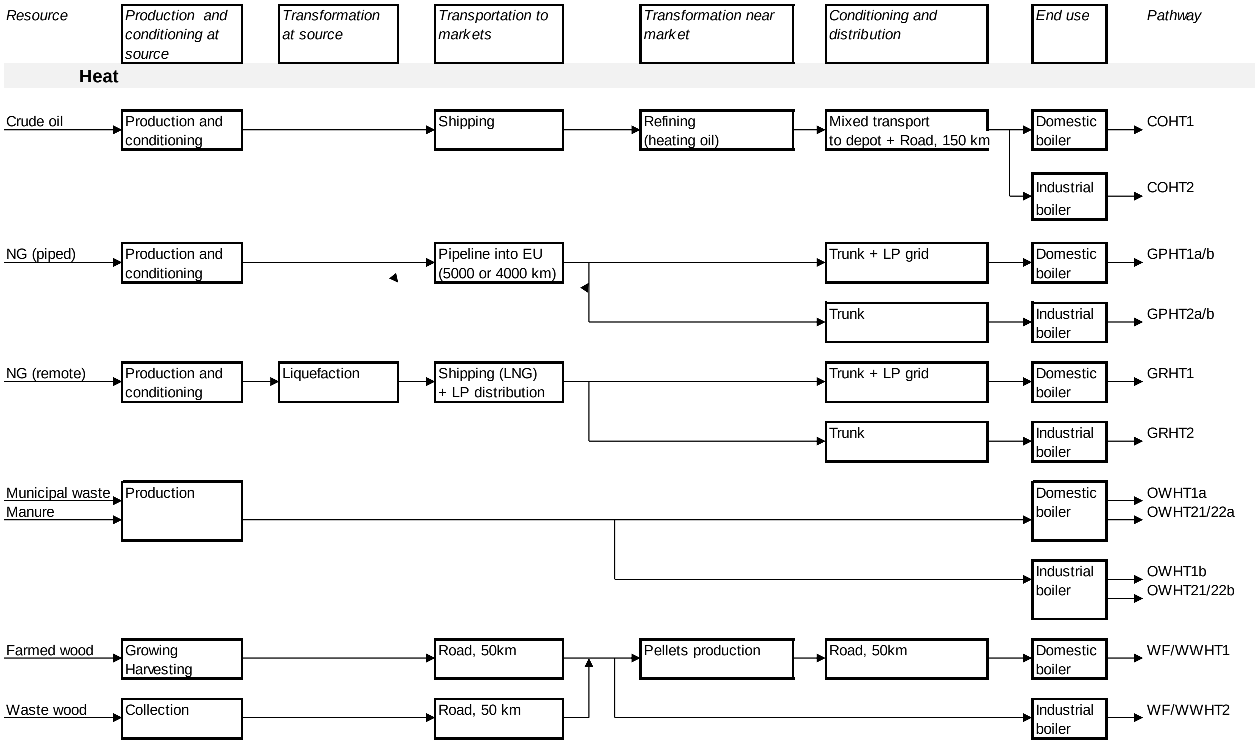
Heat is needed in many road fuel pathways as input to the process and has traditionally been produced in steam boilers fed with variety of fuels. In conventional power generation a significant amount of energy is rejected as heat. If this heat could be usefully employed, the overall efficiency of energy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

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

2.1 Heat Pathways

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

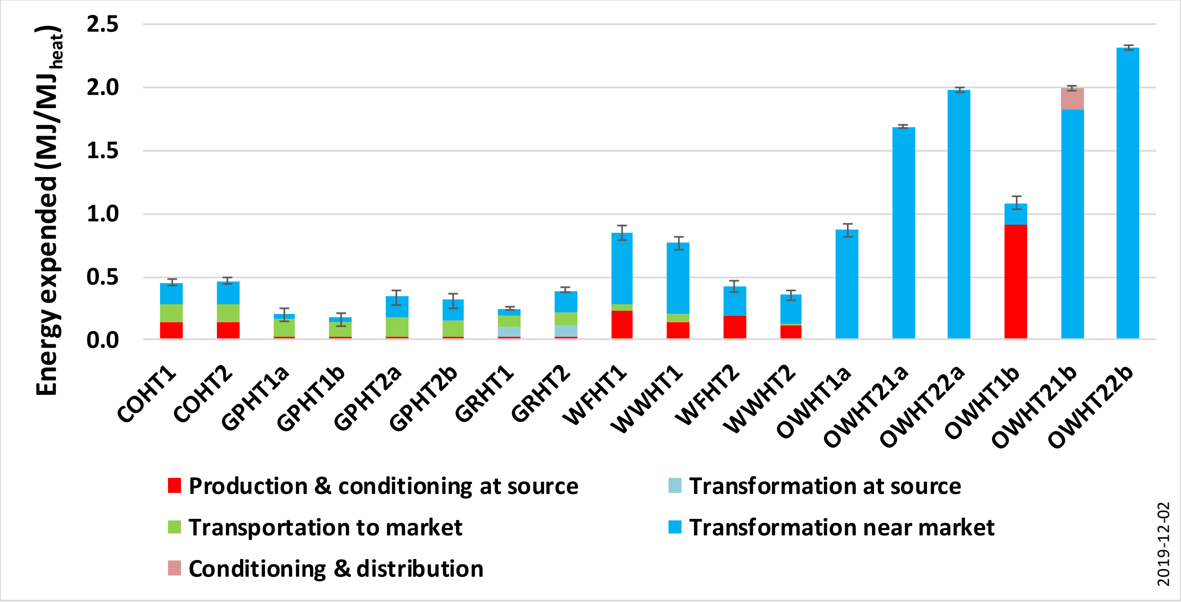
Figure 2. Heat pathways



Code	*Feedstock*	*Description*
Heat		
COHT	Diesel	Heat from fossil diesel-fired boiler. (1) small scale domestic boiler, (2) large scale industrial boiler
GPHT	Natural gas	Heat from natural gas-fired boiler. (1) small scale domestic boiler, (2) large scale industrial boiler, GPHTx: 4300 km + 700 km pipeline (Russia) (a), 4000 km pipeline (Middle East) (b)
GRHT1		Heat from natural gas-fired boiler. LNG
WxHT	Farmed / Waste wood	Heat from wood-fired boiler (F Farmed, W Waste). (1) small scale domestic boiler (2) large scale industrial boiler
OWHT	Biogas from waste	Heat from biogas-fired boiler (small scale) OWHT1a/b: Municipal waste, closed digestate storage OWHT21a/b: Wet manure, closed digestate storage OWHT22a/b: Wet manure, open digestate storage a: domestic condensing boiler; b: commercial boiler

Figures 3 & 4 show the energy use and GHG emissions to produce heat using fossil or renewable fuels.

Figure 3. Total expended energy balance for fossil heat pathways



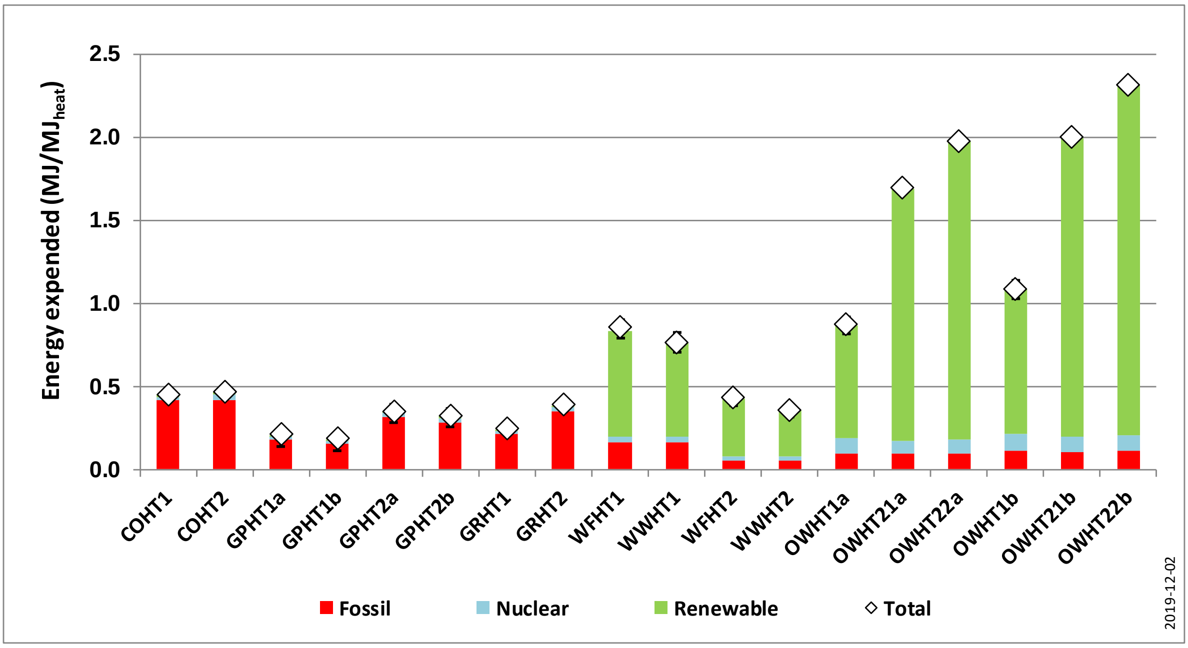
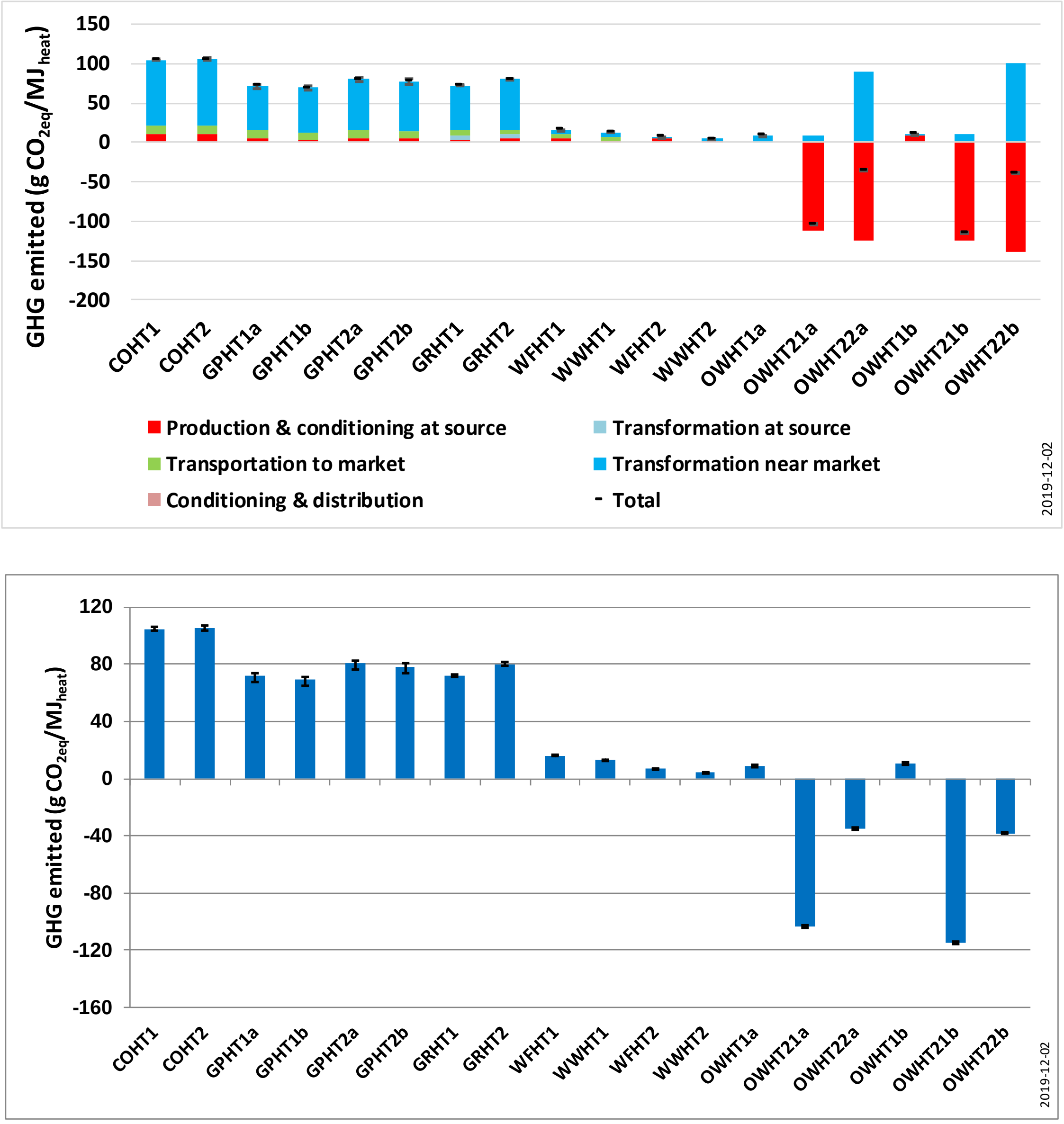


Figure 4. GHG emissions balance for fossil heat pathways



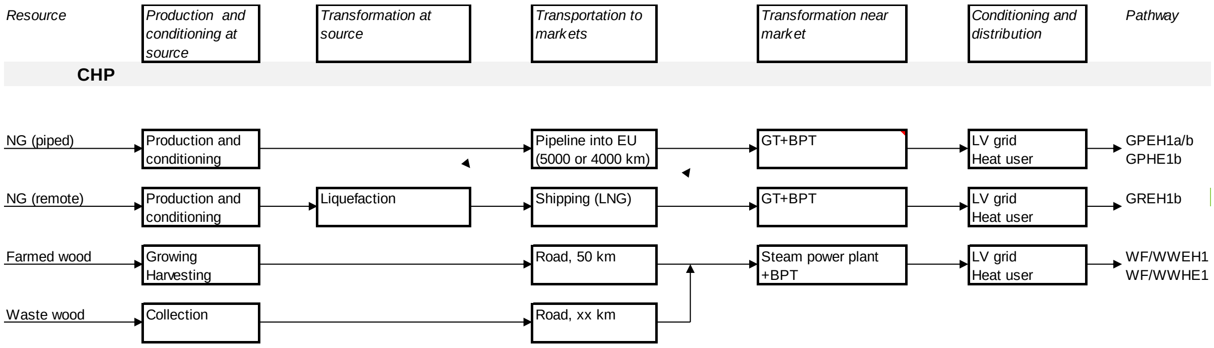
General:

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

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

2.2 CHP Pathways

Figure 5. CHP pathways



CHP		
GPEH1	Natural gas	Piped gas (a: 4300 km + 700 km, b: 4000 km) into large scale state-of-the-art gas turbine CHP plant. Heat as exported co-product.
GREH1		LNG into large scale state-of-the-art gas turbine CHP plant. Heat as exported co-product.
GPHE1b		Piped gas (4000 km) into large scale state-of-the-art gas turbine CHP plant. Electricity as exported co-product.
WF/WWEH1	Farmed / Waste wood	Farmed or waste wood into medium scale boiler/back-pressure turbine CHP. Heat as exported co-product
WF/WWHE1		Farmed or waste wood into medium scale boiler/back-pressure turbine CHP. Electricity as exported co-product

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

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

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

Energy and GHG balances for the CHP schemes considered here are presented in **Figures 6 & 7**. Note that the vertical graph axes are based on the primary fuel, i.e. per MJ electricity for the solid bars, per MJ heat for the hatched bars.

