HyWays

"Modelling of hydrogen supply chains for Poland in the E3-database"

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Contents

1 Acronyms

CCGT	Combined Cycle Gas Turbine
CCS	CO_2 Capture and Storage
CGH_2	Compressed Gaseous Hydrogen
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
FC	Fuel Cell
GHG	Green House Gas
IGCC	Integrated Gasification Combined Cycle
ICE	Internal Combustion Engine
LH_2	Liquefied Hydrogen
LNG	Liquefied Natural Gas
NG	Natural gas
PEMFC	Proton Exchange Membrane Fuel Cell
PR	Progress Ratio
PSA	Pressure Swing Adsorption
SMR	Steam Methane Reforming
WTT	Well-to-Tank
TTW	Tank-to-Wheel
WTW	Well-to-Wheel
WtStU	Well-to-Stationary Use

2 Methodology

The GHG emissions, the energy requirements and the costs of the supply of transportation fuel, electricity and heat has been carried out for a number of hydrogen energy chains using the E3 database tool. Initially as time horizon the year 2020 has been selected because it can be expected that in 2020 fuel cell vehicles as well as most of the hydrogen generation technologies are commercially available. Additionally the time horizon 2030 has been considered in order to take into account long term hydrogen production processes.

The processes used in E3 database for the calculation of the hydrogen energy pathways also have been presented in the technology fact sheets (based on EXCEL: FACT_SHEETS_LBST_31Oct2006.xls). Additionally the different hydrogen related technologies are presented in a template for MARKAL (also based on EXCEL: Template_MARKAL_13-09-2006.xls) which is used as input for the calculations in MARKAL.

2.1 General

All calculations are based on the lower heating value (LHV).

Most of the processes already have been used in the CONCAWE/EUCAR/JRC study. Newly introduced processes are processes where CO_2 capture and storage is embodied, processes which describe stationary hydrogen fueled fuel cells, gas engines and gas turbines, and Norwegian specific processes (e.g. Norwegian NG supply). For the Polish pathways the following new processes have been introduced:

- Power Station / Wind / on-shore / Enercon E-66 / 20.70 (Poland)
- Power Station / Wind / off-shore (water depth 30 m)
- Power Station / Nuclear (EPR) / GEMIS 4.3
- Bio-Methane / Biogas Purification / Druckwasserwäsche (Eco Naturgas)
- Bio-Methane / Comp / In 0.9 MPa Out 1.6 MPa (for onsite SMR)
- Biogas / organic waste / fermenter
- Electricity / Provision Mix Poland / PRIMES
- GH2 / Electrolysis / Hydrogen Systems (small and large)
- GH2 / DeOxo dryer (purity: 99.995%)
- GH2 / coal gasification / FW / CO2 sequestration (lignite)
- GH2 / coke-oven gas
- GH2 / Hard Coal / In-situ gasification with CCS
- GH2 / Nuclear Thermochemical Cycle / SI Cycle
- GH2 / NG-Poland / Steam Reforming / HyGear (small and large)
- LH2 / Tankstelle (small and large)

- FC / H2 PEMFC / IRD w/o peak boiler
- NG / Extraction / Poland (on-shore)
- NG / NG-processing Poland
- Heat / NG-Poland / Process Heating Plant / PL
- Coal / Hard / Deep mining Poland / GEMIS 4.3
- Lignite / Surface mining / Poland / GEMIS 4.3

Furthermore different electrolyzers have been used (Stuart Energy instead of GHW). In the CONCAWE/EUCAR/JRC study only passenger vehicles have been considered. In HyWays also buses are taken into account.

From the 12 calculated chains 8 chains have been selected. The selected pathways are marked red.

Figure 2-1: Overview of selected chains

	No.	Feedstock (incl. transport)	H_2 production	H_2 transport	End-use (incl. fueling station)	
1	1a	NG	central SMR (*)	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
2	1b	NG	onsite SMR	-	CGH_2 FS	FC/ICE car, buses
3	2	WW/FW	gasification	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
	3	biogas	onsite SMR	-	CGH_2 FS	FC/ICE car, buses, FC-CHP
4	4	offshore wind	onsite electr.	-	CGH_2 FS	FC/ICE car, buses
	5	onshore wind	onsite electr.	-	CGH_2 FS	FC/ICE car, buses
5	6	nuclear power	onsite electr.	-	CGH_2 FS	FC/ICE car, buses
	7	HT nuclear heat	thermochemical cycle	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
	8	hard coal	gasification (*)	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
	9a	lignite	gasification (*)	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
6	9b	lignite	gasification (*)	liquefaction, LH_2 trailer	LH_2 FS	FC/ICE car, buses
7	10	hard coal	in-situ gasification(*) with pure O_2	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
8	11	by-product	upgrading of coke oven gas	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP

[1] WW - waste wood, FW - farmed wood

* with CCS (in depleted Polish NG fields especially in NG fields containing low CH_4 NG after depletion of the field or in coal beds and replacing coal bed methane by CO_2)

2.2 Conversion factors for Greenhouse Gas Equivalents

For the conversion of the different greenhouse gases (GHG) to CO_2 equivalents the following conversion factors have been used:

Table 2-1: Conversion factors [IPCC 2001]

	g CO_2 equivalent per g
CO_2	1
CH_4	23
N_2O	296

2.3 Learning curves

Economic learning curves have been applied for technologies which will be produced at large numbers of units e.g. hydrogen filling stations, onsite electrolyzers and onsite steam reformers. The learning curve is defined by the following formula:

$$I = a \cdot N^{-b}$$

where

I = Investment of the Nth unit

a = Investment of the 1st unit

N = Number of units

b = Parameter

b ranges between 0.1 and 0.3. In some literature the so-called progress ratio (PR) is indicated. The progress ratio is used to express the progress of cost reductions for different technologies. The cost reduction is (1-PR) for each doubling of cumulative production. The progress ratio can be calculated by

$$PR = 2^{-b}$$

If the progress ratio (PR) is given the investment of the Nth unit can be calculated by

$$I = a \cdot N^{\frac{\ln(PR)}{\ln(2)}}$$

For the calculation of the fuel supply costs for the average investment per unit has to be considered. This means that e.g. if 10,000 hydrogen filling stations will be installed the investment of the 1st filling station as well as the investment of the last filling stations influences the fuel supply costs. Therefore for the cost calculation in E3 database the average investment has been used. The average investment can be calculated by integration of the formula for the learning curve:

$$A = \frac{a}{N} \cdot \int_{1}^{N} N^{-b} dN = \frac{a}{N} \cdot \left[\frac{1}{1-b} \cdot \left(N^{1-b} - 1 \right) + 1 \right]$$

where A = average investment of one unit.

As a result the average investment is always higher than the investment of the Nth unit.

2.4 Scaling by size

The investment for volume related technologies (in contrast to surface related technologies e.g. photovoltaics) like coal power stations but also steam reforming plants and hydrogen liquefaction plants do not increase linearly with the size of the plants. The investment of a plant with a size required here can be calculated by

$$I_2 = I_1 \cdot \left(\frac{C_2}{C_1} \right)^{0.7}$$

where

I_1 = Investment of the plant with capacity C_1

I_2 = Investment of the plant with capacity C_2

C_1 = Capacity of plant 1

C_2 = Capacity of plant 2

3 Well-to-Tank (WTT) analysis

3.1 Chain 1a: CGH_2 from central SMR

Natural gas (NG) from Poland is distributed via the regional and local natural gas pipeline grid to the filling station where the NG is converted to hydrogen via steam methane reforming (SMR).

Table 3-1: Input and output data for NG extraction in Poland [GEMIS 2005]

	2020		2030	
	Input	**Output**	**Input**	**Output**
Natural gas [kWh/kWh]	1.0005	1.000	1.0005	1.000
Electricity [kWh/kWh]	0.0013	-	0.0013	-
CH_4 [g/kWh]	-	0.0385	-	0.0349

Table 3-2: Input and output data for NG processing in Poland [GEMIS 2005]

	2020		2030	
	Input	**Output**	**Input**	**Output**
Natural gas [kWh/kWh]	1.0526	1.000	1.0526	1.000
Heat [kWh/kWh]	0.001	-	0.001	-
Electricity [kWh/kWh]	0.001	-	0.001	-
CH_4 [g/kWh]	-	0.0385	-	0.0349

The heat is supplied by a NG fueled heating plant with an efficiency of 85% and CO2 emissions of 235 g/kWh of heat. The CH_4 emissions amount to about 0.021 g/kWh of heat and the N_2O emissions amount to about 0.005 g/kWh of heat.

The electricity demand is met by the Polish electricity mix (Table 3-3).

Table 3-3: Input and output data for the Polish electricity mix in 2020 and in 2030 [PRIMES 2003]

	I/O	Unit	2020	2030
Biomass	Input	kWh/kWh	0.046	0.071
Lignite	input	kWh/kWh	0.637	0.519
Coal hard	Input	kWh/kWh	1.019	0.831
Crude oil	Input	kWh/kWh	0.114	0.226
Hydro	Input	kWh/kWh	0.011	0.009
NG	Input	kWh/kWh	0.343	0.359
Wind power	Input	kWh/kWh	0.038	0.048
Electricity	Output	kWh	1.000	1.000
CO_2 emissions	Output	g/kWh	708	614

The costs for the supply of natural gas without distribution have been assumed to be 45.1 US$ per barrel of oil equivalent in 2020 leading to about 0.0284 €/kWh of natural gas. For 2030 the natural gas costs have been assumed to be 59.3 US$ per barrel of oil equivalent leading to about 0.0373 €/kWh of natural gas.

The data for the high pressure (HP) natural gas distribution has been derived from [GEMIS 2005].

Table 3-4: Input and output data for NG distribution (high pressure pipeline) over 300 km

	Input	**Output**
Mechanical work [kWh/kWh]	0.0019	-
NG [kWh/kWh]	1.000	1.000
CH_4 emissions [g/kWh]	-	0.0013

The mechanical work is supplied by a gas turbine (efficiency: 33%). The costs for NG distribution via high pressure pipeline has been assumed to be 0.0004 EUR per kWh of natural gas as indicated in [CONCAWE 2006][1].

The steam methane reformer (SMR) with CO_2 capture and storage (CCS) has been derived from a study carried out by Foster Wheeler [Foster Wheeler 1996]. The CO_2 capture, extraction and compression is included. The CO_2 capture is carried out via scrubbing process using aMDEA (activated methyl diethanol amine) The CO_2 is compressed to a pressure of approximately 11 MPa which leads to liquefaction. The

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[1] in [CONCAWE 2006] only maintenance costs has been considered

CO_2 is transported via pipeline in liquid state. The CO_2 is injected into depleted natural gas and oil fields. The SMR plant is located at the coast. The plant consists of 3 single units (each 94,000 Nm^3 H_2/h). In contrast to the Linde SMR the Foster Wheeler plant has no electricity export.

Table 3-5: Technical and economic data of the SMR with CO_2 capture and storage [Foster Wheeler 1996]

Capacity [Nm^3 H_2/h]	281,300 (3 units)
NG consumption [kWh/kWh_{H2}]	1.365
CO_2 emissions [g/kWh_{H2}]	42.7
CH_4 emissions [g/kWh_{H2}]	0.057
Investment [EUR]	453,090,000
Maintenance coefficient [% of investment/yr]	1.5
Labor [EUR/yr]	546,400
Overhead [% of investment]	0.1
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	7,884

For the supply of CGH_2 the hydrogen is distributed via a hydrogen pipeline grid. The large steam methane reforming plant should most suitably to be located close to large agglomerations e.g. large cities like Katowitz, Krakow and Warsaw. It has been assumed that the hydrogen grid consists of 9 to 10 larger pipelines with a throughput of 240 GWh H_2 per year and pipeline and some smaller pipelines with a throughput of 8 GWh H_2 per year and pipeline. A rest of the hydrogen is exported to other regions. Alternatively only one 94,000 Nm^3/h unit is installed instead of three units.

Figure 3-1: Pipeline grid for the large SMR plant with CO_2 capture and storage (CCS)

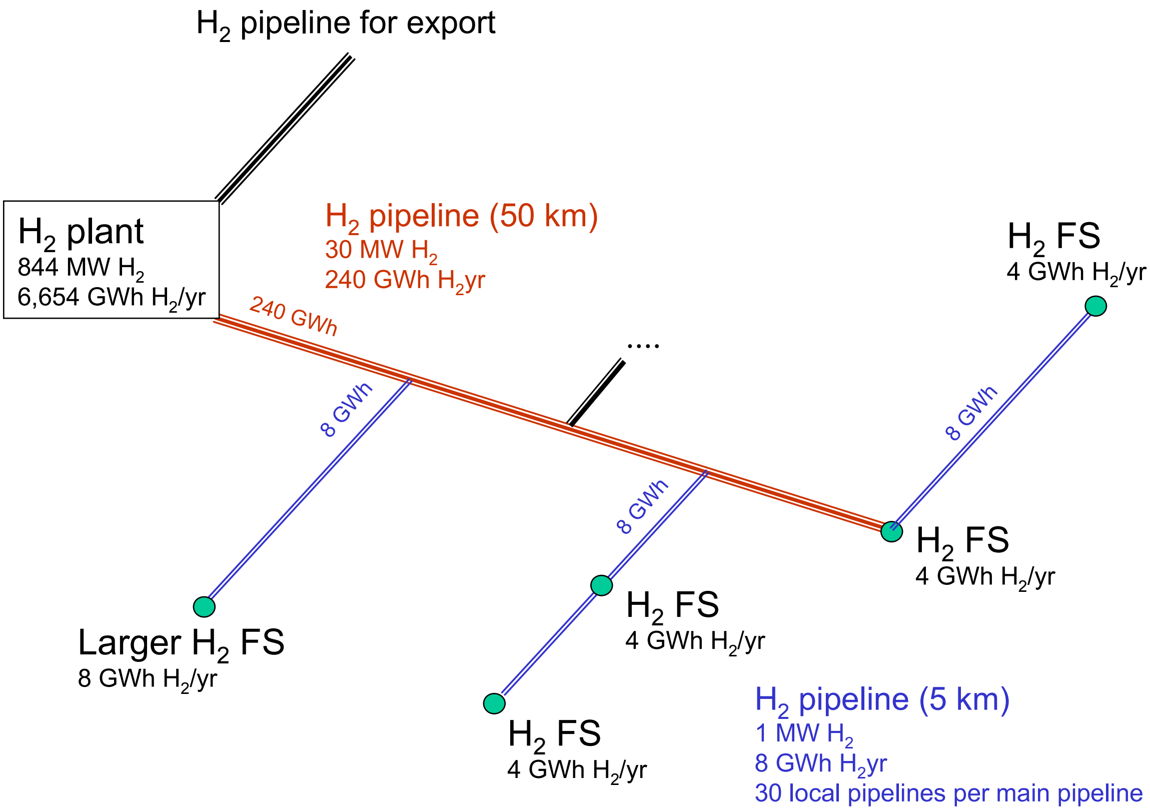


Table 3-6: Technical and economic data for a 50 km H_2 pipeline [Tschauder 1998]

Annual hydrogen throughput [GWh H_2/yr]	240
Diameter [mm]	150
Investment [EUR]	8,950,000
Labor, maintenance etc. [EUR/yr]	261,000
Useful lifetime [yr]	30

Table 3-7: Technical and economic data for a 5 km H_2 pipeline [Tschauder 1998]

Annual hydrogen throughput [GWh H_2/yr]	8
Diameter [mm]	100
Investment [EUR]	895,000
Labor, maintenance etc. [EUR/yr]	21,000
Useful lifetime [yr]	30

For the calculation it has been assumed that the annual fuel output per CGH_2 filling station amounts to some 4 million kWh per year (120 t H_2/yr). The technical and economic data of the CGH_2 filling station are shown in Table 3-8.

Table 3-8: Technical and economic data for the 120 t/yr CGH_2 filling station (suction pressure: 2.0 MPa)

	2004	2020	2030
Annual fuel output [t H_2/yr]	120	120	120
Electricity consumption [kWh/kWh_{H2}]	0.070	0.070	0.070
Investment [EUR]	496,000	231,000 1)	211,000 2)
Maintenance [% of investment]	2.7	3.7	3.7
Useful lifetime [yr]	20	20	20

1) average investment per unit when 10,000 units are installed; 2) average investment per unit when 28,000 units are installed

A significant number of larger filling stations (480 t H_2/yr) will be installed in 2030.

Table 3-9: Technical and economic data for the 480 t/yr CGH_2 filling station (suction pressure: 2.0 MPa)

	2004	2030
Annual fuel output [t H_2/yr]	480	480
Electricity consumption [kWh/kWh_{H2}]	0.070	0.070
Investment [EUR]	2,272,000	955,000 1)
Maintenance [% of investment]	3.6	4.6
Useful lifetime [yr]	20	20

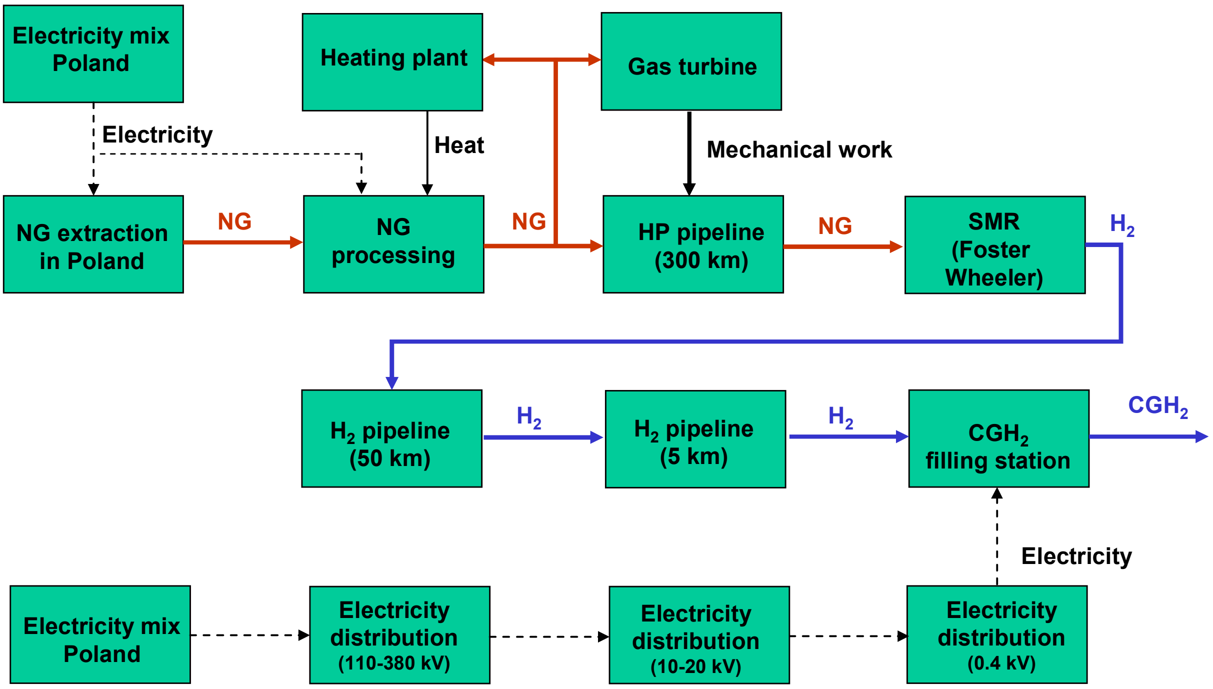
1) average investment per unit when 28,000 units are installed

The electricity requirements for the CGH_2 filling station is met by the Polish electricity mix in 2020 and 2030. The electricity mix has been derived from [PRIMES 2003]. The GHG emissions from the Polish electricity mix ex power plants amount to some 708 g/kWh in 2020 and 614 g/kWh in 2030 (see above). The costs of electricity have been estimated. The costs of electricity distribution have been derived from [RWE 1999]

Table 3-10: Costs of the electricity from Polish electricity mix (0.4 kV) [RWE 1999]

	Efficiency distribution [%]	[€/kWh$_e$]
Electricity generation	-	0.030
Distribution	94.5	0.031
Total	94.5	0.061

Fig. 3-1: CGH$_2$ from central SMR with CO$_2$ capture and storage (CCS)



3.2 Chain 1b: CGH$_2$ from onsite SMR

Natural gas (NG) from Polish NG wells is distributed via the regional NG grid (high pressure grid, see above) and local natural gas pipeline grid to the filling station where the NG is converted to hydrogen via steam methane reforming (SMR).

