



## **Modelling of Hydrogen supply chains for Finland**



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## Abbreviations

CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CGH <sub>2</sub>	Compressed Gaseous Hydrogen
CHP	Combined Heat and Power
COH	Cost of Hydrogen
DICI	Direct Injection Compression Ignition
DPF	Diesel Particulate Filter
EWEA	European Wind Energy Association
FC	Fuel Cell
FS	Filling Station
GHG	Greenhouse gases
HP	High-Pressure
I / O	Input / Output
ICE	Internal Combustion Engine
LH <sub>2</sub>	Liquefied Hydrogen
LHV	Low Heating Value
LP	Low-Pressure
MP	Medium-Pressure
NG	Natural Gas
NL	The Netherlands
PISI	Port Injection Spark Ignition
PSA	Pressure Swing Adsorption
PV	Photovoltaic
Q-following	Heat demand following
sHED	Specific Household Energy Demand
SMR	Steam Methane Reforming
StU	Stationary Use
WTStU	Well-to-Stationary Use
WTT	Well-to-Tank
WTW	Well-to-Wheel

## 1. Introduction

Within the framework of the HyWays project, work packages WP1 and WP2 present the hydrogen energy chains selected for the timeframe 2020 and 2030 by the six member states involved in Phase I of the project: France, Greece, Germany, Italy, Norway and the Netherlands. In Phase II, the analysis was extended to four more European countries: Finland, Poland, Spain and the UK.

The WP1/WP2 objectives are:

- To develop a set of relevant hydrogen energy chains for each country.
- To calculate for each hydrogen energy chain the energy efficiencies, the GHG emissions and the levelized cost of hydrogen.
- The data and assumptions made for modelling the chains will be transmitted to WP3.

This report:

- Presents the selected hydrogen energy chains for Finland, and
- Provides the results obtained from the calculations of these chains.

## 2. Methodology

During several workshops organized in Finland, where experts from the industry, government and research institutes attended, a number of relevant hydrogen energy chains have been selected. The selection was based on considerations and discussions taking into account the following aspects:

- The characteristics of the current and foreseeable energy supply system and energy infrastructure up to 2050
- The available natural resources
- The application and penetration rate to be expected for hydrogen
- The current hydrogen production sites and infrastructure (if present)
- The available and anticipated hydrogen and energy technologies

The selected chains are modelled using the E3-database tool developed by L-B-Systemtechnik (LBST, Germany) [ref. 1]. With this tool the chain primary energy use, the GHG emissions and the levelized costs of the supply of transportation fuel, electricity and heat are estimated. The results are calculated for the years 2020 and 2030, in order to see trends resulting from energy price developments and technology learning.

Most of the data used in the tool have been issued from the EUCAR/CONCAWE/JRC study [ref. 3], version December 2003<sup>1</sup> and the GEMIS database [ref. 2]. Part of the data have been adapted or created to represent the specific infrastructure of Finland. To ensure uniformity within the different Member States, all defined production processes within the database have remained unchanged.

All calculations performed within the E3-database are based on the lower heating value (LHV) of the main sources. Newly introduced processes are:

- Processes where CO<sub>2</sub> capture and storage is embodied,
- Processes which describe stationary hydrogen fuelled fuel cells.

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

- Production of Finnish electricity mix (Annex B, section B.1.4)
- Electricity transport at low-voltage level (Annex B, section B.2.3)
- Use of CHP-application in Finnish households, heat-following process (Annex B, section B.4.3)
- Use of CHP-application in Finnish households, electricity-following process (Annex B, section B.4.3)
- Heat and electricity use in Finnish households (Annex B, section B.4.3)
- Onshore wind energy for Finnish islands (Annex B, section B.1.4)

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

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<sup>1</sup> This study has been updated in 2006. See URL: <http://ies.jrc.cec.eu.int/wtw.html>

### 3. Chains Selection

#### 3.1 Possible chains

In general, a hydrogen energy chain is built up considering the following processes:

- Feedstock production
- Feedstock transport
- Hydrogen production (type of process, process scale, location)
- Hydrogen transport and distribution
- Hydrogen conversion and end use

Table 1 gives an overview of these processes.

Table 1. Overview of processes considered in the build up of a hydrogen energy chain

<b>Feedstock (production)</b>	<b>Feedstock transport</b>	<b>Hydrogen production</b>	<b>Hydrogen transport and distribution</b>	<b>Hydrogen end use</b>
Natural Gas Oil Oil residues Coal	Ship - ocean carrier - inland carrier	Reforming - central/de-central - with/without CCS	As compressed gas by: - truck - train - ship	FC vehicle - car - light duty truck - bus
Biomass Biogas	Train  Truck	Gasification - central/de-central - with/without CCS	- pipeline - with/without filling station	ICE vehicle - car - light duty truck - bus
Electricity - wind - solar PV - hydro - nuclear - mix	Pipeline	Electrolysis - central/de-central - various processes	As liquid by: - truck - train - ship - pipeline - with/without filling station	Residential CHP - FC based unit - ICE based unit
Heat - nuclear - solar		Thermo-chemical cycles		Commercial CHP - FC based unit - ICE based unit
Waste		Photo biological process		Residential heating boiler
By-product H <sub>2</sub>		Photo-electrochemical process		Power plant (GT) Combined Cycle
Import of H <sub>2</sub>				

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

#### 3.2 Chain Selection for Finland

Table 3 shows an overview of the feedstock's and end use options of hydrogen energy chains that have been considered during the Finnish stakeholder workshops. Natural gas, coal, biomass heat and electricity (wind and nuclear power) have been selected as the most relevant feedstock's for Finland. Natural gas must be imported from Russia and coal from Poland. Other resources are domestically available.

With respect to end use, hydrogen vehicles (in particular passenger cars) and residential CHP have been selected as the most relevant options. The selected Finnish hydrogen energy chains are further characterized in Table 3.

Table 2. Selected Finnish Chains for the Hydrogen pathway

<b>Feedstock</b>	NG (Russia)	✓
	Coal (Poland)	✓
	Oil (residues)	-
	Electricity <sup>2</sup>	✓
	Biomass (Russia and Finland)	✓
	Heat (nuclear power)	✓
	Waste	-
	By-product (hydrogen from industrial processes)	-
	Import	-
<b>Hydrogen end use</b>	Hydrogen vehicles	✓
	Residential CHP (Fuel Cell)	-
	Residential CHP (ICE)	-
	Residential heating (Boiler)	✓
	CCGT	-

Table 3. Selected Finnish Chains for the Hydrogen pathway

Number		Feedstock	Production Process	H <sub>2</sub> -transport & distribution	Application
1	a	Natural gas	On-site SMR	Filling Station (FS)	FC vehicle
	b	Natural gas	Central SMR	Pipeline + FS	FC vehicle
	c	Natural gas	Central SMR	CGH <sub>2</sub> -truck + FS	FC vehicle
	d	Natural gas	Central SMR	LH <sub>2</sub> -truck + FS	FC vehicle
2	a	Electricity mix	On-site Electrolysis	Filling Station (FS)	FC vehicle
	b	Nuclear electricity	Central Electrolysis	CGH <sub>2</sub> -truck + FS	FC vehicle
3	a	Biomass (FIN)	De-central Gasification	CGH <sub>2</sub> -truck + FS	FC vehicle
	b	Biomass (FIN)	De-central Gasification	CGH <sub>2</sub> -truck	Domestic CHP
	c	Biomass (RUS)	De-central Gasification	CGH <sub>2</sub> -truck + FS	FC vehicle
4	a	Coal	Central Gasification	CGH <sub>2</sub> -truck + FS	FC vehicle
	b	Coal	Central Gasification	LH <sub>2</sub> -truck + FS	FC vehicle
	c	Coal	Central Gasification	Pipeline + FS	FC vehicle
5	a	Offshore wind	De-central Electrolysis	Local grid	Domestic CHP
6	a	Nuclear heat	Central Thermoplant	Pipeline + FS	FC vehicle

In the following section, the hydrogen production and utilisation energy chains are presented, ordered by the feedstock used.

For hydrogen energy chains including distribution at the filling station, Well-to-Tank (WTT) and Well-to-Wheel (WTW) analyses for FC vehicles as end-user are performed. In the case of Well-to-Stationary-User (WTS<sub>U</sub>) analyses, the end-user is a domestic CHP installation.

<sup>2</sup> Besides electricity from fossil fuels, also electricity from wind power, solar power, nuclear power and hydropower are possible. Moreover, the electricity mix can be either the typical Finnish mix or the European mix.

## 4. Selected Chains

In this section, the selected hydrogen chains for Finland and their variants, as stated in Table 3, are presented.

### 4.1 1a. On-site SMR of natural gas without CCS; use: FC vehicle

Natural gas (NG), extracted and processed in Russia, is transported to Finland by a pipeline over a distance of 4000 km. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

From the border of Finland, the NG is transported to small-scale on-site SMR's located at the filling stations by a system of high-pressure and medium-pressure natural gas pipelines. Transport distances in the high- and medium-pressure pipelines are 250 and 10 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop over the pipeline. The SMR produces hydrogen at a pressure of 1.7 MPa (17 bar). Carbon-capture and storage (CCS) is not included as an option.

Electrical compressors (part of the filling station) are used to compress the produced hydrogen up to 88 MPa required for on-board storage. To this end, the filling station (120 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

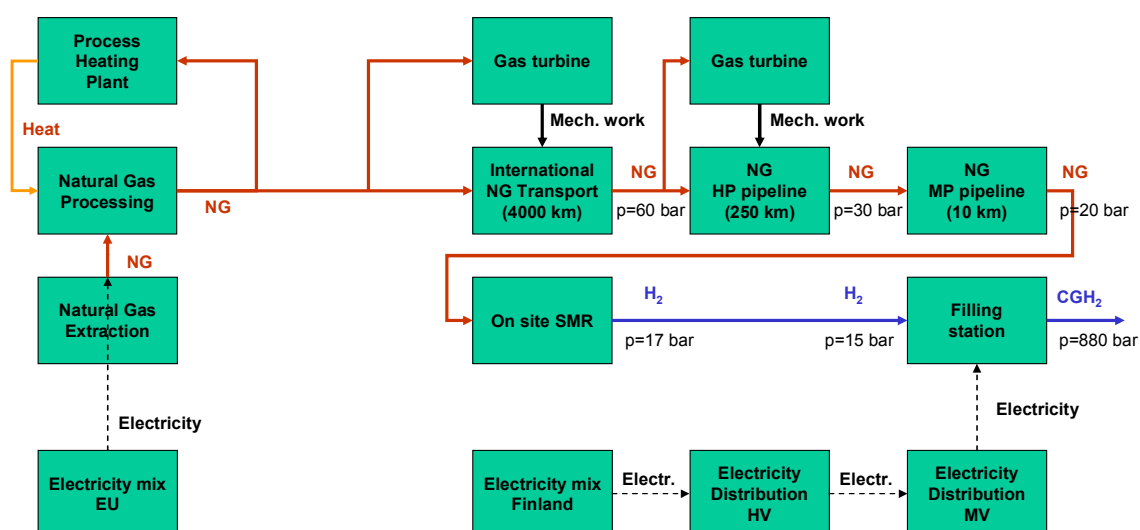


Figure 1. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from on-site SMR of NG without CCS.

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

- Natural gas extraction and conditioning B.1.1
- Electricity production B.1.4
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.3
- Hydrogen production from natural gas B.2.6
- Filling station B.4.1
- Gas turbines B.5.2
- Heating plant B.5.4

#### 4.2 1b. Central SMR of natural gas without CCS, H<sub>2</sub>-transport by pipeline

Natural gas (NG), extracted and processed in Russia, is transported to Finland by a pipeline over a distance of 4000 km. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

From the border of Finland, the NG is transported to a large-scale central SMR plants by a system of high-pressure natural gas pipelines over a distance of 250 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop over the pipelines. The SMR plants produce hydrogen at a pressure of about 3 MPa (30 bar). Subsequently, the hydrogen is transported and distributed to filling stations through hydrogen pipelines. Carbon-capture and storage (CCS) is not included as an option.

Electrical compressors (part of the filling station) are used to compress the produced hydrogen up to 88 MPa required for on-board storage. To this end, the filling station (1200 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

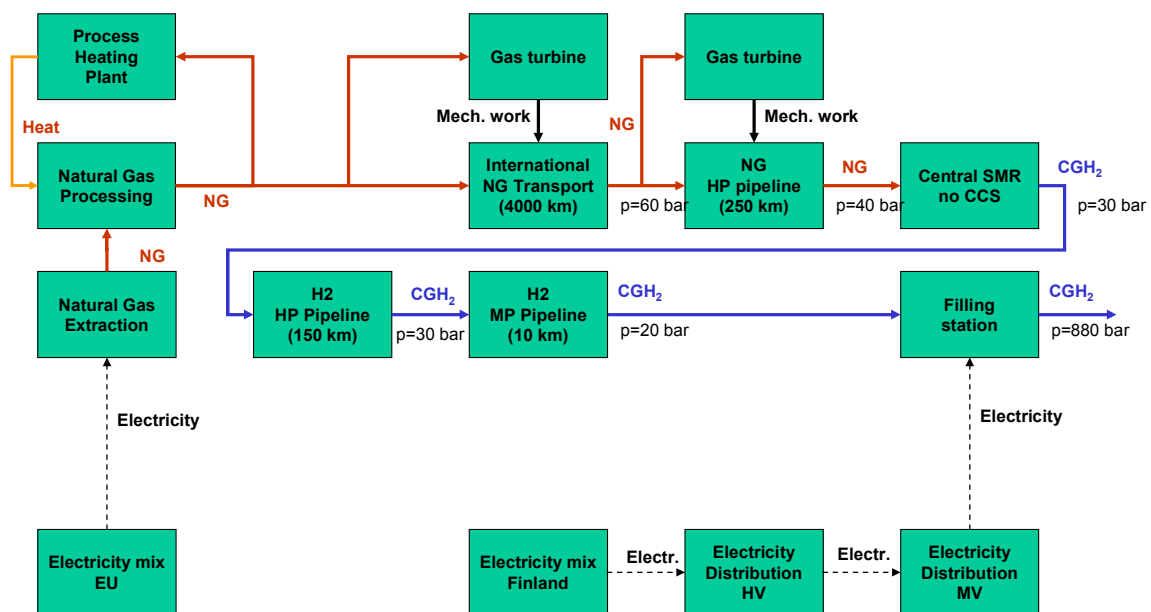


Figure 2. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from central SMR of NG and transport by pipeline.

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

- Natural gas extraction and conditioning B.1.1
- Electricity production B.1.4
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.3
- Hydrogen production from natural gas B.2.6
- Hydrogen transport by pipeline B.3.1
- Filling station B.4.1
- Gas turbines B.5.2
- Heating plant B.5.4

### 4.3 1c. Central SMR of natural gas without CCS, transport by CGH<sub>2</sub> trucks

Natural gas (NG), extracted and processed in Russia, is transported to Finland by a pipeline over a distance of 4000 km. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

From the border of Finland, the NG is transported to a large-scale central SMR plants by a system of high-pressure natural gas pipelines over a distance of 250 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop over the pipelines. The SMR plants produce hydrogen at a pressure of about 3 MPa (30 bar). Carbon-capture and storage (CCS) is not included as an option.

The hydrogen produced is compressed to approximately 30 MPa and transported to filling stations in tube trailers using diesel-fuelled trucks. Each truck can transport about 350 kg of compressed gaseous hydrogen. The distance to a filling station is 150 km on average. Electrical compressors (part of the filling station) are used to compress the hydrogen up to 88 MPa required for on-board storage. To this end, the filling station (480 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

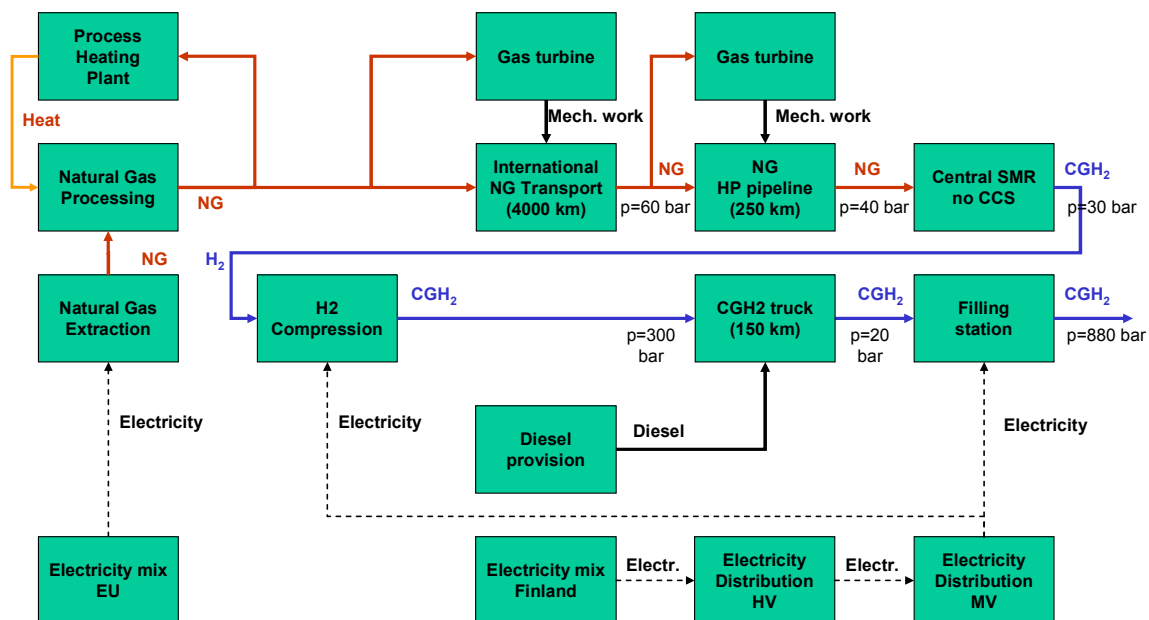


Figure 3. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from central SMR of NG, transport by CGH<sub>2</sub>-truck.

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

- Natural gas extraction and conditioning B.1.1
- Electricity production B.1.4
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.3
- Hydrogen production from natural gas B.2.6
- Hydrogen transport by CGH<sub>2</sub> truck B.3.2
- Filling station B.4.1
- Gas turbines B.5.2
- Heating plant B.5.4

#### 4.4 1d. Central SMR of natural gas without CCS, transport by LH<sub>2</sub> trucks

Natural gas (NG), extracted and processed in Russia, is transported to Finland by a pipeline over a distance of 4000 km. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

From the border of Finland, the NG is transported to a large-scale central SMR plants by a system of high-pressure natural gas pipelines over a distance of 250 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop over the pipelines. The SMR plants produce hydrogen at a pressure of about 3 MPa (30 bar). Carbon-capture and storage (CCS) is not included as an option.

The hydrogen produced is liquefied and transported to filling stations (1200 t/yr) in tanks using diesel-fuelled trucks. Each truck can transport about 3.5 ton of hydrogen. The distance to a filling station is 150 km on average. The hydrogen is stored as a liquid at the fuelling station and can be distributed to cars with either compressed gaseous (88 MPa) or liquid on-board storage. Electrical pumps dispense the liquid hydrogen. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

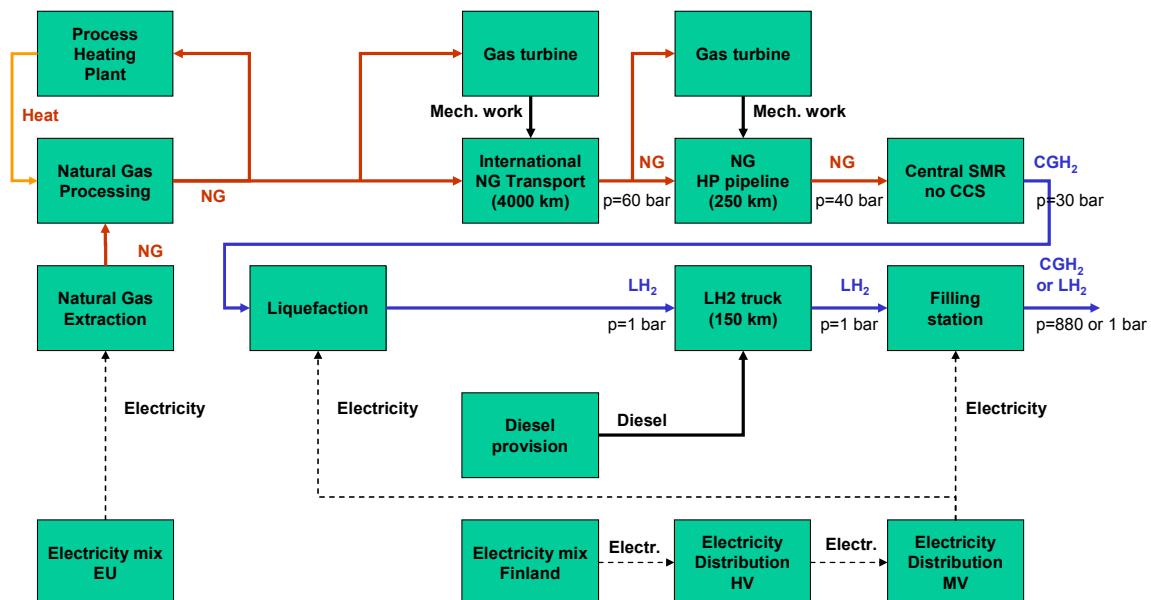


Figure 4. Hydrogen chain model for LH<sub>2</sub>/CGH<sub>2</sub> at a filling station. Hydrogen production from central SMR of NG, transport by LH<sub>2</sub>-truck.

