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AFTEEM ESTO STUDY

Introduction of alternative transport fuels in the European Energy Market: Techno-economic barriers and perspectives

Work package D: Hydrogen

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List of abbreviations

c	euro cent
(c.)	centralised
cs	carbon sequestration
CCGT	combined cycle natural gas turbine
CD	conventional driveline
CGH ₂	compressed gaseous hydrogen
CO ₂	carbon dioxide
FC	fuel cell
flh	full load hour
GH ₂	gaseous hydrogen
GHG	greenhouse gas
GM	General Motors
H ₂	hydrogen
HCN	hydrogen cyanide
HDPE	high density polyethylene
HVDT	high voltage direct current transmission
IEA	international energy agency
JAERI	Japan atomic energy research institute
kWh	kilowatt hour
LH ₂	liquid hydrogen
LNG	liquid natural gas
N.A.	North Africa
NG	natural gas
(o.)	onsite
OCU	open cycle unit
PAFC	phosphoric acid fuel cell
PAH	polycyclic aromatic hydrocarbon
PE	primary energy
PED	primary energy demand
PEM	polymer electrolyte membrane
PSA	pressure swing adsorption
PVC	polyvinyl chloride
S-I technology	Sulphur-Iodine technology
Sot.	solar thermal
WTT	well-to-tank
WTW	well-to-wheel

Executive Summary

In its Communication from 2001,¹ the EC suggests the use of hydrogen as a tool to secure and diversify the energy supply, as well as to decrease the CO₂ emissions from road transport in the EU. Therefore, target shares for hydrogen market penetration are proposed for the 2015-2020 timeframe. However, the use of hydrogen as a fuel is not a straightforward solution and there are a variety of competing technologies for the different steps of processing the fuel.

The objective of this study was to analyse alternative technological options for the production, transport and delivery of hydrogen with respect to the security of energy supply, greenhouse gas emissions, primary energy demand and costs in the transport sector.

In the first step of the techno-economic assessment, the most relevant technologies for hydrogen production, hydrogen compression and liquefaction, hydrogen delivery and hydrogen storage were analysed with the focus on process description, process availability and general advantages/disadvantages. An evaluation of a hydrogen economy has to be based on the evaluation of all the relevant process steps in order to be able to investigate the effects of combining a large number of technological options. Therefore, in Chapter 3, a so-called Well-to-Tank (WTT) or pathway analysis was carried out which accounts for the GHG emissions, the primary energy consumption and costs over the entire fuel pathway, from feedstock to fuel dispenser nozzle. It has to be kept in mind that most of the processes regarded are not at an advanced stage of development but in an experimental stage and the estimation of further technical progress and learning curves for cost reduction involves large uncertainties. Technical and economic data have to be understood as projections rather than as precisely determined values.

Producing hydrogen based on renewable feedstocks is one of the most promising solutions from an environmental perspective, however the resource availability of the various renewable energy carriers remains an open question. In chapter 4, the technical and economic potentials of renewable energy carriers for hydrogen production were analysed, taking into account the competitive situation with electricity production based on renewables.

Current research and patent activities give indications of the interest of companies as well as of governments in competing technological options. Such an analysis was carried out in Chapter 5, focusing on activities with at least one German partner and publicly financed research activities.

¹ COM (2001) 547

When different technological solutions are combined to make **Well-to-Tank pathways**, the main conclusions are:

- no clearly preferable solution emerges from reviewing complete hydrogen pathways using the three evaluation criteria of CO₂ emissions, primary energy demand and costs. Pathways based on **reforming natural gas** offer a good compromise. They perform well with respect to primary energy demand and costs (at 4 to 6 c/kWh these pathways are the cheapest) and have moderate CO₂ emissions compared to other fossil feedstock based pathways. Reforming of natural gas even remains the cheapest option if carbon sequestration is conducted and the total primary energy demand also remains moderate. But it has to be kept in mind that gas resources are limited. Furthermore, there is an increasing use of gas in other sectors such as electricity production and space heating. Taking climate policy into account, it has to be analysed in which sectors or for which applications gas should be used in the near future.
- Focusing on climate policy, the **renewable pathways, the nuclear pathways and the coal and natural gas pathways with CO₂-sequestration** have the lowest CO₂ emissions over the entire pathway. On the other hand, the costs of renewable pathways are much higher than for those with natural gas reforming and coal gasification without sequestration. Only a very high charging of CO₂ – emissions (about 50 €/t CO₂) can harmonise the total cost of renewable and fossil fuel based pathways. A general problem with regard to the use of renewable energy sources (RES) for hydrogen production is the competition with the use of renewable energies in the electricity system. Generally we find that the electricity system will not show large RES over-capacities. One option to avoid the conflict with the production of electricity could be to buffer the fluctuations of wind energy capacities by producing hydrogen during periods of very high wind power production. This strategy would even improve the performance of electricity systems with a large share of wind power. Taking into account the future potential of renewable energy carriers, the conclusion can be drawn that only the solar energy pathway with production in North Africa has a high potential and low conflict with renewable electricity production, but this pathway also has the highest cost compared with all others. The gasification of residual wood has the lowest costs of all the renewable pathways analysed. But the potential of this biomass option is limited. Furthermore, there is strong competition to use this energy carrier for electricity generation or space heating. For this reason, the direct use of biofuels in the transport sector has to be regarded as an alternative to the production of hydrogen based on biomass.
- Using **nuclear power** plants to produce electricity and then converting the electricity to hydrogen results in low CO₂ emissions, but a very high primary energy demand due to the low efficiency of the nuclear power plants. It has the lowest costs compared to all other electricity-based pathways, but these are still higher than natural gas reforming or coal gasification pathways without CO₂ sequestra-

tion. Furthermore, the controversial discussion about the use of nuclear power has to be taken into account.

- A strategy to **extend the full load hours** of existing middle load power plants is not very promising. Due to the saved investments for power plants, the total cost can be reduced by a small amount compared with the other pathways based on electrolysis of water, but the primary energy demand as well as the CO₂ emissions are relatively high compared to the natural gas reforming pathway, the coal gasification pathway or the renewable pathways.
- From the point of view of resource availability, the **gasification of coal** is a promising option. However, looking at CO₂ emissions, CO₂ sequestration would have to be carried out, which causes significantly higher costs (by about a factor of 1,5). Nevertheless compared to most pathways based on electrolysis, the total costs of the coal and sequestration pathways are lower. However, the removal, disposal and storage of CO₂ is not a standardised industrial process and there are unresolved issues with regard to technical solutions and environmental risks.
- The effect of emissions trading on the total cost is only noticeable at a very high charge for CO₂ emissions of about 50 €/t CO₂. If this is applicable then the differences between the total cost of renewable and fossil fuel based pathways are diminishing.

From the examination of the **set of different technological solutions in the hydrogen subsystems** (hydrogen production, compression/liquefaction of hydrogen and delivery of hydrogen), the following conclusions can be drawn:

- electricity production and electrolysis have a dominant influence on cost figures for **hydrogen produced** using this method. Conventional energy carriers have a significant cost advantage compared to the renewable energy pathways possible for electricity production. The cost figures for electrolysis are significantly higher than other hydrogen production options such as reforming or gasification. Bearing these figures in mind, it is understandable that most of the patents in the hydrogen production sector focus on steam reforming, which is currently the leading technology for the production of hydrogen. However, driven by the interests of governments and public foundations, electrolysis is actually the most publicly researched hydrogen production technology because it is the key technology for using renewable energy carriers like wind and solar energy as well as nuclear energy for hydrogen production.
The process efficiency of electrolysis is in the same range as natural gas reforming and is lower than that of coal gasification.
- Due to the comparably small specific energy content of hydrogen per volume, the hydrogen produced has to be **compressed or liquefied for transport and storage**. Looking at the costs involved, liquefaction is the most expensive option (by a factor of approximately 1.3). Assuming centralised hydrogen production

solutions with transportation of hydrogen to the filling stations, the costs of liquefaction increase drastically compared with the costs of compression. The reason is that liquefied hydrogen has to be transported by cryogenic trucks or trains and these transport options are more expensive than transporting compressed hydrogen via pipelines.

- If conventional energy carriers are used, the CO₂ emissions resulting from compression are only one third of those from the liquefaction process due to the different primary energy demands of compression and liquefaction.
- The **hydrogen distribution** costs are negligible compared to the other costs of a hydrogen economy. The only exception are the distribution costs for the transport of hydrogen, produced in North Africa by using solar power, to Europe. Of the different transport options, pipelines represent the most cost effective solution. Concerning the primary energy demand and the CO₂ emissions, the transport sub-system has no relevant influence on the total pathway figures. It was found that the number of R&D projects and patents in the subsystem distribution lag behind those in the other subsystems. This indicates that the distribution of hydrogen is not seen as a major problem or as an issue that can be resolved later (a so-called “chicken and egg problem”: investments in infrastructure or in application of hydrogen first?).
- Centralised hydrogen production is considered more cost effective and environmentally friendly than onsite production due to its higher efficiency and the generally low impact of transport figures on the total cost of a pathway.

If the WTT analysis is extended to a **Well-to-Wheel (WTW)** analysis by integrating data from moving the vehicle through its drive cycle, which was only realised in this study to a very limited extent, today's conventional pathways (gasoline and diesel-fuelled combustion engines) can be compared with hydrogen pathways (fuel cell-propelled vehicles) and the following conclusion can be drawn:

- Looking at the CO₂ emission balance, hydrogen pathways based on renewables, nuclear and coal with CO₂-sequestration have a relevant advantage compared with the conventional pathways. However, these are the hydrogen pathways with high costs. The natural gas pathways with steam reforming also shows advantages with respect to CO₂ -emissions, but not in the same degree. Pathways based on EU-mix electricity have the same range of CO₂-emissions compared with the conventional drive system pathways. However, it has to be regarded, that the conventional pathways have a potential for CO₂ -emissions reduction and also other alternatives like hybrid motors exist.

1 Introduction

About 50 % of Europe's final energy demand comes from imported energy carriers and this figure is projected to reach about two thirds in a baseline scenario, see Capros (2003). The dependency on imported liquid fuels amounts to about 72 % of the European oil consumption and may even increase up to 93 % by 2020, due to the depletion of the EU's own oil resources. The transport sector accounts for about 20 % of EU gross inland energy consumption and is responsible for about 67 % of the final oil demand in the EU. These facts demonstrate the serious problems caused with regard to the issue of security of supply by the extensive use of oil products for the transport sector and for the economy as a whole. Additionally global resources, especially for oil, are limited and, as far as we know today, the best oil fields have already been exploited. Furthermore the transport sector is responsible for about one third of European CO₂ emissions and the total emissions of this sector are expected to increase by 50 % up to 2020.

In this context, the EU Commission has taken the initiative to propose the introduction of alternative fuels in the transport sector and set a target of substituting 20 % of traditional fuels by alternative fuels by 2020². Hydrogen plays an important role in this strategy. Hydrogen should be used as a transport fuel (in fuel cells and/or internal combustion engines) after 2015, targeting a 5 % penetration in transport fuel by 2020.

If this target is to be realised, sizeable investments are required for new production, storage and distribution systems and new vehicle propulsion techniques have to be developed. There are various competing technological options to realise the first step towards a hydrogen economy and the development of a hydrogen roadmap is a challenging task.

This study addresses the following topics:

- A techno-economic assessment of hydrogen production methods for the transport sector is carried out. The analysis includes a comparison of different sources that can be used to produce hydrogen, including fossil fuel sources (with and without carbon sequestration for production from coal and natural gas), biomass, other renewables and nuclear energy.
- A critical comparison is made of the hydrogen delivery options, including gaseous hydrogen (via pipelines) vs. liquid hydrogen (via cryogenic truck and ship), with the emphasis on compression/liquefaction costs and losses.

This chapter is organised as follows: A techno-economic description of the most relevant technologies in the hydrogen subsystem production and delivery is provided based on an extensive literature evaluation and interviews with experts from industry and research institutions. In order to assess the hydrogen use in the transport sector, various pathways have been established combining feedstock preparation, production, transport and storage. In section 3, 26 different pathways are evaluated using the criteria of CO₂ emissions, primary energy demand and costs. To do so, a number of recent studies were utilised and accompanied by setting up FhG-ISI's own databases. The opportunities of renewable energy sources

² COM (2001) 547

(RES) as a feedstock for hydrogen production are assessed in section 4 with regard to expected potential. In the final section, the research activities and patents for hydrogen subsystems are evaluated using a specially developed database in order to analyse additional information about the priorities of industry and governments.

2. Technical Description and Technological Aspects

2.1 Introduction

Although hydrogen is the most abundant element in the universe, it is not found in its pure form since it readily combines with other elements to form substances such as water, and fossil fuels (coal, natural gas, crude oil). For hydrogen to be utilised as a fuel, however, it must be in its pure form, which means hydrogen must be separated from the elements with which it combines. This is not always a simple process. It involves numerous physical, chemical and biological processes, which consume energy, capital and emit some pollutants. In this section, all these processes are analysed thoroughly, including the advantages, disadvantages, future prospects, future improvements and environmental aspects. The issue of hydrogen storage and distribution (delivery) is another major challenge facing the use of hydrogen as a fuel for transportation. Hydrogen has a very low density, which means it has to be compressed or liquefied for proper storage and distribution.

2.2 Features and technical description of the production, distribution and storage of hydrogen

There are various processes and techniques available to produce hydrogen, which vary in their stages of development and thus, can be classified into the following categories:

- (i) conceptual technology
- (ii) fundamental research
- (iii) applied demonstration
- (iv) proven technology
- (v) fully developed commercial technology

The different processes of hydrogen production can be grouped into four main categories, depending on the kind of process involved, the type of reaction taking place and the source of energy for the process. Listed below are the different processes:

- Thermochemical processes
 - steam reforming process
 - partial oxidation
 - autothermal reforming
 - coal / biomass gasification
 - off-gas clean-up
 - thermal decomposition of water
- Electrochemical processes
 - water electrolysis
 - steam electrolysis
 - high pressure water electrolysis
- Photoprocesses

- photobiological process
- photochemical process
- photoelectrochemical process (photoelectrolysis)
- Other innovative hydrogen production processes
 - radiolysis
 - solar hydrogen
 - thermochemical water splitting

2.2.1 Thermochemical Hydrogen Production Processes

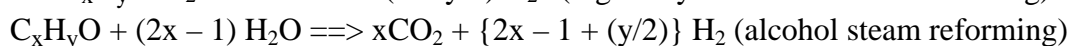
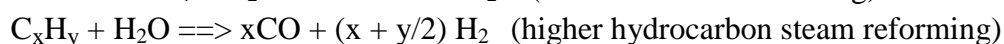
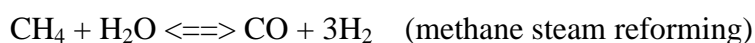
2.2.1.1 Steam reforming process:

This is a process that is already in use, mainly in refineries during crude oil distillation (cracking process). Large quantities of hydrogen are used to modify the structure of the cracked hydrocarbon molecules. The steam reforming process is a well developed process and needs no introduction in the chemical, petroleum and process industries. It is considered as a *fully developed commercial technology*.

(a) *Process description*: the main process step involves the reaction of steam with a light hydrocarbons (such as methane) over a catalyst at a temperature over 700°C and pressure 3-25 bar to form hydrogen and carbon oxides.

The steam reforming process is carried out in the following steps to remove impurities and maximise hydrogen production.

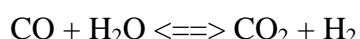
- *Purification of feed materials*: the trace elements in the hydrocarbon feed such as sulphur, chlorine and heavy metal compounds are toxic to the catalysts used in the steam reforming process. The commonest is sulphur. The level of sulphur compounds in the hydrocarbon depends mainly on the source, pre-treatment and molecular weight of the hydrocarbon. The sulphur is removed from the feed by converting the organic sulphur species to hydrogen sulphide over a hydrodesulphurisation catalyst. The catalyst removes the organo-sulphur compounds by reacting with hydrogen to convert the sulphur to hydrogen sulphide. The final purification step is the removal of hydrogen sulphide with an absorbent (zinc oxide absorbent). The same catalyst similarly converts any organo-chloride species to hydrogen chloride and also acts as an absorbent for most problematic metal species.
- *Steam reforming*: This is the main hydrogen production process. The main steam reforming reactions are :



The reaction takes place on a nickel catalyst packed in tubes in a fired furnace. This is an endothermic reaction.

The produced stream of gases consists of hydrogen as well as CO, CO₂, water and unconverted methane. A ‘water gas shift reactor’ is subsequently employed to increase the hydrogen yield by promoting further the conversion of methane and CO to CO₂ and H₂. The hydrogen produced has to be purified before it can be used directly. Carbon monoxide and other impurities often accompany hydrogen and have to be removed because the carbon monoxide, especially, is toxic to the anode of a PEM (Polymer Electrolyte Membrane) fuel cell or PAFC (Phosphoric Acid Fuel Cell) as it adsorbs onto the surface of the platinum catalysts.

- *Water-gas shift reaction:* in this step, the carbon monoxide produced reacts with additional steam to form more hydrogen and carbon dioxide.



This reaction does not eliminate all the carbon monoxide present, the residual gas must still undergo another purification step to decrease the carbon monoxide concentration. The purification step mainly implemented in industries is the “*pressure swing adsorption*” (PSA).

- *Pressure swing adsorption:* in this system, the hydrogen-containing gas is passed through several adsorbent columns that adsorb the carbon monoxide and other impurities in the gas at high pressure, leaving the hydrogen unreacted and purified. The adsorbent can be regenerated by dropping the pressure of the system and flushing out the impurities. Using today’s technology, the hydrogen gas can easily obtain 99.9% purity after this process.

There are other methods and processes for hydrogen purification such as *selective oxidation reaction, membrane reaction, methanation reaction, rectisol process etc.*

(b) *Advantages:*

1. This is the most developed and reliable process in comparison to all other processes for hydrogen production.
2. It produces hydrogen with a high degree of purity.
3. Operation is stable over a very large range of operating conditions.

(c) *Disadvantage*

1. The reaction is highly endothermic, so about 25% of the methane is burned to provide the necessary heat.
2. The methane is burned using oxygen [referring to (1)] which probably comes from air; air contains about 75% - 80% nitrogen which can form nitrogen oxides which is a pollutant. Further processing is then required to remove the NO_x.
3. Natural gas, which is usually the feed input contains some sulphur compounds and other impurities which have to be removed before the main reforming process (although not a serious disadvantage but worth mentioning since it adds to the cost of the process).

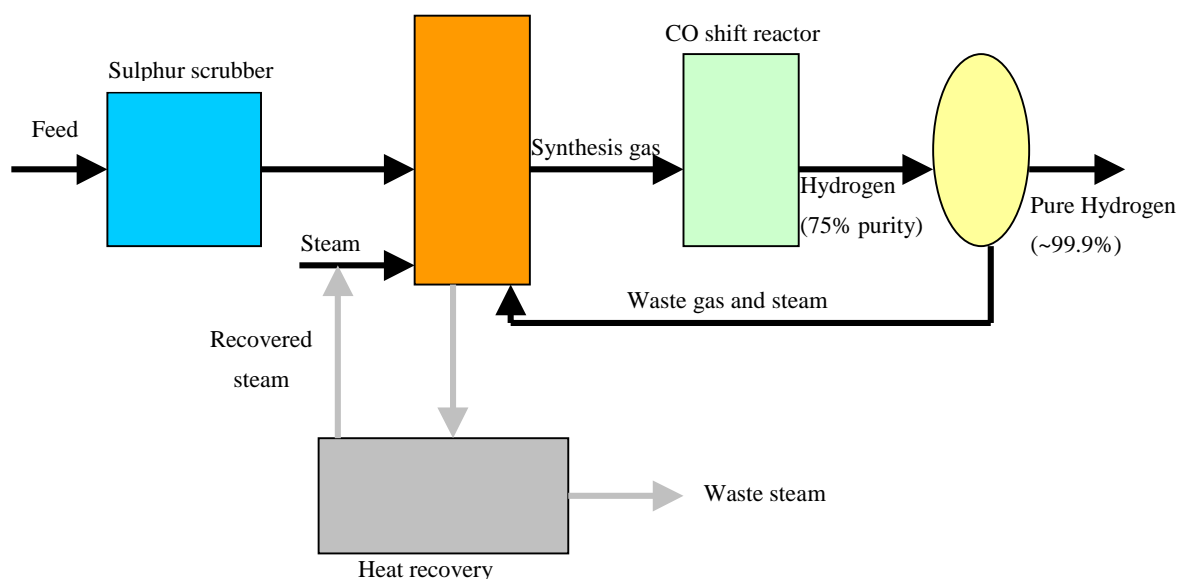


Figure 2-1 A typical diagram of steam reforming process plant

Work is proceeding in building a modified steam reformer with a built-in CO₂ remover. This will make it possible to produce hydrogen at a lower temperature than regular steam reformers. These reformers will reduce cost of hydrogen production by 25 – 30% compared to conventional technology, mainly due to reduced capital and operating expenses [US DOE, Hydrogen Program 2000].

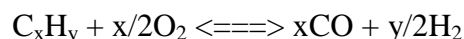
Steam reforming process is an endothermic process and requires quite a lot of heat which can be obtained from a fossil-fired heat source. A high temperature nuclear reactor can solve this problem by providing the needed heat for the reforming process. The heat is transferred via an intermediate heat exchanger, so the primary coolant remains isolated. Japan Atomic Energy Research Institute (JAERI) is planning to launch the world's first nuclear powered steam reforming hydrogen plant in 2008 [more information on this can be downloaded from the MPR Associates Inc. website at www.mpr.com/pubs/profile/pf9_hydrogen.html].

2.2.1.2 Partial oxidation of hydrocarbons

Heavy hydrocarbons are not reformed by the steam reforming process, but by a process known as *partial oxidation* due to their low volatility and often high sulphur content. Partial oxidation is the thermal conversion of heavy hydrocarbons (e.g. oil residues, diesel oil) with reduced amounts of pure oxygen. Methane can also be partially oxidised to produce hydrogen but heavy hydrocarbons are preferred. This process takes place at a temperature range of 1200 – 1600°C and pressure of up to 150 bar [Albrecht, 2001]. The oxygen to steam ratio is controlled so that the gasification continues without the use of additional energy. Partial oxidation can be catalytic or non-catalytic. Non-catalytic processes for hydrocarbon reforming require high temperatures over 1000°C, this necessitates the use of special materials

of construction and significant preheating and thermal integration of process streams. The use of a suitable catalyst (catalytic oxidation) reduces the operating temperature ($\sim 800^\circ\text{C}$ or lower), allowing the use of common and cheaper reactor materials such as steel.

The chemical reaction that takes place during the process is:



This is followed by the shift reaction: $\text{CO} + \text{H}_2\text{O} \rightleftharpoons \text{CO}_2 + \text{H}_2$; further purification may be necessary as in the case of the steam reforming process.

Partial oxidation can also work with coal as the fuel or raw material instead of heavy hydrocarbons. The coal is ground very fine and mixed with water into a pumpable suspension with 50 – 70% of solid matters. This process is profitable only in coal producing countries like China and South Africa. There are only pilot plants in Germany [this information was extracted from the Bewag Fuel Cell Innovation Park website which can be downloaded at: www.fuelcellpark.com/h2/haupt2b.html]. Partial oxidation can be classified as a *proven technology*.

(a) Advantages

1. It is an exothermic reaction, thus it does not need extra heat supply like the steam reforming process, instead it releases heat.
2. Due to the high temperature, pressure and the exothermic nature, the heat can be recovered in a gas turbine [Albrecht, 2001]. An example is the Norsk Hydro's "Hydropower" concept [Bjørnar Kruse et al., 2002].
3. It can accommodate the use of a catalyst to reduce the temperature and also increase hydrogen yield.
4. It is a fast yielding process.
5. May utilise a range of fuels from methane to heavy naphthas.

(b) Disadvantages

1. In partial oxidation, the product gas contains more carbon monoxide than from steam reforming of natural gas, thus more CO_2 is generated.
2. The demand of oxygen for this process is a big problem. Pure oxygen is needed which would be produced by an oxygen separation plant which adds to the cost of production and investment. Air can be used but the nitrogen in the air forms oxides of nitrogen or ammonia which would have to be later separated from the gas produced.

2.2.1.3 Autothermal reforming

This is the combination of partial oxidation and steam reforming processes. In autothermal reforming, the process of partial oxidation and steam reforming are highly integrated, meaning both reactions take place in one reactor – thermos reactor (also known as secondary reformers). Autothermal reforming refers to the heat exchange between the endothermic steam reforming process and the exothermic partial oxidation process. Either pure oxygen or air can be used for this process, however, the latter reduces the hydrogen concentration or causes the formation of other pollutants while the former increases the production

cost. This is a productive process that has been demonstrated with feedstocks such as natural gas, gasoline, methanol etc. It can be classified as a *proven technology*.

Norsk Hydro's "hydropower" concept, which is based on the autothermal reforming process, uses air instead of pure oxygen in reforming, both because of costs and because the nitrogen in the feed gas has a lower burning temperature and reduced flame velocity [Bjørnar Kruse et al., 2002].

(a) Advantages

1. Autothermal reforming produces streams which are more concentrated in hydrogen than the partial oxidation process but less than the steam reforming process.
2. Like partial oxidation, it allows for the reforming of heavy hydrocarbons which cannot be reformed by the steam reforming process.
3. Because of the high reaction temperature (up to 1000°C), autothermal reformers can stand a higher sulphur concentration in the feedstock.

(b) Disadvantages

1. Large volumes of carbon dioxide are produced, which have to be separated to obtain a stream of greater hydrogen concentration.
2. It requires precise control of air, steam and fuel feed rates into the reactor for a successful overall reaction and to avoid total oxidation of the hydrocarbon [Bhatia & Wang].
3. Soot formation is not well understood, particularly at low steam-to-methane ratios. If the soot formation regime under a wide variety of operating conditions could be thoroughly mapped, autothermal reformers (ATRs) could replace steam-methane reformers in several industrial processes [Brian Valentine, 2001].

2.2.1.4 Coal/Biomass gasification

Gasification is a thermochemical process that converts carbonaceous materials into combustible gases by reacting the carbonaceous materials with steam (under a high pressure) and carefully controlled amounts of air or oxygen. This technology is about a century old. The resulting gas is called "*producer gas*" and consists mainly of carbon monoxide and hydrogen. Gasification is one of the oldest methods of producing hydrogen. The heat and pressure break apart the chemical bonds in the carbonaceous material's complex molecular structure, setting into motion chemical reactions with the steam and oxygen to form the producer gas. The gasification process can be applied to any carbon based feedstock, but mainly used for coal and biomass (wood, saw dust, straws, residual wood etc.), charcoal, peat, sewage sludge, municipal waste and agricultural residues. Coal gasification is a *fully developed commercial technology*, however biomass gasification is a *proven technology* that is on the verge of commercialisation according to the "Biomass Technology Group [www.btgworld.com].

- (a) Process description:* The complete system with the goal of hydrogen production (the producer gas from the gasification process can also be used in internal combustion engines and generators for electricity production [Turare, 1997]) consists of the gasification unit (gasifier) and the purification/hydrogen separation unit.

- *Properties of the feedstock (fuel)*: As mentioned above, coal and a wide range of biomass fuels such as wood, charcoal, wood waste as well as agricultural residues (maize cobs, coconut shells, cereal straws, rice husks) can be used for gasification. Theoretically, almost all kinds of biomass with moisture content of 5-35% can be gasified. However not every fuel leads to a successful gasification. It has been discovered that fuel properties such as surface, size, shape, moisture content, volatile matter and carbon content influence the gasification process. Below is a full list of the properties of fuel which can influence the gasification process [Turare, 1997]:
 - energy content
 - moisture content
 - particle size and distribution
 - form of the fuel
 - bulk density of the fuel
 - volatile matter content
 - ash content and composition
 - reactivity of the fuel
- *The gasification process*: The gasification of solid fuels takes place in air sealed, closed chambers under pressures up to 20 bar (the gasifier). The whole gasification process is made up of different sub-processes that take place in the gasifier; these processes are explained below:
 1. Drying – Feedstock (fuels) consists of moisture ranging from 5 – 35% [Turare, 1997]. At a temperature above 100°C, the water is removed and converted into steam. During the drying process, the fuels do not undergo any kind of decomposition.
 2. Pyrolysis – After drying, the next process that the fuel is going through is known as “pyrolysis”, which initiates at around 200 – 230°C. Pyrolysis is the thermal decomposition of carbonaceous fuels with a limited supply of an oxidising agent. During pyrolysis thermally unstable components such as lignin in biomass are broken down and evaporate with other volatile components. The resulting pyrolysis gas consists mainly of tar, polycyclic aromatic hydrocarbon (PAH), methane, steam and carbon dioxide. The solid residual is coke and ashes.
 3. Oxidation – At this stage, the coke from the pyrolysis stage reacts with a controlled amount of gasification agents such as steam and air or oxygen. The coke is gradually broken down into gases such as carbon monoxide, carbon dioxide and hydrogen. This reaction takes place at the temperature of 700 – 1400°C [Elvers, B. et. al., 1989]. When air is used in the oxidation process, other components of the air such as nitrogen and argon are also supplied to the system. These gases are inert, so they do not react with the fuel constituents.
 4. Reduction – At this stage, a number of chemical reactions take place in the absence of air and at a high temperature (800 – 1100°C). The reactions are endothermic, so external heat must be supplied.

If a complete gasification takes place, all the carbon is burned or reduced to carbon monoxide, hydrogen and other gases such as carbon dioxide, methane etc. The remaining solid is ash.
- *Gas clean-up*: The producer gas leaves the gasifier as the mixture of combustible and non-combustible gases including tar vapour, water vapour, dust, mineral vapour. Sulphur compounds such as hydrogen sulphide (H₂S) and nitrogen compounds (NH₃, HCN)

in the producer gas are undesirable due to their polluting and corrosive nature. Depending on the type of fuel (feedstock), the type of gasification system, the gasification temperature and other chemical and physical conditions, the components in the producer gas vary in volume and concentration. These can be removed by various chemical and physical processes such as cyclone, filtration (electrostatic), absorption, adsorption, stripping, material recovery (such as pure sulphur and sulphuric acid recovery from the reduced sulphur compounds), quenching etc.

After this stage, the producer gas now containing mainly carbon monoxide, carbon dioxide and hydrogen. This can now undergo the “*water-gas shift reaction*” and if necessary the “*pressure swing adsorption*” process to get almost pure hydrogen.

- *Residue handling*: The ash/slag from the gasifier is non-leachable, non-hazardous and is suitable for use as construction materials. Fine particulate matter from the cyclone or e-filter can be recycled into the gasifier.

(b) *Advantages*:

1. Apart from using the hydrogen from the gasification process in fuel cells, synthesis gas (a mixture of hydrogen and carbon oxides), also from the gasification process, can be used for the synthesis of ammonia and methanol or even used as a fuel in internal combustion engines.
2. It is a very well-known and quite reliable process.
3. When biomass is gasified, carbon dioxide (which had earlier been absorbed by the plant) is released to the atmosphere. The released carbon dioxide is again absorbed by plants and trees during photosynthesis, keeping the carbon dioxide content in the atmosphere almost the same. So, biomass gasification is a process that helps to maintain a moderate level of greenhouse gases and also the use of biomass as a renewable source of energy.
4. It can accommodate almost any fuel with a reasonable carbon content, thus is flexible with regard to feedstock and also contributes to the waste-to-energy process.
5. Compared to the normal combustion process, gasification has lower relative emissions of NO_x, SO_x and particulates.

(c) *Disadvantages*:

1. In contrast to incineration (combustion), higher temperatures are required during the gasification process to destroy the organic compounds which result in increased costs.
2. Toxic heavy metal compounds are more volatile in a gasification atmosphere. Thus, the gasifier slag does not capture as much of the toxic heavy metals and they would be transported out in the producer gas.
3. The operation of biomass gasification systems faces many unforeseen challenges due to a lack of experience when compared to established technologies like coal gasification or steam reforming which have been used for decades.
4. The removal of tar and tar vapour from the producer gas is always problematic. Tar contains chemicals that are carcinogenic, also a prolonged exposure to coal tar fumes, vapour or dust can cause irritation or burning to the eyes and the respiratory tract. BTG has developed the catalytic, reverse flow tar cracking (RFTC) reactor for converting tar in producer gas using a commercial Ni-catalyst [“Biomass Technology Group” www.btgworld.com].

Gasification of coal would be suitable for producing hydrogen, if not for the high emission of greenhouse gases, especially CO₂, generated by the process. The capture and disposal (sequestration) of the CO₂ produced in underground aquifers, deep oceans, depleted oil and gas reservoirs and unminable coal beds is being considered. While this seems to be a good idea for disposing of the CO₂, there are a lot of uncertainties associated with this technology.

Los Alamos National Laboratory is developing a process known as “*Zero Emission Coal to Hydrogen*”. Here, hydrogen is produced from water and coal using a calcium oxide (CaO) to calcium carbonate (CaCO₃) intermediary reaction. Through a subsequent reaction, the calcium carbonate generated during hydrogen production is converted back into calcium oxide and a pressurised steam of pure CO₂. The calcium oxide is recycled to drive further hydrogen production, and CO₂ is disposed. The process is anaerobic, requiring no oxygen input or combustion. The absence of oxygen and combustion reduces the nitrogen oxide by-products to only those resulting from the nitrogen compounds found in the coal itself. While coal is the current focus, this process can be adapted for any fossil fuel and also biomass [Los Alamos National Laboratory].

2.2.1.5 Off-gas cleanup

After steam reforming, another common source of hydrogen is the cleanup of industrial off-gases [Morgan and Sissine, 1995]. Numerous industries give off high concentrations of hydrogen in their waste streams; petroleum refineries, blast furnaces, and some chemical plants are typical examples. For example, coke oven gas contains over 50% hydrogen by volume [Büchel K.H et. al., 1998]. Collecting and purifying these gases is often cost-effective, with costs typically ranging between 80cents and \$1.20 per kilogram [Moore and Nahmias]. Most off-gas hydrogen is used on-site by the industry that produces it, so although off-gas cleanup is an important feature of today's market, it seems unlikely that it could be expanded enough to meet the increased demand that would result from widespread use of hydrogen as a fuel. This is a *proven technology*.

2.2.1.6 Thermal decomposition of water

This process is also referred to as “*thermal water splitting*”. It is a process where heat is used to split water into hydrogen and oxygen. At higher temperatures over 2000°C, water decomposes into hydrogen and oxygen. One of the problems with this process is preventing the separated gases from recombining at the high temperatures used. Also, due to the high temperature required, this technology is yet to be adopted outside the laboratory, thus can be grouped as a technology still under *fundamental research*. In a certain solar thermal power plants with a central collector, for example Solar Two, a 10MW power plant in California, the temperatures can reach over 3000°C [Bjørnar Kruse et al., 2002] . This heat can be used to split water into hydrogen and oxygen. The breakthrough in this technology will bring “*thermal water splitting*” back into consideration, which has long been written off by many researchers due to the very high temperature requirement. There are also efforts to adopt the use of catalysts to reduce the dissociation temperature.

(b) *Advantages:*

1. The main raw material or source which is water is easily and readily available at very low cost.
2. A breakthrough in solar thermal heating of water would make it a very clean and sustainable process.

(d) *Disadvantages:*

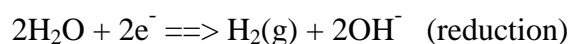
1. The high cost and energy demand in heating water to temperatures over 2000°C.
2. One big problem is also the prevention of the separated gases from recombining at high temperatures.
3. The efficiency factor is uncertain.

2.2.2 Electrochemical Hydrogen Production Processes

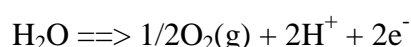
2.2.2.1 Water electrolysis

Water electrolysis is defined as passing an electric current through water to split individual water molecules into their constituent hydrogen and oxygen. In most literature, the term “*water electrolysis*” is referred to as simply “*electrolysis*”. The Greek word “*lysis*” means to dissolve or break something apart, so electrolysis can also be defined as the breaking apart of water using electricity. Water electrolysis is a *fully developed commercial technology*; the Electrolyser Corporation Ltd. (Canada) and Norsk Hydro Electrolysers AS (Norway) are well established manufacturers of conventional electrolyzers, offering units with very high capacity.

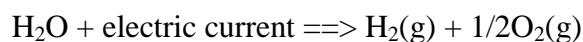
(a) *Process description:* two electrodes (very good conductors of electricity) must be dipped into water and attached to an electric current source. In order for electrolysis to be effective, the solution (water) must be a very good conductor of electrolysis. Pure water is a very poor conductor of electricity, so an electrolyte like salt is added to improve the conductivity of the water and increase the efficiency of the process. At the cathode (the negative electrode), electrons from the electric current source are added to the water molecules. The reaction of electrons with the water molecules produce hydrogen gas and hydroxide ions.



At the anode (the positive electrode), electrons are removed from the water and enter the electrode. This completes the circuit so current can flow. At the anode, water is oxidised.



The overall reaction of the electrolysis process is written below:



(b) *Advantages:*

1. It has a very high efficiency, up to 80% [energy input (electricity)/energy output (hydrogen)].
2. The electrolysis process itself is a clean and environmentally-friendly technology (without including the emissions associated with the electricity production).
3. The raw material (water) is readily available. However, pure water is not suitable as an electrolyte because of its low conductivity. Therefore, aqueous solutions of potassium or sodium hydroxide, sodium chloride, hydrochloric acid etc. are used. Depending on the electrolyte and the material of the electrodes, the reaction at the anode may give rise to other products, in particular sodium hydroxide and chlorine. For example, electrolysis of NaCl solution produces hydrogen plus aqueous NaOCl. At first, hydrogen, chlorine and NaOH are produced, then the aqueous chlorine reacts with NaOH to form NaOCl.

(c) *Disadvantages:*

1. The major drawback is the high electricity demand which increases the cost (see Figure 3-4). Electrolysis is still a costly process when compared to other processes like steam reforming etc.
2. It is not really a clean process if the whole chain is considered. Most of the electricity used for electrolysis is derived from the combustion of fossil fuels which emit carbon dioxide and other pollutants. Although there are several efforts being made to use renewable and clean technologies such as hydro-, wind, and solar power to produce electricity for electrolysis, none of these options is cheap enough at present, with the exception of hydropower, which is in limited supply. For example, one of the aims of the Wasserstoff-Energie Island-Transfer (W.E.I.T.) project which was launched on the 10th of December on the grounds of the Hamburger Gaswerke (gas works) is to generate hydrogen from hydropower using electrolysis [Deutscher Wasserstoff Verband website: www.dwv-info.de]. Storage and pumped storage hydropower plants which have enough storage capacity to off-set seasonal fluctuations in water flow and provide a constant supply of electricity throughout the year can be used for hydrogen production via electrolysis.

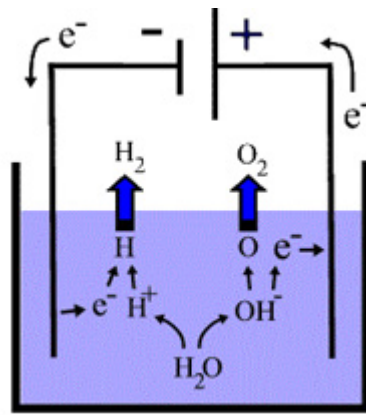


Figure 2-2 Electrolysis – splitting water with electricity to produce hydrogen and oxygen
 [Diagram taken from the New Mexico Solar Energy Association (NMSEA) website]

2.2.2.2 Steam electrolysis

This process of high-temperature electrolysis of steam is the reverse reaction of a solid oxide fuel cell. Steam is dissociated with electrons from externally provided electricity on the surface of a cathode. Hydrogen molecules form on this surface. Simultaneously, oxygen ions migrate through the electrolyte and form oxygen molecules on the surface of an anode with the release of electrons. The products, hydrogen and oxygen, are separated by the gas-tight electrolyte. Zirconium dioxide is used as the electrolyte. Hydrogen produced by this process has high purity [Hino & Miyamoto, JAERI]. The total energy demand (ΔH) for steam decomposition is the sum of the Gibbs energy (ΔG) and the heat energy ($T\Delta S$). The electrical energy demand (ΔG) decreases with increasing temperature; the ratio of ΔG to ΔH is about 93% at 100°C and about 70% at 1000°C (Figure 2-3). The reaction at higher temperatures has the advantage of improved efficiency [Hino & Miyamoto, JAERI]. This technology is in the *applied demonstration phase*, for example a pilot plant for the production of 1m³ hydrogen per hour is under construction; a 3,5 MW pilot plant is also planned but a number of material problems must be solved before realisation [Elvers, B. et. al., 1989 (p. 343)]. An example of a steam electrolyser is the German “Hot Elly”, this system can reach an efficiency of 92% [Bjørnar Kruse et al., 2002].