For the local NG distribution no energy requirements and no GHG emissions occur. But the local NG distribution leads to additional costs. The costs for the local natural gas distribution to the filling stations was assumed to be 0.0002 EUR per kWh of natural gas as indicated in [CONCAWE 2006].

Table 3-11 shows the technical and economic data of the onsite SMR for the 120 t/yr filling station. The technical data are derived from [Haldor Topsoe 1998] and the investment has been derived from [HyGear 2006]. The investment has been derived from a 500 Nm^3/h plant by down and up scaling (scaling exponent: 0.7). The specific investment of a 500 Nm^3/h plant is about 3,000 €/(Nm^3/h) and the specific investment of a 50 Nm^3/h plant is about 6,000 €/(Nm^3/h).

Table 3-11: Onsite SMR for the 120 t/yr filling station [Haldor Topsoe 1998], [HyGear 2006]

	1998	2020	2030
Capacity [Nm^3 H_2/h]	222	222	222
NG consumption [kWh/kWh_{H2}]	1.441	1.441	1.441
Electricity consumption [kWh/kWh_{H2}]	0.016	0.016	0.016
CO_2 emissions [g/kWh_{H2}]	292	292	292
CH_4 emissions [g/kWh_{H2}]	0.075	0.075	0.075
Pressure (H_2) [MPa]	1.5	1.5	1.5
Investment [€]	850,000	376,000 1)	339,000 2)
Maintenance coefficient [% of investment]	1.0	1.0	1.0
Useful lifetime [yr]	15	15	15
Equivalent full load period [h/yr]	6,000	6,000	6,000

1) average investment per unit when 10,000 units are installed; 2) average investment per unit when 28,000 units are installed

Table 3-12: Technical and economic data for the 120 t/yr CGH_2 filling station (suction pressure: 1.5 MPa)

	2004	2020	2030
Annual fuel output [t H_2/yr]	120	120	120
Electricity consumption [kWh/kWh_{H2}]	0.077	0.077	0.077
Investment [€]	591,000	273,000 1)	249,000 2)
Maintenance [% of investment]	3.9	4.7	4.8
Useful lifetime [yr]	20	20	20

1) average investment per unit when 10,000 units are installed; 2) average investment per unit when 28,000 units are installed

In 2030 larger filling stations will be installed. In 2030 the cumulative number of the 120 t/yr filling station amounts to 28,000 and the number of the 480 t/yr filling station also amounts to 28,000.

Table 3-13: Onsite SMR for the 480 t/yr filling station [Haldor Topsoe 1998], [HyGear 2006]

	1998	2030
Capacity [Nm^3 H_2/h]	889	889
NG consumption [kWh/kWh_{H2}]	1.441	1.441
Electricity consumption [kWh/kWh_{H2}]	0.016	0.016
CO_2 emissions [g/kWh_{H2}]	292	292
CH_4 emissions [g/kWh_{H2}]	0.075	0.075
Pressure (H_2) [MPa]	1.5	1.5
Investment [€]	2243,000	895,000 1)
Maintenance coefficient [% of investment]	1.0	1.0
Useful lifetime [yr]	15	15
Equivalent full load period [h/yr]	6,000	6,000

1) average investment per unit when 28,000 units are installed

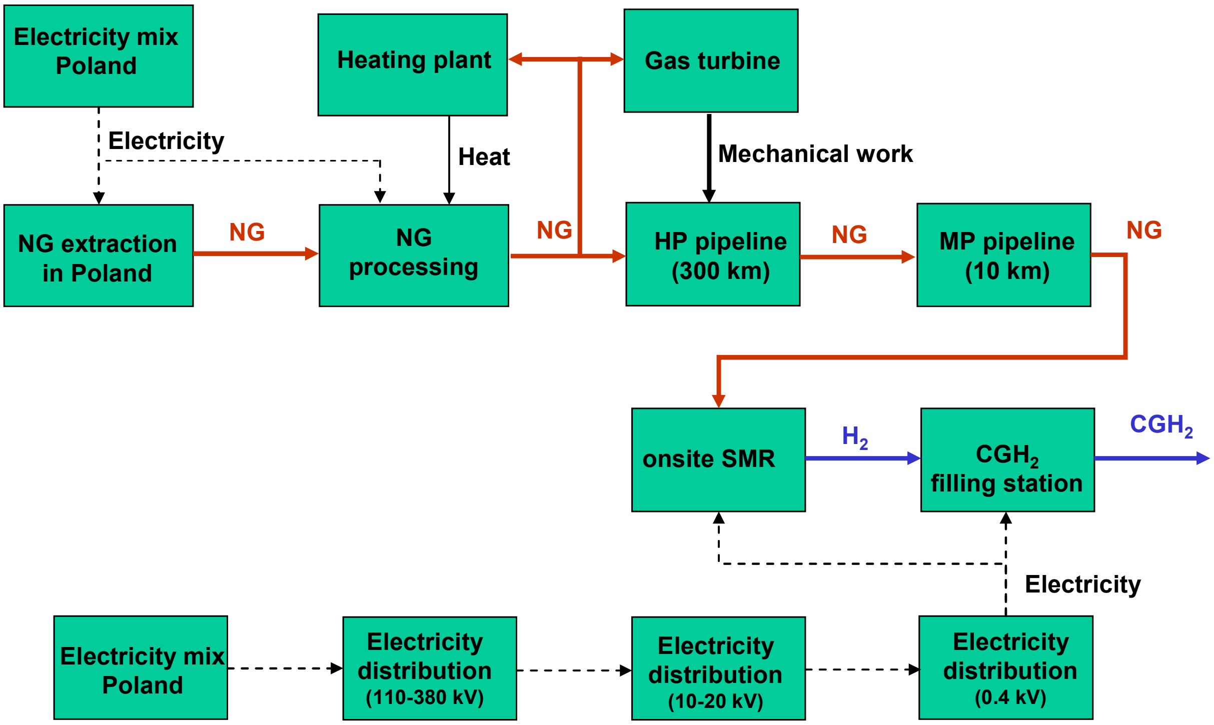
Table 3-14: Technical and economic data for the 480 t/yr CGH_2 filling station (suction pressure: 1.5 MPa)

	2004	2030
Annual fuel output [t H_2/yr]	480	480
Electricity consumption [kWh/kWh_{H2}]	0.077	0.077
Investment [€]	2,272,000	955,000
Maintenance [% of investment]	3.9	4.7
Useful lifetime [yr]	20	20

1) average investment per unit when 28,000 units are installed

The share of fuel output which comes from the larger filling station will be about 80% in 2030.

Figure 3-2: CGH_2 from onsite steam reforming of NG



The electricity requirement for the onsite steam reformer and the hydrogen compression at the filling station is met by the Polish electricity mix.

3.3 Chain 2: CGH_2 from woody biomass

In this pathway woody biomass is used as feed-stock. Two variants have been considered:

a) CGH_2 from residual wood

b) CGH_2 from wood plantation

3.3.1 Residual wood

Wood residues are generated in the process of timber harvesting and of thinning after reforestation, in the timber processing industry (carpentry shops, furniture producers etc.) and as wood waste e.g. from used furniture. The wood is chipped at the source and then transported to the gasification plant by truck. The average transport distance for the transport of the wood chips is assumed to be 50 km.

The diesel consumption for wood chipping is indicated with 0.3 to 0.5% of the energy content (LHV) of the wood [Hartmann 1995].

3.3.2 Wood plantation

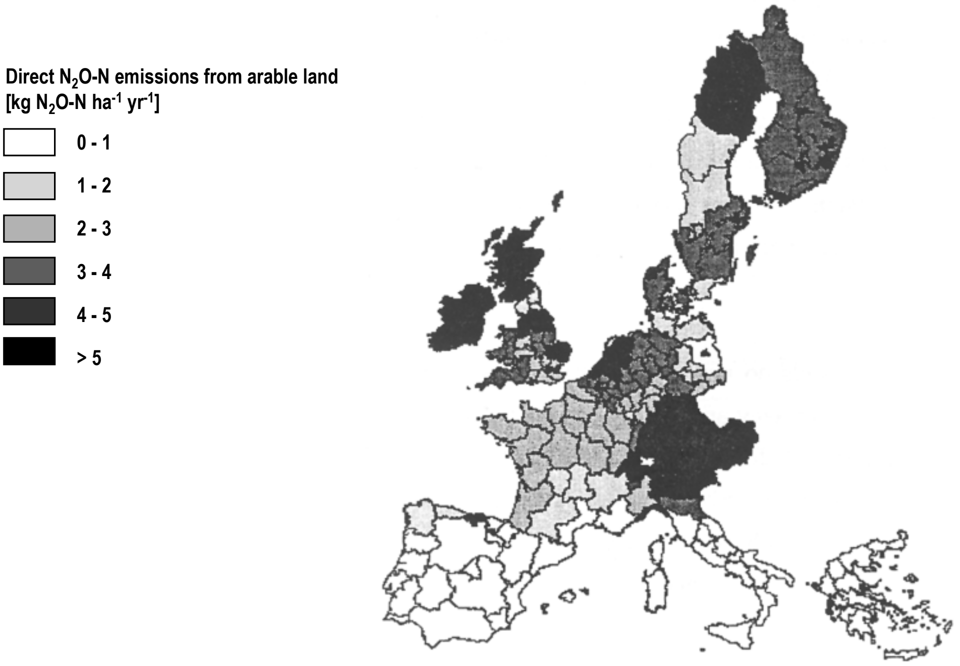
In contrast to the previous chapter (CGH_2 from residual biomass) woody biomass from plantation of poplar or willow is used here. The harvested woody biomass is chipped at the plantation site. Subsequently, the wood chips are transported to the gasification plant by truck (average distance: 50 km).

Besides the N_2O emissions from the production of synthetic nitrogen (N) fertilzer the plantation of crops causes direct N_2O emissions at the field. According to IPCC [IPCC 1/1996], [IPCC 2/1996] all kinds of fertilizers have to be considered for the calculation of the direct emissions of N_2O: the synthetic fertilizer-N as well as N-input by the crop residues and the N-input by N-fixing crops.

The formation and decomposition of N_2O in soils depend on various controlling parameters. The main factors are aeration, water content and availability of N and organic material. Apart from that the amount of N_2O emitted from soils is influenced by their physical characteristics. Measurements lead to the conclusion that there is a strong relationship between the soil texture and the de-nitrification activity. Fine-textured soils (clay soils and silty soils) can maintain a higher water content for a longer time than coarse textured soils (sandy soils). Clay soils have a higher potential for N_2O formation. On the other hand N_2O formed within the soil can also be reduced to N_2 when diffusion is slow due to high water content in fine textured soils. Fine-textured soils seem to emit more N_2O than sandy soils, but this tendency can be masked or reversed by other factors, especially climate and soil management practices.

Other factors which influence the N_2O emissions from soils are freezing and thawing, drying and rewetting [Kamp 2000].

Figure 3-3: Direct N_2O emissions from arable land



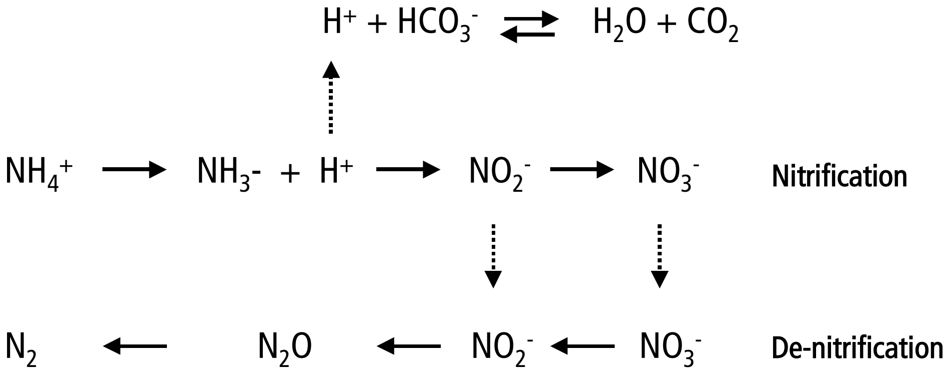
Source: Freibauer, A., Kaltschmitt, Institut für rationelle Energieanwendungen (IER), Stuttgart: Biogenic Greenhouse Gas Emissions from Agriculture in Europe, European Summary Report of the EU Concerted Action FAIR3-CT96-1877, financed by EU DG VI, February 2001

But the direct emissions of N_2O are only one part of the total emissions of N_2O from agricultural land. The indirectly emitted N_2O is also considered here. A part of the fertilizer-N is emitted as NH_3 and NO_x and is leached e.g. as NO_3 which is subsequently deposited on soils and surface waters. Atmospheric deposition of nitrogen compounds such as NO_x and NH_3 fertilizes soils and surface waters and as such enhances the biogenic N_2O formation. In soils and waters bacteria oxidize the NH_4^+ (which is formed from the NH_3 in the soil) to nitrate (NO_3^-) (nitrification) while some amounts of N_2O are formed. The NO_x (consisting of NO and NO_2) emitted from soils is converted to HNO_3 in the atmosphere according to the following reactions:

$$NO + O_3 \rightarrow NO_2 + O_2$$

$$NO_2 + OH + M \rightarrow HNO_3 + M$$

The HNO_3 is then deposited on soil and surface waters by rainfall (“acid rain”). In soils and water the HNO_3 is dissolved into H^+ and NO_3^-. Then the NO_3^- which is also formed by the nitrification of NH_4^+ is partly reduced to N_2O (de-nitrification). The conversion in the soil occurs in several stages according to the following reactions:



The same reactions occur with NO_x emitted by fuel combustion e.g. in truck engines. This source of N_2O is neglected here for the fuel supply processes such as the transport of wood chips. Here only the NO_x from fertilizer use is considered.

In contrast to the direct N_2O emissions only the input of synthetic fertilizer-N and the input of N from manure (N excreted by animals) has to be considered for the calculation of the indirect amount of N_2O (from N leaching and N from NH_3 and NO_x emitted). There are no emissions of NO_x and NH_3 from N of N-fixing crops or from N derived from the use of crop residues here.

The plantation of poplar is more similar to forestry than to agriculture. The behavior of soils in forests might be different to agricultural soils. For the calculation of the hydrogen supply from gasification of woody biomass from poplar plantation the energy requirements have been derived from [GEMIS 2002].

If the biomass yield were assumed to be 10 t of dry matter the amount of N-fertilzer (expressed as kg N) is indicated with 20 to 30 kg per ha and year [Murach 2003]. In [CONCAWE 2006] the fertilizer requirement has assumed to be 25 kg per ha and year. The direct N_2O emissions has been derived from [Flesse 1998] and the indirect N_2O emissions has been calculated according to the guidelines described in [IPCC 1/1996].

Table 3-15: Poplar plantation

	Input	Output
Woody Biomass [kWh/kWh$_{wood}$]	1.0000	1.0000
Mechanical work [kWh/kWh$_{wood}$]	0.0015	-
N fertilizer [kg/kWh$_{wood}$]	0.00049	-
N_2O [g/kWh$_{wood}$]	-	0.0123

The mechanical work is supplied by a diesel engine (efficiency: 30%).

Table 3-16: Energy requirements for the supply of N-fertilzer [Kaltschmitt 1997]

Hard coal	1.097 kWh/kg$_N$
Diesel oil	0.239 kWh/kg$_N$
Electricity (10-20 kV level)	0.174 kWh/kg$_N$
Heavy fuel oil	1.217 kWh/kg$_N$
NG	9.167 kWh/kg$_N$

Table 3-17: Emissions from the supply of N-fertilzer [Kaltschmitt 1997]

CO_2	2468 g/kg$_N$
CH_4	0.45 g/kg$_N$
N_2O	9.63 g/kg$_N$

The electricity requirements are met by the Polish electricity mix (110 kV). For the natural gas and diesel requirement the generic data from [CONCAWE 2006] has been used. The hard coal is extracted in Poland.

3.3.3 Wood chipping

In case of residual woody biomass from forestry the wood is chipped nearby the forest via mobile wood chipper. In case of wood plantation the wood is chipped during harvesting.

Table 3-18: Wood chipping

	Input	Output
Woody Biomass [kWh/kWh$_{wood}$]	1.025	1.000
Diesel [kWh/kWh$_{wood}$]	0.004	-
CO_2 [g/kWh$_{wood}$]	-	1.06

The costs of biomass supply both from residual wood and wood from short rotation forestry without transport has been assumed to be 30 US$ per barrel of oil equivalent leading to about 0.0189 €/kWh of biomass in 2020. In 2030 the biomass costs are assumed to be 35 US$ per barrel oil equivalent leading to about 0.0220 €/kWh of biomass.

3.3.4 Transport of wood chips

The wood chips are transported to the gasification plant via a 40 t truck. The maximum payload ranges between 80 and 100 m^3 and between 22 and 27 t [Kaltschmitt 2001]. A manufacturer of trailers for the transport of biomass indicates a maximum payload of 90 to 92 m^3 [Fahrzeugbau Langendorf 2001]. The water content of the wood chips is assumed to be 30%. The bulk density of wood ranges between 0.24 and 0.33 t/m^3. For the calculation of this pathway a payload of 26 t wood chips has been assumed.

3.3.5 Hydrogen generation

For the gasification an indirectly heated gasifier based on the so-called „staged reforming“ with a biomass input of 10 MW$_{th}$ has been assumed. The data has been derived from DM2 [DM2 2001]. To provide pure hydrogen a CO-shift stage and a PSA plant has been added. The tail gas of the PSA is used for electricity generation via a gas engine.

Table 3-19: Syngas generation via gasification (10 MW$_{th}$) [DM2 2001]

	Input	Output
Wood chips [MW]	10.03	-
Electricity [MW]	0.19	-
Syngas [MW]	-	7.67
Heat [MW]	-	0.50
CH_4 [g/kWh$_{syngas}$]	-	0.028
N_2O [g/kWh$_{syngas}$]	-	0.008

The investment for the gasifier is indicated with about 6,490,000 €. After 500 installed units the investment will be about 3,500,000 €. The average investment of the 500 units is 3,900,000 €. The 3,900,000 € have been used as average investment in 2030.

The lifetime is assumed to be 20 years. The maintenance is about 3% of the investment per year. The labor costs amount to about 179,000 € per year.

The gasifier is operated at about 0.1 MPa (ambient pressure). After dust removal the syngas (a mixture of H_2, CO, CO_2 and small amounts of CH_4) is compressed to about 2 MPa before it is fed into the CO shift stage.

Table 3-20: Syngas compression and CO shift

	Input	Output
Syngas [kWh/kWh$_{H2}$]	1.036	-
Electricity [kWh/kWh$_{H2}$]	0.072	-
H_2 [kWh/kWh$_{H2}$]	-	1.000

The investment for the CO shift including syngas compression is indicated with about 1,453,000 €. The lifetime is assumed to be 20 years.

The gas at the outlet of the CO shift stage consists of H_2, CO_2 and small amounts of CH_4 and non-reacted CO. The generation of pure hydrogen is carried out via pressure swing adsorption (PSA).

Table 3-21: Pressure Swing Adsorption (PSA)

	Input	**Output**
H_2 (diluted) [kWh/kWh$_{H2}$]	1.424	-
H_2 (pure) [kWh/kWh$_{H2}$]	-	1.000
Tail gas (syngas) [kWh/kWh$_{H2}$]	-	0.424

The investment for the PSA is about 445,000 € [QuestAir 2003]. The lifetime is assumed to be 20 years.

