Building up a gas station infrastructure to supply vehicles with hydrogen as an alternative fuel, taking technical, economic and ecological aspects into consideration

Abridged version of the dissertation

by

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Munich, July 2003

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submitted to Vienna University of Technology
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In July 2003

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Foreword

I would like to begin by thanking the BMW Group, Munich, who made a substantial contribution to this dissertation. The BMW Group offered me the opportunity to undertake this work within its Traffic and Environment department. I would like to thank all employees of this department for the friendly atmosphere and good co-operation.

Particular thanks are due to my tutor, Univ.-Prof. Mag. Dr. Wilfried Schönbäck for his keen interest in the work, his support and his invaluable advice on numerous occasions during the preparation of this dissertation.

I also thank Univ.-Prof. Dipl.-Ing. Dr. Adolf Stephan for his support and numerous, invaluable pieces of advice during the course of this work.

Of considerable help in this paper was Dipl.-Ing. Dr. Roger Pierrard, MBA, of the Institute of Public Finance and Infrastructure Policy at the University of Technology in Vienna, whose expert knowledge in the fields of emissions and alternative fuels made him an ideal contact for me. Dr. Pierrard constructively criticized the overall presentation of the work, and therefore contributed to a much clearer final version.

My thanks go to Dr. Juliane Wolf of the BMW Group for her thorough support of the work, and to Dipl.-Ing. Holger Braess for providing impetus and clarifying discussions.

I would like to thank all experts and participants from industrial partners - in particular Dipl.-Ing. Christian Gruber (MAN Nutzfahrzeuge AG), Mag. Christoph Lewisch (OMV AG), Dipl.-Ing. Bernd Nierhauve (Aral Forschung), Dipl.-Ing. Kurt Pollak (OMV AG), Dr. Karl-Viktor Schaller (MAN Nutzfahrzeuge AG) and Dr. Joachim Wolf (Linde AG) – for willingly answering my questions.

Thanks are also due to my family for its support.

Contents

Abstract

In recent years, the concept of “sustainability” with reference to human activities has taken on ever greater importance. Among other things, this concept requires a reduction in the dependency of fossil resources and a reduction in CO_2 emissions. In the road transport sector, this means searching for an alternative carbon-free fuel. The alternative fuel with the best long-term prospects is hydrogen.

This paper presents possible dynamic developments in the build-up of a hydrogen infrastructure (with hydrogen production, distribution, gas stations as its components) in Germany to supply vehicles with alternative fuel hydrogen. Possible means of introducing the alternative fuel for the purpose of reducing CO_2 emissions are derived from this. The first stage of the examination is a modelled development of the vehicle population, from which the development of a gas station infrastructure to supply the fuel is derived. The total system is analysed from borehole to vehicle fuel tank (‘well to wheel’), taking into consideration different processes for the production of the hydrogen, partial capacity utilization of the named components, advantages from economies of scale and learning effects.

An analysis of the favored gas station concepts shows that the lowest costs are associated with concept of exclusive supply of liquid hydrogen. Building on this gas station concept and the modelled development of the vehicle population, the time required to achieve almost complete adaptation of all conventional gas stations to supply hydrogen will be about 25 years. If there is a correspondingly rapid development in the vehicle population, a complete adaptation of the gas stations is imaginable within around 15 years. In this case, the development of the gas station population takes the form of an S-curve.

A central question with regard to realization of the stated goals (CO_2 reduction, preservation of fossil resources) is posed by hydrogen production during the period 2006 to 2035. If, during this time, the hydrogen is only produced by natural gas steam reforming (by using regeneratively produced or nuclear electricity), the specific hydrogen costs will be low, although only a marginal reduction in CO_2 will be achieved. However, if the electricity for this option is produced from fossil energy sources with use of sequestration (also in the case of natural gas steam reforming), it is possible to achieve high levels of CO_2 reduction. However, the aim of preserving fossil resources will not be satisfied. During the period in question, the highest reduction of CO_2 will be achieved with exclusive hydrogen production by electrolysis, using regeneratively produced electricity. However, this option incurs high specific hydrogen costs. If sequestration is used here as well, only marginal reductions in CO_2 will occur, due to the remaining emissions that occur.

Because of the high specific hydrogen costs associated with the exclusive production of hydrogen by electrolysis, the production of hydrogen fuel by natural gas steam reforming is highly probable during the market introduction phase. However, in order to achieve the stated aims (CO_2 reduction, preservation of fossil resources), the production share of natural gas steam reforming must be reduced in the course of time and replaced by electrolysis. In other words, starting with the exclusive production of hydrogen by natural gas steam reforming in 2006, the share of electrolysis will be increased by defined scenarios until 2035. In order to arrive at the optimal long-term composition of hydrogen production (how high the share of electrolysis in hydrogen production should be), staged optimisation will take place. In the **first stage of optimisation**, it will be shown from a comparison of the ‘total costs versus emission reduction curves’ with and without the use of sequestration that CO_2 sequestration should only be realized up to a long-term electrolysis share of about 50 % in hydrogen production as a consequence of high residual emissions. This comparison shows which technology (with or without sequestration) is to be preferred, but not the optimum composition of hydrogen production or the optimum CO_2 reduction. This is shown in the second stage of the optimisation.

As the ‘total costs versus emission reduction curves’ do not exhibit a constant increase, the optimal composition of hydrogen production and the optimal CO_2 reduction in the second stage of the optimisation are determined by using the criterion of the lowest incremental costs of the discounted total costs. As hydrogen production is taken into consideration with and without sequestration, and therefore using two different technologies, this results in two incremental cost curves. On the basis of the criterion of minimum incremental costs, the composition with a long-term electrolysis share of 40 % is determined as the optimum for hydrogen production. Interestingly, the same applies to the curve with and without the use of sequestration. In this composition (increasing the electrolysis share over time, starting with the production of hydrogen solely from natural gas), the result is a favorable “acquisition” of a further reduction in CO_2 emissions. Following the composition with the lowest incremental costs, a further reduction in CO_2 emissions can only be achieved with correspondingly high total costs.

As the electrolysis share in hydrogen production was optimised in the second stage, there is also an optimization of CO_2 reduction. For the determined optimum composition of hydrogen production with a long-term 40 % share of electrolysis, the result is a reduction in CO_2 of about 17 % in emissions from road traffic in Germany in 2035.

However, what is also important is the fact that with an increasing electrolysis share in hydrogen production by 2035, the additional achievable reductions in CO_2 emissions increase much more strongly than the discounted total costs. The gives rise to the lowest CO_2 avoidance costs (discounted total costs for each tonne of CO_2 avoided) with the exclusive production of hydrogen using electrolysis. As the exclusive production of hydrogen by electrolysis as a consequence of the high specific hydrogen costs from the start does not appear achievable from today’s standpoint, the characteristic of minimum CO_2 avoidance costs is not used as an optimisation criterion in this dissertation.

It can be shown that depending on the criterion used (e.g. maximum emissions reduction, minimum total costs, minimum incremental costs), partly different results arise as the achievable optimum. As the stated aims (criteria) partly contradict each other, the build-up of a hydrogen infrastructure can only take place as an optimised middle path, taking all the aims into consideration.

1. Introduction

The large and increasing number of people in the world with their increasing energy needs and consumption presents a huge challenge for humanity and the environment. If the increasing energy requirements and consumption are satisfied by the use of fossil energy sources, the results will, in all likelihood, be a further intensification of the anthropogenic greenhouse effect and thus a probable increase in the temperature of the Earth's surface. The use of fossil fuels by people has increased the concentration of carbon dioxide, the most important of the anthropogenic greenhouse gases, by approximately 30 % since the start of the century (Kern, 1999, p. 3). In order to counteract the threatening climate change, the output of anthropogenic greenhouse gases must be reduced as quickly and as thoroughly as possible. However, in addition to the required reduction in CO_2, dependence on fossil fuels such as oil, natural gas and coal must also be reduced. The fossil fuels mentioned here are finite resources which will eventually run out.

In recent years, the term "sustainability" has taken on ever greater importance. This term covers ecological, economic and social aspects. "One characteristic of a sustainable development is that it corresponds to the needs of the current generation without endangering the ability of future generations to satisfy their own needs and choose their lifestyle" (Dürrschmidt, 1999, p. 6). Important elements of sustainability are stated as economic growth to fight poverty, the reduction in population growth and sustainable use of the environment to safeguard the natural basics of life for future generations (Pierrard, 2002, p. 10). As well as the reduction of anthropogenic CO_2 emissions mentioned above and a reduction in dependence on fossil fuels, global ecological development is gaining in importance. A child born in Germany will use 20 times more natural resources during its lifetime than children born in most developing countries (Dürrschmidt, 1999, p. 6). As the standard of living achieved here is a model for poorer countries, development in poorer countries is indirectly encouraged to proceed in the same direction, thereby further increasing global ecological problems.

For the transport sector, the limited extent of fossil resources and the aim of reducing CO_2 necessitates a search for an alternative future fuel which can be manufactured from primary energy sources other than oil, natural gas and coal. In order to reduce anthropogenic CO_2 emissions, the production of the alternative fuel and its use in vehicles must be linked to the lowest possible CO_2 emissions. An alternative fuel with a good long-term prognosis is hydrogen, which has considerable potential for regenerative production. This will allow CO_2 emissions and supply risks in mobile and stationary contexts to be significantly reduced in the long term.

As a consequence of the high investment potential of hydrogen technologies and the application in transport, new areas of growth for the economy will be created and therefore a contribution made to the safeguarding or strengthening of the economy in the region concerned.

1.1. Task

Since the discussion on vehicles for hydrogen as an alternative fuel started, the focus has been on fundamental technical aspects. However, in recent years, important technological developments in vehicle drivelines with hydrogen combustion engines and with electric motors and fuel cells have been achieved (Chapter 2.1.4.4), so that the technical production maturity of vehicles for hydrogen as an alternative fuel has come within reach. In parallel with these technical developments, attempts have also begun recently to study the economic use and the costs of fuel substitution using hydrogen as an alternative fuel. As hydrogen is a secondary energy source[1], hydrogen production also becomes significant. Research carried out to date has mostly been limited to a static observation of the problem of fuel substitution (e.g. a hydrogen production plant working at full capacity from the start).

This paper takes up the question at precisely this point and examines the market situation created by the introduction of hydrogen as an alternative fuel. One thesis in the theory of innovation states that innovations with a preventive function (such as the preservation of fossil resources or the long-term reduction of CO_2 emissions; Own Observations, 2002), do not penetrate the market very quickly, because their effect (additional uses) develops only at an unknown future time (Leder, 1990, p. 14). By taking this thesis into account, an achievable, valid development of vehicle populations for hydrogen as an alternative fuel (inventory scenario) has worked out.

Building on the inventory scenario, the aim of this paper is to derive the development of a hydrogen infrastructure for supplying vehicles with hydrogen over a determined period of time. It concerns a long-term planning of a possible development of a hydrogen infrastructure under market economic conditions on the basis of concrete scenarios and not a strategic planning of the build-up of a hydrogen infrastructure. In the observations contained in this paper, the input side, e.g. from the CO_2 emissions trade, will not be considered. Taking into consider the output side, a possible development of a hydrogen infrastructure has been drawn up.

Directly related to the build-up of a hydrogen gas station infrastructure is determination of the development of hydrogen costs over the period of time in question. Hydrogen costs are fundamentally made up of hydrogen production, distribution and gas station costs, so that a close examination can be made of these components in the development path. Because of consideration of the time period, other effects are recorded such as the partial utilization of plant capacity, economies of scale and the learning effect (cost degression with increasing unit numbers, e.g. as a consequence of increasing experience in the installation of equipment).

An important motivational reason for the introduction of hydrogen as an alternative fuel is the increasing CO_2 component in the atmosphere, which is why particular attention is paid to the CO_2 balance along the entire process chain, from production to installation in the vehicle. As some of the processes in hydrogen production require a considerable amount of electricity and the generation of electricity produces CO_2 emissions, there is detailed observation of the electricity production, which can be achieved using a conventional power station, nuclear energy or from regenerative primary energy sources.

The empirical bases of this paper refer to the Federal Republic of Germany. Closer observation was undertaken in particular with regard to the cities of Munich and Berlin. It should be noted that the calculation and results may partly also refer to other countries.

[1] Second stage of the energy flow chain from primary energy to usable energy. It is the energy remaining after the conversion of the primary energy, which was converted into more easily storable, usable and/or transportable forms of energy.

1.2. Method

The starting point for calculations concerning the development of a gas station infrastructure is a satisfactorily precise determination of a realizable applicable scenario of the future development of vehicles for the alternative fuel (Figure 2). To this end, vehicle categories and a reference vehicle for each category are defined in Chapter 2.2. Consideration of the possible development of the inventories also finds the expected increase of traffic capacity of both passenger cars and trucks. On the basis of the scenario of the development of the vehicle population, the aspect of time is included in the calculations. The result is hydrogen that is required over the years, which must be manufactured and sold via a corresponding gas station network. The time line taken into account runs from 2006 to 2035. In 2006, in this scenario, vehicles for hydrogen as an alternative fuel will be sold for the first time.

As there is still no agreement within industry on the planned form of hydrogen to be stored in the vehicle, an examination is made of the currently preferred forms: fluid and gaseous. The fluid form requires special cryogenic units, designed for temperatures of about -250 °C. On the other hand, the gaseous version requires the highest possible compression of the hydrogen (currently 700 bar in the pilot stage), in order to be able to store a sufficient quantity in the vehicle without affecting convenience to any great extent.

The hydrogen can be produced either centrally in large power stations or directly at the gas station (on-site). In the hydrogen production processes and in the gas station concepts, only the processes that according to current investigations have the largest realization potential are discussed in more detail. Reference is also made to the relevant literature. Chapter 4 contains a comparison of these concepts based on specific hydrogen costs (depending on annual gas station sales) and CO_2 emissions (depending on the production of electricity). However, in this examination it is assumed that the hydrogen gas stations will be operated at full capacity. With this viewpoint the gas station design can be determined which, after almost complete fuel substitution, achieves the lowest costs and CO_2 emissions. In the first few years, fleet vehicles such as public-service buses in particular can be powered by hydrogen. These operate with a prederemined area, thus allowing their fuel supply to be guaranteed at their depots. A closer observation of the supply of the vehicles at their depots follows.

In an examination of the gas station infrastructure in Chapter 5, the current German gas station network is first recorded. The threshold value is determined from which comprehensive coverage can be spoken of, i.e. the number of gas stations selling the alternative fuel that will make it possible to drive through Germany without having to resort to conventional fuel. In connection with this, a possible development of gas station construction in the city of Munich is demonstrated in several possible scenarios for making hydrogen available according to the chosen development of the vehicle population in Chapter 2.3. As the modified gas stations will not achieve full capacity in the first few years, this will result in higher specific hydrogen costs, which are quantified. The experience gained from this will be used to create scenarios for the development of the number of gas stations in German cities. Finally, several variants of a possible development in Germany, separated according to development in and outside the cities, will be discussed. Comparison of the individual scenarios takes place primarily on the basis of the development of the gas station population, specific gas station costs and the total costs arising for the creation of a gas station infrastructure (in the comparison, hydrogen production and distribution components are not taken into account).

As the cost structure of the process chain from well to vehicle fuel tank is now known, a detailed overall examination is carried out in Chapter 6. In order to be able to make available the necessary amount of hydrogen, which according to Chapter 2.3 increases constantly with time, there is also an examination of the development path using either an individual hydrogen production process or a combination of processes, in order to be able to satisfy the requirement. For example, 100 % of the total annual hydrogen requirement can be produced by natural gas steam reforming, although this only results in a slight reduction of the current annual CO_2 emissions from road traffic[2]. Alternatively, 50 % of the required quantity of hydrogen can be produced by natural gas steam reforming and 50 % by water electrolysis, thus allowing annual CO_2 emissions in road traffic to be considerably reduced. Hydrogen production by natural gas steam reforming, water electrolysis and biomass gasification are considered. In addition, the process chain is considered with and without CO_2 sequestration[3].

For a high reduction in annual CO_2 emissions in road traffic, the development path of exclusive hydrogen production by electrolysis using regeneratively produced electricity or electricity from a nuclear power station needs to be achieved. However, this approach incurs high overall costs. The opposite is true with the development path of hydrogen production solely by natural gas steam reforming. Only marginal reductions in CO_2 emissions are achieved, but at lower total costs compared to the development path of 100 % production by electrolysis.

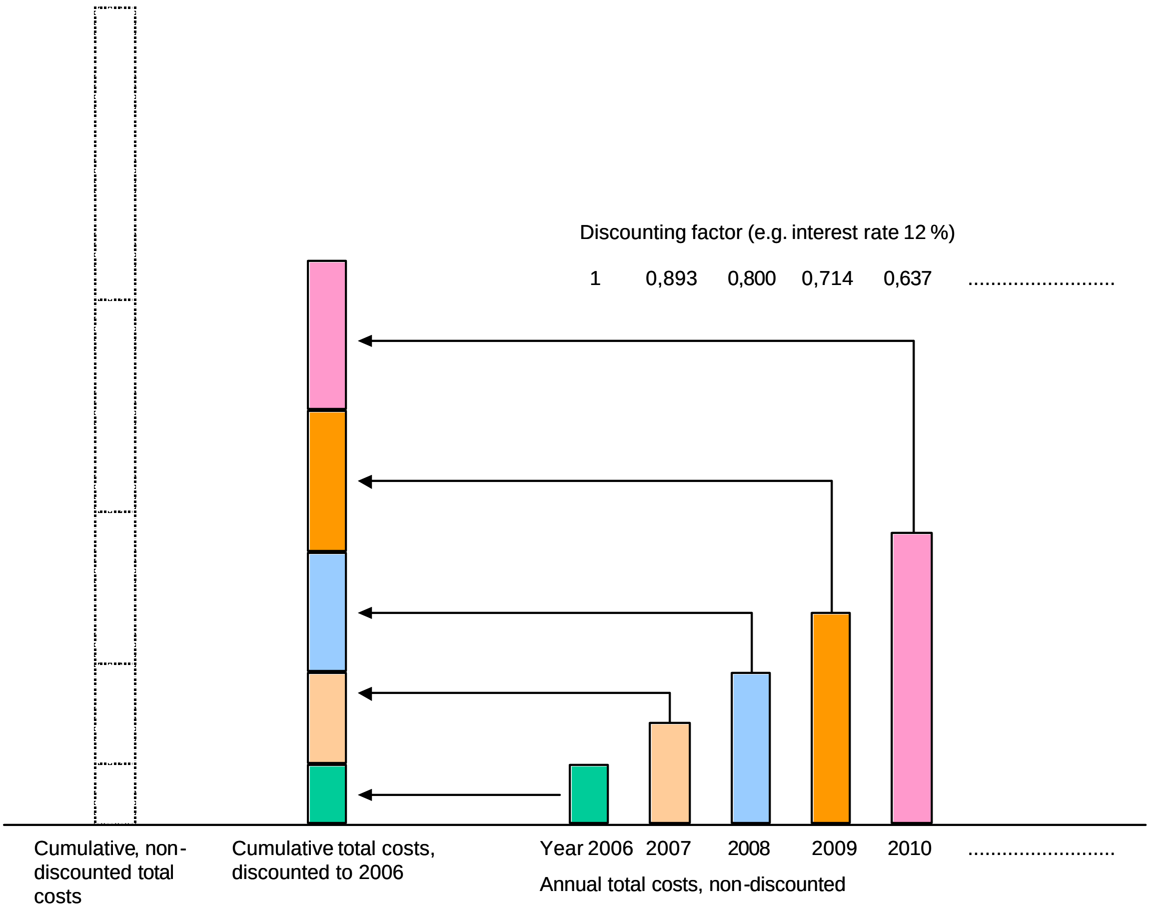
To find an optimum balance of total costs and emissions, an examination is undertaken of the total costs, discounted for 2006, that arise in the realization of a hydrogen production development path, depending on the achievable reduction in annual CO_2 emissions from road traffic. By varying the composition of the development path from sole hydrogen production by natural gas steam reforming through the combination of different production processes to the production of hydrogen solely by electrolysis, curves are obtained that indicate the connection between the discounted total costs and the reduction in CO_2 emissions, the so-called ‘total cost versus emission reduction curves’.

The total costs include the cumulative, annual annuities of investments (hydrogen production plant, distribution, gas station infrastructure) throughout the depreciation period, and the operating and maintenance costs. As the build-up of an infrastructure for supplying vehicles with hydrogen requires a planning timeframe covering several decades (in this paper, from 2006 to 2035), the total costs of a development path over this timeframe are based on 2006 (“Current value” of the costs) (Figure 1).

[2] In the case of hydrogen production by natural gas steam reforming, a slight reduction in the annual CO_2 emissions in road traffic is only achieved if the electricity required for hydrogen liquefaction is produced from regenerative primary energies or from nuclear power.

[3] The CO_2 created by fossil electricity or hydrogen production is collected and stored in suitable sites such as former natural gas or oil fields. This ensure that anthropogenic emissions are not realeased into the atmosphere.

Figure 1: Determining cumulative total costs, discounted to 2006, with a planning timeframe of 2006 to 2035



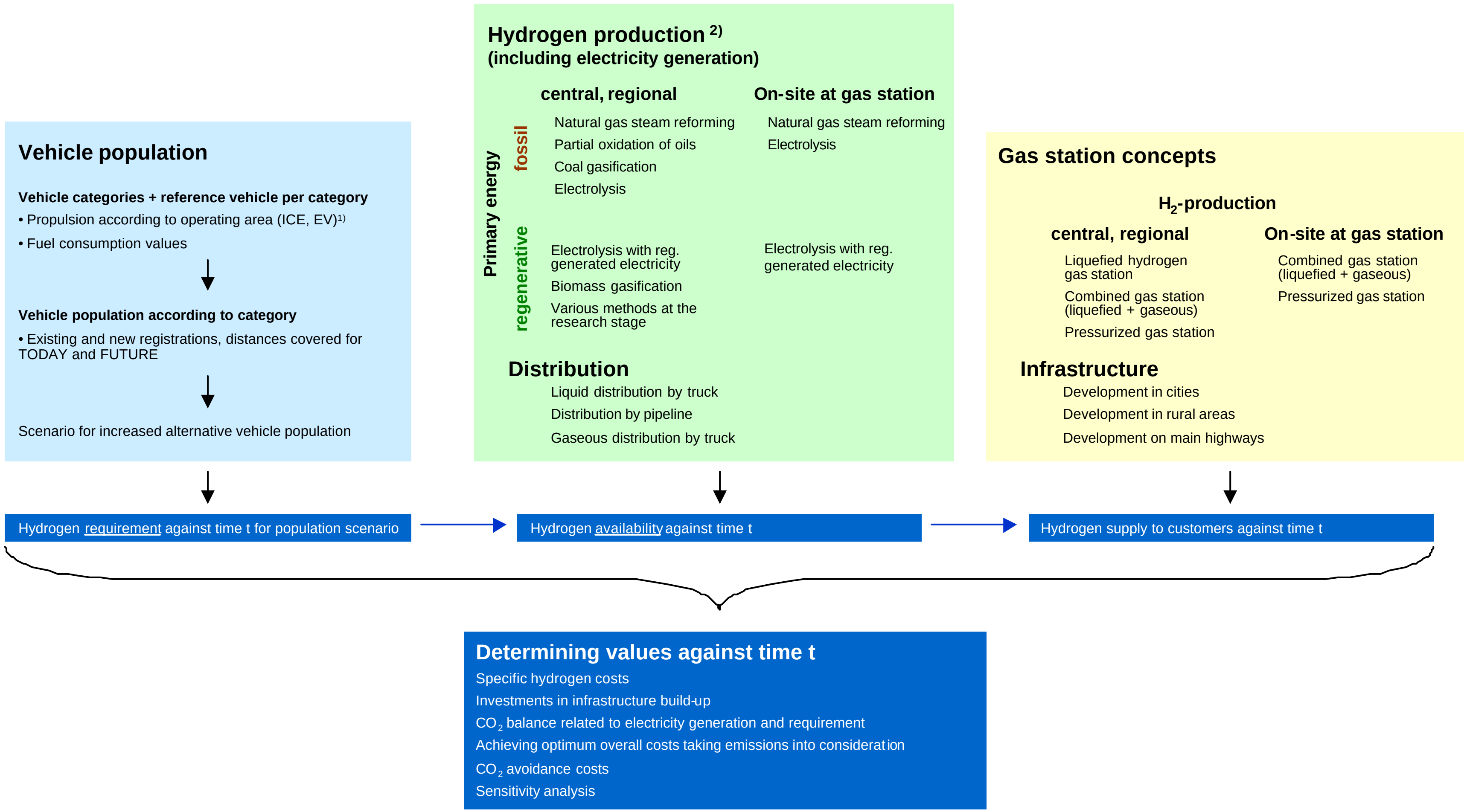
Source: Own presentation, 2003

As the 'total costs versus emission reduction curves' do not show a constant increase, the optimal situation in terms of total costs and emissions is determined by the criterion of the lowest incremental costs in the discounted total costs. Incremental costs are the additional costs of the discounted total costs of a development path compared to its previous development path (starting with the path of exclusive hydrogen production from natural gas), which are incurred in order to achieve higher CO_2 reductions. On the basis of the criterion of the lowest incremental costs, the development is shown to be the optimum for hydrogen production, up to a composition (increase in the electrolysis share in the development path starting with the path of sole hydrogen production from natural gas) where the result is a favorable "acquisition" of a further reduction in CO_2 emissions. From the lowest point on the incremental cost curve, a further reduction in CO_2 emissions can only be achieved with correspondingly higher total costs. As hydrogen production is taken into consideration with and without sequestration, and therefore using two different technologies, this results in two incremental cost curves.

By basing interest charges on future costs (expenses) on 2006, CO_2 avoidance to be achieved at a later point in time is obtained by calculation as a current preference. As already stated, the income side, for example from emissions trading, is not considered in this dissertation. If both expenses and incomes were to be considered over a fixed period of time, the time at which CO_2 avoidance occurs would have great significance. For example, a reduction in CO_2 emissions today could be realized and income could be derived from emissions trading, or in the case of future CO_2 avoidance, the costs incurred are compared with expected incomes from emissions trading and interest calculated to the current date. Taking into account the uncertainties of any sudden steps forward in the technology of the production processes and possible developments in important input factors (including conventional fuel price, economic growth and hydrogen requirements), a strategic procedural instruction can be worked out (Kaslow, 1994, p. 60 f.; Luehrman, 1998, p. 89 f.). The evaluation of an option takes place by the comparison of future expected expenses and incomes and the charging of interest at the current rate ("Present value"). However, the focus in this work lies in the assessment and analysis of concrete scenarios for the possible build-up of a hydrogen infrastructure in the event of a considered development of the hydrogen requirement as stated, so that only the expense side is analysed under market economic conditions.

As part of a sensitivity analysis (Chapter 7), changes in the results are recorded if there are changes in important input variables. Consideration is given to the influences caused by changes in natural gas and electricity costs, the interest rate and possible more rapid market penetration of vehicles than assumed in the scenario concerning the development of the vehicle population.

Figure 2: Tasks and concept of the research method



1) ICE = internal combustion engine, EV = electric vehicle
2) Natural gas steam reforming = catalytic conversion of light hydrocarbons using steam.
Partial oxidation of oils = exothermic conversion of heavy hydrocarbons with oxygen.
Carbon gasification = exothermic conversion of a carbon/water suspension with oxygen. Electrolysis = the breakdown ofwater.
Biomass gasification – gasification of the biomass using steam.
Source: Own presentation, 2002.

2. Bases and vehicle market introduction

2.1. Bases

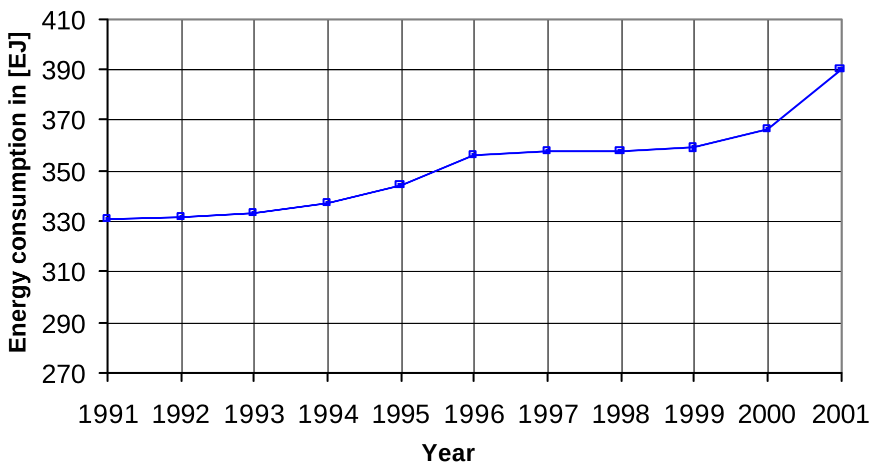
2.1.1. Primary energy consumption

There are currently some 6.1 billion people living on this planet (DSW[4], www.dsw-online.de, 20.08.2001; Globus (b), 2001). Three people are born every second, more than 250,000 each day (Gruden, 1999, p. 2). However, a study by Austrian researchers forecasts that the world population will not continue to grow forever, but will reach its peak in around 70 years' time (Lutz, www.nature.com, 21.08.2001). According to current estimates, that will be over 9 billion people. After that, the population is expected to fall again. By 2100, the Earth's population will stand at just 8.4 billion people.

The large and increasing number of people in the world along with their increasing energy needs and consumption present a major challenge for humanity and the environment. Currently, about 15 % of the people in highly developed countries consume about 80 % of the world's energy (Gruden, 1999, p. 3).

Figure 3 shows the constantly increasing worldwide consumption of primary energy plotted against time. The increase in energy consumption is being caused primarily by the Asian countries such as Bangladesh, India, Indonesia, Korea and Taiwan, as well as Russia and North and South America (BP, 2002, p. 37).

Figure 3: Worldwide consumption of primary energy from 1991 to 2001

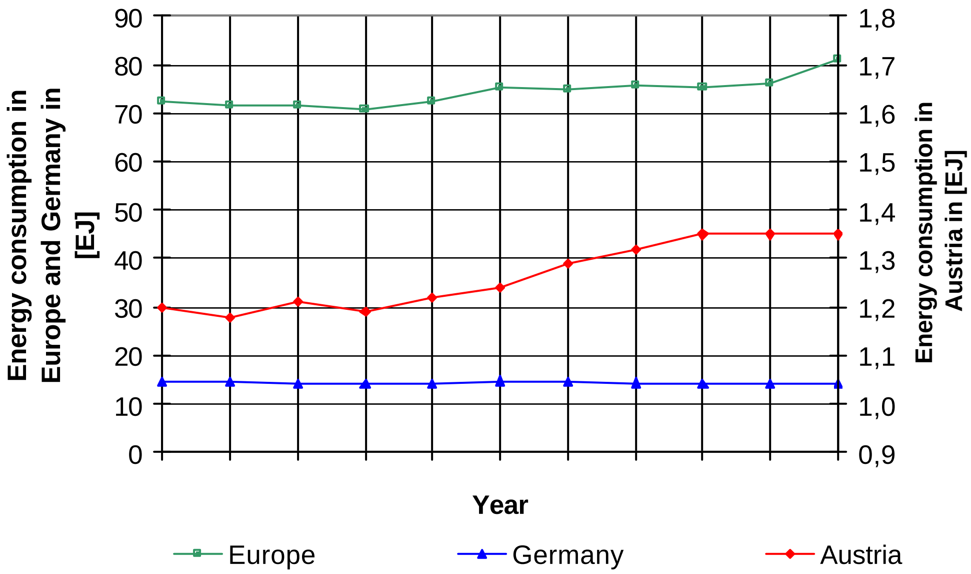


Conversion factor of 42.733 kJ/t COU[5], EJ = Exajoule (=10^{18} Joule)
Source: BP, 2002, p. 37

Primary energy consumption fell in Europe between 1991 and 1994, although worldwide primary energy consumption grew during this period (Figure 4). However, from 1996, primary energy consumption in Europe grew in accordance with worldwide primary energy consumption. In 2001, it amounted to some 81 EJ. Compared with the increase in worldwide and European primary energy consumption, since 1996, primary energy consumption in Germany has fallen continuously. In 2001, it amounted to some 14.3 EJ in Germany. In Austria, primary energy consumption varied in accordance with worldwide primary energy consumption until 1996. Until 2000, consumption grew more strongly compared with worldwide primary energy consumption. In 2001, it amounted to 1.35 EJ.

[4] DSW = German Foundation for World Population
[5] COU= Crude Oil Unit

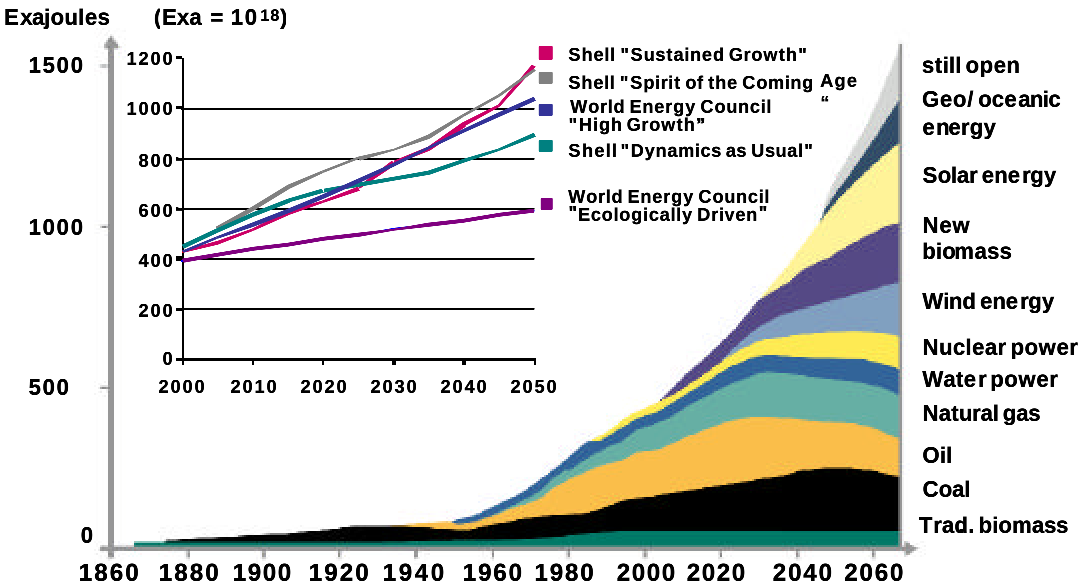
Figure 4: Primary energy consumption in Europe, Germany and Austria from 1991 to 2001



Conversion factor of 42.733 kJ/t COU, EJ = Exajoule (=10^{18} Joule)
Source: BP, 2002, p. 37

According to current estimates, worldwide primary energy consumption will increase further (Figure 5). In Shell's "Sustained Growth" scenario presented here, a tripling of world energy consumption is assumed over the next 50 years (Shell, www.shell.com, 18.11.2002). In the scenarios in the upper-left section of the chart, possible future developments of the primary energy requirement are shown, depending on criteria such as economic growth. Common to all the forecasts is a severe increase in primary energy consumption.

Figure 5: World energy consumption – "Sustained Growth" scenario of sustained development from 1860 to 2060



Source: Shell(c), 2001, p. 30-59; Grübler, 1996, p. 304-312

2.1.2.Fossil energy sources

2.1.2.1. Emissions

The most important sources of energy are fossil energy sources such as coal, natural gas and oil. Equation 1 is a qualitative representation of the combustion products (exhaust emissions) that arise during the burning of these fossil fuels.

Equation 1:

$$\underbrace{C_nH_m}_{\substack{\text{Fossil energy sources}\\ \text{- Gasoline (petrol)}\\ \text{- Diesel}\\ \text{- Natural gas}\\ \text{- ....}}} + \underbrace{N_2 + O_2}_{\text{Combustion with air}} \Rightarrow \underbrace{CO_2}_{\text{Carbon dioxide}} + \underbrace{\begin{matrix} N_2 \\ H_2O \\ O_2 \end{matrix}}_{\substack{\text{Equivalent to}\\ \text{atmospheric}\\ \text{components}}} + \underbrace{\begin{matrix} CO \\ NO_x \\ C_nH_m \\ \text{Particles/soot (PM)} \end{matrix}}_{\substack{\text{Limited exhaust emissions}\\ \text{(toxic)}}}$$

Various guidelines in the European Union essentially divide exhaust emissions into limited and unlimited emissions. An example of this is the first directive for the limiting of private car emissions in Europe, which was adopted by the Economic Commission for Europe (ECE) in 1970 (directive 70/220 EEC). Since then, the directive has been amended 6 times (Gruden, 1999, p. 27).

Limited emissions from anthropogenic sources are governed by legal regulations. They are toxic, and in high enough concentrations have a harmful effect on humans, animals and/or plants. In the past, the automobile industry focussed on the reduction of hydrocarbons (HC), carbon monoxide (CO), particle masses (PM) and oxides of nitrogen (NO_x) as limited emissions. The levels from current vehicle engines and the further reduction when future regulations come into effect will increasingly place the focus of attention on the reduction of climate-changing gases (Schaller, 2000, p. 8).

The quantities of **unlimited emissions** from anthropogenic sources are not limited by legal regulations. This primarily refers to carbon dioxide (CO_2), benzene, methane and other photochemically active or greenhouse influencing substances (Gruden, 1999, p. 15).

2.1.2.2. Greenhouse effect and greenhouse gases

An atmospheric oxygen content of 21 %, three-quarters of the surface covered in water, a difference of 100 °C between the maximum and minimum temperatures of the Earth's surface (-50 to +50 °C) and an average temperature of +15 °C have made life possible on this planet (Gruden, 1999, p. 1). This temperature balance comes about because of the **greenhouse effect**. The natural greenhouse effect is the process whereby various gases (greenhouse gases) help to retain part of the sun's energy as warmth in the lower layer of the atmosphere and prevent it from being reflected back into space. Consequently, the average annual global temperature between incoming and reflected radiation is approximately +15 °C, instead of -18 °C. This indicates that the greenhouse gases cause an average temperature increase of +33 °C.

Human activities (e.g. the burning of fossil energy sources, the release of chemical products) releases additional greenhouse gases from fossil sources, which obstruct the reflection of heat over and above the naturally balanced condition. This means in particular that quantities of CO_2 are released in the atmosphere that can no longer be absorbed by the natural carbon circulation process. These (anthropogenic) emissions of greenhouse gases caused by humans, such as carbon dioxide (CO_2) or methane (CH_4), strengthen the greenhouse effect and in the opinion of leading experts result in an additional warming of the Earth's surface. The most important greenhouse gases are shown in Table 1. The largest contribution to the natural greenhouse effect with almost +21 °C (of +33 °C), is water vapor (H_2O). The contribution of carbon dioxide (CO_2) is estimated at about +7 °C.

Table 1: Characteristics of greenhouse trace gases in the atmosphere

Greenhouse gas	Temperature increase in [°C] [1)]	Lifespan in [years]	GWP[2)]	Annual growth in [%]
Water vapor (H_2O)	20.6	---	---	---
Carbon dioxide (CO_2)	7.2	5 – 200	1	0.4 – 1.7
Low-level ozone (O_3)	2.4 – 2.7	0.1 – 0.5	1,800 – 2,000	0.5 – 2.0
Dioxides of nitrogen (N_2O)	1.4	100 – 170	150 – 290	0.2 – 0.4
Methane (CH_4)	0.8	9 – 90	20 – 63	0.75 – 1.7
FCKW (CHF_3, CF_4)	---	16 – 50,000	3,500 – 17,000	3.0 – 7.0
Sulphur hexafluoride (SF_6)	---	3,200	23,900	---

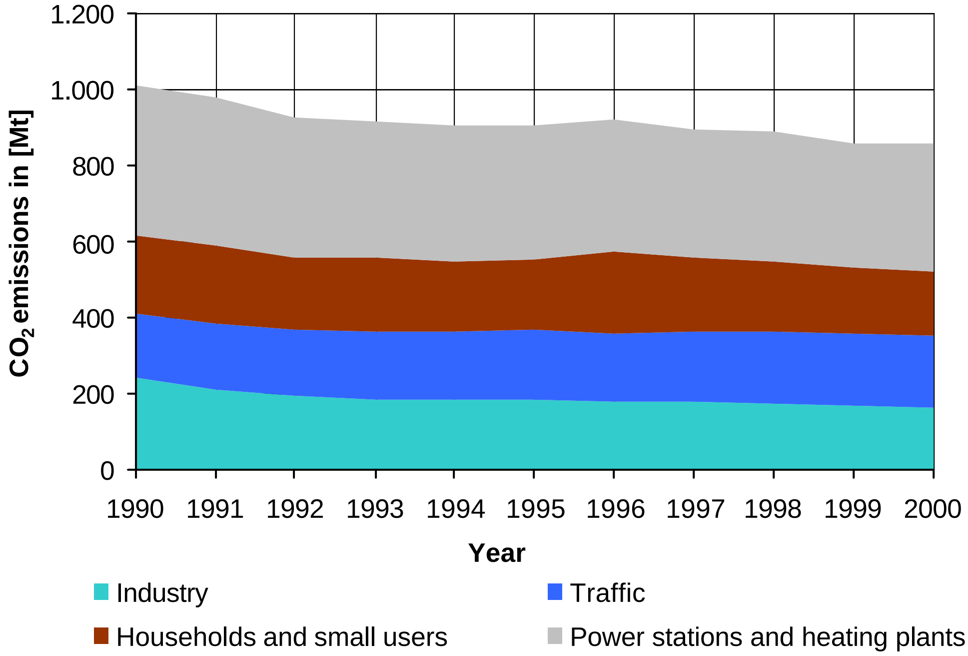
[1)] by the natural greenhouse effect
[2)] The Global Warming Potential value (GWP) is a measure of the greenhouse effectiveness of a gas. The value for CO_2 is 1. In determining the GWP value of a gas, its length of presence in the atmosphere and in particular its ability to act as heat insulation are primarily taken into account.
Source: Gruden, 1999, p. 15; Globus(a), 2001

All combustion processes produce water (H_2O), which is turned into **water vapor** by the released heat. Although water vapor is one of the strongest natural greenhouse gases, science has still not taken into account water vapor from anthropogenic sources. Only since 1980 have American researchers continuously monitored water vapor in the stratosphere using satellites. At these altitudes, 12 to 16 km high, only traces of the gas are found. In the last 45 years, the worldwide concentration of water vapor in the stratosphere has increased by 75 % (www.fz-juelich.de[6], 20.08.2001). It is not known exactly how the concentration will develop in the future. The more the Earth warms, the more water evaporates and again increases the greenhouse effect in the upper layers of the atmosphere - a positive feedback.

In 1997, the total worldwide natural and anthropogenic emissions of **carbon dioxide (CO_2)** amounted to 798 Gt, of which human activities accounted for a share of only about 3 to 4% (VDA (a), 2000, p. 136). The sources of natural global CO_2 emissions are, for example, oceans, vegetation and humus layers on the land masses. Primary anthropogenic CO_2 emitters are power stations, domestic fuel, small users, industry and the combustion of biomass and fuels in traffic (Figure 6). It is apparent that at 38 %, the largest share of CO_2 in Germany is caused by power stations and district heating plants. The entire transport sector in Germany emitted around 190 Mt of CO_2, which corresponds to a share of 22 %. Households and small users account for the considerable share of 20 %.

[6] Jülich Research Centre

Figure 6: CO_2 emissions in Germany by user category from 1990 to 2000



Source: UBA[7], 2001

It is apparent from Figure 7 that a continuous increase in German road transport emissions of CO_2 can probably be expected until 2006, and a reduction as a consequence of the **car manufacturers' voluntary commitment** will only come about in the years that follow.

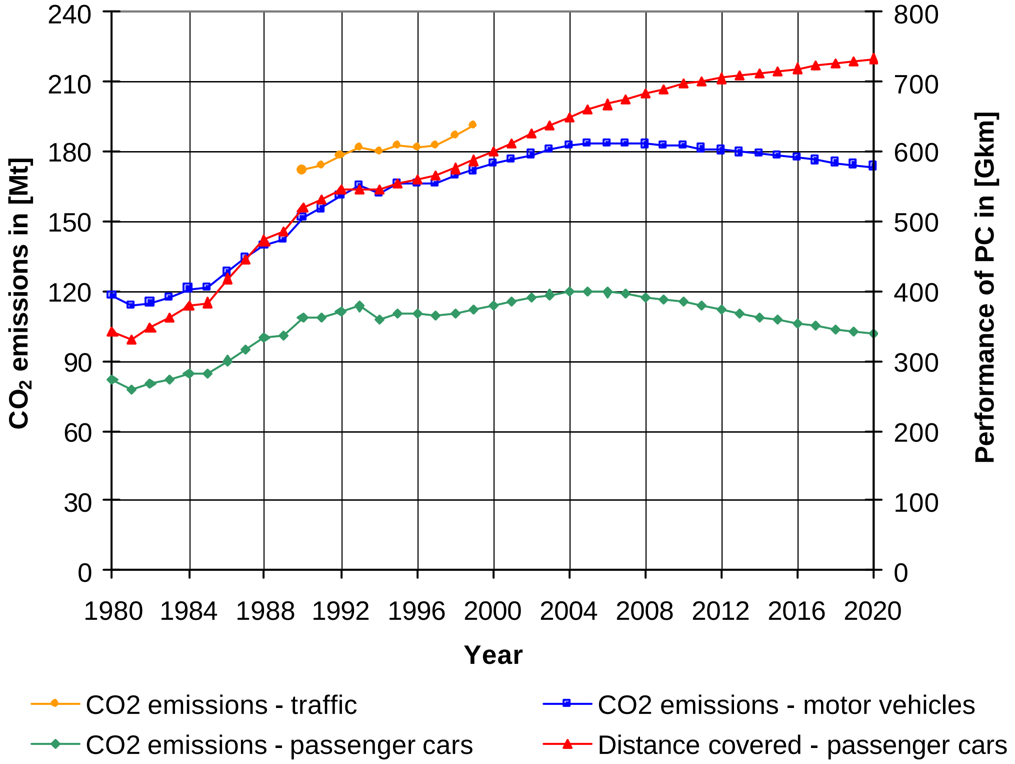
This commitment refers to the following undertakings made by the automobile industry:

- The German automobile industry has promised the Federal German Government to reduce the fuel consumption of new vehicles (passenger cars[8] including station wagons) by 2005 to a level that is 25 % lower than in 1999, in order to reduce emissions of CO_2 correspondingly (www.vda.de[9], 29.08.2001).
- At European level, the European Automobile Manufacturers' Association (ACEA[10]) has promised the European Commission to reduce CO_2 emissions for the average, newly-registered passenger car to 140 g of CO_2 per kilometer from 2008. This corresponds to a reduction in consumption of approximate 2.5 % per year (TES[11], 2000, p. 9). A further reduction beyond this time is expected.

In spite of the forecast that the distances covered by passenger cars in Germany will continue to rise, a reduction in CO_2 emissions can still be achieved. CO_2 emissions caused by passenger cars should in future have a share of about 60 % of total CO_2 emissions for motor vehicles (Figure 7).

[7] UBA = Federal Environment Agency.
[8] Passenger cars (PC) including combination motor vehicles are motor vehicles (two or more tracks), which according to their construction and orientation are mainly used for transporting people, their luggage and/or goods and have a maximum of 9 seats (including the driver) (VDA, 1999, p. 6).
[9] VDA = German Association of the Automotive Industry
[10] ACEA = Association des Constructeurs Européennes d'Automobiles (European Automobile Manufacturers' Association)
[11] VES = Transport Energy Strategy (Chapter 2.1.4.2)

Figure 7: CO_2 emissions from motor vehicles and passenger cars, the distances covered by passenger cars in Germany from 1980 to 2000 and forecasts of future developments in CO_2 emissions and distances covered up to 2020.



Source: TREMOD[12], 2001

The twentieth century was the warmest in the last thousand years. Nearly all experts assume that this warming process will leading to a warming of the climate with the following effects (Houghton, 2001, p. 2 ff.):

- Temperature rise of 0.6 °C in the last 100 years.
- A retreat of worldwide snow areas by 10 %
- An increase in sea levels of between 10 and 20 cm in the last 100 years.

Scientific findings state that with 95 % probability of the stated climate change had an anthropogenic cause, and that with a likelihood of 60 to 90 % the temperature increase arose due to the increase of greenhouse gases, in particular CO_2, in the atmosphere.

The forecast until 2100 (Houghton, 2001, p. 12, 13, 16):

- Increase in the CO_2 concentration from the current 365 ppm to between 540 and 970 ppm
- Temperature increase of 1.4 to 5.8 °C
- Rise in sea levels of 90 to 880 cm due to thermal expansion and melting of the ice caps

Since the start of the century, the use of fossil energy sources by people has increased the concentration of carbon dioxide by approximately 30 % (pre-industrial: 280 ppm, today: 365 ppm) (Kern, 1999, p. 3). If this interpretation is correct, it means that the output of anthropogenic greenhouse gases must be reduced as quickly and as thoroughly as possible.

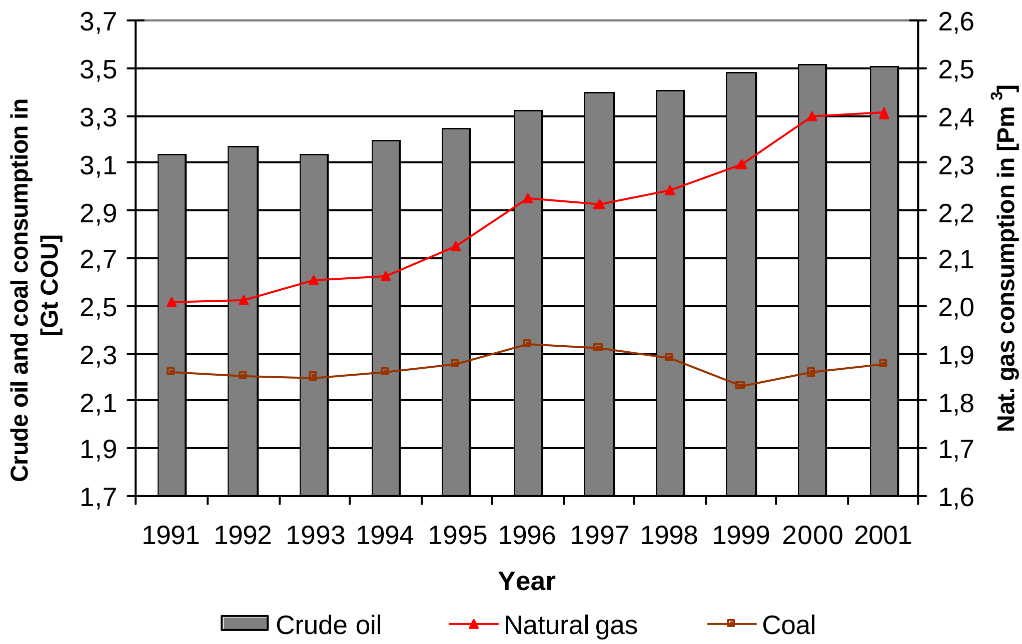
[12] TREMOD = Transport Emission Estimation Model: Data and calculation model, created by the Institute for Energy and Environmental Research (ifeu) in Heidelberg, Germany, which records all people-moving traffic and goods traffic operated in Germany as well as other vehicle traffic from the base year of 1980 annually up to 2010 or 2020. A central task of the model is the projection of traffic and emissions data under certain framework conditions (Schmidt, 1998, p. 117).

2.1.2.3. Availability of fossil resources

However, as well as the required reduction in CO_2, dependence on fossil fuels such as oil, natural gas and coal, must also be reduced. The fossil energy sources mentioned here are finite resources, which will eventually run out if they continue to be consumed. Furthermore, in future it will become geologically more expensive to make fossil energy sources available, which will most probably result in higher costs for exploration and extraction. These higher supply costs will ultimately have to be paid for by the consumer. As a consequence of the stated climate change, the continued use of fossil energy sources will also become more politically charged, so that the use of renewable energy sources will in future become more prominent.

Figure 8 shows the constantly increasing worldwide consumption of the fossil energy sources: oil, natural gas and coal. The guaranteed reserves of **oil** amount to 143 Gt. COU[13] (BP, 2002, p. 4). Therefore, given a consumption level in 2001 of around 3.5 Gt. COU, the oil will last for another 41 years (www.oeamtc.at[14], 26.09.2001). If the increasing consumption of oil is taken into account, this time is reduced accordingly. The guaranteed reserves of **natural gas** amount to 155.08 Em^3 [15] (BP, 2002, S. 20). With consumption in 2001 of around 2.4 Pm^3 [16], natural gas will last for another 62 years (www.oeamtc.at, 26.09.2001). If the increasing consumption of oil is also taken into account, this time is reduced accordingly. In 2001, the **consumption of coal** amounted to around 2,255.1 Mt COU and with a guaranteed reserve of 984.4 Gt. or 689.1 Gt. COU (BP, 2002, p. 30), coal will last for approximately 305 years.

Figure 8: Worldwide consumption of fossil energy sources: crude oil, natural gas and coal from 1991 to 2001

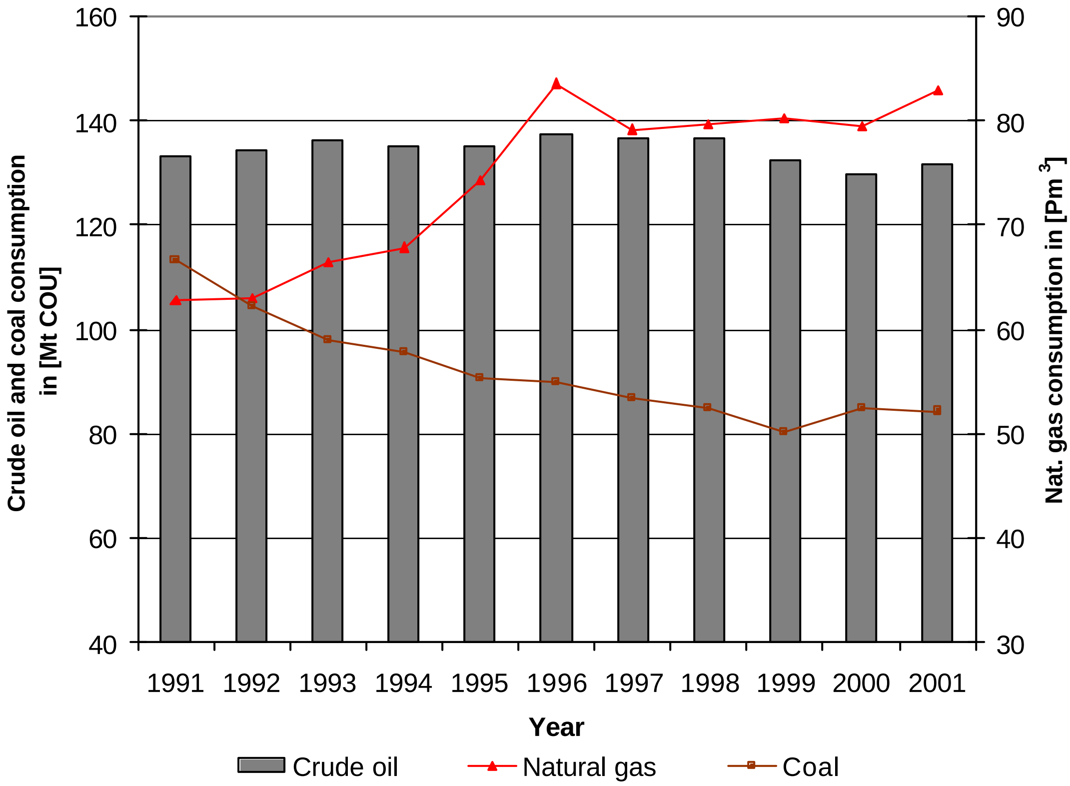


Conversion factor for coal of 0.7 t COU/t HCU[17]
Source: BP, 2002, p. 10, 25, 33

Contrary to the worldwide increase in oil and natural gas consumption, a continuous decrease in oil consumption has been achieved in Germany since 1998 (Figure 9). Natural gas and coal consumption have remained almost constant since 1997 and 1999 respectively.

[13] COU = Crude Oil Unit; 1 Gt. = Gigatonne = 10^9 t
[14] ÖAMTC = Austrian Automobile, Motorcycle and Touring Club
[15] Em^3 = cubic exameter = 10^{18} m^3
[16] Pm^3 = cubic petameter = 10^{15} m^3
[17] HCU = Hard coal unit

Figure 9: Consumption of fossil energy sources - crude oil, natural gas and coal - in Germany from 1991 to 2001



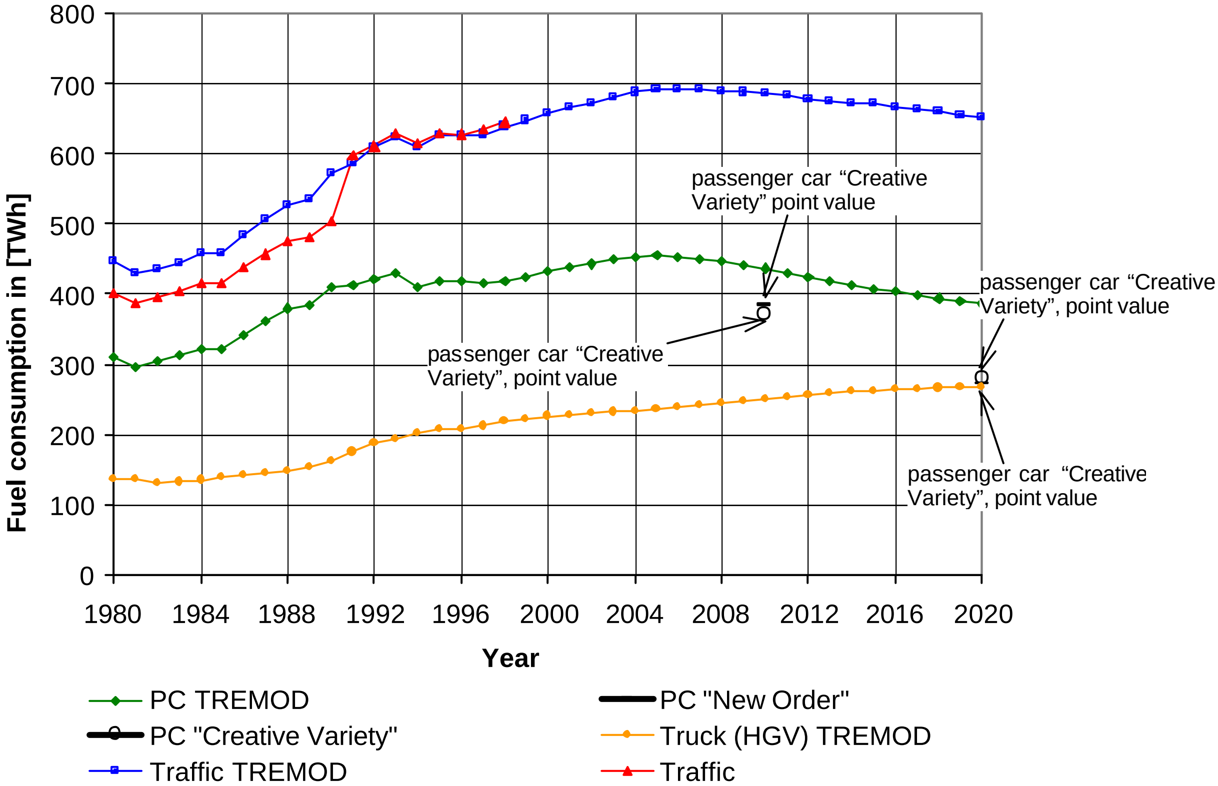
Conversion factor for coal of 0.7 t COU/t HCU
Source: BP, 2002, p. 10, 25, 33

2.1.3. Development of conventional fuel consumption

Figure 10 shows historic fuel consumption values and future consumption forecasts. The differing fuel consumption values for **road traffic** in the Federal Republic of Germany (BRD) up to 1991 are due to the fact that the fuel consumption figures up to 1991 only included the consumption of the old BRD without the former German Democratic Republic (DDR) (BMVBW[18], 1999. p. 276 f.). Following reunification of these countries, the fuel consumption data of the two quoted sources, TREMOD and the Federal Ministry, concur. The forecast for fuel consumption from 2000 to 2020 was made by TREMOD, amongst others.

[18] BMVBW = Federal German Ministry of Transport, Building and Housing

Figure 10: Fuel consumption of trucks and passenger cars in traffic in Germany from 1980 to 1998 and forecasts for future fuel consumption in Germany up to 2020



TREMOD = Transport Emission Estimation Model
Source: TREMOD, 2001; Shell, 1999, p. 4; BMVBW, 1999, p. 276 f.

2.1.3.1. Road passenger traffic

According to TREMOD, from 2005 on the anticipated fuel consumption of passenger cars in Germany will fall by 15 % up to 2020 (“TREMOD road traffic” curve in Figure 10).

Deutsche Shell AG gives two possible scenarios for the development of future fuel consumption values and the population of passenger cars (Shell (a), 1999, p. 4 f.). The “New Order” scenario takes into account transparent future markets and extensive synchronous growth of the world economy. German economic growth is shown as amounting to an average of only 2 % per year. To reduce the emissions caused by motor vehicles requires the long-term development of new technologies in the transport sector. The “Creative Diversity” scenario takes into account a hectic and highly technical world. The state loses influence and an unstable economic climate prevails. In this case, German economic growth amounts to an average of only 1.5 % per year. Both of the Shell scenarios show clearly lower fuel consumption values for the future in the passenger car segment than the TREMOD forecasts.

The TREMOD forecasts are based on the ACEA promise that CO_2 emissions for the average newly registered passenger car will be reduced to 140 g of CO_2 per kilometer from 2008. A continuous increase of the average annual distance covered per passenger car is also assumed (Figure 7). The Shell forecast, on the other hand, assume a reduction in the average annual distance covered per passenger car with reference to 1998. Therefore there will also be a stronger reduction in fuel consumption values.

The Federal German Ministry for Transport, Construction and Housing suggests an increase until 2015 of 16 % in passenger traffic to 873 Pkm (integration scenario) based on 1997 levels (BMVBW (a), 2000, p.61). If it is assumed that this 16 % is divided into an 8 %

increase in annual distance travelled and an 8 % increase in the number of people carried, this gives an identical forecast for the annual distance travelled according to TREMOD.

2.1.3.2. Road haulage traffic

According to TREMOD, fuel consumption for road haulage traffic in Germany will increase from 212 TWh in 1997 to 268 TWh in 2020 ("HGV TREMOD" curve in Figure 10). This corresponds to an increase of 26.4 %.

The Federal Ministry for Transport, Construction and Housing suggests an increase until 2015 of road haulage traffic of 59 % to 374 tkm (integration scenario) based on 1997 levels (BMVBW(a), 2000, p.61). Short-haul road haulage traffic will grow by 25.6 % to 84 Gtkm. The largest percentage growth is shown by cross-border traffic and transit traffic (BMVBW (a), 2000, p. 63). However, these only cause a slight increase in fuel consumption domestically. Consequently, the forecast of an increase in short-haul traffic can be seen as the increase of domestic fuel consumption. The forecasts of the Federal German Ministry thus correspond with the calculations made by TREMOD.

According to the VDA, commercial motor vehicle traffic capacities of will increase by around two thirds to 460 Gtkm (460 x 10^9 tkm) between 1996 and 2015 (VDA(a), 2000, p. 100). However, as the capacities of vehicle fleets will at the same time be better utilized than they are today, thanks to improvements in logistics concepts and information technology, the distance covered by freight vehicles will grow by only around one third during the same period. This corresponds to an annual rate of increase of 1.3 % (VDA (a), 2000, p.100). If the achievable reductions in the fuel consumption of trucks are also taken into account, fuel consumption will increase more slowly in the future than the growth rate of traffic capacity. Consequently, the VDA forecast also matches the forecast values of TREMOD.

2.1.4. Hydrogen – the alternative fuel

2.1.4.1. History

At the UN Conference[19] on Development and the Environment in Rio de Janeiro in 1992, an important step was taken towards a globalized environmental and development policy. The aim of the world summit was to integrate environmental and development matters at national and international levels within the institutional framework of the United Nations system (Kern, 1999, p.5). Five important documents were adopted at the conference: the Rio Declaration, Convention on Climate Change, Convention on Biological Diversity, Forest Principles and Agenda 21. In the form of the action plan concluded there, the 'Agenda 21', long-term procedural instructions are available to all states in every area of development and environmental policy (Kern, 1999, p.5).

At the 3rd Conference of the Parties, COP 3, in Kyoto in December 1997, the first binding aims for climate protection were concluded under international law. Under international law, binding protocols are legally recoverable, and states that do not carry out their obligations may be liable to economic sanctions. Initially, over 160 states agreed to a reduction in emissions of the six most significant greenhouse gases. In order for this to come into effect, at least 55 participants must ratify the agreement, and they must be responsible for at least 55 % of all emissions. Ratification is the confirmation by the relevant national bodies of an international treaty concluded by the government. So far, 96 states have ratified the Kyoto Agreement, but have not achieved the required total emission volume. With the announcement of the ratification by Russia, the climate protection agreement can probably come into effect next year, as the countries that have signed will then represent at least 55 % of the worldwide output of CO_2. The agreement plans a total reduction by the industrialised nations of 5.2 % compared with the levels of 1990, for the period from 2008 to 2012. For the European Union (EU) this means a reduction of 8 %, for the USA 7 %, for Japan and Canada 6 % each, while for Russia there is no change. The EU conference of ministers has

[19] UN = United Nations

committed its member states to varying emission reductions based on Art. 3 and 4 of the Kyoto Agreement. As part of this distribution of the burden in Europe, for the Federal Republic of Germany this means a reduction in emissions of the six most important greenhouse gases by 21 %, and for Austria a reduction of 13 % (Kern, 1999, p. 6). With a reduction in CO_2 emissions in 1999 compared to 1990 a level of 15.5 % and an additional reduction of other climate-relevant gases of 3 percentage points, Germany is only around 3 percentage points away from the obligations entered into under the Kyoto Agreement (VDA(a), 2000, p.137). However, only half of the targeted reductions in greenhouse gases can be traced back to the fortunate circumstance of German reunification. The other half is the result of an active climate protection policy with diverse activities in all areas (www.idw-online.de[20], 18.07.2001).

As already noted, the German automobile industry has promised the Federal German Government to achieve a 25 % reduction in the fuel consumption of new cars (passenger cars including station wagons) by 2005 compared to 1990 levels, in order to correspondingly reduce CO_2 emissions. At the European level, the European Automobile Manufacturers Association has promised the European Commission to reduce the consumption of newly registered passenger cars (Chapter 2.1.2.2).

In the transport sector, the finite resources of fossil energy sources and the agreed CO_2 reductions signify nothing less than the search for an alternative future fuel to replace the current ones. All three areas – economic, ecological and social aspects – must be involved in this in a balanced way.

If the guaranteed availability of fossil energy sources is taken into account (41 years for oil and 62 years for natural gas), we should already be looking for a successor to the conventional fuels, namely gasoline (petrol) and diesel oil, since the build-up of a new infrastructure for the alternative fuel will probably take several decades.

As well as the scarcity of fossil energy resources, the following factors also apply (TES, 2000, p. 8):

- lengthy time spans from the start of vehicle development to the end of the vehicle's life (approx. 25 years), which demand a forward-looking, timely conversion of vehicle development to alternative energy sources
- the necessity, in view of the need for enterprise safety, for spreading a long-term, unavoidable, capital intensive conversion to alternative energy sources over a very long period of time, while protecting company results.

The "ideal fuel" should satisfy important criteria as shown in Appendix 1.

2.1.4.2. Search for an alternative, sustainable fuel

The **Transport Energy Strategy (TES)** can be traced back to an initiative by BMW and DaimlerChrysler which other leading companies have also joined: the energy suppliers ARAL, Shell, RWE, TOTAL and BP, as well as vehicle manufacturers Volkswagen, Opel and MAN. The Federal Government of Germany supports and provides a platform for the work of this group.

"The TES initiative is based on the vision of sustainable energy supply and mobility. It has important goals: making an additional long-term contribution to CO_2 reduction, reducing the dependence of traffic on oil, protecting finite resources and extending the initiative throughout Europe. This aims are based on the vision of a crisis-proof, sustainable energy supply that protects the environment and resources and which in combination with a new generation of highly efficient vehicles should open the way to ecologically defensible and economically supportable mobility (sustainable mobility)" (TES, 2001, p. 4, 8).

[20] idw = Science Information Service

The TES initiative notes possible potential alternative fuels and checks predetermined criteria, such as supply potential, technical feasibility or the potential for CO_2 reduction. The result of the analysis has shown **hydrogen to be the most promising alternative fuel in the long-term**.

The following arguments speak in favor of hydrogen:

- high primary energy potential
- high potential for CO_2 reduction, if obtained from a regenerative source
- suitable for internal combustion engines and electric motors with fuel cells
- high innovation potential and growth areas for the economy.

The driving forces behind the introduction of hydrogen as an alternative fuel in the market are primarily the automobile and mineral oil industries. Consequently, the process is in accordance with the **supply push theory**. In contrast to the **demand pull theory**, in which the recognition of problems leads to increased demand on scientists and researchers, the supply push theory is based on autonomous innovation (Stepan, 1993, p. 3353). The supply push theory process does not refer only to the fuel, in this case hydrogen, but also to a significant extent to innovative vehicle technologies.

Some important characteristics of a supply push theory are (Stepan, 2002; own observations, 2002):

- *Attention* must be drawn to the product
- *Product acceptance* must be worked on as necessary
- *Innovators* are brought into the market, who purchase the innovative product
- *Cost/use relationship* for customers must be at an acceptable level at the start of product innovation
- *Time* of market introduction must be properly selected
- *Product improvements* must be continuously made
- *Management* of the products is difficult to implement
- *Framework conditions* for market introduction and market penetration should be favorable

In the case of hydrogen, the affected industries and the policy should demonstrate solidarity for the product.

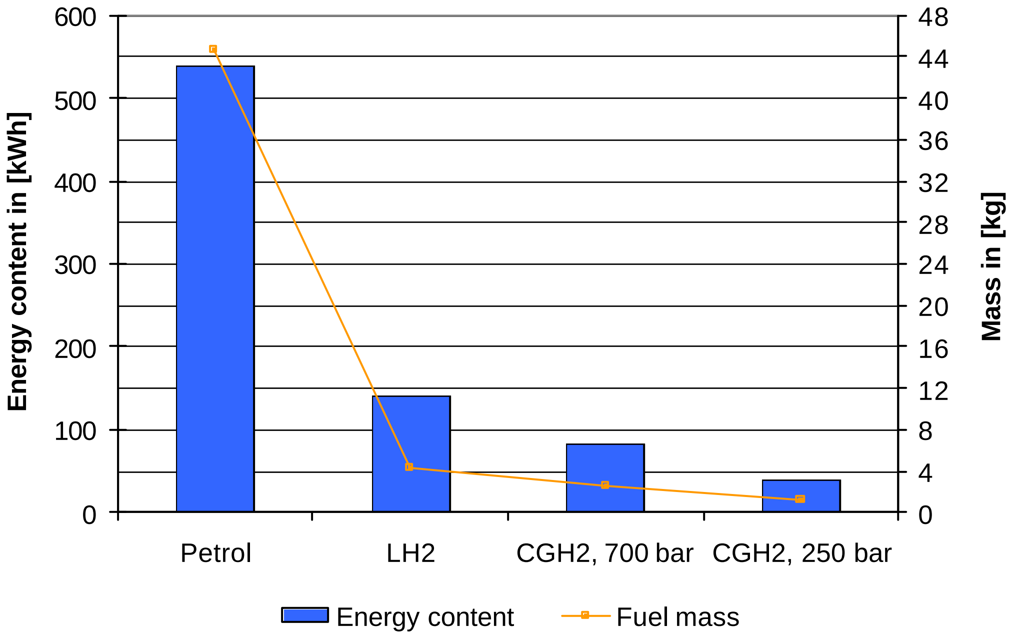
2.1.4.3. Properties of hydrogen

The hydrogen atom is the lightest and simplest atom. It consists of one proton and one electron. It stands at the beginning of the periodic table and has an atomic weight of 1. Physically, hydrogen is a colorless, odorless and tasteless gas. As hydrogen only exists in nature in a compound form, it has to be produced using energy before it can be used for energy purposes.

Hydrogen is an important raw material in the chemical industry. Amongst other things, it is needed for the manufacture of methanol and ammonia, which are indispensable in the production of fertilizers, dyes, textiles and other products. It is also used in the petrochemical industry for the manufacture of low-sulfhur fuels. In 2001, the quantity of hydrogen produced worldwide amounted to around 550 billion Nm^3, of which the largest proportion came from fossil sources (natural gas and oil) (Raman, 2002).

In terms of weight, hydrogen has a high energy content. Its energy density (33.3 kWh/kg) is about three times higher than that of gasoline (petrol). However, in terms of volume, its energy density (3 kWh/Nm^3) is only one third that of gasoline. In order to increase the energy density per unit volume, hydrogen can be stored and transported in **liquid form** (LH_2 – Liquefied Hydrogen) or in a **highly-compressed form** (CGH_2 – Compressed Gaseous Hydrogen). Figure 11 shows a comparison of the energy contents for a volume of 60 liters. For gasoline, the energy content of 60 l is about 538 kWh. For the same volume, LH_2 has an energy content of around 142 kWh, and in gaseous form compressed to 700 bar an energy content of 82 kWh. The masses correspond to the energy content.

Figure 11: Comparison of the energy content of petrol, liquid hydrogen (LH_2) and compressed gaseous hydrogen (CGH_2) for a volume of 60 liters.



Source: Own calculations, 2001

If the storage system is now also taken into account, the highest storage capacity of about 8 % by weight of a storage system (i.e. 8 % of the total weight of the tank system including the hydrogen can be stored as liquid hydrogen) is also achieved by LH_2 storage, followed by CGH_2 storage at 700 bar with a storage capacity of about 4 % by weight. The most important characteristics of LH_2 and CGH_2 are shown in Appendix 1.

The storage of gaseous hydrogen in **metal hydrides** is in the research stage. The advantage of a metal hydride is the low charging pressure, which depending on the material chosen can be between 2.5 and 100 bar. One disadvantage of a metal hydride is its heavy weight. Due to the chemical properties of the hydrides, heat is released when charging the tank. To release the hydrogen, heat must be added. In an optimized system, the current position of research permits a maximum storage capacity of hydrogen of about 1.8 % by weight (www.hydrogen.org, 26.09.2002). As a reference point, a weight of 230 – 420 kg and a volume of 60 - 90 l are given for a 30 Nm^3 store (90 kWh). Due to the low storage capacity of 1.8 % by weight compared with 8 % for LH_2, the metal hydride is not considered further here as a storage possibility in vehicles.

Liquefied hydrogen (LH_2) is a very light liquid with a density of 71 g/l at its boiling point of -253 °C (at a pressure of 1,013 bar). Consequently, LH_2 vaporises very quickly at normal temperatures. Immediately after vaporization, the gaseous hydrogen is still very cold and almost as heavy as air (it spreads out almost horizontally). However, the hydrogen warms up very rapidly, so that its density becomes lower and the gaseous hydrogen flows upwards. The concentration range in which hydrogen at normal temperature and pressure forms an explosive mixture with air is between 4.1 and 72.5 % by volume. Gas mixtures that contain hydrogen cannot be separated under the influence of the force of gravity. The gas mixtures rise like a cloud. Hydrogen burns in air without smoke and with a flame that is hardly visible in daylight.

In current mobile applications, LH_2 is carried in cryogenic tanks (Appendix 1) and CGH_2 in 250 bar pressurized containers inside the vehicle. These containers currently consist of classic steel cylinders with a high empty weight. For storing hydrogen under high pressure (prototype stage for storage at 700 bar), containers of composite fibre construction are being considered. By using carbon fiber instead of steel, the weight of the pressurized container can be reduced by 30 to 40 %. The container preferably consists of a seamless, metallic core container and a complete outer covering made from a high-tensile composite fiber plastic. By storing the gaseous hydrogen at this high pressure, the energy density compared to the stored hydrogen in 250 bar pressure containers can be increased.

An important advantage of storing the hydrogen in a compressed gaseous form is the avoidance of “boil off” (Appendix 1).

2.1.4.4. Vehicle propulsion using hydrogen

Vehicle propulsion using hydrogen is fundamentally based on two concepts:

- vehicles with internal combustion engines
- vehicles with electric motors and fuel cells

2.1.4.5. Internal combustion engines

Hydrogen engines are today the only such engines with exhaust gas that contains no CO_2, CO or unburned hydrocarbons (other than very small quantities from the lubricant). In addition, only very small quantities of oxides of nitrogen (NO_x) are produced (Schindler, 1997, p. 67).

In cryogenic tanks on the vehicle, the liquid hydrogen is transported to the inlet valves by the over-pressure of up to 4.5 bar in the vehicle tank. After leaving the storage tank, the liquid hydrogen vaporises and is transported along pipes to the inlet valves. The hydrogen is injected into the inlet pipe in a gaseous condition. Internal mixture formation, in which the cryogenic hydrogen is injected directly in the combustion chamber, offers interesting potentials, but is technically more difficult and has still not been developed (Schindler, 1997, p. 68).

If the hydrogen is stored in pressurised containers, the transport process to the inlet valves is fundamentally the same. However, as the gaseous hydrogen is compressed in the pressurised container, it does not vaporise once it leaves the pressurised container.

Vehicles with combustion engines for hydrogen as an alternative fuel were built for the first time under near series-production conditions by the automobile manufacturer BMW (Figure 12). A fleet of 15 vehicles was shown to the public for the first time at EXPO 2000 in Berlin.

Important data of these vehicles are (Pehr, 2002, p. 4, 7):

- bivalent[21] 5.4 l twelve-cylinder engines
- Output of 150 kW in hydrogen and gasoline operation
- Maximum torque of 300 Nm at 3,000 rpm
- Top speed of about 220 km/h
- LH_2 storage tank in the vehicle

[21] Bivalent means that the vehicle can run on gasoline (gasoline) as well as hydrogen. The vehicle has a tank for hydrogen and another for gasoline. If there if no more hydrogen in the tank, the control unit in the vehicle automatically switches to gasoline operation.

Figure 12: Vehicle with bivalent engine for hydrogen and gasoline fuels

Source: BMW, 2002

The bivalent drive is a significant advantage in the build-up of a gas station infrastructure. The driver can also use the vehicle in regions where there is an insufficient supply of hydrogen at gas stations.

2.1.4.6. Electric motor with fuel cell

Fuel cells convert the chemically bound energy of hydrogen by a direct, electrochemical path into electrical energy. This electrochemical reaction takes place at two electrodes which are separated from each other by an electrolyte.

The fuel cell can be driven either with pure hydrogen or with a range of hydrogen compounds, such as natural gas, biogas, methanol or gasoline. However, these substances must first be chemically prepared in an upstream reformer. This gives rise to chemical compounds that contain carbon and which in the conversion to carbon dioxide contribute to the anthropogenic greenhouse effect. The hydrogen supply is consequently of great importance here as well.

Fuel cell technologies differ in their operating temperatures, which depending on the cell type can reach values of about 1,000 °C at room temperature. It is evident from Table 2 that for use in motor vehicle drivelines only PEM-FC or PAFC fuel cells can be considered, due to their more reasonable operating temperatures and therefore the ability to start supplying electrical energy almost as soon as they are started (Schindler, 1997, p. 65; George, 2001, p. 5).

Table 2: Characteristics of fuel cell types with regard to operating temperature range, achievable efficiency and stage of development

Cell type	Temperature in [°C]	Efficiency	Stage
Polymer Electrolyte Membrane Fuel Cell (PEM-FC)	60-80	≤ 40 %	Demonstration
Phosphoric Acid Fuel Cell (PAFC)	160-220	≤ 40 %	Commercial
Molten Carbon Fuel Cell (MCFC)	620-660	≤ 65 %	Demonstration
Solid Oxide Fuel Cell (SOFC)	800-1,000	≤ 70 %	Demonstration

Source: George, 2001, p. 5-10

Examples of vehicles with an electric motor and fuel cells are the New Electric Car 4 (NECAR 4) built by DaimlerChrysler[22] (www.daimlerchrysler.com, 19.11.2002) (Figure 13) and the HydroGen3 from General Motors (www.gm.com, 13.01.2003).

[22] The NECAR 4 was presented to the public for the first time in March 1999.

Data for the NECAR 4 are:

- electric motor with a nominal output of 55 kW
- top speed of 145 km/h
- PEM fuel cell type
- LH_2 storage in the vehicle

Figure 13: Vehicle with electric motor and fuel cell

Source: www.daimlerchrysler.com, 19.11.2002

2.2. Reference vehicles for the vehicle introduction scenario

In order to avoid the obstacle that is bound to occur when hydrogen is first introduced to the market, namely building gas stations with a hydrogen supply only when the vehicles exist or vice versa, the most realiztic scenario for the development of the hydrogen vehicle population has to be worked out. The assumed consumption values of the reference vehicles provide the required annual demand for hydrogen. The gas station infrastructure is designed to cater for this development in the demand for hydrogen.

Table 3 divides vehicle categories up according to their area of use (town traffic, local traffic, long-distance traffic). Dividing the categories up in this way is considered meaningful, as there is no full coverage with hydrogen from gas stations at the start of gas station infrastructure development, so that in this phase the conventionally powered vehicles could be replaced by vehicles for the alternative fuel mainly in those vehicle categories which are not used for any longer distance journeys away from urban areas. This allows the supply of these vehicles with hydrogen at modified gas stations in urban areas to be guaranteed.

Table 3: Selected vehicle categories for Germany according to area of use

Vehicle category	Abbreviation	Conventional fuel[2)]	Area of use
Passenger car	PC	Gasoline, diesel	unlimited
Taxi	TAXI	Diesel	Urban and suburban
Rental car	RENT	Gasoline, diesel	unlimited
Regular city bus	BUS	Diesel	Urban and mixed use
Regular articulated bus	ABUS	Diesel	Urban
Long distance scheduled bus	XBUS	Diesel	Rural
Other buses (e.g. coaches)	OB	Diesel	unlimited
Heavy goods vehicle < 3.5 t GVW.[1)]	HGV<3.5	Diesel	Wide area/inner city distribution
Heavy goods vehicle 3.5 to 7.5 t GVW.[1)]	HGV<7.5	Diesel	Wide area/inner city distribution
Heavy goods vehicle 7.5 to 14 t GVW.[1)]	HGV<14	Diesel	Wide area/suburban distribution
Heavy goods vehicle > 14 t GVW.[1)]	HGV>14	Diesel	Wide area/long-distance traffic distribution
Special vehicles (e.g. refuse collectors)	SHGV	Diesel	Urban
Semi-trailer tractors	ARTIC	Diesel	Long-distance traffic

[1)] GVW = gross vehicle weight
[2)] main share of existing vehicle population
Source: Own assumptions, 2001

The vehicle categories are explained in more detail below.

2.2.1. Gasoline vehicles

It is apparent from Table 3 that it is mainly vehicles in the passenger car[23] (PC) and rental car (RENT) categories that are powered by conventional gasoline engines. Both of these vehicle categories are examined more closely in the following Chapter with regard to their efficiency and fuel consumption.

2.2.1.1. Passenger cars, rental cars

Rental cars are principally passenger cars (PC), so that the consumption data and efficiencies of PCs also apply to rental cars.

According to the calculation assumption of TES, vehicles with gasoline engines (PC-ICE-gasoline) can achieve[24] up to 24 % efficiency in the NEDC[25], which is used as the basis for calculation in this paper.

As the build-up of the gas station infrastructure will in all probability take several decades, possible future savings on fuel consumption or increases in efficiency are covered. Schindler works on the basis of a long-term average annual reduction in consumption of 2 % (Schindler, 1997, p. 47). TREMOD on the other hand assumes a 1 % reduction in consumption per year in relation to new cars of the previous year in the passenger car and light commercial vehicle categories (Keller, 1999, p. 52). The assumption of an increase in efficiency is based on the fact that major efforts are being made by automobile manufacturers to reduce consumption. Examples are direct gasoline injection, variable valve control (continuous adjustment of valve lift and/or valve timing), and direct diesel injection. As the technical state of vehicle technologies has reached a level where reductions in consumption can only achieved at relatively high additional costs and these reductions are becoming smaller in magnitude, this paper has assumed an increase in efficiency of 1 % for the period 2010 to 2020, and a further 1 % for the period 2020 to 2025. Table 4 shows future overall efficiencies for gasoline vehicles. This increase in efficiency corresponds to an average annual reduction in fuel consumption of barely 1 %.

As already stated in Chapter 2.1.2.2, the ACEA has promised the European Commission to reduce CO_2 emissions for the average, newly-registered passenger car to 140 g of CO_2 per kilometer from 2008. For the time frame from 2005 to 2010 considered in this paper, the basis of calculation chosen is the **fuel consumption** determined from 140 g/km CO_2. For gasoline vehicles, this gives an average fleet consumption for newly registered passenger cars of 52 kWh/100km (Equation 2). This amount of energy corresponds to 5.9 l of gasoline[26].

Equation 2:

$$Consumption_{gasoline} = \frac{14\frac{kg\,CO_2}{100\,km}}{3{,}175\frac{kg\,CO_2}{kg\ fuel}} * \frac{1}{0{,}742} = 5{,}9\frac{l}{100\,km} \cong 52\frac{kWh}{100\,km}$$

[23] Passenger car (PC) including combination motor vehicles are motor vehicles (two or more tracks), which according to their construction and orientation and mainly used for transporting people, their luggage and/or goods and have a maximum of 9 seats (including the driver) (VDA, 1999, p. 6).

[24] The fuel consumption data and efficiency of vehicle drives are determined in a single measurement process, the New European Driving Cycle (NEDC). The measurement is the mass emission of CO_2, from which the fuel consumption can be calculated from the carbon balance (www.vda.de. 29.08.2001).

[25] As part of the TES, reference vehicles with associated characteristics were determined to calculate the economical and ecological effects of the introduction of the alternative fuel of hydrogen.

[26] The CO_2 emissions per kg of gasoline are 3.175 kg and have a density of 0.742 kg/l (Keller, 1999, p. 52).

Taking in account the assumed increase in efficiency, this gives vehicles in the PC-ICE-gasoline category a consumption of 5.6 l/100 km for the period 2010 to 2020, and a consumption of 5.4 l/100 km for the period 2020 to 2025 (see Table 4).

Table 4: Assumed future efficiencies and fuel consumption data of newly registered passenger cars with gasoline engines (PC-ICE-gasoline) in Germany from 2005 to 2025

	Unit	2005-2010	2010-2015	2015-2020	2020-2025
Efficiency	%	24	25	25	26
Fuel consumption	l gasoline/100 km	5.9	5.6	5.6	5.4
	kWh/100 km	52	50	50	48

Source: TES, 2001; Schindler, 1997, p. 47; Own assumptions, 2001

The vehicle populations and performance of recent years as well as future forecasts for German are show in Table 35, Appendix 2.

2.2.2.Diesel vehicles

The individual vehicle categories are examined more closely in the following Chapters with regard to the efficiency and fuel consumption of their vehicles.

2.2.2.1. Passenger cars, rental cars

According to the calculation assumption of TES, vehicles with diesel engines (PC-ICE-diesel) can achieve up to 27 % **efficiency** in the NEDC[27]. Following Chapter 2.2.1.1, the future increase in efficiency is calculated with a increase of efficiency of 1 % for the period 2010 to 2020, and a further 1 % for the period 2020 to 2025 (Table 5). This increase in efficiency corresponds to an average annual reduction in fuel consumption of barely 1 %.

The calculation of fuel consumption for vehicles in the PC-ICE-diesel category for the period 2005 to 2010 again makes use of the ACEA promise to the European Commission as a basis for calculation (Chapter 2.2.1.1). For diesel vehicles, this gives an average inventory consumption of newly registered passenger cars of 52 kWh/100 km (Equation 3). This amount of energy corresponds to 5.3 l of diesel[28].

Equation 3:

$$Consumption_{Diesel} = \frac{14\frac{kg\,CO_2}{100km}}{3{,}175\frac{kg\,CO_2}{kg\ fuel}} * \frac{1}{0{,}832} = 5{,}3\frac{l}{100km} \cong 52\frac{kWh}{100km}$$

Taking in account the assumed increase in efficiency, this gives vehicles in the PC-ICE-diesel category a consumption 5.1 l/100 km for the period 2010 to 2020, and a consumption of 4.9 l/100 km for the period 2020 to 2025 (see Table 5).

Table 5: Assumed future efficiencies and fuel consumption data of newly registered passenger cars with diesel engines (PC-ICE-diesel) in Germany from 2005 to 2025

	Unit	2005-2010	2010-2015	2015-2020	2020-2025
Efficiency	%	27	28	28	29
Fuel consumption	l diesel/100 km	5.3	5.1	5.1	4.9
	kWh/100 km	52	50	50	48

Source: TES, 2001; Schindler, 1997, p. 47; Own assumptions, 2001

[27] In the framework of the TES, reference vehicles with associated specifications were determined in order to calculate the economical and ecological effects of the introduction of hydrogen as an alternative fuel.
[28] CO_2 emissions per kg of diesel are 3.175 kg and the density is 0.832 kg/l (Keller, 1999, p. 52).

As the fuel consumption vehicles in terms of energy in the PC-ICE-gasoline and PC-ICE-diesel categories is approximately the same, only the energetic fuel consumption will be used in order to simplify further calculations. A record of passenger car vehicle populations by diesel and gasoline vehicles is therefore not required in Appendix 2.

2.2.2.2. Taxis

Taxi vehicles (cabs) are primarily fitted with diesel engines. Therefore, the **efficiency** of taxicabs is considered as being identical to that of PC-ICE-diesel vehicles (Table 5) as a basis for calculation (Table 6).

As the vehicles are predominantly used in urban areas, taxicabs have a higher **fuel consumption**, than the vehicles in the PC-ICE-diesel category shown in Table 5. Fuel consumption in urban use is therefore used as a basis for calculation. The chosen reference vehicle is a Mercedes 200 CDi with a power output of 85 kW. Consumption on the urban cycle is 8.7 l/100 km and the overall average 6.1 l/100 km according to 93/116/EEC (NEDC) for a car with manual gearbox (www.mercedes-benz.de, 26.10.2001).

This concerns fuel consumption data that are currently achieved. To estimate consumption data for the period 2005 to 2010, the assumed consumption data for PC-ICE-diesel vehicles have to be examined more closely. On the basis of the undertaking to reduce CO_2 emissions made by the ACEA to the European Commission, a consumption figure of 5.3 l/100 km was calculated for 2008 in determining the diesel fuel consumption of passenger cars (Chapter 2.2.1.1). The drop in consumption, with reference to the average consumption of the selected taxi reference vehicle of 6.1 l/100 km, is therefore 0.8 l/100 km or 13%. If this 13 % saving is deducted from the taxi reference vehicle's urban cycle consumption of 8.7 l/100 km, this gives a future urban cycle consumption of 7.6 l/100 km for the period 2005 to 2010.

Table 6: Assumed future efficiencies and fuel consumption data of newly registered taxicabs with diesel engines (TAXI-ICE-diesel) in Germany from 2005 to 2025

Vehicle	Unit	2005-2010	2010-2015	2015-2020	2020-2025
Efficiency	%	27	28	28	29
Fuel consumption	l diesel/100 km	7.6	7.3	7.3	7.0
	kWh/100 km	75	72	72	69

Source: Own assumptions, 2001

The vehicle populations and performance of recent years as well as future forecasts for Germany, Munich and Berlin are shown in Appendix 2.

2.2.2.3. Buses

Buses[29]) include vehicles used on scheduled public services (in urban and rural areas), and coaches. **Scheduled buses** ply from an operating depot within a certain area, and cover daily distances of approx. 200 km. Supply and refueling at central operating depots is easy to achieve, as there is no dependency on the conventional gas station network. **Coaches** on the other hand also travel across national borders, and substitution of these vehicles can only take place when sufficient coverage of the gas station network can be guaranteed both nationally and internationally. Currently, vehicles in this category mostly use diesel fuel.

Conventional diesel engines for the most part have direct fuel injection (DI-ICE-diesel). Vehicles with diesel engines in all the bus categories defined in this paper have an **efficiency** of 30 % as a basis for calculation (Table 7). In accordance with Chapter 2.2.1.1, the future increase in efficiency is calculated as a 1 % increase for the period 2010 to 2020 and a further 1 % for the period 2020 to 2025.

[29] A bus is a commercial vehicle that according to its construction and equipment is used to transport more than 9 people (including the vehicle driver) and their luggage. It can have one or two decks (VDA, 1999, p. 6)

To determine the **fuel consumption** figures, reference vehicles were chose for the bus categories (Gruber, 2001; own assumption, 2001):

- **Scheduled town bus (BUS):** Low-aisle town bus NL 263, 2-axle, 12 m overall length, engine output up to 200 kW, 18 t gross weight limit, average fuel consumption 45 l/100 km
- **Scheduled articulated bus (ABUS):** Low-aisle town bus NL 313, 3-axle, 18 m overall length, engine output up to 230 kW, 28 t gross weight limit, average fuel consumption 55 l/100 km
- **Standard scheduled cross-country bus (XBUS):** Bus type as for BUS. However, as it is used predominantly for cross-country journeys, an average fuel consumption of 35 l/100 km is assumed
- **Other buses (OB):** Lion's Star coach, 2-axle, 12 m overall length, engine output up to 300 kW, 18 t gross weight limit, average fuel consumption 28 l/100 km

Table 7: Assumed future efficiencies and fuel consumption data of newly registered buses with diesel engines according to bus categories in Germany from 2005 to 2025

	Unit	2005-2010[1)]	2010-2015	2015-2020	2020-2025
Efficiency	%	30[2)]	31	31	32
Consumption BUS-DI-ICE diesel	l diesel/100 km	45.0	43.6	43.6	42.3
	kWh/100 km	442	428	428	415
Consumption ABUS-DI-ICE diesel	l diesel/100 km	55.0	53.3	53.3	51.6
	kWh/100 km	540	523	523	507
Consumption XBUS-DI-ICE diesel	l diesel/100 km	35.0	33.9	33.9	32.9
	kWh/100 km	344	333	333	323
Consumption OB-DI-ICE diesel	l diesel/100 km	35.0	33.9	33.9	32.9
	kWh/100 km	344	333	333	323

[1)] The consumption data are confirmed by the municipal services in Munich (Fendt, 7.09.2001)
[2)] Source: Schaller, 2000, p. 14
Source: Own assumptions, 2001

The vehicle populations and distances covered in recent years as well as future forecasts for Germany, Munich and Berlin are shown in Appendix 2.

2.2.2.4. Trucks

The extremes in the automobile industry[30] as far as the conversion to an alternative fuel are the the **truck**[31] (HGV) and the **semi-trailer tractor**[32], as these travel far beyond the action radius of the passenger car. The supply of diesel fuel on these long-distance routes is currently guaranteed without problem. In addition, these vehicles can be fitted with fuel tanks with capacities over 1,000 l, giving a range of more than 3,000 km (Schaller, 2000, p. 13). Substitution by vehicles for the alternative fuel can only take place when sufficient geographical coverage of the gas station network can be guaranteed nationally and internationally. Currently, vehicles in this category mostly use diesel fuel.

Special-purpose vehicles (waste management and street cleaning vehicles) and other **trucks** operate in urban areas, the urban hinterland and locally. These vehicles are mostly operated in fleets; the operators have their own operating depots for refueling these vehicles. Currently, most vehicles in this category also run on diesel fuel. Alternative fuels can be introduced here even at the beginning of gas station infrastructure development, since the supply of hydrogen to the operating depots can be guaranteed (assuming that they have been modified to supply hydrogen).

[30] The automobile industry includes manufacturers of motor vehicles and their engines, semi-trailer tractors, trailers, bodywork, motor vehicle components and accessories (VDA, 1999, p. 6).
[31] Trucks are commercial vehicles that according to their construction and orientation are used to transport goods (VDA, 1999, p. 6).
[32] Semi-trailer tractors are trucks that have a special device for towing articulated trailers with a significant part of the weight of the trailer carried by the articulated truck (VDA, 1999, p. 6).

For trucks with a gross weight limit of less than 3.5 t (HGV<3.5), which are mainly used in urban areas and the urban hinterland, **efficiency** is assumed to be the same as that of vehicles in the PC-ICE-diesel category (Table 5). The journey profiles of trucks with a gross weight limit of 3.5 to 7.5 t (HGV<7.5) or of 7.5 to 14 t (HGV<14) is similar to town buses and the efficiency are assumed to be the same as those of buses. Heavy goods vehicles with a gross weight limit of more than 14 t (HGV>14) and articulated vehicles (ARTIC) are mainly used for long-distance journeys (motorway routes) and have a profile with higher average speeds. The efficiency of these vehicles is given at approx. 40 % (Schaller, 2000, p. 14). Special vehicles (SHGV), like ABUS, are mainly used in urban areas, and the fuel consumptions of both of these vehicle categories are also at approximately the same level. Due to this conformity, the efficiency of vehicles in the SHGV category can be assumed to be as high as that for the ABUSB category.

To determine the **fuel consumption rates**, reference vehicles were chosen for the vehicle categories (Gruber, 2001; own assumption, 2001):

- **HGV<3.5:** average fuel consumption of 13 l/100 km assumed
- **HGV<7.5:** MAN light series L2000, 2-axle, engine output up to 115 t, 17.5 t gross weight limit, average fuel consumption 21 l/100 km
- **HGV<14:** MAN light series L2000, 2-axle, engine output up to 160 t, 12 t gross weight limit, average fuel consumption of 24 l/100 km
- **HGV>14:** MAN middle series M2000, 2-axle, engine output up to 160 kW, 18 t gross weight limit, average fuel consumption 27 l/100 km
- **ARTIC:** MAN articulated TG-A with trailer, engine output up to 300 kW, 40 t gross weight limit, average fuel consumption 35 l/100 km
- **SHGV:** MAN heavy series TG-A, 2-axle, engine output up to 230 kW, 18 t gross weight limit, average fuel consumption 60 l/100 km

Table 8: Assumed future efficiencies and fuel consumption data of newly registered trucks with diesel engines by vehicle categories in Germany from 2005 to 2025

Vehicle category		Unit	2005-2010	2010-2015	2015-2020	2020-2025
HGV<3.5 DI-ICE-diesel	Efficiency	%	27	28	28	29
	Fuel consumption	l diesel/100 km	13.0	12.6	12.6	12.2
		kWh/100 km	128	124	124	120
HGV<7.5 DI-ICE-diesel	Efficiency	%	30	31	31	32
	Fuel consumption	l diesel/100 km	21.0	20.3	20.3	19.7
		kWh/100 km	206	199	199	193
HGV<14, DI-ICE-diesel	Efficiency	%	34	35	35	36
	Fuel consumption	l diesel/100 km	24.0	23.4	23.4	22.8
		kWh/100 km	236	230	230	224
HGV>14 DI-ICE-diesel	Efficiency	%	40	41	41	42
	Fuel consumption	l diesel/100 km	27.0	26.3	26.3	25.6
		kWh/100 km	265	258	258	251
ARTIC DI-ICE-diesel	Efficiency	%	30	31	31	32
	Fuel consumption	l diesel/100 km	35.0	34.2	34.2	33.4
		kWh/100 km	344	336	336	328
SHGV DI-ICE-diesel	Efficiency	%	40[1)]	41	41	42
	Fuel consumption	l diesel/100 km	60.0	58.5	58.5	57.0
		kWh/100 km	589	574	574	559

[1)] Source: Schaller, 2000, p. 14
Source: Own assumptions, 2001

The vehicle populations and distances covered in recent years as well as future forecasts for Germany, Munich and Berlin are shown in Appendix 2.

2.2.3. Hydrogen vehicles

After reference vehicles have been defined for conventional fuel, they are also needed for hydrogen as an alternative fuel.

2.2.3.1. Passenger cars, rental cars

According to the TES, **vehicles with internal combustion engines** that use hydrogen as a fuel (PC-ICE-H_2) have an efficiency of 25 to 27 %. The reason for the higher efficiency compared to vehicles in the PC-ICE-gasoline category is that the hydrogen-fueled internal combustion engine can be operated very lean, i.e. with surplus air, which results in a reduction in fuel consumption.

In the NEDC, the efficiency of a **vehicle with an electric motor and fuel cell** (PC-PEMFC-H_2) is about 36 %. In its Hybrid Powertrain Simulation Program (HPSP), General Motors established a total efficiency of 36.3 % for the electric vehicle with fuel cell (Weber (b), 2001, p. 2-10). It should be stressed that the energy requirement of the secondary units was not taken into account and that consequently the efficiency may have been overestimated. A further investigation into the required energy needs of vehicles with an electric motor and fuel cell revealed that efficiency in the NEDC was currently 30 % (Grahl, 2000, p. 42). Due to improvements, future efficiency of 35 to 40 % is expected. The output of the electric motor on a vehicle with this efficiency in the NEDC is about 55 kW.

In order to guarantee comparability with vehicles powered by internal combustion engines, the average output of which is currently higher than 55 kW, the electric motor and the fuel cell must have a higher output (amongst other things, this will involve an increase in vehicle weight). Associated with this is an increase in fuel consumption and a reduction in efficiency. This condition is not taken into account in this paper, and a total efficiency of 36 % is assumed for vehicles in the PC-PEMFC-H_2 category (Table 9). As in Chapter 2.2.1.1, the future increase in efficiency is calculated with a increase of 1 % for the period 2010 to 2020, and a further 1 % for the period 2020 to 2025.

Table 9: Assumed future efficiencies and fuel consumption of newly registered passenger cars with hydrogen engines (PC-ICE H_2) and passenger cars with electric motor and fuel cell (PC-PEMFC-H_2) in Germany from 2005 to 2025

Vehicle category		Unit	2005-2010	2010-2015	2015-2020	2020-2025
PC-ICE-H_2	Efficiency	%	27	28	28	29
	Fuel consumption	l GE[33]/100 km	5.1	4.9	4.9	4.8
		kWh/100 km	46	44	44	43
PC-PEMFC-H_2	Efficiency	%	36	37	37	38
	Fuel consumption	l GE/100 km	3.9	3.8	3.8	3.7
		kWh/100 km	35	34	34	33

Source: TES, 2001; Weber(b), 2001, p. 2-10; Grahl, 2000, p. 42; Schindler, 1997, p. 47; Own assumptions, 2001

For vehicles fueled by hydrogen[34] the **fuel consumption** is calculated approximately from the stated efficiency. For the period 2005 to 2010, the fuel consumption of a vehicle in the PC-ICE-gasoline category is 52 kWh/100 km (Table 4). With an assumed efficiency of 24 % for vehicles in this vehicle category, this yields an energy quantum of 12.5 kWh/100 km, which after deduction of losses (e.g. friction in the engine), is available to drive the vehicle. If this energy quantum is also assumed for vehicles with hydrogen powertrains, this yields, from the efficiency of 27 % for vehicles in the PC-ICE-H_2 category, a fuel consumption of 46 kWh/100 km and, for vehicles in the PC-PEMFC-H_2 category with an efficiency of 36 %, a fuel consumption of 35 kWh/100 km (Table 9). However, what is not taken into account in this calculation is the fact that the weight of the driveline with fuel cell is higher for the same power output than that of an internal combustion engine. Consequently, the fuel consumptions of vehicles in the PC-PEMFC-H_2 category as used here are very optimistic. The reductions in consumption for vehicles in the PC-ICE-H_2 and PC-PEMFC-H_2 categories are assumed to be identical to the reduction for vehicles in the PC-ICE-gasoline category.

[33] GE = Gasoline Equivalent
[34] Vehicles with internal combustion engines and vehicles with electric motors and fuel cells,which use hydrogen as their fuel.

2.2.3.2. Taxis

The **efficiency** of vehicles in the TAXI category when driven by internal combustion engines is assumed to be identical to that of vehicles in the PC-ICE-H_2 category, and when driven by an electric motor and fuel cell to be identical to that of vehicles in the PC-PEMFC-H_2 category (Table 10).

Determining the **fuel consumption** of these vehicles again takes place using the energy quantum that is available to drive the vehicle after deducting losses (Chapter 2.2.3.1). These reference energy quanta are now calculated for the vehicle in the TAXI-ICE-diesel category.

Table 10: Assumed future efficiencies and fuel consumption of newly registered taxicabs with hydrogen-fueled internal combustion engines (TAXI-ICE-H_2) and with an electric motor and fuel cell (TAXI-PEMFC-H_2) in Germany from 2005 to 2025

Vehicle category		Unit	2005-2010	2010-2015	2015-2020	2020-2025
TAXI-ICE-H_2	Efficiency	%	27	28	28	29
	Fuel consumption	l GE/100 km	8.4	8.0	8.0	7.7
		kWh/100 km	75	72	72	69
TAXI-PEMFC-H_2	Efficiency	%	36	37	37	38
	Fuel consumption	l GE/100 km	6.4	6.3	6.3	6.1
		kWh/100 km	57	56	56	55

Source: Own assumptions, 2001

2.2.3.3. Buses

The advantages of an electric motor with fuel cell compared with a combustion engine lie in the good part-load behaviour and high starting torque. To this extent, it is obvious to equip vehicles in the category that is mainly used in urban areas with electric motors and fuel cells. Moreover, the differing efficiency patterns of an electric motor and an internal combustion engine for vehicles with electric motor and fuel cell result in good energy efficiencies in urban use for vehicles in the BUS category, so that the use of fuel cell power trains is favored in this category (Schaller, 2000, p. 14).

The **efficiency** of a scheduled bus with fuel cell drive (BUS-PEMFC-H_2) in mixed use is about 41 %. However, as the weight per horsepower (in terms of gross vehicle weight) for buses is lower than for passenger cars, an efficiency of 35 % is used in this paper (Table 11). As in Chapter 2.2.1.1, the future increase in efficiency is calculated at 1 % for the period 2010 to 2020 and a further 1 % for the period 2020 to 2025.

Determining the **fuel consumption** of these vehicles again takes place using the energy quantum that is available to drive the vehicle after deducting losses (Chapter 2.2.3.1). This reference energy quantum varies according to the type of bus (BUS, ABUS, XBUS, OB), and must be calculated for vehicles in each category.

Table 11: Assumed future efficiencies and fuel consumption values of newly registered buses with electric motor and fuel cell, divided into scheduled town bus (BUS), scheduled articulated bus (ABUS), scheduled cross-country bus (XBUS) and other buses (OB), in Germany from 2005 to 2025

	Unit	2005-2010	2010-2015	2015-2020	2020-2025
Efficiency	%	35	36	36	37
Consumption BUS-PEMFC-H_2	l GE/100 km	42.3	41.1	41.1	40.0
	kWh/100 km	379	369	369	359
Consumption ABUS-PEMFC-H_2	l GE/100 km	51.6	50.3	50.3	48.9
	kWh/100 km	463	451	451	439
Consumption XBUS-PEMFC-H_2	l GE/100 km	32.9	32.0	32.0	31.1
	kWh/100 km	295	287	287	279
Consumption OB-PEMFC-H_2	l GE/100 km	32.9	32.0	32.0	31.1
	kWh/100 km	295	287	287	279

PEMFC = Polymer Electrolyte Membrane Fuel Cell
Source: Own assumptions, 2001

2.2.3.4. Trucks

The vehicles in the HGV<3.5, HGV<7.5, HGV<14 and SHGV categories, since they are mainly used in urban areas and in the urban hinterland, will be fitted with a hydrogen internal combustion engine as soon as development of a gas station infrastructure starts, so that they can be powered bivalently. Only when a comprehensive gas station infrastructure has been built up will vehicles in this category be offered with electric motor and fuel cell (Schaller, 2001). For vehicles in the HGV>14 and ARTIC categories, there is a stalemate situation regarding efficiency between the fuel cell drive and the internal combustion engine (Schaller, 2000, p. 14). As the vehicles in both these categories are mainly used for long-distance journeys (overland highway routes) and have a profile including higher average speeds, the hydrogen-fueled internal combustion engine is preferred as a future powertrain type (Schaller, 2000, p. 14; Lloyd, 2001).

The **efficiency** of vehicles in the HGV<3.5-ICE-H_2 and HGV<3.5-PEMFC-H_2 categories is assumed to be identical to those in the PC-ICE-H_2 and PC-PEMFC-H_2 categories (Table 12). The usage profile of vehicles in the HGV<7.5, HGC<14 and SHGV categories is similar to that of buses, and the efficiency of vehicles in these categories is therefore also assumed to be similar.

Determining the **fuel consumption** of these vehicles is again by means of the energy quantum that is available to drive the vehicle after deducting losses (Chapter 2.2.3.1). This reference energy quantum varies according to vehicle category, and must be calculated for vehicles in each category.

Table 12: Assumed future efficiencies and fuel consumption of newly registered trucks (HGV) with hydrogen-fueled internal combustion engines (ICE-H_2) and with electric motor and fuel cell (PEMFC-H_2), divided up according to gross weight limit, articulated vehicles (ARTIC) and special vehicles (SHGV) in Germany from 2005 to 2025

Vehicle category		Unit	2005-2010	2010-2015	2015-2020	2020-2025
HGV<3.5-ICE-H_2	Efficiency	%	27	28	28	29
	Fuel consumption	l GE/100 km	14.3	13.8	13.8	13.4
		kWh/100 km	128	124	124	120
HGV<3.5-PEMFC-H_2	Efficiency	%	36	37	37	38
	Fuel consumption	l GE/100 km	10.7	10.5	10.5	10.3
		kWh/100 km	96	94	94	92
HGV<7.5-ICE-H_2	Efficiency	%	30	31	31	32
	Fuel consumption	l GE/100 km	23.0	22.2	22.2	21.5
		kWh/100 km	206	199	199	193
HGV<7.5-PEMFC-H_2	Efficiency	%	37	38	38	39
	Fuel consumption	l GE/100 km	18.6	18.2	18.2	17.7
		kWh/100 km	167	163	163	159
HGV<14-ICE-H_2	Efficiency	%	34	35	35	36
	Fuel consumption	l GE/100 km	26.3	25.6	25.6	25.0
		kWh/100 km	236	230	230	224
HGV<14-PEMFC-H_2	Efficiency	%	38	39	39	40
	Fuel consumption	l GE/100 km	23.6	23.1	23.1	22.5
		kWh/100 km	212	207	207	202
HGV>14-ICE-H_2	Efficiency	%	40	41	41	42
	Fuel consumption	l GE/100 km	29.5	28.8	28.8	28.0
		kWh/100 km	265	258	258	251
ARTIC-ICE-H_2	Efficiency	%	40	41	41	42
	Fuel consumption	l GE/100 km	38.4	37.5	37.5	36.6
		kWh/100 km	344	336	336	328
SHGV-ICE-H_2	Efficiency	%	30	31	31	32
	Fuel consumption	l GE/100 km	65.7	64.0	64.0	62.3
		kWh/100 km	589	574	574	559
SHGV-PEMFC-H_2	Efficiency	%	35	36	36	37
	Fuel consumption	l GE/100 km	56.3	55.1	55.1	54.0
		kWh/100 km	505	494	494	484

SHGV = Special trucks (for instance vehicles used for waste management and street cleaning)
Source: Own assumptions, 2001

2.3. Vehicle introduction scenario for Germany

To determine the most realiztic possible scenario for the growth in vehicle population[35], basic aspects of the introduction of a new product onto the market are considered in the initial phase, and earlier examples of product launches and their inventory development analyzed. After this, existing forecasts of possible developments in alternative motor vehicle populations are shown. Building on the knowledge gained from these analyses, a scenario of the growth in the motor vehicle populations can be drawn up.

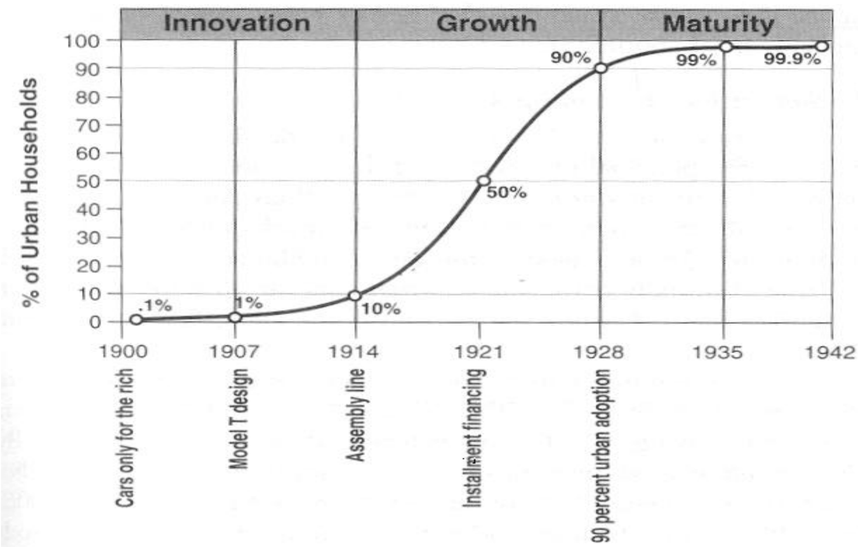
2.3.1. Knowledge from previous product launches

Observation of past product launches shows that implementation of detail changes to sub-systems (gasoline injection, anti-lock brake system) in the automobile industry can take 10 to 14 years from initial use to significant market penetration (Grebe, 2001, p. 227).

The development of the proportions of automobiles in urban households in the USA from 1900 to 1942 is shown in Figure 14. Noticeable is the curve of the shares plotted against time, which because of its shape is referred to as the **S-curve**.

The S-curve is divided into phases, all of which exhibit their own characteristics. In the **market preparation phase** (not shown in Figure 14), there is a gain in knowledge and experience in handling hydrogen, and an improvement in product acceptance amongst the population. Hydrogen technology is currently in this phase. In the **market entry phase** (start of the “innovation” area in Figure 14), small production runs are built, which, for example, are used in fleets, but which also end up in individual customers’ hands, and build-up of the infrastructure starts. In the **market penetration phase** (end of the “Innovation” stage and start of the “Growth” stage), the market is penetrated step by step and the infrastructure is further expanded and improved. In the **volume market phase** (“Growth” area), mass production of vehicles takes place, along with further expansion of the infrastructure until full coverage is obtained. In the final phase, the **market maturity phase** (“Maturity” area), market saturation is achieved. The transition between each two consecutive phases takes place without interruption.

Figure 14: Share of urban households with automobiles in the USA from 1900 to 1942



Source: Dent, 1998, p. 46

The typical shape of the S-curve shows empirically the peculiarity that the same time to reach a market penetration of 10 % is needed as to continue from 10 to 90 %. For example, at the start of the 20th century it took around 14 years for the car to reach a share of 10 % in 1914, and the same time again for growth from 10 to 90 % (Dent, 1998, p. 46-48). It is also

[35] A motor vehicle is a road vehicle driven mechanically. It may also be suitable for the towing of trailers (VDA, 1999, p. 6).

noticeable that it took seven years to achieve a market share of 1 %, and consequently half the time needed to reach 10 %. The same is true for a share of 50 %.

In the development of the share of households in the USA with an electricity supply or a telephone, 28 years were needed to grow from a market share of 10% to 90 %, twice as long as for the automobile (Dent, 1998, p. 48). However, here it is also noticeable that it took about 14 years to achieve a market share of 1 %, and consequently half the time needed to reach 10 %.

The implication of the examples quoted is that although market penetration of a product can take place more or less rapidly, the important proportions of the S-curve remain valid.