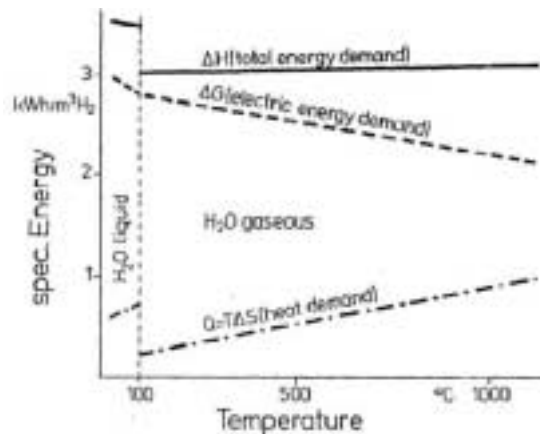


Figure 2-3: Thermodynamics of steam electrolysis [source: Jensen, S.H. et. al., Materials Research Department, Risø National Laboratory, Denmark]

2.2.2.3 High pressure water electrolysis

Through selected special material and optimisation, high pressure water electrolysis allows the generation of hydrogen at pressures up to 20 MPa [Elvers, B. et. al., 1989]. The processes under development attempt to find an appropriate capacity optimisation that will also allow for a problem free connection of the electrolyser with a fluctuating current supply (e.g. wind or PV connection for isolated plants). Since hydrogen is usually required at high pressure, and because the power consumption for the electrolysis does not increase significantly, these units save both equipment and energy for hydrogen compression. However, the construction and sealing of the electrolysis cells is complicated. The most important development work to mention is being carried out by GHW – Gesellschaft für Hochleistungswasserelektrolyseure [Zittel & Wurster, Ludwig-Bölkow-Systemtechnik GmbH, 1996]. Can be classified as a technology undergoing basic research.

2.2.3 Photoprocesses for Hydrogen Production

Photoprocesses still have a long way to go when compared to many of the thermochemical and electrochemical processes described above. They could be useful for laboratory or very small scale hydrogen production, but it is very unlikely that these technologies will play an integral part in the hydrogen economy within the time scale of this report (2020) due to their extremely low efficiencies. However, they are worth mentioning as examples of hydrogen production processes.

2.2.3.1 Photobiological process

The first stage of photosynthesis in plants involves the splitting of water into oxygen and hydrogen. The hydrogen then combines with carbon dioxide to form carbohydrates. The produced hydrogen during the process of photosynthesis is converted spontaneously into carbohydrates, but there are some micro-organisms like *algae* and *special bacteria* which

are capable of releasing this hydrogen freely into the air. Theoretically, algae can produce hydrogen with an efficiency of up to 2% (this efficiency is defined as the conversion rate of light energy “sunlight” to hydrogen) [Björnar Kruse et al., 2002]. A big problem is that oxygen is also produced together with the hydrogen, and this oxygen inhibits the hydrogen-producing enzymes “hydrogenase”, so only small amounts of hydrogen are actually produced. A research conducted by the University of Berkeley, California and the National Renewable Energy Laboratory shows that by starving the green algae of sulphates, the algae cannot maintain a protein complex which is necessary to produce oxygen during photosynthesis. The algae resorts to an alternative process whereby hydrogen is released. After about four days of producing hydrogen, the algae are allowed to take up the normal photosynthesis process to build up themselves back up again.

This process is still at the laboratory scale. It can be classified as a technology still under *fundamental research*.

(a) Advantages

1. It is a less polluting process when compared to most other hydrogen production technologies available.
2. Does not demand a lot of input raw materials or chemicals. It is still on a laboratory scale, land requirements are still difficult to determine.

(b) Disadvantages

1. Low efficiency is a problem.
2. Large scale production is still not viable.
3. Some research in the photobiological hydrogen production is based on genetic manipulation of micro-organisms which could disagree with environmental and public issues.

2.2.3.2 Photoelectrochemical process (photoelectrolysis)

Instead of first converting solar energy to electricity and then using the electricity in an electrolyser to produce hydrogen from water, it is possible to combine these two steps in a process known as *photoelectrolysis*. Photoelectrolysis use two types of electrochemical systems to produce hydrogen. One uses soluble metal complexes as a catalyst, while the other uses semiconductor surfaces. When the soluble metal complex dissolves, the complex absorbs solar energy and produces an electrical charge that drives the water splitting reaction. The other method uses semi-conducting electrodes in a photochemical cell to convert optical energy into chemical energy. The semi-conductor surface serves two functions, to absorb solar energy and to act as an electrode. Research is proceeding to increase the efficiency and the life span for such systems. Can be classified as a technology still under *fundamental research*. One of the main actors of this technology is the Hawaii Natural Energy Institute, University of Hawaii, U.S.A, this institute is working on increasing the efficiency of this process to about 7% (more information can be found on their webpage [www.hnei.hawaii.edu]).

(a) Advantages

1. It eliminates the cost of electrolyzers.

2. It is a less polluting process when compared to most other hydrogen production technologies available.

(b) Disadvantages

1. Light-induced corrosion limits the useful life of the semi-conductor.

2.2.3.3 Photochemical process

This process is similar to natural photosynthesis, but using synthetic molecules. This process is only about 0.1% efficient, but can be improved to higher efficiencies. There is still a lot of work and research to be done on this technology. Can be classified as a technology still under *fundamental research*.

2.2.4 Other Innovative Hydrogen Production Processes

2.2.4.1 Radiolysis

This is the splitting of water molecules by high-energy radiation produced in a nuclear reactor. The products of radiolysis are H, OH, H₂, H₂O₂, OH⁻(l), H⁺(l). The overall efficiency of this process is quite low. Separation of the highly radioactive particulates and gases as well as hydrogen separation is also a severe problem. Many experts have declared this process less promising because the hydrogen and oxygen atoms formed quickly recombine to form water again. The future of this technology is very bleak. It falls between the category of a *conceptual technology* and a technology under *fundamental research*.

2.2.4.2 Solar hydrogen

This concept means producing electricity from sunlight using photovoltaic cells, the electricity produced is then used to electrolyse water to produce hydrogen. However, this term is sometimes used generally to mean the electrolysis of water powered by renewable energy resources like wind, solar etc. The future of solar hydrogen is still controversial and depends on the future evolution of not only photovoltaic and electrolysis technologies, but also the competing technologies for producing hydrogen and electricity from fossil fuels, biomass, wind, nuclear etc. [Morgan and Sissine, 1995]. This technology is in the applied demonstration phase, an example of a demonstrator is the SHEC LABS - Solar Hydrogen Energy Corporation, Canada.

2.2.4.3 Thermochemical water splitting

Several processes are being developed which use chemicals (e.g. metal oxides) assisted by heat to split water into its component parts. It takes several steps to accomplish the entire process. This thermochemical process allows the use of moderate temperature and also bypasses a lot of separation obstacles. One example is the sulphur-iodine cycle. The sulphur-iodine cycle (S-I technology) uses thermochemical processes to obtain hydrogen and oxy-

gen from water. At first, water reacts with iodine and sulphur dioxide to form intermediate products. The intermediate products are broken down into their constituents upon heating (the heat can be supplied from high temperature nuclear reactors), releasing hydrogen and oxygen. The iodine and sulphur are recycled in the system. The cycle uses only water and heat as input, and the only products are hydrogen, oxygen and waste heat. This cycle is still at the experimental stage and may one day supply hydrogen efficiently without dependence on fossil fuels. Another example worth mentioning is the University of Tokyo Cycle 3 (UT-3 cycle) [Doctor, R. D., Argonne National Library, 2002].

2.2.5 Hydrogen Compression

Hydrogen is the lightest of all elements with an atomic weight of 1.0. The low atomic weight has both advantages and disadvantages. The advantage is that hydrogen stores approximately 2.6 times energy per unit mass as gasoline, and the disadvantage is that compressed gaseous hydrogen at 200 bar needs about 16 times the volume for a given amount of energy with comparison to gasoline [volumetric energy density: gaseous hydrogen (200bar) – 0,53 kWh/l; gasoline – 8,76 kWh/l]. This means hydrogen must be compressed to higher pressures to increase its energy content per unit litre.

(a) *Advantages:*

1. Compressing hydrogen increases the energy content per unit volume of hydrogen that can be stored in fuel tanks and transported via pipelines.
2. Since compression makes hydrogen more compact, the possibility to compress hydrogen to high pressures up to 700 bar can give hydrogen cars a better driving range.

(b) *Disadvantages:*

1. The compression process requires a lot of energy (see Figure 3-2).
2. The compressors are expensive to buy and maintain.
3. It is a complex process, usually requiring multiple stages. Therefore, there is the need for highly experienced and skilled operators.
4. Special seals are needed to achieve and maintain the high pressures.

2.2.6 Hydrogen Liquefaction

Liquefied hydrogen seems to have an edge over compressed gaseous hydrogen for mobile applications. Because of its low density, compressed gaseous hydrogen does not give a car as useful a range as gasoline. Hydrogen can achieve a reasonable density by adsorption on metal hydrides, but then the weight of the metals makes the system very heavy. The use of liquid hydrogen in cars provides a better driving range than gaseous hydrogen. There have been some demonstrations of prototype hydrogen cars that are fuelled with liquid hydrogen such as the DaimlerChrysler “NECAR 4” and the Opel Zafira. A reduction in the space requirement compared to gaseous hydrogen also makes the use of liquid hydrogen an attractive option in the transportation sector. But the high cost involved in the liquefaction process due to its high energy demand is a great obstacle to the future of this technology (Figure 3-4).

At atmospheric pressure, hydrogen liquefies at -253°C (20K), this makes the liquefaction, distribution and storage of liquid hydrogen a challenging technology. The liquefaction process is complex and energy intensive. Hydrogen liquefaction is a multi-stage process that requires the use of liquid nitrogen and a sequence of compressors and heat exchangers. Special procedures are required throughout the process to control the proportions of the two types of hydrogen molecule, known as “*ortho*” and “*para*”. If these are not controlled, the *ortho* hydrogen in the distribution and storage tanks would slowly but spontaneously convert to *para* hydrogen over a period of days and weeks, releasing heat and re-vaporising liquid hydrogen (0.1-1% per day depending on the size and design of the storage vessel).

(a) *Advantages:*

1. Liquid hydrogen has a higher energy density compared to gaseous hydrogen. Due to this property, more energy can be stored in vessels without an increase in volume; this is very important, especially for mobile applications, because it gives a better driving range.
2. Liquid hydrogen permits the reduction of fuel and storage tank sizes to a much greater extent than compressed hydrogen. However, liquid hydrogen storage vessels are still 2-3 times larger than the equivalent gasoline tanks.

(b) *Disadvantages:*

1. The liquefaction process requires a lot of effort, energy (see Figure 3-2) and high costs (see Figure 3-4).
2. It must be transported and stored in specially insulated tanks, which are expensive.
3. It requires careful attention and monitoring, due to the *para* and *ortho* hydrogen problem described above.
4. There are losses due to boil-off.

2.2.7 Hydrogen Distribution Technologies

Hydrogen must be transported from the point of production to the point of use. It also must be handled and moved within refuelling stations or stationary power facilities. Due to its relatively low volumetric energy density, transportation and final delivery to the point of use can be one of the significant costs and energy inefficiencies associated with using hydrogen as an energy carrier. The type of distribution/transportation method differs for gaseous and liquid hydrogen. Gaseous hydrogen is more or less transported like natural gas while liquid hydrogen is transported using more sophisticated technologies due to its extremely low temperature (-253°C).

Gaseous hydrogen can be provided via pipelines or truck delivery in cylindrical high pressure vessels. On the other hand liquid hydrogen is best transported in specially insulated trucks (cryogenic trucks) or by sea (ship transportation).

2.2.7.1 Pipeline distribution/transportation

Hydrogen delivery through pipelines seems to be the most economic option for delivery of large volumes. However, a large capital investment is required to expand the very limited existing hydrogen infrastructure to the level that would be necessary if hydrogen were to be adopted as the main energy carrier. For hydrogen to be a main energy carrier, it has to be transported in large volumes to different districts of a city, state or country. It will be very expensive to construct extensive pipeline distribution networks for this purpose. Hydrogen produced far away from the consumer can be delivered via long distance pipelines at higher pressures (60 – 80 bar). Locally produced hydrogen gas can be delivered through medium (20 bar) or low pressure (4 bar) pipeline systems [this information was taken from the Hydrogen and Fuel Cell Information System website, which is maintained by L-B-Systemtechnik, and downloadable at www.hyweb.de/Wissen/Ecn-h2.html]. Hydrogen pipes in use today are made from regular pipe steel with a diameter of 25 – 30 cm [Bjørnar Kruse et al., 2002]. In a natural gas distribution network, pressure is low (around 4 bar), so cheaper plastic pipes such as PVC (Polyvinyl Chloride) and HDPE (High Density Polyethylene) can be used. However, these pipes are too porous and not usable for transporting hydrogen [Bjørnar Kruse et al., 2002].

Using existing natural gas pipelines to transport hydrogen is an option that will be evaluated to reduce the investment required. It may be possible to mix up to about 30% hydrogen with natural gas in the existing natural gas pipeline infrastructure without modifications to the pipeline. This method is cost-effective only if there is a cheap technology to separate the pure hydrogen from the natural gas at the point of use. It is also possible, with certain modifications, to use pure hydrogen in some existing natural gas lines. This depends on the carbon levels in the pipe metal. Newer gas pipelines such as those in the North Sea, have low carbon content and are therefore suitable for transporting hydrogen [Bjørnar Kruse et al., 2002]. In addition, the compressor stations, valves and gaskets of the existing natural gas pipeline systems must be adapted for hydrogen use. Modifying natural gas pipe networks for hydrogen should be considered on a case by case basis. Some steels and welds are compatible, but others might be subject to embrittlement, particularly the welds in older segments. Compressors would generally have to be refitted with new seals and valves. Also, in a pipeline system optimised to carry hydrogen, the spacing of the compressors would have to be changed [Ocean Engineering and Energy Systems (OCEES), Hawaii]. If the flow velocity of distribution in the pipeline is increased by a factor of 2.5 – 3 to compensate for hydrogen having about 2.8 times lower energy density per volume than natural gas, then the same amount of energy can be moved. Pipeline distribution can be classified as a *proven technology*.

(a) Advantages:

1. Pipeline distribution is still the cheapest method for large scale gaseous hydrogen distribution (see Figure 3-4).
2. It is more effective for long distance distribution.
3. Gas pipelines, in addition to being used to transport gaseous hydrogen, can also be used to store great quantities of hydrogen. By regulating the pressure in the pipes, it is possible to use the large volume the pipelines offer as a storage capacity during peak periods.

(b) *Disadvantages:*

1. To move hydrogen through pipelines about 4.6 times more energy is required than for natural gas. This is a result of the low volumetric density of hydrogen which demands a higher flow velocity thus increasing the flow resistance [Eliasson and Bossel, 2002].
2. Higher hydrogen losses during pipeline transportation compared to natural gas. About 20 % of methane is lost or consumed during transport along a pipeline of 3000 km (e.g. from North Africa to Europe). In the case of hydrogen gas, this figure amounts to 34 % [Eliasson and Bossel, 2003]. Also, according to [Wagner, 2000] about 18 % of the hydrogen is lost over a distance of 2500 km (8 % for the year 2020). The summary of these two results show a range of 1.1 – 1.7% hydrogen loss every 150 km.
3. Pipes and fittings can become brittle and crack as hydrogen diffuses into the metal from which they are constructed. The severity of this problem depends on the type of steel and welding used and also the pressure in the pipeline. There are technologies available to prevent embrittlement, but these may increase costs.
4. Until there is a breakthrough in modifying the existing natural gas pipe network for hydrogen distribution (including the replacement of materials for gaskets and pipes, use of suitable compressors and any other challenges that presently make hydrogen unsuitable for the existing pipelines), the investment costs for a hydrogen pipeline network remain very high.

2.2.7.2 Hydrogen truck delivery (Gaseous)

Gaseous hydrogen can be transported via trucks in cylindrical high pressure vessels (about 350 bar). This technology is economical only over short distances because of the very high value of the ratio of energy consumed during delivery to the energy delivered (HHV) with increase in distance travelled. For example, over a distance of 500 km the delivery of liquid hydrogen, gasoline and methanol have an energy consumed to energy delivered ratio less than 5%, while that of liquid hydrogen is over 30% [Eliasson and Bossel, 2003]. This restrictions have put this technology not under serious consideration for the future, because if hydrogen is considered as a main future source of fuel and energy, large volumes of hydrogen will be required to be transported over very long distances. However, it can be a good method for hydrogen distribution within the same town/city or from a nearby city or state to another. Can be classified as a *proven technology*.

2.2.7.3 Hydrogen truck delivery (Liquid)

Liquid hydrogen can be transported via “specially insulated” trucks (cryogenic trucks). This helps to keep the temperature at -253°C (the temperature at which hydrogen gas turns into liquid). The container can be relatively lightweight because the vessel does not need to withstand high internal pressure. However, it must be super – insulated to slow down hydrogen evaporation and keep the container cold. The main disadvantage of this technology is the high energy demand of the liquefaction process (see figure 3-2), high costs of the

insulated vessels and also the problems associated with liquid hydrogen handling and storage. Can be classified as a proven technology.

2.2.7.4 Hydrogen ship delivery

Hydrogen can be transported as a liquid in tank ships. These are not too different from LNG tankers, apart from the fact that better insulation is required to keep the hydrogen cooled down over long distances. The Japanese WE – NET and German – Canadian Euro Quebec have reported on the use of such tanks. The evaporated hydrogen may be used as fuel on-board [Bjørnar Kruse et al., 2002]. This technology provides the possibility of transporting hydrogen over very long distances e.g. from one continent to the other. The main disadvantage is the high cost of the insulated vessel and the high energy demand associated with hydrogen liquefaction in general. Can be classified as a *proven technology*.

2.2.8 Hydrogen Storage Technologies

If hydrogen is to be used on a large scale basis, the storage of hydrogen is a key challenge. In transportation, the main challenge is how to store the amount of hydrogen required for a conventional driving range (over 450 kilometres), considering the constraints of weight, volume, efficiency, safety and cost. Low cost energy efficient off-board storage of hydrogen would also be needed throughout the hydrogen delivery system infrastructure. For example, storage is required at hydrogen production sites, hydrogen refuelling stations and stationary power sites. Temporary storage may also be required at terminals or at intermediate storage locations. The requirements for off-board bulk storage are generally less restrictive, because the problem of weight and volume of tank is not a big issue with off-board storage. Various storage concepts for hydrogen have been developed, these concepts are described below:

2.2.8.1 Gaseous hydrogen storage in pressurised tanks

Moderately pressurised hydrogen at large quantities and as stationary form of storage is stored in spherical vessels (10 – 15 bar). For some industrial applications, hydrogen is stored in small high pressure bottles (200 bar) or in medium sized high pressure cylindrical vessels (10 – 20 m³; > 200bar) [this information was taken from the Hydrogen and Fuel Cell Information System website (which is maintained by L-B-Systemtechnik) and downloadable at www.hyweb.de/Wissen/Ecn-h2.html]. High pressure storage vessels for gaseous hydrogen on-board storage are also considered; a lot of research and developments are going on to increase the pressure level in these tanks. The tanks are mainly made from steel, aluminium core encased with fibreglass (composite) and plastic core encased with fibreglass (composite). In stationary systems where weight and size are not decisive factors, steel tanks are used. But for vehicles, traditional steel pressure tanks are problematic in terms of weight and volume. There have been considerable breakthroughs in the development of a new composite tank which can store hydrogen at 350 bar and at the same time meet the current safety standards [Bjørnar Kruse et al., 2002]. Can be classified as a *proven technology* for stationary applications and in the *applied demonstration* phase for mobile applications. The state of the art is compression at 700 bar.

2.2.8.2 Liquid hydrogen storage

Liquid hydrogen is stored in small tanks of 0.1m^3 up to stationary spherical tanks of some 2000m^3 . The containers should be relatively lightweight because the vessel does not need to withstand high internal pressure. However, the containers must be insulated to slow down or reduce hydrogen evaporation and keep the container cold. All tanks have a vacuum insulation between inner and outer wall of the tank system. The large volume tanks usually have perlite insulation, whereas the medium to smaller size and all mobile tanks have a vacuum super-insulation consisting of a number of some 30 aluminium foil layers separated by a type of plastic foils or mats [this information was taken from the Hydrogen and Fuel Cell Information System website (which is maintained by L-B-Systemtechnik) and downloadable at www.hyweb.de/Wissen/Ecn-h2.html].

The liquid hydrogen in the storage tank gradually starts to evaporate, when a maximum acceptable pressure is reached in the tank, the evaporated hydrogen is released or lost to relief the pressure. The period between storage and the release of the evaporated hydrogen is known as *dormancy*. The evaporation rates of modern liquid hydrogen tanks typically is about 0.1% per day for large volume stationary tanks (from several 100m^3 to several 1000m^3), 1% for mobile cylindrical delivery tanks ($38 - 50\text{m}^3$) and about 1.7 – 3% for small vehicle storage tanks (about $0.1 - 0.4\text{m}^3$), this results to a loss of energy when the stored for long periods of time [this information was taken from the Hydrogen and Fuel Cell Information System website (which is maintained by L-B-Systemtechnik) and downloadable at www.hyweb.de/Wissen/Ecn-h2.html]. Can be classified as a *proven technology* for stationary application and in the *applied demonstration* phase for mobile applications.

2.2.8.3 Hydrogen storage in metal hydrides

Certain metals and metal alloys have the ability to absorb hydrogen under moderate pressure and temperature, creating hydrides. Hydrides are compounds which contain hydrogen and one or more other elements. A metal hydride tank contains a granular metal which absorbs hydrogen like a sponge absorbs water. It also contains a heat system, which draws heat away when hydrogen is filled into the tank, and requires heat to release the hydrogen from the tank. The hydrogen is released from the metal when heat is applied, this heat may be the excess heat from a fuel cell.

Conventional metal hydrides require high temperatures ($\sim 300^\circ\text{C}$) to liberate hydrogen, but sufficient heat is not always available from the fuel cells in the transportation sector. Low temperature hydrides are being explored, but they are less efficient when compared to high temperature hydrides.

Alanes are considered to be the most promising of the complex hydrides studies to date for on-board hydrogen storage applications [U.S. Department of Energy, Energy Efficiencies and Renewable Energy]. Sodium Alane (NaAlH_4) is a typical promising and reasonably inexpensive hydride. With its 4 weight percent hydrogen and 150°C release temperature, sodium alane meets the IEA requirements [Bjørnar Kruse et al., 2002]. Can be classified as a technology under *fundamental research*.

(a) *Advantages*

1. Hydrogen can be stored in higher densities than by simple compression.
2. A metal hydride system is a safe fuel system in the event of collision because the loss of pressure in a punctured tank will cool down the metal hydride, which will then cease to release hydrogen [Bjørnar Kruse et al., 2002].
3. Metal hydrides offer the advantage of hydrogen safety delivery at constant pressure.
4. Metal hydrides release very pure hydrogen by withholding the impurities when the hydrogen is released.

(b) *Disadvantages*

1. The problem with the usage of metal hydrides in the transport sector is the high weight compared to the amount of hydrogen stored. This problem is yet to be solved, although extensive research is in progress.
2. Metal hydrides retain the impurities in the hydrogen and release pure hydrogen, but the hydride's life time and ability to store hydrogen is reduced as the impurities are left behind and fill the spaces in the metal that the hydrogen once occupied [this information was taken from the FuelCellStore website, downloadable at www.fuelcellstore.com/information/hydrogen_storage.html#1].

A lot of research is being carried out in finding cheaper metal alloys which have the ability to absorb large amounts of hydrogen, and at the same time release the hydrogen at a relatively low temperature. The International Energy Agency's (IEA) metal hydride program has a goal of 5 weight percent adsorbed hydrogen and hydrogen release at $<100^{\circ}\text{C}$ [Bjørnar Kruse et al., 2002].

2.2.8.4 Hydrogen storage in carbon nanotubes

Carbon nanotubes are microscopic tubes of carbon that can store hydrogen in microscopic pores on the tubes and within the structures of the tubes. They are similar to metal hydrides in the way they store and release hydrogen and have the advantage of being able to store more hydrogen than metal hydrides. Research has shown that carbon nanotubes are capable of storing between 4.2 – 65% of their own weight in hydrogen [this information was taken from the FuelCellStore website, downloadable at www.fuelcellstore.com/information/hydrogen_storage.html#1]. However, this technology of hydrogen storage is still in the research and development stage. The research is focused on improving the manufacturing techniques and reducing costs of carbon nanotubes. Can be classified as a technology under *fundamental research*.

2.2.8.5 Hydrogen storage in glass microspheres

Tiny hollow glass spheres can be used to safely store hydrogen. The glass spheres are heated, the heat increases the permeability of their walls, and the spheres are filled by being immersed in high-pressure hydrogen gas. The spheres are then cooled, locking up the hydrogen inside the glass balls. A subsequent increase in temperature would release the hydrogen trapped in the spheres. Microspheres are quite safe and contaminant resistant. This

technology is also still at the stage of research and development. Can be classified as a technology under *fundamental research*.

2.2.8.6 Hydrogen storage in underground cavities

Underground cavities are an easy and relatively cheap method for large-scale storage of hydrogen. There are different kinds of caves that can be used, such as salt caverns, aquifer structures, mine cavities and natural or manmade caves [Hottinen, 2001]. In Kiel, Germany, city gas with a hydrogen content of about 60 – 65% has been stored in a gas cavern at a depth of 1330m, volume of 32000m³ under 80 – 100 bar pressure since 1971 [Bjørnar Kruse et al., 2002]. Salt is often found in layers that can be hundreds of metres thick. These layers are impermeable to water and air. The cavity is made in the salt by dissolving and the surface is cemented before inserting the gas [Hottinen 2001].

Aquifers are found in porous geological layers. The gas is injected into the rock pores, initially filled with water, in which the gas accumulates. The technique requires special geological conditions and can be used only in certain regions.

Besides salt caverns and aquifers, hydrogen can also be stored in natural or manmade caves. This method is currently under investigation and is not yet applied or tested [Hottinen, 2001].

The losses caused by leaks in the earth cavities are about 1 – 3% of the total volume per year [Hottinen, 2001]. As much as 50% of the working volume may be unrecoverable and solutions for this, such as displacing the hydrogen by pumping in brine, are costly [Department of Planning and Infrastructure, Government of Western Australia; website: www.dpi.wa.gov.au/fuelcells/hydrotech.html]. This is a great disadvantage to this storage technology.

Nevertheless, this is a very prospective technology for large scale storage of hydrogen, but thorough research should be carried out to further investigate the stability of hydrogen gas in these cavities. Can be classified as a technology under *fundamental research*

Table 2.1: Summary table for the hydrogen production processes

	Process type	Efficiency (%)	Investment cost (Euro / kWh _{H2})	Operating cost (cents / kWh _{H2})	Plant capacity (MW)	Major manufacturers	Readiness for deployment
Thermochemical processes	Steam reforming	Up to 85	Up to 690 ¹	Up to 1 ¹	Up to 405 ¹	Uhde, Linde, KTI	Fully developed commercial technology
	Partial oxidation	Up to 77 ¹	Up to 515 ¹	Up to 2,3 ^{1, c}	Up to 390 ¹	Uhde, Linde, KTI	Proven technology
	Autothermal reforming	Unavailable data	Unavailable data	Unavailable data	Unavailable data	Lurgi, HTW	Proven technology
	Coal gasification	Up to 69 ¹	Up to 720 ¹	Up to 1,3 ¹	Up to 486 ¹	Batelle, DMT, MTCI	Fully developed commercial technology
	Biomass gasification	Up to 72 ¹	Up to 2660 ¹	Up to 2,2 ¹	Up to 25 ¹	BTG Group	Proven technology
	Offgas clean-up	Varying – depends on process used	Varying	0,8-1,2 ^{2, a}	Varying	Refineries & chemical plants e.g. BASF	Proven technology
	Thermal decomposition of water	Uncertain	Unknown	Unknown	Unknown	Unknown	Technology under fundamental research
Electrochemical processes	Water electrolysis	50-80	~1200 ¹	5,32 ¹	2 ¹	Norsk Hydro, Lurgi	Fully developed commercial technology
	Steam electrolysis	Up to 92 ³	Unavailable data	Unavailable data	Unavailable data	R&D by DLR, Stuttgart, Germany	Applied demonstration
	High-pressure water electrolysis	Up to 77 ¹	~1280 ¹	~ 6	2 ^b	GHW, vHS	Technology under fundamental research
Photo processes	Photobiological processes	Up to 2	Unknown	Unknown	Unknown	R&D by NREL, USA	Technology under fundamental research
	Photoelectrochemical processes	~ 7	Unknown	Unknown	Unknown	R&D by HNEL, Hawaii	Technology under fundamental research
	Photochemical processes	~ 0,1	Unknown	Unknown	Unknown	Unknown	Technology under fundamental research
Other innovative processes	Radiolysis	Unknown	Unknown	Unknown	Unknown	Unknown	Conceptual tech. / fundamental research
	Solar hydrogen	Up to 85 ^b	Up to 6135 ¹	Up to 64,4 ^{1, b}	1 ¹	R&D by Solar Hydrogen Energy Corporation	Applied demonstration
	Thermochemical water splitting	50	Unknown	Unknown	Unknown	General atomic technologies	Fundamental research

¹ Data from Wagner, 2000; ² Data from Moore & Nahmias; ³ Data from Bjørnar Kruse et al., 2002;^a Units in \$ per Kg; ^b The figures are only for a photovoltaic power plant!; ^c Includes cost for feedstock preparation

3 Pathway Analysis

3.1 Introduction

According to a general definition, a well-to-wheel (WTW) analysis is an examination of the entire process of creating and using fuels to provide power to the wheels of a vehicle, resulting in an assessment of the requisite energy consumption and corresponding greenhouse gas (GHG) emissions. A well-to-tank analysis (WTT) is the first part of a well-to-wheel analysis and accounts for the GHG emissions and the energy consumption over the entire fuel pathway, from feedstock to fuel dispenser nozzle. The second part, the so-called tank-to-wheel (TTW) analysis, estimates the GHG emissions and the energy consumption resulting from moving the vehicle through its drives cycle.

This study focuses on the well-to-tank analysis of hydrogen as a fuel. Altogether 26 possible hydrogen supply pathways are analysed. The scope of the pathway analysis is to identify the most promising pathways with respect to primary energy demand (PED) and GHG-emissions (which are limited to CO₂ as the most important GHG). Costs for the different options are included as an additional evaluation criterion. For comparison reasons full well-to-wheel assessments including conventional fuels and powertrains are given for selected pathways.

3.2 Pathway selection and description

A hydrogen supply pathway consists of several sub-systems like feedstock preparation, electricity generation, hydrogen production, compression, liquefaction, hydrogen transport, storage and refuelling (see figure 3-1).

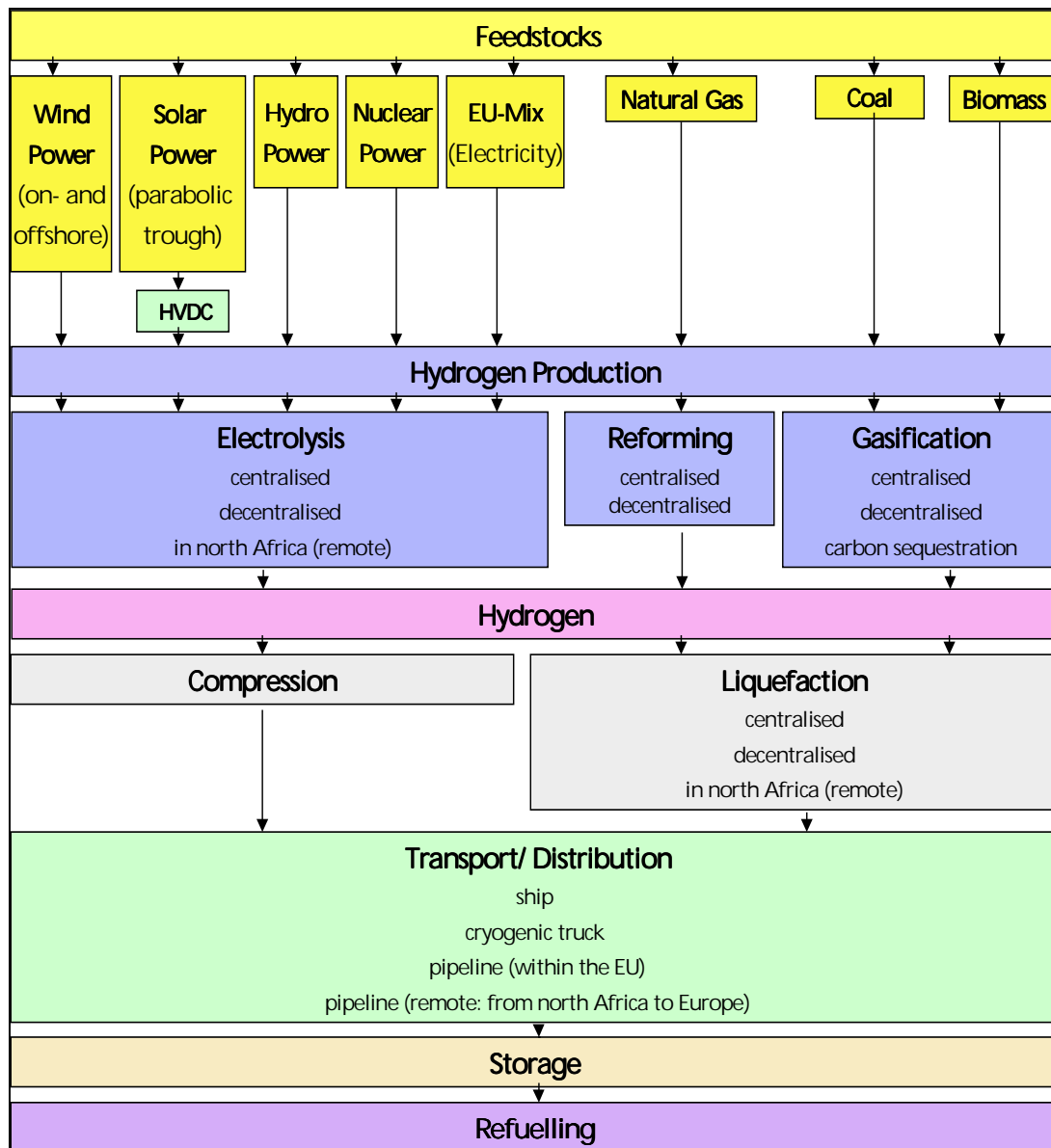


Figure 3-1: Survey of the subsystems considered.

With the sub-systems depicted in Figure 3-1 a multiplicity of pathway combinations is possible. For this project 26 possible hydrogen supply pathways were constructed. The pathways include the supply of both liquid and gaseous hydrogen at the filling station.

The first pathway step is feedstock preparation, which is considered separately for natural gas, coal and biomass. Feedstock preparation includes data for feedstock depletion (coal and natural gas mining) or in the case of biomass, biomass collection and all additional preparation processes such as purification (natural gas and coal) or chopping (biomass) as well as transport and storage. Data for feedstock preparation are included in the process of electricity generation within the pathways based on electricity from EU-mix and nuclear power.

The next pathway step is hydrogen production via reforming of natural gas, gasification of coal or biomass or electrolysis. ‘Centralised’ as well as ‘onsite’ options are considered for hydrogen production. Onsite means directly at the filling station. The drawback of onsite options is that hydrogen production plants are smaller and therefore less efficient than centralised plants with higher capacity. The advantage is that hydrogen does not have to be distributed. However, onsite options are not suitable for all pathways. The gasification of coal or the reforming of natural gas is much more realistic in big centralised plants of several hundred MW. Furthermore, onsite options for reforming or gasification have not been realised so far due to lack of demand and might give rise to logistic problems and shortage of space for feedstock storage. Therefore the focus here is on centralised options. For comparison reasons however, one onsite variant is included for natural gas reforming. For similar reasons onsite options are also excluded for the gasification of biomass (residual wood). For most pathways based on electrolysis with electricity, a centralised as well as an onsite option is analysed. Electrolysis directly at the filling station has been tested in several pilot projects and is technically an easy solution. Furthermore electricity is readily available at the filling station.

If centralised hydrogen production is assumed, the hydrogen is either liquefied in the same place and transported to the filling station in cryogenic trucks (the average transport distance is assumed to be 300 km, see table 3-2) or it is distributed in gaseous form via pipelines. In this case a hydrogen pipeline grid similar to the natural gas pipeline grid is assumed which is at least 30 % of that presently used for natural gas. The average transport distance is assumed to be 300 km. Several compressors are employed to maintain the pressure within the pipeline grid. Electricity for these compressors is received from the EU-mix. Distributing gaseous hydrogen using trucks is not considered as this option would be too inefficient.

At the filling station hydrogen is stored in a liquid or gaseous state of aggregation. Gaseous hydrogen is stored at the filling station at a pressure of 880 bar to allow a smooth refuelling process to the tank of a vehicle where hydrogen is stored at a pressure of about 700 bar. The degree of compression is, beside the storage pressure at the filling station, dependent on the output pressure of the single hydrogen production processes (reforming, gasification and electrolysis) which is assumed to be 30 bar. The degree of compression is therefore always from 30 bar to 880 bar.

Electricity for compression or liquefaction is usually received from the EU mix. Exceptions are pathways based on nuclear, solar or wind power. The respective electricity source is also used for liquefaction or compression, if these processes take place at the same place as hydrogen production.

Conduction losses during electricity transmission with the existing electricity grid are not considered, as these only range from 5 up to 10 %/1000km and are therefore negligible. For electricity transport from North Africa to Europe via high voltage direct

current transmission (HVDC) however, losses and additional costs are taken into account.

The sub-systems storage and refuelling are not taken into account in this part of the study due to a lack of data in these fields. Nevertheless it is very likely that these processes involve hydrogen losses as well as additional investment cost and primary energy demand. But as these additional expenditures are necessary for all pathways, it is assumed that the total result of the comparison is not distorted.

The 26 pathways and their underlying assumptions are briefly outlined below:

Pathways based on reforming of natural gas

Natural gas based pathways are included as this technology is applied and proven. Presently most of the world's hydrogen is produced this way.

Plant size is considered to be 385 MW with an efficiency of 78% for centralised and 4.275 MW with an efficiency of 70% for onsite reforming. Thermal energy required to reform natural gas, is generated via burning natural gas.

PW1: CGH2 via onsite reforming of European natural gas mix

Natural gas from the European natural gas (NG) mix is distributed via the NG grid to the filling station. There (onsite) reforming of NG to hydrogen and the compression and storage of hydrogen takes place.

PW2: CGH2 via centralised reforming of European natural gas mix

Natural gas from the European natural gas mix is distributed via the NG grid to a centralised reforming station where it is converted into hydrogen. Hydrogen is then distributed via a pipeline to a filling station where it is compressed and stored.

PW3: LH2 via centralised reforming of European natural gas mix

Natural gas from the European natural gas mix is distributed via the NG grid to a centralised reforming station where it is converted into hydrogen. The produced hydrogen is then liquefied at the same place (centralised) and transported to a filling station via a cryogenic truck where it is stored.

Pathways based on the gasification of hard coal

Hard coal based pathways are selected as very large resources exist in Europe and therefore feedstock availability is assured. For the centralised gasification of hard coal a 500 MW plant with an efficiency of 69% is assumed. Besides thermal energy for steam generation, the gasification plant requires about 5% electric current. The source for thermal energy is hard coal, whereas electricity derives from the EU-mix. As gasification of hard coal generates high CO₂ –emissions, scenarios with carbon sequestration are included for the supply of both liquid and gaseous hydrogen. Carbon sequestration actually covers two separate processes, namely carbon capture and carbon disposal. For carbon capture, a CO₂ –capture plant based on chemical ab-

sorption with monoethanolamine (MEA) solvent is considered³. Carbon is then transported to underground cavities or depleted oil and gas fields where it is stored.

PW4: CGH2 via centralised gasification of hard coal

Hard coal is transported to a centralised gasification plant, where it is gasified to hydrogen. Hydrogen is then distributed via a pipeline to a filling station where it is compressed and stored.

PW5: CGH2 via centralised gasification of hard coal with carbon sequestration

Hard coal is transported to a centralised gasification plant. CO₂ emitted during the gasification process is sequestered. Hydrogen is distributed via a pipeline to a filling station where it is compressed and stored.

PW6: LH2 via centralised gasification of hard coal

Hard coal is transported to a centralised gasification plant where it is gasified to hydrogen which is then liquefied (centralised). Liquid hydrogen is then distributed via cryogenic truck to a filling station where it is stored.

PW7: LH2 via centralised gasification of hard coal with carbon sequestration

Hard coal is transported to a centralised gasification plant where it is gasified to hydrogen which is then liquefied (centralised). CO₂ emitted during the gasification process is sequestered. Liquid hydrogen is then distributed via cryogenic truck to a filling station where it is stored.

Pathway based on the gasification of biomass

CO₂ –emitted during the gasification process is not calculated as this equals the amount of CO₂ absorbed from the atmosphere and stored within the biomass during the plant's lifetime. The factory size in this scenario is limited as residual wood should stem from the vicinity otherwise expenditures for transport would be too high. The capacity of the gasification plant is assumed to be 25 MW. The gasification plant requires thermal energy as well as about 5% electric current. The source for thermal energy is residual wood, electricity is taken from the EU-mix.

³ Physical absorption such as the selexol physical solvent process could be a better choice. However, for the cost analysis an estimate of the cost in \$/t (or €/t) is necessary. for the CO₂ –capture process. These costs vary for the different physical and chemical absorption processes available. For a better analysis (or being on the safer side) the most expensive and also very widely used CO₂ –capture technology is chosen - that is the MEA process. It is important to note that, the use of MEA for the analysis is not a recommendation but rather an example of a CO₂ –capture technology.