The tail gas is fed into a gas engine for heat and electricity generation (efficiency electricity generation: 34%). The hydrogen recovery rate of the pressure swing adsorption plant depends on the composition of the feed gas and the pressure. The pressure drop of the PSA is below 0.1 MPa. Furthermore, the larger the specific volume of adsorbent (volume per Nm^3 of hydrogen throughput) the larger is the hydrogen recovery rate, and the higher is the investment.

Table 3-22: Gas engine [GEMIS 2002], [Jenbacher 2002]

Capacity [kW_e]	588
Tailgas (syngas) input [kWh/kWh_e]	2.941
Heat output [kWh/kWh_e]	1.500
Investment [€]	588,000
Maintenance [% of investment]	10
Equivalent full load period [h/yr]	7,500
Useful lifetime [yr]	20

For the calculation of the credit for heat export the technical data of an existing wood chips fueled heating plant have been used. The plant is located in Hesse, Germany.

Table 3-23: Biomass fueled heating plant for credit calculation [GEMIS 2002]

	Input	**Output**
Wood chips [MW_{heat}]	2.059	-
Electricity [MW_e]	0.035	-
Heat [MW_{th}]	-	1.750

The pressure at the outlet of the PSA is about 2 MPa. The hydrogen is transported to the CGH_2 filling stations via a H_2 pipeline (distance: 5 km, throughput: 8 GWh/yr). The pressure drop during the pipeline transport can be neglected.

Figure 3-4: CGH_2 from gasification of residual wood

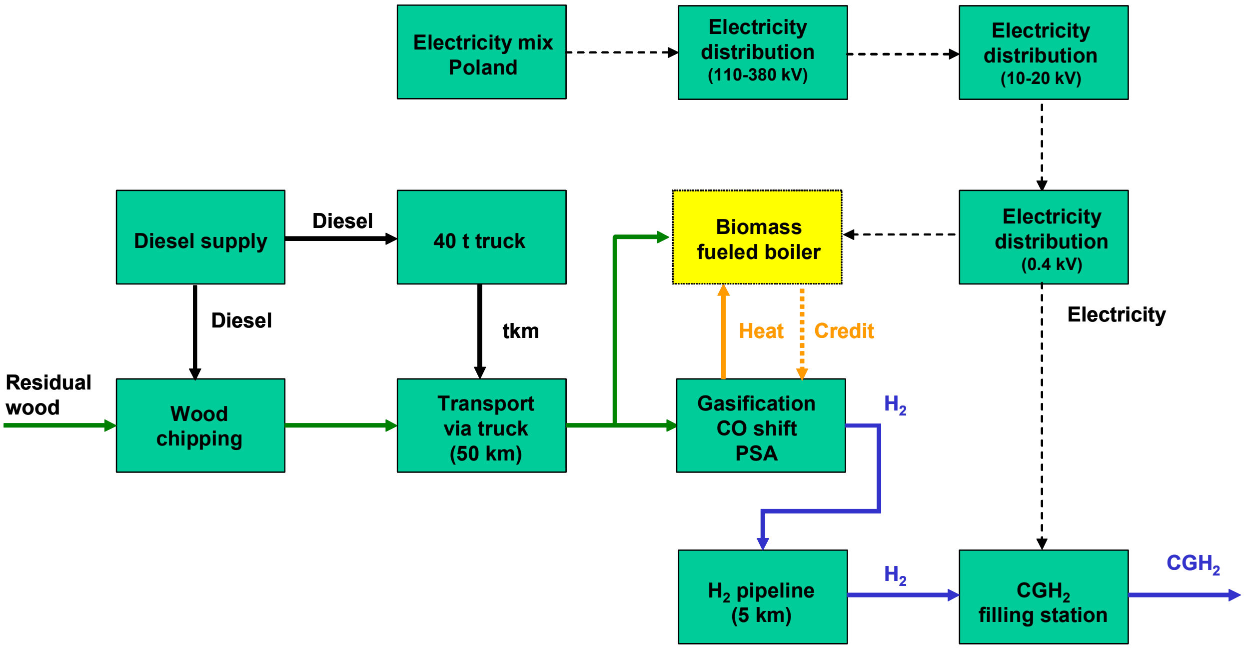
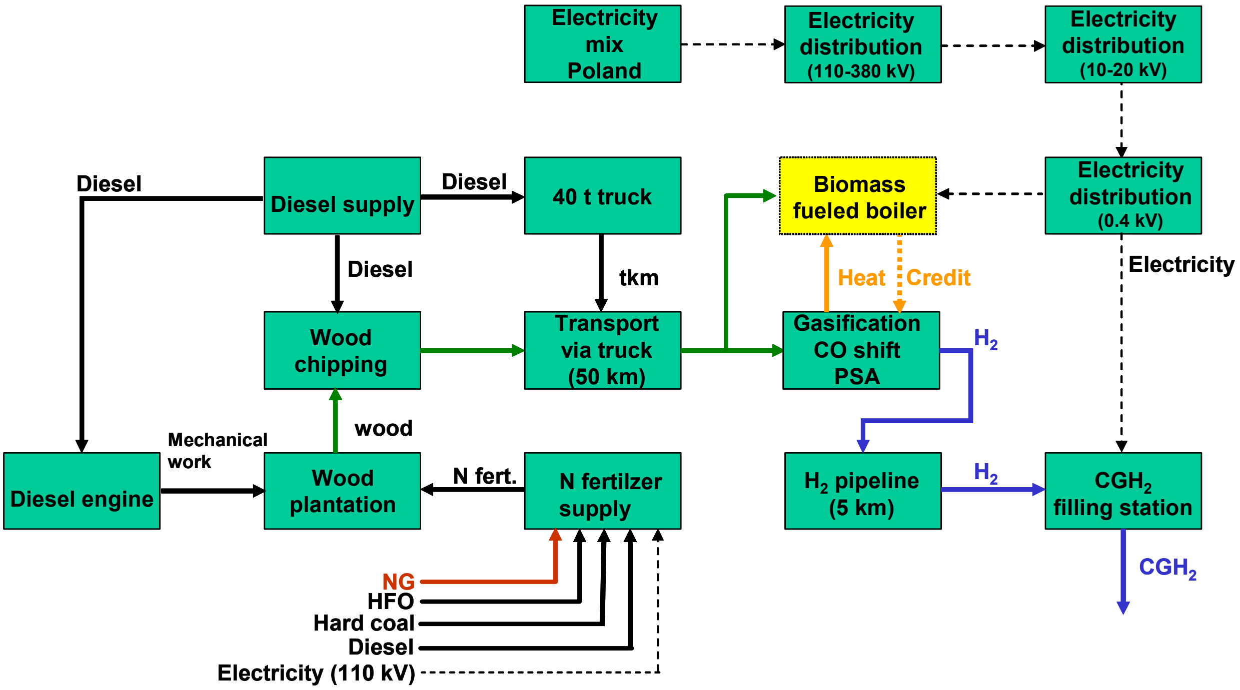


Figure 3-5: CGH_2 from gasification of wood chips from wood plantation



3.4 Chain 3: CGH_2 from biogas via SMR

Organic waste (e.g. from households, catering etc.) is fermentated to generate biogas. The heat and electricity demand of the fermenter is met by a biogas fueled CHP plant based on a gas engine. The fermentation stage include the desulphurization of the crude biogas. The desulphurized biogas mainly consists of CH_4 (60-70%) and CO_2 (30-40%).

Table 3-24: Fermentation of organic waste [GEMIS 2002], [VW 1998]

	1998	2020	2030
Capacity [kW biogas]	2031	2031	2031
Heat input [kWh/kWh$_{biogas}$]	0.154	0.154	0.154
Electricity consumption [kWh/kWh$_{biogas}$]	0.031	0.031	0.031
CH_4 emissions [g/kWh$_{CH4}$]	0.72	0.72	0.72
Investment [€]	2,560,000	1,400,000 (1)	1,360,000 (2)
Maintenance coefficient [% of investment]	7.4	7.4	7.4
Useful lifetime [yr]	20	20	20
Equivalent full load period [h/yr]	6,500	6,500	6,500

(1) average investment per unit when 10,000 units are installed; (2) average investment per unit when 15,000 units are installed

The residue of the biogas plant can be used as fertilizer. Therefore a credit for saved fertilzer has been taken into account. In case of organic municipal waste the fertilzer credit is 0.54 g/MJ of biogas [Boisen 2005]. The heat is supplied with a biogas fueled combined heat and power (CHP) plant.

The CO_2 is removed via a scrubbing process using pressurized water to achieve a CH_4 content of more than 96%.

Table 3-25: CH_4 extraction via scrubbing with pressurized water [Eco Naturgas 2004], [Schulz 2004]

	2004	2020	2030
Capacity [kW CH_4]	1,500	1,500	1,500
Biogas input [kWh/kWh$_{CH4}$]	1.01	1.01	1.01
Electricity consumption [kWh/kWh$_{CH4}$]	0.03	0.03	0.03
CH_4 emissions [g/kWh$_{CH4}$]	0.72	0.72	0.72
Investment [€]	779,000	344,000 (1)	331,000 (2)
Maintenance coefficient [% of investment]	1.7	1.7	1.7
Labor costs [€/yr]	7,300	7,300	7,300
Useful lifetime [yr]	20	20	20
Equivalent full load period [h/yr]	6,500	6,500	6,500

(1) average investment per unit when 10,000 units are installed; (2) average investment per unit when 15,000 units are installed

The pressure of the CH_4 at the outlet of the pressurized water scrubbing is about 0.9 MPa. The CH_4 is fed into a steam methane reforming (SMR) plant. Since the SMR needs a CH_4 pressure of 1.6 MPa compression is required. The electricity consumption for the compression of CH_4 from 0.9 MPa to 1.6 MPa is 0.0027 kWh per kWh of CH_4. The investment for the compressor is assumed to be 26,000 €. The CH4 is fed into the NG pipeline grid and transported to the filling station with onsite SMR.

The same SMR as for the onsite steam reforming of natural gas and the same filling station has been used. There are no CO_2 emissions because the methane is derived from biomass and therefore CO_2 neutral.

Table 3-26: Onsite SMR for the 120 t/yr filling station [Haldor Topsoe 1998], [HyGear 2006]

	1998	2020	2030
Capacity [Nm^3 H_2/h]	222	222	222
Pressure (H_2) [MPa]	1.5	1.5	1.5
CH_4 consumption [kWh/kWh_{H2}]	1.441	1.441	1.441
Electricity consumption [kWh/kWh_{H2}]	0.016	0.016	0.016
CH_4 emissions [g/kWh_{H2}]	0.075	0.075	0.075
Investment [€]	850,000	376,000 1)	339,000 2)
Maintenance coefficient [% of investment]	1.0	1.0	1.0
Useful lifetime [yr]	15	15	15
Equivalent full load period [h/yr]	6,000	6,000	6,000

1) average investment per unit when 10,000 units are installed; 2) average investment per unit when 28,000 units are installed

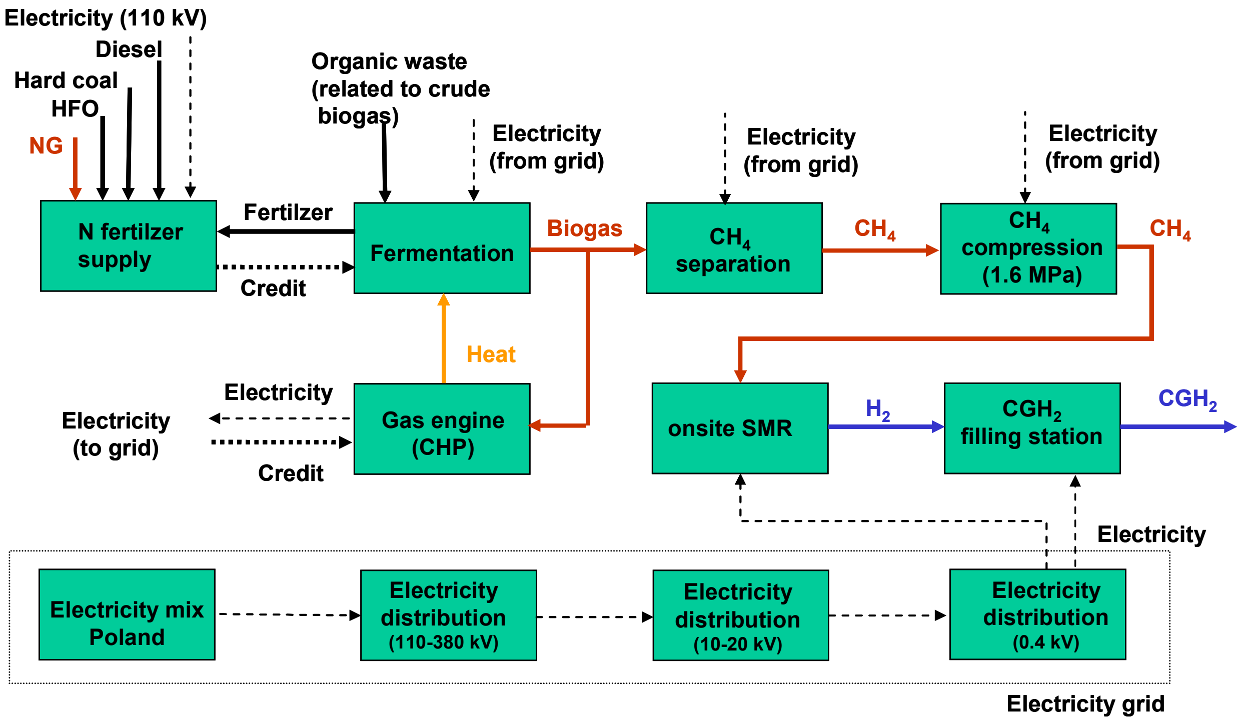
Table 3-27: Technical and economic data for the CGH_2 filling station (suction pressure: 1.5 MPa)

	2004	2020	2030
Annual fuel output [t H_2/yr]	120	120	120
Electricity consumption [kWh/kWh_{H2}]	0.077	0.077	0.077
Investment [€]	591,000	273,000 1)	249,000 2)
Maintenance [% of investment]	3.9	4.7	4.8
Useful lifetime [yr]	20	20	20

1) average investment per unit when 10,000 units are installed; 2) average investment per unit when 28,000 units are installed

Analogous to the pathway for the supply of CGH_2 from NG from onsite hydrogen generation (see chapter 3.2) for time horizon 2030 also larger filling stations have been installed. Figure 3-6 shows the supply of CGH_2 from biogas via onsite SMR. Therefore the cumulative number of the reformer is assumed to be the same as in case of natural gas.

Figure 3-6: CGH_2 from biogas via onsite SMR



The heat output of the CHP is adapted to the heat requirement of the fermenter. The electricity is fed into the electricity grid. The fermenter, CH4 separation, CH4 compression, onsite SMR and the filling station consume electricity which is derived from the electricity grid. The electricity for the electricity grid has been derived from the Polish electricity mix.

3.5 Chain 4: CGH_2 via onsite electrolysis from offshore wind power

In this pathway hydrogen is generated via electrolysis onsite the filling station using electricity from offshore installed wind power.

3.5.1 Electricity generation, transport and distribution

An offshore wind installation typically consists of 100 to 1,000 single wind turbines. The water depth can be up to 40 m.

The investment of the offshore wind power installation in Middelgrunden in Denmark which has a total capacity of 40 MW and which is already in operation has been indicated with 49,000,000 € leading to 1,250 €/kW. But the wind turbines are rather close to the cost (2-3 km) and as a result the water depth in Middelgrunden is low (2-6 m). The investment of the offshore wind power installation at Horns Rev (160 MW; water depth: 6.5-13.5 m; distance from coast: more than 17 km) is indicated with about 280 million € or about 1,700 €/kW including grid connection [Renewable Energy World 2002]. Table 3-28 shows the technical and economic data of existing offshore wind farms.

Table 3-28: Technical and economic data of existing offshore wind farms

	Unit	Blyth	Middlegrunden	Horns Rev	Kentish Flats	Scroby sands
Country		UK	Denmark	Denmark	UK	UK
Location		North Sea	Baltic Sea	North Sea	North Sea	North Sea
Capacity per unit	MW	2	2	2	3	2
Number of wind converters		2	20	80	30	30
Capacity	MW	4	40	160	90	60
Distance from coast up to	km		2	20	10	2.5
Water depth up to	m		5	14	5	12
In operation since year		2000	2001	2002	2005	2005
Electricity generation	GWh/yr	10.5	89	600	285	
Equivalent full load period	h/yr	2625	2225	3750	3167	
Investment	G€	6	49	270	158	113
Specific investment	EUR/kW	1500	1225	1688	1750	1875

According to the Department of Trade and Industry in UK the investment can be expected to be about 1,200 € per kW of installed capacity in 2010. In [NREL 2004] the investment for offshore wind power is expected to be about 800 €/kW. For wind farms not close to the coast an investment of 1200 €/kW for 2010 seems to be too low.

As a rough estimate it has been assumed that the investment for large offshore wind power installations at a water depth of 30 m is assumed to be 1,200 €/kW in 2020 and about 800 €/kW in 2030.

Table 3-29: Technical and economic data for offshore wind power

	2020	2030
Capacity per wind turbine [MW]	4.5	4.5
Water depth [m]	30	30
Investment [€]	5,400,000 1)	3,600,000 1)
Maintenance [% of investment]	4	4
Useful lifetime [yr]	25	25
Equivalent full load period [h/yr]	3,000	3,000

1) incl. additional costs (foundation, grid connection etc.)

The electricity generated by wind power has to be transported to the filling station via the electricity grid. It has been assumed that the filling stations are connected with the 10 to 20 kV grid.

Table 3-30: Technical and economic data for the transport of electricity to the filling stations (110-380 kV) [RWE 1999]

	Efficiency distribution [%]	[€/kWh$_e$]
Distribution (110-380 kV)	99.0	0.004
Distribution (10-20 kV)	99.3	0.020
Total	98.3	0.024

3.5.2 Hydrogen generation and dispensing

For the small filling station (120 t H_2/yr) two 120 Nm^3/h electrolyzer units are used. For the larger filling station (480 t H_2/yt) one 800 Nm^3/h electrolyzer is used.

Table 3-31: Technical and economic data for the electrolyzer used for onsite hydrogen generation for the 120 t/yr CGH_2 filling station [Stuart Energy 2004]

	2004	2020	2030
Capacity [Nm^3 H_2/h]	120	120	120
Electricity consumption [kWh/kWh_{H2}]	1.600	1.600	1.600
Pressure [MPa]	2.6	2.6	2.6
Investment [€]	614,500	271,800 (1)	228,800 (2)
Maintenance [% of investment]	0.9	0.9	0.9
Useful lifetime [yr]	20	20	20
Equivalent full load period [h/yr]	6,000	6,000	6,000

(1) average investment per unit when 10,000 units are installed; (2) average investment per unit when 56,000 units are installed (28,000 small fillings stations, 2 electrolyzer units per 120 t/yr filling station)

Table 3-32: Technical and economic data for the 120 t/yr CGH_2 filling station (suction pressure: 2.6 MPa)

	2004	2020	2030
Annual fuel output [t H_2/yr]	120	120	120
Electricity consumption [kWh/kWh_{H2}]	0.065	0.065	0.065
Investment [€]	496,000	231,000 (1)	211,000 (2)
Maintenance [% of investment]	2.7	3.7	3.9
Useful lifetime [yr]	20	20	20

(1) average investment per unit when 10,000 units are installed; (2) average investment per unit when 28,000 units are installed

It has been assumed that in 2020 only small filling stations have been installed. In 2030 in the EU the cumulative number both of small and large filling stations is 28,000.

