



Modelling of Hydrogen supply chains for the UK



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Contents

List of tables	4
List of figures	5
Abbreviations	7
1. Introduction	8
2. Methodology	9
3. Chains Selection	10
3.1 Possible chains	10
3.2 Chain Selection for the UK	10
4. Selected Chains	12
4.1 1a. Central SMR of natural gas without CCS; use: FC vehicle	12
4.2 1b. On-site SMR of natural gas without CCS; use: FC vehicle	13
4.3 1c. Central SMR of natural gas with CCS; use: FC vehicle	14
4.4 1d. Central SMR of Russian natural gas with CCS; use: FC vehicle	15
4.5 1e. Central SMR of NG with CCS and liquefaction; use: FC vehicle	16
4.6 1f. Central SMR of natural gas with CCS; use: FC vehicle	17
4.7 2a. Coal gasification with CCS; use: FC vehicle	18
4.8 2b. Coal gasification (UK coal) without CCS; use: FC vehicle	19
4.9 3a. Central electrolysis using the electricity mix; use: FC vehicle	20
4.10 3b. On-site electrolysis using the electricity mix; use: FC vehicle	21
4.11 3c. Central electrolysis using nuclear electricity; use: FC vehicle	22
4.12 4a. Central electrolysis using offshore wind energy; use: FC vehicle	23
4.13 4b. De-central electrolysis using onshore wind energy; use: FC vehicle	24
4.14 4c. De-central electrolysis using onshore wind energy; use: Domestic CHP	25
4.15 5a. Gasification of farmed biomass; use: FC vehicle	26
4.16 5b. Gasification of residual biomass; use: FC vehicle	27
4.17 6a. Thermo-chemical process using nuclear heat; use: FC vehicle	28
4.18 Reference for comparison of the mobile hydrogen energy chains	29
4.19 References for comparison of the stationary hydrogen energy chains	29
5. Results	31
5.1 Hypothesis required for calculations	31
5.2 Well-to-Tank analysis (WTT)	32
5.3 Well-to-Wheel analysis (WTW)	34
5.4 Well-to-Stationary use analysis (WTStU)	36
6. Bibliography	38
Annex A Calculation rules	39
A.1 Conversion factors for Greenhouse Gas Equivalent	39
A.2 Learning curves	39
A.3 Scaling by size	40
A.4 Calculation of Levelized costs	40
A.4.1 Cost calculation for phase T1 (construction of the plant)	40
A.4.2 Cost calculation for phase T2 (operation of the plant)	40
A.4.3 Cost calculation for phase T3 (dismantling of the plant)	41
A.4.4 Levelized Costs	41
A.4.5 Use of specific costs for “processes”	41
Annex B Description of processes	43
B.1 Availability of Feedstock’s	43

B.1.1	Extraction and Conditioning of Natural Gas	43
B.1.2	Liquefaction of Natural Gas	44
B.1.3	Extraction of Coal	45
B.1.4	Production of Nuclear fuel	45
B.1.5	Production of Electricity	47
B.1.6	Production of Biomass	49
B.2	Transport of Feedstock's	52
B.2.1	Natural Gas transport	52
B.2.2	Transport of Liquefied Natural Gas	52
B.2.3	Coal transport	53
B.2.4	Electricity transport	53
B.2.5	Biomass transport	54
B.2.6	Diesel and Heavy Fuel Oil transport	54
B.3	Hydrogen Production	55
B.3.1	Production of Hydrogen from Natural Gas	55
B.3.2	Production of Hydrogen from Coal	56
B.3.3	Production of Hydrogen from Electricity	56
B.3.4	Production of Hydrogen from Biomass	57
B.3.5	Production of Hydrogen from Nuclear Heat	57
B.3.6	Liquefaction of Hydrogen	57
B.3.7	Compression of Hydrogen	58
B.4	Transport of Hydrogen	58
B.4.1	Transport of Compressed Hydrogen Gas (CGH ₂) by pipeline	58
B.4.2	Transport of Compressed Hydrogen Gas (CGH ₂) by truck	59
B.4.3	Transport of Liquefied Hydrogen (LH ₂) by truck	59
B.5	Hydrogen Usage	60
B.5.1	Vehicle Filling stations	60
B.5.2	Vehicle data	61
B.5.3	Stationary use of Hydrogen	61
B.6	Auxiliary Processes	64
B.6.1	Diesel Production	64
B.6.2	Gas Turbines	64
B.6.3	Diesel Engines	65
B.6.4	Heating Plant	65
B.6.5	Coal Power Station	66
Annex C	Specific British Data	67

List of tables

Table 1.	Overview of processes considered in the build up of a hydrogen energy chain	10
Table 2.	Selected British Chains for the Hydrogen pathway	11
Table 3.	Selected British Chains for the Hydrogen pathway	11
Table 4.	Overview of technologies of passenger cars expected to be available by the year 2010..	34
Table 5.	Conversion factors [IPCC 2001].....	39
Table 6.	Input and output data for NG Extraction, NL (onshore) / GEMIS 4.1	43
Table 7.	Input and output data for NG Processing, NL / GEMIS 4.1	44
Table 8.	Input and output data for provision of EU-mix of natural gas.....	44
Table 9.	Technical and economic data of the used natural gas liquefaction plant.....	44
Table 10.	Input and output data for production of EU-mix hard coal.....	45
Table 11.	Input and output data for Uranium surface mining.....	45
Table 12.	Input and output data for UF ₆ production	46
Table 13.	Input and output data for UF ₆ enrichment	46
Table 14.	Input and output data for production nuclear fuel	46
Table 15.	Electricity production mix for The UK and Europe.	47
Table 16.	Electricity. British production mix and British import (EU-mix).....	47
Table 17.	Input and output data for electricity production using a nuclear plant	48
Table 18.	Technical and economic data of the offshore and onshore wind turbines	49
Table 19.	Poplar plantation	51
Table 20.	Technical and economic data of the chipping process.....	51
Table 21.	Input and output data for NG transport through pipelines	52
Table 22.	Economic data of the ship used for LNG transport	52
Table 23.	Economic data of the truck used for coal transport	53
Table 24.	Input and output data for High-voltage transport of electricity (GEMIS 4.1)	53
Table 25.	Input and output data for Medium-voltage transport of electricity (GEMIS 4.1).....	54
Table 26.	Input and output data for Low-voltage transport of electricity (GEMIS 4.1).....	54
Table 27.	Technical data of the train used for diesel and HFO transport	54
Table 28.	Technical and economic data of the used SMR plant.....	55
Table 29.	Technical and economic data of hydrogen generation via coal gasification without CO ₂ capture and storage.....	56
Table 30.	Technical and economic data for electrolysis	56
Table 31.	Technical and economic data of hydrogen generation via biomass gasification	57
Table 32.	Technical and economic data of the used Sulphur-Iodine plant for the production of hydrogen	57
Table 33.	Technical and economic data of large-scale H ₂ liquefaction plant.....	58
Table 34.	Technical and economic data for hydrogen compression.....	58
Table 35.	Technical and economic data of CGH ₂ pipelines	59
Table 36.	Technical and economic data for the CGH ₂ filling stations.....	60
Table 37.	Technical and economic data for the combined LH ₂ /CGH ₂ filling station.....	60
Table 38.	Passenger hydrogen cars data	61
Table 39.	Passenger reference cars data.....	61
Table 40.	Yearly household energy consumption.....	61
Table 41.	CHP-system (heat-following) for a British household, 100% boiler efficiency	62
Table 42.	Fuel mix used for heat demand (heating and warm water) used in the model of a 'typical' British household.....	63
Table 43.	Net energy demand ratio (heat/electricity) of a British household using a mix of fuels for heating and electricity from the grid for electric appliances	63
Table 44.	Gross energy demand ratio (heat/electricity) of a British household using a mix of fuels for heating and electricity from the grid for electric appliances	63
Table 45.	Technical and economic data of diesel production.....	64

Table 46.	Input and output data for used gas turbines (GEMIS 4.1.3.2)	64
Table 47.	Input and output data for mechanical work from diesel engines	65
Table 48.	Input and output data for used Heating plant (GEMIS 4.07)	65
Table 49.	Input and output data for the used coal power plant	66
Table 50.	British electricity costs	67

List of figures

Figure 1.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from central SMR of NG without CCS.	12
Figure 2.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from on-site SMR of NG without CCS.	13
Figure 3.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from central SMR of NG with CCS.	14
Figure 4.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from central SMR of NG with CCS.	15
Figure 5.	Hydrogen chain model for LGH ₂ /CGH ₂ at a filling station. Hydrogen production from central SMR with CCS and liquefaction.	16
Figure 6.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from central SMR of NG with CCS.	17
Figure 7.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from coal gasification with CCS.	18
Figure 8.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from gasification of UK's coal with CCS.	19
Figure 9.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from central electrolysis using the British electricity mix.	20
Figure 10.	Modelled hydrogen chain produced from wind energy, stationary use	21
Figure 11.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from central electrolysis using nuclear electricity.	22
Figure 12.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from central electrolysis using offshore wind energy.	23
Figure 13.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from de-central electrolysis using onshore wind energy.	24
Figure 14.	Hydrogen chain model for use of CGH ₂ at domestic CHP installations. Hydrogen production from central electrolysis using onshore wind energy.	25
Figure 15.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from central gasification of farmed biomass.	26
Figure 16.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from a de-central biomass gasifier.	27
Figure 17.	Hydrogen chain model for CGH ₂ at a filling station. Hydrogen production from a thermo-chemical process using nuclear heat.	28
Figure 18.	Chain model for stationary use of several fuels, for heat and electricity consumption of UK household.	29
Figure 19.	British WTT hydrogen energy chain efficiencies	32
Figure 20.	Primary energy use of British WTT hydrogen energy chains	32
Figure 21.	CO ₂ -equivalent emissions of British WTT hydrogen energy chains	33
Figure 22.	Costs of hydrogen and conventional fuels for British hydrogen energy chains	33
Figure 23.	WTW energy use of British hydrogen energy chains, compared to 2010 reference car technologies	34
Figure 24.	WTW CO ₂ -equivalent emissions for hybrid passenger cars in 2020	35
Figure 25.	WTW energy costs for hybrid passenger cars in 2020 - 2030	35
Figure 26.	Efficiencies of the British WTStU hydrogen energy chains	36

Figure 27. Primary energy use of British WTStU hydrogen energy chains..... 36

Figure 28. CO₂-equivalent emissions of British WTStU hydrogen energy chains 37

Figure 29. Costs of hydrogen and conventional fuels for British WTStU hydrogen energy chains.. 37

Figure 30. Direct N₂O emissions from arable land 50

Figure 31. Example of pipeline grid for hydrogen transport..... 59

Figure 32. Supply of electricity and heat for a British household (2020), Q-following system. 62

Figure 33. British electricity price development..... 67

Figure 34. Scheme of electricity costs structure for The UK..... 68

Abbreviations

CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CGH ₂	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 ₂	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
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 the UK, and
- Provides the results obtained from the calculations of these chains.

2. Methodology

During several workshops organized in the UK, 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 2003¹ and the GEMIS database [ref. 2]. Part of the data have been adapted or created to represent the specific infrastructure of the UK. 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 CO₂ capture and storage is embodied,
- Processes which describe stationary hydrogen fuelled fuel cells.

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

- Production of British electricity mix (Annex B, section B.1.5)
- Electricity transport at low-voltage level (Annex B, section B.2.4)
- Use of CHP-application in British households, heat-following process (Annex B, section B.5.3)
- Heat and electricity use in British households (Annex B, section B.5.3)
- Onshore wind energy for British islands (Annex B, section B.1.5)

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

¹ 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

Feedstock (production)	Feedstock transport	Hydrogen production	Hydrogen transport and distribution	Hydrogen end use
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 ₂		Photo-electrochemical process		Power plant (GT) Combined Cycle
Import of H ₂				

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 the UK

Table 2 shows an overview of the feedstock's and end use options of hydrogen energy chains that have been considered during the British stakeholder workshops. Natural gas, coal, biomass, heat and electricity (electricity mix, wind and nuclear power) have been selected as the most relevant feedstock's for the UK. Natural gas is available from the UK's /Norwegian gas fields offshore, but it can also be imported from Russia or from the Middle East in liquefied form. Coal and biomass (wood) must be

imported from countries worldwide. Coal resources are also domestically available, but it has been assumed that British coal mines only could become exploitable (again) on the long-term.

With respect to end use, hydrogen vehicles (in particular passenger cars) and residential CHP have been selected as the most relevant options. Based on the availability of feedstock's and earlier energy and hydrogen analyses performed for the UK [refs. 5, 6 and 7], hydrogen energy chains were selected. These energy chains are further characterized in Table 3.

Table 2. Selected British Chains for the Hydrogen pathway

Feedstock	NG (Norway, UK and Russia)	✓
	Coal (worldwide and from the UK)	✓
	Oil (residues)	-
	Electricity ²	✓
	Biomass (Russia)	✓
	Heat (nuclear power)	✓
	Waste	-
	By-product (hydrogen from industrial processes)	-
	Import	-
Hydrogen end use	Hydrogen vehicles	✓
	Residential CHP (Fuel Cell)	-
	Residential CHP (ICE)	-
	Residential heating (Boiler)	✓
	CCGT	-

Table 3. Selected British Chains for the Hydrogen pathway

Number	Feedstock	Production Process	H ₂ -transport & distribution	Application	
1	a	Natural gas	CGH ₂ -truck + FS	FC vehicle	
	b	Natural gas	On-site SMR	Filling Station (FS)	FC vehicle
	c	Natural gas	Central SMR + CCS	Pipeline + FS	FC vehicle
	d	Russian natural gas	Central SMR + CCS	Pipeline + FS	FC vehicle
	e	Natural gas	Central SMR + CCS	LH ₂ -truck + FS	FC vehicle
	f	Liquefied natural gas	Central SMR + CCS	Pipeline + FS	FC vehicle
2	a	Coal	Gasification + CCS	Pipeline + FS	FC vehicle
	b	UK coal	Gasification + CCS	Pipeline + FS	FC vehicle
3	a	Electricity mix	Central Electrolysis	Pipeline + FS	FC vehicle
	b	Electricity mix	On-site Electrolysis	Filling Station (FS)	FC vehicle
	c	Nuclear electricity	Central Electrolysis	Pipeline + FS	FC vehicle
4	a	Offshore wind power	Central Electrolysis	Pipeline + FS	FC vehicle
	b	Onshore wind power	On-site Electrolysis	Filling Station (FS)	FC vehicle
	c	Onshore wind power	Central Electrolysis	Pipeline + FS	Domestic CHP
5	a	Farmed wood	Central Gasification	Pipeline + FS	FC vehicle
	b	Residual wood	De-central Gasification	Pipeline + FS	FC vehicle
6	a	Nuclear heat	Central Thermoplant	Pipeline + FS	FC vehicle

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

² 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 British mix or the European mix.

4. Selected Chains

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

4.1 1a. Central SMR of natural gas without CCS; use: FC vehicle

Natural gas (NG), extracted from gas fields under the North Sea (mainly Norway, and UK), is processed and transported via a high-pressure pipeline to the UK coast over a distance of 500 km on average. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

In the UK, the natural gas is further transported via high-pressure pipelines to central large-scale Steam Methane Reformers (SMR). Transport distance in the high-pressure pipelines is 400 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop in the pipeline.

The large-scale 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 produced hydrogen is compressed to approximately 30 MPa (300 bar) 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 100 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 British electricity production mix.

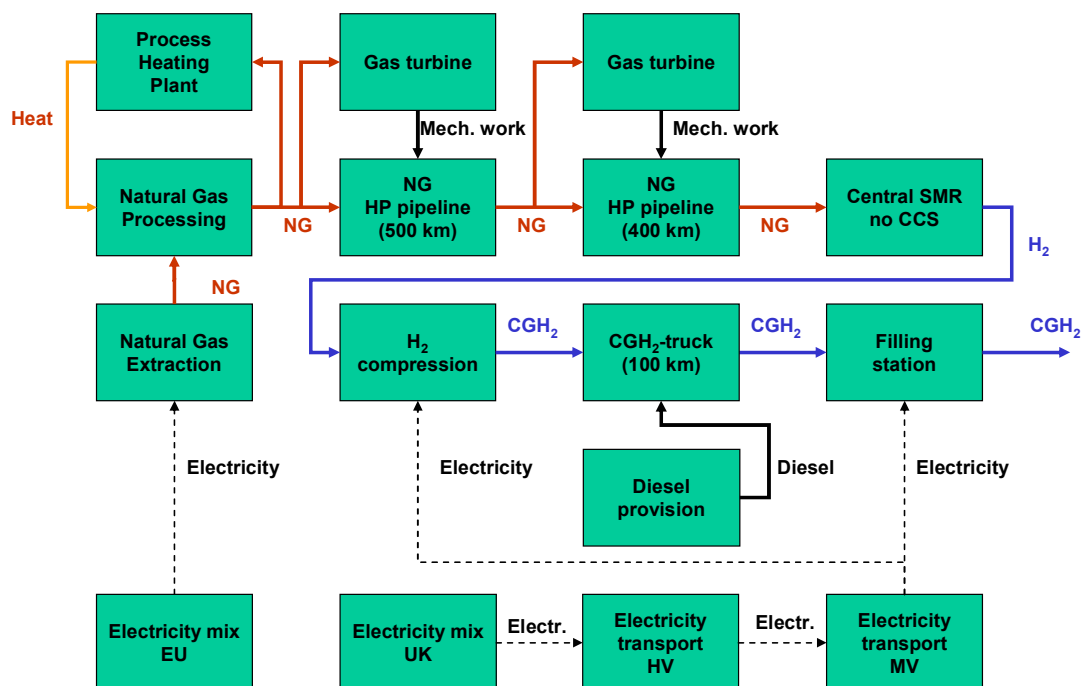


Figure 1. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from central SMR of NG without CCS.

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

- | | | | |
|------------------------------------------------|-------|-----------------------------------|-------|
| - Natural gas extraction and conditioning | B.1.1 | - Natural gas transport pipelines | B.2.1 |
| - Electricity production | B.1.5 | - Electricity transport | B.2.4 |
| - Hydrogen production from natural gas | B.3.1 | - Filling station | B.5.1 |
| - Hydrogen compression | B.3.7 | - Gas turbines | B.6.2 |
| - Hydrogen transport by CGH ₂ truck | B.4.2 | - Heating plant | B.6.4 |

4.2 1b. On-site SMR of natural gas without CCS; use: FC vehicle

Natural gas (NG), extracted from gas fields under the North Sea (mainly Norway, and UK), is processed and transported via a high-pressure pipeline to the UK coast over a distance of 500 km on average. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

In the UK, the natural gas is further transported via high- and medium-pressure pipelines to on-site small-scale Steam Methane Reformers (SMR). Transport distance in the high- and medium-pressure pipelines are 400 and 50 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop in 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 British electricity production mix.