PW8: CGH2 via gasification of biomass (residual wood)

Residual woody biomass is collected, chopped up and transported to a gasification plant where it is gasified to hydrogen. Hydrogen is then distributed via a pipeline to a filling station where it is compressed and stored.

Pathways based on electrolysis with electricity from the EU-mix**PW9: CGH2 via onsite electrolysis, electricity from European mix**

At the filling station (onsite) electrolysis using electricity from the European mix is performed. Hydrogen is then compressed and stored.

PW10: CGH2 via centralised electrolysis, electricity from European mix

Electricity from EU-mix is used at a centralised electrolysis plant for the production of hydrogen. Hydrogen is then distributed via pipeline to a filling station where it is compressed and stored.

PW11: LH2 via onsite electrolysis, electricity from European mix

At the filling station (onsite) electrolysis with electricity from the European mix is performed. Hydrogen is then liquefied (onsite) and stored. **from European mix**

Electricity from the EU-mix is used at a centralised electrolysis plant to produce hydrogen. Hydrogen is then liquefied (centralised) and transported via cryogenic trucks to a filling station where it is stored.

Pathways based on electrolysis with electricity from nuclear power

At present nuclear power is fed into the electricity grid and it is therefore improbable that pure nuclear power would be supplied for electrolysis at a filling station. Nevertheless onsite options are included as the economisation of hydrogen distribution expenditures might justify additional expenditure for power distribution to the filling station. Electricity for compression or liquefaction derives from nuclear power if these processes occur in the same place as hydrogen production.

PW13: CGH2 via onsite electrolysis with nuclear power

At the filling station, (onsite) electrolysis with electricity from a nuclear power plant is performed. Hydrogen is then compressed and stored.

PW14: CGH2 via centralised electrolysis with nuclear power

Electricity from nuclear power is used at a centralised electrolysis plant for the production of hydrogen. Hydrogen is then distributed via a pipeline to a filling station where it is compressed and stored.

PW15: LH2 via onsite electrolysis with nuclear power

At the filling station, (onsite) electrolysis with electricity from nuclear power is performed. Hydrogen is then liquefied and stored.

PW16: LH2 via centralised electrolysis with nuclear power

Electricity from nuclear power is used at a centralised electrolysis plant for the production of hydrogen. Hydrogen is then liquefied (centralised) (electricity from nuclear power) and transported via cryogenic trucks to a filling station.

Pathways based on electricity surplus from extended full load hours of shoulder load power plants.

The idea in these two scenarios is that existing European shoulder load power plants (natural gas and hard coal and lignite) are driven at full load (8000 full load hours). Thus efficiency and costs are optimised as frequent start-up and shut down procedures of the plants as well as additional investment are avoided. The induced electricity surplus is used for hydrogen production via electrolysis. The potential electricity surplus through extended operating hours are calculated on the basis of Capros (2003): Shared-analysis / Energy Outlook 2030 - Baseline forecast, reference scenario (see table 3-1). For each scenario only one option, namely gaseous hydrogen production via centralised electrolysis is analysed to get a first impression of the soundness of these pathways in comparison to direct reforming/ gasification of natural gas/ hard coal.

Table 3-1: Potential electricity surplus of shoulder load power plants with extended operating hours, based on Capros 2003

type of power plant	generation capacity in GW in 2030	shoulder load in flh ⁴ in 2030	full load in flh ⁴	potential electricity surplus for H ₂ production in GWh
open cycle unit (OCU) hard coal and lignite	101,82	3.802	8.000	427.440
combined cycle natural gas turbine (CCGT)	313,85	4.562	8.000	1.079.030
Total				1.506.470

PW17: CGH2 via centralised electrolysis, electricity from combined cycle natural gas turbine (CCGT)

Electric current surplus from combined cycle natural gas power plants is used for hydrogen production via centralised electrolysis. Hydrogen is then distributed via a pipeline grid to a filling station where it is compressed and stored.

PW18: CGH2 via centralised electrolysis, electricity from hard coal and lignite open cycle units

Electric current surplus from hard coal and lignite open cycle units is used for hydrogen production via electrolysis (centralised). Hydrogen is then distributed via a pipeline grid to a filling station where it is compressed and stored.

Pathways based on electrolysis with solar thermal energy from North Africa

The production of hydrogen from renewable energy sources (RES) is desirable, but the potential of RES in Europe for this purpose is limited due to competition with the direct consumption of electricity from RES. Therefore RES outside Europe offer

⁴ flh = full load hours

a reasonable long-term potential for the production of hydrogen. The potential of solar power in North Africa is inexhaustible. Photovoltaic, solar towers as well as parabolic trough power plants are suitable for electricity generation. According to Wagner et al. 2000, the latter are most suitable for generating electricity in North Africa to be exported to Europe. Three different pathways are considered for energy import to Europe. For comparison reasons only liquid hydrogen is regarded. The electricity source for liquefaction is solar power, if liquefaction takes place at the same place as hydrogen production.

PW19: LH2 via centralised electrolysis in Europe with solar thermal energy (parabolic trough power plants) from North Africa, electricity import via HVDC transmission

Solar thermal electricity generated in North Africa in parabolic trough power plants is transmitted to Europe via high voltage direct current transmission (HVDC). Electrolysis and liquefaction takes place at a centralised plant in Europe. The liquid hydrogen produced is transported via cryogenic trucks to filling stations where it is stored.

PW20: LH2 via electrolysis in North Africa with solar thermal energy (parabolic trough power plants), hydrogen import via ship

Electricity from parabolic trough power plants in North Africa is used for the production of hydrogen at an electrolysis plant in North Africa (remote). Hydrogen is liquefied at the same place and is then transported to Europe via ship. There it is further distributed via cryogenic trucks to filling stations, where it is stored.

PW21: LH2 via electrolysis in North Africa with solar thermal energy (parabolic trough power plants), hydrogen import via pipeline

Electricity from parabolic trough power plants in North Africa is used for the production of hydrogen at an electrolysis plant in North Africa (remote). Hydrogen is then transported to Europe via a pipeline (remote) and further distributed via a pipeline grid to a centralised liquefaction plant. Hydrogen is liquefied there and transported to a filling station via cryogenic trucks where it is stored.

Pathways based on electrolysis with electricity from wind power

Wind power like nuclear power is fed into the electricity grid at present and it is therefore not likely that pure wind power will be used for electrolysis at a filling station. Nevertheless onsite options are included as the economization of hydrogen distribution expenditures might justify additional expenditures for electric current transmission from a wind farm to a filling station. Electricity for compression/ liquefaction comes from wind power plants if electrolysis takes place at the same place.

PW22: CGH2 via onsite electrolysis with wind power

At the filling station, (onsite) electrolysis with electricity from wind power is performed. Hydrogen is then compressed and stored

PW23: CGH2 via centralised electrolysis with wind power

Wind power is used at a centralised electrolysis plant for the production of hydrogen. Hydrogen is then distributed via a pipeline grid to a filling station where it is compressed and stored.

PW24: LH2 via onsite electrolysis with wind power

At the filling station, (onsite) electrolysis with wind power is performed. The hydrogen produced is then liquefied and stored.

PW25: LH2 via centralised electrolysis with wind power

Wind power is used at a centralised electrolysis plant for the production of hydrogen. Hydrogen is then liquefied (centralised) and transported via cryogenic truck to a filling station.

Pathway based on electrolysis with electricity from hydro-power

It is not expected that hydro-power-based pathways vary significantly with regard to primary energy demand and CO₂ –emissions from wind power pathways. Therefore only one hydro power pathway is analysed as an example for a renewable pathway with comparatively low costs.

PW26: GH2 via centralised electrolysis with hydro-power

Hydro power is used at a centralised electrolysis plant for the production of hydrogen. Hydrogen is then distributed via a pipeline grid to a filling station where it is compressed and stored.

A pathway including on-board reforming of natural gas is not analysed for the following reason: With respect to the three evaluation criteria, no difference is expected up to the point of the supply of natural gas at the filling station compared to PW1: CHG2 from European natural gas mix via onsite reforming. But the subsequent step, hydrogen production, is assumed to be much less efficient and much more expensive in an on-board reformer than in an onsite one. Therefore pathways, which include on-board reforming of natural gas is expected to have poorer results and is therefore excluded.

For a review of the selected pathways see Table 3-1

Table 3-2: Selected well-to-tank hydrogen pathways

Pro- cess	Feedstock	PW	Well-to-tank hydrogen pathways
Reforming	natural gas	1	CGH2 via onsite reforming of European natural gas mix
		2	CGH2 via centralised reforming of European natural gas mix
		3	LH2 via centralised reforming of European natural gas mix
Gasification	hard coal	4	CGH2 via centralised gasification of hard coal
		5	CGH2 via centralised gasification of hard coal with carbon sequestration
		6	LH2 via centralised gasification of hard coal
		7	LH2 via centralised gasification of hard coal with carbon sequestration
	bio-mass	8	CGH2 via gasification of biomass (residual wood)
Electrolysis	EU-mix	9	CGH2 via onsite electrolysis, electricity from European mix
		10	CGH2 via centralised electrolysis, electricity from European mix
		11	LH2 via onsite electrolysis, electricity from European mix
		12	LH2 via centralised electrolysis, electricity from European mix
	nuclear power	13	CGH2 via onsite Electrolysis with nuclear power
		14	CGH2 via centralised electrolysis with nuclear power
		15	LH2 via onsite electrolysis with nuclear power
		16	LH2 via centralised electrolysis with nuclear power
	Coal and natural gas	17	CGH2 via centralised electrolysis, electricity from combined cycle natural gas turbine (CCGT) surplus
		18	CGH2 via centralised electrolysis, electricity from hard coal and lignite open cycle units surplus
	solar thermal energy from North Africa	19	LH2 via centralised electrolysis in Europe with solar thermal energy (parabolic trough power plants) from North Africa, electricity import via HVDC
		20	LH2 via electrolysis in North Africa with solar thermal energy (parabolic trough power plants), hydrogen import via ship
		21	LH2 via electrolysis in North Africa with solar thermal energy (parabolic trough power plants), hydrogen import via pipeline
	wind power	22	CGH2 via onsite electrolysis with wind power
		23	CGH2 via centralised electrolysis with wind power
		24	LH2 via onsite electrolysis with wind power
		25	LH2 via centralised electrolysis with wind power
	hydro power	26	GH2 via centralised electrolysis with hydro power

3.3 Data collection and the well-to-tank analysis

Data concerning CO₂–emissions, primary energy demand (PED) and the costs of all the single sub-systems involved, are based on the evaluation of current, comprehensive studies of hydrogen pathways. To obtain complete and updated pathways and to create new pathways, data were collected additionally by literature analysis, expert survey and performing own calculations. It has to be mentioned that, due to the different data sources and different assumptions for technologies (i.e. capacity, life time, full load hours), harmonisation of the data is difficult to perform. In addition, due to the experimental or test stage status of numerous processes, many of the technical and economical data are only draft estimations.

Table 3.2 shows the figures used for this WTT analysis as well as comparative figures. Based on this values the total PED, emissions and costs for the 26 pathways were calculated in a harmonised way. The criteria mentioned refer to 1 kWh compressed or liquid hydrogen respectively. For each of the 26 pathways analysed a detailed description is given in the form of a flow chart (see Annex A). The data include only PED and CO₂ emissions during the operational phase of plants, infrastructure etc. Energy demand and emissions during the construction and dismantling phase are neglected due to lack of data and because these data generally have only a very limited influence on the overall results. All calculations are carried out for the year 2020. This means, that a technical development process and learning effects are included.

Table 3-3: Database for the pathway analysis

Data collection, including efficiency, primary energy demand, costs and CO₂ emissions of different processes involved in hydrogen		
	values used	other values
Feedstock Preparation (including feedstock depletion/collection, preparation, transport and storage)		
Natural Gas	Efficiency: 89.5% (<i>source 1</i>)	93% (without transport) (<i>source 4</i>)
	CO ₂ emission: 12 g/kWh (<i>source 1</i>)	
	Cost: 1.267 c/kWh(NG) (<i>source 16</i>)	
Hard Coal	Efficiency: 95.5% (<i>source 1</i>)	
	CO ₂ emission: 19 g/kWh (<i>source 1</i>)	
	Cost: 0.572 c/kWh(hard coal) (<i>source 16</i>)	
Biomass	Efficiency: 95.1% (<i>source 1</i>)	94.3% (<i>source 4</i>)
	CO ₂ emission: 7 g/kWh (<i>source 1</i>)	12.7 g/kWh (<i>source 4</i>)
	Cost: 1.33 c/kWh(biomass) (<i>source 1</i>)	
Physico-chemical Processes		
Natural Gas Reforming	Efficiency: 70% (onsite, 4.275 MW power plant) (<i>source 1</i>) 78% (centralised, 385 MW power plant) (<i>source 1</i>)	85% (centralised); (<i>source 2</i>) 68.7% (onsite), (<i>source 2</i>) 70.6% (centralised) (<i>source 3</i>) 83% (centralised), (<i>source 4</i>) 71 % (onsite) (<i>source 4</i>)
	CO ₂ emission: 306 g/kWh (onsite) (<i>source 1</i>) 275 g/kWh (centralised) (<i>source 1</i>) (Reforming + Electricity Generation + feedstock preparation)	241.8 g/kWh (onsite) (<i>source 4</i>) 208 g/kWh (centralised) (<i>source 4</i>)

	Cost: 0.58 c/kWh (centralised, without cost for natural gas) 0.96 c/kWh (onsite, without cost for natural gas) (own calculation based upon <i>source 1, 10, 11, 12*</i>)	
Electrolysis	Efficiency: 70% (onsite); 75% (centralised) (assumption based on <i>source 1, 2, 3, 4</i>)	77% (<i>source 1</i>); 75% (<i>source 2</i>); 65% (<i>source 3</i>); 65% (<i>source 4</i>)
	Cost: 5.32 c/kWh (without cost for electric current) (<i>source 1</i>)	
Biomass Gasification (Residual Wood)	Electricity Demand: 0.078 kWh/kWh (H2) (Electricity from EU-mix) (<i>source 1</i>)	
	Efficiency: 72 % (plant size 25 MW) (<i>source 1</i>)	
	CO2 emission is calculated from the electricity generation for the gasification process	
	Cost: 2.18 c/kWh (without cost for electric current and biomass) (own calculation based upon <i>source 1, 10, 11, 12**</i>)	
Coal Gasification	Efficiency: 69% (plant size: 500 MW) (<i>source 1</i>)	
	Electricity demand: 0.075 kWh/kWh (H2) (electricity from EU-mix) (<i>source 1</i>)	
	Hard Coal Losses: 0.4kWh (hard coal)/kWh (H2) (<i>source 1</i>)	
	CO2 emission: 503g/kWh (<i>source 1</i>) (Gasification + electricity generation + feedstock preparation)	
	Cost: 1.29 c/kWh (without cost for electric current and coal) (own calculation based upon <i>source 10, 11, 12</i>)	
Carbon Sequestration	Energy demand: 1.878 kWh(PE)/kg (CO ₂) (<i>source 5</i>) this includes the energy demand for separation, recovery, compression & disposal	
	Cost for CO2 recovery (MEA process): 5.37 cents/kg(CO2 sequestered) (<i>source 9</i>) this includes the energy demand for separation, recovery, compression & disposal	40 – 60 \$/t CO ₂ sequestered (<i>source 17</i>)
Liquefaction	Energy demand: 0.28 kWh(electricity)/kWh(H2) (onsite) 0.22 kWh (electricity)/kWh(H2) (centralised) (assumption based upon <i>source 1, 2, 3, 4</i>)	0.22 kWh/kWh (<i>source 1</i>) 0.28kWh/kWh (<i>source 2</i>) 0.24 kWh/kWh (<i>source 3</i>) 0.35 kWh/kWh (<i>source 4</i>)
	CO2 emissions are calculated from the electricity generation for the liquefaction process	
	Cost: 2.05 c/kWh (without cost for electric current) (<i>source 1</i>)	
Compression (30 to 880 bar)	Energy demand: 0.061 kWh (electricity)/kWh (GH2) (<i>source 3</i>)	
	CO2 emission is calculated from the electricity generation for the compression process	
	Cost: 1.6 c/kWh (without cost for electric current) (<i>source 13</i>)	
Transport/Distribution		
Pipeline (within Europe)	H2 losses (leakages): 0.02 kWh(GH2)/kWh(GH2) [2%] (<i>source 1</i>)	
	Energy demand: 0.015 kWh(PE*)/kWh(GH2) [1.5%] (<i>source 1</i>) (for the operation of the pipeline, compression, etc.)	
	Electricity from EU-Mix	
	CO2-emissions are calculated from electricity generation Cost = 0.08 c/kWh (without cost for electric current) (<i>source 1</i>)	
Pipeline (remote: from Africa to Europe)	H2 losses (leakages): 0.08 kWh(GH2)/kWh(GH2) [8%] (<i>source 1</i>)	
	Energy demand: 0.015 kWh (PE*)/kWh (GH2) [1.5%] (<i>source 1</i>) (for the operation of the pipeline, compression, etc.)	
	Electricity from EU-Mix	
	CO ₂ -emissions are calculated from electricity generation Cost: 0.16 c/kWh (without cost for electric current) (<i>source 1</i>)	
Cryogenic Truck tank size: 55 m ³ Fuel consumption: 30l/ 100 km	CO2 emission: 4 g/kWh (Transport distance 300 km, if liquefaction is in Europe) (<i>source 1</i>) 8 g/kWh (Transport distance 550 km, if liquefaction is in north Africa) (<i>source 1</i>)	5.79 g/kWh (transport distance 300 km) (<i>source 4</i>)
	H2 losses (leakages): 0.5% (<i>source 3</i>)	
	Energy demand (fuel): 0.02 kWh PE/kWh H2 (Transport distance 300 km) (<i>source 1</i>)	0.03 kWh/kWh (transport distance 300 km) (<i>source 4</i>)
	Energy demand (fuel): 0.03 kWh PE/kWh H2 (Transport distance 500 km) (<i>source 1</i>)	
	Cost: 1.28 c/kWh hydrogen (<i>source 1</i>)	
HVDT from North Africa to Europe	Losses during transmission: 8.9% (<i>source 1</i>)	
	Cost: 1.38 c/kWh (fixed cost without current losses) (<i>source 1</i>)	

Ship Transport (LH2) from North Africa to Europe Transport Distance: 5000 km	Energy demand (fuel) 0.15 kWh(PE)/kWh(LH2) (<i>source 1</i>)	
	CO2 emission: 41 g/kWh (<i>source 1</i>)	
	Cost: 4.9 c/kWh(H2) (<i>source 1</i>)	
Electricity Generation		
EU-Mix	Efficiency of Electricity Generation: 44.7% (<i>source 1</i>)	
	CO2 emission: 357 g/kWh (electricity) (own calculation based upon <i>source 14, 15</i>)	393.8 g/kWh (<i>source 4</i>)
	Cost: 4 c/kWh (<i>source 8</i>)	6.9 c/kWh (<i>source 1</i>)
Solar power Parabolic trough power plant	CO2 emission: 11 g/kWh (electricity) (<i>source 1</i>)	
	Cost: 8.7 c/kWh (<i>source 1</i>)	
Wind power	CO2 emission: 8 g/kWh(electricity) (<i>source 1</i>)	
	Cost: 6 c/kWh (<i>source 8</i>)	
Nuclear power	Efficiency of the Electricity Generation Process: 34% (<i>source 1</i>)	
	Cost: 3.22 c/kWh (<i>source 6</i>)	
Natural Gas Turbine CCGT (600 MW) (8000 full load hours)	Efficiency of the Electricity Generation Process: 60% (<i>source 12</i>)	
	CO ₂ -emissions: 337 g/kWh (own calculation based upon <i>source 12, 7****</i>)	
	Cost: 2.11 cents/ kWh (including cost for natural gas) (own calculation based upon <i>source 10, 11, 12****</i>)	
coal open cycle unit (600 MW, 8000 full load hours)	Efficiency of the Electricity Generation Process: 46% (<i>source 11</i>)	
	CO ₂ -emissions: 708 g/kWh (own calculation based upon <i>source 11, 7</i>)	
	Cost: 1.24 c/kWh (including cost for coal) (own calculation based upon <i>source 10, 11, 12****</i>)	

*assumptions for centralised reforming of natural gas:

investment cost: 0.38 c/kWh (385 MW plant)

operation and maintenance: 0.2 c/kWh

assumptions for onsite reforming of natural gas:

investment cost: 0.76 c/kWh (4.275 MW plant)

operation and maintenance: 0.2 c/kWh

** assumption for gasification of biomass:

investment cost: 1.67 c/kWh (25 MW plant)

operation and maintenance: 0,51 c/kWh

***assumptions for gasification of coal:

investment cost: 0.78 c/kWh (500 MW plant)

operation and maintenance: 0.51 c/kWh

****assumptions for electricity generation with combined cycle gas turbines

no investment cost

no operation and maintenance cost

fuel cost 1.267 c/kWh

efficiency 60 %

***** assumptions for electricity generation with coal open cycle units:

no investment cost

no operation and maintenance cost

fuel cost 0.57 c/kWh

efficiency 46 %

For all our own cost calculations the following conditions are assumed:

full load hours: 8000 h

depreciation: 20 years

interest rate: 6 %

source 1: (Wagner et al. 2000)

source 2: (Eliasson & Bossel 2002)

source 3: (Altmann et al.2002)

source 4: (General Motors & LBST 2002)
source 5: (Steinberg et al. 1984)
source 6: (Uranium Information Centre Ltd 2002)
source 7: (Hohmeier 2001)
source 8: (World Energy Outlook 2002)
source 9: (U.S. Department of Energy 1993)
source 10: (Prognos AG Stuttgart 1999)
source 11: (IIP Technology Data Base 2002)
source 12: (Enquete Kommission des Bundestages 2002)
source 13: personal communication Hansen, F.-J. , Neumann und Esser GmbH, Übach Palenberg
source 14: (Capros 2003)
source 15 : (ProBas o. J.)
source 16: (Enquête-Kommission 2002b)
source 17 (Keith & Parson 2000)

3.4 Results of the well-to-tank (WTT) analysis

Figures 3-2 to 3-4 show the total primary energy demand, CO₂ –emissions and costs for the 26 pathways analysed throughout the well-to-tank analysis from feedstock preparation to hydrogen production and supply at a filling station. Three additional graphs are included to demonstrate the effect of an CO₂-emission trading amounting to 10, 30 and 50 €/t CO₂ on the total cost (figure 3-5 to 3-7).

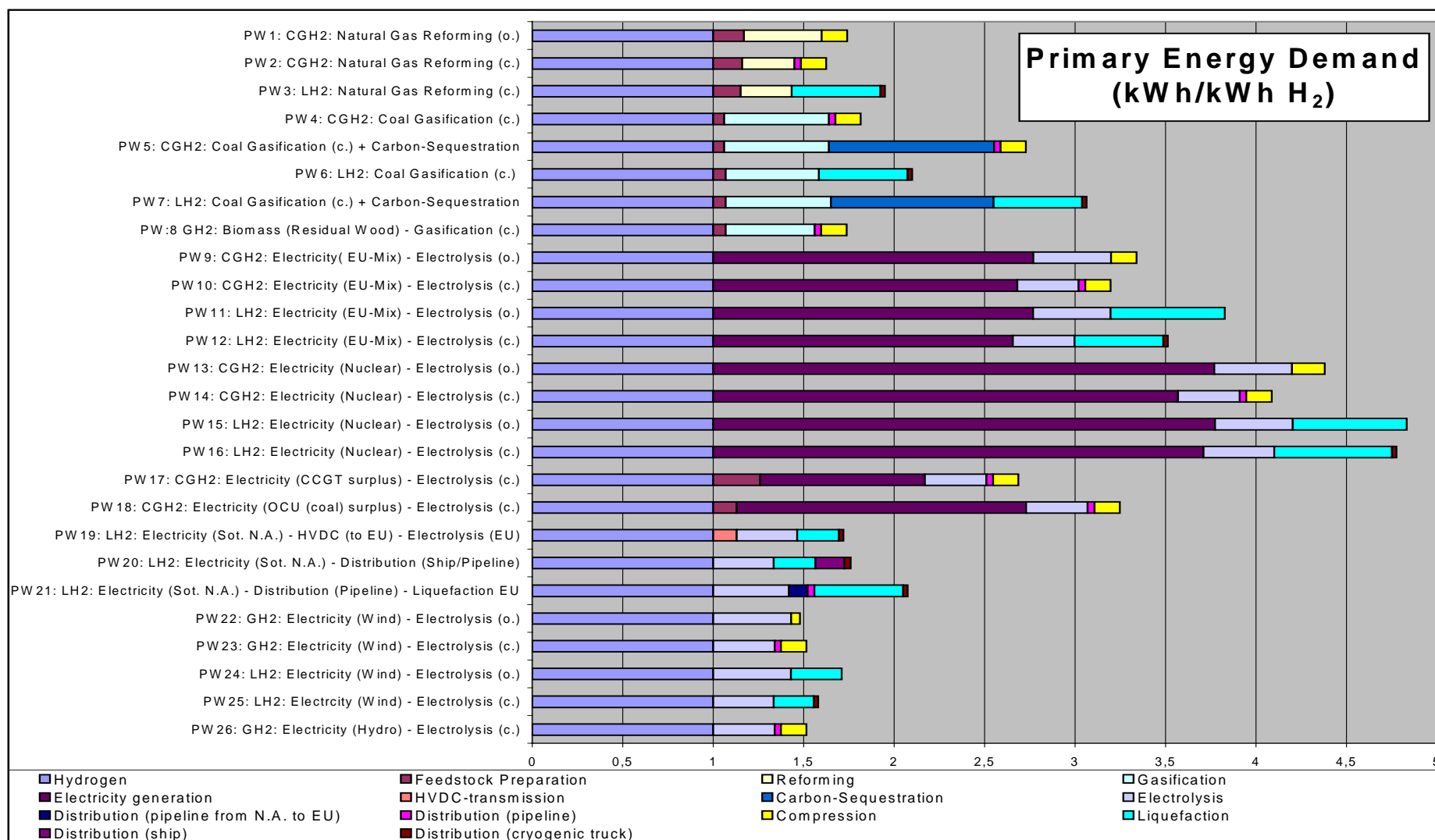


Figure 3-2: Primary energy demand per kWh hydrogen

Table 3-4: Calculated data for primary energy demand from feedstock preparation till hydrogen distribution

PW-No	Hydrogen	Feedstock Preparation	Reforming	Gasification	Electricity generation	HVDC	Carbon sequestration	Electrolysis	Distribution (pipeline from N.A. to EU)	Distribution (pipeline)	Compression	Liquefaction	Distribution (ship)	Distribution (cryogenic truck)	Total PED
01	1	0,17	0,43								0,14				1,74
02	1	0,16	0,29							0,035	0,14				1,63
03	1	0,15	0,28									0,49		0,03	1,95
04	1	0,06		0,58						0,04	0,14				1,82
05	1	0,06		0,58			0,91			0,04	0,14				2,73
06	1	0,07		0,52								0,49		0,03	2,10
07	1	0,07		0,58			0,90					0,49		0,03	3,06
08	1	0,07		0,49						0,04	0,14				1,74
09	1				1,77			0,43			0,14				3,34
10	1				1,68			0,34		0,04	0,14				3,20
11	1				1,77			0,43				0,63			3,83
12	1				1,66			0,34				0,49		0,03	3,51
13	1				2,77			0,43			0,18				4,38
14	1				2,57			0,34		0,04	0,14				4,09
15	1				2,77			0,43				0,63			4,83
16	1				2,71			0,39				0,65		0,03	4,78
17	1	0,26			0,91			0,34		0,04	0,14				2,69
18	1	0,13			1,60			0,34		0,04	0,14				3,25
19	1					0,13		0,34				0,23		0,03	1,72
20	1							0,34				0,23	0,16	0,04	1,76
21	1							0,42	0,11	0,04		0,49		0,03	2,07
22	1							0,43			0,05				1,48
23	1							0,34		0,04	0,14				1,52
24	1							0,43				0,28			1,71
25	1							0,34				0,22		0,03	1,58
26	1							0,34		0,04	0,14				1,52

3.4.1 Main issues regarding primary energy demand (PED) per kWh hydrogen:

- The diagram shows that centralised options generally perform better within the same feedstock-block than onsite options, due to a higher efficiency in hydrogen production (with the exception of the production of gaseous hydrogen via electrolysis with wind power where centralised and onsite option have roughly the same performance) and a low primary energy demand for hydrogen distribution with cryogenic trucks or pipelines.
- The supply of gaseous hydrogen at the filling station generally performs better than the supply of liquid hydrogen, because the PED is much higher for liquefaction than for compression.
- The process of electricity generation from fossil feedstock and nuclear fuel, as well as the processes of carbon sequestration and liquefaction have a dominant influence on the total energy balance.
- The pathways based on electricity from nuclear power have the highest primary energy demand due to the low efficiency for electricity generation (34%). Values lie between 4.1 and 4.8 kWh/kWh.
- The primary energy demand for pathways based on electricity from the European mix are also quite high with 3.2 to 3.8 kWh/ kWh. The efficiency of electricity generation is 44.7% in this case.
- PW18 based on hydrogen production with extended full load hours of coal open cycle units also falls in this range with a total primary energy demand of 3.2 kWh/kWh. Efficiency of electricity generation is 46%.
- Slightly below this is the PED for PW17, hydrogen production with full load driven natural gas shoulder load power plants, with a PED of 2.7 kWh/kWh, based on an efficiency of electricity generation of 60%.
- With respect to primary energy demand, the pathways based on the gasification of coal show a clear distinction. Without carbon sequestration, the total PED is relatively low with 1.8 to 2.1 kWh/ kWh, with carbon capture, it is between 2,7 and 3,1 kWh/kWh.
- Within the non-renewable energy based pathways, reforming of natural gas performs best with figures between 1.6 and 1.9 kWh/kWh.
- In an overall comparison, the pathways based on renewable energy sources (wind power, hydropower, solar thermal power and biomass) have the lowest primary energy demand. Within the renewable pathways, hydropower and wind power pathways perform best with 1.5 kWh/ kWh.
- Within the three pathways based on solar power from North Africa, PW19 with energy import via HVDC transmission performs best. The PED is about the same as the PED of the biomass-based pathway, although this option supplies GH2 whereas PW19 supplies LH2.

- All renewable pathways have the additional advantage that most of the PED is renewable

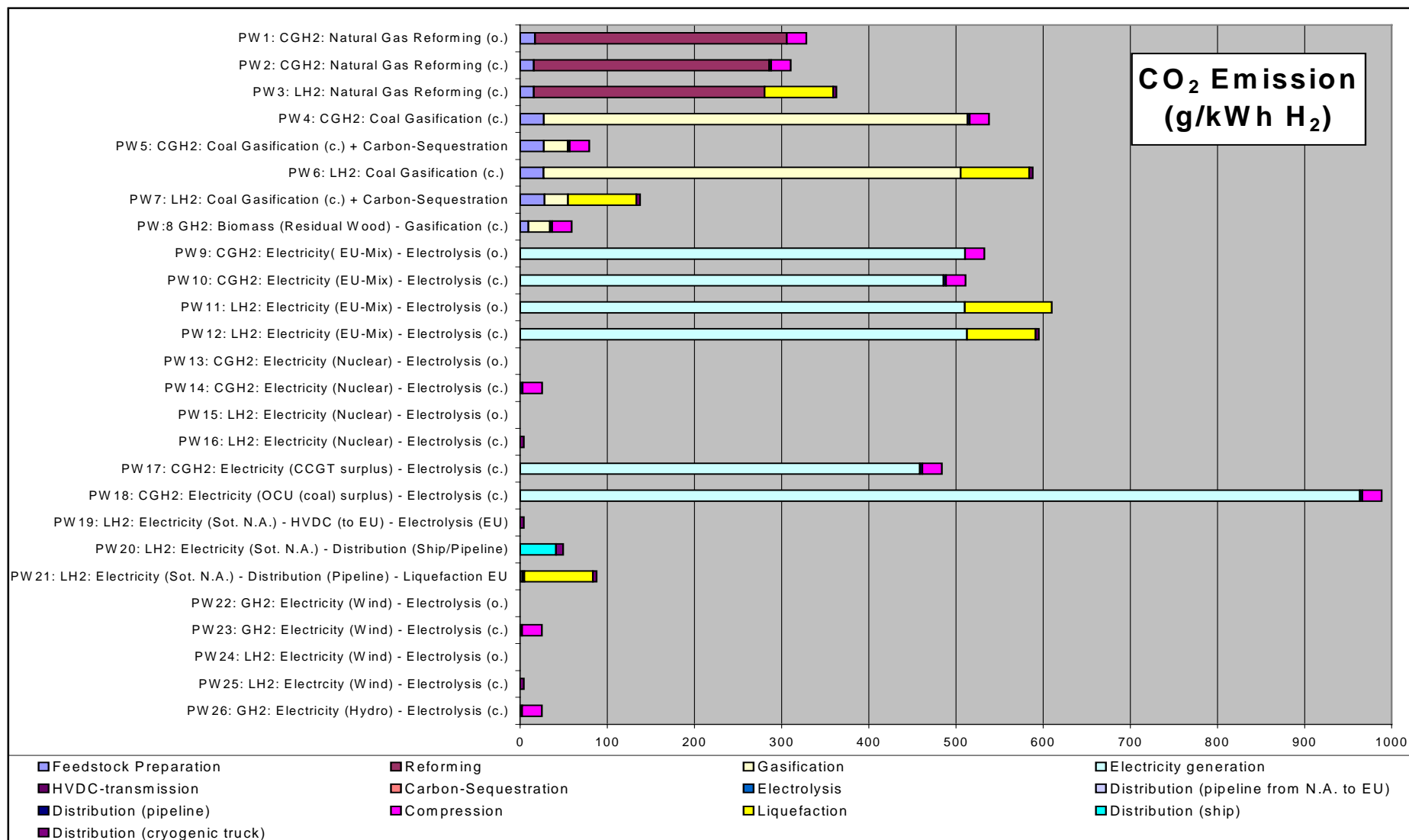
Figure 3-3: CO₂ emissions per kWh hydrogen

Table 3-5: Calculated data for CO₂ –emissions from feedstock preparation till distribution of hydrogen

PW No.	Feedstock Preparation	Reforming	Gasification	Electricity generation	HVDC-transmission	CO ₂ -sequestration	Electrolysis	Distribution (pipeline from N.A. to EU)	Distribution (pipeline)	Compression	Liquefaction	Distribution (ship)	Distribution (cryogenic truck)	Total Emissions
01	17,2	288,8								22,34				328,34
02	15,7	270							2,4	22,34				310,44
03	15,50	264,90									78,54		4,00	362,94
04	27,20		486,10						2,40	22,34				538,04
05	27,10		27,32						2,40	22,34				79,16
06	26,80		478,70								78,54		4,00	588,04
07	27,90		27,00								78,54		4,00	137,44
08	9,43		24,57						2,74	22,34				59,08
09				510,30						22,34				532,64
10				485,80					2,74	22,34				510,88
11				510,00							99,96			609,96
12				512,65							78,54		4,00	595,19
13														0,00
14									2,74	22,34				25,08
15														0,00
16													4,00	4,00
17				458,60					2,74	22,34				483,68
18				963,46					2,74	22,34				988,54
19													4,20	4,20
20												41,20	8,00	49,20
21								2,52	2,40		78,54		4,00	87,46
22														0,00
23									2,40	22,34				24,74
24														0,00
25													4,02	4,02
26									2,40	22,34				24,74

3.4.2 Main issues regarding CO₂ –Emissions per kWh hydrogen

- Of the three evaluation criteria, the criterion “CO₂ emissions” of the pathways shows the greatest variations. Figures are between 0 g/kWh and 989 g/kWh.
- The supply of gaseous hydrogen as well as centralised hydrogen production pathways generally perform better than the supply of liquid hydrogen and onsite hydrogen production pathways. Exceptions are nuclear and renewable pathways, where onsite production leads to lower emissions. Onsite production means that the zero-emission energy source is available for hydrogen production as well as liquefaction or compression. This is not the case for centralised options, where liquefaction/ compression takes place at the filling station with EU-mix as the electricity source.
- The CO₂ emissions are highest for PW 18, electrolysis with electricity surplus from full load driven shoulder load coal power plants. Emissions for the full pathway amount to 989 g/kWh due to high emissions during electricity generation (708 g/kWh).
- Electricity-based pathways with electricity from the European mix have the second highest CO₂ emissions due to low efficiency (44.7 %) and high emissions (357 g/kWh) during electricity generation. Pathways based on coal gasification without carbon sequestration show a similar result due to high emissions during the gasification process (503 g/kWh). The total CO₂ emissions range between 500 and 600 g/kWh.
- Natural gas based pathways perform much better due to lower emissions during hydrogen production (279 g/kWh (centralised) and 306 g/kWh (onsite)). Total figures are between 310 and 363 g/kWh.
- Within the fossil feedstock based pathways, coal gasification with carbon sequestration performs best. However these pathways still have CO₂ emissions as only carbon emitted during the process of gasification is captured, while CO₂ emitted during other processes like electricity generation or transport is not. The total CO₂ emissions for these pathways are therefore 79 (GH2 option) and 137 g/kWh (LH2 option).
- Fuel supply pathways based on nuclear power and renewable energy sources have drastically reduced CO₂ emissions because no CO₂ emissions occur during the processes of electricity generation and hydrogen production. CO₂ figures lie between 0 g/kWh for PW13/15 (nuclear power) and PW22/24 (wind power) and 87 g/kWh for PW21, (solar thermal energy from North Africa, hydrogen import via pipeline). CO₂ emissions in nuclear power- and renewable energy-based pathways arise from the electricity demand from the European mix for compression or liquefaction, when compression or liquefaction is not in the same place as hydrogen production, and/or from road transport of biomass or liquid hydrogen by truck.

Within the solar thermal energy based pathways (PW19–21), PW21 (hydrogen transport to Europe per pipeline and liquefaction in Europe) shows the highest CO₂ emissions (87 g/kWh). PW19 (solar thermal energy transport to Europe via HVDC transmission and hydrogen production and liquefaction in Europe) performs best (4.2 g/kWh).