The examples presented here are of course not directly comparable with the substitution of conventional motor vehicles by alternative ones. The examples described above deal with products that did not exist on the market at the time, something which is not the case here. On the contrary, the introduction of a new fuel concerns the substitution of an existing product by one that is at least currently comparable. In a conventional vehicle, the comparability is based on fuel costs, which are currently lower than the costs of regeneratively produced hydrogen, and on unlimited convenience regarding storage, e.g. the trunk (luggage boot), which in some alternative vehicles proves to be smaller as a consequence of the larger storage tank required for the hydrogen (the current reduction in the conventional boot space so that acceptable range can be achieved with the stored quantity of hydrogen is up to 50 %, Chapter 2.1.4.3). The costs of hydrogen and the production costs of alternative vehicles, which the customer will have to pay, will have an important influence on the development of the alternative vehicle population.

2.3.2. Forecasts of possible development

Different published scenarios for the possible development of new registrations of vehicles using hydrogen as an alternative fuel are presented below, and the OWN scenario that forms the basis of this paper is described in Chapter 2.3.3.

2.3.2.1. Scenario from Dresdner Kleinwort Wasserstein (DKW[36])

Figure 15 shows two scenarios for possible new vehicle registrations over the years in the PC-PEMFC-H_2 category, see the “Scenario DKW optimistic, PC” and “Scenario DKW pessimistic, PC” curves (DKW, 2001, p. 49; Own calculations, 2001). The database for this is derived from new registration forecasts in the USA, which have been transferred to Germany by own calculations. The annual share of the anticipated sales volume was calculated as a percentage of the total vehicle population in the USA and transferred to the total population in Germany of 42.25 million vehicles in 1999. In the optimistic scenario, the share of new passenger car registrations in the 10 years following the start of the introduction is about 600,000 vehicles, in the pessimistic scenario about 450,000 vehicles.

2.3.2.2. Scenario from marketing professor Dudenhöffer[37]

The theoretical market potential for vehicles for hydrogen as an alternative fuel is given as approx. 14 million vehicles worldwide (Miggiano, 2001). This figure represents possible new vehicle registrations in the PC-PEMFC-H_2 category, depending on the market area, made up of 6 million new passenger car and light commercial vehicle registrations in US urban areas, 4 million new passenger car registrations on the Japanese market and 4 million passenger vehicle sales per year in Europe. In a total world market of approx. 56 million motor vehicle sales per year, this corresponds to a share of 25 % (Dudenhöffer, 2001).

An estimation is made below of the vehicle share for Germany of the 4 million annual vehicle sales for Europe with hydrogen as an alternative fuel. In 1999, the number of passenger cars in Europe was approx. 229 million (Aral, 2000, p. 285 f.) and annual new registrations

[36] Investment bank of Dresdner Bank AG
[37] Director of the Automotive Research Center and Professor of Marketing and Business Management at the College of Advanced Education in Gelsenkirchen.

approx. 21 million vehicles. However, Dudenhöffer's estimated sales potential of 4 million vehicles in Europe refers to markets that currently already permit the build-up of a gas station infrastructure. In order to arrive at the forecast share for Germany of 4 million vehicles, the European Union markets are used as a starting point in this paper. In 1999, the number of passenger cars in the member states of the European Union was approx. 170 million, with about 15.5 million new registrations. With 45 million passenger cars, Germany has a share of the vehicle population of the European Union of approx. 26 %. If it is assumed that the annual potential of 4 million vehicle sales in the European Union is achieved, this gives Germany an annual sales potential for alternative-fuel vehicles in the PC-category of about 1 million. This corresponds to a 6.6 % share of worldwide vehicle sales.

According to Dudenhöffer, approx. 50,000 vehicles for use with hydrogen as an alternative fuel will be sold worldwide in 2010, with the figure rising to approx. 300,000 in 2015 and approx. 3 million in 2020. From this point in time on, market saturation is reached, and from 2025, the worldwide annual registration of vehicles for hydrogen as an alternative fuel will be approx. 14 million. In other words, in 2025, 50 % of the vehicles sold for use with hydrogen as an alternative fuel could be running on the potential markets.

In Germany, the vehicle share for the alternative fuel of 50 % would mean about 2.4 million vehicles in 2025 (excluding semi-trailer tractors), if the whole of Germany is considered as a potential market. In this point of view, special environmentally sensitive regions and the urban centres of modern national economies are understood as potential markets, so that the figure of 1 million vehicle registrations for hydrogen as an alternative fuel for 2005 for Germany stated above can be seen as a probable potential. If the worldwide potentials shown over the years are converted at the 6.6 % share quoted above for Germany, and if an exponential trend line is drawn through these points, we obtain a sales curve for alternative vehicles in Germany, see "Scenario DUDENHÖFFER, PC" in Figure 15.

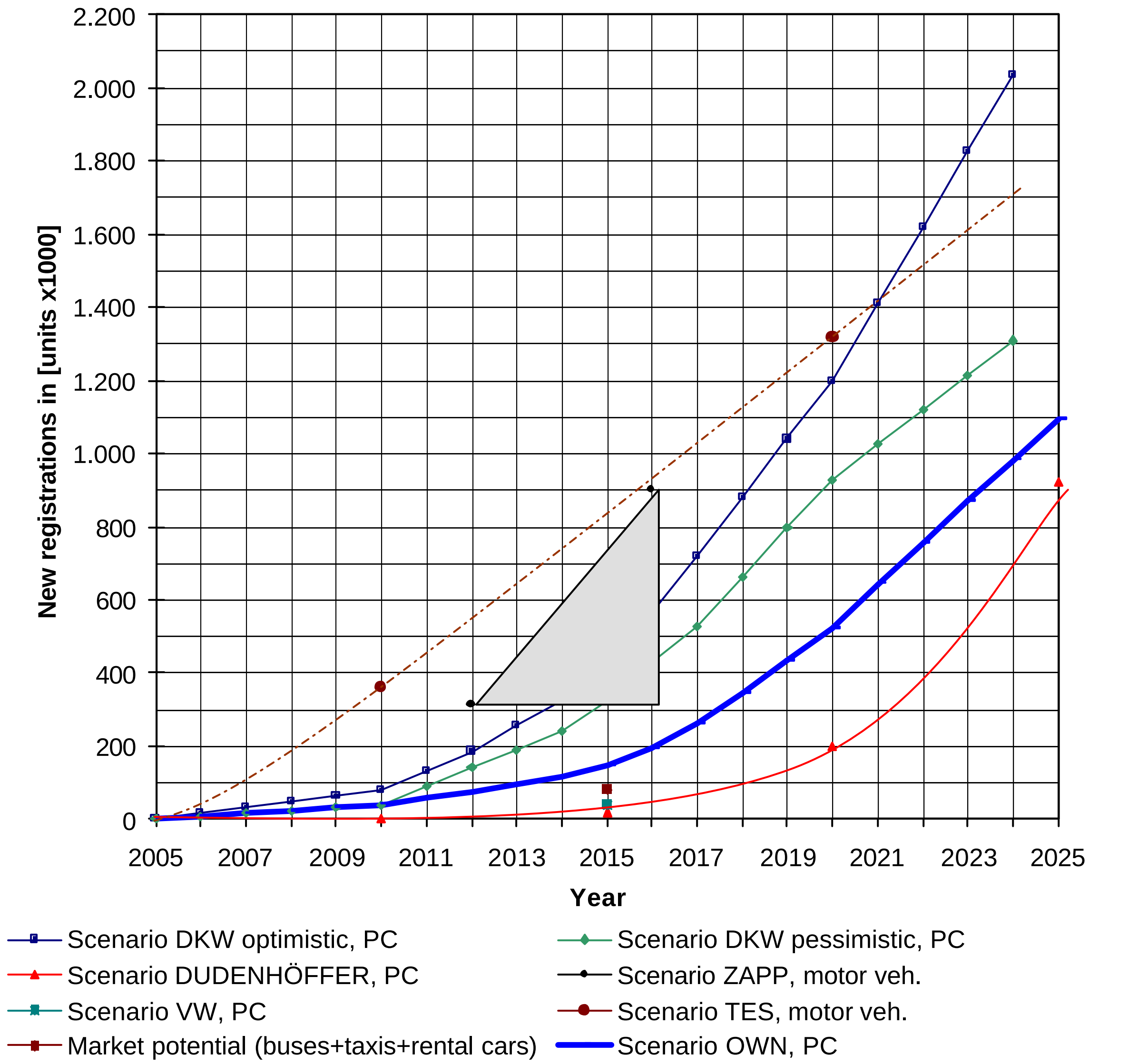
Comparison of the "Scenario DUDENHÖFFER, PC" with the "Scenario DKW optimistic, PC" and the "Scenario DKW pessimistic, PC", shows that in the first few years the scenario according to Dudenhöffer is based on a much smaller share of passenger car sales per year. In the "Scenario DKW optimistic, PC", strong growth in the annual number of vehicle registrations is forecast from 2015 onwards. In the "Scenario DUDENHÖFFER, PC", this strong increase in vehicle registrations only comes into effect after 2023. Thereafter, the share of annual new passenger car registrations increases at the same rate as in the two DKW scenarios.

2.3.2.3. Scenario from Specialist Editor Zapp[38]

According to Zapp, in the next 10 to 15 years the share of new registrations for vehicles using hydrogen as an alternative fuel in Germany is assumed to progress from 7 to 20 % (Zapp, 2001, p. 366.) The smallest new registration share of 7 % will be reached in 15 years. This figure represents the worst-case scenario and the lower-right corner of the triangle. In the best-case scenario, a 20 % new registration share will be reached in 15 years. This figure is represented by the upper-right corner of triangle. The left-hand corner of the triangle represents a new registration share of 7 % in 10 years. The triangle formed by these three corners represents the area of the future share of new registrations for hydrogen as an alternative fuel, see the "Scenario ZAPP, motor veh." triangle in Figure 15. The bottom right-hand area of the triangle corresponds to the forecasts in the DKW scenarios.

[38] Kerstin Zapp is an editor of the periodical "Internationales Verkehrswesen" (Gerd Aberle (Publ.), Deutsches Verkehrs-Verlag, Hamburg)

Figure 15: Scenarios of possible new registrations of motor vehicles and passenger cars with alternative powertrains for hydrogen in Germany from 2005 to 2025



DKW = Dresdner Kleinwort-Wasserstein (Investment Bank), VW = Volkswagen, TES = Transport Energy Strategy. Source: DKW, 2001, p. 49; Zapp, 2001, p. 366; Eichhorn, 2001; TES, 2000, p. 4; Own calculations, 2001

2.3.2.4. Scenario by Volkswagen (VW)

For Germany, the automobile manufacturer Volkswagen assumes 100 passenger car sales per day for hydrogen as an alternative fuel at the earliest in 2015, which corresponds to 36,500 vehicles per year (Eichhorn, 2001), ("Scenario VW, PC" point value in Figure 15). For 2015, this value is almost double that in the "Scenario DUDENHÖFFER, PC".

2.3.2.5. Scenario by the "Transport Energy Strategy" (TES)

The TES describes a scenario that envisages a vehicle share for hydrogen as an alternative fuel of 5-10 % of total motor vehicle registrations in Germany up to 2010. Up to 2020, this share should increase to 25 – 30 % ("Scenario TES, motor veh." curve in Figure 15).

2.3.2.6. Development to date of the population of natural gas vehicles

By way of comparison, the development of the vehicle population using natural gas as a fuel can be set against the forecasts stated above. The period from the start of market introduction of these vehicles in 1990 before a fleet of 12,000 vehicles was reached took around 10 years (Figure 56). The main share of vehicles using natural gas as a fuel consists of trucks. In 2000, the number of passenger cars using natural gas as a fuel was around 3,800 of approx. 10,000 vehicles (Federal Motor Vehicles Office, 2001).

2.3.3. Derivation a trend in the vehicle population

Which of the forecasts listed above may come about is still open. In order to obtain an approximate indication of the future increase in the number of vehicles capable of using hydrogen as an alternative fuel, an attempt is made to estimate the annual potential of new vehicle registrations. Building on these estimates, a scenario for the inventory of vehicles is assumed and stated here as **vehicle population development OWN (VPD OWN)**. It is used in this paper as a basis for calculating the development of a gas station infrastructure.

2.3.3.1. Development of the vehicle population in the BUS, ABUS, XBUS and SHGV categories

As mentioned in Chapter 2.2.2.3, vehicles in the BUS, ABUS and XBUS operate from depots within a specific area, and make daily journeys of approx. 200 km. Refueling these vehicles at central operating depots is relatively easy to achieve, with no dependency on the conventional roadside gas station network. The same is true for vehicles in the SHGV category.

According to information from the Munich municipal services, it would be possible to convert the scheduled buses within ten years (= average vehicle age) (Fendt, 2001). If an assumption is made that all buses in the BUS, ABUS and XBUS categories (which are also used as city buses) are replaced by vehicles that use hydrogen as an alternative fuel, this results in an inventory of nearly 54,000 hydrogen vehicles in 2015 for buses in Germany alone, if conversion starts in 2006. The assumption here is that all buses in all German towns are will be replaced from the start.

Substitution of vehicles used for refuse collection and street cleaning by vehicles that use hydrogen as an alternative fuel is also possible from the start. With an average age for these vehicles of approx. 16 years, the conversion would be completed in 2021 and would amount to 28,600 vehicles.

2.3.3.2. Development of the vehicle population in the TAXI category

From the start, taxicabs can be continuously substituted by vehicles that use hydrogen as an alternative fuel. As the lifespan of a taxi operated by a single vehicle owner is about 7 to 8 years, and in multi-vehicle operation about 5 to 6 years (Bleckmann, 2001), all vehicles in Germany could theoretically be replaced by vehicles that use hydrogen as an alternative fuel by 2015. With a total inventory of 56,166 taxicabs in Germany and an average vehicle age of 6.5 years, this gives an annual registration figure of vehicles that use hydrogen as an alternative fuel of about 9,800.

2.3.3.3. Development of the vehicle population in the PC, RENT, HGV<3.5, HGV<7.5 and HGV<14 categories

The trend in new vehicle registrations for hydrogen as an alternative fuel in the PC, RENT, HGV<3.5, HGV<7.5 and HGV<14 categories is based on the assumption that this development will grow at the rate of increase shown in the “Scenario OWN, PC” in Figure 15, which falls between the “Scenario DKW pessimistic, PC” and the “Scenario DUDENHÖFFER, PC” figures.

2.3.3.4. Development of the vehicle population in the OB, HGV>14 and ARTIC categories

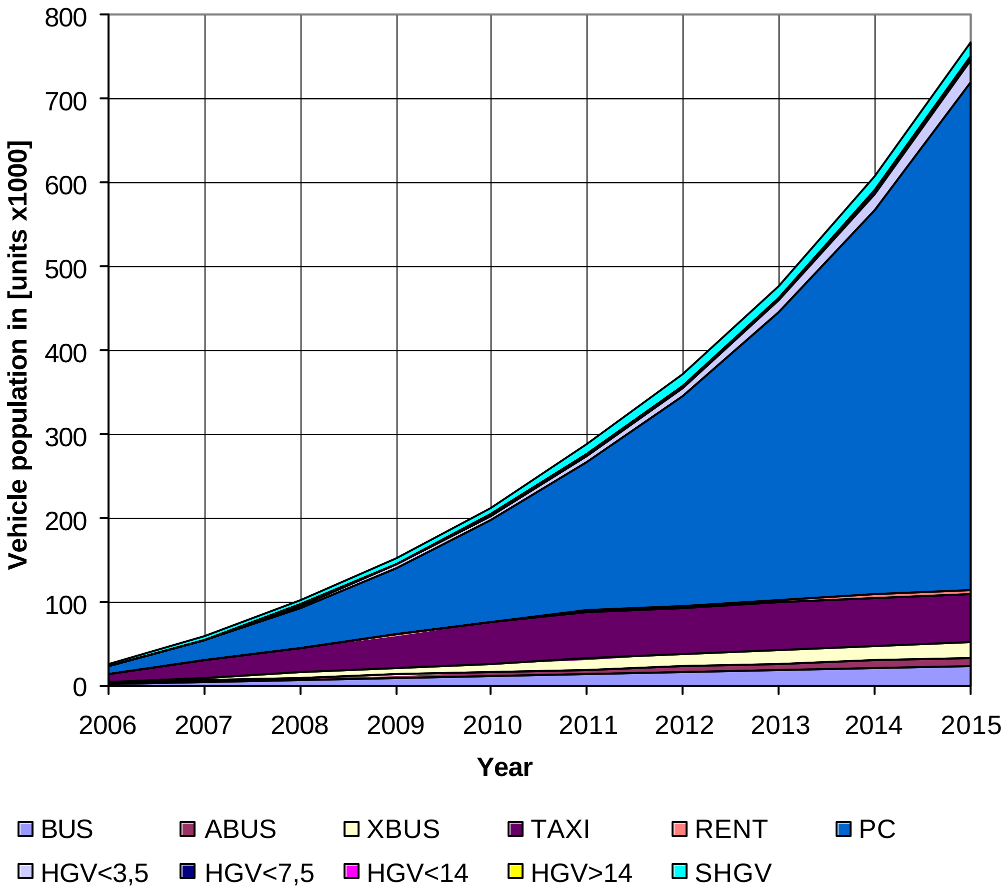
Vehicles in the OB, HGV>14 and ARTIC categories are mainly used for long-distance journeys and also travel outside the country. A substitution of these vehicles by vehicles for hydrogen as an alternative fuel can only take place when sufficient coverage of the gas station network can be guaranteed at least at the national level.

In this paper, it is assumed that for vehicles in the HGV>14 category that the substitution of these vehicles by vehicles that use hydrogen as an alternative fuel will take place from 2015 at the rate of increase for new vehicle registrations assumed in the “Scenario OWN, PC” in Figure 15.

For vehicles in the OB and ARTIC categories, it is assumed that substitution of the vehicles by vehicles that use hydrogen as an alternative fuel will start from 2063. Starting with a share of 3 % of the new vehicle registrations in these categories, a constant annual increase of the alternative registration share of 3 % until 2078, then 4 % until 2081 and 5 % until 2087, has been assumed. In 2087, there will be an alternative vehicle share of 90 % in vehicle registrations, and this will be considered as remaining constant for the time being. It should be stressed that the assumptions made here of a possible inventory development for vehicles in the OB and ARTIC categories are given for the sake of completeness and do not correspond with any supporting database.

If the possible vehicle population figures in the individual categories over the years are added up, this yields the pattern of vehicle population development using hydrogen as an alternative fuel in Germany, as shown in Figure 16. In the first few years, the overwhelming proportion of alternative vehicle populations is made up of taxicabs and buses. From 2009, the passenger car inventory starts to overtake the other vehicle populations in terms of volume.

Figure 16: Assumed development of the alternative vehicle population by vehicle category in Germany from 2006 to 2015

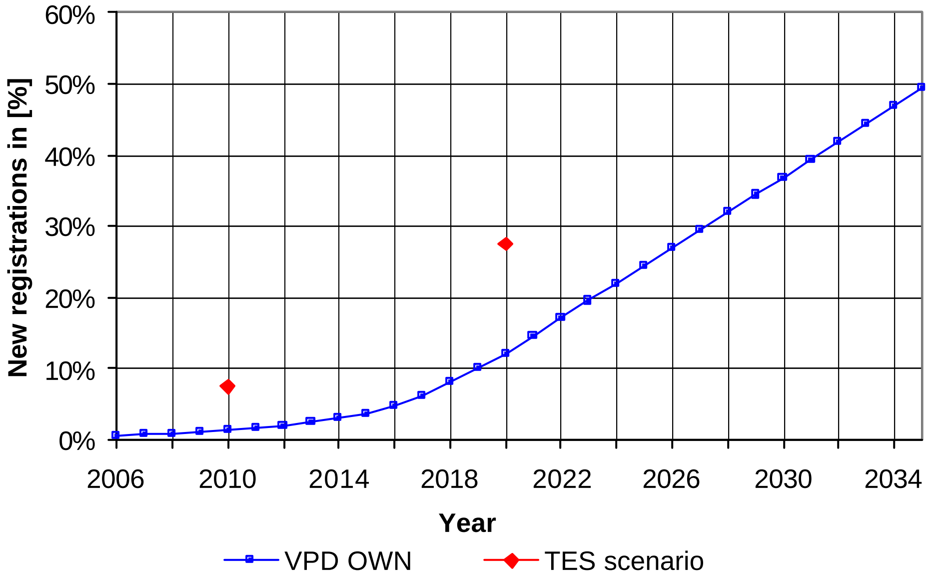


BUS = Scheduled buses, ABUS = Scheduled articulated buses, XBUS = Cross-country buses, TAXI = Taxis, RENT = Rental cars, PC = Passenger cars, HGV<3.5 = Heavy goods vehicles with gross weight limit of less than 3.5 t, SHGV = Special trucks (vehicles for refuse collection and street cleaning).
Source: Own calculations, 2001

For a better overview, we can examine the development of the share of the new alternative motor vehicle registrations in the total new vehicle registrations in Germany (Figure 17). A share of new alternative registrations of 1.2 % will be reached by 2010, and 12 % by 2020.

By way of comparison, the forecasts of the TES of 5 to 10 % for 2010 and 25 to 30 % for 2020 are also shown ("TES scenario" points values in Figure 17).

Figure 17: Development of the annual new alternative motor vehicle registration share in total new motor vehicle registrations according to vehicle population development OWN (VPD OWN) and the Transport Energy Strategy (TES) in Germany from 2006 to 2035



Source: TES, 2000, p. 4; Own calculations, 2001

2.3.4. Development of the demand for hydrogen

To determine hydrogen demand as a consequence of the chosen VPD OWN, reference vehicles with the necessary fuel consumption for each vehicle category were defined (Chapter 2.2.3). As hydrogen as an alternative fuel can be used in the selected vehicle categories both as a direct energy supplier in an internal combustion engine, and also in a fuel cell for supplying electricity to an electric motor, assumptions must be made regarding the future share of the respective type of power train (internal combustion engine or electric motor) in the alternative vehicle population.

As the build-up of a gas station infrastructure is not possible in a very short space of time, the annual distances covered will be achieved using both hydrogen and gasoline, in using bivalent vehicles. Their share of the annual distance covered will be approximately estimated.

2.3.4.1. Assumed future shares of powertrain types

As it is not currently possible to make a serious estimate of the future development of the internal combustion engine and the electric motor with fuel cell driveline in the passenger car category, it is assumed that at the start of the build-up of a gas station infrastructure, both of the alternative vehicle drives mentioned will have a share of 50 % in the private car inventory (Table 13).

For vehicles in the TAXI and RENT categories it is assumed that in the first five years these will be fitted with bivalent internal combustion engines due to the lack of a sufficient gas station infrastructure, and will only then be sold successively with electric motor and fuel cell as well. The basis for this assumption lies in the fact that vehicles in this category are also used for cross-country journeys, for which a sufficient supply of hydrogen cannot yet be guaranteed in the first years of the build-up of a gas station infrastructure. However, from 2015 on, a balance of the alternative vehicle populations consisting of 50 % with internal combustion engines and 50 % with electric motors and fuel cells is assumed.

In the case of vehicles in the bus categories (BUS, ABUS and XBUS), it has already been pointed out in Chapter 2.2.3.3 that in all probability these will be fitted with electric motors and fuel cells as the future form of powertrain. Vehicles in the OB and ARTIC categories will only be sold with an alternative drive from 2063 on, and according to current knowledge only with an internal combustion engine.

Vehicles in the HGV<3.5, HGV<7.5, HGV<14 and SHGV categories will in the first five years be fitted with bivalent internal combustion engines due to the lack of a sufficient gas station infrastructure, and will only then be sold successively with electric motor and fuel cell as well. As these vehicles are predominantly used in urban areas and in the urban hinterland, and the electric motor with fuel cell has advantages over the hydrogen-fueled internal combustion engine in this use profile, it is assumed that in 2018 a population of alternative vehicles will exist that consists of 80 % vehicles with electric motors and 20 % vehicles with internal combustion engines.

Table 13: Annual shares of power train types: internal combustion engines (ICE) and electric motor with fuel cell (FC) as a percentage of the alternative vehicle population according to vehicle category in Germany from 2006 to 2018

Vehicle category	Drive	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
PC	ICE[1)]	50	50	50	50	50	50	50	50	50	50	50	50	50
	FC[1)]	50	50	50	50	50	50	50	50	50	50	50	50	50
TAXI, RENT	ICE	100	100	100	100	100	90	80	70	60	50	50	50	50
	FC	0	0	0	0	0	10	20	30	40	50	50	50	50
BUS, ABUS, XBUS	ICE	0	0	0	0	0	0	0	0	0	0	0	0	0
	FC	100	100	100	100	100	100	100	100	100	100	100	100	100
OB	ICE	0	0	0	0	0	0	0	0	0	0	0	0	0
	FC	0	0	0	0	0	0	0	0	0	0	0	0	0
HGV<3.5, HGV<7.5, HGV<14, SHGV	ICE	100	100	100	100	100	90	80	70	60	50	40	30	20
	FC	0	0	0	0	0	10	20	30	40	50	60	70	80
HGV>14	ICE	0	0	0	0	0	0	0	0	0	100	100	100	100
	FC	0	0	0	0	0	0	0	0	0	0	0	0	0
ARTIC	ICE	0	0	0	0	0	0	0	0	0	0	0	0	0
	FC	0	0	0	0	0	0	0	0	0	0	0	0	0

1) ICE = internal combustion engine, FC = fuel cell.
BUS = Scheduled buses, ABUS = Scheduled articulated buses, XBUS = Cross-country buses, OB = Other buses (coaches), TAXI = Taxis, RENT = Rental cars, PC = Passenger cars, HGV<3.5 = Heavy goods vehicles with gross weight limit of less than 3.5 t, SHGV = Special-purpose trucks (vehicles for refuse collection and street cleaning), ARTIC = Articulated vehicles.
Source: Own assumptions, 2001

2.3.4.2. Assumption of future distance shares using hydrogen

As the build-up of a gas station infrastructure is not possible in a very short space of time, the distances will be covered using both hydrogen and gasoline in bivalent vehicles. In vehicles driven by electric motors and fuel cells, the entire annual distance covered will be covered with hydrogen as an alternative fuel from the start of the introduction of hydrogen.

Since in recent years the observed distance ratio in urban, rural and motorway conditions in Germany has been registered as approximately 30:40:30 (see Table 35 in Appendix 2) and if it is assumed that all intra-urban trips are made using hydrogen, then the share of the total distance covered using hydrogen is at least 30 %. If it is further assumed that 60 % of the distances covered on dedicated highways and rural roads (a total 70 % share) can be covered using hydrogen, this gives a total share with hydrogen of approximately 70 %, which can be used in the first years of hydrogen introduction as the basis for further calculation (Table 14). With increasing build-up of the gas station infrastructure, the hydrogen share in the annual distance covered will increase further. From 2030, it is assumed that vehicles with bivalent internal combustion engines can cover the complete distance with hydrogen fuel.

Table 14: Annual performance shares using hydrogen as a percentage of the annual distance covered by vehicles with an internal combustion engine (ICE) or electric motor with fuel cell (FC) powertrain in Germany from 2006 to 2030

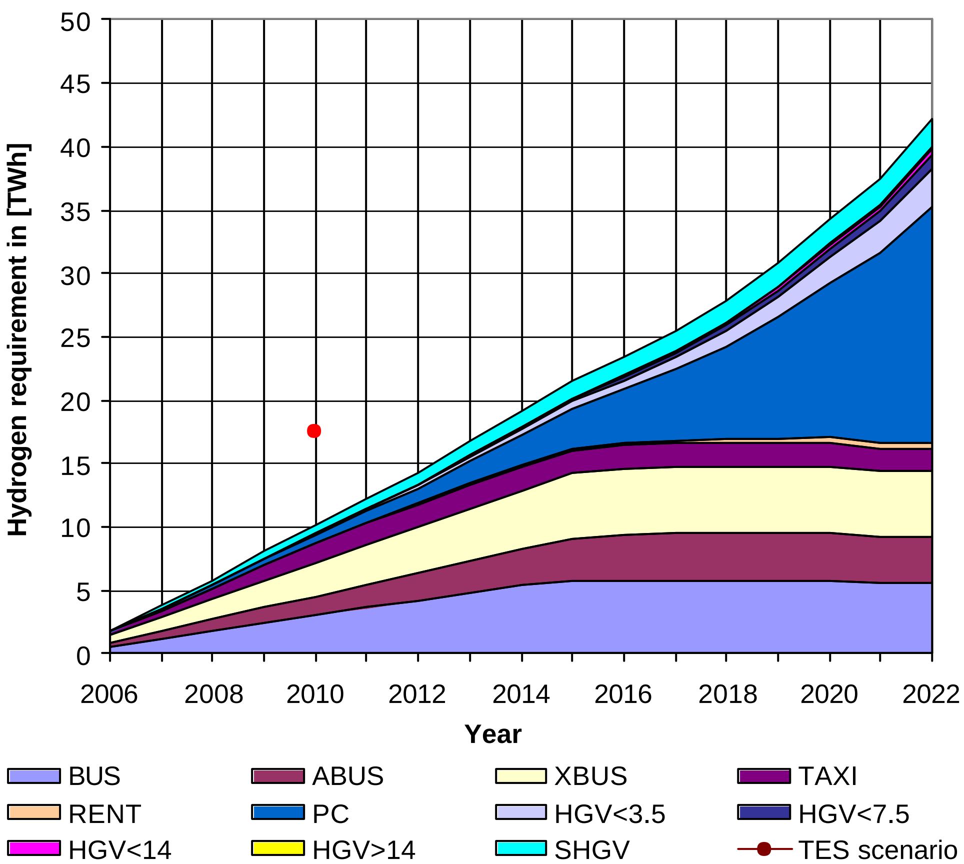
Vehicle category	Drive	2006	2007	2008	2009	2010	2011	2012	2013-2030	from 2030
ALL	FC[1)]	100	100	100	100	100	100	100	100	100
ALL	ICE	70	70	70	80	80	80	80	90	100

[1)] ICE = internal combustion engine, FC = fuel cell
Source: Own assumptions, 2001

2.3.4.3. Hydrogen demand in Germany

The **hydrogen demand development OWN (HDD OWN)** resulting over the years from the assumptions made here is presented in Figure 18. In the first years, the majority of the hydrogen will be needed by buses. Once all the buses in Germany run on hydrogen as an alternative fuel (from 2015 on), the hydrogen demand for vehicles in the passenger car category will grow very strongly. By way of comparison, the TES assumed hydrogen requirement for 2010 is included. In 2020, this is about 100 TWh, more than double the assumed HDD OWN.

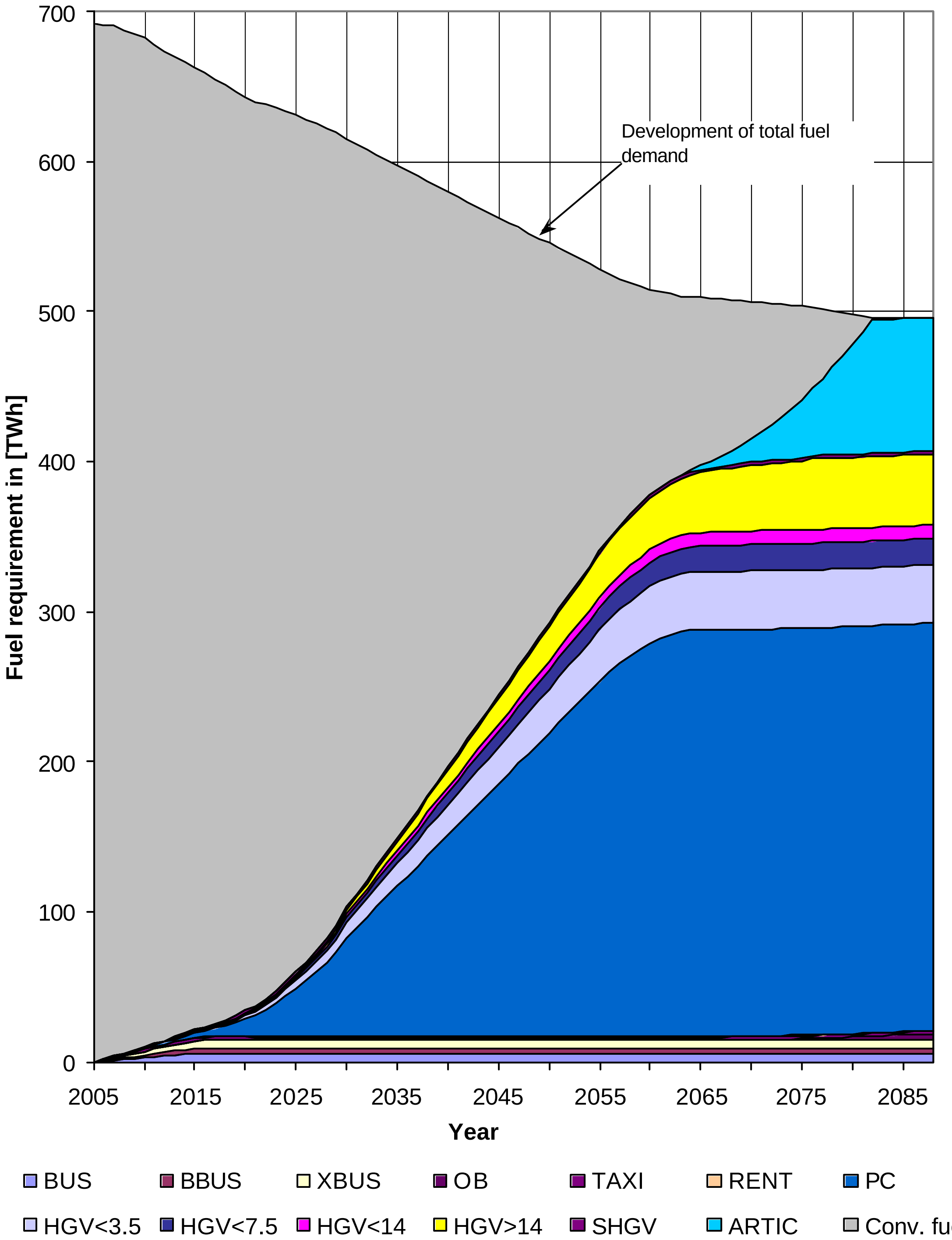
Figure 18: Development and composition of hydrogen requirement according to vehicle categories of the vehicle population development OWN (VPD OWN) and the Transport Energy Strategy (TES) in Germany from 2006 to 2022



BUS = Scheduled buses, ABUS = Scheduled articulated buses, XBUS = Cross-country buses, TAXI = Taxis, RENT = Rental cars, PC = Passenger cars, HGV<3.5 = Heavy goods vehicles with gross weight limit of less than 3.5 t, SHGV = Special trucks (vehicles for refuse collection and street cleaning).
Source: VES, 2000, p. 4; Own calculations, 2001

The division of the future fuel requirement into conventional fuel (gasoline, diesel) and alternative fuels (hydrogen) is shown in Figure 19. The total fuel requirement over the years has been assumed according to TREMOD (Figure 10).

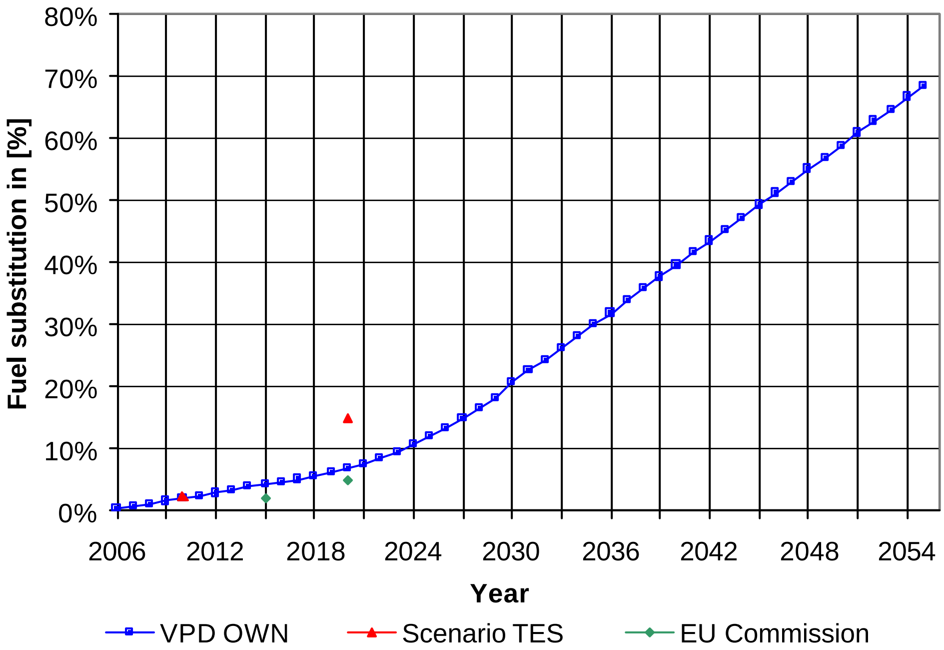
Figure 19: Development and composition of hydrogen requirement according to vehicle categories and development of conventional gasoline and diesel fuel requirements (conventional fuel) according to vehicle population development OWN in Germany from 2005 to 2088



BUS = Scheduled buses, ABUS = Scheduled articulated buses, XBUS = Cross-country buses, OB = Other buses, TAXI = Taxis, RENT = Rental cars, PC = Passenger cars, HGV<3.5 = Heavy goods vehicles with gross weight limit of less than 3.5 t, SHGV = Special trucks (vehicles for refuse collection and street cleaning), ARTIC = Articulated vehicles .
Source: TES, 2001; Own calculations, 2001

The percentage share of hydrogen fuel in total German road traffic fuel consumption is shown in Figure 20. A market share of around 2.0 % will be achieved by 2010, and around 7 % by 2020. The proposal of the European Commission for the Council Directive predicts a hydrogen share of 2 % in 2015 and 5 % in 2020 (CEC[39], 2001, p. 13). This is confirmation of the assumed HDD OWN. For purposes of comparison, the TES scenario values are still included in the diagram.

Figure 20: Development of the hydrogen fuel share of fuel consumption in German traffic according to vehicle population development OWN (VPD OWN), the Transport Energy Strategy (TES) and the Commission of the European Communities (EU Commission) from 2006 to 2055



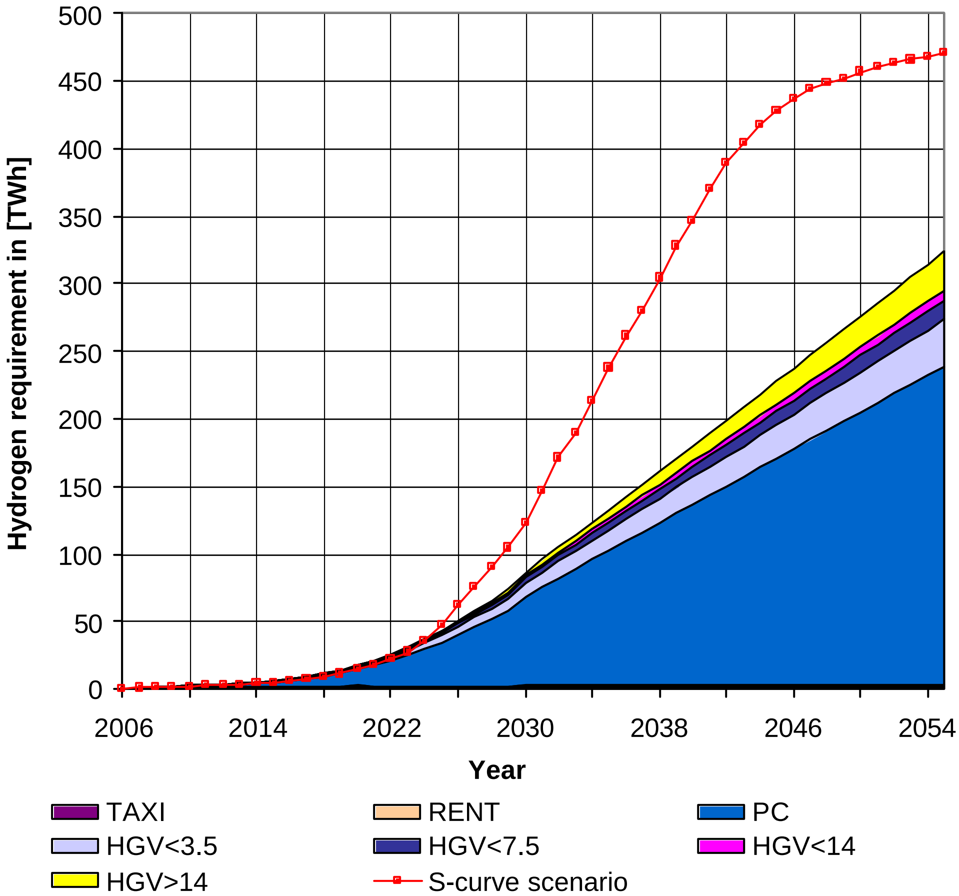
Source: CEC, 2001, p. 13; TES, 2000, p. 4; Own calculations, 2001

A comparison of fuel substitution according to VPD OWN with the characteristics of a typical S-curve (Figure 14) is shown in Figure 21. For the comparison, the hydrogen requirement of the scheduled buses and of vehicles used for refuse collection and street cleaning was deducted from the total hydrogen demand in accordance with HDD OWN, as this does not depend directly on customer acceptance, which is represented by the typical S-curve. In the S-curve scenario it was assumed that the 10 % hydrogen share of fuel substitution would be reached in 2025. It can be seen that until 2018, the hydrogen requirement grows in almost the same way as in the HDD OWN, but thereafter much more strongly because of more rapid vehicle market penetration. According to the S-curve scenario, approximately complete fuel substitution by hydrogen would already be achieved by 2055. This affects the build-up of a gas station infrastructure to the extent that the complete modification of all gas stations to supply hydrogen is then achieved earlier.

The effect that rapid market penetration of vehicles using hydrogen as an alternative fuel with the characteristic of the S-curve has on the build-up of a gas station infrastructure and on hydrogen costs is shown as part of a sensitivity analysis in Chapter 7.4.

[39] Commission of the European Communities

Figure 21: Development and composition of hydrogen requirement according to vehicle categories in the vehicle population development OWN (VPD OWN) and according to the S-curve scenario of traffic in Germany from 2006 to 2055



TAXI = Taxis, RENT = Rental cars, PC = Passenger cars, HGV<3.5 = Heavy goods vehicles with gross weight limit less than 3.5 t.
Source: Own calculations, 2001

The determining of the hydrogen requirement for supplying vehicles in Munich uses the same assumptions as for Germany in the HDD OWN. The inventory of alternative vehicles and the hydrogen demand in Munich are shown in Appendix 3.

2.4. Summary

Tasks
To calculate the possible development of the gas station infrastructure in Munich and Germany, we need an estimation of the valid development of the hydrogen demand that can be realized in relation to elapsed time. The time factor is accordingly included in the calculations.

Assumptions and approach
As in the fuel substitution phase hydrogen demand through the years may grow continually, we can determine which development of the gas station infrastructure gives rise to which effects, e.g. on vehicle supply or hydrogen costs. For a detailed determination of a valid, realizable development of the hydrogen requirement of vehicles in Munich and across Germany, vehicle categories have been selected according to their area of use (incl. local traffic, long-distance traffic). Examples of the categories are passenger cars, scheduled buses, scheduled articulated buses and trucks (divided up

additionally according to gross weight limit). As a consequence of the definition of reference vehicles in each vehicle category and the researched forecasts of a possible development of vehicle populations for the alternative hydrogen fuel, we obtain the development of the hydrogen-fueled vehicle population. The forecast increase of road traffic (private and commercial) in Germany is also taken into account.

Determining fuel consumption data in each vehicle category (divided into gasoline (petrol), diesel and hydrogen fuels) makes it possible to calculate the trend in hydrogen requirements for Munich and Germany, based on development of the population of hydrogen vehicles. Future shares of the powertrain types (internal combustion engine, electric motor with fuel cell) in the respective vehicle category will also be taken into account.

The time line under consideration runs from 2006 to 2035. From 2035 on there is only a simplified description of the development of the vehicle population to 2088, when almost complete fuel substitution should be achieved.

Findings

A market introduction of hydrogen fuel in the vehicle categories of scheduled buses (except for coaches) and vehicles used for waste collection and street cleaning appears meaningful. These vehicles operate within a certain area from central operating depots, so that the supply of these vehicles with hydrogen can be guaranteed from the start.

As taxis (cabs) essentially use the conventional roadside gas station network, vehicles in this category, like those in the passenger car category, require the quickest possible modification of the conventional gas station network to supply hydrogen. With an early substitution of these vehicles by vehicles that use hydrogen as an alternative fuel, relatively high utilization of the modified gas stations can be achieved, especially in the first years following the market launch.

Following a very slow increase in this category of the vehicle population in the first few years after the launch, market penetration by vehicles in the passenger car and truck categories grows very rapidly (increase of the vehicle population in the form of an S-curve). Although development of the vehicle population in the passenger car and truck categories quickly overtakes the substituted populations in the bus and taxi categories, the principal hydrogen demand in the first 10 years or thereabouts is created by buses, due to their high fuel consumption.

A substitution of coaches and long-distance trucks will be considered meaningful when an adequate hydrogen fuel supply can be guaranteed nationally, and to some degree internationally.

The resulting development in hydrogen demand shows that the percentage share of hydrogen fuel in the total fuel consumption of road traffic in Germany will be about 7 % after 15 years and about 30 % after 30 years. The share of alternative-fuel new vehicle registrations in total new vehicle registrations in Germany should be about 1.2 % five years after the launch, and about 12 % fifteen years after the launch.

Conclusion and recommendations

A sensitivity analysis examines development of the vehicle population, in which the percentage share of hydrogen fuel in the total fuel consumption of German road traffic increases more rapidly than shown here.

3. Hydrogen production and distribution

Having established the possible development of the hydrogen requirement from 2006 to 2035 in the HDD OWN (Chapter 2.3.4), an examination of the hydrogen supply situation now follows. Hydrogen production can take place using different processes, which are explained briefly here. The processes with the greatest potential are then examined more closely.

Steam reforming from natural gas is currently of greatest significance for hydrogen production. It involves an endothermic[40] catalytic conversion of the light hydrocarbons (here, primarily methane CH_4) with steam. A detailed description of this process can be found in Chapter 3.3.

Under **partial oxidation**, the exothermic[41] conversion of heavy hydrocarbons (e.g. residual oil from petroleum processing, heavy heating oil) takes place using oxygen. As the guaranteed reserves of oil are expected to last only about 40 years (Chapter 2.1.2.3), there will be no closer examination of this hydrogen production process.

Coal gasification functions similarly to the partial oxidation of residual oil, although the coal must be pre-treated. It is finely ground and mixed with water to form a suspension suitable for pumping (www.hydrogen.org, 9.09.2002). As the CO_2 emissions in this process have a factor approximately twice that of the emissions in natural gas steam reforming (Appendix 4), this process is not ecologically sensible for hydrogen production.

In the **plasma-arc process** (Kvaerner process), the hydrocarbons (natural gas, oil) are separated by pyrolysis[42] at around 1,600 °C into pure carbon and hydrogen. Because the carbon content of the raw materials is completely converted to pure carbon, there is no CO_2 formation (Valentin, 2001, p. 26). This process is in the pilot phase. As no large-scale production using this process appears possible now or in the foreseeable future, it is not examined more closely.

Hydrogen production by **biomass gasification** is currently not yet commercially available. The significant advantage of biomass gasification is CO_2 neutrality, as the gassing or combustion of the biomass only creates as many CO_2 emissions as were previously bound in with the growth of the plant. For this ecological reason, a closer examination of this process is made, though hydrogen production can only take place in fairly small quantities as a consequence of the limited biomass potential. Furthermore, CO_2 emissions in truck transport of the biomass to the gasification plants have to be taken into account (the effects of the use of fertilizers for accelerated plant growth are not considered in this paper).

The greatest significance in the medium and long term is hydrogen production by the **electrolysis of water**. As this process requires a relatively high level of electricity, regenerative electricity generation is of significant importance.

In addition to the processes mentioned above, intensive research into other hydrogen production processes is being carried out. These include, for example, the **biological production of hydrogen from algae** or the **thermal fission of water** at temperatures of about 700 °C as a result of catalytic influence. These processes are in the research stage and are currently only achievable in the laboratory, so that they are not considered in this paper.

As the type of electricity generation, namely nuclear-generated electricity, regeneratively produced electricity or electricity from a power station, has a significant influence on the production costs of hydrogen as well as on CO_2 emissions, there will be closer examination of electricity generation.

[40] Heat is needed for the reaction.
[41] Heat is given off by the reaction.
[42] Splitting of chemical bonds using high levels of heat.

3.1. Bases of calculation for hydrogen production and distribution

3.1.1. Business management bases

The investment figures presented in the following Chapters (investment for hydrogen production, power stations for electricity generation) show average values, which are used for the nationwide calculation. It should be stressed that the minimum and maximum volumes of investment stated here (capacities) do not represent limits, but only the size of the change of the specific investments depending on the investment size based on economies of scale (EOS).

For calculating the hydrogen and electricity costs, the investment undertaken is taken into account as annuities over the depreciation period with real interest payments. One indicator for the exploitation of the created value potentials is the "weighted average cost of capital" (WACC). The WACC represents the weighted average cost of capital funds and outside capital with the relevant share of total capital (Luehrman, 1997, p. 153). For companies in the sectors affected by the build-up of a hydrogen infrastructure, the following WACC values are determined:

- Automobile industry: DaimlerChrysler - WACC before tax 15.5 % in 1998, WACC long-term after tax at least 8 % (www.daimlerchrysler, 26.05.2003)
- Energy suppliers: E.ON - WACC before tax 11.2 % in 2000, 9.5 % in 2001 (EON, 2001, p. 45) and 9.5 % in 2002 (EON, 2003, p. 55)
- Mineral oil industry: OMV – target for WACC at least 10 % after tax (OMV, 2002, p. 13)

The high real interest before tax is due to the fact that investors in the affected sectors (including mineral oil companies, energy suppliers and the automobile industry) expect a correspondingly high return on invested capital (TES, 2001, p. 32). Furthermore, the high interest can also be seen as a risk bonus for investments in a new technology. For example, in its studies on the calculation of the total costs of CO_2 sequestration, the **International Energy Agency** (IEA) uses a real interest rate of 10 % (IEA (b), 2002).

For calculation of the specific costs and the total costs discounted to 2006 (Chapter 1.2), this paper uses a WACC with a real interest rate of 12 %. As part of a sensitivity analysis, the effects of the level of the selected interest rate on the total costs discounted to 2006 are determined.

The delivery costs of the input factors - natural gas, coal and biomass - depending on the purchased quantity are shown in Appendix 4.

3.1.2. Economies of scale

The **economies of scale (EOS)** of the hydrogen production plants considered in this paper consist primarily of (Rosegger, 1996, p. 84-90; Stepan, 2002):

- Cost degression as a result of input/output effects: This allows for the effect that with an increasing rated output from the hydrogen production plant, the specific investment costs for these plants are reduced (fixed cost degression, volume effect).
- Pecuniary cost degression: The effect is taken into account that with increasing rated output from the hydrogen production plants and the higher consumption of input factors such as electricity and natural gas, these can be purchased at lower cost compared with smaller plants.
- Learning effect: This effect takes into account that the costs relevant to the creation of value (in this paper in the form of investments) reduce with the increasing number of plants constructed, due to experience gained in the past.

Estimation of the reduction potential of plant investments is based on the **learning curve or experience curve**, which means that the costs relevant to the creation of product value fall after introduction as a result of the increase in the number of units produced (Stepan, 2002; Henderson, 1994, p. 405). An 80 % learning curve means that when the number of units doubles, the costs relevant to the creation of value of the product are only 80 % of the initial costs. The curve is an exponential function, dependent on the number of units, initial costs and an experience value b, which varies from sector to sector. With new, difficult technologies, b is larger than for known, simple technologies (Hörbst, 2000, p. IV-16 f.). For example, the automobile manufacturer Ford achieved an 85 % learning curve on its conveyor-based production lines between 1909 and 1923 (Hörbst, 2000, p. IV-16). At 30 %, the learning curve has a particular strong effect in micro-electronics, for example in memory modules.

The precondition for falling costs is the manufacture of standardised systems with suitable capacity and individual plants that are not too dissimilar. The learning effect comes into being from the first unit and has no upper limit (Stepan, 2002).

The influence of the series production of gas stations on reduction of the investment per gas station as their number increases can be taken into account in accordance with Equation 4 (Bünger, 2000, p. 8); the equation is used for general power stations as well as for hydrogen production plants:

Equation 4: $$I_n = I_1 * n^{-b}$$

I_1 .... Investment in the first plant
I_n .... Investment in the n^{th} plant
n .... Number of plants constructed
b .... Parameter, b = 0.1 – 0.2

Mathematically, the degression factor is defined according to Equation 5, which gives the investment in the n^{th} plant constructed (Thomas, 1997):

Equation 5: $$LogC_N = \frac{LogA * LogN}{Log2} + LogC_1$$

C_1 .... Investment in the first plant
C_N .... Investment in the n^{th} plant
N .... Number of plants constructed
A .... Degression factor

Table 15: Comparison of the reduction potential in plant investments with an increasing number of plants, depending on the degression factor

Number of power stations	Investment according to Equation 4, b=0.1	Investment according to Equation 4, b=0.15	Investment according to Equation 4, b=0.2	Investment according to Equation 5 with A=0.9
1	1,000,000	1,000,000	1,000,000	1,000,000
2	933,000	901,000	870,000	900,000
4	870,000	812,000	758,000	810,000
8	812,000	732,000	660,000	729,000
16	758,000	660,000	574,000	656,000
32	707,000	594,000	500,000	590,000
64	660,000	536,000	435,000	531,000
128	615,000	483,000	379,000	478,000
500	537,000	394,000	288,000	389,000

Source: Own calculations, 2001

If the reduction potentials of the investments are compared on the basis of Equation 4 and Equation 5 in Table 15, it is apparent that for a parameter b = 0.15 in Equation 4, almost identical investments are obtained as for a degression factor of A = 0.9 in Equation 5. Both of these factors correspond to average investment reduction potentials. Equation 5 is used in this paper for consideration of the learning effect.

3.2. Electricity generation

3.2.1. Conventional power stations for electricity generation

A summary of the history of electricity consumption in Germany is shown in Table 16. It can be seen that electricity consumption has increased continuously in recent years.

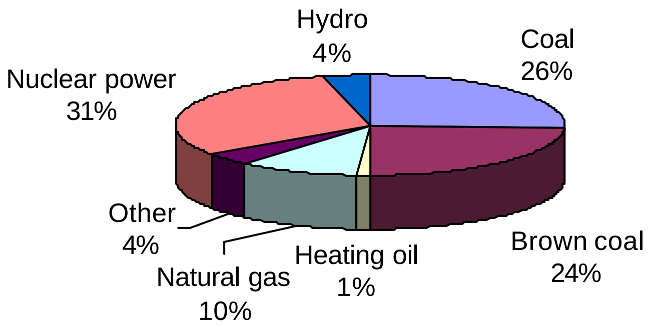
Table 16: Total electricity consumption and the share from renewable energy sources in Germany from 1996 to 2001

	Unit	1996	1997	1998	1999	2000	2001
Total electricity consumption	TWh_{el}	470	474	482	486	498	~500
Electricity from renewable energy sources	TWh_{el}	19.2	19.7	22.8	26.5	31.4	~35

Source: BMU[43], 2002, p. 10

The structure of electricity generation according to energy sources in Germany in 1999 is shown in Figure 22. Electricity generation from regenerative energy sources such as wind power, solar energy and biomass, are under the heading “Other”. About one third of the electricity produced is generated by nuclear power stations.

Figure 22: Structure of electricity generation in Germany in 1999



Source: Haupt, 2001, p. 4

As Germany has decided to stop using nuclear power to generate electricity (www.tam.de, 7.09.2001), its share must be taken over by other forms of electricity generation, such as regenerative production, and probably also by conventional gas and steam turbine power stations (GST power stations). This means that fewer than 100 % of the regenerative energy sources are available for the generation of electricity for hydrogen production. In agreement with the TES, it is assumed that 50 % of the available regenerative potential of electricity generation could be secured for traffic needs and the remaining 50 % used for stationary purposes (TES, 2001, p. 22).

The share of regenerative electricity generation in electricity consumption in Germany for 2000 was about 6.25 %, and should increase to 12.5 % by 2010 and 50 % by 2050 (BMU, 2002, p. 10). Using the electricity consumption level for 2001, this yields a regeneratively produce quantity of electricity of 60 TWh for 2010 and about 250 TWh for 2050. As this paper investigates the regenerative electricity requirement for hydrogen production, a comparison can be made using the Federal German Government’s stated target values.

[43] BMU = Federal German Ministry for the Environment, Conservation and Reactor Safety

Power stations generating electricity in Germany currently produce average CO_2 emissions of about 600 g/kWh$_{el}$ (E.ON, 2001). As the build-up of a gas station network for the supply of hydrogen will only start in a few years' time, and GST power stations will probably also be used to take the place of nuclear power stations, this paper uses a value of 700 g/kWh$_{el}$ as a basis for calculating CO_2 emissions in the generation of electricity at power stations. For this calculation it is assumed that the share of electricity generation by nuclear power stations of 31 % (see Figure 22) will be replaced by coal-fired power stations (5 %) and GST power stations (10 %).

3.2.2.Potential regenerative energy sources

The primary regenerative energy source most discussed in Germany and the European Union is wind power. Hydro-power potential is largely exhausted (Table 17).

Table 17: Overview of regenerative technical potentials of electricity generation from primary energy sources in Germany and the EU in 2001

Energy source	Potential for electricity generation	Potential for electricity generation for calculation purposes (average)	Assumption: 50% availability for traffic[2)]
Germany			
Hydro-power [1)]	6.7	6.7	3.4
- small power stations included in above	3.6	3.6	1.8
- renewable included in above	3.1	3.1	1.6
Offshore wind power	29.0 – 237.0	133.0	66.5
Onshore wind power	26.0 – 117.0	72.0	36.0
Solid biomass	24.5 – 77.5	51.0	25.5
Biogas	6.6 – 20.7	---	---
Photovoltaics	98.1	---	---
Geothermal	166.0	---	---
European Union (EU)			
Hydro-power	259.0	259.0	129.5
Offshore wind power	1,790.0	1,790.0	895.0
Onshore wind power	349.0	349.0	174.5
Solid biomass	634.0	634.0	317.0
Photovoltaics	604.0	604.0	302.0

1) still an expandable potential
2) Source: TES, 2001, p. 22
Source: TES, 2000, p. 24, 35; www.iwr.de, 2.05.2001; Dürrschmidt, 2000, p. 22, 24, 28, 53, 60; www.rwe.com, 26.10.2001; Rehfeldt, 2001, p. 53; Bain, 1997, p. 2-2 – 2-16; Entingh, 1997, p. 3-34 – 3-38; Ramesohl, 2002, 15, 30, 50; Own assumptions, 2001.

3.2.2.1. Germany

The **biomass potential** in Table 17 includes only solid materials. Among these are forestry residues and straw without the cultivation of energy plants. With an electrical usage of 0.40 for biomass gasification (Bain, 1997, p. 2.2 – 2.16) this gives a potential for electricity generation of 24.5 to 77.5 TWh$_{el}$ (average of 51.0 TWh$_{el}$).

Biogas is manufactured by the fermentation of harvest residues (maize, grass, sugar beet leaves), cow and pig manure or chicken droppings and biogenic residue. The primary energy potential of fermentable biomass is between 26.2 and 49.3 TWh (TES, 200, p. 35). Due to the low electrical usage of 0.25 to 0.52 (Dürrschmidt, 2000, p. 53), this would give a potential for electricity generation of 6.6 to 20.7 TWh$_{el}$. Assuming that only 50 % of this potential is available for traffic, this yields a generation potential of 3.3 to 10.4 TWh$_{el}$. As a consequence of this low potential, it appears sensible to use the biogas for decentralized electricity generation directly at the point of origin (with the small consumer), and not for the central production of hydrogen products.

The potentials of **photovoltaic electricity generation** in Germany amount to up to 98.1 TWh$_{el}$ (TES, 2000, p. 35). Each horizontal square kilometer of land receives between 900 and 1,200 kWh of radiated energy per year, which can be converted into electricity with an efficiency of only 0.08 to 0.1 (Dürrschmidt, 2000, S. 28). The high costs of electricity generation in Austria of 0.75 € (Own calculations, 2001), can be transferred approximately to Germany, whereby photovoltaics and solar-thermal power stations do not come into question for large-scale electricity generation in the short or medium term.

Up to 30 % of the electricity consumption in Germany, corresponding to around 166 TWh in 1998, could be satisfied using **geothermic power stations** (the hot dry rock process). This requires boring into the Earth to depths of at least 5,000 m (Dürrschmidt, 2000, p. 60). A commercial process to utilize this geothermal heat is not yet available, and is only expected in 6 to 20 years at the earliest (Entingh, 1997, p. 3.34 - 3.38). Experience to date has been with plants of around 5 MW_{el} capacity. An capacity of 50 MW_{el} is seen as realiztic (Ramesohl, 2002, p. 15). In the Ramesohl sustainability scenario, the share of geothermics in electricity generation up to 2050 is regarded as 30 TWh (Ramesohl, 2002, p. 30).

3.2.2.2. European Union

The stated regenerative technical potentials are taken from the TES and show Europe-wide scope for substituting conventional fuels with regeneratively produced hydrogen. By using these primary energy potentials, about 23 % of the conventional fuel consumption of 2.735 TWh in the European Union in 1998 could for example be replaced by liquid hydrogen (LH_2) (TES, 2001, p. 24).

3.2.3. Electricity costs and CO_2 emissions

To determine the cost level of regenerative electricity generation, the power stations used for generating electricity are examined. An overview of the sizes of the power stations for the electricity costs shown in Table 18 can be found in Appendix 5. The values determined there are based on an interest rate of 12 %. The data take into account the learning effect with which, with an increasing number of units, the investment per plant can be reduced. The range of electricity costs are result from the different rated outputs of the plants. The electricity costs of power stations using fossil energy sources are shown for comparison.

Table 18: Electricity costs [€/kWh_{el}] and CO_2 emissions in [g/kWh_{el}] of power stations for electricity generation in Germany from 2005 to 2020

Power stations for electricity generation	Period			CO_2 equivalent [g/kWh_{el}] [1)]
	2005-2010	2010-2015	2015-2020	
Regenerative energy sources				
Large hydro-power station reactivation	0.022			5
Small hydro-power station	0.143			8
Small hydro-power station reactivation	0.043			8
Hydro power station average	0.070			8
Offshore wind power station	0.055	0.053	0.052	15
Onshore wind power station	0.094	0.091	0.088	15
Biomass power station	0.084-0.113	0.080-0.107	0.075-0.100	60
Geothermal power station	Technology not yet commercially available.		0.073-0.099	n.k.
Solar thermal	0.108-0.123	0.101-0.115	0.094-0.107	13
Fossil energy sources				
Gas and steam turbine power station	0.035-0.045			489
Coal-fired power station	0.058-0.098			895
Nuclear power station[3)]	0.06			25[2)]
Transmission fee for electricity [4)]				
High-tension working price, 110kV	0.007			
Mid-tension working price, 10kV	0.015			
Low-tension working price, 0.4kV	0.025			

n.k. = not known

[1)] Weighted total: Carbon dioxide (CO_2): 1 kg CO_2-equivalent/kg CO_2
Methane CH_4: 21 kg CO_2-equivalent/kg CH_4
Dioxides of nitrogen (N_2O): 310 kg CO_2-equivalent/kg N_2O

Source: Neubarth, 2000, p. 26 f., 36, 75 f., 177 f., 344 f.

[2)] Source: www.kernenergie.de, 13.03.2002

[3)] Installed capacity of 1,300 MW, efficiency of 33 %, full-capacity hours of 7,000 h, amortization period of 25 years, investment of 1,900 €/kW; Source: Brauner, 1996, p. BW-11

[4)] Annual usage >3000 h, Working price HT periods; Source: www.swm.de, 8.06.2001; www.stromtarife.de, 27.05.2002

Source: Own calculations, 2001

What is noticeable for **biomass power stations** are the CO_2 emissions during the construction, operation (no use of heating warmth) and demolition of about 60 g/kWh$_{el}$. The share for the supply of biomass (pellets, chopped forestry residues, chopped wood) is about 40 % (Neubarth, 2000, p. 344). At 100 % use of the heating warmth, CO_2 emissions fall to approx. 20 g/kWh$_{el}$. The carbon dioxide created during the combustion of the bioenergy sources is not included in the balance-sheet for climate efficiency, as, assuming a sustained increase[44] of the biomass, it is not additionally climate-effective. As this paper takes into consideration the biomass potential for hydrogen production (Chapter 3.4), no consideration is given to biomass power stations for the supply of electricity for hydrogen production.

For the calculations in this paper, it is assumed that for regenerative electricity generation for hydrogen production in the short and medium term, only the energy sources shaded in gray in Table 18 will be used. Weighting the electricity costs (lower limit of the energy sources on a colored background) for the individual periods with their European technical potentials in Table 17), yields the **average electricity costs for regenerative electricity generation** (Table 19). The transmission charges for the respective voltages according to Table 18 are added to these costs.

Table 19: Electricity costs in [€/kWh$_{el}$] of regenerative electricity generation (weighted with European technical potentials for regenerative electricity generation) with and without transmission charges depending on grid voltage in Germany, from 2005 to 2020

Electricity supply	2005-2010	2010-2015	2015-2020	Connection capacity in [MW] [1)]
Without transmission charges	0.0715	0.0685	0.0664	---
Low-tension	0.0965	0.0935	0.0914	< 3
Medium-tension	0.0865	0.0835	0.0814	2 – 40
High-tension	0.0785	0.0755	0.0734	> 30

[1)] Source: Bünger, 2000, p. 5
Source: Own calculations, 2001

It can be seen that the anticipated medium-term potential of a drop in the costs of regenerative electricity generation is not very high. For the calculations in this paper, only the cost level for the period 2005-2010 for regenerative electricity generation is therefore used. However, as part of a sensitivity analysis, the case if, contrary to the values stated here, the regenerative electricity costs reach a much higher level, is also examined.

Electricity costs used in this paper that depend on purchasing capacity in Germany are shown in Table 20. For the future, increasing electricity costs for electricity from power stations are assumed. Liberalization and privatisation of the energy market have seen a short-term reduction in electricity costs, but because of the trend of companies to form ever-larger units through mergers and acquisitions in order to acquire market power, electricity costs will quickly increase again (Skups, 2001, p. 7 f.; Haas, 2001, p. 4).

Table 20: Electricity costs in [€/kWh$_{el}$] including transmission charges in 2001 for the electricity generation at conventional power stations and future electricity costs in [€/kWh$_{el}$] including transmission charges for electricity generation at a conventional power station (L1), nuclear power station (L2), from regenerative energy source with low cost levels (L3) and from regenerative energy sources with high cost levels (L4) depending on the annual purchased quantity of electricity (purchase capacity) in Germany

Purchase capacity	2001[45]	Level 1 (L1)	Level 2 (L2)	Level 3 (L3)	Level 4 (L4)
Electricity 25 MW, 7000 h/a	0.033	0.043	0.060	0.0785	0.100
Electricity 10 MW, 7000 h/a	0.051	0.061	0.060	0.0865	0.108
Electricity 4 MW, 5000 h/a	0.051	0.061	0.060	0.0865	0.108
Electricity 1 MW, 5000 h/a	0.051	0.061	0.060	0.0965	0.118
Electricity 100 kW, 2500 h/a	0.065	0.078	0.060	---	---

Source: Own calculations, 2001

[44] It is assumed that CO_2 arising from the use of the biomass and the CO_2 processed by the compound during growth are the same in magnitude.
[45] As part of the TES, electricity costs which correspond to the 2001 values in Table 20 are recorded.

Up to 2010 a price rise of 10 % (Förster, 2002) and up to 2002 a further continuous rise in electricity costs are assumed (Skups, 2001, p. 8). The rise in costs will be confirmed by the fact that in the near future many power stations used for generating electricity will be removed from the grid for reasons of age, and will have to be replaced by the construction of new power station, so that by 2020 an increase in the cost of electricity generated in a power station of between 0.0102 and 0.0153 €/kWh$_{el}$ can be assumed (www.tam.de, 12.10.2001). The increase in the cost of electricity at a power station is taken into consideration under Level 1 in Table 20. Level 2 presents the cost of electricity that occurs as a result of the construction of new power stations, such as nuclear power stations[46]. An optimistic level of cost for regeneratively produced electricity is taken into account by Level 3, and a more pessimistic one by Level 4.

3.3. Steam reforming of natural gas

Natural gas steam reforming (NGSR) is the endothermic catalytic conversion of light hydrocarbons (here, primarily methane CH_4) with water vapor. In broad technical terms, these process normally take place at temperatures of 800 – 900 °C and at pressures of about 25 bar (www.hydrogen.org, 26.10.2001) in accordance with Equation 6:

Equation 6: $$C_nH_m + n * H_2O \rightarrow n*CO + (n + m/2) * H_2$$

For pure hydrogen production, the exothermic catalytic conversion (shift reaction) of the carbon monoxide (CO) that is formed takes place with water vapor (H_2O) in accordance with Equation 7:

Equation 7: $$CO + H_2O \rightarrow CO_2 + H_2$$

However, because of the temperature (200 – 500 °C), the energy released by this reaction cannot be directly used for reforming. The carbon dioxide is subsequently by adsorption or membrane separation removed from the gas compound, which must then be cleaned of yet further unwanted components. The residual gas with approx. 60 % combustible parts (H_2, CH_4, CO) is used together with a partial amount of the initial gas to fuel the reformer.

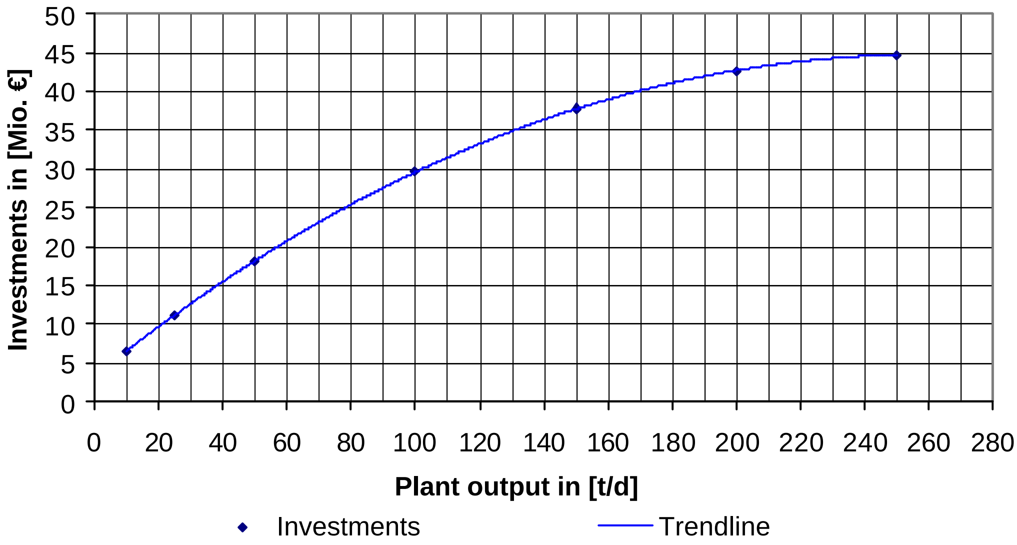
The investment in central NGSR plants[47] depending on the plant capacity (Figure 23) can in a very good approximation be calculated using a third degree polynomial equation (Equation 8):

Equation 8: $$INV = 0.2102 * X^3 - 722.04 * X^2 + 333.164 * X + 3{,}000{,}000 \qquad R^2 = 1$$

INV .... Investment in [€]
X .... Rated plant capacity in [t/d]
R^2 ...... Degree of certainty

[46] As far as it is politically and socially accepted. The costs for the removal and storage of radioactive materials, and the effects in the event of an accident are not taken into account in this section of the paper.
[47] Higher specific plant investments are envisaged for hydrogen production by NGSR plants directly at the gas station (on-site), than at centralized, higher capacity NGSR plants (Valentin, 2001, p. 60) (Appendix 6).

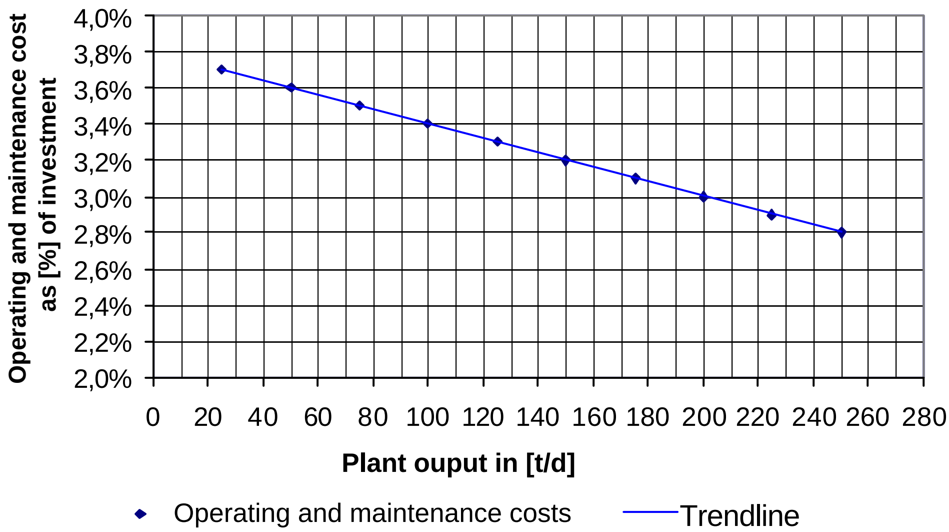
Figure 23: Investment in natural gas steam reforming plants depending on nominal plant capacity in Germany



Source: Valentin, 2001, p. 58; Own calculations, 2001

Taking into account the learning effect according to Chapter 3.1.2, following Valentin, a value for A = 0.90 is seen (Valentin, 2001, p. 80; Own assumptions, 2002).

Figure 24: Operating and maintenance costs of natural gas steam reforming plants depending on plant capacity in Germany



Source: Valentin, 2001, p. 69

In Figure 24, it is evident that the operating and maintenance costs of NGSR plants reduce with increasing plant capacity; they can be determined using a linear formula depending on the plant capacity (Equation 9):

Equation 9: $$B\&W = [(-0.00004)*X + 0.038]*100 \qquad R^2 = 1$$

B&W ... Operating and maintenance costs as [%] of the plant investment
X .... Rated plant capacity in [t/d]
R^2 .... Degree of certainty

According to Equation 9, the operating and maintenance costs of a 25 t/d plant amount to about 3.7 % of the investment in the plant, and of a 250 t/d plant to about 2.8 % of the investment. These costs also include electricity costs. According to Reijerkerk, the electricity consumption of on-site NGSR plants (capacity 200 Nm^3 H_2/h) is about 0.033 kWh_{el}/kWh H_2 (Reijerkerk, 2001, p. 67). In order to be able to investigate the effects of an increase in the cost of electricity as part of the sensitivity analysis, the electricity consumption of large capacity plants (for example, 100,000 Nm^3/h) is assumed to be 0.029 kWh_{el}/kWh H_2, as these show a lower specific electricity requirement because of a higher overall level of efficiency.

On the basis of the higher overall efficiency associated with an increase in plant capacity, there is a reduction in the specific natural gas requirement with increasing plant capacity. In order to simplify calculations, this paper assumes that the fuel consumption of natural gas, independent of the size of the plant, is 0.43 Nm^3/Nm^3 H_2 (corresponding to a plant efficiency of 0.72) (Valentin, 2001, p. 67). For an annual plant load of 85 %, the costs of hydrogen production are 0.043 €/kWh H_2 for a 6.1 t/d plant and 0.027 €/kWh H_2 for a 250 t/d plant.

The CO_2 emissions are composed of the emissions from the NGSR and those from the electricity generation. For the CO_2 created at the NGSR, this now yields emissions of 282 g/kWh H_2 with the previous mentioned natural gas fuel consumption of 0,43 Nm^3/Nm^3 H_2 (for characteristics of natural gas, see Table 45), Using the electricity requirement of NGSR plants of 0,029 kWh_{el}/kWh H_2 also mentioned earlier, this provides us with the CO_2 emissions depending on electricity generation (Chapter 3.2.3).

3.4. Biomass gasification

In the first stage of pyrolysis (gasification without air), biomass reforming produces coke, methanol and primary gases. In the second stage, the reaction with (air) oxygen and/or water vapor then creates a gas mixture of H_2, CO, CO_2, CH_4 (and N_2 if the reforming is carried out with air). The presence of oxygen in the reactor leads to partial oxidation of the intermediate products instead of reforming. Here a distinction is made between autothermal and allothermal reforming. In allothermal reforming, water vapor is used as a gasification agent and the endothermal part-reactions predominate. In this case, external energy must therefore be introduced. The advantage of the process lies in the higher proportion of usable gas components in the product gas (allothermal reforming: H_2: 47 %, CO: 15 %, CH_4: 9 %; autothermal reforming with air: 10 %, CO: 12 %, CH_4: 3 %). The conversion of this mixed gas into a hydrogen-rich gas take place by reforming (CH_4) and the CO shift reaction. The so-called shift reaction ($CO + H_2O \rightarrow CO_2 + H_2$) uses water vapor to convert the CO into carbon dioxide and hydrogen (www.hydrogen.org, 26.10.2001).

No process for producing hydrogen from biomass is currently available commercially. Depending on the method, the processes are still at different stages of research and pre-development.

The investment required for a biomass reforming plant with a rated output of 255 MW is estimated at 567,000 €/MW (column “BG 3” in Table 21). The investment required for plants BG 1 and BG2 were scaled from the BG3 reference plant using Equation 10:

Equation 10:

$$InvBG2 = InvBG3 * \left(\frac{CapBG2}{CapBG3} \right)^{0,7}$$

InvBG2, 3 ....Plant investment in [€]
CapBG2, 3 .....Plant capacity in [MW]

Table 21: Characteristics of biomass gasification plants (BG) depending on plant capacity in Germany

	Unit	BG1	BG2	BG3
Capacity (P_{Out})	MW	19.7	65	255
Efficiency		0.68	0.68	0.68
Full-capacity hours	h/a	8,000	8,000	8,000
H_2 production	GWh/a	157.6	520.0	2,040.0
Electricity requirement	GWh_{el}/a	12.92	42.64	167.28
Investment	Mill. €/ MW	1,222	0.855	0.567
	Million €	24.08	55.54	144.59
Depreciation period	Years	15	15	15
Interest rate		12.0 %	12.0 %	12.0 %
Operation and maintenance costs[1)]		5 %	5 %	5 %
Fuel costs	€/GJ	3.8049	3.8049	3.8049
Fuel use	GWh_F/a	231.77	764.71	3,000.00
Generation costs	**€/kWh**	**0.050**	**0.041**	**0.034**

[1)] As [%] of the initial investment per year
Source: TES, 2001; Own calculations, 2001

In this paper it is assumed that in addition to the active investments in the gasification plant, investments will also be required to cover the electricity requirement using solid oxide fuel cells (SOFC[48]). The investments in a reformer with a capacity of 20.91 MW is 680,000 €/MW and in the fuel cells about 800,000 €/MW (column "BG 3" in Table 22). The investment required for plants BG 1 and BG2 were scaled from the reference plant BG3 using Equation 10.

Table 22: Characteristics of plants for electricity production for biomass gasification plants (BG), depending on rated plant capacity, in Germany

	Unit	BG1	BG2	BG3
Capacity (P_{out})	MW_{el}	1.615	5.330	20.910
Efficiency[1)]		0.47	0.47	0.47
Full-capacity hours[2)]	h/a	8,000	8,000	8,000
Electricity production	GWh_{el}/a	12.92	42.64	167.28
Investment in the reformer	€/MW	1,466,000	1,025,000	680,000
Investment in fuel cells[2)]	€/MW	800,000	800,000	800,000
Depreciation period[2)]	Years	15	15	15
Interest rate		12.0 %	12.0 %	12.0 %
Operation and maintenance costs[3)]		6.6 %	6.6 %	6.6 %
Fuel costs	€/GJ	3.8049	3.8049	3.8049
Fuel use	GWh_F/a	27.5	90.7	356.0
Cost of electricity generation	**€/kWh H_2**	**0.007**	**0.006**	**0.005**

[1)] Efficiency of reforming 68 % (Table 21), efficiency of fuel cell about 70 % (George, 2001, p. 5); there is an overall efficiency of about 47 %
[2)] Source: George, 2001, p. 5-10
[3)] As [%] of the initial investment per year
Source: Own calculations, 2001

With the addition of costs for gasification and electricity generation, the total costs of hydrogen production using biomass reforming come to 0.058 €/kWh in a smaller plant according to BG 1 and to 0.040 €/kWh in a larger plant according to BG 3. When taking into account the learning effect according to Chapter 3.1.2, a degression factor of 0.9 is used.

In order to be able to supply the required quantity of biomass to the gasification plant, a considerable number of trucks is necessary (Table 23). For example, with an average heating value of the biomass of 10,250 kJ/kg, this gives plant BG 2 a biomass requirement of 300,000 t/a or 38 t/h. Using a truck with a load capacity of 20 t, this means deliveries at intervals of about 32 minutes.

[48] SOFC = Solid Oxide Fuel Cell

Table 23: Biomass requirement and period between successive truck deliveries, depending on the plant capacity of biomass gasification plants (BG) in Germany.

	Unit	BG1	BG2	BG3
Biomass requirement	t/a	128,000	300,000	1,180,000
	t/h	16	38	147
Truck delivery every ....[1)]	min	48	32	8

[1)] Truck capacity of 20 t of biomass per journey
Source: Own calculations, 2001

To determine the CO_2 emissions of the trucks, an average transport distance of 50 km (100 km for return trips) is used. With a fuel consumption of 33 l diesel/100 km (292 g CO_2/kWh of diesel) this gives CO_2 emissions of 1.7 g/kWh of biomass. As 1.7 kWh of biomass are required per kWh of hydrogen, CO_2 emissions are thus about 3 g/kWh H_2.

3.5. Electrolysis of water

According to the current state of knowledge, large-scale hydrogen production by the electrolysis of water has the greatest significance in the medium and long term. Assuming that low-CO_2 electricity generation is possible, electrolysis offers a sustained and ecologically acceptable means of producing hydrogen.

Splitting water by electrolysis consists of two part-reactions at the electrodes, which are separated by an ion-conducting electrolyte. Hydrogen is produced at the negative electrode (cathode) and oxygen at the positive electrode (anode). The necessary charge balance takes place through ion conduction. In order to keep the oxygen and hydrogen gases separate after they have been produced, the two reaction spaces must be separated by an ion-permeable separator (diaphragm). Electrical energy is used for water splitting.

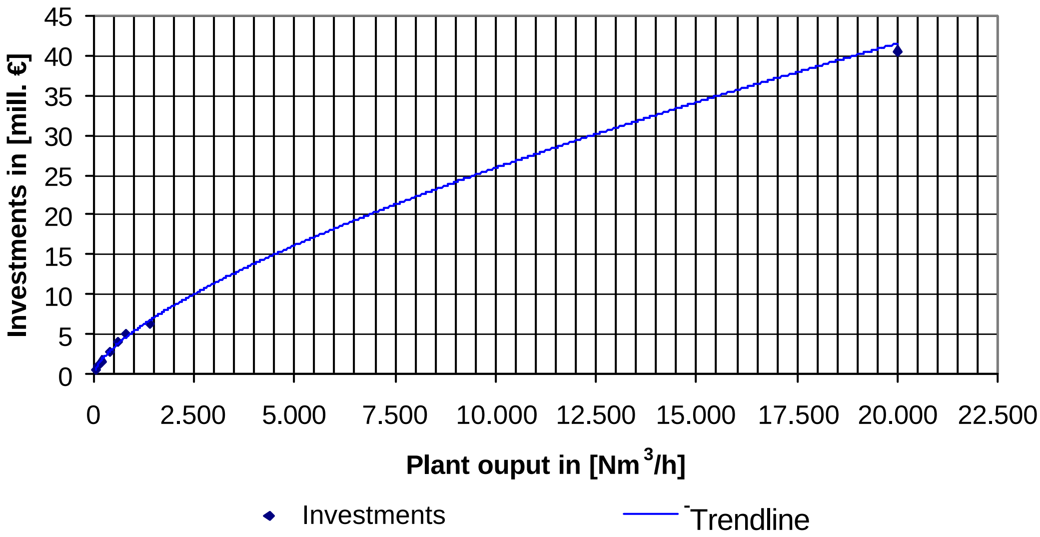
Distinctions are made between alkaline electrolysis, alkaline pressure electrolysis and high temperature electrolysis. However, this paper assumes the use of pressure electrolysers. Pressure electrolysers call for careful and optimisation of the material and then allow hydrogen pressures of up to 50 bar to be generated. Processes still under development attempt to combine a corresponding optimisation of performance with this, which will also allow unproblematical coupling of the electrolysers to a fluctuating electricity generator (www.hydrogen.org, 26.10.2001). As well as the high output pressure level, the aim of this effort is to achieve a corresponding optimization of plant efficiency at widely varying loads. The higher level of output pressure offers the advantage that additional hydrogen compression following liquefaction is lower, and the compressor can also be smaller, which results in a cut in costs.

Plant investment depending on rated output in Figure 25 can be calculated to a good level of approximation using a potential equation (Equation 11):

Equation 11: $$INV = 49{,}504 * X^{0.6796} \qquad R^2 = 0.9976$$

INV .... Investment in [€]
X .... Rated plant output in [Nm^3/h]
R^2 ...... Degree of certainty

Figure 25: Investment in electrolysis plant plants depending on rated plant capacity in Germany



Source: Valentin, 2001, p. 61 f.; TES, 2001; Own calculations, 2001

As a degression factor to take the learning effect according to Chapter 3.1.2 into account, the value A = 0.89 is used[49] (Valentin, 2001, p. 79; Own assumptions, 2002).

The operating and maintenance costs of electrolysis plants are assumed to be constant at 2.5 % of the investment.

Currently, the electricity requirement of electrolysis plants is about 1.5 $kWh_{el}/kWh\ H_2$ (Kruger, 2001, p. 1142). According to Kruger, a plant electricity requirement of only 1.17 $kWh_{el}/kWh\ H_2$ is forecast up to 2050. As the considerations in this paper end in 2035, a constant value for the electricity requirement of 1,5 $kWh_{el}/kWh\ H_2$ has been used. The efficiency of the electrolysis plant is therefore about 67 %.

The CO_2 emissions that arise during the production of hydrogen by electrolysis depend mainly on the type and method of electricity generation. If regeneratively produced electricity is used, the emissions can be kept low; on the other hand, they are very high if electricity from German power stations is used or if it is supplied by GST power stations (Chapter 3.2.3).

With an annual load on the electrolysis plants of 85 % and the use of electricity from German power stations at Level 1, the costs of hydrogen production are 0.161 €/kWh H_2 for a 200 Nm^3/h plant and 0.073 €/kWh H_2 for a 136,200 Nm^3/h plant. The electricity costs have a significant influence on the costs, because of the high electricity requirement (Chapter 3.2.3).

3.6. Hydrogen liquefaction

Current liquefaction plants work with liquid nitrogen pre-cooling of the feed hydrogen. For this, the hydrogen supply pressure must be at least 20 bar. If hydrogen production takes place using a high-pressure electrolyser, this can save a compression stage. Before liquefaction, the hydrogen is cleaned of CO_2, CO, CH_4 and H_2O. As a rule, this is done in a pressure swing adsorption plant. Depending on the throughput, different liquefaction processes are used, and higher-capacity plants often use a combination of the different possibilities (turbine processes, Joule-Thomson process). In all the processes, liquefaction takes place through the compression followed by irreversible relaxation through throttle

[49] The potential of the fall in investments in electrolysis plants is stated as being from about 600,000 €/MW in 2000 to around 250,000 €/MW in 2050 (Barreto, 2003, p. 271) and corresponds approximately to the investments needed for the development of the plant population according to the OWN scenario (Figure 49), taking a degression factor of 0.89 into consideration.

valves or partially reversible relaxation with relaxation machines. Of the several heat exchange stages, the first, as a rule, is pre-cooled using liquid nitrogen. Before the last stage, a Joule-Thomson valve is used to release the pressure. In this way, liquid hydrogen temperatures of approx. 21 K are achieved (www.hydrogen.org, 26.10.2001).

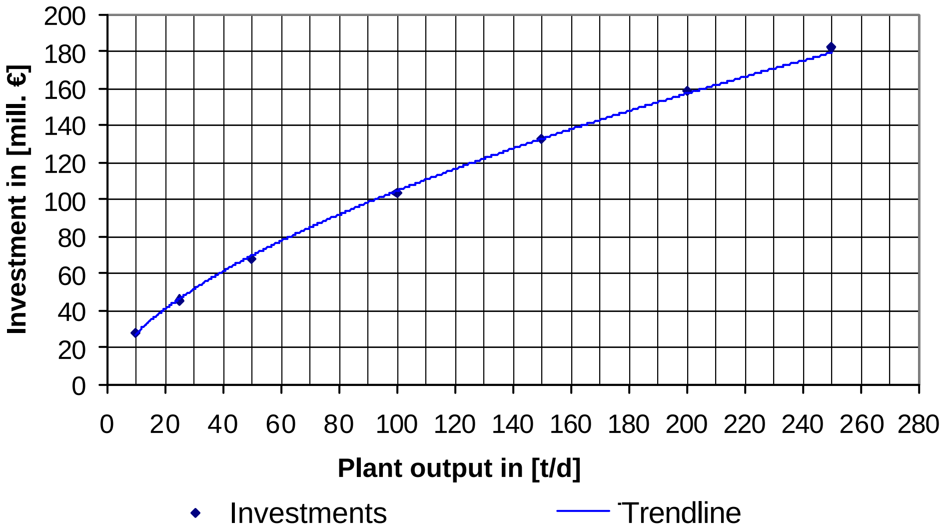
Plant investment depending on rated plant output in Figure 26 can be calculated to a good level of approximation using a potential equation (Equation 12):

Equation 12: $$INV = 7{,}000{,}000 * X^{0.5886} \qquad R^2 = 0.9995$$

INV .... Investment in [€]
X .... Rated plant capacity in [t/d]
R^2 ...... Degree of certainty

As a degression factor for taking the learning effect into account according to Chapter 3.1.2, and considering that the electrolysis plants have a similar technological state of development as the liquefaction plants, a value of A = 0.89 is assumed.

Figure 26: Investment in liquefaction plants, depending on plant capacity, in Germany



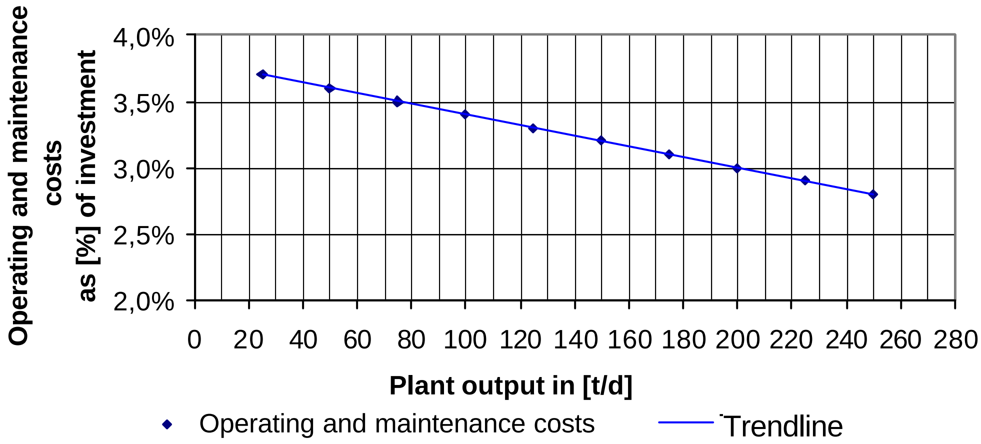
Source: Valentin, 2001, p. 59; VES, 2001; Own calculations, 2001

In Figure 27, it is evident that the operating and maintenance costs of a liquefaction plant are reduced with increasing plant capacity, and can be determined using a linear formula depending on plant capacity (Equation 13):

Equation 13: $$O\&M = [(-0.00004) * X + 0.038] * 100 \qquad R^2 = 1$$

O&M ... Operating and maintenance costs as [%] of the plant investment
X .... Rated plant capacity in [t/d]
R^2 .... Degree of certainty

Figure 27: Operating and maintenance costs of liquefaction plants, depending on plant capacity, in Germany



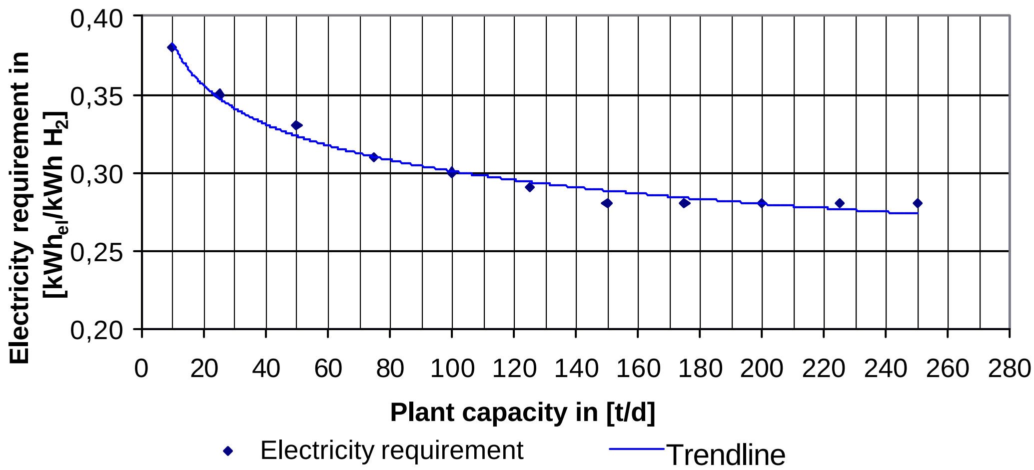
Source: Valentin, 2001, p. 69

The electricity requirement for liquefaction plants reduces with increasing plant capacity (Figure 28), but can be approximated with a potential equation (Equation 14):

Equation 14: $ELECTRICITY = 0.4859 * X^{-0.1041} \qquad R^2 = 0.9782$

ELECTRICITY Electricity requirement in [$kWh_{el}/kWh\ H_2$]
X .... Rated plant capacity in [t/d]
R^2 .... Degree of certainty

Figure 28: Electricity requirement of liquefaction plants, depending on plant capacity, in Germany



Source: Valentin, 2001, p. 68

A liquefaction plant with a capacity of 10 t/d has an electricity requirement of 0.38 $kWh_{el}/kWh\ H_2$ and a plant with a capacity of 250 t/d has an electricity requirement of 0.27 $kWh_{el}/kWh\ H_2$. According to Prof. Quack[50], in future a value of about 0.21 $kWh_{el}/kWh\ H_2$ will be achieved, resulting from the use of a neon-helium mix as a coolant (Quack, 2002, p. 9). As no plants using this neon-helium mix have been built to date, the electricity requirement values according to Valentin will be used.

[50] Professor for Low Temperature and Cryogenic Technology, TU Dresden

For an annual liquefaction plant capacity utilization of 85 % and the use of electricity from the German power stations at Level 1, the costs of hydrogen liquefaction for 2.6 t/d plant are 0.099 €/kWh H_2 and for a 250 t/d plant, 0.022 €/kWh H_2.

The CO_2 emissions that arise during the liquefaction of hydrogen depend mainly on the type and method of electricity generation. If regeneratively produced electricity is used, the emissions can be kept low; they are on the other hand very high if electricity from German power stations is used or if it is supplied by GST power stations (Chapter 3.2.3).

3.7. CO_2 sequestration

It is possible to collect the CO_2 that is created in the generation of electricity or production of hydrogen and to store it (sequestration) at suitable locations, so as to avoid any enrichment of the CO_2 concentration in the atmosphere and therefore any disadvantageous effects on the climate. The ecological evaluation of the effects of sequestration is not an aim of this paper, and is therefore not discussed.

For the **collection of CO_2** at points of emission, several possibilities are considered (IEA(a)[51], www.ieagreen.org.uk, 16.08.2002):

- Adsorption method: The exhaust (flue gas) containing CO_2 is washed using a solvent or a solid material such as aluminum and thereby cleaned of other materials.
- Liquefaction methods: The flue gas is dried and finally liquefied[52], which causes the liquid CO_2 to be separated from the other flue gas components.
- Membrane method: The flue gas is passed through membranes, which separate the CO_2.

For the **storage or further processing of CO_2**, several possibilities are currently being considered (FETC[53], www.fetc.doe.gov, 16.08.2002):

- Storage at appropriate depths in the oceans
- Storage in former oil, gas, coal or salt reservoirs
- Further processing by means of an ecosystem (soil enrichment, flora)
- Further processing by industry

For the transport and storage of the collected CO_2, the following **total costs**[54] are given on the basis of concrete examples, (IEA(b), www.ieagreen.org.uk, 16.08.2002; Kim, 2000, p. 5; www.fe.doe.gov, 14.08.2002):

- Removal of liquid CO_2 ($p > 75$ bar at ambient temperature) through pipelines, storage of liquid CO_2 on ocean bed at a depth of about 3,000 m: 4.1 €/t C (corresponds to 1.1 €/t CO_2)
- Removal of liquid CO_2 through pipelines, filling of ground water pipes or water channels at great depth: 4.7 €/t C (corresponds to 1.3 €/t CO_2)
- Removal of liquid CO_2 through pipelines, filling of former natural gas or oil reservoirs: 8 €/t C (corresponds to 2.2 €/t CO_2)

The use of these method in power stations for electricity generation and GST plants is examined more closely below.

3.7.1. Power stations for electricity generation

Depending on the type of power station used to generate electricity (coal-fired, GST power station), the collection of CO_2 results in a greater or smaller loss of efficiency (Table 24). The reduction in efficiency results from the use of additional units in the process chain.

[51] IEA = International Energy Agency
[52] The conventional process can compress the exhaust gas up to 14 to 20 bar, followed by cooling in a cold circuit (ammonia refrigerant) to about -35 to -25 °C (critical point of CO_2: $T_{crit} = 31$ °C, $p_{crit} = 73.8$ bar).
[53] FETC = Federal Energy Technology Center
[54] Without CO_2 collection, interest rate 10 %, conversion factory 1 US dollar = 1 Euro, electricity requirement of the compressors for transporting CO_2 through pipelines not taken into consideration.

Table 24: Efficiency with and without CO_2 collection and CO_2 quota in power stations used for electricity generation in 2002

	Coal-fired power station			GST power station		
	Plant efficiency …			Plant efficiency …		
	with CO_2 collection	without CO_2 collection	Quota in [%]	with CO_2 collection	without CO_2 collection	Quota in [%]
Adsorption method	29	40	90	42	52	85
Liquefaction method	---	---	---	36	42	85
Membrane method	30	40	80	47	52	80

GST power station = Gas and steam turbine power station
Source: IEA(a), www.ieagreen.org.uk, 16.08.2002

As the power stations generating electricity in Germany currently include 50 % coal-fired power stations and 10 % gas-fired power stations (Figure 22), further examination in this paper is based on the CO_2 adsorption method with a collection quota of 90 %. In addition, an efficiency loss during electricity generation of 10 % is used (Kehr, 2002; Own assumption, 2002). Fuel consumption must therefore be increased by 30 % in order to produce the same quantity of electricity generated without CO_2 collection. However, the increase of 30 % in the fuel quantity again causes an increase in CO_2 emissions of around 30 % compared with conventional electricity generation, and the residual emissions of 10 % for a collection quota of 90 % still exhibit a considerable level.

Due to the planned phasing out of nuclear power, there will probably be partial substitution of nuclear power stations by GST and coal-fired power stations (Chapter 3.2.3). For future emissions of the national power stations of 700 g CO_2/kWh it has been assumed that 55 % of the electricity would be generated by coal-fired power stations and 20 % by GST power stations. Both of these types of power station together result in a share of 590 g/kWh in relation to the 700 g/kWh figure (490 g by coal-fired power stations and 100g by GST power stations). The remaining power stations used for generating electricity in Figure 22 are responsible for about 110 g CO_2/kWh.

If it is assumed that CO_2 is collected at all coal-fired and GST power stations in Germany, the 30 % increase in the amount of fuel also results in an increase on the CO_2 share of power stations from 590 to 770 g CO_2/kWh (640 g by coal-fired power stations, 130 g by GST power stations). This gives theoretical new CO_2 emissions for German power stations of 880 g CO_2/kWh. The remaining CO_2 emissions of 10 % at coal-fired and GST power stations amount to about 77 g. If about 100 g are added to the emissions of the remaining power stations used for generating electricity, average residual emissions of 177 g CO_2/kWh result.

The effects that the level of residual emissions have on CO_2 balancing during hydrogen production is discussed in 6.

3.7.1.1. Total costs of sequestration

CO_2 collection requires an increase in investments at the power stations used for generating electricity. For coal-fired power stations this results in an increase in investment of around 80 %, and for GST power stations, around 100 %. The higher investments in the power stations used for generating electricity result in a corresponding increase in electricity costs of up to 50 % (IEA (c), www.ieagreen.org.uk, 16.08.2002; Own calculations, 2002).

This yields total costs of 34 €/t CO_2 to 94 €/t CO_2 (Kim, 2000, p. 5) depending on the method of CO_2 collection and storage. The costs of CO_2 collection form the largest part of the total costs (www.fe.doe.gov, 14.08.2002).

In the future, total costs for sequestration are anticipated as being 14 €/t CO_2 around 2015 and 3 €/t CO_2 around 2035 (Kim, 2000, p. 5). If the current total costs of sequestration of 40 €/t CO_2 and a learning effect with a degression factor of A=0.9 are assumed (for investment in both CO_2 collection and storage), this still gives total costs after 20 such plants of about 8.3 €/t CO_2. The value of 6.6 €/t CO_2 is reached with 100 plants. As the learning effect reduces logarithmically, the forecast total costs of 3 €/t CO_2 by 2035 will only be achieved once a large number of plants has been constructed. Consequently, a cost level of about 3 €/t CO_2 can only be reached with a very high learning effect and a very high number of plants. As this cost reduction is not seen as realiztic, this paper assumes total costs for sequestration from 2006 of 30 €/t CO_2 with a linear reduction to 10 €/t CO_2 by 2035.

3.7.2.Natural gas steam reforming plants

In NGSR plants, the largest quantity of CO_2 is formed during hydrogen production and not during the generation of electricity. It is assumed that for identical emissions from a coal-fired power stations and an NGSR plant, the same levels of investment are required at both types of power station for the collection of CO_2. This assumption gives the same level of total costs per tonne of CO_2 as sequestration.

In a **coal-fired power station** with a nett output of 400 MW (electricity generation of 2 TWh_{el}), the costs of CO_2 collection are around 80 % of the investment for the power station, therefore about € 350 million. CO_2 emissions of 900 g/kWh_{el} during electricity generation are equivalent to 1.8 million tonnes of CO_2 per year.

In an **NGSR plant** with an output of 408 MW (hydrogen production of about 3 TWh/a), approx. 850,000 t of CO_2 are produced per year (282 g CO_2/kWh H_2). Approximately half the investment in a coal-fired power station can be accounted for by CO_2 collection, the figure therefore being about € 175 million. If, as with the generation of electricity, a loss of efficiency from 69 to 59 % is assumed, this requires an increase in the use of fuel from 0.43 Nm^3 CH_4 /Nm^3 H_2 to 0.50 Nm^3 CH_4 /Nm^3 H_2. In order to be able to produce an identical quantity of hydrogen, this again results in an increase of CO_2 emissions from 282 to 329 CO_2/kWh H_2, of which 10 % is not collected and finds its way into the environment. Based on these assumptions, this yields a cost increase for hydrogen production at an NGSR plant from 0.027 €/kWh to 0.041 €/kWh (full capacity of the plants is assumed). The additional costs amount to 0.014 €/kWh or 50 % for a CO_2 avoidance amount of about 300 g.

3.8. Distribution

If hydrogen production takes place centrally in power stations with higher capacities, the hydrogen can be transported to the gas stations by truck trailer or in pipelines in a liquid or gas form. According to Valentin, the distribution of gaseous hydrogen in a gas cylinder transporter (200 bar) is not a suitable means of guaranteeing a permanently secure supply, due to insufficient supplier coverage of under one day if fuel substitution is above 10 %. The use of pipelines in urban areas is also shown to be economically meaningful only above a substitution quota of 50 % (Valentin, 2001, p. 129). The only remaining, economically sensible method for transporting liquid hydrogen is by truck, the cost structure of which will be examined more closely.

Significant characteristics of **current LH_2 distribution by truck** (Valentin, 2001, p. 51 f.; Bünger, 2000, p. 7):

- Truck capacity of about 45,000 l LH_2 (106,200 kWh or 3,186 kg)
- Truck purchase costs of 767,000 €
- Truck operating and maintenance costs of about 5 % of the purchase costs per year
- Usage hours of a truck of approx. 3,500 h/a, lifespan about 10 years
- Driver costs of about 50 €/h
- Duration of loading/unloading cycle of about 2.7 h, turnaround time[55] about 2.5 hours
- Transportation up to a distance of 250 km without a break

With the figures given about, this gives current transport costs[56] over an average distance of 20 km of 0.0086 €/kWh LH_2 and for a distance of 250 km of 0.0173 €/kWh LH_2 (Valentin, 2001, p. 52). For a medium distance of 500 km, transport costs of 0.035 €/kWh LH_2 are

[55] The time necessary to create the refueling connection between the refueling plant and the HGV or at the gas station between the HGV and the LH_2 storage tank, and to remove it again after refueling is complete.
[56] Interest rate 15 %

given (TES, 2001). The transport costs for medium-range transport distances of between 250 and 500 km are calculated linearly from the two key values.

Assumed future **LH_2 distribution by truck** (Valentin, 2001, p. 53; Own assumptions, 2002):

- Degression factor for the learning effect of A = 0.95: above 1,000 trucks this gives an investment per truck of about 460,000 €
- Reduction of the truck loading and unloading time to 2.7 hours, including turnaround
- Remaining assumptions as before

The future transport costs[57] with truck purchase costs of 460,000 € and a transport distance of 20 km are 0.004 €/kWh LH_2 and for a distance of 100 km about 0.0065 €/kWh LH_2.

However, the truck inventory will not grow in leaps and bounds from a few units to, say, 1,000; instead the learning affect grows continuously with the number of vehicles. There will be a continuous transition from the current to the future transport costs mentioned above. The development of transport costs depends fundamentally on the increase in the number of hydrogen production plants over the years (Chapter 4.4). With an increasing number of plants, there is a decreasing average transport distance per truck, with a concurrent increase in the size of the LH_2 truck inventory. The quantity of LH_2 fuel that can be transported annually per truck increases as the average transport distance decreases, due to shorter journey times to the gas stations.

If an average transport distance of 200 km and a journey time of 8 hours (return trip) is assumed, this give a total time including the loading, unloading and turnaround of a truck of about 14 hours. Under the assumption that this average transport distance gives approximately 200 journeys per truck and year, the annual quantity of fuel that can be transported by a truck is about 21 GWh or 8.9 mill. l LH_2 (Table 25). If an average transport distance of 80 km and a journey time of just 4 hours (return trip) is assumed, this give a total time of about 9 hours. Under the assumption that this average transport distance gives approximately 300 journeys per truck and year, the annual quantity of fuel that can be transported by truck is about 32 GWh or 13.6 mill. l LH_2.

Table 25: Transportable quantity of hydrogen fuel per truck and year and specific transport costs and CO_2 emissions depending on the average transport distance in Germany

Average transport distance	km	80	100	120	140	160	180	200
Transportable quantity of fuel per truck	GWh/a	32	29	27	25	23	22	21
Specific transport costs (approx.)[1)]	€/kWh	0.0069	0.0084	0.0094	0.0109	0.0122	0.0130	0.0139
CO_2 emissions	g/kWh	1.4	1.7	2.1	2.5	2.8	3.3	3.7

[1)] Determined by taking into account the learning affect for increasing numbers of vehicles (Chapter 4.4)
Source: Own calculations, 2002

Determining development of the average transport distance over the years is according to Valentin (Valentin, 2001, p. 24-27). With the city of Munich as an example, the average transport distance can be determined approximately. If a hydrogen production plant is constructed in the Munich area to cover the entire hydrogen requirement of the city and its environs, this gives a supply region of 977.7 km^2, comprising 310.46 km^2 for the city of Munich itself and 667.24 km^2 for the Munich district (www.muenchen.de, 16.08.2002; www.landkreis-muenchen.de, 23.05.2002). If the supply region is considered to be a circle, with the production plant at its centre, this give a maximum supply radius A, taking into consideration an additional factor of 1.25, which makes it possible to convert the straight-line distance into road kilometers, according to Equation 15:

[57] Interest rate 15 %

Equation 15: $$A = \sqrt{\frac{977.7}{p}}.1.25 = 22.05\,km$$

If the maximum supply radius A is multiplied by sin45°, this gives an average transport distance of 15.6 km. The method described here is regarded as being sufficiently accurate for calculating the average transport distance with a relatively uniform distribution in the rural area. In the example of the city of Munich, where the production plant would be in the hinterland, it is located on the circumference of its supply area, thereby increasing the average transport distance. The method described here is considered to be adequate for calculating the average transport distance.

CO_2 emissions per unit energy of hydrogen in the operation of a truck are also dependent on the average transport distance. With a fuel consumption for a truck of 33 l/100 km (Reijerkerk, 2001, p. 77), a transported quantity of LH_2 of 106,200 kWh per trip and CO_2 emissions of 292 g/kWh of diesel fuel, this gives CO_2 emissions of about 1.8 g/kWh LH_2 for an average transport distance of 80 km, and about 3.7 g/kWh LH_2 for a journey of 200 km (Table 25).

3.9. Summary

Tasks

Having arrived at an achievable, valid development of hydrogen demand in Chapter 2, there remains the question of producing this quantity of hydrogen. The important task in this chapter is to determine the characteristics (including economies of scale and learning effect) of a process that can be used for hydrogen production, now and in the future.

The aim of introducing an alternative fuel such as hydrogen is to preserve fossil resources and to reduce anthropogenic emissions of CO_2. Since producing hydrogen by electrolysis requires a considerable amount of electricity, the generation of electricity is also very important. A record of the power stations for electricity generation, including regenerative production, and their potentials in Germany has been compiled.

Assumptions and approach

The following processes for hydrogen production are considered in this paper: steam reforming of natural gas, gasification of biomass and alkaline pressure electrolysis of water. For the processes of steam reforming of natural gas and electrolysis, differences are made between production in power stations with high capacity or directly on-site at the gas station (no hydrogen transport required). Biomass gasification is of interest due to its approximate CO_2 neutrality when used for the production of hydrogen. The partial oxidation and coal gasification processes are not considered, due to the very high levels of CO_2 emissions created. Processes at the research stage, such as the plasma arc process or the biological production of hydrogen using algae, are currently only achievable on a laboratory scale, and are consequently not considered in this paper.

Although hydrogen production using fossil energy sources does not contribute to the aim of the introduction of the alternative fuel (above all conservation of fossil resources, CO_2 reduction), these are taken into consideration in this paper. The basis is in the commercially available technology of hydrogen production and the relatively cost-efficient production compared to regenerative hydrogen production. To reduce CO_2 emissions caused by producing hydrogen with the aid of fossil energy sources, CO_2 sequestration (whereby the CO_2 created by fossil electricity or hydrogen production is collected and stored in suitable sites, thereby preventing its release into the atmosphere) is taken into consideration.

The possibility of producing hydrogen abroad and transporting it to Germany continues to be handled in greater depth in projects within the industry. As such an in-depth examination of the possibilities of producing hydrogen overseas lies far beyond the scope of this paper, it is not considered here. However, it is stressed that hydrogen is produced overseas by processes identical to the ones mentioned above, though there are, for example, differences in the levels of use of power stations for regenerative electricity generation and in transport costs.

As the transport of hydrogen from the production sites to the gas stations up to a fuel substitution of about 50 % can be undertaken most cost-effectively and with high flexibility by truck in liquid form (Valentin, 2001, p. 129), only this favored form of transport is taken into consideration in this paper.

Findings

Hydrogen production can currently be achieved most cost-effectively by the steam reforming of natural gas. Hydrogen production by electrolysis is only meaningful when using regeneratively produced electricity or electricity from nuclear power (as long as this is politically and socially accepted), since the power station fleet for generating electricity in Germany consists about 50 % of coal-fired power stations. The costs of hydrogen production by electricity are correspondingly higher compared with natural gas steam reforming. In terms of cost, hydrogen production by biomass gasification is between the cost of natural gas steam reforming and electrolysis. A significant disadvantage of biomass gasification is the high level of truck traffic needed for biomass delivery at higher levels of plant capacity, and the limited potential of biomass availability for a complete fuel substitution.

If hydrogen is produced by natural gas steam reforming or if fossil fuel power stations are used for generating electricity used in the production of hydrogen by electrolysis, residual emissions of currently around 10 % in the exhaust gas must be taken in consideration in the use of CO_2 sequestration. While the use of fossil fuel sources and the use of CO_2 sequestration can keep costs relatively low compared with the use of renewable energy sources, it results in a lower absolute level of CO_2 reduction.

Conclusion and recommendations

The important task in this chapter is determining power station characteristics. To calculate the costs of hydrogen production, the investments and operating and maintenance costs depending on the capacities of the plants were determined. The effects of a dynamic development of the hydrogen infrastructure on the use of the plants and therefore on specific hydrogen costs are dealt with in Chapter 4.4.

4. Gas station concepts

The first step is to determine the current state of the German gas station network. Possible future development of the state of the gas station network in Germany is estimated. The priority concepts for gas stations with hydrogen supplies are examined more closely and compared. The most cost-effective concept is used for further calculation in the following Chapters.

4.1. Conventional gas station

The survey of the state of gas stations is carried out separately for roadside and motorway (the term used here for freeways or German ‘autobahns’) gas stations, as motorway gas stations have considerably higher sales of fuel than roadside gas stations.

In Germany, the total number of gas stations has fallen continuously in recent years (Table 26). Between 1996 and 2000, there was an average reduction of about 300 sites per year.

Table 26: History of the inventory of roadside and motorway gas stations in Germany from 1996 to 2000 and assumptions for a future development up to 2020

	1996	1997	1998	1999	2000	2010	2020
Roadside gas stations [1)]	17,632	17,334	16,740	16,287	16,061	12,650	11,650
Motorway gas stations	325	326	326	330	343	350	350
Total	17,957	17,660	17,066	16,617	16,404	13,000	12,000

[1)] Inventory figures also include gas stations for public modes of transport (depots)
Source: Aral, 2000, p. 364; Own assumptions, 2002

An important reason behind the closing of gas stations is that increased turnover at the better located gas stations and lower costs mean more income for the mineral oil than is lost through closures. A further reason is that the necessary renovation and modernisation measures would not be amortized, due to more and more comprehensive safety requirements and precautions for protecting the environment (Frei, 1993, p. 117).