Figure 6. Total expended energy balance for CHP pathways

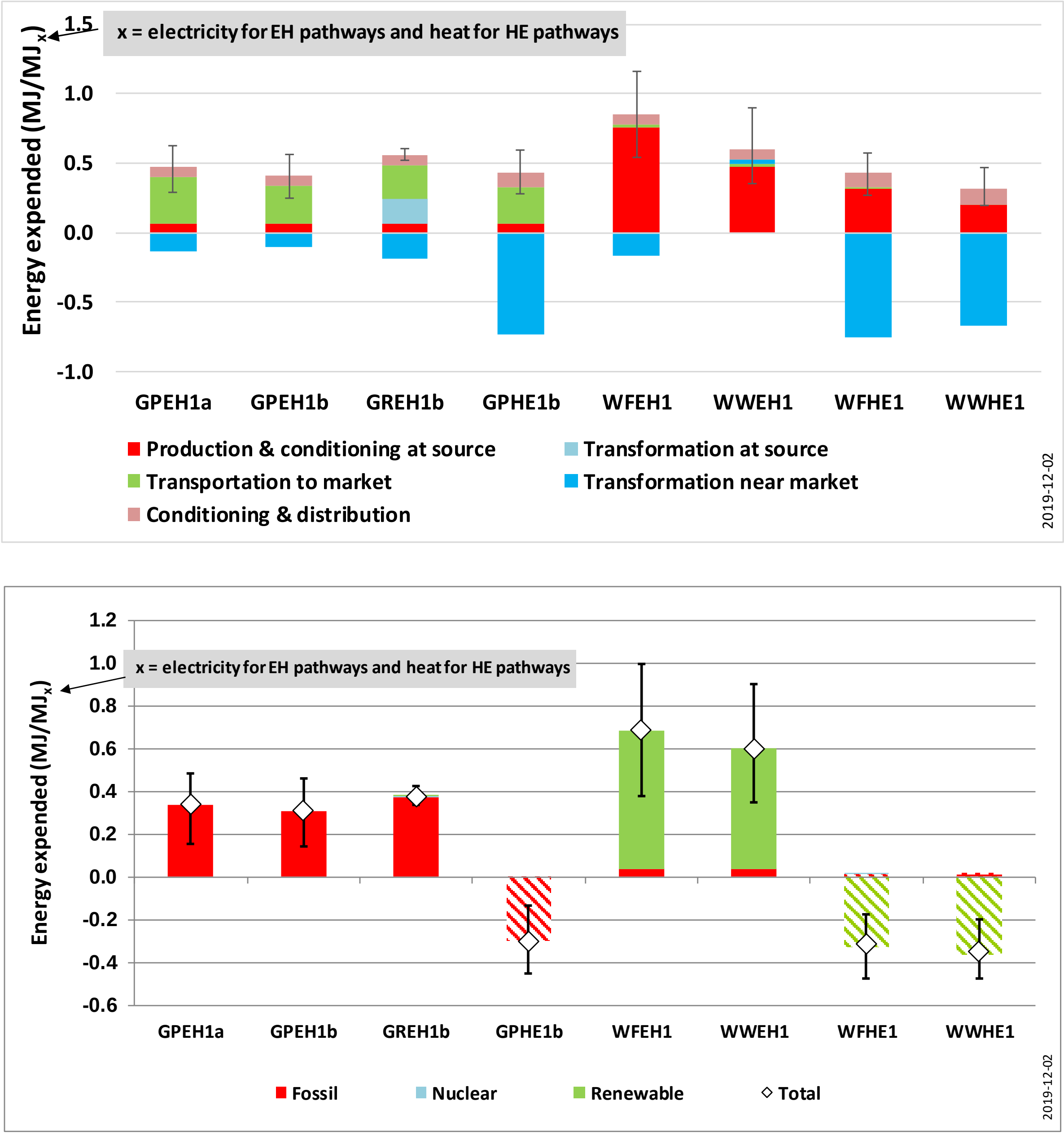
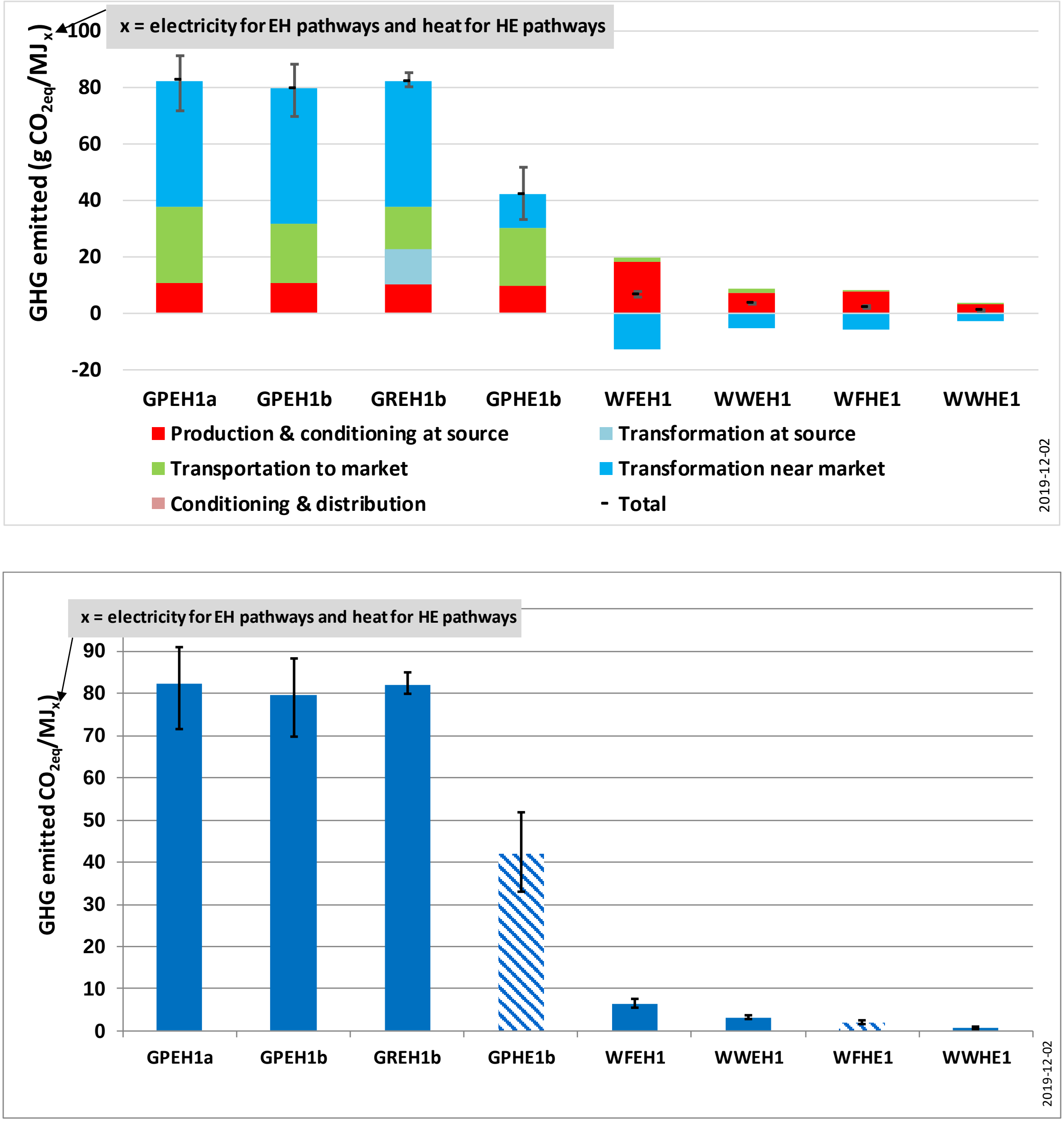


Figure 7. GHG emissions balance for CHP pathways



General:

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

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

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

3 References

See section 6 in the main report for the complete list of references

Appendix 5. JEC WTT v5

Potential effects of DLUC and ILUC on biomass based pathways

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1 Introduction

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.

This annex reports the detailed discussion about potential effects of Direct Land Use Change (DLUC) and Indirect Land Use Change (ILUC) on the GHG performance of biomass based alternative fuel production, and use.

This document is to be considered as a technical insight on the discussion that had led to the development of the current High-ILUC delegated act[1], which constitutes a relevant part of the current legislative framework (RED recast[2]) for biofuel sector.

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[1] https://ec.europa.eu/info/law/better-regulation/initiatives/ares-2019-762855_en

[2] Renewable Energy Directive recast: 2018/2001/EU

2 Land use change and marginal cultivation emissions

2.1 Marginal Direct Emissions

For biofuel made from food crops, the extra crop demand is a marginal (or incremental) change on top of the existing crop production for food. Therefore the (direct) cultivation emissions attributed to biofuels should be those for the marginal production per tonne of extra crop. That means the sum of the emissions from the following sources of extra crop production. However, the pragmatic reason that neither are known at present with any accuracy, **we continue to use average crop emissions for the existing crop production *as a proxy,*** without pretending that this is fully methodologically correct. It means we probably underestimate the actual increase in cultivation emissions caused by the increase in crop demand for biofuels.

Farming on additional land

In future, it may be possible to use models of agriculture to calculate marginal farming emissions. For example, reporting the range in energy use by different farms in EU, (*Kraenzlein 2009*) showed that the quartile of wheat farms with lowest yield used 50% more energy than the average to produce a tonne of wheat. The economic viability of farms is also largely determined by their yield. Therefore, one may expect marginal farms or fields to show significantly greater cultivation emissions than the average ones.

Soil Carbon loss from cultivated fields

Emissions from intensification

These are marginal emissions involved in increasing the existing yield in response to the marginal increase in crop price due to the extra crop demand from biofuels. The incremental production from this intensification will be associated with incremental emissions from the farming (extra use of fertilizer, pesticides, diesel, more expensive seeds, etc.). The ratio of extra emissions to extra production is likely to be higher than the ratio of existing emissions to existing production, because of diminishing returns from further intensification.

2.2 Direct Land Use Change Emissions (DLUC)

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

The document includes specific carbon stock values for common biofuels that are absent from the IPCC guidelines. We have used the default values in this methodology to calculate DLUC emissions for some example land use change scenarios in **Table 1**.

Table 1. DLUC GHG emissions for some example pathway scenarios

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

Note: Total LUC CO_2 emissions and allocated emissions in gCO_{2eq}/MJ have been calculated using crop yields from BioGrace and are based on a 20 year timescale

The table lists the different biomass types present before conversion for biofuel crop cultivation as well as details of the soil management and input strategies both before and after conversion. Definitions of the terms used here are given in the EU document. The CO_2 emissions figure (in gCO_{2e}/MJ) in the "allocated LUC CO_2 emissions row" of the table is the "land use change factor".

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

Note that the DLUC calculation guidelines in the Renewable Energy Directive do not include conversion of wetlands, (including tropical peatland drained for oil palm plantation) because the directives exclude biofuels from crops grown on wetland converted after 2008. However, very significant emissions from decomposition of peat continue for decades after drainage, usually for the entire life of an oil palm plantation *(*Page 2011), whilst historical data in (Miettinen 2012) indicates that about 14% of oil palm area in Indonesia and Malaysia was already converted from peat *before* 2008.

2.3 Indirect Land Use Change (ILUC)

2.3.1 Indirect market-mediated effects are essential to biofuels saving emissions at all

Usually a crop used for biofuel comes from fields that were already producing that crop: in this case there is no additional carbon sequestration from those fields, so the only way that the biofuel can possibly save carbon emissions is by inducing additional carbon sequestration indirectly on *other* land. The hope is that diverting the crop from its existing use for food and feed leads indirectly, through marginally higher crop prices, to additional crop production elsewhere and that will provide the additional carbon sequestration. Without this indirect expansion of crop production, there is no way that the biofuel could save greenhouse gas, as there would be no additional carbon sequestration to counter the larger carbon emissions involved in cultivating, processing and burning biofuels compared to the reference fossil fuel. Thus, the principle that diverting food crops to biofuels indirectly causes crop expansion elsewhere is actually essential to biofuels saving any carbon emissions at all.

2.3.2 Indirect land use change emissions

In the best case, the additional crop is produced by increasing global yields beyond baseline, due to the biofuel-induced increment in crop price. Nevertheless, the additional emissions for providing this additional crop are likely to be higher than the average emissions of the existing crop (see the previous section). However, part of the additional production is likely to come from expansion of cropland onto pasture or natural land somewhere on earth. This indirect land use change generally leads to very significant emissions, see Table 1, above. To correct the emissions for biofuels calculated under the "carbon neutral" assumption, one needs to add these Indirect Land Use Change (ILUC) emissions. The job of ILUC models is to estimate which, and how much, land use change indirectly results from a given production of biofuel.

2.4 Models Estimating Indirect Land Use Change emissions (ILUC)

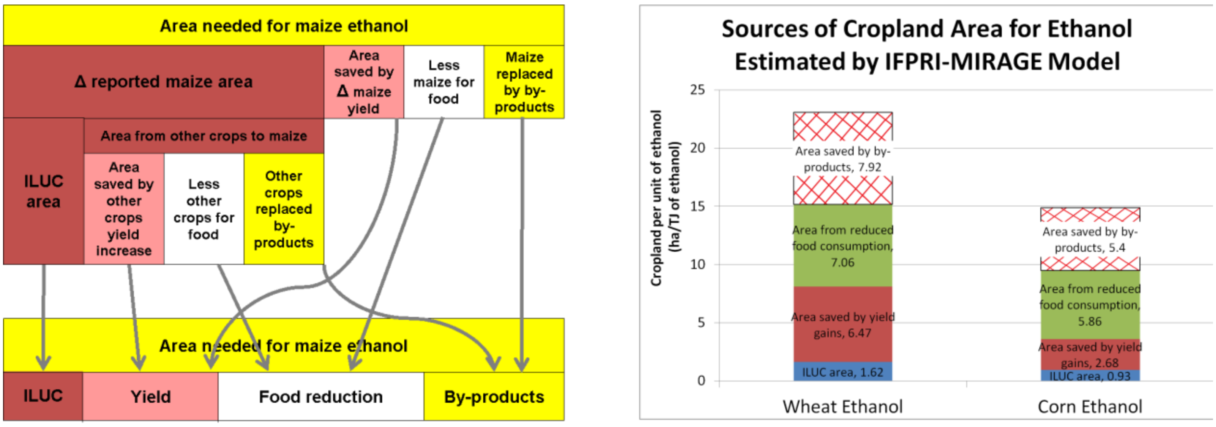
Usually, a crop going into biofuels comes from land which was already producing that crop. In this case there is no additional carbon sequestration on that land, i.e. no DLUC. However, diverting food-crops to biofuel potentially results in the food production loss being replaced through more intensive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

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

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

It is impossible to measure ILUC directly, even in retrospect, because one cannot be sure what would have happened if biofuels were not introduced. Nevertheless, even though we were not able to include them in the WTT results, a thorough evaluation requires that carbon sequestrations or emissions due to ILUC should be considered when assessing GHG emissions of biofuel production. The magnitude of ILUC is still controversial, and currently a matter of debate and scientific investigation (Woltjer et al. 2017). It is currently determined by modelling (commonly using economic modelling of agriculture and related sectors), which seeks to look at the global land use change response to increased biofuel demand. This is done by comparing an economic scenario with the biofuel, against a baseline scenario where the biofuel demand is absent. The "shock" to the model is the extra biofuel demand. This can be a given quantity of a particular biofuel (e.g. 1 Mtoe of rapeseed biodiesel in EU) or a whole policy such as the EU Renewable Energy and Fuels Quality Directives (EU COM 2009 (1)), the California Low Carbon Fuels Standard (LCFS) *[CA LCFS]* or the US Renewable Fuel Standard-2 (RFS-2) [*US RFS-2 2010 (1)]*. Models show ILUC expansion areas much smaller than the area of extra cropland needed to grow the extra crop for biofuel:-

Figure 1. Left, schematic diagram showing why models estimate much smaller ILUC areas than the total increase in crop area needed to produce the biofuel. Right, results of such an analysis on the output of one ILUC model. (Searchinger et al. 2015)



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

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

A complicating feature of land use change emissions, however, is that they occur over a period of time after the land conversion process has begun. Equilibration of soil emissions, for example, can take a particularly long time, while cultivation of perennial crops can lead to carbon accumulation in non-harvestable parts over time as they grow. The common approach to this is to consider the total land use change emissions occurring over a timescale of either 20 or 30 years. European legislation considers the timescale of 20 years. Calculations in **Table 1** are based on a 20-year timescale. The total is then annualised to produce an annual emission value (a “land use change factor”) that can be incorporated into the WTW GHG balance for the rest of the biofuel pathway.

3 Conclusions

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

4 References

See section 6 in the main report for the complete list of references

Appendix 6. JEC WTT v5

Assessment of the contribution of construction materials to the overall footprint of selected road fuels

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Foreword

The pathways described in the main body of the JEC WTW study take into account energy and GHG emissions expended as a result of the production processes of feedstocks and fuels. This does not, however, include the energy and emissions embodied in the materials used to construct the facilities, machinery, vehicles etc used in these processes.

Because of the scale at which road fuels are produced and the relatively long life time of plants and other facilities, this contribution is generally considered small and also not very different from fuel to fuel.

In order to substantiate this, we have carried out a limited assessment of this contribution for a small number of pathways. It must be noted that relevant data is scarce and difficult to come by. Accordingly, the aim of this work was not to generate accurate and definitive numbers in this respect but rather to establish whether this contribution is likely to be significant as a proportion of the total footprint of road fuels and whether there are marked differences between fuel types.

1 Methodology

For each step of a given pathway we identified the main facilities and equipment required as well as the quantity of product that would typically be processed by such facilities over their life time. For each item, we then listed the main materials involved in their construction such as steel, concrete etc using external literature references as well as data internal to LBST and Concawe.

From various sources (mostly Ecoinvent and GEMIS), we assembled a database of relevant materials and their energy and GHG footprint (**Annex 1**).

This data was then collated for each overall WTT pathway to obtain a total figure that was then compared to the overall footprint of that pathway.

2 Selected pathways

The following pathways were investigated:

Description	*Pathway Code*
Conventional gasoline / diesel fuel	COG1/COD1
Ethanol from wheat	WTET2a
RME	ROFA3
Electricity from NG	GPEL1b
Electricity from coal	KOEL1
Electricity from offshore wind	WDEL1
Compressed hydrogen from NG	GPCH2b
Compressed hydrogen from offshore wind	WDEL1/CH2

The conventional fuels pathways provide a reference point. Ethanol and RME introduce the elements of agriculture and comparatively smaller volumes over the life time of the processing plants. Electricity and hydrogen pathways are relevant in the WTW context, in relation to vehicles with electrochemical devices such as batteries and fuel cells.

3 Results

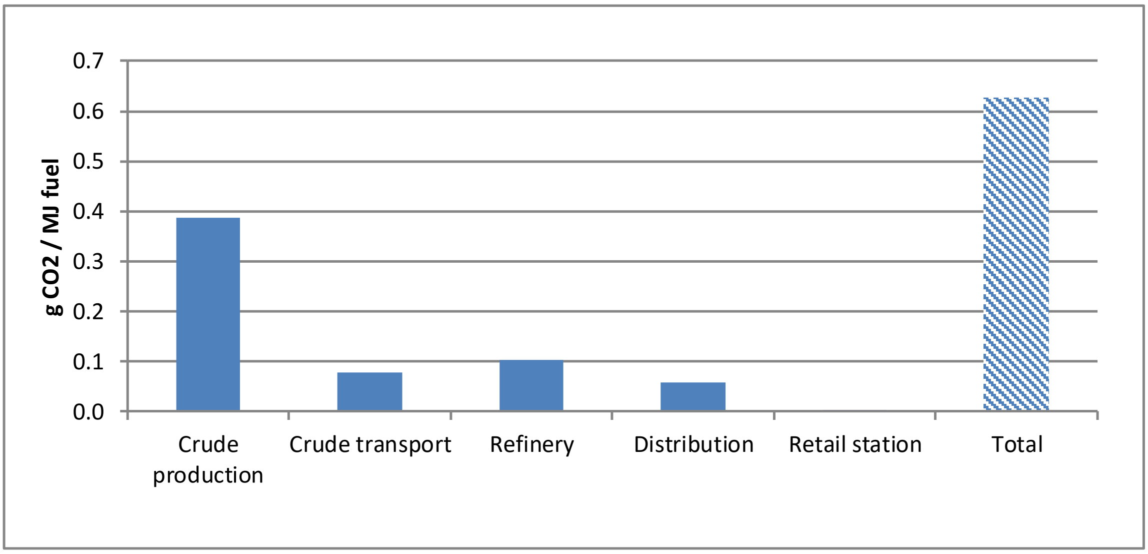
Detailed figures for the main steps of each of the above pathways are given in **Annex 2**. The overall results are shown in **Table 1**. The distribution of emissions between the main steps of each pathway are also shown graphically in the following subsections.

