HyWays

"Hydrogen supply chains for France"

Author: Sophie Avril
Commissariat à l'Energie Atomique

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1. Introduction

Within the framework of the HyWays project, work packages WP1 and WP2 present the energy chains selected for the timeframe 2020, 2030 and 2050 by the ten involved member states: Finland, France, Greece, Germany, Italy, Norway, the Netherlands, Poland, Spain and the United Kingdom.
In this report, the selected chains for France are elaborated.

The WP1/WP2 objectives are:

- To propose a set of chains for each country whose data and hypothesis will be transmitted to the WP3,
- To calculate for each chain the energy efficiencies, the GHG emissions and the levelized costs.

The selection of these chains (H_2 production, infrastructure of supply and end use technologies) were performed according to:

- The considered timeframe,
- The specificities of each country (politic, geographic,…), and
- The available and projected technologies and infrastructure.

This report:

- Presents the selected chains for France, described by means of schemes including the processes used and their links,
- Provides the results obtained from the calculations of these chains. For comparison purposes, the presentation of results has been lied out graphically.

The simulation of the chains was performed using the E3-database tool developed by L-B-Systemtechnik (LBST, Germany). Most of the data used in the tool has been issued from the EUCAR/CONCAWE/JRC study and the GEMIS database. Part of the data has been adapted or created to represent the specific infrastructure of France. To ensure uniformity within the different Member States, all defined production processes within the database have remained unchanged.

2. Methodology

During several workshops organized in France, where experts from the industry, government and research institutes attended, a number of hydrogen production (and utilization) chains were selected. This selection took place based on the specific infrastructure and natural resources of this Member State.

The selected chains were subsequently modelled using the E3-database tool of LBST. With this tool the GHG emissions, the energy requirements and the costs of the supply of transportation fuel, electricity and heat were estimated.

As a time horizon, the years 2020, 2030 and 2050 were selected. Reason of doing so is that it can be expected that in 2020 fuel cell vehicles as well as the different hydrogen generation technologies will be commercially available. The years 2030 and 2050 were added for long term processes not available in 2020.

The basis of the database is a common file created from the interview of the industrial partners and the member state representatives. This data was incorporated into the database after being validated. The processes used in E3-database for the calculation of the hydrogen energy pathways are also available in a spreadsheet bearing the name of "technology fact sheet". This is an EXCEL-based spreadsheet where all inputs and outputs of the database are presented, including the used references to come to these values.

All calculations performed within the E3-database are based on the lower heating value (LHV) of the main sources. 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 fuelled fuel cells, and
- Gas engines and gas turbines.

For the Hydrogen pathways selected in France, the following new processes were introduced:

- CO_2 sequestration / CO_2 transport 50 km for H_2 plants (this process deals with the cost of CO_2 transportation on 50 km),
- LH_2 / GH_2 Station (Station fed with LH_2 which delivers GH2),
- Power Station / Mix France 2020 (Electric mix in France),
- Transport / GH_2 / Pipeline / Distribution (100 km) (transport of GH_2 in a 100 km pipeline),
- “Cogénération + chaudière d’appoint” – Gaz de France (FC CHP system with peak boiler),
- EPR (European Pressurized Reactor),
- EHT – 900°C (High Temperature Electrolysis),
- Heat Transport / 10 km (transport of heat produced by the EPR and used in the HTE),
- Re-heater 360-900 (used for HTE),
- Pipeline / GN / 90 km (Mix NG/H_2 transport),
- Separator central (to separate hydrogen and NG),
- Credit (in order to valorise the remaining hydrogen in the gas-off).

The calculation rules used within the E3-database are presented in 7.

3. Chains Selection

3.1. Possible chains

There are many ways of grouping possible hydrogen production and utilization chains. A first approach is performed with the used feedstock as a basis. Next, depending on the location of a production plant (central or de-central) on the production process and end users, a large matrix of possible hydrogen pathways could be created. From here, if the possibility of capturing Carbon as an abatement technique is also considered, the number of possible chains almost double.
In this study the following approach was used:

Firstly, the possible chains were grouped by feedstock. As possible feedstocks were identified:

- Natural gas
- Oil residues
- Coal
- Electricity
- Nuclear, solar and wind power
- Hydroelectric power
- Biomass
- Other

Under category “Other” are included: waste, hydrogen as by-product and imported liquefied hydrogen. Although “hydrogen as by-product” is not a feedstock as such, but in fact a production process, it is included as a feedstock because it can be treated as a “ready-for-use” product.

Secondly, the hydrogen production chains were grouped by the used production process with a distinction between central and de-central processes. The identified production processes were Steam Methane Reforming (SMR), gasification and electrolysis. Some other feedstock depending processes as High Temperature Thermo-chemical, Photo-biological and fermentation are also possible, although still under development.

Thirdly, two types of hydrogen usage were identified: a filling station (FS) for all kind of vehicles and the stationary use of hydrogen (STU), the last one being either domestic or industrial.
Finally, the way hydrogen could be delivered was included: compressed gas (CGH_2) or liquefied (LH_2).

Based on these subsystems, a selection of most probable hydrogen supply chains can be performed, depending on the specific Member State infrastructure and availability of main resources.

3.2. Chain Selection for France

There are two kinds of parameters that may affect the calculation of a specific hydrogen chain for a Member State: Infrastructure distances and Member State related costs of main resources.
Moreover, depending on the considered chain, transport means and distances may vary.

Most probable hydrogen production and consumption chains were selected for the main fuel sources of natural gas, biomass and electricity (French mix and wind power). This selection was performed during a couple of workshops held between field experts, energy utilities and researchers. The choice was based on availability of a natural gas (NG) infrastructure, availability of other (renewable) resources and specific national infrastructure distances. Table 1 compiles all developed chains for France.

Table 1. Overview of the hydrogen chains considered

Feedstock	NG (Norway, Russia, Algeria, The Netherlands, …)	×
	Coal	-
	Oil residues	-
	Electricity [1]	×
	Biomass	×
	Waste	-
	By-product	×
Distribution	Filling-station (FC or ICE)	×
	Filling station (liquid H_2)	-
	CHP (FC)	×
	CHP (ICE)	-
	Heating boiler	-
	Combination CHP (FC) and heating boiler	×
	CCGT	-

For France, seven hydrogen chains were selected. It leads to 16 sub-chains, 10 for mobile applications and 6 for stationary applications. All chains include the variants for mobile use of hydrogen. The selected chains are presented in Table 2.

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[1] Both electricity from wind power and the French mix electricity are considered.

Table 2. Selected French Chains for the Hydrogen pathway

Number		**Feedstock**	**Production Process**	**Conversion**	**CO_2 seq.**	**Gas / Liquid**	**Application**
1	a1	Natural gas	Central SMR		Yes	Gas	Car Filling Station
	b1	Natural gas	Central SMR		Yes	Gas	Domestic use
	a2	Natural gas	Central SMR	Mix NG-GH_2	Yes	Gas	Car Filling Station
	b2	Natural gas	Central SMR	Mix NG-GH_2	Yes	Gas	Domestic use
	a3	Natural gas	Central SMR	Liquefaction	No	Gas	Car Filling Station
2	a2	French Mix Electricity	Central Electrolysis		No	Gas	Car Filling Station
	a3	French Mix Electricity	Central HT Electrolysis		No	Gas	Car Filling Station
3	a	French Mix Electricity	On Site Electrolysis		No	Gas	Car Filling Station
	b	French Mix Electricity	On Site Electrolysis		No	Gas	Domestic use
4	a	Biomass	On Site Gasification		No	Gas	Car Filling Station
5	a	Offshore Wind Power	On Site Electrolysis		No	Gas	Car Filling Station
	b	Offshore Wind Power	On Site Electrolysis		No	Gas	Domestic use
6	a	By-product			No	Gas	Car Filling Station
	b	By-product			No	Gas	Domestic use
7	a	Import Norway			No	Gas	Car Filling Station
	b	Import Norway			No	Gas	Domestic use

In the following section, these hydrogen production and utilization chains are presented one by one.

4. Selected Chains

In the following paragraphs, the seven selected hydrogen chains for France and their variants are presented. The chains presented are all chains as stated in Table 2.
First, all hydrogen chains for mobile applications are developed, ordered by the feedstock used.
All hydrogen chains for stationary use follow there after.

4.1. Chain 1.a1. Natural Gas, Central SMR, CCS, NG pipelines; use: car filling station

Description
Natural gas extracted and processed in NG producer countries is transported into the French gas network (1000 km distance) and becomes distributed to a central point (500 km distance, on average). A SMR located at that point produces hydrogen, which becomes subsequently distributed to the filling stations. Therefore, the hydrogen grid consists of a large pipeline (100 km) with a throughput of 240 GWh H_2 per pipeline and year and some smaller pipelines (5 km) with a throughput of 8 GWh H_2 per pipeline and year.
The central SMR separates the produced CO_2, which becomes subsequently stored in old gas/oil fields after transport (50 km distance, on average).
The filling station requires electricity, which comes from the French mix.

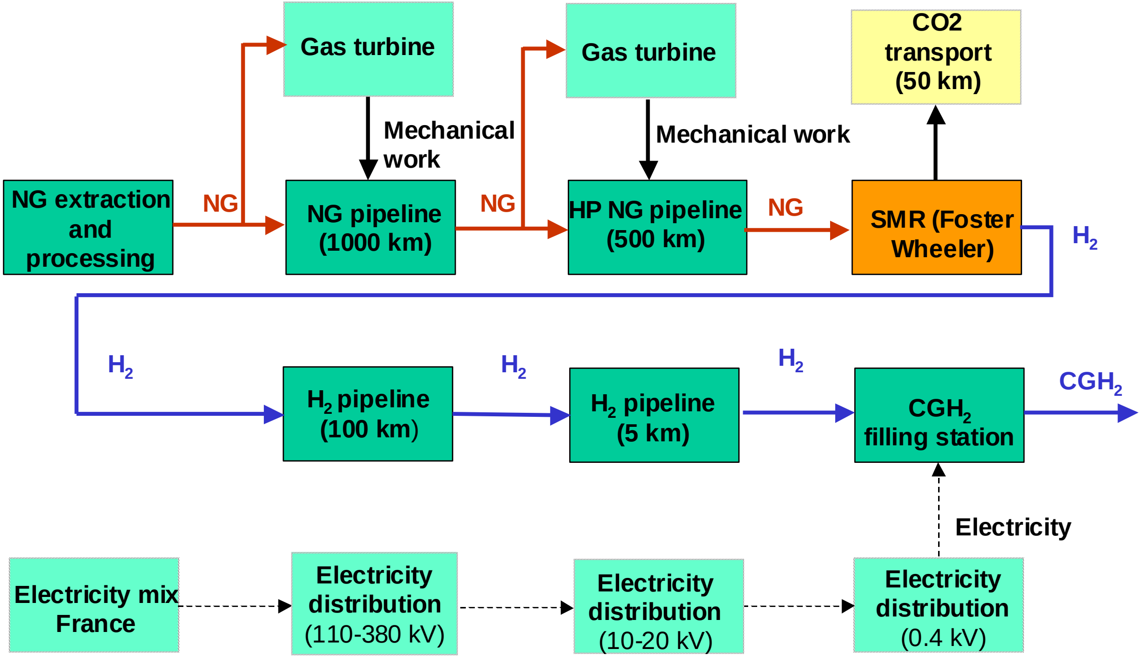

Figure 1. Modelled hydrogen chain for NG with central SMR and CCS, for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

- Natural gas processing and extraction	A.1
- Natural gas transport pipelines	A.2
- Electricity production **Erreur ! Source du renvoi introuvable.**	
- Electricity transport	A.2
- Hydrogen production from natural gas (including CCS)	A.3
- Hydrogen transport	A.4

- Filling station A.5

4.2. Chain 1.a2. Natural Gas, Central SMR, CCS, Mix NG/GH$_2$ pipelines; use: car filling station

Description

Natural gas extracted and processed in gas fields is transported into the French gas network (1000 km distance) and becomes distributed to a central point (500 km distance, on average). A SMR located at that point produces hydrogen. The hydrogen is mixed with NG (10 percents volume) in order to be transported in the existing NG pipelines (90 km distance, on average). By doing that there is no need to build a specific infrastructure and so no additional cost is needed for transport. Then, the mixture is separated in a “separator” plant of which efficiency is not one hundred percent; so, in addition to the separated hydrogen there is a gas-off in which remains hydrogen. In order to valorise this hydrogen, there is a credit which represents the fact that the NG consumers use and pay this hydrogen.

The separated hydrogen is distributed to filling stations. Therefore, the hydrogen grid consists of a large pipeline (10 km) with a throughput of 240 GWh H_2 per pipeline and year and some smaller pipelines (5 km) with a throughput of 8 GWh H_2 per pipeline and year.

The central SMR separates the produced CO_2, which becomes subsequently stored in old gas/oil fields after transport (50 km distance, on average).

Electricity required at the filling station is obtained from French mix at low-voltage level, whereas electricity required at the separator plant is obtained from French mix at high-voltage level.