If the reduction in the total number of gas stations continues at 300 sites per year, this will mean that approx. 13,000 sites remain in 2010. The mineral oil company Shell expects about 12,000 gas stations to remain in use in the medium term (Shell (b), 2001, p. 36). In this paper it is assumed that the level of 12,000 gas stations will be reached in 2020.

As the build-up of a gas station infrastructure is also dealt with specifically using the city of Munich as an example, future development of the gas station network as described above will be directly transferred to Munich, whereby the number of gas stations will fall from 171 in 2000 to 125 in 2020 (Table 53 in Appendix 6).

Average fuel sales[58] at conventional German gas stations are:

- Roadside gas station: about 2.7 mill. l/a, or 25 GWh GE/a
- Motorway gas station: about 8.2 mill. l/a, or 73.5 GWh GE/a

Characteristics of a conventional roadside as station (Own calculations, 2002):

- Average quantity of fuel: approx. 20 l of fuel/vehicle
- Average fuel energy content: approx. 434 kWh/h
- Private-car gasoline pump flow rate: 50 l/min
- Average filling time including arrival, switching off vehicle, filling up, going to pay, paying, departure: 5 min
- Theoretical maximum number of vehicle refuelings per pump and hour: 12

4.2. Gas station concepts for hydrogen supplies

The current legal regulations for the new building and conversion of gas stations are not addressed, as they would fall outside the scope of this paper.

The gas station concepts for hydrogen supply described below are favored in the TES and show the greatest potential for practical use. One option provides for the storage of the delivered, centrally produced liquid hydrogen in conventional cryogenic tanks at the gas station. The other option provides for hydrogen production directly at the gas station (on-site) by electrolysis or natural gas steam reforming. A detailed examination of these options is carried out in this paper.

Assumptions for gas station concepts for hydrogen supply:

- Gas station opening times: 24 h per day, all year round
- Fuel supply[59] per pump per year: 3.8 GWh
- Pump purchase costs: 37,000 € (Reijerkerk, 2001, p. 85 f.)

[58] Super Plus, Eurosuper, regular gasoline (gasoline) and diesel fuel. Determined in Appendix 6.
[59] Motorway gas station: 3.8 GWh/a per fuel pump (Reijerkerk, 2001, p. 52); roadside gas station: 3.1 GWh/a per fuel pump (Gärtner, 1984, p. 122); As the number of gas stations is forecast to decline in future, this paper assumes that 3.8 GWh/a per fuel pump are sold regardless of the type of gas station.

- Pump flow rate: 50 l LH_2[60]/min or 39 Nm^3 CGH_2[61]/min

Assumptions for and characteristics of a modified conventional gas station with hydrogen supply (Own assumptions, 2002):

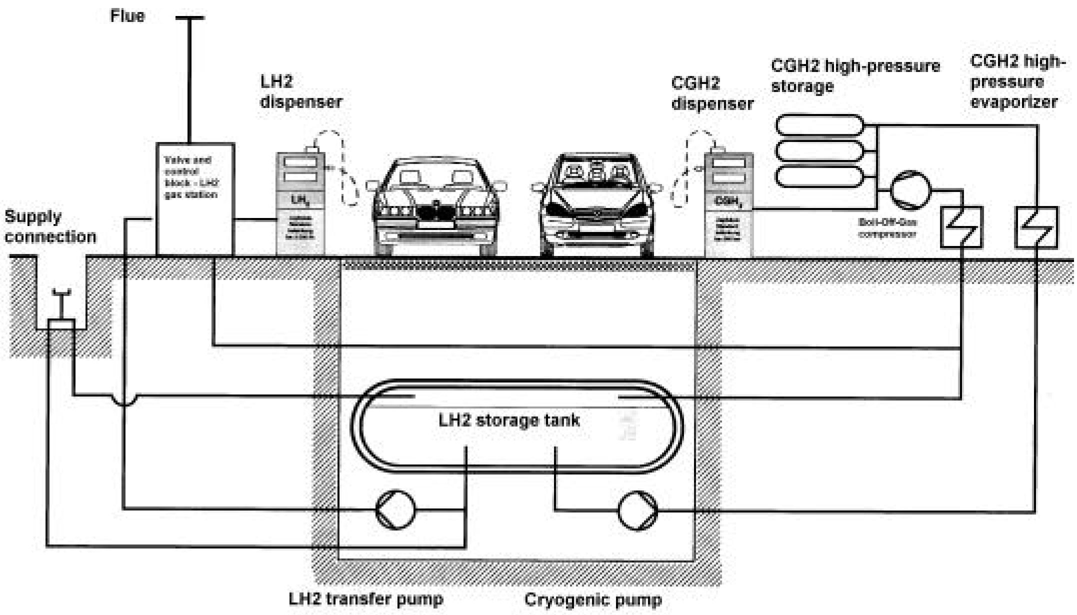
- average quantity per refueling: 76 l LH_2 or 59.8 Nm^3 CGH_2 per vehicle (corresponds to about 20 l of conventional fuel/vehicle)
- average quantity per refueling: 434 kWh/h
- average filling time including arrival, switching off vehicle, filling up, going to pay, paying, departure: 6.5 min
- theoretical maximum possible number of vehicle refuelings per pump and hour: 9

The comparison of the theoretical maximum possible number of vehicle refuelings per pump and hour between a conventional fuel pump (Chapter 4.1) and hydrogen fuel pump shows that fewer vehicle refuelings can be carried out at a hydrogen pump, because of a longer refueling time for hydrogen as a result of its lower flow rate. If it is assumed that the hydrogen pump shows the same usage as a conventional pump, this gives an annual hydrogen sale of 2.86 GWh per pump instead of the 3.8 GWh for a conventional pump. The requires a higher number of pumps at a hydrogen gas station compared with a conventional gas station. However, if it is assumed that the annual sale of a hydrogen pump is 3.8 kWh (which is the assumption in this paper), this signifies increased usage of the hydrogen pumps compared a conventional pump.

4.2.1. Centralised hydrogen production

The liquid hydrogen is delivered by trucks from the central hydrogen production plants to the gas stations, where it is stored in conventional, underground cryogenic tanks (LH_2 storage tanks) (Figure 29). A distinction is made between gas station concepts that supply either liquid hydrogen (LH_2), or compressed gaseous hydrogen (CGH_2), or both. The gas station concept at which both LH_2 and CGH_2 are available is indicated in this paper by the term $LCGH_2$ gas station.

Figure 29: Schematic representation of the build-up of a gas station for the supply of liquid hydrogen (LH_2) and gaseous hydrogen (CGH_2) for hydrogen production at centralized power stations and delivery of the liquid hydrogen by truck



Source: Wolf (a), 2002

[60] LH_2 = Liquified Hydrogen
[61] CGH_2 = Compressed Gaseous Hydrogen

If the hydrogen is stored in the vehicle's tank in liquid form, a transfer pump is used to move the liquid hydrogen from the LH_2 storage tank to the pump. However, if gaseous hydrogen is stored in the vehicle's tank under high pressure, a cryogenic pump moves the liquid hydrogen from the underground LH_2 storage tank through a high-pressure evaporator into the high-pressure storage tank. The hydrogen is stored in the high-pressure tank at a pressure of at least 850 bar, so that is can be passed through the pump into the vehicle's fuel tank, where it is stored at a pressure of 700 bar.

4.2.1.1. Gas station concept for the supply of liquid hydrogen (LH_2)

A survey of the investments incurred for the conversion of a conventional gas station for the supply of liquid hydrogen calls for an examination of the necessary units for the supply of hydrogen and their number.

Significant characteristics of and assumptions for this gas station concept are:

- one cryogenic transfer pump per fuel pump required (flow rate of 50 l/min, connection capacity 2.2 kW, purchase costs 51,000 €) for transporting the LH_2 from the storage tank through the fuel pump into vehicle fuel tank (Reijerkerk, 2001, p. 91)
- "Other investment" for various modifications of 80,000 € for a gas station with a fuel sale of about 4 GWh/a assumed (Valentin,2001, p. 77; Own assumption, 2002). in this paper depending on the annual gas station fuel sales obtained approximately from Equation 19 in Appendix 6 (taking EOS into consideration, Chapter 3.1.2)
- Engineering costs for construction, planning, ordering and supervision given as 40,000 to 100,000 per gas station), in this paper depending on the annual gas station fuel sales obtained approximately from Equation 19 in Appendix 6 (taking EOS into consideration)
- Electricity requirement at the gas station of 0.001 kWh_{el}/kWh LH_2 (Bünger, 2000, p. 8)
- Operating and maintenance costs of 8 % of the total investment for the purchased LH_2 storage tank per year (Bünger, 2000, p. 8)
- Degression factor for taking into account the learning effect of $A = 0.91$ (Valentin, 2001, p. 77; Own assumptions, 2002)
- Gas station capacity utilization of 100 %
- Remaining assumptions as listed at the beginning of Chapter 4.2

The determining of the investments in LH_2 storage tanks is presented in Appendix 6. It is evident that with increasing storage tank volumes the increase in cost is lower due to the EOS (including volume effect). As the required storage tank volume is significantly dependent on the constantly required reserve quantity which is necessary to maintain gas station operations in the event of the loss of fuel supplies, a compromise must be found between longer maintenance of gas station operations in the event of a loss of supply and a reduction in the possible total investment in the gas station.

If the loss of the fuel supply demands the maintenance of gas station operations for, say, **three days**, this yields the following storage tank volumes[62] and purchase costs depending on annual sales of hydrogen fuel[63].

- Fuel sale of 4 GWh/a: tank volume 14,000 l, investment 210,000 €
- Fuel sale of 16 GWh/a: tank volume 55,000 l, investment 260,000 €
- Fuel sale of 24 GWh/a: tank volume 85,000 l, investment 275,000 €

From an economic point of view (relatively high turnaround times of an LH_2 truck for loading and unloading, Chapter 3.8), it would be advantageous if the total capacity of about 45,000 l of an LH_2 truck could be held by the storage tank at the gas station (then there is only a costly turnaround process in terms of time per truck load). The LH_2 storage tank at the gas station should consequently have a storage capacity of at least 45,000 l. However, above this volume storage tank investment only increases a little with increasing volume, due to the

[62] Storage tank 95 % filled (Reijerkerk, 2001, p. 89).
[63] The term "hydrogen fuel sales" refers to that quantity of hydrogen that is only used as a fuel for powering vehicles. Other uses of hydrogen, e.g. in the chemical industry, are not taken into consideration in this definition.

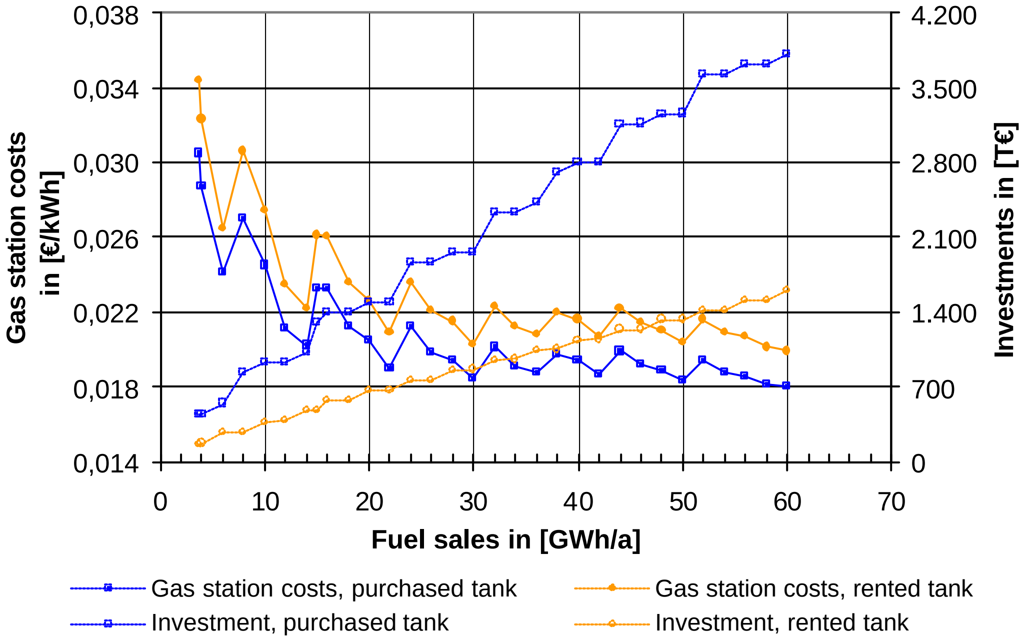
EOS. For this reason, this paper assumes a single LH_2 storage tank volume of 80,000 l, which could be described as a standardized volume[64]. The investment in a storage tank of this size amounts to about 275,000 € (Appendix 6) and the dimensions of the tank are approx. 4 m x 4 m x 12 m (Reijerkerk, 2001, p. 90 f.). For the number of LH_2 storage tanks at a gas station it is assumed in this paper that an 80,000 l LH_2 storage tank will be needed[65] per hydrogen sale of 3 mill. l LH_2/a .

Adding together the investments in the individual gas station components (LH_2 storage tank, cryogenic pump, fuel pump, "other investment", engineering costs) yields the total investment in an LH_2 gas station related to annual hydrogen fuel sales at the gas station (Figure 30). The resultant step function of the investment is a consequence of the increasing number of storage tanks with increasing hydrogen fuel sales at the gas station.

In order to lower the very high investment in the gas station, it is possible to rent the LH_2 storage tank, with the following characteristics for the rental of an 80,000 l storage tank (Guttenberger, 2002; Own assumptions, 2002):

- Rental period of ten years
- Capital interest payments of 15 %

Figure 30: Investments and specific gas station costs depending on annual hydrogen fuel sales at the gas station for the supply of liquid hydrogen (LH_2) for purchased or rented liquid hydrogen tanks in Germany



Electricity costs at Level 1 (L1) with a conventional power station
Source: Own calculations, 2002

The investment in a gas station will be reduced by renting, although the specific gas station costs will increase (Figure 30). The cost difference between the concepts with a purchased or rented storage tank goes down with increasing hydrogen fuel sales, as the costs of the storage tanks in relation to total gas station investment are reduced with increasing hydrogen

[64] The current average storage tank volume for gasoline (gasoline) at a conventional roadside gas station is about 20,000 l. In order to be able to supply the same energy content in an LH_2 storage tank as in a 20,000 l gasoline tank, the volume of the LH_2 storage tanks needs to be approx. 80,000 l.

[65] At a conventional gas station with annual fuel sales of 2.4 million l GE, there are at the moment normally four tanks for regular grade gasoline (gasoline), Eurosuper, Super Plus and Diesel. As Super Plus is sold only in very small amounts, it can be assumed that three tanks are available for the supply of 2.4 million l GE. This give a turnover per tank of about 800,000 l GE per year. The same assumption is used to determine the number of LH_2 storage tanks – an 80,000 l LH_2 tank is required for hydrogen sales of 3 million l LH_2/a (= 800,000 l GE/a).

fuel sales. The resultant step function of the investment is a consequence of the increasing number of storage tanks with increasing hydrogen fuel sales at the gas station.

4.2.1.2. Gas station concept for the supply of liquid hydrogen (LH_2) and gaseous hydrogen (CGH_2)

Significant characteristics and assumptions of this gas station concept are:

- Hydrogen fuel sales of 50 % in the form of LH_2 and 50 % in the form of CGH_2
- LH_2 storage tank volumes of 80,000 l, LH_2 storage tank number dependent on annual hydrogen fuel sales (Chapter 4.2.1.1)
- **LH_2 path:** one cryogenic transfer pump per fuel pump (purchase costs 51,000 €) for transporting the LH_2 from the storage tank through the fuel pump into the vehicle fuel tank (Reijerkerk, 2001, p. 91 f.)
- **CGH_2 path:** one cryogenic transfer pump per fuel pump required (connection capacity 20 kW, flow rate 6.7 l/min, purchase costs 55,000 €), a high-pressure evaporator (flow rate 315 Nm^3/h, purchase costs 20,000 €) and a high-pressure storage tank (storage volume[66] 2,068 l, purchase costs 53,000 €) required; the hydrogen is passed through a cryogenic pump and high-pressure evaporator into the high-pressure storage tank (Reijerkerk, 2001, p. 91 f.)
- Engineering costs for construction, planning, ordering and supervision assumed to be from 20,000 to 50,000 € for the LH_2 and CGH_2 path per gas station (Chapter 4.2.1.1), in this paper depending on the annual gas station fuel sales obtained approximately from Equation 22 in Appendix 6.
- Operating and maintenance costs of 8 % of the total investment for the purchased LH_2 storage tank per year (Bünger, 2000, p. 8; Own assumptions, 2002)
- Degression factor for taking into account the learning effect of A = 0.91 (Valentin, 2001, p. 77; Own assumptions, 2002)
- Gas station capacity utilization of 100 %
- Remaining assumptions as listed at the beginning of Chapter 4.2

For "Other investments" for various modifications, the following assumptions are made, taking EOS into account (Valentin,2001, p. 77; Own assumptions, 2002):

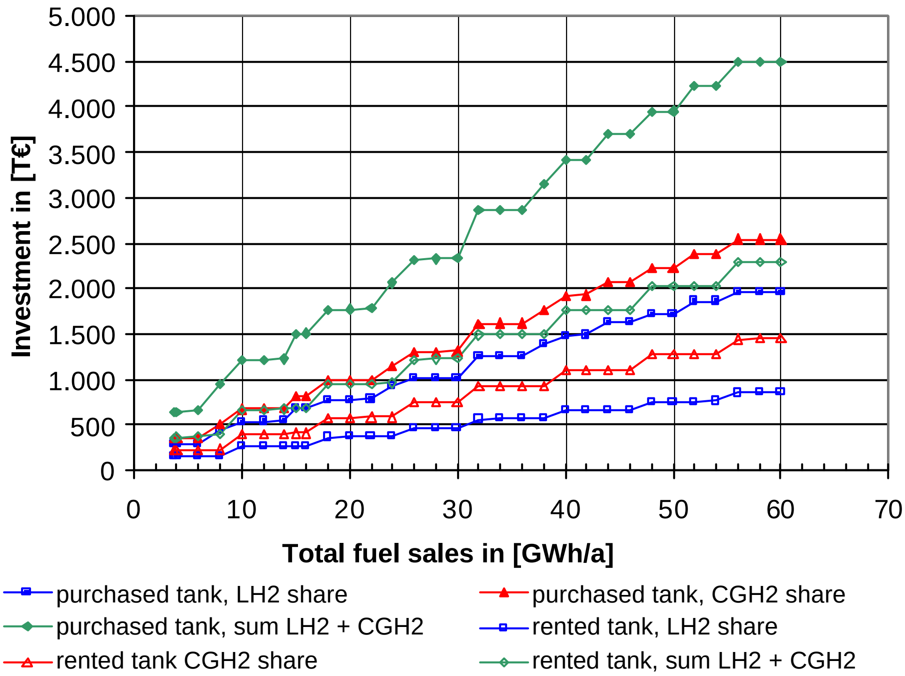
- for the LH_2 path from 50,000 to 100,000 €, in this paper depending on the annual gas station fuel sales as obtained approximately from Equation 20 in Appendix 6.
- for the CGH_2 path from 30,000 to 75,000 €, in this paper depending on the annual gas station fuel sales as obtained approximately from Equation 21 in Appendix 6.

The electricity consumption of the LH_2 path is given as 0,001 kWh_{el}/kWh LH_2 (Bünger, 2000, p. 8). The electricity consumption of the CHG_2 area is primarily due to the cryogenic pressure pump. With an annual CGH_2 sale of, for example, 4 GWh (full usage of the fuel pump), this gives the cryogenic pressure pump about 4,200 h/a operating hours and an electricity requirement of about 84,000 kWh/a (4,200 h x 20 kW).

By adding together the investments in the individual gas station components this gives the total investment in an $LCGH_2$ gas station depending on the annual hydrogen fuel sales (Figure 31). The total investment in a gas station using a rented tank can be significantly lowered than if a purchased tank is used. Moreover, the investment in the LH_2 path across the entire area of hydrogen fuel sales is below that of the CGH_2 path. The investment difference between the LH_2 and CGH_2 paths becomes greater with increasing fuel sales, since capacity expansion of the CGH_2 path per fuel pump is associated with higher investments than the LH_2 path. The resultant step function of the investment is again a consequence of the increasing number of storage tanks with increasing hydrogen fuel sales at the gas station.

[66] Two high-pressure storage tanks are used, whereby a storage tank with an internal volume of 1,034 l is sized so that one vehicle refueling is possible with one high-pressure storage tank. When the first high-pressure tank is emptied, it is refilled from the second storage tank during a vehicle refueling (Reijerkerk, 2001, p. 46-48).

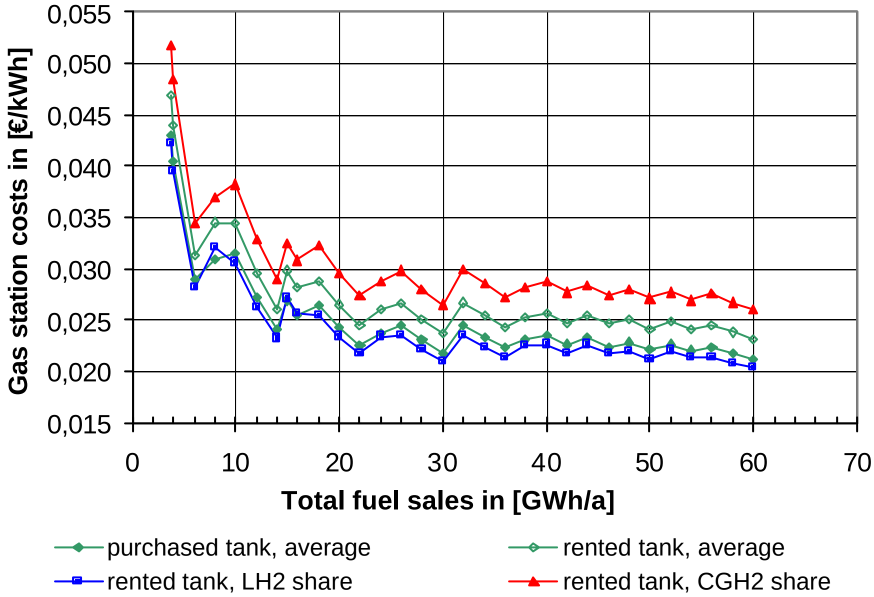
Figure 31: Investments in gas stations (divided into the supply of liquid hydrogen and gaseous hydrogen) depending on annual hydrogen fuel sales at the gas station for the supply of liquid hydrogen (LH_2) and gaseous hydrogen (CGH_2) for purchased or rented liquid hydrogen tanks in Germany



Source: Own calculations, 2002

Specific gas station costs decrease fundamentally with increasing annual hydrogen fuel sales at the as station (Figure 32). For the option of renting the LH_2 storage tanks, the gas station costs are shown separately for the LH_2 and CGH_2 paths. The specific gas station costs of the LH_2 path across the entire area of hydrogen fuel sales are significantly lower than those of the CGH_2 path, this being due to the lower investments for capacity expansion per LH_2 pump compared to a CGH_2 pump. By way of comparison, the average LH_2 and CGH_2 gas station costs with purchased LH_2 storage tanks are included in the diagram; these costs appear lower than the average specific gas station costs with rented LH_2 storage tanks. The resultant step function of the investment is again a consequence of the increasing number of storage tanks with increasing hydrogen fuel sales at the gas station.

Figure 32: Specific gas station costs (divided into the supply of liquid hydrogen and gaseous hydrogen and also as an average value) depending on annual hydrogen fuel sales at the gas station for the supply of liquid hydrogen (LH_2) and gaseous hydrogen (CGH_2) for purchased or rented liquid hydrogen tanks in Germany



Average = mid-value of the costs of the LH_2 and CGH_2 shares.
Electricity costs at Level 1 (L1) with a conventional power station
Source: Own calculations, 2002

4.2.1.3. Gas station concept for the supply of gaseous hydrogen (CGH_2)

In this gas station design only the supply path for CGH_2 refueling of a vehicle is available.

Significant characteristics and assumptions of this gas station concept are:

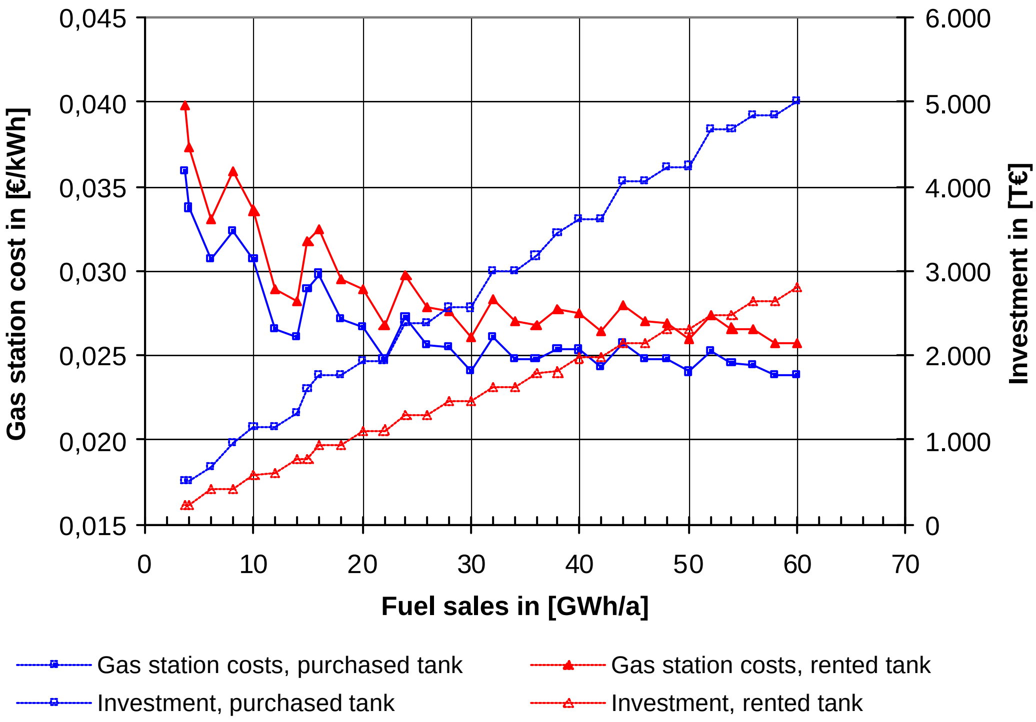
- LH_2 storage tank volumes of 80,000 l, LH_2 storage tank number dependent on annual hydrogen fuel sales (Chapter 4.2.1.1)
- One cryogenic transfer pump per fuel pump required (connection capacity 20 kW, flow rate 6.7 l/min, purchase costs 55,000 €), a high-pressure evaporator (flow rate 315 Nm^3/h, purchase costs 20,000 €) and a high-pressure storage tank (storage volume[67] 2,068 l, purchase costs 53,000 €) required; the hydrogen is passed through a cryogenic pump and high-pressure evaporator into the high-pressure storage tank (Reijerkerk, 2001, p. 91 f.)
- “Other investments” for various follow-up work at the gas station and engineering costs for construction, planning, ordering and supervision assumed over the entire area of hydrogen fuel sales approximately twice as high as for the CGH_2 path in a $LGCH_2$ gas station determined in Chapter 4.2.1.2
- Electricity requirement at the gas station twice as high as for the CGH_2 path at a $LCGH_2$ gas station determined in Chapter 4.2.1.2
- Operating and maintenance costs of 8 % of the total investment for the purchased LH_2 storage tank per year (Own assumptions, 2002)
- Degression factor for taking into account the learning effect of A = 0.91 (Valentin, 2001, p. 77; Own assumptions, 2002)
- Gas station capacity utilization of 100 %
- Remaining assumptions as listed at the beginning of Chapter 4.2

[67] Two high-pressure storage tanks are used, whereby a storage tank with an internal volume of 1,034 l is sized so that one vehicle refueling is possible with one high-pressure storage tank. When the first high-pressure tank is emptied, it is refilled from the second storage tank during a vehicle refueling (Reijerkerk, 2001, p. 46-48).

The investments in CGH_2 gas stations and the gas station costs per kWh depending on annual hydrogen fuel sales are shown in Figure 33. The investment in a gas station with a rented storage tank independent of the size of the gas station is only about 60 % of the investment with a purchased storage tank. The resultant step function of the investment is a consequence of the increasing number of storage tanks with increasing hydrogen fuel sales at the gas station.

Specific gas station costs also develop according to a discounted process. The cost difference between the concepts with a purchased or rented storage tank reduces with increasing hydrogen fuel sales, as the costs of the storage tanks with regard to the total gas station investment grow smaller with increasing hydrogen fuel sales. The resultant step function of the investment is a consequence of the increasing number of storage tanks with increasing hydrogen fuel sales at the gas station.

Figure 33: Investments and specific gas station costs depending on annual hydrogen fuel sales at the gas station for the supply of gaseous hydrogen (CGH_2) for purchased or rented liquid hydrogen tanks in Germany



Electricity costs at Level 1 (L1) with a conventional power station
Source: Own calculations, 2002

For further consideration of gas station designs, only the rental option of an LH_2 storage tank will be taken into account, as the high investment presents a significant introduction hurdle for hydrogen as an alternative fuel while renting the storage tank lowers it.

4.2.2.Hydrogen production at the gas station (on-site)

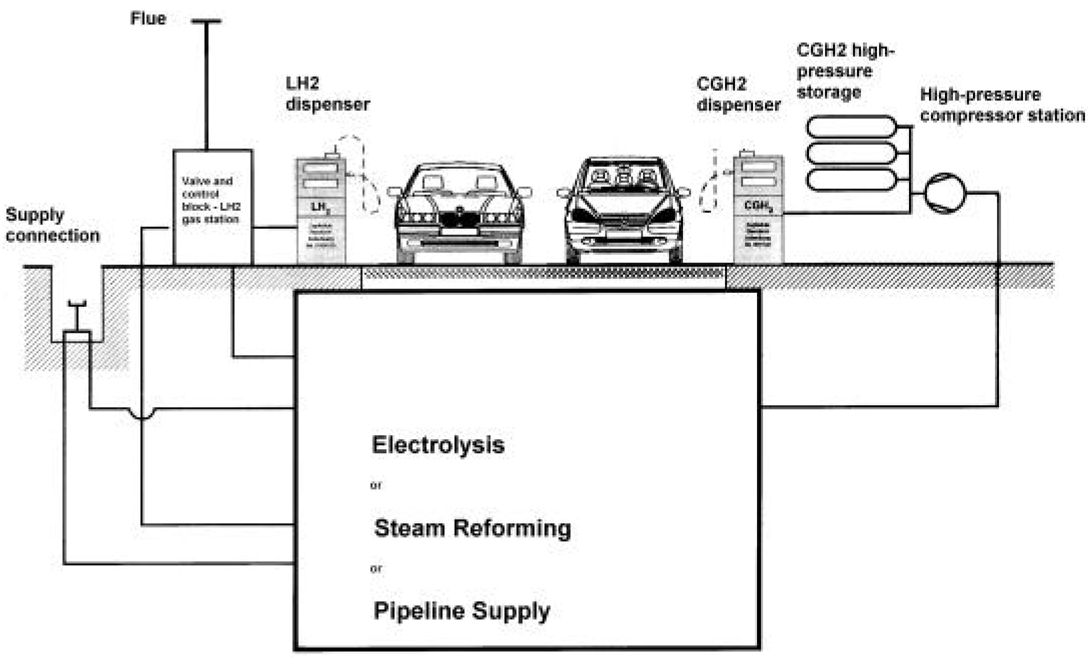
During on-site hydrogen production, the production of the hydrogen takes place directly at the gas station using an electrolyser, through natural gas steam reforming or the supply of the gas station with gaseous hydrogen through pipelines (Figure 34). Differences are made between gas station concepts that supply only gaseous hydrogen (CGH_2), or both (LH_2 and CGH_2). The gas station concept at which both LH_2 and CGH_2 are available is indicated in this paper by the term $LCGH_2$ gas station.

According to Valentin, the supply of the gaseous hydrogen through pipelines to the gas station is only shown to be economical above a fuel substitution quota by hydrogen of at least 50 %, and for this reason in this paper is not considered as a possible CGH_2 supply path for the gas station (Valentin, 2001, p. 129).

The liquid hydrogen is again delivered by trucks from the central hydrogen production plants to the gas stations, where it is stored in conventional, underground cryogenic tanks (LH_2 storage tanks). A liquefaction of the gaseous hydrogen produced at the gas station is ruled out due to the lack of space for the required units and the uneconomical nature.

If the hydrogen is stored in the vehicle in a compressed gaseous form, the hydrogen is transported from the electrolyser natural gas reforming via a high-pressure compressor station into the high-pressure storage tanks. The hydrogen is stored in the high-pressure tank at a pressure of at least 850 bar, so that is can be passed through the pump into the vehicle's fuel tank where it is stored at a pressure of 700 bar.

Figure 34: Schematic representation of the build-up of a gas station for the supply of liquid hydrogen (LH_2) and gaseous hydrogen (CGH_2) for hydrogen production at the gas station or for pipeline supply



Source: Wolf (a), 2002

The following assumptions are made for the specifications of the on-site plants (Reijerkerk, 2002, p. 101):

- 6,750 annual full capacity hours (corresponding to 75 % utilization)
- Plant rated for peak fuel sales in July (10 % of annual fuel sales are made at gas stations in July)

In the example of a gas station with an annual CGH_2 fuel sale of 4 GWh (corresponding to 1.33 million Nm^3/a), the plant has to be rated at 152 Nm^3/h for 8,760 assumed full-capacity hours. Taking into account a capacity utilization of 75 % and the plant's rating for July, this now calls for a 203 Nm^3/h plant.

4.2.2.1. On-site natural gas steam reforming: Gas station concept for the supply of liquid hydrogen and gaseous hydrogen

Significant characteristics of and assumptions for this gas station concept are:

- Hydrogen fuel sales of 50 % LH_2 and 50 % CGH_2
- LH_2 storage tank volumes of 80,000 l, number of LH_2 storage tanks dependent on annual hydrogen fuel sales, rented storage tank (Chapter 4.2.1.1)

- LH_2 path: one cryogenic transfer pump per fuel pump required (flow rate of 50 l/min, connection capacity 2.2 kW, purchase costs 51,000 €) for transporting the LH_2 from the storage tank through the fuel pump into the vehicle fuel tank (Reijerkerk, 2001, p. 91)
- Boil-off[68] from the LH_2 storage tank: is passed to the CGH_2 path using a cryogenic transfer pump (flow rate of 4.2 l/min, connection capacity 6 kW) and pressure evaporator (flow rate 200 Nm^3/h, pressure 400 bar, purchase costs 6,000 €) (Reijerkerk, 2001, p. 58); costs according to the opportunity cost principle added to the LH_2 path
- Engineering costs for construction, planning, ordering and supervision assumed to be from 20,000 to 50,000 € for the LH_2 and CGH_2 path per gas station (Chapter 4.2.1.1), in this paper depending on the annual gas station fuel sales obtained approximately given from Equation 25 in Appendix 6
- Gas station capacity utilization of 100 %
- Remaining assumptions as listed at the beginning of Chapter 4.2

For supplying vehicles with CGH_2, gaseous hydrogen from the NGSR plant is compressed using a two-stage membrane compressor to a pressure of 400 bar, and stored in an intermediate pressure tank. After a further compression of the hydrogen to 850 bar using a single-stage membrane compressor, the compressed hydrogen is stored in high-pressure storage tanks (Reijerkerk, 2001, p. 58). According to the current state of technology, one membrane compressor (850 bar) and one high-pressure storage unit is required for each CGH_2 fuel pump. A brief description of the individual components follows below.

Important characteristics of an on-site NGSR plant at the gas station are (Valentin, 2001, p. 6, 71; Own assumptions, 2002):
- Investment depending on annual hydrogen fuel sales according to Equation 26 in Appendix 6
- Natural gas consumption of 0.48 Nm^3 CH_4/Nm^3 H_2
- Natural gas purchase costs of 0.0211 €/kWh CH_4 (Appendix 4)
- Natural gas supply to the gas station using an available pipeline network (no investment in the construction of a natural gas pipeline network).

The following characteristics are determined for various compressors and pressure storage tanks (Reijerkerk, 2001, p. 58, 102 ff.):
- Two-stage membrane compressor: Compression in the first stage from 15 to 100 bar, in the second stage from 100 to 400 bar; purchase costs of the compressor dependent on compressor throughput, determined approximately according to Equation 27 in Appendix 6 (compressor throughput corresponds to maximum production volume of on-site NGSR plant in [Nm^3/h]) (Own calculations, 2002)
- Pressure storage tank (400 bar): Required storage volume of 67.2 % of the daily hydrogen fuel sales, in order to guarantee supplies in the busiest month of July; purchase costs of 36,250 €/1.000 Nm^3 of storage volume
- single-stage membrane compressor: Compression from 400 to 850 bar, throughput of 70 Nm^3/h, connection capacity of 5.5 kW, purchase costs of 59,000 70 €
- high-pressure storage tank (850 bar): Storage volume of 1,053 l, purchase costs of 27,000 €

For “Other investments” for various modifications, the following assumptions are made, taking EOS into account (Valentin,2001, p. 78; Own assumptions, 2002):
- for the LH_2 path from 100,000 to 250,000 €, in this paper depending on the annual gas station fuel sales obtained approximately from Equation 23 in Appendix 6.

[68] With progressive storage duration of the liquid hydrogen there is an incipient temperature equalization between the super-cooled liquid hydrogen and the ambient temperature. Part of the liquid hydrogen is evaporated by this and the pressure in the storage tank increases. When it reaches an overpressure of 5 bar, the gaseous hydrogen is released into the environment through safety valves, or can be used, for example, in fuel cells for generating electricity.

- for the CGH_2 path from 60,000 to 150,000 €, in this paper depending on the annual gas station fuel sales obtained approximately from Equation 24 in Appendix 6.

The operating and maintenance costs are given as follows:
- for the LH_2 path, 8 % of the total investment with a purchased storage tank per year (Bünger, 2000, S. 8; Own assumptions, 2002)
- for the CGH_2 path, 3.8 % of the total investment per year assumed, as most maintenance work in the CGH_2 area is on the NGSR plant

The electricity consumption at the gas station for the LH_2 path is given as 0,001 kWh_{el}/kWh LH_2 (Bünger, 2000, p. 8). The electricity consumption at the gas station for the CGH_2 path is predominantly composed of:
- On-site NGSR plant: Electricity consumption of 0.029 kWh_{el}/kWh H_2 (Own assumptions, 2002).
- two-stage membrane compressors (compression up to 400 bar): Electricity consumption depending on the compressor throughput (Appendix 6).
- single-stage membrane compressors (compression up to 850 bar): Electricity consumption per fuel pump and hydrogen fuel sales of 3.8 GWh/a about 34,000 kWh (Reijerkerk, 2001, p. 67).

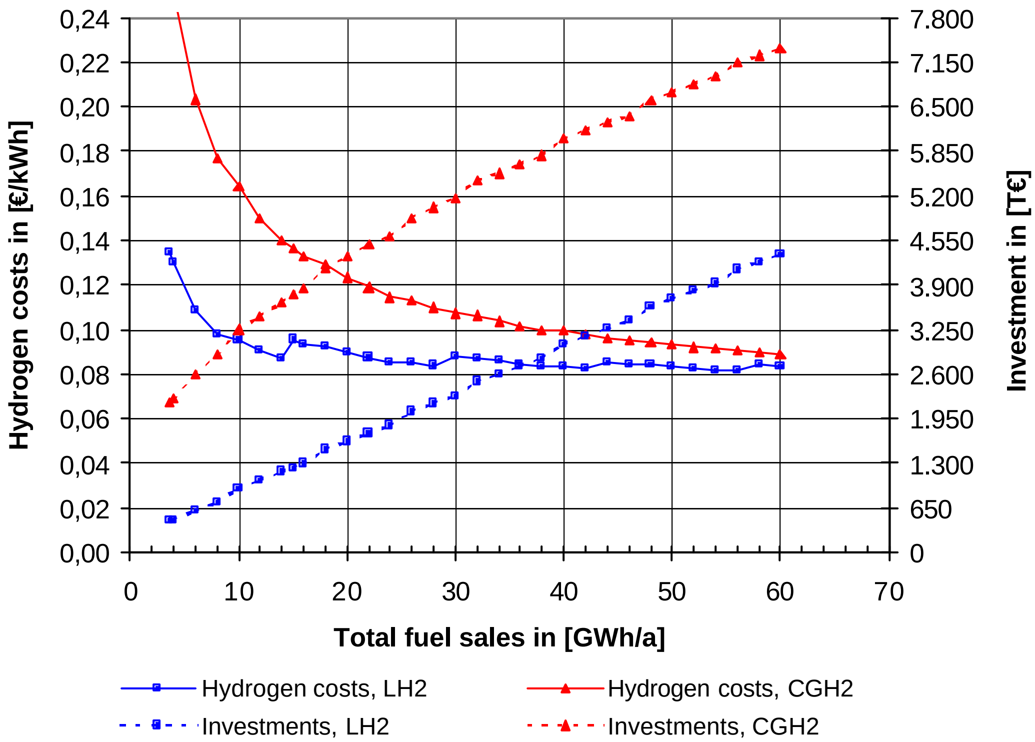
By adding together the investments in the individual gas station components, we obtain the total investment in an $LCGH_2$ gas station with an on-site NGSR plant, depending on the annual hydrogen fuel sales (Figure 35). A direct comparison of the investments for the LH_2 and CGH_2 paths is not yet meaningful, as investment in LH_2 production and distribution must be added to the investment for the LH_2 path. To compare investments, the following assumptions are made about the central LH_2 production:
- central NGSR plant: hydrogen production of 136,000 Nm^3/h (corresponding to 250 t/d), hydrogen production costs of 0.027 €/kWh H_2, plant investment of 88 million €, specific plant investments of 0.029 €/kWh H_2 (Chapter 3.3).
- central liquefaction plant: LH_2 production of 136,000 Nm^3/h (corresponds to 250 t/d), liquefaction costs of 0.022 €/kWh LH_2, plant investments of 180.5 million €, specific plant investments of 0.059 €/kWh LH_2 (Chapter 3.6).
- LH_2 truck distribution: 120 trucks required[69] for distribution of the produced hydrogen (136,000 Nm^3/h), truck distribution costs of 0.010 €/kWh LH_2, purchase costs of 550,000 € per truck, specific truck investments of 0.022 €/kWh LH_2 (Chapter 3.8).
- Electricity costs at Level 1 (L1) (Chapter 3.2.3)
- Natural gas costs at Level 1 (NL1) (Appendix 6)

With the assumptions stated above regarding central LH_2 production and distribution, specific investment of 0.11 €/kWh LH_2 are added to the previously determined investment in the LH_2 path, whereby the LH_2 and CGH_2 paths in Figure 35 are comparable. The investment in the LH_2 path across the entire area of hydrogen fuel sales is clearly below that of the CGH_2 path. Up to a gas station specification of about 50 GWh/a, the investment in the CGH_2 path is at least twice the investment in the LH_2 path.

The specific hydrogen costs fundamentally reduce with increasing annual hydrogen fuel sales (Figure 35), whereby this is more clearly the case for CGH_2 than for LH_2. The increase in LH_2 hydrogen costs with hydrogen fuel sales of 16 GWh/a is based on the need for a second LH_2 storage tank (Chapter 4.2.1.1).

[69] 240 truck journeys/a, average transport distance 150 km

Figure 35: Investments and specific hydrogen costs depending on annual hydrogen fuel sales at the gas station, with consideration from well to vehicle fuel tank for the gas station concept for the supply of liquid hydrogen (LH_2) and gaseous hydrogen (CGH_2), for delivery of the liquid hydrogen by truck and for hydrogen production of the gaseous hydrogen directly at the gas station through natural gas steam reforming, in Germany



Electricity costs at Level 1 (L1) with a conventional power station, natural gas costswith Level 1 (NL1).
Source: Own calculations, 2002

It should be stressed that an existing natural gas pipeline network to the gas stations is assumed for the CGH_2 path, whereupon the determined CGH_2 hydrogen costs and investments show very optimistic values.

4.2.2.2. On-site natural gas steam reforming: Gas station concept for the supply of gaseous hydrogen

At gas stations of this design, only the CGH_2 refueling of vehicles is possible.

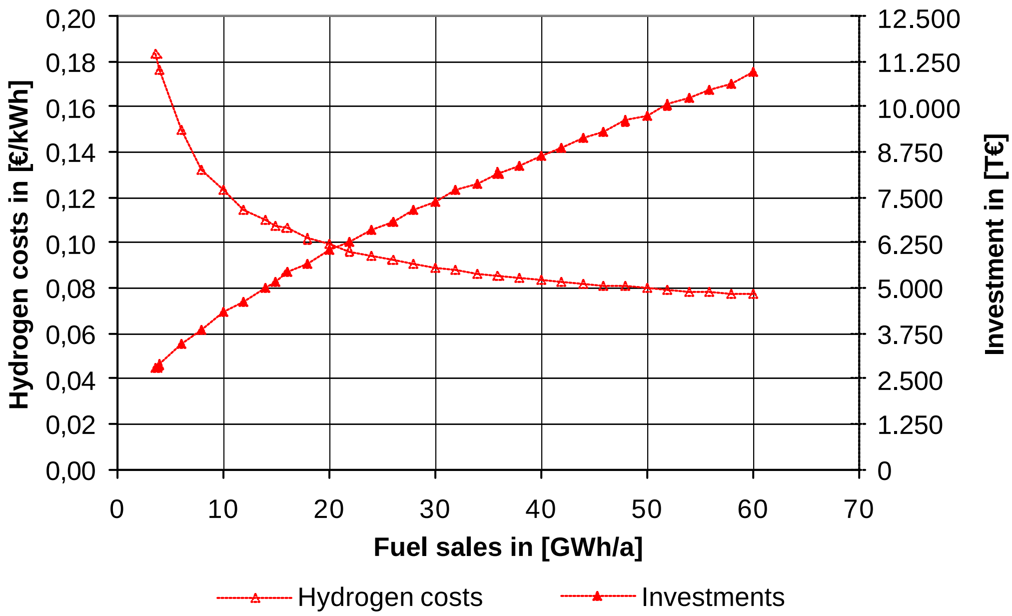
Significant characteristics of and assumptions for this gas station concept are:

- Characteristics of on-site NGSR plants depending on annual hydrogen fuel sales are determined as for the CGH_2 path of an $LCGH_2$ gas station with an on-site NGSR (Chapter 4.2.2.1)
- Characteristics of various compressors and pressure storage tanks depending on annual hydrogen fuel sales are determined as for the CGH_2 path of an $LCGH_2$ gas station with an on-site NGSR (Chapter 4.2.2.1)
- “Other investments” for various modifications to the gas station are assumed to be between 60,000 and 150,000 €, in this paper, depending on the annual gas station fuel sales arrived at approximately by Equation 24 in Appendix 6 (taking EOS into consideration)
- Engineering costs for design, planning, ordering and construction supervision are assumed to be from 40,000 to 100,000 € per gas station (Chapter 4.2.1.1) in this paper, depending on the annual gas station fuel sales as arrived at approximately by Equation 29 in Appendix 6

- Electricity requirement at the gas station is twice as high as for the CGH_2 path at an $LCGH_2$ gas station determined in Chapter 4.2.1.2, since twice the CGH_2 quantity per unit time is sold at the gas station.
- Operating and maintenance costs are assumed to be 3.8 % of the total investment, as most maintenance work is incurred on the NGSR plant
- Gas station capacity utilization of 100 %
- Remaining assumptions as listed at the beginning of Chapter 4.2

The investments in CGH_2 gas stations and the specific hydrogen production costs up to the vehicle tank are shown in Figure 36 depending on the annual hydrogen fuel sales. A comparison of these values to the values of other gas station concept can be found in Chapter 4.3.

Figure 36: Investments and specific hydrogen costs from well to vehicle fuel tank, depending on annual hydrogen fuel sales at the gas station, for the gas station concept for the supply of gaseous hydrogen (CGH_2), with hydrogen production directly at the gas station through natural gas steam reforming, in Germany



Electricity costs at Level 1 (L1) with a conventional power station, natural gas costs with Level 1 (NL1).
Source: Own calculations, 2002

4.2.2.3. On-site electrolysis: Gas station concept for the supply of liquid and gaseous hydrogen

Significant characteristics and assumptions of this gas station concept are:

- Hydrogen fuel sales of 50 % as LH_2 and 50 % as CGH_2
- LH_2 storage tank volumes of 80,000 l, number of LH_2 storage tanks dependent on annual hydrogen fuel sales, rental of the storage tank (Chapter 4.2.1.1)
- LH_2 path and boil-off[70] from the LH_2 storage tank: taken as identical with the LH_2 path of an $LCGH_2$ gas station with on-site NGSR (Chapter 4.2.2.1)
- “Other investments” for various modifications at the gas station and engineering costs for construction, planning, ordering and supervision assumed to be identical to those for an $LGCH_2$ gas station with on-site NGSR (Chapter 4.2.2.1)
- Gas station capacity utilization of 100 %
- Remaining assumptions as listed at the beginning of Chapter 4.2

[70] With progressive storage duration of the liquid hydrogen there is an incipient temperature equalization between the super-cooled liquid hydrogen and the ambient temperature. Part of the liquid hydrogen is evaporated by this and the pressure in the storage tank increases. When it reaches an overpressure of 5 bar, the gaseous hydrogen is released to the environment through safety valves or can be used, for example, in fuel cells for generating electricity.

For supplying vehicles with CGH_2, the gaseous hydrogen from the on-site electrolysis plant is compressed to 400 bar using a two-stage membrane compressor, and stored in an intermediate pressure tank. Further compression of the hydrogen to 850 bar and its storage in a high-pressure storage unit corresponds to the CGH_2 paths of the other concepts described above.

Important characteristics of an on-site electrolysis plant at the gas station are (Valentin, 2001, p. 6, 71; Own assumptions, 2002):

- Investment depending on annual hydrogen fuel sales according to Equation 11 in Chapter 3.5
- Electricity consumption of 1.5 kWh_{el} /kWh H_2 (Chapter 3.5)

The following characteristics are determined for various compressors and pressure storage tanks (Reijerkerk, 2001, p. 58, 102 ff.):

- Two-stage membrane compressor: compression in the first stage from 30 to 100 bar, in the second stage from 100 to 400 bar; purchase costs of the compressor dependent on compressor throughput are identical to the costs of an $LCGH_2$ gas station with on-site NGSR according to Equation 27 in Appendix 6
- Pressure storage tank, single-stage membrane compressor and high-pressure compressor identical to those for an $LCGH_2$ gas station with on-site NGSR (Chapter 4.2.2.1)

The operating and maintenance costs are given as follows:

- for the LH_2 path, 8 % of the total investment with a purchased storage tank per year (Bünger, 2000, p. 8; Own assumptions, 2002)
- for the CGH_2 path, an assumed 2.5 % of the total investment per year, as most maintenance work in the CGH_2 area is on the electrolysis plant

The electricity consumption at the gas station for the LH_2 path is given as 0.001 kWhel/kWh LH_2 (Bünger, 2000, p. 8). The electricity consumption at the gas station for the CGH_2 path is predominantly made up of:

- On-site electrolysis plant: Electricity consumption of 1.5 kWh_{el}/kWh H_2
- Two-stage membrane compressor (compression up to 400 bar): electricity consumption depending on compressor throughput (Appendix 6)
- Single-stage membrane compressor (compression up to 850 bar): electricity consumption per fuel pump and hydrogen fuel sales of 3.8 GWh/a about 34,000 kWh (Reijerkerk, 2001, p. 67)

By adding together investments in the individual gas station components, we obtain the total investment in an $LCGH_2$ gas station with on-site electrolysis plant, depending on annual hydrogen fuel sales (Figure 37). A direct comparison of investments in the LH_2 and CGH_2 paths is not yet meaningful, since investment in LH_2 production and distribution must be added to the investment for the LH_2 path. To compare investments, the following assumptions are made regarding central LH_2 production:

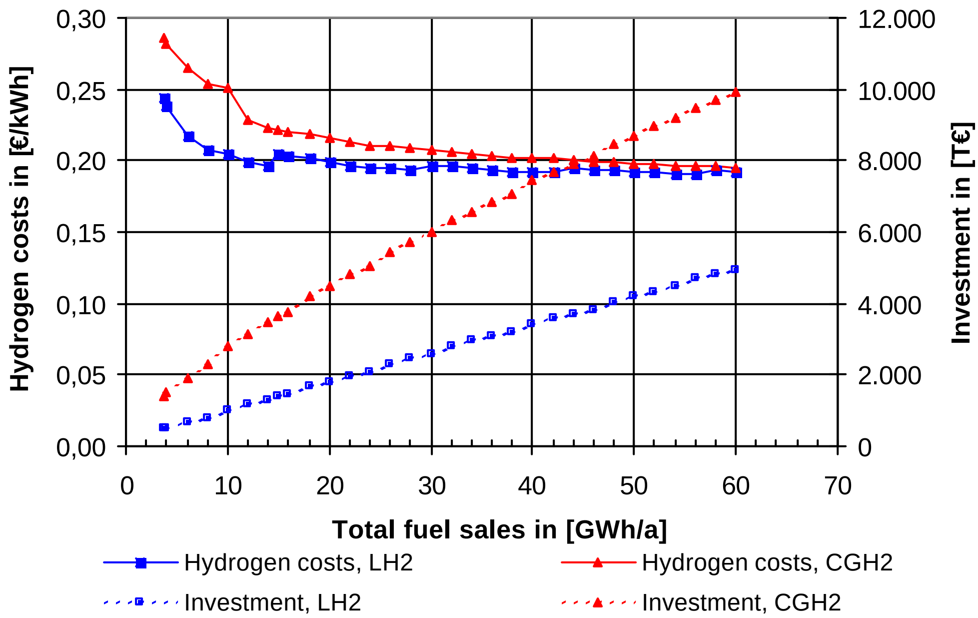
- Central electrolysis plant: hydrogen production of 136,000 Nm^3/h (corresponding to 250 t/d), hydrogen production costs of 0.126 €/kWh H_2, plant investment of 153 million €, specific plant investments of 0.049 €/kWh H_2 (Chapter 3.5)
- Central liquefaction plant: LH_2 production of 136,000 Nm^3/h (corresponds to 250 t/d), liquefaction costs of 0.032 €/kWh LH_2, plant investments of 180.5 million €, specific plant investments of 0.059 €/kWh LH_2 (Chapter 3.6)
- LH_2 truck distribution: 120 trucks required[71] for the distribution of the produced hydrogen (136,000 Nm^3/h), truck distribution costs of 0.010 €/kWh LH_2, purchase

[71] 240 truck journeys/a, average transport distance 150 km

costs of 550,000 € per truck, specific truck investments of 0.022 €/kWh LH_2 (Chapter 3.8)
- Electricity costs at Level 3 (L3) (Chapter 3.2.3)

With the assumptions stated above regarding central LH_2 production and distribution, specific investments of 0.13 €/kWh LH_2 are added to the previously determined investment in the LH_2 path, whereupon the LH_2 and CGH_2 paths in Figure 37 are then comparable.

Figure 37: Investments and specific hydrogen costs from well to vehicle fuel tank, depending on annual hydrogen fuel sales at the gas station, for the gas station concept for the supply of liquid hydrogen (LH_2) and gaseous hydrogen (CGH_2), for delivery of the liquid hydrogen by truck and for hydrogen production of the gaseous hydrogen directly at the gas station through electrolysis, in Germany



Electricity costs at Level 3 (L3) with regenerative production.
Source: Own calculations, 2002

The investment in the LH_2 path across the entire area of hydrogen fuel sales is clearly below that of the CGH_2 path. The higher the annual fuel sales, the greater the difference between the investments for the LH_2 and CGH_2 paths. From this it is evident that investments in an expansion of the capacity of the CGH_2 path are higher than those for the LH_2 path.

The specific hydrogen costs fundamentally reduce with increasing annual hydrogen fuel sales (Figure 37), this being more clearly the case for CGH_2 than for LH_2. Above annual hydrogen fuel sales at the gas station of about 60 GWh/a (corresponding to 66.7 million liters of GE), LH_2 hydrogen fuel costs are at the same level as those for CGH_2 hydrogen fuel. The increase in LH_2 hydrogen fuel costs for hydrogen fuel sales of 16 GWh/a is due to the requirement for a second LH_2 storage tank (Chapter 4.2.1.1).

4.2.2.4. On-site electrolysis: Gas station concept for the supply of gaseous hydrogen

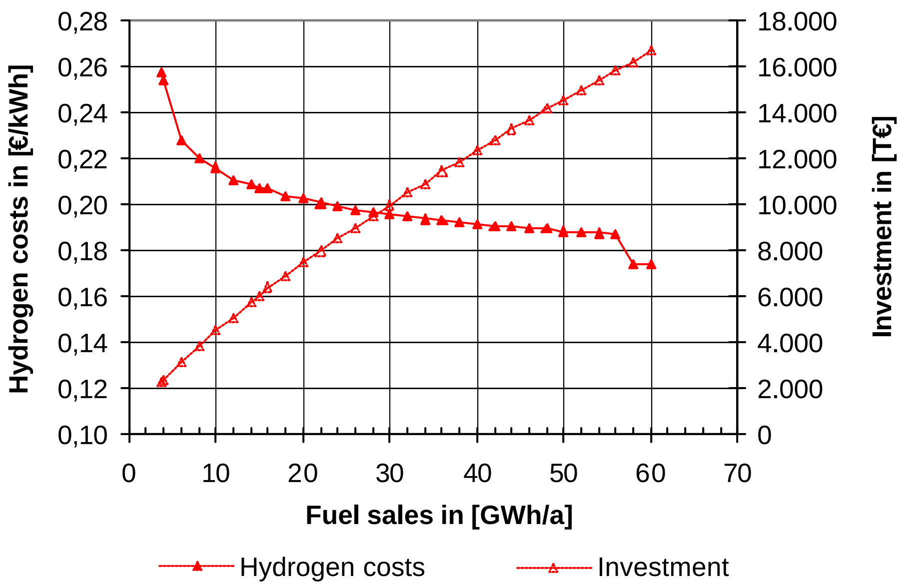
In this gas station design only the CGH_2 refueling of vehicles is possible.

Significant characteristics and assumptions of this gas station concept are:
- Characteristics of on-site electrolysis plants depending on annual hydrogen fuel sales are determined as for the CGH_2 path for an $LCGH_2$ gas station with on-site electrolysis (Chapter 4.2.2.3)
- Characteristics of various compressors and pressure storage tanks depending on annual hydrogen fuel sales are determined as for the CGH_2 path for an $LCGH_2$ gas station with on-site electrolysis (Chapter 4.2.2.3)

- "Other investments" for various modifications at the gas station and engineering costs for design, planning, ordering and construction supervision are assumed to be identical to those for an $LGCH_2$ gas station with on-site NGSR (Chapter 4.2.2.1)
- Electricity requirements at the gas station are twice as high as for the CGH_2 path at an $LCGH_2$ gas station determined in Chapter 4.2.2.3, since twice the CGH_2 quantity per unit time is sold at the gas station.
- Operating and maintenance costs of 2.5 % of the total investment per year have been assumed, since most maintenance work in the CGH_2 area is on the electrolysis plant
- Gas station capacity utilization of 100 %
- Remaining assumptions as listed at the beginning of Chapter 4.2

The investments in CGH_2 gas stations and the specific hydrogen production costs as far as the vehicle's tank are shown in Figure 38, depending on annual hydrogen fuel sales. A comparison of these values with those for other gas station concepts can be found in Chapter 4.3. The considerable drop in hydrogen costs at about 58 million kWh/a of fuel sales is based on the electricity consumption reaching a magnitude at which a more favorable supply cost level is reached (Chapter 3.2.3).

Figure 38: Investments and specific hydrogen costs from well to vehicle fuel tank, depending on annual hydrogen fuel sales at the gas station, for the supply of gaseous hydrogen (CGH_2), with hydrogen production by electrolysis directly at the gas station, in Germany



Electricity costs at Level 3 (L3) with regenerative production.
Source: Own calculations, 2002

4.3. Comparison of the alternative gas station concepts

In the first stage, for a better overview, the pure gas station concepts, i.e. those which supply LH_2 or CGH_2, are compared with each other. Comparison of the concepts takes place according to the investments made (hydrogen production, distribution, gas stations), the specific hydrogen costs and the CO_2 emissions. The next stage involves a comparison of the gas station concepts that supply both LH_2 and CGH_2 at the gas station. From this it becomes evident which gas station concept for the supply of hydrogen is best from a cost and ecological (only CO_2 emissions are considered here) perspective, and which of the two states, liquid or gaseous, is the favorite for hydrogen as the alternative fuel of the future.

In the further consideration of gas station designs, only the rental option of an LH_2 storage tank will be taken into account, as high infrastructure investments represent a significant introduction hurdle for hydrogen as an alternative fuel, whereas renting the storage tank lowers it (Chapter 4.2.1).

4.3.1. Comparison of the pure gas station concepts for the supply of liquid hydrogen or gaseous hydrogen

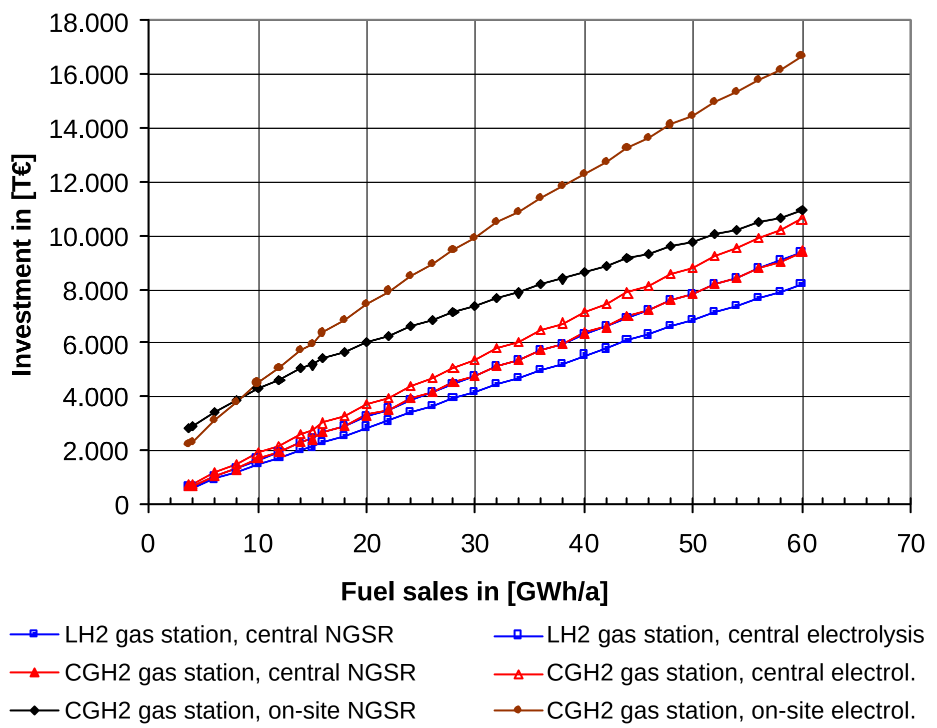
4.3.1.1. Comparison of investments

Comparison of investments in the infrastructure per gas station makes it clear that regardless of annual hydrogen fuel sales (taking into consideration up to 60 GWh/a, equivalent to 7.25 million l GE/a), the LH_2 gas station concept is the most cost-effective (Figure 39).

Investments in on-site concepts up to annual hydrogen fuel sales of approx. 60 GWh are higher than in concepts with central hydrogen production. In the example of hydrogen production using NGSR, the investment difference between the concepts with on-site production and central hydrogen production becomes lower with increasing annual hydrogen fuel sales, because EOS were taken into account when comparing investments for on-site production plants of smaller capacity (the higher the annual hydrogen fuel sales at the gas station, the higher the capacity required from the on-site production plant), but not for production plants with higher capacity (investment in a production plant with higher capacity, Chapter 4.2.2.1).

Up to annual hydrogen fuel sales of about 8 GWH (corresponding to 0.89 million l GE), investments in on-site electrolysis are lower than those in on-site NGSR. With increasing hydrogen output, the investment in electrolysis plants increases more rapidly than is the case for NGSR plants, because of lower EOS.

Figure 39: Investments per gas station from well to vehicle fuel tank, depending on annual hydrogen fuel sales at the gas station, for the gas station concept for the supply of liquid hydrogen (LH_2) or gaseous hydrogen (CGH_2) and for different hydrogen production processes, in Germany



<u>Specimen key explanation:</u> "LH_2 gas station, central NGSR" – gas station concept for the supply of liquid hydrogen with hydrogen production by central natural gas steam reforming plant (NGSR). "CGH_2 gas station, on-site electr," = gas station concept for the supply of gaseous with hydrogen production by electrolysis direct at the gas station (on-site).
Source: Own calculations, 2002

4.3.1.2. Comparison of specific hydrogen costs

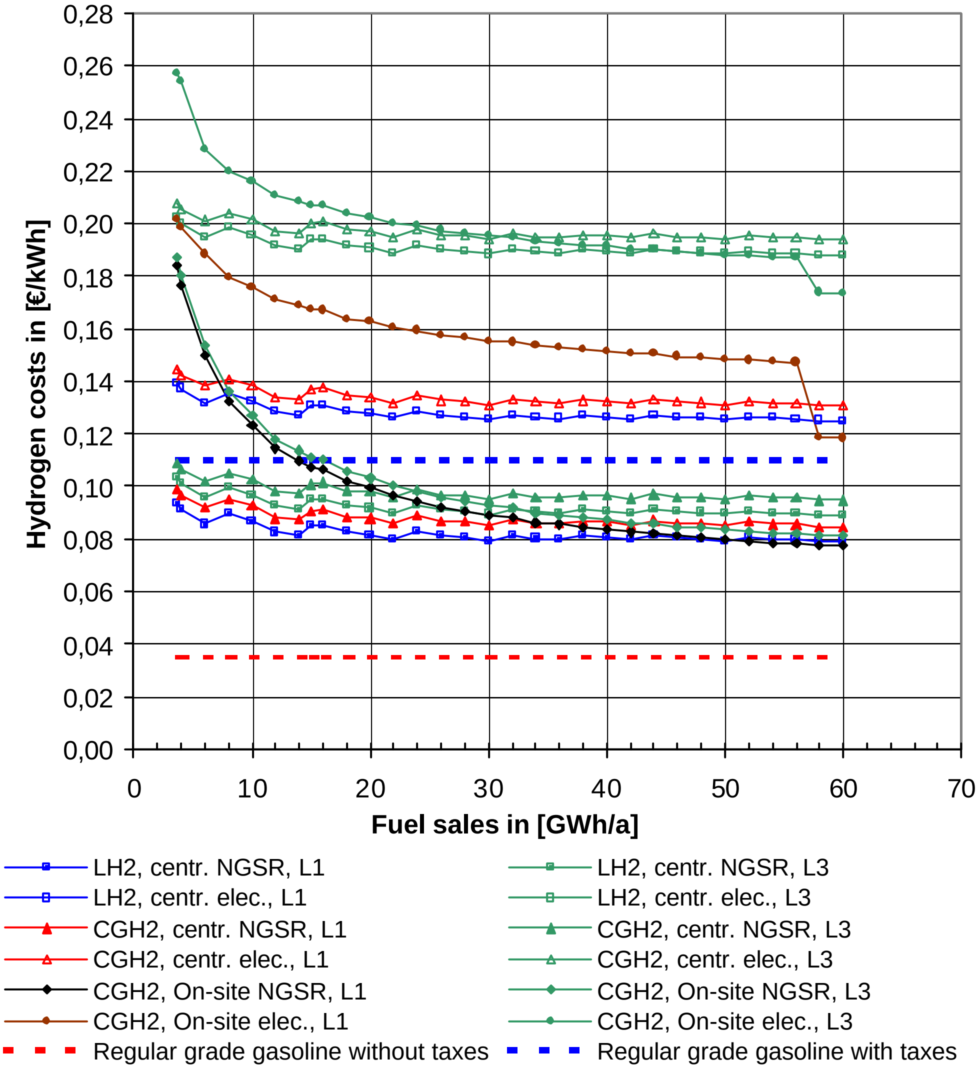
When considering the specific hydrogen costs with electricity costs at Level 1, this indicates that up to a gas station specification with annual hydrogen fuel sales of 50 GWh (corresponding to 5.6 million l GE), the most cost-effective solution is the LH_2 concept with central hydrogen production by NGSR (Figure 40). Specific hydrogen costs for the CGH_2 concept with central hydrogen production using NGSR across the entire area of annual hydrogen fuel sales are slightly higher than for the cost-effective LH_2 concept.

The cost degression that arises in the CGH_2 on-site NGSR concept with increasing annual hydrogen fuel sales comes about, as already mentioned in the earlier comparison of investments, by taking into account the EOS for on-site production plants. The CGH_2 on-site electrolysis concept, which only exhibits lower specific hydrogen costs because of the more favorable electricity costs[72] from annual hydrogen fuel sales of about 56 GWh (corresponding to 6.4. million l GE), lies well behind the LH_2 or CGH_2 concept of central electrolysis. If identical electricity costs are assumed for on-site electrolysis concepts and electrolysis plants, almost identical specific hydrogen costs are reached at average fuel sales of 25 GWh/a of a roadside gas station.

Using regeneratively produced electricity with Level 3 results in a general increase in specific hydrogen costs. The rise in costs is more severe with the higher electricity requirement in the respective process chain. If the hydrogen is produced centrally by electrolysis, the LH_2 concept is again the most cost-effective up to annual hydrogen fuel sales of about 48 GWh (corresponding to 5.35 million l GE). For the supply of CGH_2 at the gas station, on-site electrolysis of the central electrolysis is preferred if annual hydrogen sales are above 32 GWh (corresponding to 3.6 million l GE).

[72] Staggering of electricity costs according to the amount of electricity used per year (Chapter 3.2.3).

Figure 40: Specific hydrogen costs from well to vehicle fuel tank, depending on annual hydrogen fuel sales at the gas station, with electricity generation by conventional power stations (L1) and from regenerative energy (L3), for the gas station concept for the supply of liquid hydrogen (LH_2) or gaseous hydrogen (CGH_2), in Germany



L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs according to Level 1 (NL1). Specimen key description: "LH_2, centr. NGSR, L1" = gas station concept for the supply of liquid hydrogen with hydrogen production by central natural gas steam reforming plants (NGSR) using electricity from conventional power station at Level 1 (L1). "CGH_2, on-site electr., L3" = gas station concept for the supply of gaseous hydrogen with hydrogen production by electrolysis at the gas station (on-site) using electricity from regenerative energy at Level 3 (L3).
Source: www.shell.de, 22.05.2002; Own calculations, 2002

4.3.1.3. Comparison of CO_2 emissions

As well as the cost criteria, the CO_2 emissions generated across the entire process chain, from hydrogen production to vehicle refueling, form a significant decision criterion. As a global reduction in the levels of CO_2 is an important motivating reason for the introduction of hydrogen as an alternative fuel, the minimum CO_2 emissions that could be achieved by the individual concepts using regeneratively produced electricity are shown. The CO_2 emissions created by the regenerative production of electricity are assumed to be 15 g/kWh_{el} (Chapter 3.2.3).

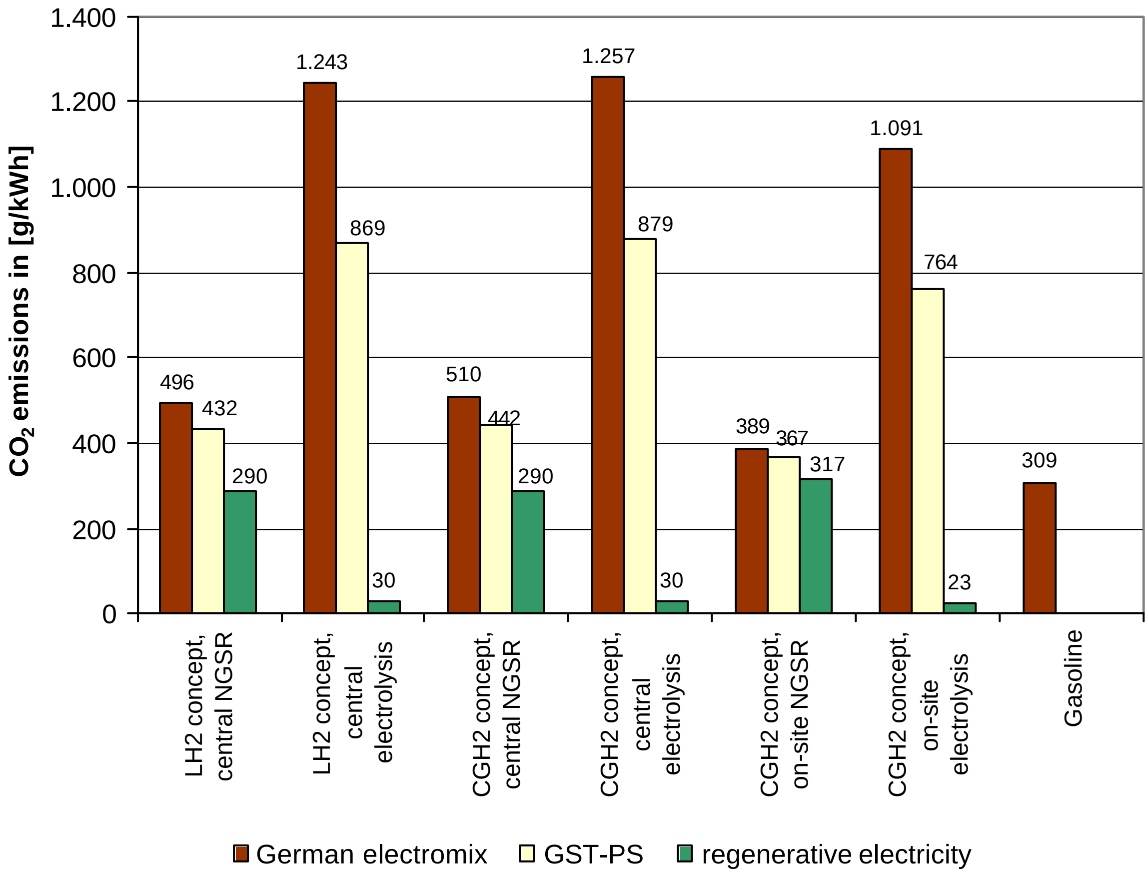
From Figure 41, it is evident that a reduction in CO_2 can be achieved in the long term only by using regeneratively produced electricity or electricity from nuclear power (except for the CGH_2 concept with on-site NGSR). The slightly higher emissions in the CGH_2 concept with central NGSR, namely 519 g/kWh compared to the LH_2 concept with central NGSR of 496 g/kWh, arise from the higher electricity requirement of the cryogenic pressure pump in the CGH_2 path. Approximately the same levels of CO_2 emissions occur when using regeneratively produced electricity. This is due to the fact that at emissions of 700 g CO_2/kWh$_{el}$ from German power stations, the lower electricity consumption of the CGH_2 concept compared to the LH_2 concept has a greater impact on the CO_2 emissions per kWh of hydrogen, whereas at emissions of 15 g CO_2/kWh$_{el}$ for regenerative electricity production, only the value behind the decimal point of the CO_2 emissions of 290 g/kWh of hydrogen changes.

The CO_2 emissions of 389 g/kWh in the CGH_2 concept with on-site NGSR, using electricity from German power stations, are lower than the figure of 510 g/kWh in the CGH_2 concept with central NGSR, since in central hydrogen production the hydrogen is liquefied and an additional electricity requirement (and therefore CO_2 emissions) is needed for this sub-process.

When using regeneratively produced electricity, the opposite is true. The CGH_2 concept with on-site NGSR produces 317 g of CO_2 emissions, the CGH_2 concept with central NGSR 290 g. CO2 emissions as a consequence of the NGSR process amount to 283 g/kWh H_2 at a central NGSR, and 315 g/kWh H_2 at an on-site NGSR. The reason for this lies in the better efficiency of higher-performance NGSR plants compared with on-site plants of lower nominal performance. By using electricity from German power stations, this creates about 204 g due to the electricity requirement of the central NGSR plant with associated liquefaction in the generation of electricity and about 95 g (no liquefaction) in the case of the on-site NGSR plant. If regeneratively produced electricity is used, CO_2 emissions for electricity generation at central NGSR plants are about 5 g, and for on-site NGSR plants, about 2 g. In spite of using regeneratively produced electricity, it is not possible to achieve a level lower than 317 g/kWh H_2 with the on-site NGSR concept, as the largest proportion of the emissions arises from the natural gas steam reforming process.

As a consequence of the electrolysis plants' high electricity requirements, the use of electricity from the German power stations results in very high CO_2 emissions (Chapter 3.5). The slightly higher emissions in the CGH_2 concept with central electrolysis of 1,257 g/kWh compared with the LH_2 concept with central electrolysis of 1,243 g/kWh again arises from the higher electricity requirement of the cryogenic pressure pump in the CGH_2 path. When using regeneratively produced electricity, approximately the same level of CO_2 emissions of 30 g/kWh is obtained (refer back three paragraphs for the reason).

Figure 41: CO_2 emissions from well to vehicle fuel tank depending on hydrogen production and electricity generation for different gas station concepts for the supply of liquid hydrogen (LH_2) or gaseous hydrogen (CGH_2), in Germany



GST-PS = Gas and steam turbine power station
Specimen key explanation: "LH_2 concept, central NGSR" = gas station concept for the supply of liquid hydrogen with hydrogen production by central natural gas steam reforming plants (central NGSR).
"CGH_2 concept, on-site electr," = gas station concept for the supply of gaseous hydrogen with hydrogen production by electrolysis direct at the gas station (on-site).
Source: VES, 2001; Own calculations, 2002

CO_2 emissions from the CGH_2 concept with on-site electrolysis are lower than from the CGH_2 concept with central electrolysis because, as mentioned above, there is no hydrogen liquefaction in the process chain.

For the **build-up of an LH_2 infrastructure**, the following conclusions can therefore be reached:

- for reasons of cost, LH_2 is preferred to CGH_2
- for reasons of cost, the introduction of hydrogen is to be achieved by the LH_2 gas station concept with central NGSR using regeneratively produced electricity or electricity from nuclear power (CO_2 emissions can be reduced below the emissions level for gasoline)
- long-term CO_2 reduction is only achieved with hydrogen production by central electrolysis using regeneratively produced electricity or electricity from nuclear power[73]

For the **build-up of a CGH_2 infrastructure**, the following conclusions are reached:

- for reasons of cost, the introduction of hydrogen up to annual hydrogen fuel sales at the gas station of 32 GWh (corresponding to 3.6 million l GE) is to be achieved using the central NGSR concept, and above this quantity using the on-site NGSR concept

[73] as far as this is politically and socially acceptable

- by using regeneratively produced electricity or electricity from nuclear power, CO_2 emissions can be reduced to the level of conventional gasoline fuel
- long-term CO_2 reduction only through hydrogen production by electrolysis using regeneratively produced electricity or electricity from nuclear power; above annual hydrogen sales of 32 GWh (corresponding to 3.6 million l GE), on-site production of central production is preferred.

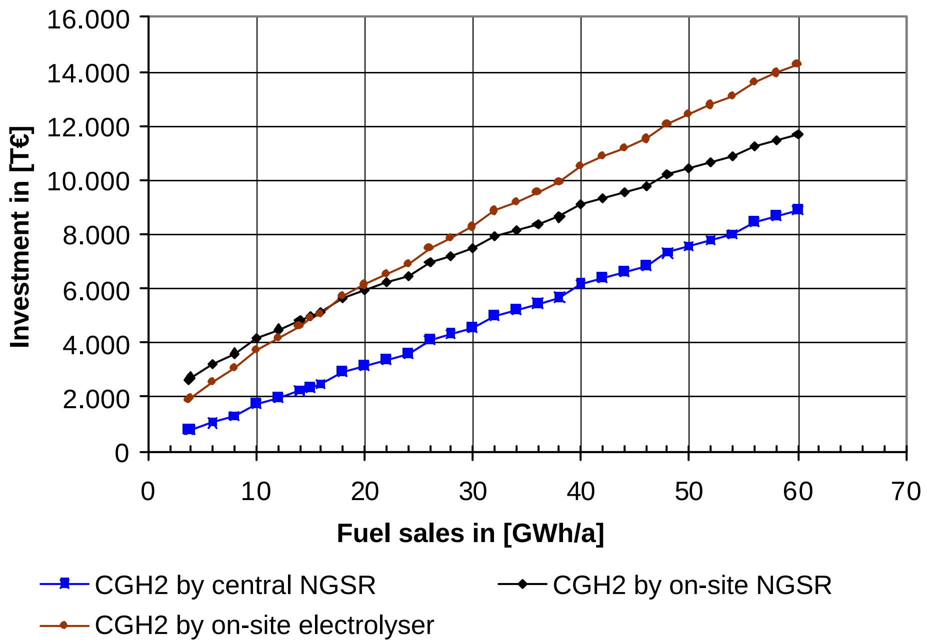
4.3.2. Comparison of the combined gas station concepts for the supply of liquid and gaseous hydrogen

4.3.2.1. Comparison of investments

An examination of the investments makes it clear that the $LCGH_2$ concept with hydrogen production at a central NGST presents the most favorable version (Figure 42). The investment in the on-site concept across the entire area of annual hydrogen fuel sales is clearly higher than that of investments in central hydrogen production. In the example of hydrogen production via NGSR, the investment difference between the concept with on-site production and central hydrogen production remains at about the same level with increasing annual hydrogen fuel sales.

Up to annual hydrogen fuel sales of about 18 GWh (corresponding to 2 million l GE), investments in on-site electrolysis are lower than those in on-site NGSR. With increasing output of the hydrogen production plants, the investment in electrolysis plants grows more strongly than is the case for NGSR plants, because of lower EOS.

Figure 42: Investments per gas station from well to vehicle fuel tank depending on annual hydrogen fuel sales at the gas station, for the gas station concept for the supply of liquid hydrogen (LH_2) and gaseous hydrogen (CGH_2) and different processes of gaseous hydrogen production, in Germany



The liquid hydrogen is produced in central natural gas steam reforming plants (NGSR) and delivered to the gas stations by truck. Specimen key explanation: "CGH_2 via central NGSR" = the gaseous hydrogen is evaporated from the supplied liquid hydrogen directly at the gas station.
Source: Own calculations, 2002

4.3.2.2. Comparison of specific hydrogen costs

Examination of the specific hydrogen costs takes place for each gas station concept, divided upaccording to the LH_2 and CGH_2 paths (Figure 43). The chosen nomenclature for the individual gas station concepts in the diagram is explained using the example of the "LH_2, central NGSR, LH2-C, L1" concept:

- LH_2: CGH_2 production concept [74]
- central NGSR: LH_2 production concept
- LH_2-C: LH_2 costs
- L1: electricity costs

An examination of the individual concepts shows that CGH_2 costs always lie clearly above LH_2 costs, except for CGH_2 production by on-site NGSR.

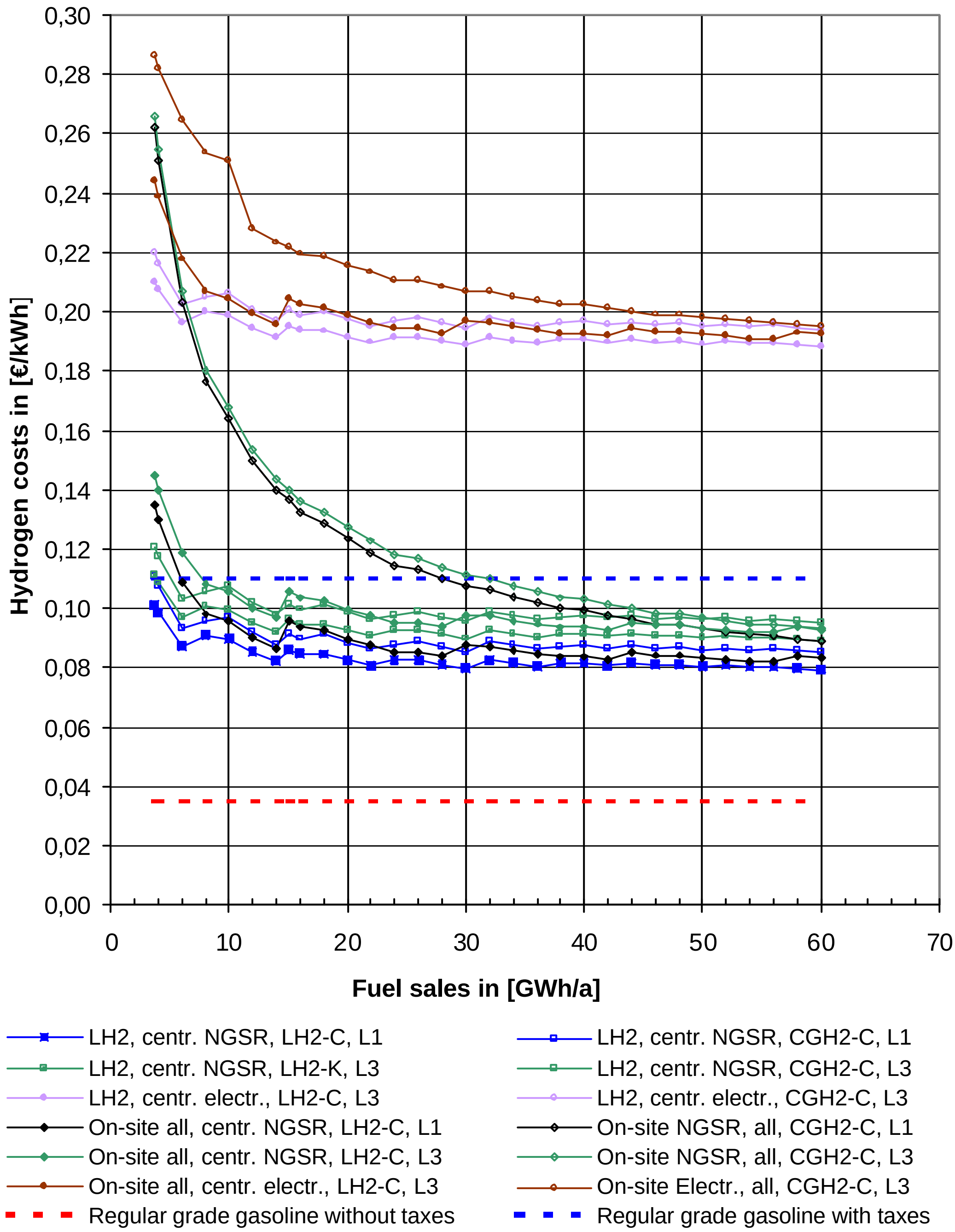
For the average specific hydrogen costs[75] with electricity from German power stations at Level 1 (L1), this indicates that, up to a gas station specification with annual hydrogen fuel sales of 60 GWh (corresponding to 6.7 million l GE), the most cost-effective solution is the LH_2 concept with central hydrogen production by NGSR (curves "LH2, centr. NGSR, LH2-C, L1" and "LH2, centr. NGSR, CGH2-C, L1" in Figure 43). Above this size, the average specific hydrogen costs for CGH_2 production by on-site NGSR are at about the same level as those for central NGSR production via LH_2 (curves "on-site all, centr. NGSR, LH2-C, L1" and "On-site NGSR, all, CGH2-C, L1").

Using regeneratively produced electricity at Level 3 (N3) results in a general increase of specific hydrogen costs. The rise in costs is more severe as the electricity requirement in the respective process chain rises. Up to annual hydrogen fuel sales at the gas station of about 60 GWH (corresponding to 6.7 million l GE), central hydrogen production by NGSR is again the most favorable option. Above this size, the average specific hydrogen costs for CGH_2 production by on-site NGSR are at about the same level as those for central NGSR production via LH_2.

In order to achieve a global reduction in CO_2, hydrogen production must take place by electrolysis using, for example, regeneratively produced electricity. The concept comparison shows that up to annual hydrogen fuel sales at the gas station of about 60 GWH (corresponding to 6,7 million l GE), central LH_2 production (CGH_2 supply at the gas station by vaporisation and superheating of the LH_2) is preferred to on-site production.

[74] "LH2" means CGH_2 production by evaporization and superheating of LH_2.
[75] The average hydrogen costs are shown as the average fo the specific hydrogen costs of the LH_2 and CGH_2 path.

Figure 43: Specific hydrogen costs from well to vehicle fuel tank (divided into the supply of liquid hydrogen and gaseous hydrogen) depending on annual hydrogen fuel sales at the gas station, with electricity generation by conventional power stations (L1) and from regenerative energy (L3), for the gas station concepts for the supply of liquid hydrogen (LH_2) or gaseous hydrogen (CGH_2) and different hydrogen production processes, in Germany



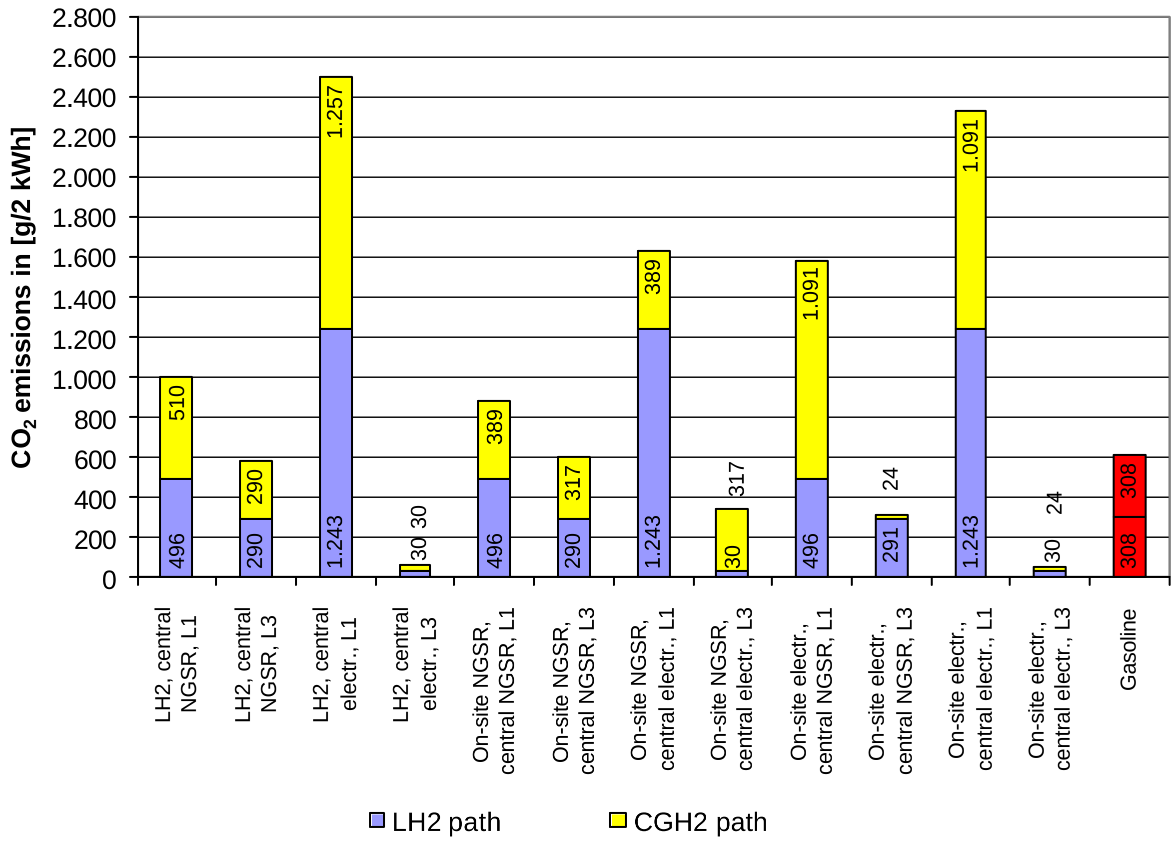
L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs according to Level 1 (NL1). Specimen key description: "LH2, centr. NGSR, LH2-C, L1": "LH2" – concept of the production of gaseous hydrogen, here by vaporisation and superheating of the liquid hydrogen, "centr. NGSR" = concept of liquid hydrogen production, here by central natural gas steam reforming plants (NGSR). "LH2-C" = costs of the making liquid hydrogen available at the filing station (C = costs), "L1" = electricity costs from conventional power stations.
Source: www.shell.de, 22.05.2002; Own calculations, 2002

4.3.2.3. Comparison of CO_2 emissions

As well as the cost criterion, CO_2 emissions generated across the entire process chain, from hydrogen production to vehicle refueling, form a significant decision criterion. CO_2 emissions are determined for the supply of 1 kWh of LH_2 and 1 kWh of CGH_2 at the gas station (because of hydrogen fuel sales at the gas station of 50 % in the form of LH_2 and 50 % in the form of CGH_2) and compared with emissions for the supply of 2 kWh of gasoline. The nomenclature chosen for the individual gas station concepts in the diagram corresponds to that for the hydrogen costs described above.

From Figure 44, it is evident that a reduction in CO_2 can be achieved in the long term only by using regeneratively produced electricity or electricity from nuclear power. The slightly higher emissions of 510 g/kWh in the CGH_2 path of the concept “LH2, central NGSR, L1” compared with the LH_2 path figure of 496 g/kWh arise from the higher electricity requirement of the cryogenic pressure pump in the CGH_2 path. Approximately the same CO_2 emission levels occur for these paths when using regeneratively produced electricity. This is due to the fact that at emissions of 700 g CO_2/kWh_{el} from German power stations, the lower electricity consumption of the CGH_2 concept compared to the LH_2 concept has a greater impact on the CO_2 emissions per kWh of hydrogen, whereas at emissions of 15 g CO_2/kWh_{el} from regenerative electricity production, only the value behind the decimal point of CO_2 emissions of 290 g/kWh of hydrogen changes.

Figure 44: CO_2 emissions from well to vehicle fuel tank (divided into the supply of 1 kWh of liquid hydrogen and 1 kWh of gaseous hydrogen) depending on the hydrogen production and electricity generation processes, for gas station concepts for the supply of liquid (LH_2) or gaseous hydrogen (CGH_2), in Germany



L1 = electricity from conventional power stations, L3 = electricity from regenerative production.
Specimen key explanation: “LH2, centr. NGSR, L1”: “LH2“ = concept of the production of gaseous hydrogen, here by vaporisation and superheating of the liquid hydrogen, “centr. NGSR” = concept of liquid hydrogen production, here by central natural gas steam reforming plants (NGSR). "L1" = electricity from conventional power stations.
Source: VES, 2001; Own calculations, 2002

CO_2 emissions of 389 g/kWh in the CGH_2 path for the “On-site NGSR, central NGSR, L1” concept are lower than the emissions of 510 g/kWh in the CGH_2 path of the “LH2, central NGSR, L1” concept, since in central hydrogen production the hydrogen is liquefied and an additional electricity requirement (and therefore CO_2 emissions) are incurred in this sub-process. When using regeneratively produced electricity, the opposite is true (see explanations in the comparison of CO_2 emissions in Chapter 4.3.1).

As a consequence of the high electricity requirement of the electrolysis plants, the use of electricity from German power stations results in very high CO_2 emissions. The slightly higher emissions in the CGH_2 path of the concept “LH2, central electrolysis, L1” of 1,257 g/kWh compared to the LH_2 path of 1,243 g/kWh again arise from the higher electricity requirement of the cryogenic pressure pump in the CGH_2 path. When using regeneratively produced electricity, approximately the same level of CO_2 emissions of 30 g/kWh is obtained (refer back two paragraphs for the reason).

CO_2 emissions from the CGH_2 concept with on-site electrolysis are lower than from the CGH_2 concept with central electrolysis because, as mentioned elsewhere above, there is no hydrogen liquefaction in the process chain.

For the **build-up of a $LCGH_2$ infrastructure**, the following conclusions are therefore reached:

- for reasons of cost, the introduction of hydrogen is to be achieved using the concept of central hydrogen production by natural gas steam reforming, independent of annual hydrogen sales at the gas station.
- by using regeneratively produced electricity or electricity from nuclear power, the CO_2 emissions can be reduced to the level of conventional gasoline fuel
- a long-term CO_2 reduction is only attainable through hydrogen production by electrolysis using regeneratively produced electricity or electricity from nuclear power; above annual hydrogen sales at the gas station of 60 GWh (corresponding to 6.7 million l GE), CGH_2 on-site production of central production from LH_2 by evaporation and superheating is preferred.

Since in view of the analyses for a long-term reduction of CO_2 that have been discussed, the on-site concepts only become interesting above annual hydrogen fuel sales of about 32 GWh (corresponding to 3.6. million l GE) for CGH_2 gas stations, and about 60 GWh (corresponding to 6.7 million l GE) for $LCGH_2$ gas stations, which are available at freeway gas stations, the build-up of an LH_2 gas station infrastructure without on-site production is examined in this paper. If an $LCGH_2$ gas station infrastructure is to be realized, higher investments and total costs are involved in the optimal concept of central hydrogen production than for the build-up of an LH_2 gas station structure infrastructure as determined in this paper.

4.4. Plant capacities for central hydrogen production

The required hydrogen requirement over a number of years can, according to HDD OWN (Chapter 2.3.4) be produced either by a higher number of central production plants of lower nominal capacity or by a smaller number of central production plants of higher capacity. With constantly increasing hydrogen demand due to the market penetration of vehicles that use hydrogen as an alternative fuel, the production plants will in all probability be designed with a capacity which will not be achieved in the year of their commissioning. For a certain time, the production plants will therefore work at part capacity, during which phase the costs per unit of hydrogen they produce will be higher than when they are operating at full capacity. The period of time needed to achieve full-capacity operation of the production plants (two or three years or more), represents a significant influencing factor on hydrogen costs.

For the total cost comparison, the future expenses, divided up into annuities of the investment and operating and maintenance costs, will be discounted as at 2006 (for further calculation assumptions, see Chapter 3.1). For the purposes of calculation, 2006 corresponds to today, as the period of time between now and 2006 is not taken into consideration.

In the example of hydrogen production by NGSR plants, the ratings of the central production plants are shown. In the first stage, they are based on HDD OWN for supplying vehicles in the city of Munich. In the second stage, there follows an examination of the plant capacities with the total hydrogen requirement according to HDD OWN for Germany used as a basis for calculation.

For the calculations in this paper, the simplified assumption is made that at the end of the technical lifespan of a plant, another plant of the same capacity will be constructed, insofar as the hydrogen requirement does not increase disproportionally. In addition, it is assumed that the NGSR plants will be built in the vicinity of existing natural gas pipelines, thus avoiding investments in the construction of new natural gas pipelines. The capacities of existing natural gas pipelines is regarded as sufficient for future needs.

4.4.1. Plant specification according to the hydrogen demand for Munich

This chapter contains an examination of the development of central hydrogen production plants including liquefaction plants to cover the hydrogen requirement according to HDD OWN for Munich. The following options for possible development of the hydrogen production plants only differ in the capacities of the individual plants, including the liquefaction plants:

- **Option 1:** All hydrogen production plants are designed for the hydrogen requirement that exists in two years after deduction of the hydrogen produced by existing production plants (plants in part-operation in the first year). In view of the non-constant increase in hydrogen demand over the years, the production plants mostly exhibit different capacities, so that the learning effect does not occur to its fullest extent.
- **Option 2:** The first hydrogen production plant is designed for the hydrogen requirement in two years' time. The other production plants are designed for the hydrogen requirement in four years' time, established after deduction of the hydrogen produced by existing plants (production plants run at part-capacity for three years).
- **Option 3:** Identical to Option 2, except that the hydrogen production plants (from the second plant on) are designed for the hydrogen requirement in seven years' time and operate at part-capacity for six years.
- **Option 4:** Identical to Option 2, except that the hydrogen production plants (from the second plant on) are designed for the hydrogen requirement in ten years' time and operate at part capacity for nine years.
- **Option 5:** All hydrogen production plants are designed for the hydrogen requirement that exists in four years after deduction of the hydrogen produced by existing production plants (production plants run at part-capacity for three years).
- **Option 6:** The first hydrogen production plant is designed for the hydrogen requirement in four years' time. The other production plants are designed for the hydrogen requirement in six years' time after deduction of the hydrogen produced by existing plants (production plants run at part-capacity for five years).
- **Option 7:** The first hydrogen production plant is designed for the hydrogen requirement in seven years' time. The other production plants are designed for the hydrogen requirement in five years' time after deduction of the hydrogen produced by existing plants (production plants run at part-capacity for four years).
- **Option 8:** All hydrogen production plants are designed with a capacity of 50 kWh/a. This option is intended to take a definite learning effect into consideration.
- **Option 9:** All hydrogen production plants up to 2018 are designed with a capacity of 100 GWh/a (exploitation of the learning effect). From this time on, the other production plants are designed for the hydrogen requirement in six years' time after deduction of the hydrogen produced by existing plants. This option in particular takes into consideration the effect of the combination of the learning effect and cost degression through larger dimensions of the production plants during the market introduction phase for hydrogen.

- **Option 10:** The first hydrogen production plant is designed for the hydrogen requirement in the first year, and therefore produces hydrogen at full capacity after a short time. All other plants up to 2017 are designed with a capacity of 100 GWh/a (exploitation of the learning effect). From this time on, the other production plants are designed for the hydrogen requirement in six years' time, after deduction of the hydrogen produced by existing plants.
- **Option 11:** The first two hydrogen production plants are designed for the hydrogen requirement in three years' time, after deduction of the hydrogen produced by existing plants (plant capacity equivalent to about 100 GWh/a). The other production plants are designed for the hydrogen requirement in five years' time, which exists after deduction of the hydrogen produced by existing plants. As the plants in this option have higher capacities, the production costs in full capacity operation can be lowered as a consequence of EOS. Compared with Option 9, this option should show whether the higher plant specifications can reduce hydrogen costs further than the learning effect according to Option 9.

4.4.1.1. Comparison of total costs

If many lower-capacity hydrogen production plants are used (Option 1), total costs[76] in the first four years can be kept relatively low (Figure 45). However, when examined up to 2016, hydrogen production by this option causes the highest cumulative total costs.

If the hydrogen production plants are designed with higher capacity from the second plant on (Options 2 to 4), total costs in 2008 and 2009 increase sharply as a consequence of the high plant investments. However, when examined up to 2016, the cumulative total costs are lower than for Option 1, as the higher-capacity plants have lower production costs in full capacity operation than plants with lower capacity, as a consequence of EOS.

Higher total costs exist in the first two years of Options 5 and 6 because of higher plant investments. From the third year onwards, the plants operate partly at full capacity, and the cumulative total costs are at a lower level than Options 1 to 4 described above.

As in Option 7 the first hydrogen production plant is designed for the requirement in seven years' time, very high plant investments arise, which only make themselves felt in high annuities and consequently annual total costs in the first six years. However, in full-capacity operation there are lower production costs, so that for this Option the lowest cumulative total costs exist up to 2016 compared with the other options considered.

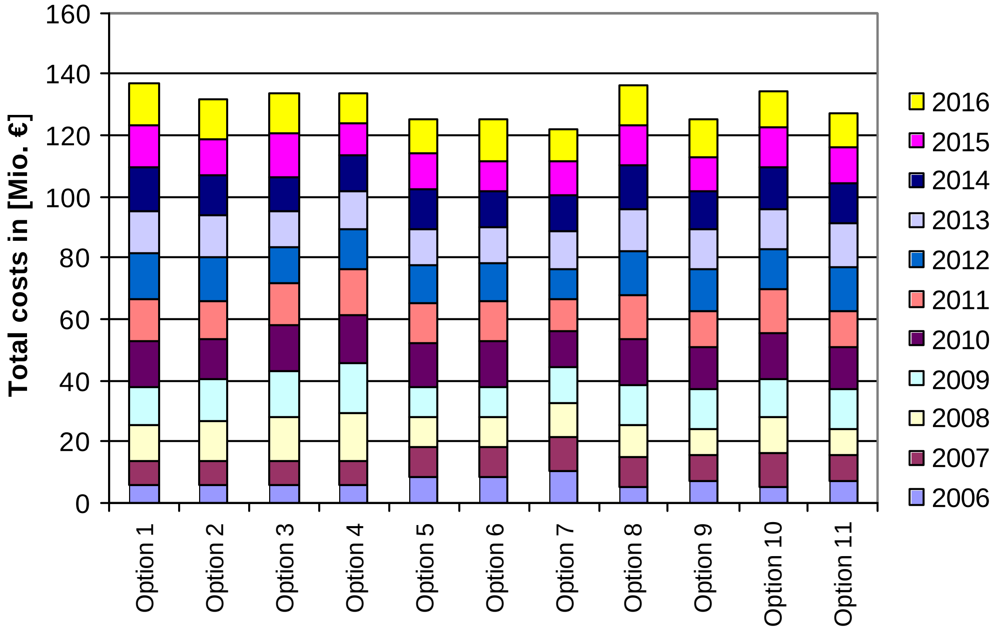
The total cost pattern in Option 8 shows that the effects of the learning effect on the total cost at a higher number of production plants of smaller capacity are lower than the effects of EOS as a result of higher-specification production plants, i.e. with a smaller number of production plants of higher capacity (for example, Option 9). In this Option, the second highest cumulative total costs are incurred up to 2016.

In 2006, Option 10 results in the lowest total costs, as the hydrogen production plants involve relatively low plant investments and are rapidly operating at full capacity. Whereas the higher-capacity plants constructed in the following years produce hydrogen at lower cost, the influence of the high production costs of the first production plants on total costs remains until the plants are decommissioned, so that the cumulative total costs for this option are very high until 2016.

If the hydrogen production plants are designed with higher capacity from the fourth year on, as in Option 9, the cumulative total costs for Option 11 in a medium-term total cost examination until 2016 cannot be reduced below the level of the total costs of Option 9.

[76] The total costs are made up of the annuities of investments and operating and maintenance costs, including electricity and fuel costs (Figures 161 and 162 in Appendix 6).

Figure 45: Total costs of hydrogen production discounted to 2006 (central natural gas steam reforming plants, liquefaction plants) depending on plant specification (Options 1 to 11) for the supply of hydrogen to vehicles according to the vehicle population development OWN for Munich from 2006 to 2016



Electricity costs using a conventional power station at Level 1 (L1), natural gas costs according to Level 1 (NL1).
Source: Own calculations, 2002

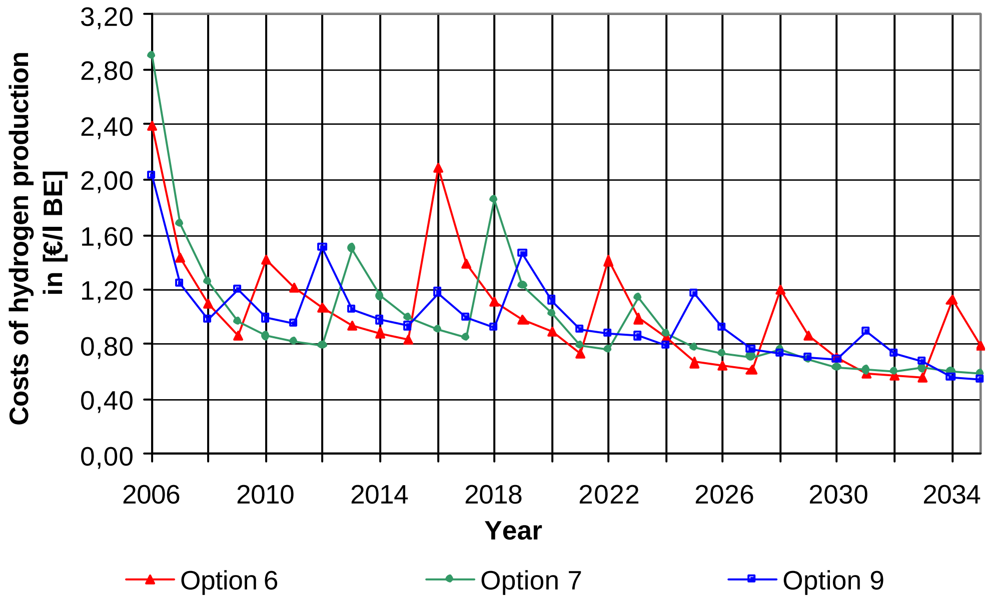
From the comparison of cumulative total costs up to 2016 it is evident that the cumulative total costs of all options are between 125 and 135 million €. Accordingly, in a medium-term examination there are no great differences in the cumulative total costs. As the lowest possible total costs for the introduction of hydrogen onto the market are preferable in the first few years in particular, cumulative total costs take on considerable significance in a medium-term examination. Here it can be seen that Option 9 represents the alternative to be aimed for. In the first few years the total costs can be kept at a low level and after the first six years has the cumulative total costs are the lowest. In a long-term examination up to 2035, the cumulative total costs of Option 9 also lie in a good mid-field position (Figure 163 in Appendix 6).

4.4.1.2. Comparison of the specific costs of hydrogen production

The specific hydrogen production cost pattern[77] per l GE (NGSR and liquefaction process) taking into account the annuities, operating and maintenance costs, natural gas and electricity costs, is shown in Figure 46. The pattern of specific hydrogen production costs according to Option 9 shows that in or around 2030 the cost level of 0.44 €/l GE or 0.049 €/kWh from production plants of higher capacity (about 3 TWh/a) will still not be achieved. Notable factors are the severe fluctuations in the specific costs, due to the commissioning of further NGSR and liquefaction plants, which produce hydrogen for a certain time at part capacity until full capacity is achieved.

[77] Values not adjusted for interest.

Figure 46: Specific costs of hydrogen production (central natural gas steam reforming plants, liquefaction plants) with variation of plant specification (Options 6, 7 and 9) for the supply of hydrogen to vehicles according to the OWN vehicle population pattern in Munich from 2006 to 2035



Electricity costs using a conventional power station at Level 1 (L1), natural gas costs according to Level 1 (NL1).
Option 6 = Hydrogen production plants achieve full capacity 4 to 6 years after commissioning.
Option 7 = Hydrogen production plants achieve full capacity 6 to 7 years after commissioning.
Option 9 = Hydrogen production plants achieve full capacity around 3 years after commissioning.
Source: Own calculations, 2002

In order to show the extent of the effects of plant capacities on the specific costs of hydrogen production, the costs according to Option 9 are compared with those in Options 6 and 7. Corresponding to the selected criteria in the selection of the options, Option 9 has the lowest specific hydrogen production costs per l GE in the first few years.

4.4.1.3. Specific hydrogen costs from hydrogen production to vehicle fuel tank

Using the specific hydrogen production costs according to Option 9, specific transport costs per truck according to Table 27 (values from the line for two plants) and specific gas station costs according to TSBE 4+7 (Chapter 5.5), this finally yields the specific hydrogen costs per l GE which would have to be paid by the customer at the gas station, assuming that there are no taxes levied on hydrogen as an alternative fuel (Figure 47). Due to the low usage of NGSR and liquefaction plant and gas station capacities, and the low learning effect in the first few years, there will be specific hydrogen costs in 2006 of about 3,2 €/l GE, which will reduce to about 1.5 €/l GE by 2020 and to about 0.8 €/l GE by 2035.

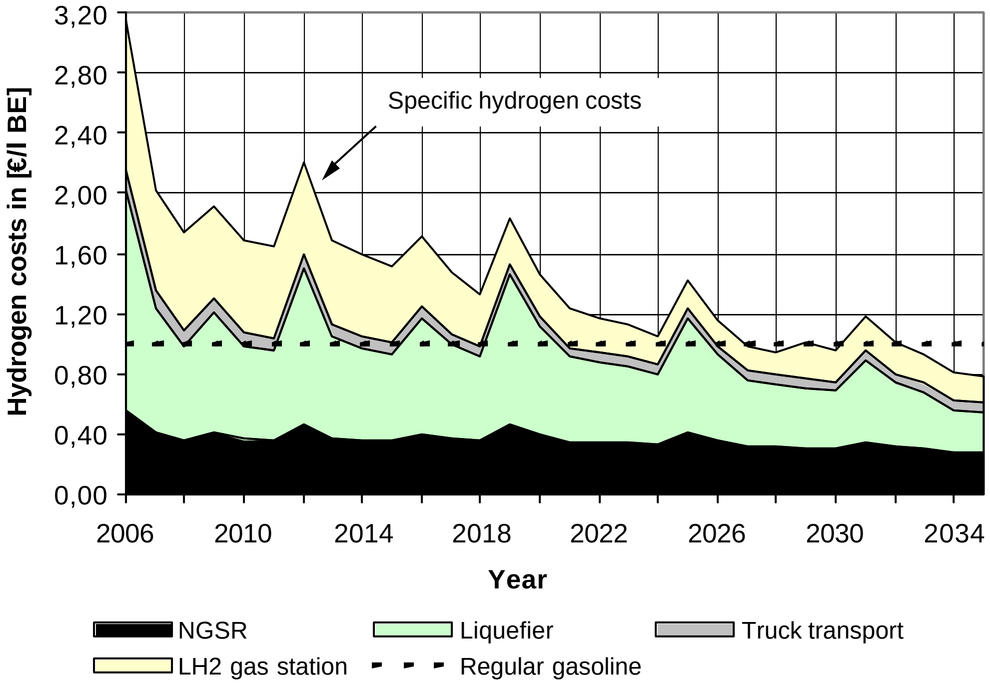
The overall cost picture shows that hydrogen liquefaction accounts for the largest share of the costs. Due to the low usage of gas stations, specific gas station costs are also extremely important in the first few years. With increasing numbers (learning effect) the liquefaction and gas station costs fall and by 2035, the cost share of liquefaction is roughly the same as that of NGSR. Although the learning effect also has to be taken into account for the NGSR plants, a clear reduction in the NGSR share is not identifiable, as the natural gas fuel costs have a considerable influence on their level (Chapter 6.8.2).

The broken line represents the average price of regular grade gasoline of 1 €/l incl. taxes as in February 2002 at German Shell stations[78] (www.shell.de, 22.05.2002). From 2007, the

[78] The share of individual types of fuel in the total fuel sales in Germany in 2000 is: Regular gasoline 16.7%, Eurosuper 31.4%, Super Plus 1.9%, Diesel 50% (MWV, 2000, p. 47), (Own calculations, 2002). As the price of Eurosuper (highest share of gasoline sales) is only around 0.02 €/l (BP, 2003) above the price of regular gasoline, the specific hydrogen costs are compared with the price of regular gasoline.

specific hydrogen costs reach or fall below the level of the average gasoline price, though the hydrogen is not yet subject to any taxes (petroleum tax, added value tax).

Figure 47: Specific hydrogen costs and their composition in electricity generation using conventional power stations (L1) and in hydrogen production using central natural gas steam reforming plants (NGSR) according to Option 9, from well to vehicle fuel tank, for the supply of hydrogen to vehicles according to the vehicle population pattern OWN for Munich from 2006 to 2035



L1 = electricity costs using a conventional power station, natural gas costs according to Level 1 (NL1), specific gas station costs according to the number of gas stations 4+7 (Chapter 5.5), specific transport costs according to Chapter 4.4.2.2.
Option 9 = Plants for hydrogen production achieve full capacity around 3 years after commissioning.
Source: Own calculations, 2002

By way of comparison, the next chapter determines the specific hydrogen costs if, instead of the hydrogen requirement for the city of Munich, the hydrogen requirement for Germany is used as a basis for the calculations.