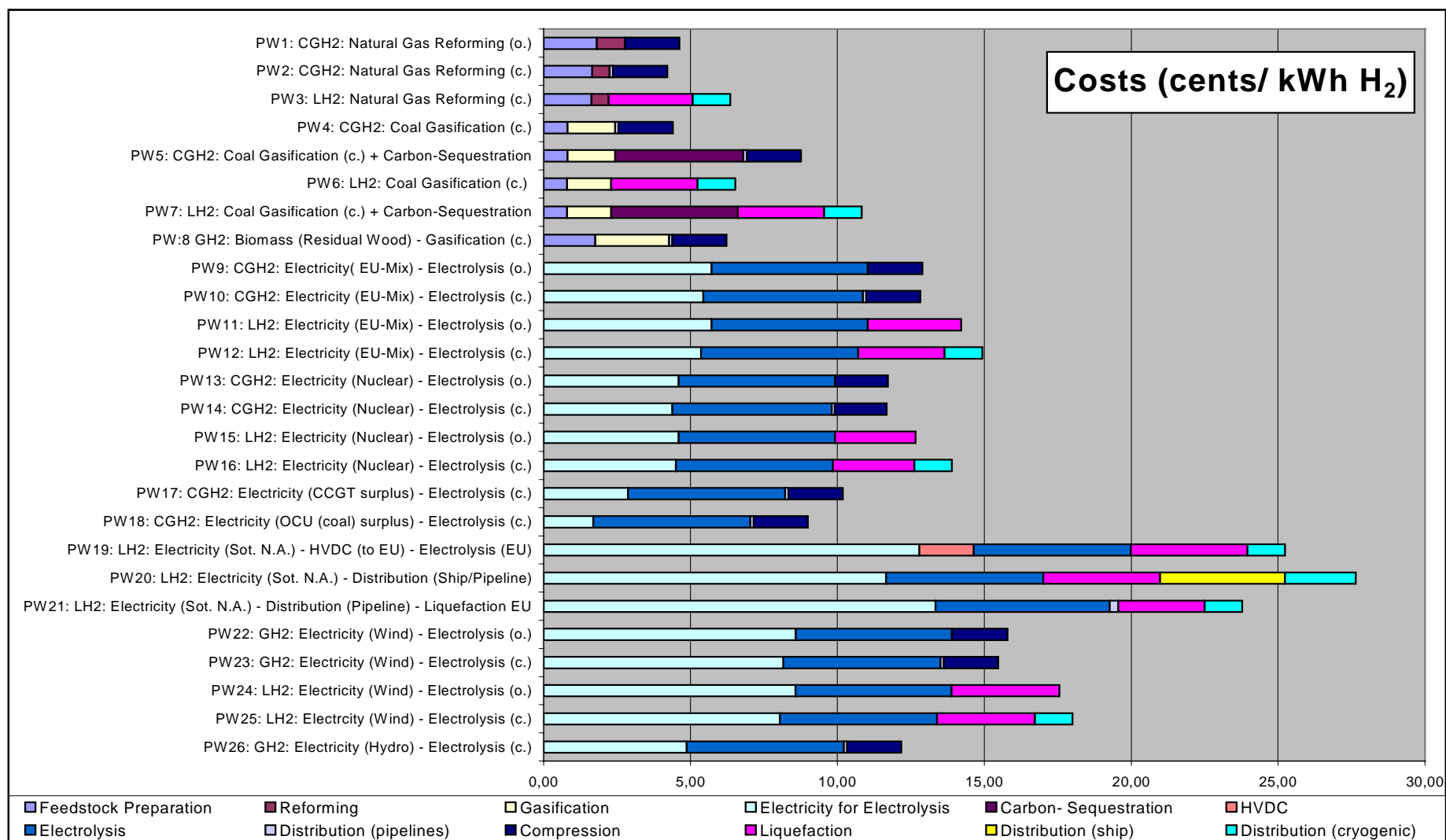
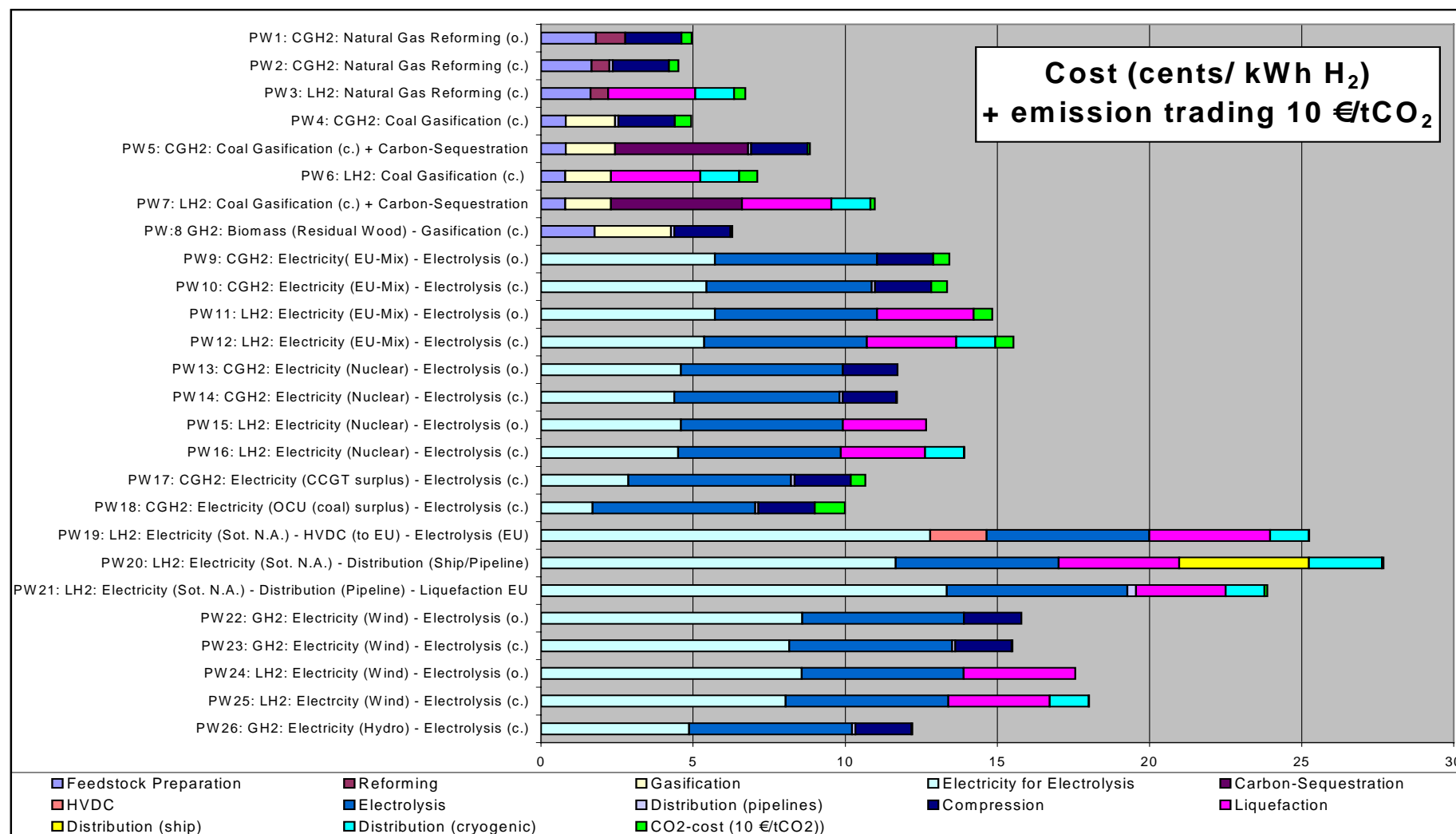


Figure 3-4: Cost per kWh hydrogen

Table 3-6: Calculated data for costs from feedstock preparation to hydrogen distribution

PW-No	Feedstock Preparation	Reforming	Gasification	Electricity for Electrolysis	CO2 Sequestration	HVDC	Electrolysis	Distribution (pipelines)	Compression	Liquefaction	Distribution (ship)	Distribution (cryogenic truck)	Total cost
01	1,81	0,96		0					1,85				4,62
02	1,66	0,59		0				0,11	1,85				4,21
03	1,63	0,58		0						2,86		1,28	6,35
04	0,82		1,62	0				0,11	1,85				4,40
05	0,82		1,62	0	4,37			0,11	1,85				8,77
06	0,80		1,50	0						2,94		1,28	6,52
07	0,80		1,50	0	4,31					2,94		1,28	10,83
08	1,76		2,51	0				0,11	1,85				6,23
09				5,72			5,32		1,85				12,89
10				5,44			5,43	0,11	1,85				12,83
11				5,72			5,32			3,18			14,22
12				5,36			5,35			2,94		1,28	14,93
13				4,60			5,32		1,80				11,72
14				4,38			5,43	0,10	1,76				11,67
15				4,60			5,32			2,74			12,66
16				4,50			5,35			2,77		1,28	13,90
17				2,87			5,35	0,11	1,85				10,18
18				1,69			5,35	0,11	1,85				9,00
19				12,79		1,85	5,35			3,97		1,28	25,24
20				11,66			5,35			3,97	4,26	2,40	27,64
21				13,34			5,93	0,29		2,94		1,28	23,78
22				8,58			5,32		1,89				15,79
23				8,16			5,35	0,11	1,85				15,47
24				8,57			5,32			3,67			17,56
25				8,04			5,35			3,33		1,28	18,00
26				4,87			5,35	0,11	1,85				12,18

Figure 3-5: Cost per kWh hydrogen taking into account costs for carbon emissions amounting to 10 €/tCO₂

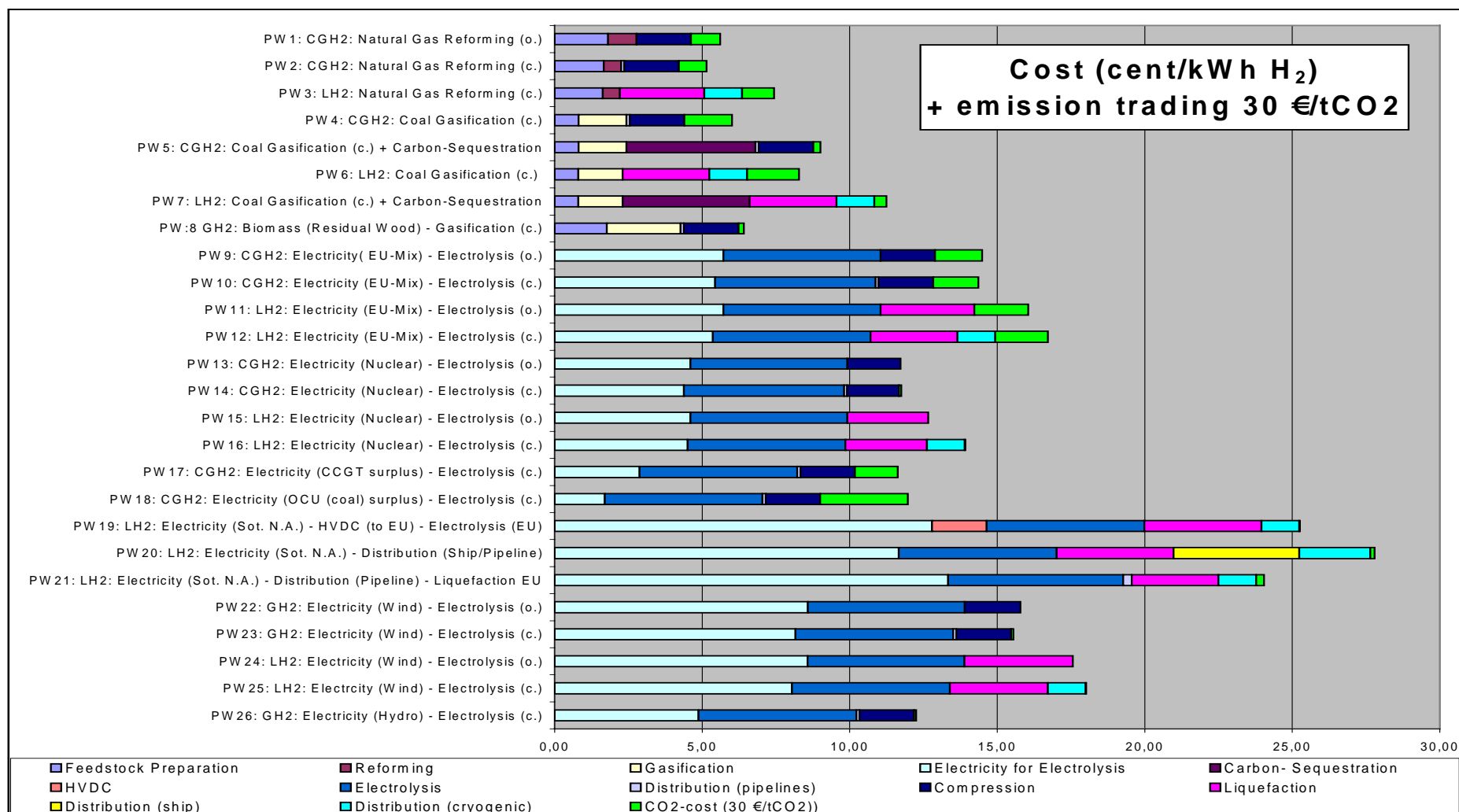


Figure 3-6: Cost per kWh hydrogen taking into account costs for carbon emissions of 30 €/t

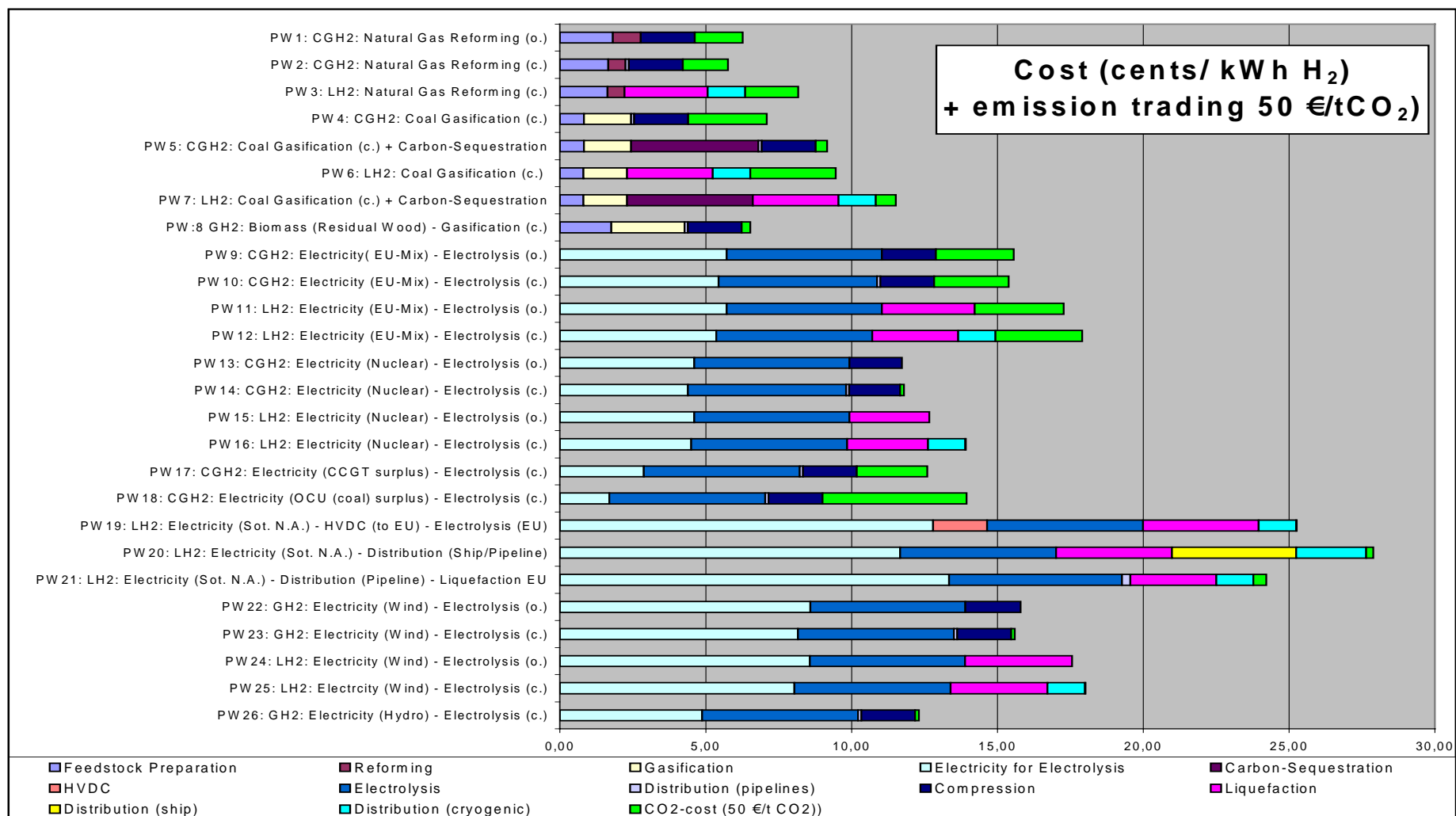


Figure 3-7: Cost per kWh hydrogen taking into account costs for carbon emissions of 50 €/t

3.4.3 Main issues regarding costs per kWh hydrogen

Figure 3-4

- Looking at the different sub-sectors, the production sector (electricity and hydrogen production via electrolysis) has a dominant influence on the total cost, followed by the cost of carbon sequestration and the transport of liquid hydrogen from North Africa to Europe per ship. The reforming of natural gas, coal gasification, compression/ liquefaction and distribution of liquid hydrogen per cryogenic truck have lower costs. Distribution via pipeline does not have an effect on the total costs.
- This explains the fact that pathways based on electricity from expensive renewable energy sources like solar power and, to a clearly lesser extent, wind power, show high total costs because of their high electricity generation costs. Costs for solar power based pathways are between 25 and 28 c/kWh, and between 16 and 18 c/kWh for wind power based pathways.
- EU-mix based pathways have slightly lower costs (between 13 and 15 c/kWh) followed by nuclear power based pathways (between 12 and 14 c/kWh).
- As electricity generation with hydropower is quite cheap compared to other renewable energy sources, the whole pathway performs quite well with 12 c/kWh.
- Costs for hydrogen production with electricity surplus of full load driven shoulder load coal and natural gas power plants are 9 (coal) and 10 (natural gas) c/kWh. Costs for electricity generation are quite low in these cases as investment costs are excluded and efficiency is optimised.
- Within the renewable pathways, the gasification of residual wood has the lowest total cost at 6 c/kWh.
- The cheapest pathways are those based on the reforming of natural gas (4 to 6 c/kWh) followed by coal gasification without carbon sequestration (4 to 7 c/kWh). Carbon sequestration leads to higher total costs of 9 to 11 c/kWh.

Figures 3-5 to 3-7

- If CO₂ emissions are charged at **10 or 30 €/t CO₂**, the overall result is barely affected.
- If CO₂ emissions are charged at **50 €/t CO₂**, the renewable pathways become more competitive.
- Hydrogen from the gasification of residual wood is cheaper than from gasification of hard coal with and without carbon sequestration. The natural gas based pathways reach the cost level of the biomass pathway and they are both the least expensive options.
- The EU-mix based pathways almost reach the level of wind power pathways.
- Hydrogen from solar power from North Africa remains the most expensive option.

3.4.4 Conclusions

The following conclusions can be made:

- When considering the three evaluation criteria there is no clearly dominant option.
- The pathways based on the reforming of natural gas offer a good compromise. They perform well with respect to primary energy demand and cost and have moderate CO₂ –emissions compared to other fossil feedstock based pathways.
- Within the natural gas pathways the centralised option for gaseous hydrogen performs best in all evaluation criteria.
- Gasification of hard coal performs worse than reforming of natural gas in all three evaluation criteria. But in comparison to EU-mix pathways, it performs better in respect of cost and PED (emissions are about the same). Compared to renewable pathways this solution only has an advantage in respect of cost.
- Hydrogen production with the energy surplus of full load driven shoulder load power plants (coal and natural gas) does not have a clear advantage over the direct reforming/ gasification of natural gas/ coal. Figures are higher in all three evaluation criteria.
- Hydrogen production with electricity from the European mix doesn't perform well with respect to all three evaluation criteria.
- Renewable pathways generally perform well in respect of primary energy demand and emissions but the total cost are quite high, especially for the pathways based on solar energy import from north Africa. Lowest cost within the renewable pathways has gasification of biomass followed by hydro power and wind power pathways. In this context one has to keep in mind, that the availability of hydro power and residual wood for hydrogen production is limited.
- Within the three analysed pathways based on solar power from North Africa, PW 19, electricity import via HVDC transmission and electrolysis in Europe (centralised) performs best with regard to PED and CO₂ –emissions. Regarding costs, PW21 performs better, but this pathway also has the highest emissions as well as the highest PED. Therefore assessing which is the best option for hydrogen production with renewable energy from overseas depends on political objectives.
- The effect of emissions trading on the total cost is only noticeable at a very high charge for CO₂ emissions of about 50 €/t CO₂. If this is applicable then the total cost of renewable and fossil fuel based pathways are more or less harmonised.
- Distribution of gaseous hydrogen via pipeline performs in all three evaluation criteria better than distribution of liquid hydrogen via cryogenic truck. But with respect to the total primary energy demand, the total CO₂ –emissions and the total cost, distribution shows only a very limited effect.
- Compression performs better than liquefaction in all three evaluation criteria. With exception of the total cost, compression only has a limited effect on the pathway analysis, whereas liquefaction does have a significant effect within the evaluation criteria primary energy demand and cost. In the field CO₂ –emissions it's effect is highly dependent on the energy source for liquefaction.

3.4.5 Carbon sequestration for natural gas reforming

Carbon sequestration for natural gas reforming has not been considered in the analysis above, because of its moderate CO₂ emissions compared to the gasification of hard coal. But as reforming of natural gas performs well in all three evaluation criteria and therefore is a very promising transient option for hydrogen production, it is of interest to evaluate the primary energy demand, emissions and costs for centralised reforming of natural gas with carbon sequestration.

PED and costs are highly dependent on the sequestration process applied, its energy source and the CO₂ exhaust content. It is probable that carbon sequestration for natural gas reforming is slightly more energy- and cost-intensive than for hard coal gasification for two reasons. First, the CO₂ exhaust content is lower and the sequestration process therefore less efficient. Second, the energy source used for the sequestration process is natural gas instead of hard coal, which is more expensive.

The cost and primary energy demand for carbon sequestration are difficult to estimate and values given range widely (e.g. 40 to 60 US \$/ kg CO₂ sequestered and disposed, Keith & Parson 2000). Because of this uncertainty, the values used can only provide a rough estimate of the increase in the total cost and primary energy demand when carbon sequestration is applied and do not claim to be precise. For this reason, the calculations for natural gas reforming with carbon sequestration are based on the same primary energy demand and the same cost as for carbon sequestration for coal gasification (PED: 1.878 kWh PE/kg CO₂ sequestered; cost: 5.37 c/kg CO₂ sequestered; PED and costs include separation, recovery, compression and disposal of CO₂, see Table 3-3).

Table 3-7 shows the values calculated for PW2cs⁵ (CGH2 from natural gas reforming centralised with carbon sequestration) and PW3cs (LH2 from natural gas reforming centralised with carbon sequestration) compared to PW2 and PW3.

Table 3-7: PED, CO₂ emissions and costs for natural gas reforming with and without carbon sequestration.

PW	PED (kWh/kWh H ₂)	CO ₂ emissions (g/kWh H ₂)	Costs (c/kWh H ₂)	Costs (c/kWh H ₂ + emission trading 50 €/t CO ₂)
PW2cs	1.908	40.43	5.66	5.88
PW2	1.625	310.43	4.21	5.76
PW3cs	2.19	98.04	7.77	8.29
PW3	1.91	362.94	6.35	8.16

⁵ cs = carbon sequestration

3.4.6 Conclusions

- With respect to the total primary energy demand, the centralised reforming of natural gas with carbon sequestration still performs better than comparable⁶ coal gasification, EU-mix or nuclear power based pathways. The total primary energy demand is lower for all renewable pathways.
- If CO₂ emissions resulting from reforming natural gas are sequestered, the total pathway emissions are lower than those of hard coal gasification with carbon sequestration, EU-mix and even biomass based pathways. The total emissions are lower for all other renewable pathways.
- The total costs are still lowest for natural gas reforming, even if carbon sequestration is conducted.
- If CO₂ emissions are charged at 50 €/t CO₂, which represents an elevated level for emission trading costs, the total pathway costs for reforming natural gas with and without carbon sequestration are assimilated, but carbon sequestration is still more expensive.

3.5 Comparison of selected hydrogen fuel pathways with conventional fuels within the scope of a well-to-wheel analysis

In order to make a thorough evaluation of hydrogen as a fuel a comparison with conventional fuels is conducted within the scope of a well-to-wheel analysis from fuel production up to its conversion in a vehicle. A simple comparison of the well-to-tank analyses is not adequate as the powertrain with its specific efficiency is crucial to the overall result. For the comparison four hydrogen pathways were chosen from the 26 pathways previously analysed. These pathways are considered to be the most realistic and most reasonable of the 26 analysed with respect to energy consumption, costs, carbon dioxide emissions, the availability of the technology and the feedstock as well as the practicability.

1. **PW2: Gaseous hydrogen production via natural gas steam reforming (centralised):** this pathway was selected because most of the present hydrogen production occurs via natural gas steam reforming. Therefore vast experience of this technology has been gained over the years in the process industry and especially in refineries. Other reasons for this choice are its low energy consumption and costs as well as its moderate CO₂ emissions compared to other fossil feedstock based pathways.

⁶ comparable with respect to the state of aggregation of the produced hydrogen (liquid/ gaseous) and the location of the hydrogen production plant (centralised/ onsite)

2. **PW5: Gaseous hydrogen production from coal gasification with carbon sequestration (centralised):** this pathway was selected due to the fact that hydrogen production will probably be based upon fossil feedstocks in the near future because of the high prices for renewable energy technologies. Compared to natural gas, coal has the advantage that large resources exist in Europe. The main obstacle to coal gasification is the high quantity of carbon dioxide emitted during this process. This problem can be combated by storing the carbon compounds in underground cavities or depleted oil and gas fields. Another disadvantage of this pathway is that there are many uncertainties about carbon sequestration, e.g. with respect to storage security, but a lot of research is being conducted in this field.
3. **PW22: Gaseous hydrogen production via electrolysis (onsite), electricity from wind power:** of all the renewable pathways analysed, wind energy has the highest potential after solar energy. Although it may not be very profitable at present, there is a great cost reduction potential and it will be the main source of electricity production in the near future. Another advantage of this pathway is that the production of hydrogen with wind power avoids the existing problems regarding the system integration of wind energy in the electricity grid.
4. **PW9: Gaseous hydrogen production via electrolysis (onsite), electricity from EU-mix.** This pathway shows a very high practicability as no additional effort for feedstock transport and storage is necessary and as the electricity grid already exists.

The propulsion selected for all four hydrogen pathways is a fuel cell (FC) with an efficiency of 44,3%. The pathways are compared with two conventional fuels: diesel and gasoline in combination with a conventional driveline (CD) with an efficiency of 22,6% (gasoline) and 25,5% (diesel) (General Motors, LBST 2002). The result of the w-t-w shows table 3-6:

Table 3-8: Comparison of four selected hydrogen pathways with two conventional pathways (well-to-tank (WTT) and well-to-wheel (WTW))

Pathway	WTT-PED kWh/kWh(fuel)	WTT ⁵ -CO ₂ g/kWh(fuel)	Power- train	efficiency in %	WTW-CO ₂ g/kWh(mech ⁶)	WTW-PED kWh/kWh(mech ⁶)
Gasoline	1.19	317	CD	22.6	1402	5.26
Diesel	1.1	298	CD	25.5	1169	4.31
PW22 ¹ : H ₂ from wind	1.49	0	FC	44.3	0	2.68
PW2 ² : H ₂ from NG	1.63	310.43	FC	44.3	701	3.68
PW5 ³ : H ₂ from coal	2.73	79.16	FC	44.3	179	6.16
PW9 ⁴ : H ₂ from EU-mix	3.34	532.64	FC	44.3	1202	7.54

values for gasoline and diesel from General Motors, LBST 2002

¹ CGH2 - Wind power – Electrolysis (onsite)

² CGH2 – Natural gas – Reforming (centralised)

³ CGH2 – Hard coal – Gasification (centralised) – Carbon Sequestration

⁴ CGH2 – EU-mix –Electrolysis (onsite)

⁵ for the two conventional pathways these figures include emissions resulting from combusting the fuel

⁶ mech = mechanical energy at the wheel

3.5.1 Results of the well to wheel analysis for selected pathways

- The total well-to-wheel primary energy demand is significantly lower for hydrogen from natural gas reforming and electrolysis with wind power compared to the conventional fuel-propulsion systems, whereas the PED for hydrogen via coal gasification with carbon sequestration as well as the PED of electrolysis with EU-mix is higher.
- The CO₂ figures of the renewable pathway and the pathway based on coal gasification with carbon sequestration are significantly lower than those of the conventional fuels and the natural gas based pathways. Emissions of the natural gas based pathway are also significantly lower than those for the two conventional fuel-propulsion systems. The emissions of the EU-mix pathway lays in the same range as the conventional pathways.
- One has to keep in mind, that for the comparison today's standards is chosen for the conventional pathways (diesel, gasoline). The conventional pathways therefore still have a potential to reduce the PED and CO₂-emissions. Furthermore alternative drive systems should be regarded (i.e. hybrid cars powered by conventional engines supplemented by electric motors).

4 Potentials for hydrogen production based on renewable energy sources by 2020

4.1 Introduction

The long-term sustainable pathway with respect to a hydrogen economy is one based on renewable energy sources (RES). Such sources have experienced increased attention and strong political support in the European Union during the past years. On the European level several (indicative) targets have been set to increase the use of renewable energy sources.⁷

Except for the direct gasification of biomass, renewable energy sources will contribute to the production of hydrogen only through the process step “electrolysis” based on electric energy. The main primary energy carriers for this pathway consist of wind energy, hydropower, biomass combustion as well as solar energy through photovoltaic and active solar thermal plants. In general, competition with the direct consumption of electricity is a key aspect to be considered when analysing renewable electricity as a potential energy source for hydrogen production.

To analyse the competition between direct electricity consumption and the production of hydrogen more closely, we look at the possible evolution of the different renewable energy sources up to 2020 under a baseline scenario as well as under the assumption of strong political promotion of RES. The *business as usual scenario* (BAU) is based on the past trends and on the currently implemented policies for the promotion of RES. The *renewable policy scenario* (RPS) assumes that the EU RES targets for 2010 will be met and best practice policies will be applied after 2010 in all European countries. These scenarios have been developed within the present project based on own data and investigations as well as based on the following sources: Pretir (2002), Admire-Rebus (2003), ElGreen (2002), Mitre-Safire (2003), Green-X (2003), Capros (2003).

⁷ In December 1997, the European Commission adopted the "White Paper for a Community Strategy and Action Plan, Energy for the Future: Renewable Sources of Energy". The objective is to increase the use of renewable energy sources (RES) to an amount that is equal to 12% of the European Union's gross inland energy consumption by 2010

In 1999 the Campaign for Take-Off (CTO) started for the period 1999-2003 with the intention of kick-starting the implementation strategy set out in the White paper.

In 2001 the European Parliament adopted the Directive on the promotion of electricity from renewable energy sources. The overall target is to increase the share of renewable electricity production to 21.7% of total electricity production in 2010. The directive includes indicative targets for the share of renewable electricity production per EU Member State.

In 2001 a draft Directive on biofuels was published. The proposed aim is to increase the consumption of biofuels to 2% of the total consumption of transport fuels in 2005 and to 5% in 2010.

The assumptions behind the two scenarios will be described in the following.

BAU scenario: This scenario models the future development in a country based on the current policies as well as based on currently existing barriers and restrictions, e.g. administrative and regulation barriers. Furthermore market barriers are analysed based on the growth rates observed during the last five years. In this sense this scenario contains a representation of promotion schemes, regulation aspects as well as socio-cultural habits in the country under consideration observed during a time span of five years. However, the scenario does not take into account very recent political developments, which did have an effect on the observed growth rates of different technologies, e.g. the introduction new feed in tariffs in Austria and France.

RPS: The policy scenario describes the development in each country assuming these countries adopt the policy of the two (in some cases one) most successful (best practice) countries in Europe showing the largest growth during the last five years. For example for onshore wind energy it is assumed in the renewable policy scenario that all countries follow the path of Spain and Germany during the past five years. Similar policies and promotion schemes on the one hand and low administrative barriers on the other hand as applied in these best practice countries will be assumed for all EU-25 countries.

4.2 Scenario results

BAU scenario: The RES evolution in the electricity sector (RES-E) for the EU-25 under the business as usual (BAU) scenario is shown in Figure 4-1. The following conclusions can be drawn from this figure: In a BAU scenario hydropower will remain the dominant RES by 2020. Wind power will show strong growth and reach about 70% of the power production of hydro power. Biomass is the third renewable technology contributing significantly to the RES-E production in the EU-25. All remaining sources like photovoltaic and geothermal electricity will in absolute terms only make up a minor fraction of the RES electricity generation until 2020. The total RES electricity production will almost double between 2000 and 2020, however this increase can easily be absorbed by the electricity system.

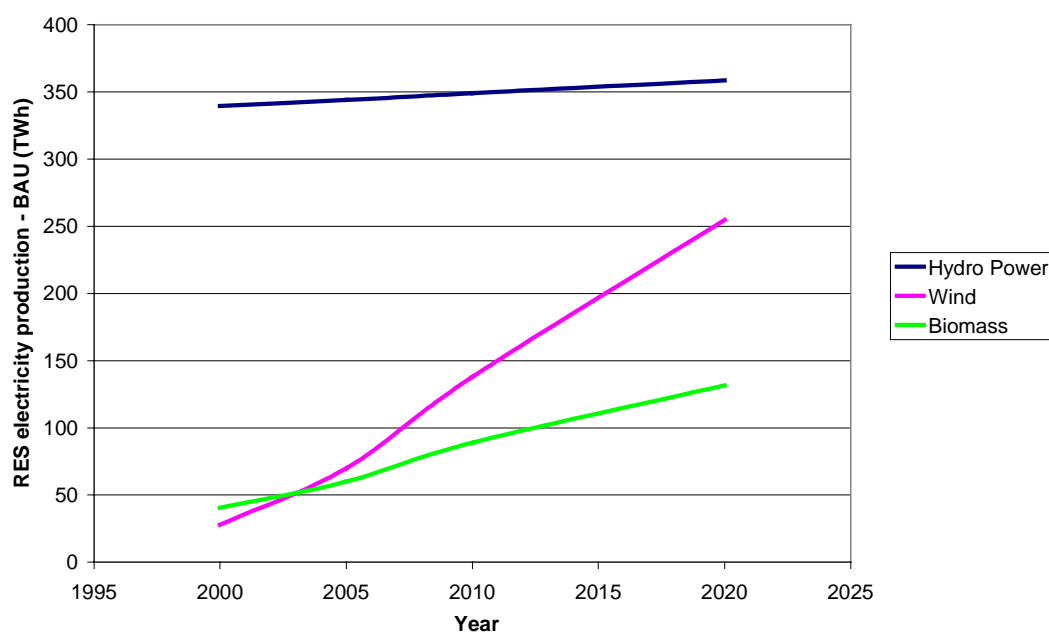


Figure 4-1: Development of RES-E production in the EU-25 - BAU

In Figure 4-2 the RES contribution to the total electricity production for the EU-25 is shown for the BAU scenario in relative terms assuming a baseline scenario for the evolution of the total electricity production. It can be seen that the EU targets for RES in the electricity sector will not be met and that a large part of the growth of wind energy will be compensated by the relative decrease of hydropower due to an increasing electricity consumption. Even in the year 2020 the contribution of RES will still be lower than the EU targets for RES in the electricity sector for 2010. This fact is prohibiting the use of RES for the production of hydrogen under a business as usual scenario.

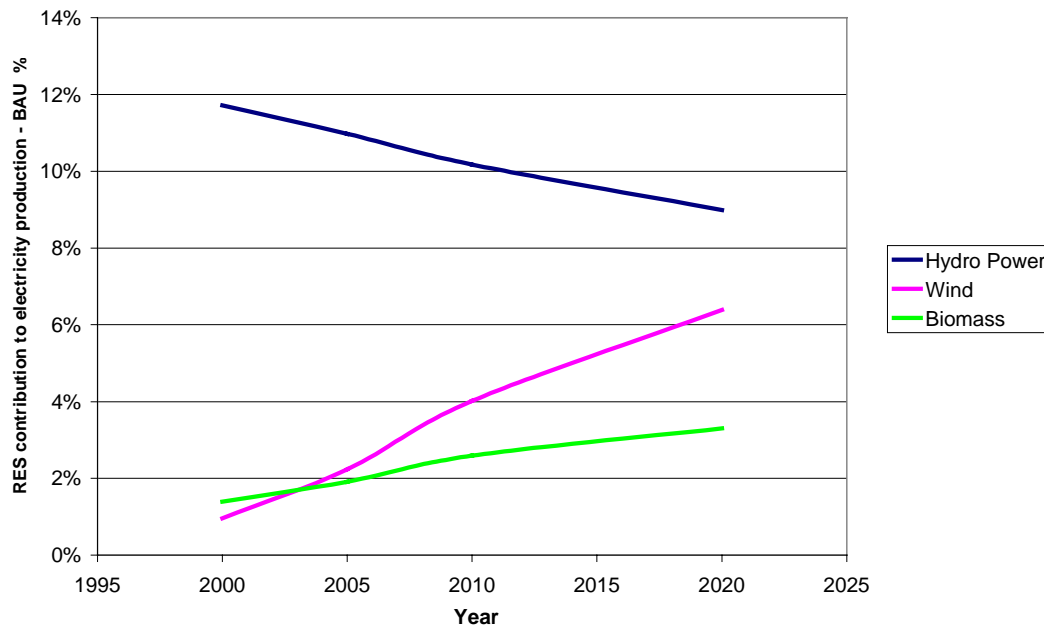


Figure. 4-2: RES contribution to EU-25 electricity consumption - BAU

RPS scenario: The “renewable policy scenario” is presented in Figure 4-3. It shows that when considering only RES within Europe, i.e. excluding solar thermal installations in northern Africa, only wind could have the potential to provide additional capacities for the production of hydrogen, see next section. Electricity from biomass can be of increasing relevance, however, a hydrogen production from biomass would most likely be based on direct gasification. Electricity generated by other RES, like PV and solar thermal electricity will still play a minor role compared to the absolute electricity generation in 2020.

Again the electricity generation using wind and hydropower as well as biomass is analysed more closely by calculating the ratio of the projected generation from these sources with the absolute electricity consumption. The outcome of this procedure is shown in Figure 4-4. Due to an increase in the absolute electricity consumption, the relative contribution of hydropower decreases steadily. The ratio of wind power increases significantly also in relative terms. However, the relative contribution remains well below 15%, which indicates that the overall European electricity system will be able to cope with fluctuating nature of the wind energy fed to the grid. Only in regional grids one might observe over-capacities in periods of strong wind production. This could offer the potential of hydrogen production leading to regional hydrogen markets in areas with a large share of wind power, e.g. in coastal regions with larger off-shore installations. We will elaborate this issue more closely in the following section.

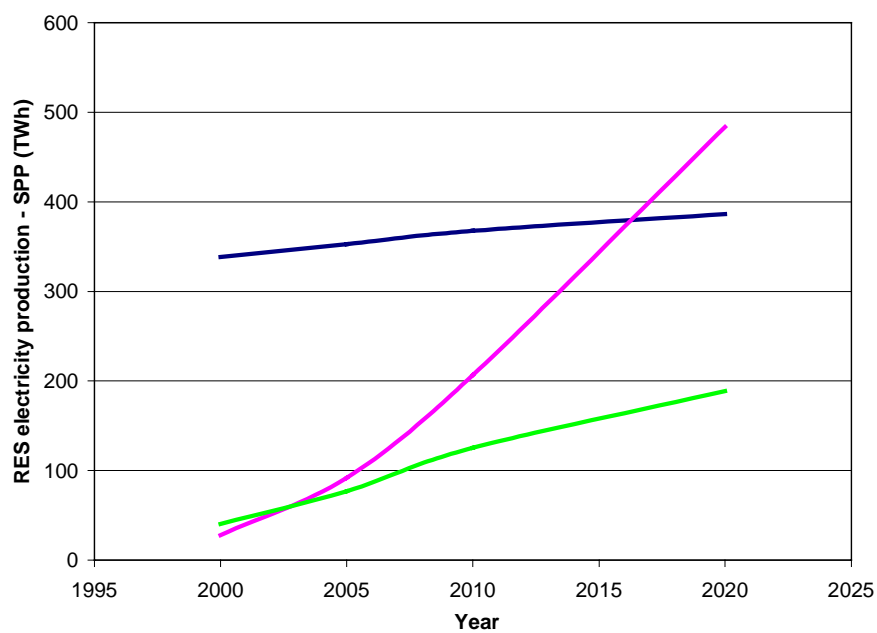


Figure. 4-3: Development of RES-E production in the EU-25 - RPS

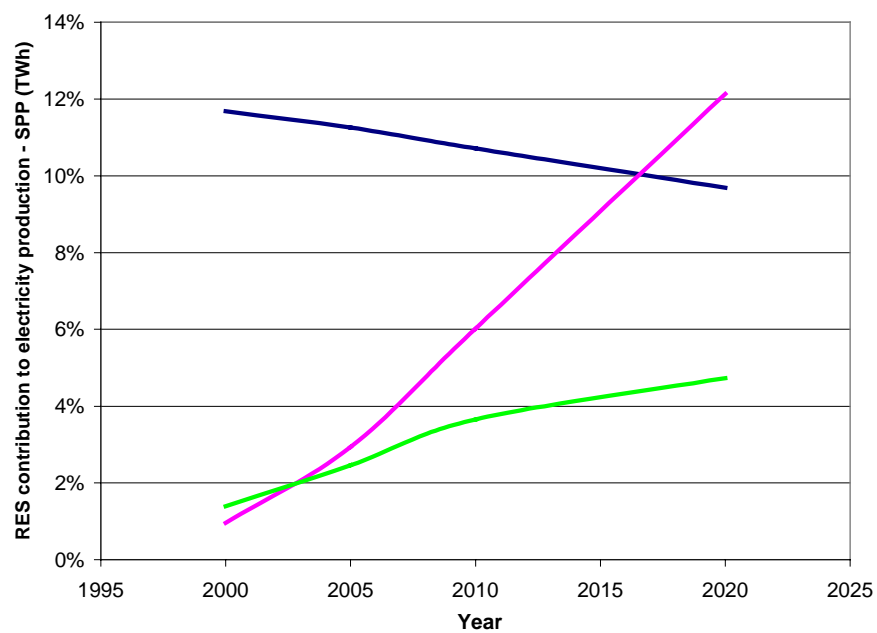


Figure. 4-4: RES contribution to EU-25 electricity consumption - RPS

4.3 Fluctuating sources

A possible contribution of RES to the production of hydrogen which shows less competition with the RES electricity targets can be seen in buffering unpredictable fluctuations of some RES, especially wind. Following such a strategy one would use the share of X% of the installed wind energy capacity for the production of electricity. Whenever the actual wind electricity production exceeds this margin, one could start to produce hydrogen. This procedure is depicted in Figure 4-5, where an example of a time series of the fluctuating power output of the German wind park during a time span of one year is shown. The upper red line indicates the installed capacity. The lower line shows the threshold below which the wind park is used to produce electricity and above it is used for the production of hydrogen. The added value of such a strategy for the electricity system lies in the fact that such a control of the wind power plants could help to significantly increase the reliability and the base load characteristics of the European wind power installations. The quantitative merit of this procedure is illustrated in Figure 4-6, where the fraction of the actually produced power of the installed capacity is shown versus the relative availability of this fraction. This graph has to be read in the following way: for example 20% of the installed capacity (figure on the y-axis) is available about 90% of the time (figure on the x-axis), but 60% of the installed power is available only 20% of the time. 100% of the installed capacity (that means all wind turbines produce maximum power simultaneously) is practically never available. This fact changes drastically if one assumes that the electricity/hydrogen production threshold is at 35% of the installed wind capacity as indicated by the red line in Figure 4-6. As can be seen this capacity (35% of the total installed capacity) would be available 70% of the time for electricity production and would amount to about 2/3 of the total power produced from wind energy (the integral of the curve below the red line). Therefore the availability of 100% of the installed wind power capacity would increase from approximately zero (with no hydrogen production) to about 70% (with hydrogen production threshold at 35% of the installed capacity) by shifting only about 1/3 of the energy generated to the production of hydrogen.