Table 3-33: Technical and economic data for the electrolyzer used for onsite hydrogen generation for the 480 t/yr CGH_2 filling station [Stuart Energy 2004]

	2004	2030
Capacity [Nm^3 H_2/h]	800	800
Electricity consumption [kWh/kWh_{H2}]	1.433	1.433
Pressure [MPa]	3.0	3.0
Investment [€]	2,200,000	878,000 [1)]
Maintenance [% of investment]	0.9	0.9
Useful lifetime [yr]	20	20
Equivalent full load period [h/yr]	6,000	6,000

[1)] average investment per unit when 28,000 units are installed

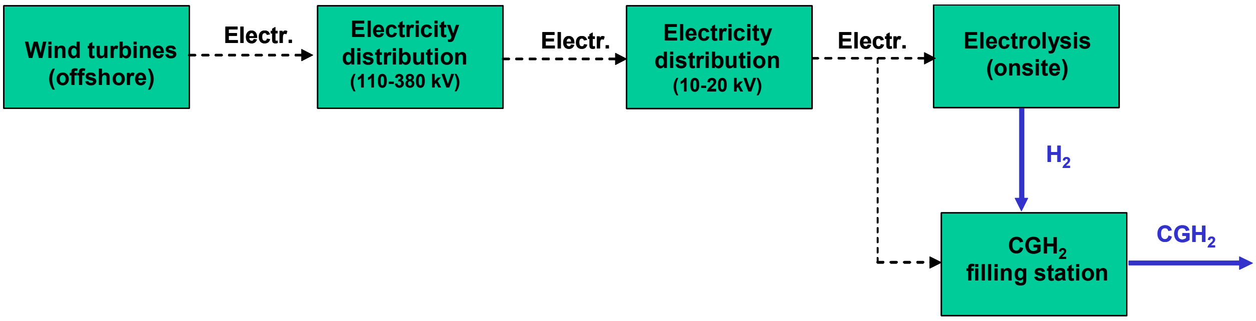
Table 3-34: Technical and economic data for the 480 t/yr CGH_2 filling station (suction pressure: 3.0 MPa)

	2004	2030
Annual fuel output [t H_2/yr]	480	480
Electricity consumption [kWh/kWh_{H2}]	0.062	0.062
Investment [€]	2,272,000	955,000 [1)]
Maintenance [% of investment]	3.6	4.6
Useful lifetime [yr]	20	20

[1)] average investment per unit when 28,000 units are installed

In contrast to the small filling station the larger filling station has a separate primary compressor. Therefore the investment of the larger filling station is more than 4 times of that of the smaller one. For the smaller filling station it has been assumed that the booster compressor also is used for the recharging of the stationary hydrogen storage. This layout is possible if the number of cars to be refueled is low e.g. at the introduction phase.

Figure 3-7: CGH_2 via onsite electrolysis from offshore wind power



3.6 Chain 5: CGH_2 via onsite electrolysis from onshore wind power

In this pathway hydrogen is generated via electrolysis onsite the filling station using electricity from onshore installed wind power.

3.6.1 Electricity generation, transport and distribution

The cost data of the wind turbine for 2004 has been derived from an Enercon model E-66 / 20.70. The investment in Table 3-29 includes the additional investment which has been assumed to be 28% of the investment for the wind turbine alone. The investment for the Enercon wind turbine with a tower height of 84 m is indicated with 1,785,000 € [Windenergie 2004].

For 2020 a learning curve has been assumed based on the EWEA target for the installed capacity in 2020 in the EU (180 GW). In 2004 about 30 GW already has been installed in the EU 25. The progress ratio for wind power installations is indicated with 0.80 to 0.85. For the calculation a progress ratio of 0.85 has been assumed until 2020 and a progress ratio of 0.90 has been assumed between 2020 and 2030. The cumulative installed capacity in 2020 in the EU has been assumed to be 180 GW in 2020 and 300 GW in 2030.

Table 3-35: Technical and economic data of the wind turbine (onshore) installed in Poland [Windenergie 2004]

	2004	2020	2030
Capacity [MW]	2	2	2
Investment [€]	2,284,800 (1)	1,501,062 (1)	1,400,000 (1)
Maintenance [% of investment]	1.5	1.5	1.5
Overhead [% of investment]	3.5	3.5	3.5
Useful lifetime [yr]	25	25	25
Equivalent full load period [h/yr]	1,800	1,800	1,800

(1) incl. additional costs (foundation, grid connection etc.)

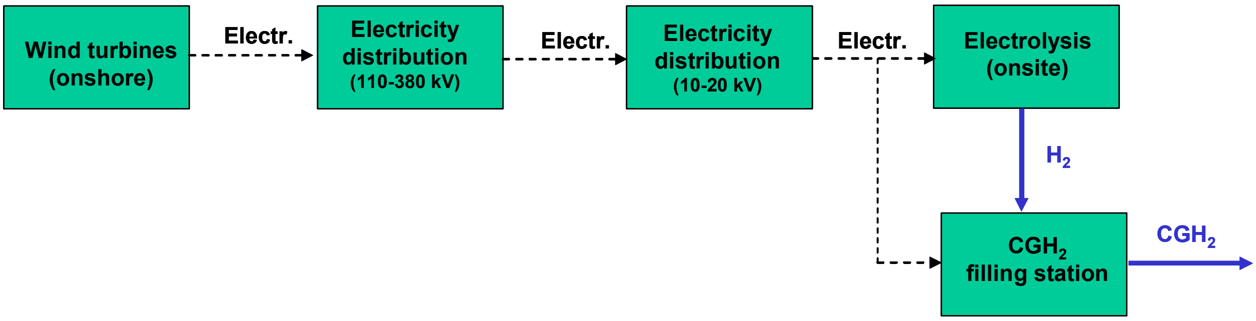
It has to be noted that the latest models of wind turbines have a higher equivalent full load period than the previous ones because of better aerodynamic and higher towers.

The transport and distribution of the electricity is carried out in the same way as in case of offshore wind power (chapter 3.5).

3.6.2 Hydrogen generation and dispensing

See chapter 3.5.

Figure 3-8: CGH$_2$ via onsite electrolysis from onshore wind power



3.7 Chain 6: CGH$_2$ via onsite electrolysis from nuclear electricity

In this pathway hydrogen is generated via electrolysis onsite the filling station using nuclear electricity.

3.7.1 Electricity generation, transport and distribution

The uranium is extracted via surface mining and transported to the EU via ship. In the EU the uranium is converted to UF_6 and enriched to the required uranium content via centrifuges. Downstream the enrichment the UF_6 converted to U_3O_8 which is used for the production of fuel rods (nuclear fuel).

Table 3-36: Uranium extraction via surface mining [GEMIS 2005]

	Input	Output
Mechanical work [kWh/kWh]	0.000023	-
Nuclear energy (uranium ore) [kWh/kWh]	1.00	-
Nuclear energy (uranium) [kWh]	-	1.00

The mechanical work is supplied by a large diesel engine with an efficiency of 36%.

The uranium costs has been assumed to be 68.2 US$/kg. The 68.2 US$/kg are related to non-enriched uranium. The burn-up rate is about 42,000 MWd/t of enriched uranium [GEMIS 2005]. About 8.11 kg non-enriched uranium is required to obtain 1 kg of enriched uranium. If the exchange rate were assumed to be 1 €/US$ the costs of enriched uranium would be about 0.00055 €/kWh in 2020 without the costs of processing (e.g. the capital, labor and maintenance costs of the enrichment plant). In 2030 the price of non-enriched uranium is expected to be 95.0 US$/kg leading to about 0.00076 €/kWh without the costs of processing.

Table 3-37: UF_6 production [GEMIS 2005]

	Input	Output
Electricity [kWh/kWh]	0.000007	-
Nuclear energy (uranium) [kWh/kWh]	1.11	-
Nuclear energy (UF_6) [kWh]	-	1.00

Table 3-38: Uranium enrichment (centrifuge) [GEMIS 2005]

	Input	Output
Electricity [kWh/kWh]	0.00135	-
Nuclear energy (uranium) [kWh/kWh]	1.000	-
Nuclear energy (enriched uranium) [kWh]	-	1.000

Table 3-39: Production of fuel rods (nuclear fuel) [GEMIS 2005]

	Input	Output
Electricity [kWh/kWh]	0.001	-
Nuclear energy (uranium) [kWh/kWh]	1.053	-
Nuclear energy (fuel rods) [kWh]	-	1.00

The costs for the conversion of uranium to UF6 without the uranium itself amount to about 85 US$/kg of enriched uranium. The costs for the enrichment is about 586 US$/kg of enriched uranium and the costs of the production of nuclear fuel is about 240 US$/kg of enriched uranium without the costs for uranium itself.

The technical and economic data of the nuclear power station have been derived from [GEMIS 2005]. The nuclear power station is based on the European Pressurized Water Reactor (EPR).

Table 3-40: Technical and economic data of a nuclear power plant based on the EPR [Gemis 2005]

Capacity [MW_e]	1,450
Consumption of nuclear fuel [kWh/kWh_e]	2.941
Investment [€]	2,682,500,000
Maintenance coefficient [% of investment]	4.3
Useful lifetime [yr]	30
Equivalent full load period [h/yr]	6,500

The transport and distribution of the electricity is carried out in the same way as in case of offshore wind power (chapter 3.5).

3.7.2 Hydrogen generation and dispensing

See chapter 3.5.

3.8 Chain 7: CGH_2 from high temperature nuclear heat via thermo chemical cycle

The uranium is extracted via surface mining and transported to the EU via ship. In the EU the uranium is converted to UF_6 and enriched to the required uranium content via centrifuges. Downstream the enrichment the UF_6 converted to U_3O_8 which is used for the production of fuel rods (nuclear fuel).

The nuclear fuel is used for the production of high temperature nuclear heat. The heat is used to drive a thermo chemical cycle. A sulfur-iodine cycle has been used for the generation of hydrogen in this pathway. The following reactions are required:

Reaction 1	$H_2SO4 => H_2O + SO_2 + 0.5\ O_2$
Reaction 2	$SO_2 + 2\ H_2O + I_2 => H_2SO_4 + 2\ HI$
Reaction 3	$2\ HI => I_2 + H_2$
Net reaction	$H_2O => H_2 + 0.5\ O_2$

Similar to the hybrid sulfur cycle the high temperature heat (~850°C) is required for reaction 1 [Le Duigou 2005].

For the sulfur-iodine cycle large amounts of water and iodine are necessary to obtain the two immiscible acid phases (H_2SO_4 and HI) in the Bunsen reaction (reaction 2). The two acid phases are subsequently mechanically separated. Thus, the concentration by distillation of the two acids H_2SO_4 and HI involves a high energy consumption which has a direct influence of the efficiency of the cycle. [Le Duigou 2005].

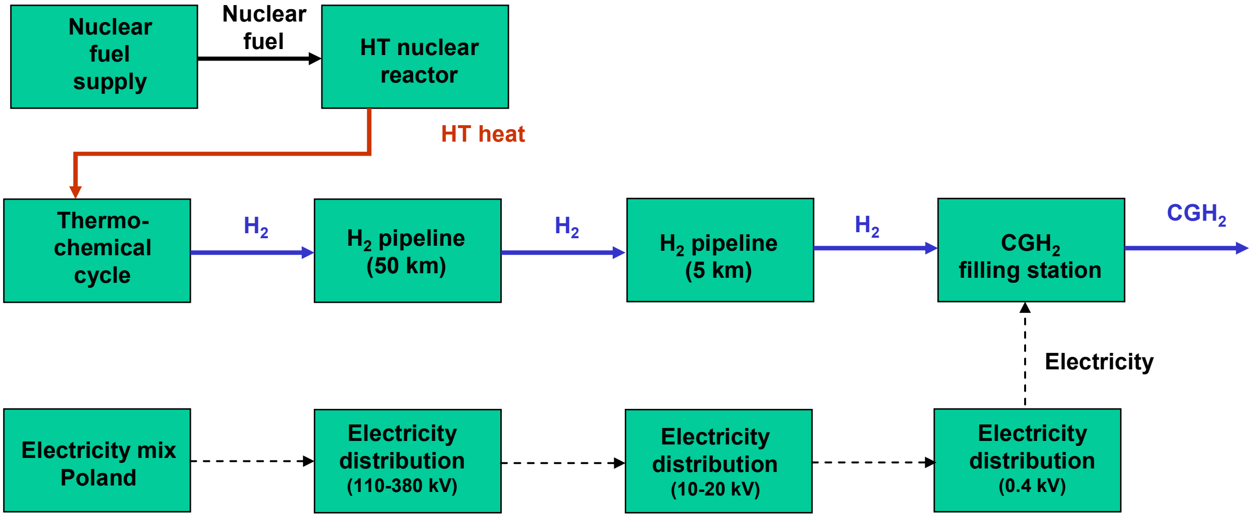
The overall efficiency related to the heat released by nuclear fission ranges between 42 and 52% related to the higher heating value (HHV) of the hydrogen. Related to the lower heating value the efficiency ranges between 36 and 44% (average: 40%).

Table 3-41: Technical and economic data of hydrogen generation from nuclear heat via thermo chemical cycle [SRNL 2005]

Capacity [Nm^3 H_2/h]	318,000
Consumption of nuclear fuel [kWh/kWh_{H2}]	2.515
Investment [€]	1,969,100,000
Maintenance coefficient [% of investment]	5
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	8,000

The hydrogen is distributed via a hydrogen pipeline grid. For the hydrogen pipeline grid and for the filling stations the same assumptions as for the central steam reformer with CCS has been made (see chapter 3.1).

Figure 3-9: CGH_2 from high temperature nuclear heat via thermo chemical cycle



3.9 Chain 8: CGH_2 from hard coal via gasification

In this pathway hydrogen is generated via large scale gasification of hard coal with CO_2 capture and sequestration. The hard coal is derived from Polish coal mines. The plant is located nearby empty natural gas field where the CO_2 is stored.

Table 3-42: Extraction of hard coal via deep mining in Poland [GEMIS 2005]

	Input	Output
Electricity [kWh/kWh]	0.0114	-
Hard coal [kWh/kWh]	1.00	1.00
CH_4 emissions [g/kWh]		0.727

The electricity is supplied by a hard coal fueled steam turbine power plant with an average efficiency over the lifetime of 43.5%.

Table 3-43: Technical and economic data of a hard coal fueld steam turbine power plant

Capacity [MW_e]	600
Hard coal consumption [kWh/kWh_e]	2.299
CO_2 emissions [g/kWh_e]	795
CH_4 emissions [g/kWh_e]	0.015
N_2O emissions [g/kWh_e]	0.041
Investment [€]	631,000,000
Maintenance coefficient [% of investment]	2.8
Labor [€/yr]	11,000,000
Useful lifetime [yr]	35
Equivalent full load period [h/yr]	4,500

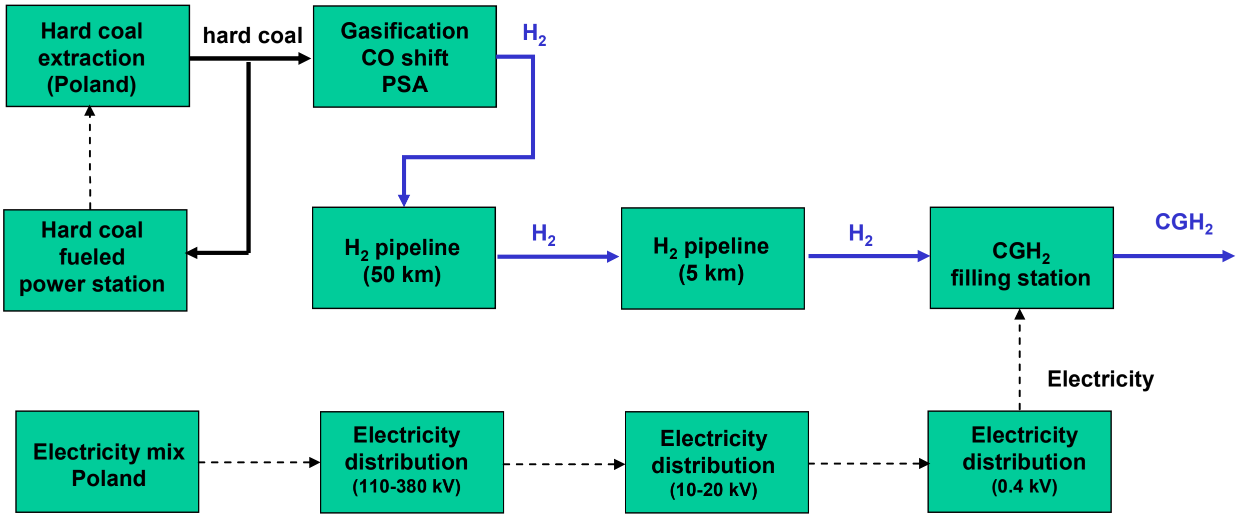
The hard coal price is assumed to be 0.0091 €/kWh of coal (14.5 US$ per barrel of oil equivalent) for 2020 and 0.0106 €/kWh of coal (16.9 US$ per barrel of oil equivalent) for 2030.

Table 3-44: Technical and economic data of hydrogen generation via coal gasification with CO_2 capture and storage [Foster Wheeler 1996]

Capacity [Nm^3 H_2/h]	281,600
Hard coal consumption [kWh/kWh_{H2}]	2.303
CO_2 emissions [g/kWh_{H2}]	20.3
Investment [€]	1,168,100,000
Maintenance coefficient [% of investment]	3.57
Labor [€/yr]	1090,000
Overhead [% of investment]	0.07
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	7,884

For the supply of CGH_2 the hydrogen is distributed via a hydrogen pipeline grid. At the CGH_2 filling station the hydrogen pressure is 2.0 MPa (see chapter 3.1).

Figure 3-10: CGH_2 from hard coal gasification with CO_2 capture and storage



3.10 Chain 9a): CGH_2 from gasification of lignite with CCS

In this pathway hydrogen is generated by gasification of lignite with CO_2 capture and storage. The technical and economic data for the gasification have been derived from a plant for the gasification of hard coal as described in [Foster Wheeler 1996]. The plant is located nearby empty natural gas fields. There are natural gas fields in the south east and the west of Poland (which could be used for CO_2 storage after depletion).

Table 3-45: Extraction of lignite via surface mining in Poland [GEMIS 2005]

	Input	Output
Electricity [kWh/kWh]	0.0073	-
Lignite [kWh/kWh]	1.00	1.00
CH_4 emissions [g/kWh]		0.005

The electricity is supplied by a newly built lignite fueled steam turbine power plant with an average efficiency over the lifetime of 44.5%.