4.4.2. Plant specification according to the hydrogen demand for Germany

To calculate the development of plant capacities over the years, the hydrogen requirement for Germany is used according to HDD OWN (Figure 18). Hydrogen production plant capacities are determined in such a way that the individual plants achieve full capacity after the same period as was the case for Option 9 (this version represents a short and medium-term cost optimum, Chapter 4.4.1). For the hydrogen production plants, this means specifying the capacity at the level that can be produced at full capacity in the third year. However, the hydrogen requirement over the years for German reaches a magnitude such that from the start plants with a capacity[79] of 3 TWh/a (corresponding to 250 t/d or 136,000 Nm^3/h) can be used, which will operate at full capacity after three years at the latest. The learning effect comes in force if all the hydrogen production plants that are constructed achieve similar performance levels over the years.

4.4.2.1. Specific costs of hydrogen production

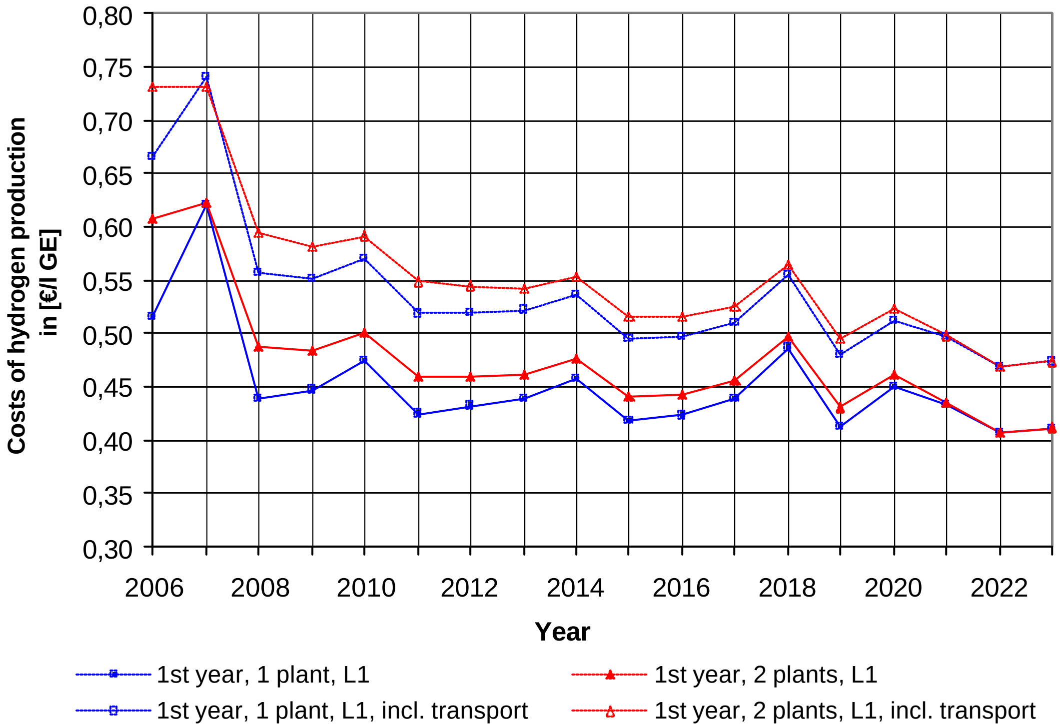
If a hydrogen production plant with a capacity of 3 TWh/a is constructed in 2006, and can satisfy the hydrogen demand in the first and partially the second year in Germany, the

[79] So far, NGSR plants with a maximum capacity of 100,000 Nm^3/h have been constructed (Wolf(c), 2002, p. 20).

specific costs of hydrogen production in 2006 at part-capacity are about 0.52 €/l GE (Line "1st year, 1 plant, L1" in Figure 48). In the second year, a further production plant of this capacity must be commissioned in order to be able to satisfy the total hydrogen requirement in this year. This production plant will operate at partial capacity in the second year, with an increase in the average specific costs of hydrogen production to about 0.63 €/l GE. In the third year, both plants will operate at full capacity with average specific hydrogen production costs of 0.44 €/l GE. However, larger average truck transport distances of 290 km (area of Germany 340,000 sq. km, determined by administrative district areas) and therefore higher average specific transport costs compared with shorter transport distances from two or three production sites in the first year must be taken into account (Table 27). Another notable factor are the fluctuations in the average specific costs of hydrogen production, due to the commissioning of further NGSR and liquefaction plants, which produce hydrogen for a certain time at part-capacity until full capacity is achieved.

If now instead of one hydrogen production plant in 2006, two production plants are constructed (together these have the same nominal capacity as just one hydrogen production plant previously), the specific costs increase to 0.61 €/l GE (Line "1st year, 2 plants, L1" in Figure 48) as a consequence of lower EOS. Further development of the hydrogen production plant structure is identical with that of only one production plant in 2006. The influence of higher specific hydrogen production costs remains effective until the decommissioning of both lower-capacity production plants in 2021. However, the average transport distance in 2006 is about 210 km and for this smaller average specific transport costs arise than for just one production plant in the first year.

Figure 48: Specific costs of hydrogen production (central natural gas steam reforming plants, liquefaction plants) with electricity generation using conventional power stations (L1) with and without specific transport costs, with variation of plant specification in the first year (2006) for the supply of hydrogen to vehicles according to the vehicle population development OWN for Germany from 2006 to 2023



L1 = Electricity costs using a conventional power station, natural gas costs according to Level 1 (NL1).
Specimen key explanation: "1st year, 1 plant, L1": In the first year, 2006, 1 hydrogen production plant is constructed, electricity generation using conventional power stations (L1). "1st year, 2 plants, L1": In the first year, 2006, 2 hydrogen production plants are constructed, electricity generation using conventional power stations (L1).
Source: Own calculations, 2002

4.4.2.2. Average specific transport costs

For a comparison of the specific hydrogen production costs including the specific transport costs of both options, an approximate determination of the average specific transport costs is carried out[80]. The difference between the average specific transport costs of the two options amounts to 0.0028 €/kWh or 0.025 €/l GE in favor of the option with two hydrogen production plants in the first year (Table 27). In subsequent years the cost difference declines rapidly, and in 2010 only a marginal cost difference is still evident.

High investments in the purchase of trucks from 2016 on are due to the assumed truck lifespan of ten years; starting in 2016, the trucks purchased in 2006 and later will be replaced by new trucks.

Table 27: Pattern of average truck transport distances, truck fleets, transportable hydrogen quantities per truck and specific truck transport costs with an increasing number of hydrogen production plants for the hydrogen demand development OWN with variation of the number of hydrogen production plants in the first year (2006), in Germany from 2006 to 2020

	Unit	2006	2007	2008	2009	2010	2011	2012	2013
1st year only 1 plant									
Average transport distance	km	291	206	206	168	145	145	130	119
Transportable quantity	GWh/truck/a	16	21	21	23	25	25	26	27
Number of trucks	Vehicles	117	181	275	351	408	489	548	622
Average transport costs	€/kWh LH_2	0.0167	0.0134	0.0131	0.0116	0.0107	0.0104	0.0098	0.0093
1st year only 2 plants									
Average transport distance	km	206	168	168	145	130	130	119	110
Transportable quantity	GWh/truck/a	20	23	23	26	26	26	27	28
Number of trucks	Vehicles	94	165	251	310	393	470	528	600
Investments in trucks	million €/a	55.5	38.0	44.5	29.8	41.3	37.7	28.1	34.6
Average transport costs	€/kWh LH_2	0.0139	0.0122	0.0119	0.0109	0.0102	0.0100	0.0094	0.0090

Continued

Continued

	Unit	2014	2015	2016	2017	2018	2019	2020
1st year only 1 plant								
Average transport distance	km	110	110	103	97	92	92	84
Transportable quantity	GWh/truck/a	28	28	29	29	31	31	32
Number of trucks	Vehicles	682	767	807	878	900	995	1,074
Average transport costs	€/kWh LH_2	0.0088	0.0086	0.0082	0.0079	0.0076	0.0074	0.0070
1st year only 2 plants								
Average transport distance	km	103	103	97	92	88	88	81
Transportable quantity	GWh/truck/a	29	29	29	31	31	31	32
Number of trucks	Vehicles	659	741	807	821	900	995	1,074
Investments in trucks	million €/a	28.1	38.7	74.7	39.3	75.5	69.8	72.7
Average transport costs	€/kWh LH_2	0.0086	0.0084	0.0081	0.0077	0.0075	0.0073	0.0069

Number of hydrogen production plants according to Chapter 4.4.2.3. Further explanations on how the values in the table were reached can be found in Appendix 6.
Source: Own calculations, 2002

By taking into consideration the average specific transport costs depending on the mean transport distance, we obtain the specific costs of hydrogen production including transport costs for both options, as shown in Figure 48. The cost difference between the lines for both options has now become smaller and continues to run in favor of the option with only one hydrogen production plant in 2006 (Lines "1st year, 1 plant, L1", incl. transport" and "1st year, 2 plants, L1, incl. transport" in Figure 48).

4.4.2.3. Development in the number of hydrogen production plants

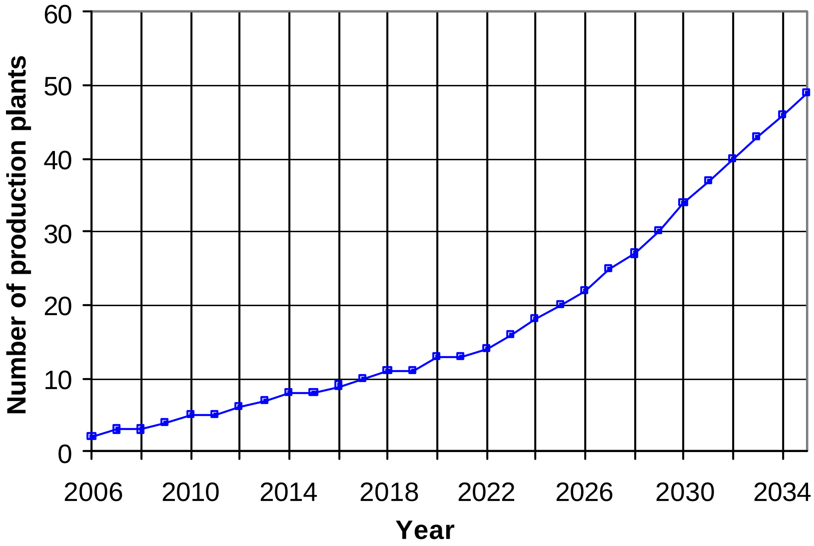
Although the operation of two hydrogen production plants with a lower output in 2006 incurs higher specific hydrogen production costs that those for one plant of higher output, the version with two such plants in 2006 is considered further in this paper. The first year corresponds in these observations to that phase of hydrogen fuel introduction on the market in which the demonstration project phase was already concluded. In this demonstration

[80] Further explanations on how the values in Table 27 were reached can be found in Appendix 6

phase, hydrogen production plants have already been constructed, so that several production plants are assumed to be available instead of just one production plant.

The number of hydrogen production plants which are in operation each year in order to satisfy the demand for hydrogen is shown in Figure 49.

Figure 49: Pattern of the required number of power stations for hydrogen production (natural gas steam reforming plants, liquefaction plants) for the supply of hydrogen according to hydrogen demand development OWN from 2006 to 2035 in Germany



1 production plant consists of 1 natural gas steam reforming plant and 1 liquefaction plant.
Source: Own calculations, 2002

Beginning with two hydrogen production plants in 2006 with a capacity of about 1.5 TWh/a per plant, this increases to 49 production plants by 2035 with a capacity of about 3 TWh/a per plant. Due to the assumed 15-year lifespan of the plants, the production plants commissioned in 2006 will be replaced by new production plants in 2021. A total of 62 hydrogen production plants will be built by 2035, of which 49 will still be in operation in 2035.

An overview of the possible locations of the production plants is shown in Figure 165, Appendix 6. The year of the respective production site indicates the year in which the production plant is commissioned. The geographical location of production sites was selected according to the existing refinery locations and tank storage sites in Germany, Figure 164, Appendix 6.

Before a concrete assessment of the build-up of a gas station infrastructure is carried out, the next chapter examines the supply of buses used for scheduled public transport and the vehicles for waste collection and street cleaning. As already mentioned in Chapter 2.3.3, these vehicle fleets are of great significance in the market introduction of hydrogen as an alternative fuel.

4.5. Supply to scheduled buses and special vehicles

Vehicles in the BUS, ABUS and SHGV categories (Chapter 2.2.2.3) operate from central depots within specific areas, making it easy to refuel them without having to depend on the publicly accessible gas station network. This chapter shows whether, from the start of the market introduction of hydrogen fuel, the depots should be modified to supply hydrogen for the fuel supply of the substituted vehicles of the vehicle categories named, or whether in the first years of the introduction of the fuel, these vehicles would be better supplied with fuel using the publicly accessible gas station network that has been partly modified to supply hydrogen.

For the comparison of the depot concepts[81] for hydrogen as an alternative fuel it is assumed in the example of depots for the refueling of vehicles in the BUS and ABUS categories that all conventional buses were substituted by buses that use hydrogen as an alternative fuel, so that only hydrogen fuel is supplied at the depots. This comparison of concepts shows which depot concept proves to be the most cost-effective for depots following the substitution of fuel and vehicles.

The following assumption are made for the comparison of depot concepts, and were determined with regard to the refueling buses at depots in Munich (Fendt, 2001; Own calculations, 2002) and elsewhere:

- To supply vehicles in the BUS, ABUS and SHGV categories, in this paper only LH_2 or CGH_2 depot concepts are considered (in the analyses in Chapter 4.3 it was shown that the specific hydrogen costs of the combined gas station concept for LH_2 and CGH_2 fell within those of the LH_2 or CGH_2 gas station concepts, so that when examining the depot concepts for LH_2 or CGH_2, references could also be made to the specific hydrogen costs of the depots for LH_2 and CGH_2)
- Vehicle refueling takes place mostly in the evening hours
- Refueling interval of two days
- Average refueling quantity per bus: 1,338 kWh (Chapter 2.2.3.3)
- Average refueling time per bus: 12 min, plus 5 min for arrival and departure
- Fuel supply of double the daily consumption to the depot every other day
- Precautionary quantity for any fuel supply shortfall required to maintain depot operations for three days
- Determining the number of fuel pumps, so that the daily refueling time of the buses does not exceed 5 hours. In the example of a depot with annual hydrogen fuel sales of 32 GWh, four fuel pumps are needed
- No consideration of the gas station margin of 0.0035 €/kWh for the depot operator

4.5.1.Hydrogen production at the gas station (on-site)

Hydrogen is stored in the vehicle's tank in a compressed gaseous form. The hydrogen produced by electrolysis or natural gas steam reforming is transported via a compressor station (two-stage membrane compressor) to the pressure store (400 bar) and via a further high-pressure compressor station (single-stage membrane compressor) to the high-pressure storage tanks. The hydrogen is stored in these tanks at a pressure of at least 850 bar, so that is can be passed through the fuel pump to the vehicle's fuel tank, where it is stored at a pressure of 700 bar (Figure 34).

As the buses can mostly only be refuelled at night, there are basically two ways in which on-site supply can be achieved:

- the capacity of the on-site hydrogen production plant is designed for the higher rate of fuel supply during the evening hours
- the number of pressure tanks (400 bar) is increased, allowing the capacity of the on-site plant to be designed for average fuel supply rates (the hydrogen produced during the day is stored in pressure tanks, so that there is a sufficient quantity of hydrogen available for refueling the buses in the evening).

4.5.1.1. Increasing the capacity of the on-site hydrogen production plant

The following characteristics were determined:

- Full-capacity hours of the on-site production plant about 1,825 h

[81]Depot concepts correspond in design to the gas station concepts for roadside gas stations (Chapter 4.2). Differences will occur, for example, in the number of fuel pumps, the pressure storage tank volume, the capacity of the on-site production plants or the LH_2 storage tank volume.

- Rating of the two-stage membrane compressor (H_2 compression to 400 bar) to match the capacity of the on-site production plant or an increase in the number of compressors
- Storage of the fuel reserve in CGH_2 pressure tanks at 400 bar
- One high-pressure tank[82] and one single-stage membrane compressor (CGH_2 compression form 400 to 850 bar) required per fuel pump (Chapter 4.2.1.2)
- Electricity consumption of the plants, operation and maintenance costs, "Other investments" and engineering costs identical to those of CGH_2 gas stations with on-site production (Chapter 4.2.2.2 and 4.2.2.4)

In the example of a supply depot for Munich public-service buses with an annual hydrogen fuel supply volume of 32 GWh, this calls for four fuel pumps and a triple fuel reserve quantity of 263,000 kWh (corresponding to 87,667 Nm^3), which is stored in CGH_2 pressure tanks at 400 bar with a volume of 43 x 30 x 8.5 m (corresponding to a volume of 10,965 m^3).

At the characteristic values determined, this concept has specific hydrogen costs depending on the annual hydrogen fuel delivery which are now higher than the specific hydrogen costs at modified roadside gas stations using identical gas-station concepts (Figure 50). The reason for the higher specific hydrogen costs is primarily the higher investment in the on-site hydrogen production plant, which has a higher capacity than an on-site plant at a conventional roadside gas station. There is also an increase in investment as a result of the higher pressure tank volume for storing the triple fuel reserve quantity.

4.5.1.2. Increase in the number of pressure tanks (400 bar)

The increase in the number of pressure tanks is easier to achieve technically, so that the nominal capacity of the on-site hydrogen production plant can be designed to match the average fuel delivery volume from the depot.

The following characteristic values were determined:

- Full-capacity hours of the on-site production plant: 6,570 h (Reijerkerk, 2001, p. 101)
- CGH_2 pressure tank volume (400 bar) required, which holds the produced quantity of hydrogen and the triple fuel reserve of the on-site hydrogen production plant at full capacity for a period of 19 hours (24 hours less 5 hours daily refueling time for buses)
- Remaining units such as two-stage membrane compressor, single-stage membrane compressor and high-pressure tank as in the concept for increasing the capacity of on-site production plants
- Electricity consumption of the plants, operation and maintenance costs, "Other investments" and engineering costs identical to those of CGH_2 gas stations with on-site production (Chapter 4.2.2.2 and 4.2.2.4)

In the example of a depot in Munich supplying public-service buses with an annual hydrogen fuel delivery volume of 32 GWh (corresponding to about 3.6 million l GE), this calls for four fuel pumps and a hydrogen quantity to be stored in CGH_2 pressure tanks of 32,000 Nm^3. Including the triple reserve quantity of 87,667 Nm^3, this yields a total space requirement for the pressure tanks of 22.5 x 30 x 30 m (corresponding to a volume of 20,250 m^3).

With the characteristic values determined, this concept has specific hydrogen costs depending on the annual hydrogen fuel sales which are now also higher than the specific hydrogen costs at modified roadside gas stations of identical concept, but lower than in the concept for increasing the capacity of on-site production plants (lines “CGH2, On-site NGSR, BH, Buffer” and “CGH2, On-site electr., BH, Buffer” in Figure 50). The reason for the higher specific hydrogen costs is primarily higher investment in the larger number of pressure tanks for storing the hydrogen that is produced.

[82]The specification of the high-pressure storage tanks (850 bar) has been left identical to that of the CGH2 path at roadside gas stations (Chapter 4.2.1.2) as their cost share of 1 % has only a slight impact on total costs.

An **extension of the possible refueling time** from 5 hours to, say, 12 hours would result in a slight reduction in specific hydrogen costs as the number of pressure tanks would be lower. In the example of a depot with an annual hydrogen fuel delivery volume of 32 GWh, the investment share for the pressure tank with a volume of about 120,000 Nm^3 CGH_2 with a five-hour bus refueling time is about 36 % (including the triple reserve) of the total investment in the depot. By extending the refueling time to 12 hours, the required pressure tank volume falls to 107,000 Nm^2 CGH_2 (including the triple reserve), and the investment is reduced by about 450,000 €, which is just 3 % of the total investment in the depot, and is consequently negligible.

By combining both of these options, an increase in the capacity of the on-site hydrogen production plant and an increase in the number of 400 bar pressure tanks, the specific hydrogen costs fall within the both of the stated limits.

In the on-site concepts, there is also the disadvantageous effect of a possible loss of hydrogen production, meaning that after three days and consumption of the stored reserve, the buses must be refuelled at other depots or at public gas stations, assuming that the same state of the hydrogen equipment is available.

4.5.2. Centralised hydrogen production

The liquid hydrogen is delivered by trucks from the central hydrogen production plants to the gas stations, where it is stored in conventional underground cryogenic tanks (LH_2 storage tanks) (Figure 29). If the hydrogen is stored in the vehicle's tank in liquid form, a transfer pump is used to move the liquid hydrogen from the LH_2 storage tank to the fuel pump. However, if gaseous hydrogen is stored in the vehicle's tank at high pressure, a cryogenic pump moves the liquid hydrogen from the underground LH_2 storage tank through a high-pressure compressor into the high-pressure storage tank (Chapter 4.2.1).

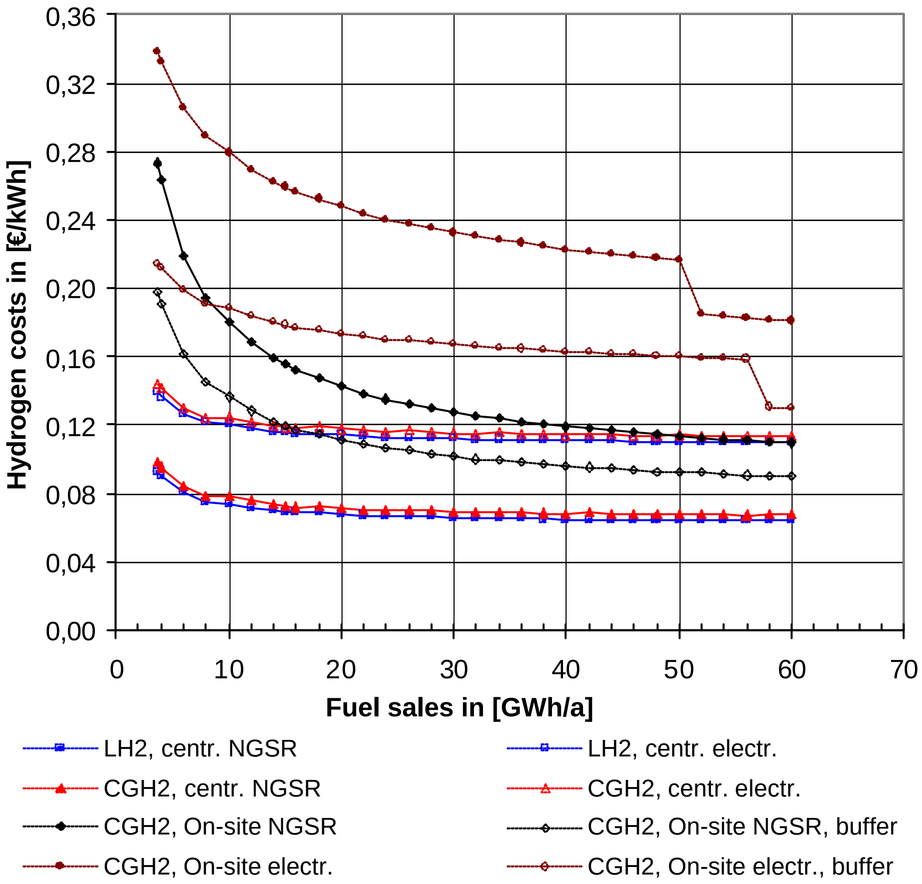
In this concept the costs of hydrogen production and transport must still be added to the expense of the depot in order to obtain a comparison with the specific hydrogen costs of the on-site production concepts.

For centralized hydrogen production in NGSR plants including transport costs to the depots, costs of 0.059 €/kWh using electricity at Level 1, and costs of 0.069 €/kWh using electricity at Level 3 are used (Chapter 4.2.2.1). For the centralized hydrogen production in electrolysis plants including transport costs to the depots, costs of 0.106 €/kWh using electricity at Level 1, and costs of 0.168 €/kWh using electricity at Level 3 are used (Chapter 4.2.2.3).

If identical assumptions are made for the supply to vehicles from the depots as stated at the beginning of Chapter 4.5, the specific hydrogen costs dependent on annual hydrogen fuel delivery volume are lower than at conventional roadside gas stations (renting the LH_2 storage tank) (Figure 50). The reason is the lower number of fuel pumps at the depots compared with a roadside gas station with the same annual fuel sales volume, as an available refueling time of 5 hours per day is assumed for the buses, so that a lower number of fuel pumps is sufficient. The CGH_2 concept results in higher specific hydrogen costs than the LH_2 concept, as there are higher investments in the necessary equipment for each CGH_2 fuel pump (single-stage membrane compressor for compression up to 850 bar, high pressure storage tank), than for each LH_2 fuel pump.

In the example of a depot in Munich supplying public-service buses with an annual hydrogen fuel delivery volume of 32 GWh, this yields four fuel pumps and a required LH_2 storage tank volume of 185,000 l (111,000 l for the triple reserve and 74,000 l for twice the daily fuel consumption, as there is fuel delivery every other day).

Figure 50: Specific hydrogen costs from well to vehicle fuel tank depending on annual hydrogen fuel sales using electricity generated by conventional power stations (L1) for depot concepts for the supply of liquid (LH_2) or gaseous hydrogen (CGH_2) for different hydrogen production processes, for supply to scheduled buses in Germany



Electricity costs using a conventional power station (L1), natural gas costs according to Level 1 (NL1).
Specimen key description: "LH2, centr. NGSR" = depot concept for the supply of liquid hydrogen with hydrogen production by central natural gas steam reforming plants (NGSR). "CGH2, on-site elect.," = depot concept for the supply of gaseous hydrogen with hydrogen production by higher capacity electrolysis direct at the gas station (on-site). "CGH2, on-site elect., buffer" = depot concept for the supply of gaseous hydrogen with hydrogen production by lower capacity electrolysis direct at the gas station (on-site) with additional expansion of the pressure tank volume for the intermediary storage of the produced gaseous hydrogen.
Source: Own calculations, 2002

From the comparison of the depot concepts, the LH_2 concept with centralized hydrogen production (both NGSR and electrolysis) has shown itself to be the most cost-effective compared with identical CGH_2 concepts. Up to annual hydrogen fuel sales of about 58 GWh (corresponding to 6.5 million l GE), the specific hydrogen costs of the concept using on-site electrolysis remain higher than those using central hydrogen production by electrolysis. From annual hydrogen sales of 58 GWh, the concept of on-site electrolysis reaches a similar level of hydrogen costs as for centralized hydrogen production using electrolysis, as a consequence of more favorable electricity costs[83]. If identical electricity costs are assumed for on-site electrolysis concepts and central electrolysis plants, the specific hydrogen costs for on-site electrolysis are only slightly higher than for centralized hydrogen production by electrolysis.

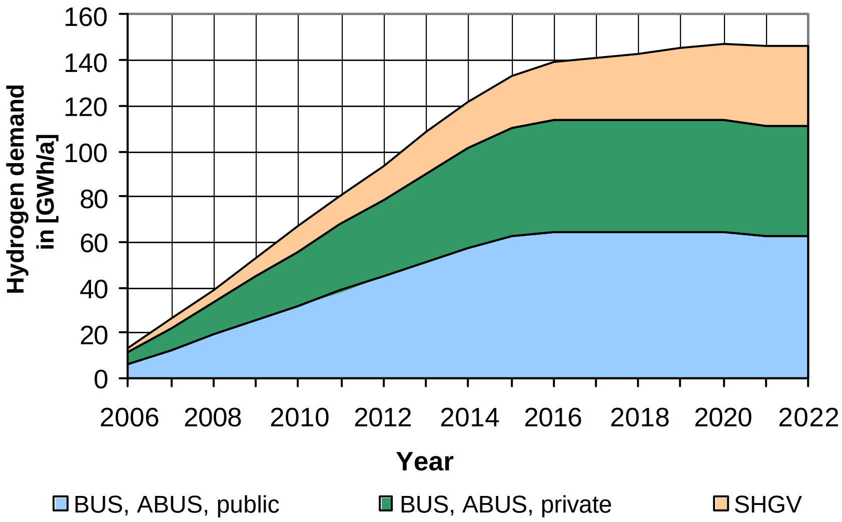
The next chapter, using the example of vehicle supply in the BUS, ABUS and SHGV categories in Munich, examines the development of hydrogen demand and therefore the load on the modified depots. By forming an analogy from the results from Munich, conclusions are also reached regarding the supply to vehicles of this category in Berlin.

[83] Electricity costs staggered according to the amount of electricity used (Chapter 3.2.3).

4.5.3. Supply to vehicles in Munich

The pattern of hydrogen demand for the BUS[84], ABUS and SHGV categories in Munich comes from the VPD OWN for hydrogen as an alternative fuel (Appendix 3). Vehicles in the BUS and ABUS categories in Munich and vehicles in the SHGV category are replaced by vehicles using hydrogen as an alternative fuel after 10 and 16 years respectively. The maximum annual hydrogen demand is reached in 2021 (Figure 51).

Figure 51: Hydrogen demand for publicly owned and operated scheduled buses (public), those in the ownership of private companies (private) and vehicles used for waste management and street cleaning (SHGV) according to hydrogen demand development OWN in Munich from 2006 to 2022



BUS = scheduled bus, ABUS = scheduled articulated bus, SHGV = special trucks (vehicles used for refuse collection and street cleaning).
Source: Own calculations, 2001

The refueling of scheduled-service buses in public ownership, scheduled-service buses in private ownership and vehicles in the SGHV category does not take place at the same depots, so that a separate examination of the supply of hydrogen to these vehicles at their depots must be carried out.

4.5.3.1. Supply to scheduled public-service buses

It is evident in Figure 51 that following the successful substitution of conventional vehicles in the BUS and ABUS categories in public ownership by vehicles using hydrogen as an alternative fuel, the maximum annual hydrogen demand of about 64 GWh comes into effect from 2016 onwards, and will then be supplied to vehicles using **two depots**. This represents a hydrogen delivery volume of about 32 GWh/a per depot.

In this paper it is assumed that buses powered by hydrogen will initially only be refuelled at a depot, and that that the refueling of buses using conventional fuel takes place at other depots, so that by 2010, the depot for hydrogen refueling must satisfy a hydrogen demand of 32 GWh/a.

Modification of the depot from 2006 on with centralized hydrogen production:

- 2006: LH_2 storage tank with a capacity of 185,000 l, two fuel pumps
- 2008: third fuel pump
- 2010: fourth fuel pump, depot reaches full capacity
- 2011: Start of modification of second depot for hydrogen supply

[84] Separate examination for vehicles in public ownership and vehicles owned by private companies, which are used by public authorities for their public transport services.

Modification of the depot from 2006 with on-site hydrogen production:

- 2006: On-site production plant with a capacity of 32 GWh/a, pressure storage volume (400 bar) of 52,000 Nm^3, two fuel pumps
- 2008: Expansion of the pressure storage tank (400 bar) by 45,000 Nm^3, third fuel pump
- 2010: Expansion of the pressure storage tank (400 bar) by 22,400 Nm^3, fourth fuel pump
- 2011: Start of modification of second depot for hydrogen supply

"Other investments" and engineering costs are taken into account in the initial investments in 2006. A degression factor to allow for the learning effect is assumed with A = 0.91 (Chapter 4.2.1).

Using **electricity from German power stations at Level 1** yields the following results (Figure 52):

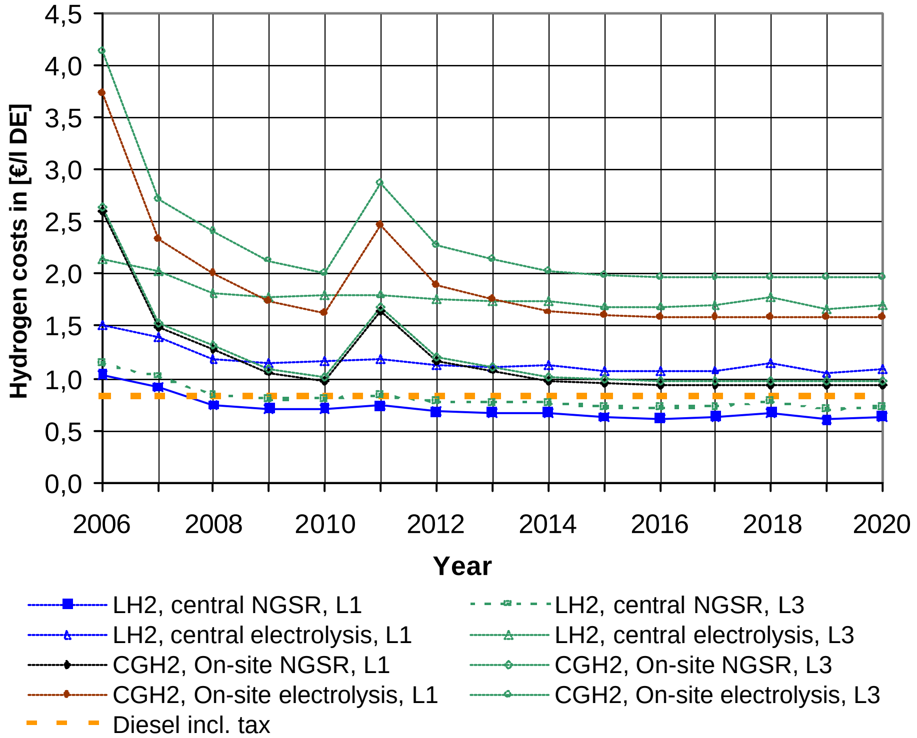
- Specific hydrogen costs using centralized hydrogen production (NGSR or electrolysis) from the start are at a lower level than for identical on-site production processes (NGSR or electrolysis)
- Specific hydrogen costs using centralized NGSR fall below the conventional diesel fuel price of 0.8355 €/l DE after two years
- Specific hydrogen costs using centralized NGSR have a long-term cost level of about 1 €/l DE
- Specific hydrogen costs for on-site production in the first few years are a multiple of the diesel fuel price (NGSR and electrolysis)
- Specific hydrogen costs using on-site NGSR have a long-term cost level of about 1 €/l DE
- Specific hydrogen costs using on-site electrolysis have a long-term cost level of about 1.6 €/l DE

Using **regeneratively produced electricity at Level 3** yields the following:

- Specific hydrogen costs using centralized NGSR from the start at a lower cost level than for on-site production; the conventional diesel fuel price of 0.8355 €/l DE is reached after two years
- Specific hydrogen costs using centralized electrolysis at a long-term cost level of 1.6 €/l DE
- Specific hydrogen costs using on-site NGSR at a long-term cost level of about 1 €/l DE
- Specific hydrogen costs using on-site electrolysis at a long-term cost level of about 2 €/l DE

Independent of annual hydrogen fuel supply volume from the depot, the CGH_2 concept using on-site electrolysis is the most expensive concept.

Figure 52: Specific hydrogen costs from well to vehicle fuel tank using electricity generation by conventional power stations (L1) and from regenerative energy (L3), for the depot concepts for the supply of liquid hydrogen (LH_2) or gaseous hydrogen (CGH_2) with different hydrogen production process, for supply to scheduled public-service buses in Munich, taking into account the degree of utilization of the depots from 2006 to 2020



L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs according to Level 1 (NL1). Specimen key description: "LH2, central NGSR, L1": "LH2" = depot concept for the supply of liquid hydrogen, "central NGSR" = hydrogen production in centralized natural gas steam reforming plants (NGSR), "L1" = electricity costs using conventional power stations. "CGH2, on-site electrolysis, L3": "CGH2 = depot concept for the supply of gaseous hydrogen, "On-site electrolysis" = hydrogen production direct at the gas station (on-site), "L3" = electricity costs using regenerative production. Diesel fuel costs[85] (www.shell.de, 22.05.2002).
Source: Own calculations, 2002

4.5.3.2. Supply of scheduled public and private buses

At the depot for supplying public-service buses, the following option is examined: during the build-up of a gas station infrastructure, buses belonging to private companies that are used by the city of Munich to operate scheduled services are also refuelled there. In 2016, the maximum annual hydrogen delivery volume increases to 114 GWh (Figure 51). This represents an annual hydrogen delivery volume of about 57 GWh per depot in 2016.

It is again assumed that buses powered by hydrogen will initially only be refuelled at one depot, and that that the refueling of buses with conventional fuel takes place at other depots, so that by 2010, the hydrogen refueling depot must satisfy a hydrogen demand of 57 GWh/a. When designing the depot for this annual sales output, the number of fuel pumps and their required additional units, the number of pressure tanks (400 bar) and the LH_2 storage tank volume change compared with the option discussed above.

If identical assumptions are made for the supply to vehicles from the depots as stated at the beginning of Chapter 4.5, this results, according to the concept, in specific hydrogen costs depending on annual hydrogen fuel delivery volumes that are partly higher than for the sole supply of public-service buses (Figure 166 in Appendix 6). In the example of a depot with an annual hydrogen fuel delivery volume of 57 GWh, this yields the following:

[85] Average diesel fuel costs in February 2000 at a conventional roadside gas station in Germany.

- For centralized hydrogen production, the LH_2 storage tank for storing the triple fuel reserve and double fuel delivery must have a volume of about 325,000 l, which can be implemented using one or more LH_2 storage tanks. This results in an increase in the rental costs for the LH_2 storage tank, which ultimately result in higher specific hydrogen costs.
- For on-site hydrogen production there are almost identical specific hydrogen costs as for supply only to public-service buses. Due to the higher capacity specification of the on-site production plant, this results in a reduction in costs, which is however balanced by the additional investments required for an increased number of pressure tanks for storing the triple fuel reserve and the storage of the volume of hydrogen not produced during the refueling time of 5 hours per day.
- Examination of the concept of a sole increase in on-site production capacity has not carried out, as the sole supply of public-service buses at depots has shown that the specific hydrogen costs for this concept increase very sharply.

On-site hydrogen production has a negative effect on the volume of the pressure storage tank in particular. For a depot with annual hydrogen fuel sales of 57 GWh, it results in a pressure storage tank (400 bar) volume of 210,000 Nm^3, which is made up of:

- the quantity of hydrogen of 57,000 Nm^3 not produced during the refueling period of 5 hours per day and
- the triple fuel reserve of 153,000 Nm^3.

The space required for this pressure tank is 54 x 10 x 54 m or 27 x 30 x 36 m (corresponding to a volume of 29,160 m^3).

The most cost-effective concept is centralized hydrogen production using NGSR (Figure 166), whereby only the use of electrolysis using regeneratively produced electricity or electricity from nuclear power is meaningful for long-term CO_2 reduction (central hydrogen production by electrolysis is preferred to on-site electrolysis, Figure 166). As a consequence of the slight increase in specific hydrogen costs in a long-term combination of the supply to publicly and privately operated scheduled buses at one depot, it is recommended that a long-term combination of the supply process should not be undertaken.

4.5.3.3. Supply of public and private scheduled buses and vehicles used for refuse collection and street cleaning

Vehicles in the SHGV category are primarily compressed-waste vehicles and private vehicles used for waste management and street cleaning. The vehicles are refuelled at three depots in Munich, but no specific refueling interval is laid down (AWM(a), 2001). In addition, there is the option of refueling these vehicles at publicly accessible gas stations within the city if required. These regulation promotes the flexible supply of fuel to these vehicles, since they are not obliged to refuel at the depot.

If publicly and privately operated buses and vehicles in the SHGV category are refuelled at a depot during the first years of the build-up of a gas station infrastructure, this yields a hydrogen demand as shown in Figure 51. The hydrogen demand for vehicles in the SHGV category only reaches a level of about 10.5 GWh/a after five years. Following the successful substitution of all vehicles in SHGV category by vehicles operating on hydrogen as an alternative fuel in 2021, the maximum hydrogen demand of 35 GWh/a for this vehicle category comes into effect (11.67 GWh/a per depot).

In the previous chapter it was shown that an increase in annual hydrogen fuel delivery volume at the depot causes a slight increase in specific hydrogen costs, but that due to the lower hydrogen demand of vehicles in the SHGV category in the first few years a common fuel supply appears meaningful. If the hydrogen demand for vehicles in the SHGV category exceeds 11.67 GWh/a, supply should take place at their own depot.

4.5.3.4. Conclusion

The most cost-effective concept is centralized hydrogen production with the supply of LH_2 to depots. In order to achieve lower specific hydrogen costs, the modified depots must exhibit the highest possible rate of utilization, especially during the substitution phase of conventional vehicles by vehicles for the alternative fuel.

If the specimen calculation with the supply of publicly operated scheduled buses at their two depots is considered, the specific hydrogen costs shown in Figure 52 could be reduced slightly more, if in the first few years the vehicles of private scheduled bus operators and vehicles used in waste management and street cleaning were to be refuelled at the first modified depot for public scheduled-service buses. If annual hydrogen fuel sales reach the 32 GWh/a capacity of the depot (this being designed for the annual fuel delivery volume to publicly owned scheduled buses and not for a higher delivery capacity), modification of the second public scheduled bus depot takes place with a capacity of 32 GWh/a. If this capacity limit is also reached, it is appropriate to convert the depots for waste management and street cleaning, which are of lower nominal output, and to use them in parallel for the supply of privately owned scheduled buses. In the event of any bottleneck in the fuel supply, vehicles in the SHGV category have advantages through the ability to refuel them with fuel cards at public gas stations; the possibility of refueling using fuel cards should also be taken into consideration for public and private buses.

Investments in the first depot for supplying publicly owned scheduled buses amount to around 300,000 € in 2006, and the total investment for the expansion of the depot to a capacity of 32 GWh/a up to 2011 to 512,000 € (cumulative). For the second depot, this yields a slightly reduced investment of 470,000 € as a consequence of the learning effect. The total investment in the depots for supplying publicly owned scheduled buses amounts to 982,000 €.

The investment in a depot with a capacity of 12 GWh/a for waste management and street cleaning amounts to 290,000 €. The total investment following successful conversion of all three depots, taking the learning effect into consideration, is 807,000 €.

On the assumption that three depots, each with 17 GWh/a, supply the private scheduled buses, investments of 370,000 € per depot are required. The total investment following successful conversion of all three depots is 1,030,000 €.

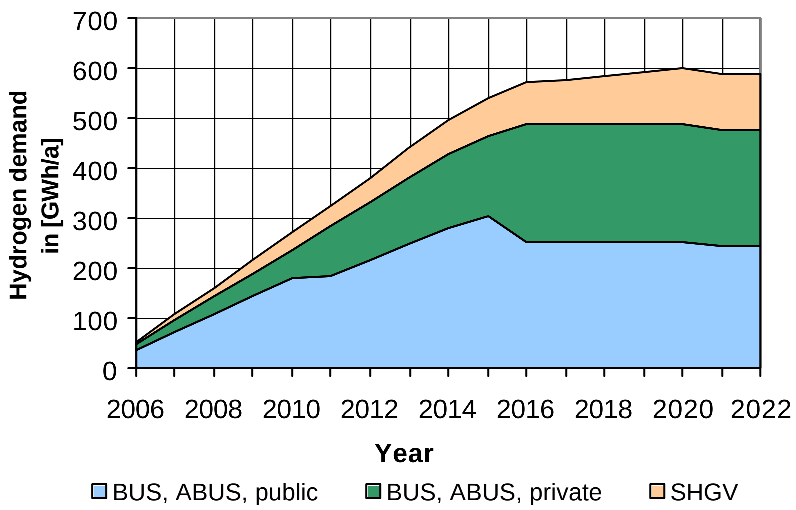
To supply scheduled buses, waste management and street cleaning vehicles at their depots, up to the complete substitution of all vehicles by vehicles that use hydrogen as an alternative fuel in Munich, involves a total investment of about 2.82 million €.

4.5.4. Supply to vehicles in Berlin

From the results of hydrogen fuel supply of vehicles in the BUS, ABUS and SHGV categories at their depots in Munich, an analogous picture of the hydrogen fuel supply of vehicles in Berlin can be obtained. Using the same assumption for the substitution of vehicles in the BUS, ABUS and SHGV categories by vehicles for hydrogen as an alternative fuel as for Germany (Chapter 2.3.3 and 2.3.4, vehicle populations for Berlin see Tables 40 and 44), vehicles in the BUS and ABUS categories in Berlin and those in the SHGV category are replaced by vehicles for hydrogen as an alternative fuel after 10 and 16 years respectively. The maximum annual hydrogen demand of some 600 GWh takes effect in 2021 (Figure 53).

The partially erratic course of hydrogen demand in 2010 and 2015 is due to the assumption that there will be a re-distribution of the scheduled bus vehicle fleets to a greater number of scheduled articulated buses (see forecast bus inventories in Table 40). As the fuel consumption rates of the reference vehicles were assumed at five-year intervals, the re-distribution of buses is clearly evident in the hydrogen demand.

Figure 53: Hydrogen demand of scheduled buses in public ownership (public), those owned by private companies (private) and of vehicles used for waste management and street cleaning (SHGV) according to hydrogen demand development OWN in Berlin from 2006 to 2022



BUS = scheduled bus, ABUS = scheduled articulated bus, SHGV = special trucks (vehicles used for refuse collection and street cleaning).
Source: Own calculations, 2001

The current fuel supply and maintenance of public-service buses and vehicles for waste management and street cleaning takes place in Berlin at 12 depots, although it is not possible to refuel a vehicle at each of these 12 depots (Buchner, 2001). The hydrogen demand of the "BUS, ABUS, public" and "SHGV" vehicle categories in Figure 53 amounts to about 350 GWh/a following complete vehicle substitution in 2021. If 10 depots are assumed to be required for possible vehicle refueling, this results in an average annual hydrogen delivery volume per depot of about 35 GWh. Consequently, the depots in Berlin have a similar specification to those in Munich for the supply to public-service buses (Chapter 4.5.3), so that investment figures for the modification of depots in Munich also apply to the modification of depots in Berlin.

Cumulative investments up to 2011 for the modification of the first depot in Munich for an annual hydrogen fuel supply volume of 32 GWh amount to 512,000 €. Taking into consideration the learning effect, this calls for a total investment of about 4.3 million € for the modification of all 10 depots in Berlin.

4.5.5.Supply to vehicles in Germany

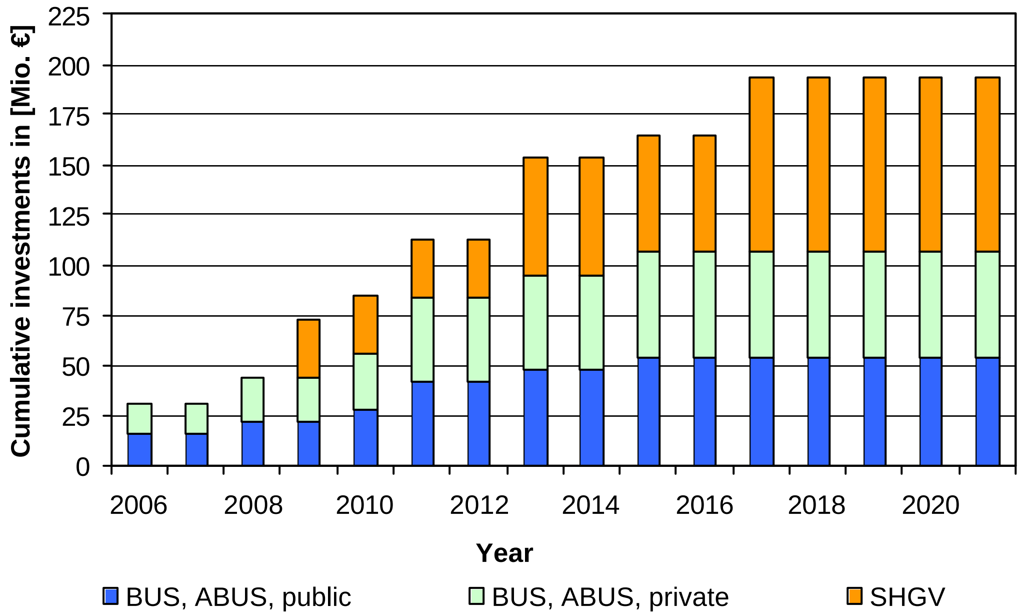
The extent of investment needed in Germany to modify depots for hydrogen fuel supply to scheduled buses and vehicles used for waste management and street cleaning, is determined approximately in this chapter.

The calculation is undertaken by creating an analogy of the investment to be made in the modification of depots in Munich with the investments in the modification of all depots in Germany. Approximate determination of the number of depots in Germany is carried out using the ratio of the vehicle population of scheduled buses of Germany to those in Munich. In Munich there are currently around 500 scheduled buses and in Germany around 54,000 scheduled buses in use, a ratio of 1:108 (Appendix 2). A similar ratio exists for the waste management and street cleaning vehicle populations.

In determining the development of the hydrogen demand for vehicles in the BUS, ABUS and SHGV categories for Germany, it was assumed that these vehicles will be replaced in all towns from the start of hydrogen introduction by vehicles that use hydrogen as an alternative fuel (Chapter 2.3.3). As a consequence of the calculation assumption, the annual investment in the modification of depots in Munich can be multiplied by a factor of 108 to give the approximate investment needed for the modification of all depots in Germany (Figure 54).

In 2006, investments in the modification of the depots will amount to around 30 million € and by the time the complete modification of all depots in Germany has been carried out will reach about 200 million €. The long-term share of investments in the depots for the fuel supply of scheduled buses is almost the same as that for the supply of vehicles used for waste management and street cleaning. One can clearly see the initial investments made in the modification of the depots of vehicles used in waste management and street cleaning in 2009, as in the first three years these vehicles can be refuelled at the bus depots.

Figure 54: Cumulative investment in depots for supplying scheduled buses in public ownership (public), in the ownership of private companies (private) and vehicles used for waste management and street cleaning (SHGV) in Germany from 2006 to 2021



BUS = scheduled bus, ABUS = scheduled articulated bus, SHGV = special trucks (vehicles used for waste management and street cleaning).
Source: Own calculations, 2002

As the private bus fleet used for scheduled bus transport is about as large as the publicly owned scheduled bus fleet (Table 38), it has been assumed for the investment calculations shown in Figure 54 that the investments in the modification of the depots of both types of vehicle operator would be about the same.

4.6. Summary

Tasks
The task is recording and analysing the gas station concepts favored by the industry for supplying hydrogen. From this comparison of the concepts one is identified which, after almost complete fuel substitution, generates the lowest costs and CO_2 emissions.

With the constantly increasing hydrogen demand (derived from the development of the vehicle population in Chapter 2.3), the production plants will in all probability be designed with a capacity that will not be achieved in the year of the commissioning. The influences of the partial usage of plants, the economies of scale and the learning effect (cost degression with increasing unit numbers, e.g. as a consequence of increasing experience in the installation of equipment) on specific hydrogen costs are determined.

An option for supplying buses in regular service and various fleet vehicles (e.g. vehicles use in waste managment) is shown.

Assumptions and approach

For the economic comparison of the gas station concepts for supplying hydrogen, depending on annual hydrogen fuel delivery volumes at the gas station when fully utilized, it is assumed that existing conventional gas stations will be modified by converting them to supply hydrogen. Distinctions are made between the gas station concepts which supply only liquid hydrogen (LH_2), only compressed gasous hydrogen (CGH_2 at 850 bar at the gas station), or both (50 % LH_2, 50 % CGH_2). Hydrogen can be produced either centrally in high-capacity plants or directly at the gas station (on-site).

The comparison of the concepts takes place according to the investments needed (hydrogen production, distribution and gas stations), the specific hydrogen costs and the CO_2 emissions. From this can be seen which hydrogen supply concept is best from a cost and ecological perspective, and which of the two states, liquid or gaseous, is favored for the future use of hydrogen as an alternative fuel.

Examination of the plant specifications for the production of hydrogen takes place with natural gas steam reforming plants as an example. An analysis of the plant specification is carried out both on the basis of the development of the hydrogen need of vehicles for Munich, and also on the basis of the development of the hydrogen demand in Germany. For the total cost comparison, the costs (expenditures) are divided up according to the annuities of the investments and operating and maintenance costs, discounted to 2006 (start of vehicle market introduction).

An examination of the supply to buses and special vehicles is carried out for vehicles in the city of Munich. Having determined the current conventional supply infrastructure via depots, the hydrogen gas station concepts mentioned earlier are assessed in terms of cost for their use at the depots. For the resulting favorite depot concept an analogous, cost-based projection is carried out for supplying these categories of vehicles in the whole of Germany.

Findings

Analysis of the favored gas station concept shows that the supply of liquid hydrogen to the gas station is associated with lower costs than the supply of compressed gaseous hydrogen. For this reason, the pure LH_2 gas station concept, i.e. only the supply of LH_2 at the gas station, takes on the role of favorite. An important reason for this is the lower equipment requirement per fuel pump for the supply of LH_2 compared to CGH_2.

If the LH_2 gas station is examined, the introduction of hydrogen must be achieved for reasons of cost by centralized natural gas steam reforming using regeneratively produced electricity or electricity from nuclear power (CO_2 emissions can be held at or reduced below the emissions level for gasoline at moderate cost). For a long-term CO_2 reduction, hydrogen production must take place by electrolysis using regeneratively produced electricity or electricity from nuclear power (in so far as this is socially and politically acceptable).

With increasing annual hydrogen fuel sales at the gas station, the cost advantage of centralized hydrogen production by electrolysis compared to on-site production by electrolysis becomes lower, so that the on-site production at highway gas stations (with correspondingly higher fuel sales) represents an option that should be carefully considered (since on-site liquefaction of the gaseous hydrogen is uneconomical, the supply of hydrogen in the case of on-site electrolysis at the gas station takes place only a gaseous condition).

CGH_2 supply at the gas station by on-site natural gas steam reforming is not seen as meaningful, since the CO_2 emissions cannot be reduced to the level of gasoline in spite of the use of regeneratively produced electricity (on-site production plants have a lower capacity and lower efficiency than central production plants of higher capacity).

Analysis of the plant specifications for the satisfaction of hydrogen demand in Munich shows that whereas total costs can be kept relatively low in the first few years at many of the lower-capacity production plants (high rate of utilization of the relatively small number of production plants), in the medium and long term, they give rise to the highest cumulative total costs. Economies of scale do not function here. As the short and medium-term cost components are of primary importance for the development of a hydrogen infrastructure, the optimum plant specification yields a capacity that exploits economies of scale as well as learning effects. In the example of the hydrogen production plants to supply vehicles in Munich, plants with a capacity of about 100 GWh/a are constructed in the first 12 years (the full capacity of each plant is reached about 3 years after its construction). After this period there is a correspondingly higher hydrogen demand, so that the capacities of the new plants to be built are higher.

Finally, when designing plants and taking into consideration the development of hydrogen demand in Germany, it is shown that by exploiting economies of scale a higher reduction in hydrogen costs is achieved than by utilizing learning effects. For the development of a hydrogen infrastructure, the most cost-effective option is centralized hydrogen production using high-capacity plants.

For fleet vehicles at depots, liquid hydrogen supply with centralized production at high-capacity plants is the depot concept that should be pursued. As the progress of conventional vehicle substitution by vehicles running on hydrogen as an alternative fuel is planned in advance by the bus and special vehicle fleet operators, depots can be designed according to hydrogen demand. This will permit a high rate of depot utilization from the start, which is reflected in more favorable specific hydrogen costs compared with those at conventional road-side gas stations. Consequently, in the market introduction phase, the regular supply of hydrogen to these vehicles using adapted roadside gas stations is not meaningful.

Conclusions and recommendations

As the gas station concept with exclusive LH_2 supply and centralized production is shown to be the most cost-effective, only the costs and emissions for this concept are examined further in the chapters that follow.

5. Hydrogen gas station infrastructure

From the comparisons of gas station concepts in Chapter 4.3 it can be deduced that the on-site concepts only become interesting above the level of annual hydrogen fuel sales at the gas station that prevails at motorway stations (above about 32 GWh/a, corresponding to 3.6 million l GE/a). It has also been observed that CGH_2 gas station concepts are more costly than LH_2 gas station concepts, so that in the following examination the build-up of an LH_2 gas station infrastructure with centralized hydrogen production in high-capacity plants is examined.

If an $LCGH_2$ gas station infrastructure is to be built up, there are higher investments and total costs involved in the optimal concept of central hydrogen production than for the build-up of an LH_2 gas station structure infrastructure contained in this paper (Chapter 4.3).

It is noted that the development of the LH_2 gas station infrastructure in terms of numbers as determined in this chapter also applies to the other gas station concepts. There will, for example, be differences in the investments and discounted total costs, as they occur at other times and levels.

An overview of the scenarios arrived and used for further calculations in this paper is shown in Figure 55. The names shown in the matrix describe the scenario in question.

Figure 55: Overview and contexts of the scenarios used

	Munich	Large German cities	Germany
Development of vehicle population	VPD OWN VPD SENSITIVITY		VPD OWN VPD SENSITIVITY
Development of hydrogen demand	HDD OWN HDD SENSITIVITY		HDD OWN HDD SENSITIVITY
Development of gas station infrastructure	GSID 1 to 7 GSID SENSITIVITY	GSID 3, 6, 7, 8 GSID SENSITIVITY	GSID 1+6, 2+3, 3+8, 4+7 GSID SENSITIVITY
Hydrogen production	Version 1 to 9 with 100 % NGSR		**Path 100N 0W 0B** 100% NGSR, 0% Electrolysis, 0% Biomass **Path 0N 100W 0B** 0% NGSR, 100% Electrolysis, 0% Biomass **Path 0N 90W 10B** 0% NGSR, 90% Electrolysis, 10% Biomass **Path 75N 25W 0B** 75% NGSR, 25% Electrolysis, 0% Biomass **Path 75N 15W 10B** 75% NGSR, 15% Electrolysis, 10% Biomass **Path 40N 60W 0B** 40% NGSR, 60% Electrolysis, 0% Biomass **Path 40N 50W 10B** 40% NGSR, 50% Electrolysis, 10% Biomass

VPD = Vehicle population development, HDD = Hydrogen demand development, GSD = Gas station infrastructure development, NGSR = Natural gas steam reforming.
Source: Own presentation, 2003

In the example of the German city of **Munich**, the scenario type VPD OWN is used for the development of the population of vehicles using hydrogen as an alternative fuel. Using the definition of reference vehicles in Chapter 2.2, this gives a development of the hydrogen demand that is referred to here as HDD OWN. To cover the HDD OWN, seven scenarios of possible gas station infrastructure development are examined, and designated as gas station infrastructure developments 1 to 7 (GSID). For hydrogen production under HDD OWN, nine options are examined (Version 1 to 9, Chapter 4.4).

In the example of the nationwide examination for **Germany**, four scenarios for the development of a gas station infrastructure are examined as a means of satisfying HDD OWN (based on VPD OWN). For the supply of hydrogen according to HDD OWN, seven basic production options are examined, each of them calculated with and without the use of sequestration (Chapter 6).

A rapid increase in the vehicle population for hydrogen as an alternative fuel for Munich and nationwide examination is also assumed as part of a sensitivity analysis (VPD SENSITIVITY, Chapter 7). Across the reference vehicles this yields the HDD SENSITIVITY. To cover the HDD SENSITIVITY closer analysis of only the gas station infrastructure takes place which, in the examination of the scenarios for the HDD OWN, appears to be the most probable. In the example of Germany this a very probable development of the gas station infrastructure in the form of an S-curve (GSID 4+7) to cover the OWN hydrogen demand. Consequently, the GSID SENSITIVITY analyses the development of the gas station infrastructure in the form of an S-curve to satisfy HDD SENSITIVITY.

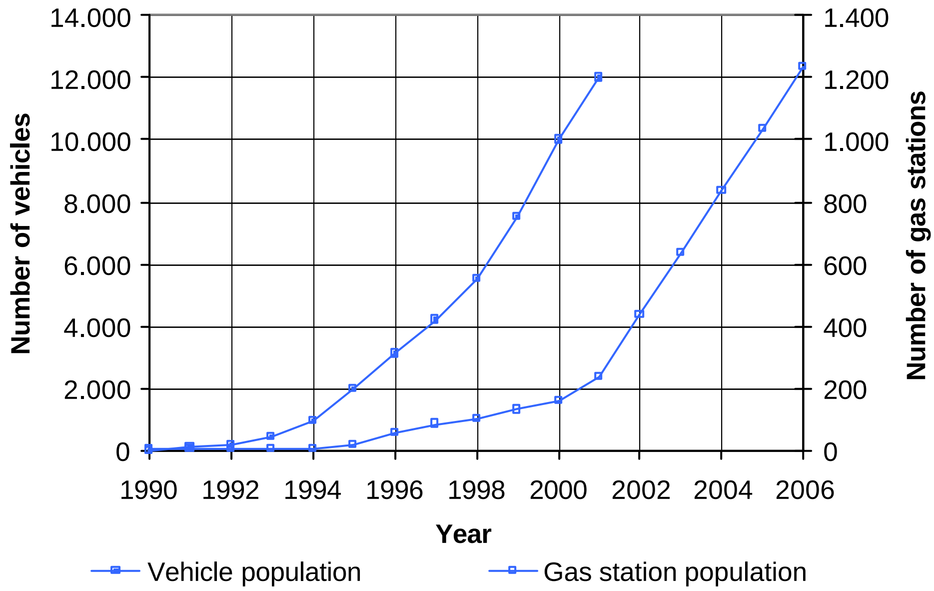
In the first part of this chapter there is an examination of the current number of gas stations modified for natural gas supply in order to obtain clues appropriate to the development of a hydrogen gas station infrastructure. In the next stage, possible development of an LH_2 gas station infrastructure in Munich is determined, as governed by the HDD OWN for that city. The findings obtained are transferred to the build-up of a gas station infrastructure in the 72 largest German towns. In connection with this, scenarios for the development of a gas station infrastructure in Germany, in separate categories according to development in the cities, outside of them and on the freeways are examined. With regard to national examination of the gas station infrastructure, national development of the hydrogen demand is based on the HDD OWN.

5.1. Development of natural gas stations to date

Examination of the number of natural gas vehicles in Germany in Figure 56 shows that the period from the start of the market introduction of the vehicles in 1990 to a fleet of 12,000 vehicles took around 10 years. Most of the vehicles using natural gas as a fuel were and remain trucks. In 2000, the inventory of passenger cars powered by natural gas was about 3,800 out of a total of about 10,000 vehicles (KGA[86], 2000). The fuel supply for natural gas vehicles in 2000 was provided by 160 gas stations. The natural gas stations partly include company depots that are not publicly accessible or can only be used by the public for limited period of the day (for example, vehicle refueling is not possible at weekends). Of the current 250 natural gas stations in Germany, the share of publicly accessible conventional gas stations modified for the supply of natural gas is about one third (Manz, 2002, p. 4).

[86] Federal German Motor Transport Office, Flensburg

Figure 56: Development of the natural gas vehicle fleet and natural gas stations in Germany from 1990 to 2001 and forecast development of gas stations in Germany up to 2006

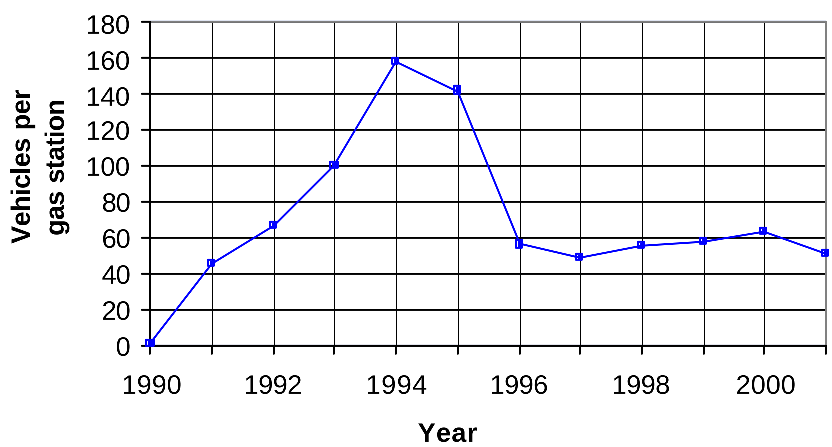


Source: Etzbach, 2000; www.erdgasfahrzeuge.de, 28.11.2001; www.gibgas.de, 28.11.2001; www.tam.de, 12.10.2001

For the future development in the number of natural gas stations, highly optimistic forecasts assumed that there will be 480 and less optimistic ones about 300 gas stations by the end of 2002. The gas industry's plan to erect 1,000 natural gas stations in the next six years in Germany (www.bundesverband-gas-und-wasser.de, 29.05.2002); Siegener Versorgungsbetriebe, www.svb-siegen.de, 29.05.2002), would correspond to an additional annual number of 200 natural gas stations (Figure Figure 56).

Examination of the ratio "average number of natural gas vehicles per natural gas station" in Figure 57 shows that in the first few years of the introduction of natural gas as a fuel a continuous increase of the vehicle population up to just 160 natural gas vehicles per natural gas station occurred in 1995, but with the rapid increase in the number of natural gas stations in 1995 and 1996, the ratio fell to below 60 natural gas vehicles per natural gas station. Since 1996, the ratio has increased again slightly and currently fluctuates between 50 and 60 natural gas vehicles per natural gas station.

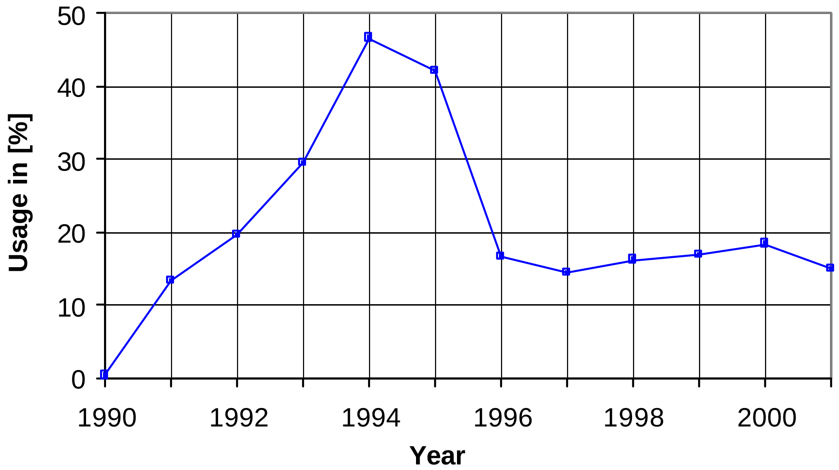
Figure 57: Development of the ratio "average number of natural gas vehicles per natural gas station" in Germany from 1990 to 2001



Source: Own calculations, 2002

If a fuel consumption of 80 kWh/100 km and an annual distance travelled of 14,000 km for the natural gas vehicles are assumed, using the number of natural gas vehicles per natural gas station determined in Figure 57, this yields an average use of the natural gas station as shown in Figure 58. An average gas station capacity utilization of over 40 % is only achieved in the fifth year after construction of the first natural gas station, which due to the rapid increase in the number of natural gas stations in 1995 and 1996 fell to about 15 % and has remained almost constant at this level of use ever since.

Figure 58: Average utilization of fuel pumps at natural gas stations[87] in Germany from 1990 to 2001

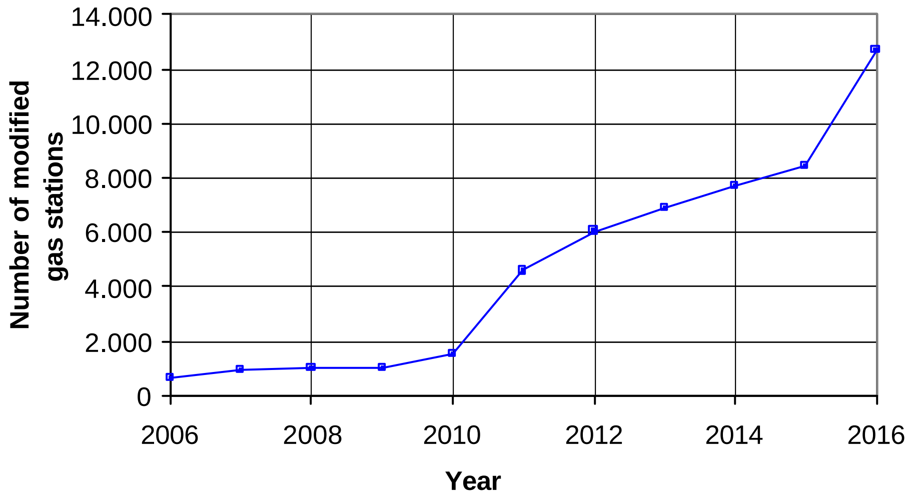


Fuel sales per fuel pump of 3.8 GWh/a correspond to a fuel pump usage of 100 %.
Source: Own calculations, 2002

If in the development of a hydrogen gas station infrastructure the same trend of the gas station usage as for the natural gas stations, but with hydrogen demand according to HDD OWN for Germany, is assumed as a basis for calculation (without hydrogen demand in the BUS, ABUS and SHGV categories, as these are refuelled at depots and not at publicly accessible gas stations), 660 conventional gas stations (fuel pump usage 13 %) modified to supply hydrogen will be required in 2006 (Figure 59). In the fifth year after the introduction of hydrogen fuel, some 1,650 modified gas stations would be required, in order to be able to supply vehicles with the hydrogen demand of about 2,900 GWh/a. As a consequence of the reduction in the usage at natural gas stations after the fifth year there will be a sharp increase in the number of modified gas stations with hydrogen supply, as the hydrogen demand according to HDD OWN grows constantly compared with the natural gas demand.

[87] No difference between publicly accessible roadside filling stations and depots.

Figure 59: Development of the number of modified gas stations with hydrogen availability to supply vehicles according to OWN hydrogen demand in Germany from 2006 to 2016, using an identical pattern of fuel pump usage as for the natural gas stations in Germany from 1990 to 2000



Fuel sales per fuel pump of 3,8 GWh/a correspond to a fuel pump usage of 100 %.
Source: Own calculations, 2002

As this paper deals with scenarios for the development of the gas station infrastructure, as governed by hydrogen demand according to HDD OWN (Chapter 2.3.4), development of the modified gas station shown in Figure 59 is not seen as being representative, which is why this chapter addresses the development of the hydrogen gas station infrastructure more closely.

5.2. Calculation assumptions and list of criteria

For further examination in this paper, the following assumptions are made:

- a political decision **in favor** of hydrogen as an alternative fuel has been taken
- international standardization for the licensing of vehicles, gas stations etc.
- no limitation on the permitted driving areas (tunnels, garages)
- demonstration phase completed (no more pilot projects)
- 15-year technical lifespan of various gas station components, followed by component replacement (re-investment)
- Expansion investments (material costs and "other investments”) at an additional 5 % in order to take into consideration the new access times and gas station planning
- Degression factor for the learning effect of A = 0.91, for initial, expansion and repeat investments

In order to evaluate the gas station infrastructure development scenarios one against the other, criteria are defined.

Criteria for the development of the gas station infrastructure:

- A sufficient number of modified conventional gas stations with hydrogen supply especially in the first few years of the market introduction of hydrogen as an alternative fuel, in order to generate acceptance among the population, and sufficient fuel supplies for fleet vehicles in particular (e.g. taxicabs in cities[88])
- Modification of conventional gas stations, especially in the first few years, at strategically located gas station sites (e.g. in urban areas)

[88] Population greater than 100,000 people

- Development of the modified number of gas stations until full coverage is achieved (see Chapter 5.2.2 for definition of terminology), taking into account the difference between a motorway/freeway and a roadside gas station
- Development of the number and usage of fuel pumps

Criteria from geographical perspectives[89]:
- Development of the area to be supplied by each modified gas station in an examination of gas stations in cities (point concentration), outside cities and for national average values or the radii they give
- Development of the number of communities to be supplied per modified gas station outside the cities
- Development of the average length of roads (see Chapter 5.2.1 for a definition of the term) between two modified gas stations outside the cities (excluding motorways/freeways)
- Development of the average length of motorway/ freeway between two modified gas stations

Criteria from economic perspectives:
- Short, medium and long-term investment pattern
- Short, medium and long-term changes in the discounted total costs
- Short, medium and long-term development of the specific gas station costs[90] per liter GE

5.2.1.Current conventional gas station infrastructure

In this paper, the term "road length” means the sum of the lengths of German main and rural roads.

In 2001, the road lengths and motorway/freeway (‘autobahn’) lengths in Germany were (www.destatis.de, 9.07.200):
- Main roads[91]: 41,300 km
- Rural roads: 86,800 km
- ‘Autobahns’: 11,700 km

For the current gas station infrastructure with approximately 16,000 gas stations (of which 350 are ‘autobahn’ gas stations) this gives the following average values for the defined characteristics:
- 2.6 km radius/gas station in Germany as a whole
- 1.35 km radius/gas station in German cities
- 2.9 km radius/gas station outside the cities
- 1 gas station/community outside the cities[92]
- 9.2 km road length/gas station outside the cities
- 66.9 km ‘autobahn’length/‘autobahn’ gas station

5.2.2.Coverage

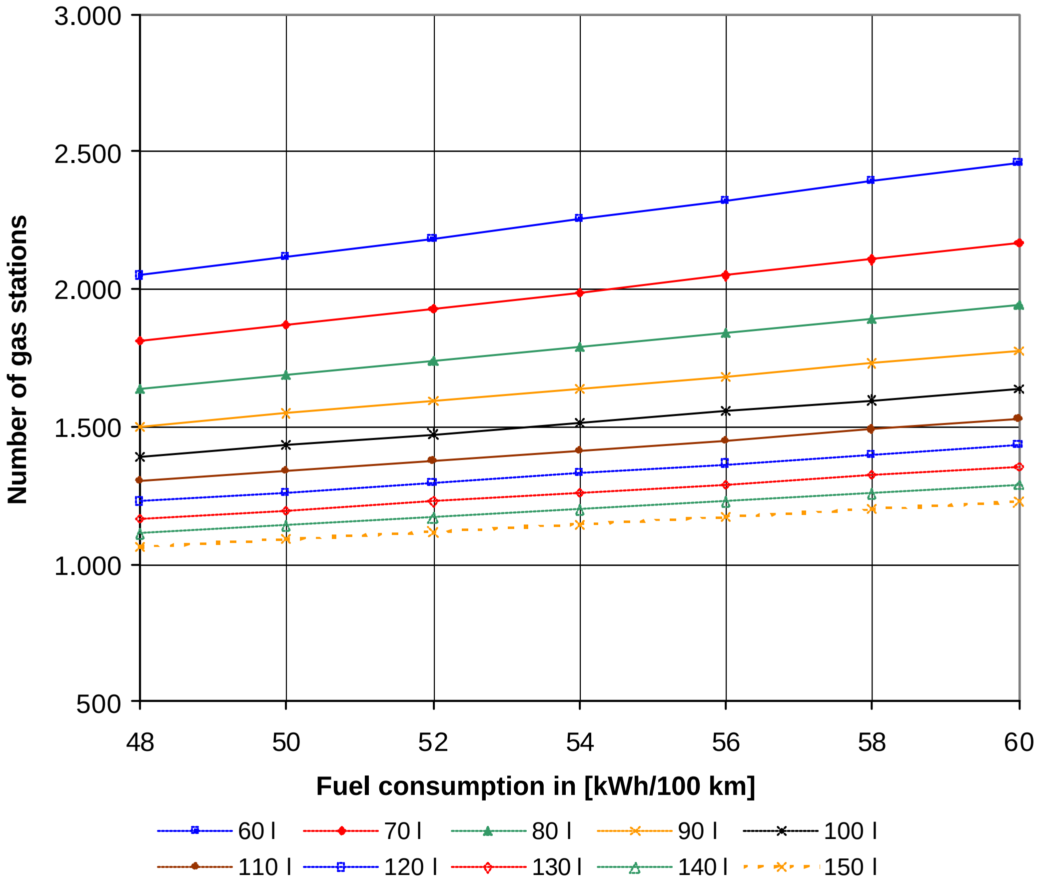
The term “**coverage**” is used to mean the number of modified gas stations for the supply of hydrogen, above which it is theoretically possible to drive on all the roads in Germany with hydrogen as an alternative fuel without any gap in the fuel supply arising. In this calculation an additional safety factor is also applied, which takes into account that the vehicle operator may only use every other gas station that supplied hydrogen, i.e. he ignores the next gas

[89] Determination of these characteristics assumes equal distribution of gas stations across the established area.
[90] Specific gas station costs include the costs from the new -build or conversion of a conventional gas station and the operating and maintenance costs at the gas station. Not included are the costs of hydrogen production and distribution of the hydrogen from the production plants to the gas stations.
[91] Arterial roads in cities are partly recorded as main roads, which leads to a slight discrepancy.
[92] 14,197 local communities in Germany as at 30.12.1998 (Albrecht, 2001, p. 183).

station for hydrogen refueling and still has the option to continue to the next gas station for hydrogen refueling with the hydrogen that remains in the tank.

As the range with hydrogen depends primarily on the capacity of the vehicle tank, this gives the coverage a bandwidth of values (Figure 60). In essence, it means that the number of gas stations rises with increasing vehicle fuel consumption and decreasing capacity of the vehicle storage tank.

Figure 60: Number of gas stations modified for hydrogen supply needed for coverage, depending on the specific fuel consumption of the vehicles and the capacity of the LH_2 vehicle's tank, in Germany



Source: Own calculations, 2002

In the example of an LH_2 vehicle tank with a capacity of 120 l of LH_2 (for example, in a compact class car such as the BMW 3 Series Compact) and a vehicle fuel consumption of 49 kWh/100 km (average of the consumption values of PC-ICE and PC-PEMFC, Chapter 2.2.3.1), the average driving range is 580 km. Taking into consideration the aspect that only every other modified gas station may be chosen by a vehicle operator, this gives a maximum distance between two consecutive modified gas stations of 290 km. This distanceis equivalent to a coverage of 1,240 gas stations, made up as follows:

- **Coverage on 'autobahns':** 80 gas stations
- **Coverage on main and rural roads:** 442 gas stations
- **Coverage on local roads in urban areas:** 314 gas stations
- **Correction factor for coverage on local roads in cities:** 404 gas stations (for an adequate supply to fleet vehicles such as taxicabs – see Scenario 7 in Chapter 5.3.1, independent of vehicle fuel consumption and capacity of the vehicle tank)

When comparing scenarios for the development of a gas station infrastructure in Chapter 5.5 on the basis of the coverage criterion, a coverage of more than 1,500 gas stations is assumed, as the necessary input factors for this, namely the capacity of an LH_2 vehicle tank and vehicle fuel consumption, assume an average value. This value is confirmed by a statement by FORD, according to which the successful market penetration of alternative vehicles requires a coverage to the extent of 10 to 15 % of all available gas stations (Birch, 2001, p. 28; Dunn, 2001, p. 55). Assuming that 12,000 as stations are available in the future, between 1,200 and 1,800 gas stations (average of 1,500) would be required for coverage.

It should be stressed that according to a statement by the petroleum industry, full-coverage gas station supply is possible above about 2,000 gas stations (TES, 2001, p. 27).

5.3. Gas station infrastructure in Munich

To create a scenario for the build-up of a gas station infrastructure in Munich, the development of hydrogen demand is based on the HDD OWN for Munich, (Appendix 3). In accordance with this the time factor is brought into the scenarios of the gas station infrastructure.

5.3.1. Scenarios for development of the gas station infrastructure

The scenarios differ fundamentally with regard to

- the increase in the number modified gas stations over the years (Figure 61)
- the increase in the number and usage of fuel pumps at modified gas stations (Figure 62)
- the period elapsing before complete modification of all conventional gas stations

The **selection of the development of the number and usage of fuel pumps** at the modified gas stations over the years, lads on the basis of the stated hydrogen demand according to HDD OWN, to the number of modified gas stations and therefore development of the gas station infrastructure in Munich (for characteristics of the scenarios, see Table 28).

Table 28: Characteristics of the scenarios for the development in the number of modified gas stations for hydrogen with regard to modified gas stations in the first year (2006), development of the number of gas stations from 2006 on, the number of fuel pumps in the first year (2006) and the average usage of fuel pumps from 2006 on according to the OWN hydrogen demand, for Munich

Scenario	Number of modified gas stations in first year[93]	Development of the gas station population	Number of fuel pumps in first year	Average fuel pump usage
GSID 1	10	approximately linear	1	medium – high
GSID 2	21	approximately linear	1	medium
GSID 3	10	progressive	1	low – medium
GSID 4	10	progressive, slow	1	high
GSID 5	10	degressive	1	low
GSID 6	10	degressive, slow	1	medium – high
GSID 7	10	S-curve	1	low – medium

GSID = Gas station infrastructure development
Source: Own calculations, 2002

GSID 1 and 2 essentially exhibit an almost linear increase in the number of modified gas stations. For GSID 7, an identical increase in the number of modified gas stations as in GSID 3 is assumed for the period up to 2018. However, from 2018 on a slower, degressive development of the inventory is assumed, to take a run-down phase into consideration[94].

[93] From Figure 192 in Appendix 3 it is evident that primarily taxicabs need a significant share of the hydrogen demand in the first few years. The taxicab operators in Munich require in the first year at least ten modified gas stations with hydrogen supply distributed across the city, as the drivers of the vehicles are not prepared for cost reasons to travel considerable distances through the city to refuel with hydrogen (Herzinger, 18.05.2001).

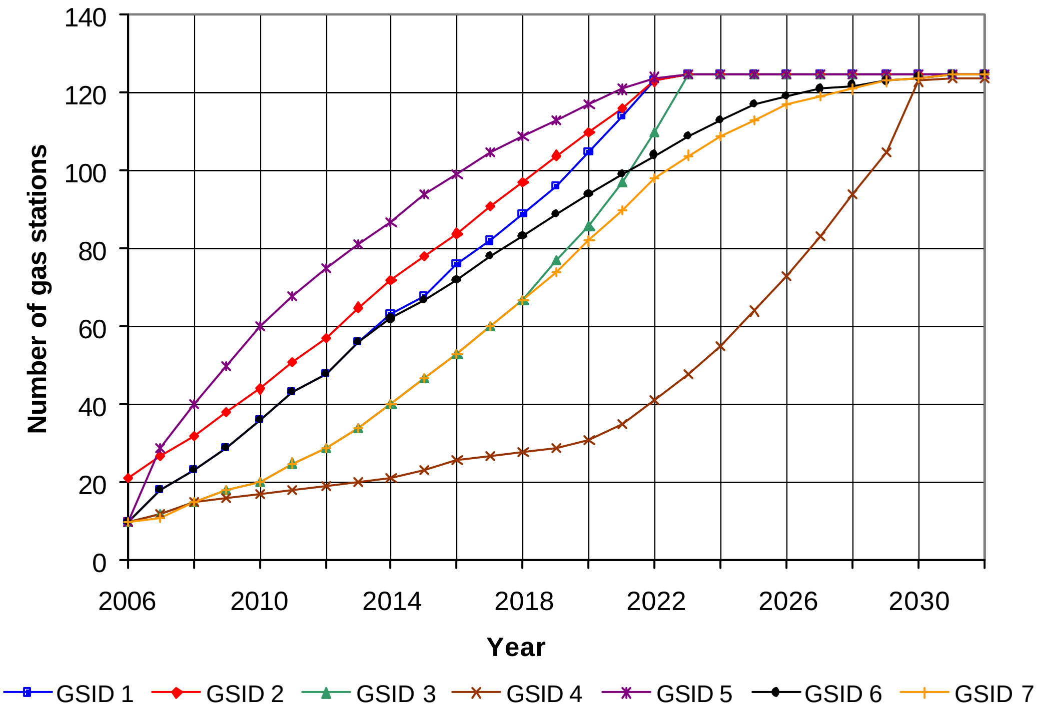
[94] Reasons for the run-down phase are for example gas stations that will only be operated by the petroleum industry for a short while longer, provided that there are no major investments, as operation of the gas station is to be abandoned (unfavorable location, unprofitable etc.). The reasons also apply to gas stations that are owned by private individuals or companies, who for financial reasons wish to delay modification of the gas station for as long as possible.

Complete modification of conventional gas stations with at least one fuel pump for supplying hydrogen is achieved in Munich with GSID 1, 2, 3 and 5 in 2023, and with GSID 4, 6, and 7 in 2031.

The following findings can be derived from Figure 61 and Figure 62:

- Jagged curve of fuel pump utilization by increasing the number of fuel pumps at gas stations, causing a reduction in fuel pump utilization.
- U-shaped curve of fuel pump utilization between 2010 and 2020 as a consequence of HDD OWN[95]
- Average fuel pump utilization in 2006 at 50 % (except in GSID 2 with 25 %)
- Higher number of fuel pumps per modified gas station permits slower development of the gas station infrastructure (see GSID 3)
- Higher number and greater utilization of fuel pumps per modified gas station causes slower progressive development of a gas station infrastructure (see GSID 4)
- A rapid increase in the number of modified gas stations causes lower fuel pump utilization (see GSID 5)

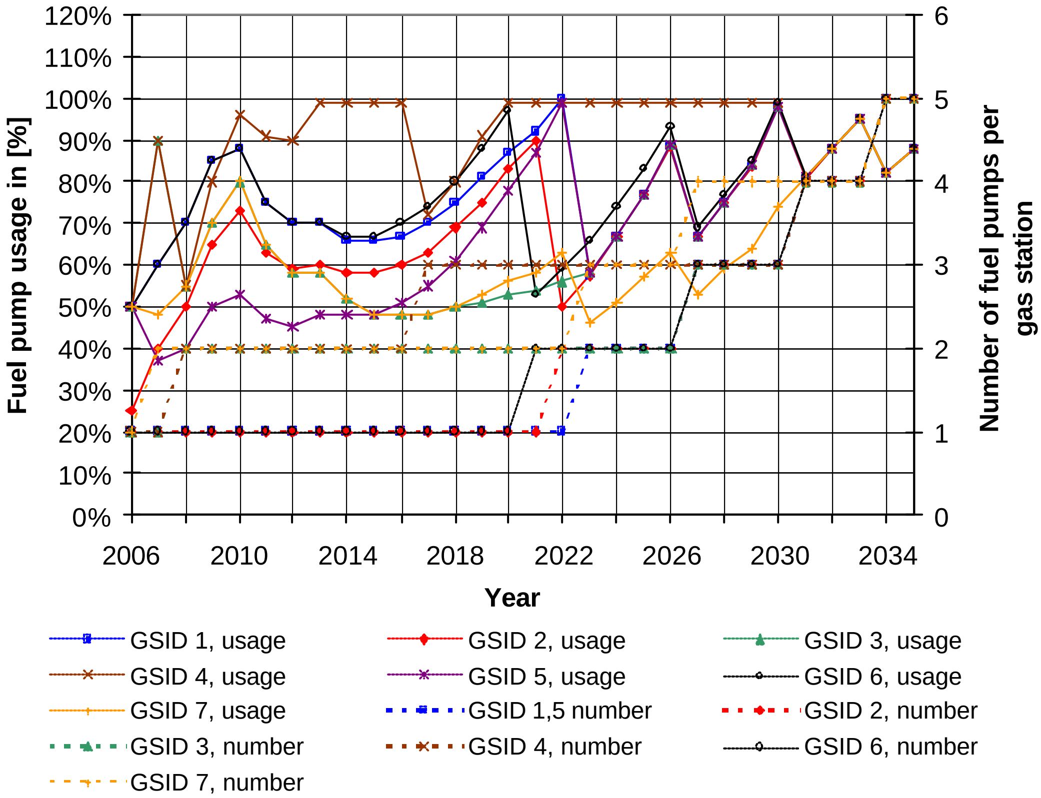
Figure 61: Scenarios for developments in the number of modified gas stations for supplying vehicles with hydrogen according to hydrogen demand development OWN, in Munich from 2006 to 2032



GSID = Gas station infrastructure development
Source: Own calculations, 2002

[95]Until 2010 there us a strong annual increase in the hydrogen demand as a consequence of taxicabs, which will be completely replaced by vehicles using hydrogen as an alternative fuel by 2010 to 2011. In the years that follow there will not be such as strong annual increase in the hydrogen demand, and therefore as a consequence of the further increase in the number of modified gas stations, their rate of utilization decreases.

Figure 62: Number and utilization of fuel pumps per modified gas station for the various gas station infrastructure development scenarios in Munich from 2006 to 2035



GSID = Gas station infrastructure development
Source: Own calculations, 2002

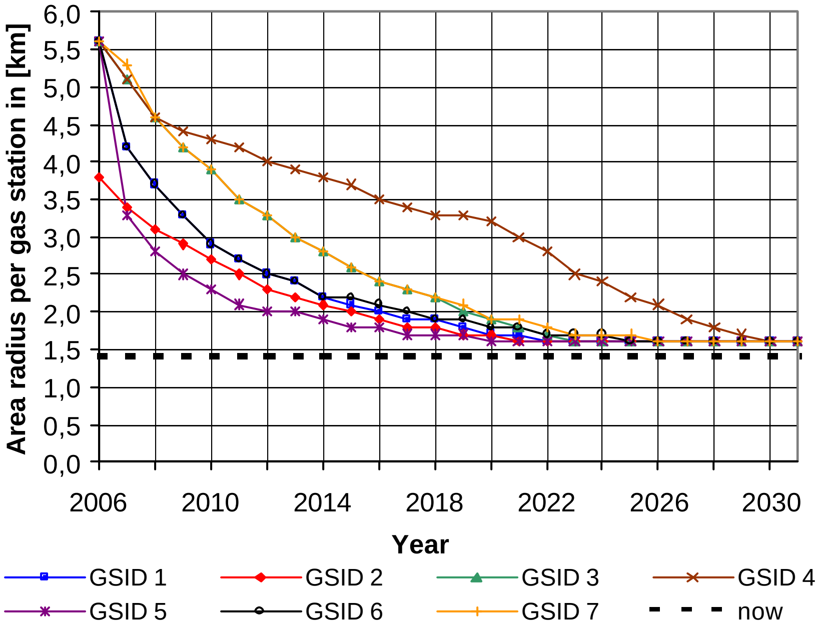
5.3.2.Comparison according to geographical criteria

A comparison of scenarios regarding the radii of the areas that must be covered per modified gas station is shown in Figure 63. It can be clearly seen that the more slowly the development of the gas station infrastructure proceeds, the flatter the area radius curve is in the diagram. This will probably go hand in hand with lower acceptance of the alternative fuel by the population. A rapid reduction in the area radii in order to achieve coverage, especially in the first few years, is advantageous.

In GSID 5, with its degressive development of the gas station inventory, very low area radius values of about 2 km per gas station are already achieved by 2012. This value is only reached by 2026 in GSID 4, with progressive development of the gas station inventory. The current average area radius of 1.4 km per gas station for the conventional gas station infrastructure in Munich is achieved in all scenarios (except GSID 4) by 2020[96].

[96] The remaining difference between the levels of the curves of the scenarios and the current value of 1.4 km from 2026 is based on the assumption that the current number of 16,000 gas stations (radius 1.4 km) will in future be reduced to 12,000 gas stations (radius 1.6 km).

Figure 63: Average land-area radii per modified gas station for gas station infrastructure development scenarios in Munich from 2006 to 2031



GSID = Gas station infrastructure development
Source: Own calculations, 2002

As the calculation of road kilometers per modified gas station has less meaning in urban areas, this characteristic is not examined for Munich.

5.3.3. Comparison according to economic criteria

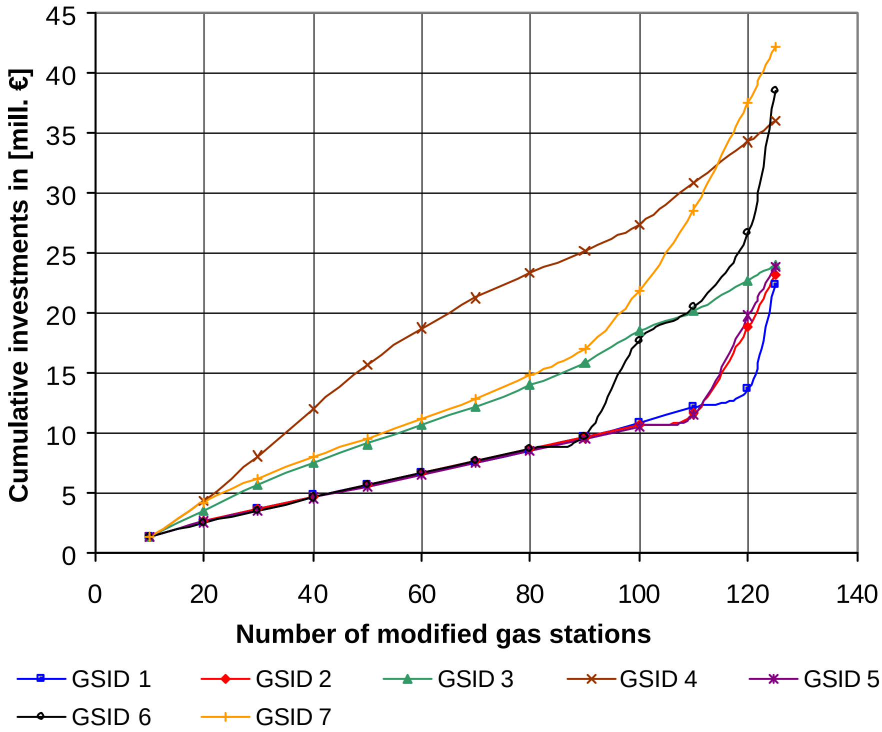
A comparison of the **cumulative investment related to the modified gas station population** is shown in Figure 64[97]. Cumulative investments in GSID 1, 2, 5 and 6 are almost identical up to a modified gas station inventory of about 90 gas stations, since up to that level there is no increase in the number of fuel pumps at modified gas stations. However, there is a rapid increase in investment compared with the remaining scenarios in GSID 3, 4 and 7 right from the start, as a consequence of the increase in the number of fuel pumps at the modified gas stations.

The increase in the number of fuel pumps per modified gas station essentially causes lower investments than the initial modification of a conventional gas station to supply hydrogen. Due to the number of gas stations already modified, the investments required for an increase in the number of fuel pumps are however higher at many gas stations (see GSID 3, 4 and 7) than the investments in the initial modification of a smaller number of conventional gas stations to supply hydrogen (see GSID 1, 2, 5 and 6). However, the effect described here exists only while there is an increase in the number of fuel pumps in GSID 1, 2, 5 and 6. This results in a strong increase in the cumulative investments for these scenarios above a number of about 110 modified gas stations.

The investments in 2006 for GSID 2 with 21 modified gas stations are 2.6 million € and for the remaining scenarios 1.4 million €. The highest cumulative investment following the modification of 125 gas stations in Munich occurs in GSID 7 at some 43 million €, the lowest in GSID 1 at about 23 million € (Note: different times are allowed for achieving the complete modification of the gas stations in these two scenarios, therefore hydrogen fuel sales and the number of fuel pumps per gas station are also different).

[97] For a better understanding of the relationships between the scenarios with regard to the investments and the number of modified gas stations, Figure 61 also contains, for reasons of clarity, a horizontal line for the number of gas stations examined; its intersections with the scenario curves indicate the timescale on the x-axis.

Figure 64: Cumulative investments for gas station modification depending on the modified gas station inventory, to achieve complete modification of the 125 gas stations for the gas station infrastructure development scenarios in Munich



GSID = Gas station infrastructure development
Source: Own calculations, 2002

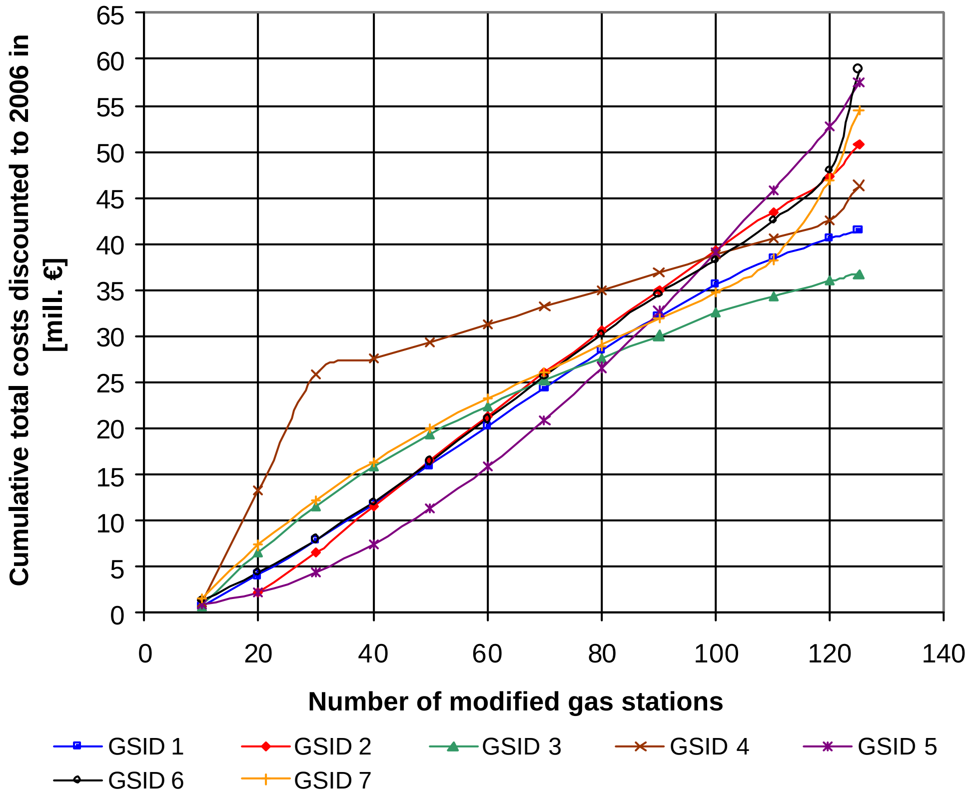
A comparison of the **cumulative investments with reference to a common timescale**, in which a complete modification of all gas stations is achieved, is shown in Figure 167, Appendix 7. For all scenarios, the modified gas stations will have five fuel pumps in 2035, which are utilized to a level of 88 %.

The **cumulative total costs, discounted to 2006, with reference to the modified gas station inventory** (in this section referred to as "total costs"), is made up of of annuities for investments including the rental costs of LH_2 storage tanks and operating and maintenance costs, using the scenarios for the modification of as stations in Munich are shown in Figure 65. It is fundamentally clear that the more rapidly construction of the gas station infrastructure takes place, the lower the total costs (Note: reference to the time axis yields the highest total costs, Figure 66). For example, the modification of 40 gas stations will be achieved in two years according to GSID 5, so that as a consequence of the short period of time, lower annual sums for annuities (investments and rental costs of LH_2 storage tanks) arise than according to GSID 1, where the modification of 40 gas stations takes five years and the annual sum of the annuities is much higher.

A large influence on the total costs is exerted by the rental costs for the LH_2 storage tanks at the modified gas station (therefore also a large influence on the total costs by the number of modified gas stations). The increase in the number of fuel pumps at the modified gas stations gives a smaller influence on the total costs. The very slow development of the as station infrastructure according to GSID 4 requires a higher number of fuel pumps per modified gas station and therefore high investments and total costs (very apparent in the case of the increase in the number of fuel pumps at 120 modified gas stations in GSID 6).

The highest total costs following the modification of 125 gas stations in Munich are found in GSID 6, at some 60 million €, the lowest in GSID 3 at about 37 million € (Note: different times for achieving the complete modification of the gas stations in these two scenarios, therefore different hydrogen fuel sales and number of fuel pumps per gas station).

Figure 65: Cumulative total gas station costs, discounted to 2006, depending on the modified gas station inventory, to achieve complete modification of 125 gas stations for the gas station infrastructure development scenarios in Munich

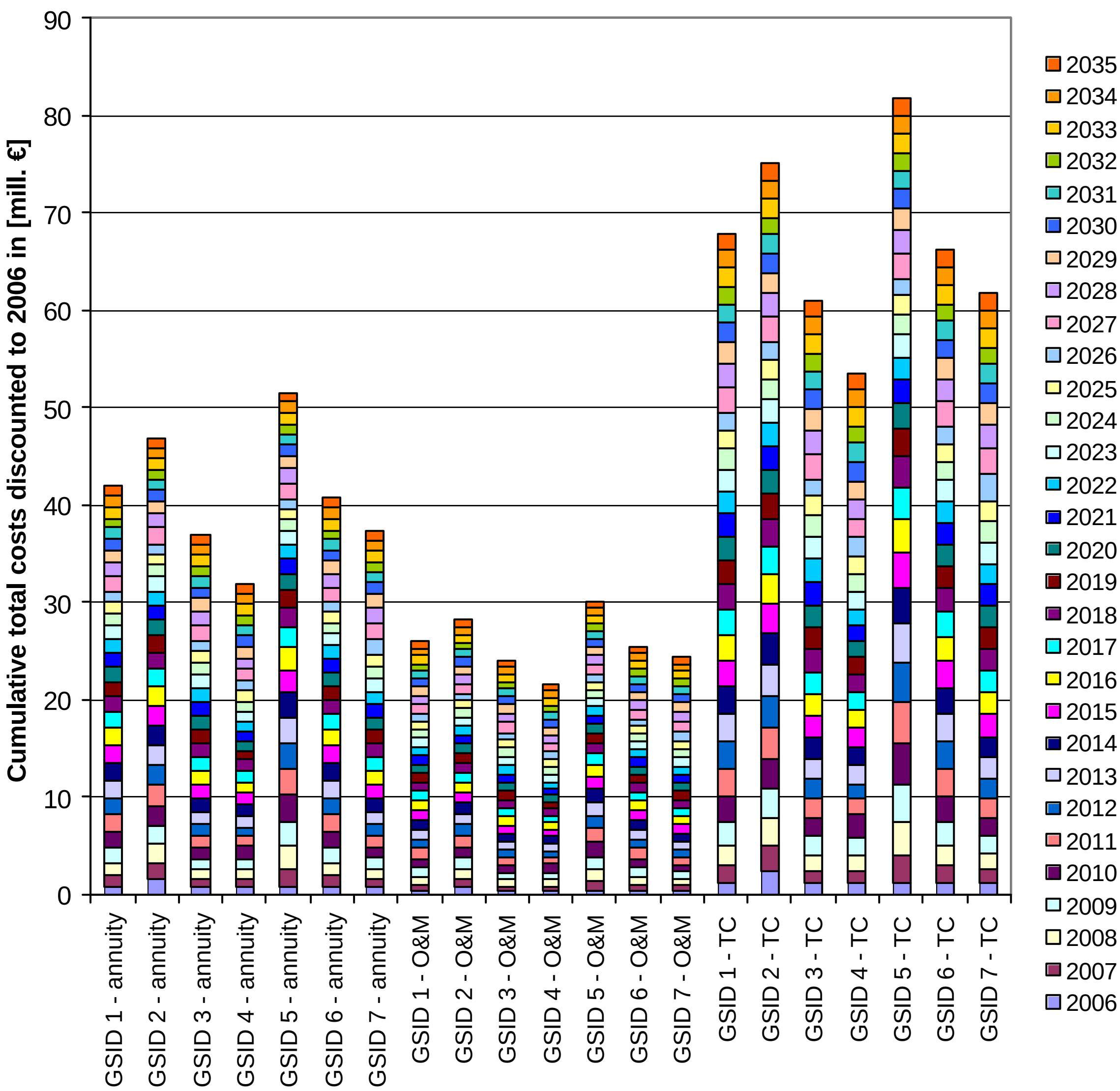


Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development
Source: Own calculations, 2002

The development of the **total costs plotted against time** is shown in Figure 66. The slower the development of a gas station infrastructure proceeds, the lower the total costs (smaller number of LH_2 storage tanks and therefore lower total rental costs, see GSID 4). More rapid development of a gas station infrastructure means high total costs in individual years, primarily as a consequence of higher sums for annual annuities including the rental costs of LH_2 storage tanks (see GSID 5).

With regard to the total cost criterion, this makes GSID 4 the option to be realized, as it incurs the lowest costs. However, with the very slow development of the gas station infrastructure, there will in all probability be a lack of the necessary customer acceptance for the purchase of vehicles using hydrogen as an alternative fuel. The next best option is GSID 7, with continuous expansion of the gas station infrastructure for still moderate total costs, so that preference should be given to this scenario.

Figure 66: Cumulative annuities (annuity), operating and maintenance costs (O&M) and total gas station costs (TC), discounted to 2006, for the gas station infrastructure development scenarios in Munich from 2006 to 2035

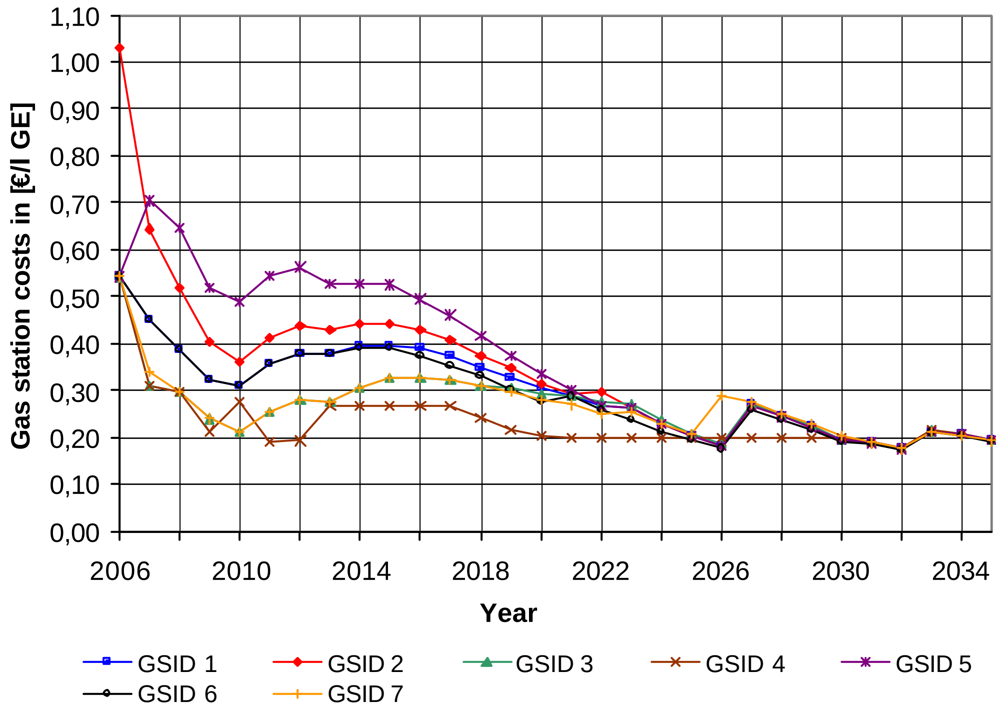


Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development, O&M = operating and maintenance costs, TC = total costs.
Source: Own calculations, 2002

In addition to cumulative investments and total costs, **development of specific gas station costs in €/l GE** forms an important criterion (Figure 67). The findings in this respect are:

- the higher the number of modified gas stations in 2006, the higher the specific gas station costs (see GSID 2)
- the slower the development of a gas station infrastructure, the lower the specific gas station costs (assuming higher fuel pump usage, see GSID 4)
- in the case of S-shaped development of the gas station inventory plotted against time, there is a rapid fall in both specific gas station costs in the first few years and in the average level of costs in the medium and long term (see GSID 7)
- long-term specific gas station costs for all scenarios are about 0.2 €/l GE

Figure 67: Specific gas station costs for gas station infrastructure development scenarios in Munich from 2006 to 2035



Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development
Source: Own calculations, 2002

5.3.4.Comparison of the scenarios with each other

From the scenario comparison in Chapters 5.3.1 to 5.3.3, it appears that, depending on the criteria taken into account, a different scenario is to be realized as the optimum for fulfilling the criteria. In order to be able to select one scenario as the optimum for developing a gas station infrastructure, taking into consideration all the criteria, a point analysis of the individual scenarios is made initially by examining the individual criteria, followed by a combination of these individual point analyses with a weighting of the criteria according to their importance for the creation of the gas station infrastructure. Points are awarded from 1 to 7, with 1 point for the best and 7 points for the worst scenario. Specific gas station costs are an important criterion for the customer, and are given the highest weighting factor of 3. The results of the analysis are shown in Table 29[98]. The best concept has the smallest total number of points.

[98] An explicit analysis of the points of the criteria of the development of the number gas stations and the usage of fuel pumps is not given, as these are reflected in the "Area radius" and "Gas station costs" criteria. The criterion of "achievablility" is not addressed here, as this is examined together with the assessment.

Table 29: Analysis of defined criteria of the gas station infrastructure development scenarios in Munich from 2006 to 2035

Criterion	GSID 1	GSID 2	GSID 3	GSID 4	GSID 5	GSID 6	GSID 7	Weighting
Average area radius	3	2	5	7	1	4	6	2
Investment by number, short-term [1)]	1	1	5	7	1	1	6	1
Investment by number, long-term [2)]	1	2	4	5	3	6	7	1
Investment by time, short-term [3)]	4	6	2	1	7	4	2	2
Investment by time, long-term [4)]	1	1	1	1	1	1	1	1
TC by number, short-term [5)]	3	2	5	7	1	4	6	1
TC by number, long-term [6)]	2	4	1	3	6	7	5	1
TC by time, short-term [7)]	4	6	1	3	7	4	1	2
TC by time, long-term [8)]	5	6	2	1	7	4	3	1
Specific gas station costs	5	6	3	1	7	4	2	3
Total number of points	**50**	**62**	**43**	**49**	**70**	**59**	**52**	

[1)] up to 80 gas stations
[2)] up to 125 gas stations
[3)] cumulative investments after five years
[4)] cumulative investments after 30 years
[5)] TC = total costs, up to 80 gas stations
[6)] TC = total costs, up to 125 gas stations
[7)] TC = total costs, up to five years
[8)] TC = total costs, up to 30 years
GSID = Gas station infrastructure development
Source: Own calculations, 2002

From the analysis, the conclusion can be reached that too rapid development of a gas station infrastructure due to a low gas station usage in the first few years, and the high total costs associated with this in the short-term, should be avoided (see GSID 2 and 5). Slow development of a gas station infrastructure according to GSID 5 does not have too negative an impact on the number of points (primarily because the specific gas station costs, which have the highest weighting, are very low – moreover, the long-term investments and total costs are at a lower level), although the short and medium-term investments and total costs assume the highest values (there will in all probably be a lack of customer acceptance for the purchase of a hydrogen-powered vehicle if a corresponding gas station infrastructure does not exist or is not constructed within an appropriate period of time).

The approximately linear development of gas station infrastructure according to GSID 1 causes higher total costs and specific gas station costs in the short and medium term. The run-down phase taken into account in GSID 6 and 7 also causes higher long-term investments and total costs related to the number of modified gas stations.

Additional aspects with an influence on the development of a gas station infrastructure that are difficult to calculate are

- possible incentives from mineral oil companies, as owners of conventional gas stations, to undertake development of the gas station infrastructure quicker or slower
- the influence of the conversion period at conventional gas stations
- the extent of investment in the conventional gas station infrastructure
- winning of new customers, image bearers

A brief description of these influencing factors follows below.

5.3.4.1. Possible incentives from mineral oil companies

Regardless of the ownership conditions, there are currently about 10 well-know gas station brands of conventional gas station in Germany (referred to in this paper as “brands”): Agip, Aral, Avia, BP, Dea, Esso, Jet, OMV, Shell and Total (www.shell.com, 26.04.2001).

If in the Munich example a conventional gas station is modified by a mineral oil company (owner of one or more gas station brands) to supply hydrogen, the following reactions on the part of competitors could occur:

- all competitors react by modifying gas stations to supply hydrogen, whereby at least 10 modified gas stations would exist; possible development of a gas station infrastructure according to GSID 1 or 5
- a number of competitors react with modified gas stations (e.g. discount gas stations such as Jet will initially be modified to supply hydrogen at a point in time when correspondingly higher annual hydrogen fuel sales are achieved at the gas stations[99]); possible development of a gas station infrastructure according to GSID 6 or 7

The development of a gas station infrastructure could possibly result in "**cluster" formation**. In this paper, the term means the following: If a mineral oil company modifies a conventional gas station to supply hydrogen in an urban area where until that time no hydrogen gas station had existed, its competitors will probably also carry out gas station modifications in order not to lose customers. The leads to a collection and over-supply of hydrogen gas stations in these urban areas, which then exhibit a lower usage of fuel pumps. However, if there are urban areas or large districts where, in the first few years of the market introduction of hydrogen fuel, there happens to be no hydrogen gas station, this can result in gaps in the fuel supply.

5.3.4.2. Influence of the conversion periods on conventional gas stations

Conversion of a gas station specifically means excavation of the ground at the gas station in order to check or renovate the underground fuel tanks and pipes. With a technical lifespan for the fuel tanks of about 25 years, this gives, assuming 125 conventional gas stations in Munich in 2020, an annual conversion rate of 5 gas stations. Modification of the gas stations to supply hydrogen would be possible according to GSID 1 or 3. As it can be assumed with a high degree of probability that in addition to normal gas station conversions (and therefore modification of the gas stations to supply hydrogen) favorably positioned conventional gas stations (on the edge of towns, on important arteries in urban areas) will be modified to supply hydrogen, there is a good reason to assume a development of the gas station infrastructure according to GSID 3, especially in the first few years. Taking into consideration the run-down phase above about 70 gas stations, this would yield a development of the gas station infrastructure according to GSID 7 (Figure 61).

5.3.4.3. Extent of investment in the conventional gas station infrastructure

Taking the example of the OMV mineral oil company (based in Austria), the following characteristics were determined:

- two conventional gas stations are commissioned each week in Eastern Europe (Rutten, 5.10.2002)
- in relation to the 420 gas stations currently operated by OMV in Eastern Europe, this means a 25 % annual growth in the number of gas stations (MÖIND, 2001, p. 19) (Own calculations, 2002)
- in relation to the 1,136 gas stations currently operated by OMV, this represents an annual growth of about 10 % in the number of gas stations
- the average investment volume for conversion or new-build roadside gas stations is between 0.73 and 1.10 million € (Frei, 1993, p. 58)

This permits the following conclusions for the development of a gas station infrastructure:

- the average investment volume for conversion or new-build of conventional roadside gas stations is far higher than for the initial modification of gas stations to supply hydrogen

[99] Discount gas stations offer conventional fuel at prices below those of normal fuel at brand-name gas stations. This is possible by passing on fuel purchase discounts to customers, storing smaller amounts of fuel and high fuel turnover at the gas station.

- the annual growth in the OMV gas station inventory of about 10 % also means an annual modification potential of 10 % of the conventional gas station inventory
- with reference to the future conventional gas station inventory of 13,000 gas stations in Germany, the figure 10 % represents an annual modification potential of 1,300 gas stations to supply hydrogen (assuming no investments in the purchase, new-build or conversion of further conventional gas stations)
- due to the modification of conventional gas stations to supply hydrogen, the investments for the conversion or new-build of conventional gas stations are reduced

If, instead of the possible 1,300 gas stations mentioned above only 500 gas stations per year are modified to supply hydrogen (i.e. a maximum of 40 % of the annual investments in the conversion or new-build of conventional gas stations are invested in the supply of hydrogen at gas stations), development of the gas station infrastructure would proceed according to GSID 3 or 7.

5.3.4.4. Winning new customers, image bearers

Additional aspects that should not be underestimated in the development of a gas station infrastructure are:

- **Winning new customers** by modifying gas stations to supply hydrogen, especially in the first few years of the market introduction of hydrogen as an alternative fuel
- **Knock-on business** in the shop and at car washes by winning new customers
- **Customer relations**, that is to say when a customer fills up his or her vehicle for the first time with hydrogen at a gas station, and continues to visit this gas station as he now knows the procedure for hydrogen refueling at this gas station
- **Creation of an environmentally friendly company image**

For the assumed development of the OWN hydrogen demand both according to the theoretical best possible fuel supply, the lowest cost principle and achievability by the mineral oil industry, gas station infrastructure development has to be achieved according to **GSID 7**.

