



Modelling of Hydrogen supply chains for Greece



Author: Sergio Herman
Energy research Centre of the Netherlands

Petten, the Netherlands

14 December 2006

Contents

List of tables	4
List of figures	5
Abbreviations	6
1. Introduction	7
2. Methodology	8
3. Chains Selection	9
3.1 Possible chains	9
3.2 Chain Selection for Greece	9
4. Selected Chains	11
4.1 1a. Wind Energy, Central Electrolysis; use: car filling station	11
4.2 2a. Wind Energy, de-Central Electrolysis; use: car filling station	12
4.3 3a. Natural Gas, Central SMR, CCS; use: car filling station	13
4.4 4a. Lignite, Central Gasification, CCS; use: car filling station	14
4.5 6a. Residual biomass, Gasification; use: car filling station	15
4.6 Reference for comparison of the mobile hydrogen energy chains	15
4.7 1b. Wind Energy, Central Electrolysis; use: CHP-system	16
4.8 2b. Wind Energy, de-Central Electrolysis; use: CHP-system	17
4.9 3b. Natural Gas, Central SMR, CCS; use: CHP-system	18
4.10 4b. Lignite, Central Gasification, CCS; use: CHP-system	19
4.11 5. Natural Gas, Central SMR, Mixed stream of NG and hydrogen	20
4.12 6b. Residual biomass, de-Central gasification; use: CHP-system	21
4.13 Reference for comparison of the stationary hydrogen energy chains	22
5. Results	23
5.1 General	23
5.2 Well-to-Tank (WTT) and Well-to-Stationary User (WTStU) analyses	24
5.3 Well-to-Wheel analysis (WTW)	28
5.4 Well-to-Stationary Use analysis (WTStU)	30
6. Bibliography	32
Annex A Calculation rules	33
A.1 Conversion factors for Greenhouse Gas Equivalent	33
A.2 Learning curves	33
A.3 Scaling by size	34
A.4 Calculation of Levelized costs	34
A.4.1 Cost calculation for phase T1 (construction of the plant)	34
A.4.2 Cost calculation for phase T2 (operation of the plant)	34
A.4.3 Cost calculation for phase T3 (dismantling of the plant)	35
A.4.4 Levelized Costs	35
A.4.5 Use of specific costs for “processes”	35
Annex B Description of processes	37
B.1 Feedstock production	37
B.1.1 Extraction and conditioning of Natural Gas	37
B.1.2 Extraction of Coal	38
B.1.3 Electricity production	39
B.1.4 Biomass production and conditioning	41
B.2 Transport of Feedstock’s	41
B.2.1 Natural Gas transport	41
B.2.2 Coal transport	42

	B.2.3 Electricity transport	42
	B.2.4 Biomass transport	43
B.3	Hydrogen Production	43
	B.3.1 Production of Hydrogen from Natural Gas	43
	B.3.2 Production of Hydrogen from Coal	44
	B.3.3 Production of Hydrogen from Electricity	44
	B.3.4 Production of Hydrogen from Residual Biomass	45
B.4	Transport of Hydrogen	45
	B.4.1 Transport of pure Compressed Hydrogen Gas (CGH ₂)	45
	B.4.2 Transport of mixed stream of Natural Gas and Hydrogen	46
B.5	Hydrogen End use	47
	B.5.1 Vehicle Filling stations	47
	B.5.2 Vehicle data	47
	B.5.3 Stationary use of Hydrogen	48
B.6	Auxiliary Processes	51
	B.6.1 Gas Turbines	51
	B.6.2 Heating Plant	51
	B.6.3 Production of Diesel	52
Annex C	Specific Greek Data	53

List of tables

Table 1. Overview of processes considered in the build up of a hydrogen energy chain	9
Table 2. Overview of the hydrogen chains considered	10
Table 3. Selected Greek Chains for the Hydrogen pathway	10
Table 4. Overview of technologies of passenger cars expected to be available by the year 2010 [ref. 1]	28
Table 5. Conversion factors [ref. IPCC 2001].....	33
Table 6. Input and output data for NG Extraction, NL (onshore) / GEMIS 4.1	37
Table 7. Input and output data for NG Processing, NL / GEMIS 4.1	38
Table 8. Input and output data for production of EU-mix lignite.....	38
Table 9. Electricity production mix for Greece and Europe.	39
Table 10. Electricity. Greek production mix and Greek import (EU-mix).	39
Table 11. Technical and economic data of the onshore wind turbine.....	40
Table 12. Technical and economic data of the chipping process	41
Table 13. Input and output data for NG transport through pipelines.....	41
Table 14. Technical data of the coal transport process.....	42
Table 15. Economic data of the truck used for coal transport.....	42
Table 16. Input and output data for High-voltage transport of electricity (GEMIS 4.1)	42
Table 17. Input and output data for Medium-voltage transport of electricity (GEMIS 4.1).....	42
Table 18. Input and output data for Low-voltage transport of electricity (GEMIS 4.1).....	43
Table 19. Technical and economic data of the used SMR plant	43
Table 20. Technical and economic data of hydrogen generation through coal gasification with CO ₂ capture and storage	44
Table 21. Technical and economic data for electrolysis.....	44
Table 22. Technical and economic data of hydrogen generation through biomass gasification.....	45
Table 23. Technical and economic data of CGH ₂ pipelines.....	46
Table 24. Technical and economic data for mixed NG/H ₂ pipelines (GEMIS 4.1.3.2).....	46
Table 25. Technical data for NG/H ₂ mixture	47
Table 26. Technical and economic data for the CGH ₂ filling station, year 2004.....	47
Table 27. Passenger hydrogen cars data	47
Table 28. Passenger reference cars data	48
Table 29. CHP-system (heat following) for a Greek household, 100% boiler efficiency	49
Table 30. CHP-system (heat following) for a Greek household, 80% boiler efficiency	49
Table 31. CHP-system (electricity following) for a Greek household, 100% boiler efficiency.....	49
Table 32. H ₂ -NG mixture boiler and electricity consumption of a typical Greek household, 100% boiler efficiency	50
Table 33. Electricity and heat consumption of a typical Greek household, normalised values with respect to electricity use	50
Table 34. Boiler and electricity consumption of a typical Greek household, based on fuel mix	50
Table 35. Input and output data for used gas turbines (GEMIS 4.1.3.2)	51
Table 36. Input and output data for used Heating plant (GEMIS 4.07).....	51
Table 37. Technical and economic data of diesel production	52
Table 38. Greek electricity costs (source: PRIMES).....	53

List of figures

Figure 1.	Modelled hydrogen chain using central electrolysis from onshore wind energy, for use in filling stations	11
Figure 2.	Modelled hydrogen chain for de-central electrolysis from onshore wind energy, for use in filling stations	12
Figure 3.	Modelled hydrogen chain for Russian NG with central SMR and CCS, for use in filling stations as CGH ₂	13
Figure 4.	Modelled hydrogen chain for coal gasification with CCS, for use in filling stations	14
Figure 5.	Modelled hydrogen chain for biomass gasification, for use in filling stations	15
Figure 6.	Modelled hydrogen chain from wind energy, for stationary use	16
Figure 7.	Modelled hydrogen chain from wind energy, for stationary use	17
Figure 8.	Modelled hydrogen chain from reforming of NG with CCS, for stationary use	18
Figure 9.	Modelled hydrogen chain from coal gasification with CCS, for stationary use	19
Figure 10.	Modelled hydrogen chain from reforming of NG with CCS, for stationary use	20
Figure 11.	Modelled hydrogen chain from biomass gasification, for stationary use	21
Figure 12.	Modelled Greek household (stationary reference)	22
Figure 13.	Development of efficiencies of selected Greek H ₂ supply chains for mobile use, WTT-analysis	24
Figure 14.	Energy use of selected Greek mobile H ₂ supply chains	24
Figure 15.	CO ₂ -equivalent emissions of mobile H ₂ supply chains, WTT-analysis	25
Figure 16.	Costs of selected mobile hydrogen supply chains, WTT-analysis	25
Figure 17.	WTW energy use of Greek hydrogen energy chains, compared to 2010 reference car technologies	28
Figure 18.	WTW greenhouse gases for hybrid passenger cars in 2020	29
Figure 19.	WTW energy cost for hybrid passenger cars in 2020	29
Figure 20.	Efficiencies of the Greek WTStU hydrogen energy chains	30
Figure 21.	Primary energy use of Greek WTStU hydrogen energy chains	30
Figure 22.	CO ₂ -equivalent emissions of Greek WTStU hydrogen energy chains	31
Figure 23.	Costs of hydrogen and conventional fuels for Greek WTStU hydrogen energy chains	31
Figure 24.	Example of pipeline grid for hydrogen transport	46
Figure 25.	Supply of electricity and heat for a Greek household (2020), Q-following system	48
Figure 26.	Scheme of electricity costs structure for Greece	53

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 Greece, and
- Provides the results obtained from the calculations of these chains.

2. Methodology

During several workshops organized in Greece, 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 Greece. 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 Greece, the following new processes have been introduced:

- Production of Greek electricity mix (Annex B, section B.1.3)
- Electricity transport at low-voltage level (Annex B, section B.2.3)
- Use of CHP-application in Greek households, heat-demand following process (Annex B, section B.5.3)
- Use of CHP-application in Greek households, electricity-demand following process (Annex B, section B.5.3)
- Heat and electricity use in Greek households (Annex B, section B.5.3)
- Onshore wind energy for Greek islands (Annex B, section B.1.3)

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

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 Greece

Table 2 shows an overview of the feedstock's and end use options of hydrogen energy chains that have been considered during the Greek stakeholder workshops. Natural gas, lignite, biomass and electricity (wind power) have been selected as the most relevant feedstock's for Greece. Natural gas must be imported from Russia and Algeria, but the other sources are domestically available.

With respect to end use, hydrogen vehicles (in particular passenger cars) and residential CHP have been selected as the most relevant options. In addition, direct residential heating is considered as an important end use option, but in this case a natural gas-hydrogen mixture (at 5% H₂ volume basis) will be supplied instead of pure hydrogen. The selected Greek hydrogen energy chains are further characterized in Table 3.

Table 2. Overview of the hydrogen chains considered

Feedstock	Natural gas (Russia, Algeria)	✓
	Coal (Hard coal, Lignite)	✓
	Oil (residues)	-
	Electricity ²	✓
	Biomass	✓
	Heat	-
	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 Greek Chains for the Hydrogen pathway

Number	Feedstock	Production Process	CO ₂ seq.	Distribution / end use	
1	a	Onshore wind power	Central Electrolysis	No	Filling station
	b	Onshore wind power	Central Electrolysis	No	Domestic use (CHP)
2	a	Onshore wind power	De-central Electrolysis	No	Filling station
	b	Onshore wind power	De-central Electrolysis	No	Domestic use (CHP)
3	a	Natural gas	Central SMR	Yes	Filling station
	b	Natural gas	Central SMR	Yes	Domestic use (CHP)
4	a	Lignite	Central Gasification	Yes	Filling station
	b	Lignite	Central Gasification	Yes	Domestic use (CHP)
5		Natural gas	Central SMR	Yes	Domestic use, mixed gaseous stream (NG and H ₂)
6	a	Residual biomass	De-central gasification	No	Filling station
	b	Residual biomass	De-central gasification	No	Domestic use (CHP)

In the following section, the hydrogen production and utilisation chains are presented one by one, ordered by the distribution (mobile or domestic use) and by the feedstock used.

² Besides electricity from fossil fuels, also electricity from wind power, solar power and hydropower are possible. Moreover, the electricity mix can be either the typical Greek mix or the European mix.

4. Selected Chains

In this section, the selected hydrogen chains for Greece and their variants, as stated in Table 3, are presented. First, all hydrogen chains for mobile applications are described. This is followed by a description of the chains with stationary application.

4.1 1a. Wind Energy, Central Electrolysis; use: car filling station

Hydrogen is produced in relatively large-scale electrolysis plants at some distance from the end use centres. The electricity for the electrolysis process is produced by onshore wind farms and is transported to the electrolysis plants through the medium-voltage electricity grid. The electrolyser produces hydrogen at a pressure of 3 MPa (30 bar). Subsequently, the produced hydrogen 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 (typical throughput 120 t/yr) has a connection to the medium voltage electricity grid. It is assumed that this electricity is obtained from the Greek electricity production mix. It is assumed that this electricity is obtained from the Greek electricity production mix.

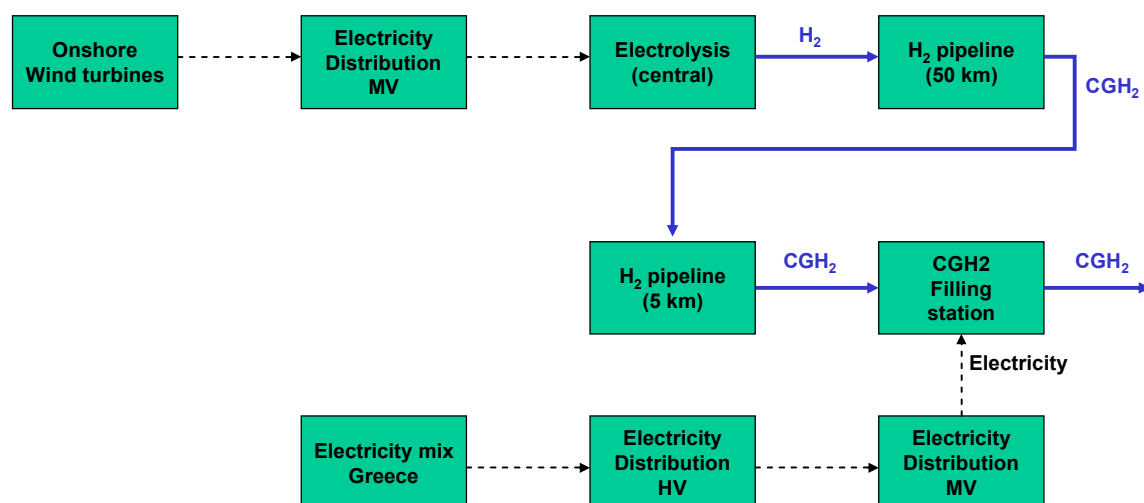


Figure 1. Modelled hydrogen chain using central electrolysis from onshore wind energy, for use in filling stations

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

- Electricity production (including wind power) B.1.3
- Electricity transport B.2.3
- Production of hydrogen from electricity B.3.3
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

4.2 2a. Wind Energy, de-Central Electrolysis; use: car filling station

In this chain, hydrogen is produced by de-central electrolysis plants located near the end-user centres. Local wind turbines generate the electricity required for the electrolysis process. The wind turbines and the electrolyser are connected through medium voltage cables. The electrolysers produce hydrogen at a pressure of 2.6 MPa (26 bar), which is distributed to a filling station (typical throughput 120 t/yr) through a local hydrogen grid. Electrical compressors (part of the filling station) are used to compress the hydrogen up to 88 MPa required for on-board storage. Due to lack of specific local data, it is assumed that the electricity required for compression at the filling station is obtained from the Greek electricity production mix.