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

- Natural gas extraction and conditioning B.1.1
- Electricity production B.1.4
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.3
- Hydrogen production from natural gas B.2.6
- Liquefaction of hydrogen B.2.10
- Hydrogen transport by LH<sub>2</sub> truck B.3.3
- Filling station B.4.1
- Gas turbines B.5.2
- Heating plant B.5.4

#### 4.5 2a. On-site electrolysis using the electricity mix; use: FC vehicle

A system of high-voltage and medium-voltage power lines transports electricity to small-scale on-site electrolysis units where hydrogen is produced from water. The electrolysis units are located at filling stations. The Finnish fuel mix (coal, gas, nuclear, etc.) determines the characteristics of the electricity in terms of primary energy and emissions per unit of electricity.

Electrical compressors (part of the filling station) are used to compress the hydrogen up to 88 MPa required for on-board storage. To this end, the filling station (120 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

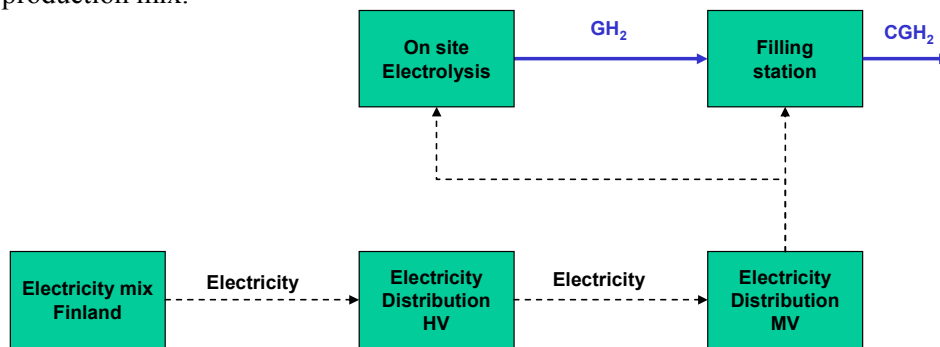


Figure 5. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from on-site electrolysis using the Finnish electricity mix.

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

- Electricity production B.1.4
- Electricity transport B.2.3
- Production of hydrogen from electricity B.2.8
- Filling station B.4.1

#### 4.6 2b. Central electrolysis using nuclear electricity; use: FC vehicle

Electricity produced from nuclear energy is transported to large-scale central electrolysis plants. The produced hydrogen is transported to filling stations in tube trailers, using diesel-fuelled trucks. For transport purposes, the hydrogen is compressed from an electrolysis plant outlet pressure of approximately 3 MPa to 30 MPa.

Each truck can transport about 350 kg of compressed gaseous hydrogen. The average distance between a central electrolysis plant and a filling station is 150 km. Electrical compressors (part of the filling station) are used to compress the hydrogen up to 88 MPa required for on-board storage. To this end, the filling station (1200 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

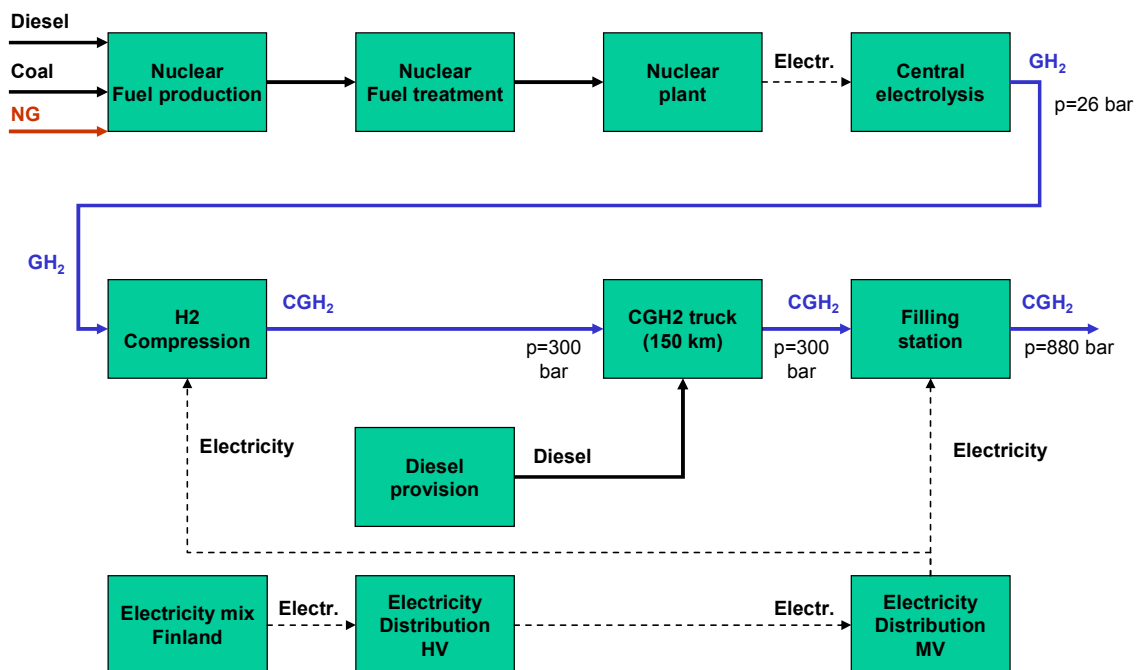


Figure 6. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from central electrolysis using nuclear electricity.

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

- Nuclear fuel production B.1.3
- Electricity production from nuclear energy B.1.4
- Electricity transport B.2.3
- Hydrogen production through electrolysis B.2.8
- Compression of hydrogen B.2.11
- Hydrogen transport by CGH<sub>2</sub> truck B.3.2
- Filling station B.4.1

#### 4.7 3a. De-central gasification of Finnish biomass; use: FC vehicle

Diesel-fuelled trucks transport biomass from Finnish farmed wood plantations to medium-scale de-central biomass gasifiers, over a distance of 50 km on average. For transport purposes, the wood is chipped into pieces. The energy needed for chipping is supplied by a diesel-fuelled generator, which drives a mechanical chipping device. The growing of biomass requires a significant input of fertilizer.

The biomass produced is converted into a product gas rich in CO and H<sub>2</sub> in the gasifier. Subsequently, CO is reacted with steam to form CO<sub>2</sub> and H<sub>2</sub> in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO<sub>2</sub> and H<sub>2</sub> using PSA units.

The produced hydrogen is transported to filling stations in tube trailers using diesel-fuelled trucks. For transport purposes, the hydrogen is compressed from an electrolysis plant outlet pressure of approximately 3 MPa to 30 MPa. Each truck can transport about 350 kg of compressed gaseous hydrogen. The average distance between the de-central gasifier and a filling station is 150 km.

Electrical compressors (part of the filling station) are used to compress the hydrogen up to 88 MPa required for on-board storage. To this end, the filling station (120 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

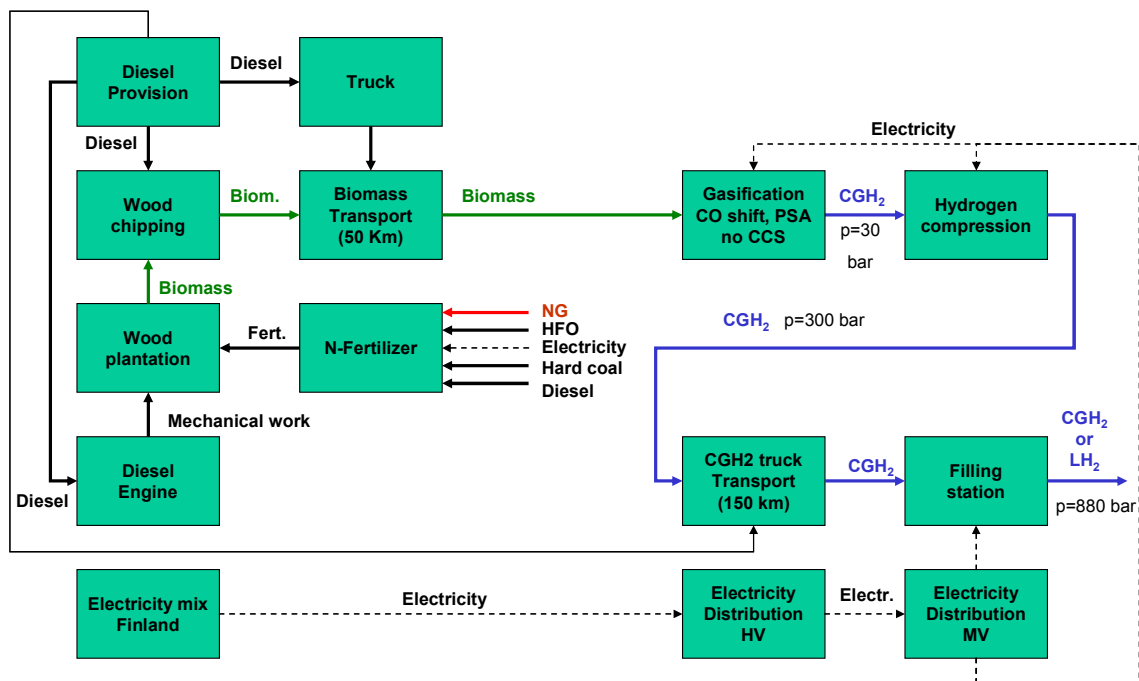


Figure 7. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from de-central gasification of Finnish biomass.

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

- Biomass production B.1.5
- Chipping plant B.1.5
- Biomass transport B.2.4
- Electricity production B.1.4
- Electricity transport B.2.3
- Hydrogen production from biomass B.2.9
- Hydrogen compression B.2.11
- Hydrogen transport by CGH<sub>2</sub> truck B.3.2
- Filling station B.4.1

#### 4.8 3b. De-central gasification of Finnish biomass; use: Domestic CHP

Diesel-fuelled trucks transport biomass from Finnish wood plantations to medium-scale de-central biomass gasifiers over a distance of 50 km on average. For transport purposes, the wood is chipped into pieces. The energy needed for chipping is supplied by a diesel-fuelled generator, which drives a mechanical chipping device. The growing of biomass requires a significant input of fertilizer.

The biomass is converted into a product gas rich in CO and H<sub>2</sub> in the gasifier. Subsequently, CO is reacted with steam to form CO<sub>2</sub> and H<sub>2</sub> in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO<sub>2</sub> and H<sub>2</sub> using PSA units.

The produced hydrogen is transported to end-users (households) in tube trailers using diesel-fuelled trucks. For transport purposes, the hydrogen is compressed from a gasification plant outlet pressure of approximately 2 MPa to 30 MPa (300 bar). Each truck can transport about 350 kg of compressed gaseous hydrogen. The average distance between the de-central gasifier and the end-users is 150 km.

It is assumed that the end-users have compressed gas tanks at their disposal for compressed gaseous hydrogen storage purposes. From these tanks, hydrogen is supplied to fuel cell-based residential micro-CHP systems. The systems are operated in heat-demand following mode. If the electricity demand is higher than it can be produced by the system, the residual demand is covered by electricity from the grid, which is produced from the Finnish fuel mix. Excess electricity produced by the CHP-system is fed back to the electric grid avoiding the electricity production by other means.

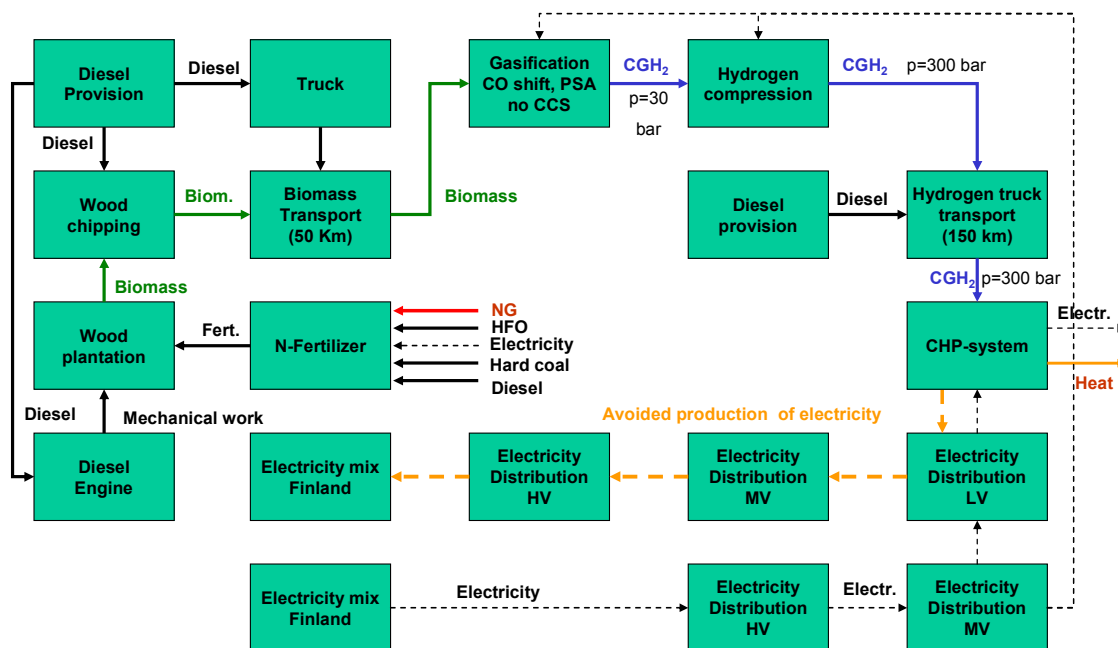


Figure 8. Hydrogen chain model for use of CGH<sub>2</sub> at domestic CHP installations. Hydrogen production from de-central gasification of biomass.

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

- Biomass production B.1.5
- Chipping plant B.1.5
- Biomass transport B.2.4
- Electricity production B.1.4
- Electricity transport B.2.3
- Hydrogen production from biomass B.2.9
- Hydrogen compression B.2.11
- Hydrogen transport by CGH<sub>2</sub> truck B.3.2
- CHP-system B.4.3

#### 4.9 3c. De-central gasification of Russian biomass; use: FC vehicle

Trains transport biomass from Russian wood plantations to medium-scale de-central biomass gasifiers, over a distance of 2000 km on average. Rail transport uses electricity at high-voltage level. For transport purposes, the wood is chipped into pieces. The energy needed for chipping is supplied by a diesel-fuelled generator, which drives a mechanical chipping device. The growing of biomass requires a significant input of fertilizer.

The biomass is converted into a product gas rich in CO and H<sub>2</sub> in the gasifier. Subsequently, CO is reacted with steam to form CO<sub>2</sub> and H<sub>2</sub> in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO<sub>2</sub> and H<sub>2</sub> using PSA units.

The produced hydrogen is transported to filling stations in tube trailers using diesel-fuelled trucks. For transport purposes, the hydrogen is compressed from a gasification plant outlet pressure of approximately 2 MPa to 30 MPa (300 bar). Each truck can transport about 350 kg of compressed gaseous hydrogen. The average distance between the de-central gasifier and a filling station is 150 km.

Electrical compressors (part of the filling station) are used to compress the hydrogen up to 88 MPa required for on-board storage. To this end, the filling station (480 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

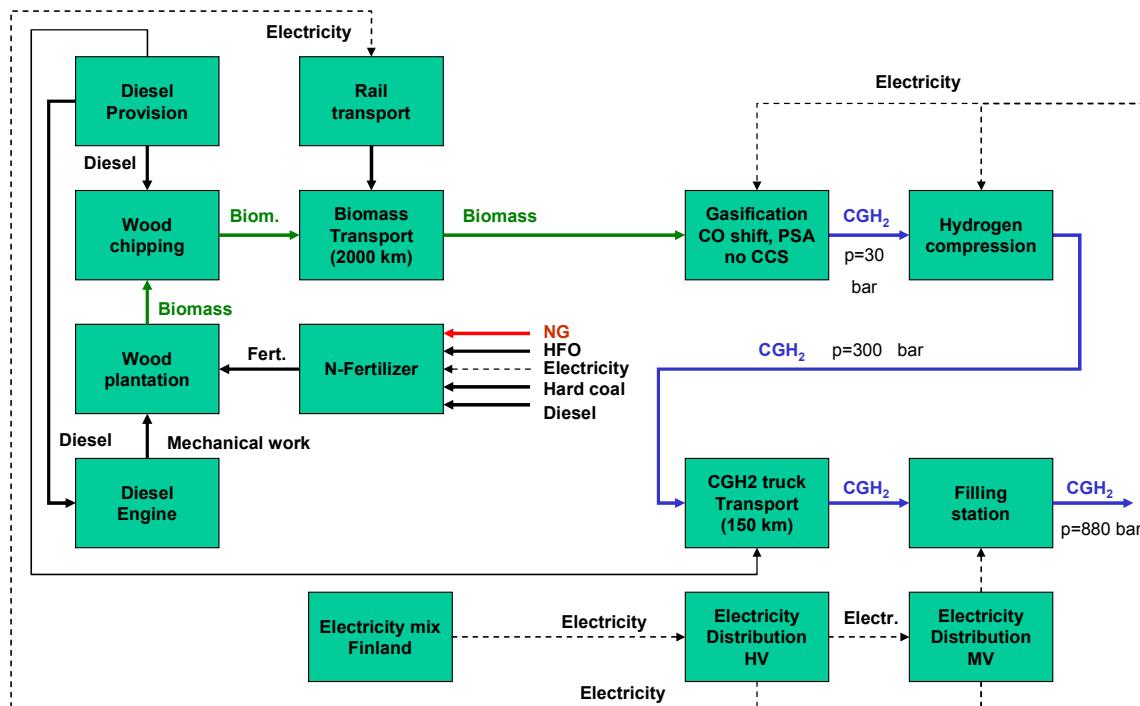


Figure 9. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from de-central gasification of Russian biomass.

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

- Biomass production B.1.5
- Chipping plant B.1.5
- Biomass transport B.2.4
- Electricity production B.1.4
- Electricity transport B.2.3
- Hydrogen production from biomass B.2.9
- Hydrogen compression B.2.11
- Hydrogen transport by CGH<sub>2</sub> truck B.3.2
- Filling station B.4.1

#### 4.10 4a. Central gasification of coal without CCS, transport by CGH<sub>2</sub>-truck

Ocean bulk carriers transport coal, extracted and processed in Poland, to Finland over a distance of approximately 1000 km. The central gasification plants are located at the Finnish coast, so no further coal transport is required.

The coal is converted into a product gas rich in CO and H<sub>2</sub> in the gasifier. Subsequently, CO is reacted with steam to form CO<sub>2</sub> and H<sub>2</sub> in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO<sub>2</sub> and H<sub>2</sub> using PSA units. Carbon-capture and storage (CCS) is not included as an option.