Table 3-46: Technical and economic data of a lignite fueled steam turbine power plant [DLR 1999]

Capacity [MW_e]	800
Lignite consumption [kWh/kWh_e]	2.247
CO_2 emissions [g/kWh_e]	919
CH_4 emissions [g/kWh_e]	0.008
Investment [€]	1,079,000,000
Maintenance coefficient [% of investment]	3.3
Labor [€/yr]	13,000,000
Useful lifetime [yr]	35
Equivalent full load period [h/yr]	7,000

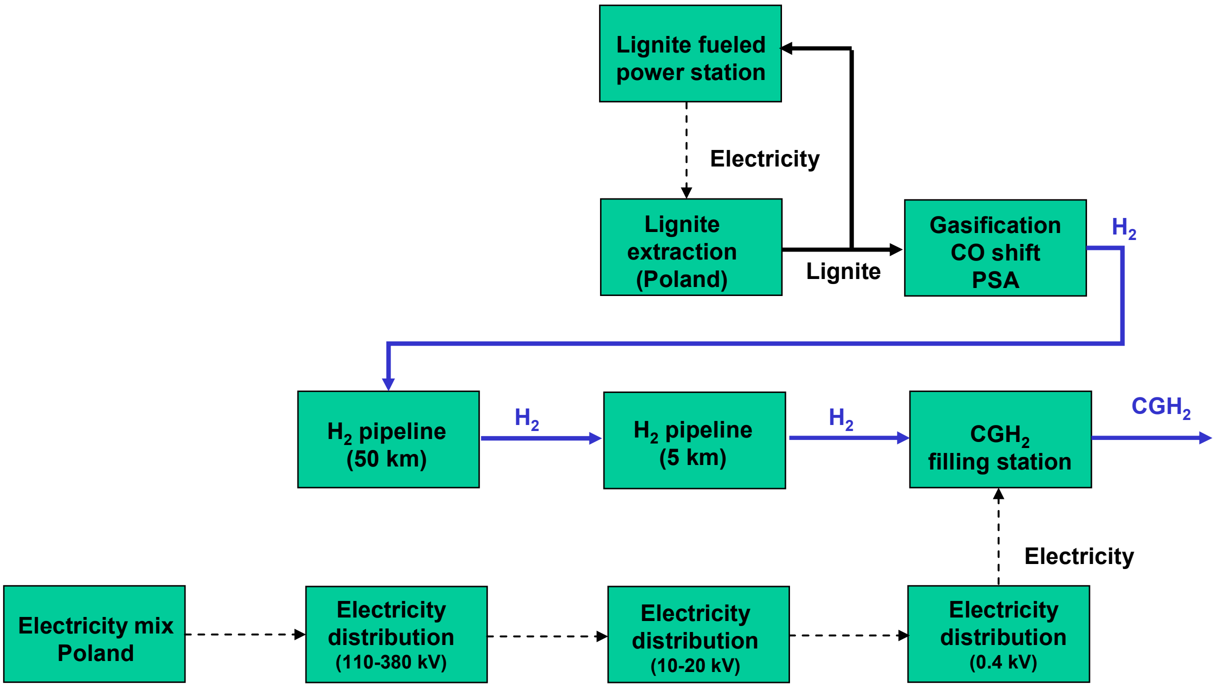
The data for lignite extraction in [GEMIS 2005] are derived from lignite mines in Poland. The lignite costs are indicated with 0.0044 € per kWh of lignite (7 US$ per barrel of oil equivalent).

Table 3-47: Technical and economic data of hydrogen generation via lignite gasification with CO_2 capture and storage

Capacity [Nm^3 H_2/h]	281,600
Lignite consumption [kWh/kWh_{H2}]	2.303
CO_2 emissions [g/kWh_{H2}]	20.3
Investment [€]	1,168,100,000
Maintenance coefficient [% of investment]	3.57
Labor [€/yr]	1090,000
Overhead [% of investment]	0.07
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	7,884

For the supply of CGH_2 the hydrogen is distributed via a hydrogen pipeline grid. At the CGH_2 filling station the hydrogen pressure is 2.0 MPa.

Figure 3-11: CGH_2 from lignite gasification with CO_2 capture and storage



3.11 Chain 9b) LH_2 from lignite gasification with CCS

For the supply of LH_2 the hydrogen is liquefied in a large hydrogen liquefaction plant (electricity consumption: 0.3 kWh per kWh of LH_2). The electricity for the hydrogen liquefaction is derived from the German electricity mix in 2020 (110-380 kV). Then the

LH_2 is distributed via truck (average distance: 150 km) and dispensed at a LH_2 filling station.

Table 3-48: H_2 liquefaction in 2020 [NHEG 1992], [TotalFinaElf 2002], [Linde 2004]

Capacity [MW_{LH2}]	300
H_2 consumption [kWh/kWh_{LH2}]	1.0
Electricity consumption [kWh/kWh_{LH2}]	0.3
Investment [€]	239,000,000
Maintenance [% of investment]	2.5
Labor [€/yr]	1,230,000
Equivalent full load period [h/yr]	8,000
Useful lifetime [yr]	30

The electricity requirements for the hydrogen liquefaction is met by a hard coal fueled integrated gasification combined cycle (IGCC) gas turbine power plant with CO_2 capture and storage (CCS) (Table 3-49).

Table 3-49: Lignite fueled integrated Gasification combined cycle (IGCC) gas turbine power plant with CO_2 capture and storage (CCS) [ENEA 2004]

Fuel	Hard coal
Capacity [MW_e]	600
Efficiency [%]	41
Investment [€]	1,110,000,000
Maintenance [% of investment]	2.5
Equivalent full load period [h/yr]	7,000
Useful lifetime [yr]	25
CO_2 emissions [g/kWh_e]	84

The LH_2 has been distributed via truck (average distance: 300 km). The transport capacity of the LH_2 trailer is 3.5 t LH_2. Including the LH_2 tank the payload is about 27 t and the gross weight is 40 t. The fuel consumption of the 40 t truck is about 3.5 kWh/km or 35 l diesel per 100 km.

The energy requirement and the GHG emissions for the supply of the diesel has been derived from [CONCAWE 2006]. The energy requirements for diesel supply are about 1.16 kWh per kWh of diesel. The GHG emissions amount to about 51.5 g/kWh of diesel.

In [Linde 2001] a scenario for the installation of 343 hydrogen filling stations at Germany motorways has been investigated. One variant was a filling station which is capable to refuel CGH_2 and LH_2 vehicles. The filling station in [Linde 2001] has two dispensers, one for LH_2 and one for CGH_2. For HyWays the technical and economic data for the LH_2 part has been used to calculate the investment for a LH_2 filling station with one dispenser and a fuel output of 115 t LH_2 per year.

For the stationary LH_2 storage at the filling station the half of the investment of the LH_2 storage of the combined LH_2/$LCGH_2$ filling station (270,000 € for 343 filling stations) has been used. The LH_2 filling station consists of a LH_2 tank (135,000 €), a LH_2 pump (51,000 €) and a LH_2 dispenser (37,000 €). Further other investment e.g. for installation, engineering etc. has been added (50,000 €). As a result the total investment for the LH_2 part is 273,000 € for the case when 343 filling stations would be installed. Then a learning curve has been applied to trace back the investment from the 343 filling stations to the 1st filling station and to calculate the average investment for the LH_2 filling stations for 10,000 installed units in 2020 and 28,000 in 2030. The result is shown in Table 3-50.

Table 3-50: Technical and economic data for the 115 t/yr LH_2 filling station [Linde 2001]

	2004	2020	2030
Annual fuel output [t H_2/yr]	115	115	115
Electricity consumption [kWh/kWh_{H2}]	0.0007	0.0007	0.0007
Investment [€]	440,700	194,900 1)	175,900 2)
Maintenance [% of investment]	2.0	2.0	2.0
Useful lifetime [yr]	20	20	20

1) average investment per unit when 10,000 units are installed; 2) average investment per unit when 28,000 units are installed

It has been assumed that in 2030 also larger filling stations will be installed. The larger LH_2 filling station consist of one LH_2 tank, 4 LH_2 pumps and 4 LH_2 dispensers and has a fuel output of 460 t LH_2 per year. The number of 460 t/yr filling stations is also 28,000.

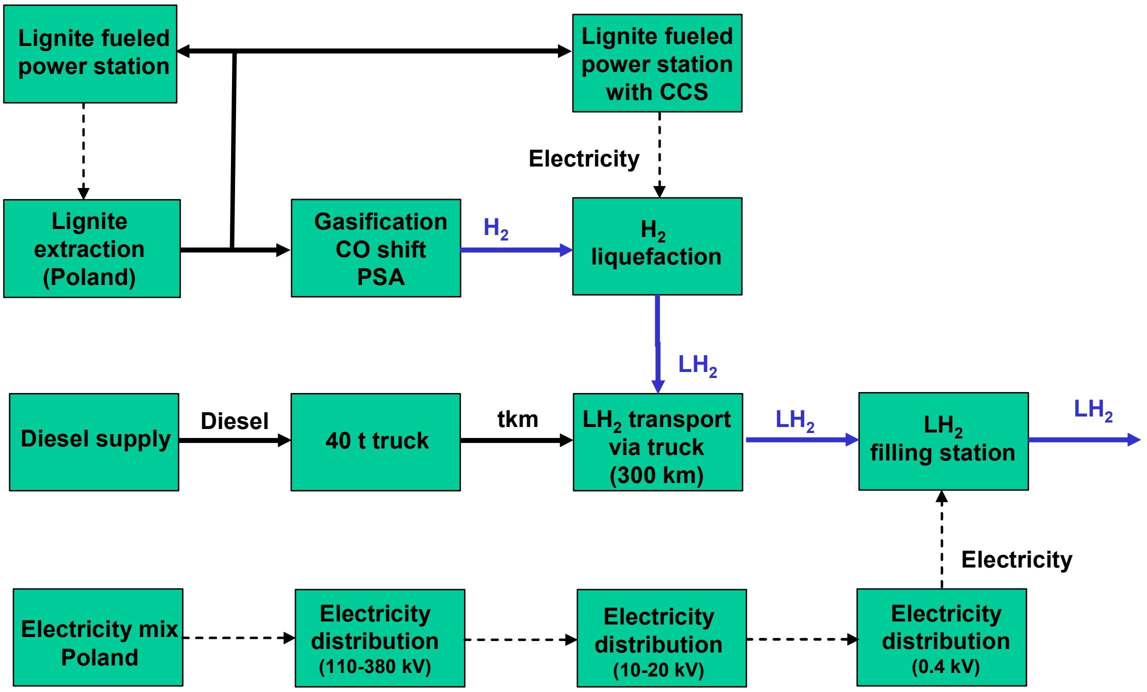
Table 3-51: Technical and economic data for the 460 t/yr LH_2 filling station [Linde 2001]

	2004	2030
Annual fuel output [t H_2/yr]	460	460
Electricity consumption [kWh/kWh$_{H2}$]	0.0007	0.0007
Investment [€]	1,327,000	529,600 (1)
Maintenance [% of investment]	2.0	2.0
Useful lifetime [yr]	20	20

(1) average investment per unit when 28,000 units are installed

The electricity consumption of the CGH_2 filling station in Poland is met by the Polish electricity mix.

Figure 3-12: LH_2 from hard coal gasification with CO_2 capture and storage



3.12 Chain 10: CGH_2 from in-situ gasification of coal

In this pathway hydrogen is generated from synthesis gas which is generated via in-situ gasification of coal. Air, oxygen or oxygen enriched air and water vapor is injected into a coal seam [Rogut 2006]. The coal is converted to a hydrogen rich gas. To generate pure hydrogen pure oxygen has to be used as gasification agent instead of air similar to aboveground gasification of coal. The CO_2 is extracted aboveground and fed into a CO_2 pipeline for transport to the CO_2 storage (e.g. depleted NG fields).

In a prototype IGCC Project based on underground coal gasification at Chinchilla in Australia about 55 million Nm^3 gas have been generated from 20,000 t of hard coal. The lower heating value (LHV) of the gas was 3.5 to 5.0 MJ/Nm^3 and the LHV of the hard coal was 23 MJ/kg [Walker 2001]. For the generation of pure hydrogen from the gas a pressure swing adsorption (PSA) plant is required. The H_2 recovery of the PSA plant (85%) has been derived from [Chiesa 2005]. As a result the hard coal input is about 2.3 kWh per kWh of pure hydrogen.

For the calculation of the investment it has been assumed that the same components are required as for aboveground coal gasification except the gasifier itself. The cost data for the different components has been derived from [Chiesa 2005] for a plant which generates hydrogen from coal gasification with CO_2 capture and storage (CCS) (Table 3-52).

Table 3-52: Investment of different components for the generation of pure hydrogen from in-situ coal gasification [€]

Air separation unit (O_2 at 0.105 MPa)	93,800,000
O_2 compression (from 0.105 MPa)	18,100,000
CO shift reactors, heat exchangers	61,300,000
Selexol H_2S removal & stripping	83,000,000
Sulfur recovery (Claus plant)	56,500,000
Selexol CO_2 absorption, stripping	58,500,000
CO_2 drying and compression	41,100,000
Pressure swing adsorption (PSA)	22,300,000
PSA purge gas compressor	8,800,000
Gas turbine	30,600,000
Heat recovery steam generator	45,300,000
Steam cycle (turbine + condenser)	60,200,000
Construction interest	71,278,500
Total	**650,778,500**

Until now there are no data for the investment of the in-situ gasification itself (drilling, pipes, etc.). Therefore the cost data are not complete.

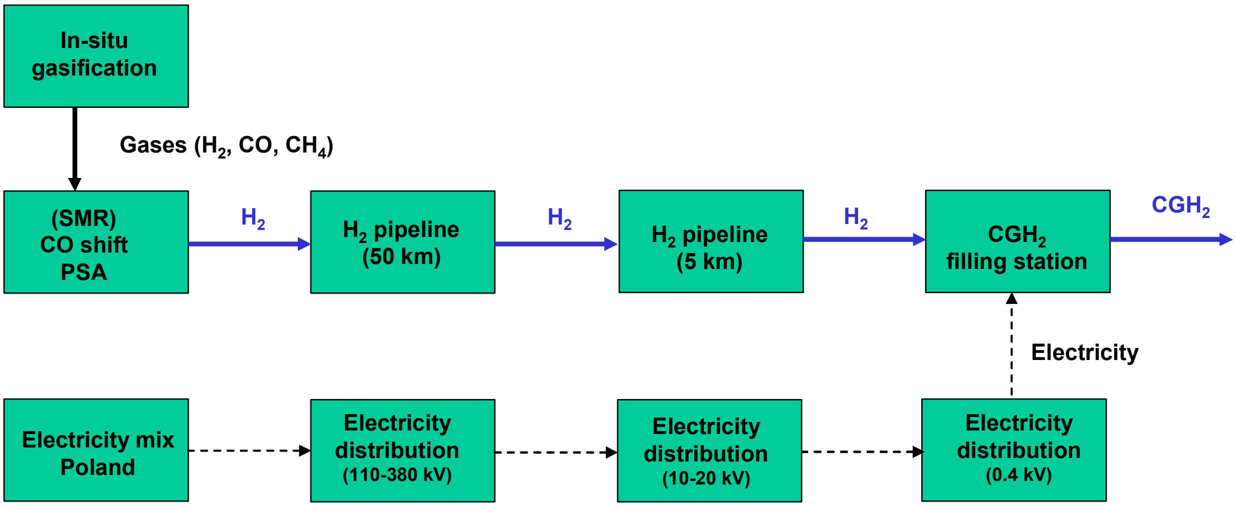
Table 3-53: Technical and economic data of hydrogen generation via in-situ gasification of hard coal with CO_2 capture and storage

Capacity [Nm^3 H_2/h]	356,800
Hard coal consumption [kWh/kWh_{H2}]	2.3
CO_2 emissions [g/kWh_{H2}]	65.8
Investment [€]	650,778,500
Maintenance coefficient [% of investment]	6.96
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	8,000

It has been assumed that the technology is available in 2030.

The hydrogen is distributed via a hydrogen pipeline grid. For the hydrogen pipeline grid and for the filling stations the same assumptions as for the central steam reformer with CCS has been made (see chapter 3.1).

Figure 3-13: CGH_2 from in-situ gasification of hard coal



3.13 Chain 11: CGH_2 from coke-oven gas

In this pathway coke-oven gas is converted to pure hydrogen. Coke-oven gas mainly consists of H_2 and CH_4. Therefore steam reforming with downstream CO shift and a downstream pressure swing adsorption (PSA) plant is required. It has been assumed that about 95% of the CH_4 is converted to H_2 and CO in the steam reforming stage and 95% of the CO is converted to H_2 and CO_2 in the CO shift stage. The H_2 recovery of the PSA plant is 85%. The tail gas of the PSA is used for heat supply for the endothermal steam reforming reaction and for electricity generation.

Table 3-54: Gas streams

	Coke-oven gas [mole]	after SMR [mole]	after CO shift [mole]	after PSA [mole]
H_2	55	129	157	133
CH_4	25.9	1	1	0
C_3H_6	2	2	2	0
CO	5	30	1	0
CO_2	2	2	30	0
N_2	10	10	10	0
H_2S	0.1	0	0	0
Total	100	174	202	133

Table 3-55: Energy content of the gas streams based on the LHV

	Coke-oven gas [kJ]	after SMR [kJ]	after CO shift [kJ]	after PSA [kJ]
H_2	13,301	31,151	37,953	32,260
CH_4	20,780	1,039	1,039	0
C_3H_6	3,441	3,441	3,441	0
CO	1,415	8,378	419	0
CO_2	0	0	0	0
N_2	0	0	0	0
H_2S	0	0	0	0
Total	38,937	44,009	42,852	32,260

The heat demand of the endothermal steam reforming reaction is 206 kJ per mole of CH_4. Not all CH_4 is converted to H_2 and CO. On the other hand heat loss in the steam methane reformer has been taken into account. As a rough estimate it has been assumed that the heat loss compensates the amount of unreacted CH_4. The efficiency of steam generation is assumed to be 85%. Then the heat demand for the steam reforming reaction is about 6,280 kJ.

The LHV of the tail gas is about 10,590 kJ. The excess tail gas is used for electricity generation. The efficiency of electricity generation has been derived from [Katofsky 1993] and is assumed to be about 44%. The gross electricity requirement of the process is about 0.060 kWh/kWh of hydrogen and the gross electricity generation is 0.059 kWh/kWh of hydrogen. The total input of coke-oven gas is about 1.20 kWh/kWh of hydrogen.

The investment for the components required for the conversion of coke-oven gas to pure hydrogen has been derived from [Katofsky 1993] and [Kreutz 2005] (Table 3-56).

Table 3-56: Investment of different components for the generation of pure hydrogen from coke-oven gas [million €]

Reformer feed compressor	44.6
SMR	38.6
WGS reactors, heat exchangers	61.3
PSA	22.3
PSA purge gas compressor	8.8
Power station	31
Total	207.1

For the calculation of the pathway for the technical and economic data shown in Table 3-57 have been used.

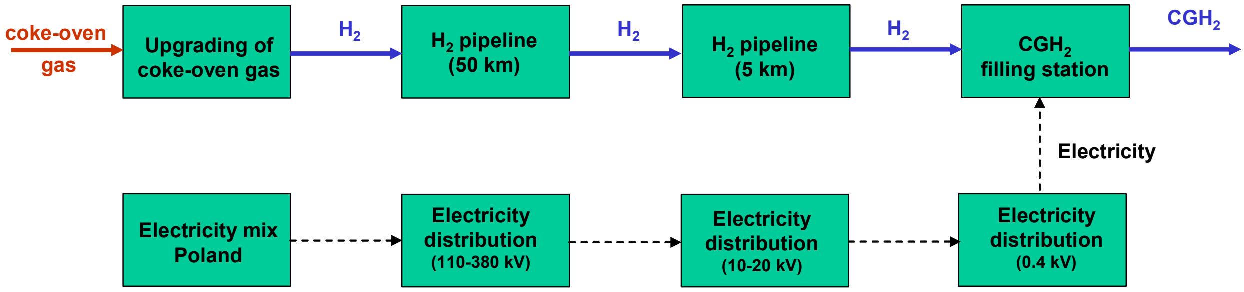
Table 3-57: Technical and economic data of hydrogen generation via upgrading of coke-oven gas

Capacity [Nm^3 H_2/h]	356,800
Coke-oven gas consumption [kWh/kWh_{H2}]	1.207
Electricity consumption [kWh/kWh_{H2}]	0.001
CO_2 emissions [g/kWh_{H2}]	189
Investment [€]	207,100,000
Maintenance coefficient [% of investment]	4
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	8,000

Today coke-oven gas is used for heat and electricity generation and substitutes natural gas. Therefore it has been assumed that the price of coke-oven gas is the same as the price of natural gas. According to the WETO scenario which is used in HyWays the price of NG amounts to about 0.0284 in 2020 and about 0.0373 €/kWh in 2030.

The hydrogen is distributed via a hydrogen pipeline grid. For the hydrogen pipeline grid and for the filling stations the same assumptions as for the central steam reformer with CCS has been made (see chapter 3.1).

Figure 3-14: CGH_2 from upgrading of coke-oven gas



4 Results

From the 12 calculated chains 8 chains have been selected. The selected pathways are marked red.