In the case of an island, it may be that the electricity is produced by (less efficient) diesel generators. In this case, the assumption of electricity transport through a high voltage grid is also questionable. The impact of this assumption on the modeling results is however small.

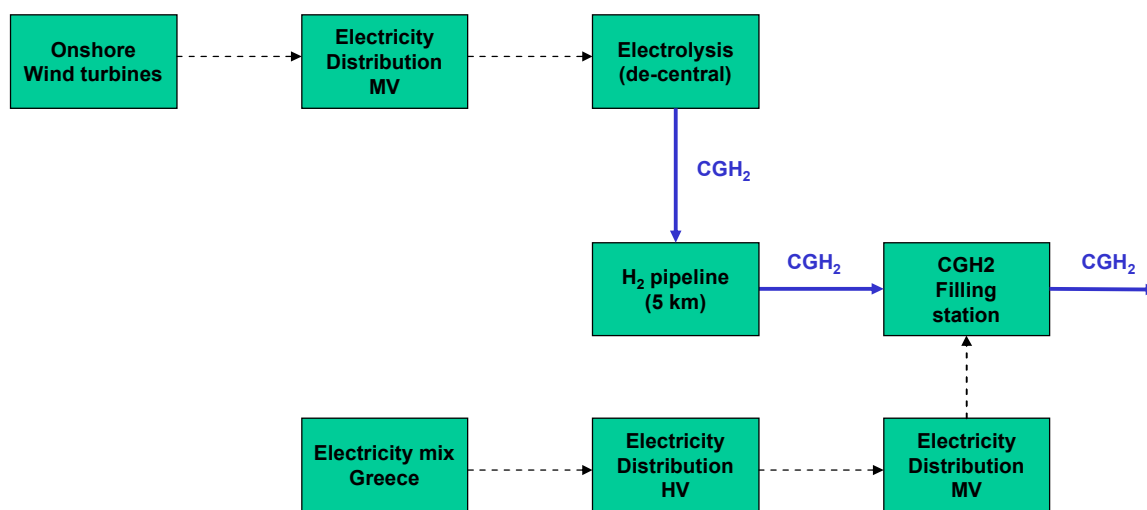


Figure 2. Modelled hydrogen chain for de-central electrolysis from onshore wind energy, for use in filling stations

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

- Electricity production (including wind power) B.1.3
- Electricity transport B.2.3
- Production of hydrogen from electricity B.3.3
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

4.3 3a. Natural Gas, Central SMR, CCS; use: car filling station

Natural gas (NG), extracted and processed in Russia³, is transported to Greece by a pipeline over a distance of 7000 km. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

From the border of Greece, the NG is transported to large-scale central SMR's at filling stations by a system of high-pressure and medium-pressure natural gas pipelines. National transport distance in the high- and medium-pressure pipelines is 250 km on average. Again, 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. Subsequently, the hydrogen is transported and distributed to filling stations through hydrogen pipelines. The plants are thought to be located near large Greek cities as Athens and Thessaloniki and are equipped with CO₂ capture facilities. For CO₂-storage, depleted oil fields in the northern part of Greece are assumed available⁴. 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 (120 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Greek electricity production mix.

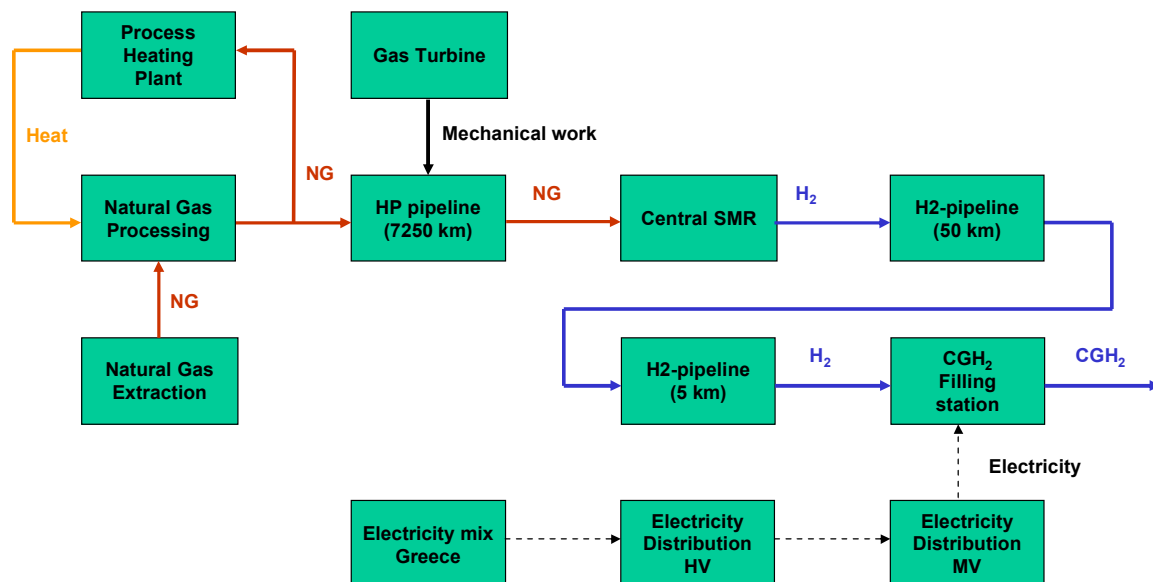


Figure 3. Modelled hydrogen chain for Russian NG with central SMR and CCS, for use in filling stations as CGH₂.

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.1.3
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.3
- Hydrogen production from natural gas B.3.1 (including CCS)
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1
- Gas turbines B.6.1
- Heating plant B.6.2

³ Liquefied natural gas (LNG) is also imported from Algeria and used in the Athens region as NG-mixture at a ratio of approximately 80% Russian NG and 20% Algerian NG.

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

4.4 4a. Lignite, Central Gasification, CCS; use: car filling station

In this energy chain, hydrogen is generated through large-scale gasification of domestic lignite with CO₂ capture and sequestration. The lignite is available from two main fields, one in northern Greece and the other in the centre of the Peloponnese.

The coal gasification plant is thought to be located at some 50 km from where lignite is available and at some distance from large Greek cities as Athens or Thessaloniki. Diesel-fuelled trucks are used to transport the lignite to the gasification plants. Transport distances are approximately 50 km. The gasification plant produces hydrogen at a pressure of about 6 MPa (60 bar). The gasification process includes CCS. For CO₂-storage, depleted oil fields in the northern part of Greece are assumed available⁵. The produced hydrogen and the sequestered CO₂ are transported to the filling stations respectively to the storage field through hydrogen 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 (120 t/yr) has a connection to the medium-voltage electricity grid. It is assumed that the electricity required is obtained from the Greek electricity production mix.

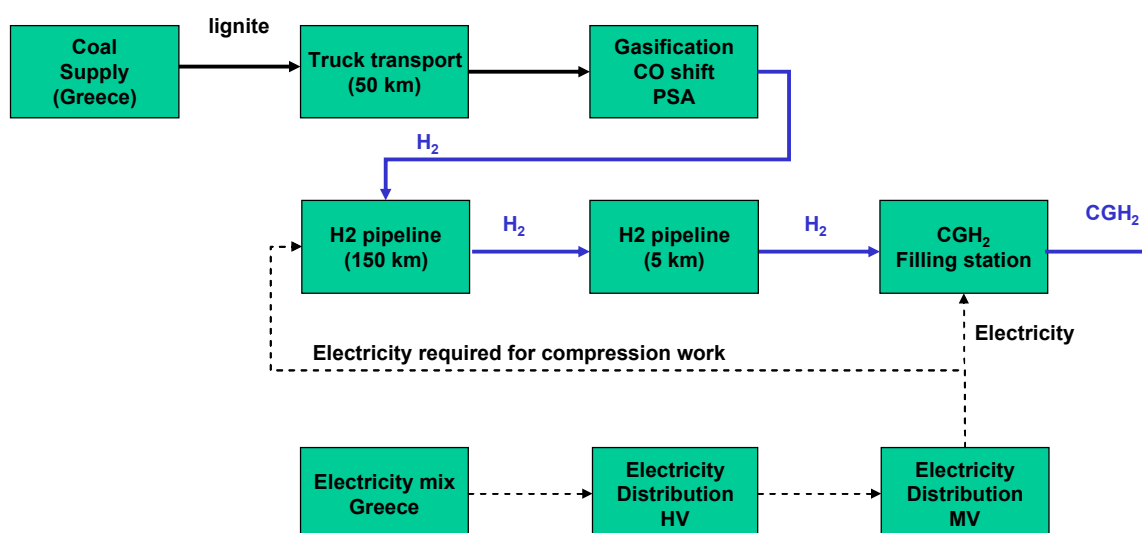


Figure 4. Modelled hydrogen chain for coal gasification with CCS, for use in filling stations

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

- Coal extraction B.1.2
- Coal transport B.2.2
- Electricity production B.1.3
- Electricity transport B.2.3
- Hydrogen production from coal B.3.2
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

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

4.5 6a. Residual biomass, Gasification; use: car filling station

In this hydrogen energy chain, residues from agricultural activities (crops, straw and others) and residues from harvesting and trees are collected and gasified in a small-scale gasification plant. The biomass is collected from the surroundings of the plant, up to a maximum distance of 50 km. To be gasified, the residual biomass is first chipped to small pieces at a chipping plant located near the gasifier.

The gasification plants produce hydrogen at a pressure of about 2 MPa (20 bar). Subsequently, the hydrogen is transported and distributed to filling stations through a small hydrogen pipeline grid (approximately 15 km). 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 Greek electricity production mix.

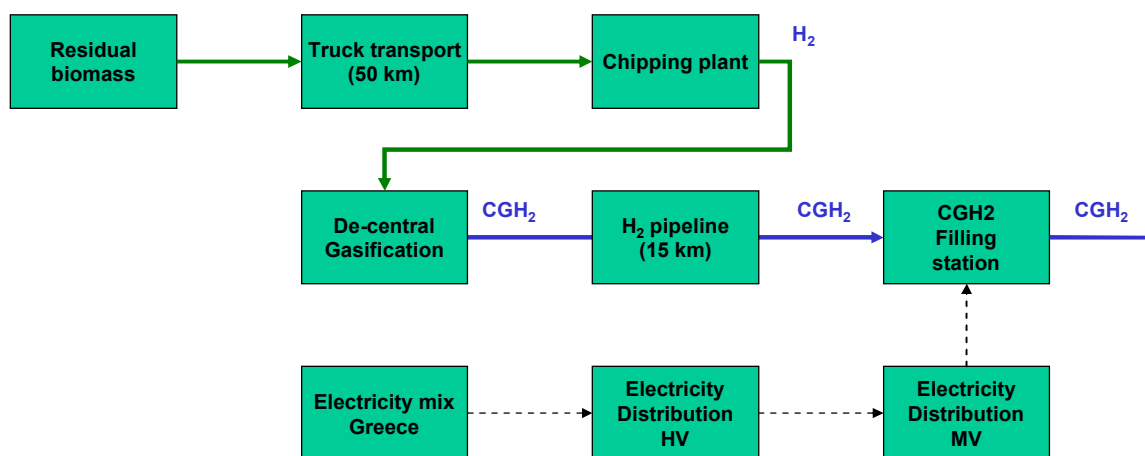


Figure 5. Modelled hydrogen chain for biomass gasification, for use in filling stations

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

- Residual biomass production and conditioning B.1.4
- Biomass transport B.2.3
- Chipping plant B.1.4
- Electricity production B.1.3
- Electricity transport B.2.3
- Hydrogen production from biomass B.3.2
- Hydrogen transport by pipeline B.4.1
- Filling station B.5.1

4.6 Reference for comparison of the mobile hydrogen energy chains

Mobile hydrogen energy chains are evaluated at two stages: Fuel delivery stage at the tank of the vehicle (well-to-tank analysis – WTT) and Fuel usage stage (well-to-wheel analysis – WTW). The hydrogen chains are compared to gasoline and diesel production and energy use in WTT-analyses. In WTW-analyses, the use of hydrogen by FC-vehicles produced according the presented chains is compared against the use of diesel and gasoline by hybrid cars, according to expected advanced technology.

4.8 2b. Wind Energy, de-Central Electrolysis; use: CHP-system

In this chain, hydrogen is produced by de-central electrolysis plants located near the end-user centres. Local wind turbines generate the electricity required for the electrolysis process. The wind turbines and the electrolyser are connected through medium voltage cables. The electrolysers produce hydrogen at a pressure of 2.6 MPa (26 bar), which is distributed to fuel cell-based residential micro-CHP systems through hydrogen pipelines. 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 Greek fuel mix. Excess electricity produced by the CHP-system is fed back to the electric grid avoiding the electricity production by other means.

In the case of an island, it may be that the electricity required by the end-users is produced by (less efficient) diesel generators. In this case, the assumption of electricity transport through a high voltage grid is also questionable. The impact of this assumption on the modeling results is however small.