Table 1. Contribution of construction materials to the energy and GHG footprint of selected pathways

Description	*Pathway Code*	*/MJ finished fuel*					
		MJ			*g CO2 $_{eq}$*		
		*WTT**	*Materials*	*% of WTT*	*WTT***	*Materials*	*% of WTT*
Conventional gasoline / diesel fuel	COG1/COD1	1.19	**0.01**	0.9%	87.8	**0.6**	0.7%
Ethanol from wheat	WTET2a	2.62	**0.05**	2.1%	64.8	**3.9**	6.0%
RME	ROFA3	2.13	**0.07**	3.2%	57.0	**4.8**	8.3%
Electricity from NG	GPEL1b	2.19	**0.06**	2.6%	132.4	**5.1**	3.9%
Electricity from coal	KOEL1	2.81	**0.05**	1.8%	292.4	**4.1**	1.4%
Electricity from offshore wind	WDEL1	1.12	**0.10**	9.3%	0.0	**7.8**	
Compressed hydrogen from NG	GPCH2b	1.81	**0.04**	2.1%	104.4	**3.5**	3.4%
Compressed hydrogen from offshore wind	WDEL1/CH2	1.87	**0.15**	7.8%	13.0	**11.4**	87.9%
		*including energy content of the fuel					
		** including combustion					

3.1 Conventional fuels

Figure 1. Distribution of GHG emissions from materials for conventional fuels



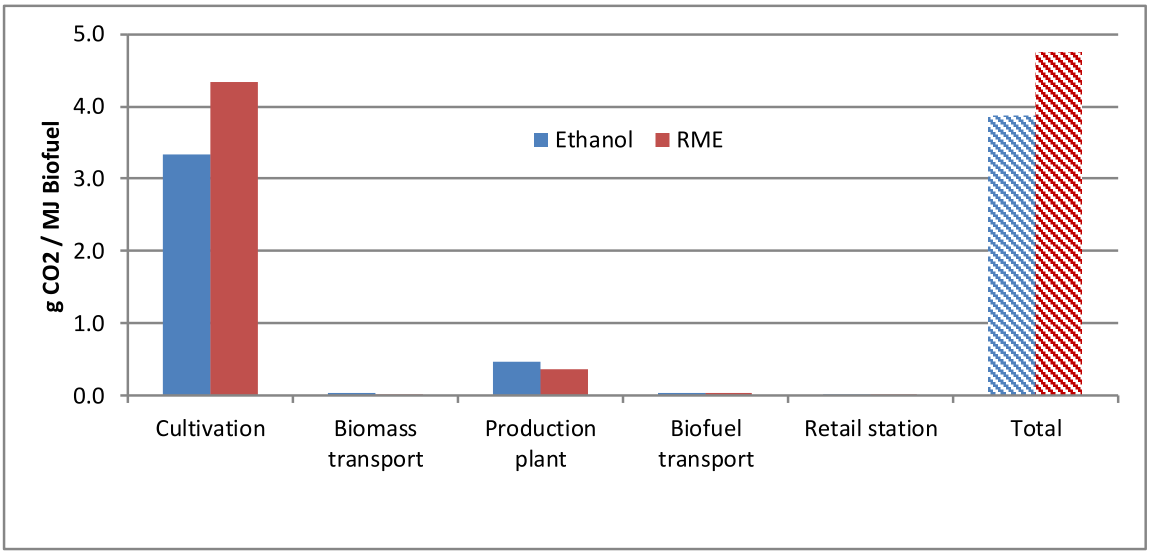
The main contributor is likely to be crude production although the actual figure will be heavily dependent on the producing region and specific circumstances of each field. The figure shown here is for Brent offshore which is likely to be one of the highest.

Although building a refinery would involve significant embedded energy and emissions, the plants have typically a long life time and the annual volumes processed are very large so that the unit contribution is small. The same applies to crude transport (ships, pipelines) and product distribution (pipelines, road/rail, tankage). The contribution of the retail station is negligible.

Overall the contribution of materials represents less than 1% of the WTT total.

3.2 Crop-based Biofuels

Figure 2. Distribution of GHG emissions from materials for crop-based biofuels

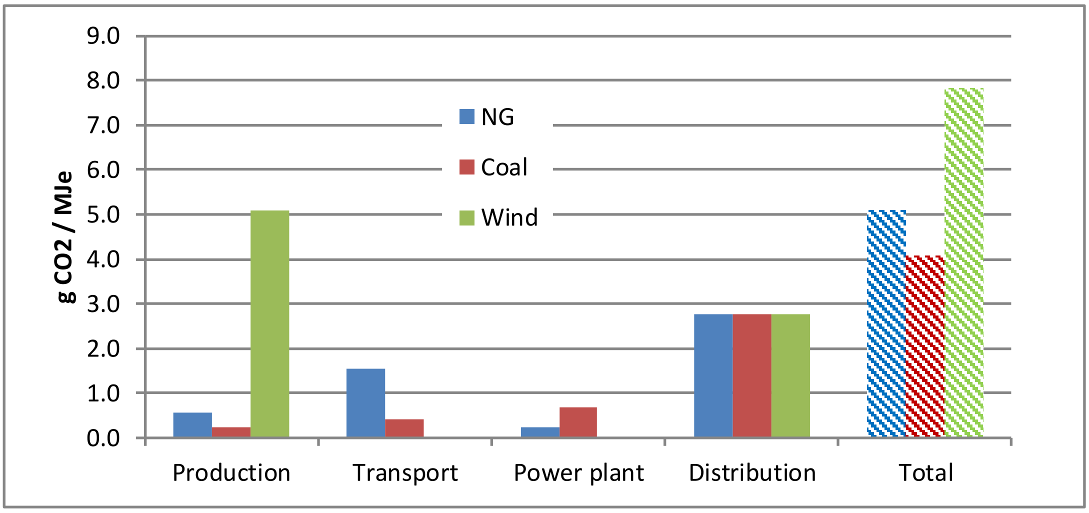


Apart from a small contribution of the production plants, the single most important post is cultivation. This is the result of the combination of highly mechanised agriculture and relatively low yields of fuel compared to the original total biomass.

Overall the contribution of materials is 2 to 3% and 6 to 8% of the WTT total energy and GHG emissions respectively[3]. This is a large enough figure to have a small but noticeable bearing on comparative assessments of different fuels.

3.2.1 Electricity

Figure 3. Distribution of GHG emissions from materials for electricity



Distribution has a significant contribution, mainly stemming from the large amounts of metals (steel, copper) required. Wind turbines, particularly offshore, are material intensive, requiring concrete, steel as well as synthetic materials.

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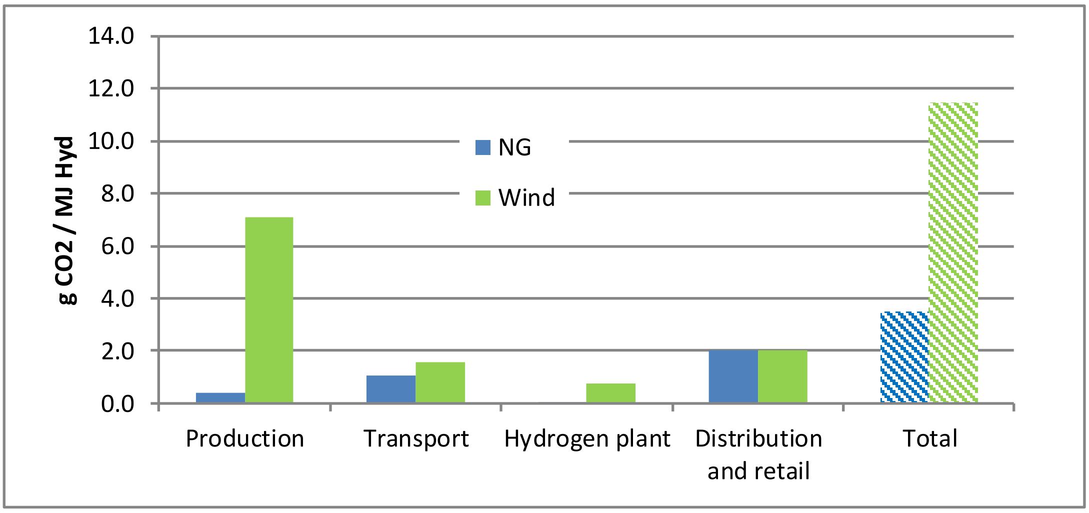
[3] The percentage is higher for GHG emissions than for energy as a large portion of the energy is from bio sources which does not produce net GHG emissions

The overall emissions contribution of materials relative to the total WTT figures represents 3.9% for natural gas and 1.4% for coal (2.6% and 1.8% for energy). There are no operational emissions from wind but this assessment shows that wind electricity is not entirely emissions-free, although, at about 8 g CO_{2eq}/MJ, emissions remain very low compared to other electricity sources.

3.3 Hydrogen

Figure 4. Distribution of GHG emissions from materials for compressed hydrogen



Compression has a noticeable contribution. For wind, electricity production shows the largest contribution.

The total contribution of materials is small for natural gas (3.4% of total WTT). For wind, adding the materials contribution almost doubles the WTT figure (although the total remains low compared to other hydrogen sources).

4 Conclusions

This limited assessment indicates that the contribution of construction materials to the overall energy and GHG emissions WTT figure is small but not always negligible. The assessment is based on limited data and should be regarded as indicative only.

Agricultural hardware manufacture appears to generate enough GHG emissions for it to contribute a notable proportion of the total footprint of crop-based biofuels, maybe in the region of 5-10%.

For electricity and hydrogen from fossil sources GHG emissions from materials may represent a few per cents of the total. Wind electricity is hardware intensive driving the total material contribution to about 10 g CO_{2eq}/MJ. This has a significant impact on the total footprint of associated pathways (for electricity or further to hydrogen).

5 References

See section 6 in the main report for the complete list of references

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Annex 1. Construction materials energy and GHG footprint

Material	*Energy* *kJ/kg*	*GHG* *g* CO_{2eq}*/kg*	*References*
Unalloyed steel from BOF	23,623	2,120	[Ecoinvent 10/2009], [GEMIS 2014]
Unalloyed hot rolled steel from BOF	26,796	2,332	[Ecoinvent 10/2009], [GEMIS 2014]
Unalloyed steel plate from BOF	31,629	2,597	[Ecoinvent 10/2009], [GEMIS 2014]
Unalloyed steel section bar from BOF	28,045	2,409	[Ecoinvent 10/2009], [GEMIS 2014]
Unalloyed steel wire from BOF	26,046	2,266	[Ecoinvent 10/2009], [GEMIS 2014]
Unalloyed steel pipes from BOF	38,403	3,050	[CPM 2008], [Ecoinvent 10/2009], [GEMIS 2014]
Low alloyed steel BOF (e.g. 34CrMo4)	31,218	2,581	[Ecoinvent 10/2009], [GEMIS 2014]
Low alloyed steel BOF pipes (e.g. 34CrMo4)	48,162	3,643	[CPM 2008], [Ecoinvent 10/2009], [GEMIS 2014]
High alloyed steel from BOF	66,792	4,489	[Ecoinvent 10/2009], [GEMIS 2014]
High alloyed hot rolled steel from BOF	73,287	4,877	[Ecoinvent 10/2009], [GEMIS 2014]
High alloyed steel plate from BOF	82,174	5,323	[Ecoinvent 10/2009], [GEMIS 2014]
Unalloyed hot rolled steel from EAF (10% pig iron, 90% steel scrap)	9,472	586	[GEMIS 2014]
Cast iron from EAF (65% pig iron, 35% steel scrap)	24,413	1,887	[Ecoinvent 10/2009], [GEMIS 2014]
Cast iron from EAF (10% pig iron, 90% steel scrap)	12,614	798	[GEMIS 2014]
Carbon fiber reinforced plastics	80,369	7,629	[Carboni et al 2004]; [De Voigt & Haije 1997]; [Dimian & Bildea 2008]; [Ecoinvent 11/2007], [GEMIS 2014]; [Griffing et al 2014]; [Stiller 1999]
Glass fiber reinforced plastics	32,213	2,086	[GEMIS 2014]; [Stiller 1999]
High density polyethylene (HDPE)	10,384	2,439	[GEMIS 2014]
Low density polyethylene (LDPE)	15,091	2,601	[GEMIS 2014]
Polyvinyl chloride (PVC)	31,960	2,174	[GEMIS 2014]
Lubricants (base oil)	10,292	1,039	[Ecoinvent 8/2007], [FEA 1999], [FZJ 1994], [GEMIS 2014], [Hydrocarbon processing 2006], [Uhde 2005]
EPDM rubber	23,242	4,148	[Ecoinvent 11/2007]; [ENI 2009]; [GEMIS 2014]
Rubber (tyres)	52,491	3,985	[Bras & Cobert 2012], [Brophy 2006], [GEMIS 2014], [Ecoinvent 8/2009], [Ecoinvent 11/2007], [ENI 2009], [EPA 1980], [European Commission 2007], [Industrial Nanotech 2010], [IPCC 2006], [Landis et al 2014], [Nor 2009], [Ophardt 2010], [Rentz et al 1999], [van der Velden et al 2014]
Primary aluminium	163,348	10,626	[GEMIS 2014]
Glass, flat, primary	13,232	1,244	[GEMIS 2014]
Primary copper	65,095	3,845	[GEMIS 2014]
Copper wire from primary copper	103,568	5,449	[Ecoinvent 10/2009], [GEMIS 2014]
Zinc for coating	55,392	3,294	[Ecoinvent 10/2009], [GEMIS 2014]
Primary lead	27,694	1,920	[GEMIS 2014]
Sulfuric acid (H2SO4)	-4,050	-257	[GEMIS 2014]
Hydrochloric acid (HCl)	16,167	721	[Ecoinvent 8/2007], [GEMIS 2014]
Nitric acid (HNO3)	8,136	758	[Ecoinvent 8/2007], [Fertilizer Europe 2014]
Acidic acid (C2H4O2)	13,580	463	[GEMIS 2014]
Potassium hydroxide (KOH)	12,775	439	[EC 2001], [GEMIS 2014]
Sodium hydroxide (NaOH)	11,877	531	[GEMIS 2014]
Nickel class I (99.5%)	129,846	8,448	[Ecoinvent 10/2009], [GEMIS 2014]
Platinum	285,701,681	27,009,476	
Cement	4,514	925	[GEMIS 2014]
Concrete	1,059	175	[GEMIS 2014]
Clay bricks	2,689	195	[GEMIS 2014]
Glass wool	36,136	1,846	[Ecoinvent 7/2007], [GEMIS 2014]
Mineral wool	14,980	1,048	[GEMIS 2014]
Metallurgical silicon	167,679	9,062	[GEMIS 2014]
Paint	22,119	1,822	[Ecoinvent 8/2007], [GEMIS 2014]

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Annex 2. Detailed results

Detailed calculations and references for specific steps/pathways are available on request

Energy and GHG associated with construction of facilities

Pathway	***/MJ output***		***Conversion factor***	***/MJ of finished fuel***	
	MJ	***g CO_{2eq}***	***MJ/MJ***	***MJ***	***g CO_{2eq}***
Conventional gasoline and diesel (COG1/COD1)					
Crude production equipment (North Sea offshore)	0.005	0.3	1.3	0.01	0.4
Crude transport media (ship, pipeline)	0.001	0.1	1.3	0.00	0.1
Refinery hardware	0.001	0.1	1.3	0.00	0.1
Distribution hardware (terminals) and media (road, rail, pipeline)	0.001	0.1	1.0	0.00	0.1
Retail station hardware	0.000	0.0	1.0	0.00	0.0
Total				0.01	0.6
Ethanol (WTET2a)					
Wheat production equipment (farm machinery)	0.027	1.8	1.8	0.05	3.3
Grain transport media (road)	0.000	0.0	1.8	0.00	0.0
Ethanol plant hardware	0.004	0.5	1.0	0.00	0.5
Distribution hardware (terminals) and media (road)	0.001	0.0	1.0	0.00	0.0
Retail station hardware	0.000	0.0	1.0	0.00	0.0
Total				0.05	3.9
RME (ROFA3)					
Rape production equipment (farm machinery)	0.039	2.6	1.6	0.06	4.3
Rape seed transport media (road)	0.000	0.0	1.6	0.00	0.0
RME plant harware	0.004	0.4	1.0	0.00	0.4
Distribution hardware (terminals) and media (road)	0.000	0.0	1.0	0.00	0.0
Retail station hardware	0.000	0.0	1.0	0.00	0.0
Total				0.07	4.8
Electricity from NG (GPEL1b)					
NG production equipment	0.003	0.3	2.2	0.01	0.6
NG long-distance pipeline	0.005	0.7	1.9	0.01	1.4
NG trunk distribution pipeline	0.001	0.1	1.9	0.00	0.1
CCGT plant hardware	0.003	0.2	1.1	0.00	0.2
Distribution hardware (to LV)	0.035	2.8	1.0	0.04	2.8
Total				0.06	5.1
Electricity from coal (KOEL1)					
Coal production equipment	0.001	0.1	2.6	0.00	0.2
Coal transport media (ship)	0.002	0.2	2.6	0.00	0.4
Power plant hardware	0.007	0.6	1.1	0.01	0.7
Distribution hardware (to LV)	0.035	2.8	1.0	0.04	2.8
Total				0.05	4.1
Electricity from offshore wind (WDEL1)					
Offshore wind farm	0.061	4.5	1.1	0.07	5.1
Distribution hardware (to LV)	0.035	2.8	1.0	0.04	2.8
Total				0.10	7.8
Compressed hydrogen from NG (GPCH2b)					
NG production equipment	0.003	0.3	1.5	0.00	0.4
NG long-distance pipeline	0.005	0.7	1.3	0.01	1.0
NG trunk distribution pipeline	0.001	0.1	1.3	0.00	0.1
SMR plant hardware	0.001	0.0	1.0	0.00	0.0
Distribution (pipeline)	0.001	0.0	1.0	0.00	0.0
Retail station hardware	0.025	2.0	1.0	0.02	2.0
Total				0.04	3.5
Compressed hydrogen from offshore wind (WDEL1/CH2)					
Offshore wind farm	0.061	4.5	1.6	0.10	7.1
Elec distribution hardware (to HV)	0.010	1.0	1.5	0.02	1.6
Electrolyser	0.010	0.8	1.0	0.01	0.8
Distribution (pipeline)	0.001	0.0	1.0	0.00	0.0
Retail station hardware	0.025	2.0	1.0	0.02	2.0
Total				0.15	11.4

* The “conversion factors” represent the energy content of materials produced in a given step of a pathway necessary to produce a MJ of finished fuel

Appendix 7. JEC WTT v5

Estimates of biofuel production costs and cost of savings

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Abstract

The cost of replacing conventional road fuels with sustainable biofuels and alternative fuels and, ultimately, the cost of saving GHG emissions by using these fuels are key aspects which need to be investigated. This report analyses and quantifies the production cost and cost of GHG savings of the main conventional and advanced biofuels produced in Europe for the time period 2014-2016, including scenarios at time horizon 2030 based on different crude oil prices. Power to liquids (PtL) pathways will be part of an extension of this chapter following a dedicated methodological approach.