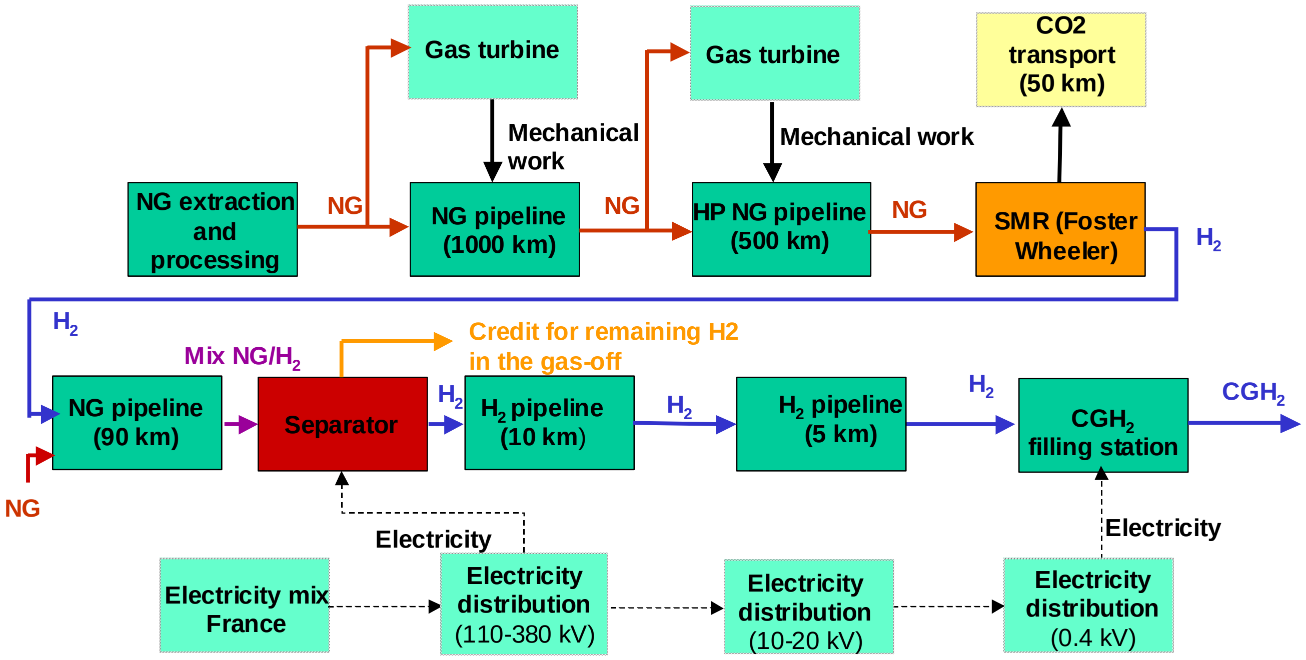

Figure 2. Modelled hydrogen chain for NG with central SMR and CCS, H_2 transport in existing NG pipelines, for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

- Natural gas processing and extraction	A.1
- Natural gas transport pipelines	A.2
- Electricity production	A.1
- Electricity transport	A.2
- Hydrogen production from natural gas (including CCS)	A.3
- Hydrogen transport	A.4

Filling station	A.5
Mix transport	A.4

4.3. Chain 1.a3. Natural Gas, Central SMR, no CCS, LH$_2$ truck; use: car filling station

Description

Natural gas extracted and processed in gas fields is transported into the French gas network (1000 km distance) and becomes distributed to a central point (500 km distance, on average). A SMR located at that point produces hydrogen. Gaseous hydrogen produced by this plant is liquefied and then transported by truck on 150 km to a vaporization plant, where LH2 is converted into CGH2.

Electricity required at the liquefaction plant is obtained from French mix at a high-voltage level, whereas electricity required at the filling station and by the vaporization plant is required at low-voltage level.

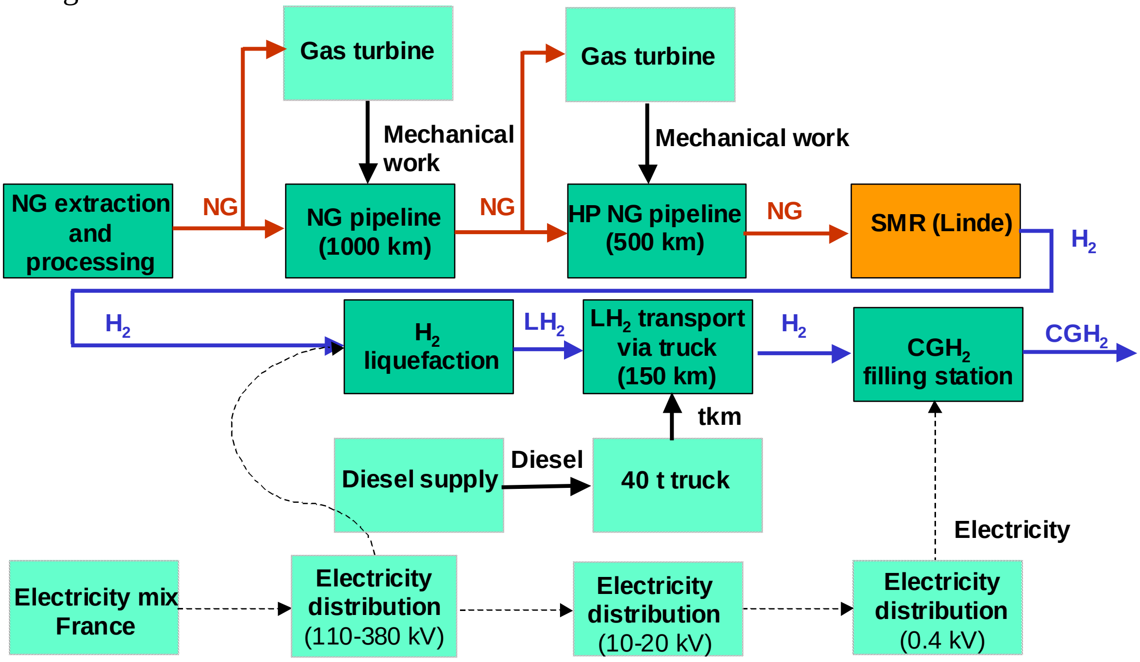

Figure 3. Modelled hydrogen chain for NG with central SMR, LH$_2$ truck transport, for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

Natural gas processing and extraction	A.1
Natural gas transport pipelines	A.2
Electricity production	A.1
Electricity transport	A.2
Hydrogen production from natural gas	A.3
Hydrogen transport	A.4
Filling station	A.5
Liquefaction of hydrogen	A.3
Vaporization of hydrogen	A.3
Transport of liquefied hydrogen	A.4

4.4. Chain 2.a2. French Mix Electricity, Central Electrolysis; use: car filling station

Description

Electricity coming from the French mix is distributed to a central electrolysis plant. Gaseous hydrogen (CGH_2) produced by this plant is subsequently distributed to the filling stations. Therefore, the hydrogen grid consists of a large pipeline (100 km) with a throughput of 240 GWh H_2 per pipeline and year and some smaller pipelines (5 km) with a throughput of 8 GWh H_2 per pipeline and year.

Electricity required at the central electrolysis and the liquefaction plant is obtained from French mix at a high-voltage level, whereas electricity required at the filling station is at low-voltage level.

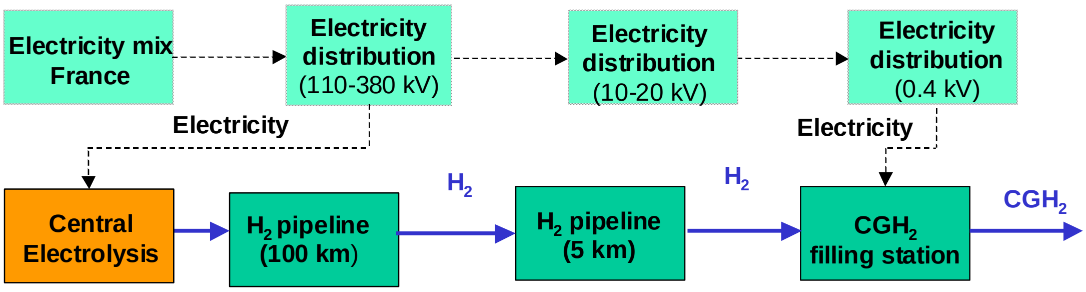

Figure 4. Modelled hydrogen chain for central electrolysis, electricity from French mix, for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

- Electricity provision	A.1
- Electricity transport	A.2
- Hydrogen production through electrolysis	A.3
- Hydrogen transport	A.4
- Filling station	A.5

4.5. Chain 2.a3. Dedicated nuclear reactor, Central High Temperature Electrolysis; use: car filling station

Description

The heat produced by the nuclear reaction in the EPR reactor is divided in two parts. The first one is used in the turbines to produce the electricity needed in the high temperature electrolysis plant (HTE) whereas the second one is transported on 10 km to HTE. Gaseous hydrogen (CGH_2) produced by this plant is subsequently distributed to the filling stations. Therefore, the hydrogen grid consists of a large pipeline (100 km) with a throughput of 240 GWh H_2 per pipeline and year and some smaller pipelines (5 km) with a throughput of 8 GWh H_2 per pipeline and year.

Electricity required at the filling station is at low-voltage level.

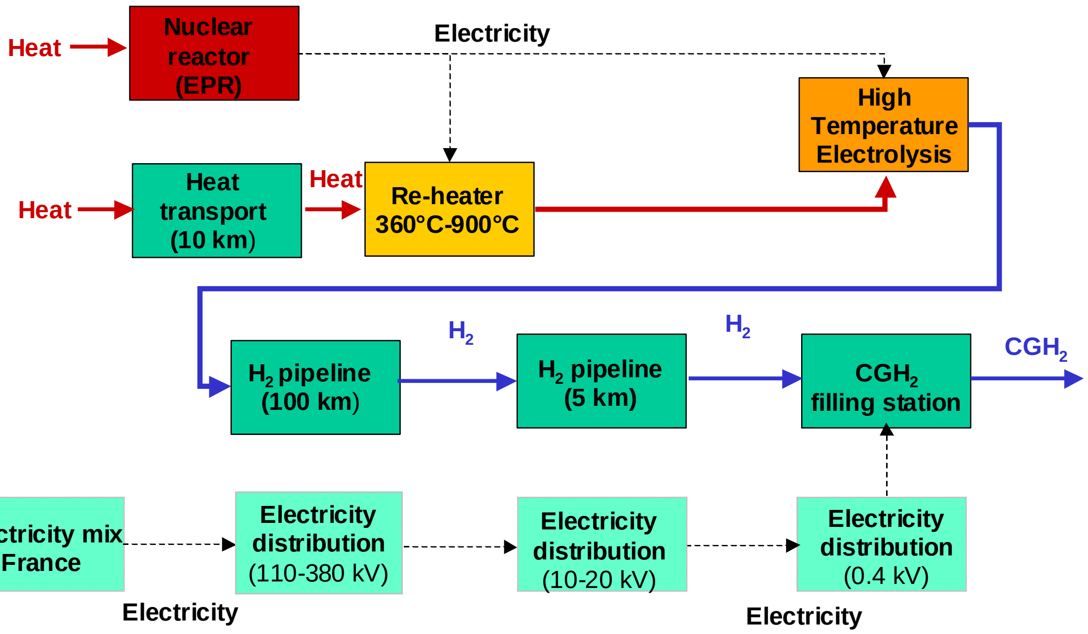

Figure 5. Modelled hydrogen chain for central HT electrolysis, electricity from dedicated nuclear reactor (EPR), for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

- Electricity provision	A.1
- Electricity transport	A.2
- Hydrogen production through HT electrolysis	A.3
- Hydrogen transport	A.4
- Filling station	A.5

4.6. Chain 3.a. French Mix Electricity, On Site Electrolysis; use: car filling station

Description

Electricity coming from the French mix is distributed to an on site electrolysis plant. Gaseous hydrogen produced by this plant feed the CGH2 filling station.

Electricity required at the electrolysis plant is obtained from French mix at a medium-voltage level whereas electricity required at the filling stations is obtained from French mix at a low-voltage level.

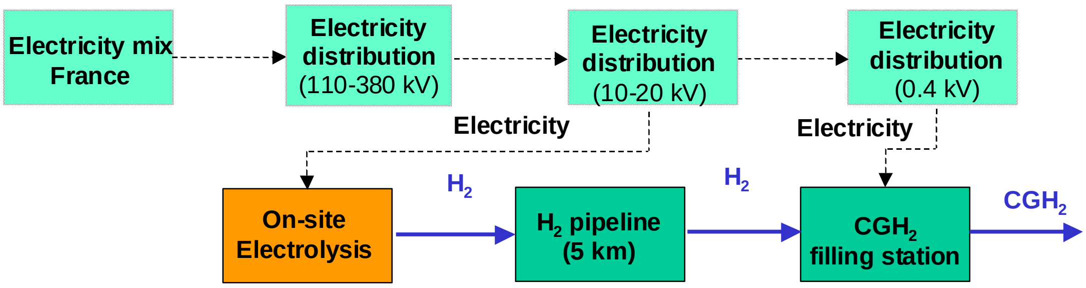

Figure 6. Modelled hydrogen chain for on site electrolysis, electricity from French mix, for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

- Electricity provision	A.1
- Electricity transport	A.2
- Hydrogen production through electrolysis	A.3
- Hydrogen transport	A.4
- Filling station	A.5

4.7. Chain 4. Biomass, On Site Gasification, no CCS; use: car filling station

Description

French residual wood is chipped and transported by a 40 tons truck over 50 km to the gasification plant. The electricity needed in the gasification plant is obtained from French mix at a low-voltage level. Once the biomass has been gasified, the hydrogen is transported to the filling station through a pipeline grid consisting in large pipelines (50 km) with a throughput of 240 GWh H_2 per pipeline and year and some smaller pipelines (5 km) with a throughput of 8 GWh H_2 per pipeline and year.

The wood chipping process uses also diesel fuel for the conversion of energy into mechanical work.

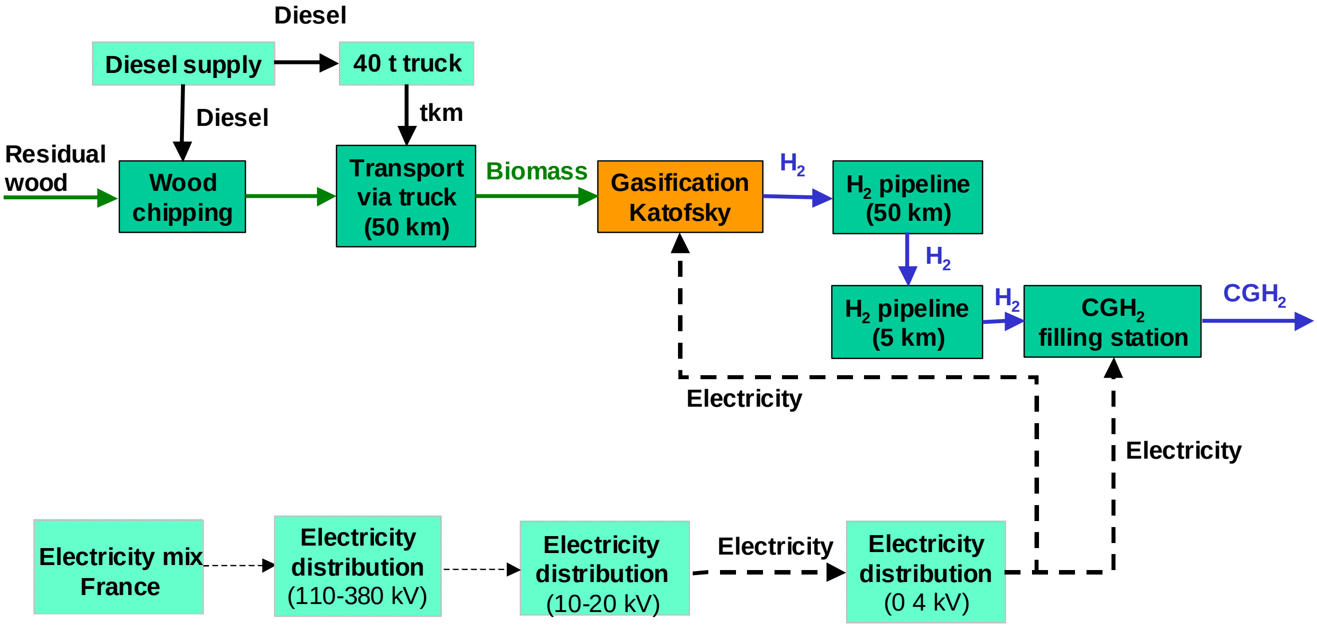

Figure 7. Modelled hydrogen chain for wood residue gasification, for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

- Biomass provision	A.1
- Biomass chipping	A.6
- Biomass transport	A.2
- Electricity provision	A.1
- Electricity transport	A.2
- Hydrogen production from biomass	A.3
- Hydrogen transport by pipeline	A.4
- Filling station	A.5

4.8. Chain 5a. Wind Energy, On Site Electrolysis; use: car filling station

Description

Electricity generated by offshore wind turbines is distributed to an on site electrolysis plant. 21% of this electricity is sold to the grid (when it is too windy). The electricity used by the electrolysis plant is obtained by the wind turbines at 50% and the French mix at 50% too, when there is no wind. Indeed, the storage capacity of the filling station is only 40% of the daily demand. Gaseous hydrogen produced by the electrolysis plant becomes subsequently distributed through a small hydrogen pipeline (5 km, 8 GWh H_2 per pipeline and year) to the end users: the filling stations. Electricity required at the electrolysis plant is obtained from electricity at a medium-voltage level and electricity required at the filling stations is obtained from French mix at a low-voltage level.