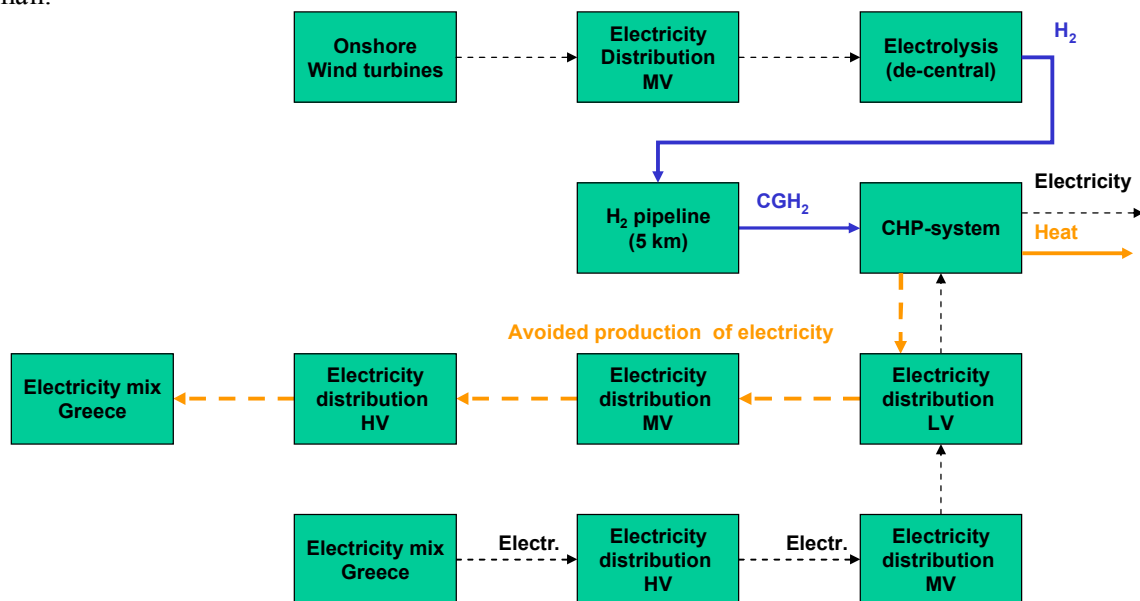


Figure 7. Modelled hydrogen chain from wind energy, for stationary use

In addition to a heat-demand following case, an electricity-demand following case is considered. In this latter case, electricity is only generated if there is a demand: No excess electricity will be produced. If the electricity demand is larger than it can be produced, electricity from the grid (Greek production mix) is used by the residential system.

In the electricity demand following case heat may be produced at times when there is no heat demand. The model used assumes the presence of a heat buffer large enough to store the heat produced at times when there is no demand. So no dumping of heat takes place. As the heat to power ratio of the demand in household is usually larger than the heat to power ratio of the conversion unit, the system still needs an additional boiler to meet the entire heat demand.

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

- Electricity production by onshore wind power B.1.3
- Electricity transport B.2.3
- Production of hydrogen from electricity B.3.3
- Hydrogen transport by pipeline B.4.1
- CHP-system B.5.3

4.9 3b. Natural Gas, Central SMR, CCS; use: CHP-system

Natural gas (NG), extracted and processed in Russia⁶, is transported to Greece by a pipeline over a distance of 7000 km. NG and electricity are used for extraction and processing. NG-fuelled compressors are used to compensate the pressure drop over the pipeline.

From the border of Greece, the NG is transported to large-scale central SMR's at filling stations by a system of high-pressure and medium-pressure natural gas pipelines. National transport distance in the high- and medium-pressure pipelines is 250 km on average. Again, 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. Subsequently, the hydrogen is transported and distributed to fuel cell-based residential micro-CHP systems through hydrogen pipelines. For CO₂-storage, depleted oil fields in the northern part of Greece are assumed available⁷. The produced hydrogen and the sequestered CO₂ are transported to the end-users respectively to the storage field by pipelines.

The residential CHP-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 Greek fuel mix. Excess electricity produced by the CHP-system is fed back to the electric grid avoiding the electricity production by other means.

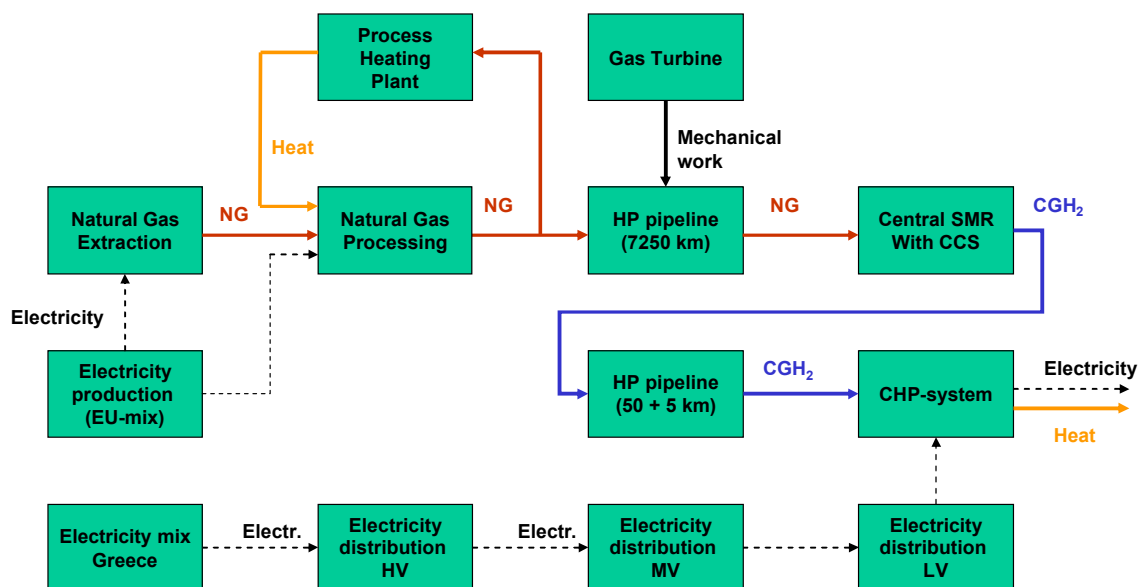


Figure 8. Modelled hydrogen chain from reforming of NG with CCS, for stationary use

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.1.3
- Natural gas transport pipelines B.2.1
- Electricity transport B.2.3
- Hydrogen production from natural gas B.3.1
- Hydrogen transport by pipeline B.4.1
- CHP-system B.5.3
- Gas turbines B.6.1
- Heating plant B.6.2

⁶ Liquefied natural gas (LNG) is also imported from Algeria and used in the Athens region as NG-mixture at a ratio of approximately 80% Russian NG and 20% Algerian NG.

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

4.10 4b. Lignite, Central Gasification, CCS; use: CHP-system

In this energy chain, hydrogen is generated through large-scale gasification of domestic lignite with CO₂ capture and sequestration. The lignite is available from two main fields, one in northern Greece and the other in the centre of the Peloponnesse.

The coal gasification plant is thought to be located at some 50 km from where lignite is available and at some distance from large Greek cities as Athens or Thessaloniki. Diesel-fuelled trucks are used to transport the lignite to the gasification plants. Transport distances are approximately 50 km. The gasification plant produces hydrogen at a pressure of about 6 MPa (60 bar). The gasification process includes CCS. For CO₂-storage, depleted oil fields in the northern part of Greece are assumed available⁸. The produced hydrogen and the sequestered CO₂ are transported to the end-users respectively to the storage field through hydrogen pipelines.

The end-users are fuel cell-based residential micro-CHP systems that 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 Greek fuel mix. Excess electricity produced by the CHP-system is fed back to the electric grid avoiding the electricity production by other means.

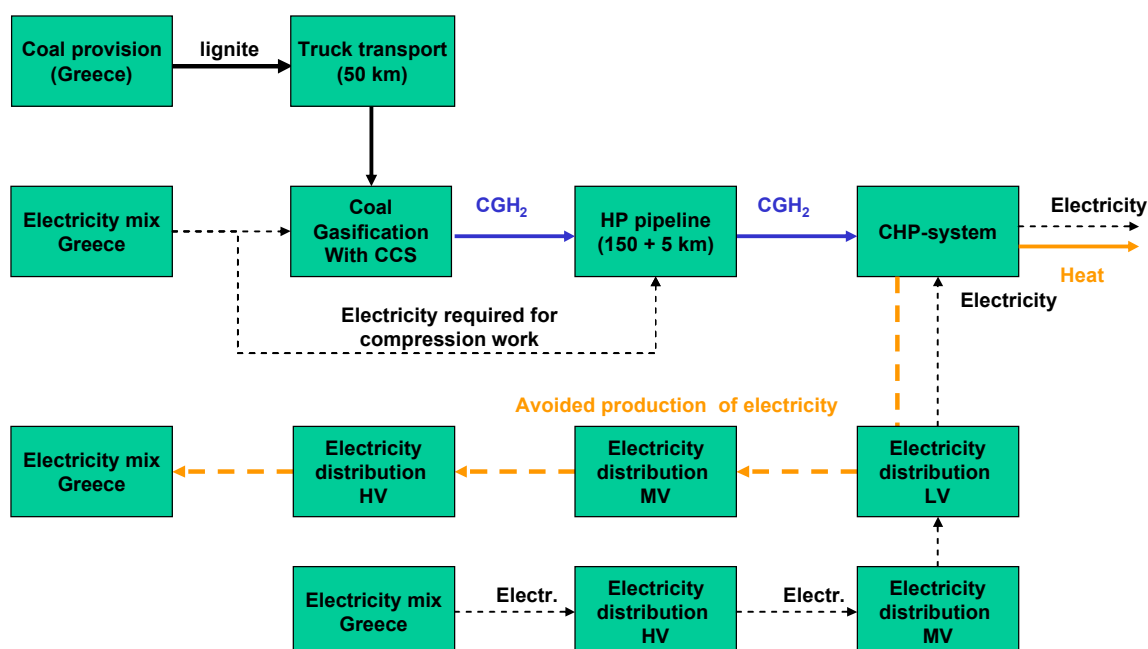


Figure 9. Modelled hydrogen chain from coal gasification with CCS, for stationary use

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

- Coal extraction B.1.2
- Coal transport B.2.2
- Electricity production B.1.3
- Electricity transport B.2.3
- Hydrogen production from coal B.3.1
- Hydrogen transport by pipeline B.4.1
- CHP-system B.5.3

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

4.11 5. Natural Gas, Central SMR, Mixed stream of NG and hydrogen

Natural gas extracted and processed in Russia (7000 km from Greek borders) is distributed to a central SMR (250 km distance from Greek borders, on average). The gaseous hydrogen produced is mixed with natural gas to a maximum mix ratio of 5% hydrogen on volume basis. It is assumed that the natural gas grid transports the mixture over a distance of about 250 km through high- and medium-pressure pipelines and about 5 km through the local low-pressure grid, on average. The mixture is used in domestic high-efficiency boilers to produce heat for space heating and tap water. The mixture is not used for the production of electricity. The electricity demand in the household is met by the Greek electricity mix from the grid.

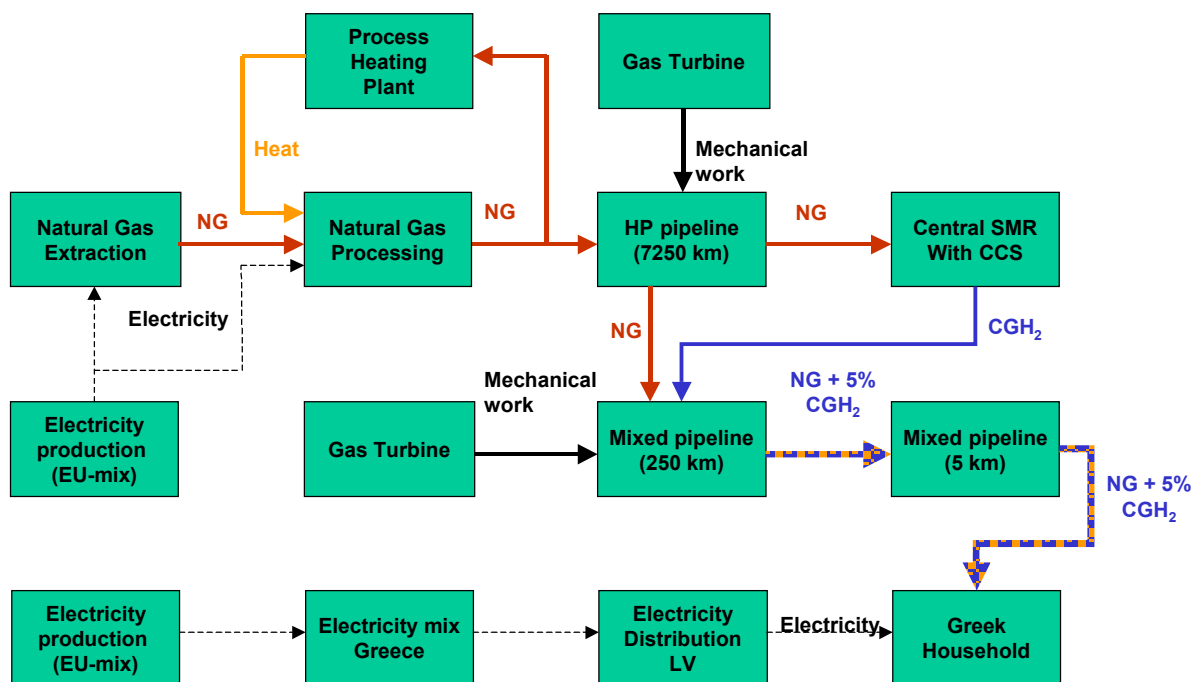


Figure 10. Modelled hydrogen chain from reforming of NG with CCS, for stationary use

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.1.3
- Natural gas transport pipelines B.2.1
- Hydrogen production from natural gas B.3.1
- Transport of NG-H₂ mixture by pipeline B.4.2
- Heating plant B.6.2
- Gas turbines B.6.1

4.12 6b. Residual biomass, de-Central gasification; use: CHP-system

In this hydrogen energy chain, residues from agricultural activities (crops, straw and others) and residues from harvesting and trees are collected and gasified in a small-scale gasification plant. The biomass is collected from the surroundings of the plant, up to a maximum distance of 50 km. To be gasified, the residual biomass is first chipped to small pieces at a chipping plant located near the gasifier.

The gasification plants produce hydrogen at a pressure of about 2 MPa (20 bar). Subsequently, the hydrogen is transported and distributed to the end-users through hydrogen pipelines. Carbon-capture and storage (CCS) is not included as an option.

The end-users are fuel cell-based residential micro-CHP systems that 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 Greek fuel mix. Excess electricity produced by the CHP-system is fed back to the electric grid avoiding the electricity production by other means.