The method implemented in this report for conventional and advanced biofuel production consists in estimating the cost to the EU as an entity following the same principles developed in the JEC-WTW v2 (2007) report, but limiting its focus to the 'well-to-tank' part of the fuel production. Therefore, we accounted for the market value of the commodity prices, the costs for plants and equipment required for the fuel production and the cost of energy, all applied on EU basis.

1 Introduction

Directive (EU) 2015/1513, amending the Renewable Energy Directive (RED, 2009/28/EC), called on the European Commission (EC) to present a comprehensive proposal for a cost-effective and technology-neutral post-2020 policy in order to decarbonise the transport sector and create a long-term perspective for investment in sustainable biofuels. On November 30, 2016, the European Commission (EC) published a proposal to the EU Council and the European Parliament to recast the RED for the 2021-2030 period (COM(2016)676, REDII).

Agreement on the use of renewable energy in Europe in 2030 was reached in June 2018 and the new Directive adopted in December 2018 (Directive (EU) 2018/2001[4]). The new regulatory framework includes a binding renewable energy target for the EU for 2030 of 32% with an upwards revision clause by 2023. Each Member State shall set an obligation on fuel suppliers to ensure the share of renewable energy supplied for final consumption in the transport sector is at least 14% by 2030. Within this share, the contribution of so-called advanced biofuels (listed in part A of Annex IX[5]) shall be at least equal to 0.2% in 2022, 1% in 2025 and, increasing up to at least 3.5% by 2030. Advanced biofuels count double towards the achievement of the 14% transport sub-target. However biofuels produced from feedstocks listed in part B of Annex IX (used cooking oil and animal fat) will be counted only up to 1.7 %.

The 7% cap on biofuels produced from food and feed crops is maintained[6]. Member States may set a lower limit for the contribution from food and feed crop-based biofuels produced from oil crops, taking into account best available evidence on indirect land-use change impact[7].

For the calculation of the 14% share, Member States shall consider 'renewable liquid and gaseous transport fuels of non-biological origin[8]', also when they are used as intermediate products for the production of conventional fuels; and may decide to include the contribution from recycled carbon fuels[9].

The focus of this report is on biofuels that are defined as '*liquid fuels for transport produced from biomass*' in the RED recast. We refer to conventional or first-generation biofuels as those fuels produced from food and feed crops (such as sugar, starch, oil) while advanced (or second-generation) biofuels as those made from feedstocks that do not compete directly with food and feed crops, such as lignocellulosic biomass (e.g. agricultural residues, woody biomass) and wastes. Other pathways including power to liquids (PtL) will be part of an extension of this report following a dedicated methodological approach. The cost of replacing traditional road fuels with sustainable biofuels and alternative fuels and, ultimately, the cost of saving GHG emissions by using these fuels are key aspects which need to be investigated.

This report analyses and quantifies the production cost and the cost of GHG savings of the main conventional and advanced biofuels produced in Europe for the time period 2014-2016, including two scenarios based on different crude oil prices at time horizon 2030. The method implemented in this report for conventional and advanced biofuel production consists in estimating the cost to the EU as an entity following the same principles developed in the JEC-WTW v2 (2007) report, but limiting its focus to the 'well-to-tank' part of the fuel production. Therefore, we accounted for the market value of the commodity prices, the costs for plants and equipment required for the fuel production and the cost of energy, all applied on EU basis.

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[4] The Renewable Energy Directive Recast to 2030 was published in the Official Journal of the Union on 21 December 2018 entering in force 20 days after publication. Member States will have to transpose the new elements of the Directive into national law 18 months after its entry into force.

[5] Annex IX includes among others: biowaste from households and industry, agriculture residues (e.g. straw, bagasse), industrial residues (e.g., husks, nut shells), forestry residues (e.g., branches, black liquor), and energy crops, algae.

[6] The 7% cap was introduced in Directive 2015/1513.

[7] The Commission shall report to the European parliament and the Council evidence about high-ILUC risk feedstocks. The contribution to the RED Recast targets from high-ILUC risk food or feed crop-based biofuels shall not exceed the level of consumption in 2019 in the Member State, unless they are certified as low indirect land-use change-risk biofuels. As of 31 December 2023, this limit shall decrease gradually to 0% by 31 December 2030 at the latest.

[8] They are defined in Directive 2018/2001 as '*liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass*'.

[9] These are defined in Directive 2018/2001 as '*liquid and gaseous fuels that are produced from liquid or solid waste streams of non- renewable origin which are not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC, or from waste processing gas and exhaust gas of non-renewable origin which are produced as an unavoidable and unintentional consequence of the production process in industrial installations'.*

For conventional pathways, EU market prices are available and serve as a comparison for our estimates of production costs. For advanced biofuels, there is not a specific reference value on the market and estimating production costs for advanced biofuels has generated considerable interest in scientific literature in recent years. A lot of research has been undertaken to better understand the implications of their actual and future costs on their future deployment, at both EU and international levels and applying different methodologies (actual or future projections based on scenarios). At European level, a recent report from the Sub Group on Advanced Biofuels SGAB published in June 2017 has collected figures from industry and shown costs for advanced biofuels pathways including cellulosic ethanol and FT-liquids from wood. At global level, a report from the International Renewable Energy Agency (IRENA) published in 2016 provided estimates of production costs of a number of advanced biofuels pathways. These reports have been used as a comparison for our production costs estimates provided in section 5.

2 Pathways included

The focus of the analysis is on the conventional and advanced biofuels which are currently produced in Europe.

In 2016, conventional biofuels were estimated to represent about 4% of transport fuels consumed in EU (on energy basis), while advanced biofuels, predominantly biodiesel and hydrotreated vegetable oil (HVO) from waste oils and fats, reached an estimated share of 1.2% in the same year according to USDA, 2017. Other advanced biofuels (such as cellulosic ethanol) have not yet come into production on a significant scale (SGAB, 2017).

a) Ethanol

EU ethanol is mainly produced from grains and sugar beet derivatives. The European renewable ethanol association (ePURE, 2017) indicates that wheat and maize represent 63% of the total ethanol production in 2016. The rest is mainly sugar-based ethanol (24%), followed by ethanol from other cereals (8%) and ethanol from ligno-cellulosic material or other feedstocks listed in Annex IX-A of RED[10] (5%). Wheat and sugar beet are mostly produced domestically, while part of the maize (8% in 2015) is sourced from Ukraine (JRC, 2017).

Table 1. Feedstocks used for EU ethanol production (%)

Feedstock	% of ethanol production in 2016
Wheat and maize	63
Sugar-based	24
Other cereals	8
Ligno-cellulosic material or other feedstock listed in Annex IX-A RED	5

Source: ePURe, 2017.

b) Biodiesel

Biodiesel (including HVO) represents about 80% of the EU transport biofuels market (on an energy basis) in 2016 (EurObserv'ER, 2017). HVO is estimated to represent 17% of the total biodiesel and HVO production reaching a production of more than 2.4 billion liters in 2016 from only 0.8 billion liters in 2012 (USDA, 2017).

Rapeseed oil is the major feedstock used for biodiesel and HVO production with a share of almost 50% in 2015. However, its share has considerably decreased compared to 2008 (72% share) mostly because of the higher use of used cooking oil (UCO) and palm oil (USDA, 2017). Palm oil is the second-most used feedstock in 2015 (with a 20% share), followed by UCO (17%). The use of palm oil has further increased in recent years mainly because of its use for the HVO production, while the use of UCO has benefitted from the introduction of double-counting in eleven MSs[11]. On the other hand, fewer MSs[12] allow double-counting for animal fat and this partly explains the lower growth of animal fat use for biofuels production (7% share in 2015). The use of soybean oil for conventional biodiesel is implicitly limited by the EU biodiesel standard EN 14214[13] and its share has been decreasing in recent years due to the competition with cheaper vegetable oils (3% share in 2015). Sunflower oil represents 2% of the total biodiesel/HVO feedstocks, while "other oils", which include pine oil and wood, fatty acids, tall oil and cottonseed oil, have a 1% share. The majority of

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[10] Annex IX, Directive 2015/1513. Annex IX includes biofuels produced from feedstocks not competing with either food/feed production or land consumption and are counted double towards the achievement of the renewable energy target set by the RED Directive. This list corresponds substantially to the list in Annex IX-A of Directive 2018/2001.

[11] Austria, Belgium, Croatia, France, Hungary, Ireland, Netherlands, Poland, Portugal, Slovenia, and United Kingdom. The data refer to 2017 and UK was part of the EU.

[12] Denmark, Finland, France, Netherlands, and United Kingdom. The data refer to 2017 and UK was part of the EU.

[13] Soybean-based biodiesel does not comply with the oxidation stability prescribed by EU standard. And also palm oil conventional biodiesel does not provide enough winter stability in northern Europe (USDA, 2017). However, it is possible to meet the standard by using a feedstock mix of rapeseed oil, soybean oil and palm oil.

rapeseed oil and sunflower oil are of domestic origin; palm oil is imported mainly from Malaysia and Indonesia, while soybeans and soybean oil are mainly imported from Argentina, Brazil and US (JRC, 2017 and USDA, 2017).

Table 2. Feedstocks used for EU biodiesel and HVO production (%)

Feedstock	% of biodiesel and HVO production in 2015
Rapeseed oil	50
Palm oil	20
Used cooking oil (UCO)	17
Animal fat	7
Soybean oil	3
Sunflower oil	2
Other oils	1

Source: USDA, 2017.

c) Advanced biofuels

Advanced biofuels pathways from lignocellulosic feedstocks which include biochemical and thermochemical conversion processes are at various stages of technical development[14]. Lignocellulosic ethanol via hydrolysis and fermentation of agricultural residues (mainly wheat straw in EU) consists in converting sugars to biofuels using yeast or bacteria and it has reached early commercial phase (up to TRL 8). Gasification of woody biomass (forest residues, short rotation forestry and coppice) is at an earlier stage of demonstration (up to TRL 7) (IRENA, 2016). Gasification is a thermochemical process in which biomass is converted into synthesis gas (syngas) and the syngas may be converted to liquid (or gaseous) transport fuel via Fischer-Tropsch catalysis, methanol synthesis, mixed alcohol synthesis or syngas fermentation. Methanol (via gasification) is also ready for commercialisation while the other production pathways are at early stages of development (IRENA, 2016).

An overview of the first-of-a-kind commercial plants and demonstration plants being developed in the EU is provided in section 3.1. As further discussed, several projects have been cancelled. Factors such as low oil prices and policy uncertainty but also technical difficulties related to feeding, handling and processing large quantities of feedstock have affected their performances (IRENA, 2016).

Considering the picture of the current EU biofuels production discussed above and the availability of data in the WTTv5 report, estimates of production costs have been provided for the following pathways: ethanol from sugarbeet, wheat and maize; biodiesel and HVO from oil seed and oils including used cooking oil (UCO) and tallow oil; cellulosic ethanol from wheat straw, and FT-diesel, methanol and dimethyl ether (DME) from woody biomass. The specific characteristics of the pathways and sub-pathways along with their code in the WTT study are reported in

Figure 1.

The WTT study provides, for each supply chain/pathway, inputs and emissions of a number of sub-pathways differentiated by the final use of by-products (e.g as animal feed or in the chemical sector) and/or by the way energy is provided (e.g. by NG boiler or NG-CHP). For the purpose of our analysis, we restricted the number of sub-pathways including only the ones considered as being representative of the existing biofuel plants in EU.

Therefore, cost estimates are provided for the sub-pathways shown in

Figure 1 (under the heading WTT code). In sugarbeet to ethanol, the sub-pathway considered is the one that assumes that pulp is sold for animal feed and slops are not used. Two processes are covered for wheat to ethanol: one in which energy is provided by natural boiler and grid electricity and the other one in which energy is provided by NG-fired CHP plant; in both cases, the by-products that are the dried distiller's grains with solubles (DDGS) are used for animal feed. The second option (energy provided by NG-CHP and DDGS to animal feed) is also considered for the maize to ethanol pathway. For biodiesel pathways, the sub-pathways

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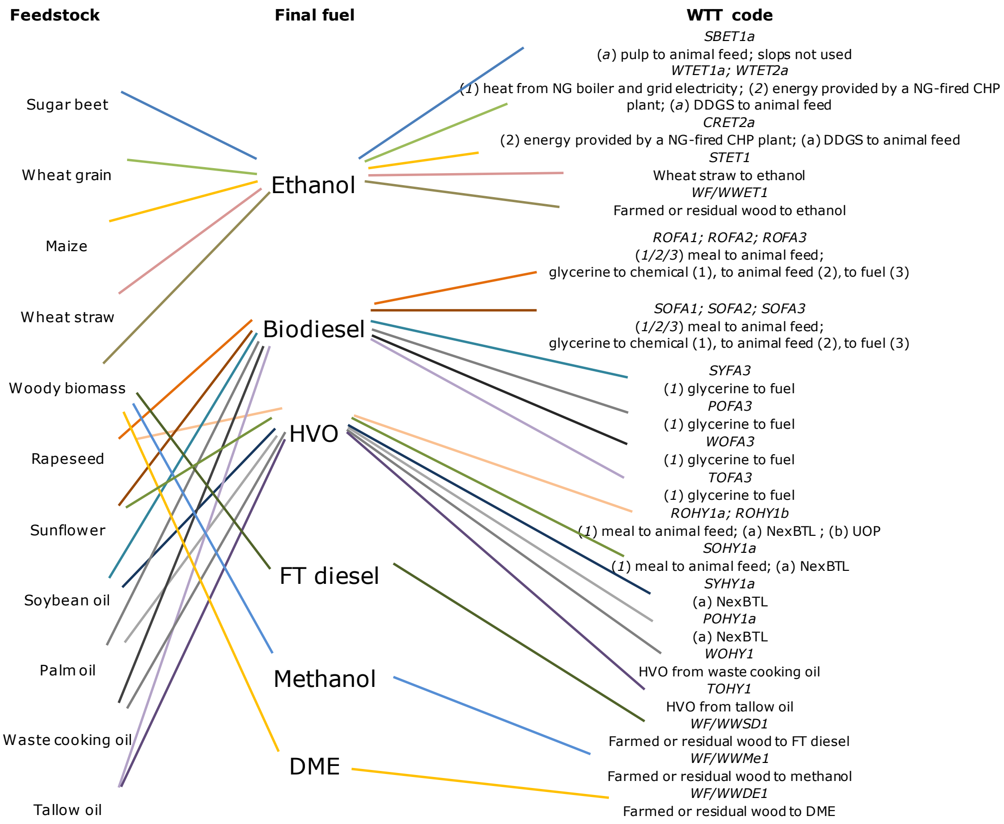
[14] The stage of development can be defined by the Technology Readiness Level (TRL): TRL 1-3 Research; 4-5 Pilot; 6-7 Demonstration; 8 First of a kind commercial demo; 9 Commercial deployment.

included are the ones that assume that meals are sold for animal feed and glycerine is sold as a chemical or as animal feed or used as a fuel. For the HVO pathways, we include the sub-pathway which adopts the Neste process as conversion technology. A single sub-pathway is also included for FT-diesel, methanol and dimethyl ether (DME) produced using farmed or residual wood.

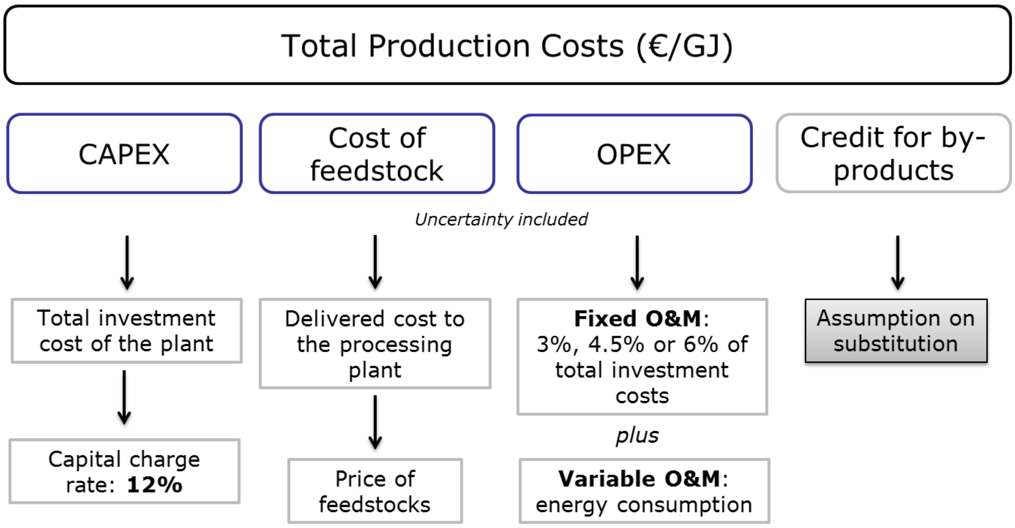
Figure 1. List of pathways (and code in WTT study)



3 Assumptions and methodology description

The total production costs of biofuels and their components are estimated applying the methodology developed in the JEC-WTW v2 (2007) report. However, updated input data from the WTT version 5 as well as recent data on prices and on costs from existing European biofuel plants and from the literature have been used. The methodology is briefly described in the following figure.