The hydrogen produced is compressed up to 30 MPa and transported to filling stations in tube trailers using diesel-fuelled trucks. Each truck can transport about 350 kg of hydrogen. The distance to a filling station is 150 km on average. Electrical compressors (part of the filling station) are used to compress the hydrogen up to 88 MPa required for on-board storage. To this end the filling station (1200 t/yr) has a connection to the medium voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

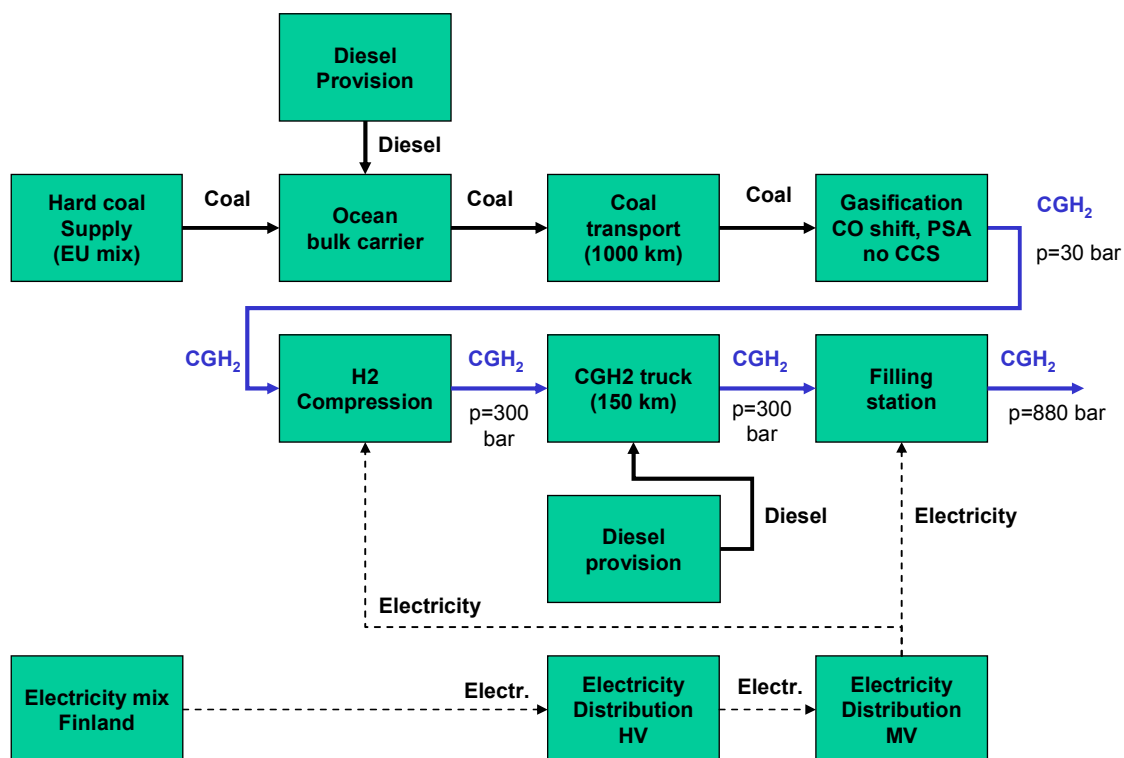


Figure 10. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from central coal gasification, transport by CGH<sub>2</sub>-truck.

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

- Hard coal extraction B.1.2
- Electricity production B.1.4
- Coal transport B.2.2
- Electricity transport B.2.3
- Hydrogen production from coal B.2.7
- Hydrogen transport by CGH<sub>2</sub> truck B.3.2
- Filling station B.4.1

#### 4.11 4b. Central gasification of coal without CCS, transport by LH<sub>2</sub> trucks

Ocean bulk carriers transport coal, extracted and processed in Poland, to Finland over a distance of approximately 1000 km. The central gasification plants are located at the Finnish coast, so no further coal transport is required.

The coal is converted into a product gas rich in CO and H<sub>2</sub> in the gasifier. Subsequently, CO is reacted with steam to form CO<sub>2</sub> and H<sub>2</sub> in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO<sub>2</sub> and H<sub>2</sub> using PSA units. Carbon-capture and storage (CCS) is not included as an option.

The hydrogen produced is liquefied and transported to filling stations (1200 t/yr) in tanks using diesel-fuelled trucks. Each truck can transport about 3.5 ton of hydrogen. The distance to a filling station is 150 km on average. The hydrogen is stored as a liquid at the filling station and it can be distributed to cars with either gaseous or liquid on-board storage. Electrical pumps are used to dispense the liquid hydrogen. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

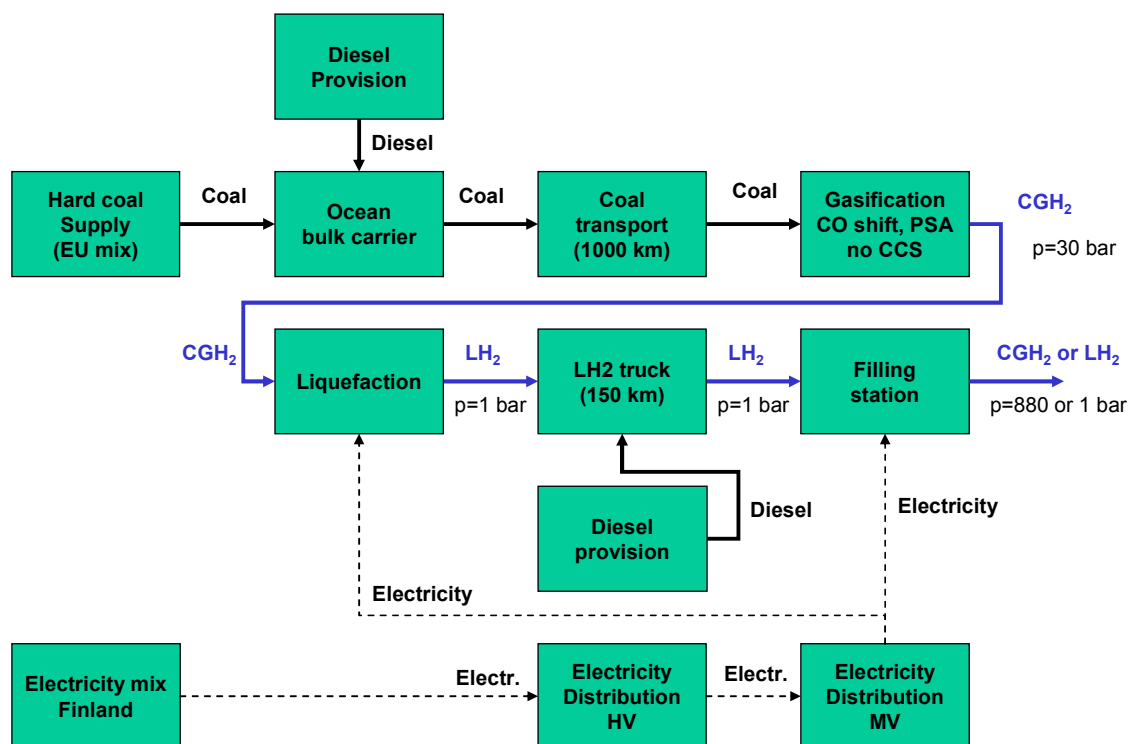


Figure 11. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from central coal gasification, transport by LH<sub>2</sub>-truck.

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

- Hard coal extraction B.1.2
- Electricity production B.1.4
- Coal transport B.2.2
- Electricity transport B.2.3
- Hydrogen production from coal B.2.7
- Liquefaction of hydrogen B.2.10
- Hydrogen transport by LH<sub>2</sub> truck B.3.3
- Filling station B.4.1

#### 4.12 4c. Central gasification of coal without CCS, transport by pipeline

Ocean bulk carriers transport coal, extracted and processed in Poland, to Finland over a distance of approximately 1000 km. The central gasification plants are located at the Finnish coast, so no further coal transport is required.

The coal is converted into a product gas rich in CO and H<sub>2</sub> in the gasifier. Subsequently, CO is reacted with steam to form CO<sub>2</sub> and H<sub>2</sub> in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO<sub>2</sub> and H<sub>2</sub> using PSA units. Carbon-capture and storage (CCS) is not included as an option.

The hydrogen produced is transported from the production site to filling stations by a system of high-pressure and medium-pressure hydrogen pipelines. The distance to a filling station is 150 km on average. Electrical compressors (part of the filling station) are used to compress the hydrogen up to 88 MPa required for on-board storage. To this end the filling station (1200 t/yr) has a connection to the medium voltage electricity grid. It is assumed that the electricity required is obtained from the Finnish electricity production mix.

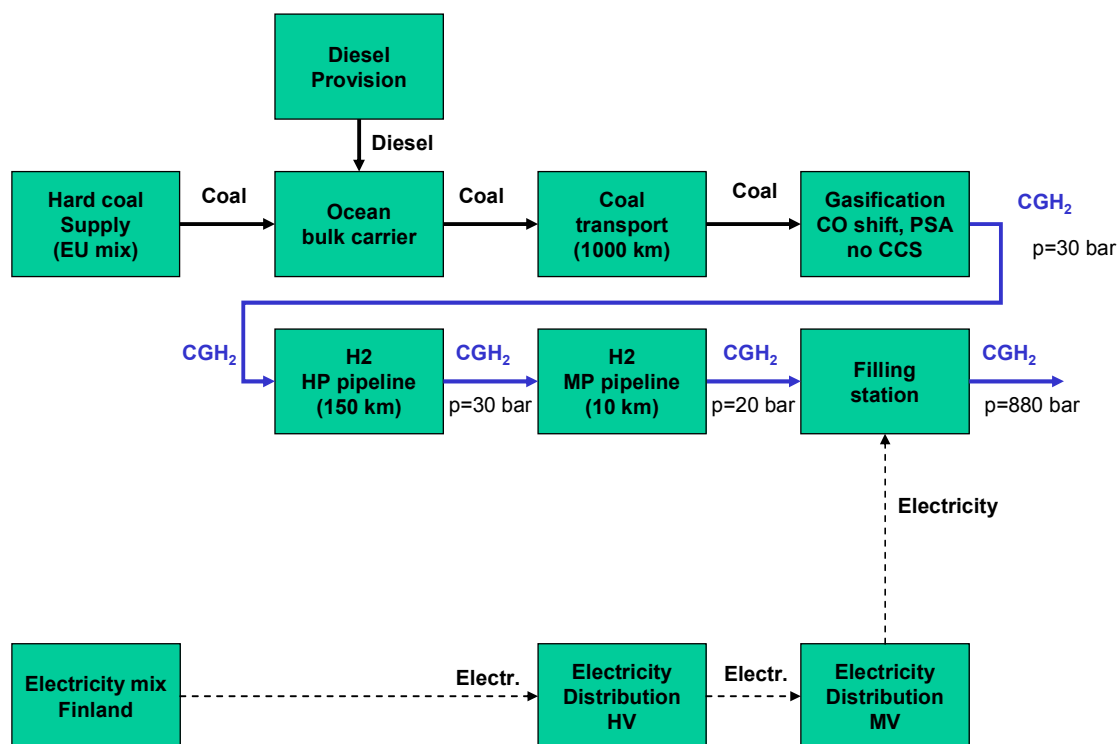


Figure 12. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from central coal gasification, transport by pipeline

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

- Hard coal extraction B.1.2
- Electricity production B.1.4
- Coal transport B.2.2
- Electricity transport B.2.3
- Hydrogen production from coal B.2.7
- Hydrogen transport by pipelines B.3.1
- Filling station B.4.1



## 4.14 6a. Thermo-chemical process using nuclear heat; use: FC vehicle

A nuclear plant is used to drive a thermo-chemical cycle in this chain. These thermo-chemical cycles use cheap high-temperature heat from high-temperature nuclear reactors for the production of hydrogen.

The hydrogen produced is transported from the production site to filling stations by a system of high-pressure and medium-pressure hydrogen pipelines. Transport distances in the high- and medium-pressure pipelines are 150 and 10 km on average. Electrical compressors (part of the filling stations) are used to compress the hydrogen up to 88 MPa required for on-board storage. To this end, the filling station (1200 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required by the filling stations is obtained from the Finnish electricity production mix.

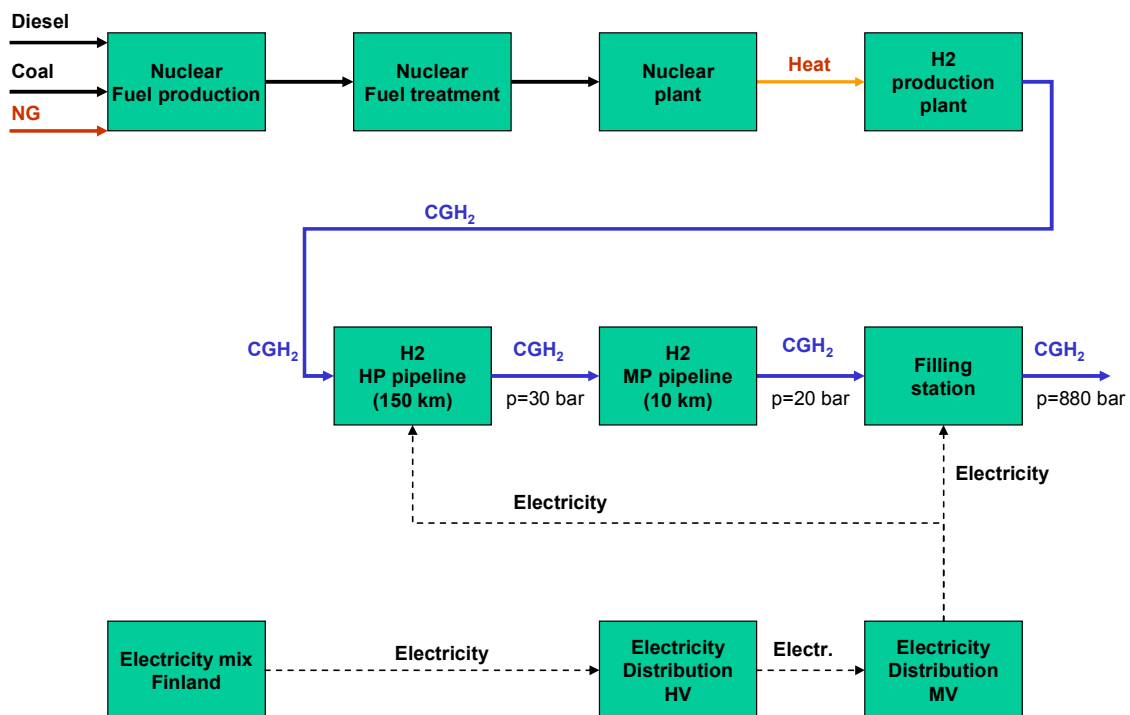


Figure 14. Hydrogen chain model for CGH<sub>2</sub> at a filling station. Hydrogen production from a thermo-chemical process using nuclear heat.

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

- Hard coal extraction B.1.2
- Diesel production B.5.1
- Natural gas extraction and processing B.1.1
- Electricity production B.1.4
- Coal transport B.2.2
- Diesel transport B.2.5
- Natural gas transport B.2.1
- Nuclear fuel treatment and nuclear plant B.1.3
- Electricity transport B.2.3
- Hydrogen production from nuclear energy B.2.7
- Liquefaction of hydrogen B.2.10
- Hydrogen transport by truck B.3.2
- Filling station B.4.1

#### 4.15 Reference for comparison of the mobile hydrogen energy chains

The hydrogen energy chains for vehicles are compared with conventional gasoline and diesel chains, both on a WTT (excluding vehicle) and on a WTW (including vehicle) basis. The modelling of the gasoline and diesel chains was performed for a typical European country, accounting several raw-oil transport means, averaged raw-oil transport distances and refinery emissions. The results of these analyses are used homogeneously for all Member States in the HyWays project. Results of the WTT-analyses and WTW-analyses are presented in sections 5.2 and 5.3 respectively.

#### 4.16 References for comparison of the stationary hydrogen energy chains

Two stationary references have been defined to compare the hydrogen energy chains for stationary use in Finland. Reference A represents the case where the production of heat and electricity is completely derived from electric energy. Reference B represents the case where household heat consumption is produced by diesel boilers and the electricity consumption is produced by the Finnish electric grid.

The comparison is based on the consumption of heat and electricity on the ratio 4:1 for the year 2020, and on the ratio 3.4:1 for the year 2030. These ratios reflect the yearly average heat to power demand of a Finnish household for the given years.

##### Reference A

The heat demanded by the Finnish households is obtained through electric powered heaters. In this case electricity is the only energy carrier supplied to the household.

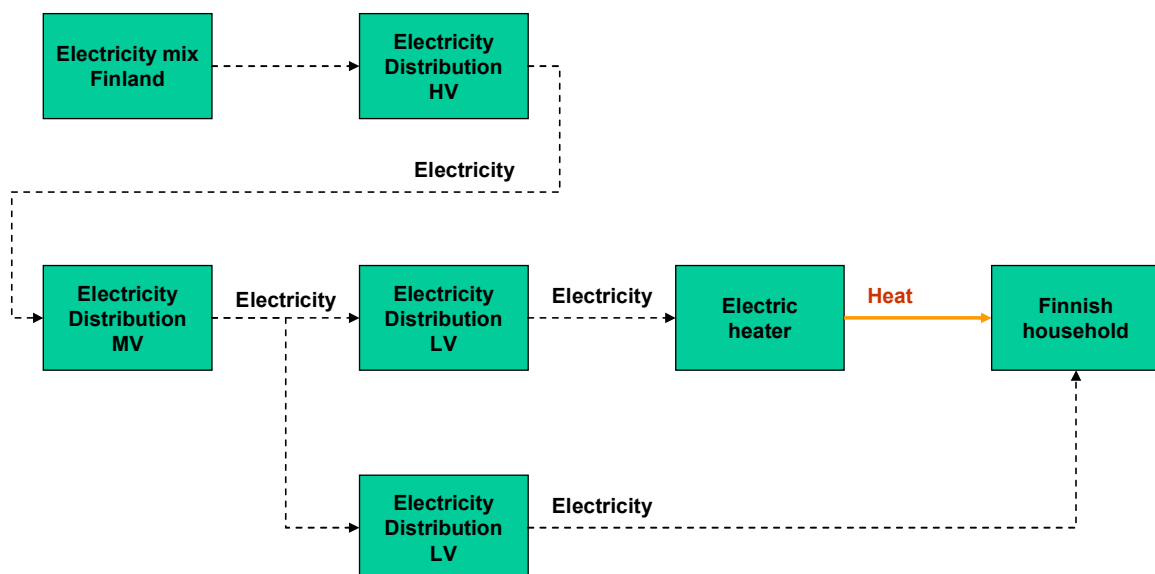


Figure 15. Modelled stationary reference, 100% electricity use

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

- Electricity production B.1.4
- Electricity transport B.2.3
- Finnish household B.4.3

##### Reference B

The heat demanded by the Finnish households is obtained through diesel-powered stoves. The required electricity is obtained from the electricity grid.

The modelling of the diesel production chain was performed for a typical European country, accounting diesel transport by ship and by train and using typical transport distances (500 km by ship and 250 km by train). The transported diesel is stored in depots. From the Finnish diesel depots, the

diesel is further transported at the national level by diesel-fuelled trucks. Therefore, a national transport distance of 150 km has been assumed.

The Finnish household is finally assumed to have diesel tanks at its disposal for storage purposes. This assumption is in accordance to households located at the countryside of Finland.