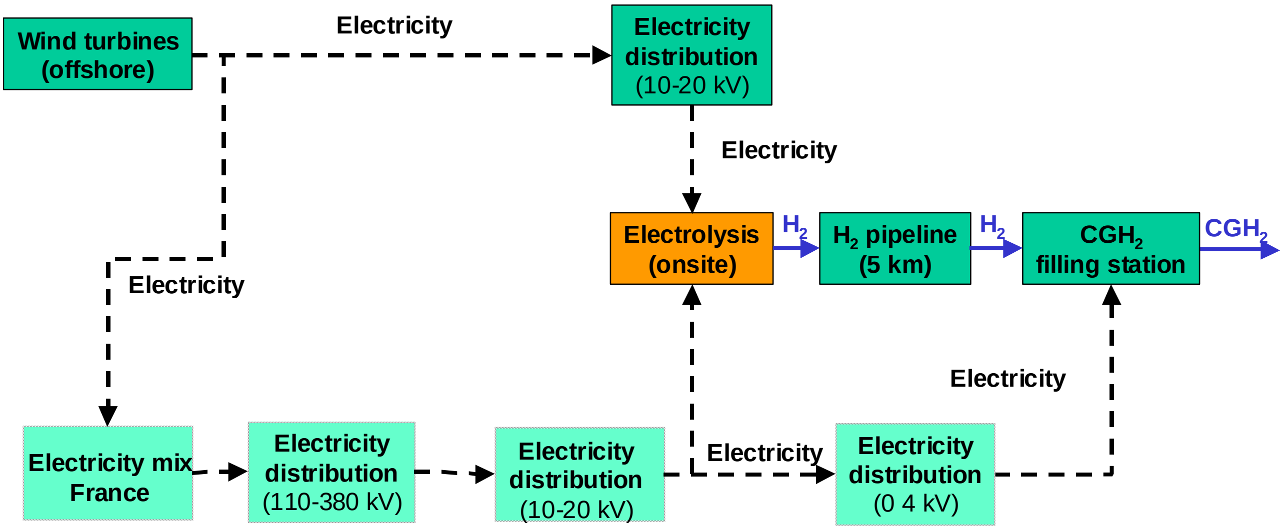

Figure 8. Modelled hydrogen chain for wind power electrolysis, for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

- Electricity provision (including wind power)	A.1
- Electricity transport	A.2
- Hydrogen production through electrolysis	A.3
- Hydrogen transport by pipeline	A.4
- Filling station	A.5

4.9. Chain 6a. By-product; use: car filling station

Description

By-product hydrogen is generated by various types of industrial processes e.g. in refineries. Today the by-product hydrogen is used as fuel for the supply of process heat within the industry. If the by-product is exported as product e.g. for hydrogen vehicles within the industry additional natural gas will be required for the supply of process heat. Therefore the generation of by-product hydrogen can be considered as a process with natural gas as input and hydrogen as output and a conversion efficiency of 100%.

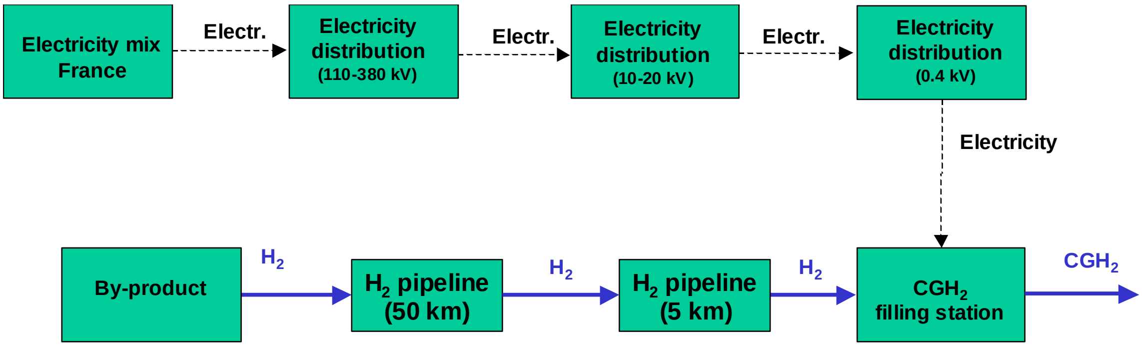

Figure 9. Modelled hydrogen chain for by-product, for use in filling stations

For description of the processes used for the model of this chain, see sections indicated below:

- Electricity provision (including wind power)	A.1
- Electricity transport	A.2
- Hydrogen transport by pipeline	A.4
- Filling station	A.5

4.10. Chain 1.b1. Natural Gas, Central SMR, CCS, NG pipelines; use: stationary

Description

Natural gas extracted and processed in Russia is transported into the French gas network (1000 km distance) and becomes distributed to a central point (500 km distance, on average). A SMR located at that point produces gaseous hydrogen. The CGH_2, distributed to small users (domestic appliances), is used in combined heat and power fuel cells (FC CHP) installations that follow the heat demand of the users. In the case that the heat demand is covered, more electricity will on average be produced than the users require. At those moments, some electricity generation elsewhere will be avoided. This process is accounted in the model as "credit".

The hydrogen grid consists of a large pipeline (100 km) with a throughput of 240 GWh H_2 per pipeline and year and some smaller pipelines (5 km) with a throughput of 8 GWh H_2 per pipeline and year.

The central SMR separates the produced CO_2, which becomes subsequently stored in old gas/oil fields after transport (50 km distance, on average).

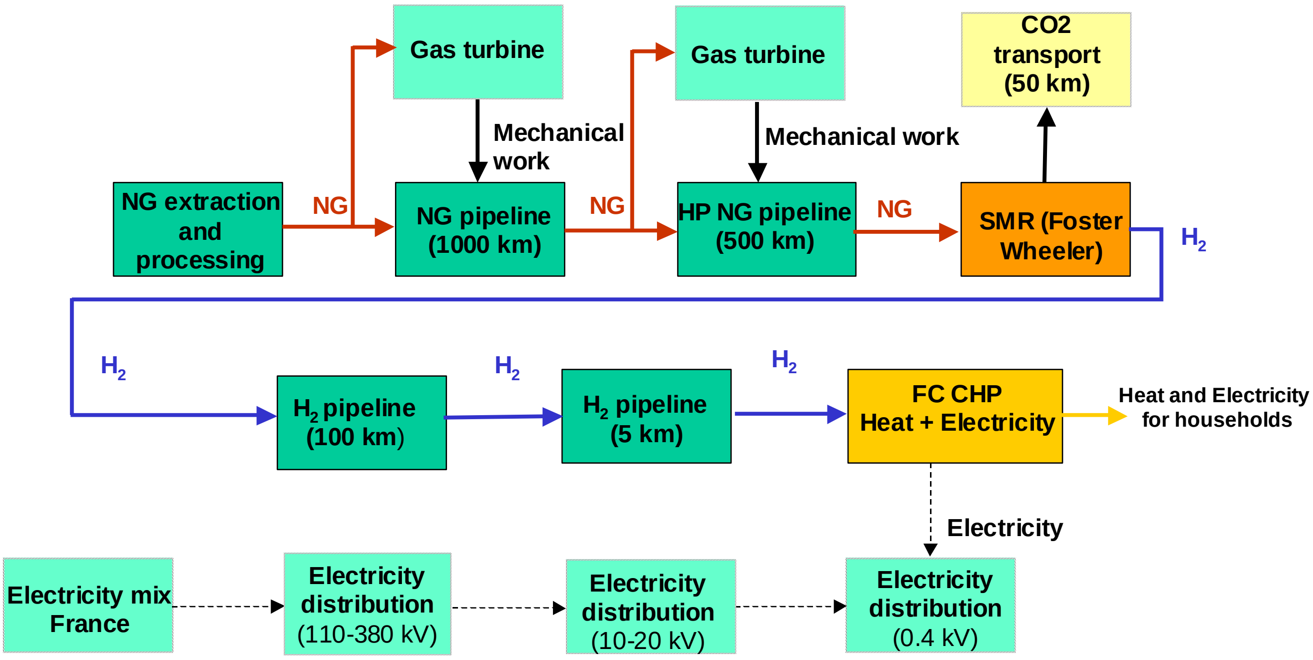

Figure 10. Modelled hydrogen chain for NG with central SMR and CCS, for use in FC CHP

For description of the processes used for the model of this chain, see sections indicated below:

- Natural gas processing and extraction	A.1
- Natural gas transport pipelines	A.2
- Electricity production	A.1
- Electricity transport	A.2
- Hydrogen production from natural gas (including CCS)	A.3
- Hydrogen transport	A.4
- FC CHP	A.5

4.11. Chain 1.b2. Natural Gas, Central SMR, CCS, Mix NG/GH$_2$ pipelines; use: stationary

Description

Natural gas extracted and processed in gas fields is transported into the French gas network (1000 km distance) and becomes distributed to a central point (500 km distance, on average). A SMR located at that point produces hydrogen. The hydrogen is mixed with NG (10 percents volume) in order to be transported in the existing NG pipelines (90 km distance, on average). By doing that there is no need to build a specific infrastructure and so no additional cost for transport. Then, the mixture is separated in a "separator" plant of which efficiency is not one hundred percent. So, in addition to the separated hydrogen there is a gas-off in which remains hydrogen. In order to valorise this hydrogen, there is a credit which represents the fact that the NG consumers use and pay this hydrogen.

The separated hydrogen, distributed to small users (domestic appliances), is used in combined heat and power fuel cells (FC CHP) installations that follow the heat demand of the users. In the case that the heat demand is covered, more electricity will on average be produced than the users require. At those moments, some electricity generation elsewhere will be avoided. This process is accounted in the model as "credit".

The hydrogen grid consists of a large pipeline (10 km) with a throughput of 240 GWh H_2 per pipeline and year and some smaller pipelines (5 km) with a throughput of 8 GWh H_2 per pipeline and year.

The central SMR separates the produced CO_2, which becomes subsequently stored in old gas/oil fields after transport (50 km distance, on average).
Electricity required at the separator plant is obtained from French mix at high-voltage level.

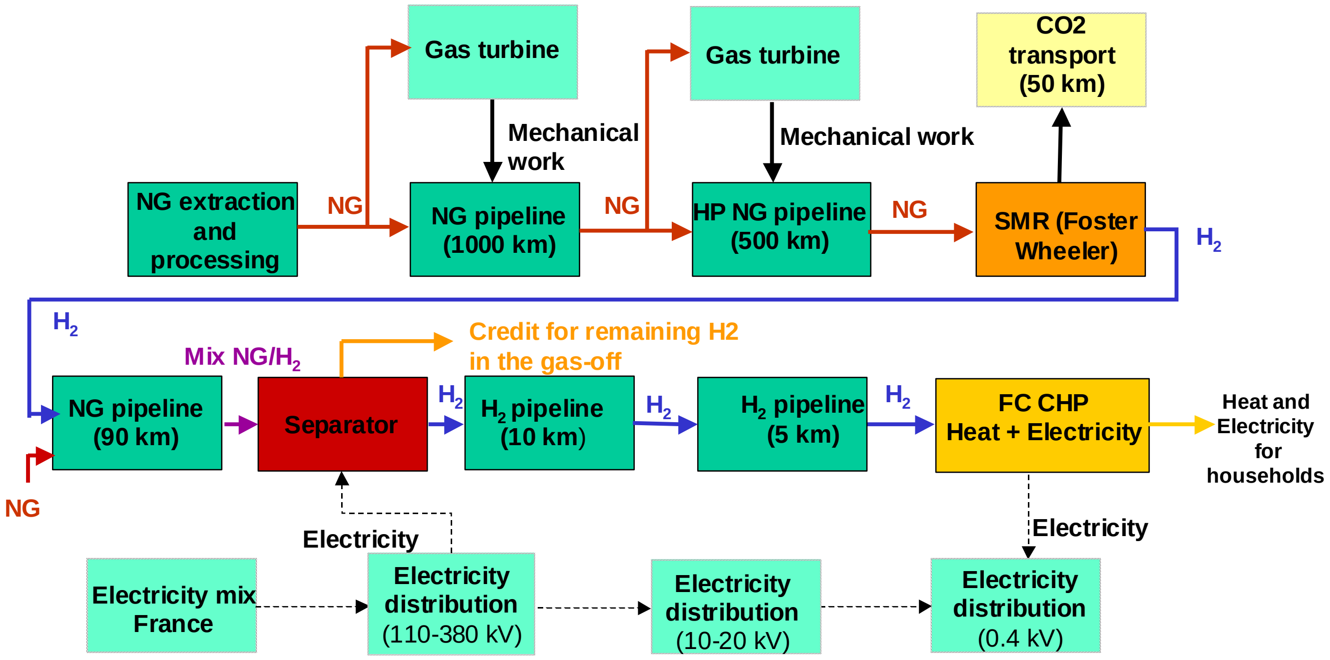

Figure 11. Modelled hydrogen chain for NG with central SMR and CCS, H_2 transport in existing NG pipelines, for use in FC CHP

For description of the processes used for the model of this chain, see sections indicated below:

- Natural gas processing and extraction	A.1
- Natural gas transport pipelines	A.2
- Electricity production	A.1
- Electricity transport	A.2
- Hydrogen production from natural gas (including CCS)	A.3
- Hydrogen transport	A.4
- FC CHP	A.5
- Mix transport	A.4

4.12. Chain 3.b. French Mix Electricity, On Site Electrolysis; use: stationary

Description

Electricity coming from the French mix is distributed to an on site electrolysis plant. Gaseous hydrogen produced by this plant, distributed to small users (domestic appliances), is used in combined heat and power fuel cells (FC CHP) installations that follow the heat demand of the users. In the case that the heat demand is covered, more electricity will on average be produced than the users require. At those moments, some electricity generation elsewhere will be avoided. This process is accounted in the model as "credit".