Figure 2. Methodology description



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 for conventional pathways and 40% uncertainties range for lignocellulosic and synthetic fuel pathways. OPEX is composed of a fixed component and a variable component which mainly depend on the energy and other inputs used for the biofuel manufacture. The fixed component is assumed to be a percentage of the total investment cost (3%, 4.5% or 6% depending on the maturity of the technology, see section 4.4) with an uncertainty of 20%. A credit for the production of by-products is also taken into account on the basis of the amount of other crops they substitute as assumed in WTTv5 (e.g. DDGS are assumed to substitute wheat grain and soya meal).

3.1 Scale of operation / Output capacity of conventional and advanced biofuels

Commercial-scale plants for which investment costs are available in the published literature have been considered to estimate the output capacities of the 'representative plant' for conventional biodiesel and HVO pathways, including the plants that use UCO and tallow as feedstocks. The capacities of the 'representative plant' have been defined as the average output capacities of a few of the existing plants in EU for which CAPEX data were available[15] (see **Figure 3**, where the horizontal lines represent the estimated average output capacity). The list of considered plants along with their capacities and capital costs is mainly based on a report by the Global Subsidies Initiative of the International Institute for Sustainable Development (GSI-IISD, 2013, Technical Annex) for existing ethanol and biodiesel plants. Neste provided data on HVOs.

d) Biofuels: 1st generation ethanol and biodiesel & HVO.

Existing biofuels plants are divided on the basis of the feedstock they use for their production, using the information available on their websites. The 'representative capacities' of the biofuels plants in EU (in ktonnes/year) assumed in this analysis are: 100 ktonnes/y for sugarbeet ethanol; 250 ktonnes/y for wheat ethanol; 200 ktonnes/y for first generation biodiesel and 100 ktonnes/y for UCO/tallow biodiesel; and 600 ktonnes/y for HVO plants.

Figure 3. Output capacities of EU first generation ethanol, biodiesel and HVO plants (kt/y)

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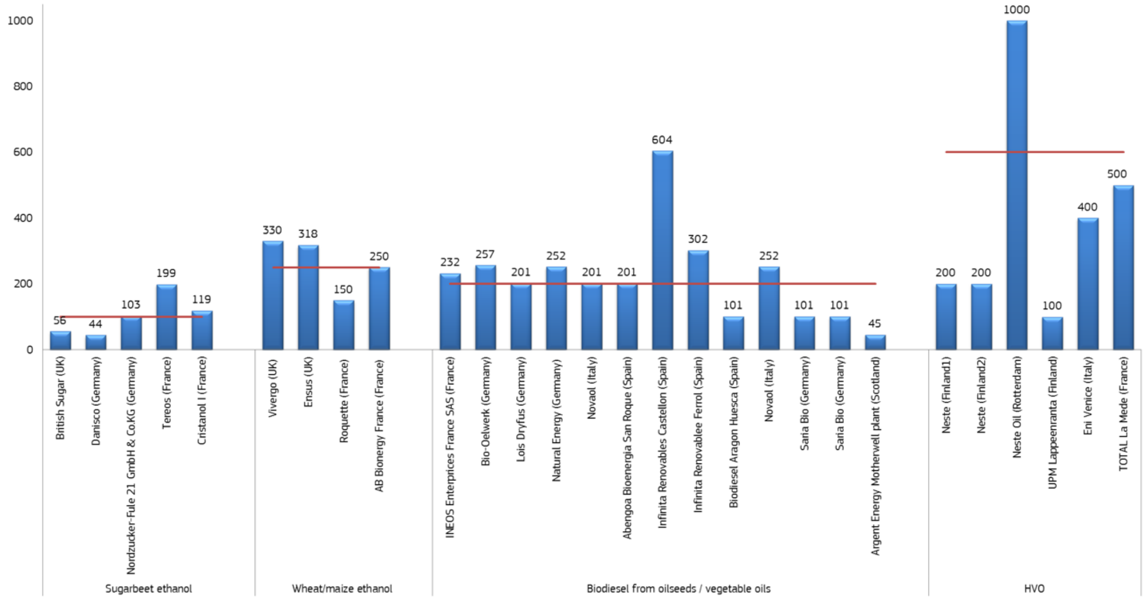
[15] It is not among the purposes of this report to provide a complete list of ethanol, biodiesel and HVO plants.



Source: GSI-IISD, 2013; Neste for HVOs.

e) Advanced biofuels

The ‘representative capacities’ for two main advanced biofuel technologies (fermentation and gasification) are based on operational, idle, planned or under construction plants collected from the database available at the International Energy Agency (IEA) Bioenergy Task 39 website[16]. Data on the name of the plant, project, owner, conversion technology[17], status, technology readiness level (TRL), output (including capacity) and main raw material used in their processes are available in the database.

Selecting ‘fermentation’ as conversion technology and excluding the plants or projects that use food or feed crops or a non-organic material as feedstock, the picture of the current situation in EU[18] is as follows: of the 30 plants/projects listed in the database, seven are first-of-a-kind commercial demo plants, but none of them is operational at present. The Beta Renewables plant in Italy was the only first-of-a-kind operational plant in Europe with a reported capacity of 40 ktonnes/y of ethanol but has been recently shut down (October 2017) as a part of a restructuring effort of the parent chemical company Mossi & Ghisolfi and it is idle. Two plants are on hold, one in Denmark and one in Slovakia (with an ethanol capacity of 50 and 55 ktonnes/y respectively); one is planned in Spain (with a capacity of 25 ktonnes/y of mixed alcohols) and 1 is under construction in Romania (with a capacity of 50 ktonnes/y of ethanol). In addition, a Finnish company (Kanteleen Voima) is planning to build a biorefinery (Nordfuel) that will produce ethanol from wood with a capacity of 65 ktonnes/y (Nordfuel the website). Two plants have been cancelled or stopped while under construction (in Spain and in UK respectively). Other 16 plants are classified as demonstration plants (TRL 6-7), but only 5 are operational (2 in Sweden, 2 in Finland and 1 in Germany, with capacities between 0.16 and 8 ktonnes/y of ethanol); 4 are idle (2 in Spain, 1 in Denmark with capacities between around 1.2 ktonnes/y and 4.3 ktonnes/y of ethanol and 1 in UK with capacity of 15 tonnes/y of butanol) and 4 cancelled or stopped while under construction[19].

Figure 4 shows a summary of the total number of ‘fermentation’ plants/projects by TRL and status, in EU (on the left side) and outside EU[20] (on the right side).

Figure 4. Number of plants/projects for ‘fermentation’ by TRL and status

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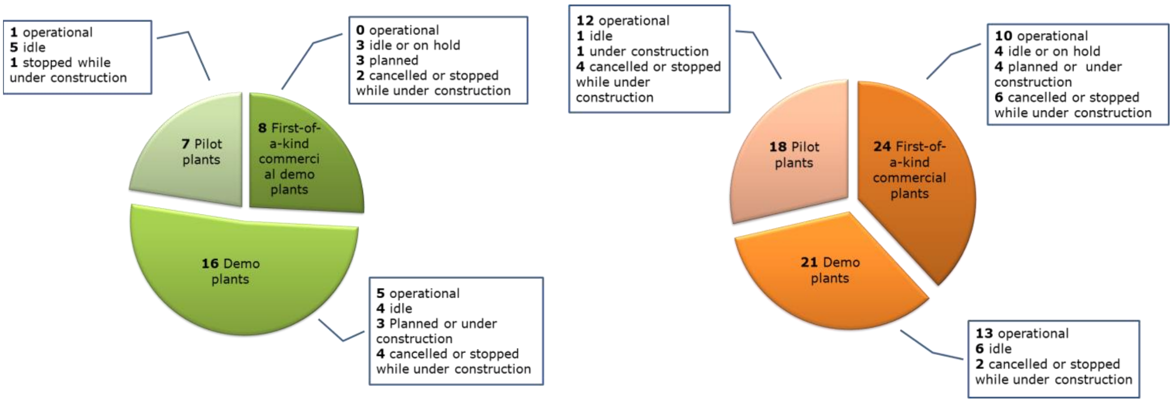
[16] The database is elaborated and maintained by the Bionergy2020+ project. It is available at: http://demoplants.bioenergy2020.eu/. The database was last accessed on January 2019 and it may not be complete or up-to-date.

[17] The conversion technologies included in the IEA database are: ‘gasification’, ‘fermentation’, ‘fast pyrolysis’, ‘hydrothermal liquefaction’, ‘hydro-treatment’ and ‘others’.

[18] Including UK.

[19] In addition, there are 7 pilot plants in EU (TRL 4-5), 1 operational (Procethol 2G in France), 5 idle (3 in Denmark, 1 in UK, 1in Italy) and 1 stopped while under construction (in Denmark).

[20] A description of operational, demonstration and pilot plants outside EU is available in the Annex.



a) EU

b) Outside EU

Source: elaboration based on IEA Bioenergy Task 39 database, Nordfuel website.

The following table indicates the range of capacities of operational, idle or on-hold and planned (or under construction) plants in EU and outside EU for first of a kind and demonstration plants.

Table 3. Range of output capacities for ‘fermentation’ by TRL and status in EU and outside EU

		Operational	Idle or on-hold	Planned or under construction
First-of-a-kind demo plant (TRL 8)	EU	-	Ethanol: 40-55 kt/y	Ethanol: 55-65 kt/y Mixed alcohols: 25 kt/y
	Outside EU	Ethanol: 2.1-75 kt/y	Ethanol: 60-90 kt/y	Ethanol: 18-50 kt/y
Demonstration (TRL 6-7)	EU	Ethanol: 0.16-8 kt/y	Ethanol: 1.2-4.3 kt/y Butanol: 0.015 kt/y	Ethanol: 50-120 kt/y Butanol: 0.8 kt/y
	Outside EU	Ethanol: 0.003-5 kt/y	Ethanol: 0.75-4.5 kt/y Butanol: 9-60 kt/y	-

Source: elaboration based on IEA Bioenergy Task 39 database, Nordfuel website.

Focusing on the installed capacity of the existing operational commercial plants, it seems reasonable to assume as representative capacity for cellulosic ethanol plants 60 ktonnes/y.

Considering ‘gasification’ conversion technology and including only liquid biofuels as output[21] (therefore excluding SNG), the picture in EU[22] is the following: of the 19 plants/projects found in the IEA database, seven are classified as first-of-a-kind commercial plants (TRL 8), most of them (4) have been cancelled or stopped while under construction. None of them is in operation; one is idle and one is on hold (both in the Netherlands, with capacities of 200 ktonnes/y and 413 ktonnes/y of methanol respectively) and one is planned in Sweden, with a capacity of 100 ktonnes/y of methanol). Additionally, there are 4 plants with TRL 6-7 (demonstration plants), but still not in operation: one is under construction in France (Total, with a capacity of 200 ktonnes/y of FT-liquids by 2020), one is on hold in Sweden (200 ktonnes of methanol) and two have been cancelled or stopped while under construction[23].

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[21] This technology can have as output the following fuels: methanol, DME, FT liquids, gasoline or diesel type fuels or ethanol.

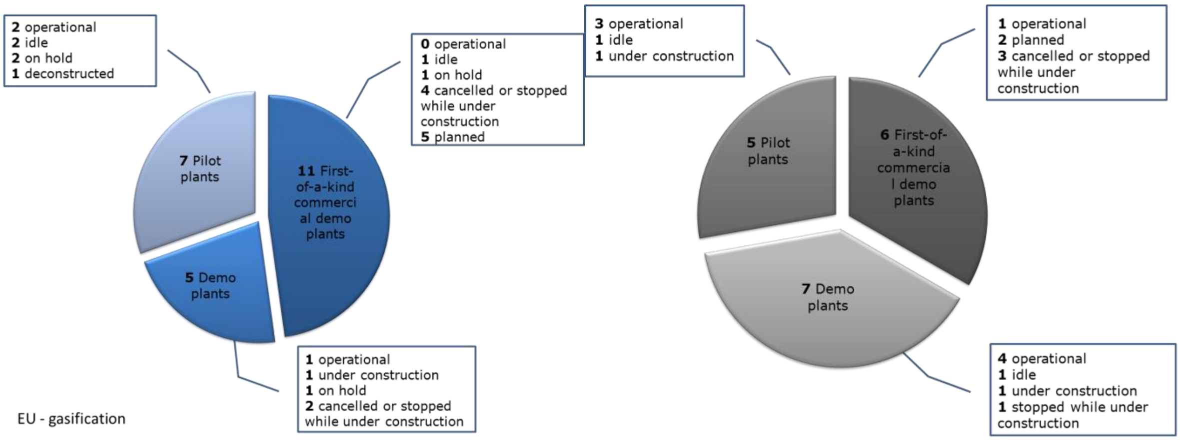
[22] Including UK.

[23] Out of the 7 pilot plants (TRL 4-5) built in EU, 3 are operational (1 in France with an installed capacity of 60 tonnes/y of FT-liquids; 2 in Germany with capacities of 0.02 t/y of FT-liquids and 2 tonnes/y of diesel-type fuel respectively). Two plants are idle (in Germany and Finland), 1 is on hold (in Austria) and 1 has been deconstructed in Sweden.

In addition, other projects/plants that are not included in the IEA database were found from other sources (Kaidi website, Enerkem website, Bioenergy International). They are all first-of a-kind commercial plants, at a very early stage of planning. One plant (Kaidi) is planned in Finland, producing FT liquids (200 ktonnes/y); two plants are planned in Sweden (consortiums of Preem & Setra and Preem, RenFuel & Rottneros) producing biofuels from pyrolysis oils and one in Rotterdam (Enerkem) producing methanol from municipal solid waste (100 ktonnes/y).

Figure 5 shows the 'gasification' plants/projects by TRL and status in EU and outside EU[24].

Figure 5. Number of plants/projects for 'gasification' by TRL and status in EU (a) and outside EU (b)



a) EU

b) Outside EU

Source: elaboration based on IEA Bionergy Task 39 database; Bioenergy international; Enerkerm website; Kaidi website; Velocys.

The following table shows the range of capacities for the operational, idle or on-hold and planned or under constuction plants in EU and outside EU reported in the IEA database, including the other sources mentioned above, for first of a kind and demostantion plants.

Table 4. Range of output capacities for 'gasification' by TRL and status in EU and outside EU

		Operational	**Idle or on-hold**	**Planned or under construction**
First-of-a-kind demo plant **(TRL 8)**	EU	-	Methanol: 200-413 kt/y	FT liquids: 200 kt/y Methanol: 100 kt/y
	Outside EU	Ethanol: 30 kt/y	-	FT liquids: 59 kt/y
Demonstration **(TRL 6-7)**	EU	-	Methanol: 200 kt/y	FT liquids: 200 kt/y
	Outside EU	Ethanol: 4-13 kt/y FT liquids: 1 kt/y	Ethanol: 53 kt/y	Ethanol: 30 kt/y

Source: elaboration based on IEA Bionergy Task 39 database; Bioenergy international; Enerkerm website; Kaidi website; Nordfuel; Velocys.

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[24] A description of operational, demonstration and pilot plants outside EU is available in the Annex.

Table 4 does not appear to provide a clear picture on 'representative capacities' for gasification processes; plants producing FT liquids that are in operation are currently at pilot scale, while methanol plants with capacities between 200 and 400 ktonnes/y are on-hold. Considering that the capacity of commercial plants depends on the availability of feedstock, it was assumed, following JEC experts' advice, a common feedstock capacity for the gasification routes of about 1,000 tonnes/day; which corresponds to around 330 ktonnes/y of dry biomass input. This leads to 'representative capacities' of around 60 ktonnes/y for FT diesel, 150 Ktonnnes/y for methanol and 100 ktonnes/y for DME plants calculated using WTTv5 data.

4 Capital costs and operational costs

4.1 Capital investment for conventional and advanced biofuels

The capital investment used for this analysis is mainly based on existing published literature and industry data whether available. For ethanol and biodiesel, capital costs have been collected from (GSI-IISD, 2013). For HVOs plants, investment costs are based on data presented by Neste, while cellulosic ethanol capital data are based on the IEA report on the status of advanced biofuels facilities with contain data provided by companies (IEA Bioenergy Task 39, 2013). For FT diesel methanol and DME, capital costs are based on IRENA, 2016.

Original capital costs from the mentioned sources have been adjusted to 2015 values using the Chemical Engineering Plant Cost Index (CEPCI), which is commonly applied to update process plant construction costs from one year to another.

The 2015 CAPEX is then normalised to the capacity of the 'representative EU plant' applying economies of scale (Equation 1), and the typical scale exponent for plants and process units has been applied.

CAPEX 'standard' = CAPEX_0 * (Capacity 'representative EU plant' / $\text{Capacity}_0)^X$ (Equation 1)

where:

CAPEX_0 and Capacity_0 = capital cost and capacity of the plant as reported in literature

X = 0.7 (typical scale value)

The final estimates of capital costs for 2015 adjusted to the standard capacity of the representative plant are shown in last column of the following tables expressed in million Eur/(ktonnes/year).

Table 5 Estimates of CAPEX (2015) for conventional ethanol plants

	Installed output capacity	**CAPEX**	**Year**	**CAPEX 2015**	**Adjusted to a standard output capacity**			**Average**
	kt/y	**M€**		**M€**	**kt/a**	**M€**	**M€/ (kt/y)**	**M€/ (kt/y)**
Sugarbeet ethanol					**100**			**0.57**
British Sugar (UK)	56	31	2007	41		61	0.61	
Danisco (Germany)	44	25	2008	28		57	0.57	
Nordzucker - Fule 21 GmbH & Co.KG (Germany)	103	43	2008	48		54	0.54	
Wheat/maize ethanol **NG CHP** **Conv boiler**					**250**			 **1.69** **1.05**
Vivergo (UK)	330	392	2007	513		423	1.69	
Ensus (UK)	318	372	2009	499		422	1.69	
AB Bionergy France (France)	250	200	2007	262		262	1.05	

Source: some estimates are based on personal communication; GSI-IISD, 2013.