The relationship of the typical time-based S-curve (Figure 14) to the development of the gas station infrastructure is essentially not transferable, as the gas stations are not products that can be purchased by the customer. The gas station infrastructure will orientate itself more and more and react to the development of the vehicle population for hydrogen as an alternative fuel and therefore to hydrogen demand. It also depends on how the mineral oil industry will react to the increasing hydrogen demand, in other words either with many modified gas stations and lower fuel pump usage or with fewer modified gas stations and higher fuel pump usage. However, there is a connection to the S-curve in that f fuel substitution follows the time-based data of the S-curve as a consequence of the vehicle population for the alternative fuel, gas station infrastructure development will react similarly to this with an S-shaped curve over the years.

5.4. Gas station infrastructure in German cities

In the first stage, the current conventional gas station inventory in the 72 German cities (population > 100,000 people) is determined (Aral, 2000, p. 294 f.). The second stage, in order to estimate gas station infrastructure development in German cities, contains a projection of the development of the modified number of gas stations in the scenarios for Munich onto German cities.

Approximate determination of the **conventional gas station inventory in German cities** takes place using the constant assumed ratio of ”motor vehicle population in the city/gas station inventory in the city”. Munich, which has an inventory of 809,710 motor vehicles (Aral, 2000, p. 294), is used as a reference city, and a forecast gas station inventory of 125 gas stations is used for 2020 (Chapter 5.3). The motor vehicle population in the city of Berlin is 1,386,959 vehicles (Aral, 2000, p. 294) and consequently 1.71 times the vehicle population of Munich. For Berlin this means an estimated 1.71 times more gas stations than Munich, i.e.

214 gas stations. If this calculation is performed for all German cities, we obtain an estimated inventory of 1,951 conventional gas stations in 2020.

5.4.1.Number of hydrogen gas stations in the first year

The HDD OWN for Munich (Appendix 3) suggest that in the first few years, the hydrogen demand will primarily be generated by taxicabs. For this reason it is appropriate to equip the required modified inventory of gas stations to supply hydrogen in the first year for a sufficient fuel supply of taxicabs.

For Munich, with a motor vehicle population of about 800,000 vehicles, this means at least 10 gas stations to supply hydrogen adequately to taxicabs in the first year (Chapter 5.3.1). Based on this requirement, the following assumptions are made to determine the required number of modified gas stations in the first year:

- 10 hydrogen gas stations per city with a motor vehicle population greater than 500,000 vehicles: in Germany, four cities and therefore 40 hydrogen gas stations
- 5 hydrogen gas stations per city with a motor vehicle population between 250,000 and 499,999 vehicles: in Germany, eight cities and therefore 40 hydrogen gas stations
- 4 hydrogen gas stations per city with a motor vehicle population less than 250.000 vehicles (one gas station for each point of the compass): in Germany, 60 cities and therefore 240 hydrogen gas stations

To guarantee the fuel supply of vehicles, above all in the first year, this means about 320 modified gas stations supplying hydrogen[100]. Due to the point concentration of the modified gas station inventory in an examination of the whole of Germany (one city can be considered to be one gas station location), this gives for the total German land area of 349,223 km^2 a theoretical land area to be supplied per city (= location of several hydrogen gas stations) of 4,850 km^2. This land area corresponds to a circle with a radius of about 39 km.

5.4.2.Scenarios for the development of a gas station infrastructure

On the basis of GSID 1 to 7, it was shown what form the annual increase in the inventory of modified gas stations could take for Munich (Chapter 5.3.1). To calculate the number of modified gas stations in German cities, the proportion of the annually modified gas stations in the total gas station inventory in Munich is left unchanged.

For example, the inventory of ten modified gas stations in 2006 in Munich represents a share of 8 % of the total inventory of 125 gas stations. 8 % of the total of 1,951 gas stations in German cities equates to 156 modified gas stations. This is less than the 320 modified gas stations determined for 2006 (Chapter 5.4.1). Account must be taken here of the effect that in cities where the share of modified gas stations of 8 % gives a value less than four, there must nevertheless be four modified gas stations in order to guarantee supply.

According to GSID 7, this gives Munich an inventory of 18 modified gas stations in the second year, corresponding to a share of 14.4 % of the city's total gas station inventory. Transferred to German cities, this share represents a modified gas station inventory of 281 gas stations and is still less than the 320 gas stations determined in Chapter 5.4.1 that are required to guarantee a sufficient fuel supply in German cities, above all in the first year. The consequence that at least four gas stations should be available in German cities in the first year takes effect over either a few or a greater number of years, depending on the speed of development of the gas station infrastructure in the reference city of Munich.

[100] As part of the California Fuel Cell Partnership (CaFCP), the forecast was made that for an alternative vehicle inventory of 2,000 to 3,000 vehicles there should be an inventory of about 100 modified gas stations (Bevilacqua, 2001, p. 3). In this paper, the inventory of hydrogen-powered taxicabs in Germany in the first year is 9,900 vehicles (Chapter 2.3.3), giving about 3,000 vehicles per modified gas station.

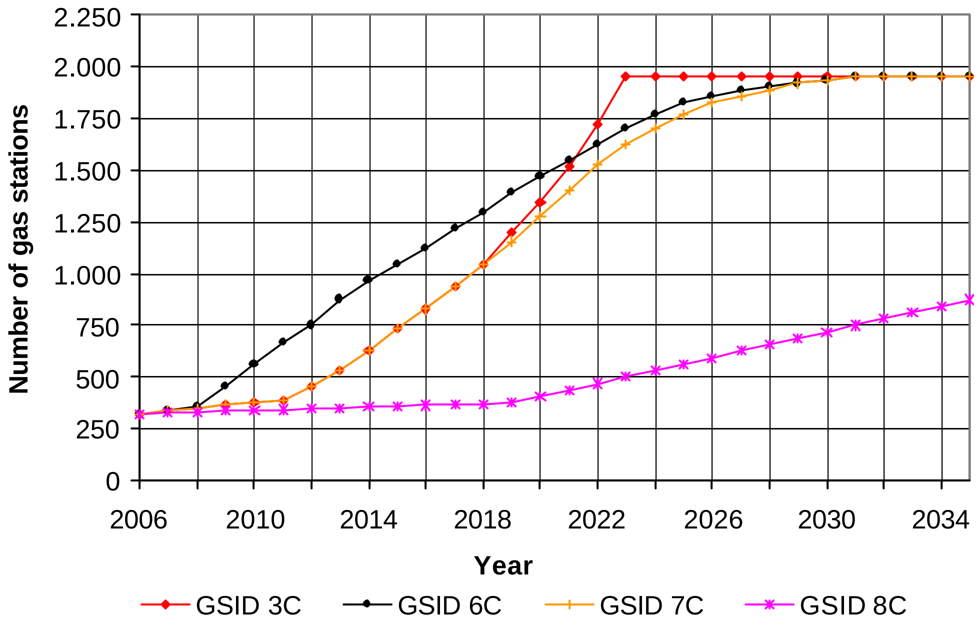
To solve this discrepancy, a linear increase in the gas station inventory starting in Year One with 320 modified gas stations and continuing to that modified gas station inventory is used at which the share in the inventory calculation for the reference city of Munich exceeds the figure of 320 modified gas stations for the first time. This assumption implies that the inventory of modified gas stations in the larger cities increases slightly and in the smaller cities, in which the share results in a modified gas station inventory of less than four, remains the same. If the share-based calculation results in the number of 320 modified gas stations being exceeded, these are realized in all 72 German cities.

The following scenarios are taken into consideration in the procedure described above for the projection of the modified gas station inventory in Munich onto the development of a gas station infrastructure in all German cities (Figure 68, gas station inventory development (GSID), C = city):

- **GSID 3C:** Specific gas station costs for gas station infrastructure development scenarios in Munich from 2006 to 2035
- **GSID 6C:** rapid development of a gas station infrastructure
- **GSID 7C:** identical to GSID 3C up to 2018, thereafter consideration of an run-down phase (Chapter 5.3.1)

To take into account very slow gas station infrastructure development in Germany (see GSID 3+8 in Chapter 5.5), a correspondingly slow development in German cities is also required. This case is covered by GSID 8C of gas station infrastructure development in German cities. Starting with 320 modified gas stations in 2006, there follows a continuous annual increase in the modified gas station inventory of four gas stations until 2018, and then by 31 gas stations annually.

Figure 68: Development scenarios for the modified gas station inventory for hydrogen supply in German cities from 2006 to 2035



GSID = Gas station infrastructure development
Source: Own calculations, 2002

5.5. Gas station infrastructure in Germany

To create a scenario of the build-up of a gas station infrastructure in Germany, HDD OWN for Germany is used (Chapter 2.3.4.3). Using this method of examination, the time reference is included in the scenarios of the gas station infrastructure.

5.5.1. Scenarios for the development of a gas station infrastructure

The scenarios differ fundamentally with regard to

- the development of the modified number of gas stations over the years in German cities, outside of them (in rural areas) and on the motorways/ freeways (Figure 69 and Figure 70)
- the development of the number and usage of fuel pumps at modified gas stations (Figure 71)

Selection of the development of the number and usage of fuel pumps at the modified gas stations over the years gives the inventory of modified gas stations based on the HDD OWN, and therefore the development of the gas station infrastructure in Germany.

The nomenclature of the scenario types is explained using "GSID 1+6" as an example:

- 1 stands for GSID 1 of the development of a gas station infrastructure in Germany
- 6 stands for GSID 6 of the development of a gas station infrastructure in German cities according to Chapter 5.4.2

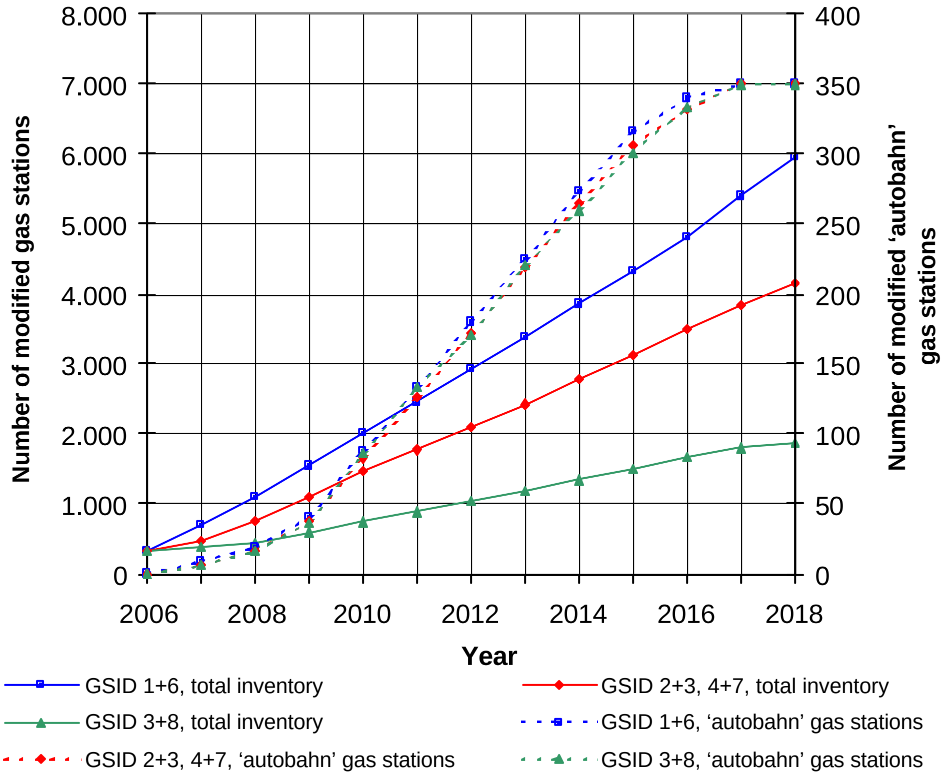
By choosing the most realiztic number and usage of fuel pumps, this yields characteristics for the development of a **gas station infrastructure on German motorways/freeways ('autobahns')** that are valid for the scenarios being examined here:

- in 2006, no modification of 'autobahn' gas stations to supply hydrogen, only modification of gas stations in urban areas
- development of the gas station infrastructure up to 2018 with an annual inventory development in the form of an S-curve
- development of the number and usage of fuel pumps over the years identical to the data for roadside gas stations

The scenarios for the development of a gas station infrastructure in Germany have the following characteristics (Figure 69 and Figure 70). In **GSID 1+6**, rapid development of a gas station infrastructure in rural areas as well as in German cities is assumed. The national coverage of about 1,500 modified gas stations will be reached by 2009. An average speed of development of a gas station infrastructure is taken into account in **GSID 2+3**. In **GSID 3+8** only around 500 conventional gas stations are modified by 2009. From 2009, an annual increase of 125 modified gas stations is assumed. The development of a gas station infrastructure in rural areas takes place very hesitantly - only around 1,200 gas stations are modified after 13 years. **GSID 4+7** takes place identically to GSID 2+3, although from the start with two fuel pumps per modified gas station[101].

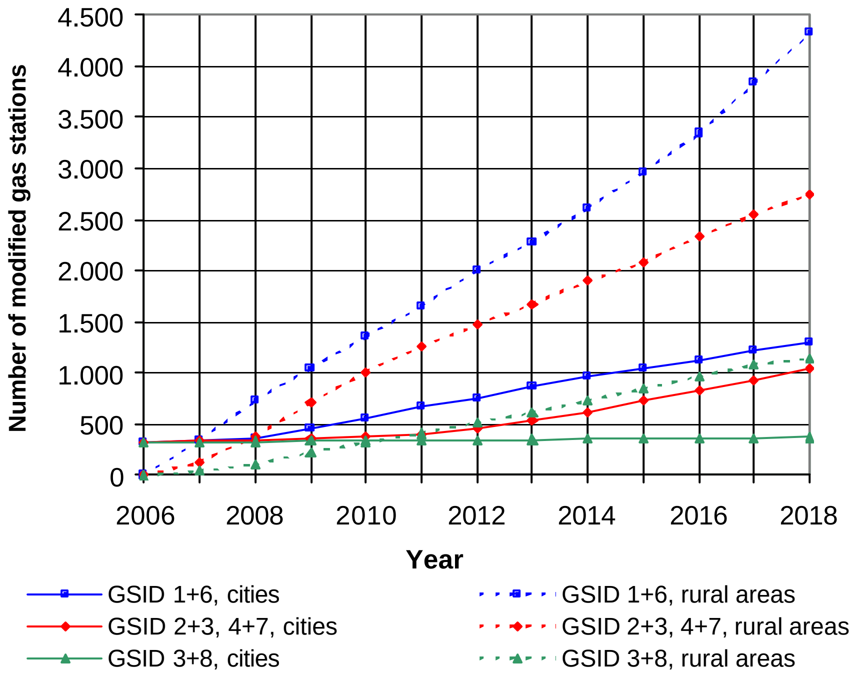
[101] The petroleum industry see at least two fuel pumps per modified gas station from the start (TES, 2001, p. 34).

Figure 69: Development scenarios for the inventory of modified gas stations supplying hydrogen, in an examination of all gas stations and 'autobahn' gas stations only in Germany from 2006 to 2018



GSID = Gas station infrastructure development
Source: Own calculations, 2002

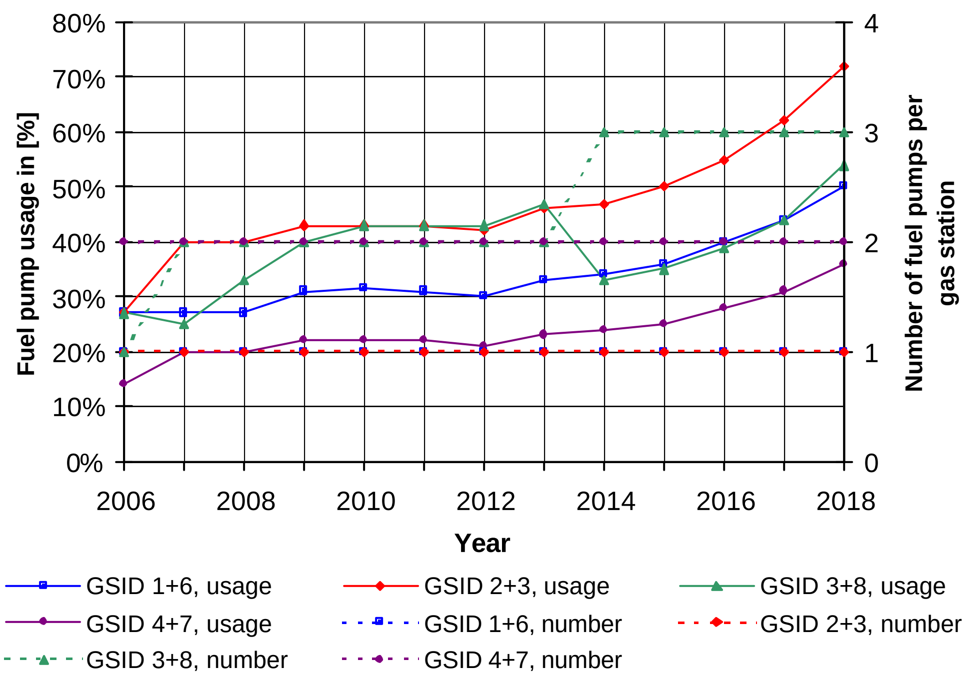
Figure 70: Development scenarios for the inventory of modified gas stations for supplying hydrogen in German cities and in rural areas from 2006 to 2018



GSID = Gas station infrastructure development
Source: Own calculations, 2002

The development of the **number and usage of fuel pumps** in Figure 71 shows that the quicker the development of a gas station infrastructure takes place, the longer it takes for a correspondingly high usage of fuel pumps to be achieved.

Figure 71: Number and usage of fuel pumps per modified gas station for gas station infrastructure development scenarios in Germany from 2006 to 2018



GSID = Gas station infrastructure development
Source: Own calculations, 2002

High usage of fuel pumps at the modified gas stations is desirable from the start, as specific hydrogen costs fall with increasing usage. In GSID 1+6, a usage of only around 50 % is reached by 2018. In order for the demanded quantity of hydrogen according to HDD OWN to be supplied to customers together with a very slow development of the gas station inventory, the modified gas stations must be fitted with a higher number of fuel pumps for supplying hydrogen, see GSID 3+8 (increase in the number of fuel pumps to two per modified gas station as early as 2007).

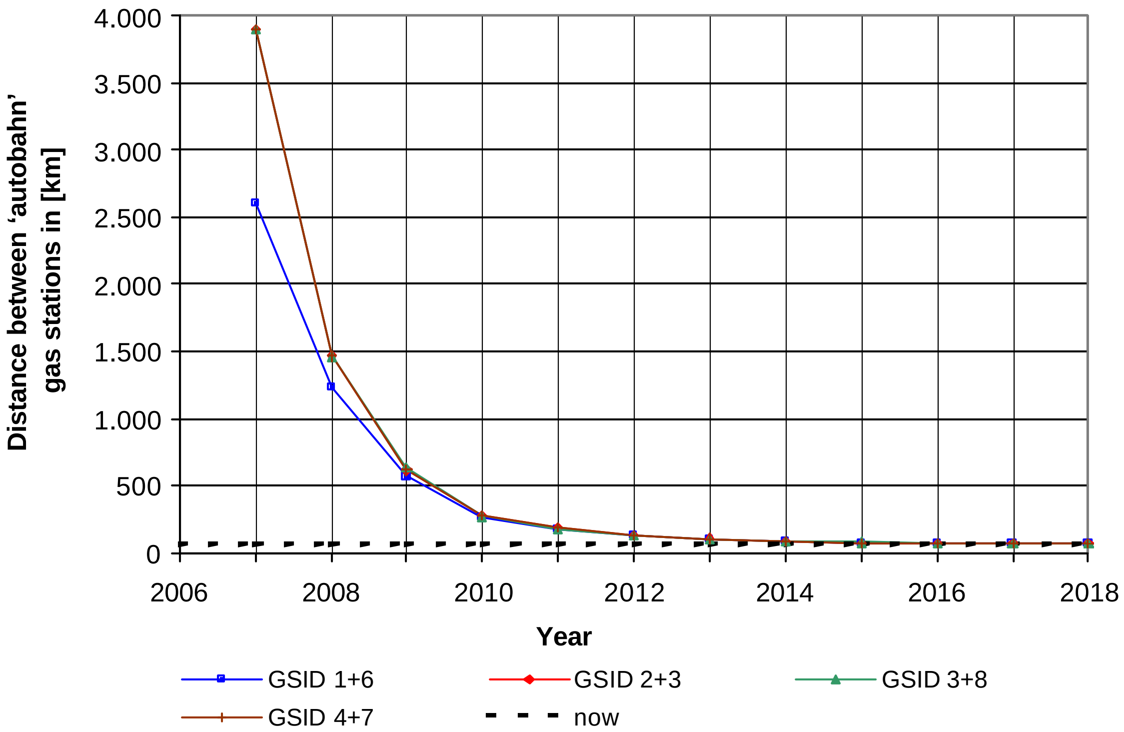
From the comparison of the development of fuel pump usage in Figure 71 with that in Figure 62, it can be seen that the U-shaped curve of fuel pump usage in the period 2010 to 2020 for Munich is no longer present in the nationwide examination. The reason for this lies in the pattern of hydrogen demand, which stagnates for Munich in the period 2010 to 2015, it having been assumed that the taxicabs would be replaced by alternative vehicles by 2010 (Chapter 5.3.1). In the national examination there is not such a strong stagnation of the hydrogen demand during this period, as the proportion of taxicabs in the country as a whole population is lower than in Munich.

As well as this curve, the level of fuel pump usage also differs in 2006. Fuel pump usage for Munich in 2006 is 50 % and 27 % for Germany. The difference arises because the national number of modified gas stations in 2006 is determined by taking into account the number of cities. At least four modified gas stations were assumed to be in cities with a vehicle population of less than 250,000 in 2006 (one at each point of the compass), although according to a calculation of the ratio for Munich, a number less than four is likely to available (Chapter 5.4.1). The fuel pump usage figure of 27 % in 2006 therefore represents the average national figure for modified gas stations.

5.5.2. Comparison according to geographical criteria

A comparison of scenarios relating to the **average length of motorway/ freeway ('autobahn') between two modified gas stations** is shown in Figure 72. The coverage of 'autobahns' is achieved after only about five years (modified inventory of 88 'autobahn' gas stations, distance between two modified 'autobahn' gas stations < 290 km, Chapter 5.2.2). The current average distance of around 67 km between two modified 'autobahn' gas stations in the conventional gas station infrastructure is achieved in all scenarios by 2015.

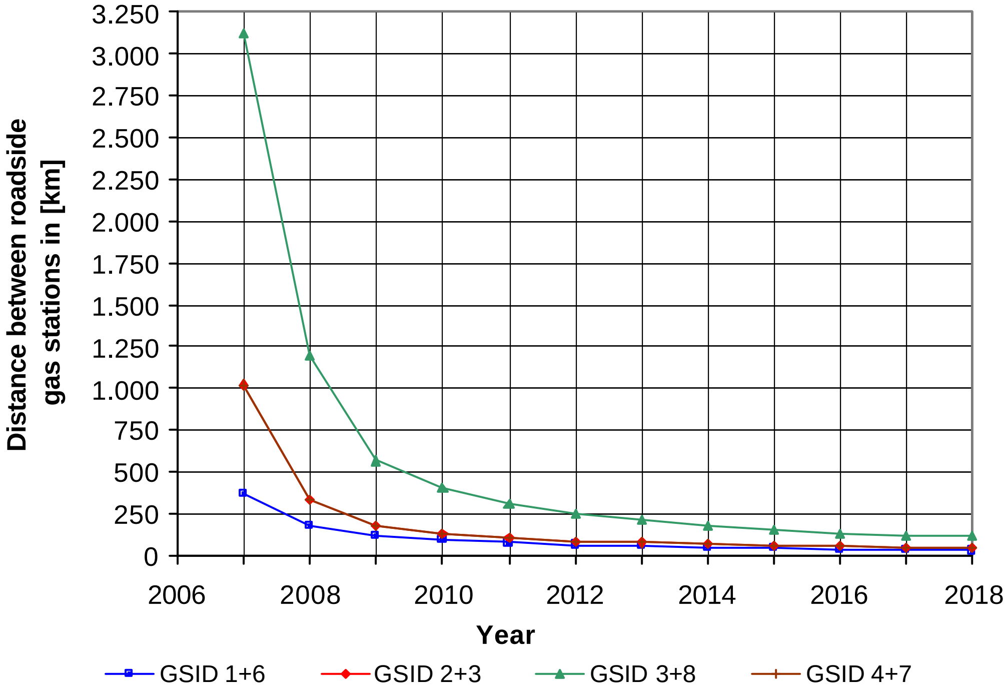
Figure 72: Average distances between two modified 'autobahn' gas stations for gas station infrastructure development scenarios in Germany from 2006 to 2018



GSID = Gas station infrastructure development
Source: Own calculations, 2002

A comparison of scenarios regarding the **average length of road between two modified roadside gas stations in rural areas** is shown in Figure 73. Rapid development of a gas station infrastructure according to GSID 1+6 already achieves a coverage of about 440 modified gas stations by 2008 (average distance between two modified gas stations < 290 km, Chapter 5.2.2).

Figure 73: Average distances between two modified roadside gas stations in rural areas for gas station infrastructure development scenarios in Germany from 2006 to 2018



GSID = Gas station infrastructure development
Source: Own calculations, 2002

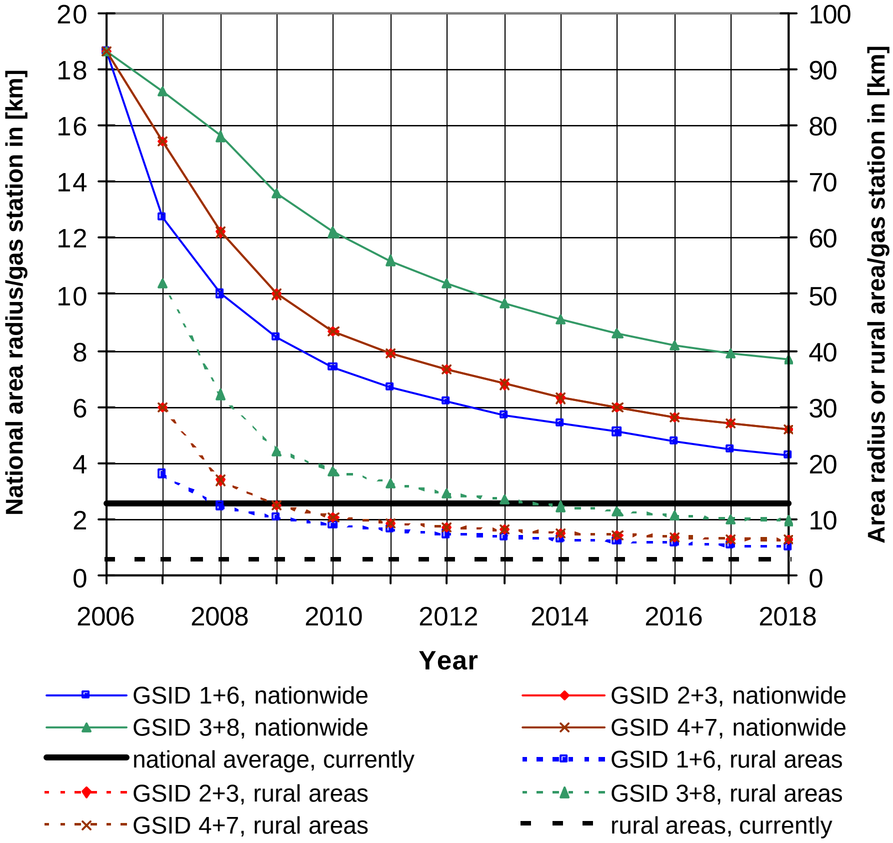
Slow development of a gas station infrastructure according to GSID 3+8 only reaches the coverage of about 440 modified gas stations from 2011 on. With this slow development there are very high distances between the modified gas stations, particularly in the first four years, which can have a disadvantageous effect on customer acceptance.

The average distance between two modified roadside gas stations of less than 50 km will be achieved in all scenarios (except GSID 3+8) from 2017. By comparison, the current average distance between two conventional roadside gas stations is given as 9.2 km (Chapter 5.2.1).

The development of the **radius of the supply area per modified gas station**, determined as a **regional average**[102] as well as for **rural areas**[103] only, is shown in Figure 74. Here it is very clear that too slow a development of a gas station infrastructure e.g. according to GSID 3+8, should be avoided for reasons of supply certainty and customer acceptance. Starting with a regional radius of about 19 km in 2006, this results in a rapid reduction of the radius to below 6 km per gas station for all scenarios (except for GSID 3+8). By 2011, the radius for the rural area is already less than 2 km.

[102] Total area of Germany of 349,223 km^2 (excluding lakes), divided by the inventory of modified gas stations.
[103] Total area of Germany of 349,223 km^2 (excluding lakes), divided by the inventory of modified gas stations in rural areas.

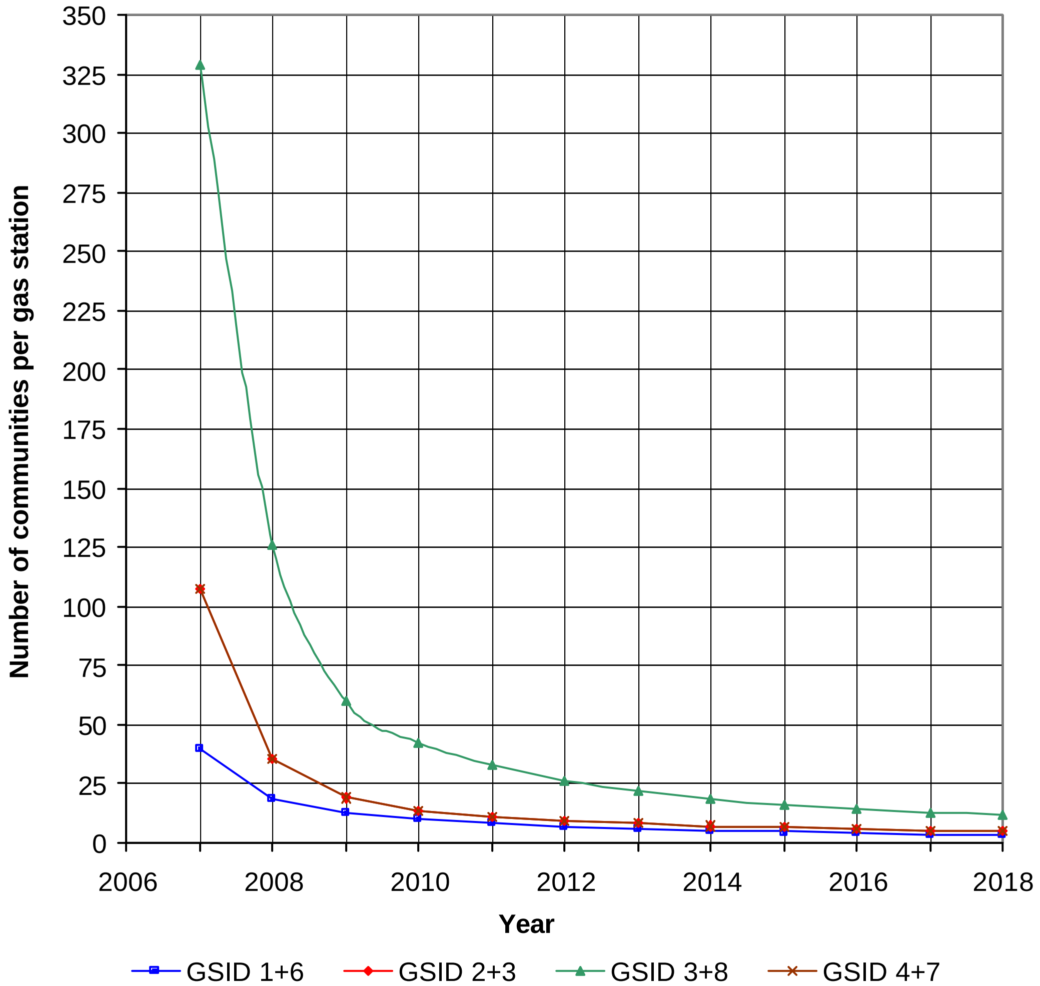
Figure 74: Average radii at national level and for rural regions of the supply area only per modified gas station for gas station infrastructure development scenarios in Germany from 2006 to 2018



GSID = Gas station infrastructure development
National examination = total area of Germany divided by the modified inventory of gas stations in Germany.
Rural area = total area of Germany divided by the modified inventory of gas stations in rural areas.
Source: Own calculations, 2002

A comparison that can more easily be visualized is the **number of communities to be supplied per gas station in rural areas**. The current density of gas stations in rural areas (without those in cities and on 'autobahns') is approximately **one per community**. The same findings can be essentially deduced from the curves in Figure 75, as already in Figure 74.

Figure 75: Average number of communities to be supplied per modified gas station in rural areas for the gas station infrastructure development scenario in Germany from 2006 to 2018



GSID = Gas station infrastructure development
Source: Own calculations, 2002

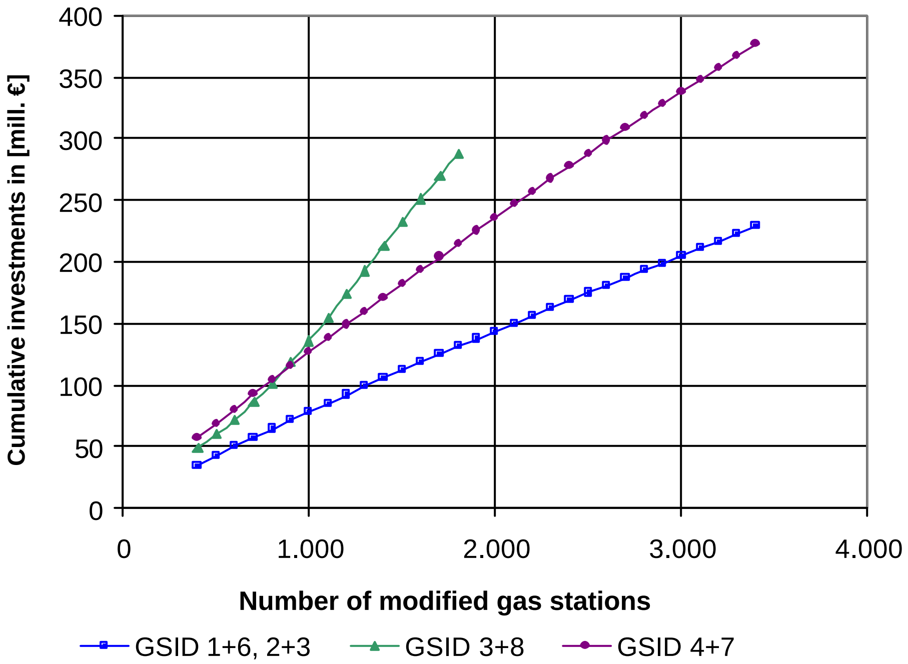
5.5.3.Comparison according to economic criteria

From the comparison of **cumulative investments related to the inventory of modified gas stations** in Figure 76, it can be seen that these run almost identically for GSID 1+6 and 2+3 up to an inventory of about 3,500 gas stations, since up to that level there is no increase in the number of fuel pumps at the modified gas stations. However, there is a rapid increase in investments in GSID 3+8 and 4+7 right from the start compared with the remaining scenarios, as a consequence of the increase in the number of fuel pumps at the modified gas stations.

The increase in the number of fuel pumps per modified gas station essentially causes lower investments than the initial modification of a conventional gas station to supply hydrogen. Due to the number of gas stations already modified, the investments required for an increase in the number of fuel pumps are, however, higher at many gas stations (see GSID 3+8 and 4+7) than the investments in the initial modification of a smaller number of conventional gas stations to supply hydrogen (see GSID 1+6 and 2+3).

To achieve the coverage of 1,500 modified gas stations, about 120 million € are needed for GSID 1+6 and 2+3, about 230 million € for GSID 3+8 and about 180 million € for GSID 4+7 (Note: there are different periods for achieving the complete modification of the gas stations in these scenarios, therefore different hydrogen fuel sales and number of fuel pumps per modified gas station[104]).

Figure 76: Cumulative investments in gas station modification depending on the modified inventory for the gas station infrastructure development scenarios in Germany from 2006 to 2018



GSID = Gas station infrastructure development
Source: Own calculations, 2002

A comparison of **cumulative investments with reference to a common timescale of 2018**, is shown in Figure 168, Appendix 7. The highest cumulative investments of 450 million € are incurred for the realization of a gas station infrastructure according to GSID 4+7, due to the initial availability of two fuel pumps per modified gas station. The quickest development of a gas station infrastructure takes place with GSID 1+6, but because of the assumed initial number of one pump per modified gas station, the cumulative investments to 2018 are about 375 million € and therefore lower than for GSID 4+7. For a slow development of a gas station infrastructure according to GSID 3+8, the cumulative investments up to 2018 are about 300 million €, which due to an increase in the number of fuel pumps from two to three per modified gas station in 2014 are higher than for GSID 2+3 at about 275 million €.

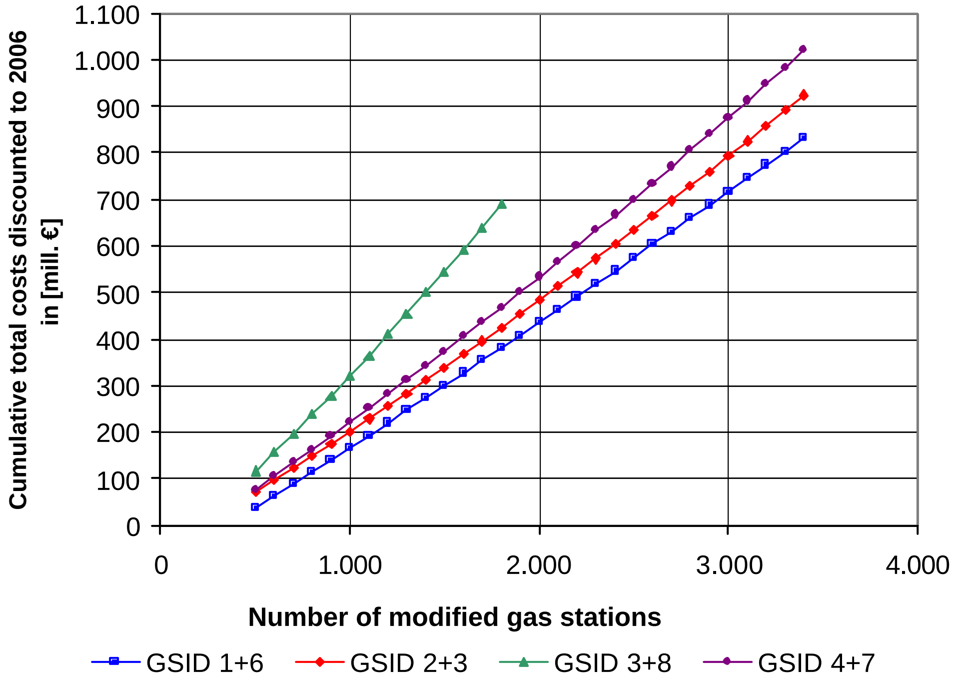
The development of **cumulative total costs, discounted to 2006, in relation to the modified gas station inventory** (in this section referred to as "total costs" and made up of investment annuities including the rental costs of LH_2 storage tanks and operating and maintenance costs) using the scenarios for the modification of gas stations in Germany, is shown in Figure 77. As already shown in the examination of the total costs for Munich, it is true in this case as well that the quicker the development of the gas station infrastructure, the smaller the total costs (Note: with reference to the time axis, this gives the highest total costs, Figure 79). For example, the modification of 1,500 gas stations will be achieved in four years according to GSID 1+6, so that, as a consequence of the short period of time, lower total annual annuities (from investments and rental costs of LH_2 storage tanks) arise than

[104] For a better understanding of the connections amongst the scenarios between investments and the number of modified gas stations, Figure 69 includes for reasons of clarity a horizontal line for the number of gas stations examined; its intersections with the scenario curves yield the timescale on the x-axis.

according to GSID 4+7, where the modification of 1,500 gas stations requires five years and the sum of annual annuities is much higher.

As already mentioned, a major influence on the total costs is exerted by the rental costs for the LH_2 storage tanks at the modified gas stations (and therefore also a major influence on the total costs according to the number of modified gas stations). The increase in the number of fuel pumps at the modified gas stations has only a smaller influence on the total costs. The very slow development of the gas station infrastructure according to GSID 3+8 requires a higher number of fuel pumps per modified gas station and therefore high investments and total costs).

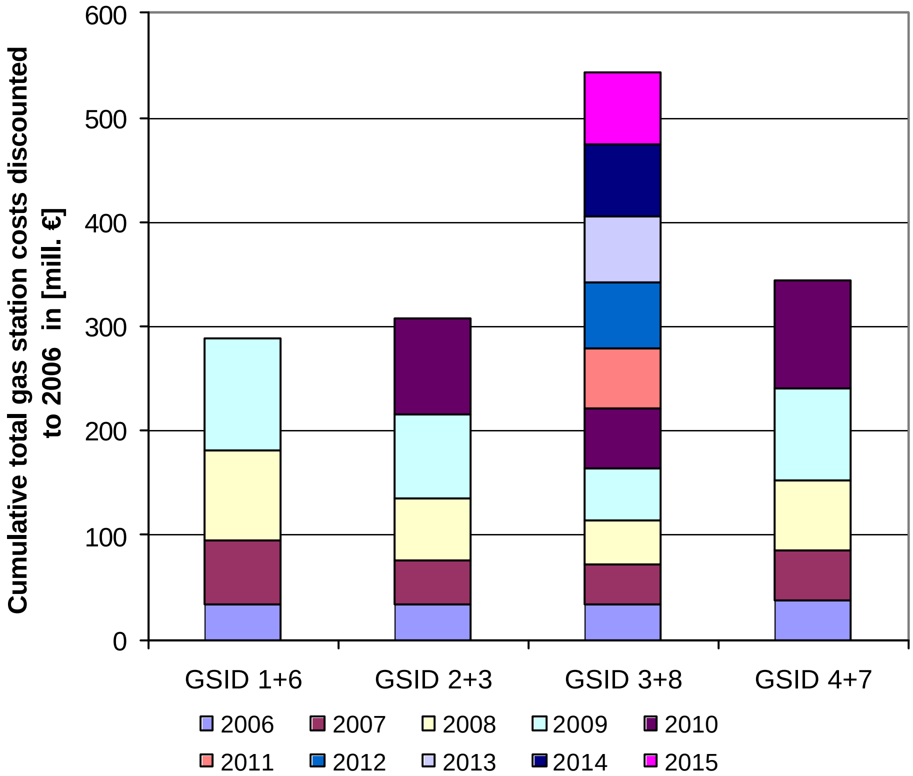
Figure 77: Cumulative total gas station costs, discounted to 2006, depending on the modified inventory for the gas station infrastructure development scenarios in Germany from 2006 to 2018



Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development
Source: Own calculations, 2002

In the development of the gas station infrastructure, considerable importance is given to the short-term total cost arising until a coverage of about 1,500 modified gas stations (Figure 78) is achieved. In GSID 1+6, this coverage is reached in 2009 (1,543 gas stations), in GSID 2+3 and 4+7 in 2010 (1,470 gas stations) and in GSID 3+8 in 2015 (1,506 gas stations). From the scenario comparisons it can be deduced that rapid development of a gas station infrastructure causes high total costs in the individual years. Wheras slow development of a gas station infrastructure causes lower total costs in the individual years, in absolute terms it results in the highest total costs due to the period of time required to reach coverage (see GSID 3+8).

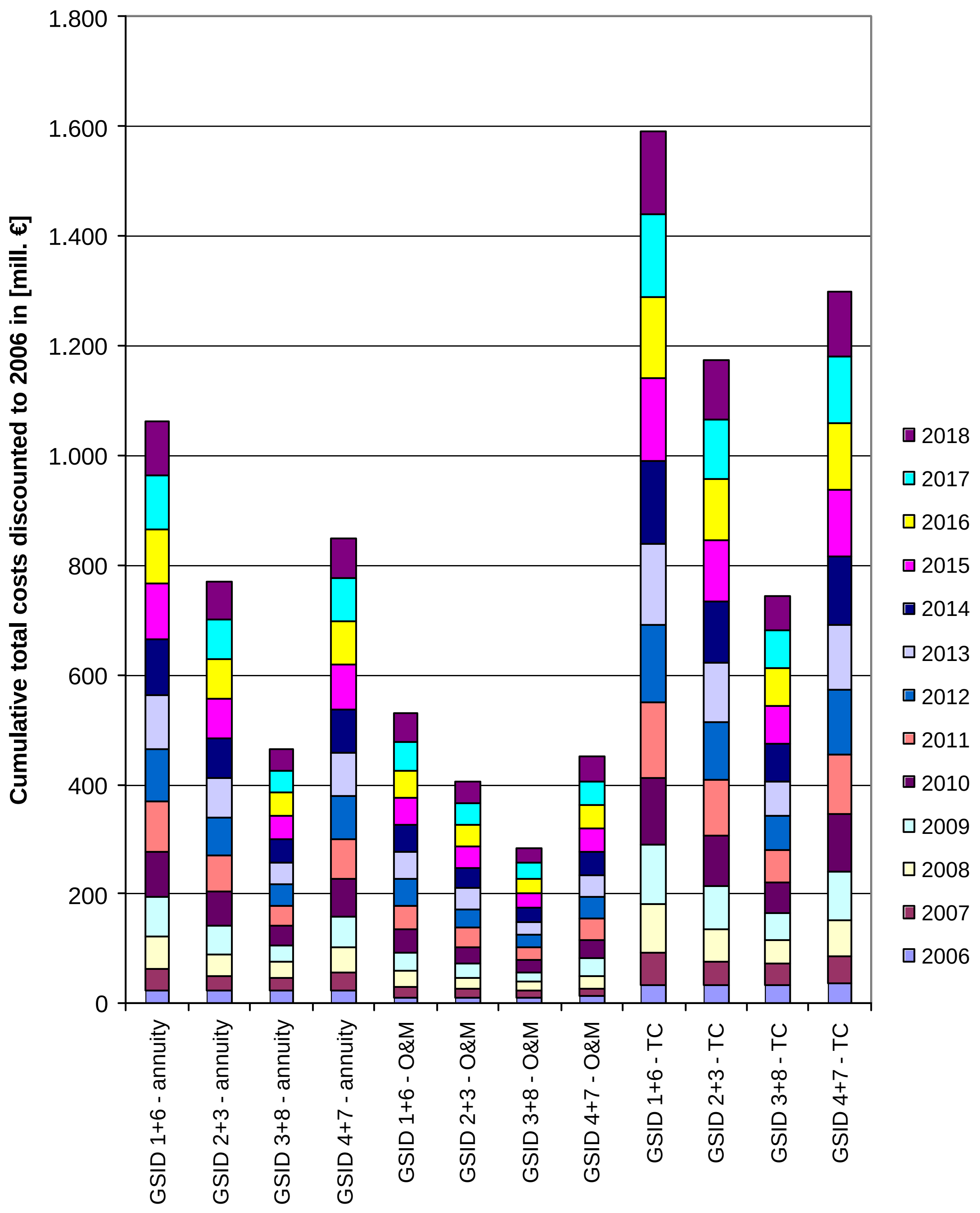
Figure 78: Cumulative total gas station costs, discounted to 2006, until coverage of about 1,500 gas stations for gas station infrastructure development scenarios in Germany.



Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development
Source: Own calculations, 2002

Development of the **total costs until 2018** is shown in Figure 79 for the sake of completeness. Explanations of this are provided in Figure 77 and Figure 78.

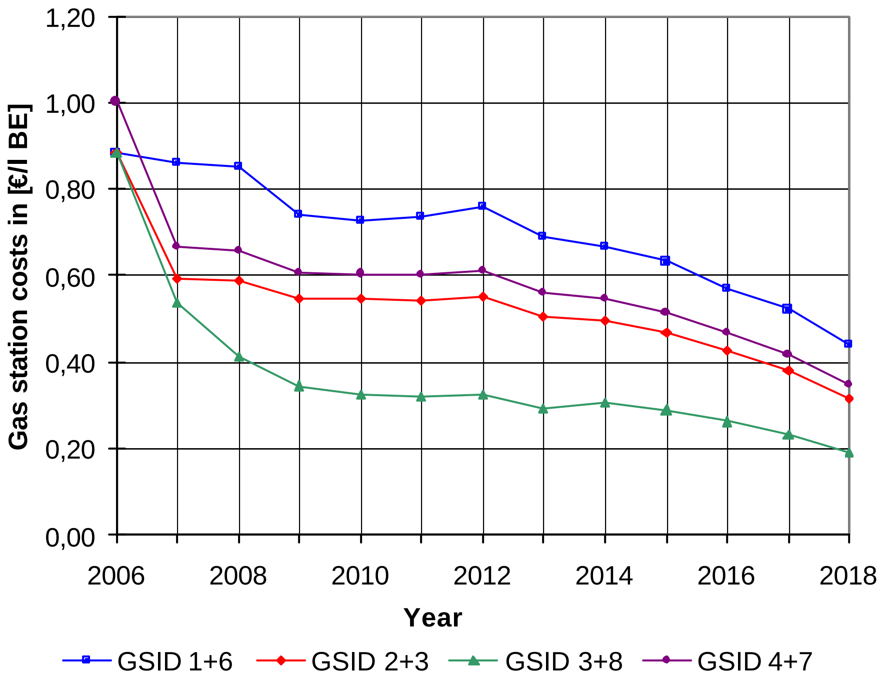
Figure 79: Cumulative annuities (annuity), operating and maintenance costs (O&M) and total gas station costs (TC), discounted to 2006, for the gas station infrastructure development scenarios in Germany from 2006 to 2018



Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development, O&M = Operating and maintenance costs, TC = Total costs.
Source: Own calculations, 2002

In addition to the cumulative investments and total costs, the pattern of **specific gas station costs[105] in €/l GE** is an important criterion (Figure 80). It can essentially be assumed that the slower the development of a gas station infrastructure proceeds, the lower the specific gas station costs (assuming higher fuel pump usage, see GSID 3+8). In addition, a higher number of fuel pumps per modified gas station starting from two pumps in GSID 4+7, compared with one fuel pump in GSID 2+3 (otherwise the same development of the infrastructure), gives rise to specific gas station costs which in 2006 are about 0.10 €/l GE higher than in GSID 2+3. However, as time progresses these additional costs decrease.

Figure 80: Specific gas station costs for gas station infrastructure development scenarios in Germany from 2006 to 2018



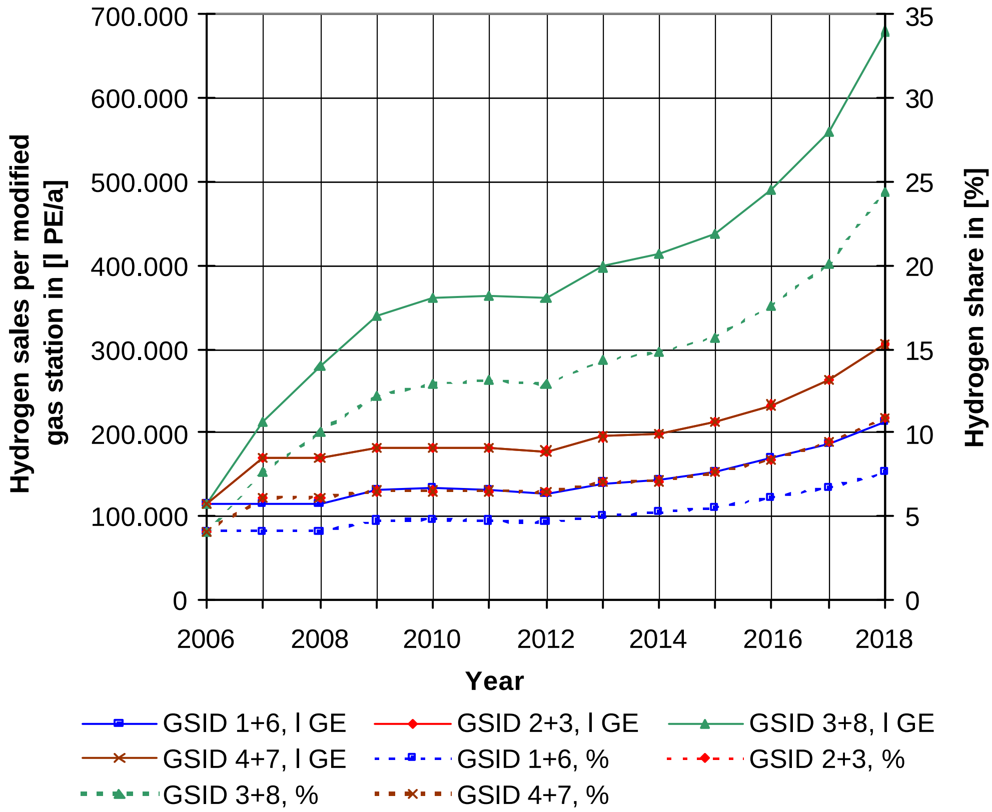
Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development
Source: Own calculations, 2002

Figure 81 is a representation of fuel substitution at the modified gas stations in Germany, i.e. the level of the average share of annual hydrogen fuel sales per modified gas station of in relation to total annual conventional fuel sales (without fuel substitution). The following conclusions are obtained:

- with rapid development of the gas station infrastructure and lower fuel pump usage, based on annual hydrogen fuel sales of about 100,000 l GE in 2006, we obtain annual sales of about 200,000 l GE in 2018 (corresponding to approx. 8 % of current annual conventional fuel sales per gas station, see GSID 1+6)
- a moderate rate of development of the gas station infrastructure yields annual hydrogen sales of about 300,000 l GE in 2018 (corresponding to approx. 11 % of current annual conventional fuel sales per gas station, see GSID 2+3 and 4+7))
- a low rate of development of the gas station infrastructure with a correspondingly higher usage of the fuel pumps yields annual hydrogen sales of about 700.000 l GE in 2018 (corresponding to approx. 24 % of current annual conventional fuel sales per gas station, see GSID 3+8)

[105] Specific gas station costs include the costs for the new-build or conversion of a conventional gas station and the operating and maintenance costs at the gas station. Not included are the costs of hydrogen production and distribution from the production plants to the gas stations.

Figure 81: Share of the annual hydrogen supply at a modified conventional gas station in liters of gasoline equivalent [l GE] and as a percentage [%] of total annual conventional fuel sales at a roadside gas station, for gas station infrastructure development scenarios in Germany from 2006 to 2018



GSID = Gas station infrastructure development, GE = gasoline equivalent.
Source: Own calculations, 2002

5.5.4.Comparison of the scenarios

From the scenario comparison in Chapters 5.5.1 to 5.5.3, it appears that each criterion taken into account results in a different scenario to be realized as the optimum for fulfilling the criteria. In order to be able to select one scenario as the optimum for developing a gas station infrastructure, taking into consideration all the criteria, there is initially a point analysis of the individual scenarios arrived at by examining the individual criteria, followed by a combination of these individual point analyses with a weighting of the criteria according to their importance for the creation of the gas station infrastructure. Points are awarded from 1 to 4, with 1 point to the best and 4 points to the worst scenario. The specific gas station costs are an important criterion for the customer, and are given the highest weighting factor of 3. The results of the analysis are shown in Table 30[106]. The best concept has the lowest total number of points.

[106] An explicit analysis of the points associated with the criteria for development of the number of gas stations and fuel pump utilization was not carried out, as these are reflected in the "Area radius" and "Gas station costs" criteria. For the criterion "Area radii per gas station" only the national average was analysed, as an additional assessment of the criterion "Area radii in rural areas" would give an disproportionate weighting to the total number of points. The criterion of "achievablility" is not addressed here, as this is examined after the assessment.

Table 30: Analysis of defined criteria of the gas station infrastructure development scenarios in Germany from 2006 to 2018

Criterion	GSID 1+6	GSID 2+3	GSID 3+8	GSID 4+7	Weighting
Distance between roadside gas stations	1	2	4	2	2
Average area radius nationally	1	2	4	2	1
Investment by number, short-term [1)]	1	1	4	3	1
Investment by number, long-term [2)]	1	1	4	3	1
Investment by time, short-term [3)]	3	2	1	4	2
Investment by time, long-term [4)]	3	1	2	4	1
TC by number, short-term [5)]	1	2	4	3	1
TC by number, long-term [6)]	1	2	4	3	1
TC by time, short-term [7)]	4	2	1	3	2
TC by time, long-term [8)]	4	2	1	3	1
Specific gas station costs	4	2	1	3	3
Total number of points	**49**	**29**	**46**	**61**	

[1)] up to 1,500 gas stations
[2)] up to 3,400 gas stations
[3)] cumulative investments after five years
[4)] cumulative investments after 12 years
[5)] TC = total costs, up to 1,500 gas stations
[6)] TC = total costs, up to 3,400 gas stations
[7)] TC = total costs, up to five years
[8)] TC = total costs, up to 12 years
GSID = Gas station infrastructure development
Source: Own calculations, 2002

From the analysis, it can be derived that too rapid development of a gas station infrastructure due to a small gas station usage in the first few years, and the high total costs associated with this in the short term, should be avoided (see GSID 1+6). Slow development of a gas station infrastructure according to GSID 3+8 does not have too negative an impact on the number of points (primarily because the specific gas station costs, which have the highest weighting, are very low and the long-term investments and total costs are also at a lower level), although the short and medium-term investments and total costs assume the highest values (there will in all probably be a lack of customer acceptance for the purchase of a hydrogen-powered vehicle if a corresponding gas station infrastructure does not exist or is not constructed in an appropriate period of time).

The points difference between GSID 2+3 with 29 points and GSID 4+7 with 61 points arises only because of the effects of a higher number of fuel pumps per modified gas station according to GSID 4+7 on the investments, the total costs and the specific gas station costs (both scenarios exhibit an identical gas station infrastructural development).

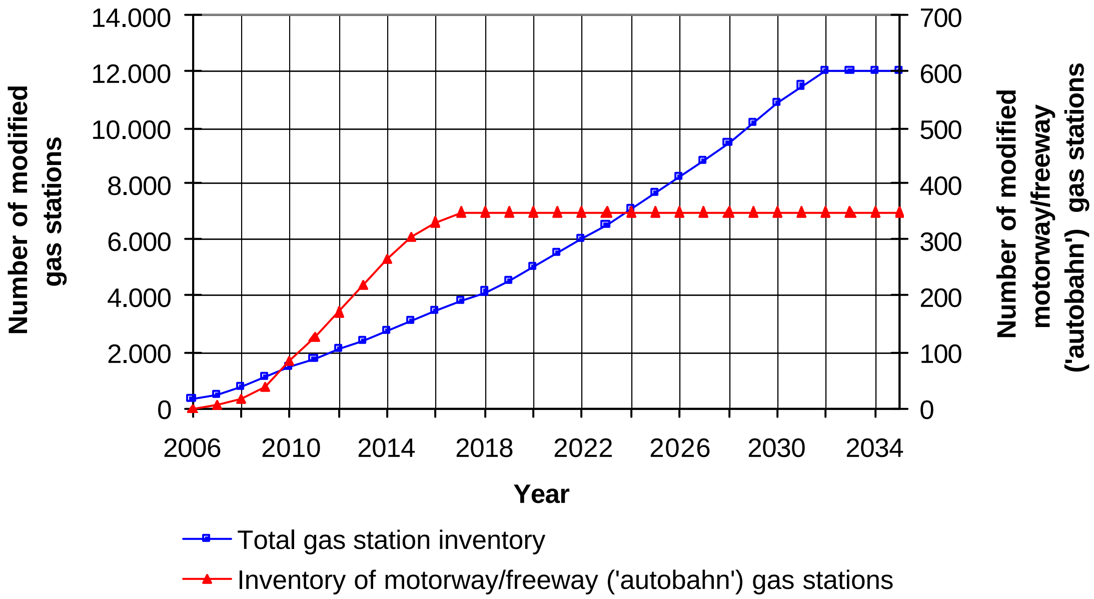
Additional aspects influencing the development of a gas station infrastructure, and those that are difficult to calculate, are shown in Chapter 5.3.4.

For further examination in this paper, the data for GSID 4+7 are used. From the overall examination GSID 2+3 appears to be the optimum solution, although the petroleum industry envisages at least two fuel pumps per modified gas station right from the start, so that it is possible that gas station infrastructural development will take place according to GSID 4+7. As the following chapter contains an overall examination from well to vehicle fuel tank up to 2035, a projection of gas station infrastructure development according to GSID 4+7 from 2018 to 2035 now follows.

5.5.4.1. Projection of the chosen scenario up to 2035

The increase in the **number of modified gas stations up to 2035** in Germany according to GSID 4+7 is shown in Figure 82. The S-curve of this development in Germany is not fully formed, as the demonstration project phase with a few dozen gas stations in the years following a new production launch as well as the saturation phase following successful market penetration of the product are not dealt with in this paper.

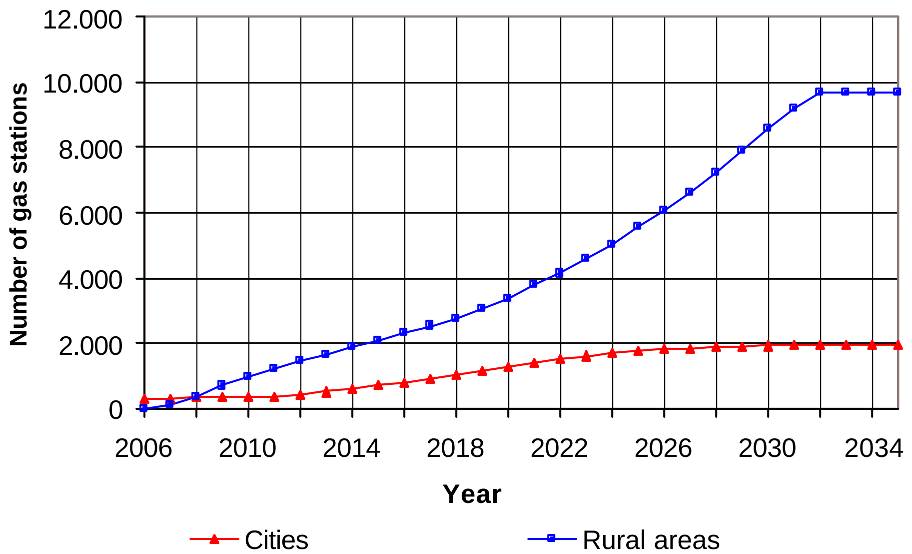
Figure 82: Favored development of the gas station inventory (GSID 4+7) in an examination of the total gas station inventory and the inventory of motorway/ freeway ('autobahn') gas stations in Germany from 2006 to 2035



Source: Own calculations, 2002

Figure 83 shows how the number of **modified gas stations in rural areas and in German cities** develops according to GSID 4+7. Corresponding to the time needed for complete modification of all rural gas stations in Germany in 2032, the complete modification of all gas stations in German cities is also achieved.

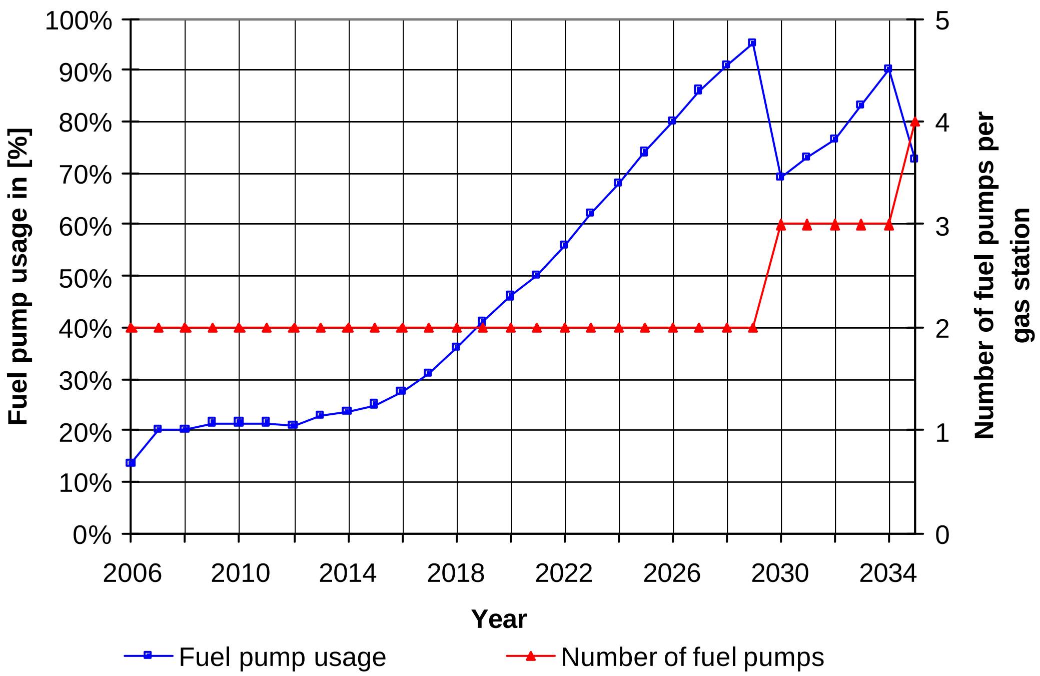
Figure 83: Favored development of the gas station inventory (GSID 4+7) in German cities and rural areas from 2006 to 2035



Source: Own calculations, 2002

The development of **fuel pump usage and number** per modified gas station according to GSID 4+7 is shown in Figure 84. With each increase in the number of fuel pumps per modified gas station there is a corresponding drop in average fuel pump usage. For the period 2006 to 2029, two fuel pumps per modified gas station are sufficient to supply hydrogen fuel. When complete modification of all conventional gas stations in Germany is achieved in 2023, there will be three fuel pumps per gas station with a fuel pump usage between 75 and 80 %. The further increase in hydrogen demand beyond 2032 according to HDD OWN (Chapter 2.3.4.3) will be balanced by the increase in the number of fuel pumps at the gas stations. Consequently, in 2035 there should already be an increase in the number of fuel pumps at all gas stations to four, in order to satisfy increasing hydrogen demand or ensure that fuel pump usage does not exceed 100 %.

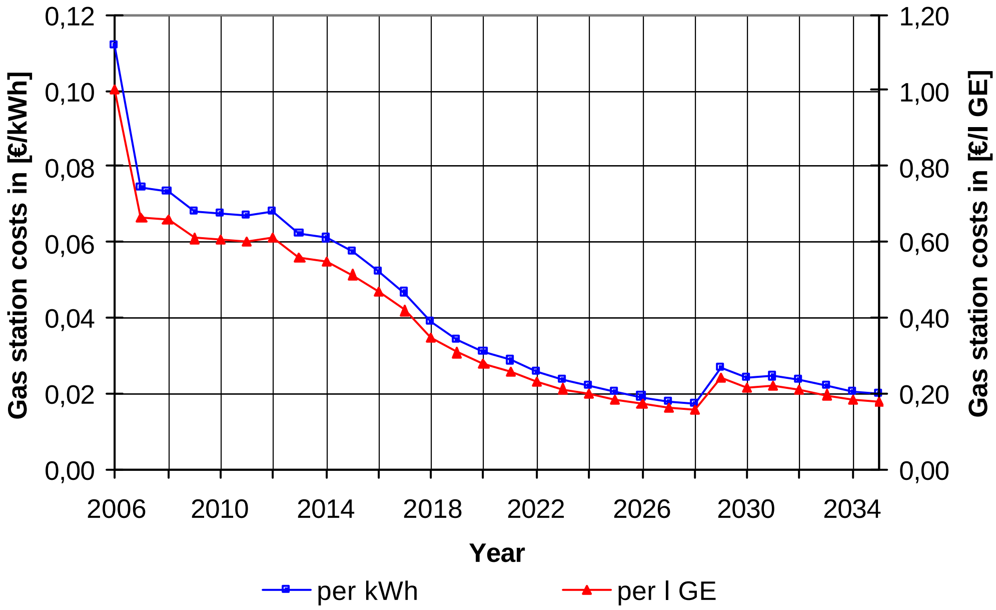
Figure 84: Number and usage of fuel pumps per modified gas station for the favored development of the gas station inventory (GSID 4+7) in Germany from 2006 to 2035



Source: Own calculations, 2002

Development of **specific gas station costs in €/kWh LH_2 or €/l GE** for GSID 4+7 is shown in Figure 85. The specific gas station costs up to the complete modification of all gas stations can be reduced from approx. 0.15 €/kWh or 1€/l GE in 2006 to approx. 0.02 €/kWh or 0.2 €/l GE in 2035. After about 20 years, the specific gas station costs are only about 20 % of those incurred in 2006. The increase in specific gas station costs in 2009 is based on the requirement for a second 80,000 l LH_2 storage tank at the modified gas stations.

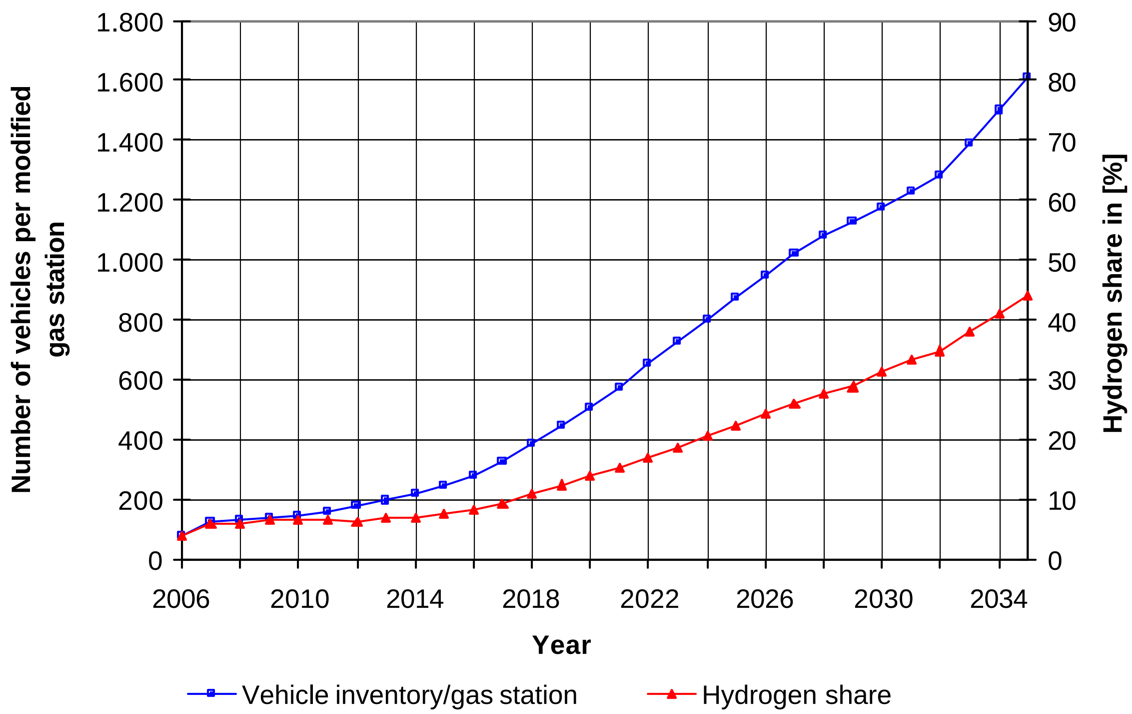
Figure 85: Specific gas station costs for the favored development of the gas station inventory (GSID 4+7) in Germany from 2006 to 2035



Electricity costs at Level 1 (L1) with a conventional power station, GE = Gasoline Equivalent.
Source: Own calculations, 2002

The increase in the **average fleet of alternative vehicles per modified gas station** and the **share of the annual hydrogen supply volume at a modified gas station** according to GSID 4+7 are shown in Figure 86. Comparison of the curve of the average fleet of alternative vehicles per modified gas station with the increase in the number of natural gas powered vehicles per natural gas station in Figure 57 reveals similarities in the first five years of the introduction of the fuel onto the market. After the first five years the fleet of natural gas powered vehicles has continued to grow only very slowly, in spite of the increase in the inventory of natural gas stations, resulting in a strong decrease in the ratio of vehicles per modified gas station. Corresponding to the chosen development of the inventory of hydrogen powered vehicles according to VPD OWN, there is continuous increase in the ratio of the vehicle population per modified hydrogen gas station.

Figure 86: Average fleet of alternative vehicles per gas station modified for the supply of hydrogen and share of the annual hydrogen supply volume at a modified conventional gas station as a percentage of total annual conventional fuel sales at a roadside gas station, according to the favored development of a gas station inventory (GSID 4+7), in Germany from 2006 to 2035



Source: Own calculations, 2002

The required investments and the resulting discounted total costs in the development of a gas station infrastructure in Germany according to GSID 4+7 are presented in Appendix 7. The total investments required to achieve complete modification of all conventional gas stations in 2023 are about 5.3 billion € (three fuel pumps per modified gas station, including LH_2 storage tank).

5.6. Summary

Tasks

In this chapter, scenarios regarded as capable of realization for the increase in the number of gas stations with hydrogen supply are determined for Munich and Germany. Hydrogen production and distribution are not taken into account in this section of the paper. The determination is based on the derived increases in the hydrogen demand for Germany and Munich.

Assumptions and approach

The gas station infrastructure is developed for the gas station concept of exclusive LH_2 supply at the gas station, as this concept has shown itself to be the most promising (Chapter 4).

In the first part there is an examination of the spread of natural gas stations in Germany, in order to obtain possible clues for the development of a hydrogen gas station infrastructure.

For a detailed determination of the gas station infrastructure in Germany there is a separate examination of possible development of the gas station infrastructure in German cities, in rural areas and along the motorways/freeways ('autobahns').

The chosen development pattern for the number and usage of fuel pumps at the modified gas stations over the years yields the number of modified gas stations based on the given hydrogen demand, and therefore the development of the gas station infrastructure. The influence of the development of the gas station infrastructure on specific hydrogen costs is determined by examining several scenarios for the development of the gas station infrastructure.

The scenarios for the gas station infrastructure are compared with each other on the basis of defined criteria. These refer to the inventory-related development of the gas station infrastructure (e.g. time that coverage is achieved, usage of fuel pumps), to geographical aspects (e.g. area to be supplied per modified gas station) and to economic aspects (e.g. investments, total costs).

Findings

From the comparison of the examined scenarios for the development of a gas station infrastructure, it can be seen that the growth in the gas station infrastructure in Munich and Germany will in all probability take the form of an S-curve. Accordingly, too rapid development of the gas station infrastructure should be avoided in the first few years, due to lower gas station usage and the associated high total costs and specific hydrogen costs.

The example of Munich shows that in the market introduction of vehicles using hydrogen as an alternative fuel, at least 10 gas stations should be made available as quickly as possible in order to guarantee a basic fuel supply. An approximate projection of this number onto German cities yields a figure of around 320 modified gas stations.

However, for coverage of the hydrogen supply in Germany we must speak about some 1,500 modified gas stations (corresponding to 15 % of the total number of gas stations in Germany). Above this gas station level, it would be theoretically possible to drive on all the roads in Germany using alternative hydrogen fuel without encountering any gap in the fuel supply. In the favored scenario for the development of the gas station inventory, which has the form of an S-curve, full coverage is achieved about five years after the introduction of the alternative fuel. The period of an almost complete modification of all conventional gas stations to supply hydrogen is calculated at approximately 25 years in Germany. The precondition for this is the assumed development of hydrogen demand according to Chapter 2.3.

The level of fuel pump usage has an important influence on specific gas station costs. In the favored scenario for the gas station inventory in the form of an S-curve, fuel pump usage increases from only about 20 % in the first few years of the infrastructural build-up to about 80 % when there is almost complete modification of all gas stations. The reason for the relatively low fuel pump usage, especially in the first few years, is on the one hand that two fuel pumps have been envisaged for the modified gas stations from the outset, and on the other that for a sufficient supply to the vehicles there must be a correspondingly rapid development of a gas station infrastructure (especially in order to achieve coverage).

Conclusions and recommendations

It should be mentioned that development of the LH_2 gas station infrastructure in terms of numbers as determined in this chapter in the form of an S-curve also applies to the other gas station concepts in Chapter 4. There will, for example, be differences in the investments and total costs, as these are incurred at other times and levels.

For the further examination in the chapters that follow, only the favored development of the gas station inventory that has been determined here is considered.

6. Economic and ecological analysis of hydrogen production from well to vehicle fuel tank

The previous chapters have dealt with matters including individual components such as hydrogen production, distribution and the development of a gas station infrastructure. This chapter brings together these components in a total examination from well to vehicle fuel tank. The first section contains a detailed examination of the exclusive production of hydrogen by natural gas steam reforming and electrolysis to cover the hydrogen demand according to the OWN scenario for Germany. The focus of the analysis is on the patterns arrived at for

- specific hydrogen costs
- CO_2 emissions or the potential for their reduction
- investments
- discounted total costs
- electricity requirement and
- the number of power stations required for electricity generation

The next section deals with a comprehensive examination of the path composition for hydrogen production (development paths) according to the stated focus of the analysis. In the final section of this chapter, the findings obtained for the individual development paths are compared with each other in order to determine the development path for hydrogen production that guarantees an optimum supply according to economic and ecological criteria.

Assumption and characteristics made for further examinations in this chapter are:

- specific costs of hydrogen production with a version using two power stations in the first year (Chapter 4.4.2)
- truck transport costs according to Table 27
- development of a hydrogen gas station infrastructure according to GSID 4+7 (Chapter 5.5.4.1)
- regarding the use of biomass, the long-term share of annual hydrogen production by biomass gasification is a maximum of 10 %, since the biomass potential for hydrogen production is limited[107]

To simplify matters, the path description of hydrogen production uses abbreviations that indicate the composition of the development path. N stands for natural gas steam reforming, W for water electrolysis and B for biomass gasification. Percentages are shown without the percentage symbol. For example, hydrogen production for the development path 75N 25W 0B is composed of 75 % natural gas steam reforming, 25 % water electrolysis and 0 % biomass gasification. These shares in the production process are not constant over time, but instead approximately indicate the long-term proportions of hydrogen production from 2035 on.

6.1. Hydrogen production by 100 % natural gas steam reforming

The abbreviation for this path is 100N 0W 0B. In the following remarks, the main aspects of the analysis mentioned above are carried out for this path.

6.1.1. Specific hydrogen costs

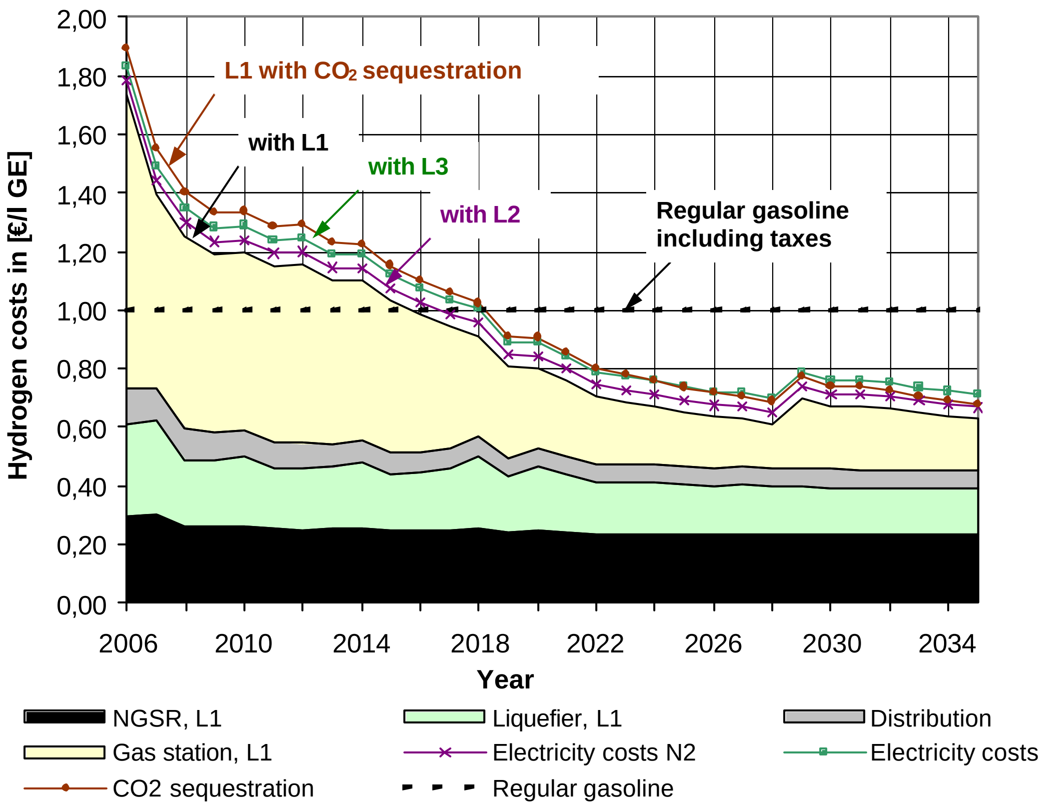
Using **electricity from German power stations at Level 1**, we obtain specific hydrogen costs in 2006 of about 1.75 €/l GE, the principal element of which is accounted for by gas station costs (Figure 87). The clear reduction in the specific hydrogen costs over time is primarily due to the increase in gas station usage (Figure 84) and the associated decrease in gas station costs. The reduction in specific hydrogen costs as a consequence of the learning

[107] In the European Union (EU), the potential of liquid hydrogen production by biomass, in spite of the utilization of fallow areas, is only 5 % of the annual necessary hydrogen demand for the substitution of all vehicles in the EU (TES, 2001, p. 24).

effect is clearly evident in the decreasing costs of hydrogen production (NGSR, liquefaction). From 2016 on, specific hydrogen costs come into effect that are lower than the average price of normal gasoline incl. taxes of about 1€/ l in February 2000[108] (dotted line in diagram) (www.shell.de, 22.05.2002). In the long term, the specific hydrogen costs reach a level of about 0.7 €/l GE.

The increase in specific hydrogen costs in 2029 is caused by the need for a second LH_2 storage tank at the modified gas stations, which causes an increase in the specific hydrogen costs per l GE. A comparison of local hydrogen costs with those of hydrogen production using lower capacity production plants (Figure 47) shows that only the use of higher capacity production plants is sensible.

Figure 87: Specific hydrogen costs for electricity generation using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank for the development path 100N 0W 0B in Germany from 2006 to 2035



L1 = electricity costs using a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, natural gas costs according to Level 1 (NL1), NGSE = natural gas steam reforming.
Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming
Source: Own calculations, 2002

A increase in electricity costs, for example, **regeneratively renewable electricity at Level 3,** causes, as a consequence of the low electricity requirement of this path, a relatively moderate increase in the specific hydrogen costs of about 0.1 €/l GE compared with the hydrogen costs using electricity from power stations at Level 1. Moreover, higher electricity costs have the effect that specific hydrogen costs fall below the price of regular gasoline of about 1 €/l including taxes at a later point in time.

The use of **electricity from German power stations with CO_2 sequestration**, both in NGSR plants and in fossil-fuel fired power stations for electricity generation, causes specific

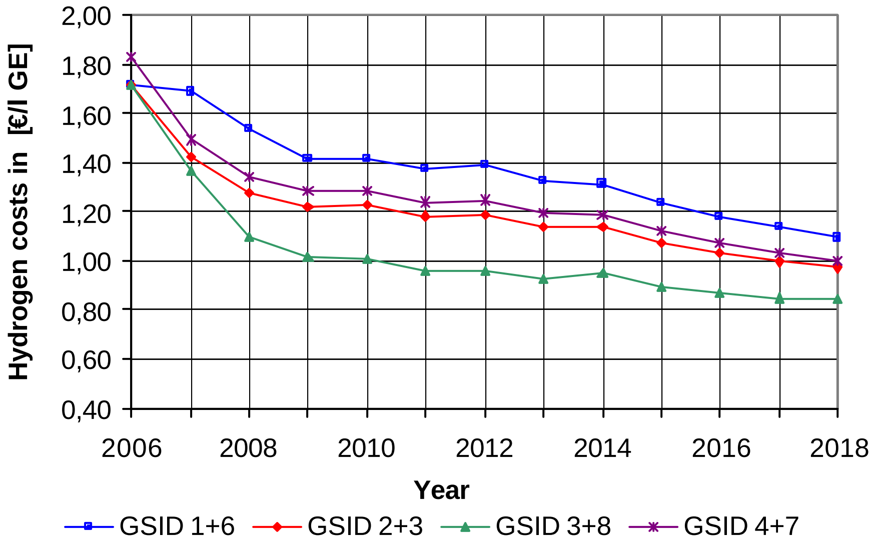
[108] The share of individual types of fuel in total fuel sales in Germany in 2000 is: Regular gasoline 16.7 %, Eurosuper 31.4 %, Super Plus 1.9 %, Diesel 50 % (MWV, 2000, p. 47) (own calculations, 2002). As the price of Eurosuper (highest share of gasoline sales) is only around 0.02 €/l (BP, 2003) above the price of regular gasoline, specific hydrogen costs are compared with the price of regular gasoline.

hydrogen costs which up to 2020 are higher than those without sequestration when using regeneratively produced electricity at Level 3. In the long term, specific hydrogen costs are obtained that are equivalent to those without sequestration when using Level 2 electricity.

If GST power stations are built to generate electricity for hydrogen production, because CO_2 emissions can then be reduced compared with German power stations (490 g CO_2/kWh_{el} instead of about 700 g CO_2/kWh_{el}), the lower costs of sequestration have only a marginal effect on the specific hydrogen costs, as the share of CO_2 emissions in electricity generation in total emissions is less than 40 % (Figure 96).

A comparison of the specific hydrogen costs if other scenarios presented for the development of a gas station infrastructure in Germany were to be adopted instead of the gas station infrastructure according to GSID 4+7 (Chapter 5.5.1), is shown in Figure 88. Development of the specific hydrogen costs in GSID 4+7 lies in the upper mid-field of the specific hydrogen costs of the scenarios considered. As the specific hydrogen costs with very rapid development of a gas station infrastructure according to GSID 1+6 are very high as a consequence of low usage of the modified gas stations, too rapid development of a gas station infrastructure should be avoided.

Figure 88: Specific hydrogen costs from well to vehicle fuel tank for electricity generation using regenerative energy (L3) using development path 100N 0W 0B, depending on development of the gas station infrastructure in Germany from 2006 to 2018



Electricity costs using regenerative production at Level 3 (L3), natural gas costs at Level 1 (NL1), GSID = Gas station infrastructure development, development path 100N 0W 0B = hydrogen production using 100 % natural gas steam reforming.
Source: Own calculations, 2002

Very slow development of a gas station infrastructure according to GSID 3+8 leads to the lowest specific hydrogen costs, although gas station coverage is only reached in 2018 although this is seen as a precondition for the market penetration of hydrogen vehicles. Very obvious are the additional hydrogen costs in 2006 of about 0.1 €/l GE for GSID 4+7 compared with the other scenarios, which result from two hydrogen fuel pumps per modified gas station from the very outset.

6.1.2. Investments depending on electricity generation

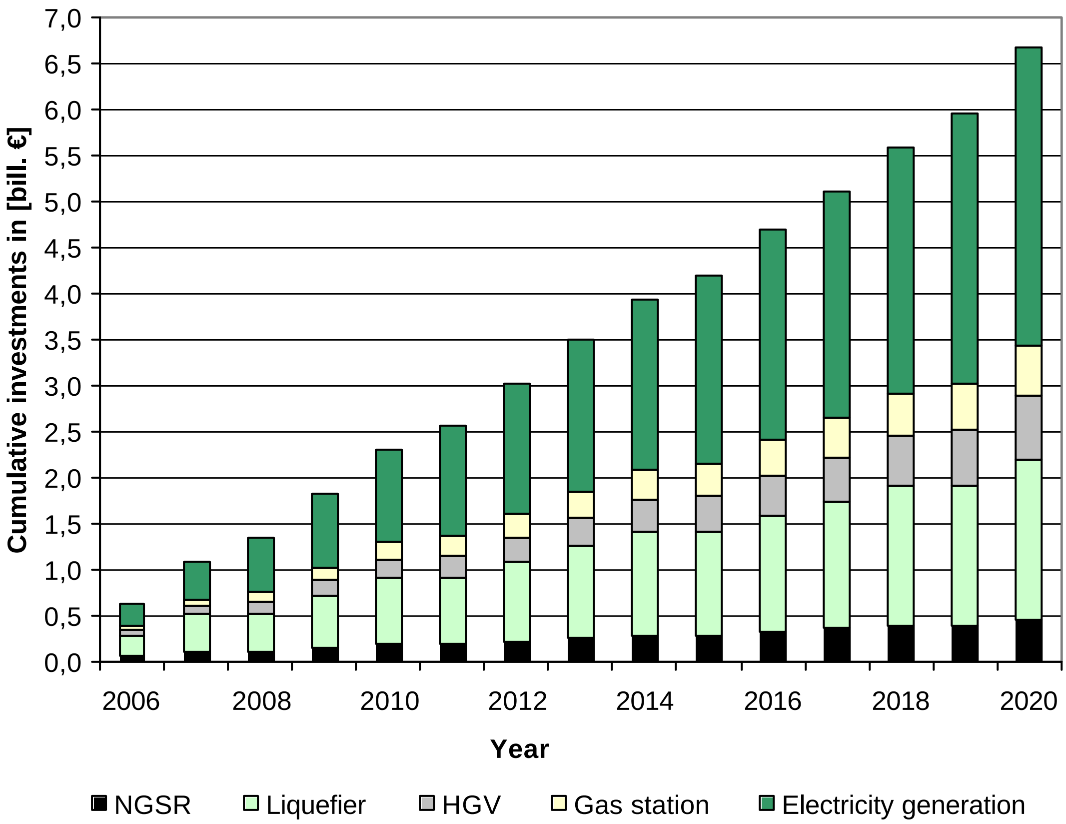
The cumulative investments in the centralized NGSR and liquefaction plants, trucks, gas stations and power stations for generating electricity based on current prices are shown in Figure 89. The highest investments are in regenerative electricity generation, presented in the diagram for wind power stations[109] (50% offshore, 50% onshore). The second largest

[109] For wind power stations, to take EOS into consideration, a degression factor of 0.95 is applied (Plant specifications in Appendix 5).

investment block is taken up by liquefaction plants. Investments in the gas station infrastructure are relatively small in magnitude and reach about the same level as for NGSR plants.

Cumulative total investments over the years are composed on average of investments at the level of 48 % in wind power stations, 9 % in the gas station infrastructure, 10 % in distribution, 26 % in liquefaction plants and only 7 % in NGSR plants.

Figure 89: Cumulative investments examined from well to vehicle fuel tank for electricity generation using wind power stations for the development path 100N 0W 0B, in Germany from 2006 to 2020



Wind power stations 50 % offshore and 50 % onshore, NGSR = Natural Gas Steam Reforming, HGV = Heavy Goods Vehicle (truck). Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming
Source: Own calculations, 2002

The presentation of the cumulative investments depending on electricity generation up to 2035 in Figure 90 refers to wind power stations (50 % offshore, 50 % onshore), geothermal power stations (capacity of 50 MW), solar-thermal power stations (capacity of 400 MW) and nuclear power stations (capacity of 1,300 MW) (Plant specifications in Appendix 5).

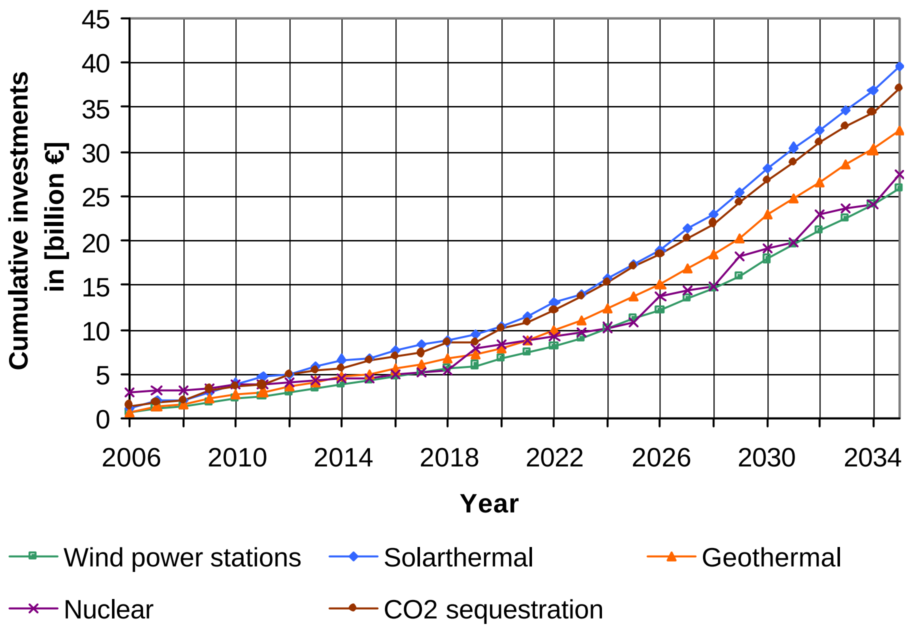
To calculate the investments when using CO_2 sequestration, the following assumptions are made:

- Each NGSR plant is fitted with a CO_2 collector (investment of 175 million €) (Chapter 3.7)
- Electricity generation using coal-fired power stations (capacity of 400 MV, investment of 436 million €)
- Each coal-fire power stations is fitted with a CO_2 collector (investment of 350 million €) (Chapter 3.7).

- Each platform[110] has a capacity to sequestrate an amount of 10,000 t CO_2/d (investment of 120 million €)
- A degression factor for NGSR plants, CO_2 collectors and platforms for taking into account the learning effect is assumed at A = 0.9

A comparison of investments shows that the lowest investments in the medium and long term occur when electricity is generated using wind power stations or nuclear power stations. The use of geothermal power stations increases the cumulative investments by about 25 %, while the use of solar-thermal power stations or CO_2 sequestration increases the cumulative investments by about 60 % compared with the use of wind power stations.

Figure 90: Cumulative investments from well to vehicle fuel tank according to energy source for the electricity generation development path 100N 0W 0B in Germany from 2006 to 2035



Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming.
Source: Own calculations, 2002

In the first few years, the investments in nuclear power stations are the highest, as these are built with correspondingly higher capacity and generate much more than the amount of electricity actually required in the first years. If the degression factor in CO_2 sequestration is, for example, 0.95 instead of 0.9, the use of sequestration results in the highest absolute investments.

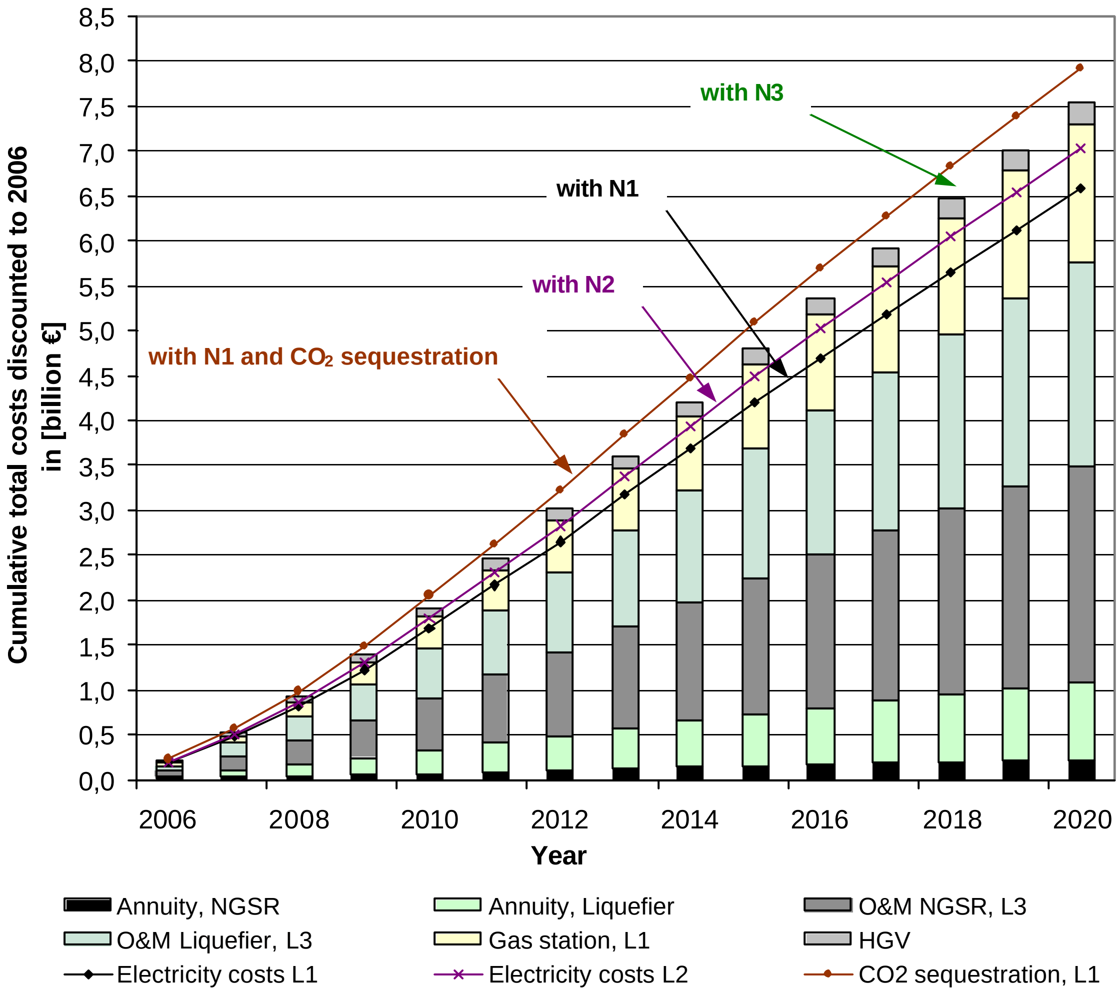
6.1.3. Discounted total costs

Which components have which share of the cumulative total costs, discounted to 2006, is shown in Figure 91. The largest share of the total costs is made up of the electricity costs for liquefaction plants (contained in the diagram by “O&M Liquefier, L3") and the natural gas costs for NGSR plants (“O&M NGSR, L3”). However, as time progresses there is an increase in the cost share for the gas station infrastructure, as this is continuously being expanded. The influence of electricity costs on the level of total costs is also clearly evident. When using

110 For the storage of those amounts of CO_2 that are produced by a 500 MW coal-fired power station, investments of around 44 million € are indicated for transporting it to former oil and natural gas reservoirs (pipeline from platform to reservoir, compressor, control station, boreholes) (IEA(b), 2002). Investments required for the transport of the CO_2 to the platform are not included here. With four boreholes, the CO_2 throughput at the boreholes is given as 10,000 t CO_2/d. For transporting CO_2 to deep level ground-water strata, investments of 170 million € are quoted, and around 142 million € for the storage of liquid CO_2 on the ocean floor. An average of these three values is used for the calculation, and yields investments of 120 million € per platform.

electricity costs at Level 2, the total costs are about 8 % lower than with electricity costs at Level 3.

Figure 91: Cumulative total costs, discounted to 2006, and their composition in the generation of electricity using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank, for the development path 100N 0W 0B in Germany from 2006 to 2020



L1 = electricity costs using a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, natural gas costs according to Level 1 (NL1), O&M = operating & maintenance costs, NGSE = Natural gas steam reforming, HGV = heavy goods vehicle (truck), development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming.
Source: Own calculations, 2002

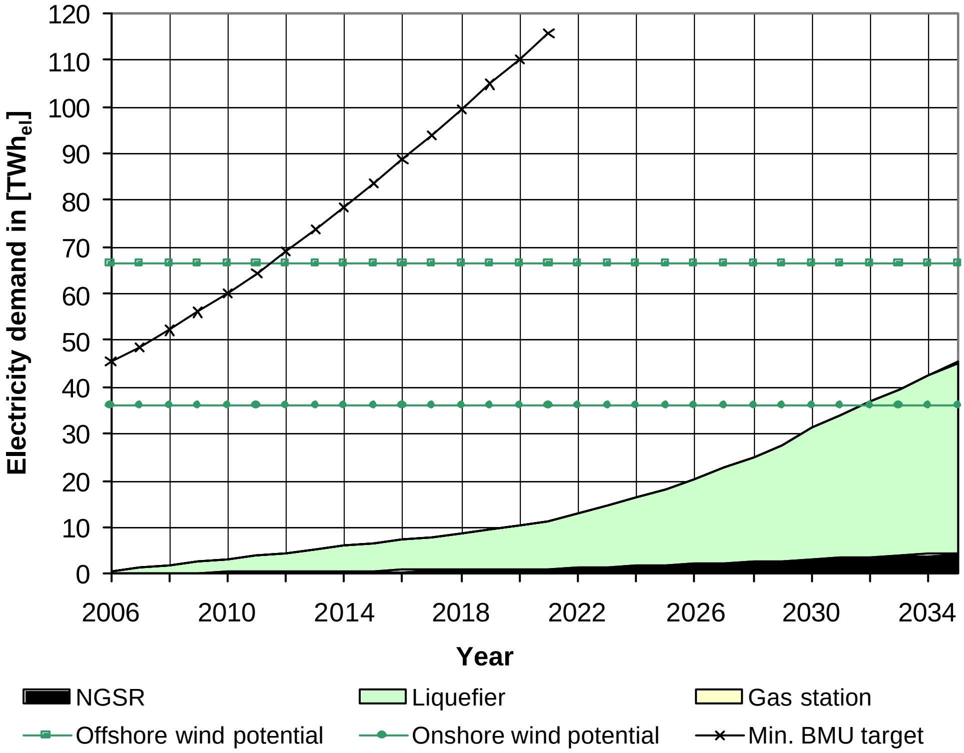
6.1.4. Electricity requirement

The following conclusions can be derived from the development of the electricity requirement (Figure 92):

- highest electricity requirement for liquefaction plants, followed by NGSR plants
- German wind power potential for electricity generation sufficient beyond 2035

The German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety has set itself the non-binding aim of increasing the share of renewable energies in electricity consumption from 6.25 % in 2006 to 12.5 % by 2010 and to 50 % by 2050 (long-term forecast) (BMU, 2002, p. 10). If a trend line is place through these three points in the diagram, this yields the “BMU minimum targets” curve. A direct comparison of the aims of the Federal Ministry with the electricity requirement for hydrogen production and supply is not entirely appropriate, as fuel substitution is not taken into account in the BMU forecast, which therefore only aims in advance to replace existing power stations and electricity consumption with regenerative production. However, the comparison of the order of magnitude shows that the regenerative electricity generation appears to be fully practicable for hydrogen production by this path.

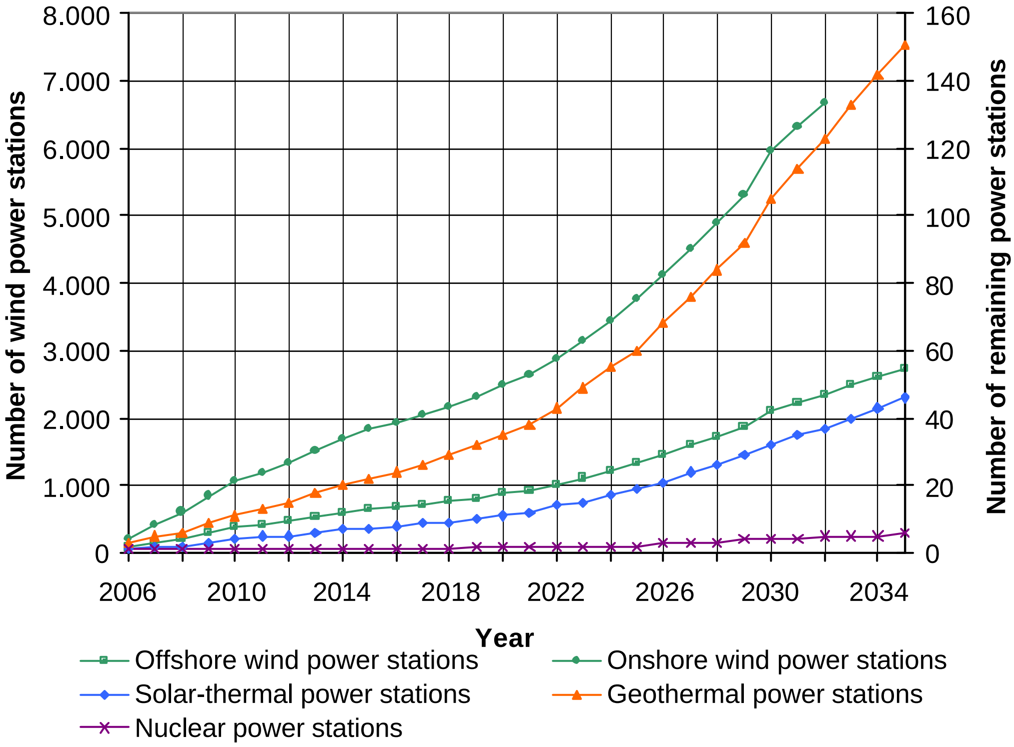
Figure 92: Electricity requirement of plants from well to vehicle fuel tank for the development path 100N 0W 0B in Germany, from 2006 to 2035



BMU = Federal Ministry for the Environment, Nature Conservation and Nuclear Safety; NGSR = Natural gas steam reforming, potential figures refer to the technical potentials for generating electricity in Germany.
Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming
Source: BMU, 2002, p. 10; Own calculations, 2002

Figure 93 is an overview of the number of power stations for electricity generation required to cover the electricity requirement for the production of hydrogen. It can be seen at which point in time the regenerative potentials for electricity generation in Germany will probably be exhausted. For the figures presented here it has been assumed that there is no combination of the different types of power station one with another. The highest number of power stations up to 2032 consists of onshore wind power stations with almost 7,000 plants (of up to 3 MW each), after which the potential is exhausted. On the other hand, around 3,000 offshore wind power stations (each up to 5 MW) will be required by 2035. However, the electricity requirement in 2035 can also be covered by 46 solar-thermal power stations (each 400 MW), 151 geothermal power stations (each 50 MW) or 6 nuclear power stations (each 1,300 MW). The area that would be taken up by solar-thermal power stations over the years is show in Appendix 8.

Figure 93: Development of the required number of power stations for electricity generation for hydrogen production from well to vehicle fuel tank when using regenerative resources or nuclear power, for the development path 100N 0W 0B in Germany from 2006 to 2035



Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming
Source: Own calculations, 2002

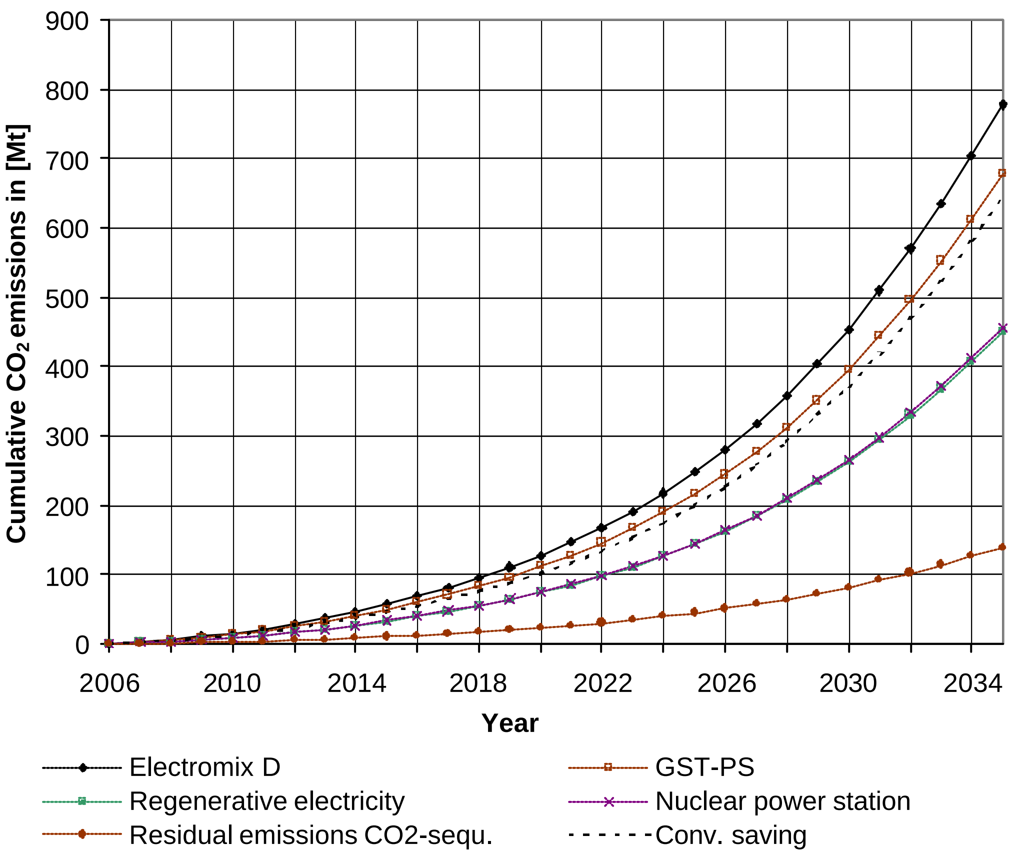
Progress in the erection of wind power stations in the first half year of 2002 in Germany amounted to 820 wind power stations (www.strom-magazin, 23.07.2002). If this development is also assumed for the second half of the year, this gives a current possible growth per year of about 1,640 wind power stations. Compared with the development discussed here to cover the electricity requirement for hydrogen production, it can be seen that this path would also be fully practicable using regeneratively produced electricity from wind power stations.

6.1.5. CO_2 emissions

An examination of the CO_2 emissions in Figure 94 shows that those generated when using electricity from German power stations are clearly higher than the reduction in CO_2 emissions as a result of the substitution of conventional fuel by hydrogen (“Conv. saving” curve in the diagram). Ultimately, this results in an increase in total CO_2 emissions. For the generation of electricity using GST power stations, the annual CO_2 emissions are also higher than the associated CO_2 savings as a result of the substitution of conventional fuel by hydrogen.

The greatest reduction in CO_2 emissions is achieved by using CO_2 sequestration, both for NGSR and for fossil-fuel fired power stations used for generating electricity at German power stations. A smaller annual reduction of CO_2 emissions is achieved using regeneratively produced electricity or electricity from nuclear power. However, emissions in relation to the use of electricity from German power stations are still relatively high, as the bulk of CO_2 emissions occurs through NGSR and not in the generation of electricity (Figure 96).

Figure 94: Cumulative CO_2 emissions by energy source for electricity generation for hydrogen production from well to vehicle fuel tank, for the development path 100N 0W 0B in Germany from 2006 to 2035

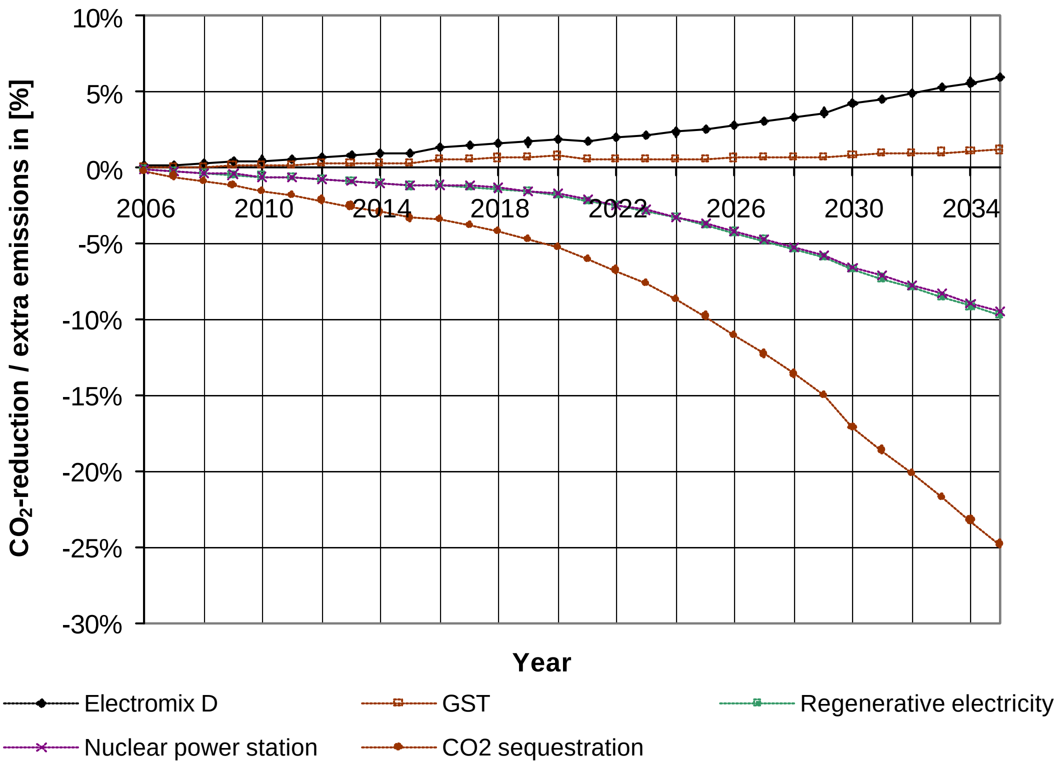


Electromix G = Electricity from conventional power stations, GST-PS = Gas and steam turbine power station. Residual emissions CO2 sequ. = remaining emissions of CO_2 that occur in the use of sequestration due to the fact that complete CO_2 separation from the exhaust during hydrogen production is currently not technologically possible. Conv. saving = reduction in CO_2 emissions only as a consequence of lower conventional fuel sales.
Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming
Source: Own calculations, 2002

The annual reductions in CO_2 emissions or additional emissions that occur in connection with electricity generation as a percentage of the total emissions from German road traffic of approx. 200 Mt/a, are shown in Figure 95. In the example, the highest reduction in CO_2 emissions of about 17 % using CO_2 sequestration would be achieved in 2030.

In general, it can be said that the higher the substitution of conventional fuel by hydrogen, the greater the differences between the reduction in CO_2 emissions or additional emissions depending on electricity generation.