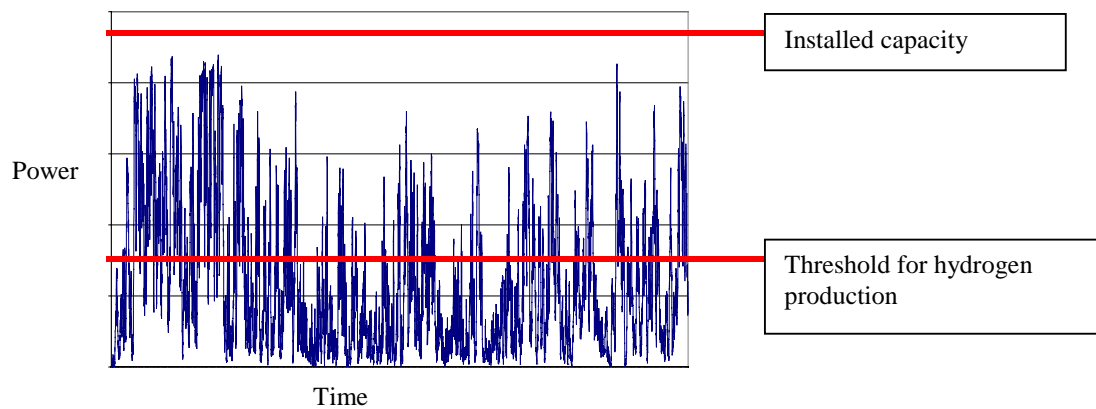


Figure 4-5: Example of a time series of the power output of the simulated German wind park, the time span shown in the graph is one year.

Assuming a utilisation of 1/3 of the total wind energy in 2020 for hydrogen production this would lead to 1,4% hydrogen contribution to the fuel consumption in road transport in the BAU scenario and 2,6% in the RPS scenario. Such a strategy could lead to a regional hydrogen economy in coastal regions with reasonable on-shore and off-shore wind potential, causing only moderate competition with the RES electricity targets.

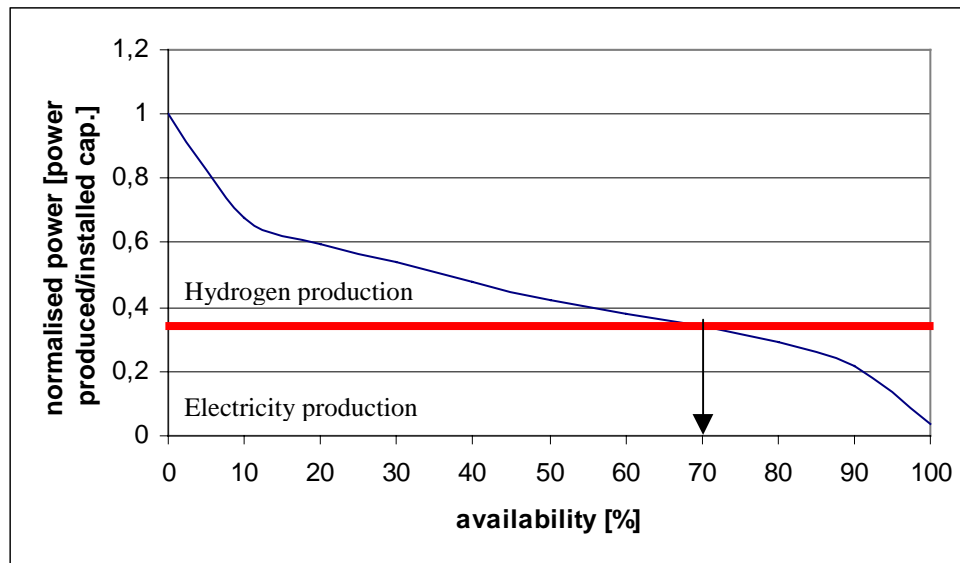


Figure. 4-6: Relative availability of the installed wind energy capacity of 50 European off-shore locations.

4.4 General conclusions

In both scenarios considered here, the only RES showing a significant increase in the electricity sector is wind power, besides a moderate increase of electricity generation

from biomass. In absolute terms, the projected electricity production from wind power plants amounts to about 255 TWh in the BAU scenario and to 485 TWh in the “renewable policy scenario”. If one assumes the production of gaseous hydrogen based on the pathway “electrolysis onsite” (Primary Energy Demand: 1,49 kWh/kWh H₂), a hydrogen production potential between 616 PJ and 1170 PJ results. This amounts to about 4.2 % or 7,9% of the projected fuel consumption for road transport (14700 PJ) in 2020.

Therefore the electricity production from wind energy based on an optimistic scenario would be sufficient to fulfil the 5 % target of hydrogen use in road transport in 2020. However, such a scenario would lead to a strong conflict with the targets for renewable energies in the electricity sector, since the relative contribution of the so far dominating RES-E, namely hydropower, is likely to decrease due to an absolute increase in electricity consumption. The additional increase of other RES, especially biomass, is just sufficient to compensate for the decrease in the relative contribution of hydropower. Therefore the use of RES electricity to an extent necessary to cover the 5% target of hydrogen in road transport would most likely lead to a violation of the EU RES electricity targets.

The possible contribution of biomass for the production of hydrogen is hard to estimate. Although the overall potential of biomass would be sufficient to reach the hydrogen targets for 2020 strong competition is seen with the use of biomass in the sectors of heat, electricity and the direct biofuel production. For the reason of this competition we see only minor potential of biomass for the production of hydrogen.

When considering RES outside Europe we see a significant long term potential in the use of solar thermal installations in northern Africa. Besides the use of the fluctuating wind energy solar thermal energy could become the most important renewable source for the production of hydrogen. For this energy source no conflicts with other European RES targets arise, but in the time frame until 2020 solar thermal energy imports from northern Africa are not likely to make up a significant share.

5 Overview of the most researched technological options for the hydrogen based transportation sector

5.1 Introduction

In order to describe the transition from a fossil fuel based transport system to a hydrogen based transport system insight into the process of technological change is necessary. The development of the necessary new technologies for the production, distribution, refuelling, storage, and conversion of hydrogen is an important aspect in this process. Therefore, the research questions are:

- How are the R&D activities distributed among different technological options and what were the developments in the past?
- Is there a lock-in or is there variety in the R&D activities of the technological options?

The following chapters describe the methodological approach and the most relevant research results. This report gives an insight into the research project⁸ of Jan-Frens van Giessel and Menno E. Ros under the supervision of Martin Wietschel.

5.2 Methodology

The hydrogen based transportation sector is divided in five subsystems, namely production, distribution, refuelling, storage and conversion. In each of the subsystems stakeholders are developing different technological options.

To determine which technological options are most important and most researched an overview of R&D projects and patents is made. This provides a useful tool to get insight in the most important technology for the five subsystems and to determine if the R&D activities are more or less focussed among the different technological options in time.

The data of the R&D projects is collected from different databases and overviews available on internet. The European Union database Cordis, the BMBF Fökat database, the Deutsche Wasserstoff Verband (DWV) site and the German hydrogen database provided by L-B-Systemtechnik, have been used. The projects are selected using two main criteria. Firstly, only projects which focus on hydrogen or fuel cell technologies for the transportation sector are taken into account. Search terms were hydrogen, electrolysis, reforming, partial oxidation, steam reforming, metal hydrides,

⁸ The research project is a result of a co-operation of the Utrecht University the Netherlands with the FHG-ISI.

etc. Secondly, only projects are selected where at least one German actor is a participant of the project. From the German actors also additional projects were retrieved via a telephonic questionnaire (further described below). In total there are 229 projects in our own database, from 1974-2003.

It should be noted that it is difficult to get insight into private funded (joint) R&D projects. Organisations regard R&D activities as classified information, because it gives insight into their strategy. This resulted in many public funded R&D projects and well announced prototype projects in our database.

For all German actors involved in R&D projects a patent search is conducted to gather the patent stock. The criterion was again hydrogen and fuel cell technologies for the transportation sector. The patents are collected from the database of the European Patent Office. In total there are 241 patents collected from 1974-2003.

Table 5-1: Source of the R&D projects and patents in the database

Source	Number of	
	projects	patents
Cordis	52	
DWV	11	
Hyweb	113	
BMBF	43	
Other	12	
European Patent Office		241
Total	229	241

To complete the information of the R&D projects found in the online databases, additional information has been collected by contacting the project co-ordinator or R&D manager of the organisation conducting the R&D project. This part of the data collection was especially important for collecting the results of the R&D projects, because that information was often not found in the online databases. Of the 229 projects, 192 people were contacted, resulting in 140 projects which could be supplied with output. The remaining projects are either still running (24 projects) so there is no output yet, or were conducted before 1986 (13 project) in which case often the prime contractor was not working at the company anymore and the results of the project were difficult to recover. All projects and patents are entered in a MS Access database.

5.3 Results

5.3.1 Introduction

Section 5.3.2 shows a descriptive overview of the amount of R&D projects and patents present in the hydrogen system. The next sections give an overview of the amount of R&D projects and patents present in subsystems production, distribution, refuelling, storage and conversion.

Note that all figures are calculated per period of three years and not per year. The length of the period is based on the average duration of a R&D project. The first period is determined by the starting year of first project in our database. This results in ten periods starting in 1974 until 2003 (see table 5-2). In all the figures the data is presented for these ten periods. Secondly, all figures display the accumulation of R&D projects and patents over time.

Table 5-2: The years covered to a period

Period number	Years	Period number	Years
1	1974 - 1976	6	1989 - 1991
2	1977 - 1979	7	1992 - 1994
3	1980 - 1982	8	1995 - 1997
4	1983 - 1985	9	1998 - 2000
5	1986 - 1988	10	2001 - 2003

5.3.2 Complete hydrogen transport system

Figure 5-1 presents the cumulative amount of R&D projects per subsystem. This figure shows that the most R&D projects focus on the conversion of hydrogen, followed by storage and production of hydrogen. The R&D activities in the subsystems distribution and refuelling seem to be of less importance, given the small amount of projects in these subsystems. The slopes of the production, storage, conversion curves show an increasing acceleration of the R&D projects from period 6 until period 10. The R&D activities in the subsystems distribution and refuelling show less acceleration.

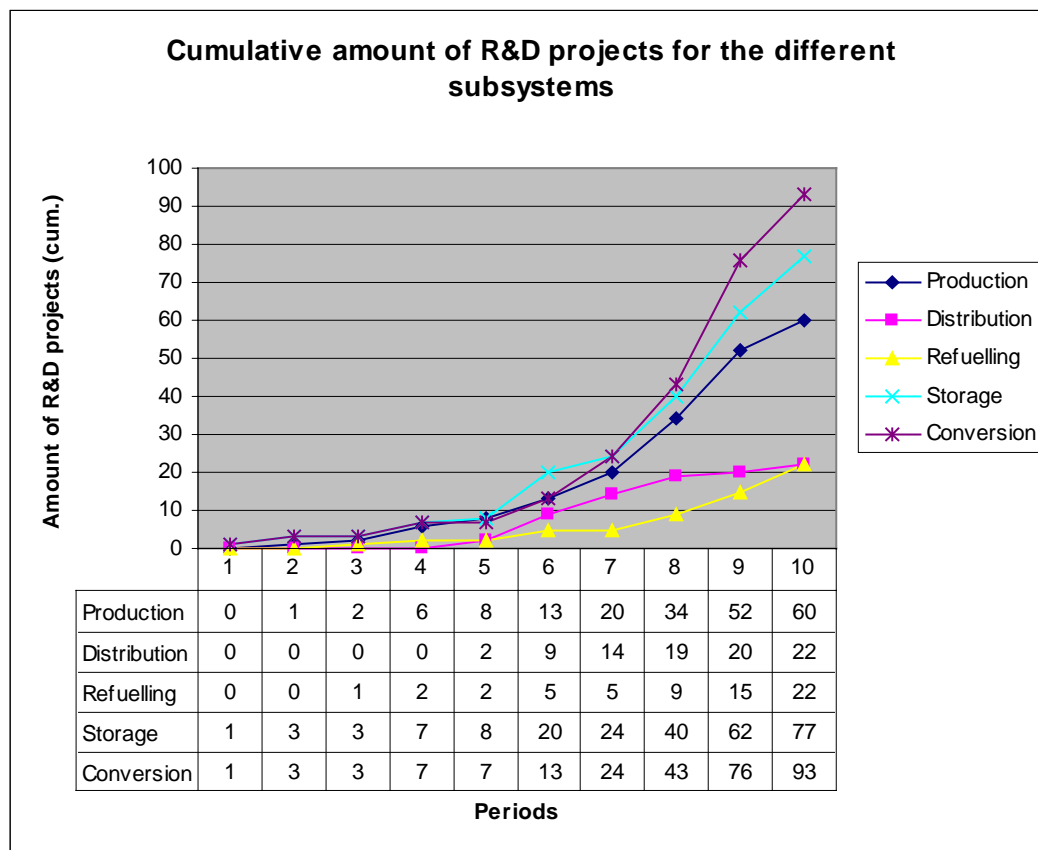


Figure 5-1: Cumulative amount of R&D projects in the different subsystems

Figure 5-2 presents the cumulative amount of patents for the five different subsystems, production, distribution, refuelling, storage, and conversion. This figure shows that most patents are applied in the subsystems production and conversion. For the subsystems distribution and refuelling no patents exist. The subsystem storage shows the highest amount of patents until period 8. Patents in the subsystem production and conversion become especially important from this period till period 10. This is also indicated by the slope of the curves. The amount of patents for production increases between periods 7-10 and the amount of patents for conversion increases exponential between periods 8-10. The amount of patents for storage shows a linear growth for all periods.

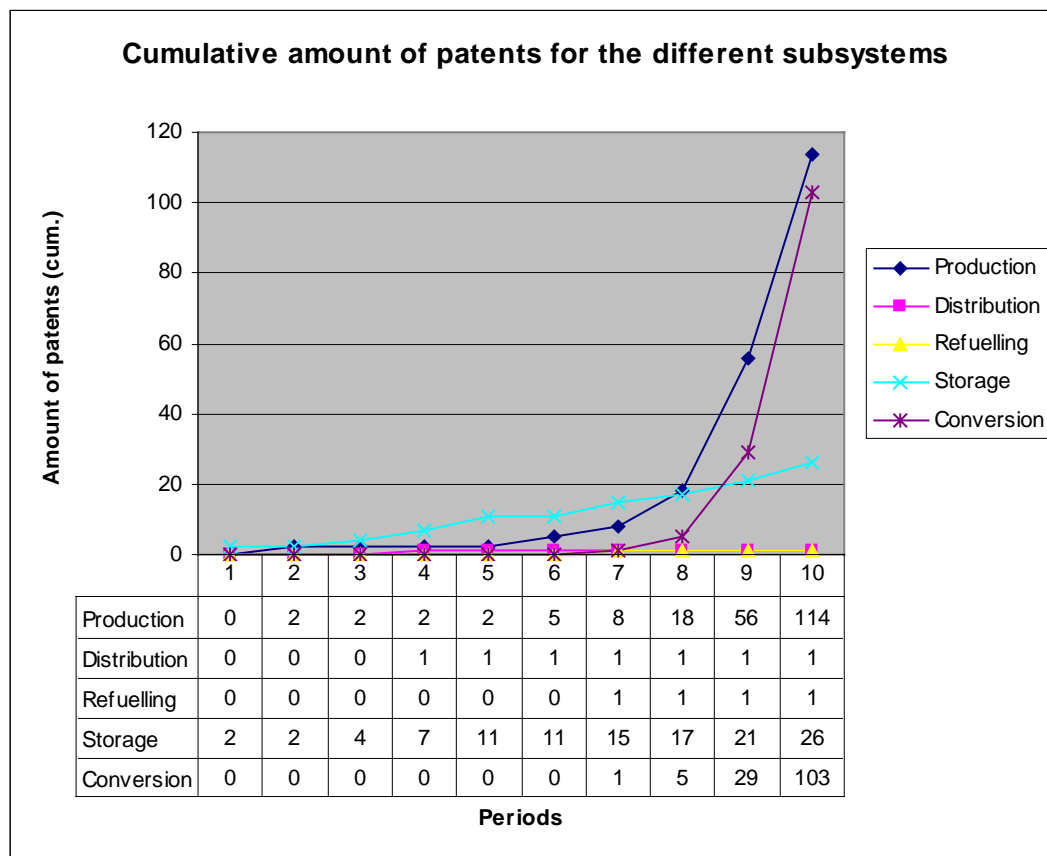


Figure 5-2: Cumulative amount of patents in the different subsystems

When figure 5-1 (cumulative amount of R&D projects) and figure 5-2 (cumulative amount of patents) are compared several observations can be made. Firstly, the amount of R&D projects in the subsystems production, conversion and storage begin to accelerate in period 6 till period 10. On the other hand, the amount of patents in the production subsystem begins to accelerate in period 7 till period 10, while the amount of patents in the subsystem conversion show acceleration between periods 8-10. The amount of patents in the subsystem storage shows no acceleration at all. This indicates for the subsystems production and conversion that an increase in R&D projects results in an increase in patents one or two periods (3 or 6 years) later.

Secondly, figure 5-1 shows that in the subsystem storage, after conversion, the most R&D projects are conducted. On the other hand, figure 5-2 shows that the amount of patents in the subsystem storage is very low, compared with the amount of patents for the subsystems production and conversion. Further research is necessary to clarify this result.

5.3.3 Subsystem production

In the subsystem production four technological options are present, namely electrolysis, partial oxidation, steam reforming, and purification of hydrogen. Autothermal reforming and gasification are not considered, because no projects and patents were found for this technological option. The technological option sodium borohydride is not displayed in the figure, because there is only one project for this option.

The cumulative amount of R&D projects for the technological options in the subsystem production is shown in figure 5-3. First, the results show that most R&D projects focus on electrolysis followed by steam reforming, purification and partial oxidation. Secondly, the slope of the curve shows that electrolysis shows the greatest acceleration of R&D activity for all periods (except between periods 6 and 7). Steam reforming shows an acceleration of R&D activity from period 6, but the acceleration rate remains lower than the acceleration rate of electrolysis.

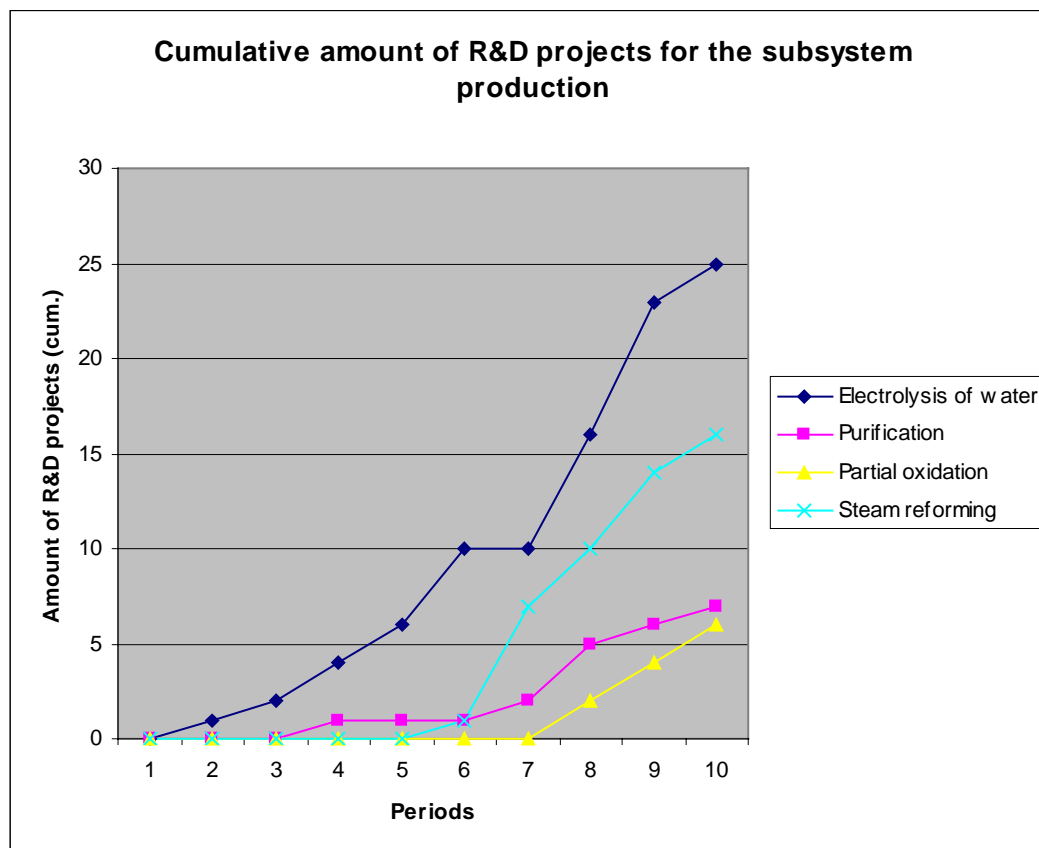


Figure 5-3: Cumulative number of projects for the subsystem production

Figure 5-4 shows the amount of projects for the onboard and central production of hydrogen. Onboard production of hydrogen is categorised as the reforming (steam reforming or partial oxidation) of a fuel (for example gasoline, methanol) onboard the vehicle. Central production of hydrogen is categorised as the production of hydrogen

in a chemical factory (via steam reforming or partial oxidation) or electrolysis of water. Figure 5-5 clearly indicates that most R&D projects focus on technological options for the central production of hydrogen, but the amount of R&D projects focusing on the onboard production of hydrogen accelerates from period 6. The acceleration rate between periods 6-7 and between periods 8-9 is higher for onboard technologies than for central production technologies. This indicates that onboard production of hydrogen is growing in importance.

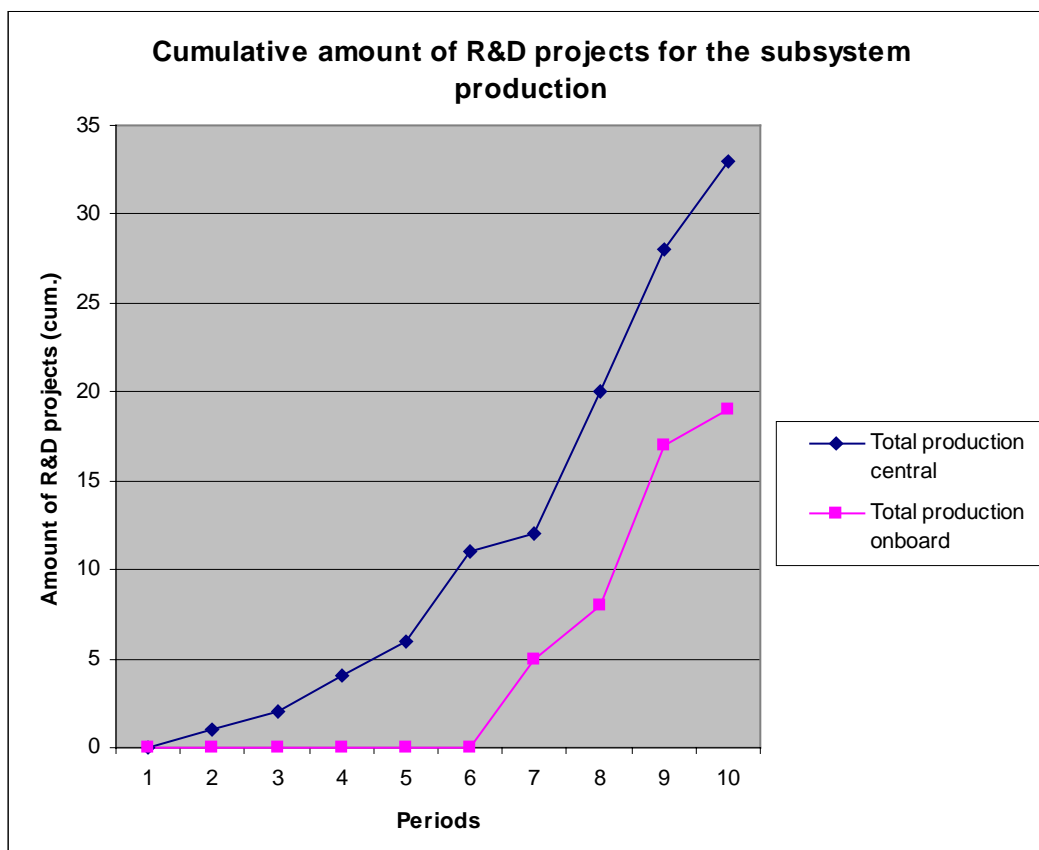


Figure 5-4: Cumulative number of projects for the subsystem production for the categories onboard and central production of hydrogen

Figure 5-5 presents the cumulative amount of patents for the technological options in the subsystem production. Shown is that steam reforming has the most patents. The slopes of these curves show that from period 5 until period 7 electrolysis has the greatest acceleration in patents, but the acceleration rate decreases and even reaches zero between the periods 9 and 10. The periods 7- 10 show a strong acceleration of patents for steam reforming. This gives a clear indication that the focus in the patents stock is shifted around period 7 from electrolysis to steam reforming. Interesting is that between the periods 9 and 10 the amount of patents for purification techniques also accelerates. This is related with the shift to steam reforming, because hydrogen produced via steam reforming has to be purified before it can be used in the PEM fuel

cell. Purification of hydrogen produced via electrolysis is not necessary, because the hydrogen is already clean enough to use.

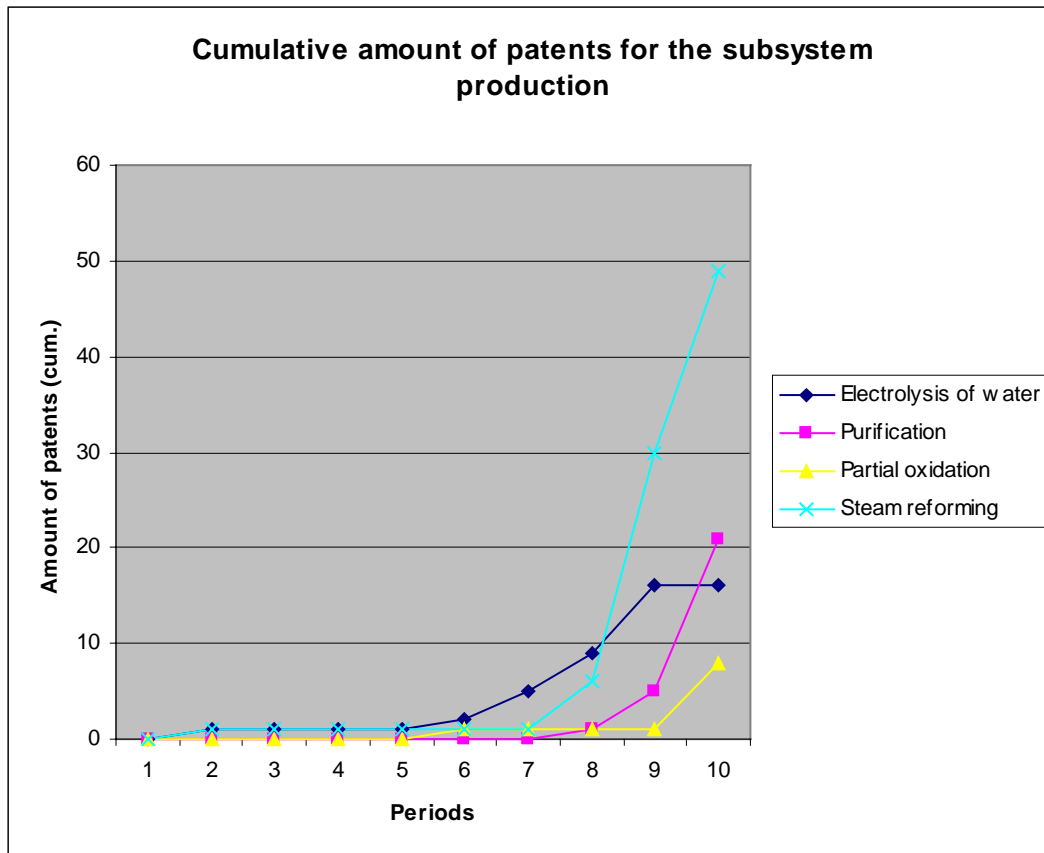


Figure 5-5: Cumulative number of patents for the subsystem production

Figure 5-6 shows the amount of patents for the categories onboard and central production of hydrogen. In period 5 until period 8 the central production of hydrogen is more patented, but from period 8 until period 10 the patents are more applied for on-board production of hydrogen. An increased acceleration of patents focussing on on-board production technologies is shown between periods 8-10.

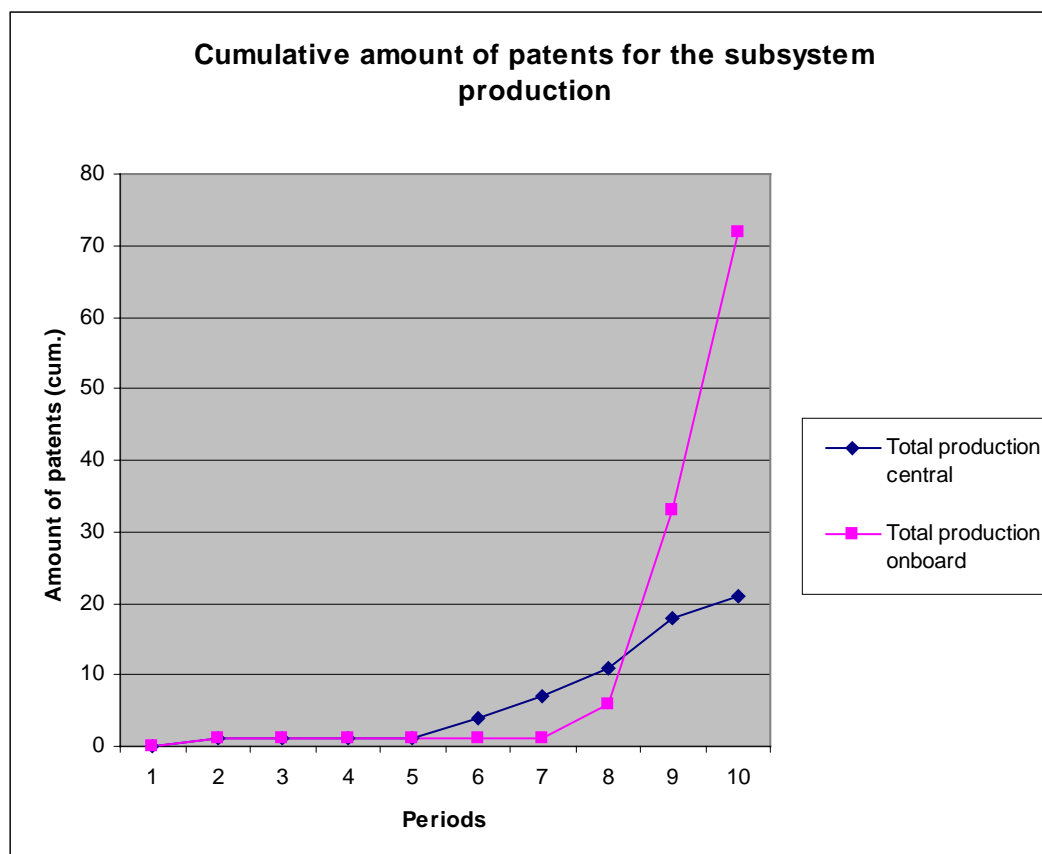


Figure 5-6: Number of patents for the subsystem production for the categories on-board and central production of hydrogen

When figure 5-3 and figure 5-5 are compared several observations can be made. Firstly, shown is that most R&D projects focus on electrolysis, while most patents are applied on steam reforming. Secondly, a time lag of 2 periods (6 years) between the R&D projects and patents is seen, because the amount of R&D projects focussing on steam reforming accelerate in period 6, while the acceleration of patents focussing on this technological option starts around period 7 and 8. The same is argued for partial oxidation. The amount of R&D projects which focus on partial oxidation accelerate in period 7 which is followed by an acceleration of patents focussing on partial oxidation in period 9.

Figure 5-4 and figure 5-6 show generally the same results as figure 5-3 and figure 5-5, because electrolysis is the most important central production technology and steam reforming is the most important onboard production technology. Again, a difference in technology focus is observed between the amount of R&D projects (central production technologies) and the patent stock (onboard technologies). The time lag between the R&D projects focussing on steam reforming (period 6) and the patents focussing on steam reforming (periods 7-8) is also noted.

5.3.4 Subsystem distribution

In the subsystem distribution three technological options are considered, namely distribution by pipeline, truck, and ship. Note the relative small amount of R&D projects in this subsystem.

Figure 5-7 presents the cumulative amount of R&D projects for the technological options in the subsystem distribution. Most R&D projects are focused on the distribution of hydrogen by pipeline. The slope of the pipeline curve shows that the R&D activity accelerates from period 4, but the rate of acceleration decreases as it reached zero between the periods 9 and 10. The technological option hydrogen distribution by ship is researched from period 4 until period 7 and even shows the strongest acceleration of R&D activity in period 8. The technological option hydrogen distribution by truck has shown little R&D activity.

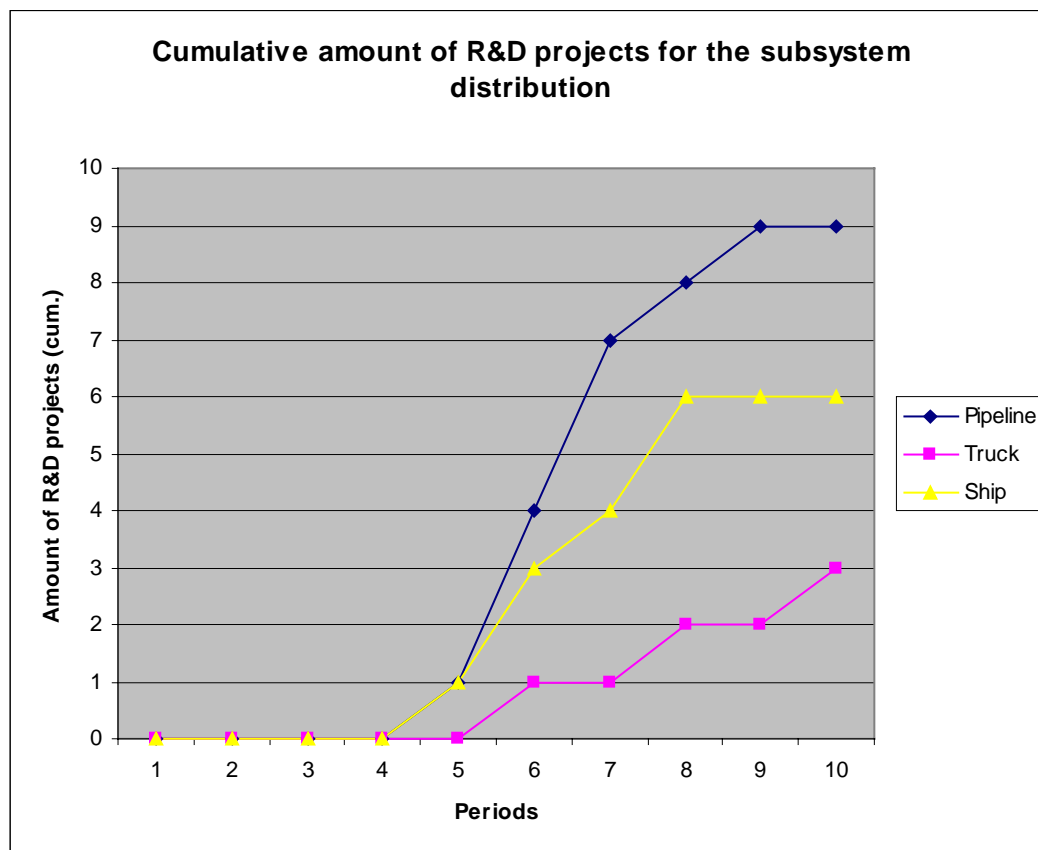


Figure 5-7: Cumulative number of projects for the subsystem distribution

The patent analysis has shown that there are no patents in the distribution subsystem.

5.3.5 Subsystem refuelling

In the subsystem distribution two technological options are considered, namely gaseous and liquid refuelling. Note the relative small amount of R&D projects in this subsystem.

The cumulative amount of R&D projects for the technological options in the subsystem refuelling is shown in figure 5-8. Gaseous refuelling shows the largest amount of R&D projects and the highest acceleration of R&D activity in all periods. The slope of the options gaseous and liquid refuelling show the same pattern. The horizontal slope of liquid refuelling after period 8 indicates that the R&D activity of liquid refuelling is terminated. However, R&D on liquid refuelling continues in the option liquid and gaseous refuelling.

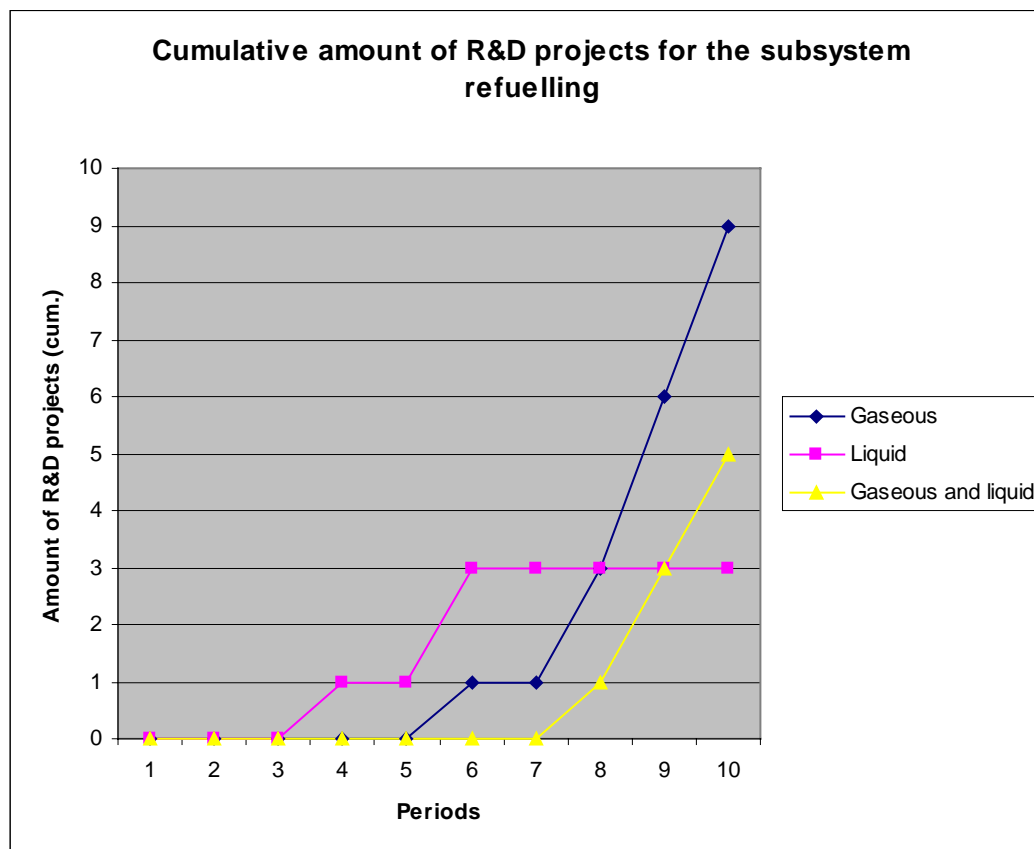


Figure 5-8: Cumulative number of projects for the subsystem refuelling

The patent analysis has shown that there are no patent in the refuelling subsystem.

5.3.6 Subsystem storage

In the subsystem storage four technological options are present, namely gaseous, liquid, metal hydrides, and non-applicable storage techniques. The category other storage techniques is a combination of carbon nanotubes, graphite nanofibres, and zeolites. For the technological options glass microspheres and fullerenes no projects were found.

Figure 5-9 shows the cumulative amount of R&D projects for the technological options in the subsystem storage. Most R&D projects focus on the gaseous and liquid storage of hydrogen. The amount of R&D projects for these two options accelerates strongly from period 7. From period 7 until period 10 also an acceleration of R&D projects focussing on other technologies to store hydrogen, like carbon nanotubes, nanofibres and zeolites, is shown. However, the rate of acceleration is not as big as the rate of acceleration of gaseous and liquid storage. Between period 1 and period 7 there is a lot of R&D projects focussing on the storage of hydrogen in metal hydrides, but from period 7 the amount of R&D projects focussing on metal hydrides is decreasing and shows no new activity in the periods 8, 9, and 10.