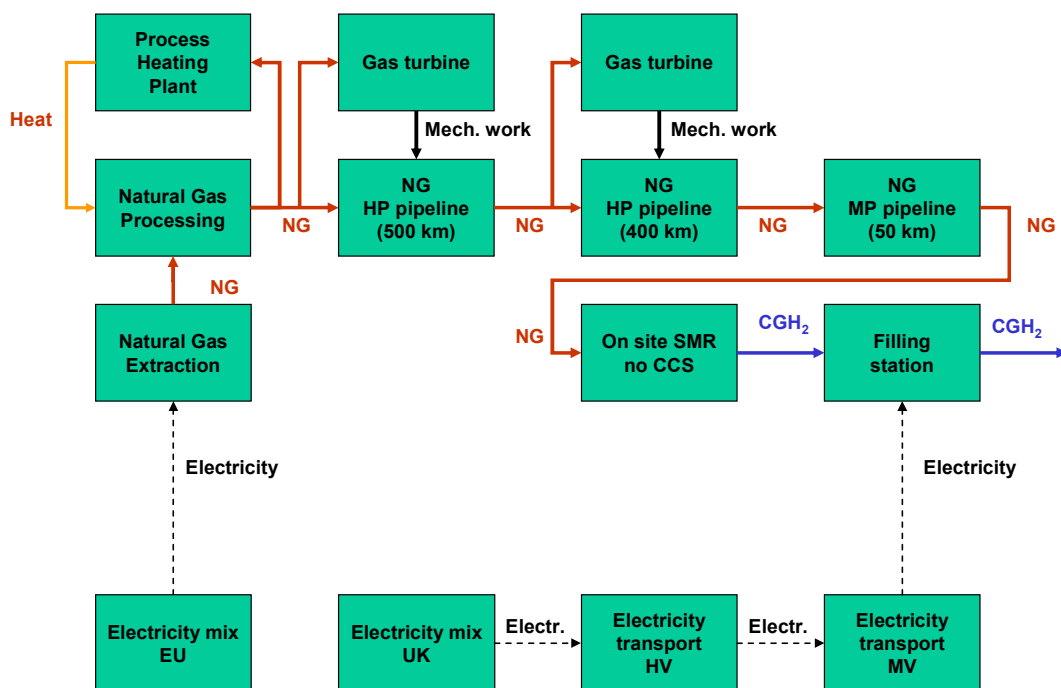


Figure 2. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from on-site SMR of NG without CCS.

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.1.5
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.4
- Hydrogen production from natural gas B.3.1
- Filling station B.5.1
- Gas turbines B.6.2
- Heating plant B.6.4

4.3 1c. Central SMR of natural gas with CCS; use: FC vehicle

Natural gas (NG), extracted from gas fields under the North Sea (mainly Norway, and UK), is processed and transported via a high-pressure pipeline to the UK coast over a distance of 500 km on average. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline. In the UK, the natural gas is further transported via high-pressure pipelines to central large-scale Steam Methane Reformers (SMR). Transport distance in the high-pressure pipelines is 400 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop in the pipeline.

The SMR plants produce hydrogen at a pressure of about 6 MPa (60 bar) and are equipped with CO₂ capture facilities. For CO₂-storage, depleted oil fields are assumed available³. The produced hydrogen and the sequestered CO₂ are transported to the filling stations respectively to the storage field by pipelines.

At the filling stations, electrical compressors 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 British electricity production mix.

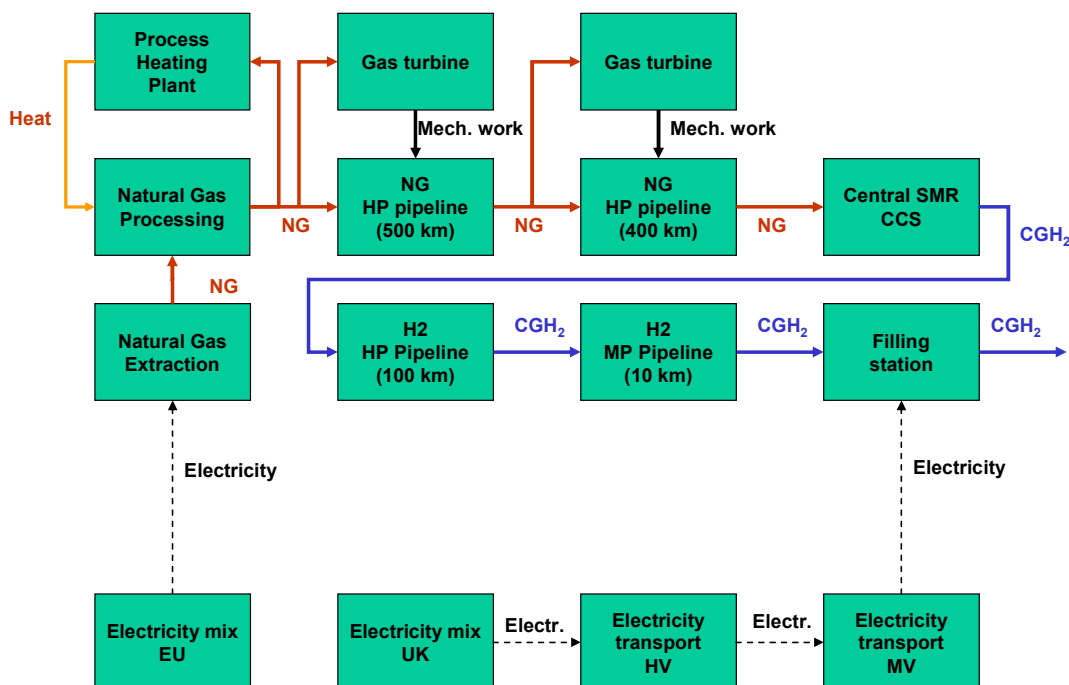


Figure 3. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from central SMR of NG with CCS.

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.1.5
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.4
- Hydrogen production from natural gas B.3.1
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1
- Gas turbines B.6.2
- Heating plant B.6.4

³ No data was available for an estimation of capacity and safety of indicated CCS-fields.

4.4 1d. Central SMR of Russian natural gas with CCS; use: FC vehicle

Natural gas (NG), extracted and processed in Russia is transported via a high-pressure pipeline to the UK coast over a distance of approximately 8000 km. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline. In the UK, the natural gas is further transported via high-pressure pipelines to central large-scale Steam Methane Reformers (SMR). Transport distance in the British high-pressure pipelines is 400 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop in the pipeline.

The SMR plants produce hydrogen at a pressure of about 6 MPa (60 bar) and are equipped with CO₂ capture facilities. For CO₂-storage, depleted oil fields are assumed available⁴. The produced hydrogen and the sequestered CO₂ are transported to the filling stations respectively to the storage field by pipelines.

At the filling stations, electrical compressors 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 British electricity production mix.

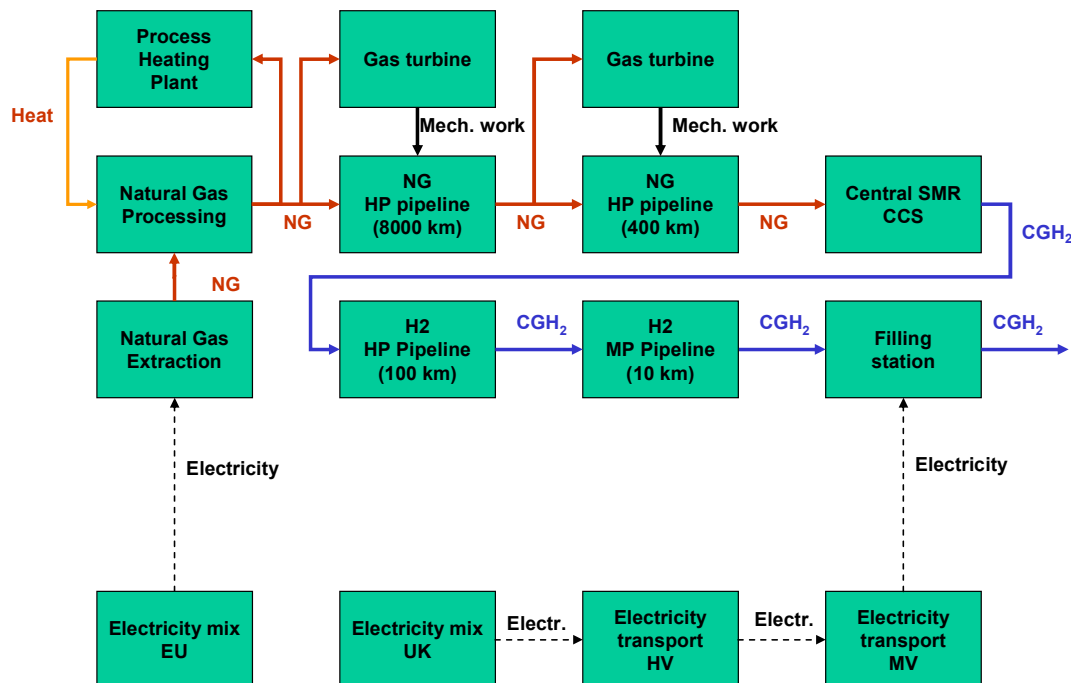


Figure 4. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from central SMR of NG with CCS.

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.1.5
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.4
- Hydrogen production from natural gas B.3.1
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1
- Gas turbines B.6.2
- Heating plant B.6.4

⁴ No data was available for an estimation of capacity and safety of indicated CCS-fields.

4.5 1e. Central SMR of NG with CCS and liquefaction; use: FC vehicle

Natural gas (NG), extracted from gas fields under the North Sea (mainly Norway, and UK), is processed and transported via a high-pressure pipeline to the UK coast over a distance of 500 km on average. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline. In the UK, the natural gas is further transported via high-pressure pipelines to central large-scale Steam Methane Reformers (SMR). Transport distance in the high-pressure pipelines is 400 km on average. Again, NG-fuelled compressors are used to compensate the pressure drop in the pipeline.

The SMR plants produce hydrogen at a pressure of about 6 MPa (60 bar) and are equipped with CO₂ capture facilities. For CO₂-storage, depleted oil fields are assumed available⁵. The sequestered CO₂ is transported to the storage field by pipelines.

The produced hydrogen is liquefied and transported to dedicated 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 100 km on average. The hydrogen is stored as a liquid at the fuelling station and can be distributed to cars with either compressed gas (88 MPa) or liquid on-board storage. Electrical pumps dispense the liquid hydrogen. It is assumed that the electricity required is obtained from the British electricity production mix.

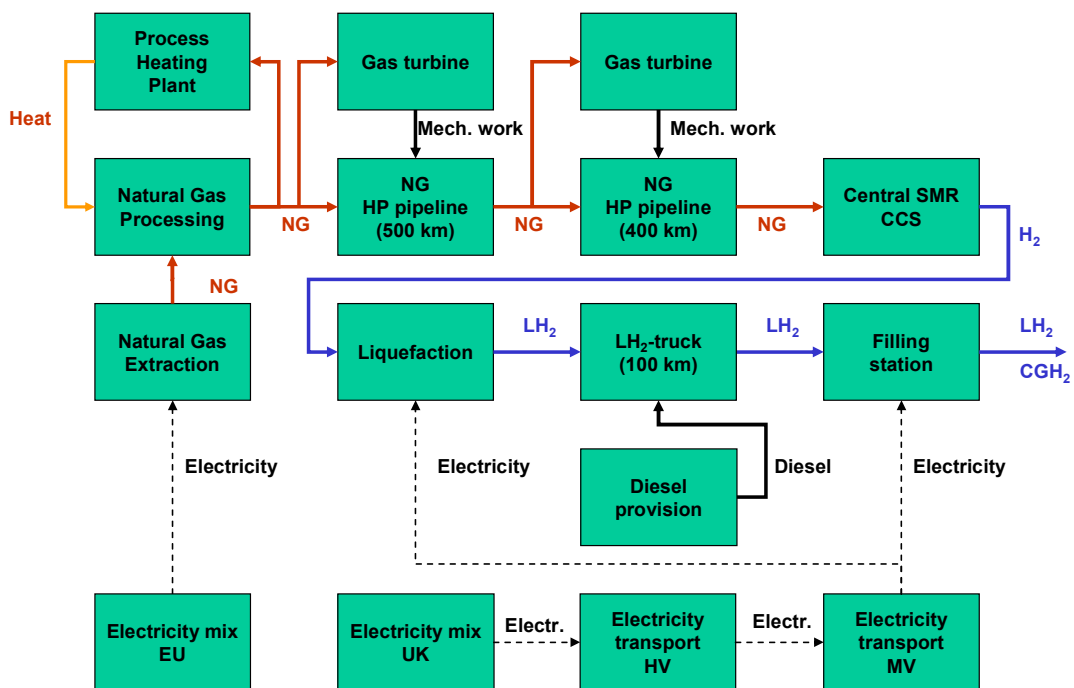


Figure 5. Hydrogen chain model for LGH₂/CGH₂ at a filling station. Hydrogen production from central SMR with CCS and liquefaction.

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.1.5 |
| - Natural gas transport pipelines | B.2.1 | - Electricity transport | B.2.4 |
| - Hydrogen production from natural gas | B.3.1 | - Filling station | B.5.1 |
| - Liquefaction of hydrogen | B.3.5 | - Gas turbines | B.6.2 |
| - Hydrogen transport by LH ₂ truck | B.4.3 | - Heating plant | B.6.4 |

⁵ No data was available for an estimation of capacity and safety of indicated CCS-fields.

4.6 1f. Central SMR of natural gas with CCS; use: FC vehicle

Natural gas (NG), extracted and processed in the Middle East, is liquefied and transported by ship to the UK coast over a distance of about 8000 km. NG and electricity are used for extraction and processing. In the UK the LNG is fed into the high-pressure natural gas grid and is transported over a distance of 100 km on average to large-scale SMR's. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

The SMR plants produce hydrogen at a pressure of about 6 MPa (60 bar) and are equipped with CO₂ capture facilities. For CO₂-storage, depleted oil fields are assumed available⁶. The produced hydrogen and the sequestered CO₂ are transported to the filling stations respectively to the storage field by pipelines.

At the filling stations, electrical compressors 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 British electricity production mix.

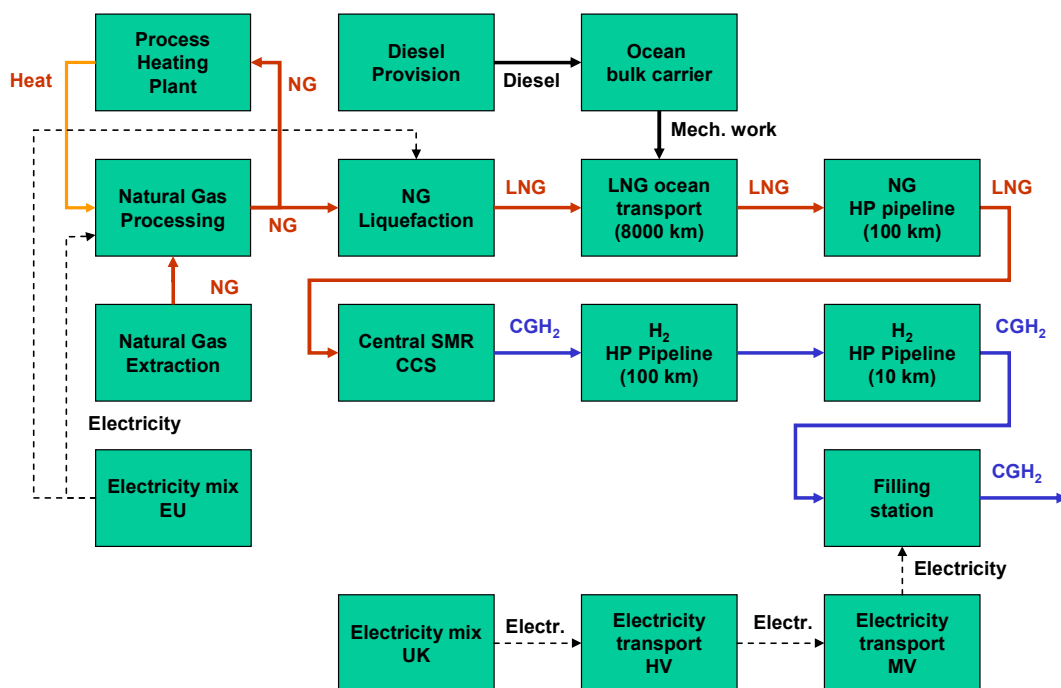


Figure 6. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from central SMR of NG with CCS.

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.1.5 |
| - Liquefaction of natural gas | B.1.2 | - Electricity transport | B.2.4 |
| - LNG ocean transport | B.2.2 | - Filling station | B.5.1 |
| - Natural gas transport pipelines | B.2.1 | - Heating plant | B.6.4 |
| - Hydrogen production from natural gas | B.3.1 | - Gas turbines | B.6.2 |
| - Hydrogen transport via pipelines | B.4.1 | | |

⁶ No data was available for an estimation of capacity and safety of indicated CCS-fields.

4.7 2a. Coal gasification with CCS; use: FC vehicle

In this hydrogen chain, hydrogen is generated via large-scale gasification of hard coal with CO₂ capture and sequestration. The hard coal is transported from several countries in the world using ocean bulk-carriers. The mean transport distance is estimated into 8000 km.

The coal gasification plant is thought to be located at the coast, so no extra coal transport on land is required. The coal is converted into a product gas rich in CO and H₂ in the gasifier. Subsequently, CO is reacted with steam to form CO₂ and H₂ in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO₂ and H₂ using PSA units. CCS is included as a part of the process. For CO₂-storage, depleted oil fields are assumed available⁷. The produced hydrogen and the sequestered CO₂ are transported to the filling stations respectively to the storage field by pipelines.

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 British electricity production mix.

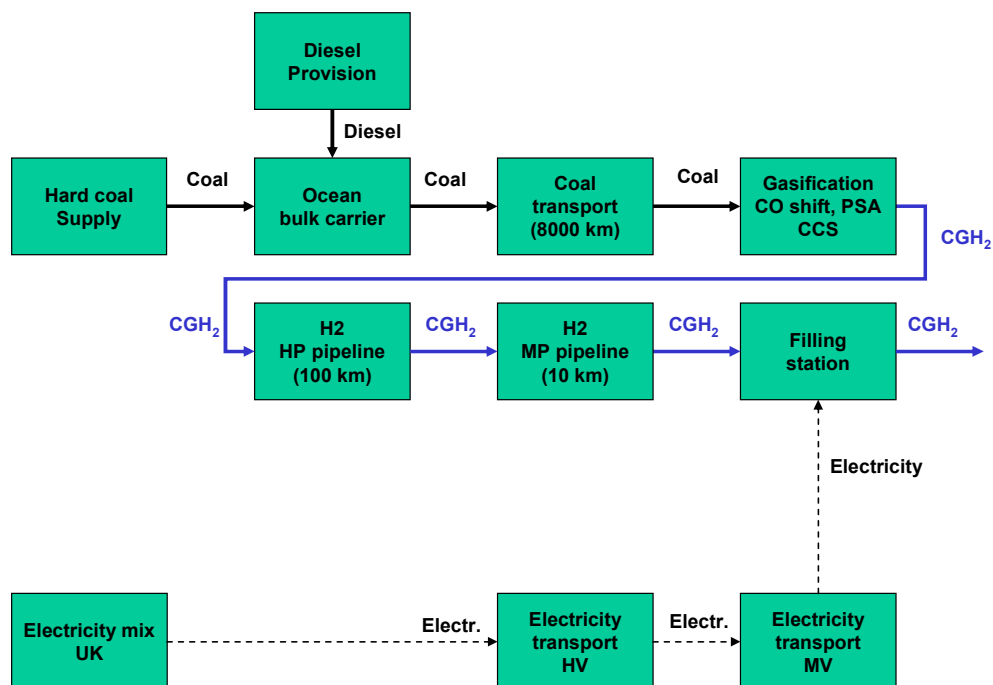


Figure 7. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from coal gasification with CCS.