Figure 95: CO_2 emissions reduction / additional emissions as a percentage of total emissions of CO_2 from road traffic in Germany of around 200 Mt per year, according to energy source for electricity generation from well to vehicle fuel tank, for the development path 100N 0W 0B in Germany from 2006 to 2035

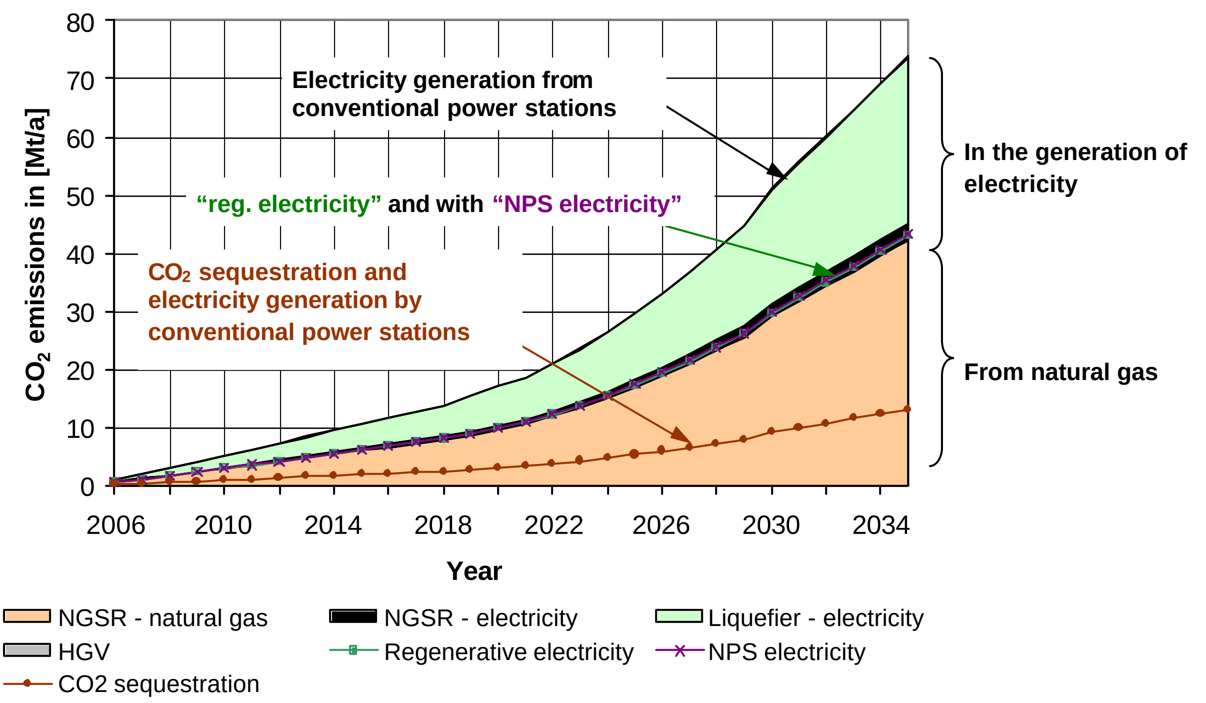


Electromix G = Electricity from conventional power stations, GST-PS = Gas and steam turbine power station.
Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming
Source: Own calculations, 2002

Which components cause which CO_2 emissions is shown in Figure 96. The area diagram applies to the use of electricity from German power stations. It is apparent that the largest element in total CO_2 emissions arises from the processing of natural gas through NGSR ("NGSR natural gas" area in the diagram). Due to the electricity requirement of the liquefaction plants, these emit approximately half the emissions of the NGSR plants ("Liquefied Electricity" area in the diagram). If regeneratively produced electricity or electricity from nuclear power is used, the emissions fall slightly below the total emissions level of NGSR plants, as only the emissions in the electricity generation for the liquefaction plants are avoided.

The diagram does not show emissions at the fillingasg stations, as these are lower than the truck emissions, which already account for only a very small share.

Figure 96: CO_2 emissions by energy source for electricity generation using conventional power stations, nuclear power (NPS electricity) and regenerative energy (reg. electricity) from well to vehicle fuel tank for the development path 100N 0W 0B in Germany, from 2006 to 2035



NPS = Nuclear power station, NGSR = Natural gas steam reforming, HGV = heavy goods vehicle (truck), Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming.
Source: Own calculations, 2002

6.2. Hydrogen production by 100 % electrolysis

The abbreviation for this path is 0N 100W 0B. Corresponding to the HDD OWN called for, this results, as already determined in the analysis of the use of NGSR plants (Chapter 6.1), in identical power station capacities for the electrolysis plants, although there is a different cost structure. The distribution and liquefaction costs can be carried over directly from the analysis of the use of NGSR plants.

6.2.1. Specific hydrogen costs

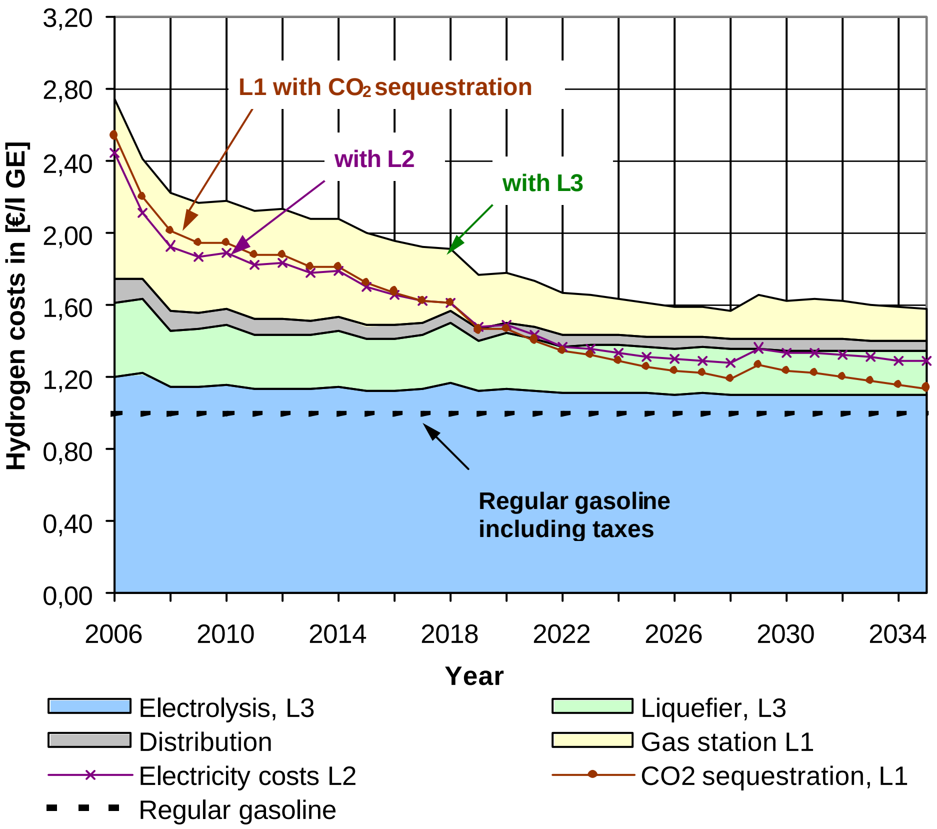
Using **regeneratively produced electricity at Level 3**, this yields specific hydrogen costs in 2006 of about 2.7 €/l GE, the main element of which is now accounted for by the electrolysis costs (operating and maintenance costs, annuity) (Figure 97). The clear reduction in specific hydrogen costs over time is primarily accounted for by the increase in gas station usage and the associated decrease in gas station costs. The reduction in the cost of hydrogen production as a consequence of the learning effect is now only marginally significant in the form of a slightly reduction in the cost of hydrogen production (electrolysis, liquefaction). The reason for the low learning effect is primarily that the main share of electrolysis costs is determined by electricity costs and not by the annuities. In the long term, specific hydrogen costs reach a level of about 1.6 €/l and consequently cannot be reduced to the price level of regular gasoline incl. taxes of about 1 €/l in February 2000[111] (dotted line in diagram) (www.shell.de, 22.05.2002).

The increase in specific hydrogen costs in 2029 is caused by the need for a second LH_2 storage tank at the modified gas stations, which causes an increase in specific hydrogen costs per l GE. A comparison of these specific hydrogen costs with those of hydrogen

[111] The share of individual types of fuel in total fuel sales in Germany in 2000 is: Regular gasoline 16.7 %, Eurosuper 31.4 %, Super Plus 1.9 %, Diesel 50 % (MWV, 2000, p. 47), (Own calculations, 2002). As the price of Eurosuper (highest share of gasoline sales) is only around 0.02 €/l (BP, 2003) above the price of regular gasoline, specific hydrogen costs are compared with the price of regular gasoline.

production using lower capacity production plants (Figure 47) shows that only the use of higher capacity production plants is sensible.

Figure 97: Specific hydrogen costs for electricity generation using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank, for the development path 0N 100W 0B, in Germany from 2006 to 2035



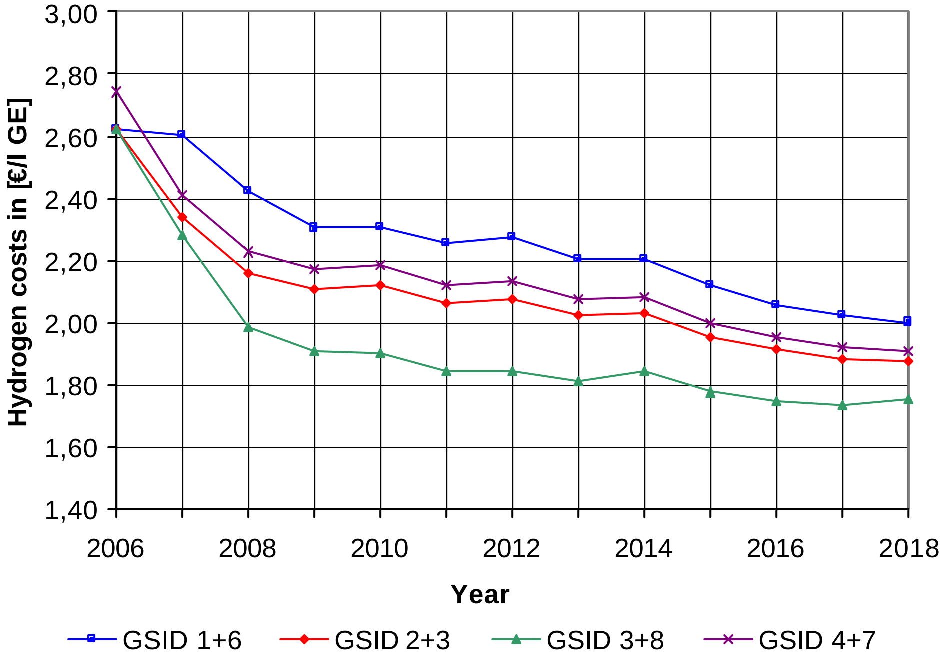
L1 = electricity costs using a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, development path 0N 100W 0B = hydrogen production by 100 % electrolysis.
Source: Own calculations, 2002

A reduction in the electricity costs, e.g. **electricity at Level 2,** causes a clear reduction in specific hydrogen costs of about 0.3 €/l GE compared with the hydrogen costs when using regeneratively produced electricity, due to the path's high electricity requirement.

The use of **electricity from German power stations with CO_2 sequestration**, both in NGSR plants and also in fossil-fuel fired power stations for electricity generation, gives rise to specific hydrogen costs which are lower than the specific hydrogen costs without sequestration when using regeneratively produced electricity at Level 3. The cost reduction in 2006 is about 0.2 €/l GE and increases to 0.4 €/l GE by 2035. The larger cost reduction occurs because of the cost assumptions that were made, including future sequestration cost reduction potentials (Chapter 3.7).

A comparison of specific hydrogen costs if, instead of GSID 4+7, the other scenarios for the development of a gas station infrastructure in Germany were to occur (Chapter 5.5.1), is shown in Figure 98. In view of the high level of specific hydrogen costs, the various scenarios for possible development of the gas station infrastructure no longer have such a strong effect on specific hydrogen costs as in the case of hydrogen production at lower hydrogen costs (for example, path 100N 0W 0B, Chapter 6.1). The cost deviations for the considered gas station infrastructure scenarios contribute to GSID 2+3 with average specific hydrogen costs of a maximum of 0.2 €/l GE, so that less importance attaches to the development of the gas station infrastructure if only the specific hydrogen costs are examined. Very obvious are the additional hydrogen costs in 2006 of about 0.1 €/l GE for GSID 4+7 compared with the other scenarios, which results from the two fuel pump per modified gas station for hydrogen supply from the very outset.

Figure 98: Specific hydrogen costs for electricity generation using regenerative energy (L3) from well to vehicle fuel tank, for the development path 0N 100W 0B, depending on development of the gas station infrastructure in Germany from 2006 to 2018



Electricity costs using regenerative production at Level 3 (L3), GSID = Gas station infrastructure development.
Development path 0N 100W 0B = hydrogen production by 100 % electrolysis
Source: Own calculations, 2002

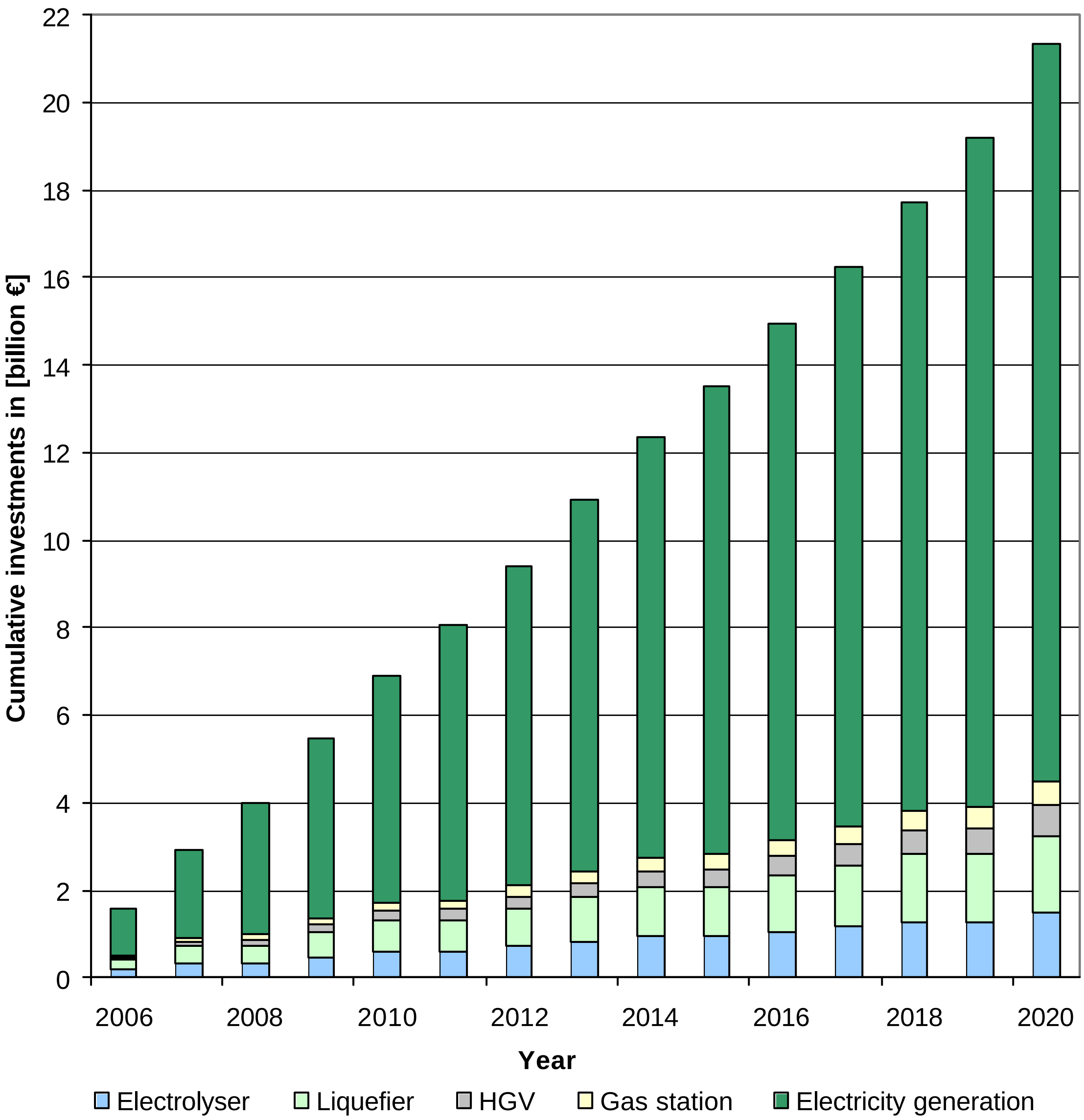
6.2.2.Investments depending on electricity generation

Cumulative investments in centralized electrolysis and liquefaction plants, trucks, gas stations and electricity generating stations based on current prices are shown in Figure 99. The highest investments need to be made in regenerative electricity production, as shown in the diagram for wind power stations[112] (50% offshore, 50% onshore). The second largest investment block is accounted for by liquefaction and electrolysis plants. Investments in the gas station infrastructure form only a small part of the total investments.

The cumulative total investments over the years are composed on average of investments at the level of 80 % in wind power stations, 2,5 % in the gas station infrastructure, 2,5 % in distribution, 8 % in liquefaction plants and 7 % in NGSR plants.

[112] For wind power stations, a degression factor of 0.95 was applied in order to take EOS into consideration, (plant specifications in Appendix 5).

Figure 99: Cumulative investments from well to vehicle fuel tank for electricity generation using wind power, for the development path 0N 100W 0B in Germany from 2006 to 2020

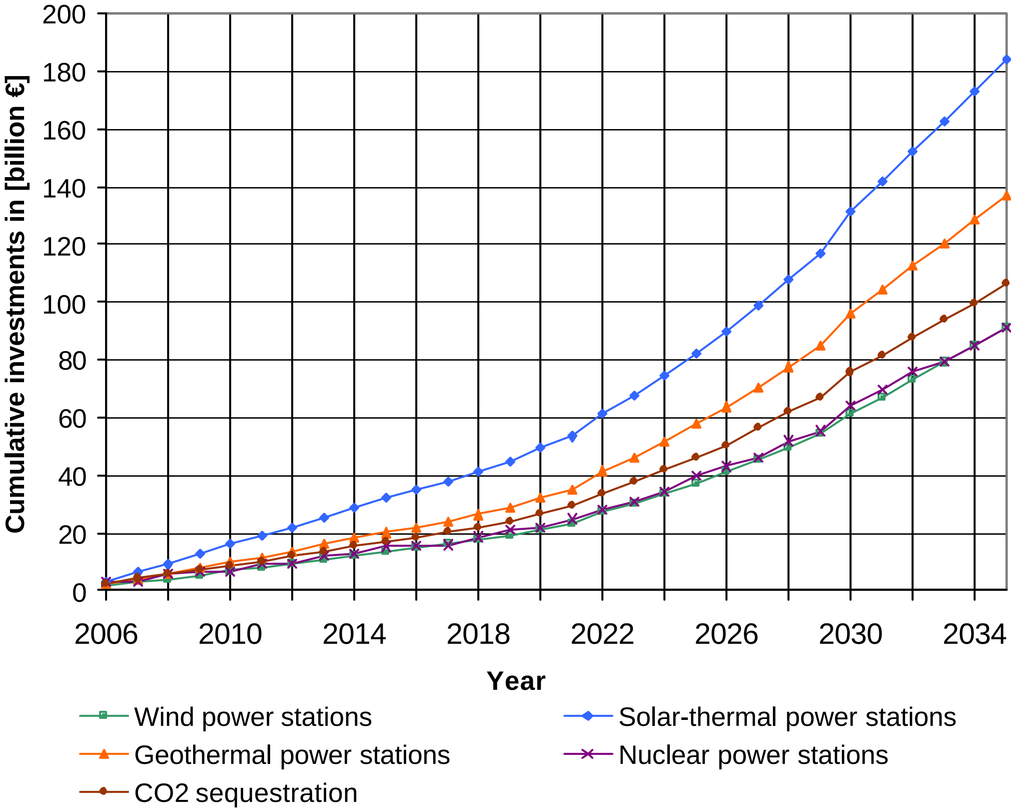


Wind power stations 50 % offshore and 50 % onshore, HGV = Heavy goods vehicle (truck).
Development path 0N 100W 0B = hydrogen production by 100 % electrolysis
Source: Own calculations, 2002

Presentation of cumulative investments depending on electricity generation up to 2035 in Figure 100 relates to wind power stations (50 % offshore, 50 % onshore), geothermal power stations (capacity of 50 MW), solar-thermal power stations (capacity of 400 MW) and nuclear power stations (capacity of 1,300 MW) (plant specifications in Appendix 5). When calculating the investments when using CO_2 sequestration, identical assumptions are made as for path 100N 0W 0B (Chapter 6.1).

A comparison of investments in Figure 100 shows that the lowest investments in the medium and long term occur when electricity is generated using wind power stations or nuclear power stations. The use of geothermal power stations increases cumulative investments by about 50 %, while the use of solar-thermal power stations or CO_2 sequestration increases them by about 100 % compared with the use of wind power stations.

Figure 100: Cumulative investments from well to vehicle fuel tank according to electricity generation energy source for the development path 0N 100W 0B in Germany from 2006 to 2035

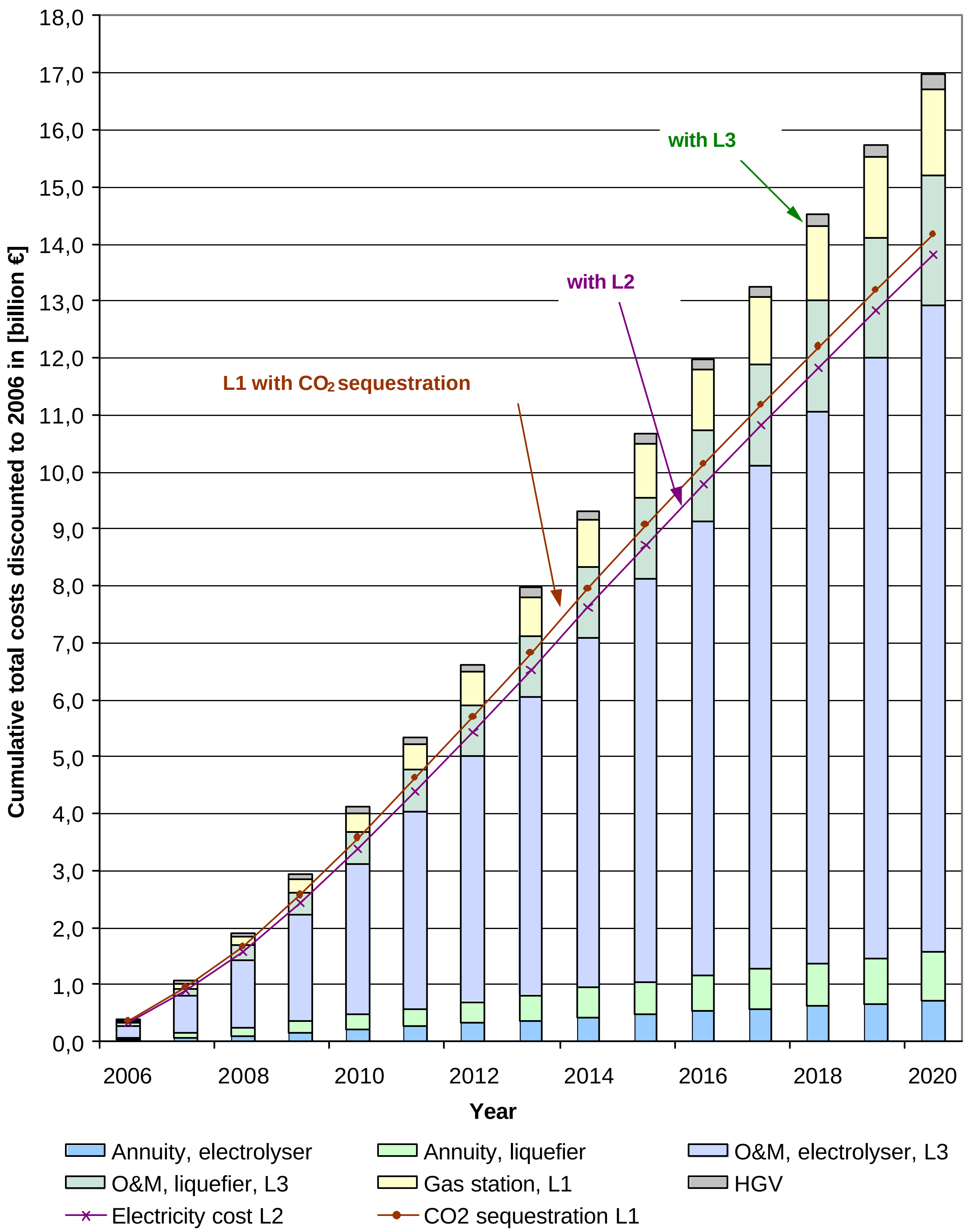


Development path 0N 100W 0B = hydrogen production by 100 % electrolysis
Source: Own calculations, 2002

6.2.3. Discounted total costs

Figure 101 shows which components have which share of the cumulative total costs, discounted to 2006. The largest share of the total costs consists of the electricity costs for electrolysis plants (included in the diagram in the area “O&M electrolyser, L3"). The influence of electricity costs on the total cost level is also clearly evident. When using electricity costs at Level 2, total discounted costs are about 20 % lower compared to total costs with electricity costs at Level 3. The lower total costs when using CO_2 sequestration compared with the total costs without sequestration, with electricity costs at Level 2, occur because of the cost assumptions, including future potentials for the cost reduction of sequestration, that were made (Chapter 3.7).

Figure 101: Cumulative total costs, discounted to 2006, in the generation of electricity using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank, for the development path 0N 100W 0B in Germany from 2006 to 2020



L1 = Electricity costs using conventional power stations, L2 – Electricity costs using nuclear power, L3 = Electricity costs using regenerative production, O&M = Operating and Maintenance costs, HGV = Heavy Goods Vehicle (truck), Development path 0N 100W 0B = hydrogen production by 100 % electrolysis

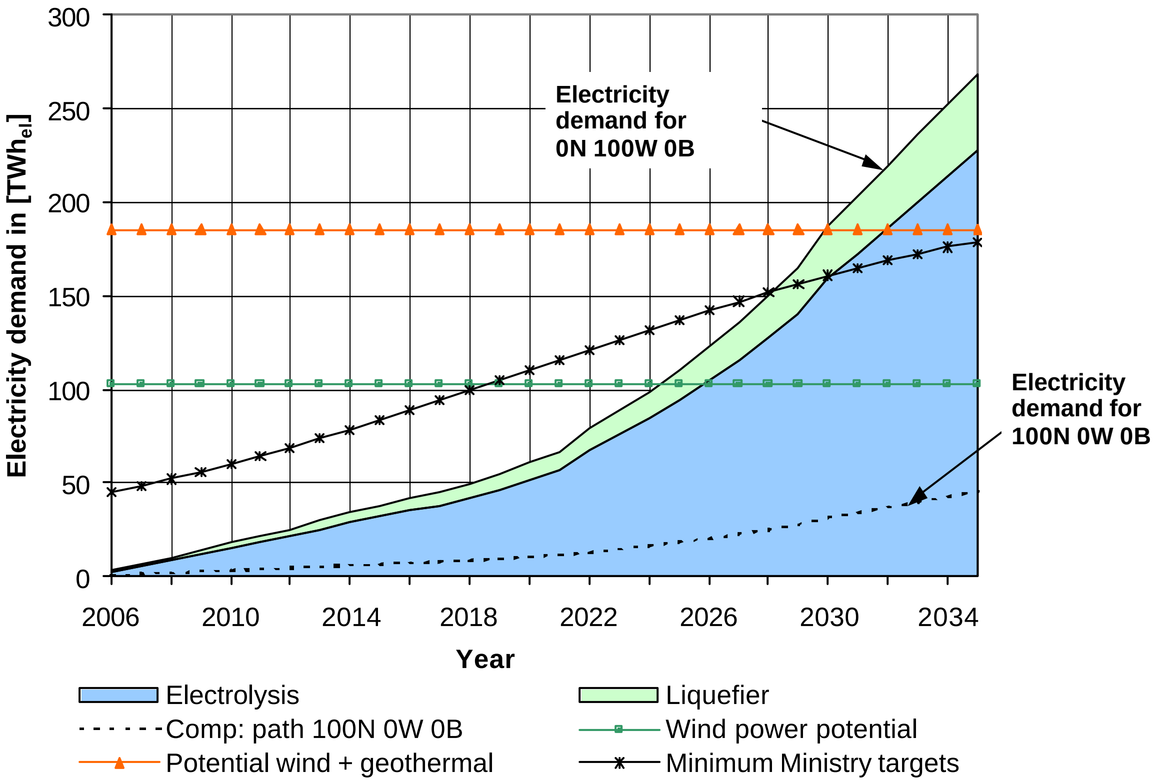
Source: Own calculations, 2002

6.2.4. Electricity requirement

From the pattern of plant electricity requirement in Figure 102, we can deduce that over 90 % of the total electricity requirement are needed by the electrolysis plants. The total electricity requirement can be covered by wind power stations (onshore and offshore) until 2024, after which the German potential is exhausted. An electricity supply could be guaranteed until 2030 by the additional use of geothermal power stations. From this point in time a primary source outside Germany needs to be used for a regenerative electricity supply.

Comparison with the non-binding targets of the Federal German Ministry for the Environment, Nature Conservation and Nuclear Safety (Chapter 6.1) shows that regenerative electricity generation for hydrogen production using this path appears to be fully achievable up to 2022. From that year on, there is a strong increase in the electricity requirement and regenerative electricity production will be very expensive to realize.

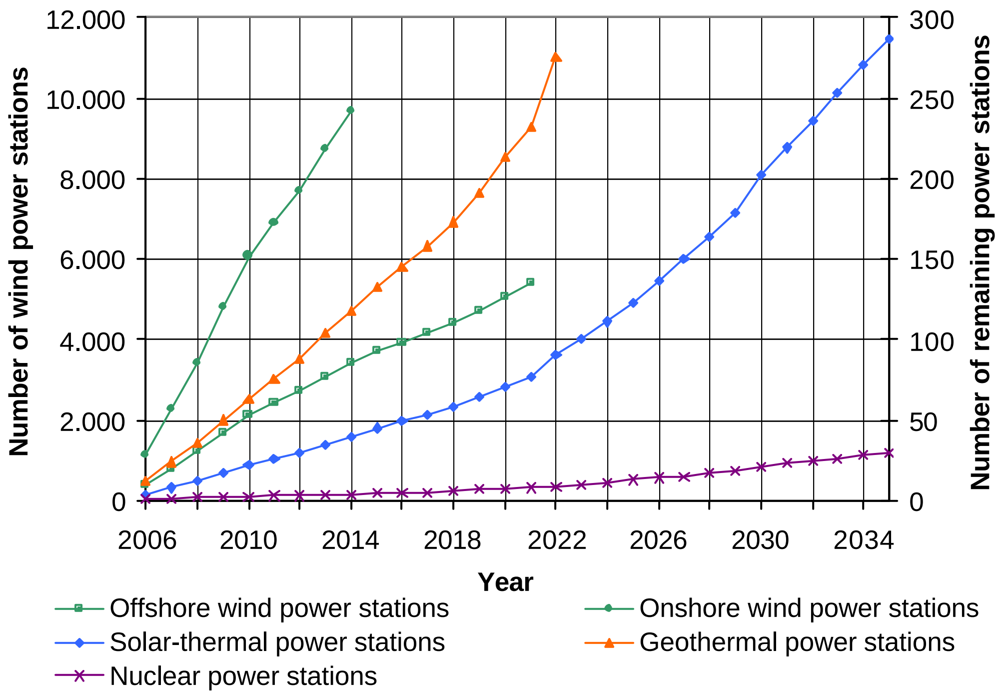
Figure 102: Electricity requirement of electricity and liquefaction plants from well to vehicle fuel tank, for the development path 0N 100W 0B in Germany from 2006 to 2035



BMU = Federal German Ministry for the Environment, Nature Conservation and Nuclear Safety. Potential figures refer to the technical potential for generating electricity in Germany. Development path 0N 100W 0B = hydrogen production by 100 % electrolysis. Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming.
Source: BMU, 2002, p. 10; Own calculations, 2002

Figure 103 is an overview of the number of power stations for electricity generation required to cover the electricity requirement. From this it is also evident whether technical realization of the regenerative potentials for electricity generation in Germany is possible. For the figures presented here it was assumed that the different types of power station are not combined with each other. The highest number of power stations up to 2014 proves to be onshore wind power stations, at almost 9,000 (of up to 3.5 MW each), after which the potential is exhausted. In contrast, 5,400 offshore wind power stations (each up to 5 MW) would be required by 2021. The geothermal potential will be reached in 2022 with 276 power stations (each 50 MW). The electricity requirement in 2035 can also be covered by 287 solar-thermal power stations (each 400 MW) or 30 nuclear power stations (each 1,300 MW). The area that would be taken up by solar-thermal power stations over the years is shown in Appendix 8.

Figure 103: Development of the required number of power stations for electricity generation for hydrogen production from well to vehicle fuel tank, using regenerative resources or nuclear power for development path 0N 100W 0B, in Germany from 2006 to 2035



Development path 0N 100W 0B = hydrogen production by 100 % electrolysis.
Source: Own calculations, 2002

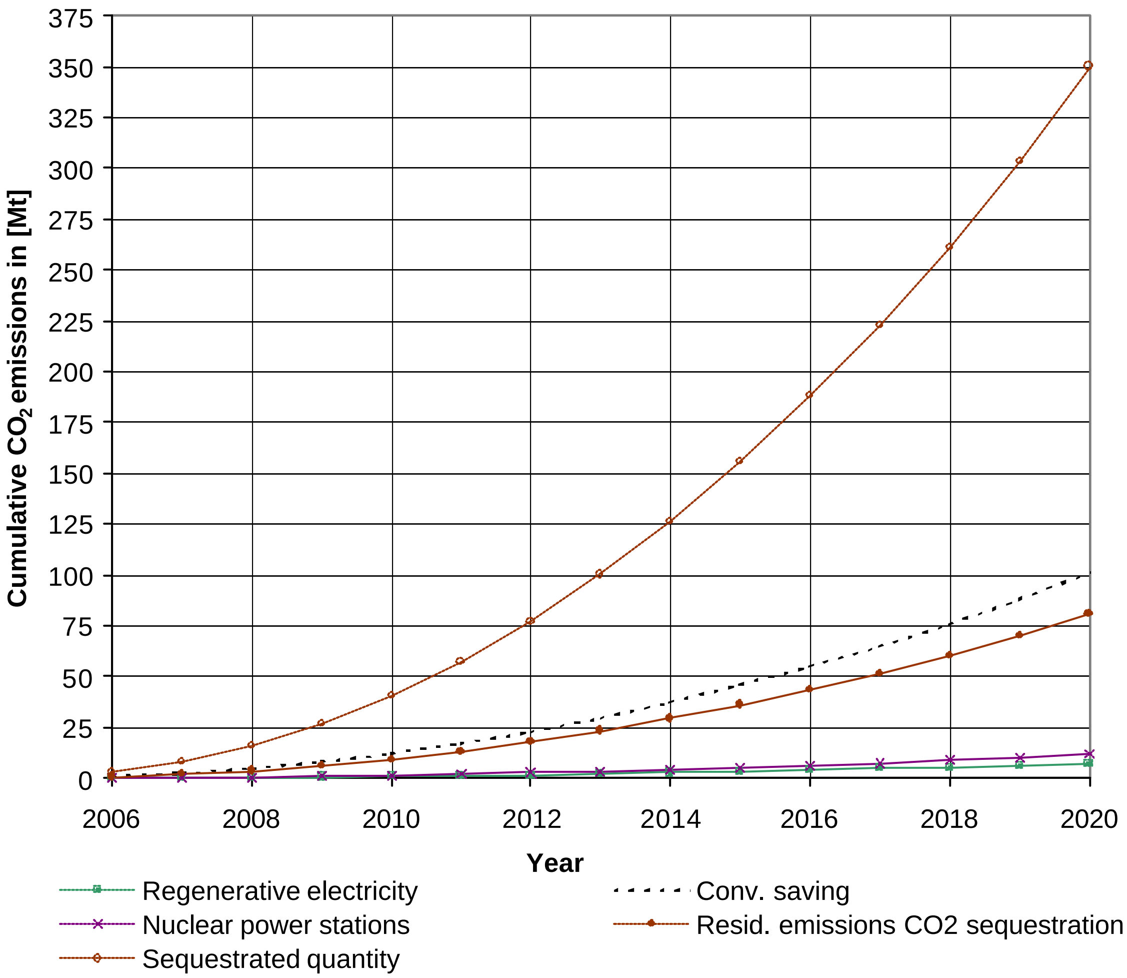
Progress in the erection of wind power stations in the first half year of 2002 in Germany led to 820 new wind power stations (www.strom-magazin, 23.07.2002). If this development is also assumed for the second half of the year, it yields a current possible growth per year of about 1,640 wind power stations. Compared with local development to cover the electricity requirement for hydrogen production, it can be seen that this path would also be fully realized using regeneratively produced electricity from wind power stations. The precondition would be that the erected wind power stations were only used for hydrogen production, which is highly improbable. It should be noted that the total installed capacity of the erected 820 wind power stations was about 1,100 MW, giving an average installed capacity per wind power station of 1.35 MW. With regard to the number of wind power stations needed for hydrogen production, a higher capacity per wind power station was assumed (Appendix 5).

6.2.5. CO_2 emissions

Examination of the CO_2 emissions in Figure 104 shows that the highest annual reductions in CO_2 emissions resulting from the use of regeneratively produced electricity are reached with this path (the difference between the curves for the reduction of CO_2 emissions as a consequence of the substitution of conventional fuel by hydrogen, the "Conv. saving" curve, and of emissions from the respective type of electricity generation represents the actual reduction in CO_2 emissions). The reduction in emissions when using electricity from nuclear power is lower than when using regeneratively produced electricity, since at 25 g/kWh$_{el}$ in a nuclear power station, the CO_2 emissions are higher than for regenerative production with about 15 g/kWh$_{el}$ (Chapter 3.2.3).

The use of CO_2 sequestration in fossil-fuel fired German power stations for the generation of electricity creates residual emissions that are only slightly lower than the achievable reductions in CO_2 emissions from substitution of the conventional fuel by hydrogen ("Conv. saving" curve). Due to the marginal reductions in CO_2 emissions, the lower hydrogen costs for sequestration in Figure 97 are relative. The amount of CO_2 to be sequestrated up to 2020 is about 350 Mt (compare: current annual CO_2 emissions from road traffic in Germany are about 200 Mt).

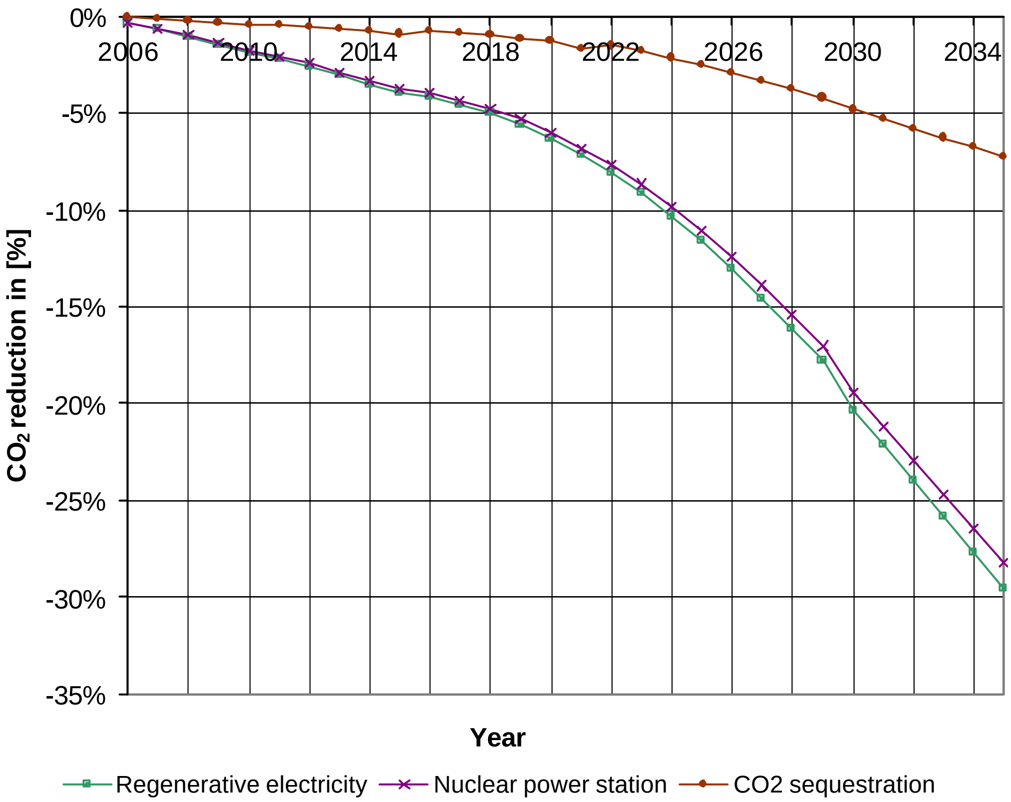
Figure 104: Cumulative CO_2 emissions by electricity generation energy source from well to vehicle fuel tank, for the development path 0N 100W 0B in Germany from 2006 to 2020



Resid. emissions CO2 sequestration = remaining emissions of CO_2 that occur in the use of sequestration due to the fact that complete CO_2 separation from the exhaust gas during hydrogen production is currently not technologically possible.
Conv. saving = reduction in CO_2 emissions only as a consequence of lower conventional fuel sales.
Development path 0N 100W 0B = hydrogen production by 100 % electrolysis.
Source: Own calculations, 2002

Annual reductions in CO_2 emissions depending on electricity generation as a percentage of total emissions from German road traffic of approx. 200 Mt/a, are shown in Figure 105. Using the year 2030 as an example, the highest reduction in CO_2 emissions of about 21 % would be achieved using regeneratively produced electricity. The use of CO_2 sequestration would bring about a reduction of only about 5 %, so that the use of sequestration in this path is not meaningful.

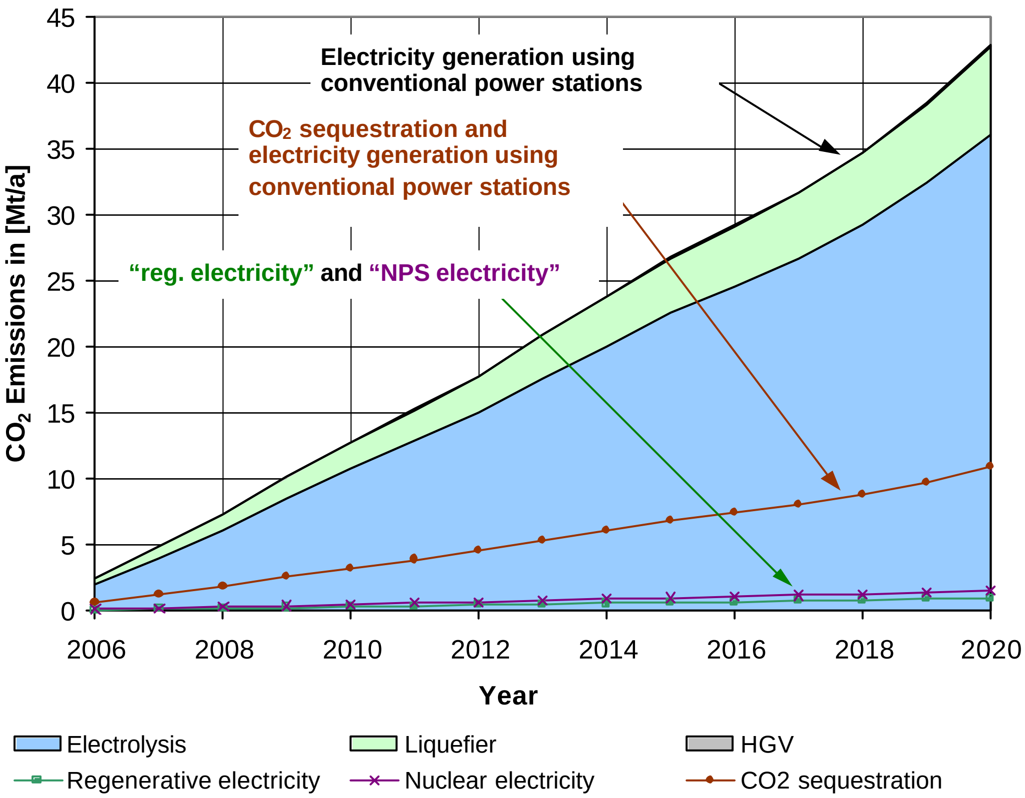
Figure 105: Reduction in CO_2 emissions as a percentage of total emissions of CO_2 from road traffic in Germany of around 200 Mt per year by electricity generation energy source, from well to vehicle fuel tank for the development path 0N 100W 0B in Germany from 2006 to 2035



Development path 0N 100W 0B = hydrogen production by 100 % electrolysis.
Source: Own calculations, 2002

Which components cause which CO_2 emissions is shown in Figure 106. The area diagram applies to the use of electricity from German power stations. It is evident that the largest proportion of total CO_2 emissions arises from the generation of electricity for the supply of electrolysis plants ("Electrolysis" area in the diagram). Due to the smaller electricity requirement of the liquefaction plants, these have a share of less than 15 % in total CO_2 emissions.

Figure 106: CO_2 emissions by electricity generation energy source using conventional power stations, nuclear power (NPS electricity) and regenerative energy (reg. electricity) from well to vehicle fuel tank for the development path 0N 100W 0B in Germany from 2006 to 2020



NPS = Nuclear power station, HGV= heavy goods vehicle (truck). Development path 0N 100W 0B = hydrogen production by 100 % electrolysis. Source: Own calculations, 2002

The diagram does not show emissions at the gas stations, as these are lower than the truck emissions which themselves account for only a very small proportion.

6.3. Hydrogen production in a long-term composition of 75 % by natural gas steam reforming and 25 % by electrolysis

The 100N 0W 0B path (Chapter 6.1) has shown that the specific hydrogen costs fall continuously in the first 15 years. Hydrogen production using this path seems thoroughly meaningful for introducing hydrogen fuel to the market, in order to obtain bring hydrogen costs approximately into line with the conventional fuel price (e.g. regular gasoline) in the shortest possible time.

In order to achieve a sustainable reduction in CO_2 emissions and preserve fossil resources, the long-term production of hydrogen must shift away from NGSR towards electrolysis by using regenerative produced electricity or electricity from nuclear power[113]. For example, this transition can be undertaken in such a way that after a few years with hydrogen production according to the path 100N 0W 0B, electrolysis plants take up hydrogen production for the first time, whereby the average level of specific hydrogen costs for the total amount of hydrogen produced increases slightly compared with the specific costs of producing hydrogen exclusively according to path 100N 0W 0B, but on the other hand CO_2 emissions can be reduced compared with the emissions from hydrogen production exclusively according to path 100N 0W 0B. With the continuously increasing share of the sustainably

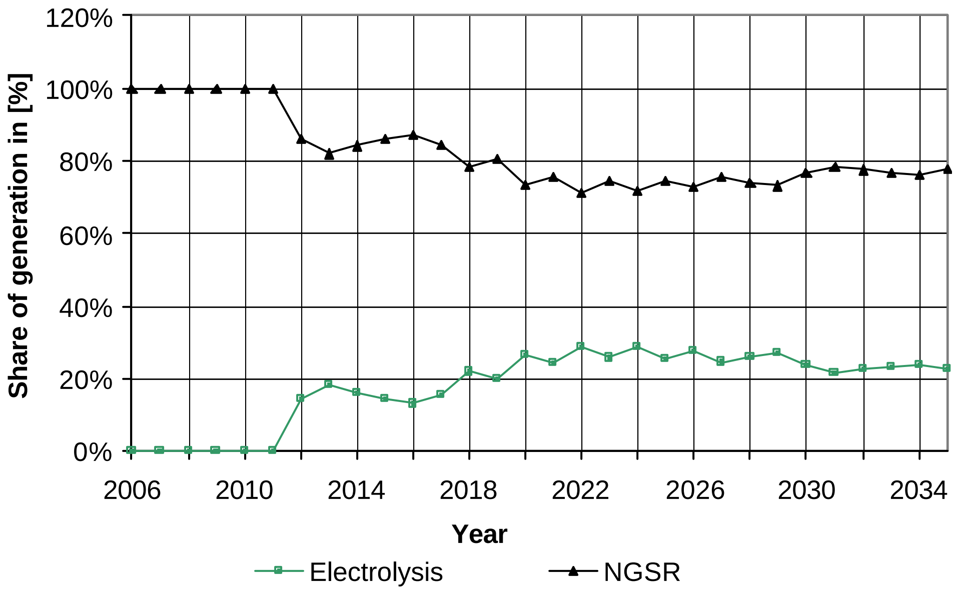
[113] as far as it is politically and socially accepted

produced quantity of hydrogen using electrolysis in the total hydrogen produced, a long-term reduction in CO_2 is ultimately reached.

The abbreviation for this path is 75N 25W 0B. In the first section of this chapter, the composition of the path over the years is shown. An analysis of the specific pattern of hydrogen costs and CO_2 emissions in connection then follows.

Development of the share accounted for by hydrogen, which in this development path is produced by electrolysis, is shown in Figure 107. As the specific hydrogen costs in the first few years for sole hydrogen production according to path 100N 0W 0B are also relatively high, the initial production of hydrogen from electrolysis plants takes place in 2012. The development path consisting of 75 % natural gas steam reforming and 25 % water electrolysis is achieved from approximately 2020 on.

Figure 107: Development of hydrogen production by natural gas steam reforming (NGSR) and electrolysis for the development path 75N 25W 0B in Germany from 2006 to 2035



Path 75N 25W 0B = long-term hydrogen production by 75 % natural gas steam reforming and 25 % water electrolysis.
Source: Own calculations, 2002

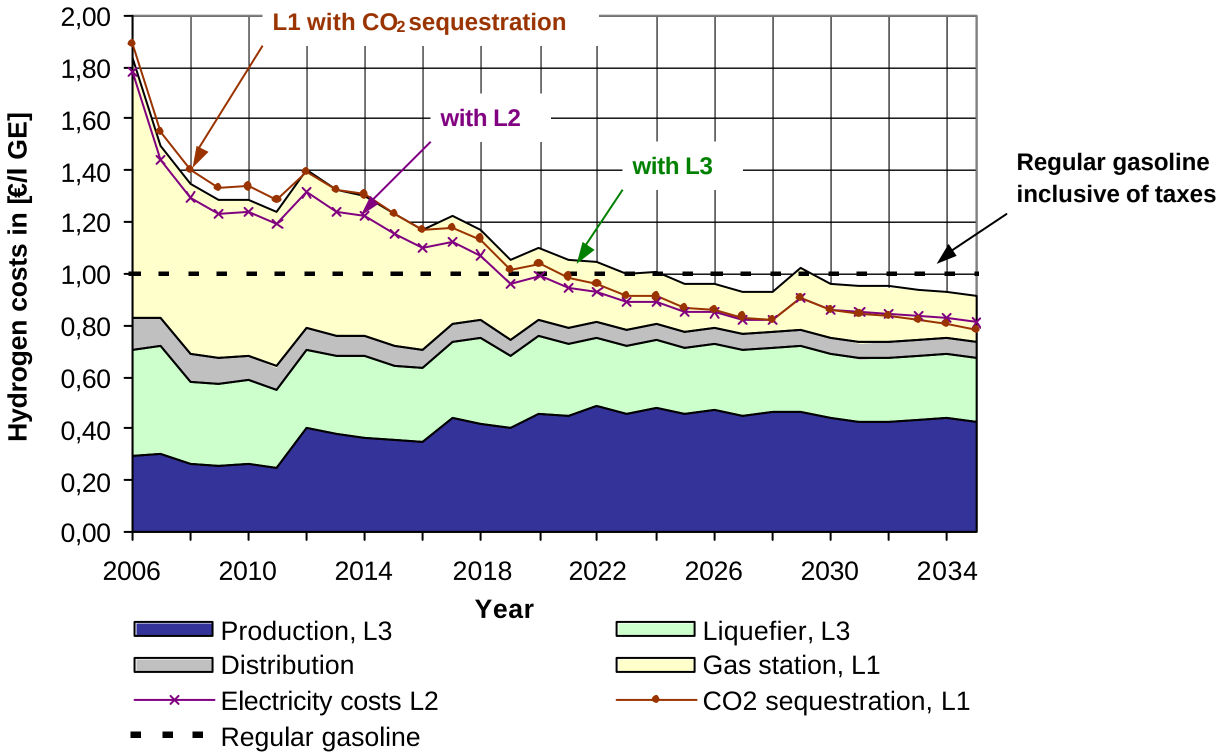
The introduction of hydrogen production using electrolysis plants only in 2012 allows the share of sustainable hydrogen production (using regeneratively produced electricity or electricity from nuclear power) to increase to about 14 % of total hydrogen production (capacity of the electrolysis plant approx. 3 TWh H_2/a). The further increase in the share of sustainable hydrogen production by electrolysis is achieved in as moderate a manner as possible by the combination of the NGST and electrolysis plants, such that on the one hand the price level of gasoline incl. taxes of 1 €/l GE (average normal gasoline price in February 2002, www.shell.de, 22.05.2002) (Figure 108), and on the other hand as high as possible share of sustainable hydrogen production are reached (Figure 107). Ultimately this gives a scenario that indicates which maximum share of sustainable hydrogen production is possible if specific hydrogen costs do not exceed the average gasoline price incl. taxes of 1 €/l.

6.3.1. Specific hydrogen costs

Using r**egeneratively produced electricity at Level 3**, specific hydrogen costs for this path of about 1.75 €/l GE in 2006 are obtained (Figure 108). The main element is again gas station costs. There is a very clear indication of the increase in production costs (NGSR, electrolysis, liquefaction) caused by the commissioning of electrolysis plants (initially in 2012). In the long term, specific hydrogen costs reach a level of about 1 €/l.

The increase in specific hydrogen costs in 2029 is caused by the need for a second LH_2 storage tank at the modified gas stations, which causes an increase in specific hydrogen costs per l GE.

Figure 108: Specific hydrogen costs for electricity generation using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank, for the development path 75N 25W 0B in Germany from 2006 to 2035



L1 = electricity costs using a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1), development path 75N 25W 0B = long-term hydrogen production by 75 % natural gas steam reforming and 25 % by water electrolysis.
Source: Own calculations, 2002

If **electricity at Level 2** is used, it can be seen that the higher the share of electrolysis in total hydrogen production, the higher the electricity requirement for and the influence of electricity costs on the specific hydrogen costs. From 2019, the costs fall clearly below about 1 €/l GE.

It can basically be stated that the lower the electricity costs of regenerative production, the higher the share of sustainable hydrogen production by electrolysis that becomes possible in total hydrogen production, without exceeding a cost of about 1 €/l GE in the long term.

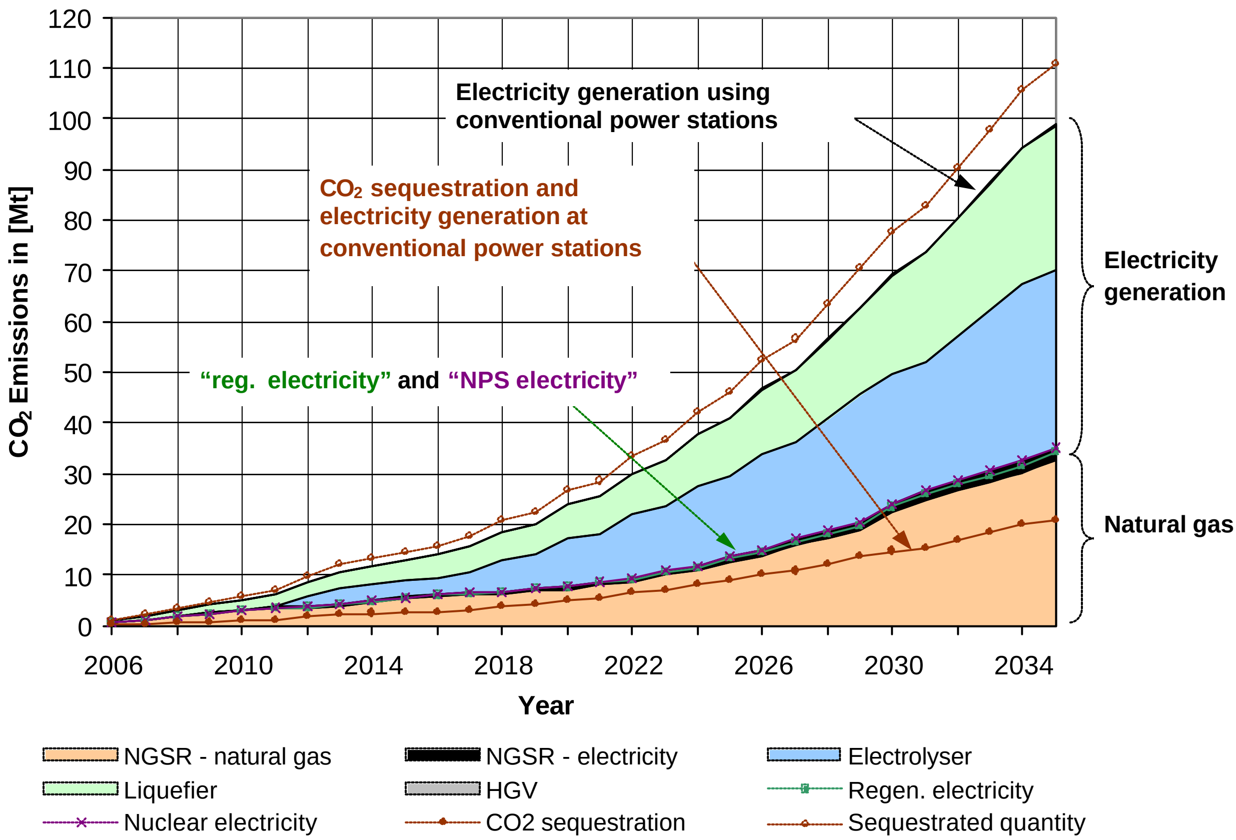
The use of **electricity from German power station at Level 1 with CO_2 sequestration**, both in NGSR plants and also in the fossil-fuel fired power stations, causes almost identical specific hydrogen costs up to 2020 as those incurred without sequestration when using regeneratively produced electricity at Level 3. The fact that the specific hydrogen costs without sequestration when using Level 3 electricity are not reached from 2020 on is explained by the cost assumptions made, including future potentials for sequestration cost reduction of (Chapter 3.7).

6.3.2. CO_2 emissions

Annual reductions in CO_2 emissions depending on electricity generation, as a percentage of the total emissions from German road traffic of approx. 200 Mt/a, are shown in Figure 125. The highest reduction in CO_2 emissions is achieved by using sequestration.

Which components cause which CO_2 emissions can be seen in Figure 109. The area diagram applies to the use of electricity from German power stations. It is evident that almost all the CO_2 emissions are caused equally by NGSR ("NGSR-natural gas" area) and by electricity generation for the electrolysis and liquefaction plants. If regeneratively produced electricity or electricity from nuclear power is used, CO_2 emissions are still at about 35 % with reference to total CO_2 emissions when using electricity from the German power stations, which are mainly caused by NGSR and by the generation of electricity.

Figure 109: CO_2 emissions by energy source for electricity generation using conventional power stations, nuclear power (NPS electricity) and regenerative energy (reg. electricity) from well to vehicle fuel tank for the development path 75N 25W 0B in Germany from 2006 to 2035



NGSR = Natural gas steam reforming, NPS = Nuclear power station, HGV = Heavy goods vehicle (truck). Sequestrated quantity = CO_2 quantity which must be collected during hydrogen production and stored in storage sites (e.g. former oil fields). Path 75N 25W 0B = long-term hydrogen production by 75 % natural gas steam reforming and 25 % water electrolysis.
Source: Own calculations, 2002

The use of CO_2 sequestration both in NGSR plants and fossil-fuel fired power stations used for generating electricity results in a reduction in CO_2 emissions of 25 %, with reference to total CO_2 emissions when using electricity from German power stations. The amount of CO_2 to be sequestrated up to 2035 is about 110 Mt (for comparison, current annual CO_2 emissions from traffic in Germany are about 200 Mt).

Further information on this path regarding investments, discounted total costs and electricity requirements can be found in Appendix 8.

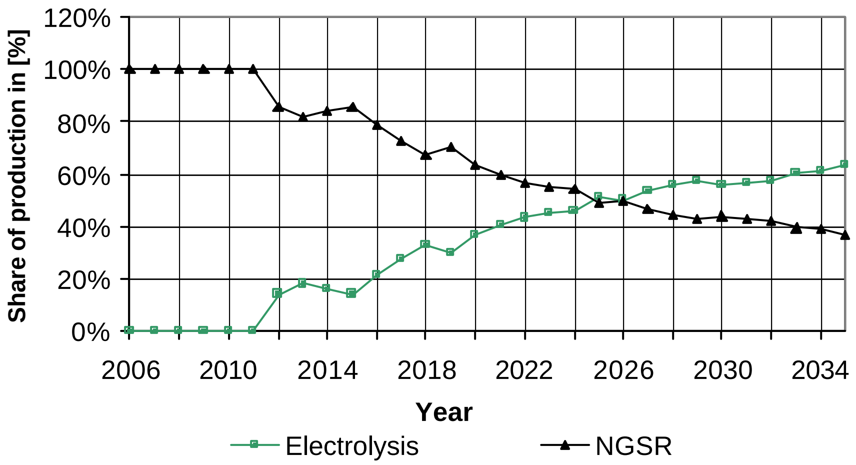
6.4. Hydrogen production in a long-term composition of 40 % by natural gas steam reforming and 60 % by electrolysis

The abbreviation for this path is 40N 60W 0B. In the first section of this chapter, the composition of the path over the years is shown. In connection with this, there is an analysis of the development of specific hydrogen costs and CO_2 emissions.

The progress of the proportion of hydrogen that is produced by electrolysis in this development path is shown in Figure 110. As specific hydrogen costs in the first few years are also relatively high for sole hydrogen production according to path 100N 0W 0B, initial production of hydrogen art electrolysis plants takes place only in 2012. In 2026 almost 50 % parity of the two process of hydrogen production will be reached. The long-term composition of this path, with 40 % by natural gas steam reforming and 60 % by water electrolysis, will be achieved from approximately 2033 on.

Starting hydrogen production from electrolysis plants in 2012 allows the share of sustainable hydrogen production (using regeneratively produced electricity or electricity from nuclear power) to increase to about 14 % of total hydrogen production (nominal output of the electrolysis plant about 3 TWh H_2/a). Further increases in the share of sustainable hydrogen production by electrolysis takes place in such a way that output from electrolysis plants increases continuously to 60 % of total hydrogen production in the long term.

Figure 110: Development of the composition of hydrogen production by natural gas steam reforming (NGSR) and electrolysis for the development path 40N 60W 0B in Germany from 2006 to 2035



Path 40N 60W 0B = long-term hydrogen production by 40 % natural gas steam reforming and 60 % water electrolysis.
Source: Own calculations, 2002

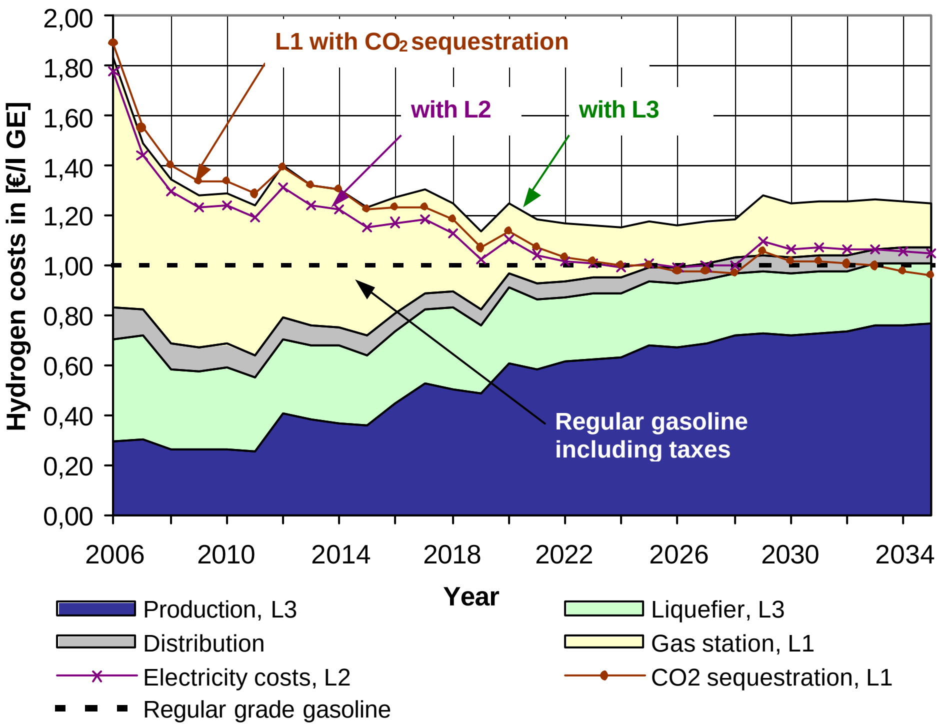
6.4.1. Specific hydrogen costs

Using **regenerative produced electricity at Level 3** results in specific hydrogen costs in 2006 of about 1.85 €/l GE, the principal share being accounted for by gas station costs (Figure 111). One can clearly see the increase in production costs (NGSR, electrolysis, liquefaction) caused by the commissioning of electrolysis plants (initially in 2012). In the long term, specific production costs reach a level of about 1 €/l and the specific hydrogen costs about 1.25 €/l GE. Consequently, specific hydrogen costs cannot be reduced to the price level of regular grade gasoline incl. taxes of about 1€/l in February 2000 (dotted line in diagram) (www.shell.de, 22.05.2002).

The increase in specific hydrogen costs in 2029 is caused by the need for a second LH_2 storage tank at the modified gas stations, which causes an increase in the specific hydrogen costs per l GE.

The higher the share of electrolysis in total hydrogen production, the higher the electricity requirement for and the influence of electricity costs on specific hydrogen costs. In the example using **electricity at Level 2**, long-term specific hydrogen costs of about 1 €/l GE are obtained, which is clearly lower than the costs with Level 3 electricity. It can basically be stated that the lower the electricity costs from regenerative production, the higher the share of sustainable hydrogen production by electrolysis in total hydrogen production that becomes possible without this increase resulting in higher specific hydrogen costs than existed before the increase.

Figure 111: Specific hydrogen costs for electricity generation using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank for the development path 40N 60W 0B in Germany from 2006 to 2035



L1 = electricity costs using a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1), development path 40N 60W 0B = long-term hydrogen production by 40 % natural gas steam reforming and 60 % by water electrolysis.
Source: Own calculations, 2002

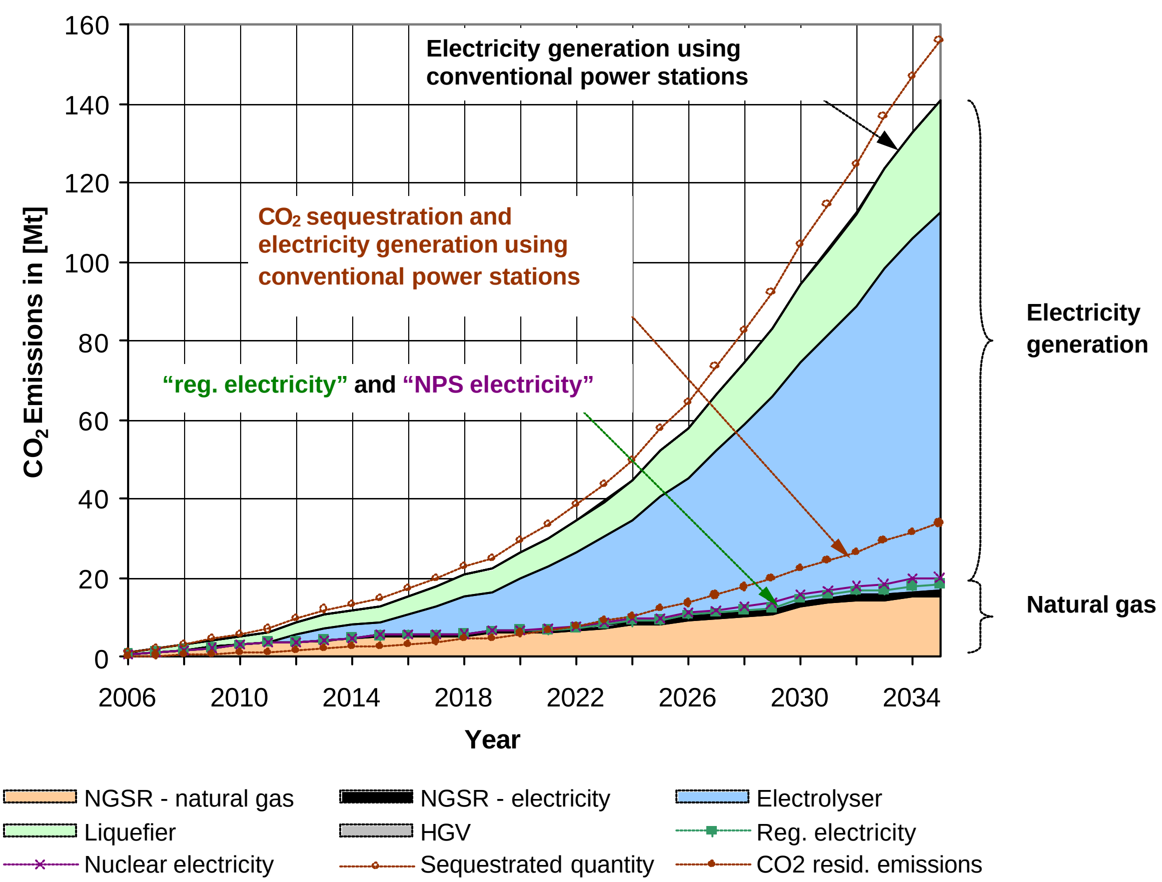
The use of **electricity from German power stations at Level 1 with CO_2 sequestration**, both in the NGSR plants and also in the fossil-fuel fired powers stations for electricity generation, causes until 2015 almost identical specific hydrogen costs as those without sequestration when using regeneratively produced electricity at Level 3. The fact that the specific hydrogen costs without sequestration when using Level 3 electricity from 2015 are not reached is due to the cost assumptions that have been made, including future potentials for sequestration cost reduction (Chapter 3.7).

6.4.2. CO_2 emissions

Annual reductions in CO_2 emissions, depending on the electricity generation as a percentage of the total emissions from German road traffic of approx. 200 Mt/a, are shown in Figure 125. The reduction in CO_2 emissions using regeneratively produced electricity is about 22 % in 2035 and about 14 % using sequestration. In other words, although the use of sequestration caused the highest reduction of CO_2 emissions in the 75N 25W 0B development path, the result here is a reversal in the trend due to higher residual emissions.

The components that cause which CO_2 emissions is shown in Figure 112. The area diagram applies to the use of electricity from German power stations. It is evident that the bulk of total CO_2 emissions arises through the generation of electricity for the electrolysis plants. The share of CO_2 emissions in the generation of electricity for the liquefaction plants is almost as high as the CO_2 emissions for NGSR ("NGSR - natural gas" area in the diagram). If regeneratively produced electricity or electricity from nuclear power is used, CO_2 emissions are still about 28 % with reference to total CO_2 emissions when using electricity from the German power stations, these being mainly caused by NGSR and not by the generation of electricity.

Figure 112: CO_2 emissions by energy source for electricity generation using conventional power stations, nuclear power (NPS electricity) and regenerative energy (reg. electricity) well to vehicle fuel tank, for the development path 40N 60W 0B in Germany from 2006 to 2035



NPS = Nuclear power station, NGSR = Natural gas steam reforming, HGV = Heavy goods vehicle (truck). Sequestrated quantity = amount of CO_2 that must be collected during hydrogen production and stored in storage sites (e.g. former oil fields). Path 40N 60W 0B = long-term hydrogen production by 40 % natural gas steam reforming and 60 % water electrolysis.
Source: Own calculations, 2002

The use of CO_2 sequestration both in NGSR plants and fossil-fuel fired power stations used for generating electricity results in a 28 % reduction in CO_2 emissions of, with reference to total CO_2 emissions when using electricity from German power stations. The amount of CO_2 to be sequestrated up to 2035 is about 160 Mt (for comparison: the current annual CO_2 emissions from road traffic in Germany are about 200 Mt).

Further information on this path regarding investments, discounted total costs and electricity requirements can be found in Appendix 8.

6.5. Hydrogen production in a long-term composition of 75 % by natural gas steam reforming, 15 % by electrolysis and 10 % by biomass gasification

The abbreviation for this development path is 75N 15W 10B. In the first section of this chapter, the composition of the path over the years is shown. In connection with this there is an analysis of the development of specific hydrogen costs and CO_2 emissions.

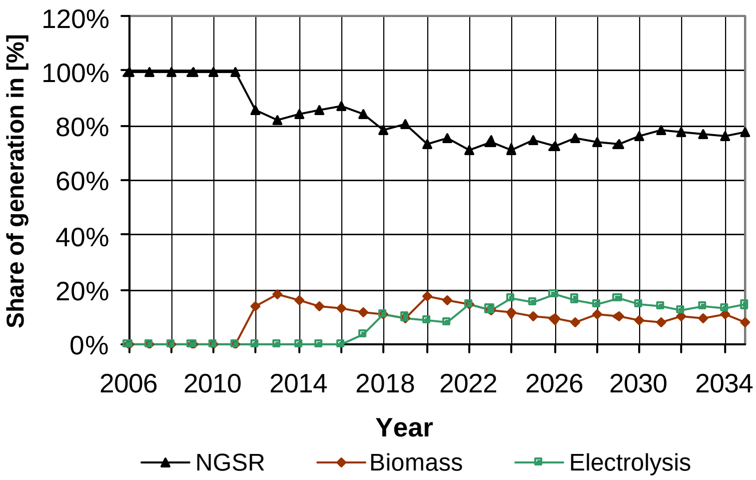
As already mentioned in Chapter 3.4, biomass gasification is important for its approximate CO_2 neutrality. Whereas the costs of hydrogen production are higher than for production by NGSR, according to the assumptions made they are lower than for production by electrolysis. With a smaller share of hydrogen production by biomass gasification in total hydrogen production, the hydrogen costs for this development path, compared with the nearly identical path 75N 25W 0B, can be slightly reduced, with almost identical reductions of CO_2 emissions.

The calculation of hydrogen costs for biomass gasification in this chapter is performed for gasification plants with a capacity of about 190 MW (type BG2, Table 21). As a basis for these calculation assumptions possible logistical problems with biomass delivery to the type BG 3 gasification plants of are identified, a biomass delivery by truck being required about every 8 minutes (Table 23).

The development of they hydrogen share produced on this development path by electrolysis and biomass gasification is shown in Figure 113. The share of sustainable hydrogen production (electrolysis and biomass gasification) corresponds to development path 75N 25W 0B (Chapter 6.3), although in this path there is partial substitution of the electrolysis plants by biomass gasification plants, which allows hydrogen costs to be reduced. Iinitial hydrogen production by biomass gasification in 2012 allows the share of sustainable hydrogen production to increase to about 20 % of the total. In the long term, the share of biomass gasification will stabilise at about 10 %.

Initial hydrogen production using electrolysis plants will take place in 2017 (capacity of an electrolysis plant of about 3 TWh H_2/a). The share of sustainable hydrogen production using electrolysis plants (using regeneratively produced electricity or electricity from nuclear power) will in the long term be held at a level of about 15 % of the total hydrogen production.

Figure 113: Development of the composition of hydrogen production by natural gas steam reforming (NGSR), electrolysis and biomass gasification for the development path 75N 15W 10B in Germany from 2006 to 2035



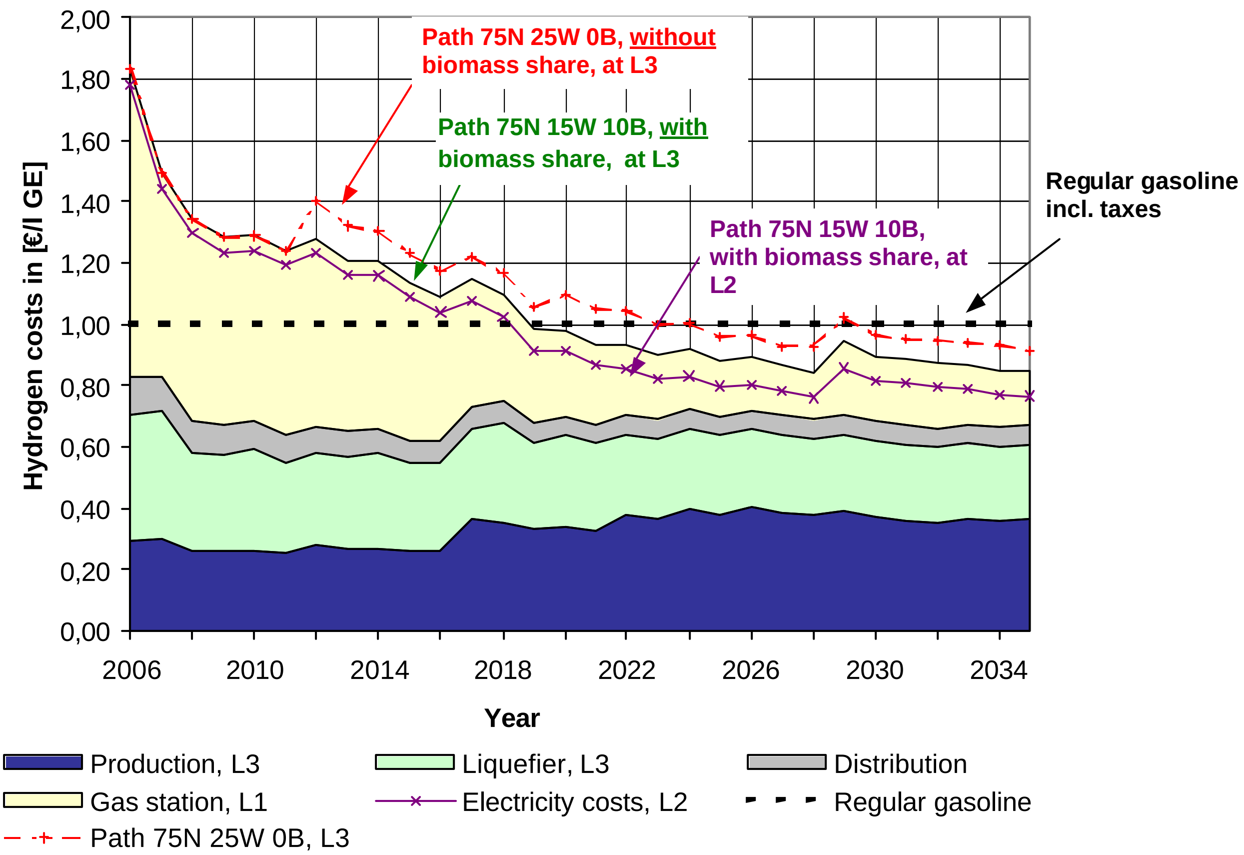
Path 75N 15W 10B = long-term hydrogen production by 75 % natural gas steam reforming, 25 % water electrolysis and 10 % biomass gasification. Source: Own calculations, 2002.

6.5.1. Specific hydrogen costs

Using **regeneratively produced electricity at Level 3** yields specific hydrogen costs in 2006 of about 1,75 €/l GE, of which the principal share is accounted for by gas station costs (Figure 114). The commissioning of biomass gasification plants (initially in 2012) causes a moderate increase in production costs (NGSR, electrolysis, biomass gasification, liquefaction). Consequently, biomass gasification results in a reduction in specific hydrogen costs by about 0.1 €/l GE compared with development path 75N 25W 0B. The use of electrolysis plants (initially in 2017) again causes a clear increase in specific production costs.

The higher the share of electrolysis in total hydrogen production, the higher the electricity requirement for and the influence of electricity costs on hydrogen costs. In the example showing the use of **electricity at Level 2**, this gives long-term specific hydrogen costs of about 0.8 €/l GE, which is clearly lower than the costs for Level 3 electricity.

Figure 114: Specific hydrogen costs for electricity generation using nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank, for the development path 75N 15W 10B with a biomass share in Germany from 2006 to 2035



L1 = electricity costs using a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1), development path 75N 15W 10B = long-term hydrogen production by 75 % natural gas steam reforming, 15 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

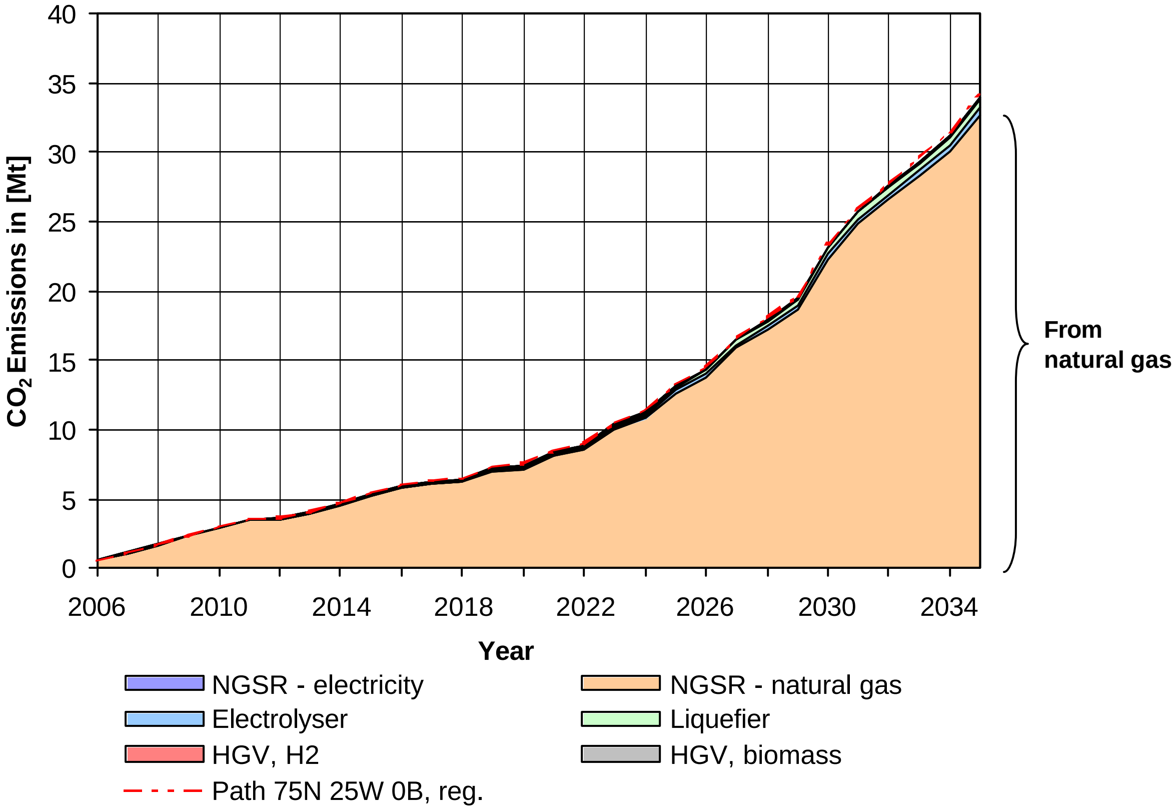
The specific hydrogen costs when using CO_2 sequestration are not shown for this development path, as there are no serious changes in the specific hydrogen costs with sequestration compared with those without sequestration at Level 2 (see development 75N 25W 0B in Figure 108).

6.5.2. CO_2 emissions

The annual reductions in CO_2 emissions as a percentage of total emissions of German road traffic of approx. 200 Mt/a are shown in Figure 125. The reduction in CO_2 emissions using regeneratively produced electricity is about 14 % in 2035, and is consequently at about the same high level as in the development path 75N 25W 0B without biomass gasification.

Which components cause which CO_2 emissions is shown in Figure 115. The area diagram applies to the use of regeneratively produced electricity. It is apparent that NGSR ("NGSR - natural gas" area) accounts for almost the entire CO_2 emissions. The CO_2 emissions caused by biomass delivery by trucks ("HGV, biomass" area) only account for a very small share of the total emissions.

Figure 115: CO_2 emissions by energy source for electricity generation from regenerative energy from well to vehicle fuel tank for development path 75N 15W 10B, with a biomass share, in Germany from 2006 to 2035



NGSR = Natural gas steam reforming. "HGV, H2" = CO_2 emissions from the transportation of liquid hydrogen by trucks from the hydrogen production plants to the gas stations. "HGV, biomass" = CO_2 emissions from the transportation of biomass by trucks from the biomass collection points to the biomass gasification plants. "Path 75N 25W 0B, reg" = CO_2 emissions in the manufacturing path 75N 25W 0B without biomass share when using regeneratively produced electricity, Development path 75N 15W 10B = long-term hydrogen production by 75 % natural gas steam reforming, 25 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

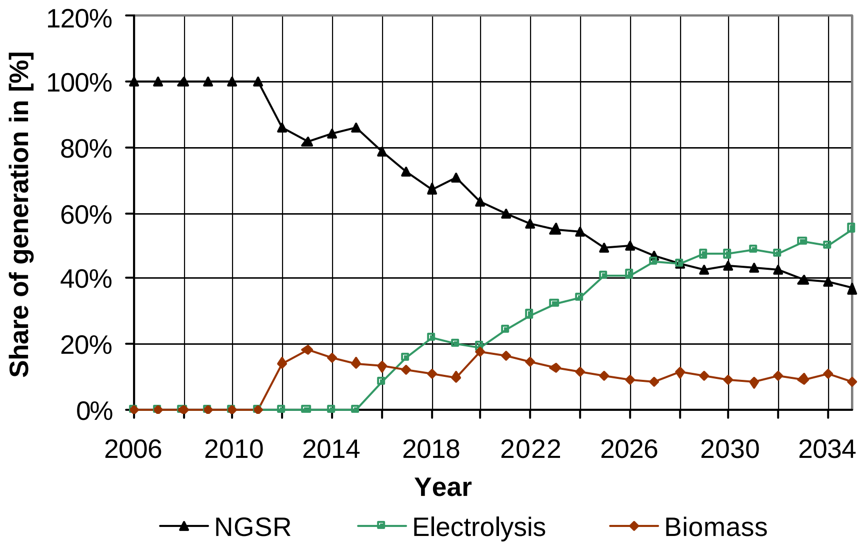
Further information on this path regarding investments, discounted total costs and electricity requirements can be found in Appendix 8.

6.6. Hydrogen production in a long-term composition of 40 % by natural gas steam reforming, 50 % by electrolysis and 10 % by biomass gasification

The abbreviation for this development path is 40N 50W 10B. In the first section of this chapter, the composition of the path over the years is shown. In connection with this there is an analysis of the development of specific hydrogen costs and CO_2 emissions. The calculation of hydrogen costs for biomass gasification is undertaken for production plants as determined for development path 75E 15W 10B in Chapter 6.5.

The development of the proportion of hydrogen produced on this development path by electrolysis and biomass gasification is shown in Figure 116. The share of sustainable hydrogen production (electrolysis and biomass gasification) corresponds to development path 40N 60W 0B (Chapter 6.4), although in this path there is partial substitution of the electrolysis plants by biomass gasification plants, which allows hydrogen costs to be reduced. Initial hydrogen production by biomass gasification in 2012 allows the share of sustainable hydrogen production to increase to about 20 % of total hydrogen production. In the long term, the share of biomass gasification will stabilise at about 10 %. Initial hydrogen production using electrolysis plants will take place in 2015 (capacity of an electrolysis plant approx. 3 TWh H_2/a). The share of sustainable hydrogen production using electrolysis plants (using regeneratively produced electricity or electricity from nuclear power) will in the long term be held at a level of about 50 % of the total hydrogen production.

Figure 116: Development of the composition of hydrogen production by natural gas steam reforming (NGSR), electrolysis and biomass gasification for development path 40N 50W 10B, in Germany from 2006 to 2035



Development path 40N 15W 10B = long-term hydrogen production by 40 % natural gas steam reforming, 50 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

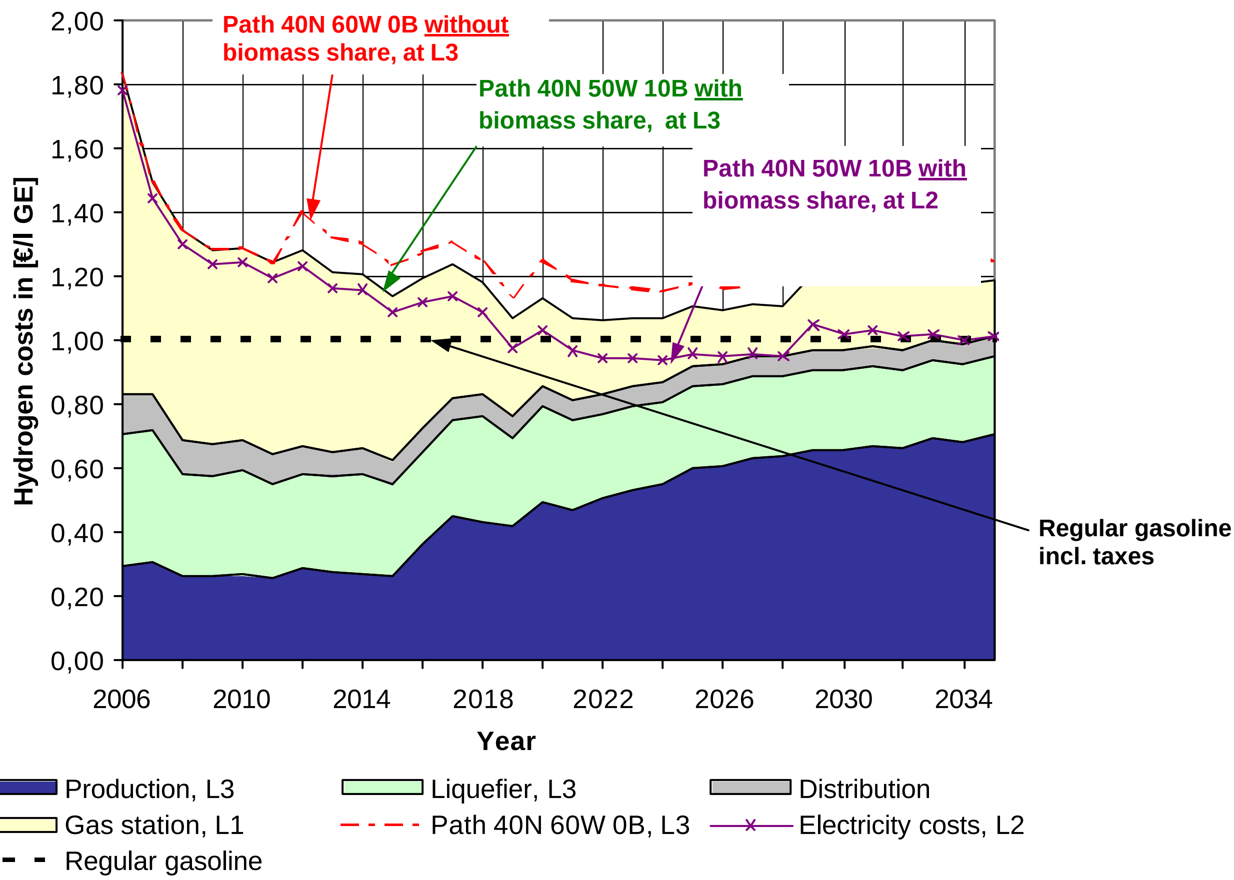
6.6.1. Specific hydrogen costs

Using **regeneratively produced electricity at Level 3**, we obtain specific hydrogen costs for this path in 2006 of about 1.75 €/l GE (Figure 117). As already described for development path 75E 15W 10B, the commissioning of biomass gasification plants (initially in 2012) leads to only a moderate increase in production costs (NGSR, electrolysis, biomass gasification, liquefaction). Due to the high long-term electrolysis share of about 50 %, the use of electrolysis plants (initially in 2017) results in a distinct increase in production costs. The long-term specific hydrogen costs are about 1.2 €/l GE, which due to the relatively high share of electrolysis is still slightly below the specific hydrogen costs of path 40N 60W 0B without a biomass share.

The increase in specific hydrogen costs in 2029 is caused by the need for a second LH_2 storage tank at the modified gas stations, which leads to an increase in specific hydrogen costs per l GE.

Specific hydrogen costs when using CO_2 sequestration are not shown for this development path, as there are no serious changes to the specific hydrogen costs with sequestration compared with those without sequestration at Level 2 (see development path 40N 60W 0B in Figure 111).

Figure 117: Specific hydrogen costs for electricity generation using nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank, for the development path 40N 50W 10B with a biomass share in Germany from 2006 to 2035



L1 = electricity costs with a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1), development path 40N 50W 10B = long-term hydrogen production by 40 % natural gas steam reforming, 50 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

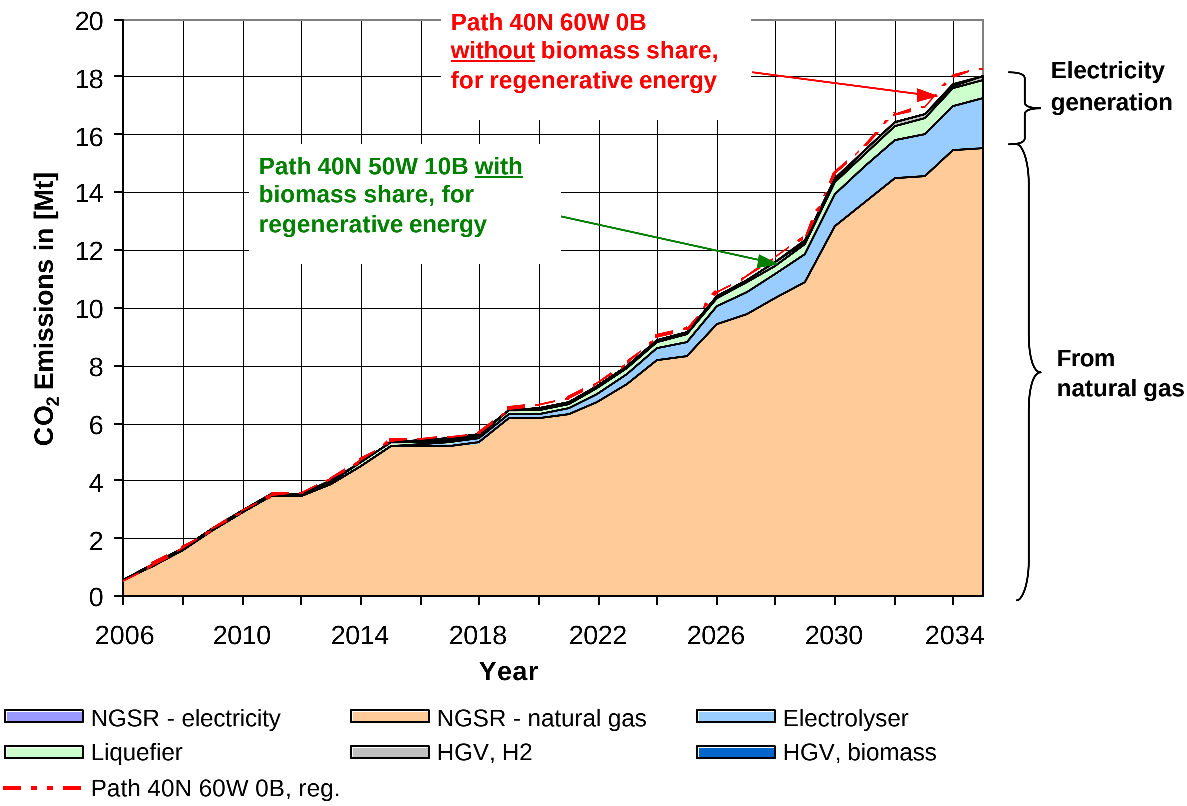
6.6.2. CO_2 emissions

Annual reductions in CO_2 emissions as a percentage of total emissions of German road traffic of approx. 200 Mt/a are shown in Figure 125. The reduction in CO_2 emissions using regeneratively produced electricity is about 22 % in 2035, and is consequently at about the same high level as with development path 40N 60W 0B.

Which components cause which CO_2 emissions is shown in Figure 118. The area diagram applies to the use of regeneratively produced electricity. It is evident that NGSR ("NGSR - natural gas" area) accounts for almost all the CO_2 emissions. Total emissions for this development path are about the same as for development path 40N 60W 0B (using regeneratively produced electricity). CO_2 emissions caused by biomass delivery by truck account for only a very small share of total emissions.

Further information on this path regarding investments, discounted total costs and electricity requirements can be found in Appendix 8.

Figure 118: CO_2 emissions by energy source for electricity generation from regenerative energy from well to vehicle fuel tank, for the development path 40N 50W 10B with a biomass share in Germany from 2006 to 2035

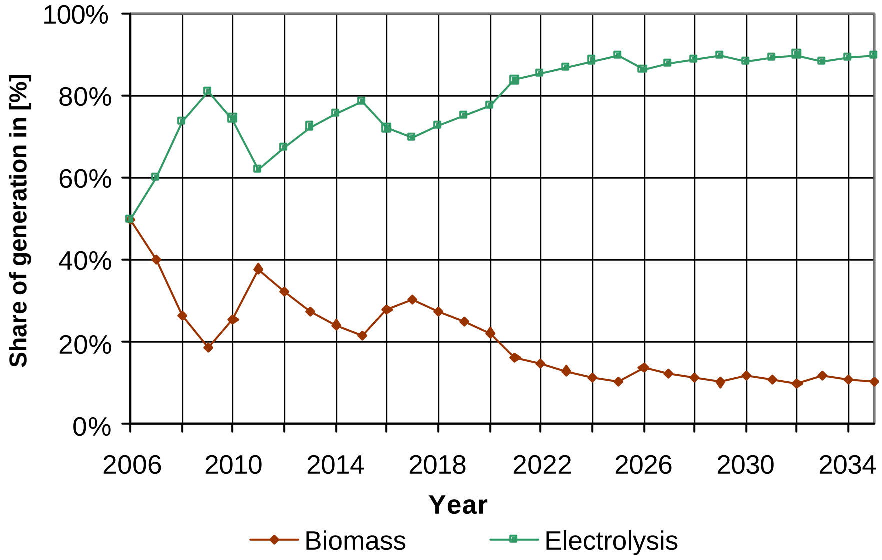


NGSR = Natural gas steam reforming. “HGV, H2" = CO_2 emissions from the transportation of liquid hydrogen by trucks from the hydrogen production plants to the gas stations. “HGV, biomass” = CO_2 emissions from the transportation of biomass by trucks from the biomass collection points to the biomass gasification plants. “Path 40N 60W 0B, reg” = CO_2 emissions in the development path 40N 60W 0B without biomass share when using regeneratively produced electricity. Development path 40N 50W 10B = long-term hydrogen production by 40 % natural gas steam reforming, 50 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

6.7. Hydrogen production in a long-term composition of 90 % by natural gas steam reforming and 10 % by biomass gasification

The abbreviation for this development path is 0N 90W 10B. The development of the hydrogen share which in this development path is produced by electrolysis and biomass gasification is shown in Figure 119. The share of both production process in the total amount of hydrogen produced is 50 % each in the first year. The production share obtained from biomass gasification decreases by 2025 to 10 % and that of the electrolysis plants increases to about 90 %. The high production share of biomass gasification in the first few years can be achieved without the risk of exhausting the potential, as the annual quantities of hydrogen required in this period are still small.

Figure 119: Development of the composition of hydrogen production by electrolysis and biomass gasification for the development path 0N 90W 10B in Germany from 2006 to 2035



Development path 0N 90W 10B = long-term hydrogen production by 90 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

6.7.1.Specific hydrogen costs

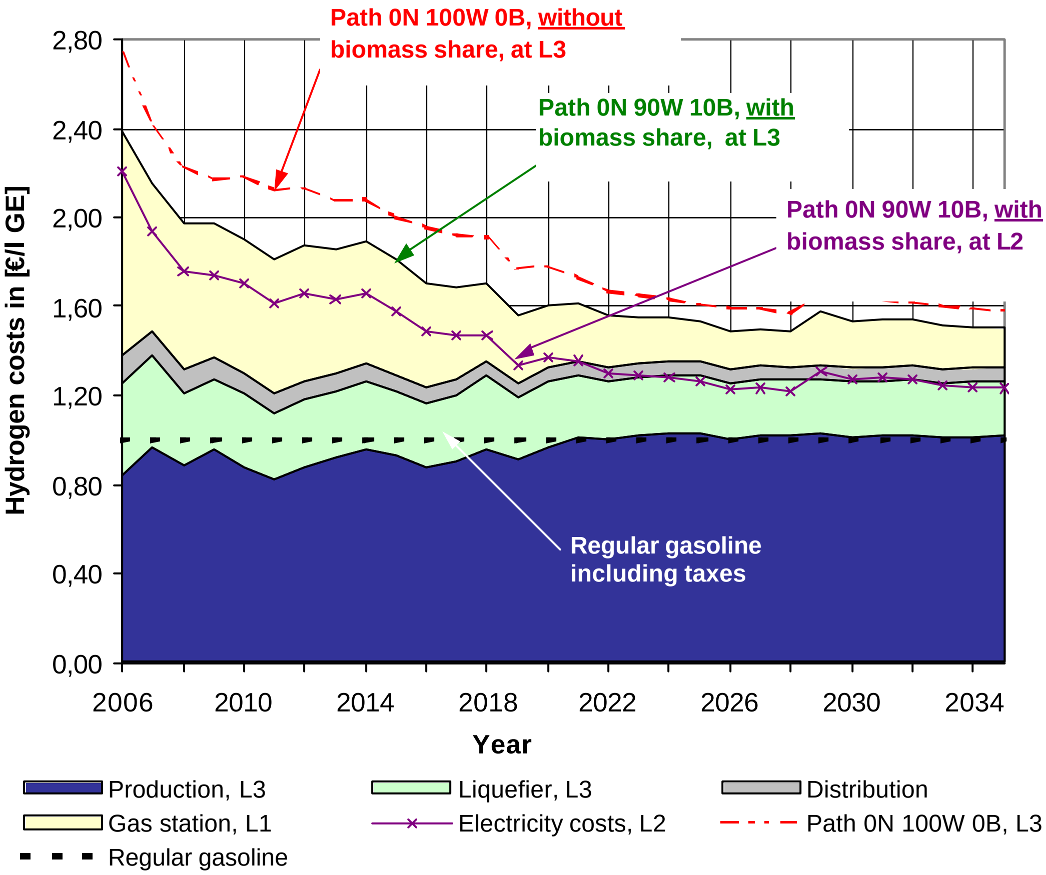
Using **regeneratively produced electricity at Level 3** gives specific hydrogen costs in 2006 of about 2.4 €/l GE, the principal share being accounted for by electrolysis and gas station costs (Figure 120). The reduction in specific hydrogen costs in the subsequent period is primarily accounted for by the increase in gas station usage and the associated decrease in gas station costs. As electricity costs form the main element in electrolysis costs, there is also limited potential for the reduction of production costs.

The increase in specific hydrogen costs in 2029 is caused by the need for a second LH_2 storage tank at the modified gas stations, which causes an increase in specific hydrogen costs per l GE.

The use of biomass gasification results in a clear reduction up to 2022 in specific hydrogen costs compared with development path 0N 100W 0B without biomass gasification. This reduction is brought about by the relatively high share of hydrogen production by biomass gasification during this period. As the biomass potential is limited, the long-term production share can only be about 10 %, and the long-term reduction of specific hydrogen costs is therefore equally low compared with path 0N 100W 0B.

Specific hydrogen costs when using CO_2 sequestration are not shown for this development path, as there are no serious changes to the specific hydrogen costs with sequestration compared to those without sequestration at Level 2 (see development path 0N 100W 0B inFigure 97).

Figure 120: Specific hydrogen costs for electricity generation using nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank, for the development path 0N 100W 10B with a biomass share in Germany from 2006 to 2035



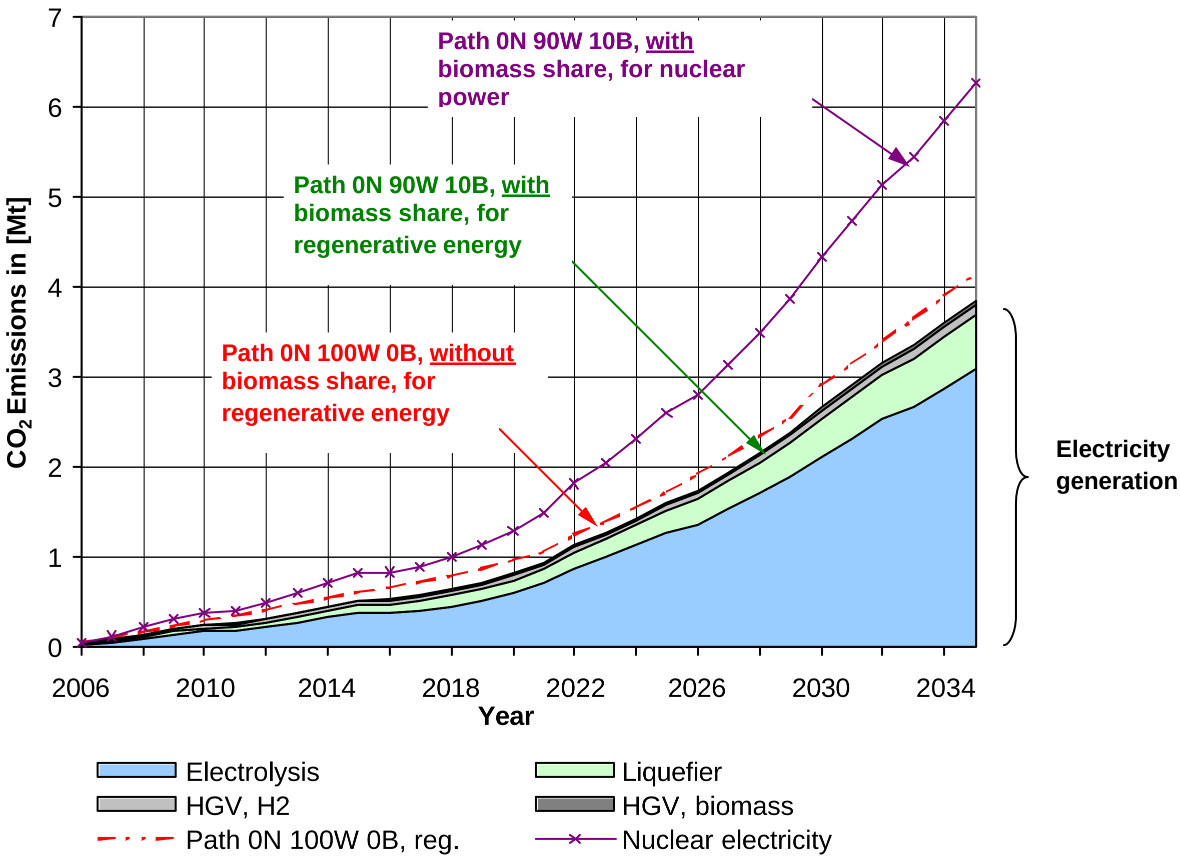
L1 = electricity costs using a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, development path 0E 90W 10B = hydrogen production by 90 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

6.7.2. CO_2 emissions

Annual reductions in CO_2 emissions as a percentage of the total emissions from German road traffic of approx. 200 Mt/a are shown in Figure 125. The reduction in CO_2 emissions using regeneratively produced electricity is about 29 % in 2035, and is consequently at approximately the same high level as in development path 0N 100W 0B.

Which components cause which CO_2 emissions is shown in Figure 121. Due to the lower electricity requirement of the liquefaction plants compared with the electrolysis plants, these have a share in total CO_2 emissions of less than 10 %. Due to the long-term share of about 10 % of biomass gasification in total hydrogen production, there is a slight reduction in emissions compared with path 0N 100W 0B. CO_2 emissions from biomass delivery by trucks ("HGV, biomass" curve) account for only a very small share of the total emissions.

Figure 121: CO_2 emissions by energy source for electricity generation from regenerative energy from well to vehicle fuel tank for the development path 0N 90W 10B, with a biomass share in Germany from 2006 to 2035



"HGV, H2" = CO_2 emissions from the transportation of liquid hydrogen by trucks from the hydrogen production plants to the gas stations. "HGV biomass" = CO_2 emissions from the transportation of biomass by trucks from the biomass collection points to the biomass gasification plants. NPS = Nuclear power station. "Path 0N 100W 0B, reg" = CO_2 emissions in the development path 0N 100W 0B without biomass share when using regeneratively produced electricity. Development path 0N 90W 10B = long-term hydrogen production by 90 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

The use of electricity from nuclear power causes clearly higher total emissions, since on average about 25 g CO_2/kWh_{el} and for regeneratively produced electricity only about 15 g CO_2/kWh_{el} arise per generated unit of energy at nuclear power stations (Chapter 3.2.3).

Further information on this path regarding investments, discounted total costs and electricity requirements can be found in Appendix 8.

6.8. Comparison of the paths

This chapter contains a comparison of the development paths, following a comprehensive examination of significant path compositions in Chapters 6.1 to 6.7. The focus of the analysis lies in the development of

- specific hydrogen costs
- potential for the reduction of CO_2 emissions
- discounted total costs
- incremental costs
- electricity requirements and
- composition of the average specific hydrogen costs

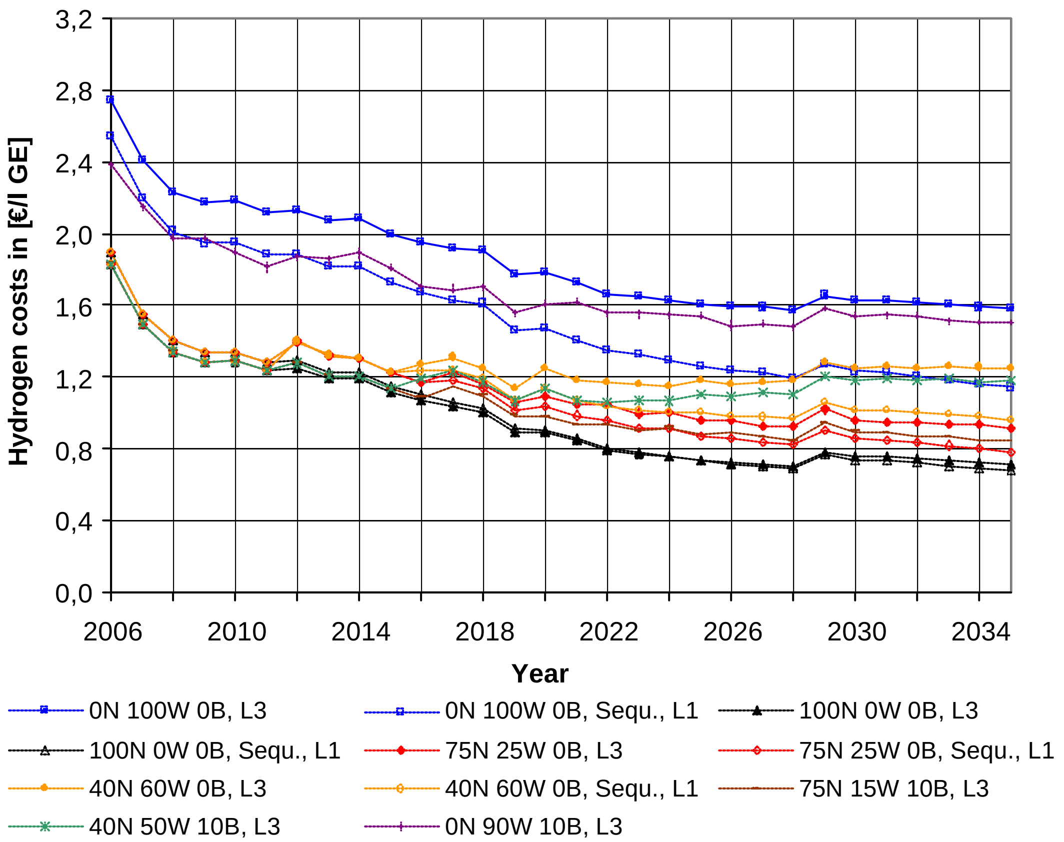
A summary of the results reduced to key analysis factors for the development of a hydrogen infrastructure in Germany if the various development paths are realized is shown in table form in Tables 55 and 56 in Appendix 9. As Chapter 6 contains adequate documentation of the values, this is not undertaken in the appendix.

6.8.1.Level and development of specific hydrogen costs

Comparison of the patterns of specific hydrogen costs for the paths in Figure 122 shows that the highest hydrogen costs in path 0N 100W 0B arise when using regeneratively produced electricity at Level 3. The lowest hydrogen costs are found in path 100N 0W 0B. The specific hydrogen costs of these two paths run approximately parallel as time progresses, with a cost difference of about 0.9 €/l GE.

The specific hydrogen costs of all the development paths assume a flatter curve from 2012 on and therefore a higher cost level compared with path 100N 0W 0B, due to the initial commissioning in that year of plants for sustainable hydrogen production (electrolysis, biomass gasification).

Figure 122: Specific hydrogen costs for electricity generation using conventional power stations (L1) and regenerative energy (L3) from well to vehicle fuel tank, for various hydrogen production development paths with and without sequestration, in Germany from 2006 to 2035



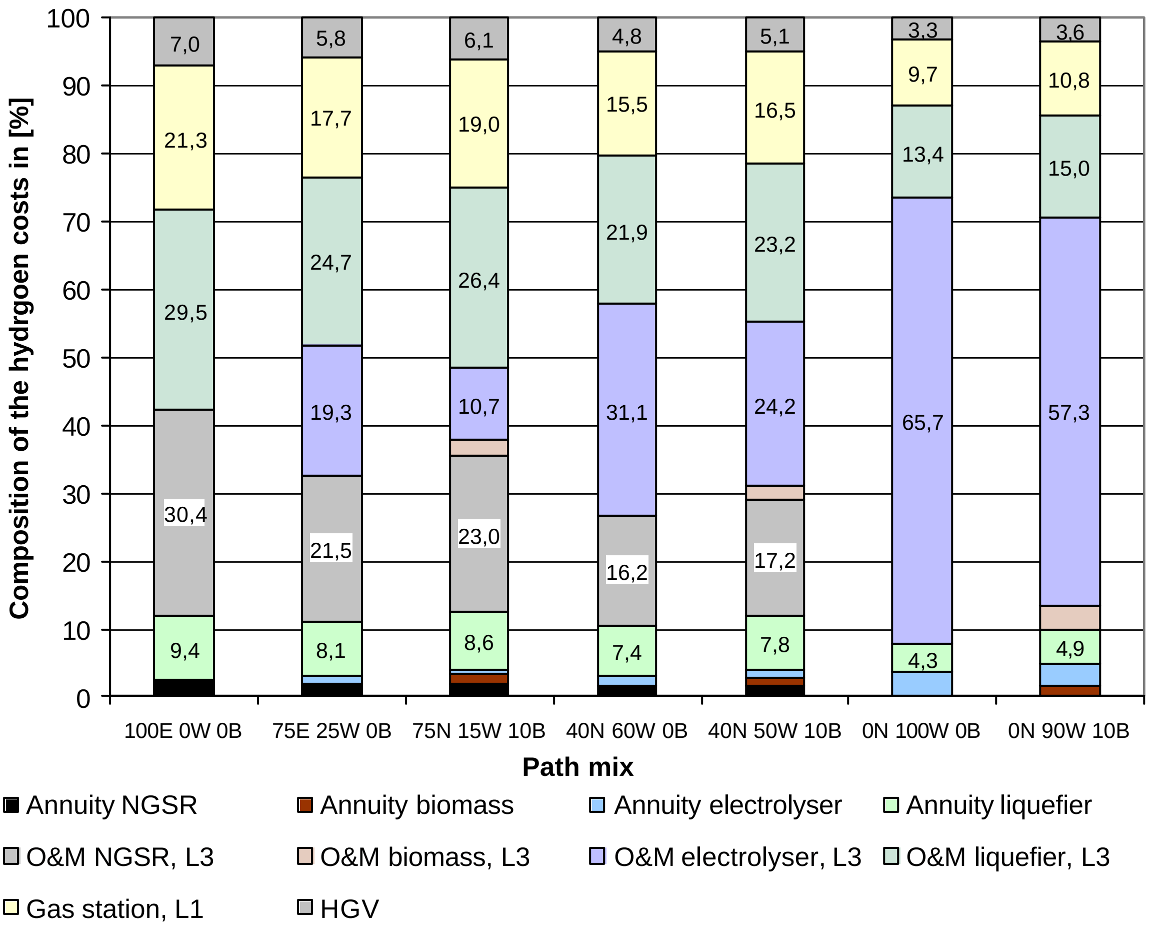
L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs according to Level 1 (NL1). Specimen key description: "75N 15W 10B, L3" = long-term hydrogen production by 75 % natural gas steam reforming, 15 % water electrolysis and 1 0% biomass gasification with electricity generation from regenerative energy. "75N 25W 0B, Sequ., L1" = long-term hydrogen production by 75 % natural gas steam reforming, 25 % water electrolysis when using CO_2 sequestration in the generation of electricity using conventional power stations.
Source: Own calculations, 2002

6.8.2.Composition of specific hydrogen costs

The extent to which individual components influence specific hydrogen costs when using regeneratively produced electricity at Level 3 is shown in a detailed overview in Figure 123. The average composition of specific hydrogen costs for the period 2006 to 2035 was used as a basis for the calculation (Figure 86, Figure 97, Figure 108, Figure 111, Figure 113, Figure 117 and Figure 120). It should be stressed that the cost influence of the individual components on specific hydrogen costs varies over the years. To maintain the clarity of the diagram, only meaningful shares are indicated in the data description.