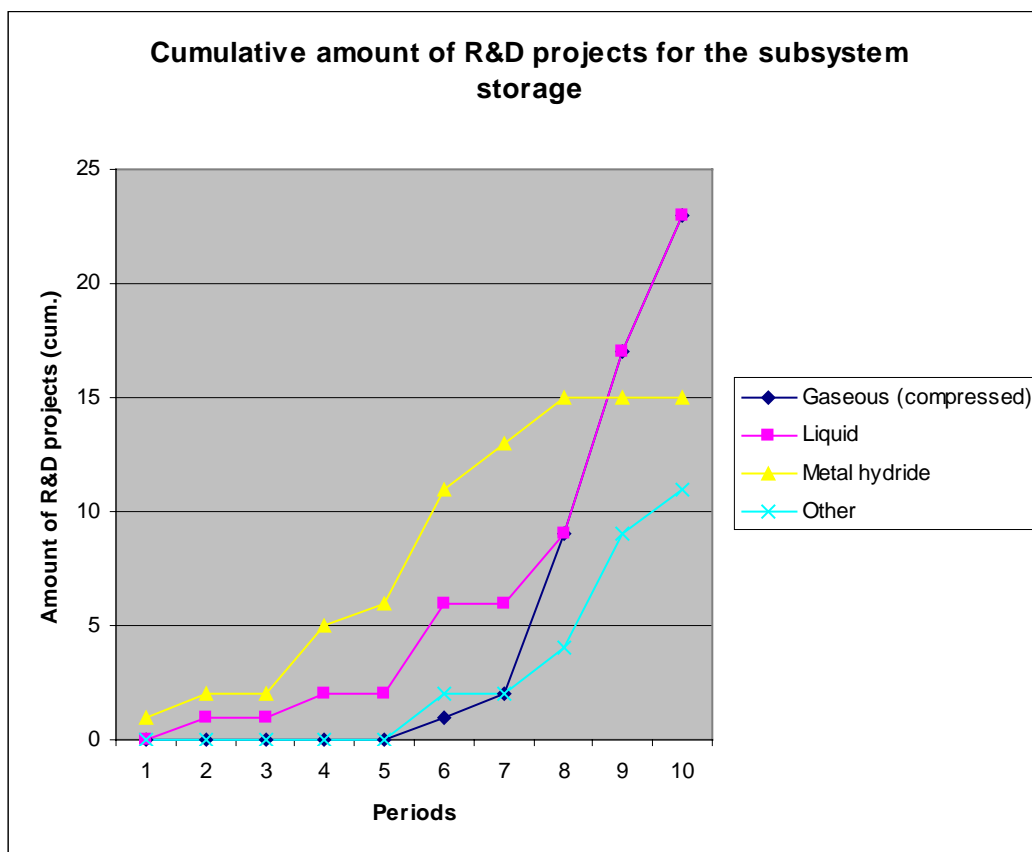


Figure 5-9: Cumulative number of projects for the subsystem storage

The cumulative amount of patents for the technological options in the subsystem storage is shown in figure 5-10. The figure shows that liquid storage of hydrogen has the

most patents. The slope of this curve indicates that the amount of patents for this option accelerates the most from period 6 until period 10. All other options show no patent activity in these periods, which is indicated by the horizontal line. Between periods 2 and 3, and between periods 4 and 5 metal hydrides shows the greatest acceleration in amount of patents. Between periods 3 and 4 gaseous storage shows the greatest acceleration of patents.

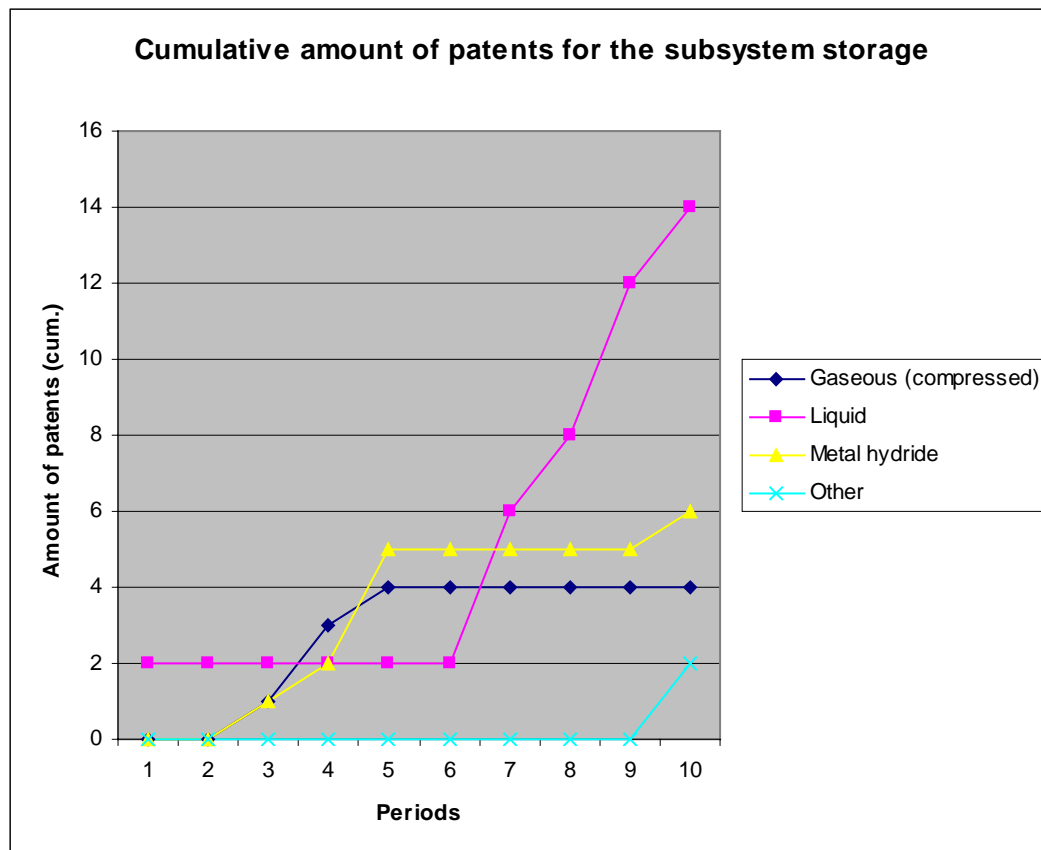


Figure 5-10: Cumulative number of patents for the subsystem storage

When figure 5-9 and 5-10 are compared several observations can be made. Firstly, the most researched technological options are gaseous and liquid, especially between periods 7-10, while the most patented technological option gaseous storage is. The patents focussing on this option accelerate between periods 6-10, while the amount of projects accelerates between periods 7-10. This indicates that the R&D projects follow the focus in the amount of patents. Secondly, the amount of R&D projects focussing on other storage technologies accelerate between periods 7-10 which is followed by an acceleration of patents focussing on these technologies between periods 9-10. Although there are only two patents, this indicates a time lag of two periods (6 years) between R&D projects and patents.

5.3.7 Subsystem conversion

For the subsystem conversion two technological options are described, namely hydrogen combustion engine and the PEM fuel cell.

Figure 5-11 shows the cumulative amount of R&D projects for the technological options in the subsystem conversion. Most R&D projects focus on the technological option fuel cell. Between periods 1 and 6 the combustion engine has the highest amount of R&D projects and greatest acceleration in R&D projects, but this changes in period 6 when the slope of the fuel cell curve accelerates more than the slope combustion engine. This trend continues in the next periods and the amount of projects focussing on the fuel cell accelerates strongly.

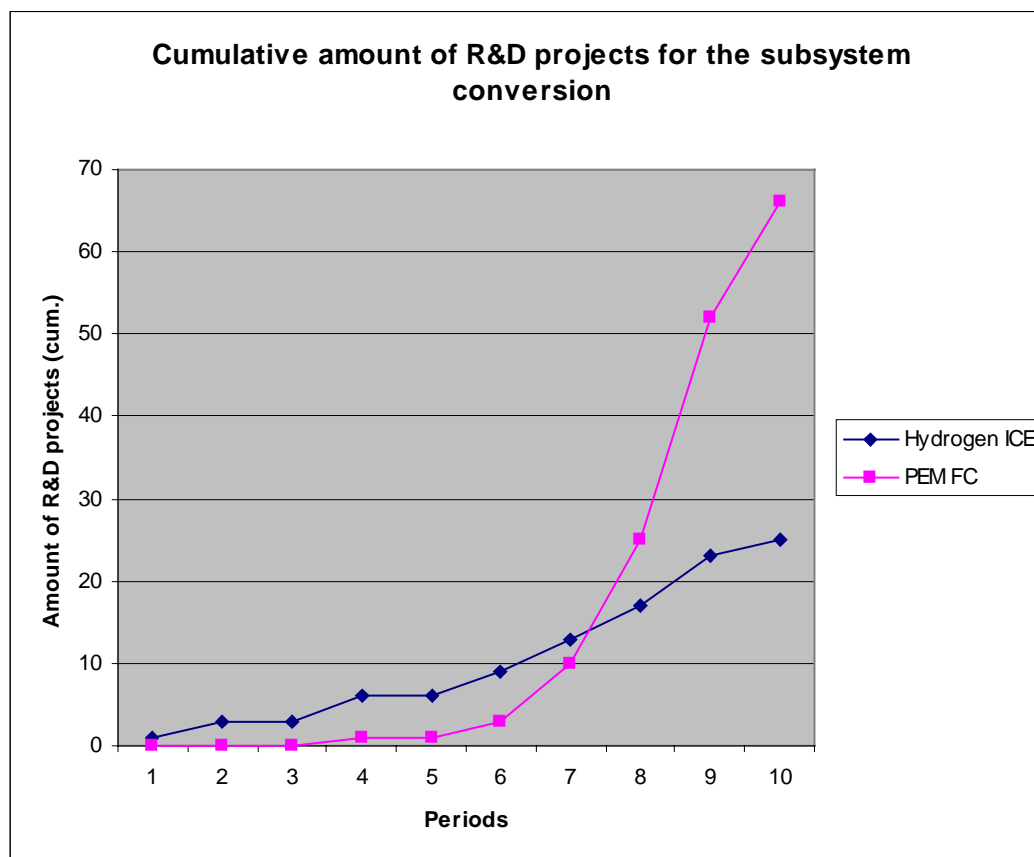


Figure 5-11: Cumulative number of projects for the subsystem conversion

Figure 5-12 shows the cumulative amount of patents for the technological options in the subsystem conversion. The acceleration of patents focussing on the PEM fuel cell begins in period 8 and continues until period 10. Note that there are no patents for the hydrogen combustion engine found.

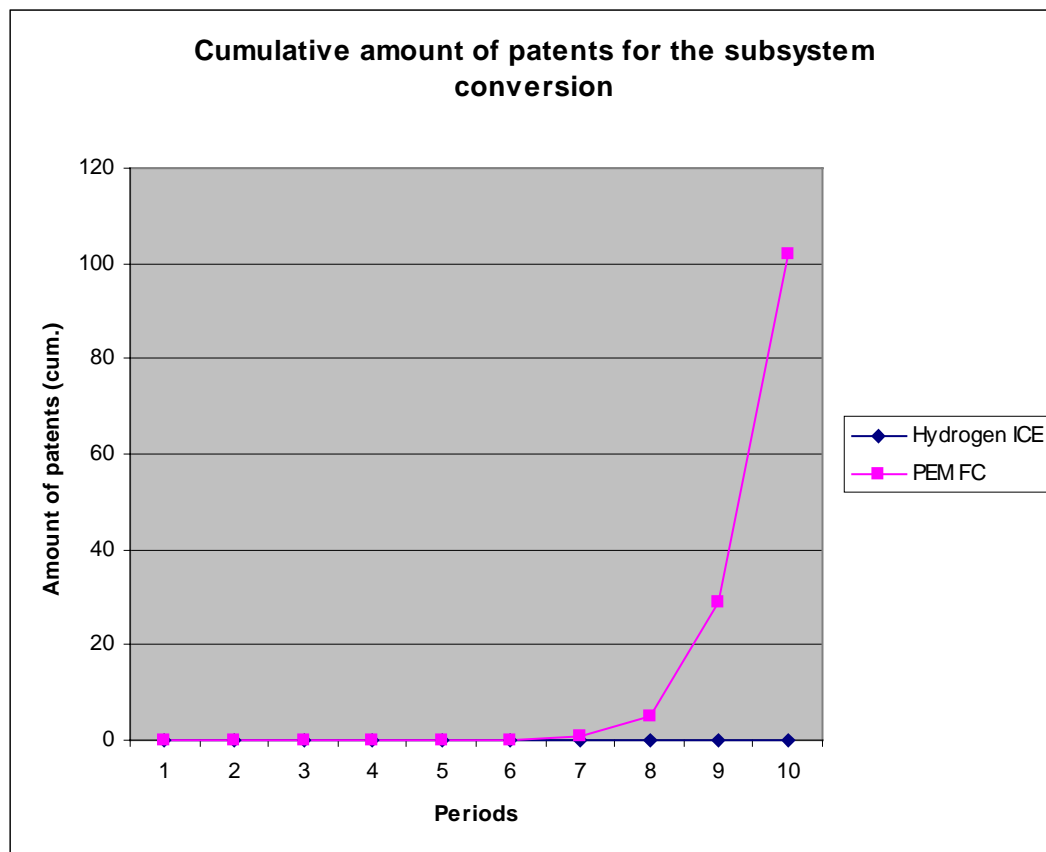


Figure 5-12: Cumulative number of patents for the subsystem conversion

A comparison between figure 5-11 and 5-12 shows that both the amount of R&D projects and the amount of patents focus on the PEM fuel cell. For the hydrogen combustion engine even no patents were found. Furthermore, the amount of projects focussing on the PEM fuel cell accelerates from period 6, while the acceleration of patents focussing on this technological options show acceleration since period 8. This is a time lag between the amount of R&D projects and patents of two periods (6 years).

5.4 Conclusions

The results show that the amount of R&D projects in the subsystems production, storage, and conversion have increased since period 6 (1990). The acceleration of amount of patents in these subsystems begins two periods later (1996). The same phenomenon is seen at the subsystem level. For the subsystems production, storage, and conversion, it can be observed that the acceleration of R&D projects focusing on a specific technological option is followed by an acceleration in the amount of patents focusing on that technological option two periods (6 years) later.

An explanation for the time lag between projects and patents is that joint R&D projects funded by the EC and the German federal government are used to explore a technological option in a pre-competitive stage of technology development. Organisations further develop the technological options in-house or in a privately funded R&D project. These privately funded projects often result in a patent, while the results of government funded projects are public, which makes patent application difficult.

Based on the results, it can be concluded that technological variety in the hydrogen based transportation sector is high. This means that in all five subsystems one or more technological options are being researched. It is worth noting that the number of R&D projects and patents in the distribution and refuelling subsystems lags behind the other subsystems. The results are discussed in more detail per subsystem below.

Subsystem production: the focus on electrolysis techniques here can be explained by the fact that the German federal government began promoting this technological option at the beginning of the eighties (1980-1995, since period 3). However, looking at the patents, the technological focus is on steam reforming. This contradiction can be explained by the fact that our data on R&D projects emphasises publicly funded projects. Private R&D projects are not well represented in our data set, except for the prototype vehicles. The patent data shows all patenting activity of organisations, regardless of whether this patent resulted from a publicly or privately funded R&D project. This means that R&D subsidies of government only have a limited influence on technology development. Private parties only follow the research direction given by the government to a certain extent.

Subsystem distribution: the few projects and no patents in this subsystem indicate that the distribution of hydrogen is not seen as a problem, or as a problem that can be solved later. The priority is given to technologies to produce, store and convert technology and it is generally assumed that the distribution network will follow. Pipeline distribution of hydrogen is the most researched topic, but this is a well proven technology, because hydrogen distribution pipelines already exist.

Subsystem refuelling: here, there are also only a few projects and absolutely no patents. The emphasis on prototypes (meaning refuelling stations) in this subsystem indicates that the technology for refuelling is ready to use, but the (potential) customers need to gain experience with the idea of refuelling hydrogen instead of gasoline or diesel. Most refuelling stations are built for demonstration and to serve the prototype hydrogen vehicles and busses. Gaseous refuelling is the most researched option, but it does not matter how (gaseous or liquid) hydrogen is fuelled. If hydrogen is stored in liquid form at the refuelling station, a vehicle can be fuelled with gaseous or liquid hydrogen. Only a dispenser is needed to make the hydrogen gaseous.

Subsystem storage: Figures 5-9 and 5-10 show that R&D projects and patents focusing on metal hydrides have terminated since period 7 and that since then there has been a strong focus on storing hydrogen as a liquid or a gas. Apparently the techno-

logical option metal hydride was regarded as the most promising storage technology in the early eighties, but did not fulfil this promise. One reason may be that metal hydrides are relatively heavy and cannot store large volumes of hydrogen. The strong focus on the development of conventional storage options, like gaseous and liquid, indicate that the problem of storing hydrogen is being avoided. Conventional storage (gaseous and liquid) technologies have disadvantages, but there is no alternative storage technology for the short term. New storage technologies, for instance carbon nanotubes, are still far away from application. The European and German governments have described the storage of hydrogen as a major problem for the hydrogen energy system and the development of new storage techniques for hydrogen is a key research theme of EC funded R&D projects, but without results so far. In the subsystem storage the government should stimulate the development of alternative storage technologies to the gaseous and liquid ones. Otherwise, there will be no suitable storage technology available for hydrogen in the long term.

Subsystem conversion: the results, presented in Figures 5-11 and 5-12 indicate a lock-in of the PEM fuel cell technology. This conforms with the government R&D programmes, which aim to stimulate new propulsion technologies and have defined the fuel cell as the most appropriate technological option. A main research goal of the EU and the German federal governments is to reduce the costs of fuel cells. This indicates that the fuel cell is ready for market introduction, but besides the cost aspect, many other technological problems still have to be overcome, for example, water management in the fuel cell and the intolerance for CO, before the PEM fuel cell can be applied in the transport sector. It is questionable whether the government should already be steering towards the PEM fuel cell as the only propulsion technology for a future sustainable transport sector, as long as this option has not been fully developed and as long as other fuel cells and the hydrogen combustion engine may also represent alternative solutions if these are developed further. The government should introduce more variety in the subsystem conversion by funding more joint R&D projects which focus on hydrogen combustion engines and fuel cell technologies to serve as propulsion techniques.

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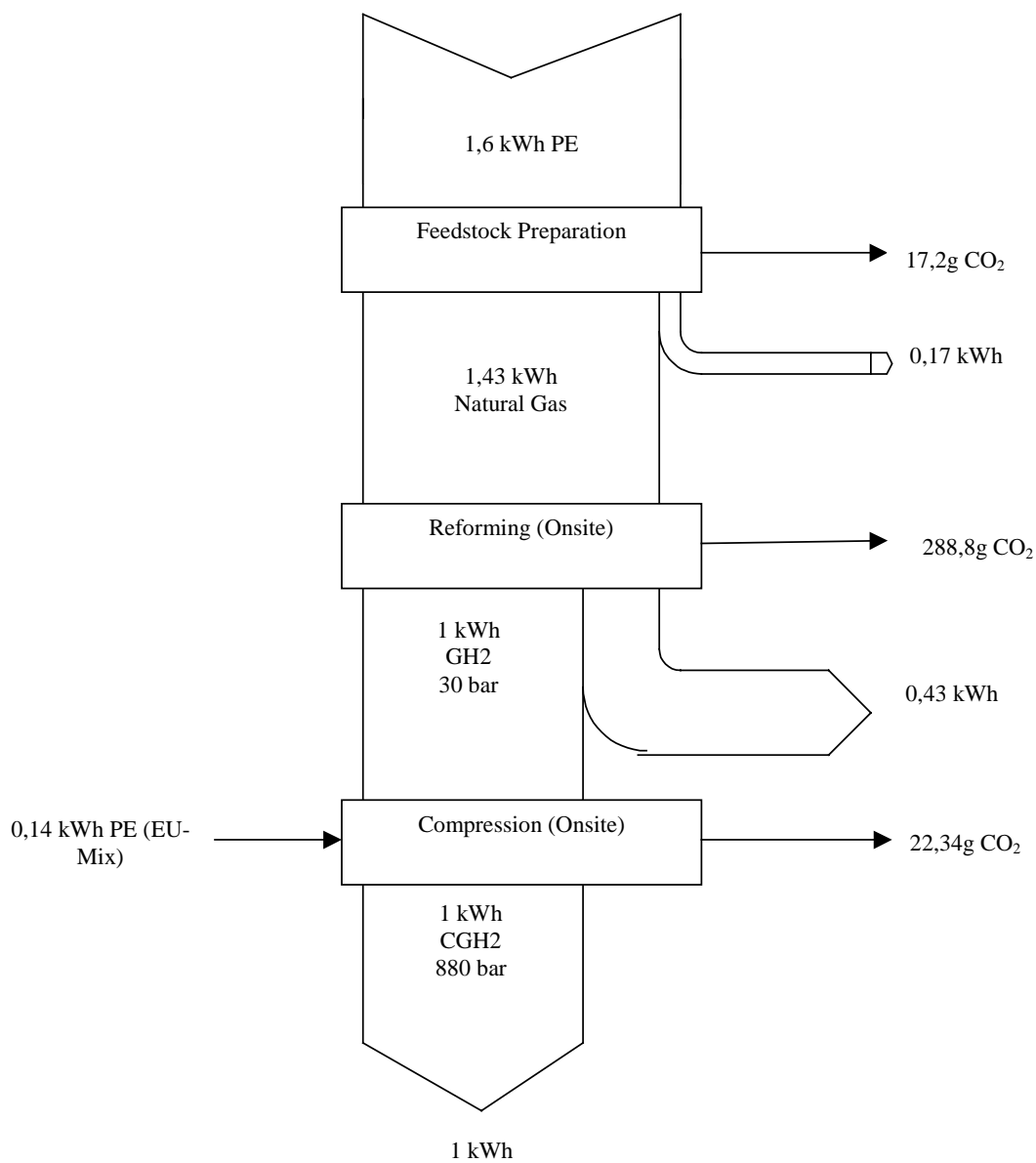
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Annex A: Sankey diagrams of WTT-Pathways

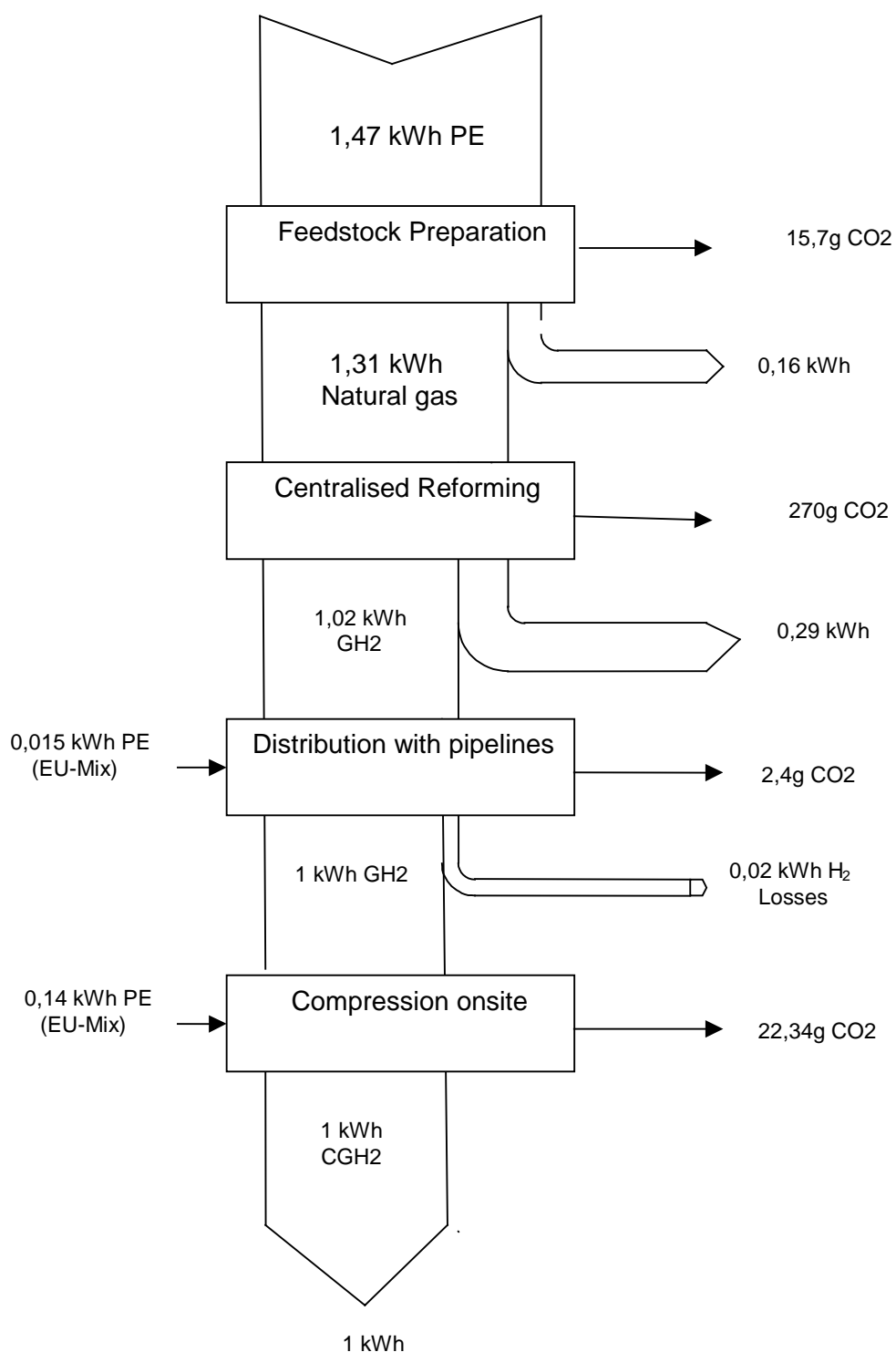
Path Way 1

CGH2: Natural Gas Reforming (onsite)



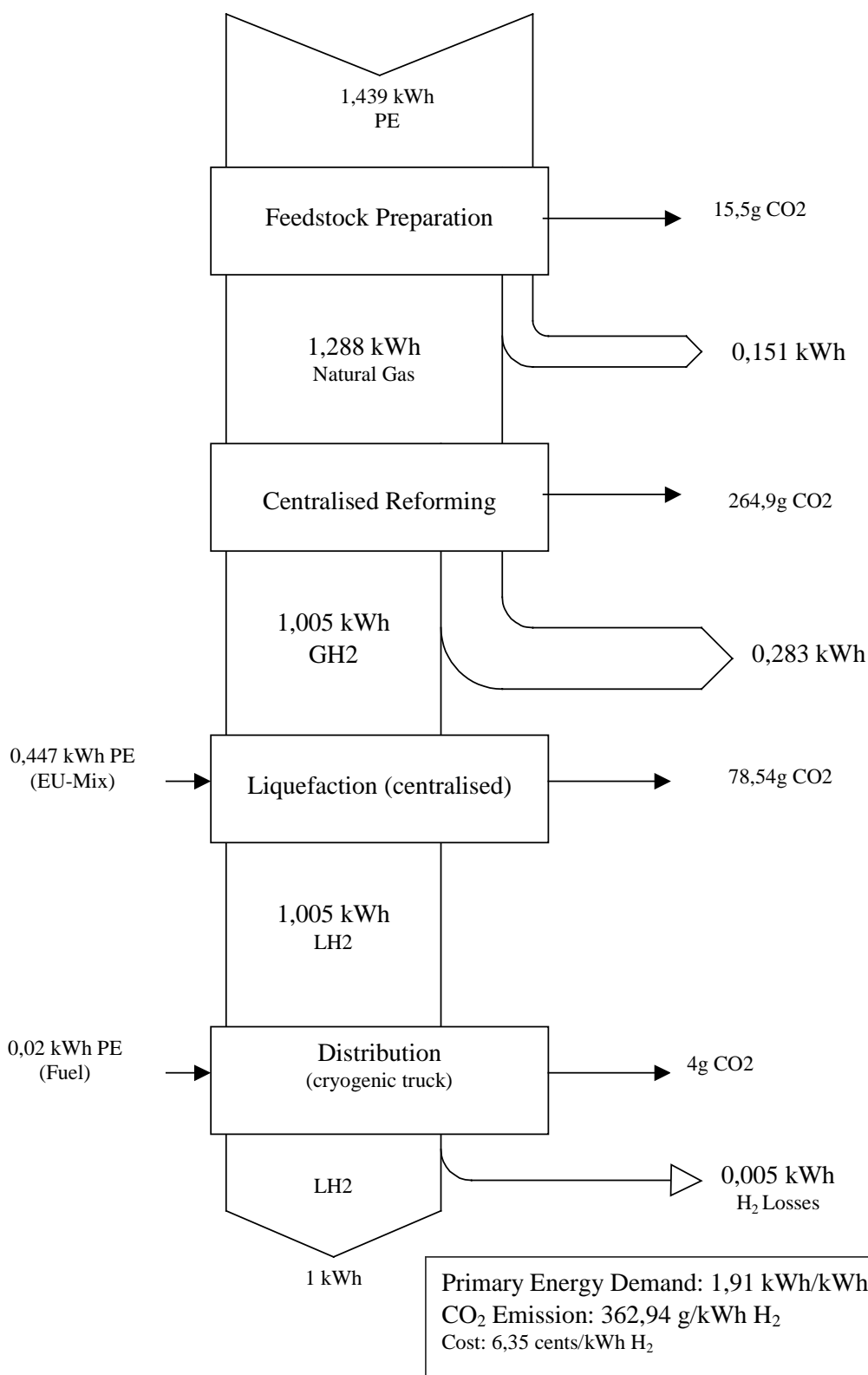
Primary Energy Demand: 1,74 kWh/kWh H₂ CO₂
Emission: 328,34 g/kWh H₂
Cost: 4,62 cents/kWh H₂

Path Way 2
CGH2: Natural Gas Reforming (centralised)

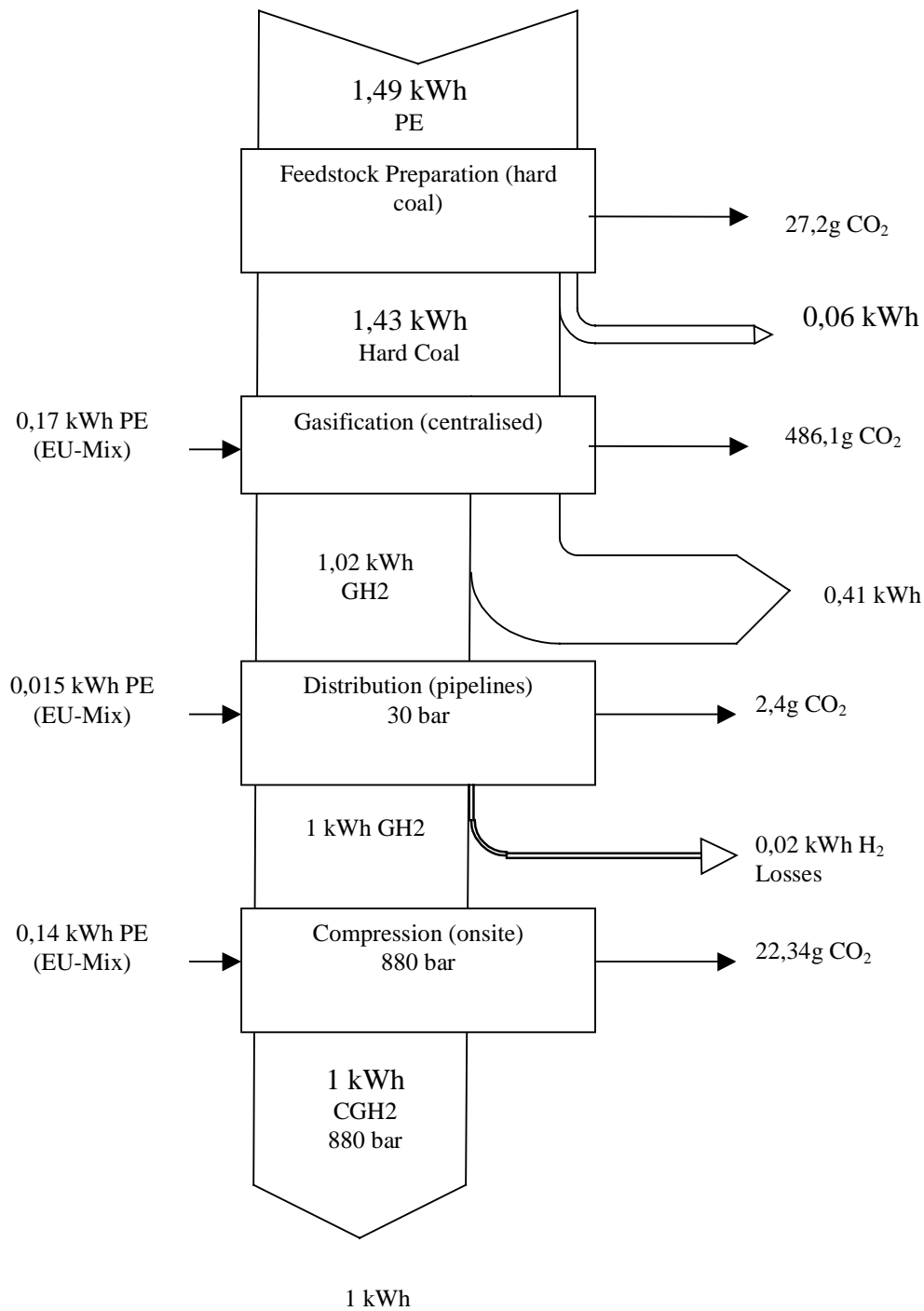


Primary Energy Demand: 1,625 kWh/kW H₂
CO₂ Emission: 310,43 g/kWh H₂
Cost: 4,21 cents/kWh H₂

Path Way 3
LH2: Natural Gas Reforming (centralised)

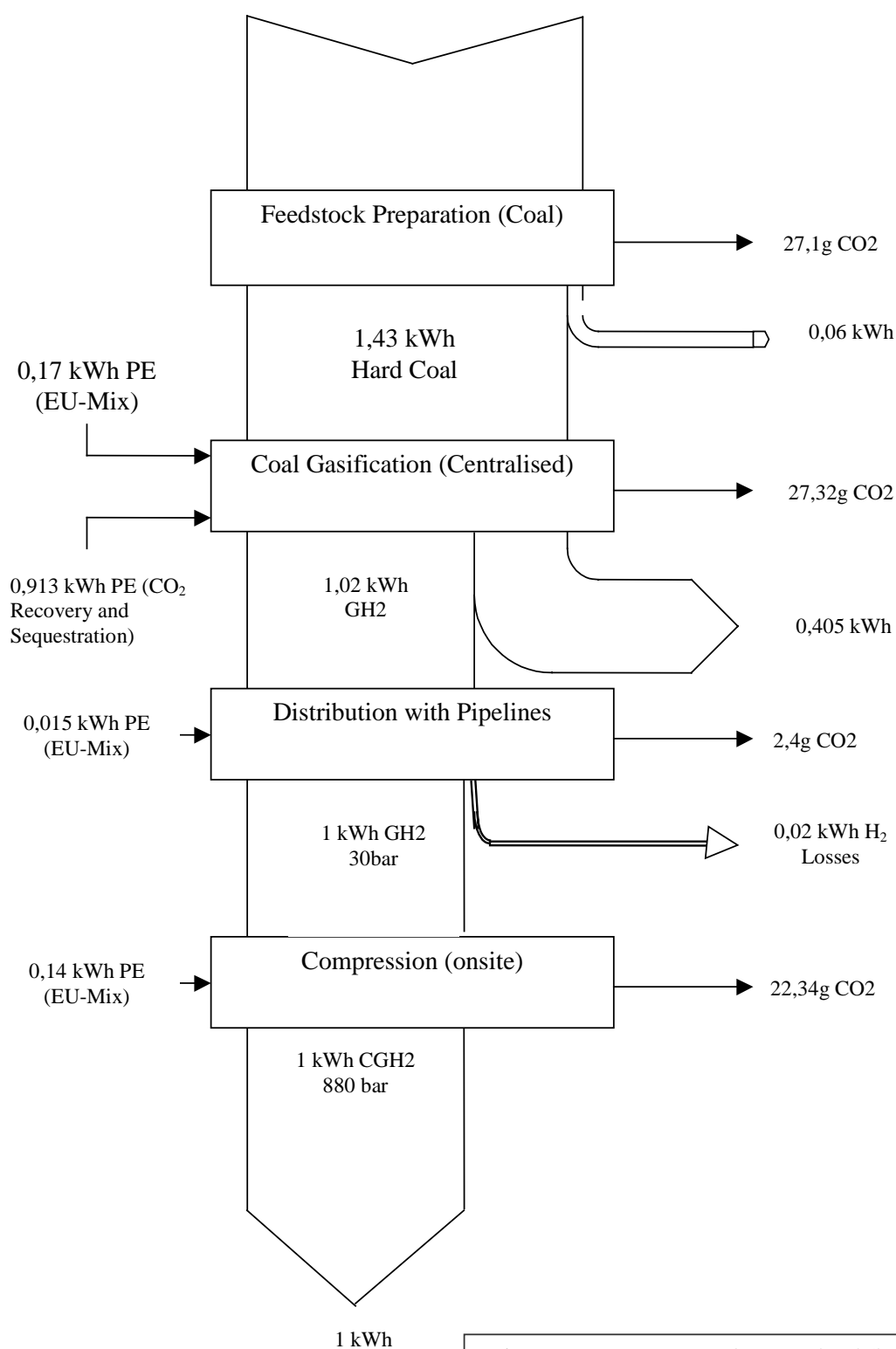


Path Way 4
CGH2: Coal Gasification (centralised)



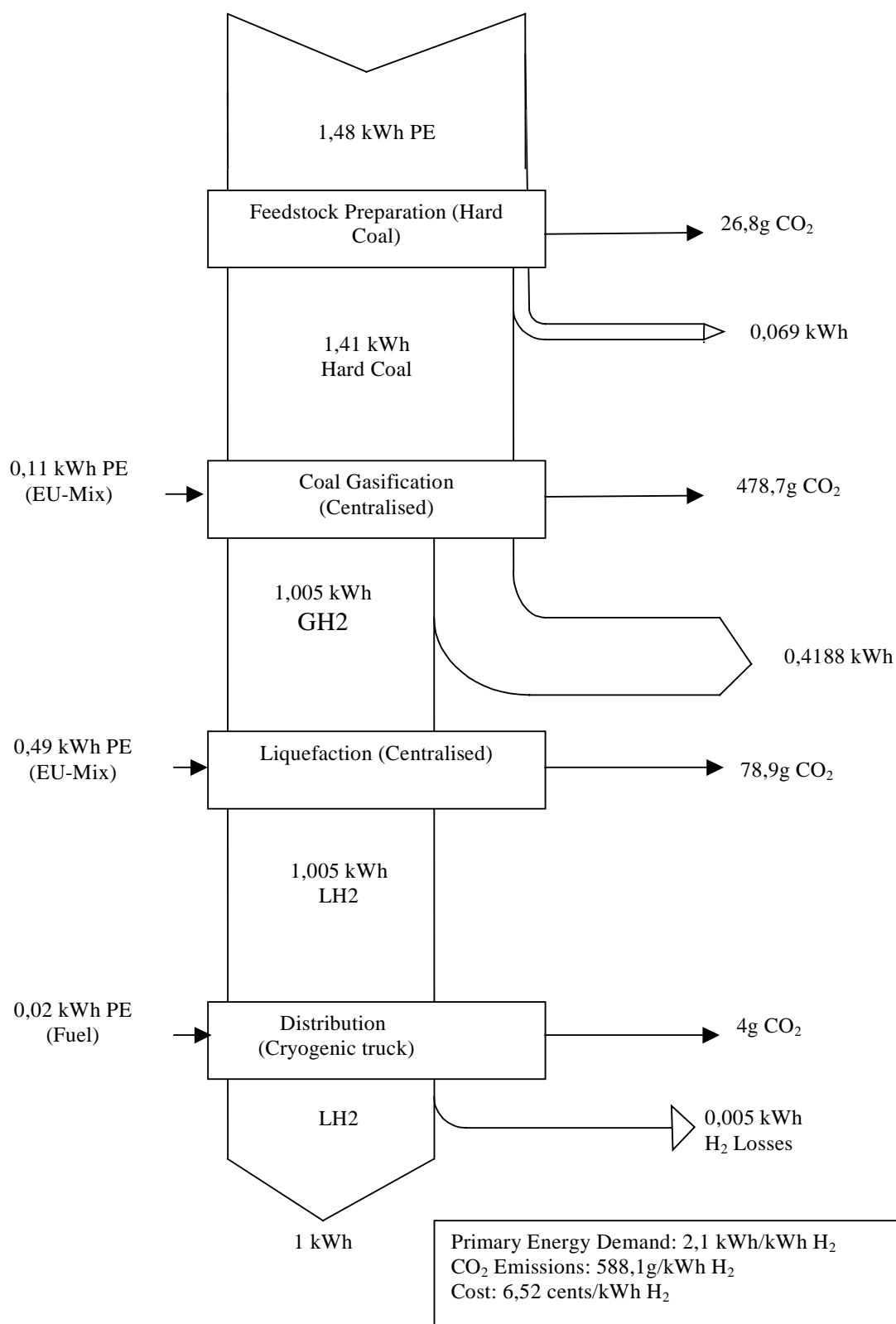
Primary Energy Demand: 1,815 kWh/kWh H₂
 CO₂ Emission: 538 g/kWh H₂
 Cost: 4,4 cents/kWh H₂