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

- Hard coal extraction B.1.3
- Coal transport B.2.3
- Electricity production B.1.5
- Electricity transport B.2.4
- Hydrogen production from coal B.3.2
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

⁷ No data was available for an estimation of capacity and safety of indicated CCS-fields.

4.8 2b. Coal gasification (UK coal) without CCS; use: FC vehicle

This hydrogen energy chain is similar to the previous presented coal gasification chain. The only difference is that the coal used in the process is obtained from UK coal mines. The chain is included to account with an anticipated UK coal demand.

Instead of being transported by ocean bulk carriers, the coal is extracted in the UK and transported by diesel-fuelled trucks over a distance of 300 km to the gasifier, where it is converted into a product gas rich in CO and H₂. Subsequently, CO is reacted with steam to form CO₂ and H₂ in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO₂ and H₂ using PSA units. CCS is included as a part of the process. For CO₂-storage, depleted oil fields are assumed available⁸. The produced hydrogen and the sequestered CO₂ are transported to the filling stations respectively to the storage field by pipelines.

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 British electricity production mix.

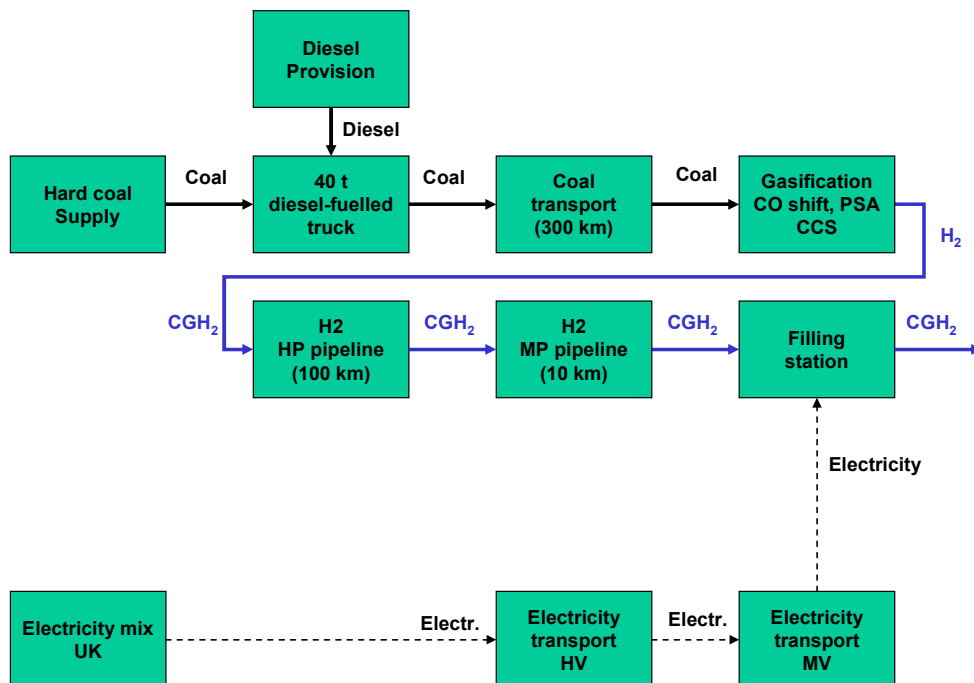


Figure 8. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from gasification of UK's coal with CCS.

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

- Hard coal extraction B.1.2
- Coal transport B.2.2
- Electricity production B.1.5
- Electricity transport B.2.4
- Hydrogen production from coal B.3.2
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

⁸ No data was available for an estimation of capacity and safety of indicated CCS-fields.

4.9 3a. Central electrolysis using the electricity mix; use: FC vehicle

Relatively large-scale electrolysis plants produce hydrogen at some distance from the end use centres. The electricity for the electrolysis process is obtained from the British electricity mix and is transported to the electrolysis plants through the high- and medium-voltage electricity grid.

The hydrogen produced by the electrolyser at a pressure of 3 MPa (30 bar) is transported and distributed to filling stations through hydrogen pipelines. 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 this electricity is obtained from the British electricity production mix.

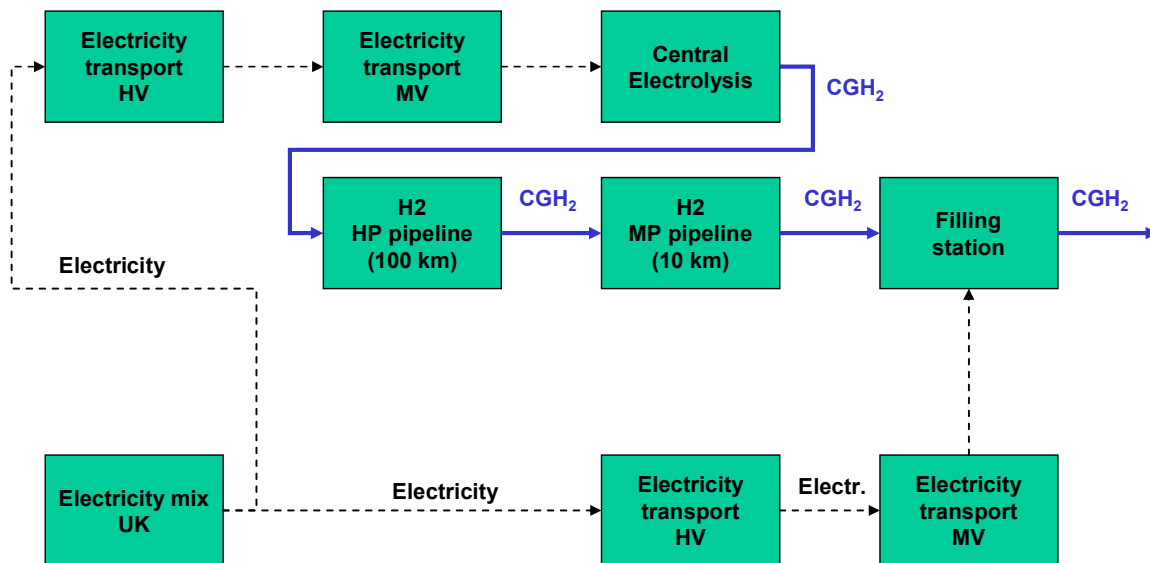


Figure 9. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from central electrolysis using the British electricity mix.

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

- Electricity production B.1.5
- Electricity transport B.2.4
- Production of hydrogen from electricity B.3.3
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

4.10 3b. On-site electrolysis using the electricity mix; use: FC vehicle

In this chain, hydrogen is produced at de-central electrolysis plants located on-site at the filling stations. The electricity required for the electrolysis process is obtained from the British electricity grid.

The hydrogen produced by the electrolyser at a pressure of 2.6 MPa (26 bar) is compressed up to 88 MPa for on-board storage by electrical compressors that are part of the filling station. To this end, the filling station (120 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that this electricity is also obtained from the British electricity production mix.

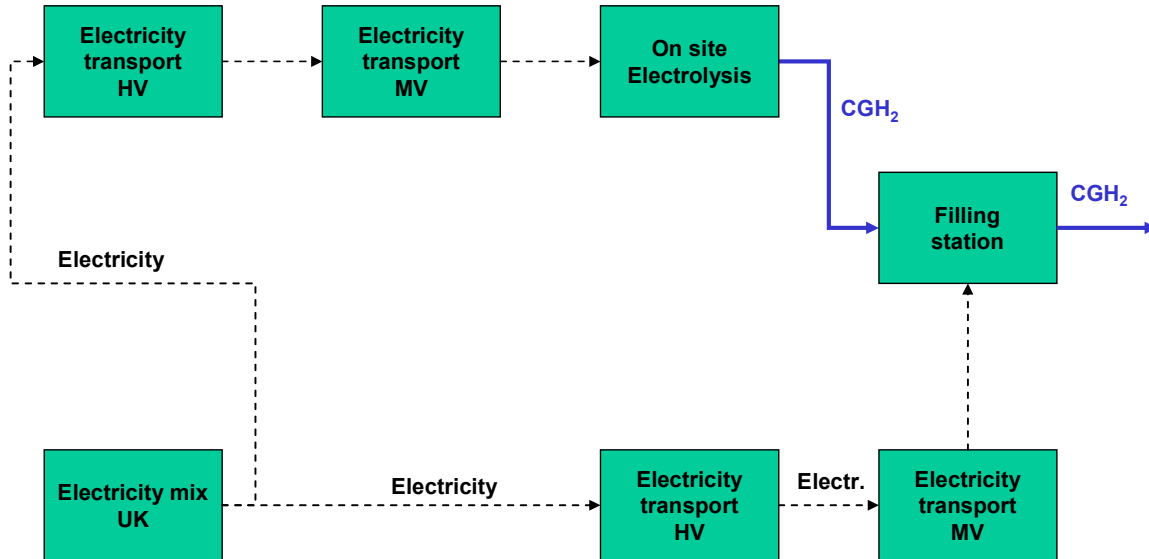


Figure 10. Modelled hydrogen chain produced from wind energy, stationary use

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

- Electricity production B.1.5
- Electricity transport B.2.4
- Hydrogen production through electrolysis B.3.3
- Filling station B.5.1

4.11 3c. Central electrolysis using nuclear electricity; use: FC vehicle

Electricity produced from nuclear energy is transported to relatively large-scale central electrolysis plants through the British electricity grid. The hydrogen produced by the electrolyser at a pressure of 3 MPa (30 bar) is transported and distributed to filling stations through hydrogen pipelines. 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 this electricity is obtained from the British electricity production mix.

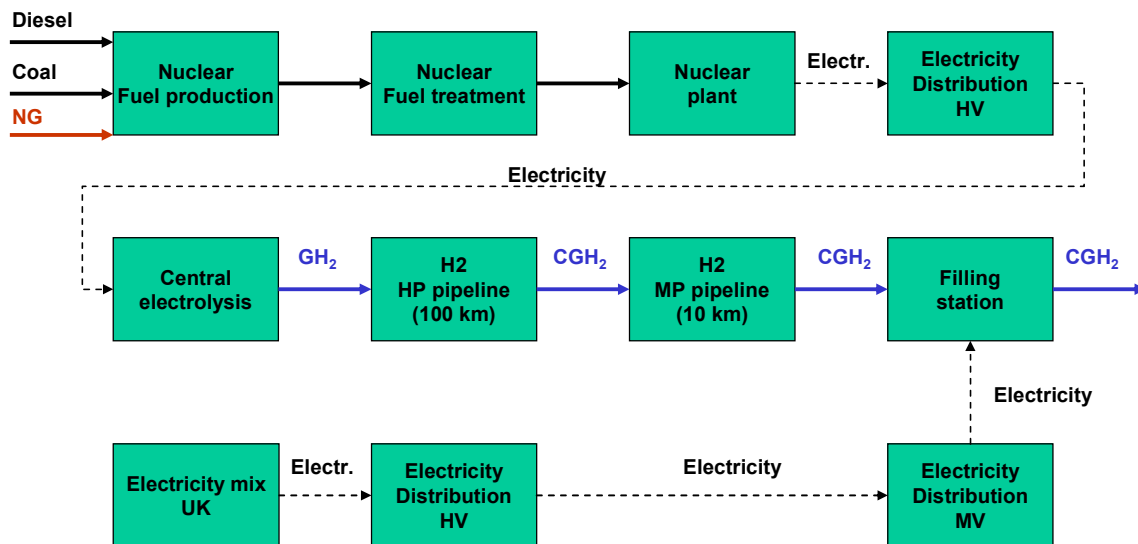


Figure 11. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from central electrolysis using nuclear electricity.

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

- Nuclear fuel production, treatment and enrichment B.1.4
- Electricity production from nuclear energy B.1.5
- Electricity transport B.2.4
- Hydrogen production through electrolysis B.3.3
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

4.12 4a. Central electrolysis using offshore wind energy; use: FC vehicle

In this chain, hydrogen is produced by central electrolysis plants located at some distance from the end use centres. Offshore wind turbines generate the electricity required for the electrolysis process. A system of high-voltage cables connects the wind turbines and the electrolyser with each other.

The hydrogen produced by the electrolyser at a pressure of 3 MPa (30 bar) is transported and distributed to filling stations through hydrogen pipelines. 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 this electricity is obtained from the British electricity production mix.

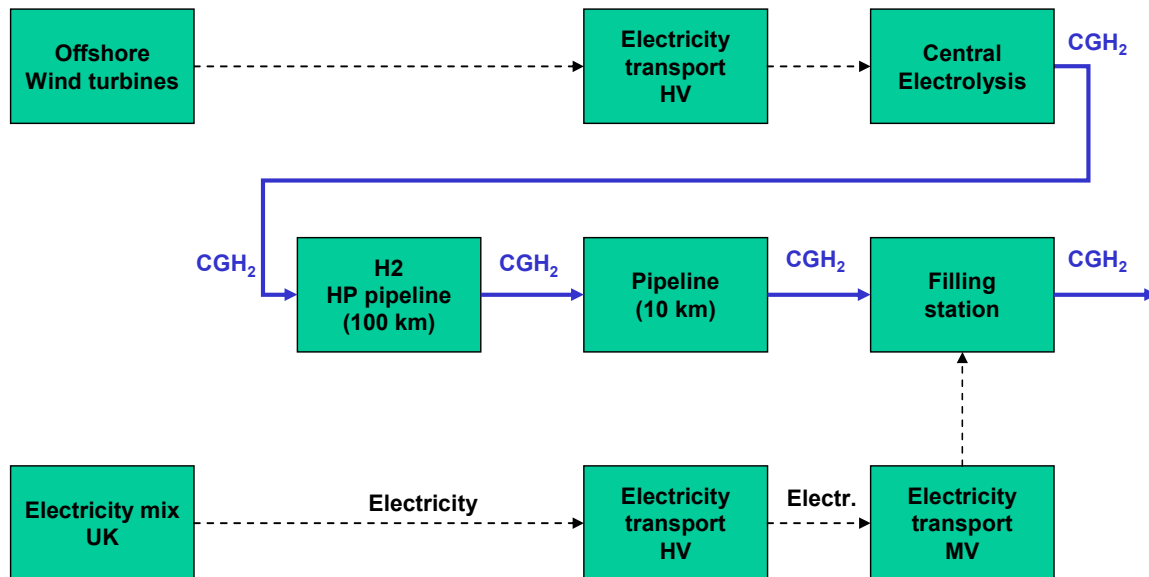


Figure 12. Hydrogen chain model for CGH_2 at a filling station. Hydrogen production from central electrolysis using offshore wind energy.

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

- Electricity production (mix and offshore wind energy) B.1.5
- Electricity transport B.2.4
- Hydrogen production through electrolysis B.3.3
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

4.13 4b. De-central electrolysis using onshore wind energy; use: FC vehicle

Onshore wind turbines generate the electricity required for the electrolysis process. A system of high-voltage and medium-voltage power lines transports the electricity to small-scale electrolysis units where the hydrogen is produced. The electrolysis units are located on-site at the filling stations.

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 British electricity production mix.

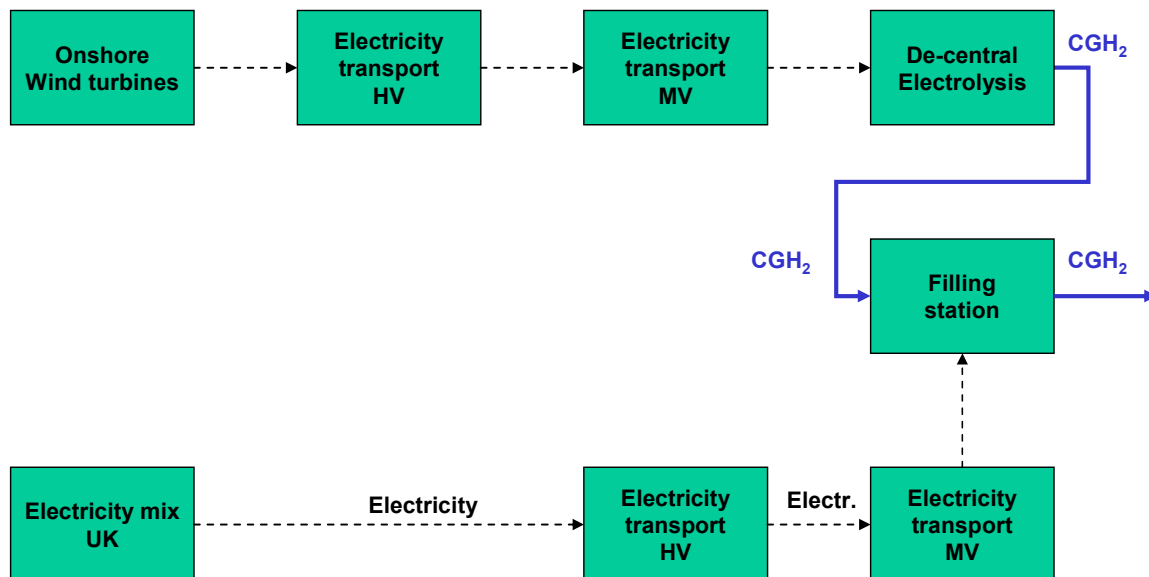


Figure 13. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from de-central electrolysis using onshore wind energy.

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

- Electricity production (mix and onshore wind energy) B.1.5
- Electricity transport B.2.4
- Hydrogen production through electrolysis B.3.3
- Filling station B.5.1

4.14 4c. De-central electrolysis using onshore wind energy; use: Domestic CHP

In this chain, hydrogen is produced by central electrolysis plants located at some distance from the end use centres. Onshore wind turbines generate the electricity required for the electrolysis process. A system of high-voltage cables connects the wind turbines and the electrolyser with each other. The electrolysers produce hydrogen at a pressure of 3 MPa (30 bar). Hydrogen pipelines transport the produced hydrogen to the end-users.

The CGH₂ distributed is used in 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 British fuel mix. Excess electricity produced by the CHP-system is fed back to the electric grid avoiding the electricity production by other means.