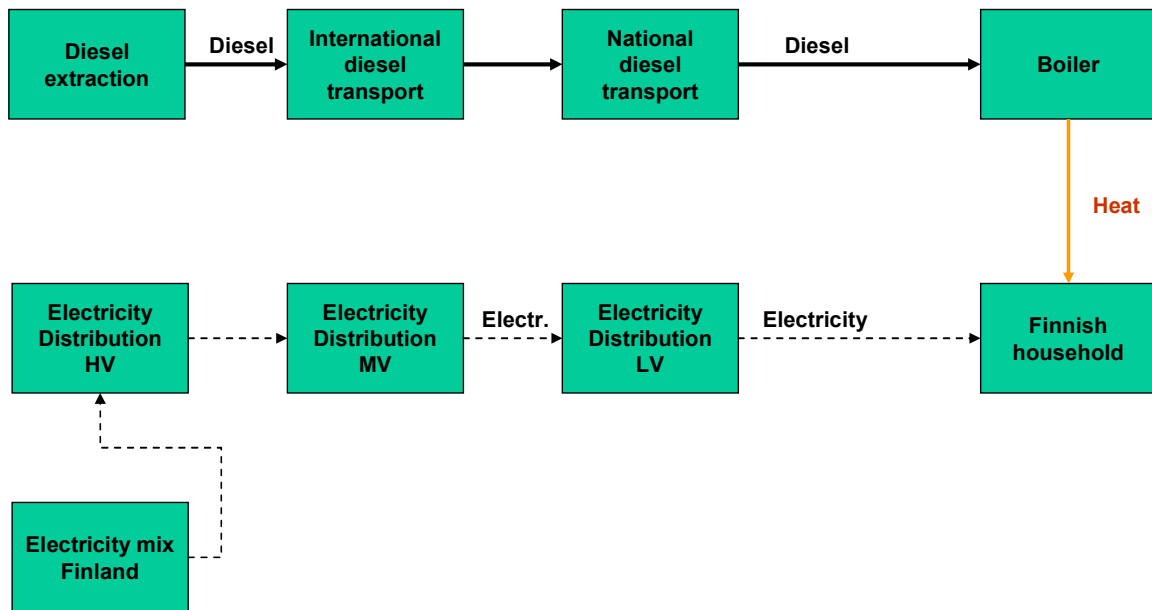


Figure 16. Modelled stationary reference, fuel mix

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

- Electricity production B.1.4
- Diesel production B.5.1
- Electricity transport B.2.3
- Diesel transport B.2.5
- Finnish household B.4.3

## 5. Results

### 5.1 General

The results of the analysis performed to the hydrogen energy chains are presented for the years 2020 and 2030 in paragraphs 5.2 to 5.4. They cover the following aspects:

- Chain energy efficiency
- Primary energy use per unit of energy carrier (e.g. kWh of H<sub>2</sub>), or energy service (e.g. a kilometre of transport), supplied by the chain.
- CO<sub>2</sub>-equivalents emitted per unit of energy carrier, or energy service, supplied by the chain.
- Costs per unit of energy carrier, or energy service, supplied by the chain.

In paragraph 5.2 the results are presented for the Well-to-Tank (WTT) analysis of the hydrogen energy chains. This analysis includes all processes in the chains up to and including the distribution at the filling station. Results are presented for the following chains:

- 1a Natural gas, on-site SMR; use: car filling station (CGH2)
- 1b Natural gas, central SMR, Pipeline transport; use: car filling station (CGH2)
- 1c Natural gas, central SMR, CGH2-truck transport; use: car filling station (CGH2)
- 1d Natural gas, central SMR, LH2-truck transport; use: car filling station (CGH2 and LH2)
- 2a Electricity mix, on-site electrolysis; use: car filling station (CGH2)
- 2b Nuclear electricity, central electrolysis, CGH2-truck transport; use: car filling station (CGH2)
- 3a Finnish farmed biomass, de-central gasification, CGH2-truck transport; use: car filling station (CGH2)
- 3c Russian farmed biomass; de-central gasification, CGH2-truck transport; use: car filling station (CGH2)
- 4a Coal, central gasification, CGH2-truck transport; use: car filling station (CGH2)
- 4b Coal, central gasification, LH2-truck transport; use: car filling station (CGH2 and LH2)
- 4c Coal, central gasification, Pipeline transport; use: car filling station (CGH2)
- 6a Nuclear heat, central thermoplant, Pipeline transport; use: car filling station (CGH2)

In paragraph 5.3 the results are presented for the Well-to-Wheel (WTW) analysis of the hydrogen energy chains. A Fuel Cell Hybrid vehicle represents the end use of hydrogen. The hydrogen energy chains are compared to diesel and to gasoline reference chains, where the end-user is assumed to be an ICE-Hybrid vehicle (technology 2010, assumed unchanged for 2020 and 2030). The WTW-results include the same hydrogen chains of the WTT-analysis.

In paragraph 5.4 the results are presented for the Well-to-Stationary User (WTStU) analysis including the end use of hydrogen in a CHP-unit or boiler. Results are presented for the following chains:

- 3b Finnish farmed biomass, de-central gasification, CGH2-truck transport; use: CHP-system, Q-following system
- 5a Offshore wind energy, de-central electrolysis; use: CHP-system, Q-following system
- Ref A 100% electric household energy provision
- Ref B Combined oil-electric household energy provision

The calculated costs of all analyses are levelized for the years 2020 and 2030 according to the calculation rules presented in Annex A. For Finland, a discount rate of 6% has been used.

## 5.2 Well-to-Tank analysis (WTT)

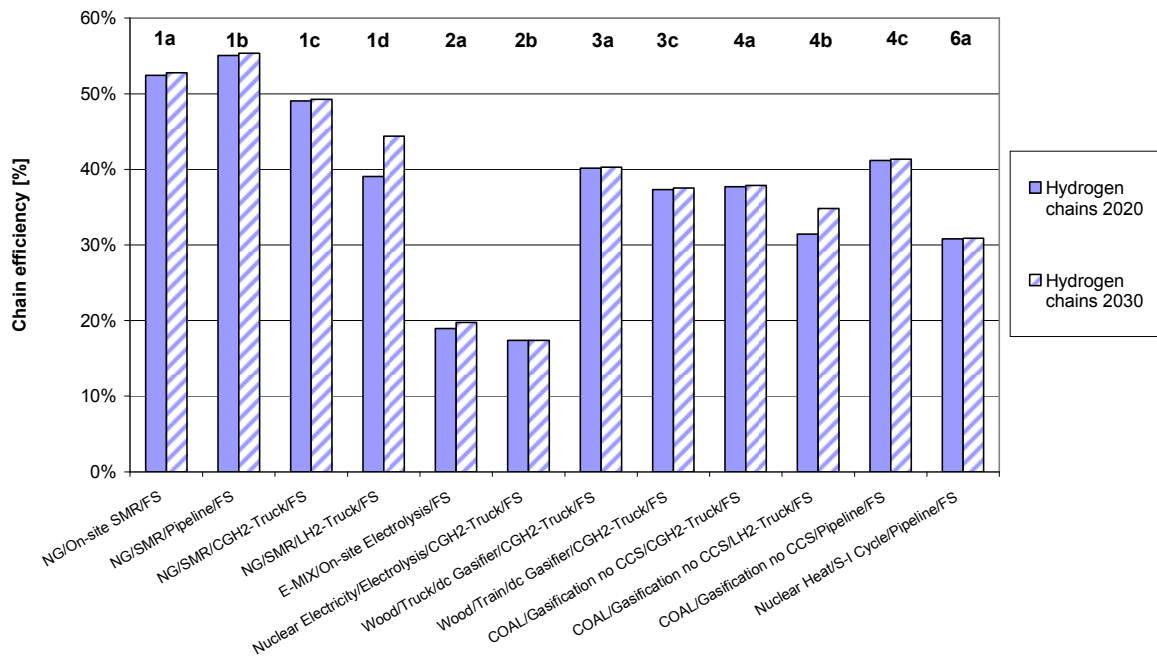


Figure 17. Finnish WTT hydrogen energy chain efficiencies

Figure 17 shows the results on energy efficiency for the hydrogen supply chains. The electrolysis chains show a much lower efficiency than the other chains, while the NG-based chains are the most efficient. CGH<sub>2</sub>-transport by truck is less efficient than pipeline transport. Due to the high energy needed for the liquefaction process, the LH<sub>2</sub>-chains are less efficient than the comparable CGH<sub>2</sub>-chains. Transport of CGH<sub>2</sub>, however, will require much more truck movements.

Comparing the results for 2020 and 2030, the only two hydrogen chains that show a clear efficiency improvement through the years are chain 1d and 4b. The reason of this efficiency increase is the assumed efficiency improvement of the liquefaction process that both chains involve.

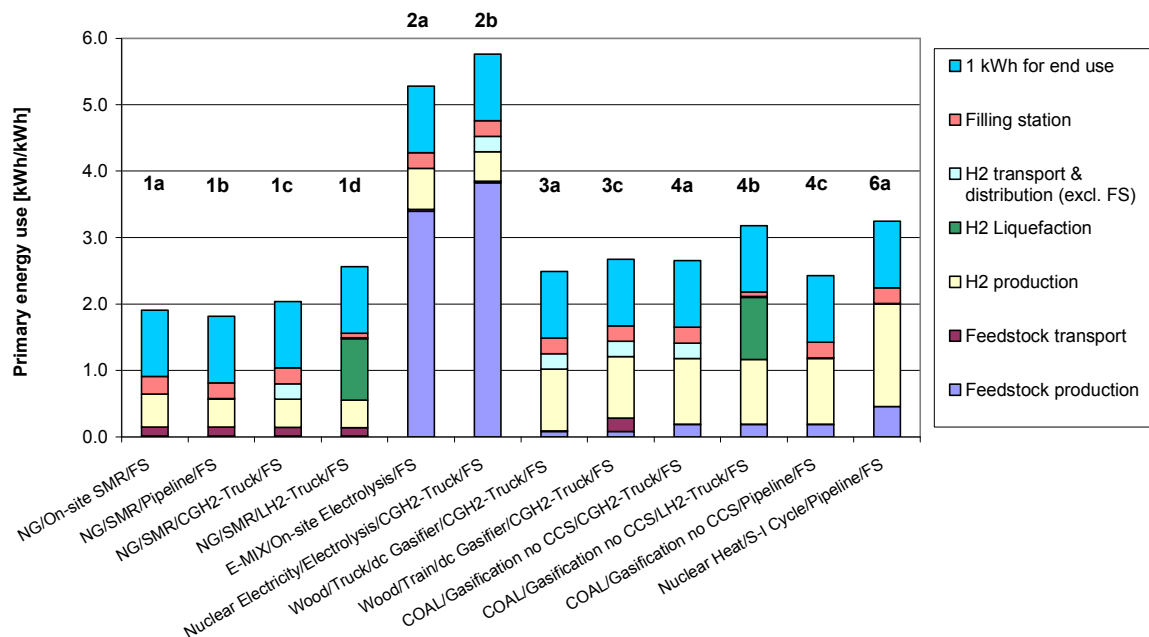


Figure 18. Primary energy use of Finnish WTT hydrogen energy chains

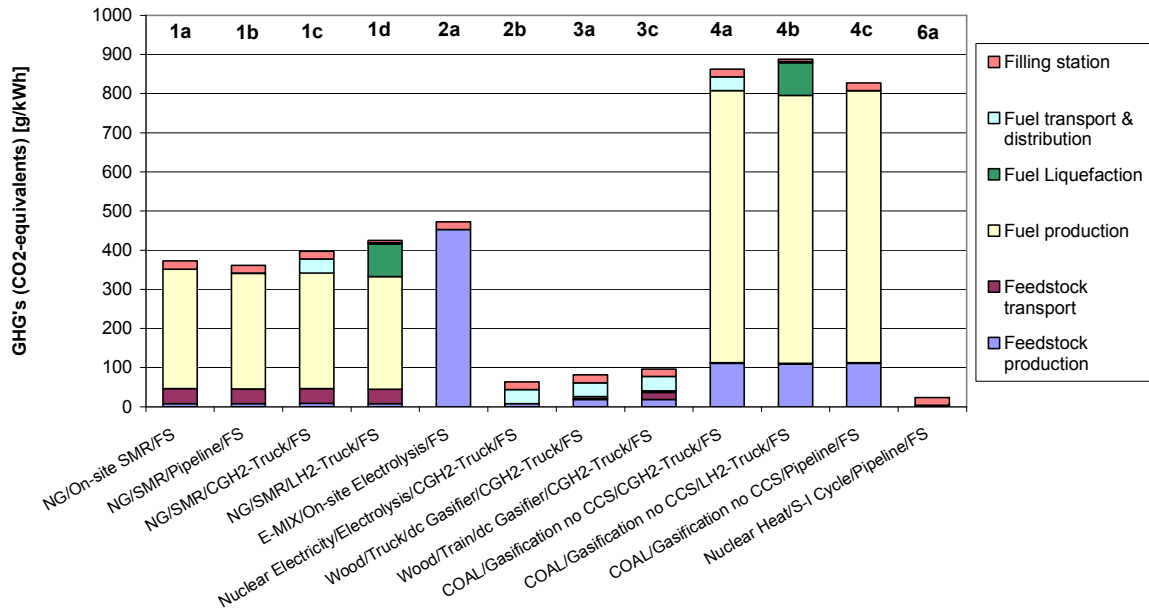


Figure 19. CO<sub>2</sub>-equivalent emissions of Finnish WTT hydrogen energy chains

Figure 18 shows the primary energy use for the selected WTT energy chains. Based on the assumptions made the primary energy consumption is highest for production of hydrogen from electricity. The comparison of chains 1b and 1c shows the effect of transporting compressed gaseous hydrogen using tube trailers instead of using pipelines.

Figure 19 shows the greenhouse gas (GHG) emissions related to the hydrogen supply chains. Due to the absence of carbon capture and storage in the coal-based chains, they have the highest level of GHG-emissions. The hydrogen energy chains using nuclear energy (directly or as electricity) and biomass are, as expected, the chains with the lowest amount of equivalent greenhouse gases per kWh of produced energy.

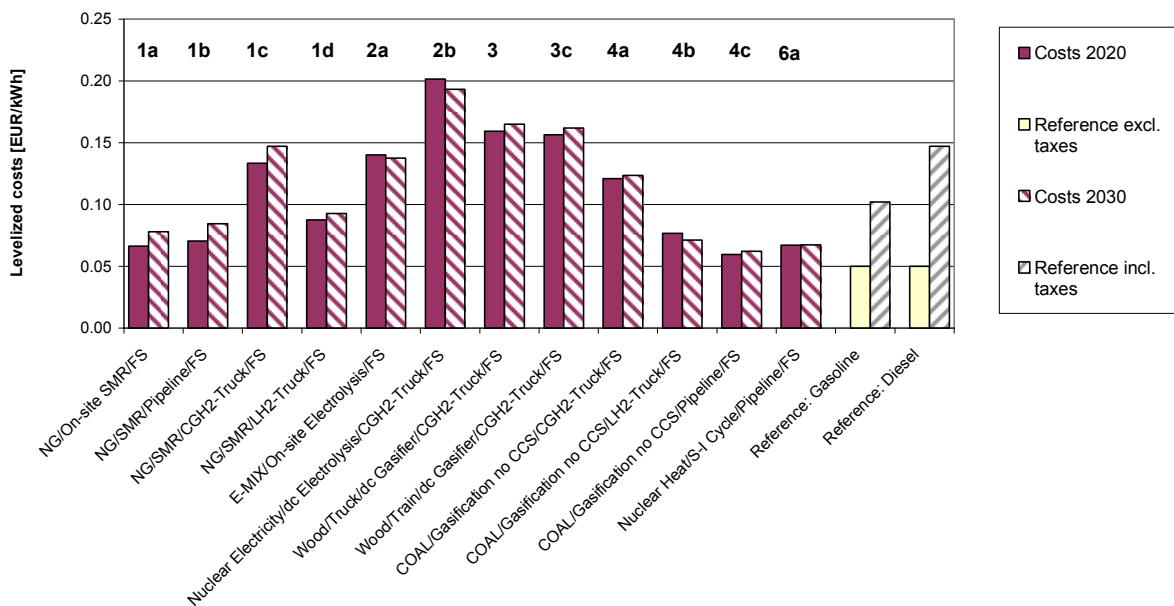


Figure 20. Costs of hydrogen and conventional fuels for Finnish hydrogen energy chains

The GHG emissions of the natural gas based chains are mainly the result of the conversion of natural gas into hydrogen without the application of CCS and of the long-distance gas transport from Russia. The latter contribution results from the compression energy required to keep the gas flowing and from methane leakages out of the pipelines.

Figure 20 presents the results for the cost of hydrogen (COH) per unit of energy. The costs are compared with the expected cost of the conventional fuels in 2020, and with the price of these fuels including present day taxes.

The results for 2020 and 2030 show that, based on the assumptions made, the COH of the fossil fuel based chains increase. This is due to an increase in feedstock price, especially the price of natural gas. The increase in the COH of the biomass based chain is the result from increase of the oil price (transport of biomass) and increase of the cost of electricity.

### 5.3 Well-to-Wheel analysis (WTW)

Figure 21, Figure 22 and Figure 23 present the results of the WTW-analysis. WTW-results are obtained by combining the results of the supply chains (WTT) with a mobile end use application. In this study, only passenger cars have been considered. Table 4 presents an overview of the considered vehicles, see also section B.4.2 of Annex B.

Table 4. Overview of technologies of passenger cars expected to be available by the year 2010

	Fuel consumption [kWh/km]	GHG emissions [g CO <sub>2</sub> equiv./km]
CGH <sub>2</sub> or LH <sub>2</sub> FC hybrid vehicle	0.2325	0
Gasoline hybrid vehicle	0.4492	143
Diesel hybrid vehicle	0.4044	120

Only results for FC Hybrid and conventional fuel ICE Hybrid vehicles are presented. Results with respect to WTW primary energy use are presented in Figure 21. In most of the cases, the primary energy use of the hydrogen chains is higher than that of the conventional fuel chains, especially for the electrolysis-based cases. Only the natural gas-based chains show comparable or even lower values of primary energy use than the conventional chains.

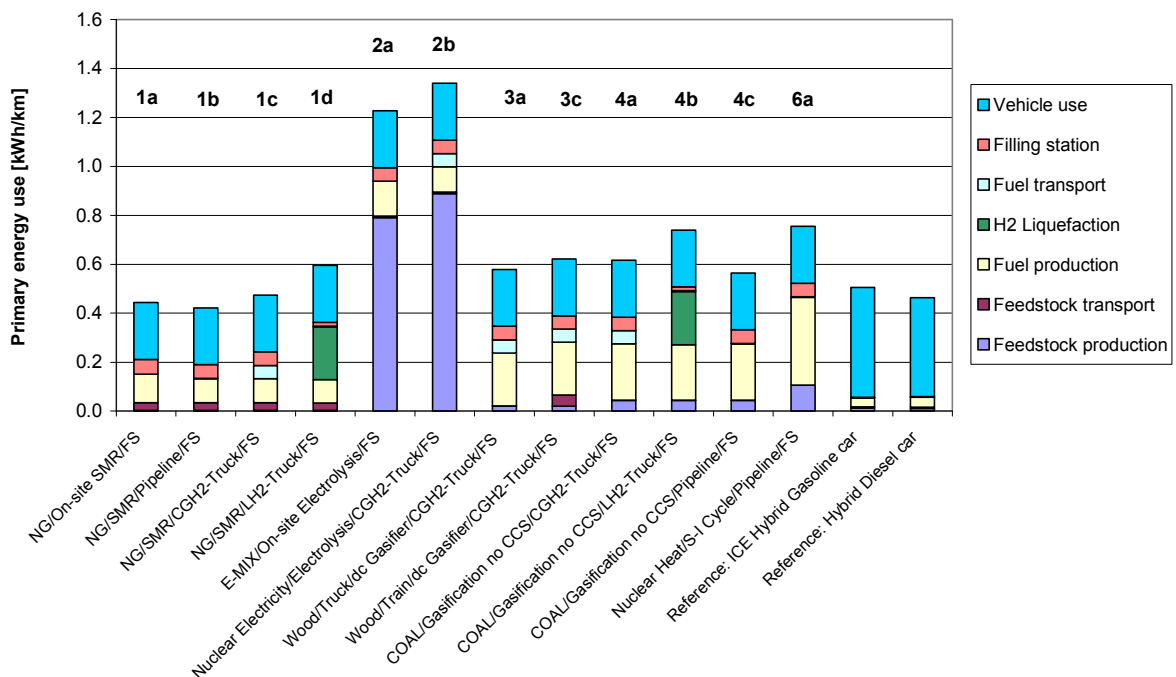


Figure 21. WTW energy use of Finnish hydrogen energy chains, compared to 2010 reference car technologies

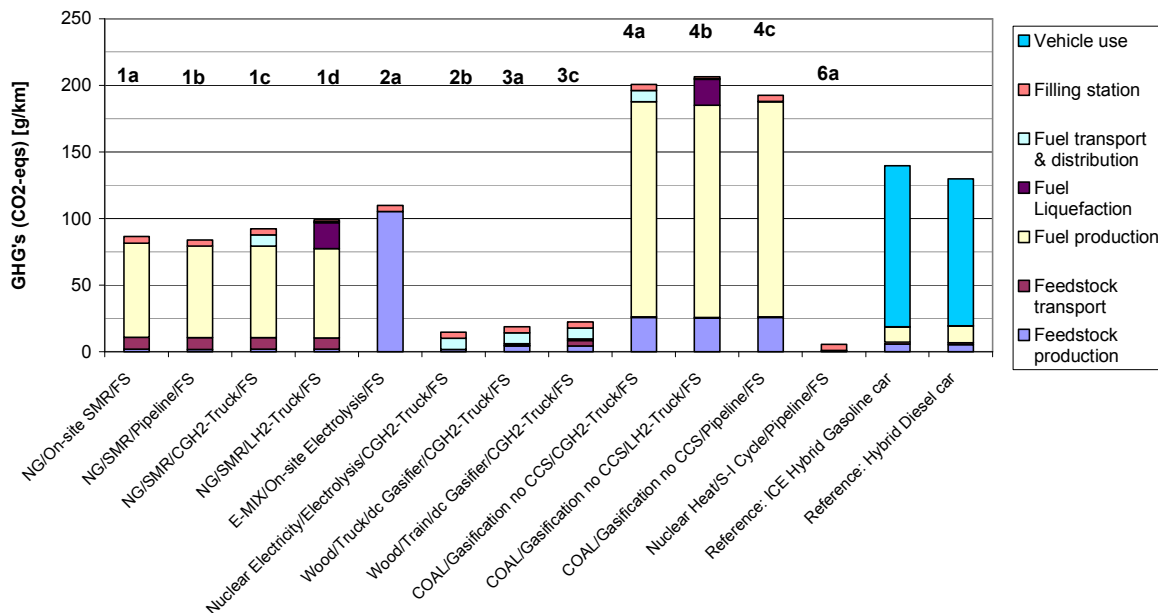


Figure 22. WTW CO<sub>2</sub>-equivalent emissions for hybrid passenger cars in 2020

Figure 22 shows that, with exception of the coal-based chains, the GHG emissions for the hydrogen chains are on a much lower level than for the conventional fuel chains. This also applies for the hydrogen chains based on the use of natural gas, even though carbon capture and storage is not included in the chains. The low emission level of the electrolysis chain using electricity from the mix is remarkable given the high primary energy use (Figure 21). This is explained by a large share of nuclear and renewable energy used for the production of electricity in Finland, both energy carriers having no contribution to the GHG emissions of the electricity mix.