Path Way 5
CGH2: Coal Gasification (centralised) with CO₂ Sequestration

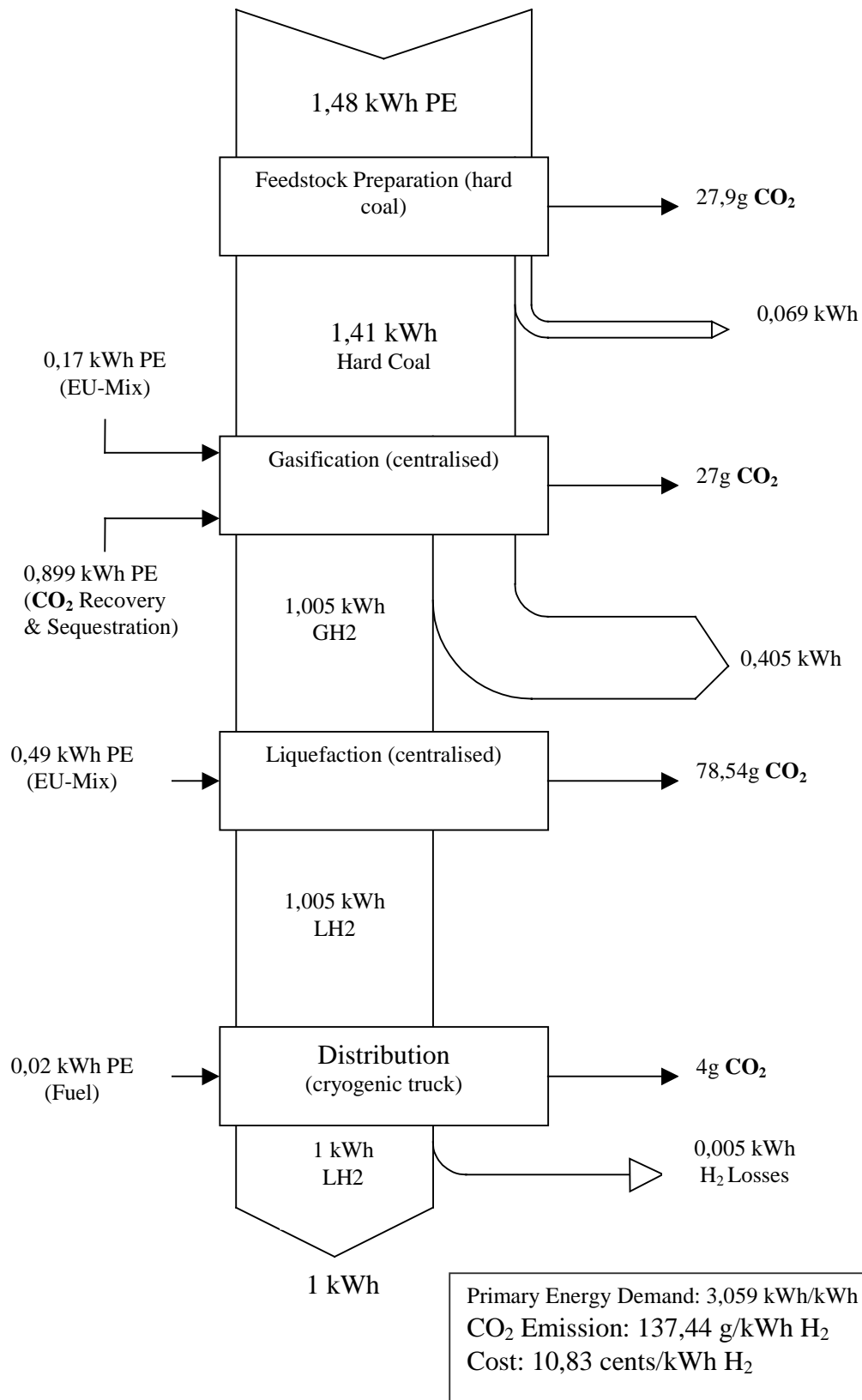


Primary Energy Demand: 2,728 kWh/kWh H₂
CO₂ Emission: 79,16 g/kWh H₂
Costs: 8,77 cents/kWh H₂

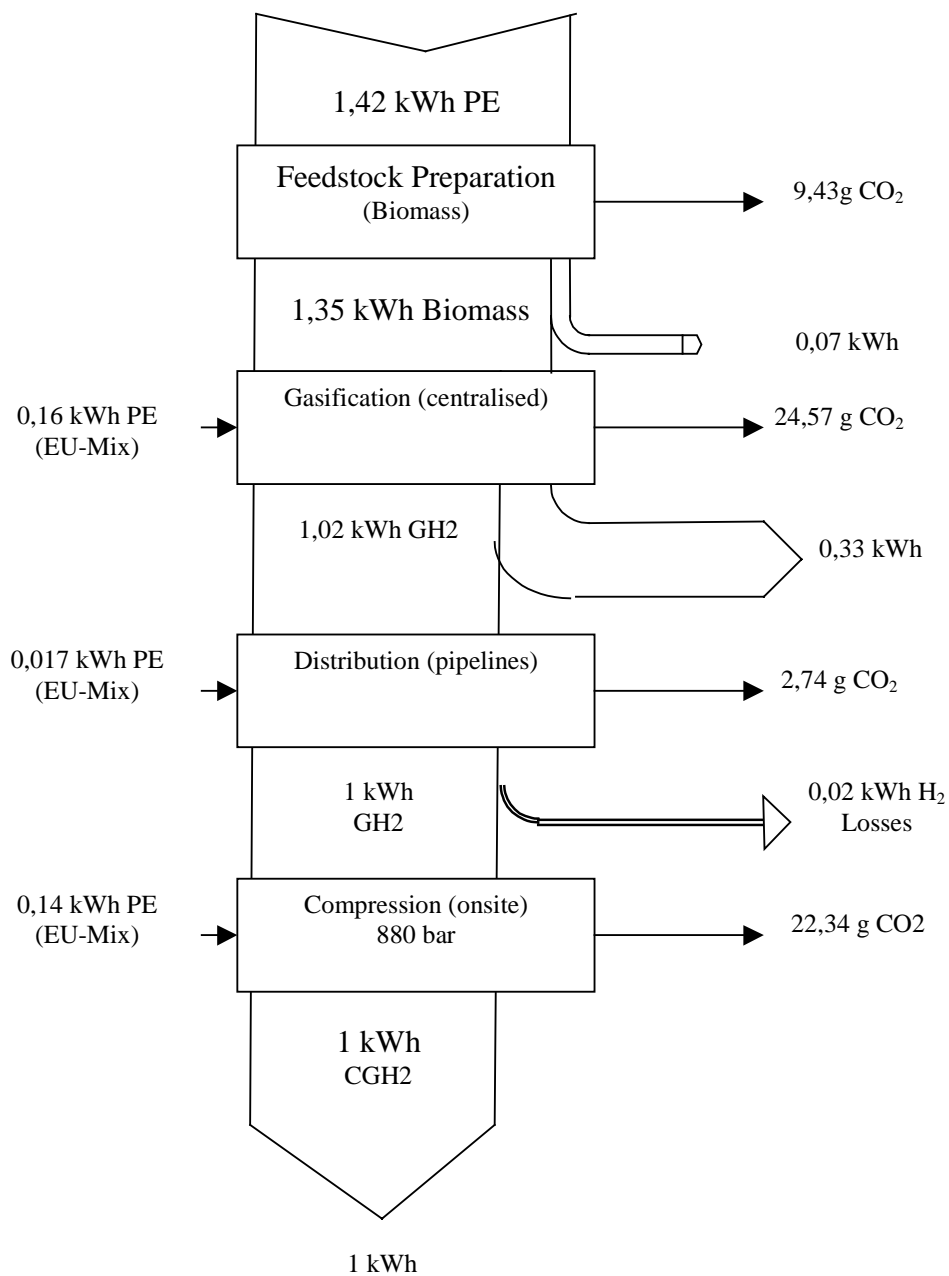
Path Way 6
LH2: Coal Gasification (centralised)



Path Way 7
LH2: Coal Gasification (centralised) with CO2 Sequestration

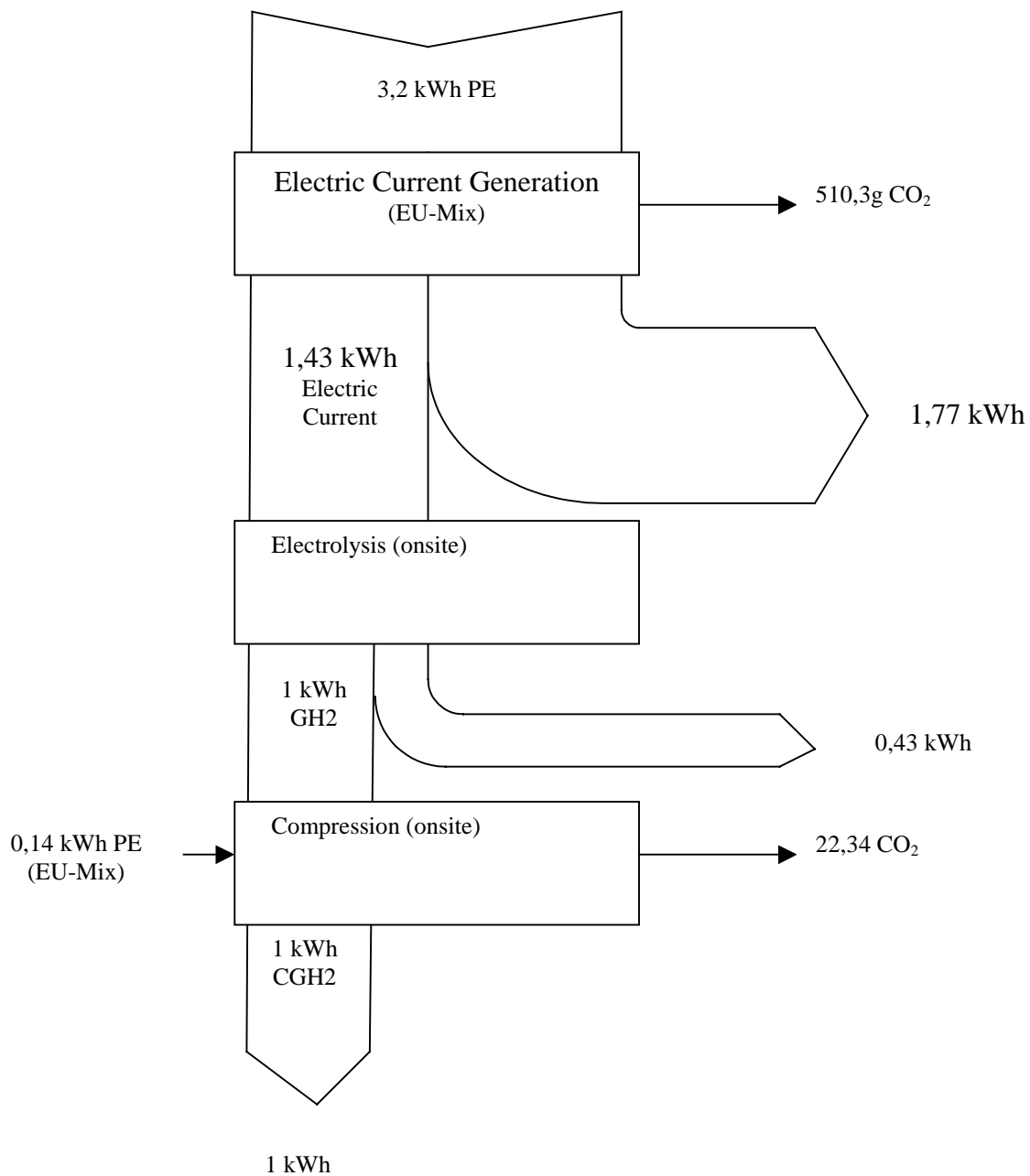


Path Way 8
GH2: Biomass (Residual Wood) - Gasification (centralised)



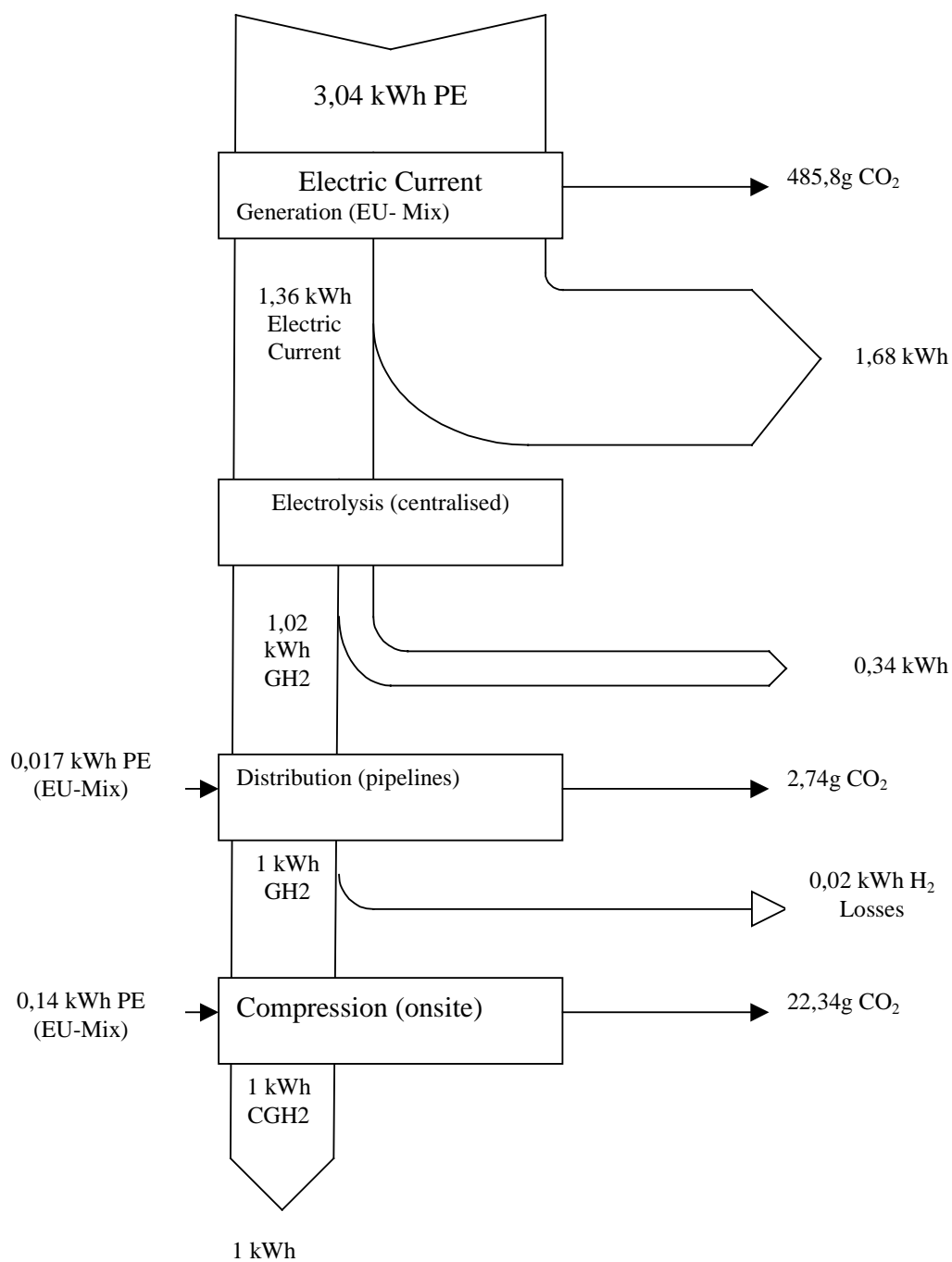
Primary Energy Demand: 1,737 kWh/kWh H₂
CO₂ Emission: 59,08 g/kWh H₂
Cost: 6,23 cents/kWh H₂

Path Way 9
CGH2: Electricity (EU-Mix) - Electrolysis (onsite)

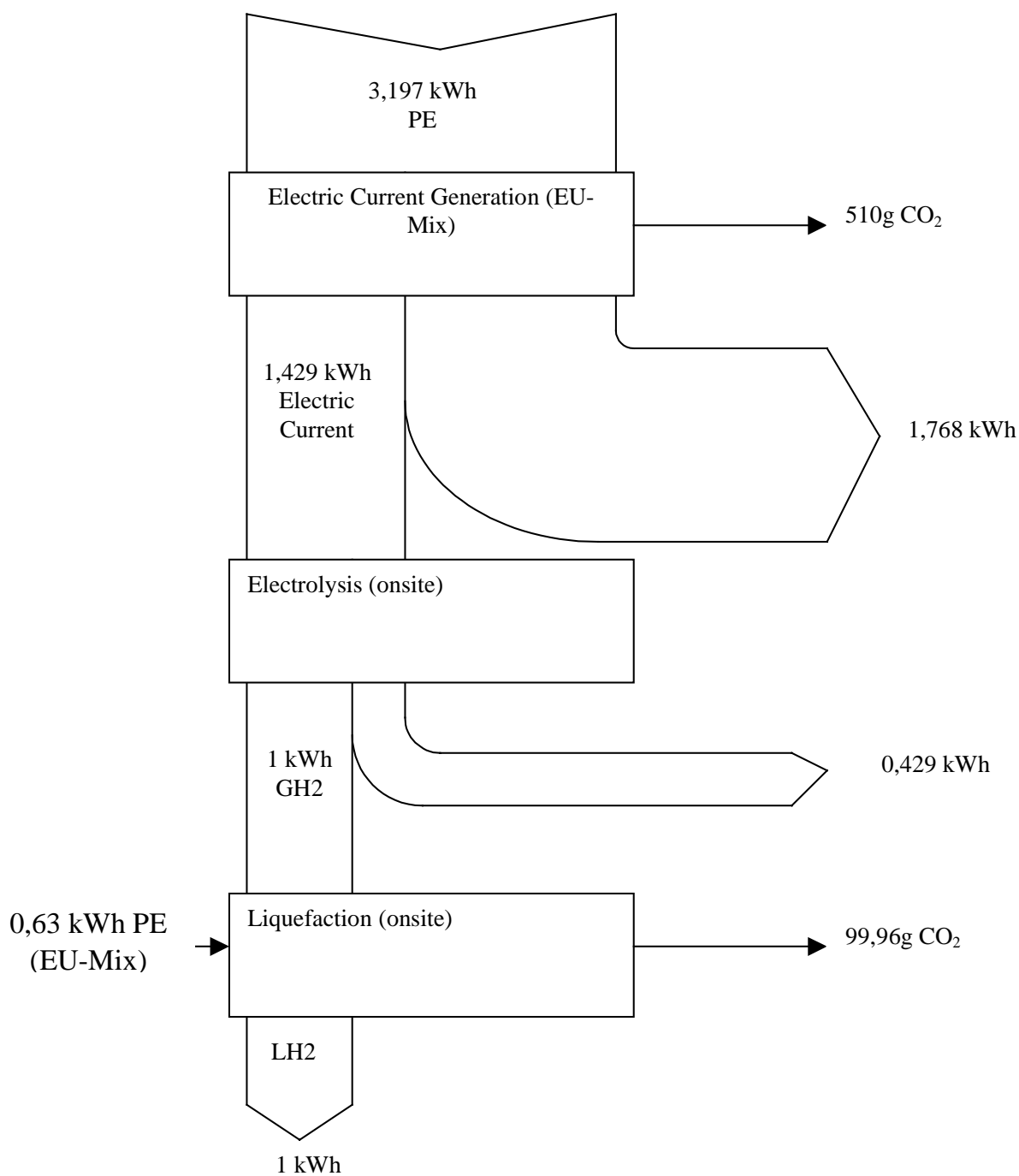


Primary Energy Demand: 3,34 kWh H₂
CO₂ Emission: 532,64 g/kWh H₂
Cost: 12,89 cents/kWh H₂

Path Way 10
CGH2: Electricity (EU-Mix) - Electrolysis (centralised)



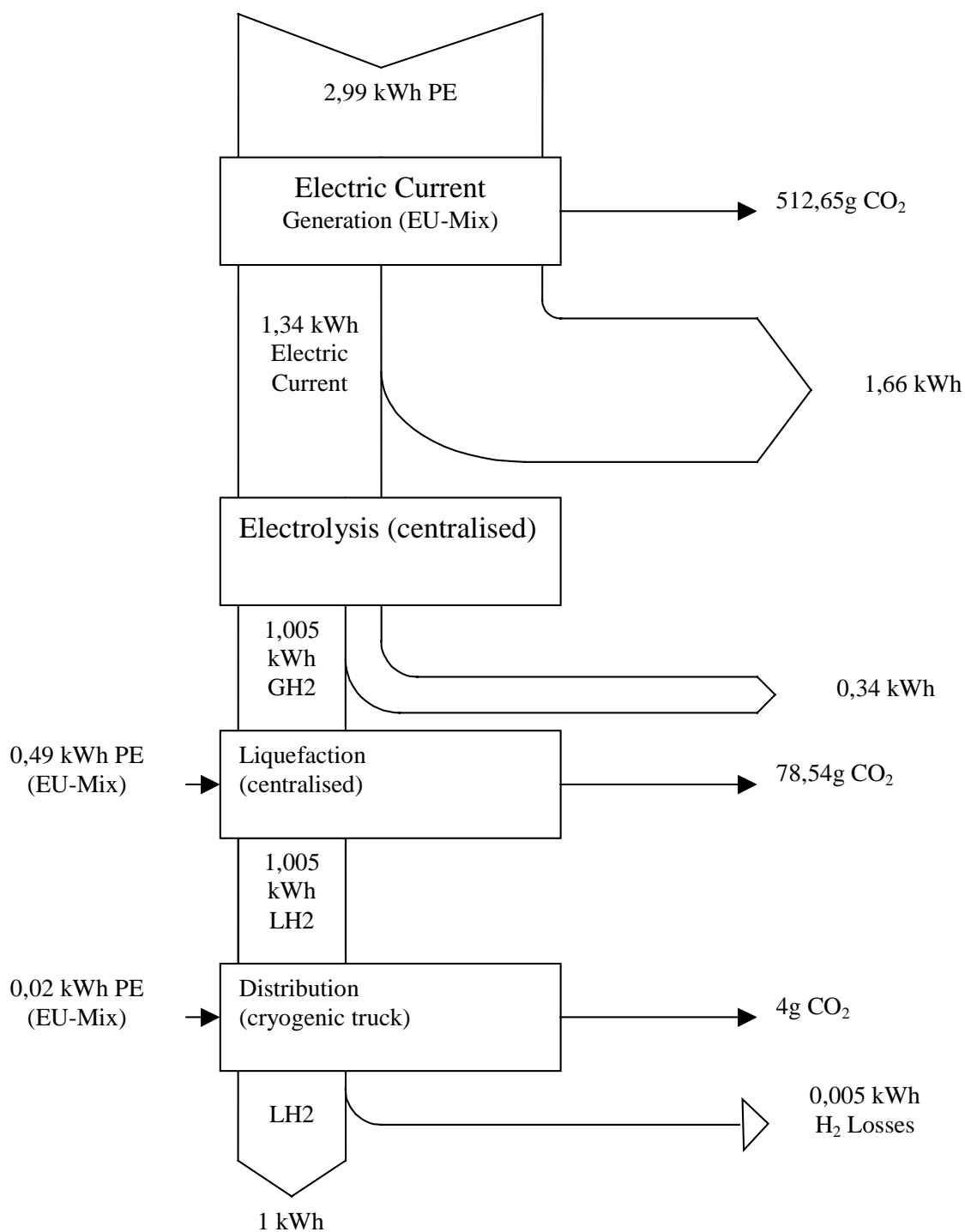
Primary Energy Demand: 3,197 kWh/kWh H₂
 CO₂ Emission: 510,88 g/kWh H₂
 Cost: 12,83cents/kWh H₂

Path Way 11**LH2: Electricity (EU-Mix) - Electrolysis (onsite)**

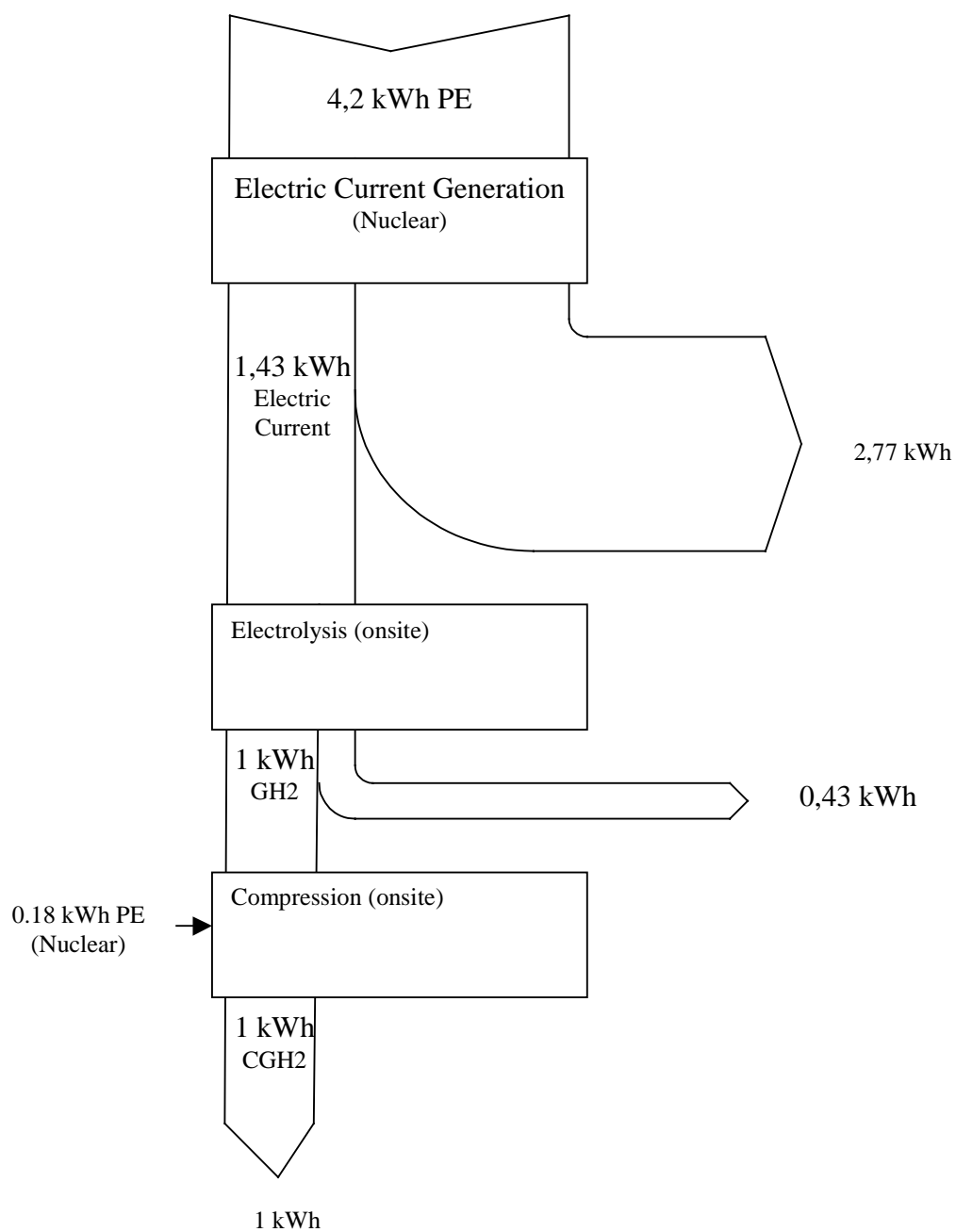
Primary Energy Demand: 3,827 kWh/kWh H₂
CO₂ Emission: 609,96 g/kWh H₂
Cost: 14,22 cents/kWh H₂

Path Way 12

LH2: Electricity (EU-Mix) - Electrolysis (centralised)

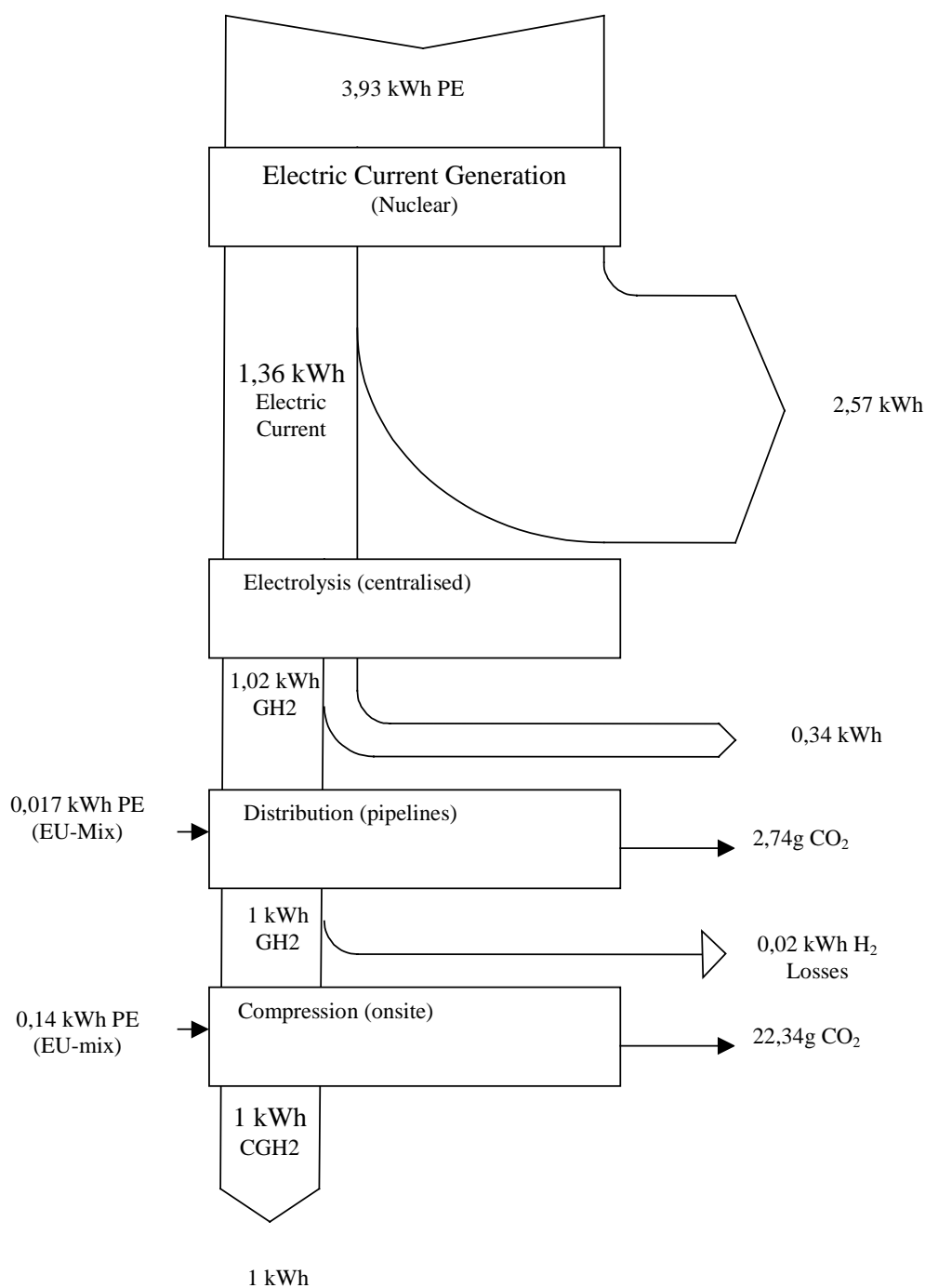


Primary Energy Demand: 3,5 kWh/kWh H₂
CO₂ Emission: 595,19 g/kWh H₂
Cost: 15,431cents/kWh H₂

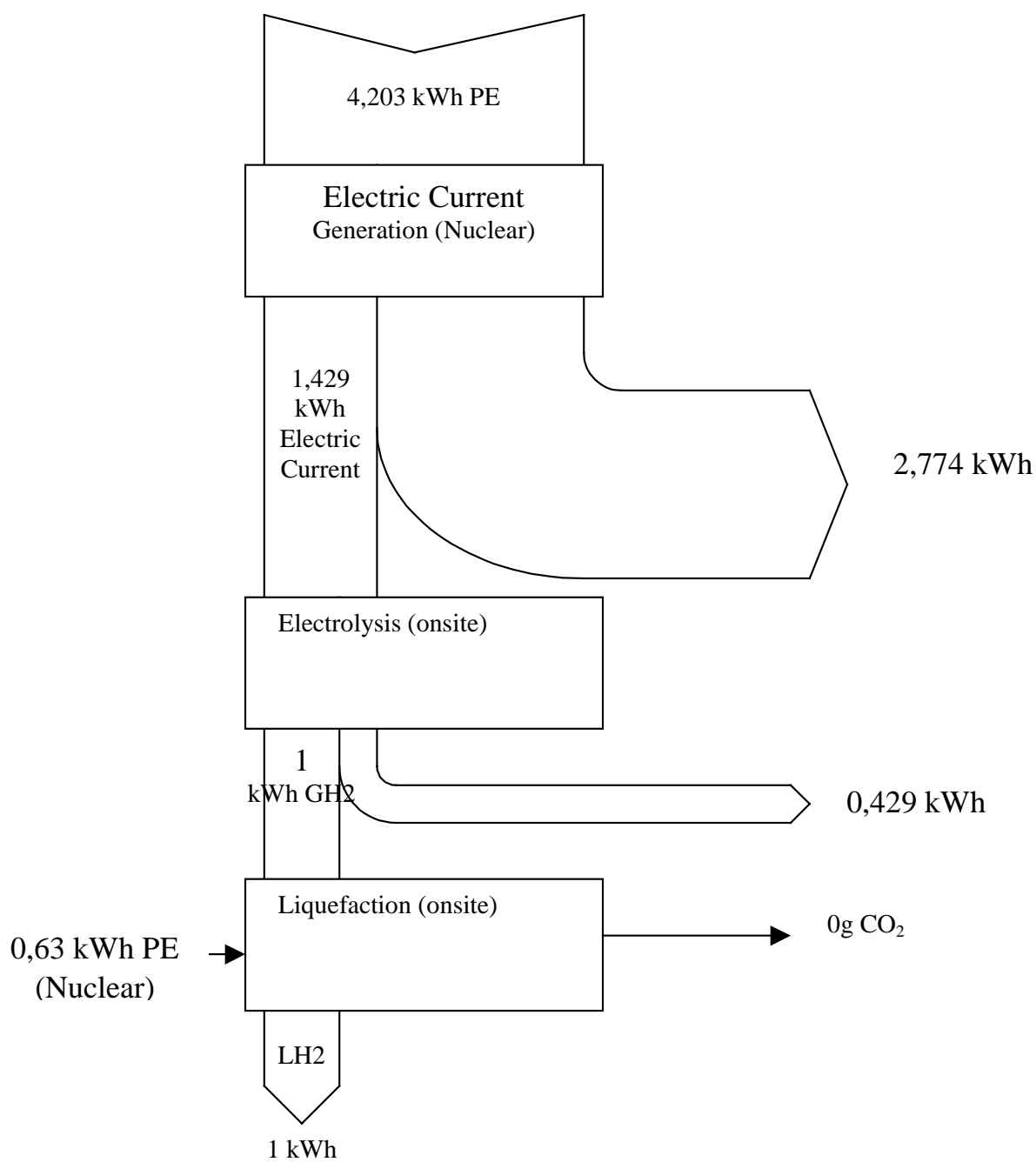
Path Way 13**CGH2: Electricity (Nuclear) - Electrolysis (onsite)**

Primary Energy Demand: 4,38 kWh/kWh H₂
CO₂ Emission: 0 g/kWh H₂
Cost: 11,72 cents/kWh H₂

Path Way 14
CGH2: Electricity (Nuclear) - Electrolysis (centralised)

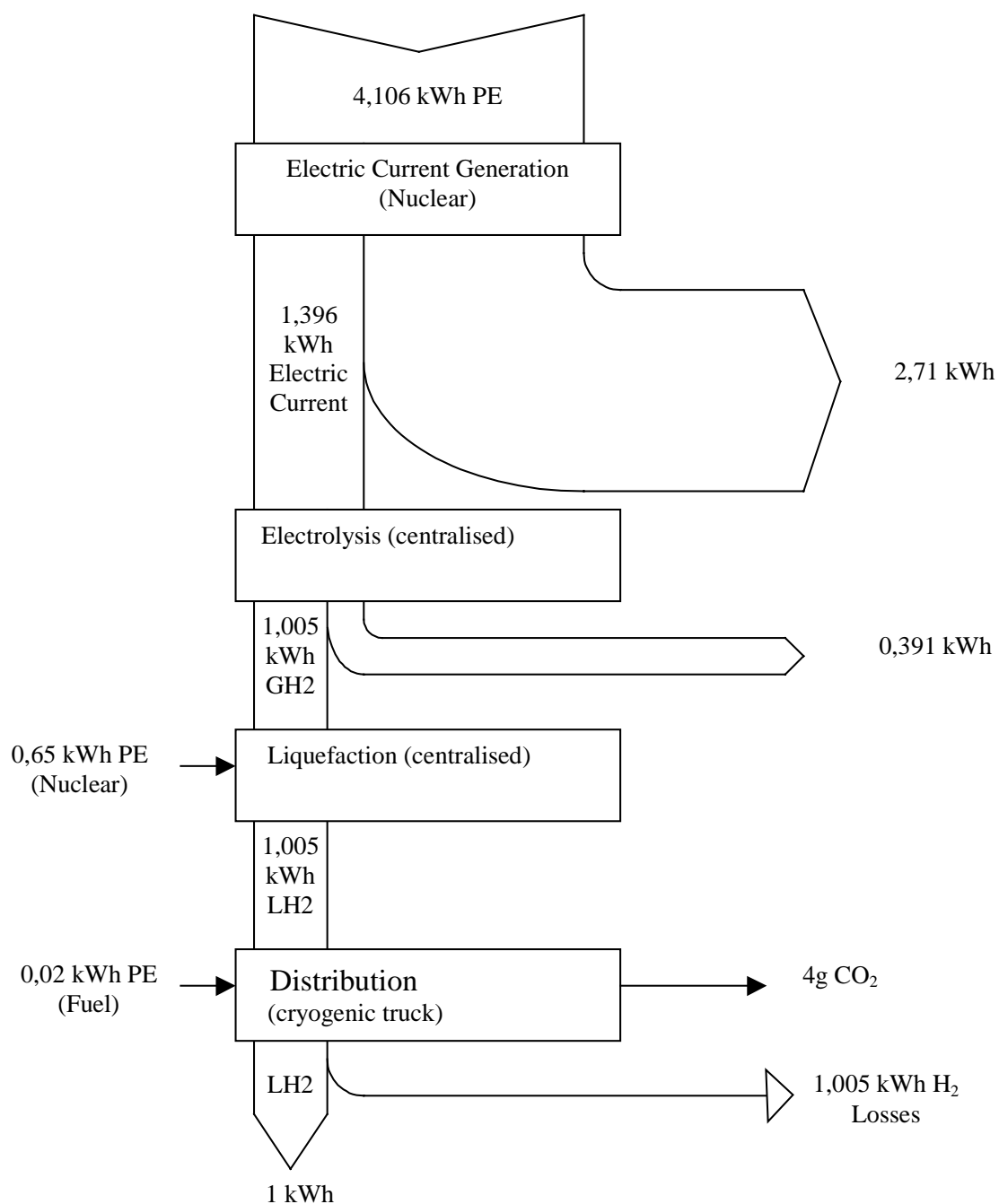


Primary Energy Demand: 4,087 kWh/kWh H₂
 CO₂ Emission: 25,08 g/kWh H₂
 Cost: 11,67 cents/kWh H₂