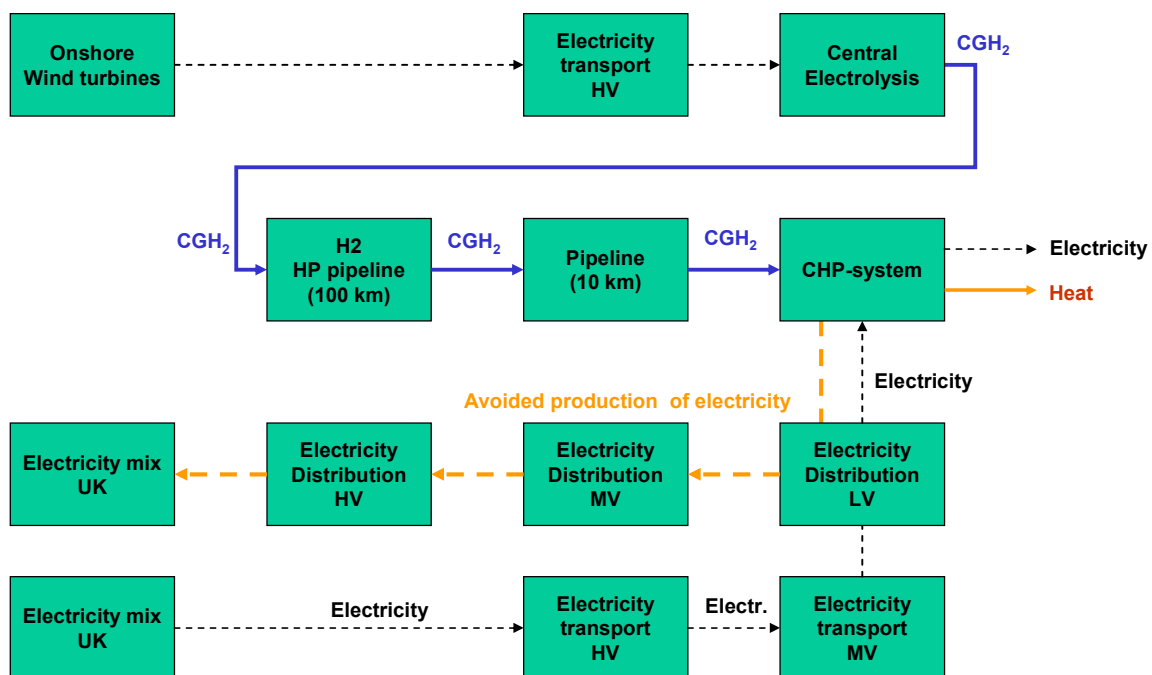


Figure 14. Hydrogen chain model for use of CGH₂ at domestic CHP installations. Hydrogen production from central electrolysis using onshore wind energy.

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

- Electricity production (mix and onshore wind energy) B.1.5
- Electricity transport B.2.4
- Hydrogen production through electrolysis B.3.3
- Hydrogen transport by pipeline B.4.1
- Stationary use of hydrogen (CHP-system) B.5.3

4.15 5a. Gasification of farmed biomass; use: FC vehicle

Ocean bulk carriers transport biomass from wood plantations at various locations in the world over a distance of 8000 km on average. For transport purposes, the wood is chipped in 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 H₂ in a central gasification plant. After gasification, the CO produced is reacted with steam to form CO₂ and H₂ in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO₂ and H₂ using PSA units.

The produced hydrogen is transported to filling stations by a system of high-pressure and medium-pressure hydrogen pipelines. Transport distances in the high and medium-pressure pipelines are 100 and 10 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 British electricity production mix.

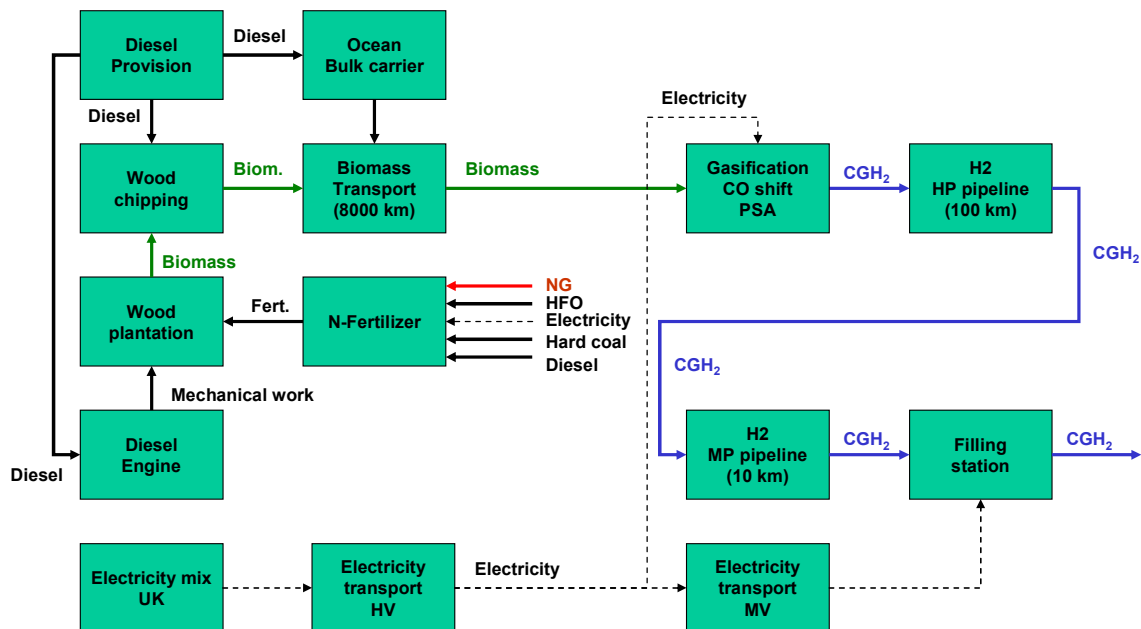


Figure 15. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from central gasification of farmed biomass.

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

- Electricity production B.1.5
- Biomass production B.1.6
- Chipping plant B.1.6
- Electricity transport B.2.4
- Biomass transport B.2.5
- Hydrogen production from biomass B.3.4
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

4.16 5b. Gasification of residual biomass; use: FC vehicle

Diesel-fuelled trucks transport residual biomass to medium-scale de-central gasifiers over a distance of 50 km on average. The biomass considered consists of residues from agricultural activities (straw and similar) and residues of pruned trees. For transport purposes, the biomass is chipped into pieces. The energy needed for chipping is supplied by a diesel-fuelled generator, which drives a mechanical chipping device.

Once in the gasifier, the biomass is converted into a product gas rich in CO and H₂. Subsequently, CO is reacted with steam to form CO₂ and H₂ in a water-gas-shift reactor. Finally, pure hydrogen is produced by separating the ultimate mixture of CO₂ and H₂ using PSA units.

The produced hydrogen is transported to filling stations by a system of medium-pressure hydrogen pipelines. Transport distance in the pipelines is 10 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 British electricity production mix.

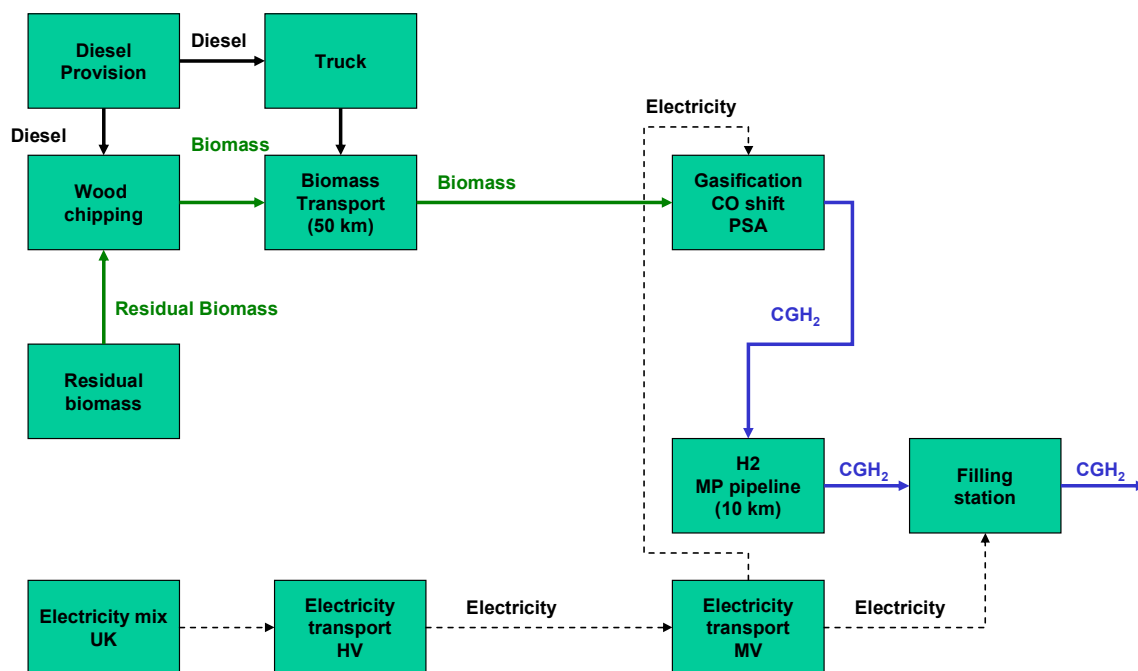


Figure 16. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from a de-central biomass gasifier.

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

- Electricity production B.1.5
- Biomass production B.1.6
- Chipping plant B.1.6
- Electricity transport B.2.4
- Biomass transport B.2.5
- Hydrogen production from biomass B.3.4
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

4.17 6a. Thermo-chemical process using nuclear heat; use: FC vehicle

A nuclear plant drives 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 100 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 British electricity production mix.

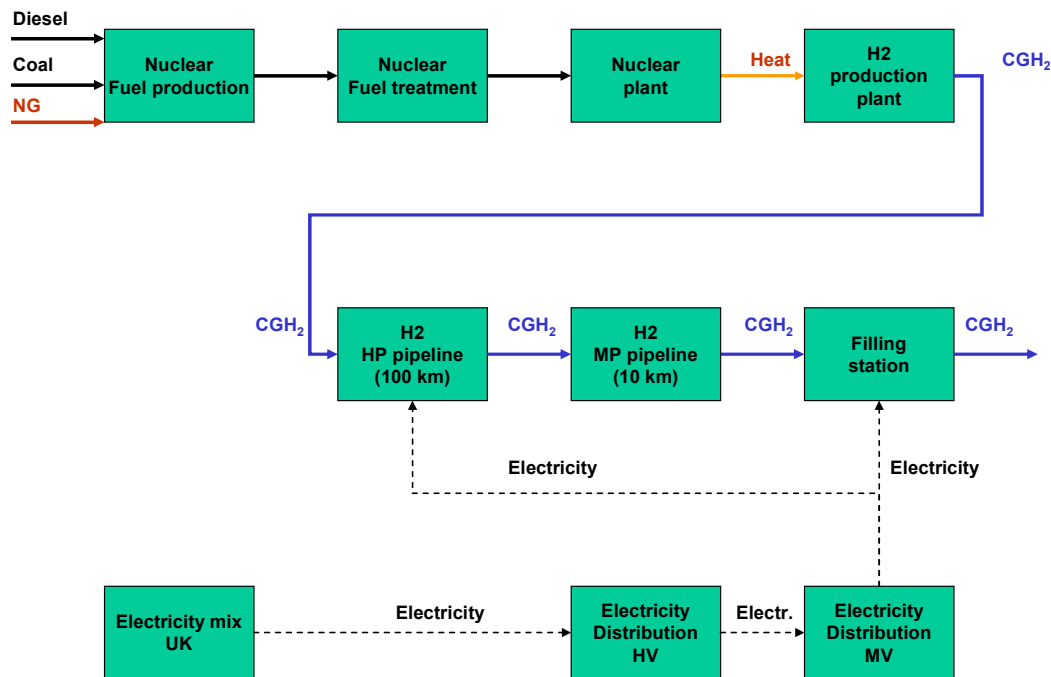


Figure 17. Hydrogen chain model for CGH₂ at a filling station. Hydrogen production from a thermo-chemical process using nuclear heat.

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

- Natural gas extraction and processing B.1.1
- Hard coal extraction B.1.3
- Diesel production B.6.1
- Natural gas transport B.2.1
- Coal transport B.2.2
- Diesel transport B.2.6
- Nuclear fuel treatment and nuclear plant B.1.4
- Hydrogen production from nuclear heat B.3.5
- Hydrogen transport by pipeline B.4.1
- Electricity production (E-mix) B.1.5
- Electricity transport B.2.4
- Filling station B.5.1

4.18 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.

4.19 References for comparison of the stationary hydrogen energy chains

A stationary reference has been defined to compare the hydrogen energy chain for stationary use in the UK. The reference represents a British household that uses a mix of fuels for the production of heat. The electricity required at the household is taken from the British electric grid. The mix of fuels modelled to represent the household, has been derived from specific data (see Annex C) considering all kind of household heat-producing systems used in the UK.

The comparison is based on the consumption of heat and electricity on the ratio 6:1. This ratio reflects the yearly average heat to power demand of a British household.

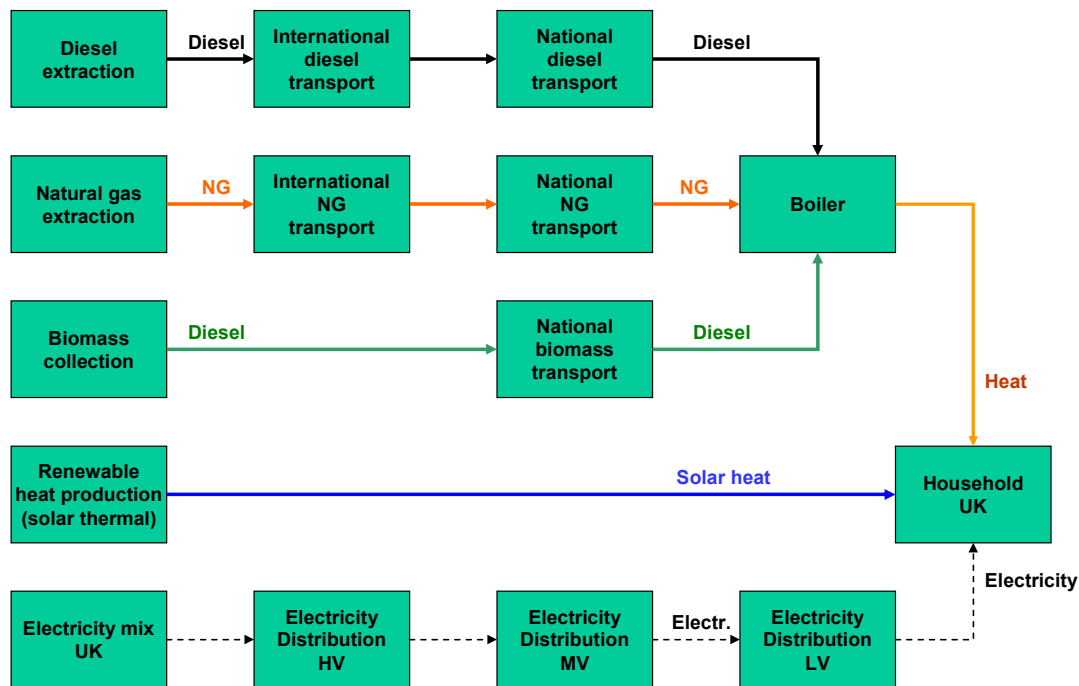


Figure 18. Chain model for stationary use of several fuels, for heat and electricity consumption of UK household.

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

- | | | | |
|-------------------------------------------|-------|-----------------------------------|-------|
| - Natural gas extraction and conditioning | B.1.1 | - Natural gas transport pipelines | B.2.1 |
| - Coal extraction | B.1.3 | - Coal transport | B.2.3 |
| - Diesel production | B.6.1 | - Diesel transport | (*) |
| - Residual biomass production | B.1.6 | - Biomass transport | B.2.5 |
| - Electricity production | B.1.5 | - Electricity transport | B.2.4 |
| - British household (includes boiler) | B.5.3 | | |

(*) Modelled but not presented in the Annex.

5. Results

5.1 Hypothesis required for calculations

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 H₂), or energy service (e.g. a kilometre of transport), supplied by the chain.
- CO₂-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 excluding the end use. Results are presented for the following chains:

- 1a Natural gas, central SMR, CGH2-truck transport; use: car filling station (CGH2)
- 1b Natural gas, on-site SMR; use: car filling station (CGH2)
- 1c Natural gas, central SMR+CCS, Pipeline transport; use: car filling station (CGH2)
- 1d Natural gas from Russia, central SMR+CCS, Pipeline transport; use: car filling station (CGH2)
- 1e Natural gas, central SMR+CCS, LH2-truck transport; use: car filling station (CGH2 and LH2)
- 1f LNG, central SMR+CCS, Pipeline transport; use: car filling station (CGH2)
- 2a Coal, central gasification +CCS, Pipeline transport; use: car filling station (CGH2)
- 2b UK Coal, central gasification +CCS, Pipeline transport; use: car filling station (CGH2)
- 3a Electricity mix, central electrolysis, Pipeline transport; use: car filling station (CGH2)
- 3b Electricity mix, on-site electrolysis; use: car filling station (CGH2)
- 3c Nuclear electricity, central electrolysis, Pipeline transport; use: car filling station (CGH2)
- 4a Offshore wind energy, central electrolysis; use: car filling station (CGH2)
- 4b Onshore wind energy, on-site electrolysis; use: car filling station (CGH2)
- 5a Farmed biomass, central gasification, Pipeline transport; use: car filling station (CGH2)
- 5b Residual wood; de-central gasification, Pipeline transport; use: car filling station (CGH2)
- 6a Nuclear heat, central thermo-plant, 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 hydrogen end-user. The hydrogen energy chains are compared to diesel and to gasoline reference chains, being the end-user 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 Onshore wind energy, central electrolysis; use: CHP-system, Q-following system
- Ref Household energy provision from a mix of fuels

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

5.2 Well-to-Tank analysis (WTT)

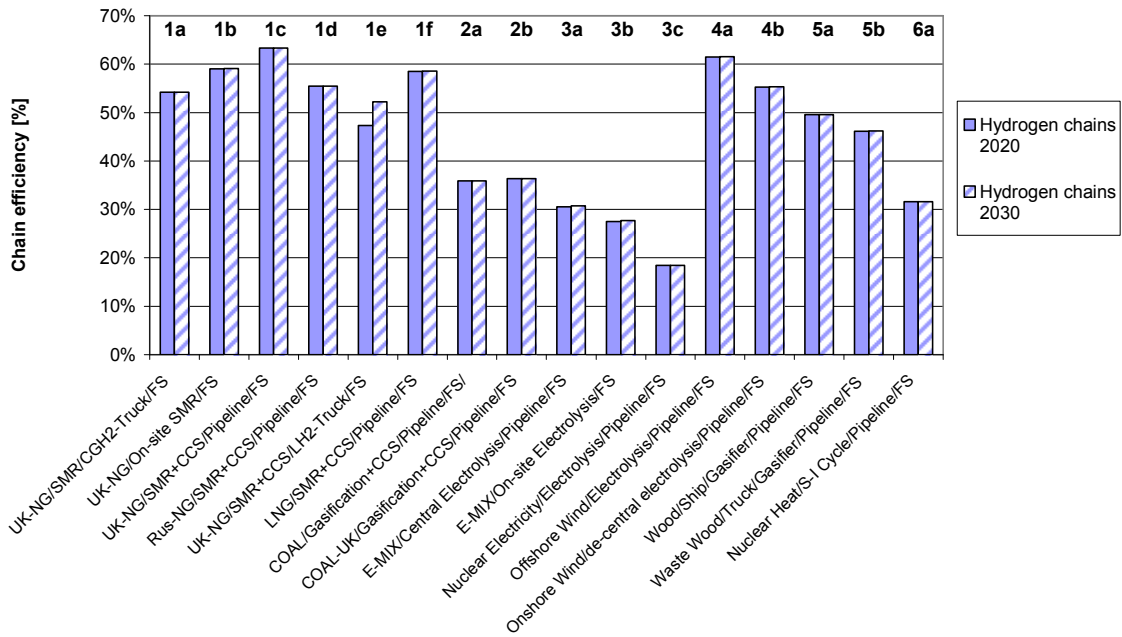


Figure 19. British WTT hydrogen energy chain efficiencies

Figure 19 shows the results on energy efficiency for the hydrogen supply chains. Only chain 1e shows a clear efficiency improvement through the years. The reason of this efficiency increase is the assumed efficiency improvement of the liquefaction process that this chain involves.