Table 55. Estimates of CAPEX (2015) for biodiesel and HVO plants

	Installed output capacity	**CAPEX**	**Year**	**CAPEX 2015**	**Adjusted to a standard output capacity**			**Average**
	kt/y	**M€**		**M€**	**kt/a**	**M€**	**M€/ (kt/y)**	**M€/ (kt/y)**
Biodiesel from rapeseed					**200**			**0.36**
INEOS Enterprices France SAS (France)	232	70	2008	90		81	0.41	
Bio-Oelwerk (Germany)	257	21	2003	30		25	0.12	
Lois Dryfus (Germany)	201	85	2007	111		111	0.55	
Biodiesel from Vegetable oils					**200**			**0.32**
Novaol (Italy)	201	26	2010	31		31	0.15	
Abengoa Bioenergia San Roque (Spain)	201	42	2010	51		50	0.25	
Infinita Renovables Castellon (Spain)	604	300	2006	378		174	0.87	
Infinita Renovablee Ferrol (Spain)	302	80	2009	107		80	0.40	
Biodiesel Aragon Huesca (Spain)	101	20	2008	26		41	0.21	
Biodiesel from animal fat and UCO oils					**100**			**0.20**
Saria Bio (Germany)	101	24	2006	30		30	0.15	
Saria Bio (Germany)	101	32	2006	41		41	0.20	
Argent Energy Motherwell plant (Scotland)	45	21	2005	28		49	0.24	
HVO					**600**			**0.82**
Neste (Finland1)	200	100	2007	131		282	0.47	
Neste Oil (Rotterdam)	1000	670	2011	799		559	0.93	
UPM Lappeenranta (Finland)	100	179	2015	2015		613.4	1.05	

Legend: NA = Not Available.

Sources: GSI-IISD, 2013; data from Neste for HVOs.

Table 7. Estimates of CAPEX (2015) for lignocellulosic plants

	Installed output capacity	CAPEX	Year	CAPEX 2015	Adjusted to a standard output capacity			Average
	kt/y	**M€**		**M€**	**kt/a**	**M€**	**M€/ (kt/y)**	**M€/ (kt/y)**
Ethanol from lignocellulose					**60**			**3.36**
Chemtex (Beta renewables) (Italy)	40	150	2012	165		220	3.66	
POET-DSM Advanced Biofuels (USA)	75	195	2012	215		184	3.06	
FT synthesis					**60**			**6.70**
IRENA, 2016 (various sources) small scale	17	118	2014	136		325	5.41	
IRENA, 2016 (various sources) large scale	174	648	2014	750		356	5.94	
Dena, 2006	114	650	2006	852		543	9.06	
Kaidi (Finland)	200	1000	2015/16	1000		431	7.18	
Velocys (US)	59	350	2015/16	350		354	5.90	
Methanol synthesis					**150**			**2.20**
Hannula 2013 (plant design 1 and 2)	232	347	2010	419		309	2.06	
Hannula 2013 (plant design 3)	253	344	2010	415		288	1.92	
Hannula 2013 (plant design 4)	218	338	2010	409		315	2.10	
Hannula 2013 plant (design 5)	218	345	2010	416		320	2.14	
VärmlandsMetanol AB (Sweden)	115	350	2016	350		422	2.81	
DME synthesis					**100**			**3.29**
Hannula 2013 (plant design 1 and 2)	159	357	2010	431		414	2.76	
Hannula 2013 (plant design 3)	176	355	2010	428		383	2.56	
Hannula 2013 (plant design 4)	149	348	2010	420		422	2.81	
Hannula 2013 (plant design 5)	149	354	2010	428		430	2.86	
Domsjo project (Sweden) (stopped)	100	300	2009	402		402	4.02	

Task 39, 2013; IRENA, 2016; Hannula (2013); VärmlandsMetanol AB; Kaidi website; Velocys; Domsjo project

Sources: Crescentino in figures (http://www.betarenewables.com/en/crescentino/the-project); IEA Bioenergy press release (http://www.mynewsdesk.com/se/pressreleases/sek-500-million-in-investment-grant-for-biofuels-project-at-swedish-domsjoe-fabriker-323574).

4.2 Costs of feedstocks

Agricultural crops and animal-feed by-products are internationally traded and their market prices represent the cost to EU of using them for energy purposes as they could otherwise be traded. Most of the food commodity prices including soybean meals are based on FAO or World Bank international prices at European ports. For sugar beet, it was considered the producer price in EU28, available in the OECD/FAO Agricultural Outlook. The cost of feed wheat is taken from DG AGRI which publishes EU market prices for representative products based on Member States notifications. Used cooking oil and tallow as well as glycerine prices are taken from 'Square Commodities', a consultant which publishes analyses on market trends and industry developments of the alternative fuels markets. Wheat straw price is assumed to be the factory gate cost estimated in a European project (Biocore) based on the price provided by a French biorefinery company (CIMV). Wood prices are average prices of wood chips prices and forest residue chips prices for Germany provided by a German association (Carmen eV, a network for renewable resources).

Table 8 shows the costs of feedstocks used for the production of conventional and advanced biofuels pathways and their sources. The data refer to the average of the three years (2014-2016) and they are used to estimate the biofuel production costs in section 5. In section 8, these costs are estimated on the basis of their correlation to the crude oil price (following the methodology adopted in the WTWv2 report).

Table 8. Costs of feedstocks

	2014-2016 Eur/tonne	Description	Source
Sugar beet	28	Producer price in EU28	[1]
Feed wheat	157	Market price in EU	[2]
Maize	147	Maize	[3]
Rapeseed	364	Rapeseed, Europe, 00, CIF Hamburg	[4]
Rapeseed oil	693	Rape oil, Dutch, FOB ex-mill	[4]
Sunflower	376	Sunflower seed, EU, CIF Lower Rhine	[4]
Sunflower oil	732	Sun oil, FOB North West European Ports	[4]
Soybean	360	Soybean seed, US, No.2 yellow, CIF Rotterdam	[4]
Soybean oil	679	Soybean oil (Dutch FOB; Ex-Mill, FOB Rotterdam)	[4]
Palm oil	590	Palm oil, CIF North West (NW) Europe	[4]
Used cooking oil	661	ddp NWE	[5]
Animal fat/tallow	475	Tallow ddp NWE	[5]
Wheat straw (13.5% moisture)	80	Wheat straw price at the factory gate	[6]
Wood chips SRF (35% water)	92	Average price of SRF wood chips in Germany for delivered cost (including IVA)	[7]
Forest residues chips (35% moisture)	94	Cost including VAT (in Germany)	[8]
Soya meal	346	Soybean meal, Pellets, 44/45%, Argentina, CIF Rotterdam	[4]
Glycerine crude	210	EX-NWE	[5]
Glycerine refined	517	EX-NWE	[5]

Legend: FOB = Free On Board; CIF = Cost, Insurance and Freight

Sources

[1] OECD/FAO Agricultural Outlook 2016-2025

[2] EC, DG AGRI, EU market prices for representative products

[3] World Bank Commodity Price Data (The Pink Sheet), World Bank commodity prices: http://www.worldbank.org/en/research/commodity-markets

[4] DataM JRC-IPTS from FAO International Prices (retrieved February 2017)

[5] Square Commodities, website: http://www.squarecommodities.com/ (av 2014-2016); except for glycerine (av 2014-2015).

[6] BIOCORE project (prices from CIMV, company in France)

[7] http://www.carmen-ev.de/infothek/preisindizes/kup-hackschnitzel/graphiken

[8] http://www.carmen-ev.de/infothek/preisindizes/hackschnitzel/jahresmittelwerte

4.3 Fossil fuels prices

The average prices for the time period 2014-2016 of the main fossil fuels used in biofuels production (e.g. natural gas and electricity) and including crude oil are shown in the following table along with their description and sources. These values are used to estimate the biofuel production costs in section 5, while fossil fuels prices are estimated as a function of an assumed crude oil price in section 8.

Table 9 Fossil fuels (and chemical) prices

	Av 2014-2016	Description	Source

Crude oil	54 Eur/bbl	Crude oil, UK Brent 38° API	[1]
Natural gas	20 Eur/MWh	DE import border price EU	[2]
Electricity	40 Eur/MWh	European average (Platts PEP, Pan European Power Index)	[2]
Heavy fuel oil	7.4 Eur/GJ	Heavy fuel oil (Rotterdam), FOB - 1% of sulfur	[3]
Methanol	18 Eur/GJ	Methanol T2 FOB Rotterdam	[4]
Hexane	9.1 Eur/GJ	FOB (free on board) Rotterdam	[5]
ICE Gasoil	11 Eur/GJ	ICE Gasoil EU (front month)	[5]

Sources:

[1] World Bank Commodities Price Data (The Pink Sheet)

[2] EC, DG ENERGY, 2016 (figure 5)

[3] INSEE, National Institute of Statistics and Economic Study (France)

[4] Square Commodities, website: http://www.squarecommodities.com/; (av 2014-2015 for methanol; av 2014-2016 for ICE gasoil).

[5] ICIS News: https://www.icis.com/resources/news/2016/02/17/9970902/Europe-hexane-largely-stable-on-steady-upstream-prices/ (av 2015-2016)

4.4 Fixed and variable component operational costs/OPEX data

The fixed component of the operational costs (OPEX) has been assumed as a fixed proportion of CAPEX, the percentage depending on technology maturity: 3% of the investment costs for conventional technologies; 4.5% of the investment costs for ethanol from cellulose and 6% for FT diesel, methanol and DME from wood, following the assumption made in the previous WTWv2c (2007) and new information available from IRENA, 2016[25] on the FT diesel pathway.

The variable component of OPEX depends mainly on the energy input of the plants. Data on primary energy input required by the representative EU production plant are taken from WTTv5. The same reference is consistently used also for data on LHV of feedstocks and biofuels moisture content of feedstocks, biofuels yields, energy use (e.g. natural gas, electricity) and by-product credits.

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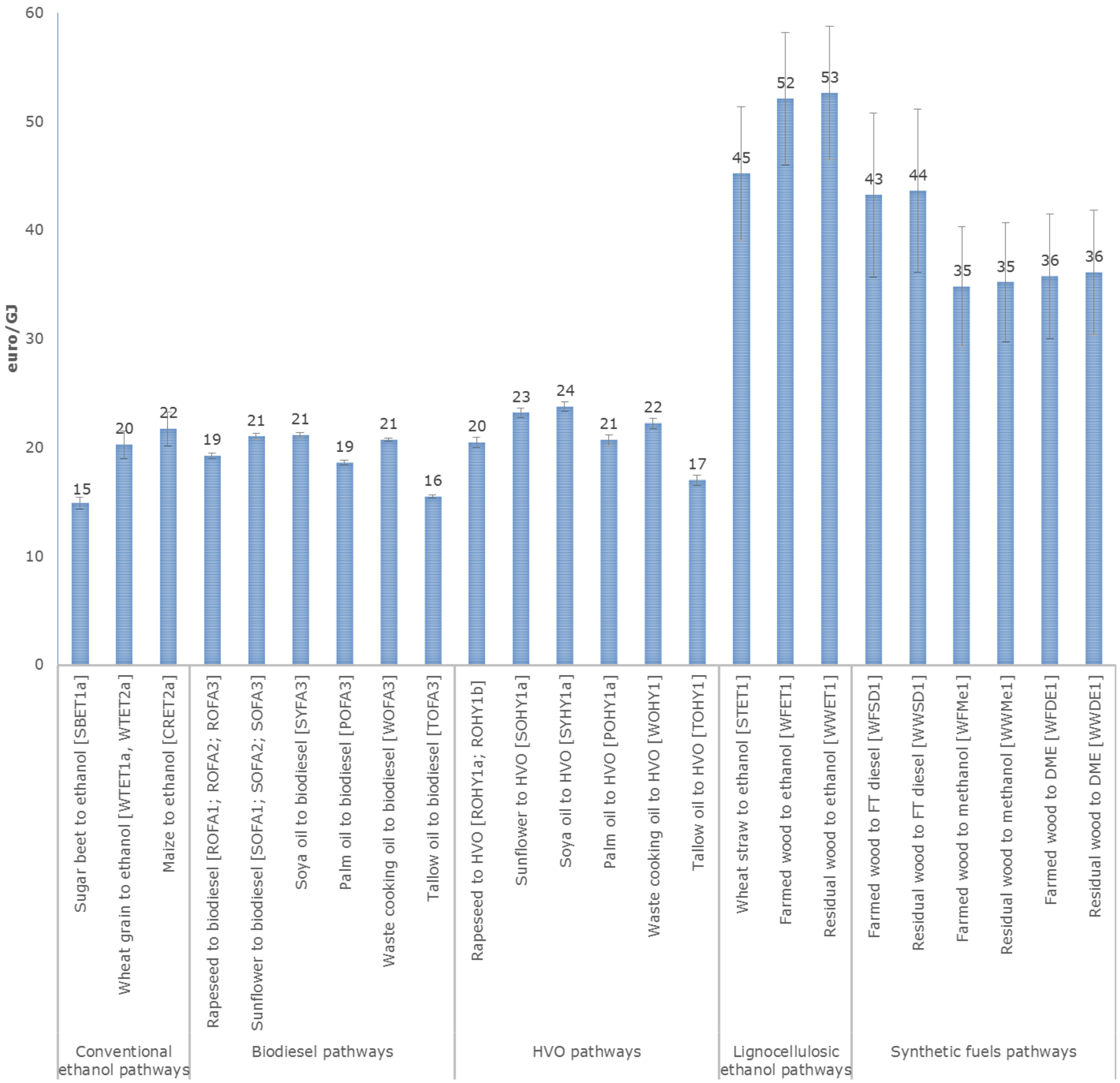
[25] In IRENA, 2016 (Annex D, Table 26), O&M costs have been considered 6% of the capital investment.

5 Results: production costs

5.1 Conventional and advanced biofuels including uncertainties

Total production costs for conventional and advanced biofuel pathways are shown in the following figure including uncertainties; costs are expressed per unit of energy content (Eur/GJ).

Figure 6. Total production costs (2014-2016) in Euro/GJ (with uncertainties)



Our estimate shows a range of production costs (between 2014 and 2016) for conventional ethanol pathways from 15 Eur/GJ for ethanol produced from EU grown sugar beet to 22 Eur/GJ for ethanol from EU grown maize; for biodiesel pathways, the range varies from 16 Eur/GJ for tallow oil biodiesel to 21 Eur/GJ for sunflower, soya oil and waste cooking oil biodiesel. The estimated costs obtained applying the WTT method are consistent with biofuels market prices: ethanol price is about 23 Eur/GJ[26] in the period 2014-2015, while for biodiesels, prices range from 20 Eur/GJ for palm oil biodiesel to 24 Eur/GJ for used cooking oil biodiesel (average for 2014-2016, FOB Rotterdam, Square Commodities, 2018).

Production cost for HVO pathways are estimated to be in the range of 17 Eur/GJ for tallow oil to HVO to 24 Eur/GJ for soy oil to HVO, showing the dependence to the feedstock prices as for biodiesels. This range is also consistent with the production costs for HVO liquids reported in the SGAB, 2017 report where they are estimated between 14 and 25 Eur/GJ depending on the feedstock price.

For lignocellulosic ethanol, production costs from wheat straw and farmed or residual wood have been estimated in the range of 45-53 Eur/GJ being double compared to the conventional ethanol production costs. Slightly lower costs were found for the synthetic fuels pathways included in the analysis, varying from 35 Eur/GJ for farmed or residual wood to methanol to 44 Eur/GJ for residual wood to FT diesel.

These price ranges appear to be higher compared to the range of production costs reported in the SGAB report where, for cellulosic ethanol, costs are estimated between 24-29 Eur/GJ, for FT liquids between 25 and 35 Eur/GJ and for biomethane, methanol and DME from wood between 16-25 Eur/GJ.

Nevertheless, these estimates are close to the ones provided by IRENA, 2016 where for first commercial plants the production costs related to cellulosic ethanol are between 34 and 61 USD/GJ (that converted to Euro assuming the 2015 exchange rate correspond to 31-55 Eur/GJ), while for the FT synthesis process, production costs are found to be in the range 31-53 USD/GJ corresponding to 28 and 48 Eur/GJ (2015 exchange rate).

Total production costs for conventional and advanced biofuel pathways by components are shown in the following figure (expressed in Eur/GJ).

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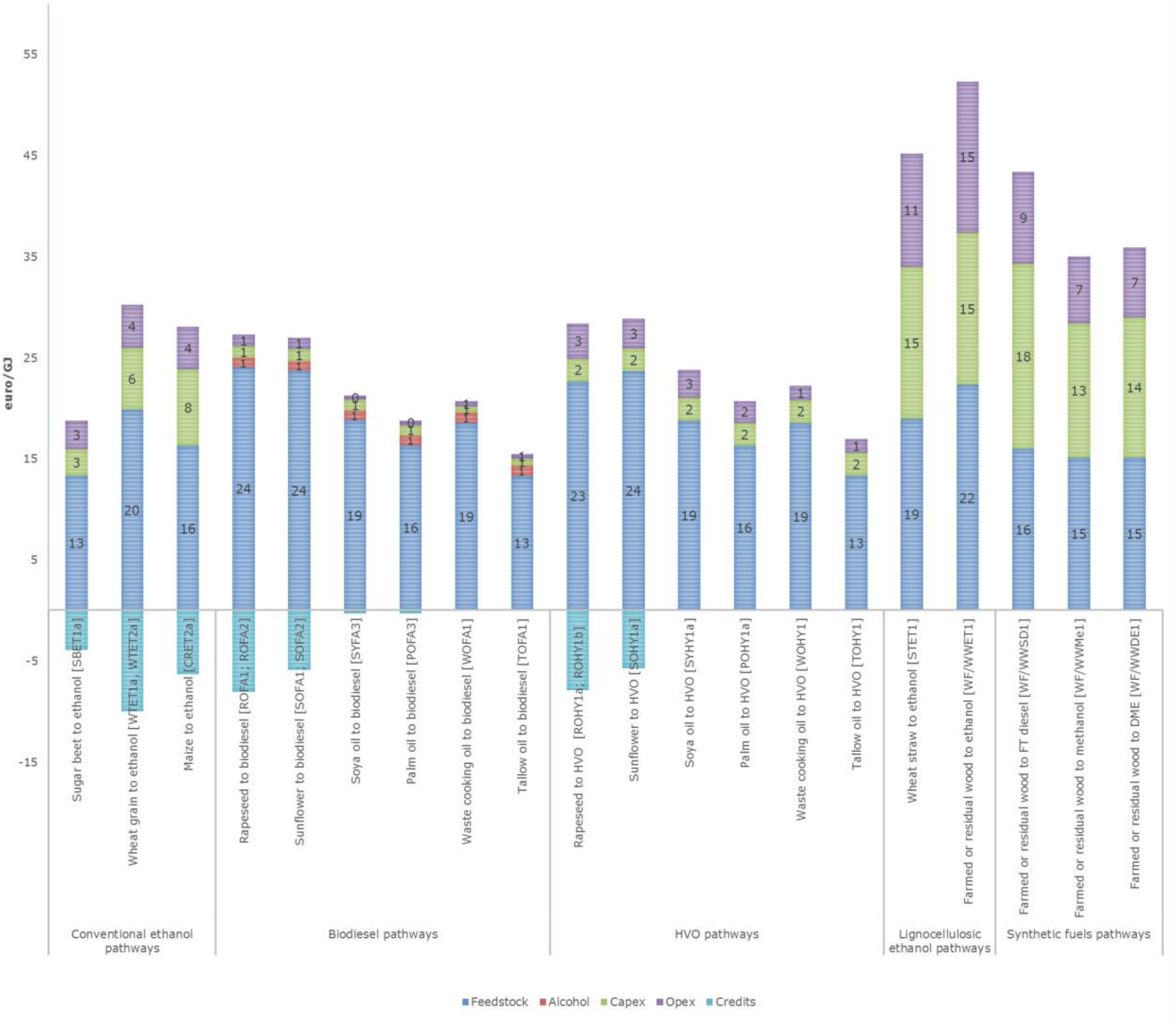
[26] Price of ethanol anhydrous RED FOB ARA provided by Square Commodities.