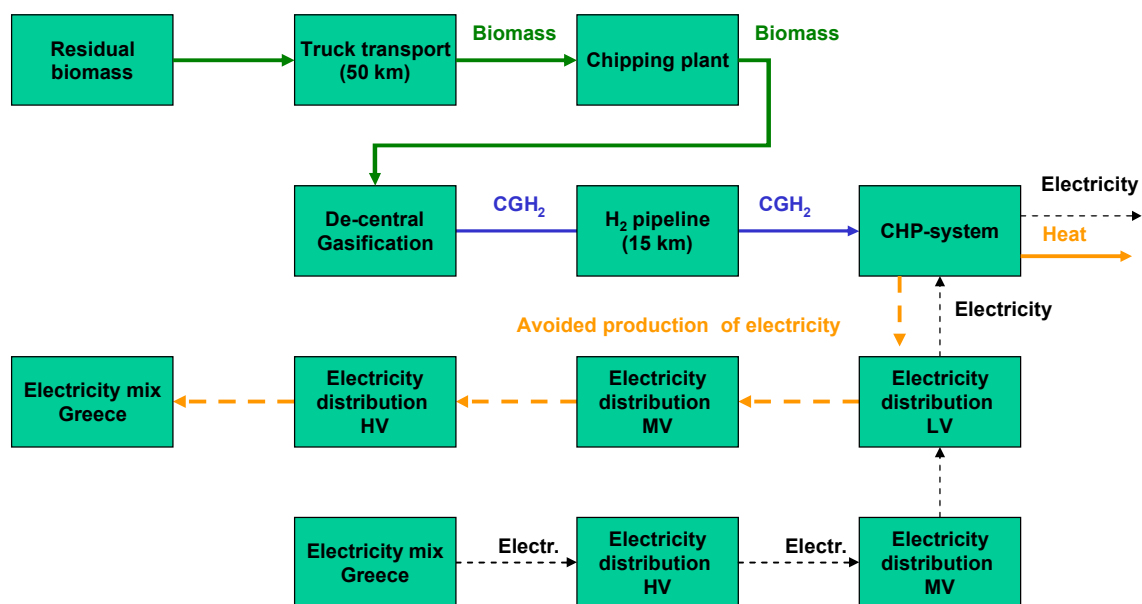


Figure 11. Modelled hydrogen chain from biomass gasification, for stationary use

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

- Residual biomass production and conditioning B.1.4
- Biomass transport B.2.4
- Chipping plant B.1.4
- Electricity production B.1.3
- Electricity transport B.2.3
- Hydrogen production from biomass B.3.2
- Hydrogen transport by pipeline B.4.1
- CHP-system B.5.3

4.13 Reference for comparison of the stationary hydrogen energy chains

The hydrogen energy chains with stationary end-use of hydrogen in a household are compared with the energy chains that currently prevail. These are space heating and tap water (based on solar thermal, natural gas and domestic fuel oil boilers) and use of electricity (Greek mix) from the grid.

The stationary chains are compared to each other based on the use of heat and electricity on the ratio 3.3 : 1 for the year 2020, and on the ratio 2.7 : 1 for the year 2030. These ratios reflect the yearly average heat to power demand of a Greek household for the given years.

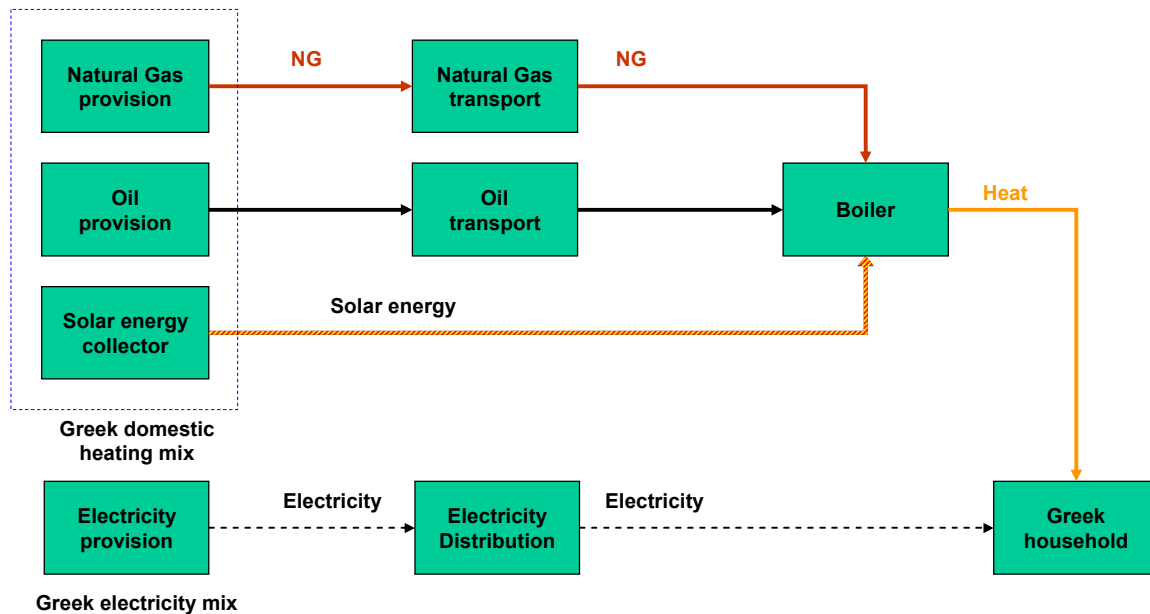


Figure 12. Modelled Greek household (stationary reference)

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

- Greek electricity production B.1.1 and B.1.3
- Natural gas transport B.2.1
- Oil transport Modelled, but not presented
- Electricity transport B.2.3
- Greek household B.5.3

5. Results

5.1 General

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

- Chain energy efficiency
- Primary energy use per unit of energy carrier (e.g. kWh of 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) and Well-to-Stationary User (WTStU) analyses of the hydrogen energy chains. These analyses include all processes in the chains up to and excluding the end use. Results are presented for the following chains:

- 1 Central electrolysis using electricity generated by wind turbines
- 2 De-central electrolysis using electricity generated by wind turbines
- 3 Central reforming of natural gas (SMR), including carbon capture and storage (CCS)
- 4 Central gasification of lignite, including carbon capture and storage
- 5 Central reforming of natural gas, use of a mixed stream of NG and hydrogen
- 6 De-central gasification of residual biomass

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 following chains:

- 1a Wind Energy, central electrolysis; use: car filling station (CGH₂)
- 2a Wind Energy, de-central electrolysis; use: car filling station (CGH₂)
- 3a Natural Gas, central SMR, CCS; use: car filling station (CGH₂)
- 4a Lignite, central gasification, CCS; use: car filling station (CGH₂)
- 6a Residual biomass, de-central gasification; use: car filling station (CGH₂)

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:

- 1b Wind Energy, central electrolysis; use: CHP-system, Q-following system, 100% efficiency
- 1b2 Wind Energy, central electrolysis; use: CHP-system, Q-following system, 80% efficiency
- 2b Wind Energy, de-central electrolysis; use: CHP-system, Q-following system, 100% efficiency
- 2b2 Wind Energy, de-central electrolysis; use: CHP-system, E-following system, 100% efficiency
- 3b Natural Gas, central SMR, CCS; use: CHP-system, Q-following system, 100% efficiency
- 4b Lignite, central Gasification, CCS; use: CHP-system, Q-following system, 100% efficiency
- 5 Natural Gas, central SMR, Mixed pipeline with NG
- 6b Residual biomass, de-central gasification; use: CHP-system, Q-following system, 100% efficiency

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

5.2 Well-to-Tank (WTT) and Well-to-Stationary User (WTStU) analyses

Figure 13, Figure 14, Figure 15 and Figure 16 present the results of these analyses.

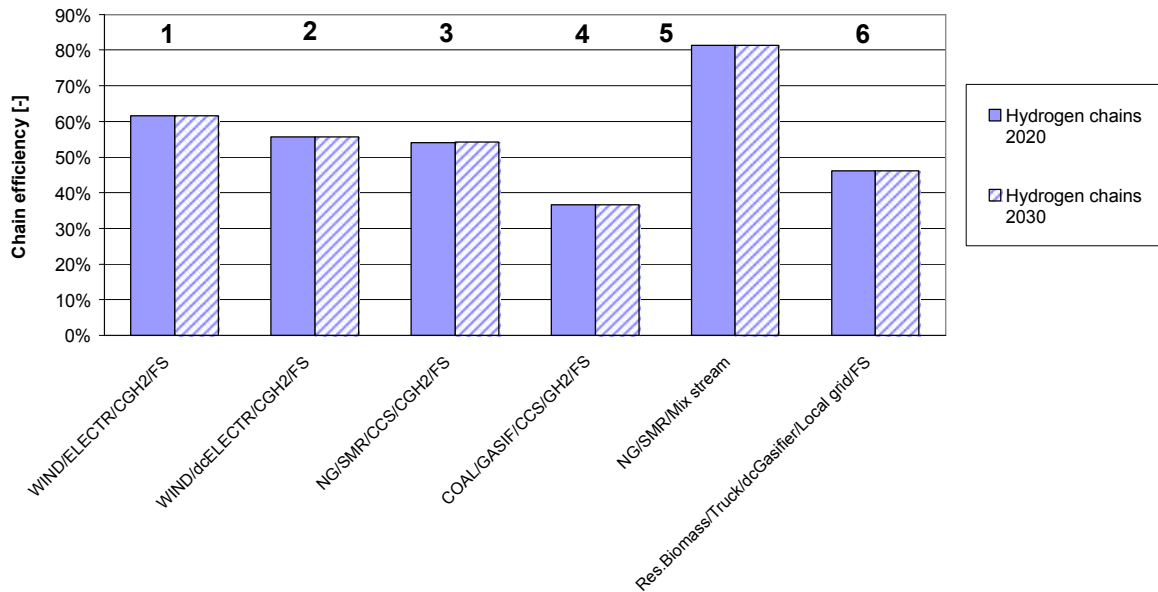


Figure 13. Development of efficiencies of selected Greek H₂ supply chains for mobile use, WTT-analysis.

Figure 13 shows the results on energy efficiency for the hydrogen supply chains. Similar supply chains have been assumed for the selected mobile and stationary applications. The only difference is that for mobile applications the hydrogen needs to be compressed at a filling station for high-pressure onboard storage. The results for the supply chains are shown including the filling station with exception of the mixture chain (chain 5), for which no mobile application is foreseen. The efficiency of chain 5 is higher than for the other chains because per unit of energy carrier supplied, less hydrogen (5% vs. 100% on volume basis) is produced, and no energy use for compression is included.

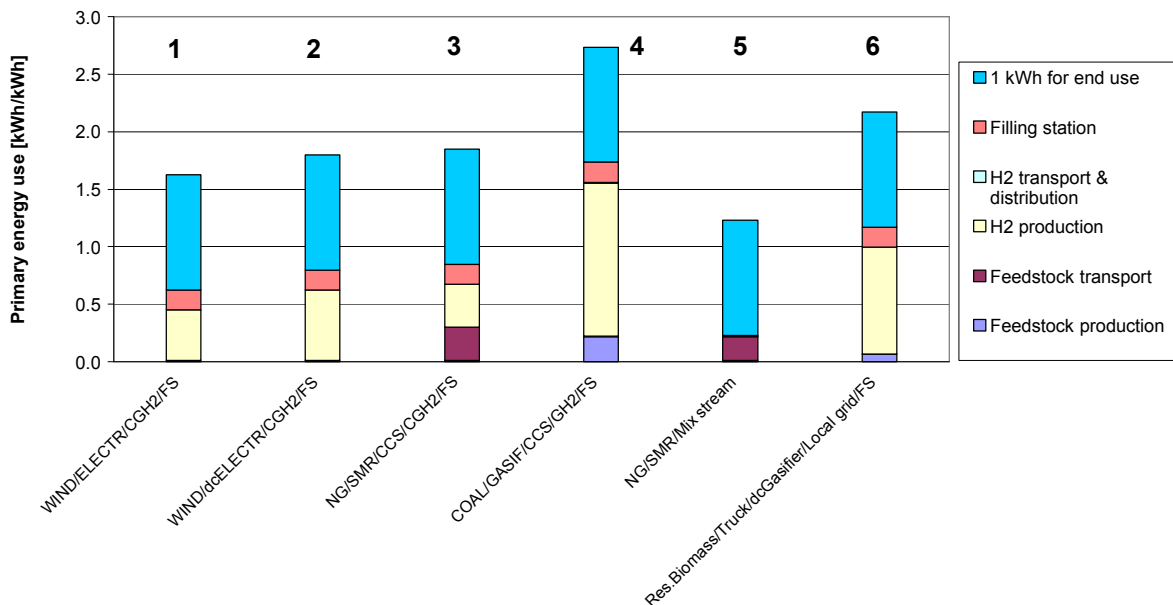


Figure 14. Energy use of selected Greek mobile H₂ supply chains

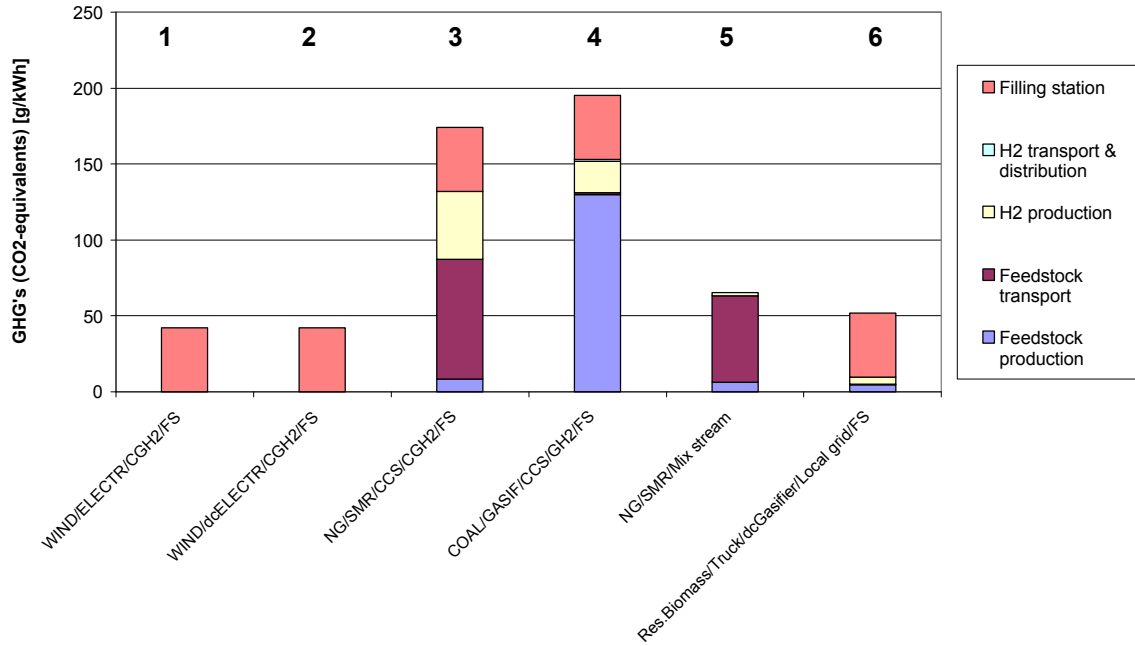


Figure 15. CO₂-equivalent emissions of mobile H₂ supply chains, WTT-analysis

The chain efficiency results for 2020 and 2030 (Figure 13) are similar, which indicates that no efficiency improvement is assumed for the technologies considered in these chains.