Electricity required at the electrolysis plant is obtained from French mix at a medium-voltage level.

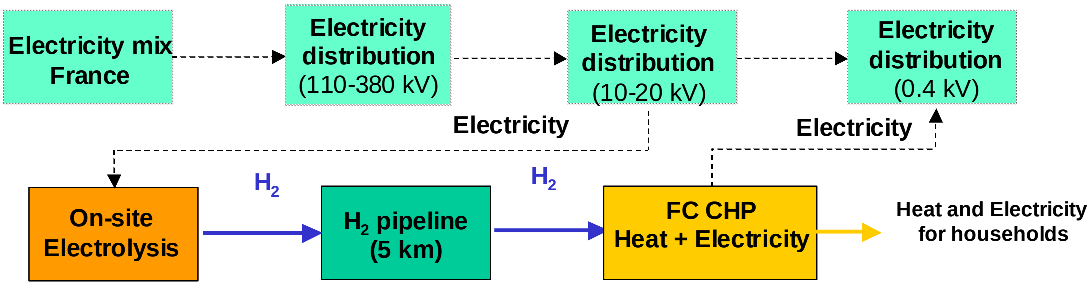

Figure 12. Modelled hydrogen chain for on site electrolysis, electricity from French mix, for use in FC CHP

For description of the processes used for the model of this chain, see sections indicated below:

- Electricity provision	A.1
- Electricity transport	A.2
- Hydrogen production through electrolysis	A.3
- Hydrogen transport	A.4
- FC CHP	A.5

4.13. Chain 5b. Wind Energy, On Site Electrolysis; use: stationary

Description

Electricity generated by offshore wind turbines is distributed to an on site electrolysis plant. 21% of this electricity is sold to the grid (when it is too windy). The electricity used by the electrolysis plant is obtained by the wind turbines at 50% and the French mix at 50% too, when there is no wind. Gaseous hydrogen produced by the electrolysis plant, distributed to small users (domestic appliances), is used in combined heat and power fuel cells (FC CHP) installations that follow the heat demand of the users. In the case that the heat demand is covered, more electricity will on average be produced than the users require. At those moments, some electricity generation elsewhere will be avoided. This process is accounted in the model as "credit".

Electricity required at the electrolysis plant is obtained from electricity at a medium-voltage level.

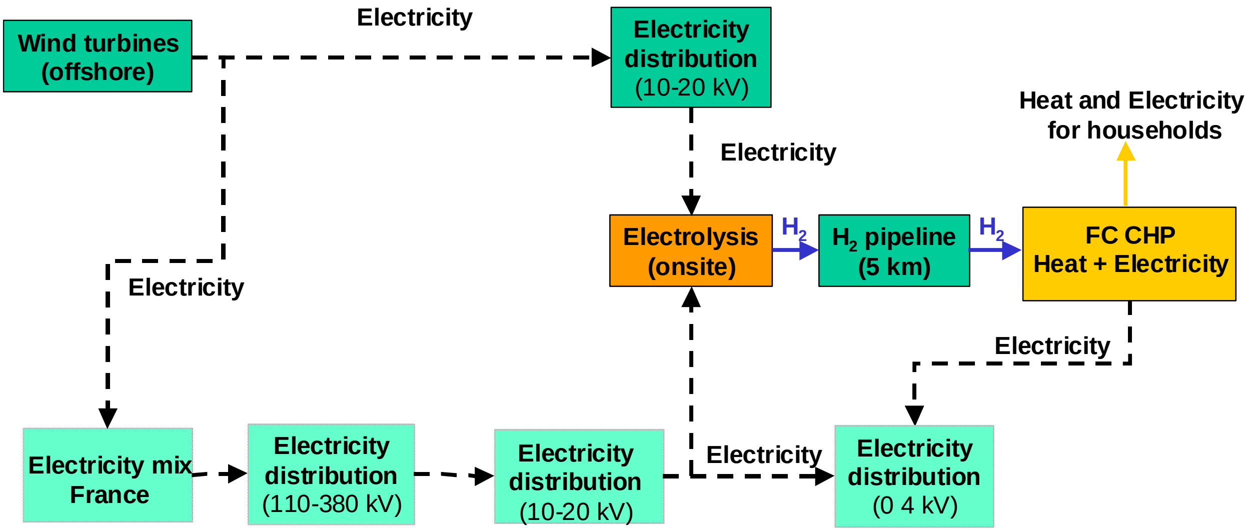

Figure 13. Modelled hydrogen chain for wind power electrolysis, for use in FC CHP

For description of the processes used for the model of this chain, see sections indicated below:

- Electricity provision (including wind power)	A.1
- Electricity transport	A.2
- Hydrogen production through electrolysis	A.3
- Hydrogen transport by pipeline	A.4
- FC CHP	A.5

4.14. Chain 6b. By-product; use: stationary

Description

By-product hydrogen is generated by various types of industrial processes e.g. refineries. Today the by-product hydrogen is used as fuel for the supply of process heat within the industry. If the by-product is exported as product e.g. for FC CHP within the industry additional natural gas will be required for the supply of process heat. Therefore the generation of by-product hydrogen can be considered as a process with natural gas as input and hydrogen as output and a conversion efficiency of 100%.

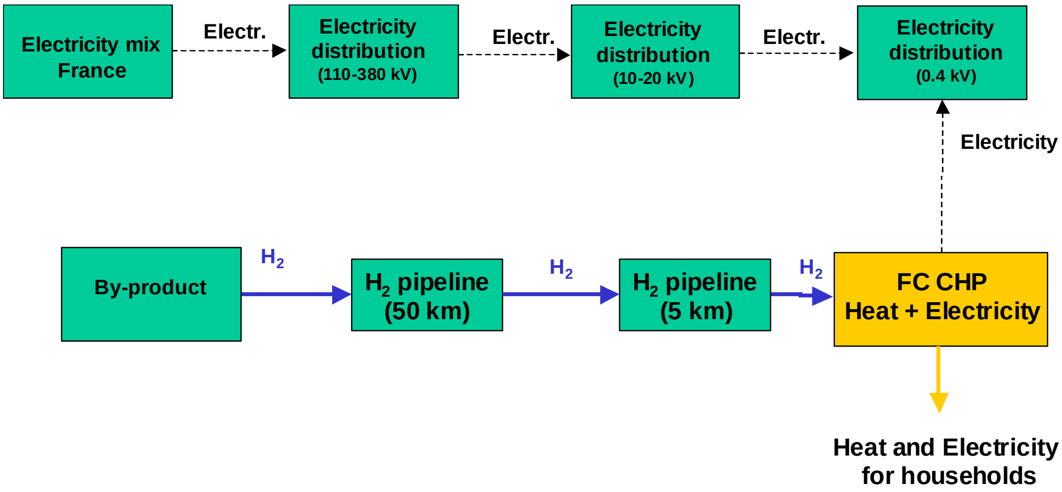

Figure 14. Modelled hydrogen chain for by-product, for use in FC CHP

For description of the processes used for the model of this chain, see sections indicated below:

- Electricity provision (including wind power)	A.1
- Electricity transport	A.2
- Hydrogen transport by pipeline	A.4
- FC CHP	A.5

5. Results

5.1. Hypothesis required for calculations

The calculated costs (kWh of hydrogen for mobile applications or kWh of heat + electricity for stationary applications) are levelized for the years 2020, 2030 and 2050 according to the calculation rules presented in 7. For France, a discount rate of 8% has been used.

In the following paragraphs, the results for mobile and stationary applications are given for 1 provided kWh. For mobile applications, well-to-tank (WTT) analyses have been performed. For stationary use, the analyses are of the type well-to-stationary-use (WTStU).

5.2. Efficiencies: WTT and WTStU

The following figures show the efficiencies of all selected hydrogen supply chains in accordance to the following list:

Description of mobile supply chains

1.a1 Natural Gas, Central SMR, CCS, NG pipelines; use: car filling station (2050)
1.a2 Natural Gas, Central SMR, CCS, Mix NG/GH_2 pipelines; use: car filling station (2030)
1.a3 Natural Gas, Central SMR, CCS, LH_2 truck; use: car filling station (2020)
2.a2 French Mix Electricity, Central Electrolysis; use: car filling station (2030 ; 2050)
2.a3 Dedicated nuclear reactor, Central High Temperature Electrolysis; use: car filling station (2030 ; 2050)
3.a French Mix Electricity, On Site Electrolysis; use: car filling station (2020 ; 2030 ; 2050)
4. Biomass, On Site Gasification, no CCS; use: car filling station (2030 ; 2050)
5a. Wind Energy, On Site Electrolysis; use: car filling station (2030 ; 2050)
6a. By-product; use: car filling station (2020)

Description of stationary use of hydrogen supply chains

1.b1 Natural Gas, Central SMR, CCS, NG pipelines; use: stationary (2050)
1.b2 Natural Gas, Central SMR, CCS, Mix NG/GH_2 pipelines; use: stationary (2030)
3.b French Mix Electricity, On Site Electrolysis; use: stationary (2020 ; 2030 ; 2050)
5b. Wind Energy, On Site Electrolysis; use: stationary (2030 ; 2050)
6b. By-product; use: stationary (2020)

Figure 15 shows the efficiencies of the selected chains for the provision of hydrogen for mobile end users.

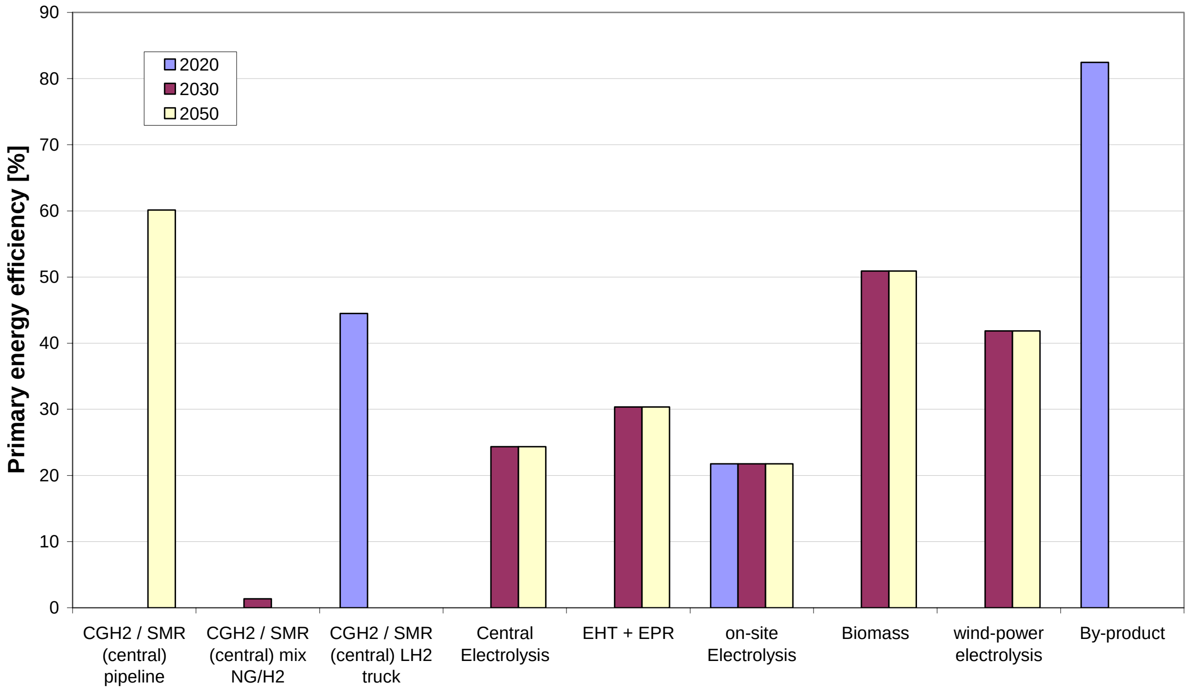

Figure 15. Efficiencies of selected mobile H2 supply chains

Figure 16 shows the efficiencies of the selected chains for the provision of hydrogen for stationary end users.

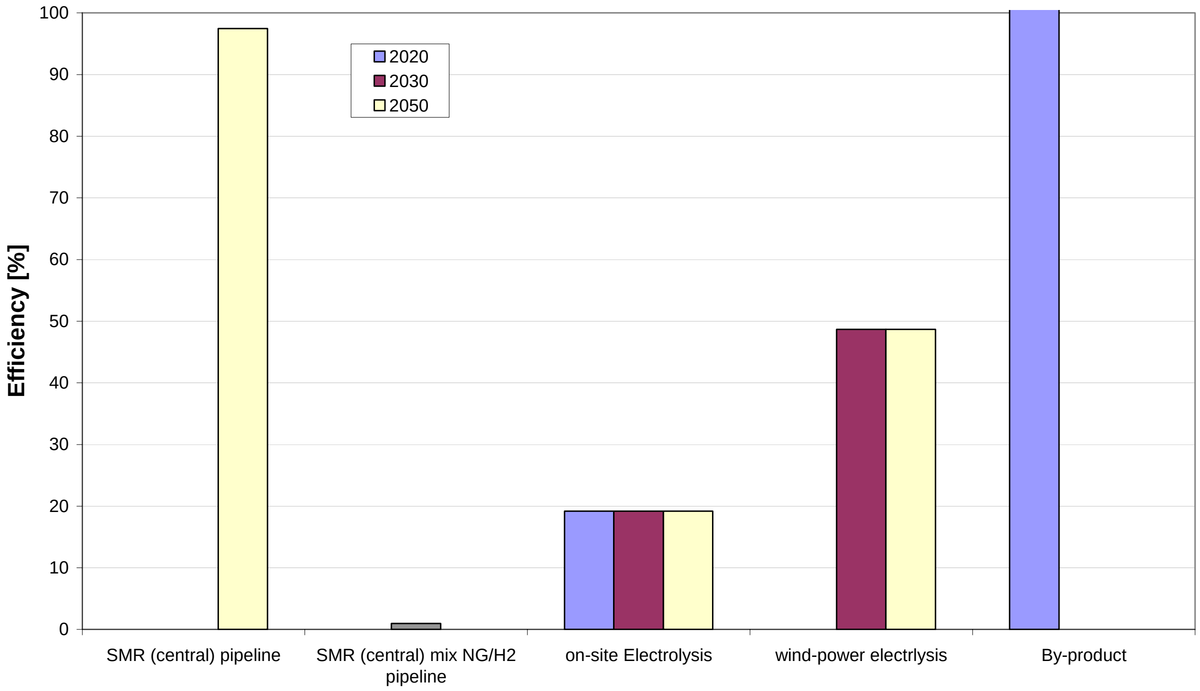

Figure 16. Efficiencies of selected H_2 supply chains for stationary use

5.3. Greenhouse Gas Emissions: WTT and WTStU

In 2020 there are only three ways to produce hydrogen for the mobile applications: Steam Methane Reforming with LH_2 transport by trucks, on-site electrolysis and by-product. Figure 17 shows the Greenhouse Gas Emissions of the selected chains for the provision of hydrogen for mobile end users.