Figure 4-1: Overview of selected chains

	No.	Feedstock (incl. transport)	H_2 production	H_2 transport	End-use (incl. fueling station)	
1	1a	NG	central SMR (*)	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
2	1b	NG	onsite SMR	-	CGH_2 FS	FC/ICE car, buses
3	2	WW/FW	gasification	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
	3	biogas	onsite SMR	-	CGH_2 FS	FC/ICE car, buses, FC-CHP
4	4	offshore wind	onsite electr.	-	CGH_2 FS	FC/ICE car, buses
	5	onshore wind	onsite electr.	-	CGH_2 FS	FC/ICE car, buses
5	6	nuclear power	onsite electr.	-	CGH_2 FS	FC/ICE car, buses
	7	HT nuclear heat	thermochemical cycle	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
	8	hard coal	gasification (*)	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
	9a	lignite	gasification (*)	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
6	9b	lignite	gasification (*)	liquefaction, LH_2 trailer	LH_2 FS	FC/ICE car, buses
7	10	hard coal	in-situ gasification(*) with pure O_2	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP
8	11	by-product	upgrading of coke oven gas	pipeline	CGH_2 FS	FC/ICE car, buses, FC-CHP

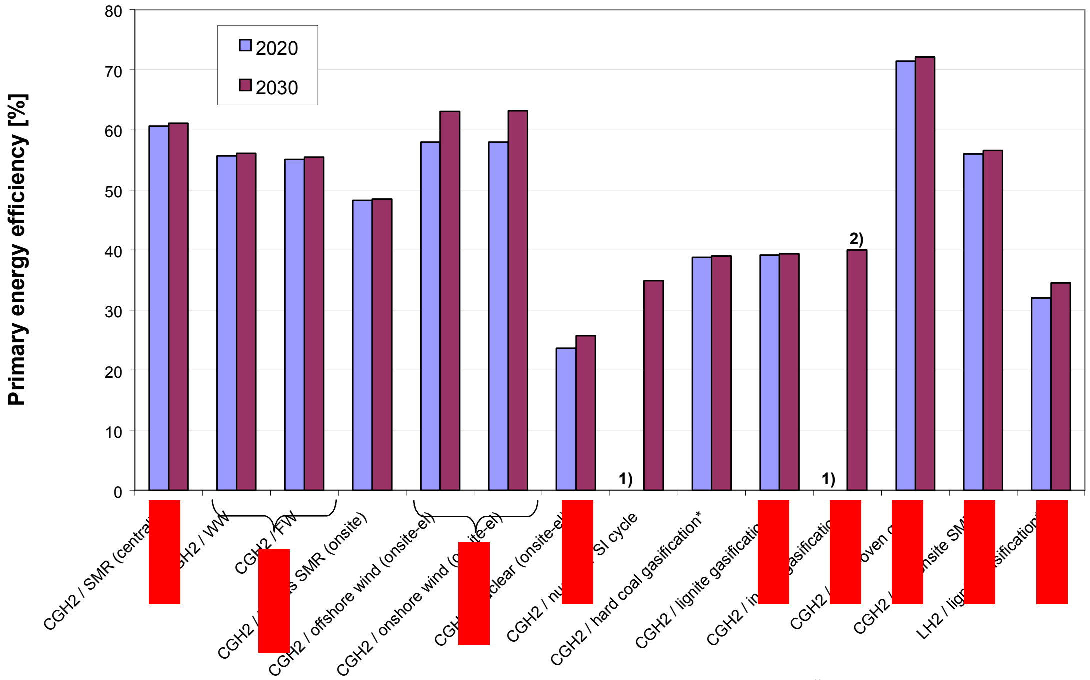
[1] WW - waste wood, FW - farmed wood

* with CCS (in depleted Polish NG fields especially in NG fields containing low CH_4 NG after depletion of the field or in coal beds and replacing coal bed methane by CO_2)

4.1 Well-to-Tank

The selected pathways are marked with red arrows.

Figure 4-2: WTT efficiency



* with CO_2 capture and storage (CCS); 1) technology not available in 2020; 2) not complete

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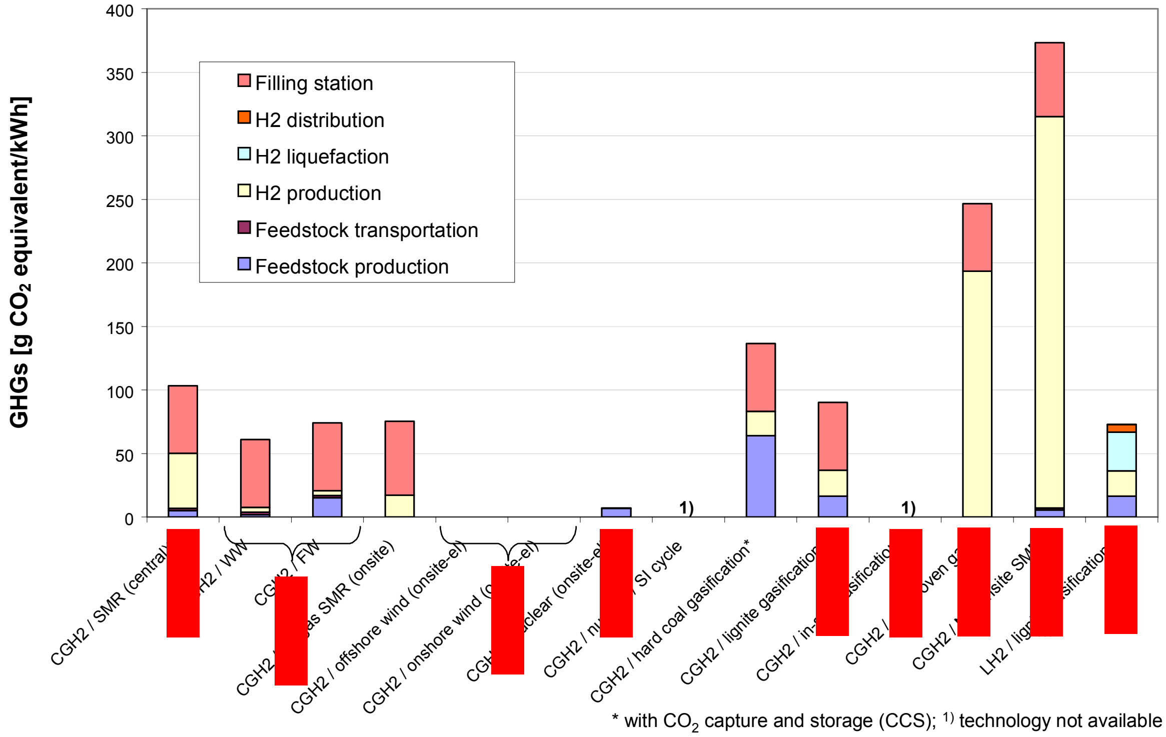
Figure 4-3: WTT GHG emissions in 2020



* with CO_2 capture and storage (CCS); 1) technology not available in 2020

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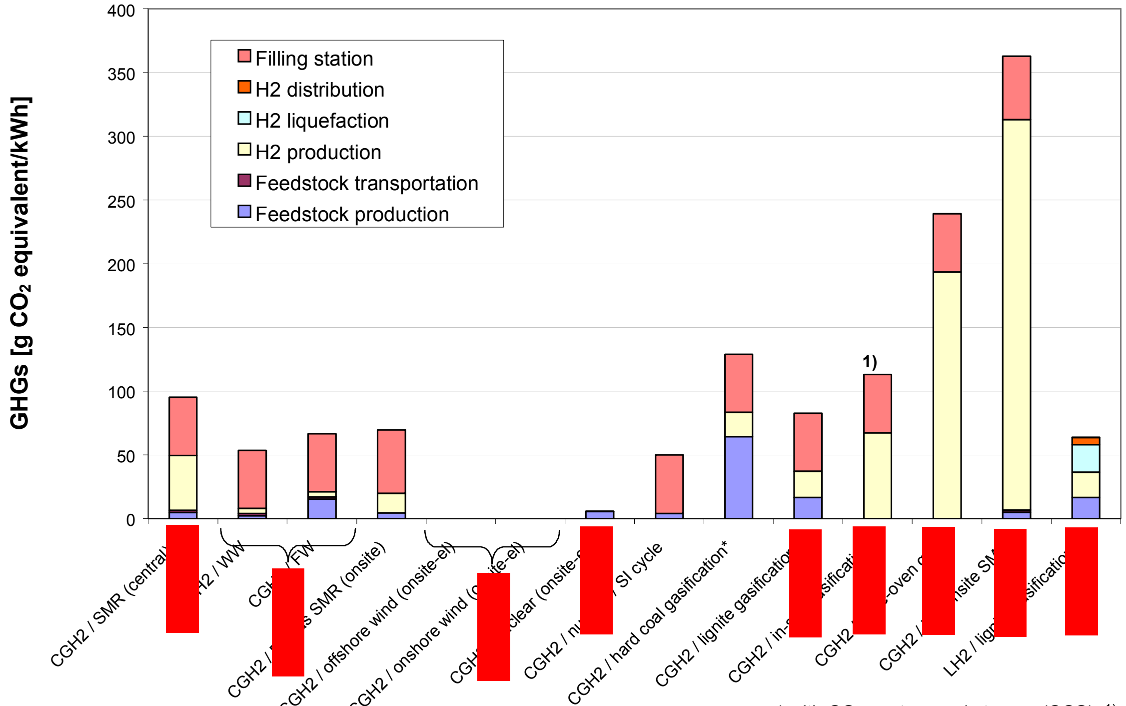
Figure 4-4: WTT GHG emissions in 2030



* with CO_2 capture and storage (CCS); 1) not complete

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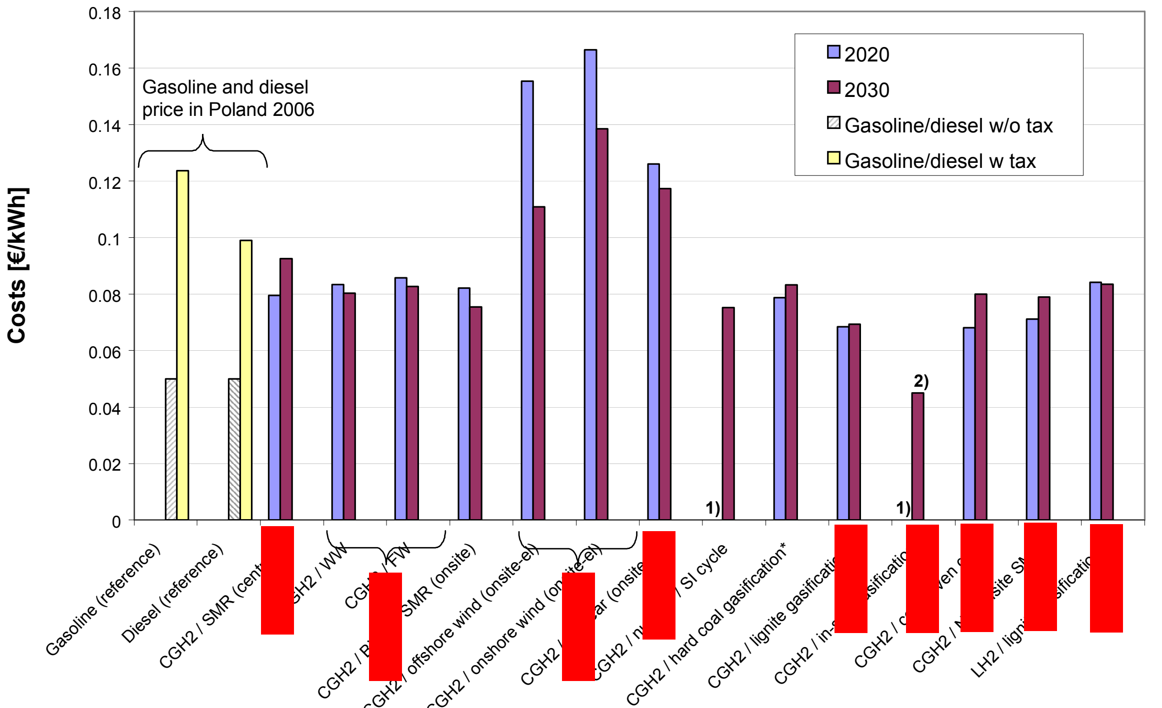
Figure 4-5: Fuel supply costs



* with CO_2 capture and storage (CCS); [1] technology not available in 2020; [2] not complete

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4.2 Tank-to-Wheel (TTW)

The passenger vehicle data has been derived from the CONCAWE/EUCAR/JRC study [CONCAWE 2006]. The passenger vehicles are based on a VW Golf.

Table 4-1: Passenger vehicle data [CONCAWE 2006]

	Fuel consumption [kWh/km]	GHG emissions [g CO_2 equivalent/km]
CGH_2 FC vehicle	0.261	0
CGH_2 FC vehicle hybrid	0.233	0
CGH_2 ICE vehicle	0.465	0.5
CGH_2 ICE vehicle hybrid	0.413	0.5
LH_2 FC vehicle	0.261	0
LH_2 FC vehicle hybrid	0.233	0
LH_2 ICE vehicle	0.465	0.5
LH_2 ICE vehicle hybrid	0.393	0.5
Gasoline ICE vehicle	0.529	140.3
Gasoline ICE vehicle hybrid	0.449	119.5
Diesel ICE vehicle	0.492	131.6
Diesel ICE vehicle hybrid	0.406	108.9

The data for the bus has been derived from [Jorach 1997] and [LBST 1997]. The energy consumption of the bus is derived from a typical driving cycle (“Linie 66”) of a typical city bus (Figure 4-6).

Figure 4-6: Hydrogen fueled bus (source: MAN)

Table 4-2: Buses (MAN "Linie 66" driving cycle) [Jorach 1997] [LBST 1997]

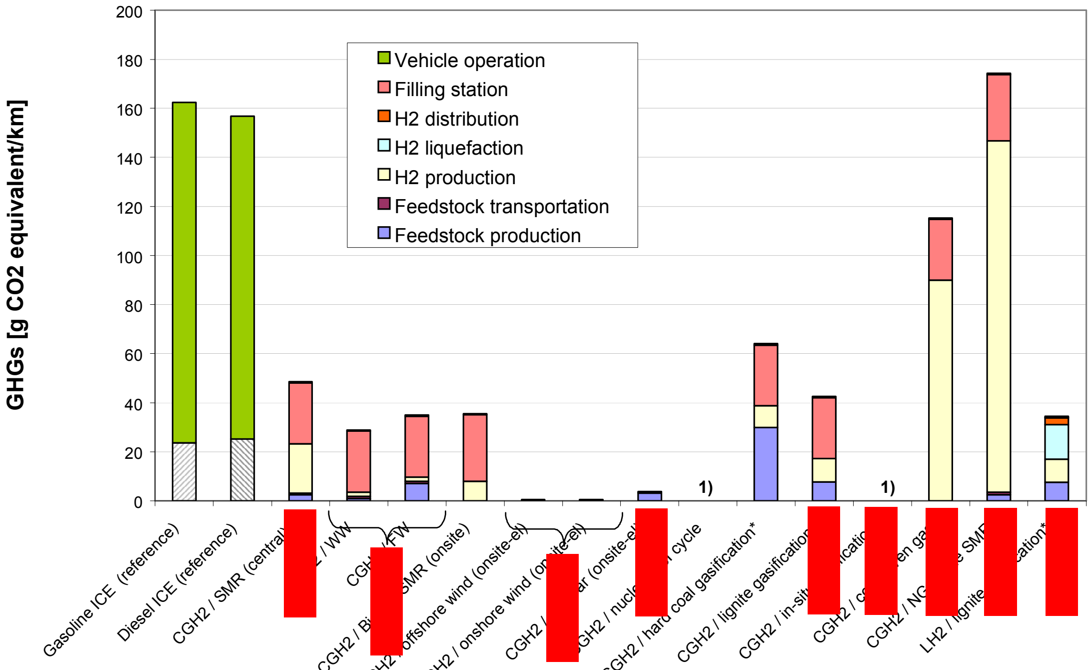
	Fuel consumption [kWh/km]	GHG emissions [g CO_2 equivalent/km]
CGH_2 FC bus	2.86	0
CGH_2 ICE bus	4.90	4.4
LH_2 FC bus	2.74	0
LH_2 ICE bus	4.90	4.4
Diesel ICE (reference)	3.98	1073.7
CNG ICE (reference)	5.38	1086.7

The GHG emissions in case of the hydrogen fueled ICE are from N_2O emissions.

4.3 Well-to-Wheel (WTW)

For CGH_2 fueled FC vehicles and hydrogen generated via electrolysis a deOxo dryer has been installed at the filling station to elevate the hydrogen purity from 99.95% to 99.995%. For CGH_2 fueled ICE vehicles no deOxo dryer is required. The electricity consumption of the deOxo dryer is about 0.0139 kWh/kWh of hydrogen which is less than 1% of the total electricity consumption of the electrolyzer (1.6 kWh/kWh of hydrogen in case of the 120 Nm^3/h electrolyzer). For 2030 it has been assumed that the deOxo dryer is already included in the electricity consumption of the electrolysis plant. The purity of LH_2 is above 99.995% in any case.