The WTW hydrogen costs shown in Figure 23, vary from somewhat below up to two times above the WTW cost of the conventional fuel chains excluding taxes. The chains including CGH<sub>2</sub>-transport by truck show relatively high cost compared to the chains with pipeline and LH<sub>2</sub>-transport. Although the WTW hydrogen cost of the electrolysis and biomass-based chains are relatively high, all of them fall within the range of the price of conventional fuels including taxes.

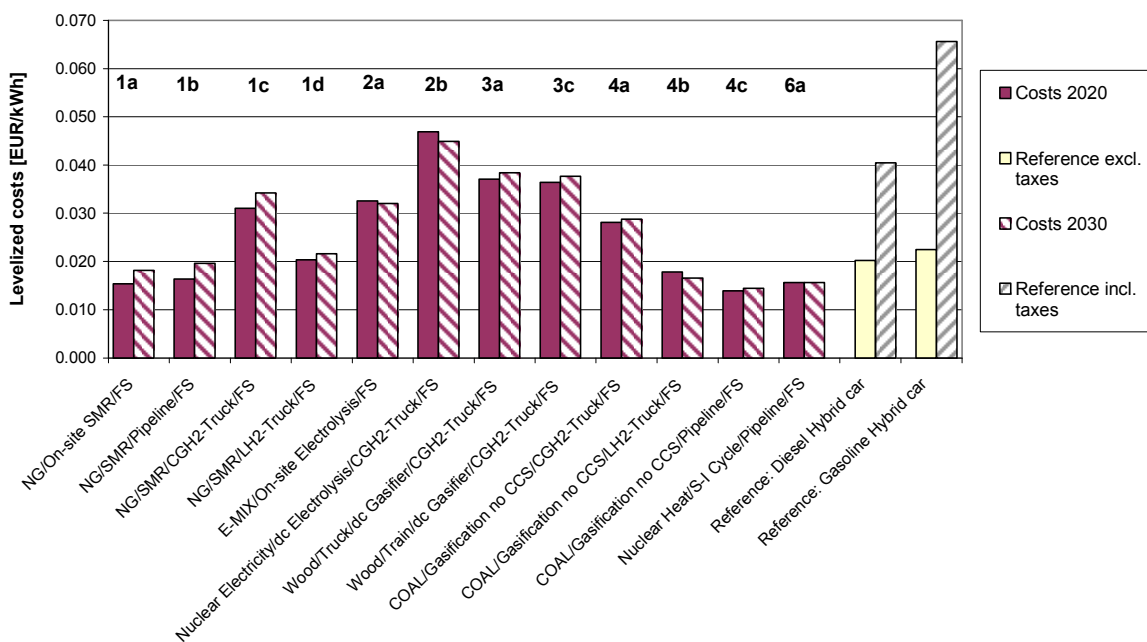


Figure 23. WTW energy costs for hybrid passenger cars in 2020 – 2030

The WTW COH of the coal-based and NG-based chains is even lower the WTW cost of the conventional fuels excluding taxes. These chains are less preferable from a GHG emission point of view. Carbon capture and storage could be a solution, but would lead to an increase in cost.

### 5.4 Well-to-Stationary use analysis (WTStU)

Figure 24, Figure 25, Figure 26 and Figure 27 present the results of the WTStU-analysis performed.

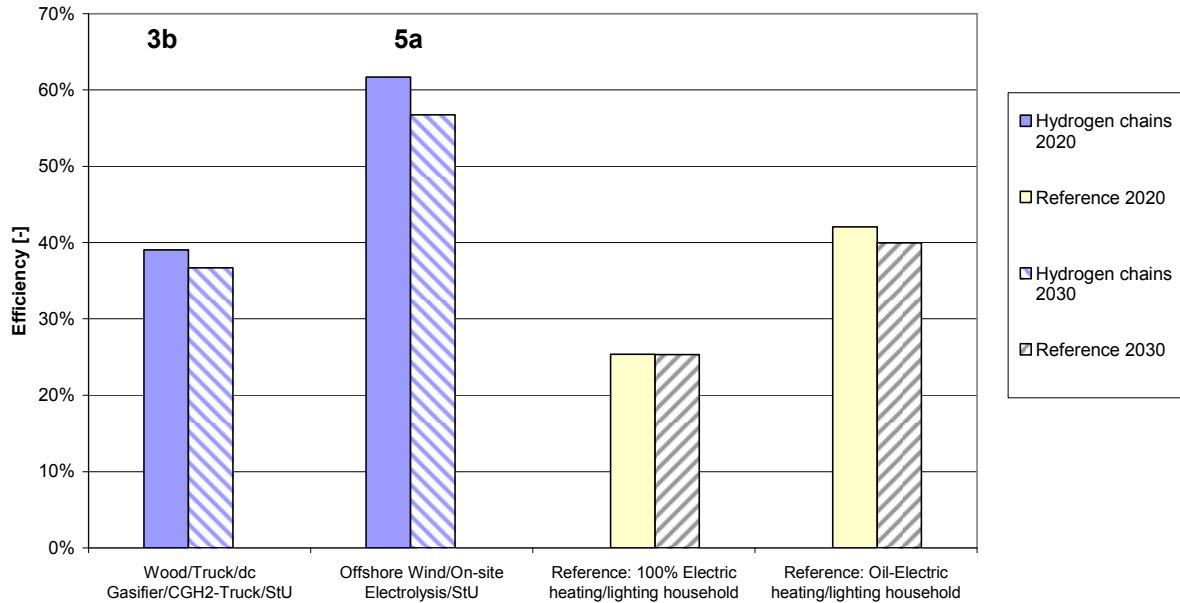


Figure 24. Efficiencies of the Finnish WTStU hydrogen energy chains

Figure 24 presents the development of energy efficiency of the stationary hydrogen pathways for the period 2020-2030 compared to the reference cases. The efficiency is calculated as the primary energy used to deliver the required specific household energy demand (sHED). The efficiency decrease observed between the year 2020 and 2030 is mainly due to a household energy consumption change expected through the years. The efficiency of chain 2b (Offshore wind energy) is clearly higher than the references. This is due to the fact that wind energy is a free form of energy that does not consume any primary energy.

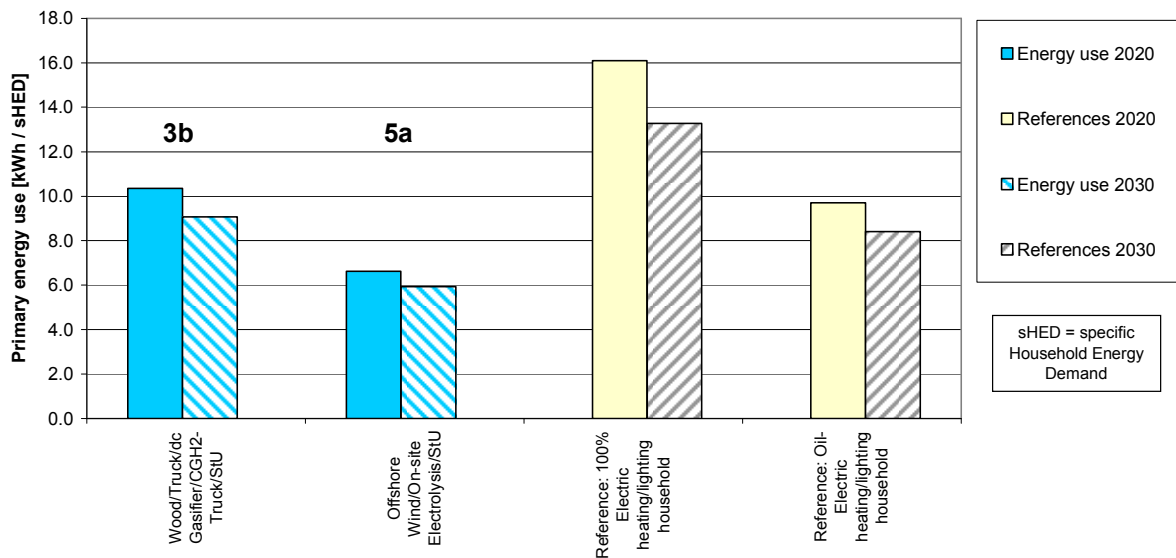


Figure 25. Primary energy use of Finnish WTStU hydrogen energy chains

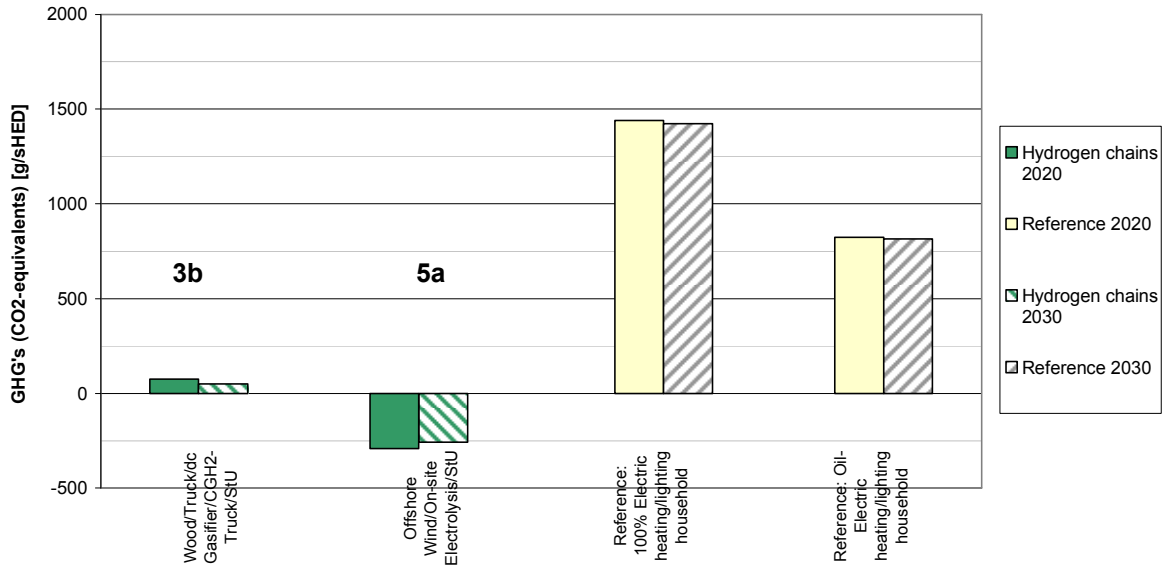


Figure 26. CO<sub>2</sub>-equivalent emissions of Finnish WTStU hydrogen energy chains

The energy service provided by these chains (residential micro-CHP) is the specific energy demand in Finnish households. This sHED equals to 1 kWh of electricity and about 4 kWh of heat for the year 2020 in Finland. This is different from the WTW chains, where the energy service provided is car-kilometres.

The difference in energy use between the years 2020 and 2030, observed in Figure 25, is mainly due to a household energy consumption change through the years: it is expected that a typical Finnish household will consume more electricity and less heat in the future [ref. 4]. The efficiency of electricity generation is also expected to increase. See section B.1.4 for details.

Figure 26 presents the results for the GHG calculations for the WTStU-analysis including the end use of hydrogen. Due to the use of CO<sub>2</sub>-free primary feedstock's in the production of hydrogen, the results on GHG emissions show a clear reduction compared to the reference case, where part of the energy mix is formed by fossil fuels.

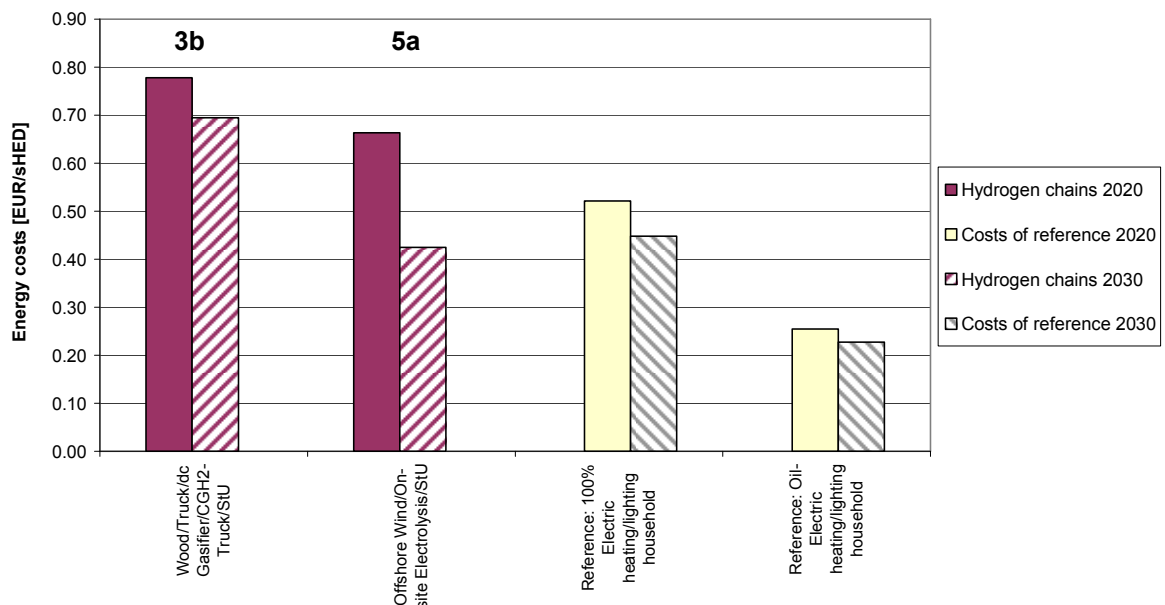


Figure 27. Costs of hydrogen and conventional fuels for Finnish WTStU hydrogen energy chains

With respect to the references, the stationary hydrogen chain using farmed wood as feedstock (3b) presents much lower CO<sub>2</sub>-equivalent emissions. In the case of the wind energy-based hydrogen energy chains, the value of the GHG emissions becomes negative, meaning that emissions are avoided with respect to the reference. This is due to the production of excess electricity that it is delivered to the grid, avoiding the production of fossil fuel-based electricity elsewhere.

Figure 27 presents the cost of hydrogen (COH) per unit of energy, as defined in this study for an average Finnish household. It should be noted that the investment cost of the equipment needed to supply the heat and electricity to the household are not included in the calculations (e.g. CHP-unit and boiler).

The results show that the cost of hydrogen for an average household is higher than the cost of energy for the reference case, although a positive cost development is expected from 2020 to 2030. The picture may be somewhat different if taxes are included, similar to what it has been presented for the conventional fuels in Figure 23.

Figure 27 shows also that although a positive cost development from 2020 to 2030 is expected, the biomass-based hydrogen chain appears to be more expensive than the references. Due to an expected reduction in cost of wind energy and electrolysis, the wind energy-based hydrogen chain shows similar costs than electricity in the year 2030 although it is still more expensive than the oil-based domestic heat production. In this cost calculation, the price of the equipment needed by the consumer to get the heat and electricity required in the household is not included.

## 6. Bibliography

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3. EUCAR/CONCAWE. "*Well-to-wheels analysis of future Automotive fuels and powertrains in the European context*"; Tank-to-wheels report, version 2b. May 2006.
4. National Technical University of Athens. "*PRIMES, Baseline Scenario for Finland. Summary results Primes version 2 Energy Model*" Athens, March 2003.

## Annex A Calculation rules

### A.1 Conversion factors for Greenhouse Gas Equivalents

For the conversion of the different greenhouse gases (GHG) to CO<sub>2</sub>-equivalents, the following conversion factors have been used:

Table 5. Conversion factors [IPCC 2001]

Emission	g CO <sub>2</sub> equivalent per g
CO <sub>2</sub>	1
CH <sub>4</sub>	23
N <sub>2</sub> O	296

### A.2 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 electrolyzers and onsite steam reformers. The learning curve is defined by the following formula:

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

where:

I	=	Investment of the N <sup>th</sup> unit
a	=	Investment of the 1 <sup>st</sup> 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<sup>th</sup> 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 1<sup>st</sup> 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:

$$A = \frac{a}{N} \cdot \int_1^N N^{-b} dN = \frac{a}{N} \cdot \left[ \frac{1}{1-b} \cdot (N^{1-b} - 1) + 1 \right]$$

where A = average investment of one unit. As a result, the average investment is always higher than the investment of the N<sup>th</sup> unit.

### A.3 Scaling by size

The investment for volume related technologies (in contrast to surface related technologies e.g. photo-voltaics) 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

### A.4 Calculation of Levelized costs

#### A.4.1 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.

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

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

#### A.4.2 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.

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

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

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

where

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

### Operating and maintenance costs

The operating and maintenance expenditures in the year  $t$  are

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

where

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

### Energy and material costs

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

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

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 $T_2$

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

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

#### ***A.4.3 Cost calculation for phase T3 (dismantling of the plant)***

For the costs for the dismantling a fixed amount is defined:

$$C_{T3} \quad [€]$$

#### ***A.4.4 Levelized Costs***

The levelized costs (LEC) per unit are

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

#### ***A.4.5 Use of specific costs for “processes”***

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”.

The E3 database also allows the direct input of specific costs for a process as “total variable costs” (e.g. electricity costs: 0.03 €/kWh).

## Annex B 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:

- Feedstock production
- Feedstock transport
- Hydrogen production
- Hydrogen transport (if present)
- Filling stations
- Hydrogen end use

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 Finnish chains are described.

### B.1 Availability of Feedstock’s

In this section the following feedstock's are considered:

- Natural gas
- Coal
- Biomass
- Nuclear fuel
- 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.

#### B.1.1 Extraction and Conditioning of Natural Gas

To be used, natural gas (NG) must be extracted, processed and transported. NG is assumed to be imported from Russia, through the EU natural gas mix transport pipeline.

Behind the international transport pipeline, the NG is distributed via the national, regional and local natural gas high-pressure pipeline grids. The data used in the models, and presented in Table 6 and Table 7 is related to the processes as performed in the Netherlands. These values have been used due to lack of Russian data and because the extraction and processing of natural gas is considered to be similar for both countries.

Table 6. Input and output data for NG Extraction, NL (onshore) / GEMIS 4.1

	I / O	Value	Units
Electricity	I	0.0011	[kWh/kWh]
NG source	I	1.0012	[kWh/kWh]
Process scale	-	1,000,000	[kW NG]
NG	O	1.0	[kWh]
CH <sub>4</sub> emissions	O	0.0828	[g/kWh]
Useful lifetime	-	20	[yr]
Annual full load hours	-	7,000	[h/yr]

The cost of natural gas extraction is assumed zero. The cost of this process is accounted in the price of natural gas. The efficiencies and emissions of the natural gas extraction process are assumed not to change with time.