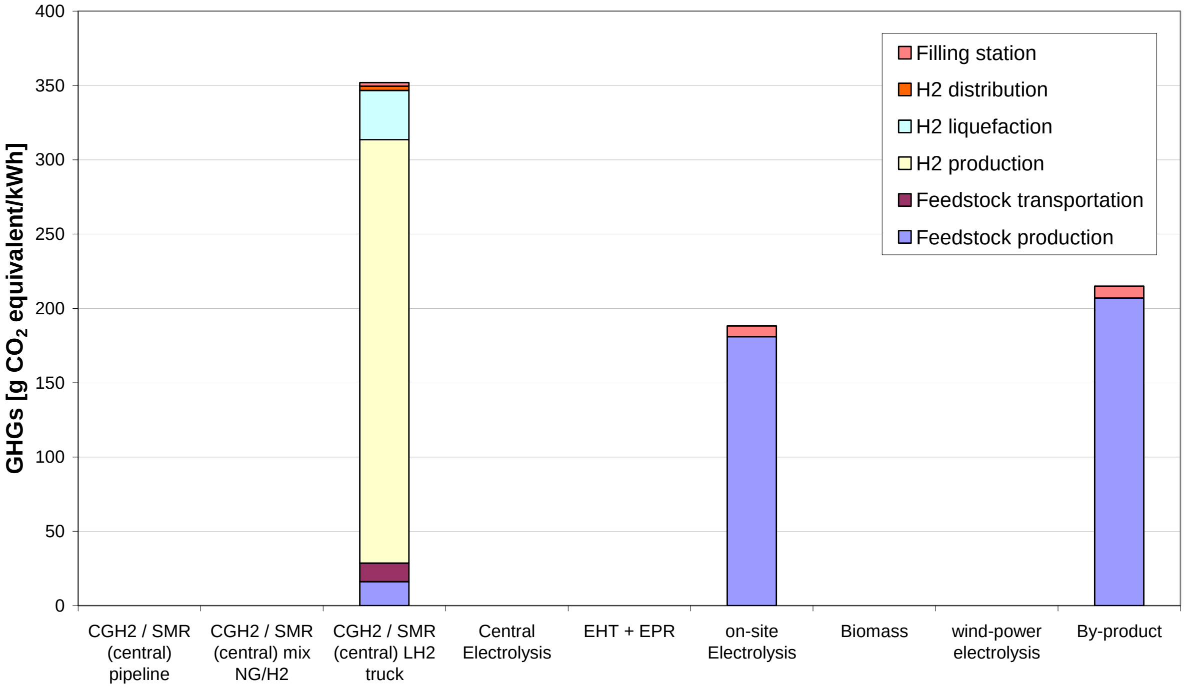

Figure 17. CO_2-equivalent emissions of mobile H_2 supply chains in 2020

In 2020, we assumed that there is no carbon capture and sequestration (CCS), and so there are more GHG emissions when using a SMR than using an electrolysis plant.

For the chain which is dealing with Steam Methane Reforming, the GHG emissions are mainly due to the hydrogen production. The second cause of GHG emissions is the hydrogen liquefaction which needs electricity from the French mix. Indeed, this kind of electricity mix has few emissions due the high part of nuclear energy, but it is not zero.

In 2030 there are six ways to produce hydrogen for the mobile applications: Steam Methane Reforming with CCS and Mix NG/H_2 transport by existing NG pipelines, central electrolysis, HTE with dedicated reactor, on-site electrolysis, gasification of biomass and wind-power electrolysis. Figure 18 shows the Greenhouse Gas Emissions of the selected chains for the provision of hydrogen for mobile end users.

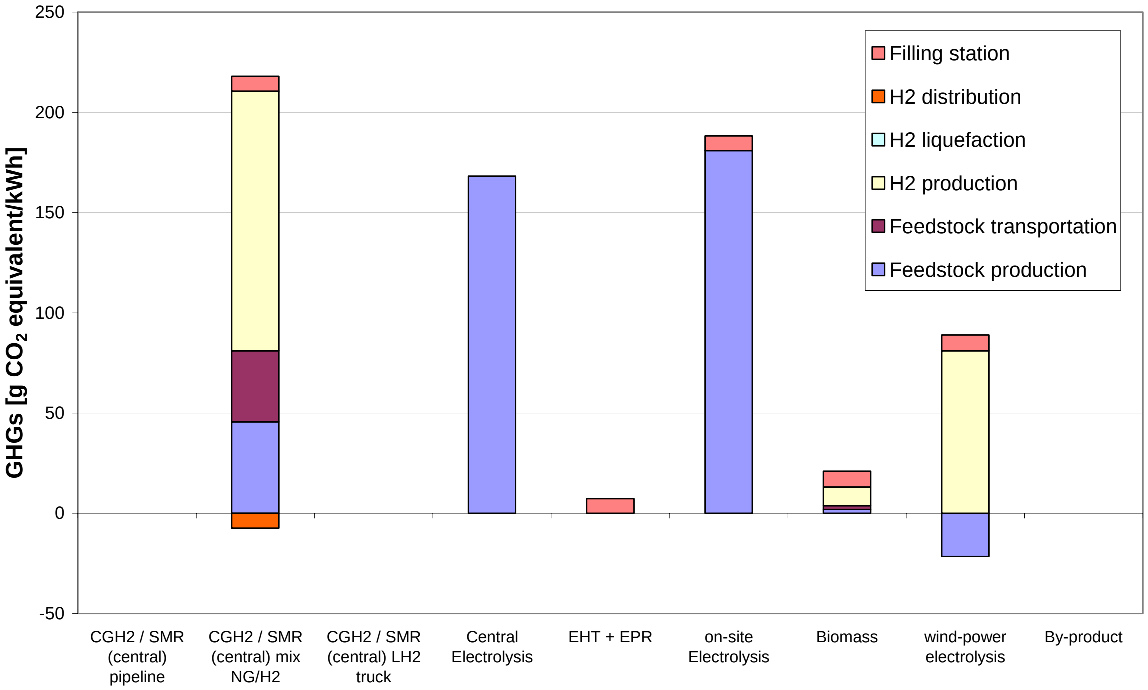

Figure 18. CO_2-equivalent emissions of mobile H_2 supply chains in 2030

In 2030, we assumed that the CCS is feasible, but the use of the mix NG/H_2 to transport hydrogen induces an increase of NG consumption and so an increase of GHG. However, the hydrogen consumption by the NG users avoids some GHG emissions, which appears on the graph in orange.

As it was expected, the chain which is dealing with high temperature electrolysis with a dedicated reactor has the fewer emissions (only due to the consumption of electricity from the mix in the FS).

The negative GHG emissions for the chain which is dealing with wind-power correspond to the fact that 21% of electricity produced by the wind power is sold to the grid.

The weak difference between the two chains of water electrolysis and the chain with SMR can be explained by the fact that we assumed CCS for the SMR and not for the production of electricity.

In 2050 there are six ways to produce hydrogen for the mobile applications: Steam Methane Reforming with CCS and H_2 pipelines, central electrolysis, HTE with dedicated reactor, on-site electrolysis, gasification of biomass and wind-power electrolysis. Figure 19 shows the Greenhouse Gas Emissions of the selected chains for the provision of hydrogen for mobile end users.

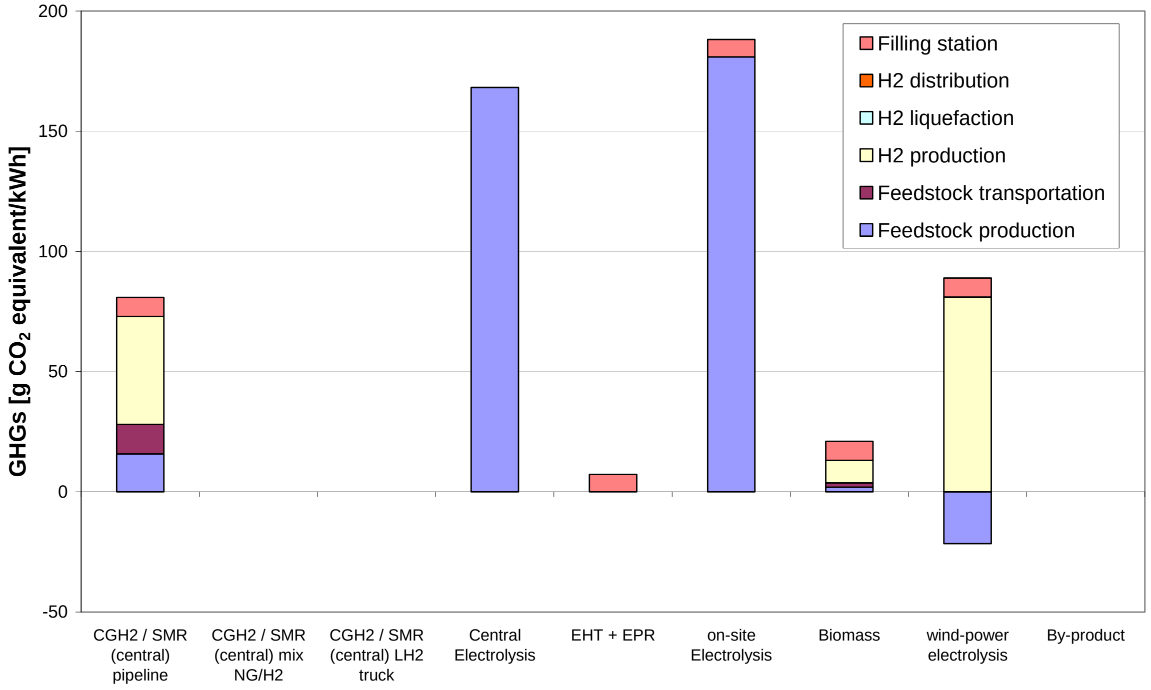

Figure 19. CO_2-equivalent emissions of mobile H_2 supply chains in 2050

The use of CCS is well efficient since the use of SMR is no more the most GHG producer.

Note that the GHG of the vehicles are independent of the selected chains and that they are small (near to zero) compared to the whole chain contribution.

There are five ways to produce hydrogen for the stationary applications : Steam Methane Reforming with CCS and H_2 pipelines (2050), Steam Methane Reforming with CCS and Mix NG/H_2 transport by existing NG pipelines (2030), on-site electrolysis (2020,2030,2050), wind-power electrolysis (2030,2050) and by-product (2020).Figure 20 shows the Greenhouse Gas Emissions of the selected chains for the provision of hydrogen for mobile end users.

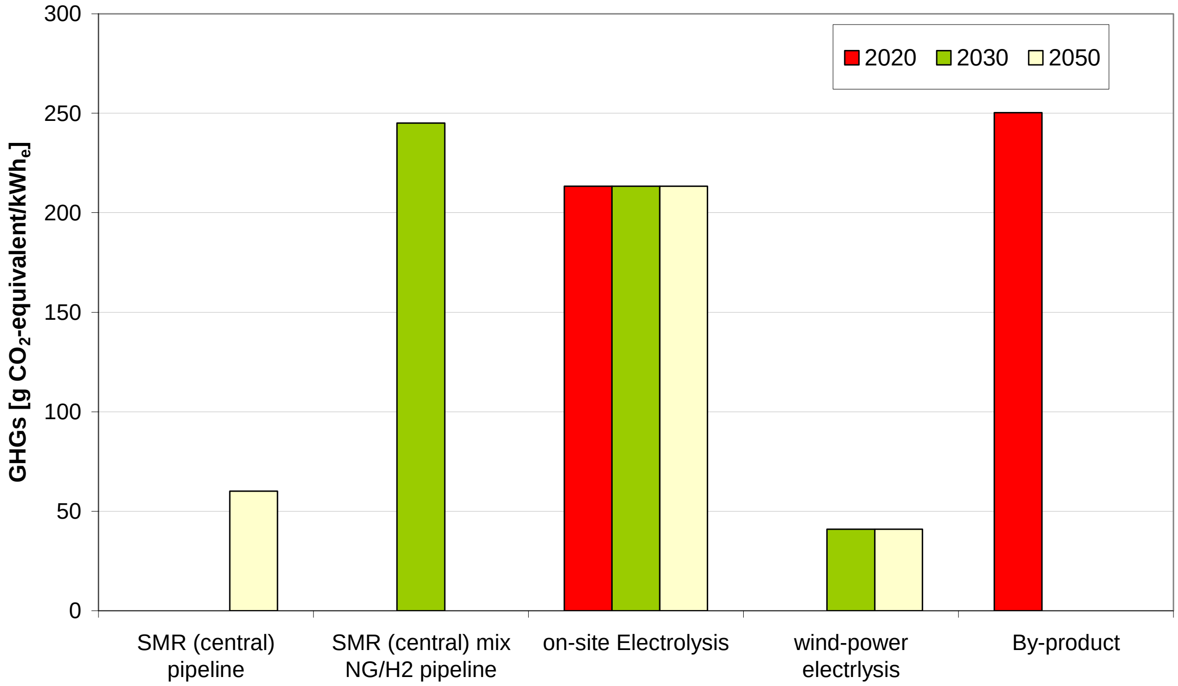

Figure 20. CO_2-equivalent emissions of stationary use of H_2 supply chains

5.4. Costs: WTT and WTStU

In Figure 21 and Figure 22, the given costs are calculated in [€/kWh] hydrogen, delivered at 880 bar to provide a full pressure of 700 bar to the vehicle tank for mobile applications and heat + electricity for stationary applications.