Figure 14 shows the primary energy use for the selected WTT and WTStU energy chains. Based on the assumptions made the primary energy consumption is highest for production of hydrogen from coal. For this chain, the energy use associated to capture and storage of CO₂ is included in the H₂ production process. This may explain the rather large difference in primary energy use between the large-scale coal gasifier and the small-scale biomass gasifier, which intuitively should be smaller or should even be the other way around.

The contribution of hydrogen production to the energy use of the mixture chain is very small, much smaller than may be expected based on the results of the NG-based chain 3. This is explained by the fact that the contribution of hydrogen on an energy basis (1.5%) is smaller than the contribution of its volume in the mixture (5%). Based on energy, the mix-chain is almost entirely a natural gas chain.

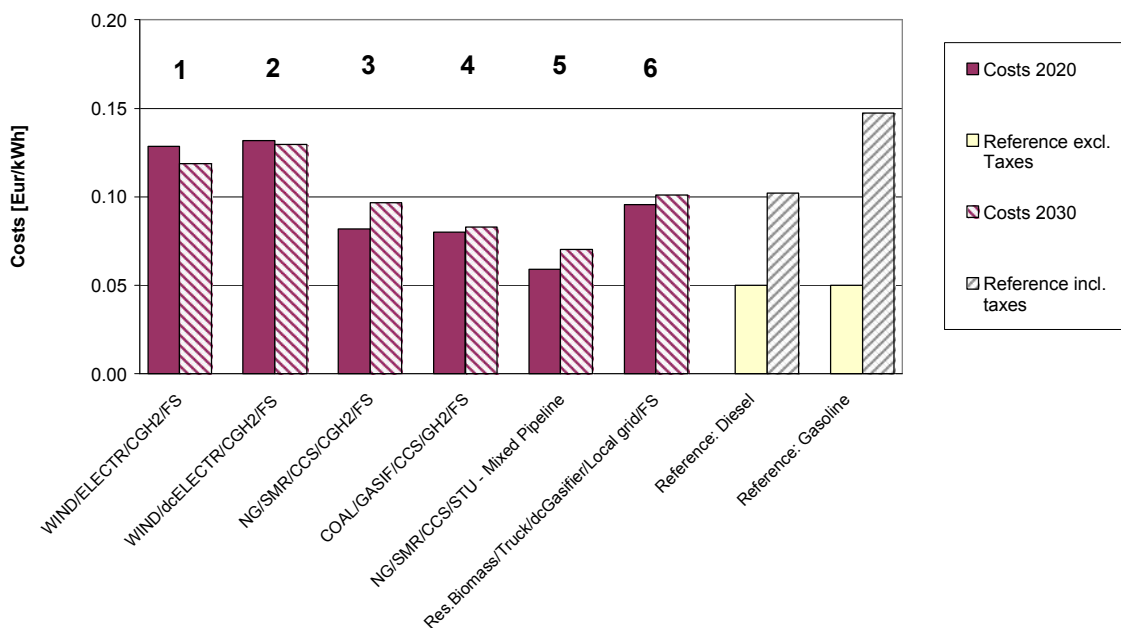


Figure 16. Costs of selected mobile hydrogen supply chains, WTT-analysis.

Figure 15 shows the greenhouse gas (GHG) emissions connected with the hydrogen supply chains. Despite carbon capture and storage in the coal-based chain, this chain still has the highest level of GHG-emissions. This is largely the result of methane emissions released at the mining of coal. Methane is a strong GHG. As data have been used for hard coal mining, the emissions may be overestimated. Specific data for Poland in the E3 database show CH₄ emissions of 0.727 g/kWh for deep mining of hard coal and only 0.005 g/kWh for surface mining of lignite. For the calculations performed in this study, data for an EU coal mix have been used with a specific CH₄ emission of 1.374 g/kWh (see Annex B, section B.1.2).

The GHG emissions for the natural gas based chains are mainly the result of the long-distance gas transport from Russia. The emissions result from the compression energy used to keep the gas flowing and from methane leakages out of the pipelines.

The GHG emissions of the three other chains are primarily linked to the compression energy used for vehicle onboard storage of hydrogen at the filling station. The emissions result from the assumption that the electricity required for compression is obtained from the Greek electricity production mix. By assuming that the compression energy required is obtained from electricity generation out of renewable sources, the GHG emissions for the wind and biomass based supply chains would reduce to (almost) zero.

Figure 16 presents the calculation results for the cost of hydrogen (COH) per unit of energy. With the exception of chain 5, COH for mobile applications are shown. 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. Clearly, for all chains, the COH are above the cost level of the conventional fuels. However, the COH are lower than the price of these fuels including taxes.

The results for 2020 and 2030 show that, based on the assumptions made, the COH of the fossil fuel based chains increase, while the cost of the wind energy based chains decrease. The former effect is due to an increase in feedstock price, especially the price of natural gas, while the latter is due to a decrease in investment cost of the involved technologies (wind turbines and electrolysers). The increase in the COH of the residual biomass based chain is the result from increase of the oil price (transport of biomass) and increase of the cost of electricity. It is assumed that the residual biomass is free of charge and that the investment cost of the technology will not change with time.

This page has been intentionally left blank

5.3 Well-to-Wheel analysis (WTW)

Figure 17, Figure 18 and Figure 19 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 possible available vehicles.

Table 4. Overview of technologies of passenger cars expected to be available by the year 2010 [ref. 1].

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

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 17. The WTW primary energy use of the hydrogen chains is comparable with that of the conventional fuel chains, on average. The wind-based hydrogen chains and also the natural gas-based chain show better results than the conventional chains, especially when compared to the gasoline chain. Only the coal-based hydrogen chain clearly shows an increase in primary energy use per kilometre.

For comparison of the hydrogen energy chains with fossil fuel-based chains, it is important to note that the revocation of existing forbiddance of diesel cars in Athens and Thessaloniki regions is under discussion.

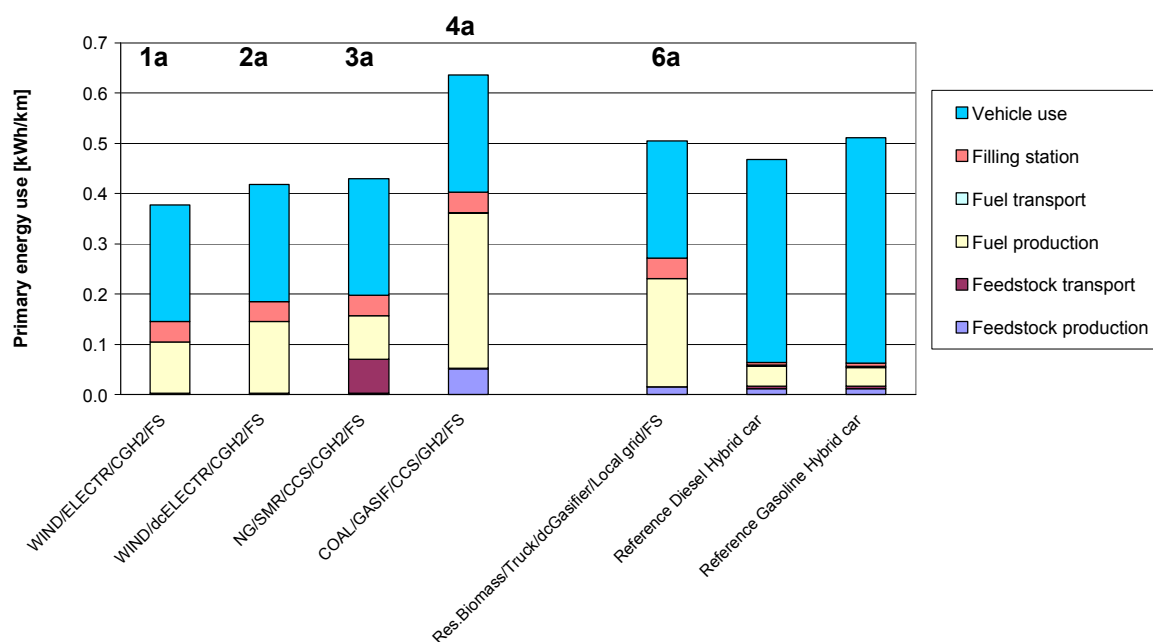


Figure 17. WTW energy use of Greek hydrogen energy chains, compared to 2010 reference car technologies

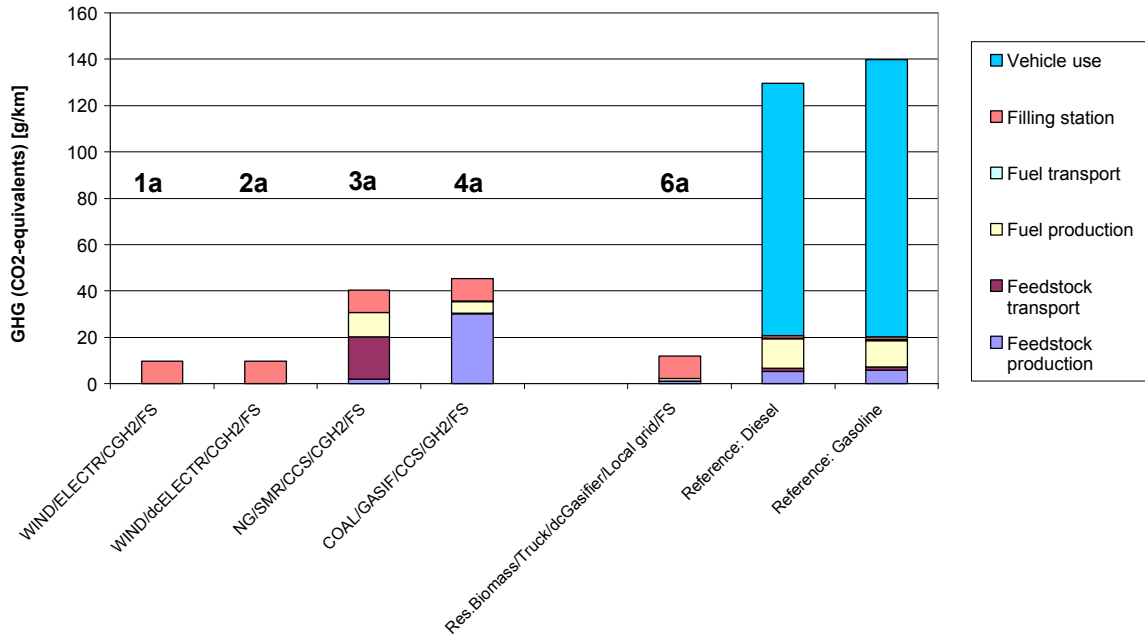


Figure 18. WTW greenhouse gases for hybrid passenger cars in 2020

Figure 18 shows that 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 fossil feedstock's, due to the application of carbon capture and storage. An import issue with respect to CCS is the availability of adequate storage capacity, in terms of size and safety. Most emissions of the conventional fossil fuel chains concern the end use. Hydrogen powered cars, on the contrary, do not emit any GHG gases.

Figure 19 shows the results for the WTW fuel cost. With exception of the wind energy-based hydrogen chains, the WTW COH are comparable with the cost of the conventional fuels. If the fossil fuel taxes are taken into account, all hydrogen energy chains are cheaper.

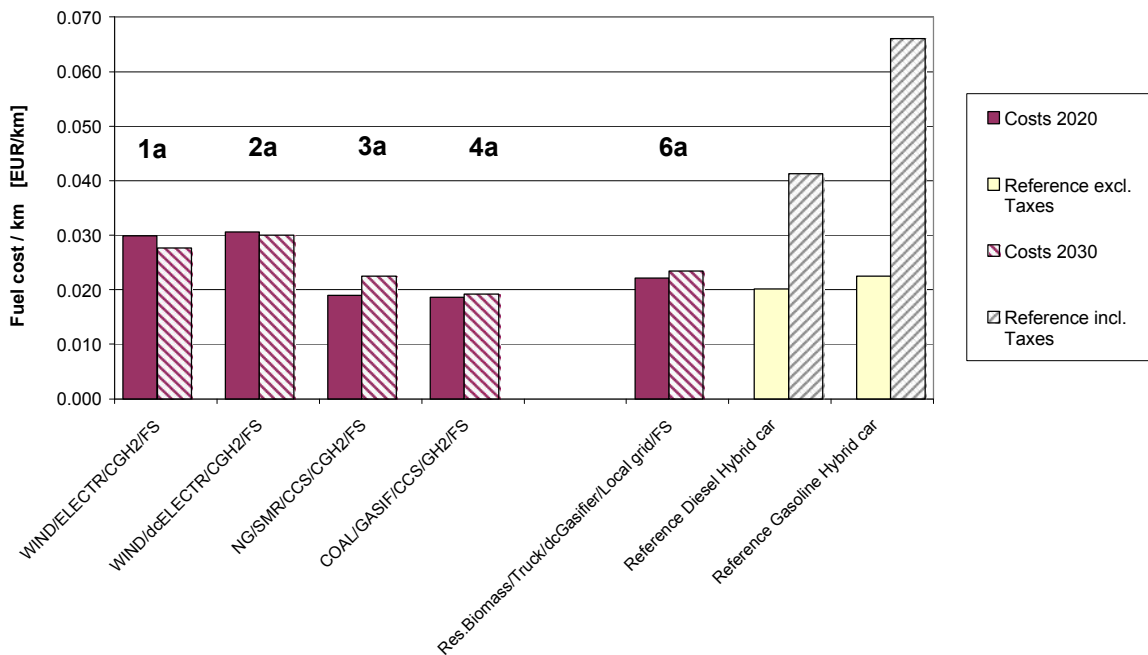


Figure 19. WTW energy cost for hybrid passenger cars in 2020

5.4 Well-to-Stationary Use analysis (WTStU)

Figure 21, Figure 20, Figure 22 and Figure 23 present the results of the WTStU-analysis.