Figure 20 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, especially with nuclear energy as feedstock for the production of electricity. The comparison of chains 1c and 1e shows the effect of transporting liquid hydrogen using tanks on trucks, instead of using pipelines.

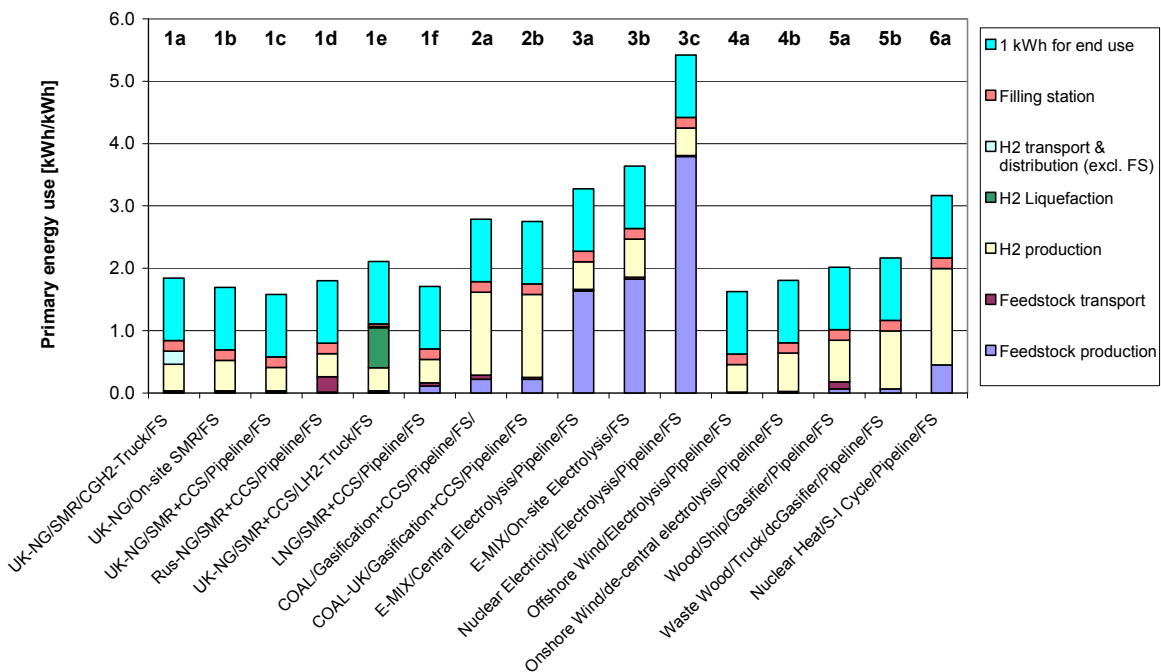


Figure 20. Primary energy use of British WTT hydrogen energy chains

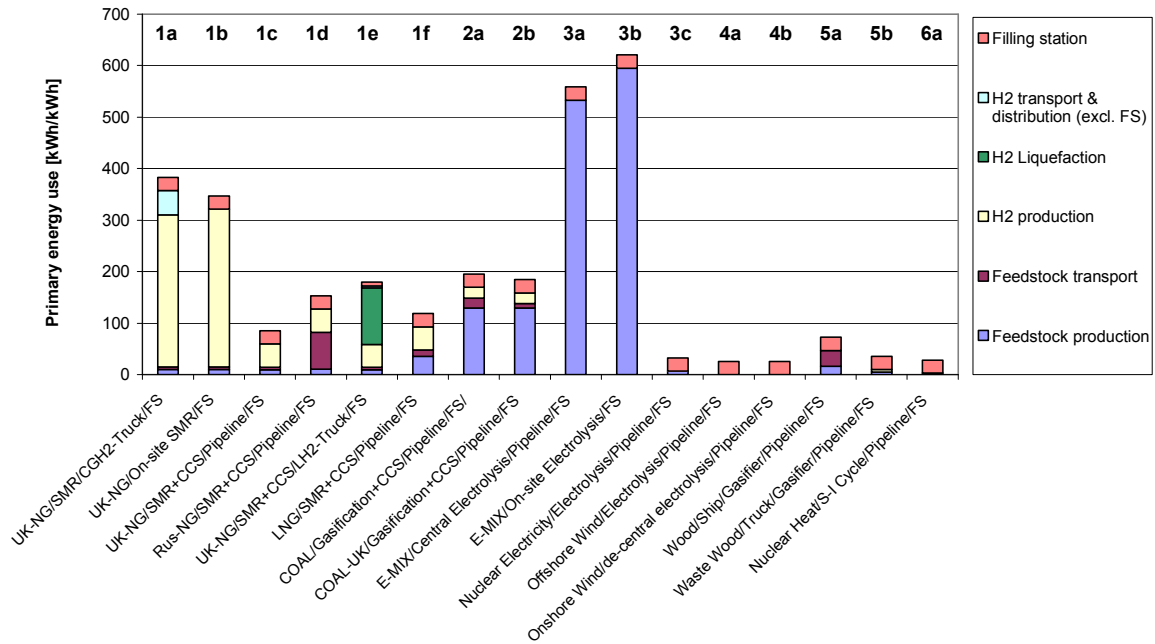


Figure 21. CO₂-equivalent emissions of British WTT hydrogen energy chains

Figure 21 shows the greenhouse gas (GHG) emissions related to the hydrogen supply chains. The hydrogen energy chain using electricity from the British mix has the highest level of GHG-emissions. This is due to the high level of emissions involved in the production of electricity (~360 g/kWh of electricity produced, see B.1.5).

The hydrogen energy chains using nuclear energy (directly or as electricity), wind energy and biomass are, as expected, the chains with the lowest amount of equivalent greenhouse gases per kWh of produced energy.

The GHG emissions of the natural gas based chains 1a and 1b are mainly the result of the absence of carbon capture and storage.

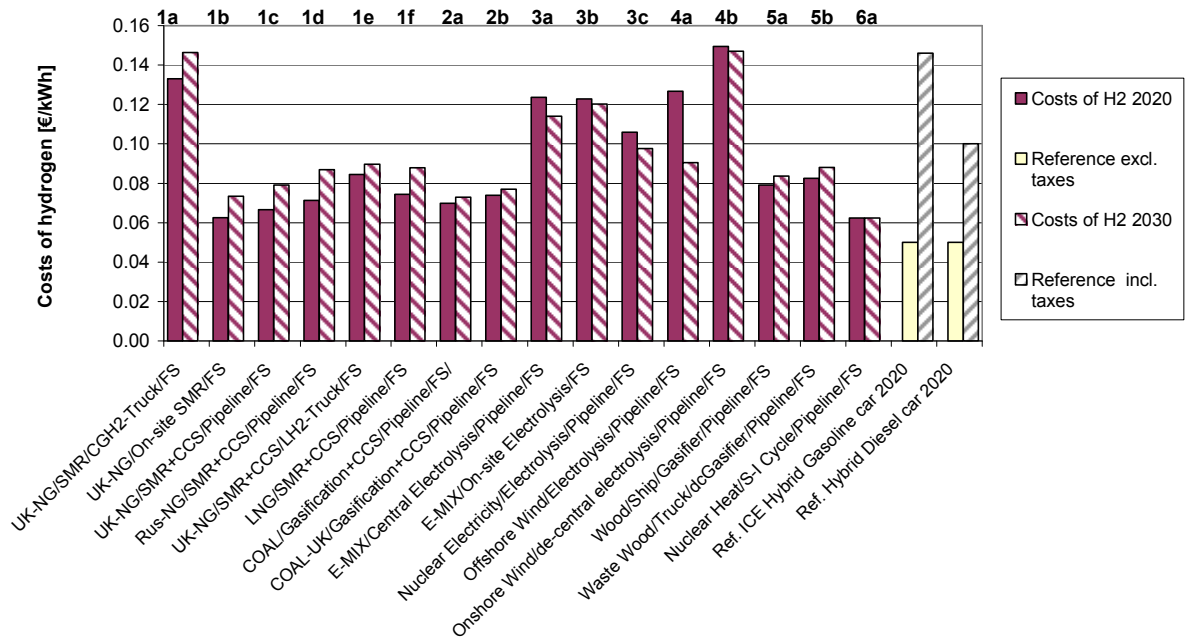


Figure 22. Costs of hydrogen and conventional fuels for British hydrogen energy chains

Figure 22 presents the calculation 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 23, Figure 24 and Figure 25 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.5.2 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 ₂ equiv./km]
CGH ₂ or LH ₂ FC hybrid vehicle	0.2325	0
Gasoline hybrid vehicle	0.4492	120
Diesel hybrid vehicle	0.4044	110

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 23. The WTW primary energy use of the hydrogen chains is comparable with that of the conventional fuel chains, on average. The natural gas-based and the wind energy-based chains show better results than the conventional chains, especially when compared to the gasoline chain.

Coal, electricity and nuclear (electricity)-based chains show higher primary energy consumption than the fossil fuel-based chains. For coal and nuclear heat-based chains is this due to the low efficiency of the hydrogen production processes involved: The production of hydrogen through gasification of coal has an efficiency of ~43% and the production of hydrogen using nuclear heat has an efficiency of ~40%. For the electricity mix-based chains, the electricity production itself coupled to the electrolysis process account for an efficiency of ~29%.

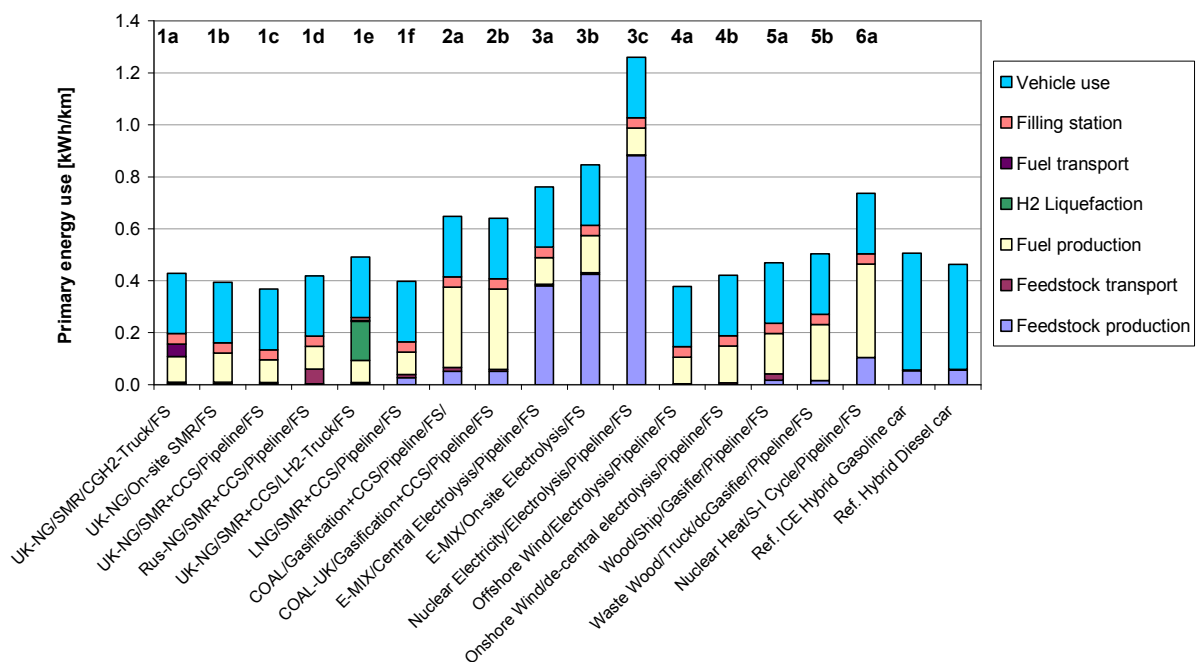


Figure 23. WTW energy use of British hydrogen energy chains, compared to 2010 reference car technologies

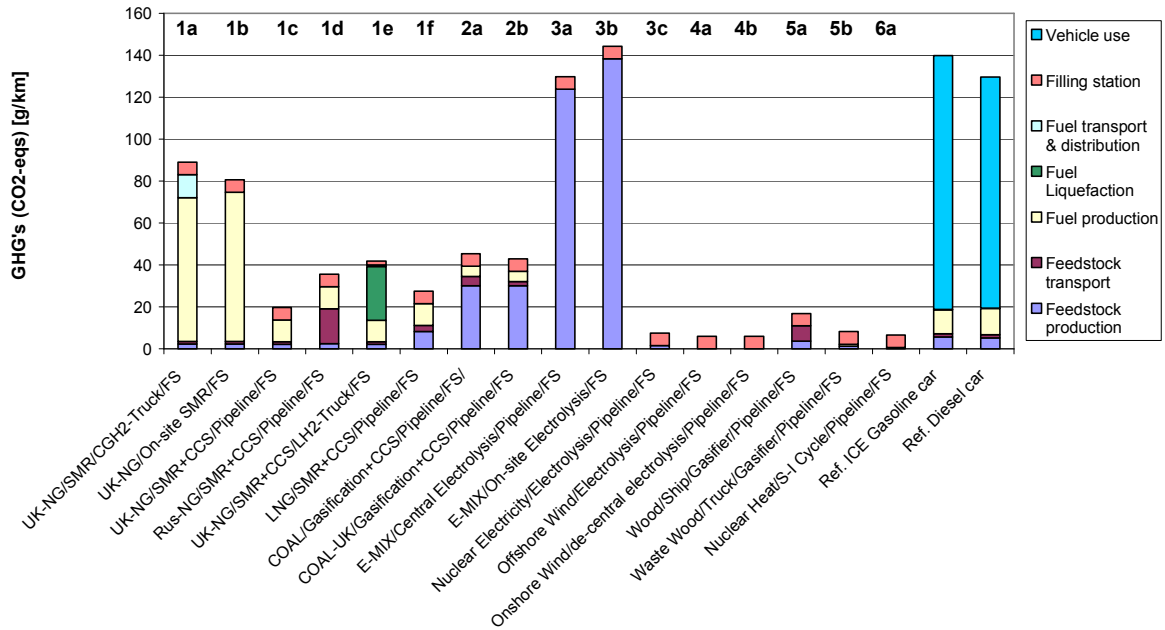


Figure 24. WTW CO₂-equivalent emissions for hybrid passenger cars in 2020

Figure 24 shows that, with exception of the electricity mix-based chains, the GHG emissions for the hydrogen chains are on a much lower level than for the conventional fuel chains. This is also applicable for the hydrogen chains based on the use of natural gas, even in absence of the application of carbon capture and storage (chains 1a and 1b).

Figure 25 shows the results for the WTW fuel cost. If the fossil fuel taxes are taken into account, all hydrogen energy chains are cheaper than the references.

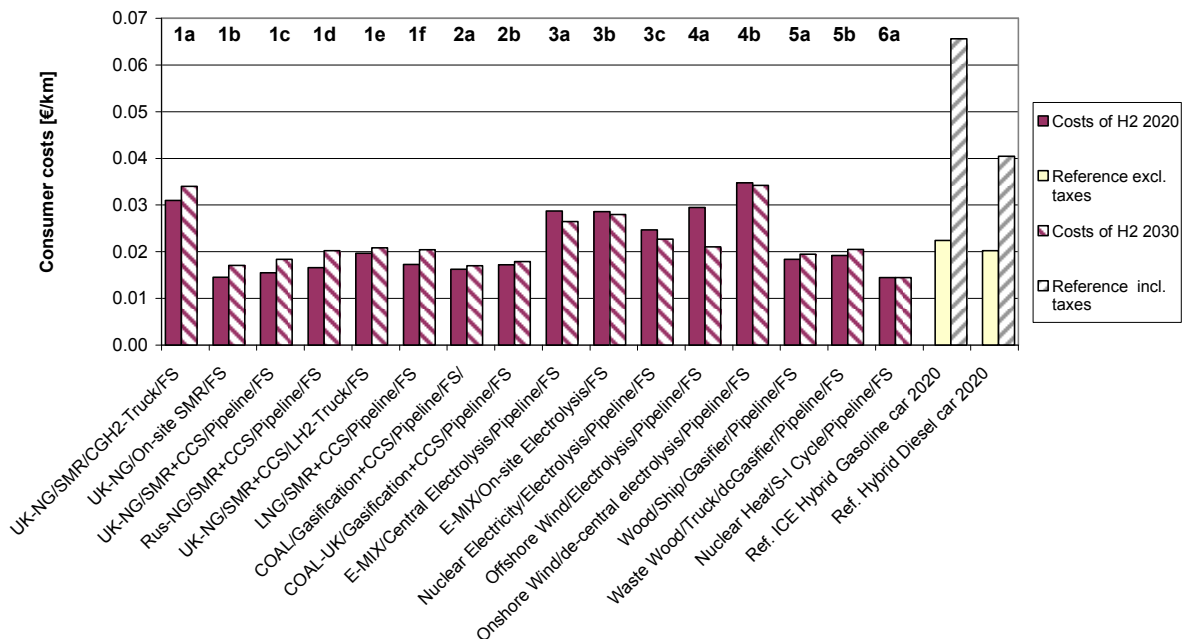


Figure 25. WTW energy costs for hybrid passenger cars in 2020 - 2030

5.4 Well-to-Stationary use analysis (WTStU)

Figure 26, Figure 27, Figure 28 and Figure 29 present the results of the WTStU-analysis performed. Only one hydrogen energy chain was selected for application in domestic appliances: chain 3b.