Table 7. Input and output data for NG Processing, NL / GEMIS 4.1

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Electricity	I	0.0010	[kWh/kWh]
Heat	I	0.0010	[kWh/kWh]
NG source	I	1.0015	[kWh/kWh]
NG	O	1.0000	[kWh]
Process scale	-	1,000,000	[kW NG]
CH <sub>4</sub> emissions	O	0.0828	[g/kWh]
Useful lifetime	-	20	[yr]
Annual full load hours	-	7,000	[h/yr]

Processing of NG is required because heavier hydrocarbons and contaminants such as H<sub>2</sub>S 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 efficiencies and emissions of the processing of natural gas are assumed not to change with time. The price of natural gas has been harmonised for all analysed Member States within HyWays. For the year 2020, the price of 0.0263 €/kWh has been assumed. For 2030 the price is 0.0355 €/kWh.

Table 6 and Table 7 show that a certain amount of electricity is required in the extraction and production processes. Because the gas is assumed to come from Russia and electricity figures from Russia are not available, the use of European electricity mix as input has been modelled.

For processes occurring outside of Finland, but forming a part of a Finnish hydrogen chain, natural gas is assumed obtained from the EU-mix. Provision of EU-mix natural gas has the following characteristics:

Table 8. Input and output data for provision of EU-mix of natural gas

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
NG source	I	1.128	[kWh/kWh]
Process scale	-	1	[kWh/h]
Useful lifetime	-	20	[yr]
Annual full load hours	-	8760	[h/yr]
NG	O	1.0	[kWh]
CO <sub>2</sub> emissions	O	23.7	[g/kWh]
CH <sub>4</sub> emissions	O	0.7133	[g/kWh]
N <sub>2</sub> O emissions	O	0.0008	[g/kWh]

### B.1.2 Extraction of Coal

The coal used in Finland is assumed to be of a quality derived from a mixture of coals used in the EU. The energetic characteristics of this coal are presented in Table 9, and represent the amount of energy needed to obtain 1 [kWh] of coal ready for use in other processes.

Table 9. Input and output data for production of EU-mix hard coal

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Brown Coal	I	0.002	[kWh/kWh]
Hard Coal	I	1.025	[kWh/kWh]
Hydro-power	I	0.003	[kWh/kWh]
Mineral oil	I	0.041	[kWh/kWh]
NG	I	0.010	[kWh/kWh]
Nuclear	I	0.011	[kWh/kWh]
Waste	I	0.002	[kWh/kWh]
Hard Coal	O	1.000	[kWh/kWh]

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
CO <sub>2</sub> emissions	O	23.30	[g/kWh]
NO <sub>x</sub> emissions	O	0.1624	[g/kWh]
PM emissions	O	0.0254	[g/kWh]
SO <sub>2</sub> emissions	O	0.1798	[g/kWh]
NM VOC emissions	O	0.0069	[g/kWh]
CO emissions	O	0.0308	[g/kWh]
CH <sub>4</sub> emissions	O	1.3743	[g/kWh]
N <sub>2</sub> O emissions	O	0.0010	[g/kWh]

The GHG emissions of using this coal are set to 55.2 g CO<sub>2</sub>/kWh. The price of coal has been harmonised for all analysed Member States within HyWays. For the year 2020, the price of 0.0088 €/kWh has been assumed. For 2030 the price amounts 0.0104 €/kWh.

### B.1.3 Production of Nuclear fuel

To obtain nuclear fuel ready for use in a nuclear plant, a couple of processes have been identified. Firstly, Uranium ore must be extracted. From the extracted ore, Uraniumhexafluoride (UF<sub>6</sub>) is produced. After production, UF<sub>6</sub> must be enriched and finally the nuclear fuel is produced. Each of these processes has its own inputs and outputs. Furthermore, they consume feedstock's at specific efficiencies. Finally, these activities have their own costs.

In the next tables, the processes mentioned above are presented. For each process, the input energy plotted represents the energy required to produce 1 kWh of the respective output.

There are two Uranium ore extraction processes known: Surface and deep mining. In the Finnish chains, surface mining has been assumed.

Table 10. Input and output data for Uranium surface mining

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Uranium ore	I	1	[kWh/kWh]
Mechanical work	I	0.000023	[kWh/kWh]
Extracted uranium ore	O	1	[kWh]
Process scale	-	1,500,000	[kWh/yr]
Full load hours	-	7000	[hr/yr]

The cost of Uranium ore have been harmonised within HyWays. For the year 2020 uranium costs are estimated into 0.00055 €/kWh, while for 2030 they amount 0.00076 €/kWh.

The characteristics of UF<sub>6</sub> production presented in the next table, have been derived from French data present in the GEMIS database [2]. The (harmonised) process cost given is applicable independently of the year of production.

Table 11. Input and output data for UF<sub>6</sub> production

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Extracted uranium ore	I	1.1111	[kWh/kWh]
Electricity	I	7 x 10 <sup>-6</sup>	[kWh/kWh]
UF <sub>6</sub>	O	1	[kWh]
Process scale	-	2,000,000	[kWh/yr]
Full load hours	-	7000	[hr/yr]
Production costs	-	0.00008	[€/kWh]

Natural uranium contains 0.7205% of the U-235, the fissile isotope of uranium. Most power reactors use enriched uranium fuel containing 3 to 4% U-235. Within HyWays there are two processes defined to enrich the UF<sub>6</sub> produced: enrichment by diffusion and enrichment by centrifugation. For the pur-

poses of power generation in Finland, the process of enrichment by centrifugation has been assumed. Cost of enrichment process is harmonised within HyWays.

Table 12. Input and output data for UF<sub>6</sub> enrichment

	I / O	Value	Units
UF <sub>6</sub>	I	1	[kWh/kWh]
Electricity	I	0.00135	[kWh/kWh]
Enriched UF <sub>6</sub>	I	1	[kWh]
Process scale	-	1,500,000	[kWh/yr]
Full load hours	-	7000	[hr/yr]
Enrichment costs	-	0.00055	[€/kWh]

The production of nuclear fuel out of UF<sub>6</sub> requires some electricity and heat as input. For Finland, the required heat is assumed to be provided by the use of a natural gas process heating plant. The costs of nuclear fuel production are harmonised within HyWays.

Table 13. Input and output data for production nuclear fuel

	I / O	Value	Units
Enriched UF <sub>6</sub>	I	1.0526	[kWh/kWh]
Electricity	I	0.0010	[kWh/kWh]
Heat	I	0.0010	[kWh/kWh]
Nuclear fuel	O	1	[kWh]
Process scale	-	1,500,000	[kWh/yr]
Full load hours	-	6000	[hr/yr]
Production costs	-	0.00024	[€/kWh]

#### B.1.4 Production of Electricity

In the chains modelled for Finland, three types of electricity production have been considered: electricity from the Finnish electric grid (national electricity mix), electricity from wind turbines and electricity produced using a nuclear plant.

##### Electricity mix

The electricity produced in Finland is a mix of energy produced out of typical Finnish feedstock's. A small percentage of the total electricity mix is imported from other European countries. According to PRIMES, the share of feedstock's used in the production of the Finnish electricity mix varies with time [ref. 4]. In Table 14 the electricity mix shares for Finland (years 2020 and 2030) and for the EU-15 countries are presented.

The cost of electricity varies from country to country. The price used for Finland has been taken from PRIMES. In Annex B it is explained how the cost of electricity used for the Finnish mix as presented below, matches the values presented in PRIMES.

Table 14. Electricity production mix for Finland and Europe.  
Share in percentage according to the used feedstock.

Source	Finnish E-mix 2020 [%]	Finnish E-mix 2030 [%]	MIX EU 15 <sup>3</sup> [%]
Biomass	2.4	1.6	0.3
Brown Coal	2.7	2.4	7.1
Hard Coal	15.3	20.5	19.9
Electricity (imported)	6.6	6.2	N.A.
Fuel Oil (1.8%S)	0	0	-

<sup>3</sup> Based on 1999 figures. These data exclude power plants according to GEMIS and without the energy requirements and associated emissions for the construction of the plants.

Source	Finnish E-mix 2020 [%]	Finnish E-mix 2030 [%]	MIX EU 15 <sup>3</sup> [%]
Hydro and other renewables	15.2	15.5	4.6 <sup>(4)</sup>
Geothermal	N.A.	N.A.	0.1
Mineral Oil (diesel)	0	0	8.7
NG	9.5	11.1	12.3
Nuclear	36.6	32.5	40.5
Waste	11.7	10.1	6.6
Total	100.0	100.0	100.0

Based on the above table, and using the intrinsic energy value of the feedstock's presented, it is possible to derive how much primary energy is required to produce 1 kWh of electricity. The result of this exercise is presented in Table 15.

The emission factors used in the analysis for the years 2020 and 2030 were calculated using the electricity generation processes of the E3-database for each feedstock separately and considering their share in the mix.

Table 15. Electricity. Finnish production mix and Finnish import (EU-mix).

Source	I / O	Finnish E-mix 2020	Finnish E-mix 2030	EU-mix	Units
Biomass	I	0.0747	0.0487	0.0074	[kWh/kWh]
Brown Coal	I	0.0679	0.0616	0.1979	[kWh/kWh]
Hard Coal	I	0.3882	0.5199	0.5570	[kWh/kWh]
Electricity (EU-mix)	I	0.1841	0.1749	-	[kWh/kWh]
Fuel Oil (1.8%S)	I	0.0038	0.0031	-	[kWh/kWh]
Renewables	I	0.1516	0.1548	0.1283	[kWh/kWh]
Geothermal	I	0	0	0.0016	[kWh/kWh]
Mineral Oil	I	0	0	0.2440	[kWh/kWh]
NG	I	0.1804	0.2112	0.3454	[kWh/kWh]
Nuclear	I	1.1082	0.9836	1.1357	[kWh/kWh]
Waste	I	0.8886	0.7673	0.1847	[kWh/kWh]
Electricity	O	1.0	1.0	1.0	[kWh]
CO <sub>2</sub> emissions	O	265.2	306.2	427.5	[g/kWh]
NO <sub>x</sub> emissions	O	0.5924	0.5938	1.0444	[g/kWh]
SO <sub>2</sub> emissions	O	0.2248	0.2436	1.6032	[g/kWh]
PM emissions	O	0.0501	0.0546	0.2835	[g/kWh]
NM VOC emissions	O	0.0483	0.0426	0.0641	[g/kWh]
CO emissions	O	0.2594	0.2610	0.2617	[g/kWh]
CH <sub>4</sub> emissions	O	0.1024	0.0971	1.0454	[g/kWh]
N <sub>2</sub> O emissions	O	0.0172	0.0175	0.0192	[g/kWh]
Equivalent CO <sub>2</sub> emissions	O	273	314	457.0	[g/kWh]

Because of the national mix, the total input of primary energy is about 3.05 kWh per kWh of produced electricity leading to an electricity generation efficiency of about 33% in the year 2020. Similar values are obtained for 2030: 2.92 kWh/kWh (34.2% efficiency). The production cost of electricity in Finland has been set on 0.046 €/kWh for both years analysed, 2020 and 2030. See also Annex B.

### Electricity from nuclear power

<sup>4</sup> Primes gives the electricity production share from 'renewables'. Into this item wind, solar, hydro and geothermal energy are included.

A nuclear plant produces electricity out of nuclear fuel. For the hydrogen energy chains of Finland, a nuclear plant as present in Germany has been chosen. Details of the nuclear plant process are presented in the next table. The efficiency of the process is estimated into 33%.

Table 16. Input and output data for electricity production using a nuclear plant

	I / O	Value	Units
Nuclear fuel	I	3.030	[kWh/kWh]
Mechanical work	I	0.001	[kWh/kWh]
Electricity	O	1	[kWh]
Process scale	-	1,250,000	[kWh/yr]
Annual full load hours	-	6500	[hr/yr]
Useful lifetime	-	40	[yr]
Investment (scaled up)	-	2,556,460,000	[€]
Maintenance costs	-	5%	[% of investment/yr]

### Offshore wind power

An offshore wind energy plant typically consists of a number of single wind turbines. The cost data of the wind turbine for 2020 has been derived from Enercon model E-66 / 20.70 located offshore at 30 metres water depth, data from the year 2004. The investment presented in Table 17 includes the investment of the foundation and grid connection, equal to 28% of the investment for the wind turbine alone. The investment for the Enercon wind turbine having a tower of 84 metres height was € 1,785,000 [Windenergie 2004].

For 2020, a learning curve based on the EWEA target for the installed capacity of 180 GW in the EU was assumed. From this target, about 30 GW was already installed in the EU 25 in 2004. The progress ratio for wind energy installations has been assumed 0.85 (range: 0.80 to 0.85).

Table 17. Technical and economic data of the offshore wind turbine

Wind Energy, yr 2020	Onshore	Units
Capacity	4.5	[MW]
Investment 2020	5,400,000	[€]
Investment 2030	3,622,500	[€]
Maintenance	4	[% of investment]
Useful lifetime	25	[yr]
Equivalent full load period	3000	[h/yr]

Transmission of electricity generated by wind turbines is assumed to occur at medium-voltage level. The process of wind energy conversion into electricity using wind turbines has been assumed not to improve in the course of time (constant equivalent full load period).

### B.1.5 Production of Biomass

Biomass may be obtained from residual or farmed wood. For Finland only farmed wood has been considered. The wood is assumed chipped at the source and then transported to a gasification plant for hydrogen production. Two cases have been investigated: wood farmed in Finland self and wood farmed in Russia. Both cases differ from each other only in the way the wood is transported to the hydrogen production plant, so the processes of wood plantation and wood chipping presented below apply for both cases.

#### Farmed Wood

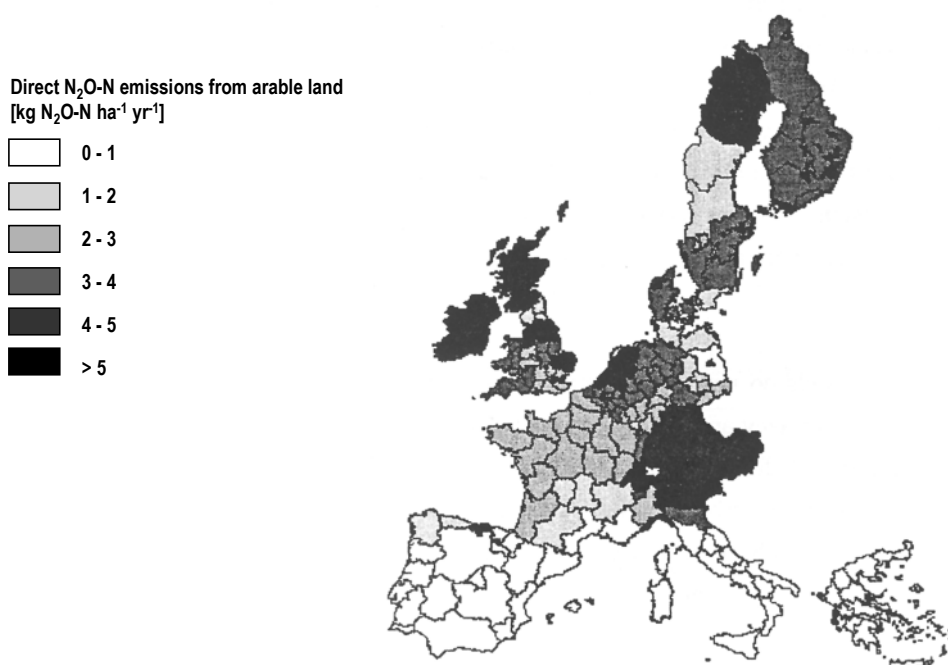
With farmed wood, it is understood woody biomass from plantation of poplar or willow. The harvested woody biomass is assumed chipped at the plantation site and subsequently transported to the gasification plant.

Besides the N<sub>2</sub>O emissions from the production of synthetic nitrogen (N) fertilizer, the plantation of crops causes direct N<sub>2</sub>O 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<sub>2</sub>O: 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<sub>2</sub>O in soils depend on various controlling parameters. The main factors are aeration, water content and availability of N and organic material. Moreover, the amount of N<sub>2</sub>O 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 salty soils) can maintain higher water content for a longer time than coarse textured soils (sandy soils). Clay soils have a higher potential for N<sub>2</sub>O formation. On the other hand, N<sub>2</sub>O formed within the soil can also be reduced to N<sub>2</sub> when diffusion is slow due to high water content in fine textured soils. Fine-textured soils seem to emit more N<sub>2</sub>O than sandy soils, but this tendency can be masked or reversed by other factors, especially climate and soil management practices.

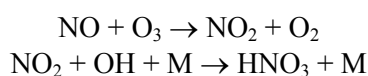
Other factors that influence the N<sub>2</sub>O emissions from soils are freezing and thawing, drying and rewetting [Kamp 2000].

Figure 28. Direct N<sub>2</sub>O emissions from arable land



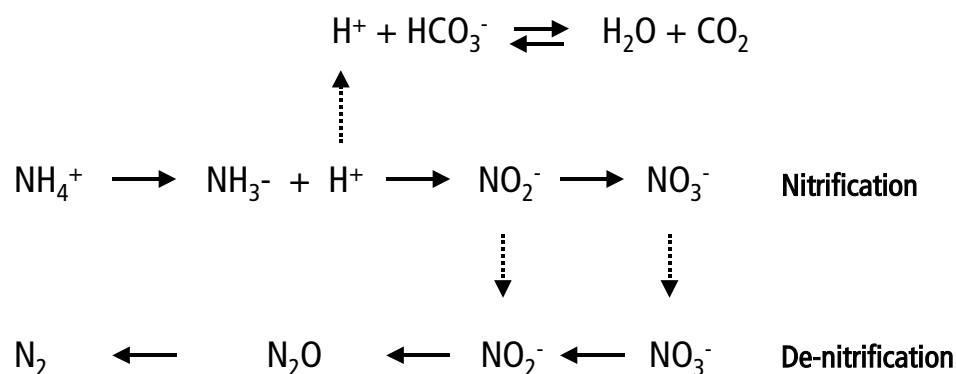
Source: Freibauer, A., Kaltschmitt, Institut für rationelle Energieanwendungen (IER), Stuttgart: Biogenic Greenhouse Gas Emissions from Agriculture in Europe, European Summary Report of the EU Concerted Action FAIR3-CT96-1877, financed by EU DG VI, February 2001

The direct emissions of N<sub>2</sub>O are only one part of the total emissions of N<sub>2</sub>O from agricultural land. Indirectly emitted N<sub>2</sub>O is also considered here. Part of the fertilizer-N is emitted as NH<sub>3</sub> and NO<sub>x</sub> and is leached e.g. as NO<sub>3</sub><sup>-</sup>, which is subsequently deposited on soils and surface waters. Atmospheric deposition of nitrogen compounds such as NO<sub>x</sub> and NH<sub>3</sub> fertilizes soils and surface waters and as such enhances the biogenic N<sub>2</sub>O formation. In soils and waters, bacteria oxidize the NH<sub>4</sub><sup>+</sup> (which is formed from the NH<sub>3</sub> in the soil) to nitrate (NO<sub>3</sub><sup>-</sup>) (nitrification) while some amounts of N<sub>2</sub>O are formed. The NO<sub>x</sub> (consisting of NO and NO<sub>2</sub>) emitted from soils is converted to HNO<sub>3</sub> in the atmosphere according to the following reactions:



The HNO<sub>3</sub> is then deposited on soil and surface waters by rainfall (“acid rain”). In soils and water, the HNO<sub>3</sub> is dissolved into H<sup>+</sup> and NO<sub>3</sub><sup>-</sup>. Then the NO<sub>3</sub><sup>-</sup>, which is also formed by the nitrification of NH<sub>4</sub><sup>+</sup>

is partly reduced to N<sub>2</sub>O (de-nitrification). The conversion in the soil occurs in several stages according to the following reactions:



The same reactions occur with NO<sub>x</sub> emitted by fuel combustion e.g. in truck engines. This source of N<sub>2</sub>O is neglected here for the fuel supply processes such as the transport of wood chips. Here only the NO<sub>x</sub> from fertilizer use is considered.

In contrast to the direct N<sub>2</sub>O 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<sub>2</sub>O (from N leaching and N from NH<sub>3</sub> and NO<sub>x</sub> emitted). There are no emissions of NO<sub>x</sub> and NH<sub>3</sub> 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 behaviour 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 10 t of dry matter the amount of N-fertilizer (expressed as kg N) is indicated with 20 to 30 kg per ha and year [Murach 2003]. In [CONCAWE 1/2003] the fertilizer requirement has assumed 25 kg per ha and year. The direct N<sub>2</sub>O-emissions have been derived from [Flesse 1998] and the indirect N<sub>2</sub>O-emissions have been calculated according to the guidelines described in [IPCC 1/1996].