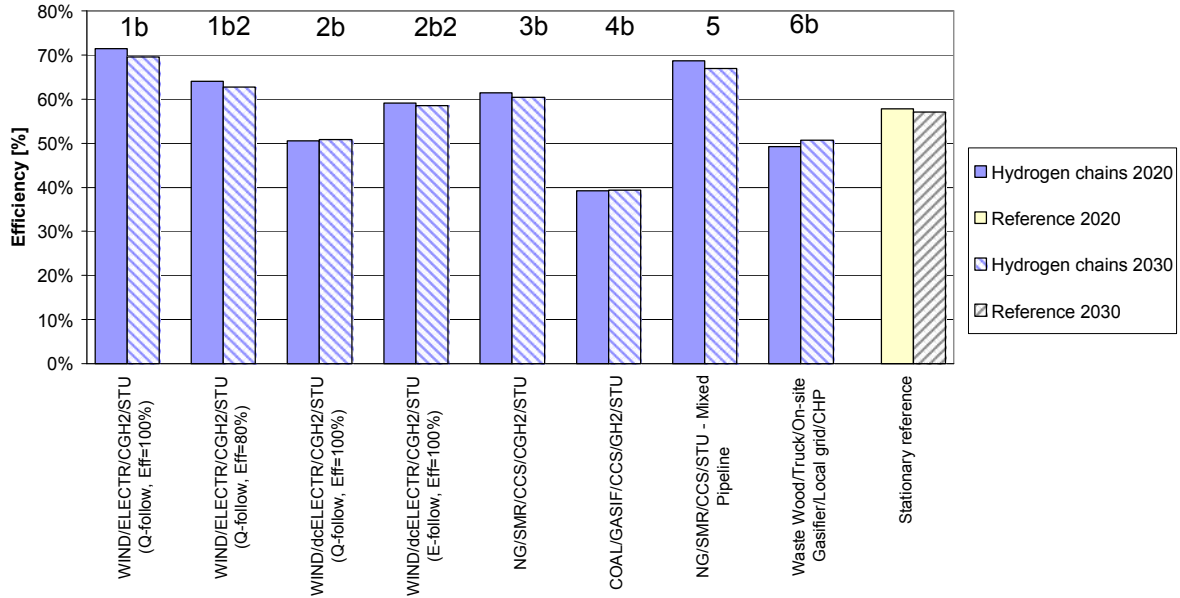


Figure 20. Efficiencies of the Greek WTStU hydrogen energy chains

The energy service provided by these chains (residential micro-CHP) is 1 kWh of electricity and about 3 kWh of heat, equal to the yearly average heat to power ratio of the average energy demand in Greek households. This is different from the WTW chains, where the energy service provided is car-kilometres.

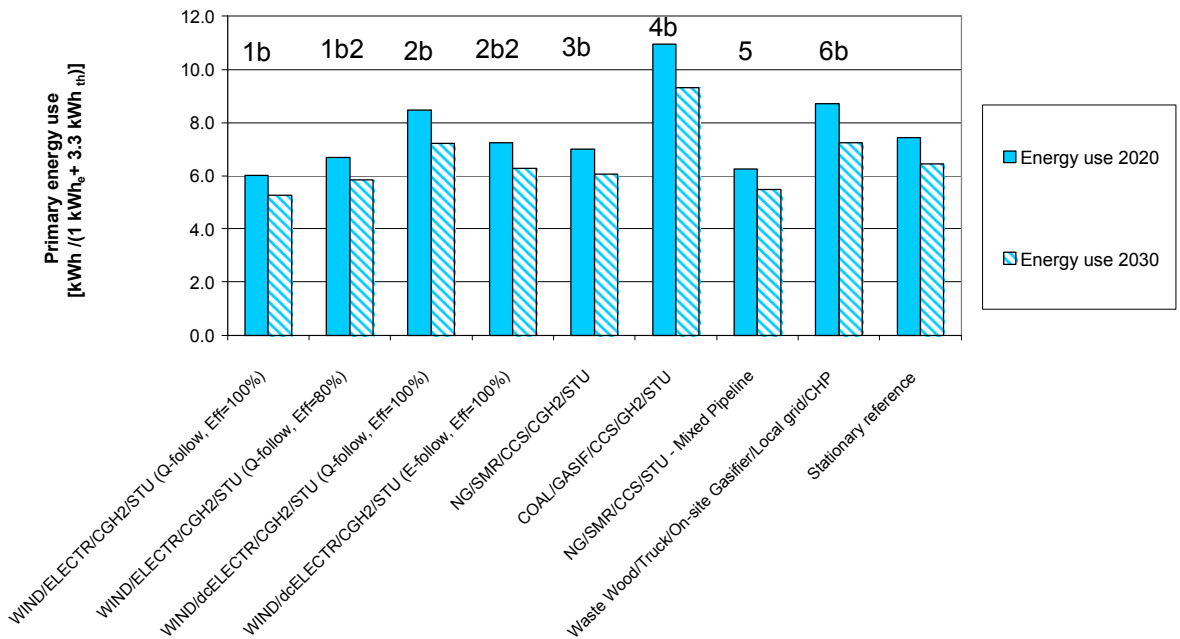


Figure 21. Primary energy use of Greek WTStU hydrogen energy chains

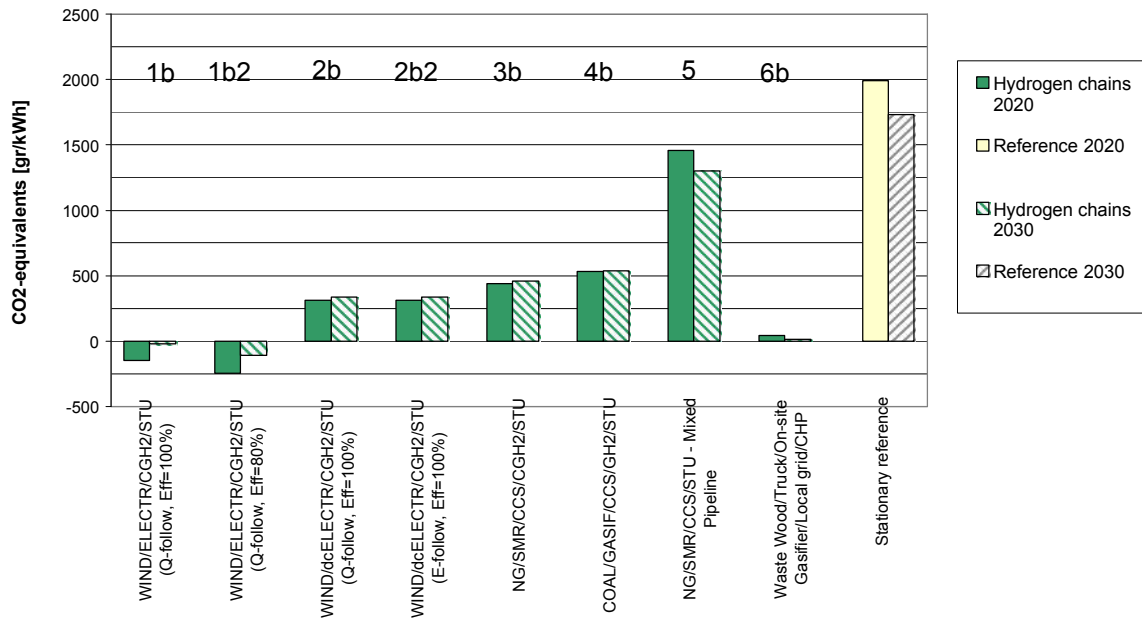


Figure 22. CO₂-equivalent emissions of Greek WTStU hydrogen energy chains

The results are similar to the results of the WTW analysis. Figure 20 shows that with respect to primary energy use, the use of hydrogen in micro-CHP units does not seem to offer a particular advantage with respect to the reference case (electricity from the Greek mix supplied by the grid and heating mainly from conversion of domestic fuel oil and natural gas in boilers).

The lower energy use values for 2030 shown in Figure 21, are the result of an assumed decrease in heat demand and not the result of an increase in efficiency.

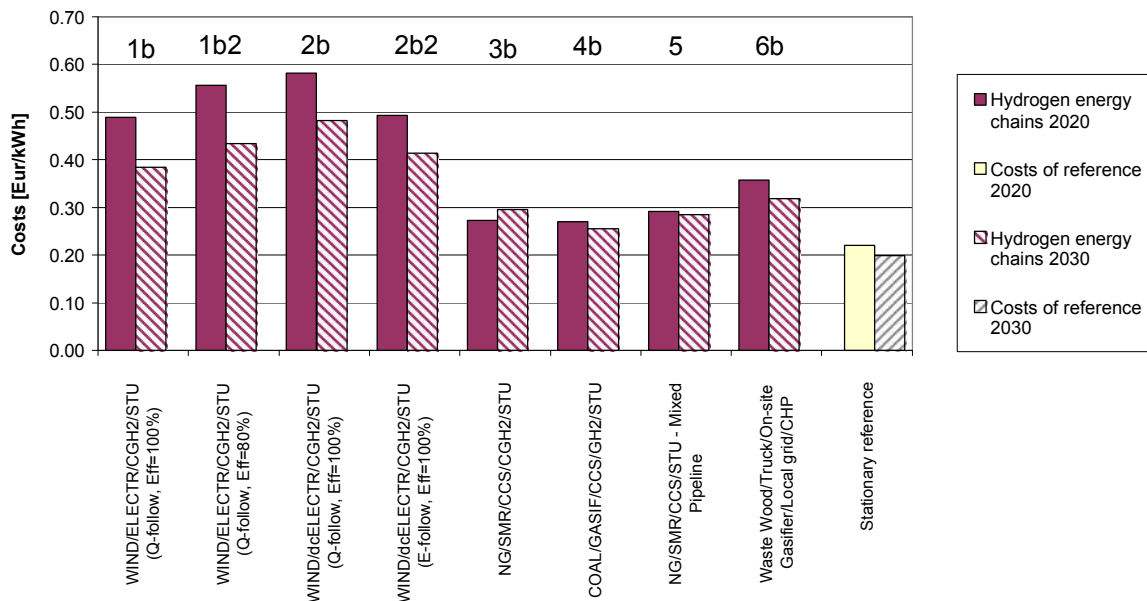


Figure 23. Costs of hydrogen and conventional fuels for Greek WTStU hydrogen energy chains

Figure 22 presents the results for the GHG calculations for the WTStU-analysis including end use of hydrogen. Due to the use of CO₂-free primary feedstocks and the application of CCS in the production of hydrogen, the results on GHG emissions show a clear reduction compared to the reference case, which is based mainly on the use of fossil fuels without CCS.

In the case of the wind energy-based hydrogen energy chains, the value of the GHG emissions becomes negative, meaning that emissions are avoided with respect to the reference. This is due to the production of excess electricity that it is delivered to the grid, avoiding the production of fossil fuel-based electricity elsewhere.

In case 2b there is no compensation for excess electricity. In case 2b2, no excess electricity is produced because it is assumed that the CHP-unit operates in an electricity demand following mode.

The NG-H₂ mixture chain (chain 5) seems to offer an advantage with respect to GHG emissions. The advantage, however, is mainly the result of a switch from domestic fuel oil to natural gas for heating purposes rather than the result of the use of hydrogen. In fact, only a small amount of hydrogen is used in this chain (5% on volume basis approximates 1.5% on energy basis). The effect will be more pronounced if the amount of hydrogen mixed into the natural gas is increased and if CO₂-free feedstock's are used for the production of hydrogen. The last mentioned option would contribute to "the greening of natural gas".

Figure 23 presents the cost of hydrogen (COH) per unit of energy, as defined in this study for an average Greek household. It should be noted that the investment cost of the equipment needed to supply the heat and electricity to the household are not included in the calculations (e.g. CHP-unit and boiler). The results show that the cost of hydrogen for an average household is higher than the cost of energy for the reference case, although a positive cost development is expected from 2020 to 2030. The picture may be somewhat different if taxes are included, similar to what it has been presented for the conventional fuels in Figure 19.

6. Bibliography

1. L-B-Systemtechnik GMBH Ottobrunn. E3-database version 2.0 RC4.
2. Institute for Applied Ecology - Öko-Institut. *Global Emission Model for Integrated Systems (GEMIS)*. Versions 3.03 up to 4.3.0.0.
3. EUCAR/CONCAWE. "*Well-to-wheels analysis of future Automotive fuels and powertrains in the European context*"; Tank-to-wheels report, version 2b. May 2006.
4. National Technical University of Athens. "*PRIMES, Baseline Scenario for Greece. Summary results Primes version 2 Energy Model*" Athens, March 2003.

Annex A Calculation rules

A.1 Conversion factors for Greenhouse Gas Equivalents

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

Table 5. Conversion factors [ref. 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 Greek chains are described.

B.1 Feedstock production

In this section the following feedstock's are considered:

- Natural gas
- Coal
- Biomass
- Electricity

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

B.1.1 Extraction and conditioning of Natural Gas

To be used, natural gas (NG) must be extracted, processed and transported. NG is assumed to be imported from Russia and transported through large pipelines to Greece. In reality, liquefied natural gas (LNG) is also imported from Algeria and used in the Athens region as NG-mixture at a ratio of approximately 80% Russian NG and 20% Algerian NG.

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

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

	I / O	Value	Units
Electricity	I	0.0011	[kWh/kWh]
NG source	I	1.0012	[kWh/kWh]
Process scale	-	1,000,000	[kW NG]
NG	O	1.0	[kWh]
CH 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 amounts 0.0355 €/kWh.

B.1.2 Extraction of Coal

The coal used in Greece is lignite. The lignite is available from two main fields, one in northern Greece and the other in the centre of the Peloponnese. The long-term resources are located in the northern Greece, in the West Macedonia area.

The domestic lignite is characterised by its high moisture and ash content. The energetic characteristics of lignite are assumed equal to a typical mix of European Brown Coal. The values presented in Table 8 represent the amount of energy needed to obtain 1 [kWh] of lignite ready for use in other processes.

Table 8. Input and output data for production of EU-mix lignite

	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 lignite in Greece are 55.2 g CO₂/kWh. The price of coal (lignite) has been harmonised for all analysed Member States within HyWays. For the year 2020, the price of 0.0088 €/kWh has been assumed. For 2030 the price amounts 0.0104 €/kWh.

B.1.3 Electricity production

Electricity mix

The electricity used in the processes considered comes from a European mix (imported electricity in Greece) or from a national production mix. For the production of natural gas in Russia, also the European electricity mix is used in the model as figures from Russia are not available.

In some specific cases, electricity may be considered to come directly from wind turbines. The cost of electricity varies from country to country. The price used for Greece has been taken from PRIMES [ref. 4]. In Annex C it is explained how the cost of electricity used for the Greek mix as presented below, matches the values presented in PRIMES.

According to PRIMES, the Greek electricity mix varies with time. In Table 9 the electricity mix shares for Greece (years 2020 and 2030) and for the EU-15 countries is presented.

Table 9. Electricity production mix for Greece and Europe.
Share in percentage according to the used feedstock.