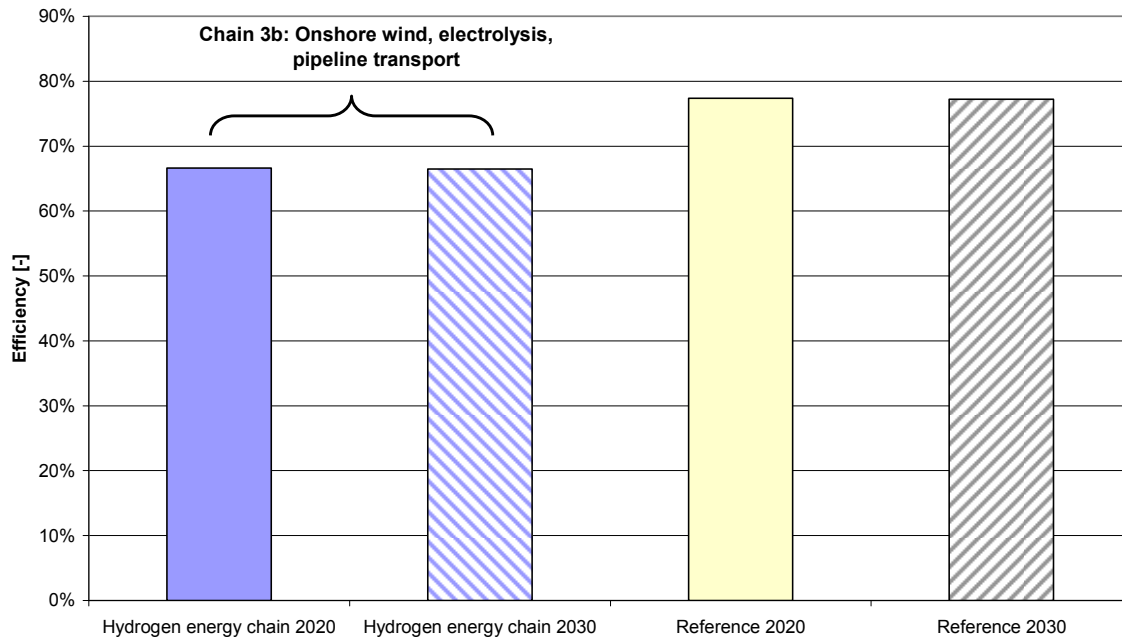


Figure 26. Efficiencies of the British WTStU hydrogen energy chains

The energy service provided by these chains (residential micro-CHP) is 1 kWh of electricity and about 5.6 kWh of heat, equal to the yearly average heat to power ratio of the average energy demand in British households for the year 2020. 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 27, is mainly due to a small fluctuation in the household energy consumption through the years. The efficiency of electricity generation is also expected to increase. See section B.5.3 for details on household energy demand and section B.1.5 for details on electricity generation.

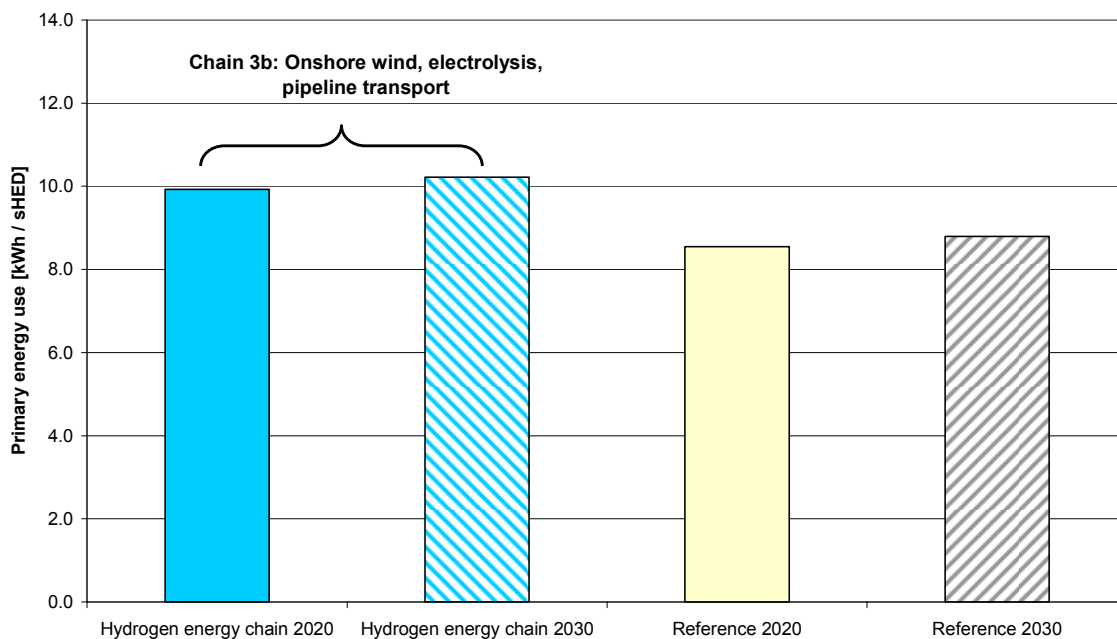


Figure 27. Primary energy use of British WTStU hydrogen energy chains

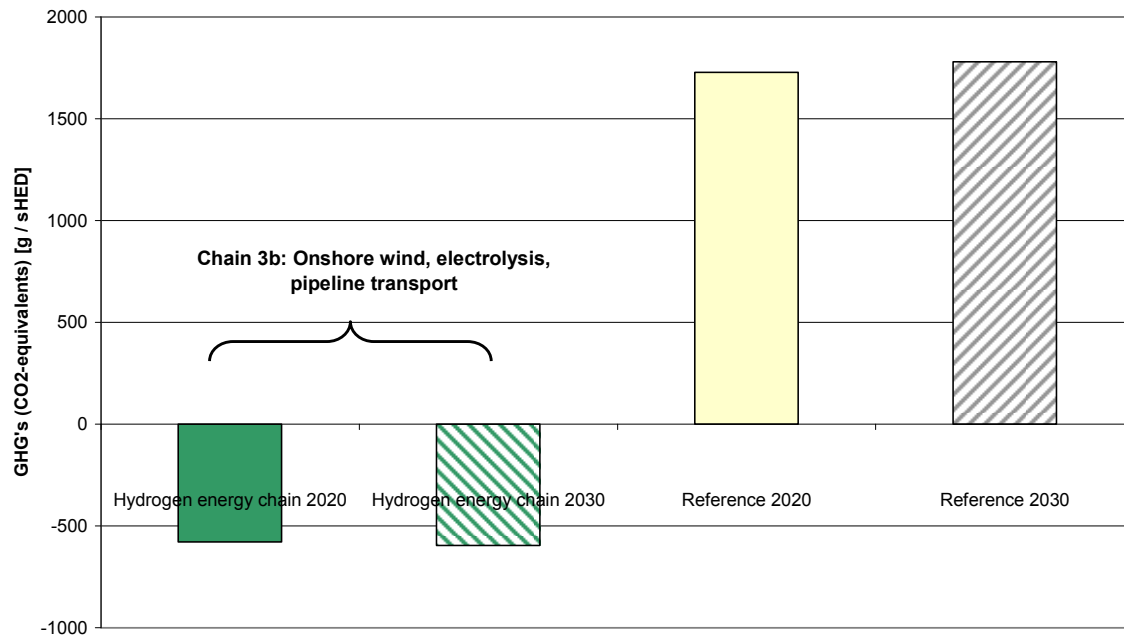


Figure 28. CO₂-equivalent emissions of British WTStU hydrogen energy chains

Figure 28 presents the results for the GHG calculations for the WTStU-analysis including end use of hydrogen. With respect to the reference, the stationary hydrogen chain using wind energy as feedstock, 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, which is delivered back to the grid, avoiding the production of fossil fuel-based electricity elsewhere.

Figure 29 presents the cost of hydrogen (COH) per unit of energy, as defined in this study for an average British 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. The picture may be somewhat different if taxes are included, similar to what it has been presented for the conventional fuels in Figure 25.

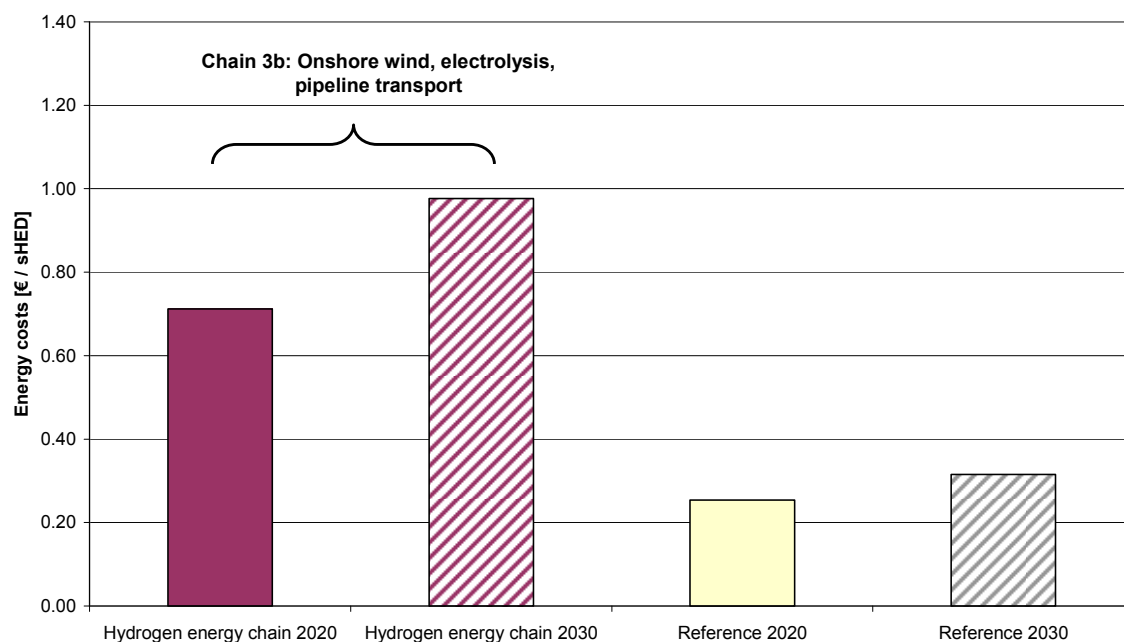


Figure 29. Costs of hydrogen and conventional fuels for British WTStU hydrogen energy chains

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Annex A Calculation rules

A.1 Conversion factors for Greenhouse Gas Equivalents

For the conversion of the different greenhouse gases (GHG) to CO₂-equivalents, the following conversion factors have been used:

Table 5. Conversion factors [IPCC 2001]

Emission	g CO ₂ equivalent per g
CO ₂	1
CH ₄	23
N ₂ 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 th unit
a	=	Investment of the 1 st unit
N	=	Number of units
b	=	Parameter

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

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

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

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

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

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

where A = average investment of one unit. As a result, the average investment is always higher than the investment of the Nth 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 British 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 produced at locations at the North Sea, nearby the international water borders of The UK and Norway. Also, the natural gas can 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 for the process performed in UK waters because the extraction and processing of natural gas is considered to be similar for European countries. For the extraction and conditioning processes performed in Russia, the same data has been used due to lack of specific Russian data.

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 ₄ 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

	I / O	Value	Units
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 ₄ 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 H₂S 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. The European electricity mix is used as input in these cases. For natural gas using processes occurring outside of The UK, but forming a part of a British hydrogen chain, natural gas is assumed obtained from a European mix of natural gas. This natural gas EU-mix has the following characteristics:

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

	I / O	Value	Units
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 ₂ emissions	O	23.7	[g/kWh]
CH ₄ emissions	O	0.7133	[g/kWh]
N ₂ O emissions	O	0.0008	[g/kWh]

B.1.2 Liquefaction of Natural Gas

Instead of being extracted, conditioned and transported by pipelines, natural gas is also produced and transported as liquefied natural gas (LNG). The process described here accounts the required energy for the liquefaction process and the corresponding production costs. The energy required for the liquefaction process is obtained from a part of the natural gas that is being liquefied. Next table shows the data used in the model.

Table 9. Technical and economic data of the used natural gas liquefaction plant

	I / O	Value	Units
Natural gas input	I	1.0693	[kWh/kWh _{LNG}]
LNG	O	1.0	[kWh]
CO ₂ emissions	O	15.7	[g/kWh]
CH ₄ emissions	O	0.010	

	I / O	Value	Units
N2O emissions	O	0.006	
Process scale	-	7,220	[MW _{LNG}]
Investment	-	769	[M€]
Maintenance costs	-	4%	[% investment/yr]
Useful lifetime	-	20	[yr]
Annual full load hours	-	7920	[hr/yr]

B.1.3 Extraction of Coal

The coal used in The UK 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 10, and represent the amount of energy needed to obtain 1 [kWh] of coal ready for use in other processes.

Table 10. Input and output data for production of EU-mix hard coal

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

The GHG emissions of using this coal are set to 55.2 g CO₂/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.1.4 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 (UF₆) is produced. After production, UF₆ 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 British chains, surface mining has been assumed.

Table 11. Input and output data for Uranium surface mining

	I / O	Value	Units
Uranium ore	I	1	[kWh/kWh]

	I / O	Value	Units
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 UF₆ 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 12. Input and output data for UF₆ production

	I / O	Value	Units
Extracted uranium ore	I	1.1111	[kWh/kWh]
Electricity	I	7 x 10 ⁻⁶	[kWh/kWh]
UF ₆	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 UF₆ produced: enrichment by diffusion and enrichment by centrifugation. For the purposes of power generation in The UK, the process of enrichment by centrifugation has been assumed. Cost of enrichment process is harmonised within HyWays.

Table 13. Input and output data for UF₆ enrichment

	I / O	Value	Units
UF ₆	I	1	[kWh/kWh]
Electricity	I	0.00135	[kWh/kWh]
Enriched UF ₆	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 UF₆ requires some electricity and heat as input. For The UK, 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 14. Input and output data for production nuclear fuel

	I / O	Value	Units
Enriched UF ₆	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.1.5 Production of Electricity

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

Electricity mix

The electricity produced in The UK is a mix of energy produced out of typical British 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 British electricity mix varies with time [ref. 4]. In Table 15 the electricity mix shares for The UK (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 The UK has been taken from PRIMES. In Annex B it is explained how the cost of electricity used for the British mix as presented below, matches the values presented in PRIMES.

Table 15. Electricity production mix for The UK and Europe.
Share in percentage according to the used feedstock.

Source	British E-mix 2020 [%]	British E-mix 2030 [%]	MIX EU 15 ⁹ [%]
Biomass	0.7	0.6	0.3
Brown Coal	0	0	7.1
Hard Coal	10.5	10.5	19.9
Electricity (imported)	2.7	2.3	N.A.
Fuel Oil (1.8%S)	0	0	-
Hydro and other renewables	8.1	8.2	4.6 ⁽¹⁰⁾
Geothermal	N.A.	N.A.	0.1
Mineral Oil (diesel)	0.3	0.2	8.7
NG	63.8	65.5	12.3
Nuclear	13.0	12.2	40.5
Waste	0.3	0.4	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 16.

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 16. Electricity. British production mix and British import (EU-mix).

Source	I / O	British E-mix 2020	British E-mix 2030	EU-mix	Units
Biomass	I	0.0213	0.0191	0.0074	[kWh/kWh]
Brown Coal	I	0	0	0.1979	[kWh/kWh]
Hard Coal	I	0.2649	0.2671	0.5570	[kWh/kWh]
Electricity (EU-mix)	I	0.0761	0.0656	-	[kWh/kWh]
Fuel Oil (1.8%S)	I	0.0209	0.0056	-	[kWh/kWh]

⁹ 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.

¹⁰ PRIMES gives the electricity production share from 'renewables'. Into this item wind, solar, hydro and geothermal energy are included.

Source	I / O	British E-mix 2020	British E-mix 2030	EU-mix	Units
Renewables	I	0.0808	0.0821	0.1283	[kWh/kWh]
Geothermal	I	0	0	0.0016	[kWh/kWh]
Mineral Oil	I	0	0	0.2440	[kWh/kWh]
NG	I	1.2157	1.2470	0.3454	[kWh/kWh]
Nuclear	I	0.3947	0.3690	1.1357	[kWh/kWh]
Waste	I	0.0266	0.0315	0.1847	[kWh/kWh]
Electricity	O	1.0	1.0	1.0	[kWh]
CO ₂ emissions	O	352.4	353.8	427.5	[g/kWh]
NO _x emissions	O	1.0253	1.0430	1.0444	[g/kWh]
SO ₂ emissions	O	0.1144	0.1039	1.6032	[g/kWh]
PM emissions	O	0.0256	0.0244	0.2835	[g/kWh]
NMVOC emissions	O	0.0220	0.0222	0.0641	[g/kWh]
CO emissions	O	0.2481	0.2505	0.2617	[g/kWh]
CH ₄ emissions	O	0.0537	0.0500	1.0454	[g/kWh]
N ₂ O emissions	O	0.0160	0.0160	0.0192	[g/kWh]
Equivalent CO ₂ emissions	O	358	360	457.0	[g/kWh]

Because of the national mix, the total input of primary energy is about 2.1 kWh per kWh of produced electricity leading to an electricity generation efficiency of about 48% in the year 2020. Almost identical values are obtained for 2030. The production cost of electricity in The UK has been set on 0.036 €/kWh for both years analysed, 2020 and 2030. See also Annex B.

Electricity from nuclear power

A nuclear plant produces electricity out of nuclear fuel. For the hydrogen energy chains of The UK, 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 17. 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 and onshore wind energy

An offshore wind energy plant typically consists of a number of single wind turbines. The cost data for the wind turbines has been derived from an Enercon wind turbine, model E-66 / 20.70 located onshore or offshore at 30 metres water depth, data from the year 2004. The investment presented in Table 18 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 18. Technical and economic data of the offshore and onshore wind turbines

Wind Energy, yr 2020	Offshore	Onshore	Units
Capacity	4.5	2.0	[MW]
Investment 2020	5,400,000	1,501,062	[€]
Investment 2030	3,622,500	1,501,062	[€]
Maintenance costs	4	1.5	[% of investment]
Overhead costs	-	3.5	[% of investment]
Useful lifetime	25	25	[yr]
Equivalent full load period	3000	2500	[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.1.6 Production of Biomass

Biomass may be obtained from residual or farmed wood. For The UK 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 The UK 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.

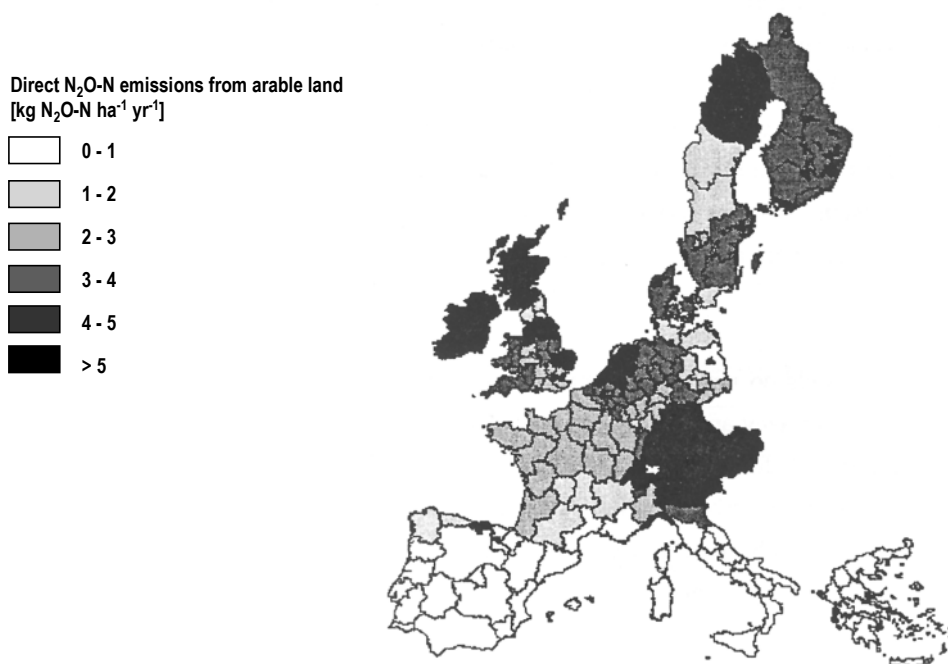
Farmed Wood

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 N₂O emissions from the production of synthetic nitrogen (N) fertilizer, the plantation of crops causes direct N₂O 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 N₂O: 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 N₂O 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 N₂O 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 N₂O formation. On the other hand, N₂O formed within the soil can also be reduced to N₂ when diffusion is slow due to high water content in fine textured soils. Fine-textured soils seem to emit more N₂O than sandy soils, but this tendency can be masked or reversed by other factors, especially climate and soil management practices.