Table 18. Poplar plantation

	I / O	Value	Units
Woody Biomass	I / O	1.00000	[kWh/kWh]
Mechanical work	I	0.00150	[kWh/kWh]
N fertilizer	I	0.00049	[kg/kWh]
Biomass	O	1	[kWh]
N <sub>2</sub> O emissions	O	0.01230	[g/kWh]
Useful lifetime	-	10	[yr]
Annual full load hours	-	8760	[hr/yr]

The mechanical work required for this process is supplied by a diesel engine (see B.5.3). The specific energetic value of the biomass considered is 18 GJ/ton for dried biomass. In the calculations, 30% water content was accounted. By doing so, the specific energetic value of the biomass becomes (18/3.6)\*0.7 = 3.5 kWh/kg.

To be used in a gasification plant, biomass must be chipped into very small pieces (millimetres size). Therefore, a chipping process running on diesel fuel is required. The characteristics of this process are:

Table 19. Technical and economic data of the chipping process

	I / O	Value 2020	Value 2030	Units
Biomass	I	1.025	1.025	[kWh/kWh]
Diesel oil	I	0.004	0.004	[kWh/kWh]

	I / O	Value 2020	Value 2030	Units
Biomass chips	O	1.0	1.0	[kWh]
Process scale	-	1	1	[kWh/h]
CO <sub>2</sub> emissions	O	1.056	0.790	[g/kWh]
NO <sub>x</sub> emissions	O	0.047	0.035	[g/kWh]
CO emissions	O	0.010	0.008	[g/kWh]
CH <sub>4</sub> emissions	O	0.00015	0.00010	[g/kWh]
N <sub>2</sub> O emissions	O	0.00015	0.00010	[g/kWh]

Cost of the (harmonised) chipping process were set to 0.0189 €/kWh produced biomass chips for 2020 and to 0.022 €/kWh for 2030.

## B.2 Transport of Feedstock's

### B.2.1 Natural Gas transport

Natural gas is assumed produced in Russia. The distance from the extraction (and processing) point up to the Finnish borders is estimated in 4000 km. Consequently, the natural gas is distributed via a regional and a local NG pipeline grid under different pressures to hydrogen production plants. Nearly all transports require mechanical work performed by gas turbines (efficiency = 30%), which use a small amount of the NG for their power. This mechanical work has been modelled in all hydrogen chains using natural gas as feedstock. The data for the high-pressure (HP ≈ 60 bar) and low-pressure (LP ≈ 10 bar) natural gas transport pipelines has been derived from [GEMIS 2002].

The costs of NG transport via pipelines have been neglected, because these costs are accounted in the harmonised natural gas price. See also section B.1.1.

Table 20. Input and output data for NG transport through pipelines

			4000 km HP	250 km HP	10 km LP
	I / O	Units	Value		
Mechanical work	I	[kWh/kWh]	0.024	0.015	0
NG (including losses)	I	[kWh/kWh]	1.0052	1.000015	1.0
NG (delivered)	O	[kWh/kWh]	1.0	1.0	1.0
Process scale	-	[kW NG]	1E+8	1E+8	1E+6
CH <sub>4</sub> emissions	O	[g/kWh]	0.374	0.011	0
Useful lifetime	-	[yr]	30	30	30
Annual full load hours	-	[h/yr]	7500	7500	8000

For the local NG transport (low-pressure pipelines), no energy requirements and no GHG emissions occur.

### B.2.2 Coal transport

The coal considered in the Finnish chains is coal extracted in Poland. The coal is assumed transported by ship from the production region to Finland by an ocean bulk carrier, travelling distance being approximately 1000 km. A coal gasification plant is assumed located at the Finnish coast, so there is no need to transport the coal further by other means.

Characteristics of the coal transport are presented in the next table, expressed in t\*km (1 ton coal being transported 1 km).

Table 21. Technical data of the coal transport process

	I / O	Value	Units
Diesel consumption of ship	I	0.0225	[kWh/t*km]
Process scale	-	362,000	[t*km/h]

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
CO <sub>2</sub> emissions	O	6.3	[g/t*km]
NO <sub>x</sub> emissions	O	0.100	[g/t*km]
CO emissions	O	0.016	[g/t*km]
CH <sub>4</sub> emissions	O	3* 10 <sup>-4</sup>	[g/t*km]
SO <sub>2</sub> emissions	O	3* 10 <sup>-5</sup>	[g/t*km]

Table 22. Economic data of the ship used for coal transport

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Investment	-	50,000,000	[€]
Labour costs	-	100,000	[€/yr]
Maintenance costs	-	250,000	[€/yr]
Useful lifetime	-	30	[yr]
Annual full load hours	-	8760	[hr/yr]

The efficiencies and emissions of the transport process and the characteristics of the ship used for transport are assumed not to change with time.

### B.2.3 Electricity transport

Depending on the user, three types of electricity transport have been considered: transport at high-voltage (HV, 150-400 kV), transport at medium-voltage (MV, 20 kV) and transport at low-voltage (LV, ~0.4 kV). Costs of transport of electricity on HV and MV-level have been harmonised. The cost of electricity transport at LV-level is considered country specific. In Annex B it is explained how the electricity transport costs used match the values taken from PRIMES.

Table 23. Input and output data for High-voltage transport of electricity (GEMIS 4.1)

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
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]
Transport costs	-	0.004	[€/kWh]

Table 24. Input and output data for Medium-voltage transport of electricity (GEMIS 4.1)

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
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]
Transport costs	-	0.02	[€/kWh]

Table 25. Input and output data for Low-voltage transport of electricity (GEMIS 4.1)

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
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]
Transport costs (2020)	-	0.03	[€/kWh]

The electricity transport cost at HV-, MV- and LV-level, are assumed not to develop with time. See also Annex C.

#### B.2.4 Biomass transport

The biomass used in the Finnish chains is farmed wood. Wood chips are transported by truck over a distance of 50 km (Finnish biomass) or 200 km by train (Russian biomass) to the gasification plant. Characteristics of the biomass transport by truck and train are presented in the next tables. The Process scale for the biomass transport process over 50 km by truck is 1725 [kWh/h].

Table 26. Techno-economic data of the truck used for biomass transport

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Diesel consumption of truck	I	0.26	[kWh/t*km]
CO <sub>2</sub> emissions	O	68.6	[g/t*km]
NO <sub>x</sub> emissions	O	0.341	[g/t*km]
CO emissions	O	0.146	[g/t*km]
CH <sub>4</sub> emissions	O	0.005	[g/t*km]
SO <sub>2</sub> emissions	O	0.0004	[g/t*km]
Truck transport scale	-	193	[t*km/h]
Investment	-	160,000	[€]
Labour costs	-	125,000	[€/yr]
Maintenance costs	-	19,200	[€/yr]
Useful lifetime	-	8	[yr]
Annual full load hours	-	8760	[hr/yr]

Table 27. Technical data of the train used for biomass transport

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Train type	-	Electric (HV-level)	-
Electricity consumption of train	I	0.0583	[kWh/t*km]
Process scale	-	1,700	[t*km/h]

No costs are accounted for the use of the transport train. The costs involved are accounted in the price of the biomass consumed (see wood chipping process, B.1.5).

#### B.2.5 Diesel and Heavy Fuel Oil transport

For the calculation of the reference chains for mobile and for stationary use of hydrogen, transport of diesel and transport of heavy fuel oil (HFO) were accounted. Diesel and HFO transport occurs partially by pipeline, partially by train and partially by ship. The characteristics of the train are already given in Table 27 (biomass transport). Ship characteristics are similar to the ones used for coal transport (see Table 22). Data over diesel and HFO transport by pipeline has been derived from data provided by Shell and implemented in the E3 database used in HyWays.

Table 28. Technical data of the coal transport process

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Electric consumption (diesel transport – compressors)	I	0.0002	[kWh/kWh]
HFO consumption (HFO transport – efficiency of process = 99%)	I	0.0101	[kWh/kWh]

## Hydrogen Production

In this section, the production of hydrogen from the different feedstock's is presented.

### B.2.6 Production of Hydrogen from Natural Gas

Hydrogen production from natural gas is performed using steam methane reformers (SMR). The SMR may or may not include CO<sub>2</sub> capture and storage (CCS). For Finland, only SMR processes excluding CCS have been selected due to the absence of empty gas and oil fields or other places where the CO<sub>2</sub> captured could be stored. In Table 29 technical and economic data of the SMR plants used in the models is given.

Table 29. Technical and economic data of the used SMR plant

	I / O	Central SMR (Linde)	On-site SMR (HyGear)	Units
Inlet pressure	-	4.0	1.6	[MPa]
Discharge pressure H <sub>2</sub>	-	3.0	1.7	[MPa]
Process scale	-	300,000	667	[kW H <sub>2</sub> ]
NG consumption	I	1.4167	1.4406	[kWh/kWh <sub>H2</sub> ]
GH <sub>2</sub> output	O	1.0	1.0	[kWh]
Electricity output <sup>5</sup>	O	0.05	0	[kWh/kWh <sub>H2</sub> ]
CO <sub>2</sub> emissions	O	288	292.3	[g/kWh <sub>H2</sub> ]
CH <sub>4</sub> emissions	O	0.0573	0.0750	[g/kWh <sub>H2</sub> ]
NO <sub>x</sub> emissions	O	0.0821	0.0540	[g/kWh <sub>H2</sub> ]
CO emissions	O	0.0792	0.1050	[g/kWh <sub>H2</sub> ]
Investment 2020 (scaled-up)	-	77,716,366	375,981	[€]
Investment 2030 (scaled-up)	-	N/A	339,200	[€]
Maintenance coefficient	-	3.0	1.0	[% of Investment]
Labour costs	-	600,000	N/A	[€/yr]
Useful lifetime	-	20	15	[yr]
Equivalent full load period	-	8000	6000	[h/yr]

N/A: Data not available

Due to lack of data, the investment costs of this central SMR plant have been assumed not to change with time. Investment costs have been derived using learning curves with a parameter b equal to 0.1 (see section A.2). The efficiency of both SMR plants is assumed to remain constant within the period 2020-2030.

### B.2.7 Production of Hydrogen from Coal

With coal as feedstock, the hydrogen is produced via large-scale gasification. For Finland, CO<sub>2</sub> capture and sequestration has not been included as an option.

Table 30. Technical and economic data of hydrogen generation via coal gasification without CO<sub>2</sub> capture and storage

	I / O	Value	Units
Process scale	-	844,866	[kW H <sub>2</sub> ]
Hard coal consumption	I	1.967	[kWh/kWh <sub>H2</sub> ]
GH <sub>2</sub> output	O	1.0	[kWh]
Pressure (output)	-	N/A <sup>6</sup>	[bar]

<sup>5</sup> The central SMR defined by Linde includes export of electricity generated by the process. In the models of HyWays, this electricity export was accounted as loss, without being used further.

<sup>6</sup> Output pressure of coal gasifier not available. Based on similar known processes, it was assumed that the output pressure equals 30 bar.

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
CO <sub>2</sub> emissions	O	681	[g/kWh <sub>H<sub>2</sub></sub> ]
Investment (2020)	-	859,360,000	[€]
Maintenance coefficient	-	3.6	[% of investment]
Labour	-	1,090,000	[€/yr]
Overhead	-	0.1	[% of investment]
Useful lifetime	-	25	[yr]
Equivalent full load period	-	7,884	[h/yr]

N/A: Not available

Due to lack of data, the energy use and investment costs of this plant have been assumed not to change with time.

### B.2.8 Production of Hydrogen from Electricity

Hydrogen energy chains involving electricity as feedstock are all chains where the Finnish electricity mix, nuclear electricity and electricity from wind energy are used. The hydrogen is produced via water electrolysis. A central electrolysis plant consists of a large number of 800 Nm<sup>3</sup>/h electrolyser units. If the total hydrogen generation capacity of the central electrolysis plant were 100,000 Nm<sup>3</sup>/h the number of 800 Nm<sup>3</sup>/h units would be 125. For the plants used in the models, the investment costs have been derived, using learning curves with a parameter b equal to 0.1 (see section A.2).

Electrolysers presented in Table 31 have different capacities according to a central or de-central (on-site) application.

Table 31. Technical and economic data for electrolysis

	<b>I / O</b>	<b>Central Electrolyser</b>	<b>On-site Electrolyser</b>	<b>Units</b>
Process scale	-	2400	360	[kW H <sub>2</sub> ]
Electricity consumption	I	1.433	1.6	[kWh / kWh <sub>H<sub>2</sub></sub> ]
GH <sub>2</sub> output	O	1.0	1.0	[kWh / kWh]
Pressure (output)	-	3.0	2.6	[MPa]
Investment (2020)	-	2,200,000	271,812	[€]
Investment (2030)	-	877,930	228,800	[€]
Maintenance	-	0.9	0.9	[% of investment]
Labour costs	-	0	0	[€/yr]
Overhead costs	-	0	0	[% investment/yr]
Useful lifetime	-	20	20	[yr]
Equivalent full load period	-	6000	6000	[h/yr]

### B.2.9 Production of Hydrogen from Biomass

Only small-scale gasification plants are accounted to produce hydrogen from biomass in Finland. The investment, labour and maintenance costs presented in the table below, have been derived from actual data using learning curves with a parameter b equal to 0.1 (see section A.2).

Table 32. Technical and economic data of hydrogen generation via biomass gasification

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Process scale	-	5,250	[kW H <sub>2</sub> ]
Biomass consumption	I	1.9108	[kWh/kWh]
GH <sub>2</sub> output	O	1.0	[kWh]
Pressure (output)	-	20	[bar]

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Heat production <sup>7</sup>	O	0.3039	[kWh/kWh]
Investment	-	6,401,067	[€]
Labour costs	-	178,952	[€/yr]
Maintenance costs	-	332,855	[€/yr]
Useful lifetime	-	20	[yr]
Equivalent full load period	-	7,500	[h/yr]
CO <sub>2</sub> emissions	O	0	[g/kWh]
NO <sub>x</sub> emissions	O	0.6208	[g/kWh]
SO <sub>2</sub> emissions	O	0.0203	[g/kWh]
CO emissions	O	0.2717	[g/kWh]
CH <sub>4</sub> emissions	O	0.0407	[g/kWh]
N <sub>2</sub> O emissions	O	0.0121	[g/kWh]

### B.2.10 Liquefaction of Hydrogen

To liquefy hydrogen, a liquefaction plant consuming only electricity as input has been used. The electricity consumption has been assumed to range between 0.3 and 0.4 kWh per kWh of LH<sub>2</sub> 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 upscaling. The technical and economic data of liquefier plant are given in Table 33.

Table 33. Technical and economic data of large-scale H<sub>2</sub> liquefaction plant

	<b>I / O</b>	<b>Liquefaction plant (2020)</b>	<b>Liquefaction plant (2030)</b>	<b>Units</b>
Plant capacity	-	300,000	300,000	[kWh/h]
GH <sub>2</sub> consumption	I	1.0	1.0	[kWh/kWh <sub>LH2</sub> ]
Electricity consumption	I	0.30	0.21	[kWh/kWh <sub>LH2</sub> ]
Inlet pressure	-	30	30	[bar]
LH <sub>2</sub> production	O	1.0	1.0	[kWh]
Investment	-	239,000,000	239,000,000	[€]
Maintenance	-	2.5	2.5	[% of investment]
Labour	-	1,230,000	1,230,000	[€/yr]
Equivalent full load period	-	8,000	8,000	[h/yr]
Useful lifetime	-	30	25	[yr]

### B.2.11 Compression of Hydrogen

Compression of hydrogen is required in hydrogen energy chains that involve hydrogen transport by means of a tube trailer diesel-fuelled truck. It has been assumed that compression work is performed by electric driven compressors, using electricity at low-voltage level. The final pressure of the compression process is 300 bar. The inlet pressure depends on the hydrogen process considered, and varies between 20 and 30 bar.

Table 34. Technical and economic data for hydrogen compression

	<b>I / O</b>	<b>Compression plant</b>	<b>Units</b>
Installation capacity	-	300	[kWh/h]
GH <sub>2</sub> consumption	I	1.0	[kWh/kWh]

<sup>7</sup> The small-scale biomass gasification plant used generates also heat as output. In the models of HyWays, this heat output was accounted as loss, without being used further.

	I / O	Compression plant	Units
Electricity consumption	I	0.046	[kWh/kWh]
CGH <sub>2</sub> production	O	1.0	[kWh]
Investment	-	90,000	[€]
Maintenance	-	10	[% of investment]
Equivalent full load period	-	2980	[h/yr]
Useful lifetime	-	20	[yr]

### B.3 Transport of Hydrogen

#### B.3.1 Transport of Compressed Hydrogen Gas (CGH<sub>2</sub>) by pipeline

The supply of CGH<sub>2</sub> is performed through a hydrogen pipeline grid. It has been assumed that this grid consists of large pipelines (100 km) with a throughput of 240 GWh H<sub>2</sub> per year per pipeline and some smaller pipelines (10 km) with a throughput of 8 GWh H<sub>2</sub> per year per pipeline (Figure 29). The pressure drop during the pipeline transport has been neglected for distances below 100 km. If the transport distance is more than 100 km, the pressure drop must be compensated using electric compressors. Technical and economic data for CGH<sub>2</sub> pipelines is given in Table 35.

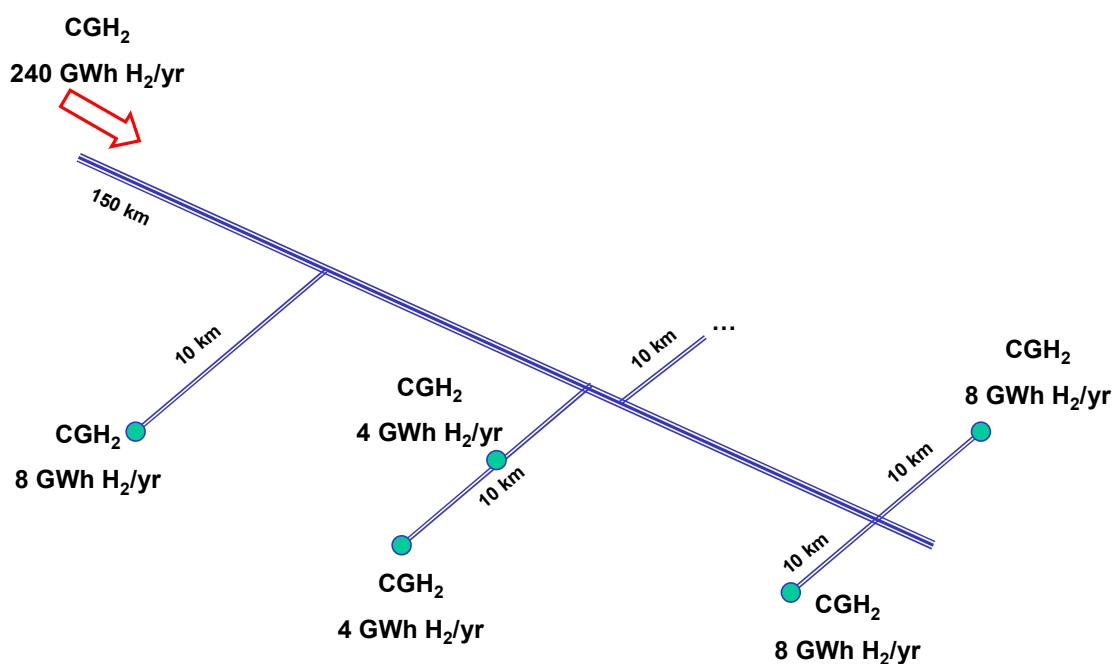


Figure 29. Example of pipeline grid for hydrogen transport

Table 35. Technical and economic data of CGH<sub>2</sub> pipelines

	10 km	150 km	Units
Annual hydrogen throughput	8	240	[GWh H <sub>2</sub> /yr]
Diameter	100	150	[mm]
Wall thickness	7.1	7.1	[mm]
Required electricity	0	0.0022	[kWh/kWh]
Investment	1.79	26.85	[M€]
Labour, maintenance etc.	42,000	783,000	[€/yr]
Annual full load	8000	8000	[hr]
Useful lifetime	30	30	[yr]

### B.3.2 Transport of Compressed Hydrogen Gas (CGH<sub>2</sub>) by truck

Compressed hydrogen gas is transported using the same type of truck defined before for transport of biomass. Therefore, Table 26 applies. The difference with biomass transport is the process scale involved, because the same truck can transport only 350 kg of CGH<sub>2</sub> in a one-way trip. The Process scale for the CGH<sub>2</sub> transport process over 150 km by truck is 552 [kWh/h]. A transport efficiency of 100% is accounted (no leakage).