Figure 123 essentially shows that the annuities of investments in hydrogen production plants (NGSR, electrolysis and liquefaction plants, biomass gasification) and the transport costs ("HGV" block) only have a small influence on the costs. However, at about 10 to 20 %, a very important influence is exerted by the annuities of investments in the gas station infrastructure, as a consequence of low gas station utilization in the first few years (Figure 84 and Figure 85). Partial substitution of the electrolysis plants by biomass gasification plants causes a slight reduction of the influence of electricity costs in all cases.

Figure 123: Average composition of the specific hydrogen costs from well to vehicle fuel tank for various hydrogen production development paths in Germany from 2006 to 2035

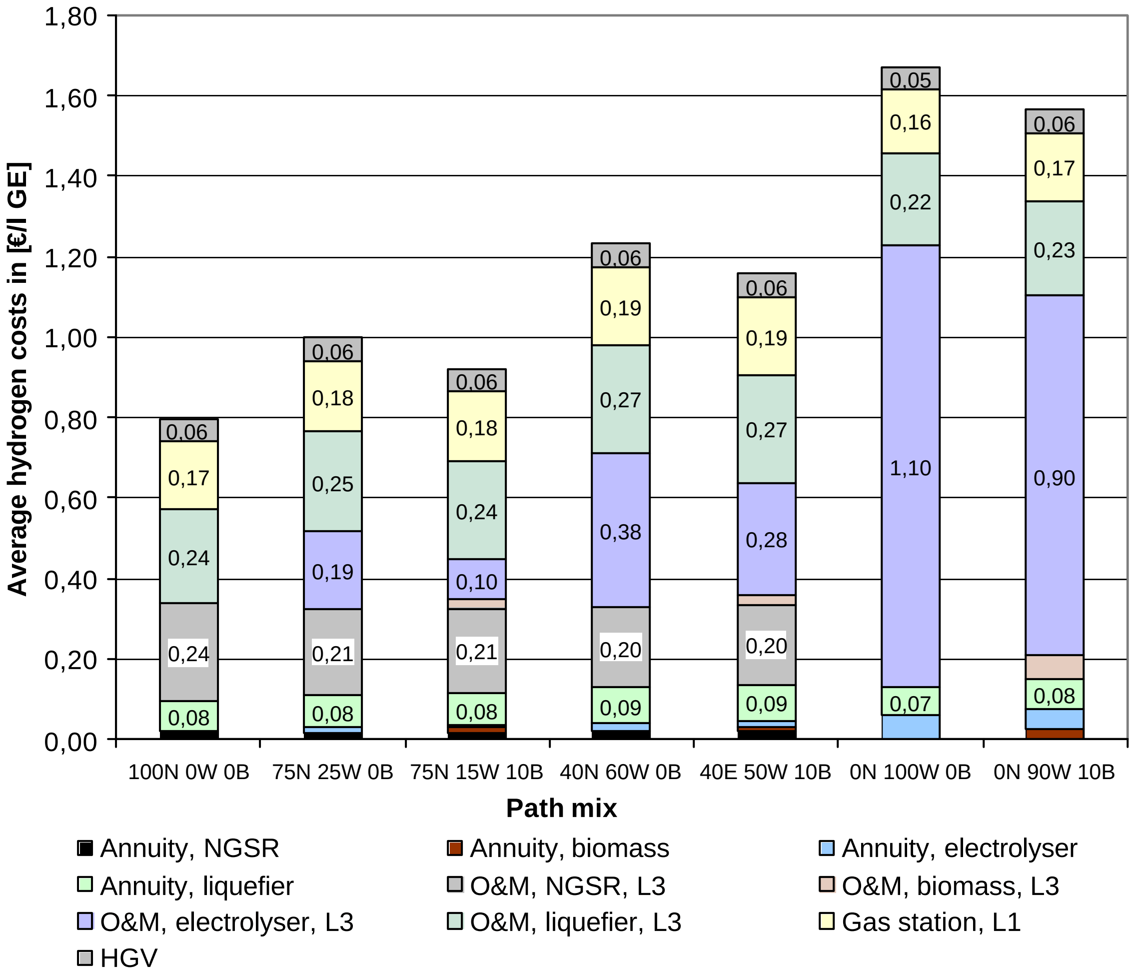


L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1), O&M = operating and maintenance costs, NGSR = Natural Gas Steam Reforming, truck = Heavy Goods Vehicle. Specimen key description: "40N 50W 10B" = long-term hydrogen production by 40 % natural gas steam reforming, 50 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

Development path 100N 0W 0B exhibits a clear cost influence through the natural gas costs (the "O&M NGSR, L3" bar), the electricity costs (bar "O&M liquefier, L3") and the gas station costs (the "Gas station, L1" bar). With an increasing share of electrolysis in the production path, the influence of electricity costs on hydrogen costs rises. The greatest influence of the electricity costs is in **development path 0N 100W 0B**, at about 80 % (the "O&M electrolyser, L3" and "O&M liquefier, L3" bars).

The level and compositions of average hydrogen costs when using regeneratively produced electricity at Level 3 are shown in Figure 124. It should be stressed that average hydrogen costs are only slightly higher than long-term specific hydrogen costs. Starting from the lowest average hydrogen costs of about 0.8 €/l GE for development path 100N 0W 0B, the increase in the share of electrolysis in hydrogen production also results in an increase in average hydrogen costs. If the hydrogen is produced exclusively by electrolysis, as in development path 0N 100W 0B, the average hydrogen costs reach a level of around 1.7 €/l GE.

Figure 124: Level and composition of the average hydrogen costs from well to vehicle fuel tank for various hydrogen production development paths in Germany from 2006 to 2035

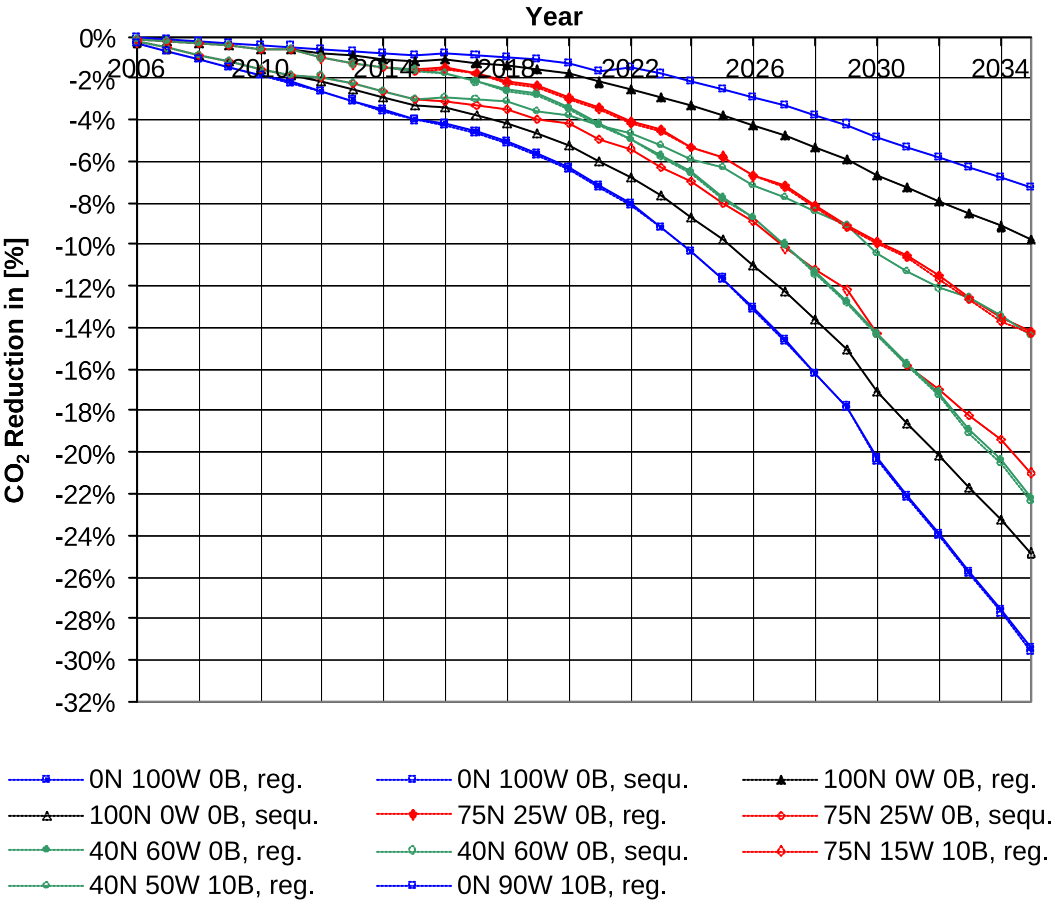


L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1), O&M = operating and maintenance costs, NGSR = Natural gas steam reforming, HGV = Heavy goods vehicle (truck). Specimen key description: "40N 50W 10B" = long-term hydrogen production by 40 % natural gas steam reforming, 50 % water electrolysis and 10 % biomass gasification.
Source: Own calculations, 2002

6.8.3. Long-term potential for CO_2 reduction

The potential annual reductions in CO_2 emissions as a percentage of the total emissions of German road traffic of approx. 200 Mt/a for the individual development paths are shown in Figure 125. The highest potential CO_2 reduction of 30 % (using regeneratively produced electricity) is obtained with development path 0N 100W 0B in 2035, followed by 25 % for development path 100N 0W 0B when using CO_2 sequestration. The worst results are for development paths 0N 100W 0B using CO_2 sequestration and 100N 0W 0B using regeneratively produced electricity.

Figure 125: Reduction in CO_2 emissions as a percentage of the total emissions of CO_2 of road traffic in Germany of around 200 Mt per year by electricity-generation energy source from well to vehicle fuel tank, for various hydrogen production development paths with and without sequestration in Germany from 2006 to 2035



Specimen key description: "75N 15W 10B, reg" = long-term hydrogen production by 75 % natural gas steam reforming, 15 % water electrolysis and 10 % biomass gasification with electricity generation from regenerative energy. "75N 25W 0B, sequ." = long-term hydrogen production by 75 % natural gas steam reforming, 25 % water electrolysis when using CO2 sequestration in the generation of electricity using conventional power stations.
Source: Own calculations, 2002

Figure 122 and Figure 125 show that for a possible long-term CO_2 reduction, development path 0N 100W 0B using regeneratively produced electricity should be aimed for; however, this accounts for the highest specific hydrogen costs. At the other end of the scale is development path 100N 0W 0B, which accounts for the lowest specific hydrogen costs but achieves only a marginal long-term reduction in CO_2, assuming the use of regeneratively produced electricity or electricity from nuclear power. To find an optimum balance of total costs and emissions, the total costs that arise from the realization of the hydrogen production development paths in relation to the achievable reduction in annual CO_2 emissions from road traffic are examined.

6.8.4. Discounted total costs

To arrive at an **optimum balance of total costs and emissions**, the total costs, discounted for 2006, that arise in the realization of a hydrogen production development path, in relation to the achievable reduction in annual CO_2 emissions from road traffic, are examined. Through the variation of the composition of the development path from exclusive hydrogen production by natural gas steam reforming and the combination of different production processes to the exclusive hydrogen production by electrolysis, S-shaped curves are obtained, which represent the relationship between the discounted total costs and the reduction in CO_2 emissions, in other words the **total cost/emission reduction curves** (Figure 126). In terms of the discounted total costs (identified in this chapter as "total costs"), this concerns the cumulative annual annuities of the investments (hydrogen production plant, distribution, gas stations) over the writing-off period and the operating and maintenance costs. As the build-up of a hydrogen infrastructure for supplying vehicles with hydrogen requires a planning timeframe covering several decades (in this paper, from 2006 to 2035), the total costs of a development path over this timeframe are based on 2006 (the "current value" of the costs).

The calculation assumptions for the diagrams are:

- determining the total costs in five-year stages for the years 2020, 2025, 2030 and 2035 (resulting in four S-curves)
- each S-curve represents the connection between total cost and CO_2 reduction depending on the development paths for a particular period of time
- regenerative electricity production makes use of wind power stations (50 % offshore, 50 % onshore, with a learning degression factor of 0.95; the plant specifications are shown in Appendix 5)
- development of a gas station infrastructure according to GSID 4+7 (Chapter 5.5.1)
- percentage reductions in CO_2 emissions in relation to total CO_2 emissions from road traffic in Germany of approx. 200 Mt/a.

For the development paths that do not take sequestration into account, the achievable CO_2 reduction as well as the total costs increase with the proportion of electrolysis in the development path, starting from the path of exclusive hydrogen production by natural gas steam reforming with the lowest total costs and potential for CO_2 reduction. **The total cost – emissions reduction curve for a year is an S-shaped curve and runs from bottom left to top right.**

The development path with hydrogen production exclusively by natural gas steam reforming using sequestration has the lowest total costs with the highest potential for CO_2 reduction (the CO_2 produced in the fossil generation of electricity and hydrogen production is collected and stored at storage sites, so that there is no release of anthropogenic emissions into the atmosphere). With an increasing share of electrolysis in the production path, the total costs increase and the achievable CO_2 reductions decrease. Accordingly, the higher the share of electrolysis in total hydrogen production (and therefore the electricity requirement), the higher the residual emissions when using sequestration. **The total cost – emissions reduction curve for a year is an S-shaped curve and runs from bottom right to top left.**

It should be remembered here that according to VPD OWN the complete modification of the 12,000 gas stations (Chapter 5.5), a fuel substitution of about 30 % (Chapter 2.3.4) and a share of registrations of new vehicles for hydrogen as an alternative fuel of about 50 % will be reached in Germany in 2035.

For a better overview, there is an examination of total costs and CO_2 reduction separately for paths with and without a biomass share in the hydrogen production.

6.8.4.1. Total costs for paths without biomass share

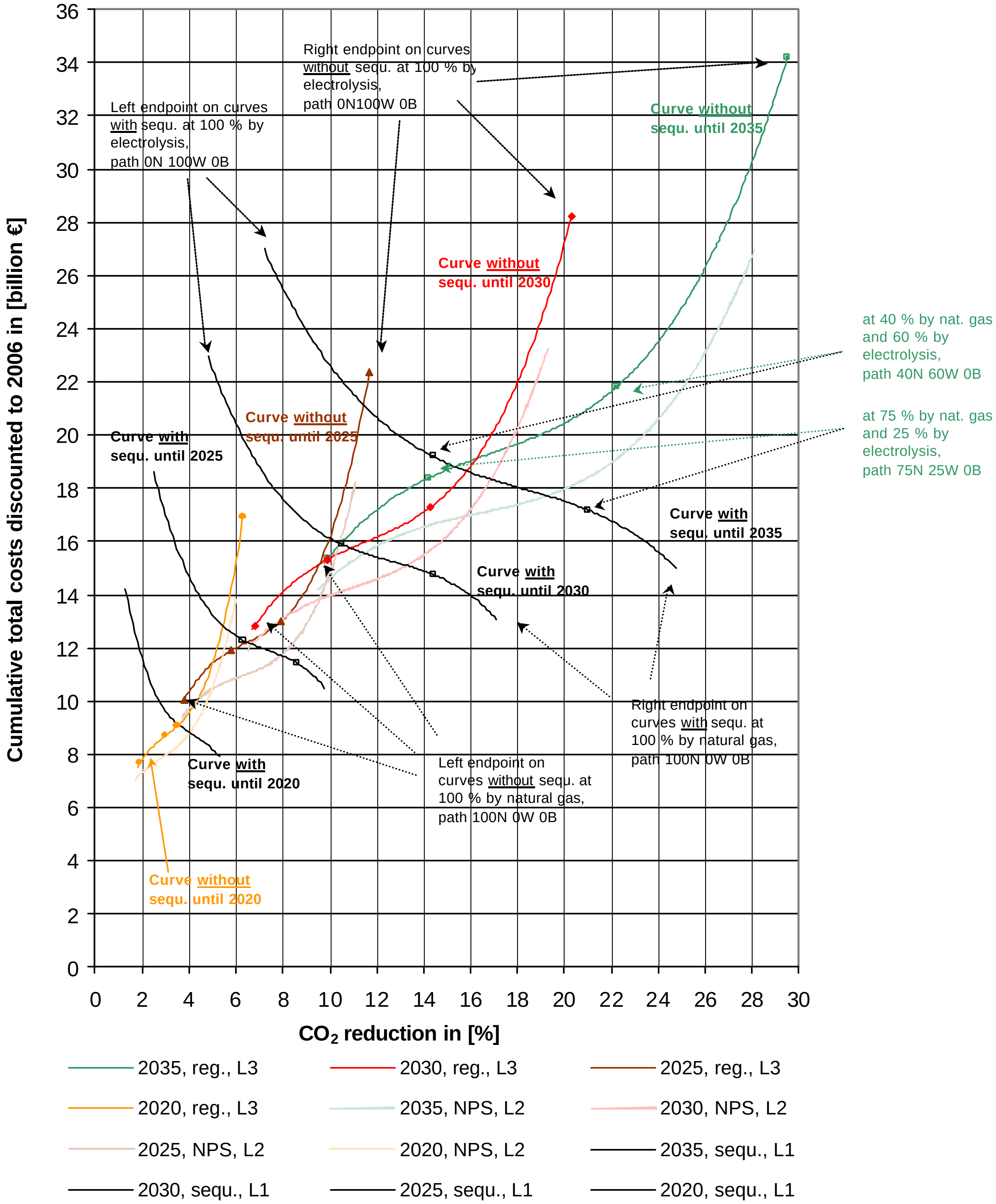
For the **development path without sequestration** using regeneratively produced electricity at Level 3 for 2035 it can be seen that the highest CO_2 reduction of about 30 % is achieved in path 0N 100W 0B, with total costs of about 34 billion € (curve "Year 2035, reg., L3" in Figure 126). The lowest CO_2 reduction of about 10 % is achieved with path 100N 0W 0B, with total costs of about 15 billion €. For the remaining development paths, the values for the total costs and CO_2 reduction fall within the range formed by the paths 100N 0W 0B and 0N 100W 0B. An analysis of the different gradients of the S-curves is provided in Chapter 6.8.5.

For development paths without sequestration using electricity from nuclear power at Level 2, the total costs can be clearly reduced compared with those incurred when using regeneratively produced electricity at Level 3. However, the achievable CO_2 reductions have lower values than the reductions obtained when using the identical development path with regeneratively produced electricity, since nuclear power stations emit higher CO_2 emissions than those from regenerative electricity generation (Chapter 3.2.3).

To determine the total costs and the CO_2 reduction for the **development paths with sequestration** in Figure 126, electricity from German power stations at Level 1 has been assumed (Chapter 3.2.1). The total cost – emissions reduction curves run in opposing directions to those for the paths without sequestration, i.e. the higher the share of electrolysis in total hydrogen production (and therefore the electricity requirement), the higher the residual emissions when using sequestration. The limited application of CO_2 sequestration can also be seen here. Up to the point where the total cost – emissions reduction curves with the use of sequestration cross those without sequestration, the development paths with sequestration, which lie to the right of the intersection of the curves, are to be preferred over the development paths without sequestration. For example, whereas the development path 100N 0W 0B with sequestration achieves a CO_2 reduction of about 25 % at total costs of about 15 billion €, the development path 100N 0W 0B using regeneratively produced electricity at Level 3, on the other hand, achieves a CO_2 reduction of about 10 % at total costs of also approximately 15 billion €.

In the example of the total cost – emissions reduction curves for 2035, the intersection of the curves mentioned above is analysed more closely, with and without the use of sequestration. When using regeneratively produced electricity at Level 3, development without sequestration up to an electrolysis share of around 30 % is at a disadvantage compared with the development paths with sequestration. However, the curve with sequestration exhibits an electrolysis share of 50 % in the development path up to the intersection of the two curves, where the total costs are identical with development path 70N 30W 0B with regeneratively produced electricity at Level 3. When quoting the path data for the intersection of the total cost – emissions reduction curves with and without the use of sequestration, the reference curve data (with or without sequestration) is therefore also significant.

Figure 126: Total cost – emissions reduction curves for electricity generation using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) with and without the use of CO_2 sequestration from well to vehicle fuel tank for various hydrogen production development paths in Germany from 2020 to 2035



L1 = electricity costs using a conventional power station, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1), reg. = regenerative, NPS = nuclear power station, Sequ. = sequestration. Specimen key description: "Year 2035, reg., L3" = Cumulative total costs, discounted to 2006, of the considered timeframe of 2006 to 2035 in the generation of electricity using regenerative energy.
"Year 2035, Sequ., L1" = Cumulative total costs, discounted to 2006, of the considered timeframe of 2006 to 2035 for the use of sequestration with the generation of electricity using conventional power stations.
Source: Own calculations, 2002

The use of sequestration is only interesting for the development path with an electrolysis share above 50 % if the residual emissions can be held at a level lower than the one assumed here. In the diagram, residual power station emissions of 177 g CO_2/kWh were used to determine CO_2 reductions (Chapter 3.7). If higher residual emissions occur, the overall cost – emissions reduction curves with the use of sequestration move to the left, towards lower CO_2 reductions. Moreover, an increasing electrolysis share in the development path (and therefore higher electricity requirements and residual emissions) also results in a more marked flattening of the curves with sequestration, which implies that the intersection of the total cost – emissions reduction curves with and without the use of sequestration shifts to the left, towards lower CO_2 reductions. This also results in a reduction of the electrolysis share in the development paths with sequestration, up to which it had until now showed advantages compared with the paths without sequestration.

Influence of the development of the gas station infrastructure on total costs
In this section there is an estimation of the variation in the level of the total costs of the development paths depending on the gas station infrastructure development scenarios examined in Chapter 5.5.1. Figure 126 shows the total costs of the development paths for the development of the gas station infrastructure in Germany according to GSID 4+7. If these total costs are now higher than assumed, the total cost – emissions reduction curves move upwards, and vice versa.

The GSID 4+7 gas station infrastructure chosen for the calculation in Figure 126 shows total costs which lie in the centre of the total costs of the other scenarios (Figure 79). The variation in the total costs of all scenarios up to 2018 is a maximum of plus/minus 20 % with reference to the total costs with GSID 4+7.

To further estimate the total costs up to 2035, there is an examination of the variation in total costs of the gas station infrastructure development scenarios in Munich (Figure 66). The level of these total costs is not precise, although it approximately reflects the extent of the variation in the total costs in a long-term examination of different developments of the gas station infrastructure. Using the ratio determined earlier, the Munich GSID 7 was transferred to the development of the gas station infrastructure in German cities (Chapter 5.4), for which the total costs are shown in Figure 126. The total costs of GSID 7 represent the average value compared with the other gas station infrastructure development scenarios in Munich. The variation in the total costs of all scenarios up to 2035 is also a maximum of plus/minus 20 % with reference to the total costs of GSID 7.

In view of the good conformity of the variance of the total costs of a maximum of plus/minus 20 %, both for a short-term and long-term examination of the total costs, this estimated value can be used for the examination of the influence on the total costs of the paths in Figure 126. The total costs for the development of the gas station infrastructure in Germany according to GSID 4+7 up to 2035 are approximately 3 billion € (Appendix 7). With the maximum variance of 20 %, this results in total costs of approximately 2.4 to 3.6 billion € (bandwidth of 1.2 billion €).

In the example using development path 40N 60W 0B, the total costs up to 2035 amount to approx. 22 billion €. Taking into consideration the maximum bandwidth of total gas station infrastructure development costs, this yields a variation of the total costs for the development path of between 21.4 and 22.6 billion €.

In general, the following statements can be made:

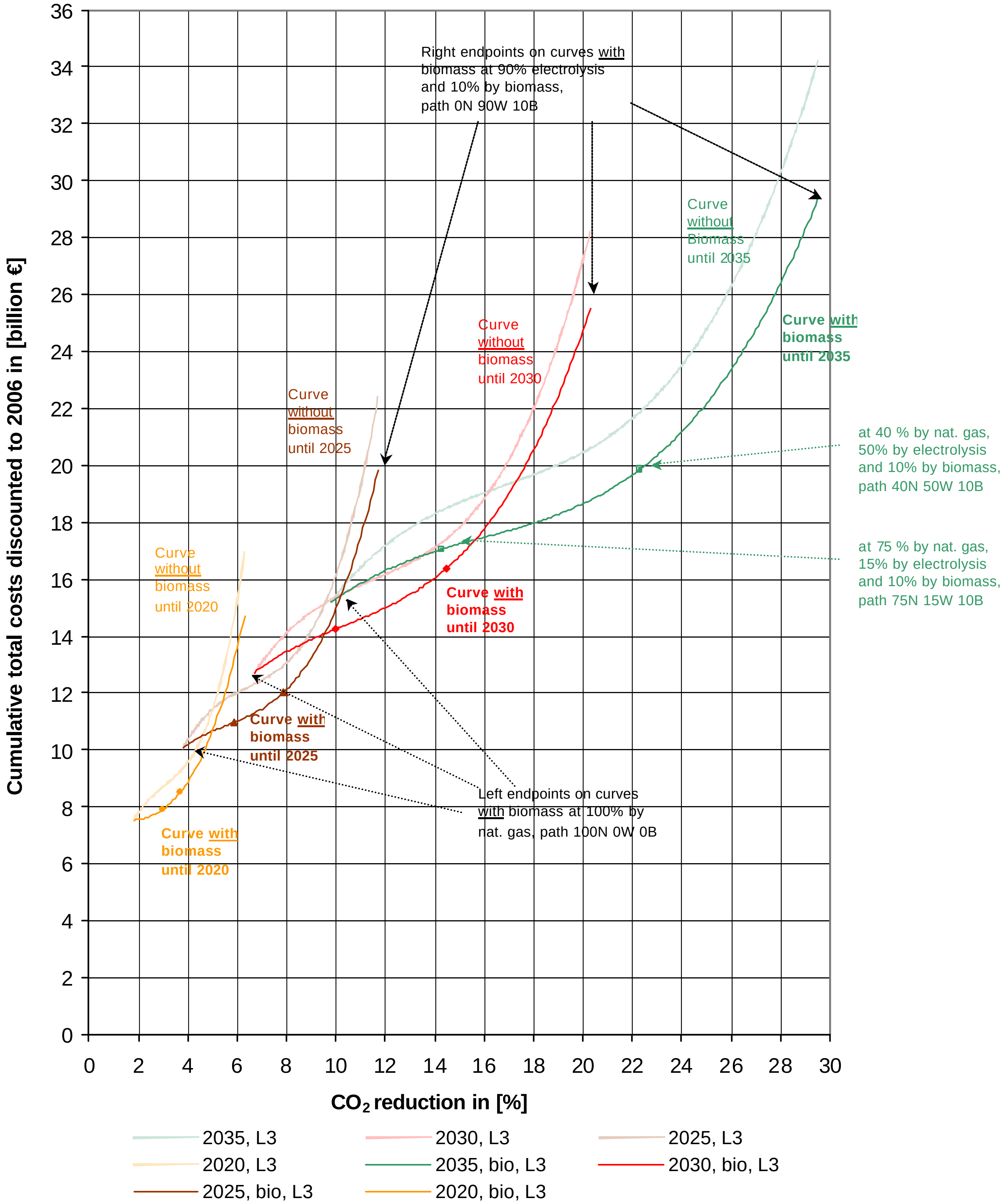
- the influence of the total costs of the development of a gas station infrastructure has a subordinate role on the total costs of the development path
- the higher the total costs of the development path prove to be (e.g. path 0N 100W 0B), the lower the influence of the total costs of the gas station infrastructure

6.8.4.2. Total costs for paths with biomass share

The effects of a long-term share of about 10 % of biomass gasification in the total hydrogen production on the total costs, and the CO_2 reduction, are shown in Figure 127. The total costs for the development paths with a biomass share essentially fall by around 10 % compared with the total costs without a biomass share, at approximately the same level of CO_2 reductions, as a consequence of the approximate CO_2 neutrality of the biomass.

As already described in the analysis of the development paths without a biomass share, by using electricity from nuclear power at Level 2, there is a clear drop in total costs compared with the total costs using electricity at Level 3.

Figure 127: Total cost – emissions reduction curves for electricity generation using regenerative energy (L3) from well to vehicle fuel tank for various hydrogen production development paths with and without consideration of biomass, in Germany from 2020 to 2035



L3 = Electricity costs using regenerative production, natural gas costs at Level 1 (NL1), Bio = biomass. Specimen key description: “Year 2035, L3” = Cumulative total costs, discounted to 2006, without a biomass share in hydrogen production of the considered timeframe of 2006 to 2035 with electricity generation using regenerative energy.
“Year 2035, Bio, L3” = Cumulative total costs, discounted to 2006, with a biomass share in hydrogen production of the considered timeframe of 2006 to 2035 with electricity generation using regenerative energy.
Source: Own calculations, 2002

There is no presentation of the development paths with CO_2 sequestration, as the development paths without a biomass share have shown that a sequestration only has advantages up to a limited share of electrolysis (Chapter 6.8.4.1). This result can also be carried over approximately to the development paths with a biomass share.

6.8.5.Incremental costs

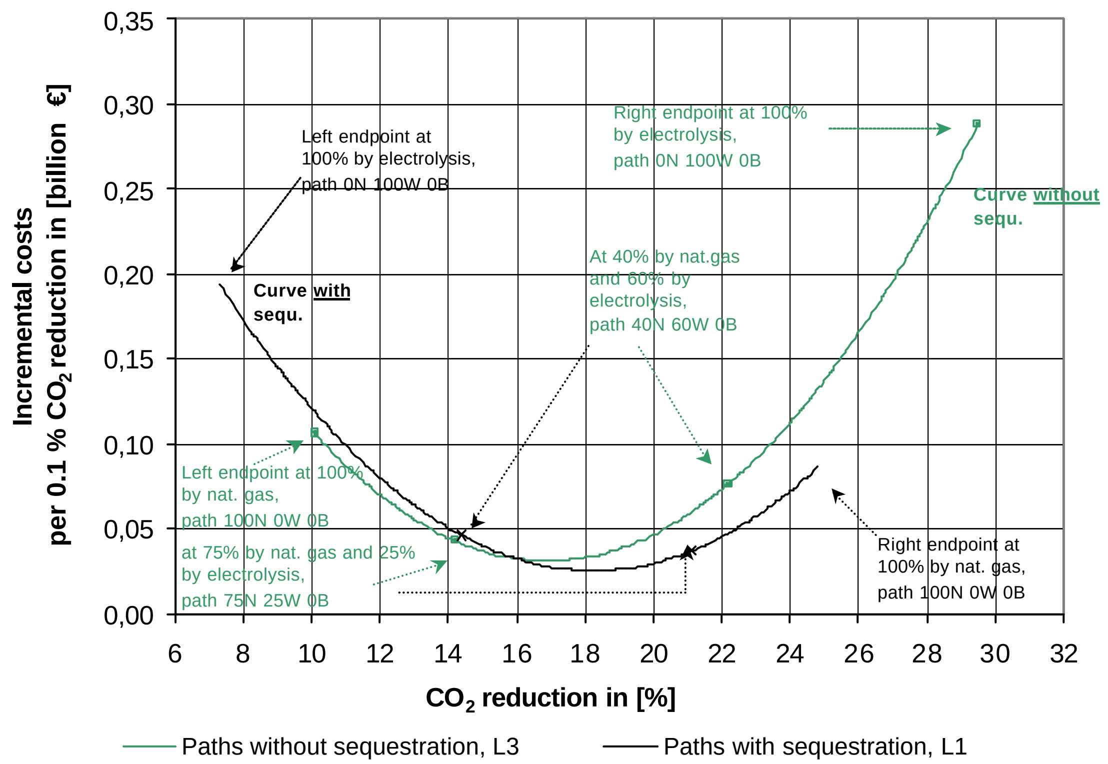
Figure 126 and Figure 127 show the total cost - emissions reduction curves for the period of time in question, depending on the composition of the path and method of generating electricity. As these curves do not show a constant increase, the optimal situation in terms of total costs and emissions is determined by the **criterion of the lowest incremental costs** of the discounted total costs. Incremental costs are the additional costs of the discounted total costs of a development path compared with its previous development path (starting with the path for exclusive hydrogen production from natural gas), which are incurred in order to achieve higher CO_2 reductions. On the basis of the criterion of the lowest incremental costs, a development is shown to be the optimum for hydrogen production until the point in its composition (increase of the electrolysis share in the development path starting with the path of exclusive hydrogen production from natural gas) at which a favorable “acquisition” of a further reduction in CO_2 emissions is obtained. From the lowest point on the incremental cost curve, a further reduction in CO_2 emissions can only be achieved at correspondingly higher total costs. As hydrogen production is taken into consideration with and without sequestration, and therefore using two different technologies, this results in two incremental cost curves, each of which exhibits a U-shaped form.

For the **development paths without the use of sequestration**, starting from the path of exclusive hydrogen production by natural gas steam reforming, up to an electrolysis share of about 40 % in the development path, the reductions in CO_2 emissions increase as the incremental costs decrease (assuming that regenerative produced electricity or electricity from nuclear power is used) (Figure 128). In other words, starting with the path with the exclusive production of hydrogen by natural gas steam reforming, an increase in the share of electrolysis up to about 40 % in the development path results in a favorable “acquisition” of a further reduction in CO_2 emissions. From the lowest point of the incremental cost curve, the incremental costs for a further reduction in CO_2 emissions clearly increases again. In other words, for the development paths with a long-term share of electrolysis higher than 40 %, there is an expensive “acquisition” of a further reduction in CO_2 emissions. The lowest point of the incremental cost curve with the lowest incremental costs shows a reduction in CO_2 emissions of about 17 %. This point corresponds to the turning point of the related total cost – emissions reduction curve in Figure 126.

For the **development paths with the use of sequestration**, starting from the path of exclusive hydrogen production by electrolysis, up to a natural gas steam reforming share of about 60 % in the development path, the reductions in CO_2 emissions increase as the incremental costs decrease (assuming electricity generated from fossil fuels). In other words, starting with the path with the exclusive production of hydrogen by electrolysis, an increase in the share of natural gas steam reforming up to about 6 % in the development path results in a favorable “acquisition” of a further reduction in CO_2 emissions. From the lowest point of the incremental cost curve, the incremental costs for a further reduction in CO_2 emissions clearly increase again. In other words, for the development paths with a long-term share of natural gas steam reforming higher than 60 %, there is an expensive “acquisition” of a further reduction in CO_2 emissions. When using sequestration, the incremental cost curve consequently has a mirrored course compared with the incremental cost curve with the use of sequestration. The lowest point of the incremental cost curve with the lowest incremental costs shows a reduction in CO_2 emissions of about 18 %. This point corresponds to the turning point of the related total cost – emissions reduction curve.

Comparison of the two incremental cost curves shows that the use of sequestration gives rise to slightly lower incremental costs than in the development paths without the use of sequestration. Moreover, the lowest incremental costs occur with the use of sequestration at a reduction in CO_2 emissions of about 18 %, which is slightly higher than in the development paths without the use of sequestration. Although two different technologies are used, almost identical development paths of 60N 40W 0B and therefore achievable reductions in CO_2 emissions at the lowest incremental costs are obtained.

Figure 128: Incremental costs of CO_2 reductions with and without the use of sequestration from well to vehicle fuel tank for various hydrogen production development paths, without consideration of biomass, in Germany up to 2035



L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1). Sequ. = sequestration.
Source: Own calculations, 2002

No presentation of the incremental costs for the development path without sequestration with a biomass share in the production of hydrogen is included, as it essentially exhibits a curve identical to the development paths without sequestration and with a biomass share.

6.8.6.Electricity requirement

The plants' electricity requirement depending on the development path used is summarized in Figure 129. For a better understanding of the absolute electricity requirement levels, the non-binding aims of the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety for the proportional development of renewable energies in total German electricity consumption (Chapter 6.1) are included in the diagram.

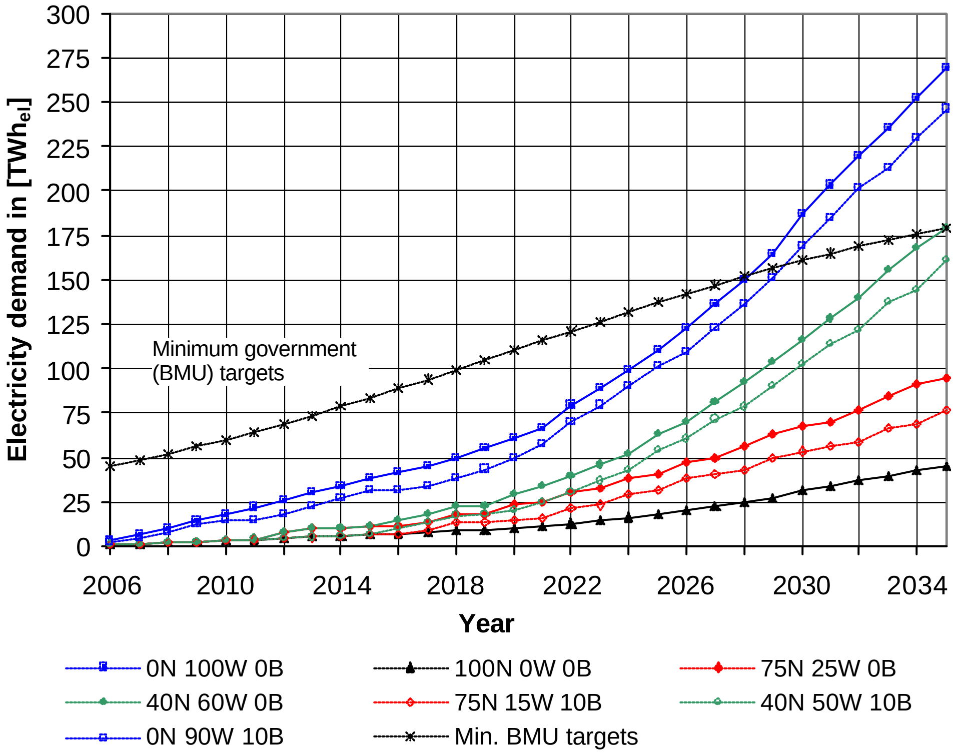
The electricity requirement for the **development path 100N 0W 0B** in 2035 is about 10 % of current total electricity consumption in Germany. Compared with the Federal German Government's aim of achieving a regenerative share of about 175 TWh in total electricity production at this time, the additional requirement of around 50 TWh for hydrogen production appears to be a thoroughly realiztic quantity.

The electricity requirement increases with an increasing share of electrolysis in the path. Consequently, the maximum electricity requirement is in **development path 0N 100W 0B**. In

2035, the electricity requirement corresponds to more than 50 % of the total current electricity requirement in Germany and exceeds the non-binding aim of the German Federal Government stated above.

The production of the necessary quantity of regeneratively produced electricity for hydrogen production is seen as one of the greatest challenges in the build-up of a hydrogen infrastructure.

Figure 129: Development of the electricity requirement from well to vehicle fuel tank for various hydrogen production development paths, with and without a biomass share, in Germany from 2006 to 2035



BMU = Federal Ministry for the Environment, Nature Conservation and Nuclear Safety.
Specimen key description: "40N 50W 10B" = long-term hydrogen production by 40 % natural gas steam reforming, 50 % water electrolysis and 10 % biomass gasification.
Source: BMU, 2002, p. 10; Own calculations, 2002

6.9. External effects

In this paper, the cost- and emissions-related effect of the development of a hydrogen infrastructure has been recorded in the analyses thus far. In addition to the "internal" costs that have been determined, substitution of conventional fuel by hydrogen as an alternative fuel will also have positive effects on the health of humans, flora, fauna and the climate. These effects have not so far been taken into consideration and were therefore described as "external" effects.

In the first part of this cinhapter, the impact of external effects in general is explained and discussed with the development of a hydrogen infrastructure as an example. In connection with this, the effects of a reduction in CO_2 emissions on the climate that arise during the development of a hydrogen infrastructure are monetarised in the form of CO_2 avoidance costs and compared with the external costs of other measures for reducing CO_2 emissions.

6.9.1. Consequences of external effects

When presenting external effects, classical financial-science literature often refers to the example of the two companies, Krickerode and Pfister (Rosen, 1992, p. 222). Krickerode owns a sugar refinery and feeds waste products as waste water into the nearby river. In the course of time, the river becomes unprepossessing and emits an objectionable odor. Downstream, a publican (Pfister) operates a garden restaurant, which many of his guests avoid due to the effects of the river. The impact on Pfister is described as a **negative external effect**.

Pfister's lost monetary income represents the opportunity costs of waste water introduction. As Krickerode does not take into consideration the opportunity costs in its individual budget, its limit costs do not reflect the value of all resources. Because Krickerode places too little emphasis on limit costs, it produces an inefficiently large amount of sugar. If external effects arise, their impact is not included in the perpetrator's costs and do not reveal themselves in the market price. The impact of external effects consequently lead to losses in efficiency (Rosen, 1992, p. 222). If the loss of income at Pfister is taken into consideration in Krickerode's financial calculations, there is an **internalization** of the external effects. Krickerode will reduce its sugar production in accordance with the higher limit costs.

The following aspects of external effects are also important (Rosen, 1992, p. 226 f.):

- **They are caused by companies as well as by households (individuals):** For example, smoking a cigarette in a room being used by other people can reduce the sense of well-being of certain individuals.
- **External effects have an imminent** (intrinsic) **reciprocity**: For example, a reduction of external damage at Pfister causes a loss of profit at Krickerode. If Pfister gives up his restaurant, Krickerode would no longer incur an economic burden.
- **External effects can be positive or negative:** For example, inoculating a person against influenza also has the positive external effect that people coming into contact with this person cannot catch the disease from him.
- **Categorization as a positive or negative external effect is based on the subjective interpretation of the affected person** (change of value): For example, the fruit trees in the owner's orchard are sprayed with a herbicide. The wind blows some of the herbicide onto the plants on a neighbour's plot of land. Whether the result is a positive or negative effect depends on the attitude of the neighbour to the use of such substances.

Finally, external effects are the result of non-existent or badly defined property rights (Rosen, 1992, p. 224). In the example of Krickerode and Pfister, neither of the two companies owns the river and both can use it "free of charge".

This statement is confirmed by the example of the necessity to substitute conventional fuel by the alternative fuel. **There are no ownership conditions applicable to the atmosphere and climate**; until now CO_2 emissions caused by conventional fuels and vehicles have been released into the atmosphere without careful consideration or consideration of economic aspects (this applies fundamentally to all anthropogenic emissions of greenhouse gases). The anthropogenic emissions of such gases strengthen the greenhouse effect and, in the opinion of leading experts, result in additional warming of the Earth's surface, which would represent an external effect. Possible future effects of a rise in temperature, such as shrinking of worldwide snow fields or a rise in sea level, represent negative external effects.

At the present time there is no market for emissions avoidance, consequently the market system is incomplete and can therefore not afford the efficient allocation of all resources (Weimann, 1995, p. 35 ff.). The basic assumption for a functional emissions avoidance market is one that is mutually beneficial to the participants - i.e. those who cause the emissions, and those who suffer as a result of them. Due the complexity of the trade in emissions, a close inspection of it is not undertaken in this paper.

6.9.2. Internalization of external effects

An **internalisation (monetarization) of the external effects** assumes a precise knowledge of the damages and dangers that arise. Costs determined by economic principles can be added to the monetarized external effects (**external cost[114], damages**), with the result that in due course the consumer of the product has to bear the costs (insofar as he or she is prepared to pay the higher cost resulting from the internalization of the external costs). Various measures are under discussion as instruments of internalization, e.g. taxes, conditions and certificates (Bickel, 1995, p. 10).

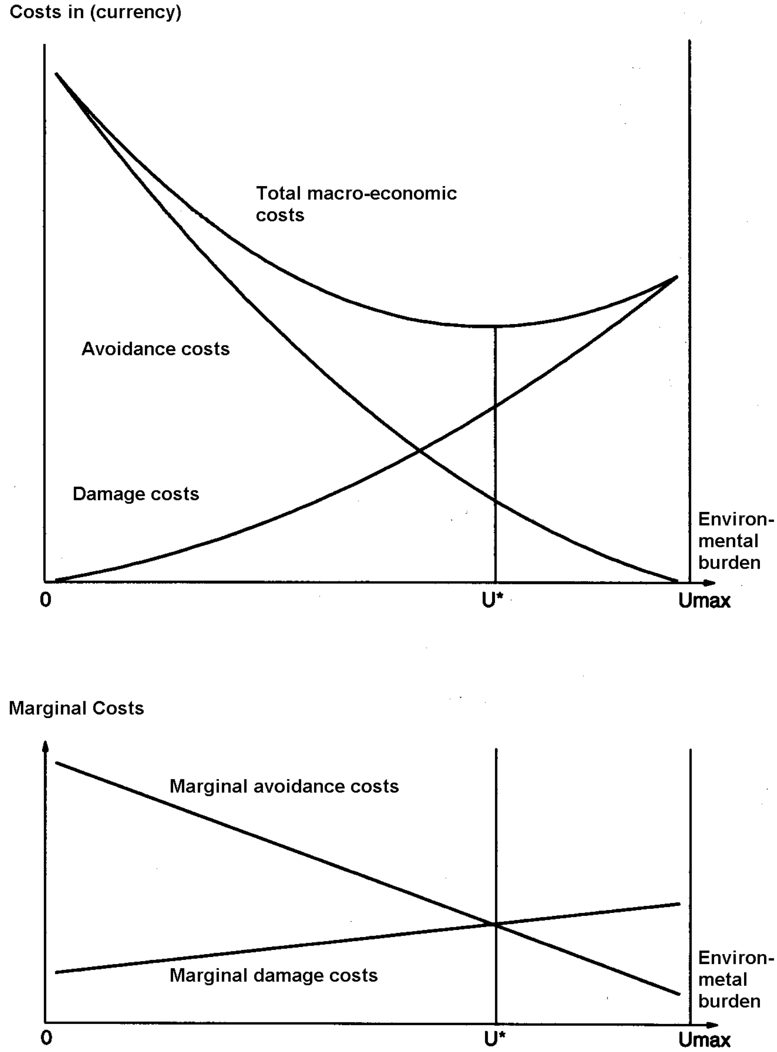
The possibility of reducing or avoiding damage and risk exists in many areas. For example, traffic noise can be reduced by measures such as the erection of noise protection barriers. The costs in this context are ascertainable and are known as **avoidance costs**.

The relationship between damages (external costs), avoidance costs and total economic costs is explained in Figure 130. The environmental pollution is shown on the abscissa (U_{max} = upper limit of reasonable environmental pollution). Typically, avoidance costs rise with falling environmental pollution, while damage rises with increasing environmental pollution. As a rule, the less polluted the environment, the more has to be invested to achieve further improvements (see the decreasing trend of marginal avoidance costs with increasing environmental pollution in the diagram below). From an economic point of view, the minimum total economic costs are found at the intersection of the marginal avoidance and marginal damage cost curves. If the predominant environmental pollution is to the right of U*, it is cheaper to carry out damage avoidance than to accept the damage. For environmental pollution less than U*, it is economically more beneficial to permit further environmental pollution, since the marginal damage costs are lower than the marginal avoidance costs.

If the **avoidance costs** are used **to estimate the external costs**, the result is mostly an over- or underestimation of these costs. In the area to the left of the intersection of the two marginal cost curves, there is overestimation of the external costs; to the right of the intersection there is underestimation. Avoidance costs are only suitable for estimating external costs in the vicinity of the intersection of the curves. However, as the position of the intersection is not known, some data, such as the establishment by the government of a share of damage to be avoided (for example, a reduction of 21 % in CO_2 emissions in Germany by 2008), can be used to calculate the marginal avoidance costs. The marginal avoidance costs (corresponding to the external costs for the avoidance of damage and consequently dependent on the extent of the damage reduction) can be used, for example, to determine the level of an ecology tax per ton of CO_2 emitted.

[114] As an example, the statistical value of a human life is given as 2.6 million €. It is a measure of how much society is prepared to pay for small reductions in the risk to suffer a fatality. (Bickel, 1995, 22 et.seq.).

Figure 130: Schematic representation of the development of (marginal) avoidance costs, (marginal) damage costs and total economic costs with increasing environmental pollution

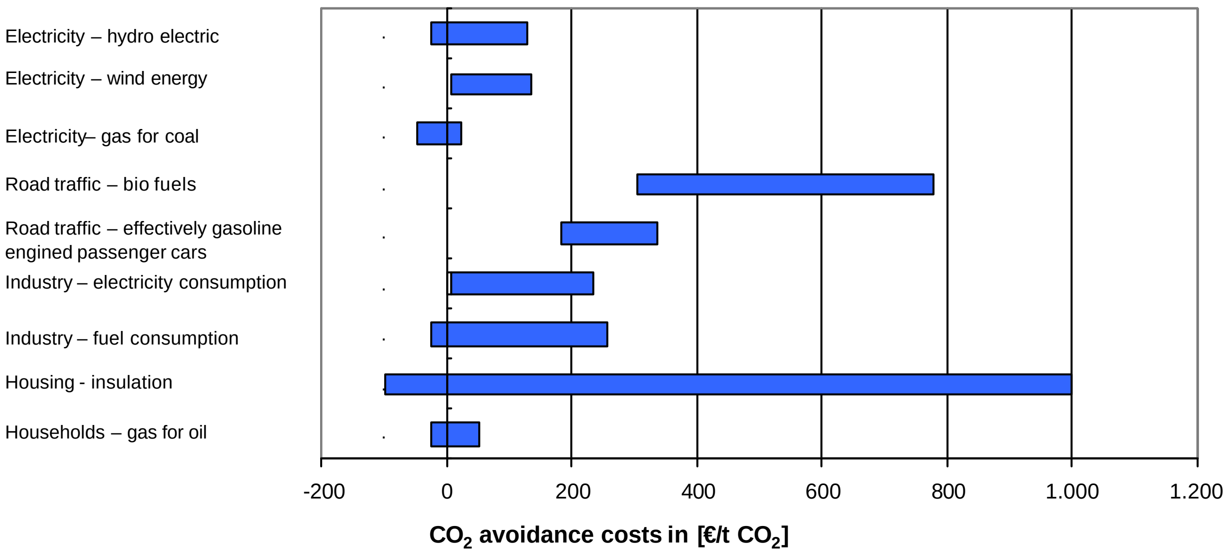


Source: Bickel, 1995, p. 12

A **comparison of the CO_2 avoidance costs** (discounted to 1990) of selected technical measures is shown in Figure 131. It is important to note that each of these individual measures causes a different level of damage reduction up to a determined point in time. The following assumptions are made as the basis for calculating the CO_2 avoidance costs (IER, 1997, p. 22, 27, 37 f., 57, 103, 116):

- **all forms of electricity generation:** CO_2 reduction potential compared to a hard coal power station, commissioning of power stations in 2005
- **Vehicle bio-fuels:** alcohol-based fuels of methanol and ethanol (produced from biomass), rapeseed oil and rape methyl ester (RME)
- **Road traffic – effectively gasoline-engined passenger cars:** e.g. reduction of friction, variable valve control, forced aspiration, cylinder shutdown
- **Industry – electricity consumption:** lowering of electricity consumption, e.g. by modifying existing production plants
- **Industry – fuel consumption:** e.g. heat recovery, heat insulation
- **Residential buildings – insulation:** e.g. replacement windows, roof insulation, flat roof (heat-insulated roof)
- **Households – oil and gas:** e.g. modern gas central heating systems

Figure 131: CO_2 avoidance costs of selected technical measures in Germany at price/cost ratios for 1990



Discount rate 4 %
Source: IER, 1997, p. 121

Negative CO_2 avoidance costs are an example here of an especially efficient reduction measure, for instance the replacement of hard coal by GST power stations, or the exchange of oil for gas-fired heating units.

6.9.3. CO_2 avoidance costs per tonne of CO_2 avoided

In determining the external costs for the development of a hydrogen infrastructure, the total costs (depending on the hydrogen production development path) arising within a particular period of time are discounted[115] to a reference point of time (in this paper, 2006). The total costs per tonne of CO_2 avoidance, discounted to 2006, are used as a measure of the efficiency of CO_2 avoidance. Various levels of **CO_2 avoidance costs**[116] are given, depending on the hydrogen production development path.

6.9.3.1. CO_2 avoidance costs in the development of a hydrogen infrastructure

For reasons of clarity, only CO_2 avoidance costs up to 2035 are shown in Figure 132. For the period in question (2006 to 2035), the development paths without the use of sequestration show the highest CO_2 avoidance costs of about 150 €/t CO_2 for exclusive hydrogen production by natural gas steam reforming (development path 100N 0W 0B). The exclusive production of hydrogen by electrolysis causes the lowest CO_2 avoidance costs of about 120 €/t CO_2. In other words, with an increasing electrolysis share in the development path, the additional achievable CO_2 emission reductions increase much more strongly than the total costs for achieving them.

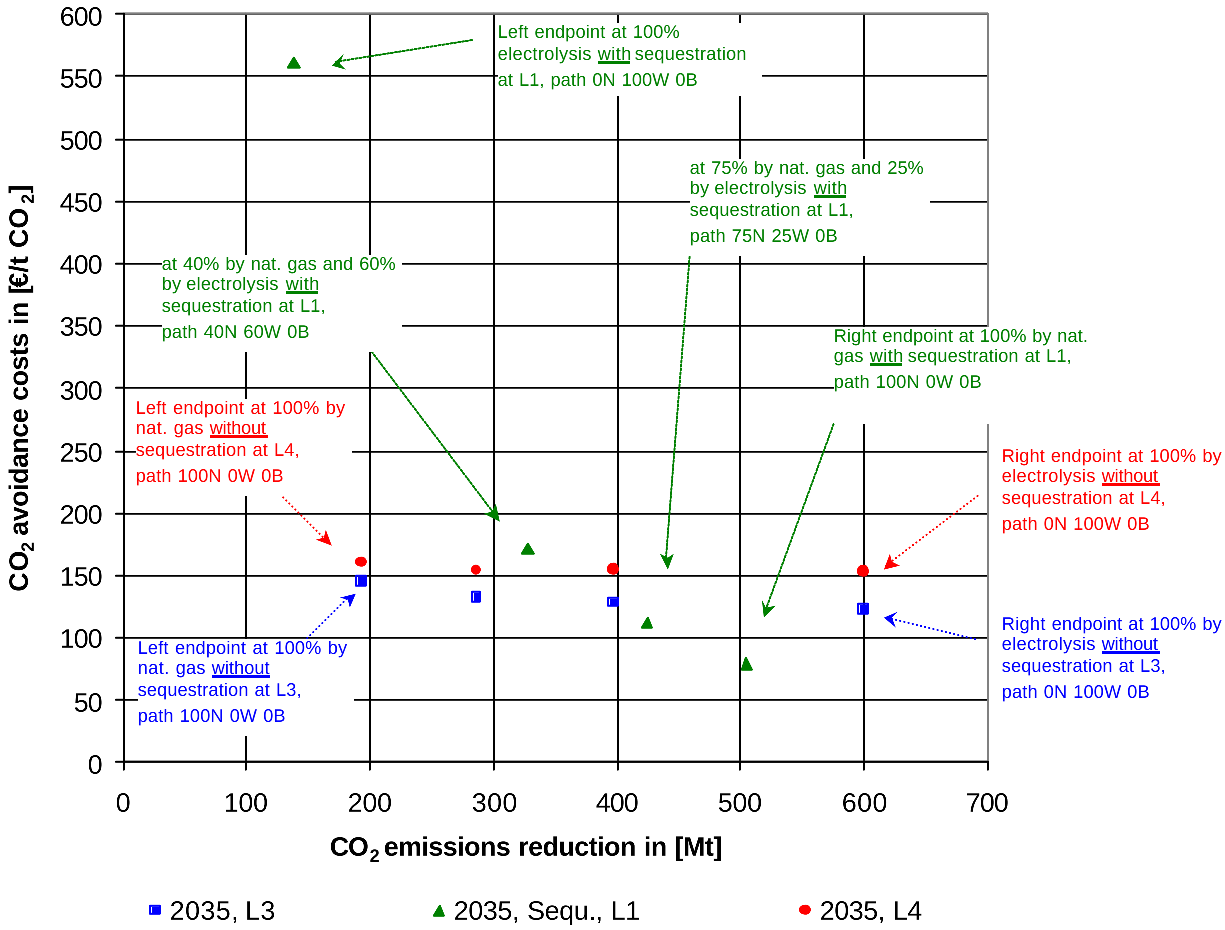
The reverse is true of the development paths with the use of sequestration. Over the period in question, the highest CO_2 avoidance costs of 560 €/t CO_2 occur for exclusive hydrogen production by electrolysis (lowest reduction of CO_2 emissions because of higher residual emissions, development path 0N 100W 0B). The exclusive production of hydrogen by natural gas steam reforming causes the lowest CO_2 avoidance costs of about 80 €/t CO_2. In other words, an increasing share of natural gas steam reforming in the development path results in both an increase in the reductions of CO_2 emissions and a decrease of the total costs to achieve them.

[115] Economic (real) interest rate of 4 % selected (Matthes, 1998, p. 5; IER, 1997, p. 83)
[116] Without additional vehicle purchase costs possibly needed in the future for hydrogen as an alternative fuel compared with vehicles for conventional fuel.

Comparison of CO_2 avoidance costs for development paths with and without sequestration shows that the use of sequestration up to an electrolysis share of about 40 % in the development path causes lower CO_2 avoidance costs than development paths without the use of sequestration. Above this electrolysis share, the CO_2 avoidance costs of the development paths with sequestration exceed those of the development paths without sequestration. According to the criterion of the lowest CO_2 avoidance costs, the exclusive production of hydrogen by natural gas steam reforming using sequestration would be desirable. However, in realizing this option, the stated aim of reducing dependence on fossil resources will not be fulfilled, so that the selection of a development path according to the lowest CO_2 avoidance costs cannot be considered as the optimum. For the total costs and emissions related optimum determined according to the criterion of the lowest incremental costs with a long-term share of electrolysis of about 40 % in the development path (both with and without sequestration), the CO_2 avoidance costs are about 130 €/t CO_2.

Great importance at the CO_2 avoidance cost level attaches to electricity costs. In the example of 2035, the CO_2 avoidance costs in the path 0N 100W 0B using regeneratively produced electricity at Level 3 are in the region of 130 €/t CO_2. If the electricity costs are increased to Level 4, there is an increase in the CO_2 avoidance costs to about 150 €/t CO_2. In this concrete case, an increase of 30 % in the electricity costs causes an increase in the CO_2 avoidance costs of around 16 %. The influence of the electricity costs on CO_2 avoidance costs is essentially less, the higher the NGSR share in the hydrogen production path.

Figure 132: CO_2 avoidance costs with the use of sequestration for electricity generation using regenerative energy (L3 and L4) and CO_2 avoidance costs with the use of sequestration for electricity generation using conventional power stations (L1) from well to vehicle fuel tank, for various hydrogen production development paths in Germany up to 2035



Discount rate 4 %, Sequ. = sequestration. L1 = Electricity costs using conventional power stations, L3 = moderate electricity costs using regenerative energy. L4 = high electricity costs using regenerative energy.
Source: Own calculations, 2003

According to the1997 Kyoto Agreement, Germany is to reduce the six most important greenhouse gases by 21 % in the target period of 2008 to 2012 (based on 1990 emission levels) (Chapter 2.1.4.1). This means around 15 years to achieve this aim. As the share of CO_2 emissions in the total emissions of the six anthropogenic greenhouse gases is over 90 % (in the case of Switzerland and Finland, around 97 % (Schneider, 2002, p. 9)), the following examination assumes that the stated reduction of 21 % refers only to CO_2 emissions.

Figure 131 shows that there are economic areas in which a reduction in CO_2 is linked to lower costs (for example in electricity generation, residential building insulation, stationary heating plants) than in the automobile sector, for example. From an economic point of view it appears sensible to realize a reduction in CO_2 emissions initially in those economic areas which are associated with the lowest possible costs.

However, if it assumed contrary to the economic point of view that the achievement of the reduction in CO_2 emissions according to the Kyoto Agreement, each individual economic area has to achieve a reduction in CO_2 emissions of 21 % within around 15 years, this means for the automobile sector a reduction in CO_2 emissions of 21 % from road traffic. On the assumption that the stated reduction in CO_2 emissions should be achieved in around

15 years (starting in 2006) (i.e. CO_2 emissions of about 160 Mt/a in 2020 instead of approx. 200 Mt/a), this would not be achievable with the assumed development of hydrogen demand in Germany.

6.10. Summary

Tasks

This chapter brings together the components of hydrogen production dealt with in the chapters thus far, the distribution and the gas station infrastructure in a dynamic total examination from well to vehicle fuel tank. By examining different hydrogen production development paths of (composition of hydrogen production according to process), the development path is to be found which guarantees optimal supply according to economic and ecological criteria (optimum regarding total costs and emissions).

Determination of the CO_2 avoidance costs for the development of a hydrogen infrastructure makes a comparison possible with the CO_2 avoidance costs of other measures.

Assumptions and approach

The point of origin is represented by the development of the hydrogen demand in Germany in Chapter 2.3.4. Building on the findings of the favored hydrogen production process in Chapter 3, the plant specifications determined for satisfaction of hydrogen demand in Chapter 4.4 and the favored gas station development in Chapter 5.5, these components are combined into a total system.

The timeframe examined extends from 2006 to 2035. Hydrogen demand in Germany in this period grows continuously. For hydrogen production during the period, the following development paths are examined: production solely by natural gas steam reforming, solely by electrolysis, by natural gas steam reforming and electrolysis (with variation of the production proportions) and the same development paths with a maximum share of 10 % biomass gasification in hydrogen production taken into consideration. For these development paths, the use of CO_2 sequestration is also investigated more closely. The collection of CO_2 in flue gases is considered for natural gas steam reforming and also for coal-fired power stations used for the electricity supply.

The focus of the analysis of development paths for the stated period lies in the development of specific hydrogen costs, the potential for the CO_2 emissions reduction, the investments, the total costs discounted to 2006 (due to the timescale of 30 years, the future annual total costs are adjusted for interest based on 2006), the incremental costs and the electricity requirement.

In order to reach an **optimum balance of total costs and emissions**, there is an examination of the total costs, discounted for 2006, that arise in the realization of a hydrogen production development path, depending on the achievable reduction in annual CO_2 emissions from road traffic. Through the variation of the composition of the development path from exclusive hydrogen production by natural gas steam reforming through a combination of different production processes to exclusive hydrogen production by electrolysis, curves are obtained that show the relationship between discounted total costs and the reduction of CO_2 emissions, the so-called **total costs-emission reduction curves**. The total costs are the cumulative annual annuities of investments (hydrogen production plant, distribution, gas station infrastructure) across the depreciation period and the operating and maintenance costs. As the construction of an infrastructure for supplying vehicles with hydrogen requires a planning timeframe covering several decades (in this paper, from 2006 to 2035), the total costs of a development path over this timeframe are based on 2006 (“current value” of the costs).

As the total costs-emission reduction curves do not show a constant increase, the optimal situation in terms of total costs and emissions is determined by the **criterion of the lowest incremental costs** of the discounted total costs. Incremental costs are the additional costs of the discounted total costs of a development path compared to its previous development path (starting with the path with sole hydrogen production from natural gas), which are incurred in order to achieve higher CO_2 reductions. On the basis of the criterion of the lowest incremental costs, the optimum development path for hydrogen production is shown, up to the composition (increase of the electrolysis share in the development path starting with the path with exclusive hydrogen production from natural gas) at which the result is a favorable “acquisition” of a further reduction in CO_2 emissions. From the lowest point of the incremental cost curve, a further reduction in CO_2 emissions can only be achieved with correspondingly higher total costs. As hydrogen production is taken into consideration with and without sequestration, and therefore using two different technologies, this results in two incremental cost curves.

Findings

For a long-term reduction in CO_2 reduction, the sole production of hydrogen should be achieved by electrolysis using regeneratively produced electricity or electricity from nuclear power, because producing hydrogen by this process causes the lowest CO_2 emissions. However, the highest specific hydrogen costs are incurred of all the development paths under examination. The specific hydrogen costs without taxes over the period in question (2006 to 2035) are higher than the conventional fuel price inclusive of taxes. The opposite is true for the sole production of hydrogen by natural gas steam reforming, which causes the lowest specific hydrogen costs, but achieves only a marginal long-term reduction in CO_2 (assuming the electricity for hydrogen liquefaction is generated from regenerative primary energy or from nuclear power). However, hydrogen production by natural gas steam reforming seems thoroughly meaningful for introducing hydrogen fuel onto the market, in order to bring the specific hydrogen costs close to the conventional fuel price in the shortest possible time.

For hydrogen production solely by natural gas steam reforming the specific hydrogen costs from 2006 to 2035 of 1.8 €/l GE can be reduced by 65 % to about 0.7 €/l GE (assuming that regeneratively produced electricity is used) due to increasing usage for hydrogen production, increasing gas station usage, the economies of scale and the learning effects. However, with an increasing share of electrolysis in the production path, the influence of electricity costs on the hydrogen costs increases. The highest influence of electricity costs of some 80 % is found in the development path with the sole production of hydrogen by electrolysis. For this path, the specific hydrogen costs from 2006 to 2035 of 2.8 €/l GE can reduced by 45 % to about 1.6 €/l GE (assuming the use of regeneratively produced electricity) due to the effects mentioned. As the power stations used for generating electricity are a technically mature technology and therefore have only limited future potential for reducing electricity costs, there is also a limited potential for reducing specific hydrogen costs.

For the development paths that do not take sequestration into account, the achievable CO_2 reductions as well as total costs rise as the share of electrolysis in the development path increases, starting from the path of exclusive hydrogen production by natural gas steam reforming with the lowest total costs and potential for CO_2 reduction. The total costs-emissions reduction curve for a year shows an S-shaped curve. The use of biomass gasification for hydrogen production of around 10 % in the development path permits a reduction in the total costs of around 1 0% and an almost identical reduction in CO_2.

The limited application of CO_2 sequestration can also be seen in the total cost - emissions reduction curves. The development path with hydrogen production solely by natural gas steam reforming using sequestration has the lowest total costs with the highest potential for CO_2 reduction (the CO_2 produced in the fossil generation of electricity and hydrogen production is collected and stored at storage sites, therefore there is no release of anthropogenic emissions into the atmosphere). With an increasing share of electrolysis in the production path, the total costs increase and the achievable CO_2 reductions decrease. This means that the higher the share of electrolysis in total hydrogen production (and therefore the electricity requirement), the higher the residual emissions when using sequestration. Comparison of the total costs incurred and CO_2 reductions of the development paths with and without sequestration shows that the use of sequestration is only meaningful up to an electrolysis share of about 50 % in the development path, due to the residual emissions that occur.

As hydrogen production is taken into consideration with and without sequestration, and therefore using two different technologies, this results in two incremental cost curves, each of which exhibits a U-shaped form. For the development paths without the use of sequestration, starting from the path of exclusive hydrogen production by natural gas steam reforming and up to an electrolysis share of about 40 % in the development path, the reductions in CO_2 emissions increase as the incremental costs decrease (assuming that regeneratively produced electricity or electricity from nuclear power is used). In other words, starting with the path with hydrogen production solely by natural gas steam reforming, an increase in the share of electrolysis up to about 40 % in the development path results in a favorable “acquisition” of a further reduction in CO_2 emissions. From the lowest point of the incremental cost curve, the incremental costs for a further reduction in CO_2 emissions increase again significantly. In other words, for the development paths with a long-term share of electrolysis higher than 40 %, there is an expensive “acquisition” of a further reduction in CO_2 emissions. The lowest point of the incremental cost curve with the lowest incremental costs shows a reduction in CO_2 emissions of about 17 %. This point corresponds to the turning point of the related total cost – emissions reduction curve.

For the development paths with the use of sequestration, starting from the path of hydrogen production solely by electrolysis, up to a natural gas steam reforming share of about 60 % in the development path, the reductions in CO_2 emissions increase as the incremental costs decrease (assuming electricity generated from fossil fuels). In other words, starting with the path with hydrogen production solely by electrolysis, an increase in the share of natural gas steam reforming up to about 60 % in the development path results in a favorable “acquisition” of a further reduction in CO_2 emissions. From the lowest point of the incremental cost curve, the incremental costs for a further reduction in CO_2 emissions clearly increase again. In other words, for development paths with a long-term share of natural gas steam reforming higher than 60 %, there is an expensive “acquisition” of a further reduction in CO_2 emissions. When using sequestration, the incremental cost curve is consequently a mirror image of the incremental cost curve with the use of sequestration. The lowest point of the incremental cost curve with the lowest incremental costs shows a reduction in CO_2 emissions of about 18 %. This point corresponds to the turning point of the related total costs – emissions reduction curve.

Comparison of the two incremental cost curves shows that the use of sequestration gives rise to slightly lower incremental costs than in the development paths without the use of sequestration. Moreover, the lowest incremental costs occur with the use of sequestration if there is a reduction in CO_2 emissions of about 18 %, which is slightly higher than in the development paths without the use of sequestration. Although two different technologies are used, almost identical compositions of the development paths and therefore achievable reductions in CO_2 emissions at the lowest incremental costs are obtained.

Analysis of the electricity requirement for the development paths shows that with an increasing electrolysis share in the development path and therefore increasing electricity requirements, the challenge of achieving a hydrogen infrastructure is increasingly focussed on producing the necessary regeneratively produced amount of electricity for hydrogen production (if CO_2 sequestration is not used). The challenges refer to the exploitation of the potentials for regenerative primary energies and the measured time-related technical performance needed to make them available. However, it can be shown that regenerative production of electricity represents an achievable valid optimum for the determined total costs and emissions related optimum with a long-term share of electrolysis of about 40 % with regard to the potential of the regenerative primary energies as well as the time-related technical performance.

For the period in question (2006 to 2035), development paths without the use of sequestration show the highest **CO_2 avoidance costs** of about 150 €/t CO_2 for the production of hydrogen solely by natural gas steam reforming. The production of hydrogen solely by electrolysis yields the lowest CO_2 avoidance costs of about 120 €/t CO_2. In other words, with an increasing electrolysis share in the development path, the additional achievable reductions in CO_2 emissions increase much more strongly than the total costs for achieving them.

The reverse is true for development paths with sequestration. Over the period in question (2006 to 2035), the highest CO_2 avoidance costs of 560 €/t CO_2 arise for hydrogen production solely by electrolysis (lowest reduction of CO_2 emissions because of higher residual emissions). The production of hydrogen solely by natural gas steam reforming causes the lowest CO_2 avoidance costs of about 80 €/t CO_2. In other words, an increasing share of natural gas steam reforming in the development path results in both a greater reduction in CO_2 emissions and a decrease of the total cost of achieving them.

The comparison of CO_2 avoidance costs for the development paths with and without sequestration shows that the use of sequestration up to an electrolysis share of about 40 % in the development path causes lower CO_2 avoidance costs than in development paths without sequestration. Above this electrolysis share, the CO_2 avoidance costs of the development paths with sequestration exceed those of the development paths without sequestration. According to the criterion of the lowest CO_2 avoidance costs, the production of hydrogen solely by natural gas steam reforming using sequestration ought to be striven for. However, in realizing this option, the declared aim of reducing dependence on fossil resources is not fulfilled, so that selecting an optimum development path according to the lowest CO_2 avoidance costs cannot be considered the optimum. For the total costs and emissions-related optimum determined according to the criterion of the lowest incremental costs, with a long-term share of electrolysis of about 40 % in the development path (both with and without sequestration), CO_2 avoidance costs are about 130 €/t CO_2.

Conclusions and recommendations

In addition to the criterion of the lowest incremental costs, considerable attention is also paid to other aspects, e.g. the time-based development of the expansion of regenerative electricity production. Selection of the achievable valid development path must ultimately be made by taking the dynamic development of the total system into consideration.

7. Sensitivity analysis

In the sensitivity analysis it is shown how changes to the assumptions made for the calculation affect the results. These examinations are limited to the development paths without a biomass share, as the changes shown in the results for development paths without a biomass share can be approximately carried over to the results for development paths with a biomass share.

Chapter 7.1 examines the effects on the development of hydrogen demand which arise when the ratio of new vehicle registrations in the passenger car category with hydrogen combustion engines to those with electric motors and fuel cells is changed from the 50:50 ratio used so far. The effects of the change of the ratio of new vehicle registrations in the remaining vehicle categories according to Table 3 on the development of hydrogen demand are of lesser significance, since up to 2035, the hydrogen demand is mostly generated by the passenger car category. In Chapter 7.2, the effects of an increase in electricity and/or natural gas costs on the cumulative discounted total costs of the build-up of a hydrogen infrastructure and the average hydrogen costs are investigated. The influence of the interest rate on the cumulative discounted total costs and incremental costs is discussed in Chapter 7.3. By postulating a more rapid increase in hydrogen demand over time compared with HDD OWN, Chapter 7.4 shows how

- the development of the gas station infrastructure changes
- the specific hydrogen costs develop
- the cumulative total costs, discounted to 2006, behave according to the reduction in CO_2
- the incremental costs change

7.1. Assumptions regarding reference vehicles

In VPD OWN, the assumption was made for vehicles to run on hydrogen as an alternative fuel that 50 % of the vehicles in the passenger car category would be fitted with hydrogen combustion engines (ICE[117]) and 50 % with electric motors and fuel cells (FC[118]) (= status quo, Chapter 2.3.4.1). An increase or reduction of the shares of the respective vehicle propulsion systems (ICE, FC) causes a change in the hydrogen demand, since according the assumption made for reference vehicles in Chapter 2.2.3, the vehicles with ICE drive have a higher fuel requirement than those with an FC drive (Figure 133).

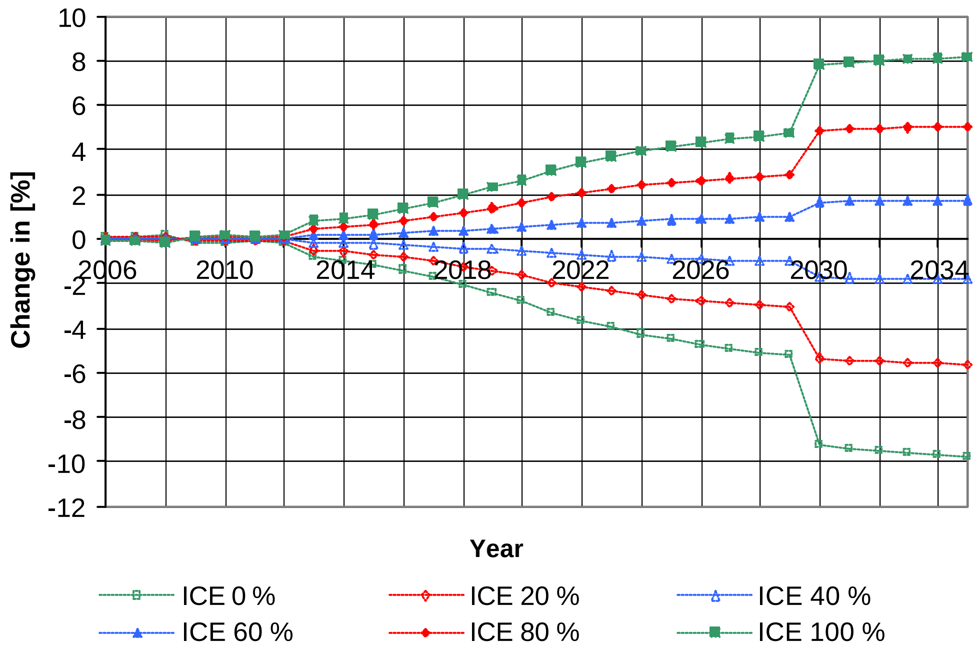
From the diagram it is evident that due to the low volume of passenger cars for the alternative fuel, only very small effects on the hydrogen demand are caused by the ICE/FC ratio. When market penetration by passenger cars for the alternative fuel starts from 2012 on, there is a more or less marked change in hydrogen demand compared with HDD OWN.

A change in the status quo of 10 % causes a change in hydrogen demand of around 2 % up to 2030. With an increasing ICE share, the hydrogen demand increases compared with the status quo, and vice versa. A clear influence occurs from an ICE/FC composition of 30/70 or 70/30 from 2020 on. The extra or reduced demand for hydrogen compared with the status quo grows by more than 2 %.

The marked increases in the changes from 2029 to 2030 are a result of the calculation assumptions made for the HDD OWN, namely that the share of hydrogen in the total annual distance covered by all ICE vehicle categories grows from 90 % in 2029 to 100 % in 2030 (Chapter 2.3.4.2). Even if the passenger-car ICE share were to be 0 %, this leap in the change of the hydrogen demand would still occur as a consequence of the truck ICE share.

[117] ICE = internal combustion engine
[118] FC = fuel cell

Figure 133: Change in the total demanded hydrogen requirement according to the variation in the share of the hydrogen combustion engine (ICE) drive form in the passenger car category (PC) in Germany from 2006 to 2035



In the passenger car vehicle category, the propulsion system of hydrogen combustion engine (ICE) and electric motor with fuel cell (FC) were considered. The status quo contains an ICE share of 50 % and an FC share of 50 %. For example, if the ICE share is 40 %, the FC share is 60 %.
Source: Own calculations, 2002

7.2. Increase in the electricity and / or natural gas costs

In the first step there is an examination of the sensitivity of the average hydrogen costs to an increase in the electricity and/or natural gas costs compared with the calculations in Chapter 6.8.2. The determined cumulative total costs, discounted to 2006, for the build-up of a hydrogen infrastructure in relation to CO_2 reduction for the higher cost level of the two input factors (electricity and natural gas) are presented and analysed.

7.2.1. Effects on the average hydrogen costs

Examination of the change in hydrogen costs takes place with reference to average hydrogen costs with electricity costs at Level L1 and natural gas costs at Level NL1 (determined in Chapter 6.8.2) (Table 31). From the table it is also evident that the specific hydrogen costs in 2035 for all paths are around 10 % less than the average hydrogen costs up to 2035 (according to VPD OWN, in 2035 the fuel substitution by hydrogen is about 30 % and the share of new vehicle registrations with hydrogen as an alternative fuel is about 50 %). This makes it possible to draw conclusions from the new average hydrogen costs given by the change in input costs regarding specific hydrogen costs for a fuel substitution of about 30 % or a new registration share of alternative vehicles of 50 %.

Table 31: Average hydrogen costs for the period 2006 to 2035 and specific hydrogen costs in 2035 with electricity generation by conventional power stations (L1) and natural gas costs at Level 1 (NL3) from well to vehicle fuel tank, for various hydrogen production development paths with and without the use of sequestration (sequ.) in Germany

Development path	Average hydrogen costs up to 2035 in [€/l GE]	Specific hydrogen costs in 2035 in [€/l GE]	Proportion of specific to average hydrogen costs in [%]
100N 0W 0B	0.712	0.627	88.06
75N 25W 0B	0.805	0.718	89.19
40N 60W 0B	0.911	0.870	93.05
0N 100W 0B	1.109	1.018	91.79
100N 0W 0B, sequ.	0.789	0.678	85.93
75N 25W 0B, sequ.	0.906	0.785	86.64
40N 60W 0B, sequ.	1.039	0.964	92.78
0N 100W 0B, sequ.	1.300	1.143	87.92

L1 = electricity costs using conventional power stations, L3 = electricity costs using regenerative energy, natural gas costs at Level 1 (NL1), Sequ. = sequestration, GE = gasoline equivalent.

Specimen key description: "75N 25W 0B" = long-term hydrogen production by 75 % natural gas steam reforming and 25 % water electrolysis. "75N 25W 0B, Sequ." = long-term hydrogen production by 75 % natural gas steam reforming and 25 % water electrolysis with the use of sequestration.

Source: Own calculations, 2002

The relationship between the percentage increase in the average hydrogen costs depending on the percentage increase in the electricity or natural gas costs is shown in Figure 134. Starting from level L1 for the electricity costs and NL1 for the natural gas costs, there is now a percentage increase in the costs of the input factors, which results in an increase in average hydrogen costs.

The following can be derived from the curves:

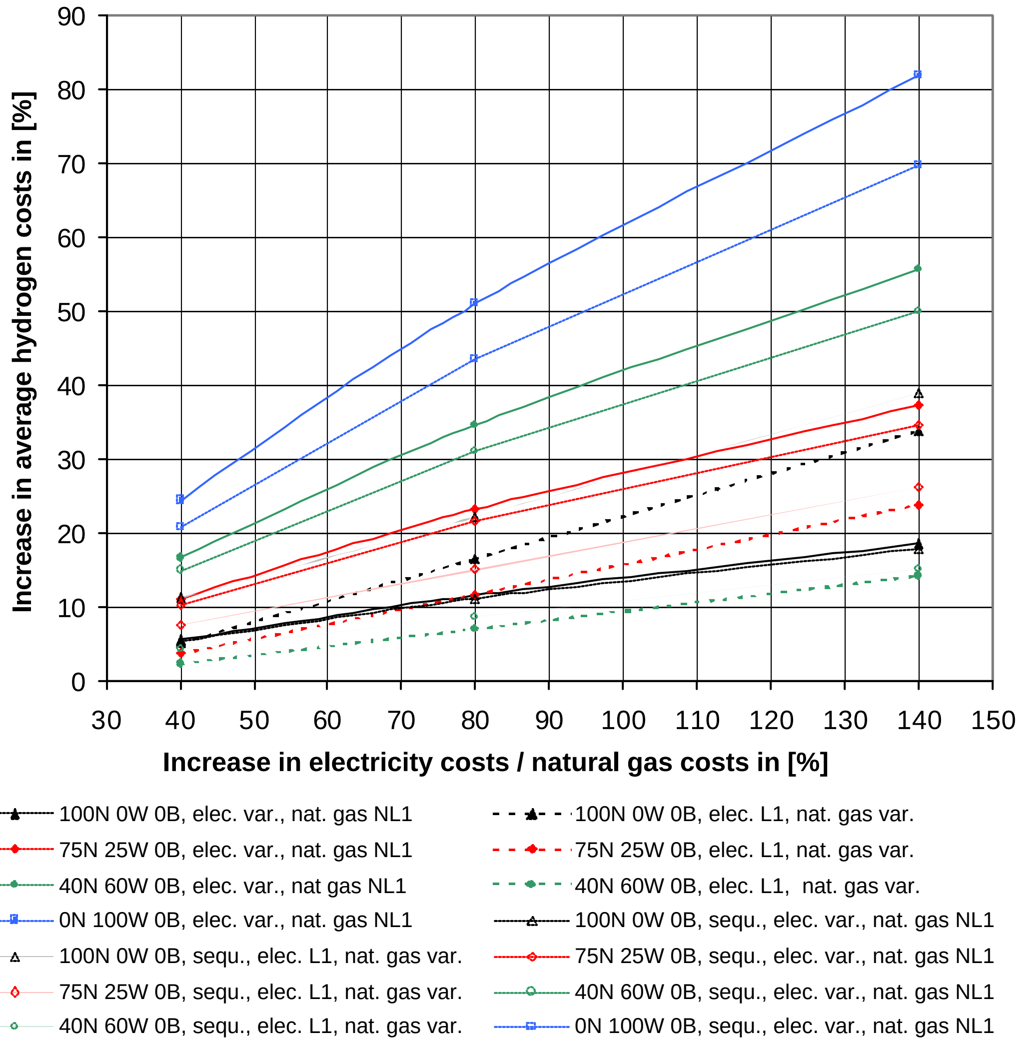
- **for an increase in the electricity costs[119]:** the higher the electrolysis share in the development path (and therefore a higher electricity requirement), the steeper the curves of the percentage increase in average hydrogen costs
- the effect described above is lower in the development paths with sequestration than in those without sequestration, since the average hydrogen costs for the paths with sequestration are higher, and correspondingly cause a smaller increase in the electricity costs
- **for an increase in natural gas costs:** the higher the electrolysis share in the development path (and therefore a lower natural gas requirement), the flatter the curves for the percentage increase in the average hydrogen costs
- the effect described above is stronger in the development paths with sequestration than in those without sequestration, since a higher natural gas requirement exists for NGSR in the paths with sequestration due to a reduction in efficiency compared with NGSR in paths without sequestration.

If, for example, the **100N 0W 0B development path** is considered, a 40 % increase in electricity costs means an increase in average hydrogen costs of around 5 %, while a 140 % increase (corresponding to the higher cost level of regeneratively produced electricity) only causes an increase in the average hydrogen costs of about 18 %. The relatively low increase in average hydrogen costs can be explained by the path's lower electricity requirement. Natural gas costs have a greater influence on average hydrogen costs. An increase in natural gas costs results in a corresponding increase in the average hydrogen costs of between 5 and 35 %.

In the **0N 100W 0B development path**, an increase in electricity costs has a very marked effect on the average hydrogen costs, due to the path's high electricity requirement. Given an increase in electricity costs of about 40 %, the average hydrogen costs increase by about 25 %, and for an increase of 140 %, by about 82 % (almost double).

[119] The validity of the increase in the average hydrogen costs depending on the increase in electricity costs in Figure 134 is only given for the development paths defined in this paper. The hydrogen production in these paths takes place in high-capacity production plants (therefore with a high electricity requirement as well), whereby the increase in the electricity costs for a reduction in electricity capacity of about 25 MW and 7,000 h/a (Table 20) has a strong influence on the increase in the average hydrogen costs.

Figure 134: Increase in the average hydrogen costs for the period 2006 to 2035 for an increase in electricity and/or natural gas costs based on electricity generation using conventional power stations (L1) and natural gas costs at Level 1 (NL3) from well to vehicle fuel tank for various hydrogen production development paths with and without the use of sequestration (sequ.) in Germany



L1 = Electricity costs using conventional power stations, NL1 = natural gas costs with Level 1, Elec. var. = electricity cost variation, Nat. gas. var. = natural gas cost variation, Sequ. = sequestration.
Specimen key description: “40N 60W 0B, Elec. var., NG NL 1” = Increase in the average hydrogen costs for long-term hydrogen production by 40 % natural gas steam reforming and 60 % electrolysis with constant natural gas costs at Level 1 with variation in the electricity costs. “40N 60W 0B, Sequ., Elec. L1, NGvar.” = Increase in the average hydrogen costs for long-term hydrogen production by 40 % natural gas steam reforming and 60 % electrolysis with use of sequestration with constant natural gas costs at Level 1 and variation of natural gas costs.
Source: Own calculations, 2002

If the costs of both input factors (electricity and natural gas) increase, the percentage increase in average hydrogen costs can be approximately determined by addition. As an example, the effects of an increase in the cost of both input factors on the average hydrogen costs of development path 40N 60W 0B is examined. The average hydrogen cost in this path with electricity costs at L1 and natural gas costs at NL1 is 0.935 €/l GE (Table 31). If there is an 80 % increase in the electricity costs, the average hydrogen costs increase by 35 % to about 1.26 €/l GE. If there is an increase in natural gas costs of 40 %, the average hydrogen costs increase by 5 % to about 0.98 €/l GE. The average hydrogen costs that result from both price increases together are then about 1.31 €/l GE, and some 40 % higher than before the cost increase of the input factors. Multiplying the average hydrogen costs of 1.31 €/l GE by a factor of 0.9 yields approximate hydrogen costs of about 1.18 €/l GE for a fuel substitution of about 30 % and a new registration share of alternative vehicles of 50 %.

7.2.2. Effects on discounted total costs and incremental costs

This chapter contains an examination of the changes in cumulative total costs, discounted to 2006 (in this paper, “total costs” for short) according to Figure 126 and the incremental costs of an increase in the electricity and natural gas costs. In the first section, the focus is on the changes in the total costs with an increase only in natural gas costs. In the second section, the total costs with an increase only in the electricity costs are determined. In the third section, the total costs following an increase in both electricity and natural gas costs are discussed.

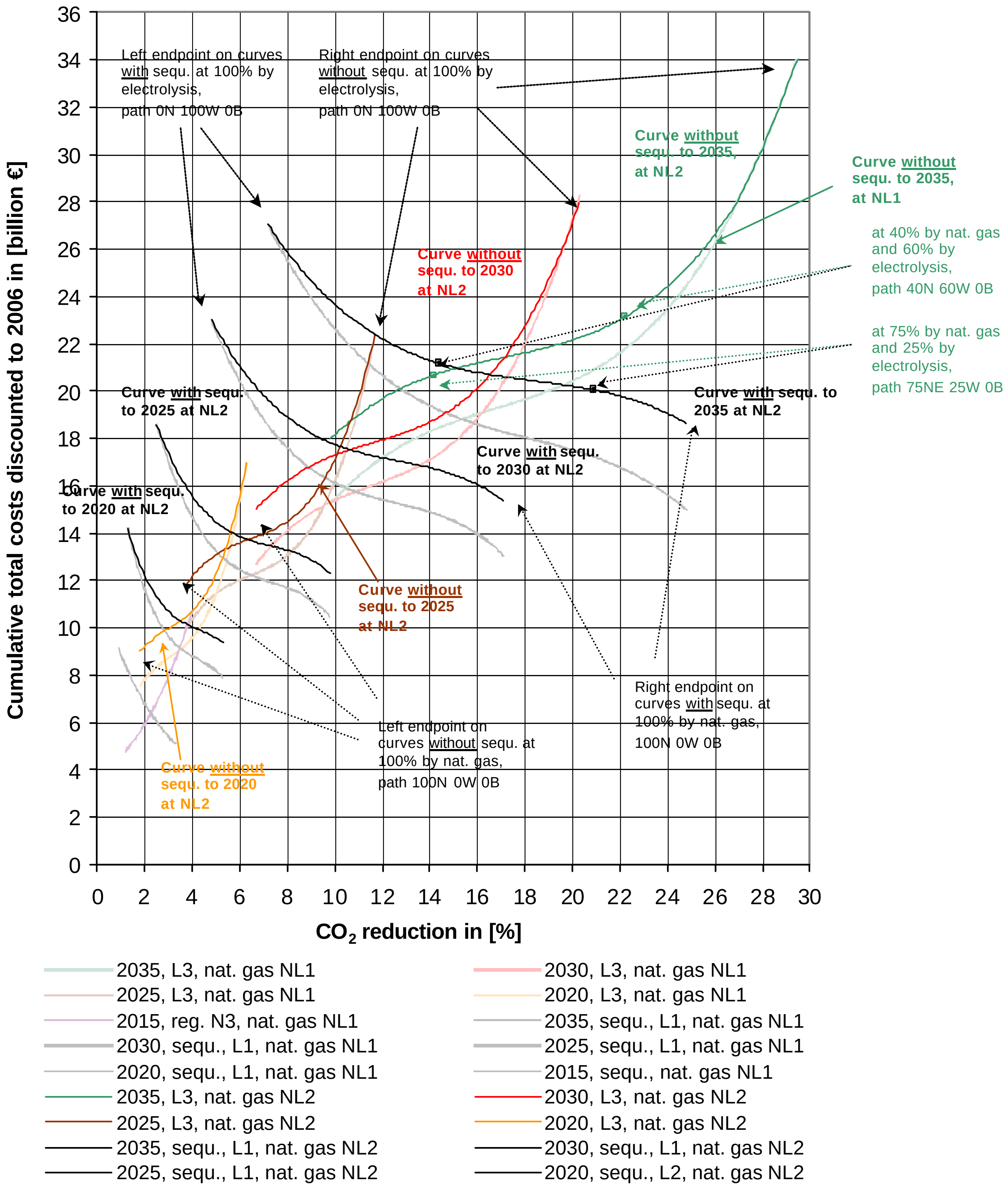
7.2.2.1. Increase in natural gas costs

There follows an examination of the total costs for an increase only in natural gas costs of around 60 % from Level LN1 to LN2 (natural gas costs according to Table 45). The total costs are calculated for the paths without sequestration with electricity costs at Level 3 (regeneratively produced electricity) and for the paths with sequestration with electricity costs at Level 1 (electricity from German power stations) (Figure 135).

The following statements can be made:

- **Development paths without sequestration:** an increase in natural gas costs of around 60 % leads to an average increase of about 20 % in the total costs for path 100N 0W 0B
- **Development paths with sequestration:** an increase in natural gas costs of around 60 % leads to an average increase of about 23 % in the total costs for path 100N 0W 0B
- the greater increase in the total costs for the development paths with sequestration compared with the development paths without sequestration is due to the fact that in the paths with sequestration there is a reduction in the efficiency of the total hydrogen production process due to the CO_2 collection plants in the NGSR plants, which necessitate a greater use of natural gas.
- the higher the increase in natural gas costs, the flatter the total cost – emissions reduction curves for a year, starting with development path 100N 0W 0B
- the higher the electrolysis share in the development path, the lower the increase in the total costs
- there is a marginal shift of the intersection of the total cost – emissions reduction curves between the development paths with and without sequestration to a path composition with a higher electrolysis share in the development path with sequestration.

Figure 135: Total cost – emissions reduction curves for electricity generation using conventional power stations (L1) and regenerative energy (L3) with and without the use of CO_2 sequestration from well to vehicle fuel tank for various hydrogen production development paths if there is an increase in natural gas costs from Level 1 (NL1) to Level 2 (NL2) in Germany from 2020 to 2035



L1 = electricity costs using conventional power stations, L3 = electricity costs using regenerative energy, NL1 = Natural gas costs at Level 1, NL2 = Natural gas costs at Level 2, Sequ. = sequestration.

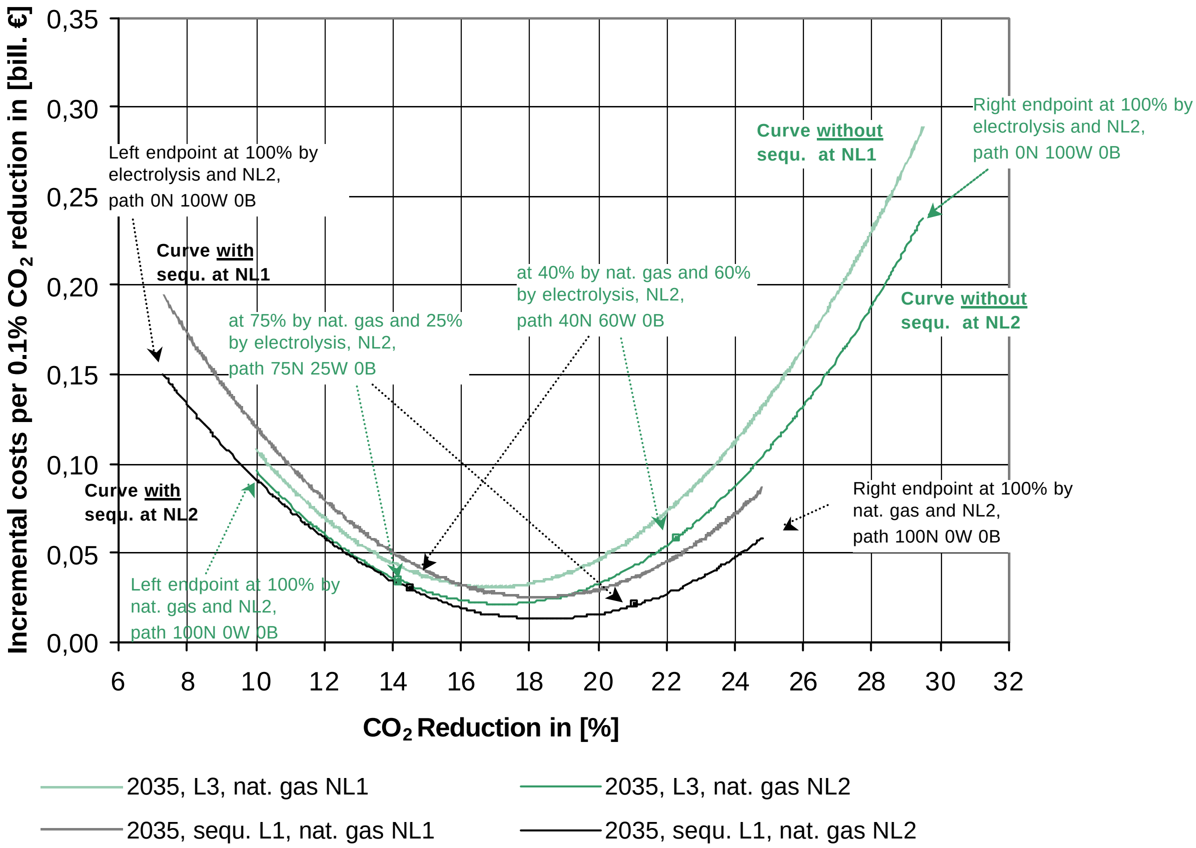
Specimen key description: "Year 2035, L3, nat. gas NL1" = Cumulative discounted total costs for the period 2006 to 2035 in the generation of electricity using regenerative energy (L3) and natural gas costs at Level 1 (NL1).

"Year 2035, sequ., L1, nat. gas NL2" = Cumulative discounted total costs for the period 2006 to 2035 with the use of sequestration with the generation of electricity using conventional power stations (L1) and natural gas costs at Level 2 (NL2).

Source: Own calculations, 2002

Due to the flatter total cost - emissions reduction curve in Figure 135 compared with the curves before the increase in natural gas costs, there is also a change in the incremental cost, shown in Figure 136 as the example of incremental costs up to 2035. In general, there is a decrease in the level of costs.

Figure 136: Incremental costs of CO_2 reductions with and without the use of sequestration from well to vehicle fuel tank for various hydrogen production development paths with an increase in natural gas costs from Level 1 (NL1) to Level 2 (NL2) in Germany up to 2035



L1 = electricity costs using conventional power stations, L3 = electricity costs using regenerative production, NL1 = Natural gas costs at Level 1, NL2 = Natural gas costs at Level 2, Sequ. = sequestration.
Specimen key description: "Year 2035, L3, nat. gas NL1" = Incremental costs for the period 2006 to 2035 in the generation of electricity using regenerative energy (L3) and natural gas costs at Level 1 (NL1).
"Year 2035, sequ., L1, nat. gas NL2" = Incremental costs for the period 2006 to 2035 with the use of sequestration with the generation of electricity using conventional power stations (L1) and natural gas costs at Level 2 (NL2).
Source: Own calculations, 2002

7.2.2.2. Increase in electricity costs

There follows an examination of the total costs for an increase in electricity costs only of around 30 %. For regeneratively produced electricity the result is an increase in costs from Level L3 to L4 and for electricity generated at German power stations from Level L1 to L2 (Table 20). Natural gas costs are assumed to be at Level NL1.

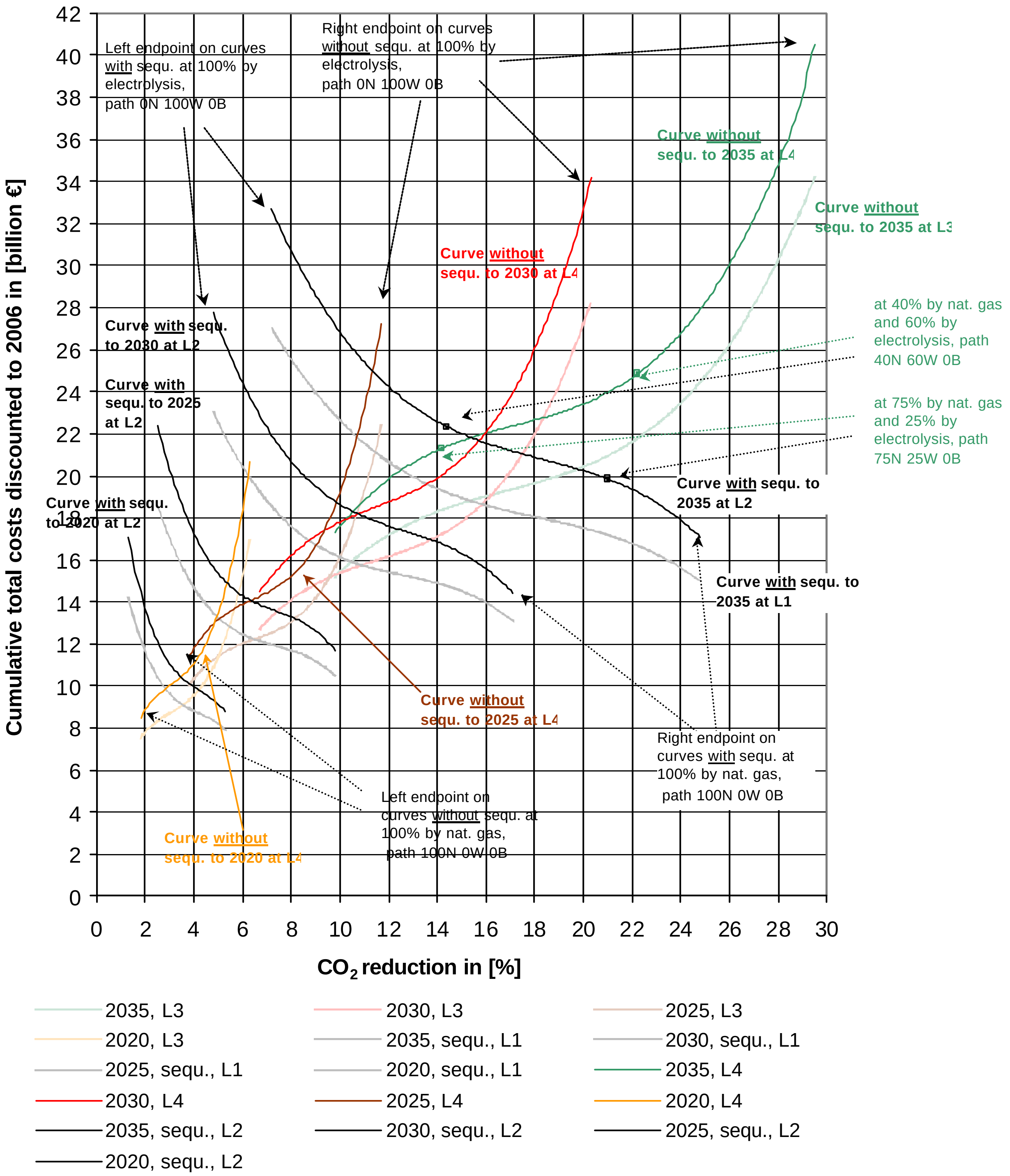
In examining the total cost – emissions reduction curves, taking into account the higher electricity costs in Figure 137, the following statements can be made:

- **development paths without sequestration:** an increase in electricity costs of around 30 % causes an average increase in the total costs for path 100N 0W 0B of about 15 %, and for path 0N 100W 0B of about 21 %
- **development paths with sequestration:** an increase in electricity costs of around 30 % causes an average increase in the total costs for path 100N 0W 0B of about 15 %, and for path 0N 100W 0B of about 23 %

- the more marked increase in total costs for the development paths with sequestration compared with those without sequestration results from the fact that in the paths with sequestration there is a reduction in efficiency due to the CO_2 collection plants at the power stations for electricity generation, which necessitate a higher number of power station for electricity generation or a higher capacity at the power stations.
- the greater the increase in the electricity costs and the higher the electrolysis share in the development path, the steeper the total cost – emissions reduction curves starting with development path 100N 0W 0B
- there is no shift in the development path for the intersection of the total cost – emissions reduction curves between those with and without sequestration, as identical percentage increases in the regenerative electricity costs and electricity costs of German power stations can be assumed.

In Figure 137, the turning points are also evident from the total cost - emissions reduction curves at which the path composition yields the lowest incremental costs. As this amounts approximately to a parallel shift of the total cost - emissions reduction curves compared with the electricity costs at Level 1, the incremental costs are not shown.

Figure 137: Total cost – emissions reduction curves for electricity generation using conventional power stations and regenerative energy with and without the use of CO_2 sequestration from well to vehicle fuel tank for various hydrogen production development paths, with an increase in electricity costs from Level 1 (NL1) to Level 2 (NL2) and in regenerative energy from Level 3 (L3) to Level 4 (L4) in Germany from 2020 to 2035



L1, L2 = electricity costs using conventional power stations, L3, L4 = electricity costs using regenerative energy, Natural gas costs at Level 1 (NL1), Sequ. = Sequestration.
Specimen key description: "Year 2035, L1" = Cumulative discounted total costs for the period 2006 to 2035 with the generation of electricity using regenerative energy (L3). "Year 2035, Sequ., L2" = cumulative discounted total costs for the period 2006 to 2035 with the use of sequestration with electricity generation by conventional power stations (L2).
Source: Own calculations, 2002

7.2.2.3. Increase in electricity and natural gas costs

An extreme case is presented by a serious increase in both electricity and natural gas costs, between which there is a relationship, at least in Germany. GST power stations in the German grid have an electricity generation share of around 10 % (Figure 22). Due to the future planned reduction in electricity generation from nuclear power stations in Germany, the nuclear power stations removed from the grid will probably be partly replaced by conventional power stations such as GST power stations. Consequently, an increase in natural gas costs can also be assumed to mean an increase in electricity costs (Own assumption, 2002; ZEUS, 2002, p. 6).

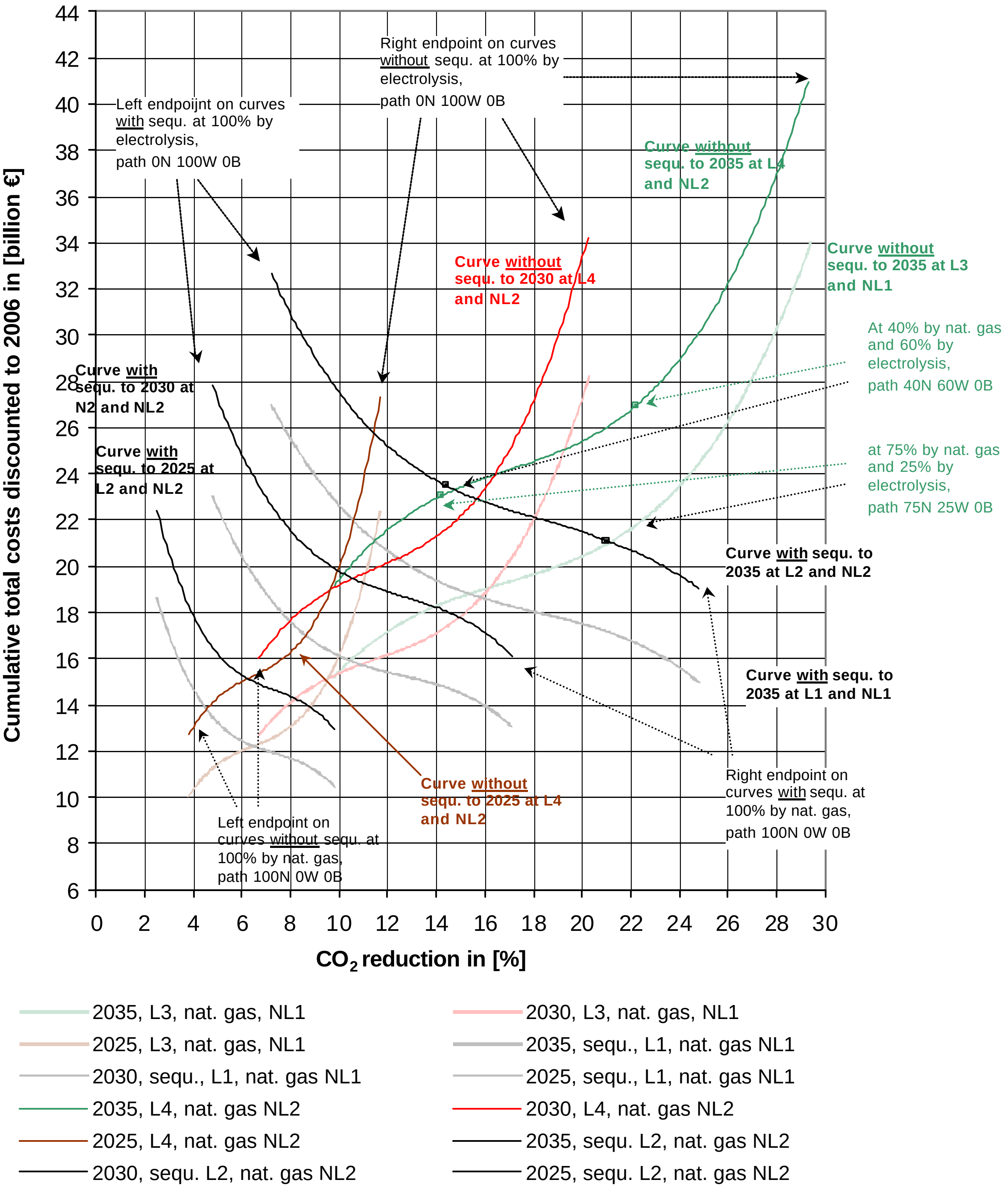
For the following examination of the changes in the total costs, it is assumed that an increase in the electricity costs of regeneratively produced electricity from Level L3 to L4 and the electricity costs of German power stations from Level L1 to L2 takes place (Table 20). Natural gas costs are assumed to be at Level NL2 (Table 45).

Examining the development of the total costs and taking into consideration the cost increases of the input factors in Figure 138, the following statements can be made (for reasons of clarity, only the total cost - emissions reduction curves for the years 2025, 2030 and 2035 are shown in the diagram):

- **development paths without sequestration:** an increase in the input factors causes an average increase in the total costs for path 100N 0W 0B of about 27 %, and for path 0N 100W 0B of about 21 %
- **development paths with sequestration:** an increase in the input factors causes an average increase in the total costs for path 100N 0W 0B of about 28 %, and for path 0N 100W 0B of about 22 %
- essentially, there is an almost parallel shift of the total cost – emissions reduction curves to a higher level of costs
- there is a marginal shift of the intersection of the total cost – emissions reduction curves between the paths with and without sequestration (for details, see also Chapters 7.2.2.1 and 7.2.2.2)

In Figure 138, the turning points of the total cost - emissions reduction curves for the path composition ehxibiting the lowest incremental costs are also evident,. As this amounts to an approximately parallel shift of the total cost - emissions reduction curves, no presentation of the incremental costs has been made.

Figure 138: Total cost – emissions reduction curves for electricity generation using conventional power stations and regenerative energy with and without the use of CO_2 sequestration from well to vehicle fuel tank for various hydrogen production development paths, if there is an an increase in electricity costs from conventional power stations from Level 1 (NL1) to Level 2 (NL2) and from regenerative energy from Level 3 (L3) to Level 4 (L4) and with an increase in natural gas costs from Level 1 (NL1) to Level 2 (NL2) in Germany from 2025 to 2035



L1, L2 = electricity costs using conventional power stations, L3, L4 = electricity costs using regenerative energy, NL1, NL2 = Natural gas costs, Sequ. = sequestration.
Specimen key description: "Year 2035, L3, nat. gas NL1" = Cumulative discounted total costs for the period 2006 to 2035 in the generation of electricity using regenerative energy (L3) and natural gas costs at Level NL1.
"Year 2035, sequ., L1, nat. gas NL2" = Cumulative discounted total costs for the period 2006 to 2035 with the use of sequestration with the generation of electricity using conventional power stations (L2) and natural gas costs at Level NL2.
Source: Own calculations, 2002

7.3. Variation of the interest rate

An important influence on the level of the cumulative total costs, discounted to 2006, is the chosen interest rate. Figure 126 contains a detailed presentation of the discounted total costs at an interest rate of 12 %. The high real interest rate is based on the fact that investors in the affected sectors (including petroleum companies, energy suppliers and the automobile industry) expect a correspondingly high return on their invested capital.

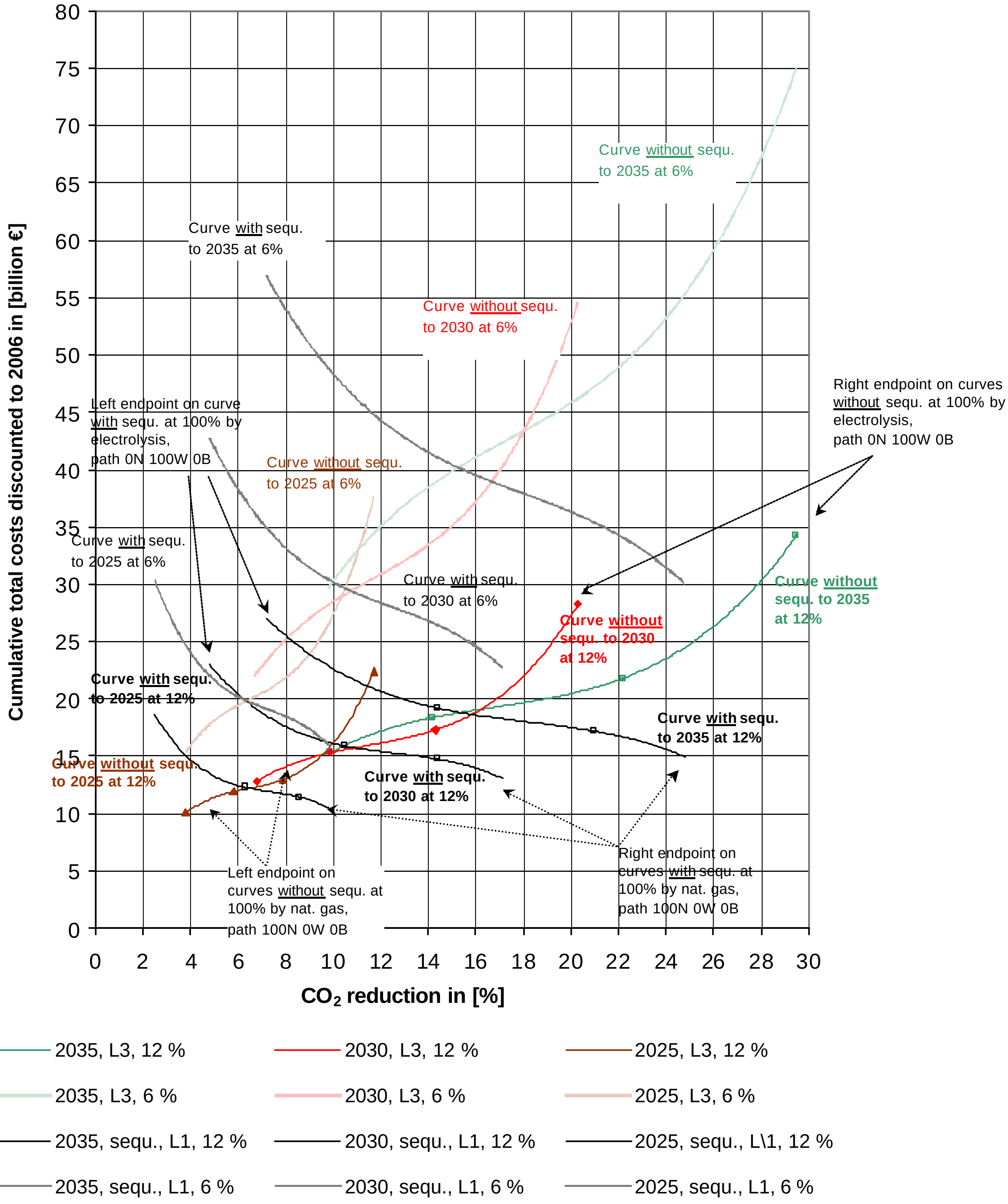
As this paper examines a timeframe of 30 years, a higher interest rate has a strong weakening effect on the discounting of future costs to 2006. This chapter therefore contains an examination of the changes to the cumulative total costs, discounted to 2006 and the incremental costs at a lower interest rate. Particular attention is paid to the possible change, caused by the level of the interest rate, in the determined optimum for the lowest incremental costs criterion.