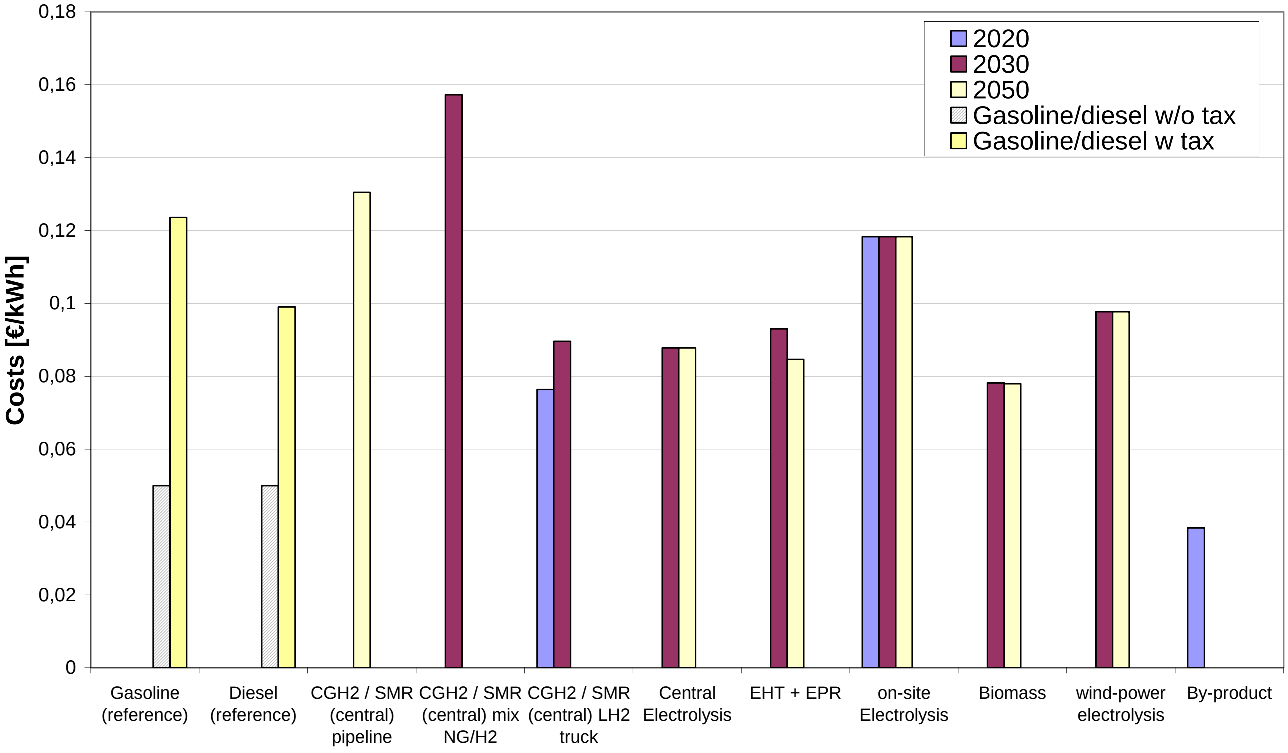

Figure 21. Costs of selected mobile hydrogen supply chains.

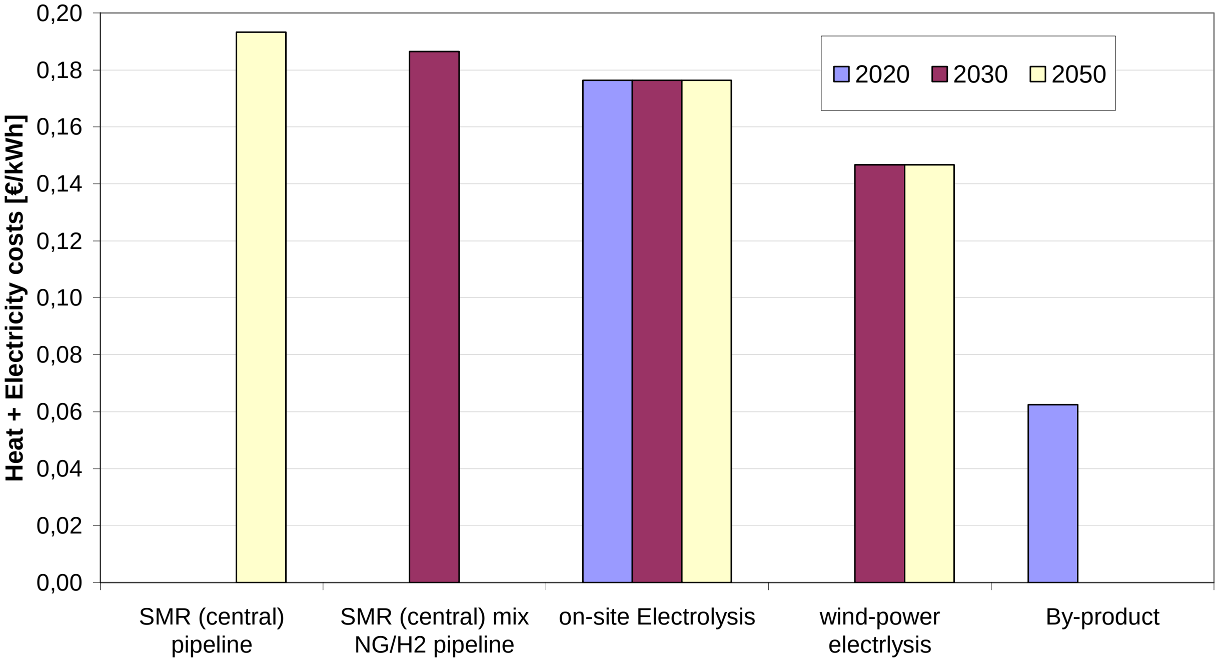

Figure 22. Costs of selected stationary use hydrogen supply chains.

In both cases, the use of by-product is the cheapest way. After 2030, water electrolysis is cheaper than the SMR, because of the increase of NG prices.

6. Remarks

In this report a synthesis of the selected chains and data for France has been performed. The tables presented allow a synthetically overview of the choices made.

7. Calculation rules

o 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 3. Conversion factors [IPCC 2001]

Emission	**g CO_2 equivalent per g**
CO_2	1
CH_4	23
N_2O	296

o Learning curves

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

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

where:

I = Investment of the N^{th} unit
a = Investment of the 1^{st} unit
N = Number of units
b = Parameter

The 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 N^{th} 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.

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

Levelized costs

Cost calculation for phase T1 (construction of the plant)

In this phase of the life cycle only capital expenditures are considered. It is assumed that a plant is built needing capital expenditures during its construction time T1.

$$C_{C(T1)} = C_{T1} = (Invest_{plant} \cdot r) \cdot T1 \cdot 0.5 \qquad [€]$$

where

$C_{C(T1)}$ = Capital costs during construction of the plant
$Invest_{plant}$ = Investment for the plant
r = Interest rate
T1 = Construction period in years

Cost calculation for phase T2 (operation of the plant)

Capital costs

The capital costs are levelized by assuming equal capital expenditures for every year t in the period T2.

$$C_{DI(t)} = \frac{r}{1-(1+r)^{-T2}} \cdot Invest_{plant} \qquad [€/yr]$$

where
$C_{DI(t)}$ = Capital expenditure in every year t
r = Interest rate
T2 = Economic lifetime of the plant in years
$Invest_{plant}$ = Investment for the plant

Overhead costs

$$C_{OH(t)} = Invest_{plant} \cdot OH \qquad [€/yr]$$

where
$Invest_{plant}$ = Investment for the plant
OH = Overhead coefficient.

Operating and maintenance costs

The operating and maintenance expenditures in the year t are

$$C_{OM(t)} = Invest_{plant} \cdot OM + C_{Lab} \qquad [€/yr]$$

where
$C_{OM(t)}$ = Operating and maintenance costs
$Invest_{plant}$ = Investment for the plant
OM = Maintenance coefficient
C_{Lab} = Labour costs in € per year

Energy and material costs

The processes are connected with upstream processes which supply the inputs. The costs of the inputs for a process are

$$C_{E(t)} = \sum_i Input_i \cdot IC_i \cdot P \cdot AFLH_t \qquad [€/yr]$$

where
$Input_i$ = Input of type i (e.g. natural gas, coal, etc.)
IC_i = Consumption of input of type i (e.g. kWh/kWh, kWh/kg, kg/kWh, kg/kg, tkm/kWh)
P = Process scale (e.g. in kWh/h, kg/h, tkm/h)
$AFLH_t$ Equivalent full load period (annual full load hours)

Levelized annual costs in period T_2

$$C_{T2(t)} = C_{DI(t)} + C_{OH(t)} + C_{OM(t)} + C_{E(t)} \qquad [€/yr]$$

$$C_{T2} = C_{T2(t)} \cdot T2 \qquad [€]$$

- *Cost calculation for phase T3 (dismantling of the plant)*

For the costs for the dismantling a fixed amount can be defined:

C_{T3} [€]

- *Levelized Costs*

Then the levelized costs per unit are

$$LEC = \frac{C_{T1} + C_{T2} + C_{T3}}{T2 \cdot AFLH_t \cdot P} \qquad [€/kWh], [€/kg], [€/tkm]$$

where:
LEC = Levelized costs

- *Use of specific costs for "processes" / plants*

There are situations where it seems preferable to directly input specific costs for a process instead of calculating the costs using the detailed cost input information as described above.

Possible reasons are:

- The detailed economic data are not available.
- It seems preferable to use market prices for certain energies / materials /services e.g. the market price for crude oil based gasoline and diesel
- The process scale of the process is some order of magnitude bigger than the process scale needed in the supply chain for the "Supply Scenario".

E3database also allows the direct input of specific costs for a process as "total variable costs" (e.g. electricity costs: 0.03 €/kWh).

8. Description of processes

In this section all processes used in the modelling of the hydrogen supply chains using the E3-database are presented. The processes are grouped as follows:

- Extraction of feedstock's
- Transport of feedstock's to production facilities
- Hydrogen production
- Hydrogen transport (if present)
- Hydrogen usage

There are also other processes used that do not directly match into the groups above. Example of such a process is the required mechanical work used to compensate the energy losses during pipeline transport. All these processes are grouped under the name 'auxiliary'.

In the following paragraphs, only the processes used into the selected French chains are described.

A.1 Availability of Feedstock's

In this section the following feedstock's are considered:

- Natural gas
- Biomass
- Electricity

The last one, electricity, is not a feedstock as such. Nevertheless, it is included here because it is used as a feedstock from which hydrogen can be produced through electrolysis.

Provision of Natural Gas

To be used, natural gas (NG) must be extracted, processed and transported. NG may be originally from the Netherlands or imported (from Norway, Russia, Algeria…), through the EU natural gas mix transport pipeline. Thereafter it is distributed via the national, regional and local natural gas high-pressure pipeline grids.

Processing is required because heavier hydrocarbons and contaminants such as H_2S must be removed. The extraction and processing processes require electricity and some additional heat, which can be provided by burning some NG in a heating plant.

The cost of the supply of natural gas has been assumed to be 0.012 EUR per kWh of natural gas (3.45 EUR/GJ)[2] as indicated in [CONCAWE 1/2003]. The cost of NG distribution via high-pressure pipeline has been assumed equal to 0.0004 EUR per kWh of natural gas.

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[2] 75% of the price of crude oil (4.6 EUR/GJ)

Table 4. Input and output data for NG Extraction + Processing, France / GEMIS 4.1

	I / O	Value	Units
NG source	I	1.0242	[kWh/kWh]
NG	O	1.0	[kWh]
Process scale	-	10,000,000	[kW NG]
CH_4 emissions	O	0.3	[g/kWh]
CO_2 emissions	O	4.1	[g/kWh]
NO_x emissions	O	0.0162	[g/kWh]
Dust-particles emissions	O	0.0009	[g/kWh]
SO_2 emissions	O	0.0044	[g/kWh]
NMVOC emissions	O	0.0004	[g/kWh]
CO emissions	O	0.004	[g/kWh]
Useful lifetime	-	20	[yr]
Annual full load hours	-	8,760	[h/yr]
Cost	-	0.0124	[€/kWh]

- *Provision of Biomass*

Biomass may be issued from residual or farmed wood. The residual wood and wood plantation are chipped at the source and then transported to the gasification plant by trucks.

For the French case, only residual wood has been considered.

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].

The costs of biomass supply from residual wood without transport have been assumed to be 0.0135 EUR per kWh of biomass.

- *Provision of Electricity*

The electricity may come from a European mix or from a national production mix. Besides, electricity may be considered to come directly from wind turbines or a dedicated nuclear reactor.

Table 5 gives the repartition of the different sources of the European electricity mix considered.

Table 5. Electricity mix in 2020 for France and Europe.
Values used are kWh (I) per kWh produced (O), i.e. kWh/kWh

Source	**I / O**	**France**	**MIX EU 15 [1)] (1999)**
Biomass	I	0.04	0.0074
Brown Coal	I	-	0.1956
Hard Coal	I	0.196	0.5512
Fuel Oil (1.8%S)	I	0.005	-
Geothermal	I	-	0.0016
Hydro	I	0.105	0.1239
Mineral Oil	I	-	0.2397
NG	I	0.207	0.3440
Nuclear	I	2.091	1.1354
Waste	I	-	0.1838
Wind Power	I	0.016	0.0044
Electricity	O	1.0000	1.0000
Equivalent CO_2 emissions	O	109 g/kWh	452 g/kWh

o Equivalent CO_2 emissions in [g / kWh]; ex power plants according to GEMISwithout the energy requirements and associated emissions for the construction of the plants

As a result of the national mix, the total input of primary energy is about 2.66 kWh per kWh of delivered electricity leading to an electricity generation efficiency of about 38%. The GHG emissions for the French electricity mix in 2020 are 109 [g / kWh] of electricity delivered.

In the next table, the feedstock rate into electricity production is detailed.

Table 6. Electricity mix in 2020 for France and Europe.
Source share in EU-mix according to the used feedstock's (%)

Source	**France**	**MIX EU 15 (1999)**
Biomass	1.5	0.30
Brown Coal	-	7.10
Hard Coal	7.4	19.90
Fuel Oil (1.8%S)	0.2	-
Geothermal	-	0.10
Hydro	4	4.40
Mineral Oil	-	8.70
NG	7.8	12.30
Nuclear	78.6	40.50
Waste	-	6.60
Wind Power	0.6	0.20
Electricity	100.00	100.00

Offshore wind power

An offshore wind energy plant typically consists of up to 1,000 single wind turbines. The water depth can be up to 40 m. According to the Department of Trade and Industry in UK the investment can be expected to be about 1,200 [€/kW] of installed capacity in 2010. The investment of the offshore wind power installation at Middelgrunden in Denmark, which has a total capacity of 40 MW and which is already in operation, has been indicated with 49,000,000 EUR leading to 1,250 [€/kW]. These wind turbines are rather close to the coast (2-3 km) and as a result the water depth in Middelgrunden is low (2-6 m). The investment of the offshore win power installation at Horns Rev (160 MW; water depth: 6.5-13.5 m; distance from coast: 17 km) is indicated with 268 million EUR or 1,675 [€/kW] including grid connection [Renewable Energy World 2002].
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.

If wind power (offshore or onshore) is used to provide electricity, the next data apply.