### B.3.3 Transport of Liquefied Hydrogen (LH<sub>2</sub>) by truck

Similarly to the transport of CGH<sub>2</sub>, liquefied hydrogen is transported using the same truck defined before. Therefore, Table 26 applies and the Process scale for the LH<sub>2</sub> transport process over 150 km by truck is 4257 [kWh/h]. In a tube trailer, approximately 3500 kg of liquefied hydrogen can be transported. Moreover, an efficiency of 99.5% is accounted due to small leakage, meaning that the LH<sub>2</sub> consumption equals 1.005 kWh for each kWh of LH<sub>2</sub> being transported.

## B.4 Hydrogen Usage

### B.4.1 Vehicle Filling stations

Three different filling stations for gaseous hydrogen distribution and one for combined liquid and gaseous hydrogen distribution have been modelled. The filling stations delivering gaseous hydrogen differ from each other in the size of the station considered. A large size filling station (1200 t/yr) is coupled to large-scale hydrogen producing plants. A small size filling station (120 t/yr) is coupled to de-central and/or on-site hydrogen producing plants.

Table 36 presents the technical and economic data for the years 2020 and 2030, derived from available data of 2004. The electricity required is assumed of being at medium-voltage level (10 – 20 kV). By doing so, the cost of electricity that a filling station experiences equals to the cost of electricity at industrial level (see also Annex B). The assumption of a 10-20 kV level is reasonable if the maximum power demand of the filling station exceeds 1 MW.

Table 36. Technical and economic data for the CGH<sub>2</sub> filling stations

Filling station size	120 t/yr	480 t/yr	1200 t/yr	Units
Annual fuel output	457	1826	4566	[kWh H <sub>2</sub> /h]
Hydrogen input <sup>8</sup>	1.02	1.02	1.02	[kWh/kWh]
Electricity consumption	0.0704	0.0704	0.0704	[kWh/kWh <sub>H2</sub> ]
Investment (2020)	231,000	1,050,000	2,548,000	[€]
Investment (2030)	211,000	955,000	2,316,000	[€]
Maintenance costs (2020)	3.7	4.5	4.3	[% of investment]
Maintenance costs (2030)	3.9	4.6	4.5	[% of investment]
Useful lifetime	20	20	20	[yr]
Full load hours	8760	8760	8760	[hr]

The filling stations described include dispensers delivering compressed gas hydrogen fuel (CGH<sub>2</sub>). For a LH<sub>2</sub> car, a dedicated station is necessary.

Table 37. Technical and economic data for the combined LH<sub>2</sub>/CGH<sub>2</sub> filling station

Filling station size	1200 t/yr	Units
Annual fuel output	4566	[kWh H <sub>2</sub> /h]
Hydrogen input	1.02	[kWh/kWh]
Electricity consumption	0.0212	[kWh/kWh <sub>H2</sub> ]

<sup>8</sup> A value of 1.02 [kWh/kWh] corresponds to an efficiency of approximately 98%.

<b>Filling station size</b>	<b>1200 t/yr</b>	<b>Units</b>
Investment (2020)	1,563,830	[€]
Investment (2030)	529,551	[€]
Maintenance costs	2.0	[% of investment]
Useful lifetime	20	[yr]
Full load hours	8760	[hr]

#### B.4.2 Vehicle data

The passenger vehicle data has been taken from the CONCAWE/EUCAR/JRC study [ref. 3]. The fuel consumption and emission values of the vehicles of Table 38 and Table 39 are based on a VW Golf.

Table 38. Passenger hydrogen cars data

	<b>Fuel consumption [kWh/km]</b>	<b>GHG emissions [g CO<sub>2</sub> equiv./km]</b>
CGH <sub>2</sub> FC car	0.2611	0.0
CGH <sub>2</sub> FC car hybrid	0.2325	0.0
CGH <sub>2</sub> ICE car	0.4653	0.5
CGH <sub>2</sub> ICE car hybrid	0.4125	0.5
LH <sub>2</sub> FC car	0.2611	0.0
LH <sub>2</sub> FC car hybrid	0.2325	0.0
LH <sub>2</sub> ICE car	0.4653	0.5
LH <sub>2</sub> ICE car hybrid	0.3928	0.5

Table 39. Passenger reference cars data

	<b>Fuel consumption [kWh/km]</b>	<b>GHG emissions [g CO<sub>2</sub> equiv./km]</b>
PISI Gasoline hybrid 1.6 l	0.4492	119.6
DICI Diesel hybrid with DPF	0.4044	108.4

#### B.4.3 Stationary use of Hydrogen

CHP plants generate electricity and heat. For the calculation, the consumer e.g. a single-family user is considered.

The approach considers that all heat the consumer requires is provided by the CHP-installation, while the electricity is a by-product (heat-demand following system). Because at some times not all required electricity is provided by the CHP-installation, some electricity from the grid is required. At other times, more electricity is produced than the consumer requires. In this case, the surplus electricity is delivered back to the grid.

Based on Finnish statistics, data available at PRIMES for Finland and data provided by VTT, a electricity and heat consumption pattern was set for a 'typical' Finnish household. Next table presents the energy use assumptions modelled for the stationary hydrogen use chains.

Table 40. Yearly household energy consumption

<b>Household consumption</b>	<b>Units</b>	<b>Year 2005</b>	<b>Year 2020</b>	<b>Year 2030</b>
Space heating	[kWh/yr]	14,287	12,294	11,051
Warm water	[kWh/yr]	5,772	5,772	5,772
Electricity	[kWh/yr]	3,682	4,448	5,027

Next figure gives an example of a heat-demand following system based on the energy demand of a Finnish household for the year 2020. The values within the dotted box follow from ECN internal computations for a Q-following CHP-system.

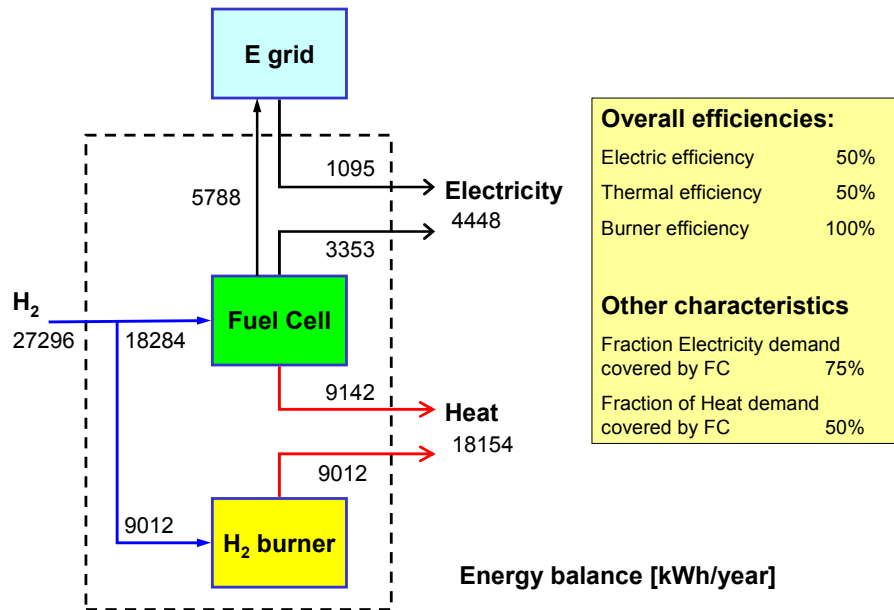


Figure 30. Supply of electricity and heat for a Finnish household (2020), Q-following system.

In a - heat-following or electricity -following - CHP-system, the main output is „heat + electricity“ and the inputs are hydrogen and external electricity (from the electricity mix). If the electricity generation of the FC CHP plant is higher than the demand then a net export of electricity occurs.

The FC of the example above is designed to cover 50% of the heat demand, leaving the other 50% of the heat demand to be covered by the H<sub>2</sub>-burner. The electricity generation of the FC does not cover the demand at the moment the user requires, reaching 75% coverage as a mean value. The electricity mix covers the other 25% electricity demand.

To account for a delivery of electricity to the electricity grid, an electricity credit has been incorporated, meaning that all electricity delivered back to the grid result in a discount of total energy required and in a discount of emissions. For this reason, specific hydrogen chains could have a "negative" emission, or with other words, a reduction of emissions with respect to the reference, due to the mentioned back delivery of electricity.

The thermal efficiency of a modern "high-efficiency" boiler, may reach values higher than 100%, meaning that more heat energy can be obtained from the boiler than the intrinsic energy that the fuel has. This may be achieved by using the energy freed during the vapour condensation process. The efficiency of the hydrogen boilers is modelled as being equal to 100% (all energy from H<sub>2</sub> is converted into heat).

In the following tables all characteristics of the modelled Q-following CHP-system for the years 2020 and 2030 are given.

Table 41. CHP-system (heat-following) for a Finnish household, 100% boiler efficiency

	Input/Output	year 2020	year 2030	Units
GH <sub>2</sub>	I	6.1369	5.1715	[kWh/kWh]
Electricity from grid	I	0.2462	0.2666	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	4.0815	3.3622	[kWh/kWh]
Electricity to grid	O	1.3013	1.0758	[kWh/kWh]
Process scale	-	5	5	[kWh/h]
Electric efficiency (CHP)	-	50	50	[%]
Thermal efficiency (CHP)	-	50	50	[%]
FC burner efficiency	-	100	100	[%]

	<b>Input/Output</b>	<b>year 2020</b>	<b>year 2030</b>	<b>Units</b>
Equivalent full load period	-	8760	8760	[h/yr]
Useful lifetime	-	20	20	[yr]

Two reference households were modelled for stationary hydrogen use comparison. Reference A comprises an all-electric household, where space heating as well as warm water provision are electric powered. Reference B involves household heat provision by oil-burning boilers, providing both the space heating and the warm water demand of the users.

### **Stationary reference A**

In this reference, an electric efficiency of 95% was set for warm water provision, while the other efficiencies are equal to 100%. Technical data of stationary reference A is presented in Table 42. The values are normalized with respect to electricity use.

Table 42. Typical 'all-electric' Finnish household, stationary reference A

	<b>Input/Output</b>	<b>year 2020</b>	<b>year 2030</b>	<b>Units</b>
Electricity from grid	I	5.1301	4.4071	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	4.0815	3.3622	[kWh/kWh]
Process scale	-	3	3	[kWh/h]
CO <sub>2</sub> -emissions	O	0	0	[g/kWh]

The emissions of the stationary reference A are accounted in the electricity production processes.

### **Stationary reference B**

In this reference, the space heating efficiency of a oil-boiler was set at 70%. For warm water provision a slightly higher efficiency was set: 73%. The electric efficiency equals to 100%. Technical data of stationary reference B is presented in Table 43. The values are normalized with respect to electricity use.

Differently than the case of stationary reference A, stationary reference B does involve emissions due to the burning of oil locally. The CO<sub>2</sub>-emissions of the stationary reference B were approximated by the CO<sub>2</sub> resulting from the complete combustion of a mean type diesel oil with a specific energy content of 11.9 kWh/kg (LHV). No other emissions were modelled due to lack of data.

Table 43. Typical Finnish household using only diesel oil and electricity as feedstock's

	<b>Input/Output</b>	<b>year 2020</b>	<b>year 2030</b>	<b>Units</b>
Diesel oil input	I	5.7264	4.7135	[kWh/kWh]
Electricity from grid	I	1.0	1.0	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	4.0815	3.3622	[kWh/kWh]
Process scale	-	3	3	[kWh/h]
CO <sub>2</sub> -emissions	O	260.5	260.5	[g/kWh]

## B.5 Auxiliary Processes

Auxiliary processes are those that do not take part in hydrogen generation (from well to H<sub>2</sub> production), but help to realize the production or transport. These processes are:

- Gas Turbines (mechanical work for pumping gas through pipelines)
- Mechanical work provided by diesel engines
- Heating plant
- Coal power station

### B.5.1 Diesel Production

Diesel is used as fuel for mechanical conversion of energy. In the selected hydrogen chains several processes use diesel as fuel.

Table 44. Technical and economic data of diesel production

	I / O	Value	Units
Mineral oil consumption	I	1.160	[kWh/kWh]
Diesel oil production	O	1.000	[kWh]
Production costs	-	0.0436	[€/kWh]
CO <sub>2</sub> emissions	O	51.5	[g/kWh]
SO <sub>2</sub> emissions	O	0.13	[g/kWh]

Cost and emissions of diesel oil have been kept constant for the year 2030.

### B.5.2 Gas Turbines

This process is used only when the pressure of the delivered natural gas (mixture) decreases below the pressure level the process receiving the gas requires. In the Finnish hydrogen chains, this process has been used for all gas transports through pipelines longer than 200 km.

Table 45. Input and output data for used gas turbines (GEMIS 4.1.3.2)

	I / O	Value	Units
Natural gas	I	3.3333	[kWh/kWh]
Mechanical work	O	1.0	[kWh]
Process scale	-	10,000	[kWh/h]
Useful lifetime	-	15	[yr]
Annual full load hours	-	5,000	[h/yr]
CO <sub>2</sub> emissions	O	677	[g/kWh]
NO <sub>x</sub> emissions	O	3.527	[g/kWh]
PM emissions	O	0.050	[g/kWh]
SO <sub>2</sub> emissions	O	0.005	[g/kWh]
NM VOC emissions	O	0.101	[g/kWh]
CO emissions	O	1.008	[g/kWh]
CH <sub>4</sub> emissions	O	0.050	[g/kWh]
N <sub>2</sub> O emissions	O	0.030	[g/kWh]

### B.5.3 Diesel Engines

All chains involving biomass and nuclear energy use some mechanical work, which is provided by diesel engines. Nuclear energy and biomass chains use mechanical work during the mining respectively farming processes (see Table 10 and Table 18).

The efficiency of diesel engines is set at 30%. Table 46 presents the technical characteristics of the process of mechanical work delivery by a diesel engine.

Table 46. Input and output data for mechanical work from diesel engines

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Diesel oil	I	3.3333	[kWh/kWh]
Mechanical work	O	1.0	[kWh]
Process scale	-	1,000	[kWh/h]
Useful lifetime	-	10	[yr]
Annual full load hours	-	2,500	[h/yr]
CO <sub>2</sub> emissions	O	880	[g/kWh]
NO <sub>x</sub> emissions	O	11.626	[g/kWh]
PM emissions	O	0.969	[g/kWh]
SO <sub>2</sub> emissions	O	0.929	[g/kWh]
NM VOC emissions	O	0.037	[g/kWh]
CO emissions	O	2.519	[g/kWh]
CH <sub>4</sub> emissions	O	0.037	[g/kWh]
N <sub>2</sub> O emissions	O	0.037	[g/kWh]

#### B.5.4 Heating Plant

This process is used for the natural gas processing, which requires heat and electricity as inputs. Because natural gas is available, the gas is partially used to produce the heat required.

Table 47. Input and output data for used Heating plant (GEMIS 4.07)

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Natural gas	I	1.1765	[kWh/kWh]
Heat	O	1.0000	[kWh]
Process scale	-	10,000	[kWh/h]
Useful lifetime	-	15	[yr]
Annual full load hours	-	2,500	[h/yr]
CO <sub>2</sub> emissions	O	238	[g/kWh]
NO <sub>x</sub> emissions	O	0.2403	[g/kWh]
PM emissions	O	0.0006	[g/kWh]
SO <sub>2</sub> emissions	O	0.0019	[g/kWh]
NM VOC emissions	O	0.0108	[g/kWh]
CO emissions	O	0.1202	[g/kWh]
CH <sub>4</sub> emissions	O	0.0108	[g/kWh]
N <sub>2</sub> O emissions	O	0.0048	[g/kWh]

#### B.5.5 Coal Power Station

This process is used by hydrogen chains involving nuclear energy generation. The production of UF<sub>6</sub> as presented in Table 11, uses a small quantity of electricity as input. The UF<sub>6</sub> production process is derived from French data, where coal is used to produce the required electricity. Since the electric energy required by this process is very small, the assumption of a coal power plant for electricity production will not affect the results largely. Technical data of the power generation process using coal as feedstock is presented in the next table.

Table 48. Input and output data for the used coal power plant

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
Hard coal	I	2.299	[kWh/kWh]
Electricity	O	1.0	[kWh]
Process scale	-	600,000	[kWh/h]
Useful lifetime	-	35	[yr]
Annual full load hours	-	4500	[h/yr]
CO <sub>2</sub> emissions	O	795	[g/kWh]

	<b>I / O</b>	<b>Value</b>	<b>Units</b>
CH <sub>4</sub> emissions	O	0.0146	[g/kWh]
N <sub>2</sub> O emissions	O	0.0409	[g/kWh]

## Annex C Specific Finnish Data

The Member State specific data considered are the electricity mix, availability of wind when using wind turbines, costs of electricity and transport distances. Another parameter that has been set for Finnish calculations is the discount rate with which the calculated costs of hydrogen energy chains are levelized. For Finland, the value of 6% has been used.

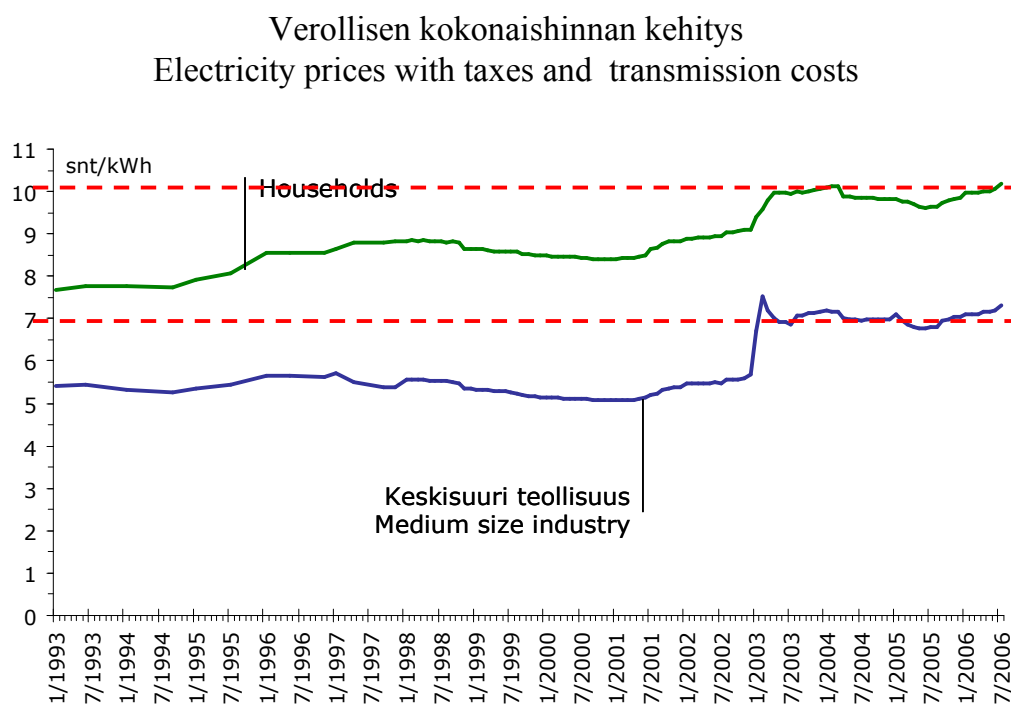
The costs of all feedstock's with exception of electricity, have been harmonised within HyWays. Harmonised costs are:

- Coal price
- Natural Gas price
- Diesel and gasoline prices
- Fuel oil price

The costs of electricity generated using the specific Finnish mix of feedstock's and generated by on-shore wind turbines is specified here below.

### Cost of electricity

According to the electricity price development in Finland, the cost of electricity for households are more or less constant at 10 €ct/kWh. For medium-size industry, these costs level is approximately 7 €ct/kWh. See figure below.



Source: Energy market Authority

Figure 31. Finnish electricity price development

For the purpose of hydrogen energy chains calculations, the cost of electricity for the years 2020 and 2030 are assumed equal to the actual electricity price level, see next table.