Figure 7. Production costs by component (2014-2016) in Eur/GJ



Generally, capital costs accounts for a relatively small proportion of total production cost for conventional biofuels. Whereas advanced biofuels that are at the early stage of commercialisation, such as cellulosic ethanol and synthetic fuels, are still facing significant technology challenges and risk for large scale commercial production showing significant capital costs at present but having potential for future reduction.

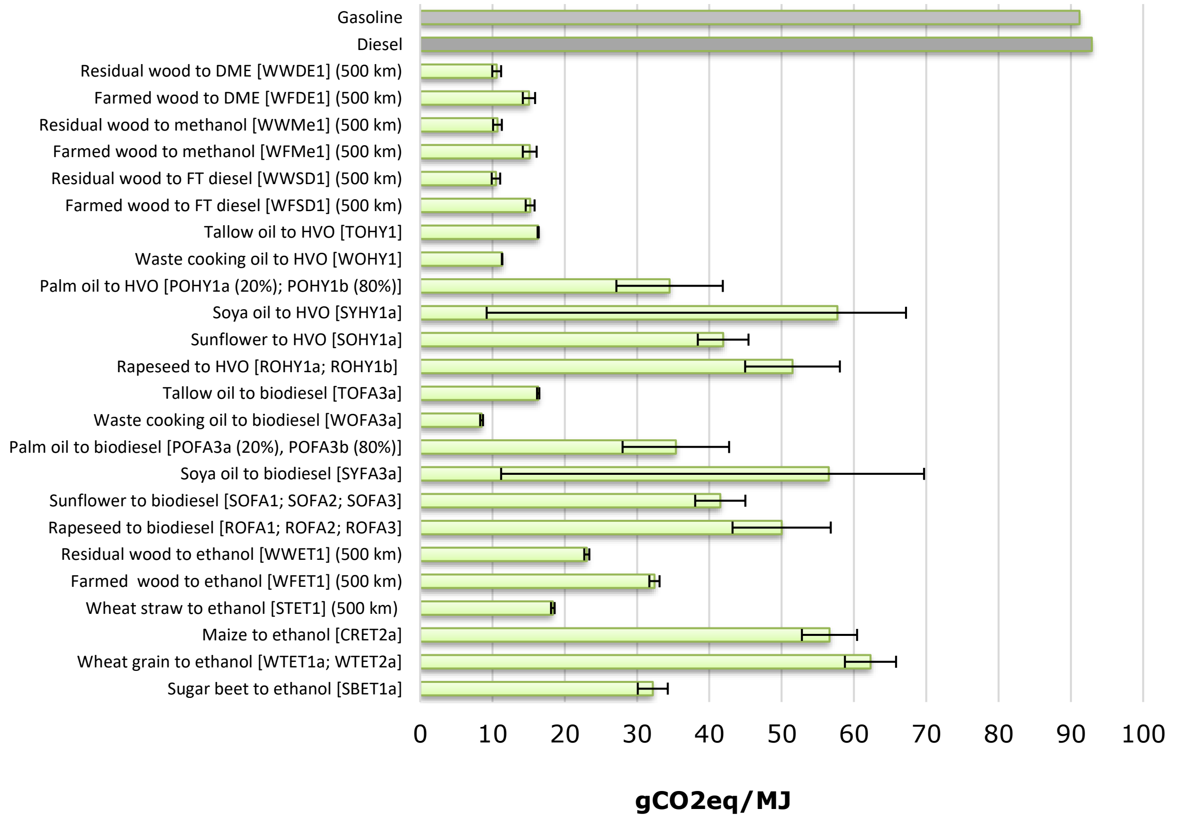
Feedstock costs dominate conventional biofuel total production costs. The largest component of operating costs for first generation biofuel plants is the cost of feedstock which makes the economics of production heavily dependent on movements in the local and global markets for the feedstock used.

For cellulosic ethanol pathways, OPEX also includes costs of enzymes as reported in Johnson, 2016; while for synthetic fuels, the OPEX has been assumed to be 6% of the capital investment on the basis of IRENA, 2016.

6 GHG emissions from WTTv5

The greenhouse gas (GHG) emissions of conventional and advanced biofuels extracted from the JEC Well-to-Tank (v5) report are reported for the pathways included in the analysis in the following figure expressed in gCO_{2eq}/MJ of fuel (including uncertainties). Emissions for gasoline and diesel are also displayed[27].

Figure 8. GHG emissions for conventional and advanced biofuel pathways and gasoline and diesel (JEC WTTv5) including uncertainties



The GHG emissions calculated following the WTT methodology include emissions related to the biofuel production but excluding emissions due to direct or indirect land use change. These emissions are particularly significant for conventional biofuels pathways. In 2015, a study commissioned and funded by the European Commission was published (Valin et al., 2015) aiming to provide new insights on indirect carbon and land impacts from biofuels consumed in the EU compared to available studies.

Final results of the study in terms of total land use change (LUC) emissions expressed in gCO_{2eq} per MJ of biofuels for the individual feedstocks considered in our analysis are presented in **Table** . These estimated values combined with the WTT emissions are used in the following section to estimate the cost of greenhouse gas savings with LUC emissions, in order to inform the reader on the different results estimated including the land use change impact.

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[27] Soya pathways present huge range due to uncertainty in N2O emissions on credit Maize in Brazil, modelled with IPCC values.

Table 10 LUC emissions for individual feedstocks estimated by Valin et al., 2015

	gCO_{2eq}/MJ biofuel
Sugar beet to ethanol	15
Wheat grain to ethanol	34
Maize to ethanol	14
Rapeseed oil to biodiesel	65
Sunflower oil to biodiesel	63
Soya oil to biodiesel	150
Palm oil to biodiesel	231
Wheat straw to ethanol	16
Short rotation plantations to FT diesel	-29
Forest residues to FT diesel	17

*It should be noted that average LUC values are used. However, important ranges of uncertainty exist related to variability around biophysical values and causalities assumed in the modelling approach.

7 Results: cost of greenhouse gas savings

The cost of replacing fossil fuels with conventional and advanced biofuel, replacement costs, have been calculated, on the basis of energy content, by subtracting the estimated biofuel production costs to the price (without tax) of the equivalent fossil fuel[28]. Results in Eur/GJ are reported in the following table along with uncertainties.

Table 11. Replacement costs in Euro/GJ (including uncertainties) in 2014-2016

		EUR/GJ	UNCERTAINTIES
CONVENTIONAL ETHANOL PATHWAYS	Sugar beet to ethanol [SBET1a]	3	20%
	Wheat grain to ethanol [WTET1a, WTET2a]	8	16%
	Maize to ethanol [CRET2a]	10	16%
BIODIESEL PATHWAYS	Rapeseed to biodiesel [ROFA1; ROFA2; ROFA3]	8	3%
	Sunflower to biodiesel [SOFA1; SOFA2; SOFA3]	10	2%
	Soya oil to biodiesel [SYFA3]	10	2%
	Palm oil to biodiesel [POFA3]	7	3%
	Waste cooking oil to biodiesel [WOFA3]	9	1%
	Tallow oil to biodiesel [TOFA3]	4	3%
HVO PATHWAYS	Rapeseed to HVO [ROHY1a; ROHY1b]	9	5%
	Sunflower to HVO [SOHY1a]	12	3%
	Soya oil to HVO [SYHY1a]	13	3%
	Palm oil to HVO [POHY1a]	9	4%
	Waste cooking oil to HVO [WOHY1]	11	4-%
	Tallow oil to HVO [TOHY1]	6	7%
LIGNOCELLULOSIC ETHANOL PATHWAYS	Wheat straw to ethanol [STET1]	33	19%
	Farmed wood to ethanol [WFET1]	40	15%
	Residual wood to ethanol [WWET1]	40	15%
SYNTHETIC FUELS PATHWAYS	Farmed wood to FT diesel [WFSD1]	32	24%
	Residual wood to FT diesel [WWSD1]	32	23%
	Farmed wood to methanol [WFMe1]*	23	24%
	Residual wood to methanol [WWMe1]*	23	24%
	Farmed wood to DME [WFDE1]**	24	23%
	Residual wood to DME [WWDE1]**	25	23%

* Methanol has been assumed to replace gasoline (WTT report, section 4.6.1).

** DME has been assumed to replace diesel (WTT report, section 4.6.1).

Table shows that biofuel production costs result to be higher compared with diesel and petrol prices per GJ of energy and that the differences increase considering advanced biofuels as replacement to fossil fuels.

Ultimately, the cost of saving a tonne of CO_2 by using biofuels has been estimated by looking at the cost of replacing the fossil fuel with biofuels along with the emission savings related to biofuels. The ratio between the replacement costs and the GHG emission savings (expressed in Euro per tonne of CO_2 avoided) can be used to assess the cost efficiency of biofuels for GHG reduction allowing comparison between different biofuels and other options for saving GHG.

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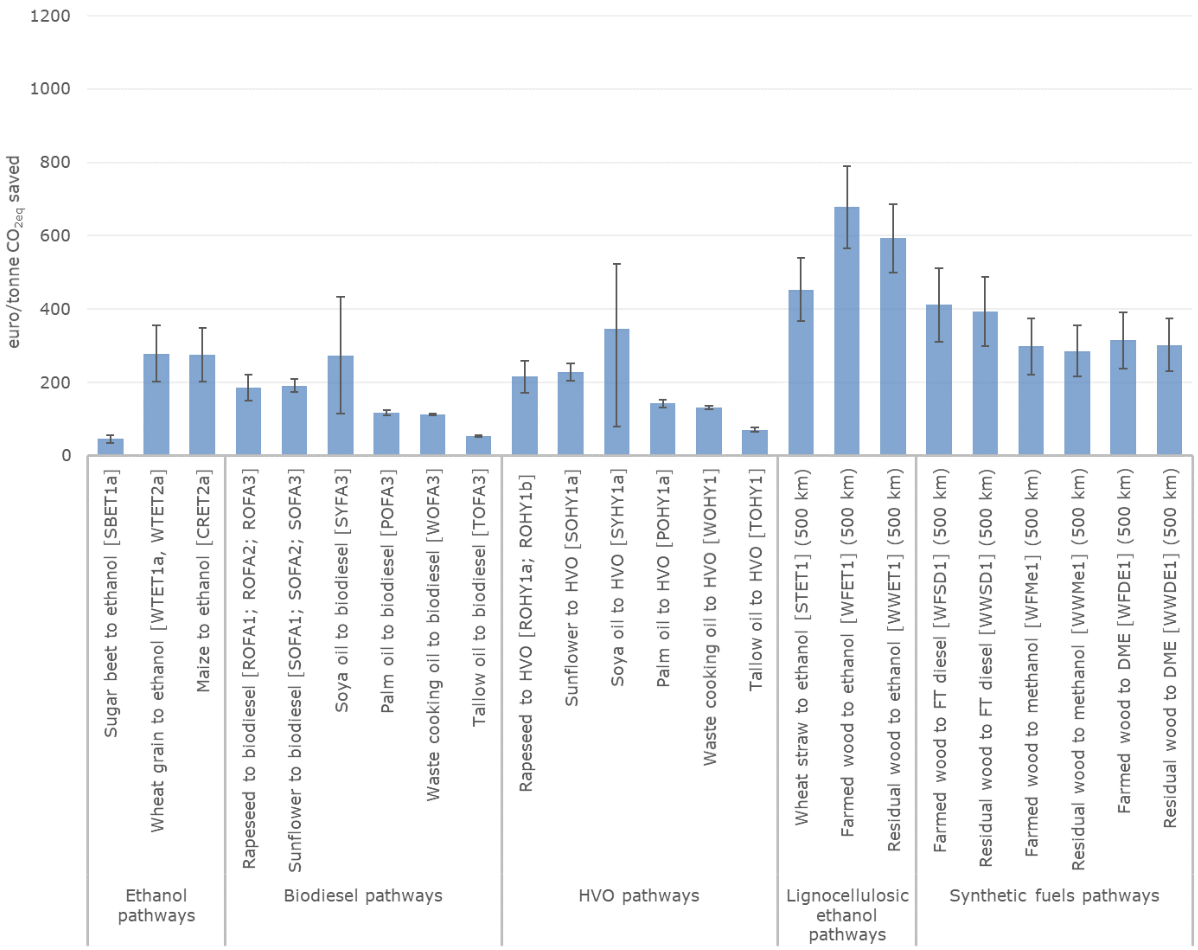
[28] Fossil prices have been assumed to be equal to 12 Euro/GJ for gasoline 10 ppm CIF NEW/Basis ARA and 11 Euro/GJ for diesel CIF NEW/Basis ARA extrapolated from Platts, European Marketscan (October 31, 2016).

The figure below provides an overview of the cost per tonne of CO_2 avoided in 2014-2016 for the conventional and advanced biofuel pathways considered in our analysis.

Figure 9. Cost of savings expressed in Eur/tonne CO_2eq saved (with uncertainties) in 2014-2016



Among conventional ethanol pathways, wheat and maize ethanol present a higher cost per tonne of CO_2 saved compared to sugar beet ethanol: using wheat or maize ethanol to save a tonne of CO_2 costs six times more than using sugar beet (around 270 Eur/tonne CO_{2eq} saved for wheat and maize ethanol and 46 Eur/tonne CO_{2eq} for sugar beet ethanol).

Even if cellulosic ethanol from wheat straw or wood is able to save more in terms of emissions compared to fossil fuel, according to our estimates for the time period 2014-2016, the cost of saving those emissions are currently much higher than for conventional ethanol pathways ranging between 453 and 678 Eur/tonne CO_{2eq} saved.

The main biodiesel fuels exhibit different cost of CO_2 reduction, varying from around 55 Eur/tonne CO_{2eq} avoided for tallow oil biodiesel to about 270 Eur/tonne CO_{2eq} avoided for soya oil biodiesel. For HVO pathways, the range varies between 75 and 356 Eur/tonne CO_{2eq} avoided for tallow to HVO and soya oil to HVO respectively.

Synthetic fuels pathways resulted in cost of savings in the range of 286 to 393 Eur/tonne CO_{2eq} avoided, benefitting from significant GHG emission savings that make them competitive with some biodiesel and HVO pathways.

These results change if the LUC emissions shown in **Table** (Valin et al., 2015) are included in the calculations.

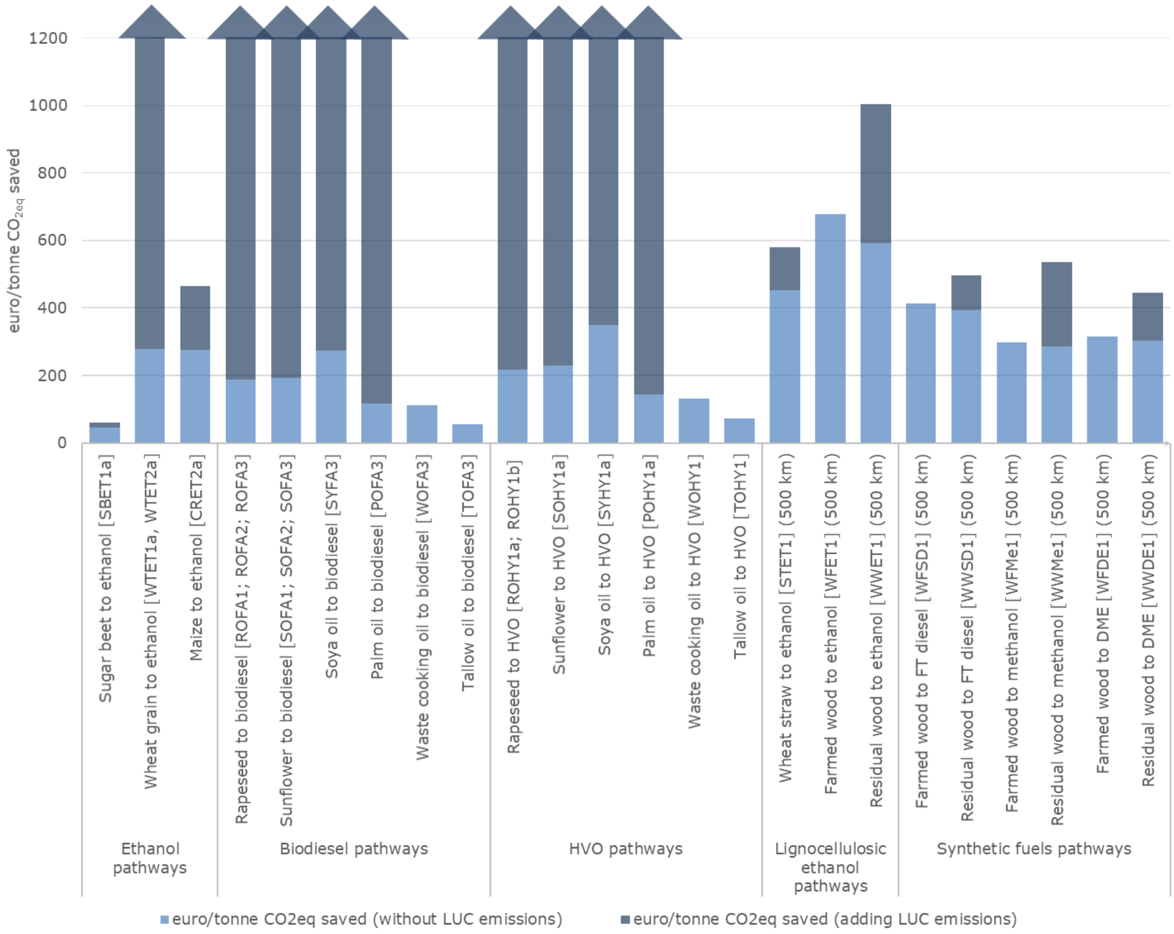
Figure 10. Cost of savings expressed in Eur/tonne CO2eq saved in 2014-2016, including LUC emissions

Figure 10 shows the results of the cost of savings when LUC emissions[29] are added to the emissions estimated using the WTT methodology.