Figure 4-7: WTW GHG emissions non-hybrid ICE passenger vehicles 2020



* with CO_2 capture and storage (CCS); $^{1)}$ technology not available in 2020

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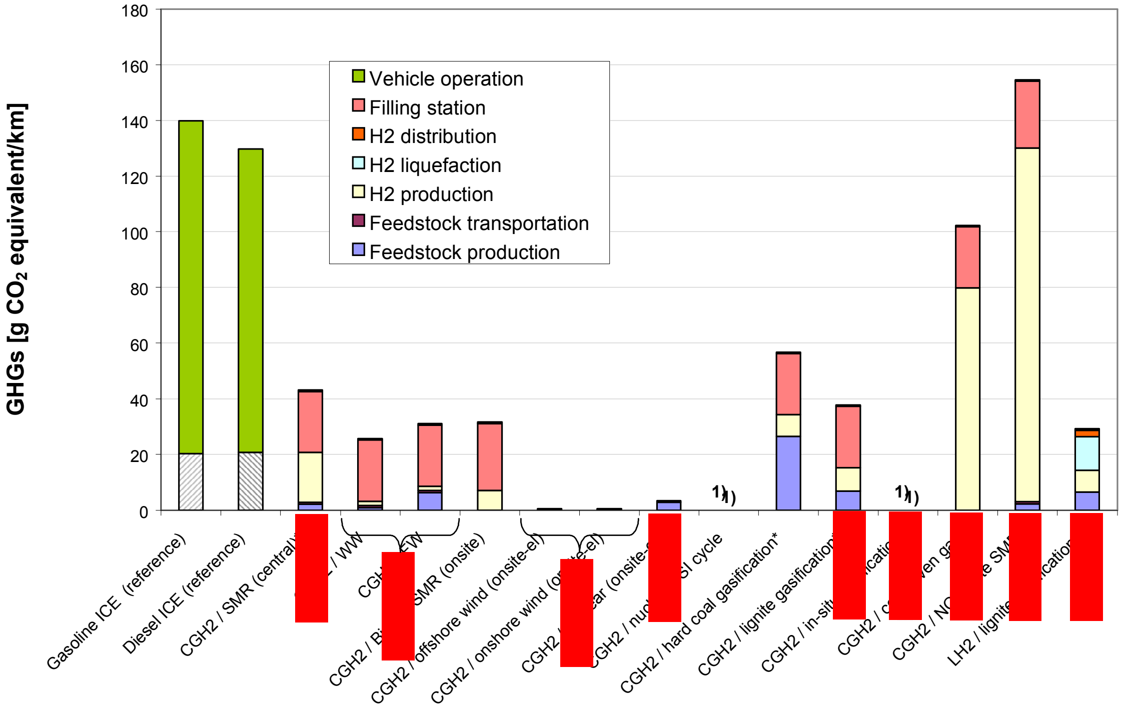
Figure 4-8: WTW GHG emissions hybrid ICE passenger vehicles 2020



* with CO_2 capture and storage (CCS); $^{1)}$ technology not available in 2020

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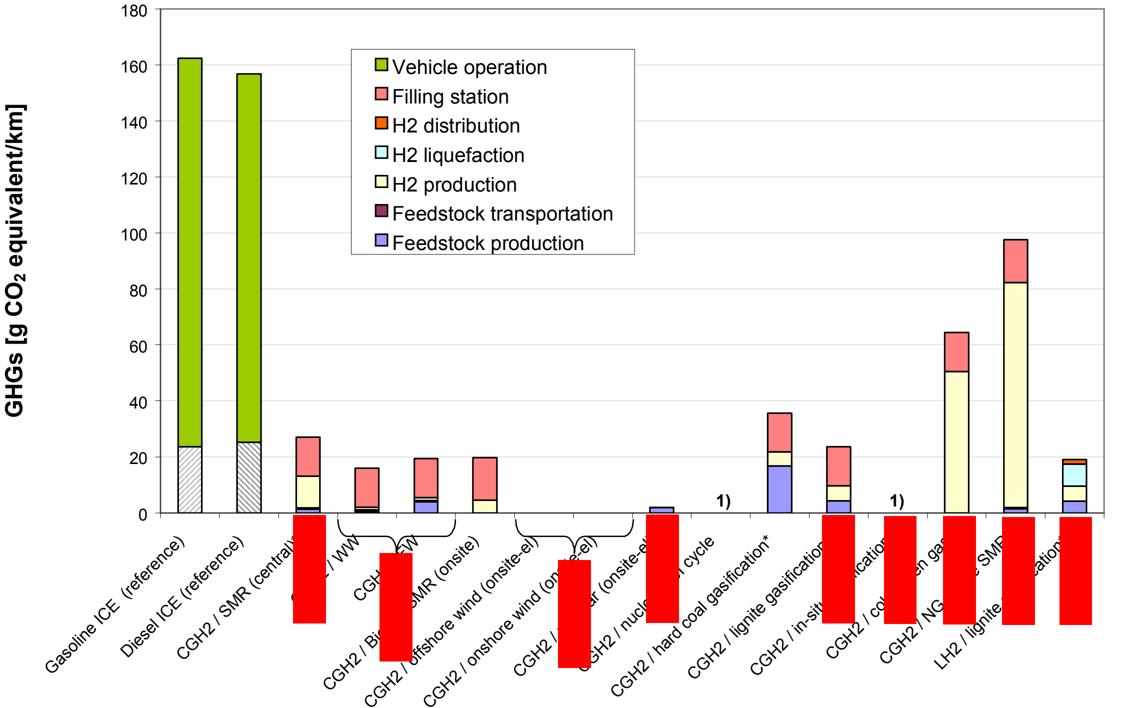
Figure 4-9: WTW GHG emissions non-hybrid FC passenger vehicles 2020



* with CO_2 capture and storage (CCS); $^{1)}$ technology not available in 2020

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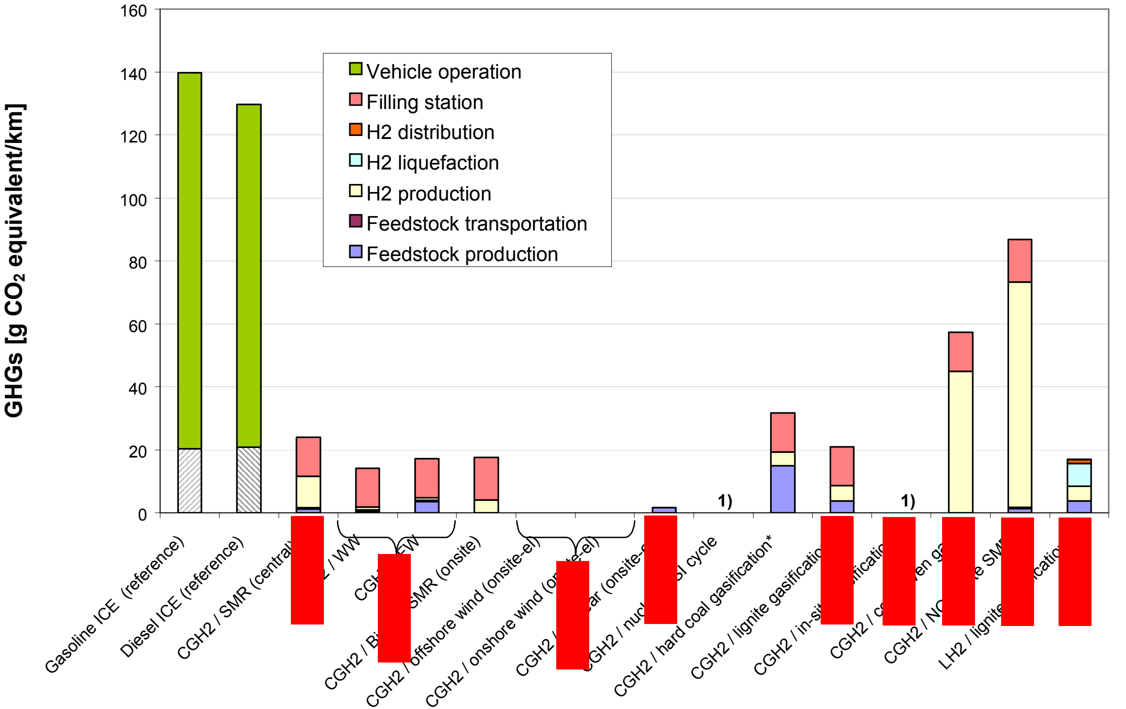
Figure 4-10: WTW GHG emissions hybrid FC passenger vehicles 2020



* with CO_2 capture and storage (CCS); $^{1)}$ technology not available in 2020

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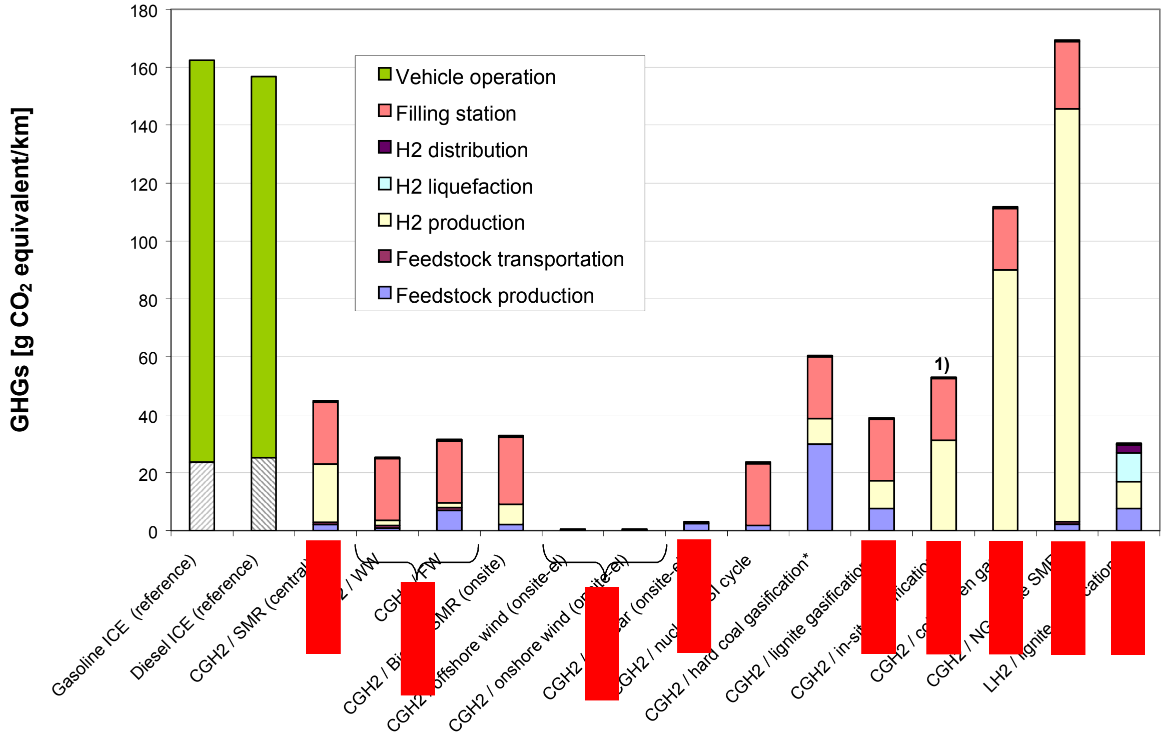
Figure 4-11: WTW GHG emissions non-hybrid ICE passenger vehicles 2030



* with CO_2 capture and storage (CCS); 1) not complete

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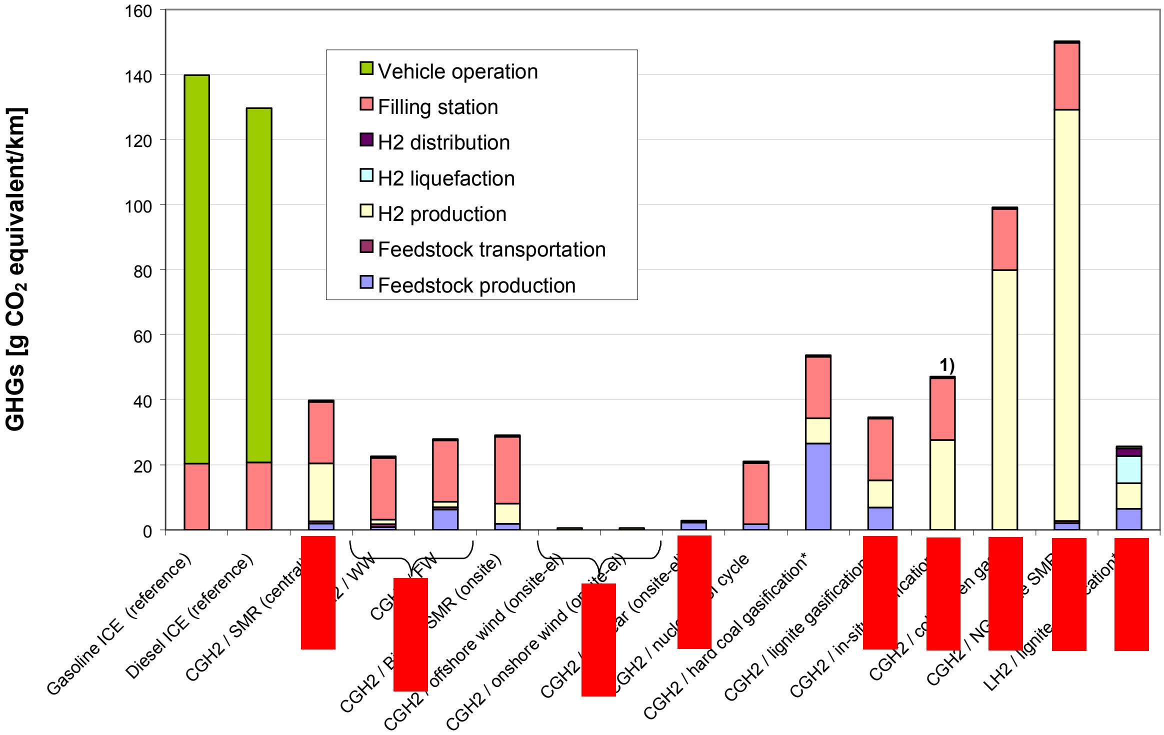
Figure 4-12: WTW GHG emissions hybrid ICE passenger vehicles 2030



* with CO_2 capture and storage (CCS); $^{1)}$ not complete

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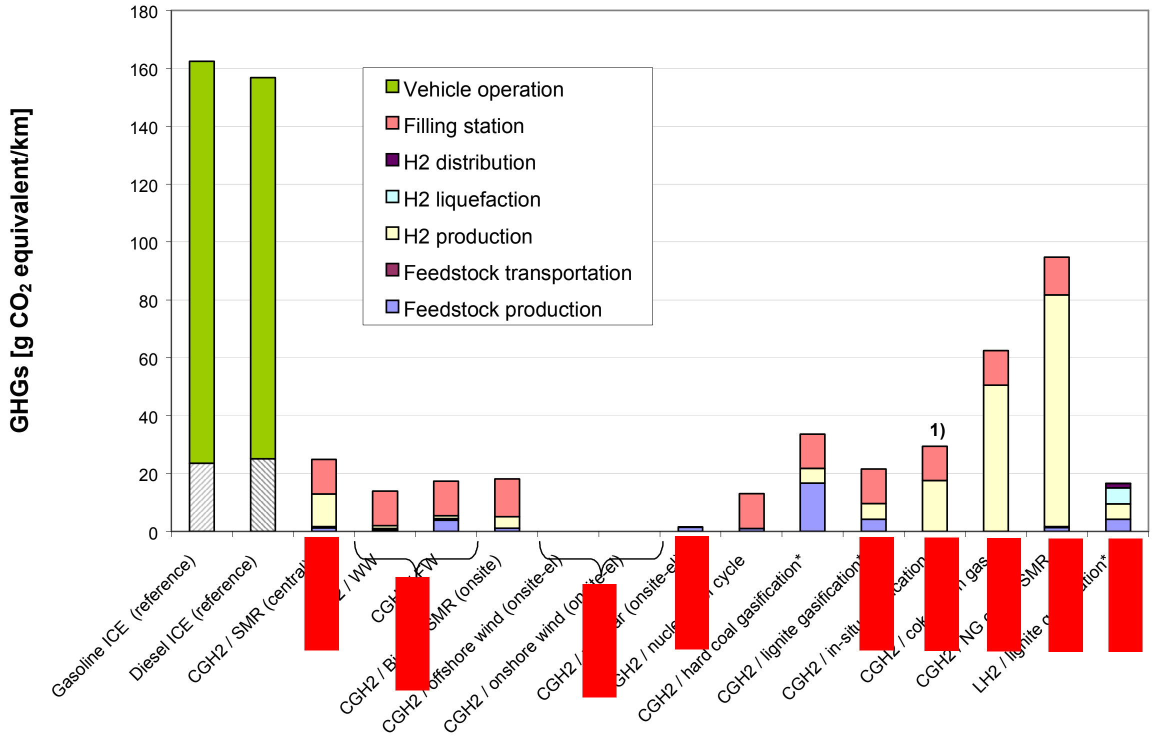
Figure 4-13: WTW GHG emissions non-hybrid FC passenger vehicles 2030



* with CO_2 capture and storage (CCS); 1) not complete

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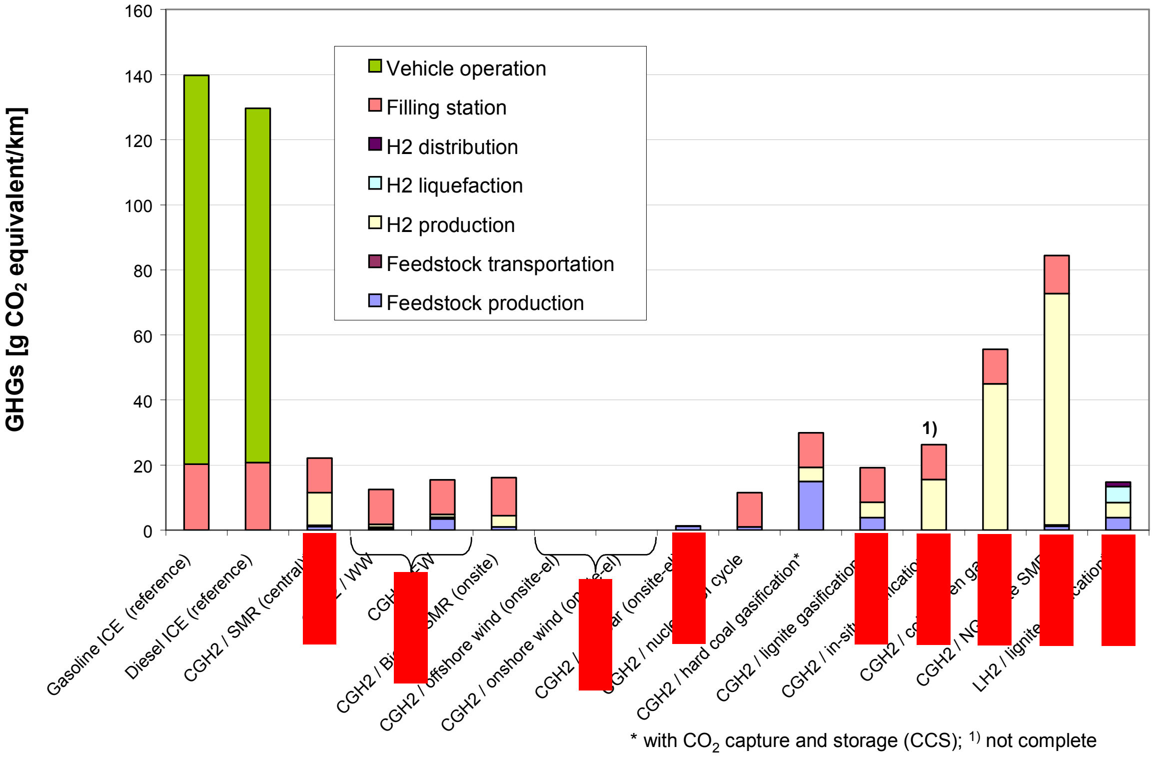
Figure 4-14: WTW GHG emissions hybrid FC passenger vehicles 2030



* with CO_2 capture and storage (CCS); 1) not complete

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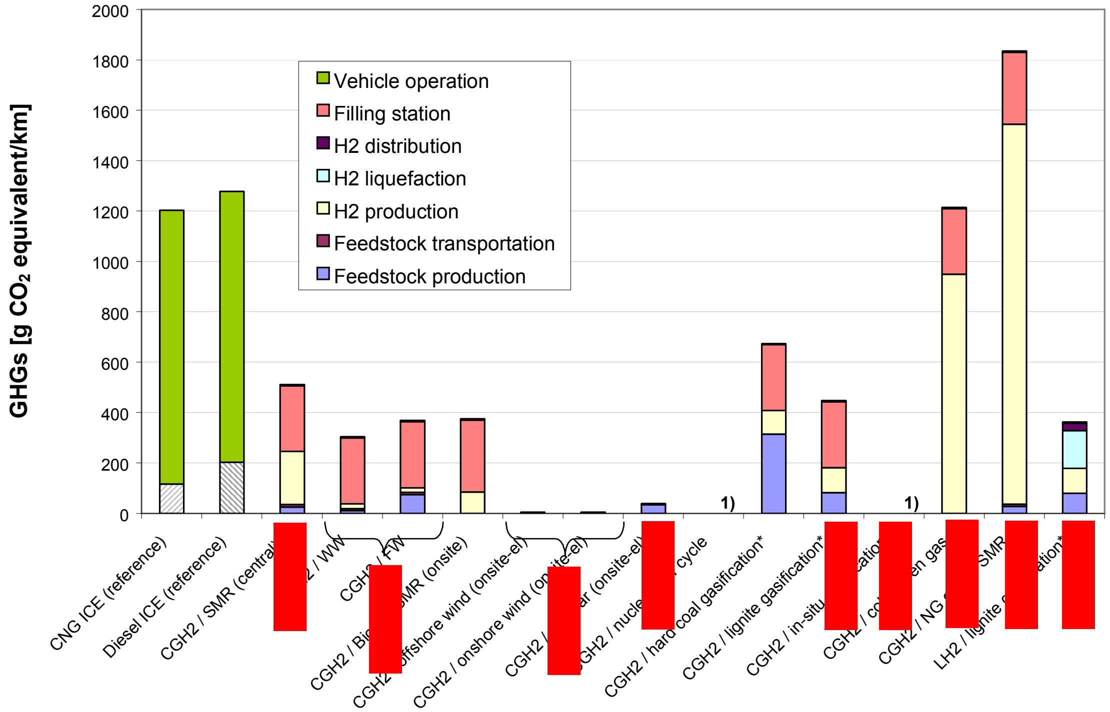
Figure 4-15: WTW GHG emissions ICE bus 2020