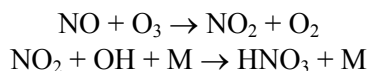
Other factors that influence the N₂O emissions from soils are freezing and thawing, drying and rewetting [Kamp 2000].



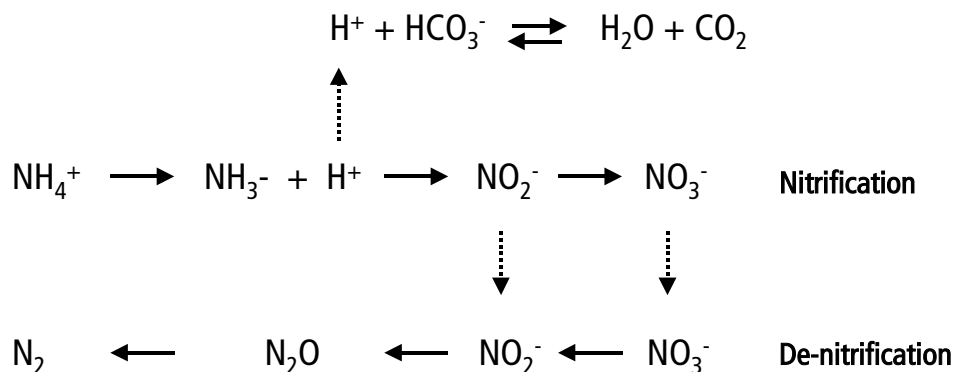
Source: Freibauer, A., Kaltschmitt, Institut für rationelle Energieanwendungen (IER), Stuttgart: Biogenic Greenhouse Gas Emissions from Agriculture in Europe, European Summary Report of the EU Concerted Action FAIR3-CT96-1877, financed by EU DG VI, February 2001

Figure 30. Direct N₂O emissions from arable land

The direct emissions of N₂O are only one part of the total emissions of N₂O from agricultural land. Indirectly emitted N₂O is also considered here. Part of the fertilizer-N is emitted as NH₃ and NO_x and is leached e.g. as NO₃⁻, which is subsequently deposited on soils and surface waters. Atmospheric deposition of nitrogen compounds such as NO_x and NH₃ fertilizes soils and surface waters and as such enhances the biogenic N₂O formation. In soils and waters, bacteria oxidize the NH₄⁺ (which is formed from the NH₃ in the soil) to nitrate (NO₃⁻) (nitrification) while some amounts of N₂O are formed. The NO_x (consisting of NO and NO₂) emitted from soils is converted to HNO₃ in the atmosphere according to the following reactions:



The HNO₃ is then deposited on soil and surface waters by rainfall (“acid rain”). In soils and water, the HNO₃ is dissolved into H⁺ and NO₃⁻. Then the NO₃⁻, which is also formed by the nitrification of NH₄⁺ is partly reduced to N₂O (de-nitrification). The conversion in the soil occurs in several stages according to the following reactions:



The same reactions occur with NO_x emitted by fuel combustion e.g. in truck engines. This source of N₂O is neglected here for the fuel supply processes such as the transport of wood chips. Here only the NO_x from fertilizer use is considered.

In contrast to the direct N₂O 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 N₂O (from N leaching and N from NH₃ and NO_x emitted). There are no emissions of NO_x and NH₃ 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 N₂O-emissions have been derived from [Flesse 1998] and the indirect N₂O-emissions have been calculated according to the guidelines described in [IPCC 1/1996].

Table 19. 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 ₂ 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.6.3). 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 (millimetre size). Therefore, a chipping process running on diesel fuel is required. The characteristics of this process are:

Table 20. 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]
Biomass chips	O	1.0	1.0	[kWh]
Process scale	-	1	1	[kWh/h]
CO ₂ emissions	O	1.056	0.790	[g/kWh]
NO _x emissions	O	0.047	0.035	[g/kWh]
CO emissions	O	0.010	0.008	[g/kWh]
CH ₄ emissions	O	0.00015	0.00010	[g/kWh]
N ₂ 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.

Residual Biomass

Under residual biomass it is understood residues from agricultural activities (straw and similar semi-dry woody biomass) and residues from pruned trees like those obtained from maintenance of parks. Because this biomass is considered as a residue, it has no price and there is no energy involved in its production. Energy use and biomass related costs of chains using residual biomass are accounted in the transport of biomass and in the chipping process required to obtain biomass in small pieces respectively.

B.2 Transport of Feedstock's

B.2.1 Natural Gas transport

Two sources have been considered for the origin of the natural gas used in the UK hydrogen energy chains. In the first place, natural gas is considered obtained from the gas fields existent under the North Sea, nearby the international water borders with Norway. To evaluate possible hydrogen energy chains based on reforming of natural gas in the future, also natural gas produced in Russia has been considered. The distance from the extraction (and processing) point under the North Sea up to the British land borders is estimated in 500 km. In the case that the natural gas is produced in Russia, the distance from the extraction (and processing) point up to the British land borders is estimated in 8000 km.

From the British land borders, the natural gas is distributed via a regional and a local NG pipeline grid under different pressures to hydrogen production plants. The distance considered for high-pressure natural gas transport on land is estimated in 400 km as a mean value in all cases. 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 \approx 60 bar) and low-pressure (MP \approx 40 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 21. Input and output data for NG transport through pipelines

			8000 km HP	500 km HP	400 km HP	100 km HP	50 km MP
	I / O	Units	Value				
Mechanical work	I	[kWh/kWh]	0.048	0.003	0.002	<0.001	0
NG (including losses)	I	[kWh/kWh]	1.0104	<1.0001	<1.0001	\sim 0	\sim 0
NG (delivered)	O	[kWh/kWh]	1.0	1.0	1.0	1.0	1.0
Process scale	-	[kW NG]	1E+7	1E+7	1E+7	1E+6	1E+6
CH ₄ emissions	O	[g/kWh]	0.749	0.0022	0.0017	<0.001	<0.001
Useful lifetime	-	[yr]	20	20	20	20	20
Annual full load hours	-	[h/yr]	8000	8000	8000	8000	8000

B.2.2 Transport of Liquefied Natural Gas

Liquefied natural gas is transported in large ocean diesel-fuelled LNG carriers from the Middle East, over an approximate distance of 8000 km. The process scale for LNG transport is 911,600 [kWh/h].

Characteristics of the LNG transport are presented in Table 22, expressed in t*km (1 ton being transported 1 km). The efficiencies and emissions of the transport process and the characteristics of the ship used for transport are assumed not to change with time.

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

	I / O	Value	Units
Diesel consumption of ship	I	0.0225	[kWh/t*km]
Investment	-	50,000,000	[€]
Process scale	-	362,000	[t*km/h]
Labour costs	-	100,000	[€/yr]
Maintenance costs	-	250,000	[€/yr]
Useful lifetime	-	30	[yr]
Annual full load hours	-	8760	[hr/yr]
CO ₂ emissions	O	6.3	[g/t*km]
NO _x emissions	O	0.100	[g/t*km]
CO emissions	O	0.016	[g/t*km]
CH ₄ emissions	O	$3 \cdot 10^{-4}$	[g/t*km]
SO ₂ emissions	O	$3 \cdot 10^{-5}$	[g/t*km]

B.2.3 Coal transport

The coal considered in the British chains is in principle extracted all around the world. The coal is assumed transported by ship from the production region to The UK by an ocean bulk carrier, travelling distance being approximately 8000 km. A coal gasification plant is assumed located at the British coast, so there is no need to transport the coal further by other means.

Characteristics of the coal transport by ship are similar to the transport of LNG, only the process scale is different, being 605,750 [kWh/h]. The ship investment, maintenance and labour costs are the same than for the ship used for LNG transport, so Table 22 applies.

As an alternative, the use of UK coal (re-opening of old mines) has been considered too as feedstock for the production of hydrogen through gasification. In this case, the coal is transported by diesel-fuelled trucks, travelling approximately 300 km from the extraction point to the central coal gasifier.

Characteristics of the coal transport by truck are presented in the next table, expressed in t*km (1 ton coal being transported 1 km). The scale of the process is 4,200 [kWh/h]. The efficiencies and emissions of the transport process and the characteristics of the truck used for transport are assumed not to change with time.

Table 23. Economic data of the truck used for coal transport

	I / O	Value	Units
Investment	-	160,000	[€]
Diesel consumption of truck	I	0.26	[kWh/t*km]
Labour costs	-	125,000	[€/yr]
Maintenance costs	-	19,200	[€/yr]
Process scale	-	193	[t*km/h]
Useful lifetime	-	8	[yr]
Annual full load hours	-	8760	[hr/yr]
CO ₂ emissions	O	68.6	[g/t*km]
NO _x emissions	O	0.34	[g/t*km]
CO emissions	O	0.15	[g/t*km]
CH ₄ emissions	O	5* 10 ⁻³	[g/t*km]
SO ₂ emissions	O	4* 10 ⁻⁴	[g/t*km]

B.2.4 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 24. Input and output data for High-voltage transport of electricity (GEMIS 4.1)

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

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

	I / O	Value	Units
Electricity	I	1.0070	[kWh/kWh]
Electricity	O	1.0000	[kWh]
Process scale	-	1,300	[kWe]
Useful lifetime	-	50	[yr]
Annual full load hours	-	5,000	[h/yr]
Transport costs	-	0.02	[€/kWh]

Table 26. Input and output data for Low-voltage transport of electricity (GEMIS 4.1)

	I / O	Value	Units
Electricity	I	1.0120	[kWh/kWh]
Electricity	O	1.0000	[kWh]
Process scale	-	100	[kWe]
Useful lifetime	-	50	[yr]
Annual full load hours	-	5,000	[h/yr]
Transport costs (2020)	-	0.028	[€/kWh]
Transport costs (2030)	-	0.029	[€/kWh]

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

B.2.5 Biomass transport

The biomass used in the British chains is farmed and residual wood. For transport purposes, the biomass is chipped into small pieces. In the case of farmed wood, wood chips are transported by ship over a distance of 8000 km on average to the gasification plant. In the case of residual biomass (straw, pruned trees), the transport to the gasification plant occurs by truck over a distance of 50 km (British biomass).

The ship used for biomass transport is the same as used for the transport of coal, only the process scale for the biomass transport over 8000 km by ship differs, being 133,560 [kWh/h]. The characteristics of the ship as defined before in Table 22 apply.

Similarly, the truck used for biomass transport is the same as used for the transport of coal, so the characteristics of the truck as defined before in Table 23 apply. Only the process scale is different, having a value of 3100 [kWh/h].

B.2.6 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 ship are already given in Table 22 (LNG transport). Train characteristics are given in the next table:

Table 27. Technical data of the train used for diesel and HFO transport

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

B.3 Hydrogen Production

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

B.3.1 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 CO₂ capture and storage (CCS). In Table 28 technical and economic data of the SMR plants used in the models is given.

Table 28. Technical and economic data of the used SMR plant

	I / O	Central SMR no CCS	Central SMR with CCS	On-site SMR	Units
Inlet pressure	-	4.0	3.4	1.6	[MPa]
Discharge pressure H ₂	-	3.0	6.1	1.7	[MPa]
Process scale	-	300,000	844,000	667	[kW H ₂]
NG consumption	I	1.4167	1.365	1.4406	[kWh/kWh _{H2}]
GH ₂ output	O	1.0	1.0	1.0	[kWh]
Electricity output ¹¹	O	0.05	0	0	[kWh/kWh _{H2}]
CO ₂ emissions	O	288	42.7	292.3	[g/kWh _{H2}]
CH ₄ emissions	O	0.0573	0.0573	0.0750	[g/kWh _{H2}]
NO _x emissions	O	0.0821	0.0821	0.0540	[g/kWh _{H2}]
CO emissions	O	0.0792	0.0792	0.1050	[g/kWh _{H2}]
Investment 2020 (scaled-up)	-	77.7	453	0.38	[M€]
Investment 2030 (scaled-up)	-	N/A	N/A	0.34	[M€]
Maintenance coefficient	-	3.0	2.7	1.0	[% of Investment]
Labour costs	-	600,000	546,400	N/A	[€/yr]
Useful lifetime	-	20	25	15	[yr]
Equivalent full load period	-	8000	7884	6000	[h/yr]

N/A: Data not available

Due to lack of data, the investment cost of the central SMR plants 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 the SMR plants is assumed to remain constant within the period 2020-2030.

¹¹ 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.

B.3.2 Production of Hydrogen from Coal

With coal as feedstock, the hydrogen is produced via large-scale gasification. For The UK, CO₂ capture and sequestration is included as an option.

Table 29. Technical and economic data of hydrogen generation via coal gasification without CO₂ capture and storage

	I / O	Value	Units
Process scale	-	844,866	[kW H ₂]
Hard coal consumption	I	2.303	[kWh/kWhH ₂]
GH ₂ output	O	1.0	[kWh]
Pressure (output)	-	N/A ¹²	[bar]
CO ₂ emissions	O	20.3	[g/kWhH ₂]
Investment (2020)	-	1168	[M€]
Maintenance coefficient	-	3.6	[% of investment]
Labour	-	1	[M€/yr]
Overhead	-	0.07	[% 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.3.3 Production of Hydrogen from Electricity

Hydrogen energy chains involving electricity as feedstock are all chains where the British 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 Nm³/h electrolyser units. If the total hydrogen generation capacity of the central electrolysis plant were 100,000 Nm³/h the number of 800 Nm³/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 30 have different capacities according to a central or de-central (on-site) application.

Table 30. Technical and economic data for electrolysis

	I / O	Central Electrolyser	On-site Electrolyser	Units
Process scale	-	2400	360	[kW H ₂]
Electricity consumption	I	1.433	1.6	[kWh / kWhH ₂]
GH ₂ 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]

¹² Output pressure of coal gasifier not available. Based on similar known processes, it was assumed that the output pressure equals 30 bar.

B.3.4 Production of Hydrogen from Biomass

Only small-scale gasification plants are accounted to produce hydrogen from biomass in The UK. 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 31. Technical and economic data of hydrogen generation via biomass gasification

	I / O	Central gasification	De-central gasification	Units
Process scale	-	254,800	5,250	[kW H ₂]
Biomass consumption	I	1.4625	1.9108	[kWh/kWh]
GH ₂ output	O	1.0	1.0	[kWh]
Pressure (output)	-	75 ¹³	20	[bar]
Heat production ¹⁴	O	0	0.3039	[kWh/kWh]
Investment	-	153	6.4	[M€]
Labour costs	-	1.2	0.18	[M€/yr]
Maintenance costs	-	6.0	0.33	[M€/yr]
Useful lifetime	-	25	20	[yr]
Equivalent full load period	-	7887	7500	[h/yr]
CO ₂ emissions	O	0	0	[g/kWh]
NO _x emissions	O	N/A	0.6208	[g/kWh]
SO ₂ emissions	O	0	0.0203	[g/kWh]
CO emissions	O	N/A	0.2717	[g/kWh]
CH ₄ emissions	O	0	0.0407	[g/kWh]
N ₂ O emissions	O	0	0.0121	[g/kWh]

N/A = Not available

B.3.5 Production of Hydrogen from Nuclear Heat

The production of hydrogen using nuclear energy is based on the Sulphur-Iodine cycle. The process consists of thermo-chemical water-splitting, a chemical process that accomplishes the decomposition of water into hydrogen and oxygen. The 'feedstock' for the process is heat, obtained from the utilization of nuclear fuel. The techno-economic data of this process is given in the next table.

Table 32. Technical and economic data of the used Sulphur-Iodine plant for the production of hydrogen

	I / O	Value	Units
Nuclear fuel	I	2.515	[kWh/kWh H ₂]
Gaseous hydrogen	O	1.0	[kWh]
Process scale	-	954,315	[kWh H ₂]
Investment 2020	-	1969	[M€]
Maintenance costs	-	5%	[% of investment/yr]
Useful lifetime	-	25	[yr]
Construction time	-	3	[yr]
Annual full-load hours	-	8000	[hr/yr]

B.3.6 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 LH₂ produced

¹³ Pressure after PSA = 11 bar. An electric compressor, part of the installation, increases the pressure of the hydrogen output up to 75 bar.

¹⁴ 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.

(LHV). This assumption corresponds to large hydrogen liquefaction plants in the near future, as presented in the CONCAWE/JRC/EUCAR study. The investment, maintenance and labour costs have been derived from [NHEG 1992] via up-scaling. The technical and economic data of liquefier plant are given in Table 33.

Table 33. Technical and economic data of large-scale H₂ liquefaction plant

	I / O	Liquefaction plant (2020)	Liquefaction plant (2030)	Units
Plant capacity	-	300,000	300,000	[kWh/h]
GH ₂ consumption	I	1.0	1.0	[kWh/kWh _{LH2}]
Electricity consumption	I	0.30	0.21	[kWh/kWh _{LH2}]
Inlet pressure	-	30	30	[bar]
LH ₂ 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.3.7 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

	I / O	Compression plant	Units
Installation capacity	-	300	[kWh/h]
GH ₂ consumption	I	1.0	[kWh/kWh]
Electricity consumption	I	0.046	[kWh/kWh]
CGH ₂ production	O	1.0	[kWh]
Investment	-	90,000	[€]
Maintenance	-	10	[% of investment]
Equivalent full load period	-	2980	[h/yr]
Useful lifetime	-	20	[yr]

B.4 Transport of Hydrogen

B.4.1 Transport of Compressed Hydrogen Gas (CGH₂) by pipeline

The supply of CGH₂ 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 H₂ per year per pipeline and some smaller pipelines (10 km) with a throughput of 8 GWh H₂ per year per pipeline (Figure 31). 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 CGH₂ pipelines is given in Table 35.