Table 7. Technical and economic data of the wind turbine, (onshore and offshore)

Wind Energy(offshore)	**2020**	**2030**	**Units**
Capacity	4.5	4.5	[MW]
Water depth	30	30	[m]
Investment	5,400,000	3,622,500	[€]
Maintenance	4	4	[% of investment]
Overhead	-	-	[% of investment]
Useful lifetime	25	25	[yr]
Equivalent full load period	3,000	3,000	[h/yr]

Dedicated nuclear reactor: EPR

The characteristics of the EPR reactor are listed in the table bellow.

Table 8. Technical and economic data of the EPR

EPR 2030	**Value**	**Units**
Life time	40	[yr]
Capacity	1 600	[$MW_{él}$]
Electricity cost	28.4	[$€/MWh_{él}$]
Efficiency	37	[%]
Overhead	-	[% of investment]
Uranium consumption	21	[$mg/kWh_{él}$]

- *Provision of Diesel*

Diesel is used as fuel for mechanical conversion of energy. Processes that uses diesel are: truck transport and wood chipping.

Table 9. Technical and economic data of diesel provision

	I / O	**Value**	**Units**
Mineral oil consumption	I	1.160	[kWh/kWh]
Diesel oil production	O	1.000	[kWh]
Production costs	-	0.02304	[€/kWh]
CO_2 emissions	O	51.500	[g/kWh]
NOx emissions	O	0.147	[g/kWh]
Dust-particles emissions	O	0.007	[g/kWh]
SO_2 emissions	O	0.13	[g/kWh]
NMVOC emissions	O	0.162	[g/kWh]
CO emissions	O	0.061	[g/kWh]

A.2 Transport of Feedstock's

- *Natural Gas*

NG is mainly imported from Russia and transported in a large European pipeline. The gas is consequently distributed via a regional and a local NG pipeline grid under different pressures to hydrogen production plants. All transports require mechanical work made by gas turbines, which use a small amount of NG for their power. The data for the high-pressure (HP) natural gas distribution has been derived from [GEMIS 2002].

Table 10. Input and output data for NG distribution (high-pressure pipeline) over 1000 km

	I / O	**Value**	**Units**
Mechanical work	I	0.0058	[kWh/kWh]
NG	I	1.0016	[kWh/kWh]
NG	O	1.000	[kWh]
Process scale	-	10,000,000	[kW NG]
CH_4 emissions	O	0.115	[g/kWh]
Useful lifetime	-	30	[yr]
Annual full load hours	-	7,500	[h/yr]

The mechanical work needed for transport purposes is supplied by a gas turbine (efficiency: 30%).

Table 11. Input and output data for NG distribution (high-pressure pipeline) over 500 km

	I / O	**Value**	**Units**
Mechanical work	I	0.003	[kWh/kWh]
NG	I	1.00003	[kWh/kWh]
NG	O	1	[kWh/kWh]
Process scale	-	10,000,000	[kW NG]
CH_4 emissions	O	0.0022	[g/kWh]
Useful lifetime	-	30	[yr]
Annual full load hours	-	7,500	[h/yr]

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 NG distribution via high-pressure pipeline of 500 km have been assumed to be 0.0004 EUR per kWh of natural gas.

- *Biomass*

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/m3. For the calculation of this pathway a payload of 26 t wood chips has been assumed.

Table 12. Input and output data for biomass transport system truck wood chips over 50 km

	I / O	**Value**	**Units**
Wood Chips	I	1.0000	[kWh]
Travelling distance	I	0.0148	[t km / kWh]
Biomass	O	1.0000	[kWh]

Table 13. Input and output data for truck

	I / O	**Value**	**Units**
Diesel Oil	I	0.26	[kWh/tkm]
Travelling distance	O	1	[t km]
CH_4	O	0.005	[g / t km]
CO_2	O	68.6	[g / t km]
NO_X	O	0.341	[g / t km]
Dust-Particles	O	0.002	[g / t km]
SO_2	O	0.00043	[g / t km]
CO	O	0.146	[g / t km]
NMVOC	O	0.04	[g / t km]

- *Electricity*

Depending on the user, three types of electricity transport have been considered: transport at high-voltage (HV, 110-220 kV), transport at medium-voltage (MV, ~20 kV) and transport at low-voltage (LV, ~0.4 kV).

The costs for high voltage transport of electricity are indicated with about 0.004 €/kWh and the costs for the distribution (10-20 KV level and 0.4 kV level) are indicated with 0.027 €/kWh (RWE 1999). As a first approach it has been assumed that 0.020 € of the 0.027 €/kWh can be allocated to the 10-10 kV level and 0.007 € can be allocated to the 0.4 kV level.

Table 14. Input and output data for High-voltage transport of electricity (GEMIS 4.1), (RWE 1999)

	I / O	**Value**	**Units**
Electricity	I	1.0101	[kWh/kWh]
Electricity	O	1.0000	[kWh]
Process scale	-	80,000,000	[kWe]
Useful lifetime	-	50	[yr]
Annual full load hours	-	5,000	[h/yr]
Costs of electricity transport	-	0.004	[€/kWh]

Table 15. Input and output data for Medium-voltage transport of electricity (GEMIS 4.1), (RWE 1999)

	I / O	**Value**	**Units**
Electricity	I	1.0070	[kWh/kWh]
Electricity	O	1.0000	[kWh]
Process scale	-	1,300	[kWe]
Useful lifetime	-	50	[yr]
Annual full load hours	-	5,000	[h/yr]
Costs of electricity transport	-	0.020	[€/kWh]

Table 16. Input and output data for Low-voltage transport of electricity (GEMIS 4.1) (RWE 1999)

	I / O	**Value**	**Units**
Electricity	I	1.0120	[kWh/kWh]
Electricity	O	1.0000	[kWh]
Process scale	-	100	[kWe]
Useful lifetime	-	50	[yr]
Annual full load hours	-	5,000	[h/yr]
Costs of electricity transport	-	0.007	[€/kWh]

A.3 Hydrogen Production

In this section, production of hydrogen from the different feedstock is presented. Also the process of hydrogen liquefaction is included, which delivers the hydrogen 'ready for use'.

Production of Hydrogen from Natural Gas

Hydrogen production from natural gas is performed using steam methane reformers (SMR). The French chains only consider SMR with CO_2 capture and storage (CCS).
SMR data that includes the CCS process has been derived from a study carried out by Foster Wheeler [Foster Wheeler 1996].
For central SMR plants including CCS, the CO_2 capture is carried out via scrubbing process using AMDEA (activated methyl diethanol amine) units. There after, CO_2 becomes compressed to a pressure of approximately 11 MPa, leading to carbon dioxide liquefaction. Thereafter, CO_2 is transported in liquid state via pipelines and injected into depleted natural gas and oil fields. The plant consists of 3 single units (each 94,000 Nm^3 H_2/h).

In Table 17 technical and economic data used in modelling are given.

Table 17. Technical and economic data for Foster Wheeler SMR plant

	Foster Wheeler [3] 1996
Inlet pressure [MPa]	**3.4**
Discharge pressure H_2 [MPa]	**6.1**
Capacity [Nm^3 H_2/h]	281,300
NG consumption [kWh/kWh_{H2}]	1.365
CO_2 emissions [g/kWh_{H2}]	42.7
CH_4 emissions [g/kWh_{H2}]	0.057
NO_x emissions [g/kWh_{H2}]	0.0821
CO emissions [g/kWh_{H2}]	0.0792
Investment [€]	453,090,000
Maintenance coefficient [% of Investment]	1.5
Labour [€/yr]	546,400
Overhead [% of investment]	0.1
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	7,884

In case of the Foster Wheeler plant the natural gas input pressure is lower than the pressure of the hydrogen at the outlet of the pressure produced hydrogen. The reason is that the Foster Wheeler plant has an additional hydrogen compressor downstream the pressure swing adsorption (PSA) plant.

---

[3] With CO_2 capture and storage

- *Production of Hydrogen from Biomass*

In France, biomass is used with origin from residual. The provided biomass is gasified. The gasification process is the Katofsky gasification. The result is CGH_2.

For this plant the technical and economic data is given in Table 18.

Table 18. Technical and economic data for H_2 generation via biomass gasification (Katofsky)

	I / O	**Value**	**Units**
Biomass	I	1.4624	[kWh/kWh]
Electricity	I	0.0820	[kWh/kWh]
CGH_2	O	1.0	[kWh]
Investment	-	152,960,000	[€]
Maintenance	-	3.9	[% investment per yr]
Labour	-	1,180,000	[€/yr]
Overhead coefficient	-	2.3	[% investment per yr]
Equivalent full load period	-	7 887	[h/yr]
Useful lifetime	-	25	[yr]
Dust-Particles[4]	O	0.0025	[g/kWh]

The gasifier chosen to produce the syngas is indirectly heated: the atmospheric fast fluidised bed gasifier of Battelle Colombus Laboratory (BCL).

The BCL gasifier is indirectly heated by a heat transfer mechanism wit as shown in Figure 23. The indirectly heated, twin bed gasifier of BCL [Katofsky, 1993]. Ash, char and sand are entrained in the product gas, separated using a cyclone, and sent to a second bed where the char is burned in air to reheat the sand. The heat is transferred between the two beds by circulating the hot sand back to the gasification bed. This allows providing heat by burning some of the feed, but without the need to use oxygen because combustion and gasification occur in separate vessels.

Some additional biomass has to be burned in the combustor to ensure a high enough gasification temperature, which is necessary for a good carbon conversion. The product is a low CO_2 gas, consequently containing more hydrocarbons. Tar cracking is necessary after atmospheric gasification [Tijmensen 2000]; a CFB reactor containing dolomite is therefore integrated with the gasifier. Per kg dry wood, 0.0268 kg dolomite is consumed, for wood with 15% moist. Part of the H_2S and HCl present adsorb on dolomite [van Ree et al. 1995]. The BCL gasifier is fast fluidised. This means that the specific throughput is significantly higher than in a conventional fluidised bed like the IGT gasifier, there by compensating for low pressure.

Because biomass gasification temperatures are relatively low, significant departures from equilibrium are found in the product gas. Kinetic gasifier modelling would be complex and different for each reactor type [Consonni and Larson 1994a; Li et al. 2001]. Biomass syngas compositions are taken from [Williams et al.1995].

The syngas produced by different gasifiers contain various contaminants: particulates, condensable tars, alkali compounds, H_2S, HCl, NH_3, HCN and CoS. No full data sets of syngas compositions including these contaminants are available for the gasifiers considered [Tijmensen 2000].

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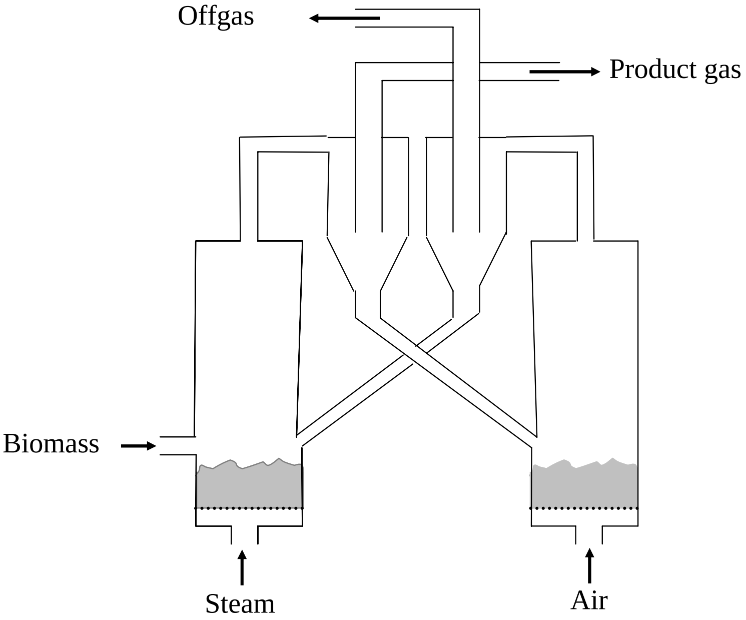
[4] CO_2 emissions are per definition of use of biomass equal to zero

Figure 23. The indirectly heated, twin bed gasifier of BCL [Katofsky, 1993]



- *Production of Hydrogen from Mix Electricity*

Hydrogen is produced via water electrolysis. The central electrolysis plant consists of a large number of electrolyser units. If the total hydrogen generation capacity of the central electrolysis plant were 100,000 Nm^3/h the number of 800 Nm^3/h units would be 125. As a first approach for the central electrolysis, no learning curve has been applied for the investment.

Electrolysers presented in Table 19 have different capacities according to a central or de-central application and are characterised by different output pressures.

Table 19. Technical and economic data for electrolysis

		Central Electrolyser	**On Site Electrolyser**
Capacity	[Nm^3 H_2/h] / [kW]	2400	360
Electricity consumption	[kWh / kWhH_2]	1.433	1.6
Pressure	[MPa]	3.0	2.6
Investment	[€]	2,200,000	271,800 [5]
Maintenance	[% of investment]	0.9	0.9
Labour costs	[€/yr]	0	0
Overhead costs	[% investment/yr]	0	0
Useful lifetime	[yr]	8,000	6,000
Equivalent full load period	[h/yr]	20	20

---

[5] Average investment per unit when 10,000 units are installed

- *Hydrogen production through HT electrolysis*

Hydrogen is produced via water HT electrolysis.

The maintenance is supposed to be equal to the one of an alkaline electrolysis plant with the same capacity. We also include in the maintenance the cost of cells change.

Table 20. Technical and economic data for HT electrolysis

		Units	**HTE**
Capacity		[Nm^3 H_2/h] / [kW]	2400
Electricity consumption		[kWh / kWhH_2]	1.076
Heat consumption		[kWh / kWhH_2]	0.15
Water consumption		[kg / kWhH_2]	0.27
Investment		[€]	2,191,634
Maintenance	2030 (cells lifetime = 5 yr)	[% of investment]	11.8
	2040 (cells lifetime = 7 yr)	[% of investment]	7.7
	2050 (cells lifetime = 10 yr)	[% of investment]	4.6
Useful lifetime		[yr]	20
Equivalent full load period		[h/yr]	8,000

- *Liquefaction of Hydrogen*

To liquefy hydrogen, a liquefaction plant consuming only electricity as input has been used. The electricity consumption has been assumed to be 0.3 kWh per kWh of LH_2 produced (LHV). This assumption corresponds to large hydrogen liquefaction plants in the near future, as presented in the CONCAWE/JRC/EUCAR study. The investment, maintenance and labour costs have been derived from [NHEG 1992] via up scaling. These costs have been confirmed by [Linde 2004]. The technical and economic data of liquefier plant are given in Table 21.