Adding the LUC impact, wheat to ethanol as well as biodiesel and HVO pathways produced from crops exhibit negative GHG savings (i.e. additional net emissions) resulting in emissions-reduction cost that could be considered infinite. The LUC impact has much less effect on the costs of GHG savings for sugar beet and maize ethanol pathways.

In general, advanced biofuel pathways perform better when LUC emissions are included in the calculations; in particular, farmed wood to fuel pathways register a decrease in the costs of savings since the LUC emission factor is negative (see **Table** LUC emissions for short rotation plantations).

Figure 10. Cost of savings expressed in Eur/tonne CO2eq saved in 2014-2016, including LUC emissions



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[29] For pathways that are not included in Valin et al. 2015 (such as forest residues to ethanol), the LUC emissions are calculated by using the LHV ratio of the fuels (e.g. LHV ratio of FT diesel and ethanol).

8 Crude oil price scenarios

In this section, crude oil price scenarios are considered in order to understand the influence of future evolution of crude oil prices on potential costs of greenhouse gas emission savings of biofuel pathways. For this purpose, two scenarios are analysed based on LOW and HIGH crude oil price projections for 2030. Scenarios are based on the World Energy Outlook 2018 (WEO) oil projections done by the International Energy Agency (IEA). The LOW scenario is based on the 'New policies[30]' scenario from the IEA WEO, assuming 100 $2017/bbl, while the HIGH scenario is based on the 'Current policies' scenario, with a projection of 120 $2017/bbl. **Table** shows the different oil prices used for the analysis, using Eur 2014-2016 consistently with the cost analysis performed above.

Table 12. Oil prices scenarios

WTTv5	LOW	HIGH
54 Eur/bbl	85 Eur/bbl	100 Eur/bbl

Since 2005, the prices of agricultural commodities and crude oil have been rising simultaneously. For instance, since biodiesel has been responsible of most of the increase in the European vegetable oil demand, biodiesel production in EU has had a significant impact on world vegetable oil markets.

Therefore, crude oil price variations may have an impact on feedstock prices and other energy commodities, altering the production cost of biofuels. In order to adjust the commodity prices to oil price changes, Oil Cost Factors (OCF), see

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[30] New policies scenario assumes a concerted effort to move to cleaner and more efficient technologies, with the power sector in the vanguard of change, and a large and expanding role for natural gas.

Table table 13, were applied in the scenario analysis, following the methodology adopted in the WTWv2 report. OCF were estimated by correlating variation of historical commodity prices to oil price changes (prices from 2005-2018 on a monthly basis). In this way, when oil prices are assumed to increase, commodity prices also do proportionally to their correlation factor. This allows projecting feedstock prices and other energy costs taking into account oil price variations. It should be noted that CAPEX is assumed constant for all scenarios. **Error! Reference source not found.** in the annex display the different commodity prices a ssumed for each scenario.

Table 13 Estimated Oil Cost Factors (OCF) for Oil price scenarios

Commodity	Oil Cost factor (OCF)
Natural gas	0.73
Electricity prices	0.5
Diesel	1
Gasoline	1
Heavy fuel Oil	1
Methanol	0.4
Hexane	0.7
H_2	0.66
Sugarbeet	0.22
Feed wheat	0.16
Maize	0.28
Rapeseed	0.49
Rapeseed oil	0.49
Sunflower seed	0.39
Sunflower oil	0.39
Soybean seed	0.51
Soybean oil	0.51
Soya meal	0.34
Palm oil	0.43
Used cooking oil	0.45
Animal fat/tallow	0.39
Wheat straw	0.16
Wood chips & forest residues	0.07

Sources:

[1] IndexMundi commodity price indices

[2] World Bank Commodities Price Data

[3] FRED Economic Data

According to the increase of vegetable oil biodiesel production in Europe for the considered time period, the OCF estimated for vegetable oils shows significant correlation to oil prices. On the other hand, OCF for cereals and sugar crops used for ethanol, as well as lignocellulosic materials, is quite low since they represent a small part of the total markets and are usually produced locally.

Figure 11 shows the production costs estimates for the three oil scenarios. Among all pathways, only sugarbeet ethanol becomes cheaper than gasoline assuming the LOW price scenario. While in the HIGH scenario, tallow biodiesel, as well as sugarbeet, becomes a competitive alternative to conventional fuels.

shows the cost of greenhouse emissions savings for the different oil price scenarios. Overall, for higher oil prices, the cost of greenhouse gas savings decreases to a greater or lesser extent depending on the OCF of the respective feedstock and energy contribution to the production cost.

For conventional ethanol pathways, feedstock prices do not present high correlation to oil prices so replacement costs decrease significantly for high oil prices. Ethanol results in 2 and 5 Eur/GJ cheaper than gasoline for LOW and HIGH scenario respectively. Wheat ethanol cost of greenhouse gas savings drops to 95 (LOW) and 0.5 (HIGH) Eur/tonne CO_{2eq} saved, while maize ethanol goes down to 162 (LOW) and 104 (HIGH) Eur/tonne CO_{2eq}.

Regarding conventional biodiesel and HVO, replacement costs decrease slightly due to the high correlation of vegetable oil prices and tallow to crude oil. The main biodiesel fuels cost of GHG savings varies from 14 (LOW) and -6 (HIGH) Eur/tonne CO_{2eq} for tallow oil biodiesel to 251 and 242 Eur/tonne CO_{2eq} for soya oil biodiesel. Similar moderate reduction is achieved in HVO pathways.

For lignocellulosic and synthetic fuels pathways, the reduction of the cost of savings is moderate. For lignocellulosic fuel pathways, the cost of GHG savings varies from 397-615 Eur/tonne CO_{2eq} in the LOW scenario and 369-583 Eur/tonne CO_{2eq} in the HIGH. While synthetic fuels pathways result in cost of savings in the range of 206-336 Eur/tonne CO_{2eq} in the LOW scenario and 165-297 Eur/tonne CO_{2eq} in the HIGH scenario.

Figure 11. Production costs for oil price scenarios

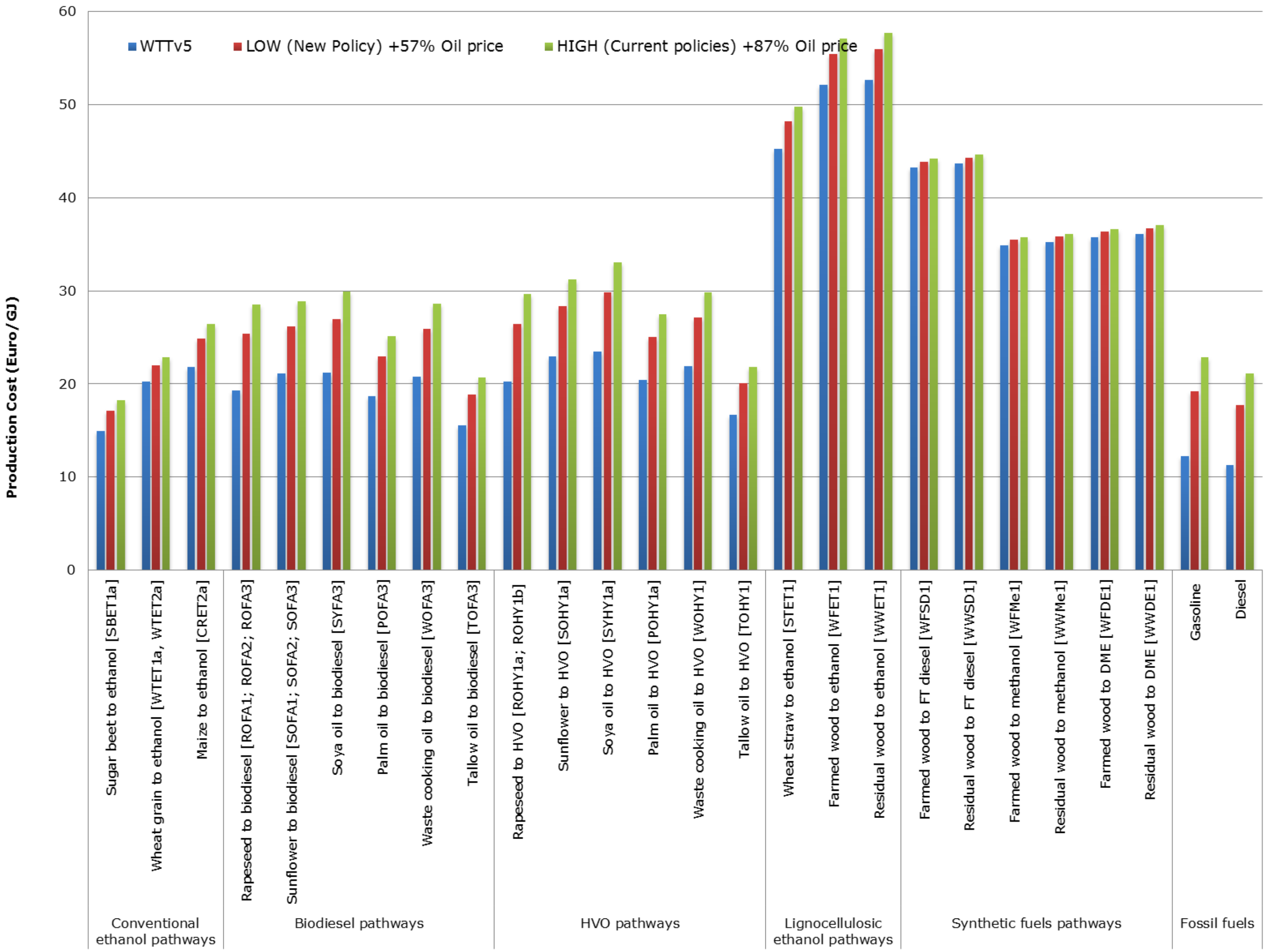
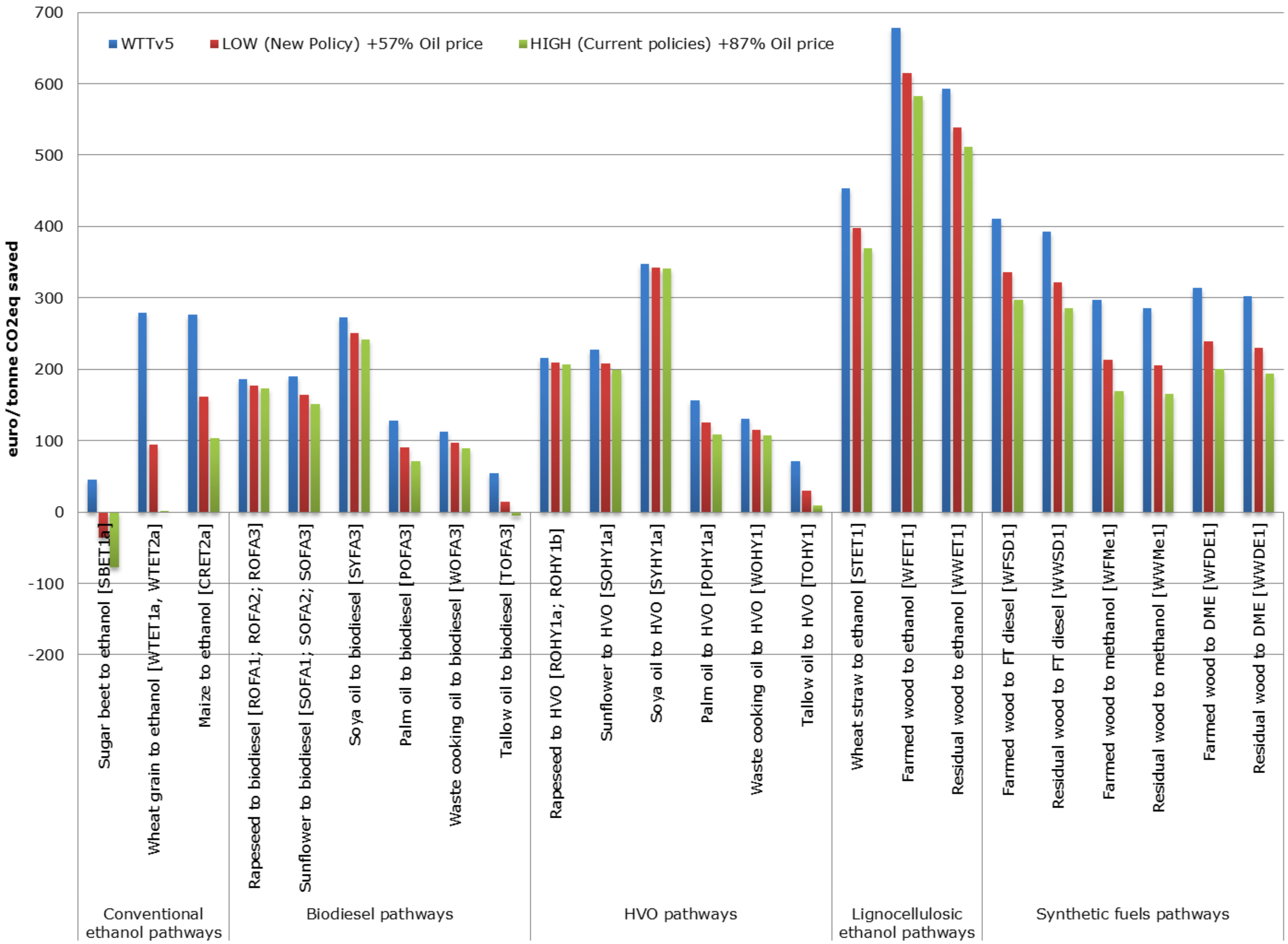


Figure 12. Cost of greenhouse gas savings for different oil price projections



9 Conclusions

- Production costs and costs of GHG savings of the main conventional and advanced biofuels produced in Europe for the time period 2014-2016 have been estimated (including two scenarios based on different crude oil prices at time horizon 2030) following the same principles developed in the JEC-WTW v2 (2007) report, but limiting the focus to the 'well-to-tank' part of the fuel production.

- Our estimate shows ranges of production costs for conventional ethanol pathways and for biodiesel pathways in the range of 15-22 Eur/GJ for the considered time period 2014-2016 and they are consistent with the actual biofuels market prices. Production costs for HVO pathways have been estimated in the range of 17-24 Eur/GJ and they are in line with the ones reported in SGAB, 2017. For lignocellulosic ethanol, production costs range between 45-53 Eur/GJ (double compared to the conventional ethanol production costs). Slightly lower costs were found for the synthetic fuels pathways included in the analysis, varying from 35 Eur/GJ for farmed or residual wood to methanol to 44 Eur/GJ for residual wood to FT diesel. The price ranges for lignocellulosic and synthetic fuels pathways appear to be higher compared to the range of production costs reported in the SGAB report but they are close to the ones provided by IRENA, 2016.

- In terms of costs of savings, among conventional ethanol pathways, wheat and maize ethanol present a higher cost per tonne of CO_2 saved compared to sugar beet ethanol (around 270 Eur/tonne CO_{2eq} saved for wheat and maize ethanol and 46 Eur/tonne CO_{2eq} for sugar beet ethanol). Even if cellulosic ethanol from wheat straw or wood is able to save more in terms of emissions compared to fossil fuel, according to our estimates, the cost of saving those emissions are currently much higher than for conventional ethanol pathways (ranging between 453 and 678 Eur/tonne CO_{2eq} saved). The main biodiesel fuels exhibit different cost of CO_2 reduction, varying from around 55 Eur/tonne CO_{2eq} avoided for tallow oil biodiesel to about 270 Eur/tonne CO_{2eq} avoided for soy oil biodiesel. For HVO pathways, the range varies between 75 and 356 Eur/tonne CO_{2eq} avoided for tallow to HVO and soy oil to HVO respectively. Synthetic fuels pathways resulted in cost of savings in the range of 286 to 393 Eur/tonne CO_{2eq} avoided, benefitting from significant GHG emission savings that make them competitive with some biodiesel and HVO pathways.

- Adding the LUC impact, wheat to ethanol as well as biodiesel and HVO pathways produced from crops exhibit negative GHG savings (i.e. additional net emissions) resulting in emissions-reduction cost that could be considered infinite. The LUC impact has much less effect on the costs of GHG savings for sugar beet and maize ethanol pathways. In general, advanced biofuel pathways perform better when LUC emissions are included in the calculations; in particular, farmed wood to fuel pathways register a decrease in the costs of savings since the LUC emission factor is negative.

- The cost of greenhouse emissions savings for the two scenarios based on LOW and HIGH crude oil price projections for 2030. Overall, for higher oil prices, the cost of greenhouse gas savings decreases to a greater or lesser extent depending on the oil cost factor (OCF) of the respective feedstock and the energy contribution to the production cost. For conventional ethanol pathways, feedstock prices do not present high correlation to oil prices so replacement costs decrease significantly for high oil prices. For conventional biodiesel and HVO, replacement costs decrease slightly due to the high correlation of vegetable oil prices and tallow to crude oil. Similar moderate reduction is achieved in HVO pathways. For lignocellulosic and synthetic fuels pathways, the reduction of the cost of savings is moderate.

10 References

See section 6 in the main report for the complete list of references

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