Source	Greek E-mix 2020 [%]	Greek E-mix 2030 [%]	MIX EU 15 ⁹ [%]
Biomass	0.3	0.5	0.3
Brown Coal (lignite)	42.1	36.9	7.1
Hard Coal	1.3	10.4	19.9
Electricity	0.2	0.2	N.A.
Fuel Oil (1.8%S)	6.6	3.8	-
Wind Power	11.2	12.4	0.2 ⁽¹⁰⁾
Geothermal	N.A.	N.A.	0.1
Hydro	N.A.	N.A.	4.4
Mineral Oil (diesel)	2.7	2.5	8.7
NG	35.3	33.0	12.3
Nuclear	0	0	40.5
Waste	0.3	0.2	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 10.

It is known that the emissions related to the production of electricity in Greece (2005) are approximately 850 gCO₂-equivalents per kWh electricity produced. 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 10. Electricity. Greek production mix and Greek import (EU-mix).

Source	I / O	Greek E-mix 2020	Greek E-mix 2030	EU-mix	Units
Biomass	I	0.0107	0.0168	0.0074	[kWh/kWh]
Brown Coal (lignite)	I	1.0655	0.9344	0.1979	[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	Greek E-mix 2020	Greek E-mix 2030	EU-mix	Units
Hard Coal	I	0.0323	0.2636	0.5570	[kWh/kWh]
Electricity (EU-mix)	I	0.0057	0.0056	-	[kWh/kWh]
Fuel Oil (1.8%S)	I	0.2240	0.1527	-	[kWh/kWh]
Wind Power ¹⁰	I	0.1117	0.1242	0.0044	[kWh/kWh]
Geothermal	I	N.A.	N.A.	0.0016	[kWh/kWh]
Hydro	I	N.A.	N.A.	0.1239	[kWh/kWh]
Mineral Oil	I	0	0	0.2440	[kWh/kWh]
NG	I	0.6731	0.6277	0.3454	[kWh/kWh]
Nuclear	I	0	0	1.1357	[kWh/kWh]
Waste	I	0.0194	0.0157	0.1847	[kWh/kWh]
Electricity	O	1.0	1.0	1.0	[kWh]
CO ₂ emissions	O	578.8	584.1	427.5	[g/kWh]
NO _x emissions	O	0.8018	0.7817	1.0444	[g/kWh]
SO ₂ emissions	O	0.3243	0.3246	1.6032	[g/kWh]
PM emissions	O	0.0663	0.0710	0.2835	[g/kWh]
NM VOC emissions	O	0.0138	0.0123	0.0641	[g/kWh]
CO emissions	O	0.3177	0.3221	0.2617	[g/kWh]
CH ₄ emissions	O	0.0342	0.0349	1.0454	[g/kWh]
N ₂ O emissions	O	0.0233	0.0236	0.0192	[g/kWh]
Equivalent CO ₂ emissions	O	586.5	591.9	457.0	[g/kWh]

Because of the national mix, the total input of primary energy is about 2.14 kWh per kWh of produced electricity leading to an electricity generation efficiency of about 47% in the year 2020. Similar values are obtained for 2030. The production cost of electricity in Greece has been set on 0.053 €/kWh for both years analysed, 2020 and 2030. See also Annex C.

Onshore wind power

An onshore wind energy plant typically consists of a number of single wind turbines. The cost data of the wind turbine for 2020 has been derived from Enercon model E-66 / 20.70, data from the year 2004. The investment presented in Table 11 includes an additional investment for 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 11. Technical and economic data of the onshore wind turbine

Wind Energy, yr 2020	Onshore	Units
Capacity	2	[MW]
Investment	1,501,062	[€]
Maintenance	1.5	[% of investment]
Overhead	3.5	[% of investment]
Useful lifetime	25	[yr]
Equivalent full load period	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). Also the cost of wind turbines has been kept constant with time (cost in 2030 are equal to cost in 2020).

B.1.4 Biomass production and conditioning

The biomass considered as feedstock consists of residues from agricultural activities (crops, straw, olive stones, maize and others) and residues from harvesting and trees. Framed wood is not included. 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 $(18/3.6) \cdot 0.7 = 3.5$ kWh/kg.

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

Table 12. 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 chipping process were set to 0.0189 €/kWh produced biomass chips for 2020 and to 0.022 €/kWh for 2030.

B.2 Transport of Feedstock's

B.2.1 Natural Gas transport

Natural gas is assumed produced in Russia. The distance from the extraction (and processing) point up to the Greek borders is estimated in 7000 km. Consequently, the natural gas is distributed through a regional and a local NG pipeline grid under different pressures to hydrogen production plants. Nearly all transports require mechanical work performed by gas turbines (efficiency = 30%), which use a small amount of the NG for their power. This mechanical work has been modelled in all hydrogen chains using natural gas as feedstock. The Greek system does not have NG grid compression stations yet. The data for the high-pressure (HP ≈ 60 bar) and medium-pressure (MP ≈ 30 bar) natural gas transport pipelines has been derived from [GEMIS 2002].

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

Table 13. Input and output data for NG transport through pipelines

			7000 km HP	250 km HP	50 km MP
	I / O	Units	Value		
Mechanical work	I	[kWh/kWh]	0.0015%	0.0015%	0%
NG (including losses)	I	[kWh/kWh]	1.0112	1.0004	1.000003
NG (delivered)	O	[kWh/kWh]	1	1	1
Process scale	-	[kW NG]	1E+9	1E+8	1E+6
CH ₄ emissions	O	[g/kWh]	0.70	0.025	0.005
Useful lifetime	-	[yr]	20	20	20
Annual full load hours	-	[h/yr]	7500	7500	7500

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

B.2.2 Coal transport

The coal considered in the Greek chains is the national Lignite. The coal is assumed transported by truck from the production region to a gasification plant, at no more than 50 km distance thereof. Characteristics of the coal transport are presented in the next table, expressed in t*km (1 ton coal being transported 1 km).

Table 14. Technical data of the coal transport process

	I / O	Value	Units
Diesel consumption of truck	I	0.26	[kWh/t*km]
Process scale	-	193	[t*km/h]
CO ₂ emissions	O	68.6	[g/t*km]
NO _x emissions	O	0.341	[g/t*km]
CO emissions	O	0.146	[g/t*km]
CH ₄ emissions	O	0.005	[g/t*km]
SO ₂ emissions	O	0.0004	[g/t*km]

Table 15. Economic data of the truck used for coal transport

	I / O	Value	Units
Investment	-	160,000	[€]
Labour costs	-	125,000	[€/yr]
Maintenance costs	-	19,200	[€/yr]
Useful lifetime	-	8	[yr]
Annual full load hours	-	8760	[hr/yr]

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

B.2.3 Electricity transport

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

Table 16. 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]

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

Table 17. 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]

	I / O	Value	Units
Useful lifetime	-	50	[yr]
Annual full load hours	-	5,000	[h/yr]
Transport costs	-	0.02	[€/kWh]

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

Table 18. 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)	-	0.021	[€/kWh]

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

B.2.4 Biomass transport

The biomass used in the Greek chains is agricultural residue. Similar to coal, biomass residues are transported by truck over a distance of 50 km as a maximum. Therefore, Table 14 and Table 15 presented before are also applicable for biomass transportation.

B.3 Hydrogen Production

In this section, the production of hydrogen from the different selected 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). For Greece, only the SMR process coupled to CCS has been selected. SMR data that includes CCS has been derived from a study carried out by Foster Wheeler [Foster Wheeler 1996].

For central SMR plants including CCS, the CO₂ capture is carried out via scrubbing process using aMDEA (activated methyl diethanol amine) units. Thereafter, CO₂ becomes compressed to a pressure of approximately 11 MPa, leading to carbon dioxide liquefaction. The liquefied CO₂ is transported through pipelines and injected into depleted natural gas and oil fields. The SMR plant considered consists of 3 single units (each 94,000 Nm³ H₂/h). In Table 19 technical and economic data used in the models is given.

Table 19. Technical and economic data of the used SMR plant

	I / O	Foster Wheeler¹¹ 1996, C2	Units
Inlet pressure	-	3.4	[MPa]
Discharge pressure H ₂	-	6.1	[MPa]
Process scale	-	844,000	[kW H ₂]
NG consumption	I	1.365	[kWh/kWh _{H2}]
CO ₂ emissions	O	42.7	[g/kWh _{H2}]
CH ₄ emissions	O	0.057	[g/kWh _{H2}]
NO _x emissions	O	0.082	[g/kWh _{H2}]

¹¹ With CO₂ capture and storage

	I / O	Foster Wheeler ¹¹ 1996, C2	Units
CO emissions	O	0.079	[g/kWh _{H2}]
Investment (1996)	-	453,090,000	[€]
Maintenance coefficient	-	2.7	[% of Investment]
Labour	-	546,400	[€/yr]
Overhead	-	0.1	[% of Investment]
Useful lifetime	-	25	[yr]
Equivalent full load period	-	7,884	[h/yr]

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

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

B.3.2 Production of Hydrogen from Coal

With coal as feedstock, the hydrogen is produced through large-scale gasification. For Greece, a gasification system including CO₂ capture and sequestration has been selected.

Table 20. Technical and economic data of hydrogen generation through coal gasification with CO₂ capture and storage

	I / O	Value	Units
Process scale	-	844,866	[kW H ₂]
Lignite consumption	I	2.303	[kWh/kWhH ₂]
CO ₂ emissions	O	20.3	[g/kWhH ₂]
Investment (1996)	-	1,168,100,000	[€]
Maintenance coefficient	-	3.57	[% of investment]
Labour	-	1,090,000	[€/yr]
Overhead	-	0.07	[% of investment]
Useful lifetime	-	25	[yr]
Equivalent full load period	-	7,884	[h/yr]

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 is produced through water electrolysis. The 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 these plants, an economic learning curve has been applied for the investment.

Electrolysers presented in Table 21 have different capacities according to a central or de-central (on site) application.

Table 21. Technical and economic data for electrolysis

	I / O	Central Electrolyser	De-central 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]

	I / O	Central Electrolyser	De-central Electrolyser	Units
Investment (2020)	-	2,200,000	271,812	[€]
Investment (2030)	-	877,930	228,800	[€]
Maintenance	-	0.9	0.9	[% of investment]
Labour costs	-	0	0	[€/yr]
Overhead costs	-	0	0	[% investment/yr]
Useful lifetime	-	20	20	[yr]
Equivalent full load period	-	6000	6000	[h/yr]

B.3.4 Production of Hydrogen from Residual Biomass

Hydrogen produced from residual biomass is obtained through small-scale gasification plants. 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 22. Technical and economic data of hydrogen generation through biomass gasification

	I / O	Value	Units
Process scale	-	5,250	[kW H ₂]
Biomass consumption	I	1.9108	[kWh/kWh]
Hydrogen production	O	1.0	[kWh]
Heat production	O	0.3039	[kWh/kWh]
Investment	-	6,401,067	[€]
Labour costs	-	178,952	[€/yr]
Maintenance costs	-	332,855	[€/yr]
Useful lifetime	-	20	[yr]
Equivalent full load period	-	7,500	[h/yr]
CO ₂ emissions	O	0	[g/kWh]
NO _x emissions	O	0.6208	[g/kWh]
SO ₂ emissions	O	0.0203	[g/kWh]
CO emissions	O	0.2717	[g/kWh]
CH ₄ emissions	O	0.0407	[g/kWh]
N ₂ O emissions	O	0.0121	[g/kWh]

B.4 Transport of Hydrogen

B.4.1 Transport of pure Compressed Hydrogen Gas (CGH₂)

The supply of CGH₂ is performed through a hydrogen pipeline grid. It has been assumed that the hydrogen grid needed in Greece consists of large pipelines (150 or 50 km, depending of chain considered) with a throughput of 240 GWh H₂ per year per pipeline and some smaller pipelines (15 or 5 km, depending of chain considered) with a throughput of 8 GWh H₂ per year per pipeline (Figure 24). 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 23.

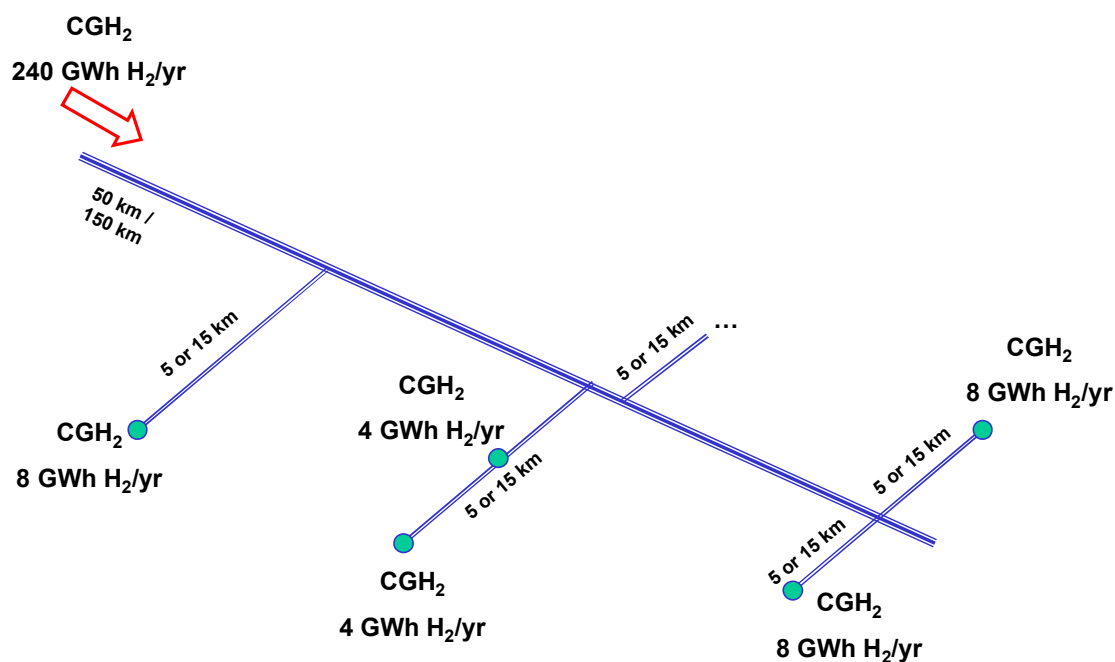


Figure 24. Example of pipeline grid for hydrogen transport

Table 23. Technical and economic data of CGH₂ pipelines

	5 km	15 km	50 km	150 km	Units
Annual hydrogen throughput	8	8	240	240	[GWh H ₂ /yr]
Diameter	100	100	150	150	[mm]
Wall thickness	7.1	7.1	7.1	7.1	[mm]
Required electricity	0	0	0	0.0022	[kWh/kWh]
Investment	0.895	2.685	8.95	26.85	[M€]
Labour, maintenance etc.	21,000	63,000	261,000	783,000	[€/yr]
Annual full load	8000	8000	8000	8000	[hr]
Useful lifetime	30	30	30	30	[yr]

B.4.2 Transport of mixed stream of Natural Gas and Hydrogen

This hydrogen chain was chosen by Greece explicitly, although data has not been validated. It is assumed that a maximum of 5% hydrogen is transported together with natural gas, without adaptation of the (existent) natural gas pipeline grid. The mixture is used as "Hythane", which is a gas mixture without the gases being separated from each other.