Table 21. Technical and economic data of H_2 liquefaction plant

	I / O	**Value**	**Units**
Plant capacity	-	300,000	[kW]
GH_2 consumption	I	1.00	[kWh/kWh_{LH2}]
Inlet pressure	-	30	[bar]
LH_2 production	O	1.00	[kWh]
Electricity consumption	I	0.3	[kWh/kWh_{LH2}]
Investment	-	23,900,000	[€]
Maintenance	-	2.50	[% of investment]
Labour	-	1,230,000	[€/yr]
Equivalent full load period	-	8,000	[h/yr]
Useful lifetime	-	30	[yr]

- *Gasification of liquefied hydrogen*

To be used into family households CHP Fuel Cell, liquefied hydrogen needs to be gasified. The technical and economic data of gasification plant are given in Table 22.

Table 22. Technical and economic data of LH_2 gasification plant

	I / O	**Value**	**Units**
Plant capacity	-	437.5	[kW]
LH_2 consumption	I	1.00	[kWh/kWh]
GH_2 production	O	1.00	[kWh]
Electricity consumption	I	0.0212	[kWh/kWh]
Investment	-	150,000	[€]
Maintenance	-	2	[% of investment]
Equivalent full load period	-	8,760	[h/yr]
Useful lifetime	-	20	[yr]

A.4 Transport of Produced Hydrogen

- *Compressed Hydrogen Gas (CGH$_2$)*

The supply of CGH$_2$ is performed through a hydrogen pipeline grid. It has been assumed that the hydrogen grid consists of large pipelines (50/100 km) with a throughput of 240 GWh H$_2$ per year and pipeline and some smaller pipelines (5 km) with a throughput of 8 GWh H$_2$ per year and pipeline. The pressure drop during the pipeline transport has been neglected.

Technical and economic data for CGH$_2$ pipelines is given in Table 23.

Table 23. Technical and economic data for H2 pipelines

	Units	**5 km**	**50 km**	**100 km**
Annual hydrogen throughput	[GWh H$_2$/yr]	8	240	240
Diameter	[mm]	100	150	150
Wall thickness	[mm]		7.1	
Investment	[M€]	0.895	8.95	17.9
Labour, maintenance etc.	[€/yr]	21,000	261,000	522,000
Annual full load	[hr]	8000	8000	8000
Useful lifetime	[yr]	30	30	20

- *Liquefied Hydrogen (LH$_2$)*

LH$_2$ is transported by truck on 150 km (roundtrip = 300 km). The truck gross weight is 40 t while the payload is about 27 t. Because the tank mass is estimated to be approximately 24 t, the transport capacity of the LH$_2$ trailer is approximately 3.5 t LH$_2$. The fuel consumption of the 40 t truck is about 3.5 kWh/km or 35 l diesel per 100 km.

Table 24. Technical and economic data for LH$_2$ truck transport

	I / O	**Value**	**Units**
Fuel use	I	0.2600	[kWh/t km]
Energy use	O	0.0354	[t km/kWh]
Investment	-	500,000	[€]
Maintenance	-	2%	[% of investment]
Lifetime	-	15	[yr]
Annual full load hours	-	8760	[hr/yr]

- *Mixture NG/GH$_2$*

The hydrogen is mixed with NG (10 percents volume) in order to be transported in the existing NG pipelines (90 km distance, on average). By doing that there is no need to build a specific infrastructure and so no additional cost is needed for transport.
The PCI of hydrogen is 3 kWh/Nm^3, and the PCI of NG is 9 kWh/Nm^3.

Table 25. Technical and economic data for NG/GH_2 pipeline transport

	I / O	Value	Units
GH_2	I	0.04	[kWh/kWh]
NG	I	0.96	[kWh/kWh]
Steel	I	1 075 200	[kg]
90%NG//10%GH_2	O	1	[kWh]
Lifetime	-	30	[yr]
Annual full load hours	-	8760	[hr/yr]

Then, the mixture is separated in a "separator" plant of which efficiency is not one hundred percent; so, in addition to the separated hydrogen there is a gas-off in which remains hydrogen.

Figure 24. Principle of separation

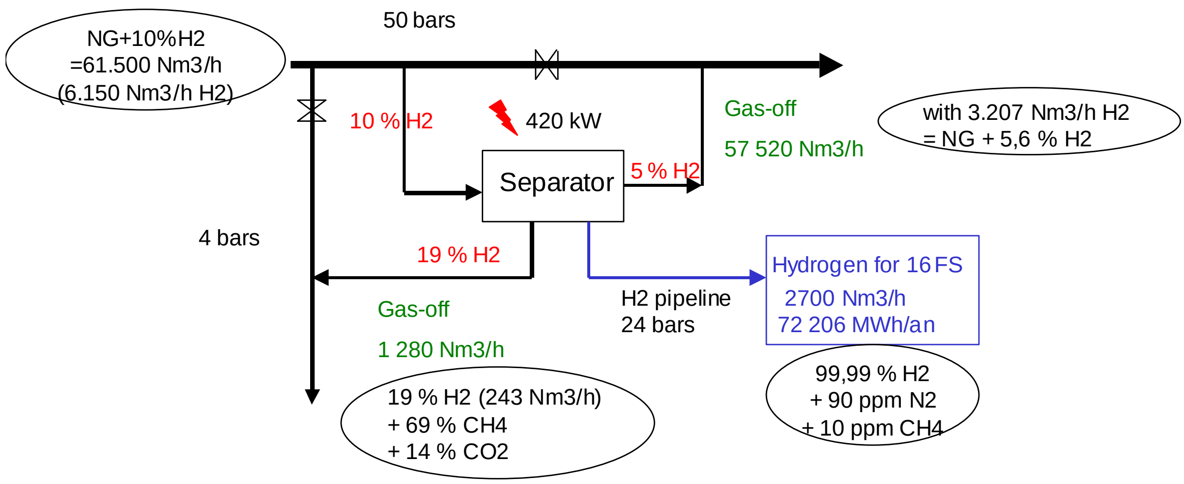


Table 26. Technical and economic data for the central separator

		I / O	Value	Units
90%NG//10%GH_2		I	72.175	[kWh/kWh]
Electricity		I	0.05	[kWh/kWh]
GH_2		O	1	[kWh]
GH_2 (gas-off)		O	1.16	[kWh/kWh]
Gas-off		O	68.55	[kWh/kWh]
Process Scale	2020	-	953	[kW]
	2030	-	8 409	[kW]
Investment	2020	-	538 000	[€]
	2030	-	2 514 000	[€]
Lifetime		-	20	[yr]
Annual full load hours		-	8760	[hr/yr]

It has been assumed that there are 515 systems in operation in 2020 and 568 systems in operation in 2030.

In order to valorise this hydrogen, there is a credit which represents the fact that the NG consumers use and pay this hydrogen which emits less carbon than natural gas. The selling price of this hydrogen is 0.063 €/kWh (pessimistic value calculated for a low NG price) and the consumers avoid 11 g/kWh of CO_2.

A.5 Hydrogen Usage

- *Vehicle Filling Stations*

Two different filling stations for gaseous hydrogen distribution and one filling station for gaseous hydrogen distribution from liquefied hydrogen inlet have been used. The difference between these filling stations is the suction pressure considered.

Characteristics of filling stations delivering CGH_2 for the year 2004 are presented in Table 27. Table 28 presents the derived data for the year 2020. The electricity voltage level is 0.4 kV except for filling stations which are connected with an onsite electrolyser. In case of onsite electrolysis the electricity voltage level is 10 kV. The 10-20 kV level is reasonable if the maximum power demand exceeds 1 MW.

Table 29 presents the data of the CGH_2/LH_2 filling station for the years 2010 and 2020.

Table 27. Technical and economic data for the CGH_2 filling station, year 2004

	Suction pressure	**2.0 MPa**	**2.6 MPa**
Annual fuel output	[t H_2/yr]	120	120
Electricity consumption	[kWh/kWh$_{H2}$]	0.070	0.0647
Investment [6]	[€]	496,000	496,000
Maintenance	[% of investment]	2.7	2.7
Useful lifetime	[yr]	20	20
Efficiency	[-]	98%	

Table 28. Derived technical and economic data for the CGH_2 filling station, year 2020

	Suction pressure	**2.0 MPa**	**2.6 MPa**
Annual fuel output	[t H_2/yr]	120	120
Electricity consumption	[kWh/kWh$_{H2}$]	0.070	0.0647
Investment [6]	[€]	231,000	231,000
Maintenance	[% of investment]	3.7	3.7
Useful lifetime	[yr]	20	20

Table 29. Derived technical and economic data for the CGH_2/LH_2 filling station, year 2010-2020

	Year	**2010**	**2020**
Annual fuel output	[t H_2/yr]	115	115
Electricity consumption	[kWh/kWh$_{H2}$]	0.0212	0.0212
Investment [6]	[€]	300,000	214,223
Maintenance	[% of investment]	2	2
Useful lifetime	[yr]	20	20

- *Vehicle data*

The passenger vehicle data has been derived from the CONCAWE/EUCAR/JRC study [CONCAWE 2/2003]. The passenger vehicles are based on a VW Golf.

Table 30 and Table 31 present the vehicle technical data used in the study.

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[6] Average investment per unit when 10,000 units are installed.

Table 30. Passenger cars data

	Fuel consumption [kWh/km]	**GHG emissions [g CO_2 equiv./km]**
CGH_2 FC car	0.261	0
CGH_2 FC car hybrid	0.233	0
CGH_2 ICE car	0.465	0.5
CGH_2 ICE car hybrid	0.413	0.5
LH_2 FC car	0.261	0
LH_2 FC car hybrid	0.233	0
LH_2 ICE car	0.465	0.5
LH_2 ICE car hybrid	0.393	0.5
NG+5%H_2 car	0.465	0

Table 31. Buses data

	Fuel consumption [kWh/km]	**GHG emissions [g CO_2 equiv./km]**
CGH_2 FC bus	2.86	0
CGH_2 ICE bus	4.90	4
LH_2 FC bus	2.74	0
LH_2 ICE bus	4.90	4
HCNG ICE bus	5.38	1092

For CGH_2 fuelled FC vehicles and hydrogen generated via electrolysis a de-Oxo dryer has been installed at the filling station to elevate the hydrogen purity from 99.95% to 99.995%. For CGH_2 fuelled ICE vehicles no de-Oxo dryer is required.

Table 32. Technical and economic data for a de-Oxo dryer [Stuart Energy 2004]

	I / O	**Value**	**Units**
Capacity	-	120	[Nm3 H2/h]
Electricity consumption	O	0.0139	[kWh/kWhH2]
Investment	-	94,500	[€]
Maintenance	-	0.24	[% of investment]
Useful lifetime	-	20	[yr]
Equivalent full load period	-	6,000	[h/yr]

The purity of LH_2 is above 99.995% in any case.

- *Stationary use of Hydrogen*

CHP plants generate electricity and heat. The approach considered is to look at the consumer e.g. a single-family user. The single-family user requires electricity and heat, the last one being supplied by a FC CHP plant including a peak boiler.

Heat as main product

The single-family user needs electricity and heat, the last one being supplied by a FC CHP plant including a peak boiler. The specific French data have been provided by Gaz de France, according to the average French heat demand.

Supply of heat and electricity for a single family house via a FC CHP system with peak boiler:
Fuel cell: 3600 operating hours/yr
Heat supply from FC: 18 000 kWh/h
Heat supply from peak boiler: 2 000 kWh/h
Electricity supply from FC for house needs: 3 500 kWh/h
Electricity supply from FC exported to the grid: 9 100 kWh/h
Electricity supply (el grid - net metering strategy): 0 kWh/h
=> Total: 20 000 kWh/h for the house and 9 100 kWh/h exported to the grid

Investment:
FC CHP system: 5 250 €(optimistic figure by 2010); Peak boiler: 1 000 € => 6 250 €

Maintenance:
Useful lifetime peak boiler: 20 yr; Lifetime FC: 5 yr
=> 4 FC are required during 20 years => 3 FC replacements/(20 years)
Maintenance: 200 EUR/y
M = [200+3* 5250 (3 changes of FC)/20]/I = 15.8% of I/yr

To account for a delivery of electricity to the electricity grid, an electricity credit has been incorporated.

Table 33. Supply of electricity and heat for a single-family user

	Input	Output	Units
GH_2	1.447	-	[kWh/kWh]
Heat + Electricity to user	-	1.000	[kWh]
Electricity to grid	-	0.387	[kWh/kWh]
Process scale	93.06	-	[kWh/h]
Investment	6,250	-	[€]
Maintenance	15.8	-	[% of investment]
Equivalent full load period	3,600	-	[h/yr]
Useful lifetime	20	-	[yr]

A.6 Auxiliary Processes

Auxiliary processes are those that do not take part in hydrogen generation (from well to H_2 production), but help to realize the production or distribution. These processes are:

- Gas engine
- Gas Turbines (mechanical work for pumping gas through pipelines)
- Wood chipping

Gas Engine

Gas engine is used for small industries.

Table 34. Gas engine [GEMIS 2002], [Jenbacher 2002]

	I / O	**Value**	**Units**
Capacity	-	125	[kWe]
GH2	I	3	[kWh/kWhe]
Electricity	O	1	[kWhe]
Investment	-	83,000	[€]
Maintenance	-	10	[% of investment]
Equivalent full load period	-	6,000	[h/yr]
Useful lifetime	-	10	[yr]

Gas Turbines

Table 35. Input and output data for used gas turbines (GEMIS 4.1.3.2)

	I / O	**Value**	**Units**
Natural gas	I	3.3333	[kWh/kWh]
Heat	O	1.0000	[kWh]
Process scale	-	10,000	[kWh/h]
Useful lifetime	-	15	[yr]
Annual full load hours	-	5,000	[h/yr]
CO_2 emissions	O	677	[g/kWh]
NO_X emissions	O	3.527	[g/kWh]
Dust-particles emissions	O	0.050	[g/kWh]
SO_2 emissions	O	0.005	[g/kWh]
NMVOC emissions	O	0.101	[g/kWh]
CO emissions	O	1.008	[g/kWh]
CH_4 emissions	O	0.050	[g/kWh]
N_2O emissions	O	0.030	[g/kWh]

- *Wood chipping*

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

Table 36. Input and output data for Wood Chipping / Hartmann 1995

	I / O	**Value**	**Units**
Woody Biomass	I	1.025	[kWh/kWh]
Woody Biomass	O	1.0	[kWh]
Diesel [kWh/kWh$_{wood}$]	I	0.004	[kWh/kWh]
Process Scale	-	50,000	[kW]
CO_2 emissions	O	1.32	[g/kWh]
NO_x emissions	O	0.0581	[g/kWh]
Dust-particles emissions	O	0.0048	[g/kWh]
CH_4 emissions	O	0.0002	[g/kWh]
N_2O emissions	O	0.0002	[g/kWh]
NMVOC emissions	O	0.0002	[g/kWh]
CO emissions	O	0.0126	[g/kWh]
Useful lifetime	-	10	[yr]
Annual full load hours	-	1,000	[h/yr]
Cost	-	0.0135	[€/kWh]

9. Literature

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