7.3.1. Effects on discounted total costs

The change in the cumulative total costs, discounted to 2006 (in this section, "total costs") at various interest rates is shown in Figure 139. Starting from a lower total cost level with an interest of 12 %, the result in the example of a lower interest rate level of 6 % is increasing total costs with an increasing examined timeframe. The effect here is that the longer the timeframe and the higher the chosen interest rate, the lower the future cost influence on the discounted costs in the present.

However, changing the interest rate leads to no change in the position of the intersection between the total cost – emissions reduction curve with and without sequestration. In the example of the curves with and without sequestration for 2035 at an interest rate of 12 %, the use of sequestration is only meaningful up to an electrolysis share of a maximum of 50 %, as above that the residual emissions become too high. At an interest rate of 6 % there is no change in this statement. Independent of the chosen level of interest, sequestration should only be used up to a maximum electrolysis share of 50 %.

Figure 139: Total cost – emissions reduction curves for electricity generation using conventional power stations (L1) and regenerative energy (L3) with and without the use of CO_2 sequestration from well to vehicle fuel tank for various hydrogen production development paths at interest rates of 6 % and 12 % in Germany from 2025 to 2035

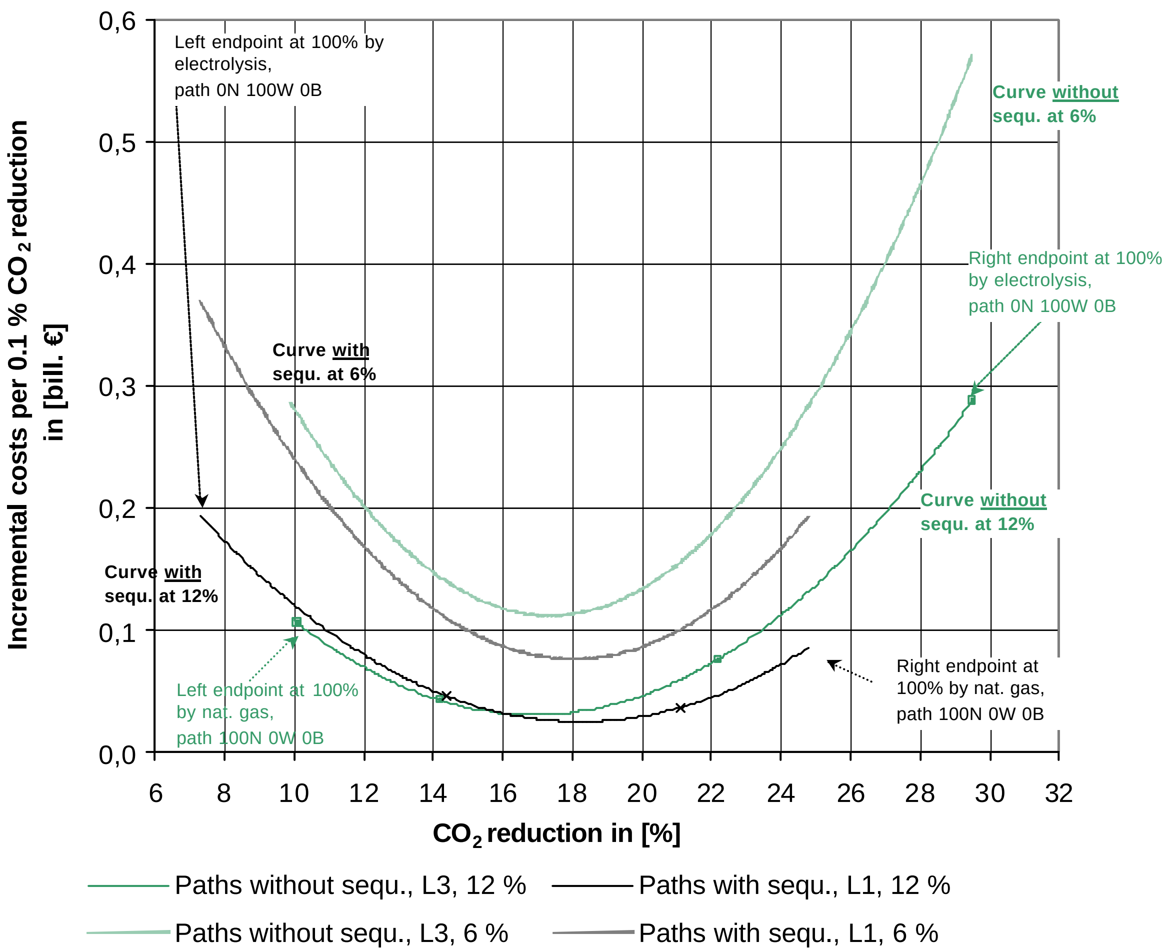


L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1). Sequ. = sequestration.
Specimen key description: "Year 2035, L3, 12%" = Cumulative total costs, discounted to 2006 with an interest rate of 12 %, of the considered timeframe of 2006 to 2035 in the generation of electricity using regenerative energy (L3). "Year 2035, sequ., L1, 6%" = Cumulative total costs, discounted to 2006 with an interest rate of 6 %, of the considered timeframe of 2006 to 2035 using sequestration in the generation of electricity using conventional power stations (L1).
Source: Own calculations, 2002

7.3.2.Effects on incremental costs

Figure 139 clearly shows the steeper increase in the total cost – emissions reduction curves both with and without the use of sequestration. Consequently, at a lower interest rate there is an increase in the incremental costs (Figure 140). The level of the incremental costs for the development paths without sequestration increases much more strongly at a lower interest rate than for the development paths with sequestration, i.e., the total cost – emissions reduction curves in the development paths with sequestration are flatter than in the development paths without sequestration. The cost effect of regenerative electricity production compared to conventional power stations takes effect here. In the development paths with sequestration, moderate electricity costs at the conventional power stations were assumed. On the other hand, this implied the use of regeneratively produced electricity in the development paths with sequestration. The higher the electrolysis share in the development path, the greater the extent to which the higher regenerative electricity costs affect the total costs and ultimately the incremental costs.

Figure 140: Incremental costs of CO_2 reductions with and without the use of sequestration from well to vehicle fuel tank for various hydrogen production development paths at interest rate levels of 6 % and 12 % in Germany up to 2035



L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1). sequ. = sequestration.
Source: Own calculations, 2002

7.4. Development of hydrogen demand occurs more rapidly than assumed

The calculations and the results of the options discussed thus far are all based on the assumption that hydrogen demand as an alternative fuel corresponding to the chosen development of the hydrogen vehicle population will develop (VPD OWN; Chapter 2.3.4). What effects a more rapid market penetration of vehicles using hydrogen as an alternative fuel and therefore a more rapid annual increase in hydrogen demand will have on the build-up of a hydrogen infrastructure are discussed in this chapter.

The first step is the definition of a new scenario for the increase in the hydrogen demand over the years, HDD SENSITIVITY. In the second step, taking the chosen scenario into consideration there is an examination of the development of the following focal points of the analysis:

- Gas station infrastructure hydrogen supply
- Specific hydrogen costs
- CO_2 reduction potential
- Discounted total costs
- Incremental costs

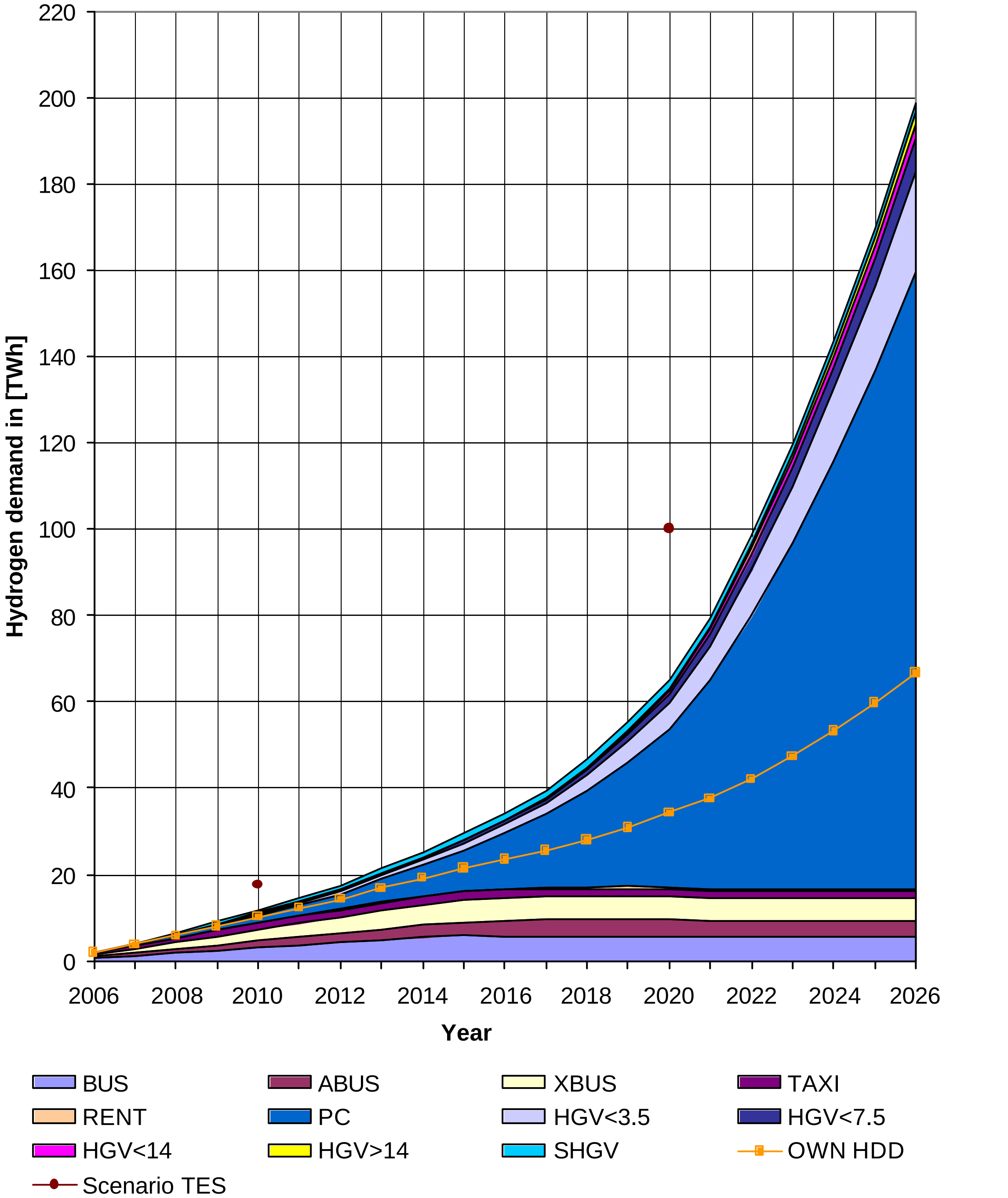
7.4.1. Determining hydrogen demand

The increasing hydrogen demand over time according to HDD SENSITIVITY was chosen according to the characteristic features of an S-curve (Figure 141).

The following was assumed for the development of **hydrogen demand according to HDD SENSITIVITY**.

- The hydrogen demand of the vehicle categories BUS, ABUS, CCB, SHGV, TAXI and RENT was left identical to that in HDD OWN, since the increase in the inventory of vehicles using hydrogen as an alternative fuel in these vehicle categories has already been assumed very optimistically
- Sales of vehicles using hydrogen as an alternative fuel in the vehicle categories PC, HGV<3.5, HGV<7.5 and HGV<14 proceed more rapidly and according to the characteristic features of an S-curve (Figure 21)
- the periods of time for the substitution of conventional fuel to rise from 1 % to 10 % and from 10 % to 50 % are assumed to be around 8 years (compare the period of time for market penetration from 1 % to 1 0% and from 10 % to 50 % for automobiles in urban areas in the USA, which took about 8 years, Figure 14)

Figure 141: Development and composition of hydrogen demand by vehicle categories with more rapid market penetration of vehicles using hydrogen as an alternative fuel, according to hydrogen demand development OWN and the Transport Energy Strategy (TES) in Germany from 2006 to 2026



BUS = Scheduled buses, ABUS = Scheduled articulated buses, XBUS = Cross-country buses, TAXI = Taxis, RENT = Rental cars, PC = Passenger cars, HGV<3.5 = Heavy goods vehicles with gross weight limit of less than 3.5 t, SHGV = Special trucks (vehicles for waste management and street cleaning),
Source: TES, 2000, p. 4; Own calculations, 2002

For the hydrogen demand according to HDD SENSITIVITY in the above diagram to arise, there is the need for an **increase in the vehicle population** using hydrogen as an alternative fuel as shown in Figure 191, Appendix 10. The appendix also shows the development of the hydrogen demand and the hydrogen vehicle population as an alternative fuel according to the SENSITIVITY scenario, for the city of Munich.

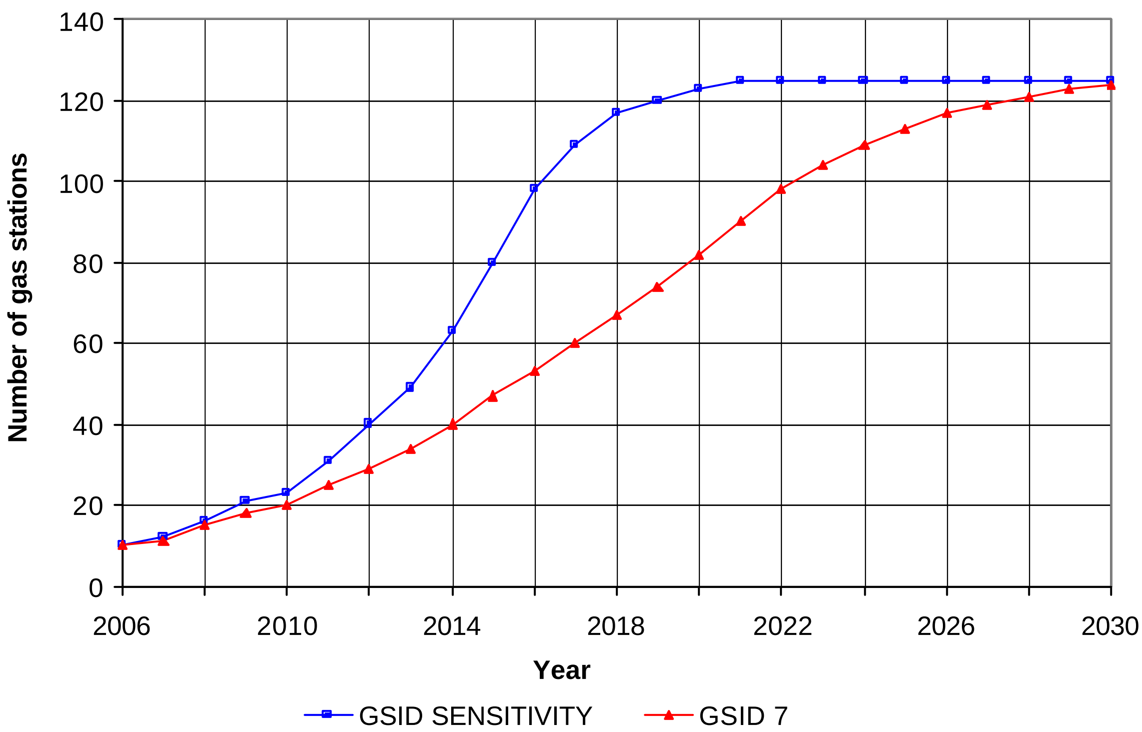
7.4.2.Hydrogen gas station infrastructure

Based on HDD SENSITVITY, the first part of this chapter determines the possible development of a gas station infrastructure in the German city of Munich. This is followed by an examination of gas station infrastructure development in Germany.

7.4.2.1. Gas station infrastructure in Munich

Due to the more rapid increase in the hydrogen demand according to HDD SENSITIVITY compared with HDD OWN (for this scenario GSID 7 was used), the almost complete modification of the conventional gas stations in Munich to provide at least one fuel pump for hydrogen is achieved after about 13 years (Figure 142). By comparison, in GSID 7 it takes about 25 years to achieve almost full modification of the conventional gas stations.

Figure 142: Development of the number of modified gas stations for supplying vehicles with hydrogen according to OWN hydrogen demand (GSID 7) and SENSITIVITY hydrogen demand patterns (HDD SENSITIVITY) in Munich from 2006 to 2030



GSID = Gas station infrastructure development
Source: Own calculations, 2002

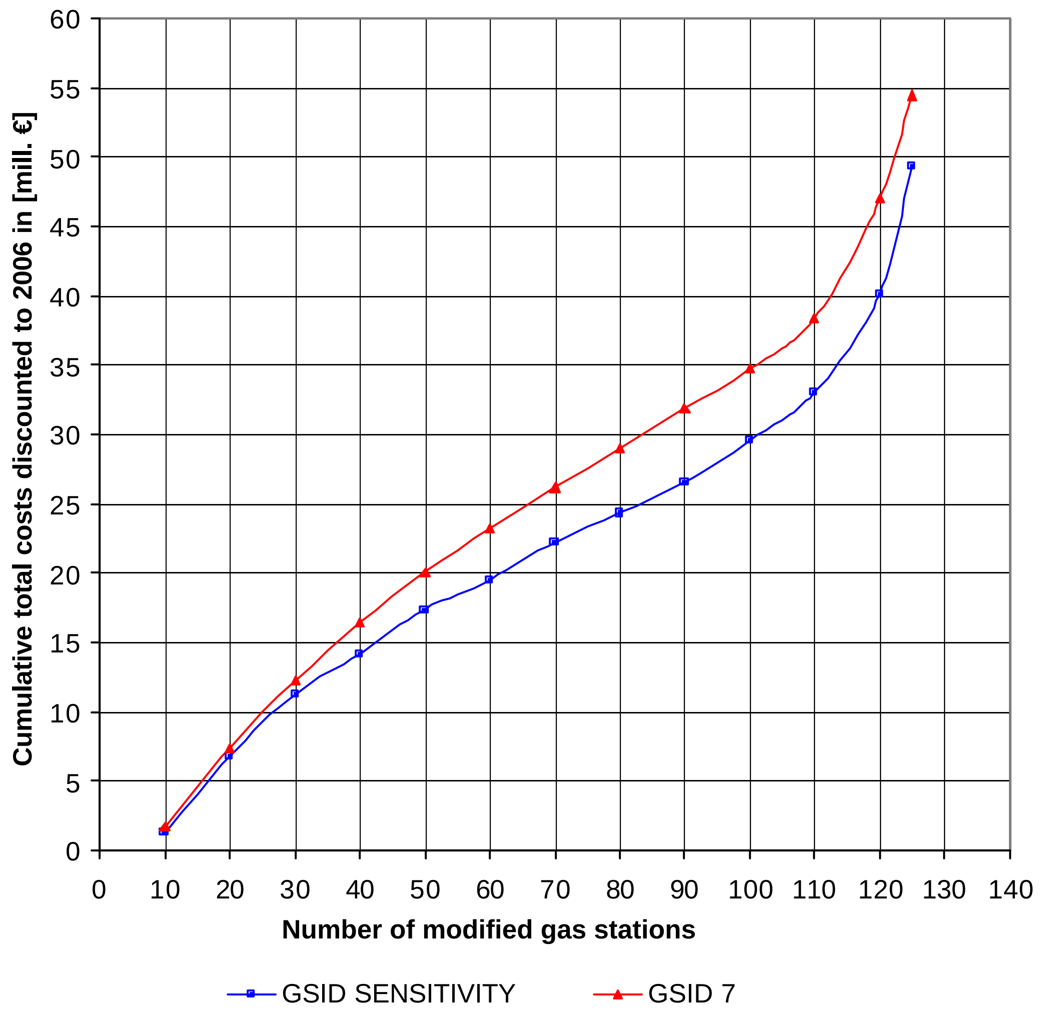
Assuming the development of the **number and usage of fuel pumps** at the modified gas stations as in Figure 194, Appendix 10, the inventory of modified gas stations is shown in Figure 142 in accordance with hydrogen demand according to HDD SENSITIVITY. Until 2017, fuel pump usage is identical to that of GSID 7 in OWN HDD. From 2017 on and the almost complete modification of all conventional gas stations in Munich, fuel pump usage per modified gas station increases. From this point in time there is also an increase in the number of fuel pumps per modified gas station (11 pumps per modified gas station in 2030).

The comparison of **cumulative total costs discounted to 2006** for the build-up of a gas station infrastructure in Munich in Figure 195, Appendix 10, shows that the total costs are higher than for GSID 7, due to higher hydrogen fuel sales at the modified gas stations and the necessity for a higher number of fuel pumps.

The development of **cumulative total costs, discounted to 2006, with reference to the number of modified gas stations** in Munich is shown in Figure 143. With the rapid development of a gas station infrastructure based on HDD SENSITIVITY, total costs compared with GSID 7 can be clearly reduced for the following reasons:

- lower number of fuel pumps (3) per modified gas station on achieving total modification of 125 gas stations in 2019 for HDD SENSITIVITY compared with four fuel pumps per modified gas station in 2034 for HDD OWN.
- lower re-investment in various items of gas station equipment (e.g. fuel pumps, other pumps) until almost complete modification of the gas stations in GSID SENSITIVITY compared with re-investments for GSID 7 (the gas station equipment is assumed to have a technical lifespan of 15 years)

Figure 143: Cumulative total gas station costs, discounted to 2006, depending on the modified gas station inventory up to the time when complete modification of 125 gas stations is achieved, in OWN hydrogen demand development (GSID 7) and in the SENSITIVITY (GSID SENSITIVITY) hydrogen demand development in Munich



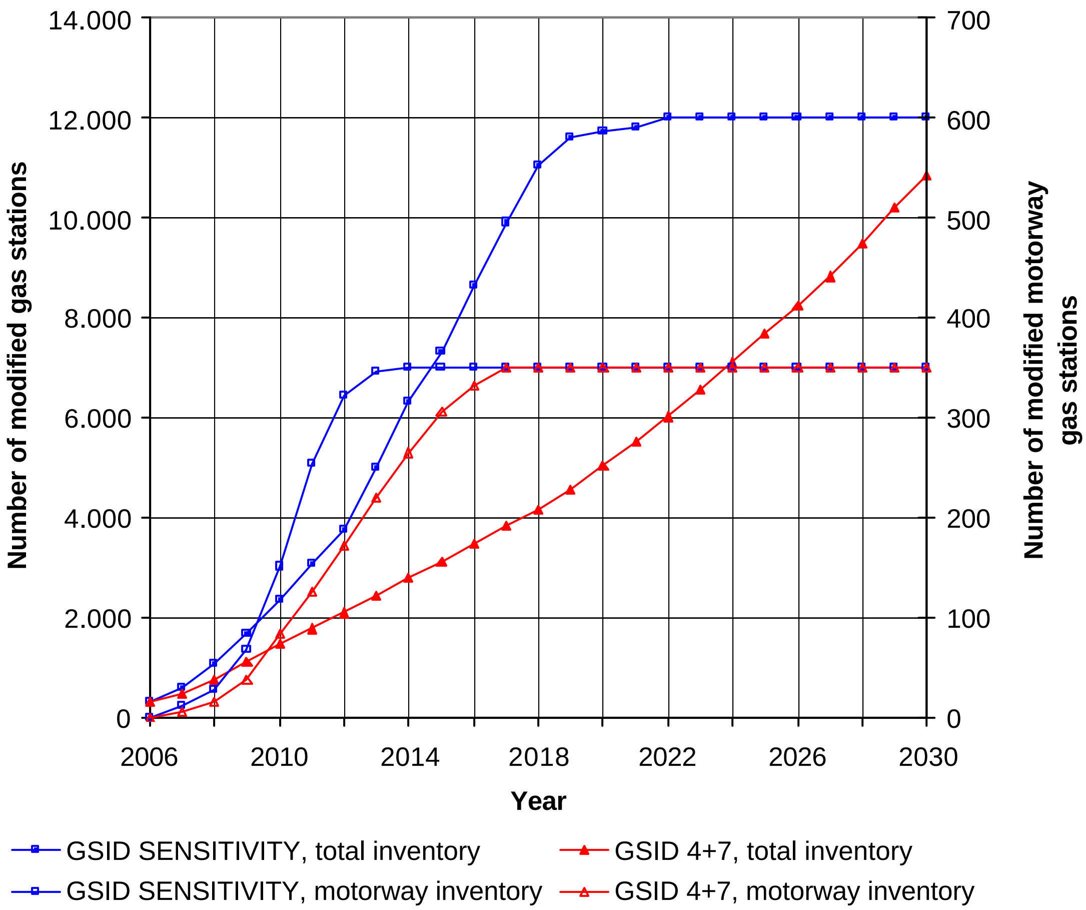
Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development
Source: Own calculations, 2002

7.4.2.2. Gas station infrastructure in Germany

If the development of the gas station infrastructure in Munich is extrapolated to possible development in Germany (for calculation scheme, see Chapter 5), an **inventory of modified gas stations** according to Figure 144 will be obtained over the years. The gas station coverage of around 1,500 gas stations (definition in Chapter 5.2.2) will be achieved in 2008 and 2009 and therefore about two years earlier than for GSID 4+7 and HDD OWN. The modification of gas stations is almost complete in 2021.

Accordingly, the build-up of a gas station infrastructure for HDD SENSITIVITY runs at almost twice the speed of the build-up of an equivalent infrastructure according to HDD OWN.

Figure 144: Development of the modified gas station inventory by examination of the total gas station inventory or only the motorway ('autobahn') gas station inventory of in terms of OWN (GSID 4+7) and SENSITIVITY hydrogen demand development (GSID SENSITIVITY) in Germany from 2006 to 2030

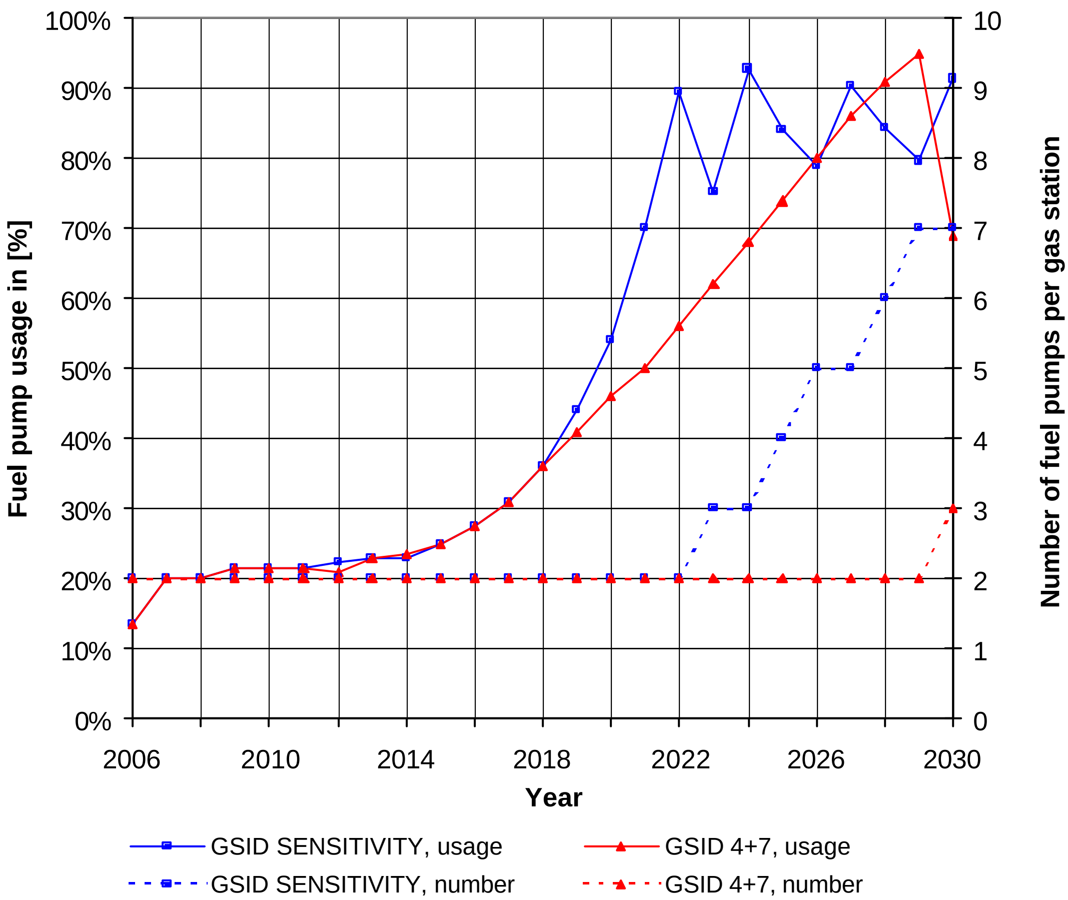


GSID = Gas station infrastructure development
Source: Own calculations, 2002

The development of the gas station infrastructure, divided into German cities and rural areas, is shown in Figure 196, Appendix 10.

The development of the **number and usage of fuel pumps** at modified gas stations in Germany in Figure 145 is similar to the development for Munich discussed above (Figure 194). From the comparison of the two figures it can again be seen that the U-shaped curve of fuel pump usage in the period 2010 to 2019 for Munich is no longer present in the nationwide examination.

Figure 145: Number and usage of fuel pumps per modified gas station for OWN (GSID 4+7) and for SENSITIVITY hydrogen demand development (GSID SENSITIVITY) in Germany from 2006 to 2030

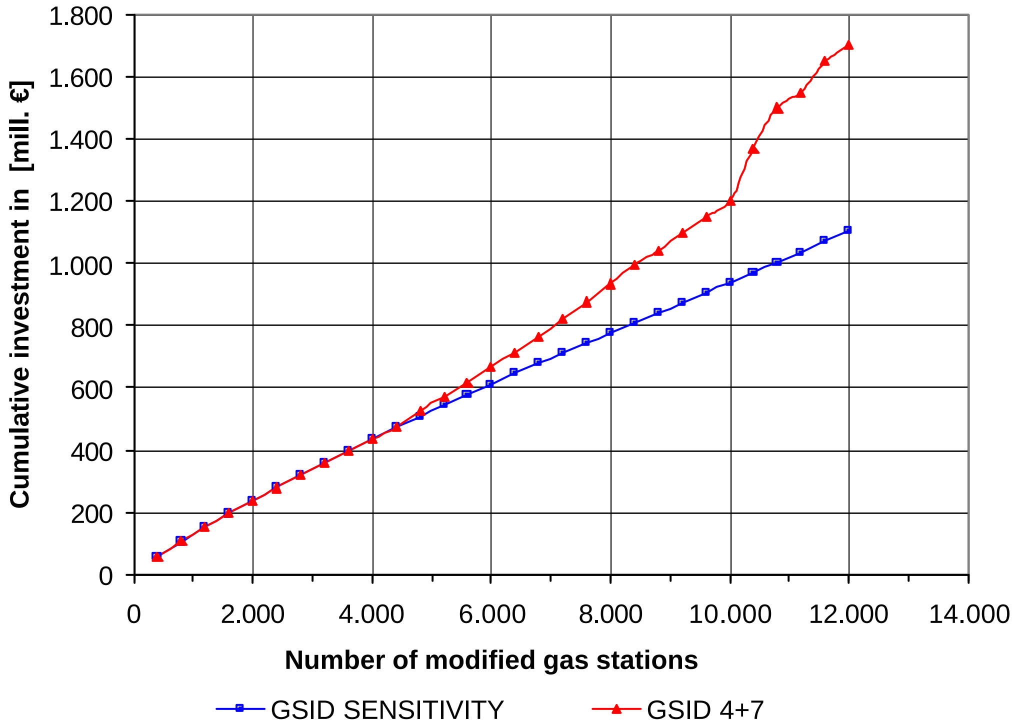


GSID = Gas station infrastructure development
Source: Own calculations, 2002

The development of the **number of communities to be supplied per gas stations in rural areas** is shown in Figure 197, Appendix 10. The current density of gas stations in rural areas (without those in cities and on motorways ('autobahns')) is approximately one gas station per community. In GSID SENSITIVITY, the figure of 5 districts per modified gas station is already achieved in 2012. The number of districts to be supplied by each modified gas station falls almost twice as quickly as in GSID 4+7.

The relationship between **cumulative investments in the gas station infrastructure and the inventory of modified gas stations** leads to a reduction in the cumulative investment in GSID SENSITIVITY compared with GSID 4+7 (Figure 146). The effect here is that due to the quicker development of a gas station, the number of two fuel pumps per modified gas station after almost complete modification of the existing gas station infrastructure is below the number of three fuel pumps at this stage according to GSID 4+7 (note: there are different times for achieving the complete modification of the gas stations in these scenarios, and therefore different hydrogen fuel sales and numbers of fuel pumps per modified gas station). The clear rise in the investment curve in GSID 4+7 above a gas station inventory of about 10,000 gas stations is caused by the increase in the number of fuel pumps from two to three per modified gas station. The steeper overall rise in the investment curve in GSID 4+7 above a gas station inventory of about 5.000 gas stations is due to the necessary re-investments (various items of gas station equipment such as fuel pumps and other pumps are renewed after the technical lifespan of about 15 years).

Figure 146: Cumulative investments of the gas station modification depending on the modified gas station inventory in OWN (GSID 4+7) and SENSITIVITY hydrogen demand development (GSID SENSITIVITY) in Germany



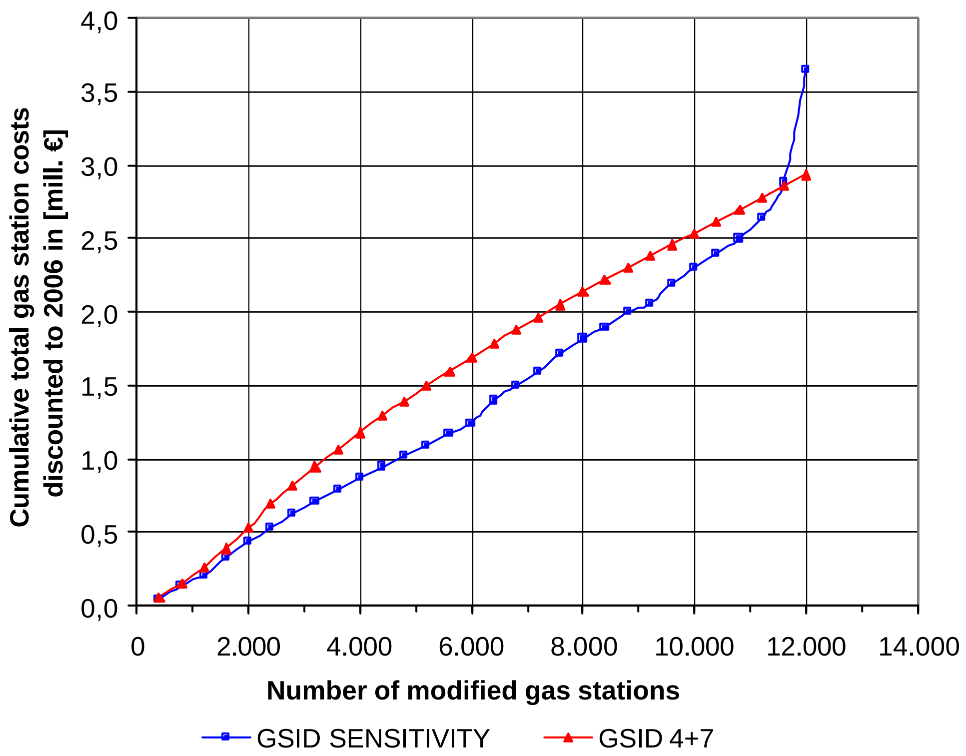
GSID = Gas station infrastructure development
Source: Own calculations, 2002

Comparison of **cumulative investments in the gas station infrastructure**, depending on the development of hydrogen demand (Figure 198 in Appendix 10), clearly shows the increase in investments in a more rapid build-up of the gas station infrastructure. The step-pattern curve of cumulative investments in GSID SENSITIVITY is caused by the increase in the number of fuel pumps at the modified gas stations.

An examination of the **cumulative total gas station costs, discounted to 2006, with reference to the inventory of modified gas stations** (in this section, "total costs") in Figure 147 yields the following:

- the more rapid the build-up of the gas station infrastructure, the lower the total short- and medium-term costs (Note: reference to the time axis yields the highest total costs, Figure 199, Appendix 10; for example, modification of 5,000 gas station according to GSID SENSITIVITY is reached in about 8 years, so that as a consequence of the shorter period of time lower sums of annual annuities (from investments and rental cost of LH_2 storage tanks) arise than according to GSID 4+7, where the modification of 5,000 gas stations requires about 17 years and the sums of annual annuities are much higher.
- clear increase in the total costs in GSID SENSITIVITY from an inventory of modified gas stations of about 11,000 due to the increase in the number of fuel pumps per modified gas station

Figure 147: Cumulative total gas station costs, discounted to 2006, depending on the modified gas station inventory up to the almost complete modification of all gas stations in OWN (GSID 4+7) and SENSITIVITY hydrogen demand development (GSID SENSITIVITY) in Germany

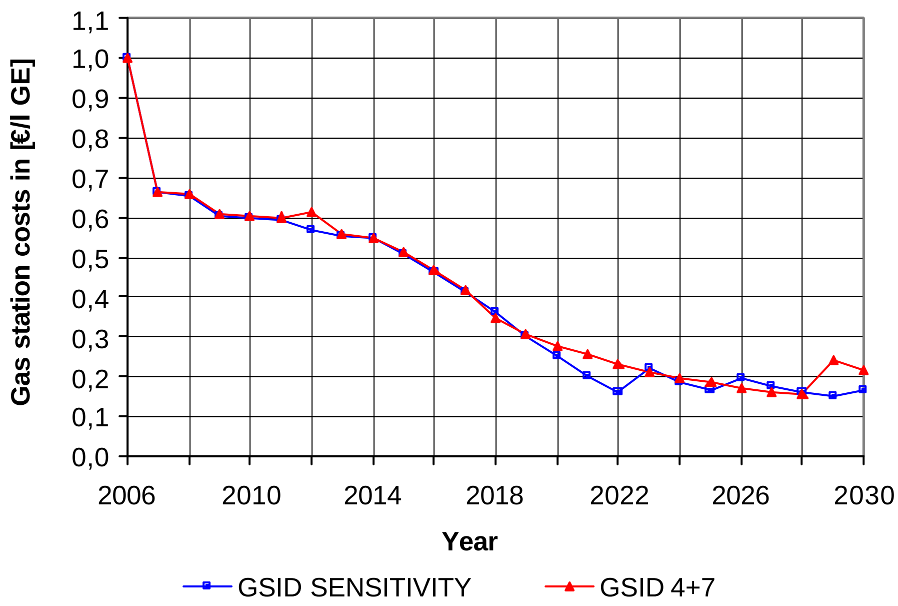


Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development.
Source: Own calculations, 2002

The comparison of the **cumulative total gas station costs discounted to 2006 depending on time** shows that due to the rapid increase in the annual hydrogen demand according to GSID SENSITIVITY there is an equivalent increase in total costs (Figure 199, Appendix 10).

The development of **specific gas station costs in €/l GE** is shown in Figure 148. As almost identical fuel pump usages have been assumed in the first few years of the build-up of the gas station infrastructure (Figure 145), the specific gas station costs up to 2018 are virtually identical for both the scenarios under examination. Only after almost complete modification of the gas stations according to GSID SENSITIVITY has been reached in 2018 is there an increase in the usage of fuel pumps and therefore a reduction in specific gas station costs compared to GSID 4+7. Due the increased number of fuel pumps at the modified gas stations and the reduction in fuel pump usage, the costs climb again. From 2022 there is an interplay between the two scenarios of the gas station costs, depending on the additional number of fuel pumps.

Figure 148: Development of specific gas station costs for favored gas station inventory developments (GSID) for the OWN (GSID 4+7) and SENSITIVITY hydrogen demand development (GSID SENSITIVITY) in Germany from 2006 to 2030



Electricity costs using conventional power stations at Level 1 (L1), GSID = Gas station infrastructure development
Source: Own calculations, 2002

The development of **hydrogen fuel sales at the modified gas stations** is shown in Figure 200, Appendix 10).

7.4.3. Economic and ecological analysis of hydrogen production from well to vehicle fuel tank

This chapter brings together the components as an overall examination from well to vehicle fuel tank. In the first section, a detailed examination of hydrogen production is carried out according to different development paths aimed at satisfying hydrogen demand in Germany according to GSID SENSITIVITY. The focus of the analysis is the development of specific hydrogen costs and CO_2 emissions (or the potential for their reduction). In the next section, the results obtained for the individual development paths are compared.

Assumption and characteristic data for further examinations in this chapter are:

- costs of hydrogen production with the variant using two power stations in the first year (Chapter 4.4.2)
- truck transport costs according to Table 27
- development of a gas station infrastructure according to GSID SENSITIVITY (Chapter 7.4.2.2)
- for the use of biomass, the long-term share of annual hydrogen production by biomass gasification is a maximum of 10 %, as the biomass potential for hydrogen production is limited.[120]

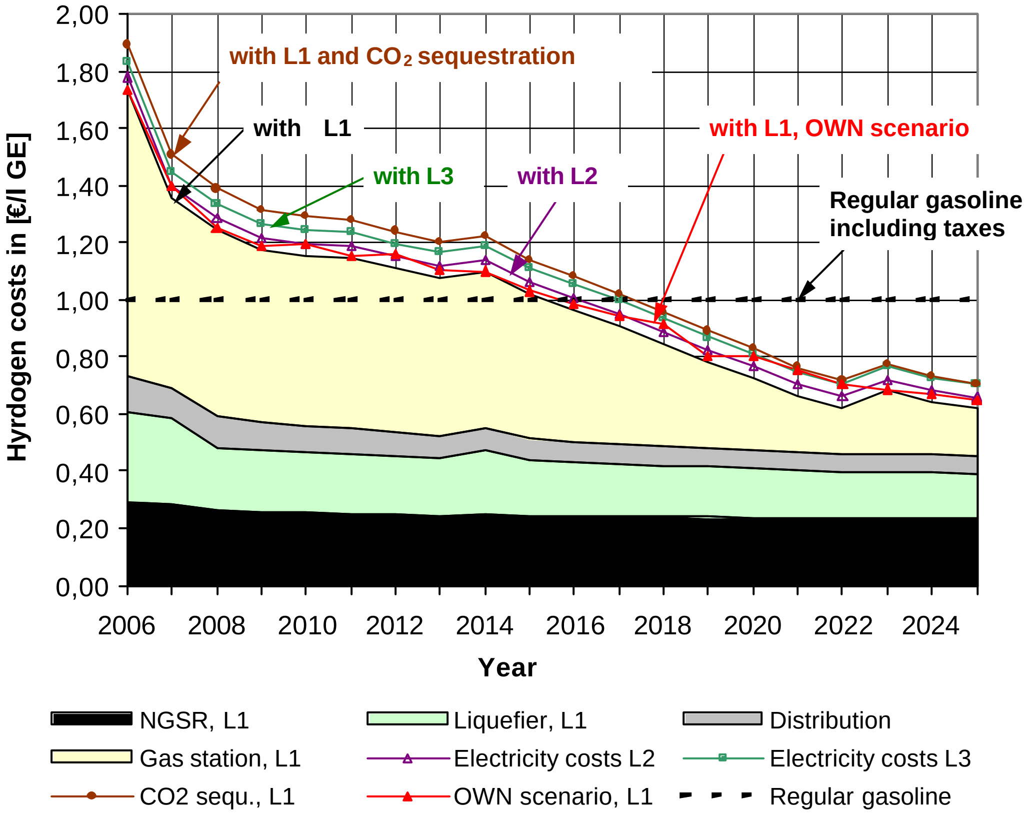
7.4.3.1. Hydrogen production by 100 % natural gas steam reforming

The development of the **specific hydrogen costs** is shown in Figure 149. The specific hydrogen costs in a more rapid build-up of the gas station infrastructure according to HDD SENSITIVITY are only slightly lower than for the slower development according to HDD OWN, since in a quicker development full utilization of the hydrogen production plants is achieved earlier. From 2020 on, the specific hydrogen costs when using regeneratively produced electricity at Level 3 are about 0.7 €/l GE.

[120] In the European Union (EU), the potential for liquid hydrogen production by biomass, in spite of full utilization of all fallow areas, is only 5 % of the necessary annual hydrogen demand for the substitution of all vehicles in the EU (TES, 2001, p. 24).

The increase in specific hydrogen costs in 2022 is caused by the need for a second LH_2 storage tank at the modified gas stations, which causes an increase in specific hydrogen costs per liter GE.

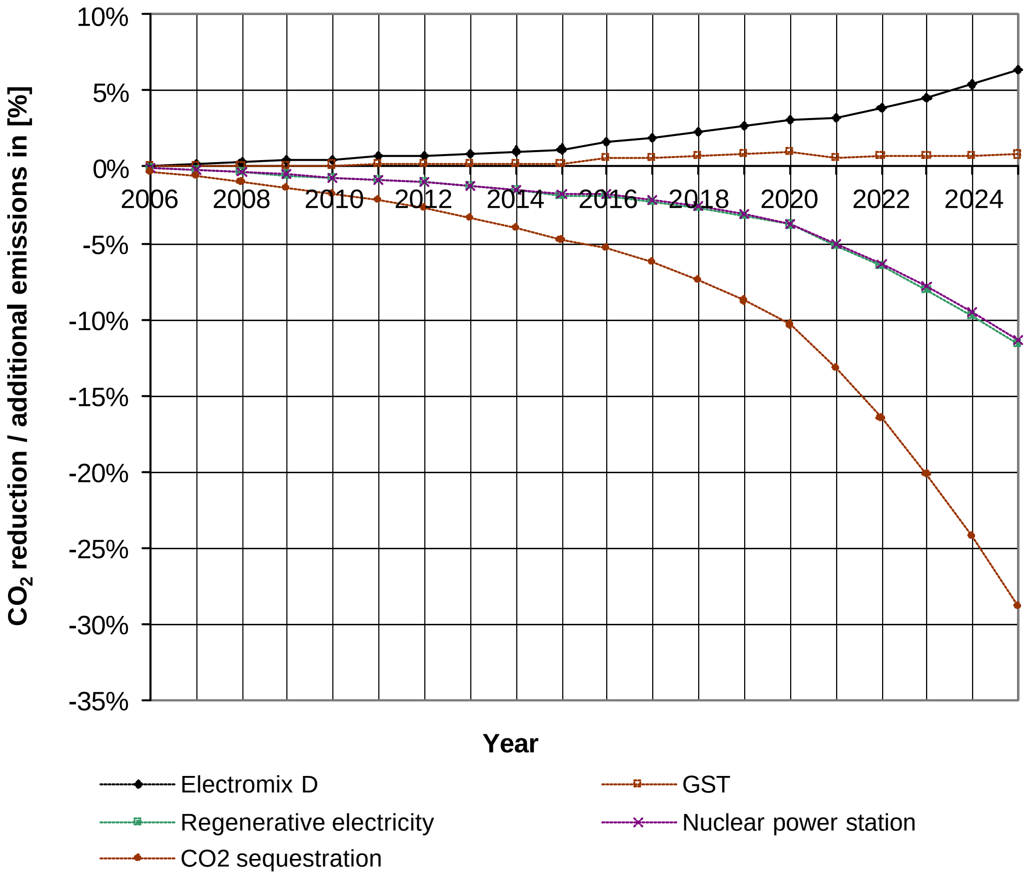
Figure 149: Specific hydrogen costs for electricity generation using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank for the 100N 0W 0B development path, for the SENSITIVITY hydrogen and OWN hydrogen demand developments (OWN scenario) in Germany from 2006 to 2025



L1 = electricity costs using conventional power stations, L2 = electricity costs using nuclear power, L3 = electricity costs using regenerative produc tion, natural gas costs at Level 1 (NL1), NGSR = Natural gas steam reforming.
Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming.
Source: Own calculations, 2002

The annual **reductions in CO_2 emissions or additional emissions** that occur, depending on electricity generation, as a percentage of the total emissions from German road traffic of approx. 200 Mt/a, are shown in Figure 150. It can be seen that the more rapidly the build-up of a hydrogen infrastructure takes place, the sooner the calculated reduction in CO_2 emissions will be achieved. The reduction in CO_2 emissions is about 12 % in 2025 using regeneratively produced electricity, compared with 4 % in the same year for a build-up of the hydrogen infrastructure according to HDD OWN (Figure 95).

Figure 150: CO_2 emissions reduction / additional emissions as a percentage of total emissions of CO_2 from road traffic in Germany of around 200 Mt per year, according to the electricity generation energy source, from well to vehicle fuel tank, for the development path 100N 0W 0B in Germany from 2006 to 2035



Electromix G = Electricity from conventional power stations, GST = Gas and steam turbine power station
Development path 100N 0W 0B = hydrogen production by 100 % natural gas steam reforming
Source: Own calculations, 2002

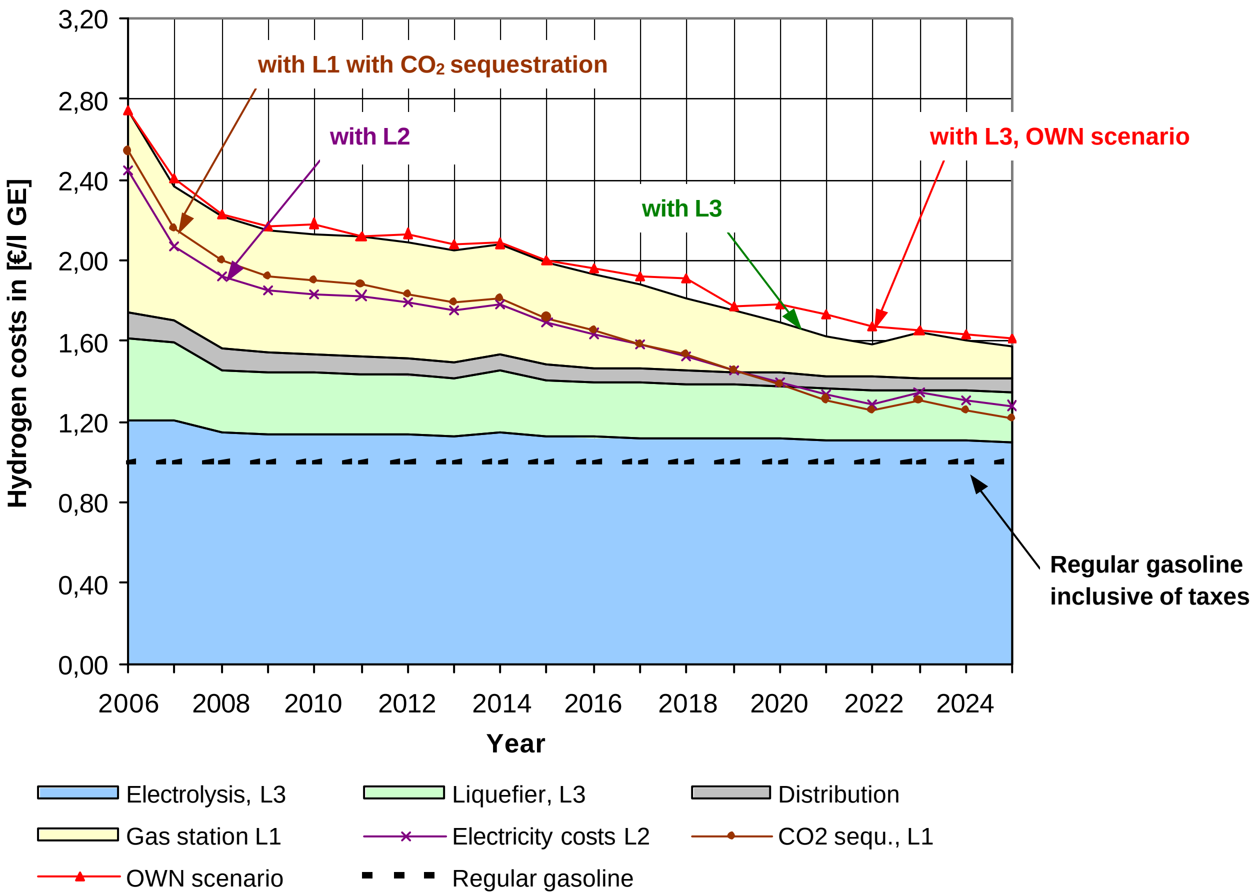
The pattern of cumulative discounted total costs is shown in Appendix 10. In accordance with the more rapid build-up of the hydrogen infrastructure, the investments and discounted total costs compared with a development according to HDD OWN are at a higher level.

7.4.3.2. Hydrogen production by 100% electrolysis

Examination of the development of **specific hydrogen costs** in Figure 151 shows that with a more rapid development of the hydrogen infrastructure according to HDD SENSITIVITY these are only slightly lower than with slower development according to HDD OWN, as in the more rapid development situation the full usage of hydrogen production plants is achieved earlier. From 2021, the specific hydrogen costs using regeneratively produced electricity at Level 3 are about 1.6 €/l GE.

The increase in specific hydrogen costs in 2022 is caused by the need for a second LH_2 storage tank at the modified gas stations, which causes an increase in the specific hydrogen costs per l GE.

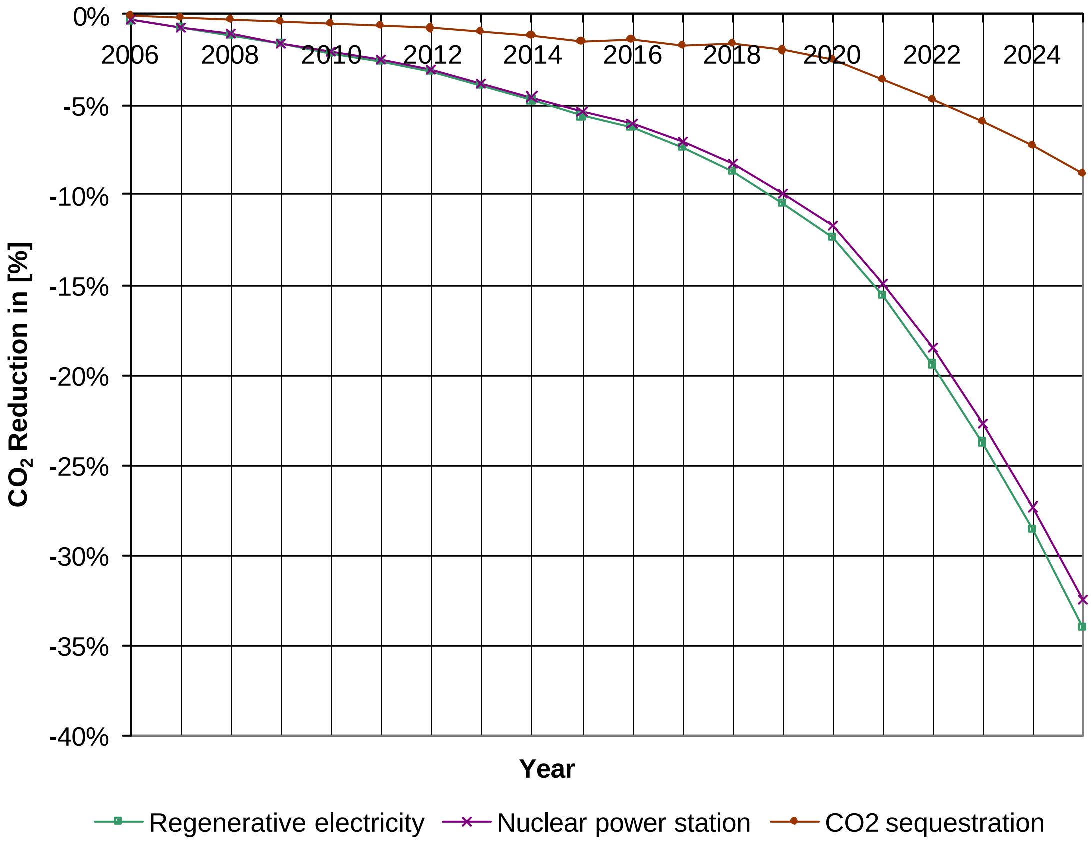
Figure 151: Specific hydrogen costs for electricity generation using conventional power stations (L1), nuclear power (L2) and regenerative energy (L3) from well to vehicle fuel tank for the development path 0N 100W 0B, for the SENSITIVITY and OWN (own scenario) hydrogen demand developments in Germany from 2006 to 2025



L1 = Electricity costs using conventional power stations, L2 = Electricity costs using nuclear power, L3 = Electricity costs using regenerative production, Sequ. = sequestration, Development path 0N 100W 0B = hydrogen production by 100 % electrolysis
Source: Own calculations, 2002

The annual reductions in CO_2 emissions or additional emissions that occur in relation to electricity generation as a percentage of the total emissions from German road traffic of approx. 200 Mt/a, are shown in Figure 152. Due to the more rapid HDD SENSITIVITY, a reduction in CO_2 emissions of about 34 % in 2025 using regeneratively produced electricity, compared with 12 % in the same year for a build-up of the hydrogen infrastructure according to HDD OWN is achieved (Figure 105).

Figure 152: CO_2 emissions reduction / additional emissions as a percentage of total emissions of CO_2 from road traffic in Germany of around 200 Mt per year by electricity generation energy source from well to vehicle fuel tank, for the development path 0N 100W 0B in Germany from 2006 to 2035



Development path 0N 100W 0B = hydrogen production by 100 % electrolysis.
Source: Own calculations, 2002

The pattern of cumulative investments and cumulative total costs discounted to 2006 is shown in Appendix 10. In accordance with the more rapid build-up of the hydrogen infrastructure, investments and discounted total costs compared to HDD OWN are at a higher level.

The development of specific hydrogen costs, cumulative investments and cumulative discounted total costs for the development paths 75N 25W 0B and 40N 60W 0B is shown in Appendix 10.

7.4.3.3. Comparison of the development paths

This chapter contains a comparison of the development paths, following a comprehensive examination of significant path compositions in Chapters 7.4.3.1 and 7.4.3.2. The focus of the analysis is on the development of cumulative total costs discounted to 2006 and incremental costs depending on the CO_2 reduction.

A key summary of the results of the development of an infrastructure in Germany according to the SENSITIVITY scenario for the realization of the respective development path is shown in table form in Tables 57 and 58, Appendix 11.

A joint examination of the **cumulative total costs discounted to 2006** (in this chapter, “total costs”) and the achievable reductions in CO_2 when using the individual development paths is shown for the period up to 2035 in Figure 135.

The calculation assumptions for the diagrammatic representations are:

- determining the total cost – emissions reduction curves in five-year stages for the years 2020 and 2025 (there are consequently two S-curves[121])
- an S-curve represents the connection between the total costs and the CO_2 reduction depending on development path for one year
- regenerative electricity production takes place using wind power stations (50 % offshore, 50 % onshore, the degression factor for learning effects is 0.95, plant specifications are in Appendix 5)
- build-up of a gas station infrastructure according to GSID SENSITIVITY (Chapter 7.4.2.2)
- reductions in CO_2 emissions are given as a percentage of total CO_2 emissions from road traffic in Germany of approx. 200 Mt/a.

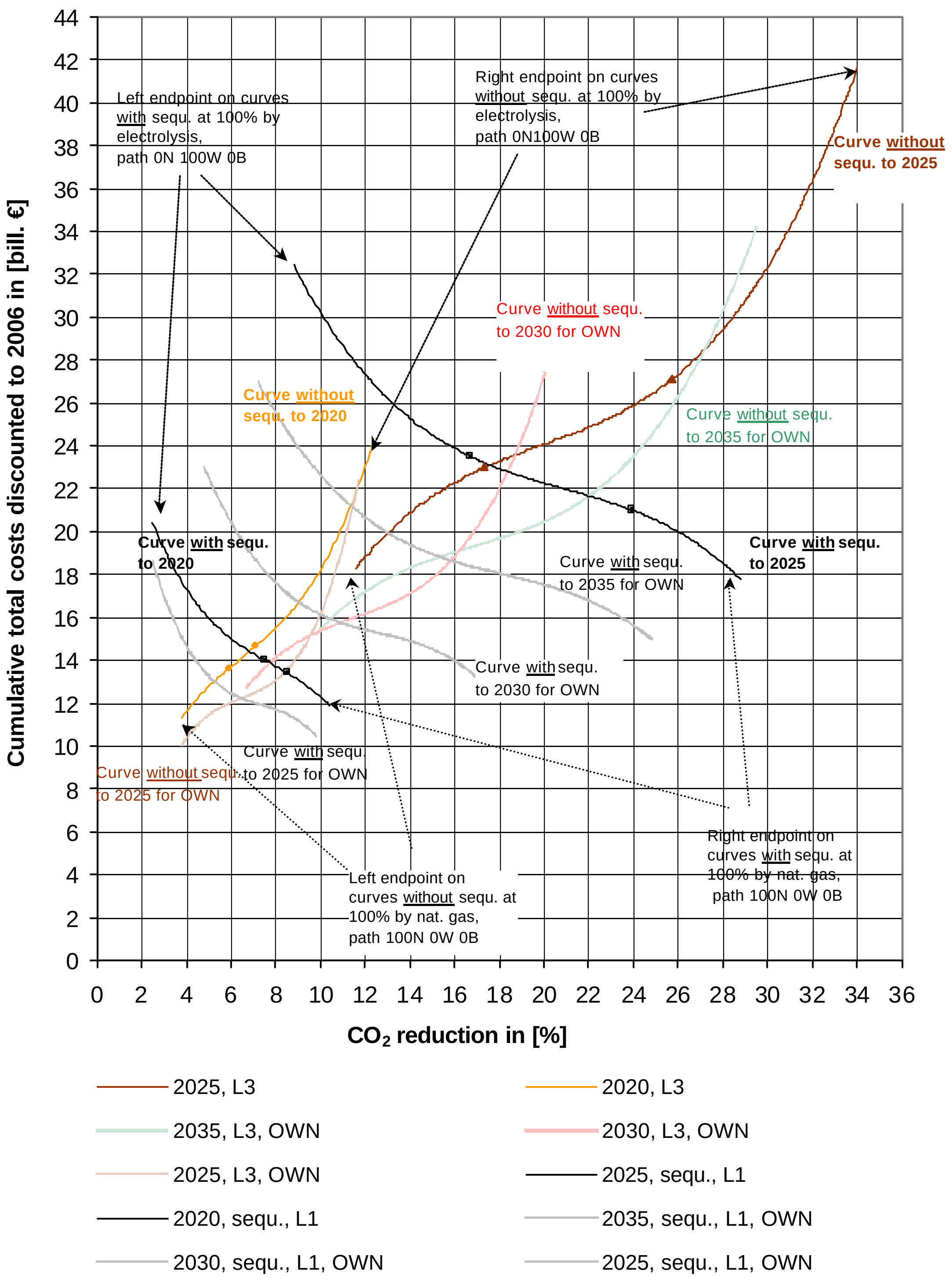
The build-up of the diagram corresponds essentially to that in Figure 126. However, the total costs for the SENSITIVITY scenario are only determined up to 2025, as a higher hydrogen demand is already necessary in this year than for HDD OWN (hydrogen demand of 150 TWh in 2035).

To determine the total cost – emissions reduction curves for the **development paths with the use of sequestration** in Figure 153, electricity from German power stations at Level 1 was assumed (Chapter 3.2.1). Here it is also shown that up to the intersection of the total cost – emissions reduction curves with and without the use of sequestration, the development paths with sequestration, which lie to the right of the intersection of the curves, are to be preferred over the development paths without sequestration (maximum electrolysis share of 50 % in the development path). For example, if the development path 100N 0W 0B with sequestration achieves a CO_2 reduction of about 28 % at a total cost of about 18 billion € in 2025, the development path 100N 0W 0B using Level 3 regeneratively produced electricity, on the other hand, achieves a CO_2 reduction of about 12 %, also at a total cost of about 18 billion €.

In a **long-term examination**, more rapid build-up of the hydrogen infrastructure according to HDD SENSITIVITY is to be preferred over a slower development according to HDD OWN, since a clear reduction in CO_2 can be achieved at a much earlier point in time (2025) for moderate additional costs. However, in a **short-term examination** the total costs increase up to 2020 rapidly and almost linearly due to the rapid rate of development (total costs increase from 2015 to 2020 by around 17 billion €).

[121] The curve has an inverted S-form

Figure 153: Total cost – emissions reduction curves for electricity generation using conventional power stations (L1) and regenerative energy (L3) with and without the use of CO_2 sequestration from well to vehicle fuel tank for various hydrogen production development paths, for OWN and SENSITIVITY hydrogen demand development, in Germany from 2025 to 2035

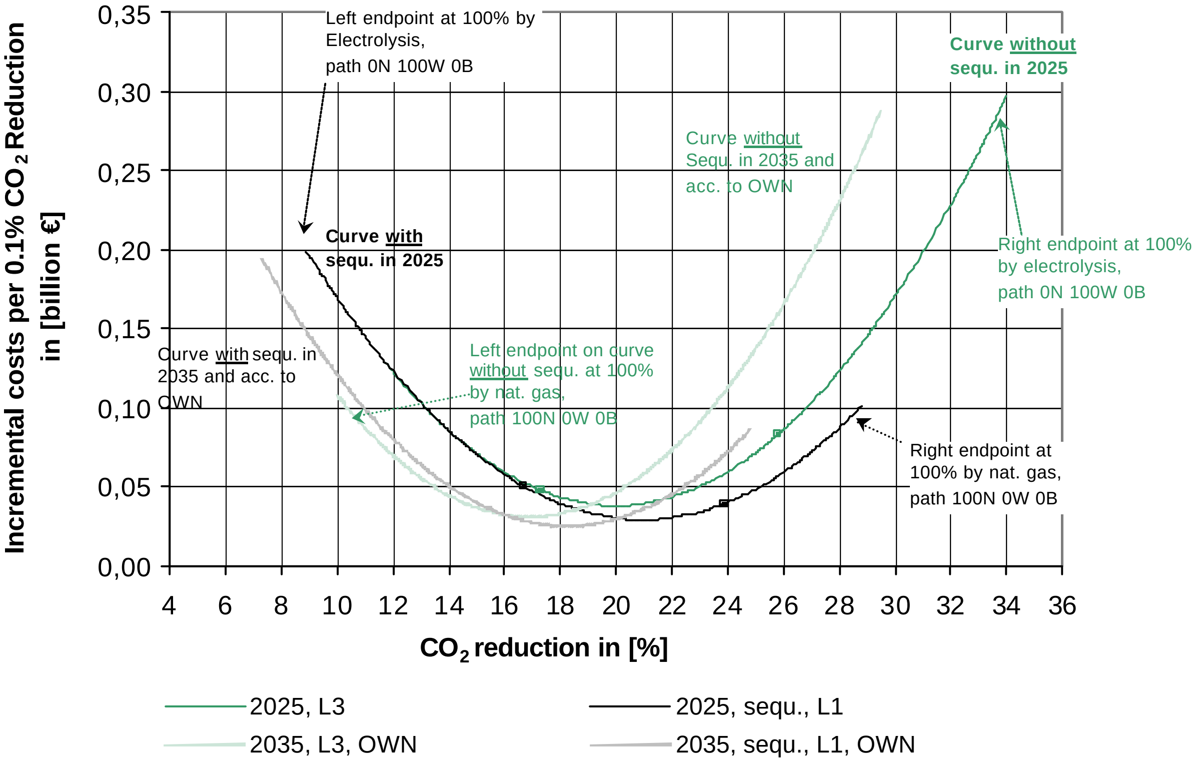


L1 = Electricity costs using conventional power stations, L3 = electricity costs using regenerative energy, Sequ. = Sequestration. Specimen key description: "Year 2035, L3, OWN" = Cumulative discounted total costs for the period 2006 to 2035 in the generation of electricity using regenerative energy (L3) for the hydrogen demand development OWN. "Year 2025, Sequ., L1" = Cumulative discounted total costs for the period 2006 to 2035 for the use of sequestration with the generation of electricity using conventional power stations (L1) for the hydrogen demand development SENSITIVITY.
Source: Own calculations, 2002

The development of the incremental costs for HDD SENSTIVITY for 2025 and for HDD OWN for 2035 is shown in Figure 154. Due to the higher hydrogen demand of about 170 TWh in 2025 according to HDD SENSITIVITY, compared with 150 TWh in 2035 according to HDD OWN, there is a shift in the incremental cost curve to the right, toward a higher reduction in CO_2. The lowest incremental costs occur in the development paths without sequestration at a CO_2 reduction of around 20 % (corresponds to the turning point of the total cost - emissions reduction curve in Figure 153). The path composition of 60N 40W 0B with the lowest incremental costs also corresponds approximately to that for the development according to HDD OWN in 2035.

The comparison of the two incremental cost curves essentially shows again that sequestration gives rise to slightly lower incremental costs than development paths without the use of sequestration. Based on the criterion of the lowest incremental costs, the technological application of sequestration is preferred to the application without sequestration.

Figure 154: Incremental costs of CO_2 reductions with and without sequestration from well to vehicle fuel tank for various hydrogen production development paths for OWN hydrogen demand development up to 2035 and SENSITIVITY hydrogen demand development up to 2025 in Germany



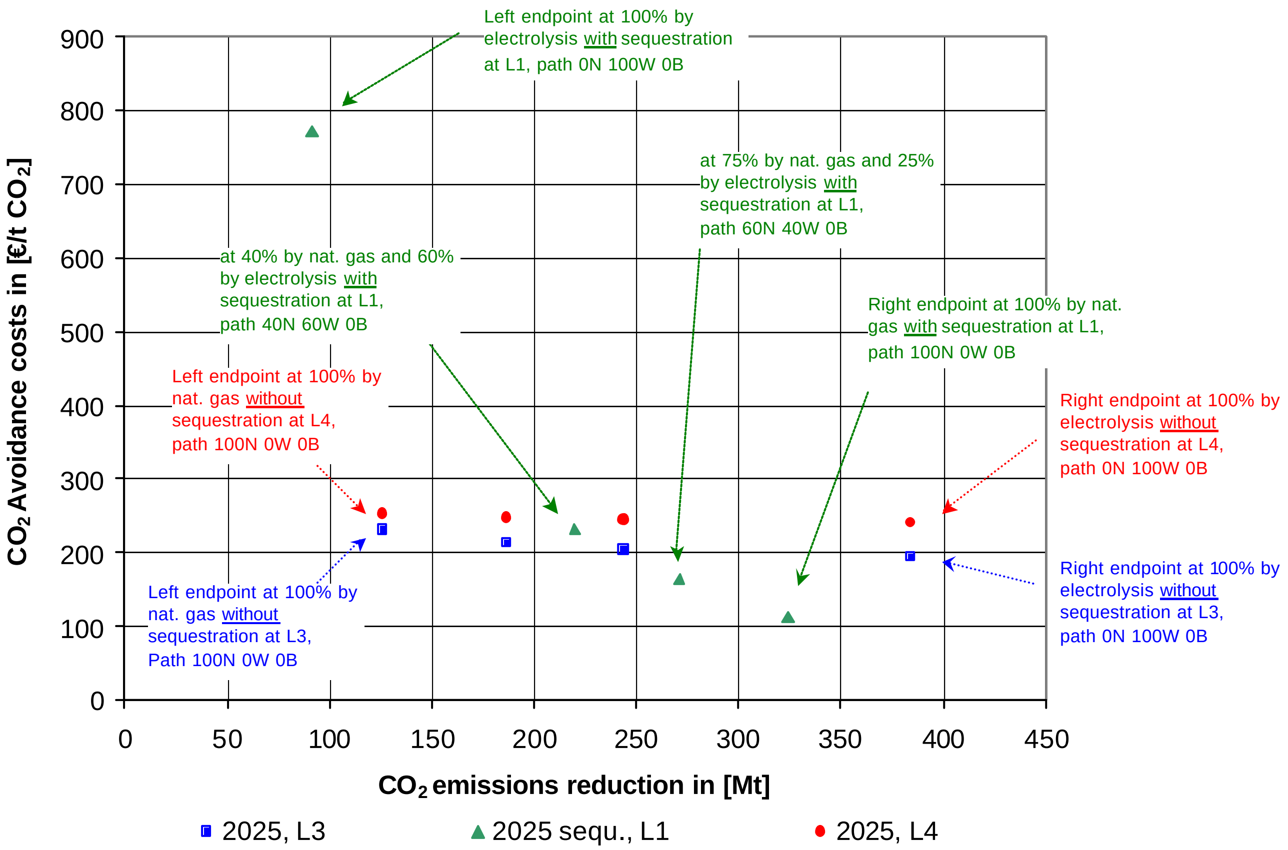
L1 = electricity costs using a conventional power station, L3 = electricity costs using regenerative production, natural gas costs at Level 1 (NL1). Sequ. = sequestration.
Source: Own calculations, 2002

7.4.4. CO_2 avoidance costs in the development of a hydrogen infrastructure

The pattern of CO_2 avoidance costs for HDD SENSITIVITY is shown in Figure 155. Due to the more rapid development of an infrastructure and the higher total costs associated with it, the CO_2 avoidance costs are also higher. In the example of 2025, the CO_2 avoidance costs decrease, starting from around 230 €/t CO_2, when path 100N 0W 0B without sequestration and with the use of regeneratively produced electricity is implemented (with possible reductions in CO_2 emissions of only around 125 Mt), to about 190 €/t CO_2, according to path 0N 100W 0B with possible reductions in CO_2 emissions of around 380 Mt.

The advantage of using sequestration up to a share of electrolysis in the development path of about 40 % is again clear. Up to this electrolysis share, the absolute lowest CO_2 avoidance costs occur in the development paths with sequestration (see also the opposing course of the total cost – emissions reduction curves in Figure 153).

Figure 155: CO_2 avoidance costs without sequestration for electricity generation using regenerative energy (L3 and L4) and CO_2 avoidance costs with sequestration for electricity generation from conventional power stations (L1) from well to vehicle fuel tank for various hydrogen production development paths in Germany up to 2025



Discount rate 4 %, Sequ. = sequestration, L1 = Electricity costs using conventional power stations, L3 = moderate electricity costs using regeneratively energy, L4 = high electricity costs using regenerative energy.
Source: Own calculations, 2003

However, if it assumed contrary to the economic standpoint that for the achievement of a reduction in CO_2 emissions according to the Kyoto Agreement, each individual economic area has to achieve a reduction of 21 % within approximately 15 years, this means a reduction of 21 % in CO_2 emissions from road traffic for the automobile sector. On the assumption that the stated reduction in CO_2 emissions should be achieved in around 15 years (starting in 2006) (i.e. CO_2 emissions of about 160 Mt/a in 2020, instead of approx. 200 Mt/a), this would not be achievable using the assumed HDD SENSITIVITY in Germany.

In order to reach a reduction of CO_2 emissions of 21 % in road traffic in 2020, about 22 % of conventional fuel would have to be replaced by hydrogen as an alternative fuel, assuming hydrogen production exclusively by electrolysis using regeneratively produced electricity.

7.5. Summary

Tasks

As part of the sensitivity analysis it is shown how changes to the calculation assumptions, including price changes to the input factors of electricity and natural gas as well as the interest rate, affect the results.

The effects on the build-up of the hydrogen infrastructure of more rapid market penetration of vehicles using hydrogen as an alternative fuel, and therefore a more rapidly increasing annual hydrogen demand, are outlined.

Assumptions and approach

The examinations are limited to the development paths without a biomass share, as the changes shown in the results for development paths without a biomass share can be approximately carried over to the result for development paths with a biomass share.

In the first step there is an examination of the sensitivity of the average hydrogen costs to an increase in the electricity and/or natural gas costs. Next, the sensitivity of the average hydrogen costs to an increase in electricity and/or natural gas costs is determined.

When the interest rate is changed from 12 to 6 %, particular attention is paid to the change in the total costs – emissions reduction curves and the incremental costs.

Using the definition of a quicker development of the hydrogen demand such as that in Chapter 2.3.4, the effects on the resulting development of the gas station infrastructure and on the specific hydrogen costs are presented. The assumptions made predict for this development of hydrogen demand a fuel subsitiution of about 7 % in 2015 and 35 % in 2025 (compare this with the fuel substitution in Chapter 2.3.4 of about 4 % in 2015 and 13 % in 2025).

Findings

The sensitivity analysis shows that the higher the electrolysis share in the development path (and therefore the electricity requirement), the greater the influence of electricity costs on average hydrogen costs. The reverse is also true, that is to say the higher the share of natural gas steam reforming in the development path, the greater the influence of natural gas costs on average hydrogen costs. For example, an increase in electricity costs of around 40 % causes an increase in average hydrogen costs of around 25 % if hydrogen is produced solely by electrolysis. On the other hand, a 40 % increase in natural gas costs causes an increase in average hydrogen costs of around 5 % if the production of hydrogen takes place solely by natural gas steam reforming.

An important influence of the level of the cumulative total costs, discounted to 2006, is the chosen interest rate. This is because the higher the chosen interest rate and the longer the timescale, the lower the future cost influence on the costs discounted to the present day. However, changing the interest rate causes no change in the result, as sequestration should only be used up to a maximum 50 % share of electrolysis in the development path.

The lower the selected interest rate, the higher the incremental costs. The level of incremental costs for the development paths without the use of sequestration grows much more strongly at a lower interest rate than for the development paths with sequestration. Here the cost effect of the regenerative electricity production compared to the conventional power stations comes into effect.

Almost complete modification of the conventional gas stations in Germany could be achieved in 15 years with a correspondingly rapid market penetration of the vehicles. The national coverage of about 1.500 modified gas stations will be constructed within three years. For the development of hydrogen demand it is assumed that fuel substitution will be about 7 % in 2015 and about 35 % as soon as 2025. The rapid development of the hydrogen infrastructure exerts, up to almost complete modification of all the gas stations in Germany, only a small influence on specific hydrogen costs. The reason for this is the assumption for calculation purposes that fuel pump usage develops almost identically for the more rapid and the slower development of the hydrogen infrastructure up until almost complete modification of all the gas stations. Only after almost complete modification has taken place do the specific hydrogen costs drop to a lower level as a consequence of higher gas station usage.

The more rapid build-up of a hydrogen infrastructure has no influence on the optimum total costs and related emissions as determined. The breakdown of hydrogen production in the development path into about 60 % by natural gas steam reforming and 40 % electrolysis with the lowest incremental costs is identical to that for slower development of the hydrogen infrastucture. However, the more rapid development of the hydrogen infrastructure is preferred to a slower one, since distinctly higher reductions in CO_2 can be achieved in the same period of time at moderate additional cost.

Higher CO_2 avoidance costs are also associated with the more rapid development of the hydrogen infrastructure. For the period in question (2006 to 2025), the development paths without sequestration show the highest CO_2 avoidance costs of about 230 €/t CO_2 for hydrogen production solely by natural gas steam reforming. The production of hydrogen solely by electrolysis causes the lowest CO_2 avoidance costs of about 200 €/t CO_2. The opposite is true for development paths with sequestration. The highest CO_2 avoidance costs of 780 €/t CO_2 arise during the production of hydrogen solely by electrolysis. Its production solely by natural gas steam reforming causes the lowest CO_2 avoidance costs of about 110 €/t CO_2. Again, it is clearly noticeable that the use of sequestration up to an electrolysis share of about 40 % in the development path results in lower CO_2 avoidance costs than in development paths without the use of sequestration.

Conclusions and recommendations

It can be said that rapid development of a hydrogen infrastructure, including the development of a gas station infrastructure, is to be preferred over slower development (assuming the presence of vehicles with a demand for hydrogen). A distinctly higher reduction in CO_2 can be achieved in the same period of time at moderate additional cost.

8. Summary

In recent years, the concept of the sustainable development of human activities has taken on ever greater importance. Important elements of sustainability are economic growth to fight poverty, the restriction of population growth and sustainable use of the environment to ensure the natural basics of life for future generations. The aspect of ecologically acceptable use of the environment primarily encompasses the reduction of anthropogenic CO_2 emissions and reduced dependence on fossil sources of energy. For the transport sector, the aim of a long-term reduction in CO_2 and the limited availability of fossil resources necessitate a search for an alternative future fuel that can be manufactured from primary energy sources other than oil, natural gas or coal. An alternative fuel with a good long-term prognosis is hydrogen, which has considerable potential for regenerativeproduction.

8.1. Tasks

This paper presents possible dynamic developments of a hydrogen infrastructure in Germany for the supply of hydrogen to vehicles as an alternative fuel. The term infrastructure covers both the components of hydrogen production and distribution and also the the gas station areas. Examining the total hydrogen infrastructure is intended to provide handling recommendations that will guarantee an optimal supply of fuel according to economic and ecological criteria. Significant elements of the dynamic examination are on the one hand determination of an appropriate timescale for the construction of a hydrogen infrastructure, and on the other conclusions regarding cost-reduction potentials for the hydrogen supply as a result of economies of scale (e.g. the higher the annual amount of electricity required, the lower the specific electricity costs) and learning effects (cost degression with increasing unit number, e.g. as a consequence of increasing experience in the installation of equipment).

Determination of the CO_2 avoidance costs associated with the development of a hydrogen infrastructure permits a comparison with the CO_2 avoidance costs of other measures, and rounds the paper off.

8.2. Assumptions and approach

The timeframe examined in the dynamic build-up of a hydrogen infrastructure runs from 2006, the assumed start of fuel substitution, until 2035.

To calculate the possible development of the gas station infrastructure in the city of Munich and in Germany as a whole, an estimate of probable **development of the hydrogen demand** in relation to time is necessary. Accordingly, the time factor is included in the calculations. For determination of a valid and feasible hydrogen requirement pattern for vehicles in Munich and across Germany, vehicle categories are selected according to their area of use (including local traffic, long-distance traffic). As a consequence of the definition of reference vehicles in each vehicle category and the researched forecasts of possible inventory development of vehicles using hydrogen as an alternative fuel supplies the inventory of hydrogen vehicles. Consideration is also given to the forecast increase in road traffic (private and commercial) in Germany. The determination of fuel consumption data in each vehicle category (divided into gasoline, diesel and hydrogen fuels) make it possible to calculate the development of the hydrogen requirement for Munich and Germany.

Having arrived in this way at a pattern of hydrogen demand over the years, attention is directed to the production of this quantity of hydrogen. The following **hydrogen production** processes are considered in this paper: natural gas steam reforming, gasification of biomass and alkaline pressure electrolysis of water. In the steam reforming of natural gas and electrolysis processes, distinctions are made between production in high-capacity power stations or directly on site at the gas station (no hydrogen transport required). Biomass gasification is of interest for the production of hydrogen due to its approximate CO_2 neutrality. Although hydrogen production using fossil energy sources does not contribute to the aims of introducing the alternative fuel (above all conservation of fossil resources, CO_2 reduction), it is taken into consideration in this paper. The reason for this is the commercial availability of hydrogen production technology and its relative cost efficiency compared with regenerative hydrogen production. To reduce CO_2 emissions caused by producing hydrogen with fossil energy sources, CO_2 sequestration (whereby the CO_2 created by fossil electricity or hydrogen production is collected and stored in suitable sites, thereby preventing its release into the atmosphere) is also taken into consideration.

As the **transport of hydrogen** from the production sites to the gas stations up to a fuel substitution of about 50 % can be achieved most cost-effectively and with high flexibility by truck in liquid form (Valentin, 2001, p. 129), only this favored form of transport is taken into consideration in this paper.

Before concrete steps can be taken to develop a gas station infrastructure, the **gas station concepts** favored by the industry must be analyzed. The concepts differ in the supply at the gas station of only liquid hydrogen, only gaseous hydrogen or a combination of the two. From a comparison of these concepts on the basis of specific hydrogen costs (depending on annual gas station sales) and the CO_2 emissions (depending on the production of electricity), the gas station concept is determined which, following almost complete fuel substitution, will give rise to the lowest costs and CO_2 emissions.

For the gas station concept thus established, there follows determination of the **quantitative development** of modified gas stations for hydrogen supply, both for Germany and for Munich. Hydrogen production and distribution are not taken into account in this section of the paper. The basis for determination of the gas station infrastructure is the previously derived development of hydrogen demand in Germany and Munich. For a detailed determination of the gas station infrastructure in Germany, there is a separate examination of possible gas station infrastructure development in German cities, in rural areas and along the main highways ('autobahns'). By selecting the number and usage of fuel pumps at the modified gas stations over the years, one obtains the number of modified gas stations related to the given hydrogen demand, and therefore the overall development of the gas station infrastructure. The influence of the development of the gas station infrastructure on specific hydrogen costs is determined by examining several gas station infrastructure development scenarios. The gas station infrastructure scenarios are compared on the basis of defined criteria. These relate to the inventory-related development of the gas station infrastructure (e.g. time when geographical coverage is achieved, usage of fuel pumps), to geographical aspects (e.g. area to be supplied by each modified gas station) and to economic aspects (e.g. investments, total costs).

On the basis of the findings relating to the hydrogen production process, distribution and the favored development of the gas station infrastructure the development of these components is combined into a dynamic **overall system**. For hydrogen production, the following development paths are examined: production solely by natural gas steam reforming, production solely by electrolysis, production by both natural gas steam reforming and electrolysis (with variation of the production proportions) and the same development paths with a maximum share of 10 % biomass gasification in hydrogen production. For these development paths, the use of CO_2 sequestration is also investigated more closely. The collection of CO_2 in exhaust gases is considered for natural gas steam reforming and also for coal-fired electricity generating stations. The main aspects of the analysis of the development paths for the stated period are the pattern of specific hydrogen costs, the potential for the reduction of CO_2 emissions, the investments, the discounted total costs, the incremental costs and the electricity requirement.

For a high reduction of annual CO_2 emissions in road traffic, the development path involving exclusive hydrogen production by electrolysis using regeneratively produced electricity or electricity from a nuclear power station is needed. However, this approach leads to high overall costs. The opposite is true of the development path involving exclusive hydrogen production by natural gas steam reforming. Only a marginal reduction in CO_2 emissions is achieved (when using regeneratively produced electricity or electricity from nuclear power for hydrogen liquefaction), but at lower overall cost than the development path with 100 % electrolysis.

To arrive at an **optimum balance of total costs and emissions**, an examination is made of the total costs, discounted for 2006, that arise in the realization of a hydrogen production development path, depending on the achievable reduction in annual CO_2 emissions in road traffic. Through variation of the composition of the development path from exclusive hydrogen production by natural gas steam reforming through the combination of different production processes to exclusive hydrogen production by electrolysis, curves are obtained that show the connection between the discounted total costs and the reduction in CO_2 emissions: the so-called total costs/emission reduction curves. The total costs comprise the cumulative, annual annuities of investments (hydrogen production plant, distribution, gas station infrastructure) across the depreciation period and the operating and maintenance costs. As the construction of an infrastructure for supplying vehicles with hydrogen requires a planning timeframe covering several decades (in this paper, from 2006 to 2035), the total costs of a development path over this timeframe are based on 2006 ("current value" of the costs).

As the total costs/emission reduction curves do not exhibit a constant increase, the optimal situation in terms of total costs and emissions is determined by the **criterion of the lowest incremental costs** of the discounted total costs. Incremental costs are the additional costs of the discounted total costs of a development path compared with its previous development path (starting with the path with exclusive hydrogen production from natural gas), which are incurred in order to achieve higher CO_2 reductions. On the basis of the criterion of the lowest incremental costs, that development is shown to be the optimum for hydrogen production, until the composition (increase of the electrolysis share in the development path starting with the path with exclusive hydrogen production from natural gas) is reached at which a favorable "acquisition" of a further reduction in CO_2 emissions takes place. From the lowest point of the incremental cost curve, a further reduction in CO_2 emissions can only be achieved with correspondingly higher total costs. As hydrogen production is taken into consideration with and without sequestration, and therefore using two different technologies, this results in two incremental costs curves.

The costs per ton of CO_2 are used as a measure of the efficiency of CO_2 avoidance when hydrogen is introduced as an alternative fuel. Using this characteristic, the introduction of hydrogen as an alternative fuel as an option for reducing CO_2 emissions can be compared with other options. Any additional costs of alternative vehicles are not taken into consideration. **CO_2 avoidance costs** are determined by taking into consideration the total costs of developing a hydrogen station infrastructure (see total cost – emissions reduction curves).

In the **sensitivity analysis** it is shown how changes to the calculation assumptions, including price changes to the input factors of electricity and natural gas, affect the results. The effects of more rapid market penetration of vehicles using hydrogen as an alternative fuel and therefore a more rapidly increase in annual hydrogen demand on the development of a hydrogen infrastructure are shown.

8.3. Findings

Market introduction of hydrogen fuel in the vehicle categories of scheduled buses (except for coaches) and vehicles used for waste management (refuse collection vehicles) and street cleaning appears meaningful. These vehicles operate within a certain area from central operating depots, and their supply with hydrogen can be guaranteed from the start.

As taxicabs essentially use the conventional roadside gas station network, vehicles in this category, like those in the private car category, will rely on the quickest possible modification of the conventional gas station network to supply hydrogen. If they are replaced at an early stage by vehicles that use hydrogen as an alternative fuel, a relatively high usage of the modified gas stations can be achieved, especially in the first years following the market launch.

Following a slow increase in the inventory in the first few years after the launch, market penetration by vehicles in the passenger car and truck categories grows very rapidly (increase of the vehicle population in the form of an S-curve). Although the development of the vehicle population in the passenger car and truck categories is a multiple of the substituted inventories in the bus and taxi categories, the principal hydrogen demand in the first 10 years or so is represented by buses. This is due to their high fuel consumption. Substitution of coaches and long-distance trucks will be considered meaningful when an adequate hydrogen fuel supply can be guaranteed nationally, and partly internationally.

The resulting development of hydrogen demand shows that the percentage share of hydrogen fuel in total road traffic fuel consumption in Germany will be about 7 % after 15 years, and about 30 % after 30 years.

Analysis of the favored **gas station concepts** (with the plants at full capacity) shows that the production of liquid hydrogen (LH_2) at the gas station is associated with lower costs than the production of compressed gaseous hydrogen (CGH_2). For this reason, the pure LH_2 gas station concept, i.e. only for the supply of LH_2 at the gas station, takes on the role of favorite. An important reason for this is the lower requirement of units per fuel pump for the supply of LH_2 compared to CGH_2. If the LH_2 gas station is examined, then for reasons of cost hydrogen is to be produced by centralized natural gas steam reforming using regeneratively produced electricity or electricity from nuclear power (CO_2 emissions can then at moderate cost be held at or reduced below the emissions level for gasoline). For a long-term CO_2 reduction, hydrogen must be produced by electrolysis using regeneratively produced electricity or electricity from nuclear power (in so far as it is socially and politically accepted).

With increasing annual hydrogen fuel sales at the gas station, the cost advantage of centralized hydrogen production by electrolysis compared to on-site production by electrolysis becomes lower, so that on-site production at motorway/freeway gas stations (which have correspondingly higher fuel sales) presents an option that should be thoroughly considered (since on-site liquefaction of the gaseous hydrogen is uneconomical, the supply of hydrogen by on-site electrolysis at the gas station takes place only in a gaseous condition).

A CGH_2 supply at the gas station by on-site natural gas steam reforming is not regarded as meaningful, since the CO_2 emissions cannot be reduced to the level of gasoline in spite of the use of regeneratively produced electricity (on-site production plants are of lower capacity and lower efficiency than the high-capacity central production plants).

Analysis of the plant specifications to cover hydrogen demand in the city of Munich shows that while the total costs can be kept relatively low in the first few years at many of the lower-capacity production plants (high usage of a relatively small number of production plants), in the medium and long term, they give rise to the highest cumulative total costs. Economies of scale do not function here. As the short and medium-term cost components are of fundamental importance for the development of a hydrogen infrastructure, the optimum plant specification is that capacity which exploits the economies of scale as well as the learning effects.

In the supply of fleet vehicles at depots, liquid hydrogen supply with centralized production at high-capacity plants is again the depot concept to be achieved. As the process of replacing conventional vehicles by those using hydrogen as an alternative fuel will be planned in advance by the bus and special-purpose vehicle fleet operators, the depots can be designed according to the hydrogen demand. This will permit high utilization of the depots from the start and be reflected in more favorable specific hydrogen costs than those incurred at conventional road-side gas stations. Consequently, in the market introduction phase, a regular hydrogen supply for these vehicles using adapted road-side gas stations is not meaningful.

Development of a **gas station infrastructure** therefore uses the gas station concept offering exclusive LH_2 supply at the gas station (with centralized hydrogen production), as this concept has shown itself to be the most promising. From a comparison of the gas station infrastructure development scenarios that were examined, it can be seen that the development of a gas station infrastructure inventory in Munich and Germany will in all probability take the form of an S-curve. This means that in the first few years too rapid development of the gas station infrastructure should be avoided, in view of lower gas station usage and the associated high total costs and specific hydrogen costs.

The example of Munich shows that when vehicles using hydrogen as an alternative fuel are introduced to the market, at least 10 gas stations should be made available as quickly as possible in order to guarantee a basic fuel supply. An approximate projection of this number onto all German cities calls for about 320 modified gas stations.

However, for full coverage of the hydrogen supply in Germany about 1,500 modified gas stations (corresponding to 15 % of the total gas station inventory in Germany) will be needed. Above this gas station inventory, it will theoretically be possible to drive on all the roads in Germany with hydrogen as an alternative fuel without encountering a gap in the fuel supply. In the favored scenario for the development of the gas station inventory in the form of an S-curve, full coverage is achieved about 5 years after the introduction of the alternative fuel. Almost complete modification of all conventional gas stations to supply hydrogen will take about 25 years in Germany.

Usage of the fuel pumps has an important influence on the specific gas station costs. In the favored scenario of the gas station inventory in the form of an S-curve, fuel pump usage increases from only about 20 % in the first few years of the build-up of the infrastructure to about 80 % when modification of all gas stations is almost complete. The reason for the relatively low fuel pump usage, especially in the first few years, is on the one hand that two fuel pumps have been specified for the modified gas stations from the outset, and on the other that for an adequate supply to vehicles there must be a correspondingly rapid build-up of the gas station infrastructure (especially in order to achieve geographical coverage).

It should be mentioned that the quantitative development of the LH_2 gas station infrastructure as determined in this chapter in the form of an S-curve also applies to the other gas station concepts that were examined. There will, for example, be differences in the investments and total costs, as these occur at other times and levels.

Examination of the overall system (hydrogen production, distribution and gas station) shows that for a long-term CO_2 reduction, hydrogen production by electrolysis using regeneratively produced electricity or electricity from nuclear power should be realized, since the lowest CO_2 emissions are generated by this hydrogen production process. Nevertheless, the paths in question cause the highest specific hydrogen costs. The specific hydrogen costs without taxes for the period in question (2006 to 2035) are higher than the price of conventional fuel inclusive of taxes. The opposite is true for the production of hydrogen solely by natural gas steam reforming, which has the lowest specific hydrogen costs but achieves only a marginal long-term reduction in CO_2 (assuming that the electricity used for hydrogen liquefaction is generated from regenerative primary energy or from nuclear power). Hydrogen production by natural gas steam reforming seems thoroughly meaningful as a way of introducing hydrogen fuel to the market, in order to approximate hydrogen costs to the conventional fuel price in the shortest possible time.

For the production of hydrogen solely by natural gas steam reforming, the specific hydrogen costs from 2006 to 2035 of 1.8 €/l GE, can be lowered by 65 % to about 0.7 €/l GE (assuming that regeneratively produced electricity is used), due to increasing hydrogen production and gas station usage, economies of scale and learning effects. However, with an increasing share of electrolysis in the production path, the influence of electricity costs on the hydrogen costs increases. This highest influence of the electricity costs of some 80 % exists in the development path with hydrogen production solely by electrolysis. For the production of hydrogen solely by natural gas steam reforming, the specific hydrogen costs from 2006 to 2035 of 2.8 €/l GE, can be lowered by 45 % to about 1.6 €/l GE (assuming that regeneratively produced electricity is used), due to the effects mentioned. As the power stations for generating electricity possess a technically matured technology and therefore only low future potential for the reduction of electricity costs, there is also only limited potential for the reduction of the specific hydrogen costs.

To obtain an **optimum balance between total costs and emissions**, the total costs, discounted for 2006, that arise in the realization of a hydrogen production development path are examined in relation to the achievable reduction in annual CO_2 road-traffic emissions. By variation of the composition of the development paths from hydrogen production solely by natural gas steam reforming through a combination of different production processes to exclusive hydrogen production by electrolysis, curves are obtained that show the connection between the discounted total costs and the reduction in CO_2 emissions; these are the **total costs/emission reduction curves** (Chapter 8.2).

For the development paths that do not take sequestration into account, the achievable CO_2 reduction as well as the total costs increase with the increasing share of electrolysis in the development path, starting from the path of exclusive hydrogen production by natural gas steam reforming with the lowest total costs and CO_2 reduction potential. The total cost – emissions reduction curve for a year has an S-shaped pattern. The use of about 10 % biomass gasification for hydrogen production in the development path permits a reduction of about 10 % in total costs with approximately the same reduction of CO_2.

The limited applicability of CO_2 sequestration can also be seen in the total cost – emissions reduction curves. The development path with exclusive hydrogen production by natural gas steam reforming and sequestration has the lowest total costs with the highest potential for CO_2 reduction (the CO_2 produced in the fossil generation of electricity and hydrogen production is collected and stored at storage sites, therefore no release of anthropogenic emissions into the atmosphere takes place). With an increasing share of electrolysis in the production path, the total costs increase and the achievable CO_2 reductions decrease. The higher the share of electrolysis in total hydrogen production (and therefore the electricity requirement) in this case, the higher the residual emissions when using sequestration. Comparison of the total costs incurred and the CO_2 reductions of the development paths with and without sequestration shows that the use of sequestration is only meaningful up to an electrolysis share of about 50 % in the development path due to the residual emissions that arise.

As the total costs/emission reduction curves do not show a constant increase, the optimal situation in terms of total costs and emissions is determined by the **criterion of the lowest incremental costs** of the discounted total costs (Chapter 8.2). As hydrogen production is taken into consideration with and without sequestration, and therefore using two different technologies, this results in two incremental costs curves, each of which has a U-shaped form. For the development paths without the use of sequestration, starting from the path of exclusive hydrogen production by natural gas steam reforming and including an electrolysis share of up to about 40 % in the development path, the reductions in CO_2 emissions increase as the incremental costs decrease (assuming that regenerative produced electricity or electricity from nuclear power is used). In other words, starting with the path with the exclusive production of hydrogen by natural gas steam reforming, an increase in the share of electrolysis up to about 40 % in the development path results in a favorable “acquisition” of a further reduction in CO_2 emissions. From the lowest point of the incremental cost curve, the incremental costs for a further reduction in CO_2 emissions clearly increase again. In other words, for the development paths with a long-term share of electrolysis higher than 40 %, there is an expensive “acquisition” of a further reduction in CO_2 emissions. The lowest point of the incremental cost curve with the lowest incremental costs shows a reduction in CO_2 emissions of about 17 %. This point corresponds to the turning point of the related total cost – emissions reduction curve.

For the development paths including sequestration, starting from the path of exclusive hydrogen production by electrolysis, up to a natural gas steam reforming share of about 60 % in the development path, the reductions in CO_2 emissions increase as the incremental costs decrease (assuming the use of electricity generated from fossil fuels). In other words, starting with the path of exclusive hydrogen production by electrolysis, an increase in the share of natural gas steam reforming up to about 60 % in the development path results in a favorable “acquisition” of a further reduction in CO_2 emissions. From the lowest point of the incremental cost curve, the incremental costs for a further reduction in CO_2 emissions clearly increase again. In other words, for the development paths with a long-term share of natural gas steam reforming higher than 60 %, there is an expensive “acquisition” of a further reduction in CO_2 emissions. When using sequestration, the incremental cost curve consequently has a mirror-image course compared with the incremental cost curve when sequestration is used. The lowest point of the incremental cost curve with the lowest incremental costs shows a reduction in CO_2 emissions of about 18 %. This point corresponds to the turning point of the related total cost – emissions reduction curve.

Comparison of the two incremental cost curves shows that the use of sequestration gives rise to slightly lower incremental costs than in the development paths without the use of sequestration. Moreover, the lowest incremental costs occur with the use of sequestration and a reduction in CO_2 emissions of about 18 %, which is slightly higher than in the development paths without the use of sequestration. Although two different technologies are used, the compositions of the development paths almost agree and therefore achievable reductions in CO_2 emissions at the lowest incremental costs are obtained.

Analysis of the electricity requirement for the development paths shows that with an increasing electrolysis share in the development path and therefore an increasing electricity requirement, the challenge of achieving a hydrogen infrastructure is increasingly focussed on the supply of the necessary regeneratively produced quantity of electricity for the production of hydrogen (if CO_2 sequestration is not used). The challenges relate to exploitation of the potentials of the regenerative primary energies and the appropriate time-related technical realization for the availability. However, it would seem that a regenerative production of electricity for the determined total costs and emissions related optimum with a long-term share of electrolysis of about 40 % represents an achievable valid optimum regarding both the potential of the regenerative primary energies and the time-related technical realization.

Determination of the **CO_2 avoidance costs** takes the total costs of developing a hydrogen infrastructure (see total cost – emissions reduction curves) into consideration. For the period in question (2006 to 2035), the development paths without the use of sequestration show the highest CO_2 avoidance costs of about 150 €/t CO_2 for hydrogen production solely by natural gas steam reforming. The exclusive production of hydrogen by electrolysis causes the lowest CO_2 avoidance costs of about 120 €/t CO_2. I.e. with an increasing electrolysis share in the development path, the additional reductions in CO_2 emissions increase much more strongly than the total costs for achieving them.

The reverse is true of the development paths with the use of sequestration. Over the period in question (2006 to 2035), the highest CO_2 avoidance costs of 560 €/t CO_2 are incurred for exclusive hydrogen production by electrolysis (lowest reduction of CO_2 emissions because of higher residual emissions). The exclusive production of hydrogen by natural gas steam reforming gives rise to the lowest CO_2 avoidance costs of about 80 €/t CO_2. In other words, an increasing share of natural gas steam reforming in the development path results in both greater reductions in CO_2 emissions and a decrease in the total costs needed to achieve them.

Comparison of CO_2 avoidance costs for the development paths with and without sequestration shows that sequestration, up to an electrolysis share of about 40 % in the development path, causes lower CO_2 avoidance costs than in the development paths in which it is not used. Above this electrolysis share, the CO_2 avoidance costs of the development paths with sequestration exceed those of the development paths without the use of sequestration. According to the criterion of the lowest CO_2 avoidance costs, the exclusive production of hydrogen by natural gas steam reforming using sequestration should be appropriate. However, in realizing this option, the declared aim of reducing dependence on fossil resources is not fulfilled, so that the selection of a development path according to the lowest CO_2 avoidance costs cannot be considered the optimum. For the total costs and emissions-related optimum determined according to the criterion of the lowest incremental costs with a long-term share of electrolysis of about 40 % in the development path (both with and without sequestration), the CO_2 avoidance costs are about 130 €/t CO_2.

The **sensitivity analysis** shows that the higher the electrolysis share in the development path (and therefore the electricity requirement), the greater the influence of electricity costs on average hydrogen costs. The reverse is the case in that the higher the share of natural gas steam reforming in the development path, the greater the influence that natural gas costs exert on average hydrogen costs. For example, an increase in electricity costs of around 40 % causes an increase in average hydrogen costs of around 25 % if hydrogen is produced solely by electrolysis. On the other hand, a 40 % increase in natural gas costs causes an increase in average hydrogen costs of only 5 % if the hydrogen is produced solely by natural gas steam reforming.

The chosen interest rate has an important influence on the position of the total cost – emissions reduction curves: the higher the chosen interest rate and the longer the timescale, the lower the future cost influence on the costs discounted to the present day. However, changing the interest rate does not alter the conclusion that sequestration should only be used up to a maximum share of electrolysis of 50 % in the development path.

The lower the selected interest rate, the higher the incremental costs. The level of incremental costs for the development paths without sequestration increases much more strongly at a lower interest rate than for the development paths with sequestration. In this case the cost effect of regenerative electricity production compared with conventional power stations is felt.

Almost complete modification of the conventional gas stations in Germany could be achieved in 15 years if there were correspondingly rapid market penetration of the vehicles. The national coverage of about 1,500 modified gas stations will be built up within three years. With regard to the development of hydrogen demand it is assumed that fuel substitution will be about 7 % in 2015 and already as high as 35 % in 2025. The rapid development of the hydrogen infrastructure, up to almost complete modification of all gas stations in Germany, exerts only a small influence on the development of specific hydrogen costs. The reason for this lies in the calculation assumption that fuel pump usage up to almost complete modification of all gas stations is almost identical for the quicker and the slower development of the hydrogen infrastructure. Only after almost complete modification of all gas stations has taken place do the specific hydrogen costs drop to a lower level as a consequence of the now higher rate of gas station utilization.

More rapid development of the hydrogen infrastructure has no influence on the determined total costs and emissions-related optimum. The composition of hydrogen production in the development path of about 60 % by natural gas steam reforming and 40 % electrolysis with the lowest incremental costs is identical to that with a slower development of the hydrogen infrastructure. However, a faster hydrogen infrastructure development is preferred to a slower one, since distinctly higher reductions in CO_2 can be achieved in the same period of time for moderate additional costs.

Higher CO_2 avoidance costs are also associated with quicker compared with slower development of a hydrogen infrastructure. For the period in question (2006 to 2025), the development paths without sequestration show the highest CO_2 avoidance costs of about 230 €/t CO_2 for exclusive hydrogen production by natural gas steam reforming. The exclusive production of hydrogen by electrolysis causes the lowest CO_2 avoidance costs of about 200 €/t CO_2. The opposite is true for the development paths including sequestration. The highest CO_2 avoidance costs of 780 €/t CO_2 arise during the production of hydrogen solely by electrolysis. Its production solely by natural gas steam reforming yields the lowest CO_2 avoidance costs of about 110 €/t CO_2. Again, it is clearly noticeable that the use of sequestration up to an electrolysis share of about 40% in the development path causes lower CO_2 avoidance costs than those for the development paths without the use of sequestration.

It can generally be said that rapid hydrogen infrastructure development, including the gas station infrastructure, is to be preferred to slower development (assuming that a demand for hydrogen for vehicles is present). A clearly higher reduction in CO_2 can be achieved in the same period of time for moderate additional costs.

8.4. Conclusions and recommendations

This paper makes it clear that a hydrogen infrastructure can be achieved within an entirely reasonable period of time. However, the appropriate overall conditions are a precondition for this, for example the development and harmonisation of global guidelines and laws for the storage, transport and use of hydrogen.

From this investigation of the overall dynamic system it is clear that depending on the criteria considered, rather different results emerge as the optimum to be achieved. This is partly because the aim of a long-term high level of CO_2 reductions cannot be achieved at low cost. On the other hand, the institution concerned must decide which primary aim it proposes to pursue. The following table is an overview of some of the hydrogen infrastructure development criteria examined in this paper (Table 32). As the stated aims (criteria) partly contradict each other, the build-up of a hydrogen infrastructure can only proceed as an optimised “golden mean”, taking all the aims in consideration.

Table 32: Overview of some of the optima for the development of a hydrogen infrastructure depending on the aims to be pursued

Aim (criterion)	Determined optimum
Maximum CO_2 reduction (absolute)	Hydrogen production solely by electrolysis
Minimal expenditure (absolute)	Hydrogen production solely by natural gas steam reforming
Cost- and emissions related optimum	
- minimal incremental costs	Long-term electrolysis share of about 40 % (with or without the use of sequestration)
Minimum regenerative electricity needs	Hydrogen production solely by natural gas steam reforming
Minimum specific hydrogen costs	Hydrogen production solely by natural gas steam reforming
Development of the gas station inventory	
- for the customers and suppliers	Rapid development is advantageous
- for the operators and the costs	Slow development with high usage is advantageous
Lowest CO_2 avoidance costs	Hydrogen production solely by natural gas steam reforming with the use of sequestration
Political independence	Hydrogen production solely by electrolysis (challenge: long-term sustainable generation of electricity)

The use of electrolysis assumes the use of regeneratively produced or nuclear-power electricity.
Source: Own presentation, 2003

Recommendations for further investigation

- Supply at regeneratively produced electricity via regenerative power stations to cover the electricity requirement of the scenarios considered in this paper (consideration of load fluctuations, network expansion)
- Ecological effects of CO_2 sequestration
- “Real option" examination: Working out a strategic guide for action, taking into consideration uncertainties such as sudden steps forward in technology and possible changes to important input factors (including conventional fuel price, hydrogen demand) on the basis of income-expenditure analysis (e.g. emission trading).
- Awareness of existing guidelines and regulations regarding hydrogen in significant countries, deriving the handling requirement for harmonisation of the regulations as a basis for international hydrogen fuel substitution

Tables

Figures

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Abbreviations

€	Euro
000s	thousand items/units
ABUS	Regular articulated bus
ACEA	Association des Constructeurs Européennes d'Automobiles (European Automobile Manufacturers' Association)
AG	Joint stock company ('Aktiengesellschaft')
approx.	approximately
Art.	Article
ATZ	Automobiltechnische Zeitschrift (magazine)
BG	Biomass gasification
Bio.	Biomass
BMU	Federal German Ministry for the Environment, Nature Conservation and Nuclear Safety
BMVBW	Federal German Ministry of Transport, Building and Housing
bn	billion
BRD	Federal Republic of Germany
BUS	Regular city bus
BVG	Berliner Verkehrsbetriebe (transport company)
CaFCP	California Fuel Cell Partnership
Cap.	Capacity
CD	Compact Disc
CEC	Commission of the European Communities
centr.	central
CF_4	Tetrafluoromethane
CGH_2	Compressed gaseous hydrogen
CH_4	Methane
CHF_3	Trifluoromethane
cm	centimetre
CNG	Compressed natural gas
C_nH_m	Hydrocarbon
CO	Carbon monoxide
CO_2	Carbon dioxide
conv.	conventional
COP	Conference of the Parties
COU	crude oil unit
cum.	cumulative
DDR	German Democratic Republic
DE	Diesel equivalent
DEP	Depot
DI	direct injection
DKW	Dresdner Kleinwort Wasserstein
DM	German Mark
DOE	Department of Energy
e. g.	for example
e. V.	e.V.
ECE	Economic Commission for Europe
Ed.	Editor
EEA	European Environment Agency
eff.	efficient
EJ	Exajoule (= 10^{18} Joule)
el.	electric, electrical

Elec. var.	Cost of electricity variation
Electr.	Electrolysis
Em^3	Exa cubic meter (= 10^{18} cubic meter)
EOS	Economies of scale
etc.	et cetera
EU	Europäische Union
EV	Electric vehicle
EZEV	Equivalent zero emission vehicle
FC	Fuel cell
FETC	Federal Energy Technology Center
FHC	Fluorohydrocarbon
FHC	Force heat coupling
FPH	Fuel price history
FTP cycle	(American Test Cycle)
g	gram
GDP	Gross domestic product
GE	Gasoline equivalent
Gkm	Giga kilometer (= 10^9 km)
GNP	Gross national product
GSID	Gas station infrastructure development
GST-PS	Gas and steam turbine power station
Gt	Giga tonnes (= 10^9 tonnes)
Gtkm	Gigatonne-kilometers (= 10^9 tonne-kilometers)
GVW	Gross vehicle weight
GWh	Gigawatt-hour
GWP	Global warming potential
h	hour
h/a	hours/year (hours/annum)
H_2	Hydrogen
H_2O	Water
HBEFA	Handbook (of) Emission Factors for Road Transport
HCU	hard coal unit
HDD	hydrogen demand development
HPSP	Hybrid Powertrain Simulation Program
Hydr. subst. non tax	hydrogen substitution without taxes on hydrogen
i.e.	that is
ICE	Internal combustion engine
idw	Science information service
IEA	International Energy Agency
IER	Institute for Energy Economics and the Rational Use of Energy
ifeu	Institute for Energy and Environmental Research
incl.	including
Inv.	Investment
IPCC	Intergovernmental Panel on Climate Change
IWR	International Economic Forum on Regenerative Energies
K	Kelvin
k€	thousand Euro
KBA	Kraftfahrt-Bundesamt (Federal German Motor Vehicle Office)
kg	kilogram
kJ	kilojoule
km	kilometer
km/h	kilometers per hour
km^2	square kilometer
kW	kilowatt
kWh	Kilowatt-hour
l	liter

$LCGH_2$	Liquified and compressed gaseous hydrogen
LH_2	Liquified hydrogen
Log	logarithm
LRT	Law against restraint of trade
m^3	cubic meter
max.	maximum
MCFC	Molten carbonate fuel cell
MFS	Motorway gas station
min	minutes
MinTax	mineral oil tax
MOIND	mineral oil industry
MPU	Munich Public Utilities
Mt	Megatonnes (= 10^6 tonnes)
MTA	Mineral oil trade association
MW	Megawatt
n. a.	not available
n. k.	not known
N_2	nitrogen
N_2O	dinitrogen oxide
NECAR	(New Electric Car)
NEDC	New European Driving Cycle
Newreg.	New registration
NG var.	Natural gas cost variation
NGSR	Natural gas steam reforming
NL	Natural gas cost level
Nm	Newton-meter
Nm^3	Standard cubic meter
NMHC	Non-methane hydrocarbons
nom.	nominal
NO_x	Nitrogen oxides
NPS	Nuclear power station
O&M	Operating and maintenance costs
O_2	oxygen
O_3	ozone
ÖAMTC	Austrian Automobile, Motorcycle and Touring Club
OB	other buses
p.	page
PAFC	Phosphor acid fuel cell
PB	private business
PC	Ppassenger car
PEM-FC	Polymer electrolyte membrane - fuel cell
perm. tot. wt.	gross weight limit
Pkm	person-kilometer
PM	particle mass
Pm^3	Peta cubic meter (= 10^{15} cubic meter)
ppm	parts per million
Prof.	Professor
PS	Power station
Publ.	Publisher
reg.	regenerative
RENT	Rental car
RFS	Roadside gas station
rpm	revolutions per minute
Sc	scenario
Sequ.	sequestration
SF_6	sulphur hexafluoride

SHGV	Special truck
SO_2	sulphur dioxide
SOFC	Solid oxide fuel cell
t	tonne
t/d	tonnes/day
t/h	tonnes/hour
TC	Total costs
TES	Transport Energy Strategy
tkm	Tonne-kilometer
Tot. AC.	Total avoidance costs
trad.	traditional
TREMOD	Transport emission estimation model
truck	truck
TWh	Terawatt hour (= 10^{12} Watt hours)
UBA	Federal Office for Environmental Protection
UN	United Nations
USA	United States of America
VAT	Value added tax
VDA	German Association of the Automotive Industry
Vol. -%	volume percentage
VPD	Vehicle population development
WACC	Weighted average cost of capital
wt. -%	Weight percentage
XBUS	Cross-country bus
ZEV	Zero emission vehicle