Path Way 15**LH2: Electricity (Nuclear) - Electrolysis (onsite)**

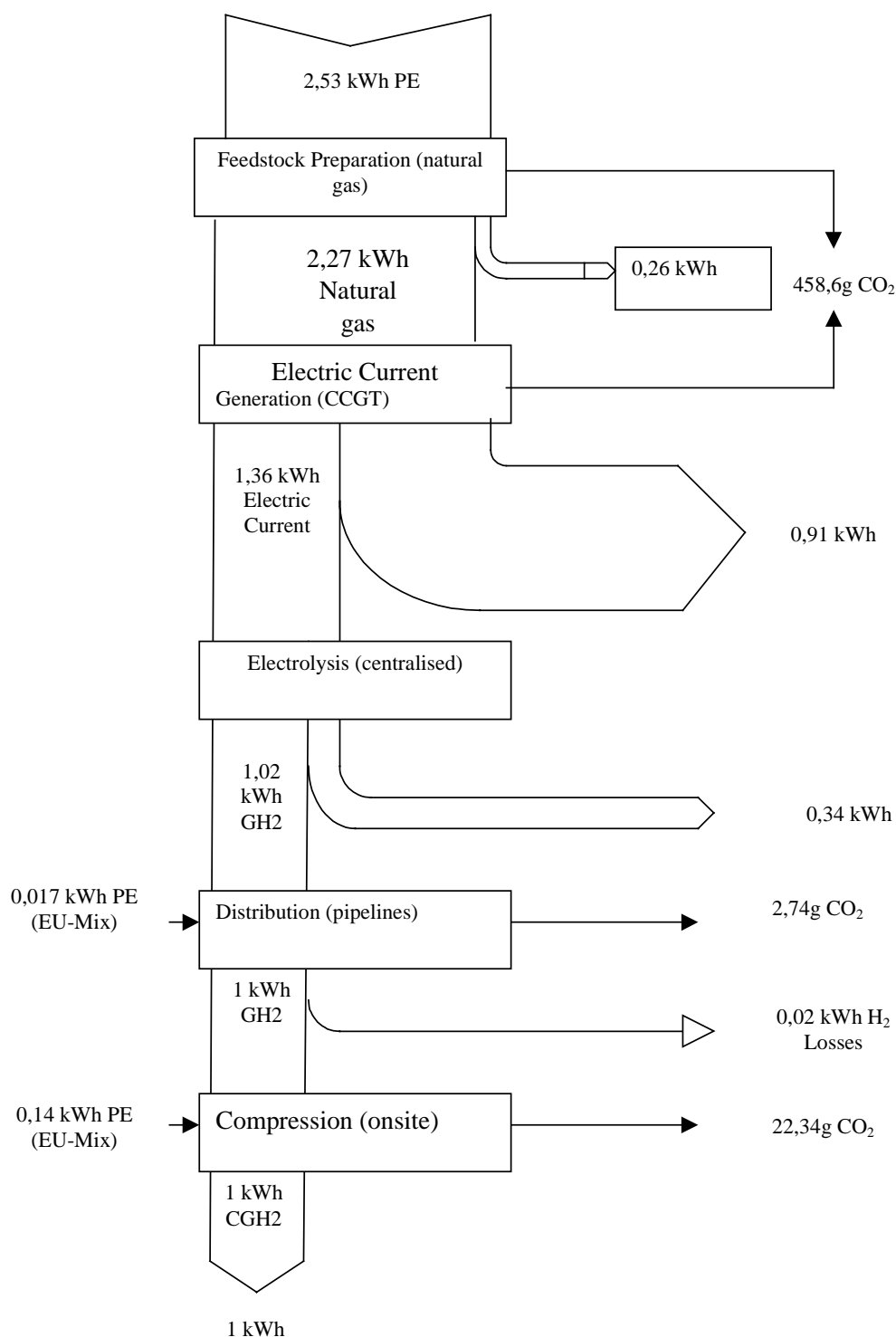
Primary Energy Demand: 4,833 kWh/kWh H₂
CO₂ Emission: 0 g/kWh H₂
Cost: 12,66 cents/kWh H₂

Path Way 16
LH2: Electricity (Nuclear) - Electrolysis (centralised)



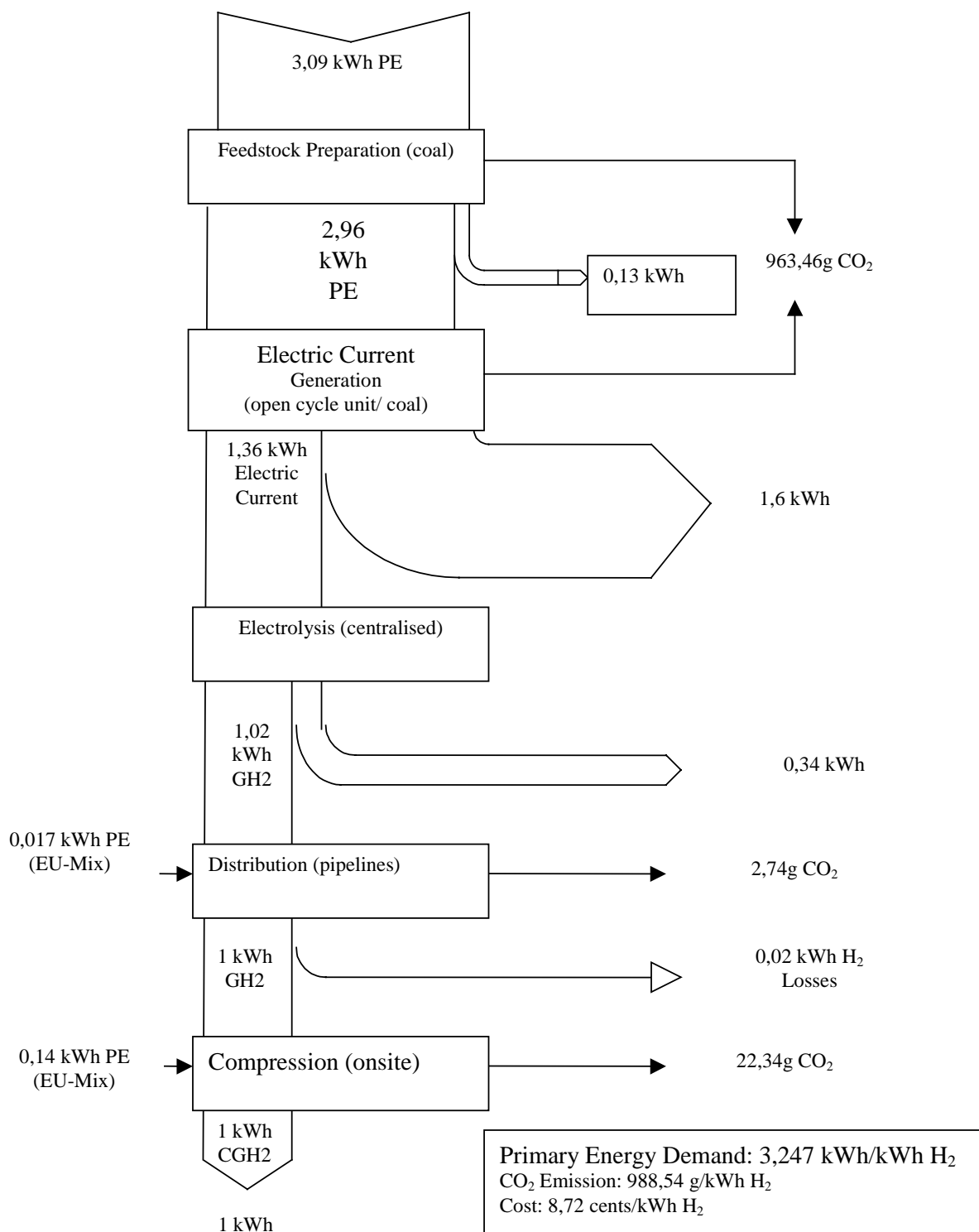
Primary Energy Demand: 4,776 kWh/kWh H₂
CO₂ Emission: 4 g/kWh H₂
Cost: 13,9 cents/kWh H₂

Path Way 17
CGH2: Electricity (CCGT surplus) - Electrolysis (centralised)

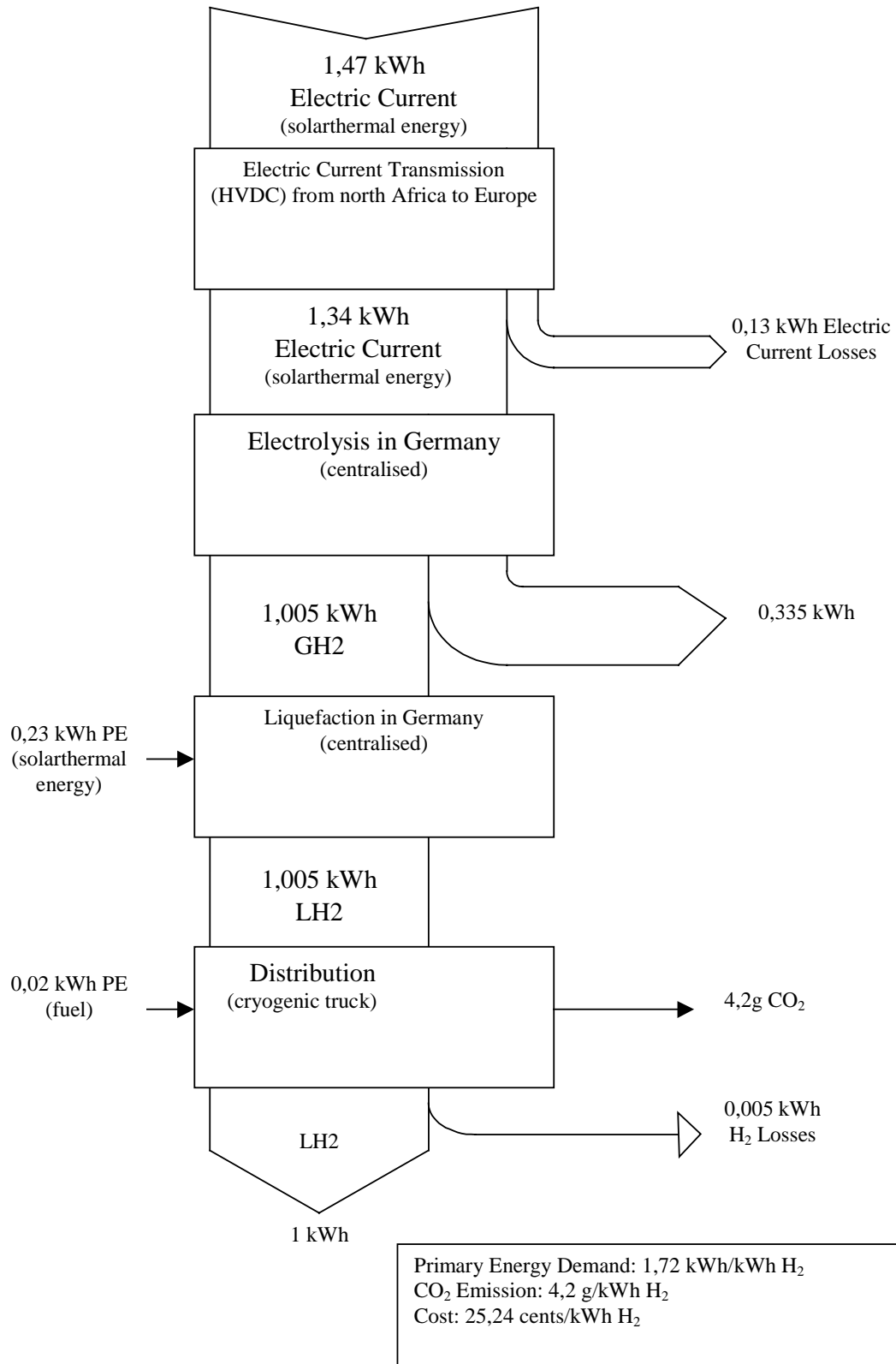


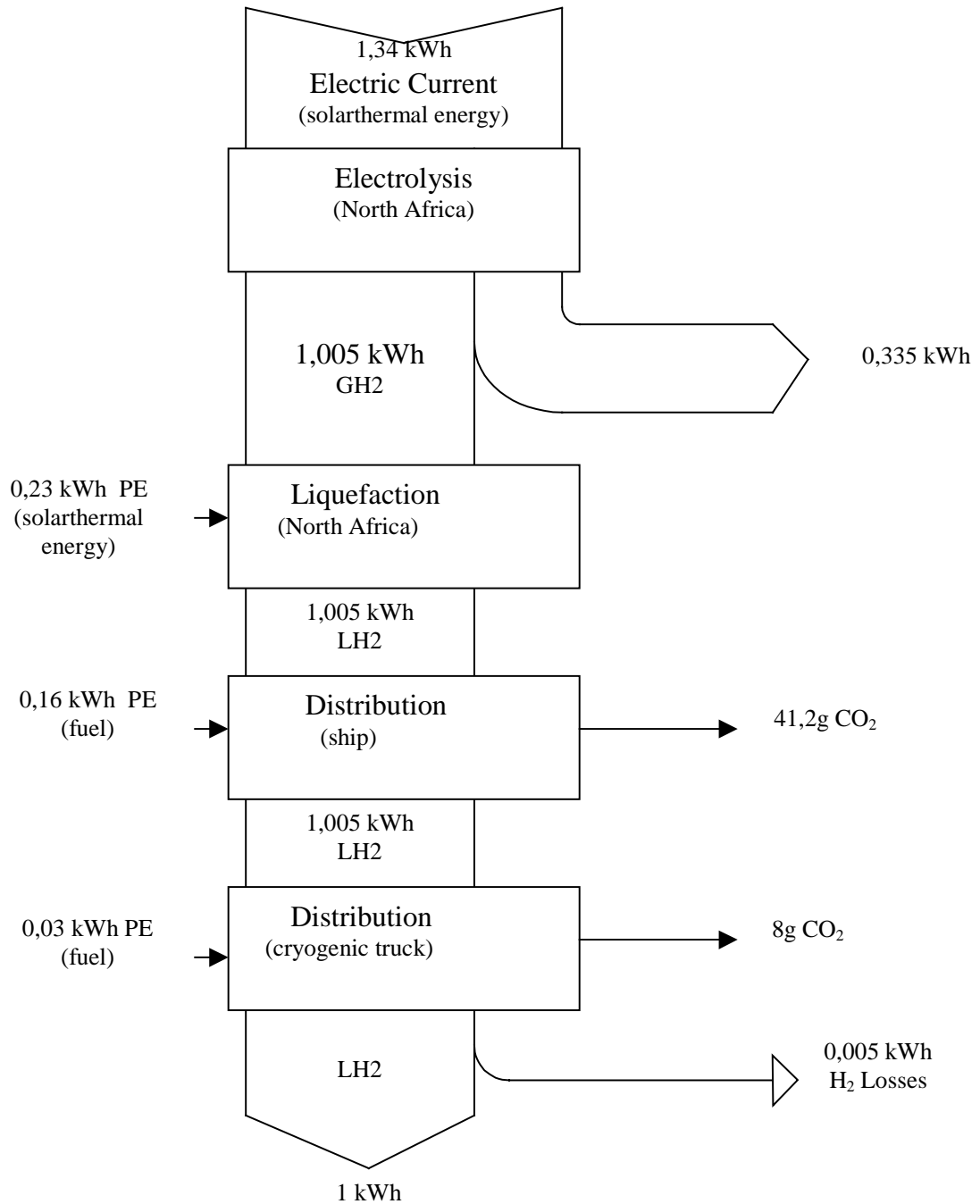
Primary Energy Demand: 2,687 kWh/kWh H₂
CO₂ Emission: 483,68 g/kWh H₂
Cost: 9,9 cents/kWh H₂

Path Way 18
CGH2: Electricity (hard coal and lignite open cycle unit)
- Electrolysis (centralised)

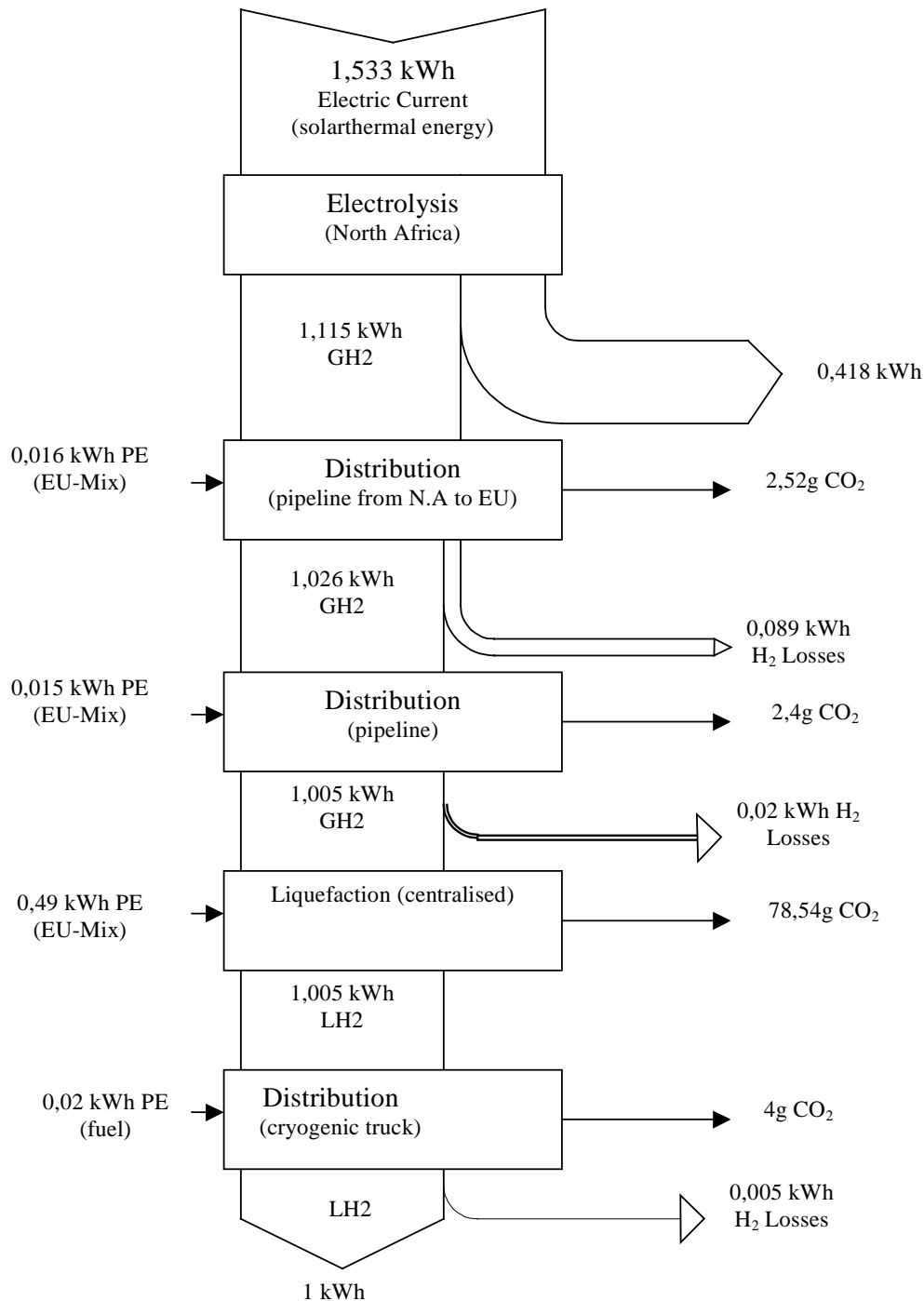


Path Way 19
LH2: Solar thermal Energy “North Africa” (Parabolic Trough) - HVDC -
-Electrolysis (centralised)



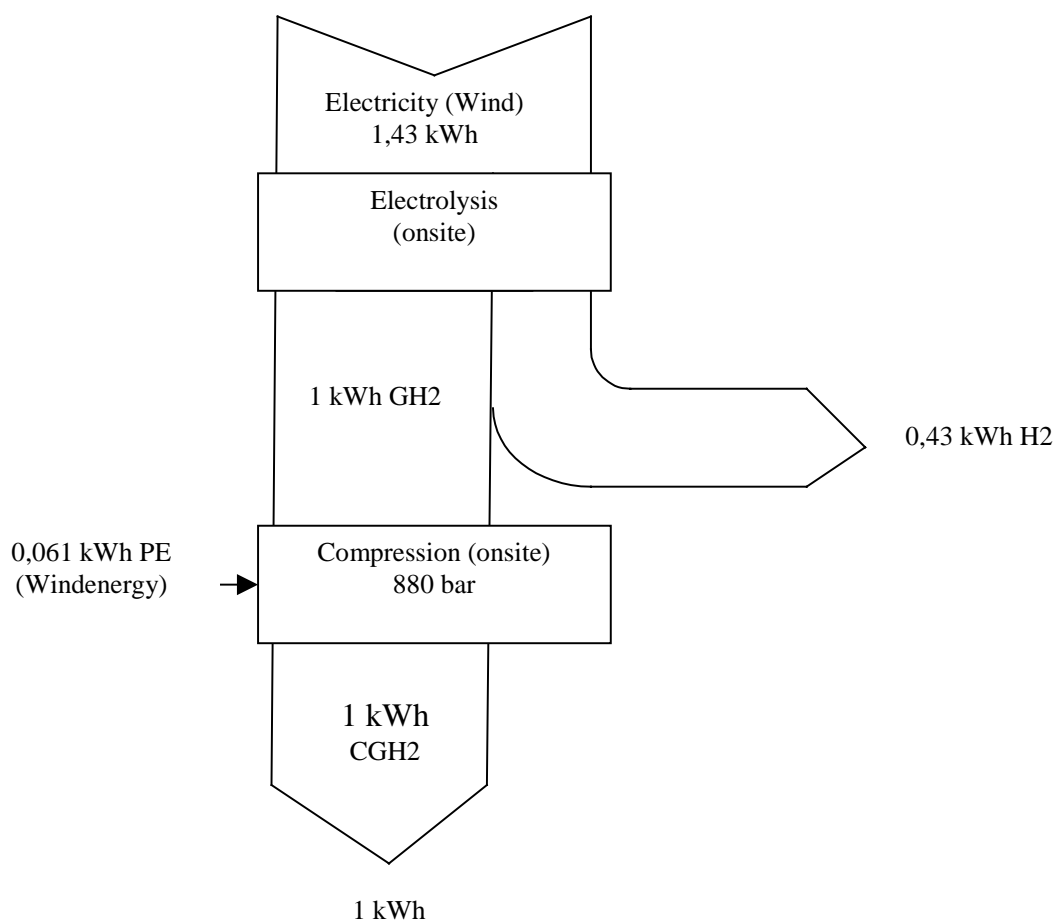
Path Way 20**LH2: Solar thermal Energy “North Africa” (Parabolic Trough) - Electrolysis (North Africa) - Liquefaction (North Africa) - Distribution (ship + cryogenic)**

Primary Energy Demand: 1,76 kWh/kWh H₂
 CO₂ Emission: 49,2 g/kWh H₂
 Cost: 27,64 cents/kWh H₂

Path Way 21**LH2: Solar thermal Energy “North Africa” (Parabolic Trough) - Electrolysis (North Africa) - Distribution (pipeline from North Africa to EU) - Distribution (pipelines local)**

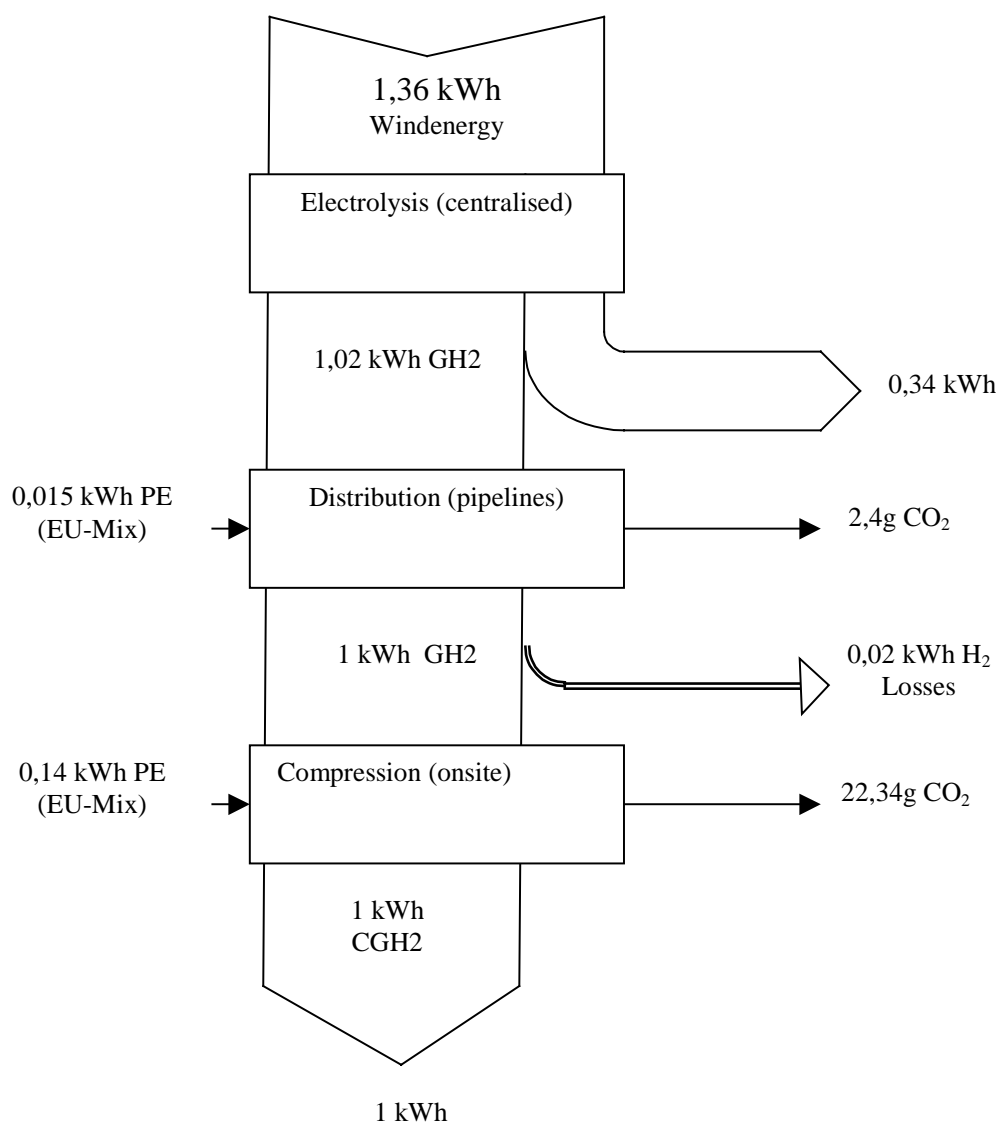
Primary Energy Demand: 2,072 kWh/kWh H₂
 CO₂ Emission: 87,46 g/kWh H₂
 Cost: 23,78 cents/kWh H₂

Path Way 22
CGH2: Wind energy - Electrolysis (onsite)

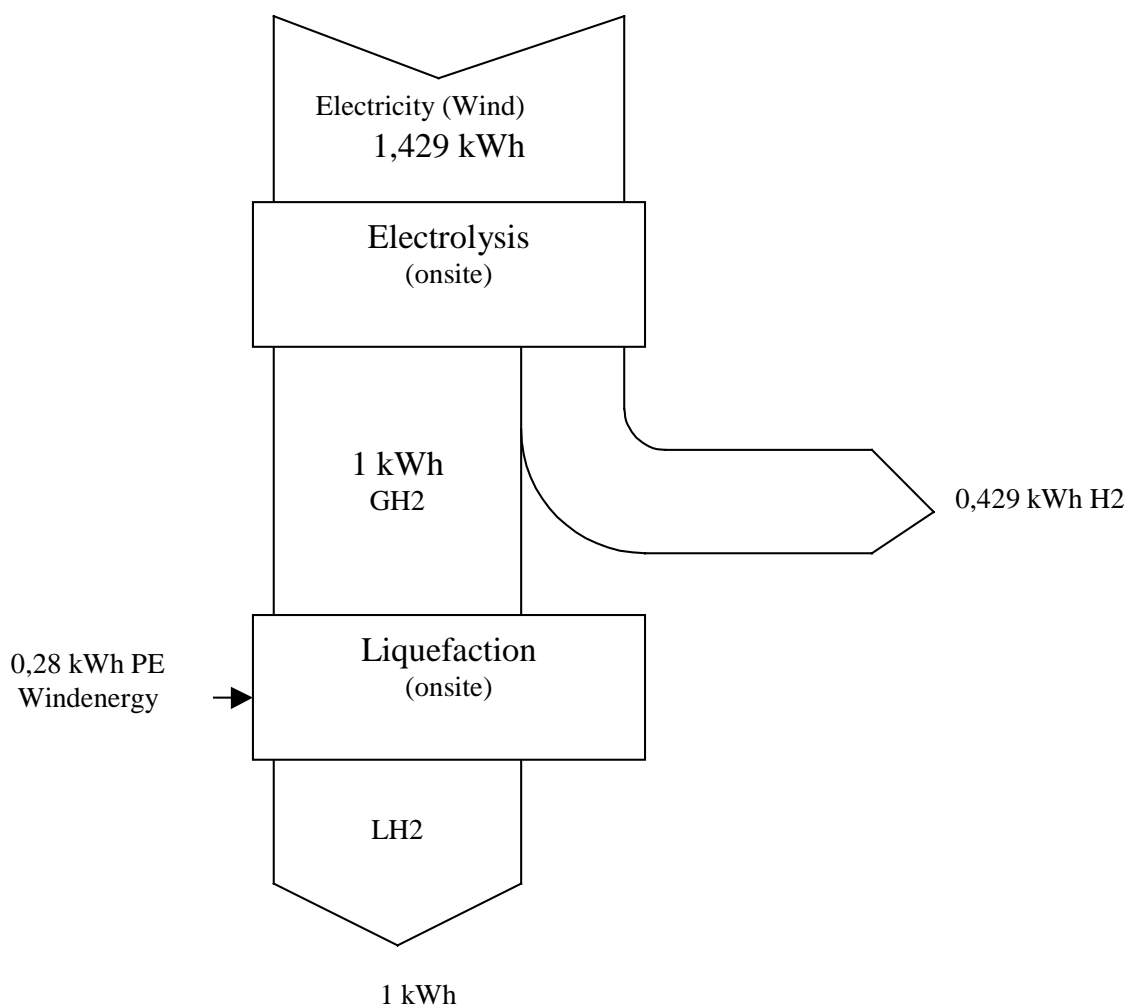


Primary Energy Demand: 1,49 kWh/kWh H₂
CO₂ Emission: 0 g/kWh H₂
Cost: 15,79 cents/kWh H₂

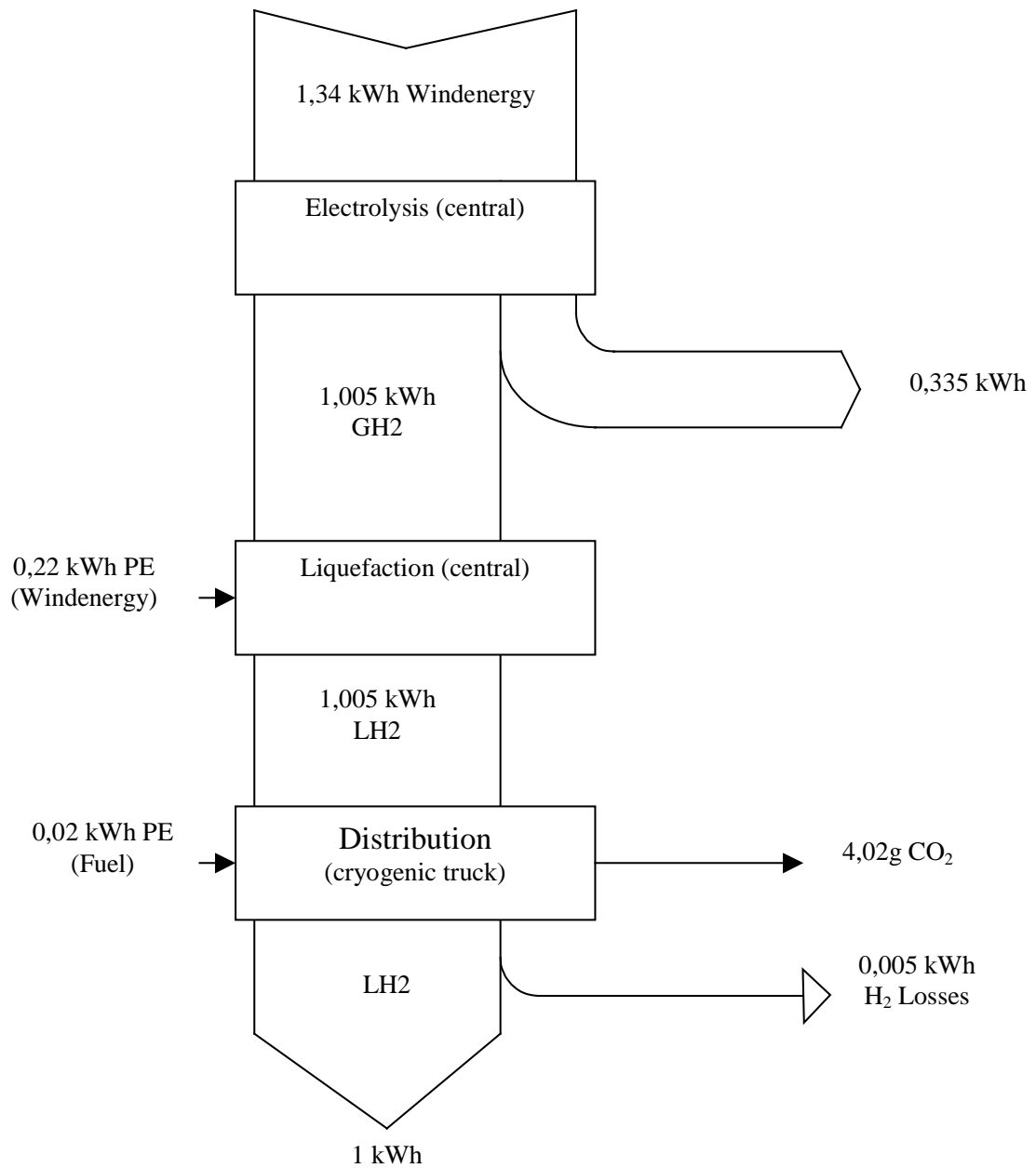
Path Way 23
CGH2: Wind energy - Electrolysis (centralised)



Primary Energy Demand: 1,51 kWh/kWh H₂
CO₂ Emission: 24,74 g/kWh H₂
Cost: 15,47 cents/kWh H₂

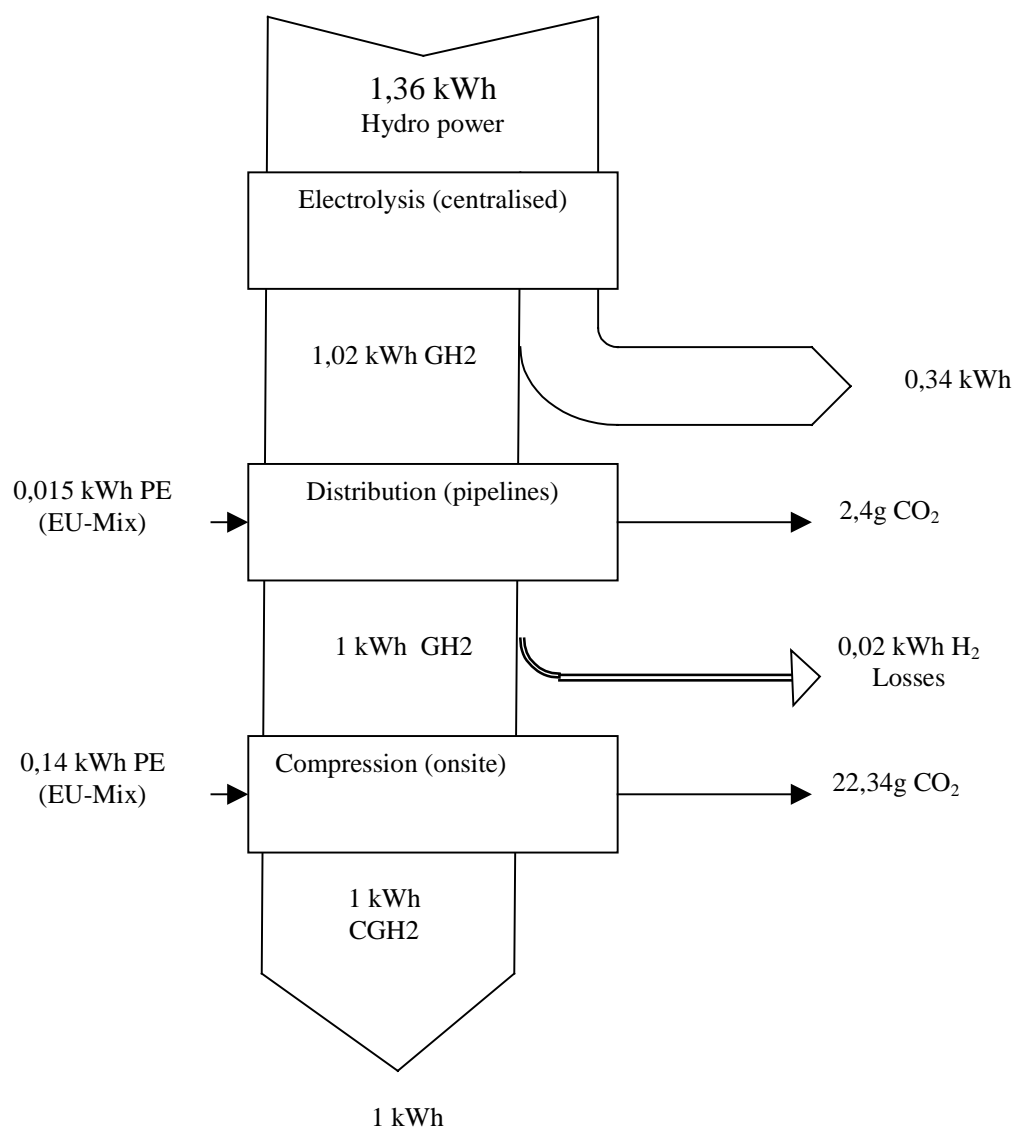
Path Way 24**LH2: Wind energy - Electrolysis (onsite)**

Primary Energy Demand: 1,709 kWh/kWh H₂
CO₂ Emission: 0g/kWh H₂
Cost: 17,56 cents/kWh H₂

Path Way 25**LH2: Wind energy - Electrolysis (centralised)**

Primary Energy Demand: 1,58 kWh/kWh H₂
CO₂ Emission: 4,02 g/kWh H₂
Cost: 18,00 cents/kWh H₂

Path Way 26
CGH2: Hydro power - Electrolysis (centralised)



Primary Energy Demand: 1,515 kWh/kWh H₂
CO₂ Emission: 24,74 g/kWh H₂
Cost: 12,18 cents/kWh H₂

Annex B: Comparison of our findings with results of ABB by Eliasson and Bossel

In a recent paper “The future of hydrogen economy: bright or bleak” Eliasson and Bossel give a rather pessimistic vision with regard to a future hydrogen economy. They argue that because of its basic physical properties hydrogen might never be an acceptable energy carrier “The Pure-Hydrogen-Only solution may never be acceptable.”. Their statements are solely based on the consideration of the energy balances of the whole hydrogen production chain. They quantify the energy losses of every single process step during the production and delivery of hydrogen. Unfortunately they do not give the aggregated results for such a pathway, neither do they compare a hydrogen pathway with a complete (well-to-wheel) alternative one.

We have analysed the single process steps given by Eliasson and Bossel and compared the various values with typical values given in the literature and used in our analysis. The result of this is shown in Tab. 1. The general statement of this is that the assumptions of Eliasson and Bossel are comparable to ours, sometimes they are even more optimistic, i.e. energy losses are lower or efficiency is higher (e.g. for electrolyses and reforming of natural gas). The only process step, which we consider very unreasonable, but which obtains strong attention in the paper of Eliasson and Bossel, is the transport of gaseous hydrogen by truck. This path leads to very high energy losses. However, the alternatives of GH2 pipeline transport and LH2 truck transport are way more efficient and therefore considered in our assessment as the dominating pathways. In the case of pipeline transport Eliasson and Bossel have neglected the effect of technology learning, which is considered to be very relevant in the literature. In Fig. 1 the comparisons between our results and two possible pathways based on the figures given by Eliasson and Bossel is shown. One can see that both results are within the same range, although one observes the significant difference between “ABB truck transport” and pipeline transport.

Generally the assumptions of Eliasson and Bossel are reasonable, except for the case of hydrogen transport, but the conclusions are wrong. In the introduction they say: “The global energy problem cannot be solved in a renewable energy environment, if the energy consumed to make and deliver hydrogen becomes comparable to the energy content of the delivered fuel.” This statement is misleading since one has to compare the **full** primary energy (well-to-wheel) chain of a hydrogen path with alternative solutions. For example the well-to-wheel primary energy need of a typical hydrogen path assuming a fuel cell efficiency of 55% is about 3,2 MJ/MJ, whereas the respective value is about 5,4 MJ/MJ for a gasoline internal combustion engine. Therefore the hydrogen path would be certainly preferable from the primary energy perspective, although “the energy consumed to make and deliver hydrogen becomes comparable to the energy content of the delivered fuel”.

	ABB	Own values
production		
<u>electrolysis</u> efficiency	75 %	70 % onsite, 75 % centralised
<u>Reforming (natural gas)</u> efficiency	85 %	70 % onsite 78 % centralised
liquefaction		
Energy needed	Ca. 0,28 kWh/kWh	0,28 kWh/kWh, onsite 0,22 kWh/kWh, centralised
compression		
Energy needed	200 bar: 0,1 MJ/MJ	0,061 kWh/kWh (30/880bar)
Transport		
<u>Truck</u> Size of tank H ₂ -losses	500 kg (200 bar) GH₂ ca. 100%, therefore 1MJ/MJ	55 m ³ = 3893,45 kg LH₂ 0,5% GH₂ not considered because unreasonable
<u>Pipeline long distance transport</u> Pressure Transport losses (2.500 km)	75 bar 22 %	30 bar 8 % (+ electricity for compression 1,5%) in 2020 currently 18% however significant learning effects expected