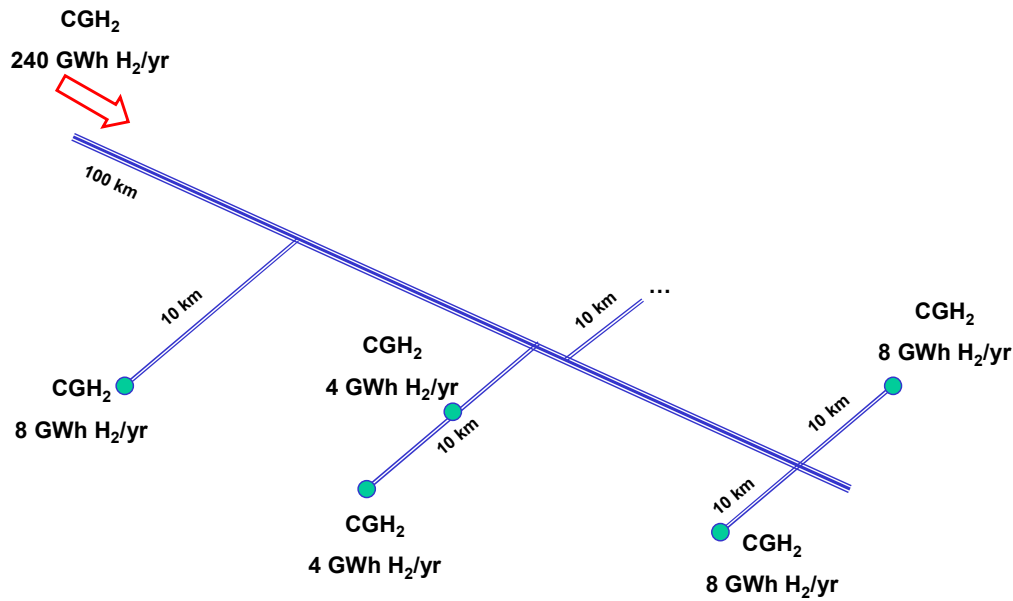


Figure 31. Example of pipeline grid for hydrogen transport

Table 35. Technical and economic data of CGH₂ pipelines

	10 km	100 km	Units
Annual hydrogen throughput	8	240	[GWh H ₂ /yr]
Diameter	100	150	[mm]
Wall thickness	7.1	7.1	[mm]
Required electricity	0	0	[kWh/kWh]
Investment	1.79	17.9	[M€]
Labour, maintenance etc.	42,000	422,000	[€/yr]
Annual full load	8000	8000	[hr]
Useful lifetime	30	30	[yr]

B.4.2 Transport of Compressed Hydrogen Gas (CGH₂) by truck

Compressed hydrogen gas is transported using the same type of truck defined before for transport of biomass. Therefore, Table 23 applies. The difference with biomass transport is the process scale involved, because the same truck can transport only 350 kg of CGH₂ in a one-way trip. The Process scale for the CGH₂ transport process over 100 km by truck is 710 [kWh/h]. A transport efficiency of 100% is accounted (no leakage).

B.4.3 Transport of Liquefied Hydrogen (LH₂) by truck

Similarly to the transport of CGH₂, liquefied hydrogen is transported using the same truck defined before. Therefore, Table 23 applies and the process scale for the LH₂ transport process over 100 km by truck is 5474 [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 LH₂ consumption equals 1.005 kWh for each kWh of LH₂ being transported.

B.5 Hydrogen Usage

B.5.1 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 CGH₂ filling stations

Filling station size	120 t/yr	480 t/yr	1200 t/yr	Units
Annual fuel output	457	1826	4566	[kWh H ₂ /h]
Hydrogen input ¹⁵	1.02	1.02	1.02	[kWh/kWh]
Electricity consumption	0.0704	0.0704	0.0704	[kWh/kWh _{H2}]
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 (CGH₂). For a LH₂ car, a dedicated station is necessary.

Table 37. Technical and economic data for the combined LH₂/CGH₂ filling station

Filling station size	1200 t/yr	Units
Annual fuel output	4566	[kWh H ₂ /h]
Hydrogen input	1.02	[kWh/kWh]
Electricity consumption	0.0212	[kWh/kWh _{H2}]
Investment (2020)	1,563,830	[€]
Investment (2030)	529,551	[€]
Maintenance costs	2.0	[% of investment]
Useful lifetime	20	[yr]
Full load hours	8760	[hr]

¹⁵ A value of 1.02 [kWh/kWh] corresponds to an efficiency of approximately 98%.

B.5.2 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

	Fuel consumption [kWh/km]	GHG emissions [g CO₂ equiv./km]
CGH ₂ FC car	0.2611	0.0
CGH ₂ FC car hybrid	0.2325	0.0
CGH ₂ ICE car	0.4653	0.5
CGH ₂ ICE car hybrid	0.4125	0.5
LH ₂ FC car	0.2611	0.0
LH ₂ FC car hybrid	0.2325	0.0
LH ₂ ICE car	0.4653	0.5
LH ₂ ICE car hybrid	0.3928	0.5

Table 39. Passenger reference cars data

	Fuel consumption [kWh/km]	GHG emissions [g CO₂ equiv./km]
PISI Gasoline hybrid 1.6 l	0.4492	119.6
DICI Diesel hybrid with DPF	0.4044	108.4

B.5.3 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 British statistics, data available at PRIMES for The UK and data provided by VTT, a electricity and heat consumption pattern was set for a 'typical' British household. Next table presents the energy use assumptions modelled for the stationary hydrogen use chains.

Table 40. Yearly household energy consumption

Household consumption	Units	Year 2005	Year 2020	Year 2030
Space heating	[kWh/yr]	13,366	13,938	14,242
Warm water	[kWh/yr]	5,162	4,851	4,813
Electricity	[kWh/yr]	3,500	3,365	3,308

Next figure gives an example of a heat-demand following system based on the energy demand of a British household for the year 2020. The values within the dotted box follow from ECN internal computations for a Q-following CHP-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 unit is higher than the demand, then a net export of electricity occurs.

The FC of the example above is designed to cover 45% of the heat demand, leaving the other 55% of the heat demand to be covered by the H₂-burner. The electricity generation of the FC does not cover the demand at the moment the user requires, reaching 82% coverage as a mean value. The electricity mix covers the other 18% electricity demand.

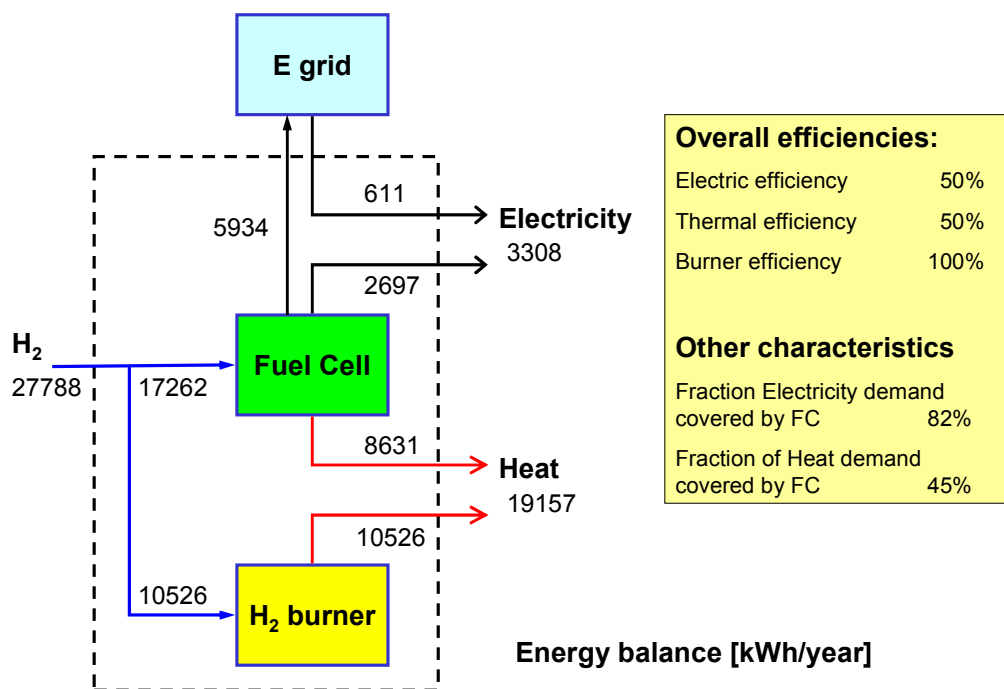


Figure 32. Supply of electricity and heat for a British household (2020), Q-following system.

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.

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 H₂ 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 British household, 100% boiler efficiency

	Input/Output	year 2020	year 2030	Units
GH ₂	I	8.1837	8.4009	[kWh/kWh]
Electricity from grid	I	0.1887	0.1847	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	5.6142	5.7916	[kWh/kWh]
Electricity to grid	O	1.7581	1.7940	[kWh/kWh]
Process scale	-	5	5	[kWh/h]
Electric efficiency (CHP)	-	50	50	[%]
Thermal efficiency (CHP)	-	50	50	[%]
FC burner efficiency	-	100	100	[%]
Equivalent full load period	-	8760	8760	[h/yr]
Useful lifetime	-	20	20	[yr]

A reference household was modelled for stationary hydrogen use comparison. The reference involves household heat provision by boilers based on a mix of fuels, providing both the space heating and the warm water demand of the users. The fuel mix used in the analysis has been derived from PRIMES [4].

Table 42. Fuel mix used for heat demand (heating and warm water) used in the model of a 'typical' British household

Feedstock	Percentage of mix Year 2020	Percentage of mix Year 2030
Solid fuels	0.12%	0.06%
Liquid fuels	7.13%	6.57%
Gas fuels	91.33%	93.18%
Biomass	1.14%	1.07%
Solar heat	0.27%	0.30%

Based on the energy demand as presented in Table 40 and the fuel mix distribution shown in Table 42, it is possible to derive the net energy input of each specific fuel for provision of the required energy.

Table 43. Net energy demand ratio (heat/electricity) of a British household using a mix of fuels for heating and electricity from the grid for electric appliances

	Input /Output [-]	year 2020 [kWh/kWh]	year 2030 [kWh/kWh]	Specific CO ₂ -emissions [g/kWh]
Solid fuels (coal)	I	0.0067	0.0036	372
Liquid fuels (oil)	I	0.4005	0.3805	260
Natural gas	I	5.1276	5.3966	197
Biomass	I	0.0642	0.0620	0
Renewable electricity	I	0.0153	0.0176	0
<i>Subtotal net heat demand</i>	-	<i>5.6142</i>	<i>5.7916</i>	
Electricity from grid	I	1.0	1.0	0 ¹⁶

Finally, to obtain the gross energy demand of the modelled British household for each fuel, burning efficiencies for boilers must be assumed. In the next table the efficiencies, the gross energy and the related CO₂ emissions for each of the mentioned fuels are given.

Table 44. Gross energy demand ratio (heat/electricity) of a British household using a mix of fuels for heating and electricity from the grid for electric appliances

	Input /Output [-]	Boiler ¹⁷ efficiency [%]	year 2020 [kWh/kWh]	CO ₂ - emissions 2020 [g/kWh _E]	year 2030 [kWh/kWh]	CO ₂ - emissions 2030 [g/kWh _E]
Solid fuels (coal)	I	75	0.0089	3	0.0048	2
Liquid fuels (oil)	I	73	0.5486	143	0.5212	136
Natural gas	I	100	5.1276	1010	5.3966	1063
Biomass	I	75	0.0856	0	0.0826	0
Renewable electricity	I	100	0.0153	0	0.0176	0
Subtotal gross heat demand	-	N/A	<i>5.7859</i>	<i>1156</i>	<i>6.0228</i>	<i>1200</i>
Electricity from grid	I	100	1.0	0	1.0	0

¹⁶ Emissions from electricity of the grid are accounted during electricity production.

¹⁷ In the case of electricity the efficiency given does not represent a boiler, but electricity transmission. An efficiency of 100% is used, meaning that there are no electric losses involved.

B.6 Auxiliary Processes

Auxiliary processes are those that do not take part in hydrogen generation (from well to H₂ 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.6.1 Diesel Production

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

Table 45. 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 ₂ emissions	O	51.5	[g/kWh]
SO ₂ emissions	O	0.13	[g/kWh]

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

B.6.2 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 British hydrogen chains, this process has been used for all gas transports through pipelines longer than 200 km.

Table 46. 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 ₂ emissions	O	677	[g/kWh]
NO _x emissions	O	3.527	[g/kWh]
PM emissions	O	0.050	[g/kWh]
SO ₂ emissions	O	0.005	[g/kWh]
NM VOC emissions	O	0.101	[g/kWh]
CO emissions	O	1.008	[g/kWh]
CH ₄ emissions	O	0.050	[g/kWh]
N ₂ O emissions	O	0.030	[g/kWh]

B.6.3 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 11 and Table 19).

The efficiency of diesel engines is set at 30%. Table 47 presents the technical characteristics of the process of mechanical work delivery by a diesel engine.

Table 47. Input and output data for mechanical work from diesel engines

	I / O	Value	Units
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 ₂ emissions	O	880	[g/kWh]
NO _x emissions	O	11.626	[g/kWh]
PM emissions	O	0.969	[g/kWh]
SO ₂ emissions	O	0.929	[g/kWh]
NM VOC emissions	O	0.037	[g/kWh]
CO emissions	O	2.519	[g/kWh]
CH ₄ emissions	O	0.037	[g/kWh]
N ₂ O emissions	O	0.037	[g/kWh]

B.6.4 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 48. Input and output data for used Heating plant (GEMIS 4.07)

	I / O	Value	Units
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 ₂ emissions	O	238	[g/kWh]
NO _x emissions	O	0.2403	[g/kWh]
PM emissions	O	0.0006	[g/kWh]
SO ₂ emissions	O	0.0019	[g/kWh]
NM VOC emissions	O	0.0108	[g/kWh]
CO emissions	O	0.1202	[g/kWh]
CH ₄ emissions	O	0.0108	[g/kWh]
N ₂ O emissions	O	0.0048	[g/kWh]

B.6.5 Coal Power Station

This process is used by hydrogen chains involving nuclear energy generation. The production of UF₆ as presented in Table 12, uses a small quantity of electricity as input. The UF₆ 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 49. Input and output data for the used coal power plant

	I / O	Value	Units
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 ₂ emissions	O	795	[g/kWh]
CH ₄ emissions	O	0.0146	[g/kWh]
N ₂ O emissions	O	0.0409	[g/kWh]

Annex C Specific British 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 British calculations is the discount rate with which the calculated costs of hydrogen energy chains are levelized. For The UK, 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 British mix of feedstock's and generated by on-shore wind turbines is specified here below.

Cost of electricity

According to PRIMES [4], the cost of electricity for households in The UK are more or less constant at 8.9 €ct/kWh. For medium-size industry, these costs level is approximately 6 €ct/kWh. See figure below.

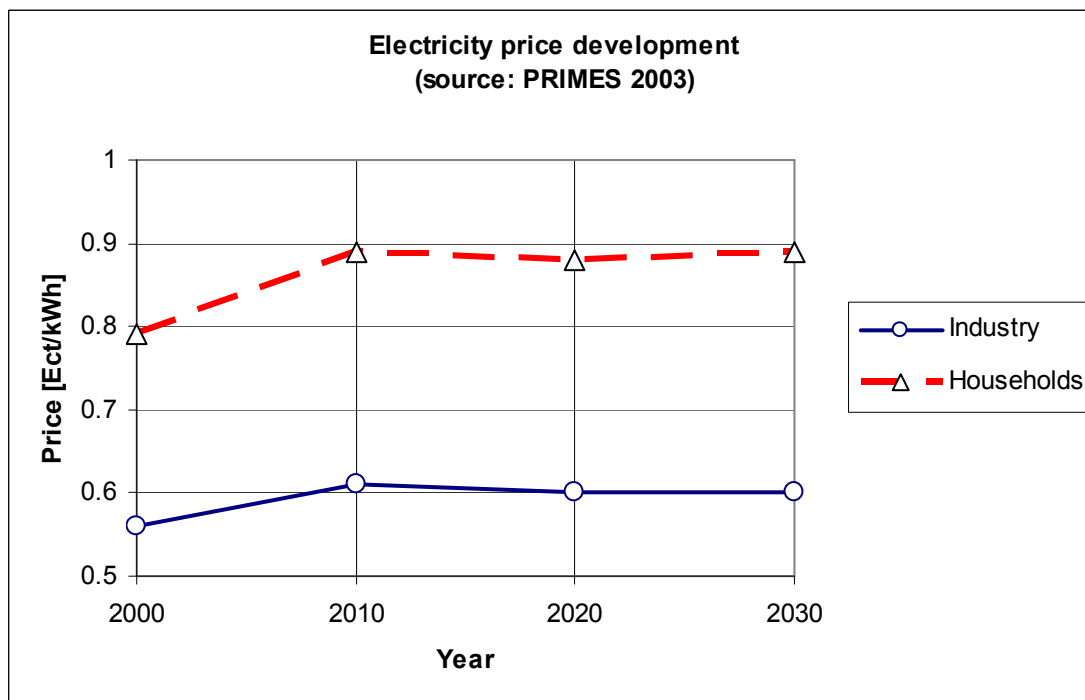


Figure 33. British electricity price development

For the modelling of the hydrogen energy chains, the following electricity prices have been used:

Table 50. British electricity costs

User	Electricity tariff 2020 [€/kWh]	Electricity tariff 2030 [€/kWh]
Households	0.088	0.089
Industry	0.060	0.060

The electricity cost structure, for households and industry, is explained using the following scheme:

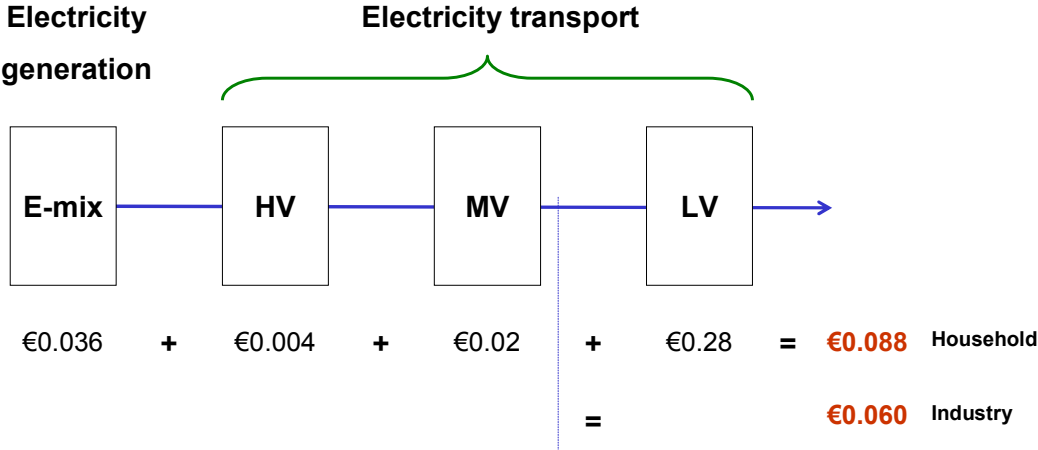


Figure 34. Scheme of electricity costs structure for The UK

The cost of electricity transport at high- and medium voltage level are more or less the same for all European countries, leaving specific British costs to the production mix and transport at low-voltage level. The difference in electricity price between industry and households is therefore obtained by giving a specific cost to the transport of electricity at low-voltage level and adjusting the electricity generation cost to the level of The UK.

Offshore and onshore wind energy

The cost of electricity generation using wind turbines are deducted from the cost of wind turbine investments and maintenance, see section B.1.5. For The UK, a yearly offshore full-load hours factor of 0.342 has been assumed for 2020, corresponding with 3000 hours a year. For onshore wind energy, a full-load hours factor of 0.285 has been assumed (2500 hours/yr).

Although wind turbine availability is expected to increase with time, the same number of full-load hours have been used for the year 2030.