* with CO_2 capture and storage (CCS); $^{1)}$ technology not available in 2020

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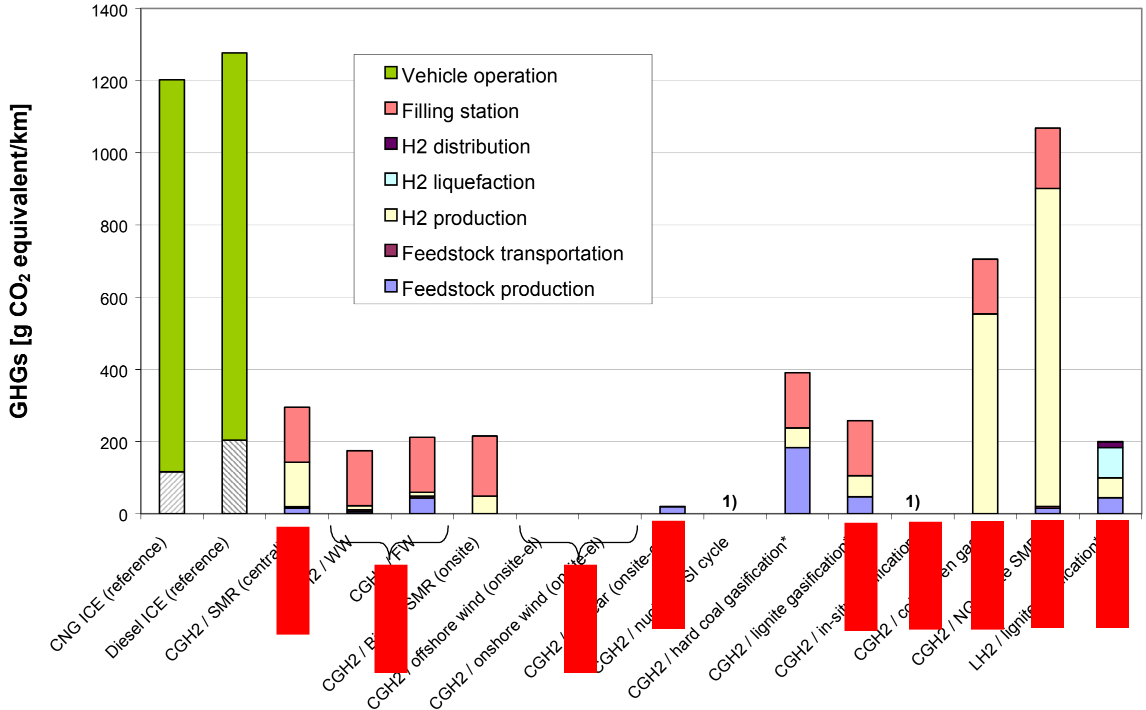
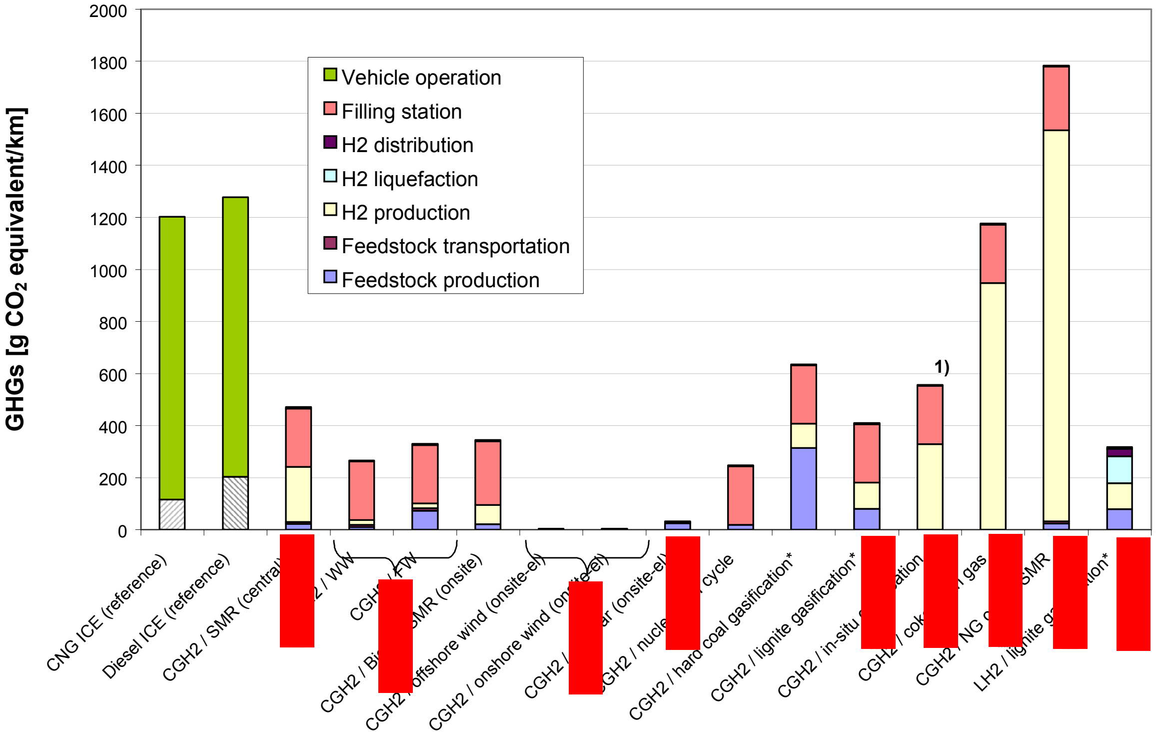
Figure 4-16: WTW GHG emissions FC bus 2020



* with CO_2 capture and storage (CCS); 1) technology not available in 2020

🟥 **Preliminary choice of pathway**

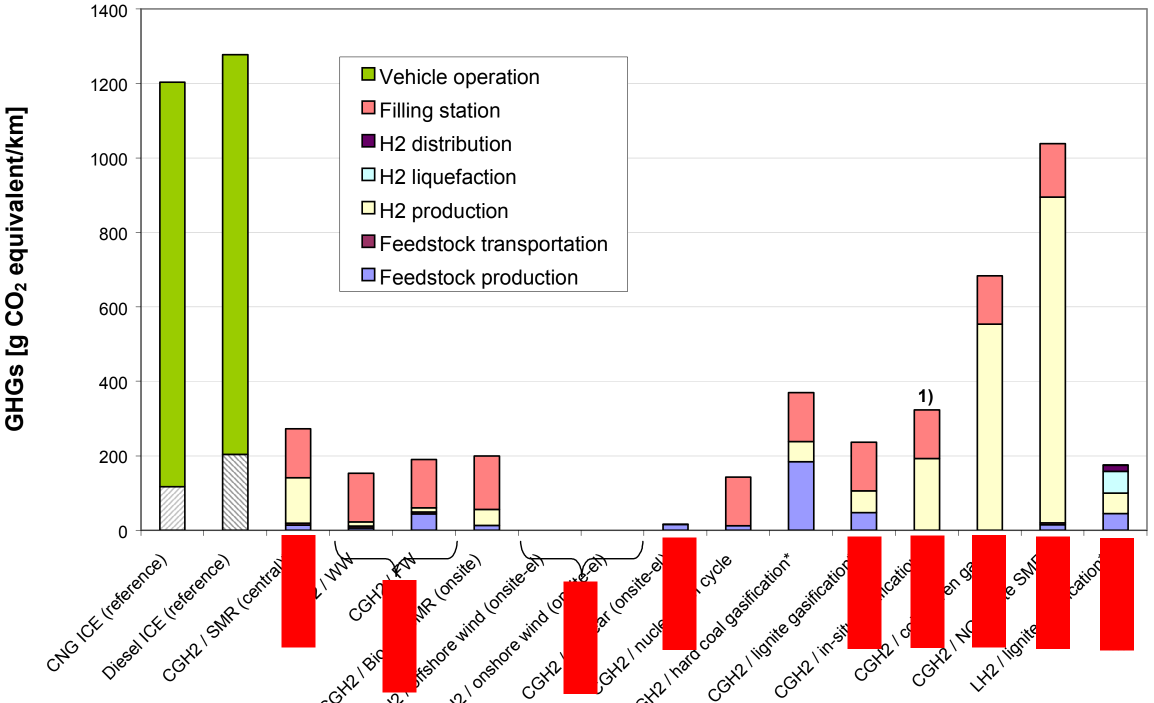
Figure 4-17: WTW GHG emissions ICE bus 2030



* with CO_2 capture and storage (CCS); [1)] not complete

🟥 **Preliminary choice of pathway**

Figure 4-18: WTW GHG emissions FC bus 2030



* with CO_2 capture and storage (CCS); 1) not complete

🟥 **Preliminary choice of pathway**

5 Well to stationary use (WtStU)

5.1 Methodology

In case of stationary applications WTT pathways without a filling station has been used for the supply of hydrogen. Further no LH_2 pathways has been considered because stationary fuel cell (FC) combined heat and power (CHP) plants usually are connected to a hydrogen grid.

Table 5-1: FC CHP plant without H_2 fueled peak boiler (50 kW_e)

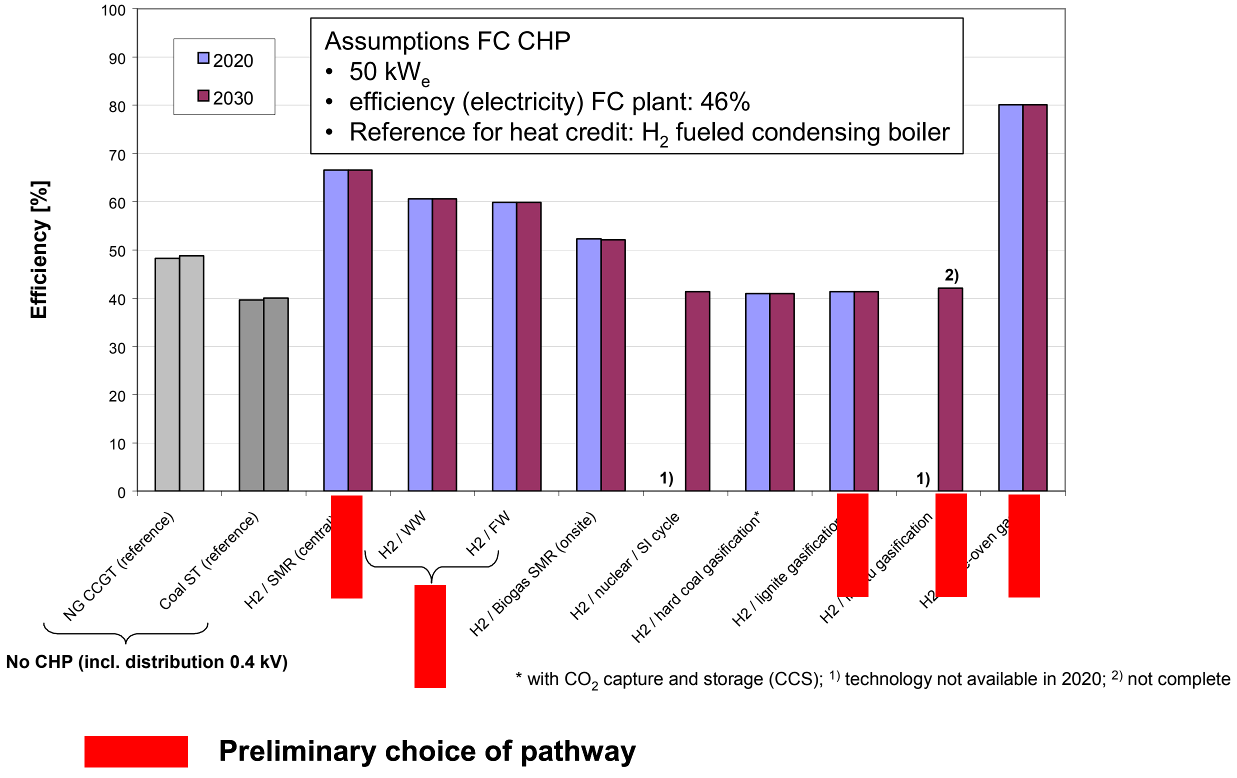
Capacity [kW_e]	50
H_2 input [kWh/kWh_e]	2.16
Heat output [kWh/kWh_e]	1.20
Investment [€]	25,000
Maintenance [% of investment]	10
Equivalent full load period [h/yr]	5,000
Useful lifetime [yr]	8

In Poland today town gas which mainly consists of hydrogen and CO is distributed with pipelines. The town gas could be replaced by pure hydrogen. Therefore it has been assumed that the heat replaces heat from a hydrogen fueled condensing boiler. The efficiency of the condensing boiler is about 106% related to the LHV (which is about 90% related to the HHV). The hydrogen for the condensing boiler is derived from the same hydrogen source as the hydrogen for the FC CHP plant.

The equivalent full load period has been assumed to be 5,000 h/yr which is typical for CHP plants for residential buildings. For peak heat demand in winter generally a peak boiler is installed.

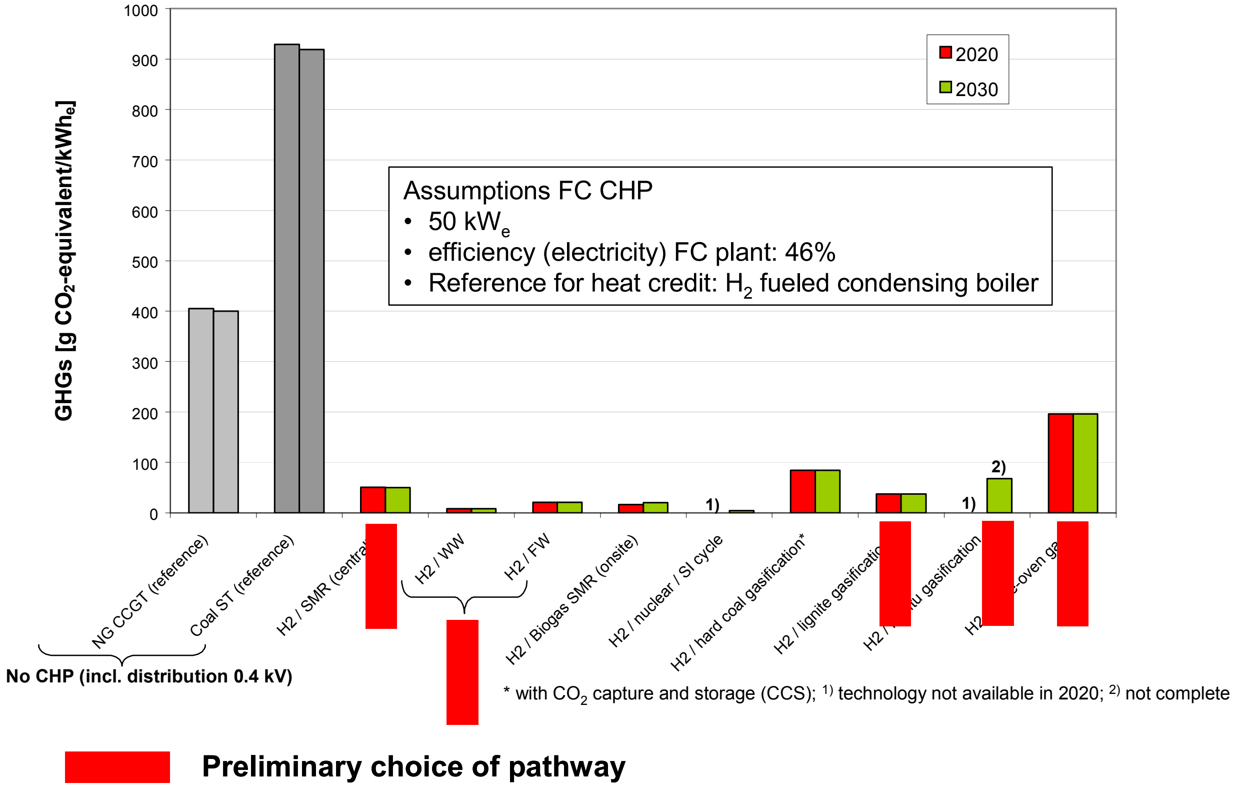
5.2 Results

Figure 5-1: Well-to-Stationary Use (WtStU) efficiency



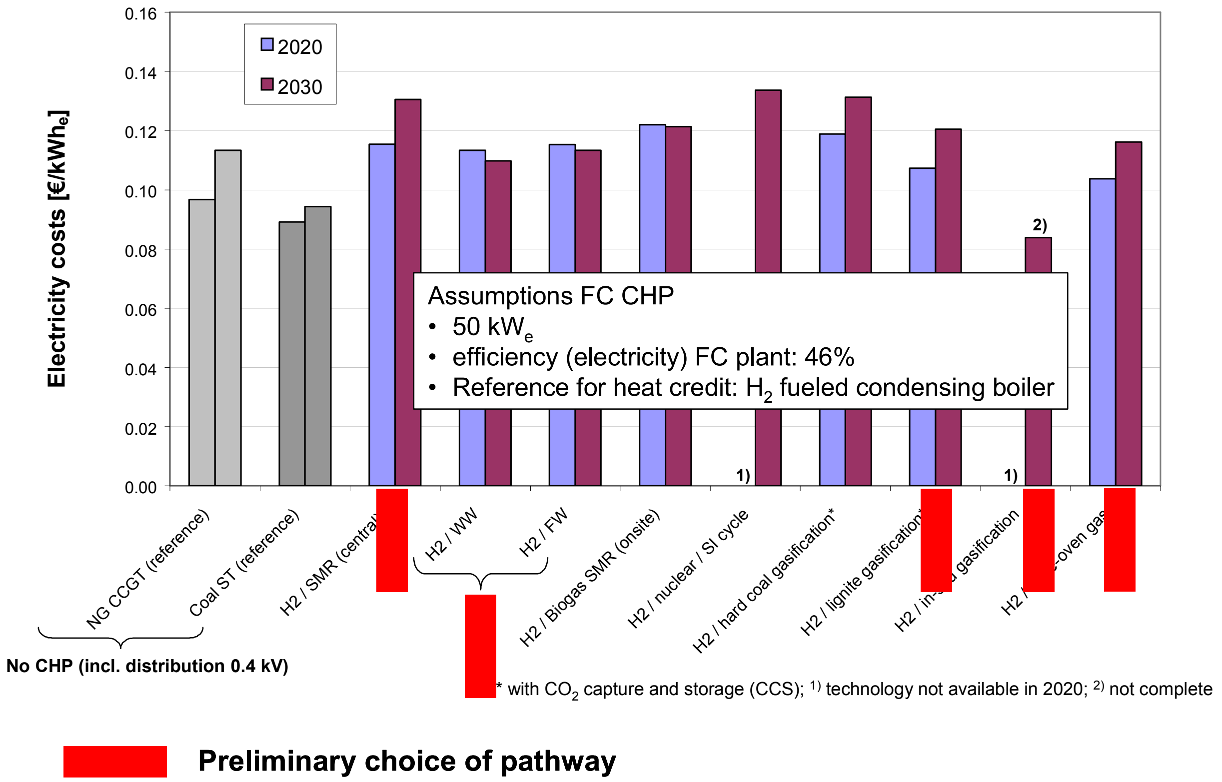
* with CO_2 capture and storage (CCS); $^{1)}$ technology not available in 2020; $^{2)}$ not complete

Figure 5-2: Well-to-Stationary Use (WtStU) GHG emissions



* with CO_2 capture and storage (CCS); $^{1)}$ technology not available in 2020; $^{2)}$ not complete

Figure 5-3: Well-to-Stationary Use (WtStU) costs



* with CO_2 capture and storage (CCS); $^{1)}$ technology not available in 2020; $^{2)}$ not complete

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7 Appendix