Two transport pipeline distances have been considered: 250 and 5 km.

Table 24. Technical and economic data for mixed NG/H₂ pipelines (GEMIS 4.1.3.2)

	I / O	5 km	250 km	Units
Hydrogen input	I	0.0156	0.0156	[kWh / kWh]
Natural gas input	I	0.9844	0.9844	[kWh / kWh]
Mechanical work	I	0	0.0015	[kWh / kWh]
Annual full load	-	8000	7500	[hr]
Useful lifetime	-	30	30	[yr]
Transport costs	-	0.0253	0.0004	[€/kWh]

The mechanical work required for the 250 km mix transport is delivered using some small part of the natural gas being transported. The hydrogen and natural gas inputs and outputs were derived based on a mixture of 5% hydrogen with natural gas on volume basis.

Table 25. Technical data for NG/H₂ mixture

	Volume [m ³]	Energy of stream [kWh]	Normalised energy of stream [kWh/kWh]
Natural gas	0.95	9.462	0.9844
Hydrogen	0.05	0.150	0.0156
Mixture	1.00	9.612	1.0

B.5 Hydrogen End use

B.5.1 Vehicle Filling stations

Two different filling stations for gaseous hydrogen distribution have been modelled. The difference between these filling stations is 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 26 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 C). The assumption of a 10-20 kV level is reasonable if the maximum power demand of the filling station exceeds 1 MW.

Table 26. Technical and economic data for the CGH₂ filling station, year 2004

Filling station size	120 t/yr	1200 t/yr	Units
Annual fuel output	457	4566	[kWh H ₂ /h]
Hydrogen input	1.02 ¹²	1.02	[kWh/kWh]
Inlet pressure	20	20	[bar]
Electricity consumption	0.0704	0.0704	[kWh/kWh _{H2}]
Investment (2020)	231,000	2,548,000	[€]
Investment (2030)	211,000	2,316,000	[€]
Maintenance costs (2020)	3.7	4.3	[% of investment]
Maintenance costs (2030)	3.9	4.5	[% of investment]
Useful lifetime	20	20	[yr]

The filling stations described include dispensers delivering compressed gas hydrogen fuel (CGH₂). For a LH₂ car, a dedicated station is necessary.

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 27 and Table 28 are based on a VW Golf.

Table 27. Passenger hydrogen cars data

	Fuel consumption [kWh/km]	GHG emissions [g CO ₂ equiv./km]
CGH ₂ FC vehicle	0.2611	0.0
CGH ₂ FC hybrid vehicle	0.2325	0.0
CGH ₂ ICE vehicle	0.4653	0.5

¹² A value of 1.02 [kWh/kWh] corresponds to an efficiency of approximately 98%.

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

Table 28. Passenger reference cars data

ICE vehicle type	Fuel consumption [kWh/km]	GHG emissions [g CO ₂ equiv./km]
PISI Gasoline hybrid 1.6 l	0.4492	119.6
DICI Diesel hybrid with DPF	0.4044	108.4

All figures of the WTW-analysis are presented for the most favourable vehicle types. For the hydrogen chains, a hybrid fuel cell car technology was assumed, with an energy use of 0.2325 kWh_{H₂}/km. The expected car energy consumption of fuel cell vehicles varies between 0.2325 and 0.2611 kWh_{H₂}/km. For the mobile references, a hybrid (DICI¹³) diesel car technology including DPF¹⁴ and a hybrid (PISI¹⁵) gasoline car were assumed. The car energy consumption of diesel vehicles is expected to vary between 0.3919 (without DPF) and 0.4908 kWh_{diesel}/km. The car energy consumption of gasoline vehicles is expected to vary between 0.4492 and 0.5278 kWh_{gasoline}/km. Vehicle data of these and other cars is given in section B.5.2 of Annex B.

B.5.3 Stationary use of Hydrogen

Next figure gives an example of a heat-demand following system as modelled for the WTStU Greek hydrogen energy chains. The values of electricity and heat shown (right side of the scheme) represent the energy demand of a Greek household, as predicted by PRIMES for the year 2020. The values within the dotted box follow from ECN internal computations for a heat-demand following CHP-system.

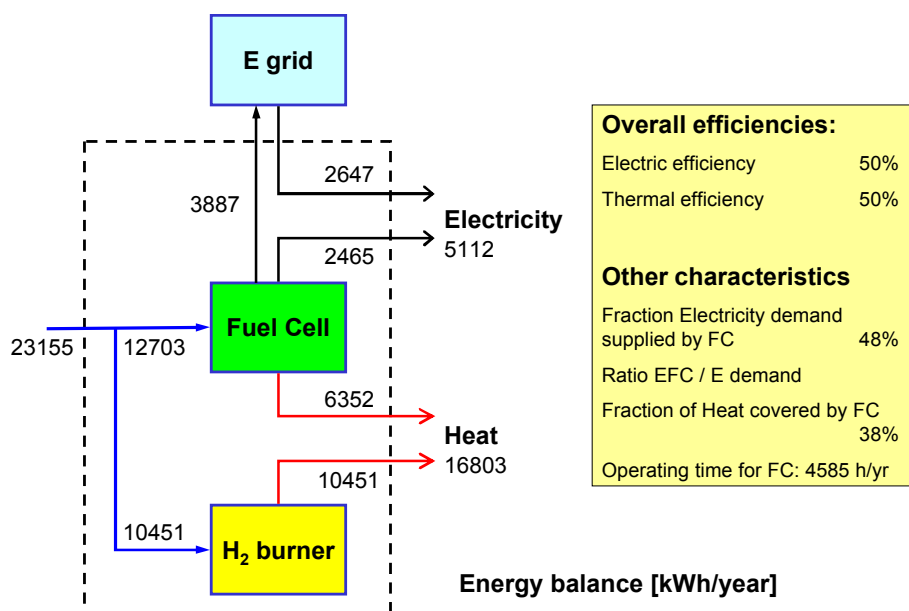


Figure 25. Supply of electricity and heat for a Greek household (2020), Q-following system.

¹³ DICI = Direct Injection Compression Ignition

¹⁴ DPF = Diesel Particulate Filter

¹⁵ PISI = Port Injection Spark Ignition

The electrical capacity of the CHP-system is assumed 1.5 kW. At the same time, the system produces 1.5 kW of heat, which can be used for space heating and/or tap water heating. In addition to the fuel cell, the system is equipped with a hydrogen boiler to meet heat peak demands. Similar to the fuel cell system, the boiler efficiency is assumed to be 100%. Furthermore, it is assumed that the system operates in heat-demand following mode. Consequently, sometimes electricity is produced when there is no electricity demand. This excess electricity is delivered back to the grid. If there is demand for electricity but there is no production, or if the electricity demand is larger than its production, the household obtains electricity from the grid. It is assumed that this electricity out of the grid is produced from the Greek fuel mix.

In the following tables all characteristics of the modelled CHP-systems (Q-following and E-following, 80% and 100%) for the years 2020 and 2030 are given. Electric and heat consumption of the Greek households have been taken from PRIMES [ref. 4].

Table 29. CHP-system (heat following) for a Greek household, 100% boiler efficiency

	I/O	year 2020	year 2030	Units
GH ₂	I	4.5300	3.7039	[kWh/kWh]
Electricity from grid	I	0.5178	0.5518	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	3.2872	2.6689	[kWh/kWh]
Electricity to grid	O	0.7608	0.5867	[kWh/kWh]
Process scale	-	5	5	[kWh/h]
Electric efficiency (CHP)	-	50	50	[%]
Thermal efficiency (CHP)	-	50	50	[%]
Burner efficiency	-	100	100	[%]
Equivalent full load period	-	8760	8760	[h/yr]
Useful lifetime	-	20	20	[yr]

Table 30. CHP-system (heat following) for a Greek household, 80% boiler efficiency

	I/O	year 2020	year 2030	Units
GH ₂	I	5.2611	4.3166	[kWh/kWh]
Electricity from grid	I	0.4368	0.4786	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	3.2872	2.6689	[kWh/kWh]
Electricity to grid	O	0.8467	0.6555	[kWh/kWh]
Process scale	-	5	5	[kWh/h]
Electric efficiency (CHP)	-	50	50	[%]
Thermal efficiency (CHP)	-	30	30	[%]
Burner efficiency	-	80	80	[%]
Equivalent full load period	-	8760	8760	[h/yr]
Useful lifetime	-	20	20	[yr]

Table 31. CHP-system (electricity following) for a Greek household, 100% boiler efficiency

	I/O	year 2020	year 2030	Units
GH ₂	I	3.7692	3.1170	[kWh/kWh]
Electricity from grid	I	0.5178	0.5518	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	3.2870	2.6687	[kWh/kWh]
Electricity to grid	O	0	0	[kWh/kWh]
Process scale	-	5	5	[kWh/h]

	I/O	year 2020	year 2030	Units
Electric efficiency (CHP)	-	50	50	[%]
Thermal efficiency (CHP)	-	50	50	[%]
Burner efficiency	-	100	100	[%]
Equivalent full load period	-	8760	8760	[h/yr]
Useful lifetime	-	20	20	[yr]

For the Greek hydrogen energy chain 5, a typical household consuming the produced mix is modelled, based on the energy consumption pattern derived from PRIMES [4]. The CO₂-equivalent emissions resulting from the use of this mix are derived from the specific CO₂-equivalent emission of natural gas, being 197.5 [g/kWh] at complete combustion (no methane emissions). These values are given in the next table:

Table 32. H₂-NG mixture boiler and electricity consumption of a typical Greek household, 100% boiler efficiency

	Input/Output	year 2020	year 2030	Units
H ₂ -NG mixture	I	3.2872	2.6689	[kWh/kWh]
Electricity from grid	I	1.0	1.0	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	3.2872	2.6689	[kWh/kWh]
Process scale	-	5	5	[kWh/h]
CO ₂ -emissions ¹⁶	O	639.1	518.9	[g/kWh]

The emissions resulting from the winning and processing of fossil fuels involved and the emissions from the use of electricity are accounted in other modelled processes of the chain.

For the comparison of stationary use of hydrogen, a reference case was also modelled. In the reference, a typical Greek household consuming a mix of fuels was modelled. In the next table, the fuel mix used in Greek households and the efficiencies in energy conversion are given.

Table 33. Electricity and heat consumption of a typical Greek household, normalised values with respect to electricity use

	Normalised energy consumption 2020 [kWh/kWh _e]	Normalised energy consumption 2030 [kWh/kWh _e]	Conversion efficiency [%]	Specific CO ₂ -emissions [g/kWh]
<u>Heating purposes</u>				
Solar energy	0.0476	0.0398	95%	0
Diesel oil	3.0567	2.4807	73%	260.5 ¹⁷
Natural gas	0.1611	0.1308	100%	197.5 ¹⁸
<u>Electricity use</u>				
Electricity from grid	1.0	1.0	100%	0 ¹⁹

Based on the table shown above, a typical Greek household as used in the reference is modelled as follows:

Table 34. Boiler and electricity consumption of a typical Greek household, based on fuel mix

	Input/Output	year 2020	year 2030	Units
Solar energy	I	0.0501	0.0419	[kWh/kWh]
Diesel oil	I	4.3573	3.5360	[kWh/kWh]

¹⁶ Emissions from fossil fuels burned with a boiler. No NO_x or other emissions considered due to lack of data.

¹⁷ Based on a specific energy of diesel equal to 11.9 kWh/kg (LHV)

¹⁸ Based on a specific energy of NG equal to 13.885 kWh/kg (LHV)

¹⁹ Emissions equal zero when electricity is used. Emissions due to electricity production are already accounted earlier in the chain.

Natural gas	I	0.1511	0.1227	[kWh/kWh]
Electricity from grid	I	1.0	1.0	[kWh/kWh]
Electricity to user	O	1.0	1.0	[kWh]
Heat to user	O	3.2872	2.6689	[kWh/kWh]
Process scale	-	2.5	2.5	[kWh/h]
CO ₂ -emissions ²⁰	O	1165	945	[g/kWh]

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)
- Heating plant
- Production of diesel

B.6.1 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 Greek hydrogen chains, this process has been used for all gas transports through pipelines longer than 200 km.

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

	I / O	Value	Units
Natural gas	I	3.3333	[kWh/kWh]
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.6.2 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 36. 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]

²⁰ Emissions from fossil fuels burned with a boiler. No NO_x or other emissions considered due to lack of data.

	I / O	Value	Units
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.6.3 Production of Diesel

Diesel is used as fuel for mechanical conversion of energy. In the selected hydrogen chains two processes use diesel as fuel: truck transport and chipping of biomass.

Table 37. 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 (2020)	-	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.

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

Cost of electricity

According to PRIMES [ref. 4], two levels of electricity prices can be distinguished: Cost of electricity for the industry and cost of electricity for households. The electricity costs given by PRIMES for the years 2020 and 2030 are presented in the next table.

Table 38. Greek electricity costs (source: PRIMES)

User	Electricity tariff 2020 [€/kWh]	Electricity tariff 2030 [€/kWh]
Households	0.098	0.098
Industry	0.077	0.077

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

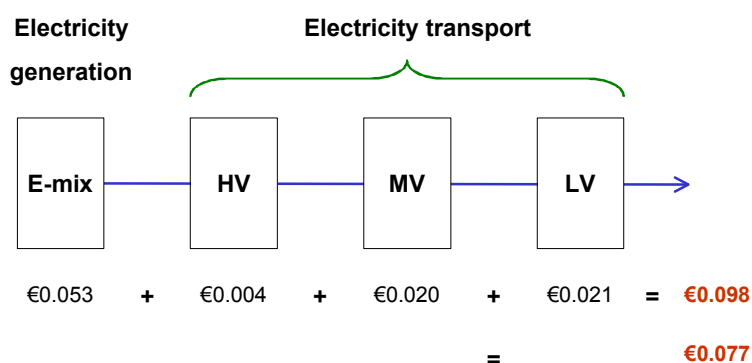


Figure 26. Scheme of electricity costs structure for Greece

The cost of electricity transport at high- and medium voltage level are more or less the same for all European countries, leaving specific Greek 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 Greece.

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.1.3, onshore wind power. For Greece, a yearly onshore full-load hours factor of 0.285 has been assumed for 2020, corresponding with 2500 hours a year.

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