MSc Program
Renewable Energy Systems

Economic and ecologic feasibility of an electrolyser in combination with a hydropower plant

A Master's Thesis submitted for the degree of
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supervised by
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Affidavit

I, **TOM RENKEN, BSC**, hereby declare

1. that I am the sole author of the present Master's Thesis, "ECONOMIC AND ECOLOGIC FEASIBILITY OF AN ELECTROLYSER IN COMBINATION WITH A HYDROPOWER PLANT", 129 pages, bound, and that I have not used any source or tool other than those referenced or any other illicit aid or tool, and
2. that I have not prior to this date submitted the topic of this Master's Thesis or parts of it in any form for assessment as an examination paper, either in Austria or abroad.

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Abstract

Without a doubt, the world needs to be more sustainable and humanity has to indemnify the past mistakes. The climate change will most likely affect my life somehow in the future. My motivation is to participate in the energy transition into a greener future. With increasing numbers of fluctuating renewables in Germany, the production side barely matches the demand side, resulting in a lack of surplus production. Storing or converting electricity is one of the significant challenges in the following years. Therefore, the core objective of this thesis is, to find out which type of electrolyser might be the best to be operated with the electricity of a hydropower plant. After this step the economical and ecologic feasibility of an electrolyser, which should sell the produced green hydrogen at its current market value, is of interest.

The polymer electrolyte membrane electrolysers seems to fulfil most of the requirements. The answer to our second question, does it make sense to invest into an electrolyser, is definitively yes. Until achieving a successful market ramp-up, a hydropower plant might provide the required constant electricity supply of around 7.000 full load hours per year, keeping the costs of investment and operation in relationship low compared to the amount of produced hydrogen. Adding assumed costs into a profit and loss statement of around 2,5 Mil. € and including the plant operation costs, the whole project becomes tangible. Even if the electricity price increases from around 4 to 8 ct/kWh over 20 years, a 1,25 Megawatt electrolyser, is able to produce 150 tons of hydrogen at a price of 5€/kg. Besides a competitive production price of green hydrogen, the ecological benefit is vast. The later use of hydrogen in the transportation sector might significantly benefit battling global warming. Evaluating the benefits of hydrogen by comparing different conventional technologies; The use of fuel cell vehicles (13,5 g/km CO_2 Equivalent) compared to an internal combustion vehicles (159 g/km CO_2 Equivalent) reduces the emissions by 91,5%!

This thesis shows that even though green hydrogen production is still at the beginning, starting to produce it now and built up a regional market is already economically and ecologically feasible. Nevertheless, the regional market development initiative and finding a demand side is a core aspect of hydrogen production. What is the point of producing cheap green hydrogen if no one is willing to buy it?

Content

1 Introduction

One of the, maybe even the biggest challenge of the current living generations is global warming. Humanity itself is the perpetrator of the GHG (greenhouse gas) emissions, which are, in the end, the driver of global warming. Gladly the perpetrator can be the solvent and several signed agreements and protocols, which resulted in national laws or guidelines, are a step in the right direction. The idea that written statutes and policies themselves reduce the emissions is plain wrong. The process begins with agreements but does not end there without a lot of effort and investment. As public awareness is rising, scientists will develop proper solutions, and environmentally friendly implementations will develop. Still, a lot of effort is necessary.

Such environmentally friendly implementation is electricity production out of renewables such as photovoltaics (PV), wind, biomass, and hydropower. In Germany's electricity sector, a big target is to continuously install and implement fluctuating renewable energy systems (mostly wind and PV). The process concerning increasing installed renewable capacities can be lead back to the renewable energy law (EEG - Erneuerbare Energien Gesetz in German). Nowadays, Germany reaches around 124 Giga Watt (GW) (Umweltbundesamt, 2020) of renewables by the end of 2019. In comparison, in 1990, the renewable capacity where negligibly small with 4 GW. The total installed capacity, including conventional power plants, in Germany, was 220 GW. Figure 1 shows the development of installed renewable capacity from 1990 till 2019. Some technologies, such as hydropower (blue), seem to be stable in installed capacity. Technologies such as wind power onshore (grey) and PV (yellow) show a remarkable development.

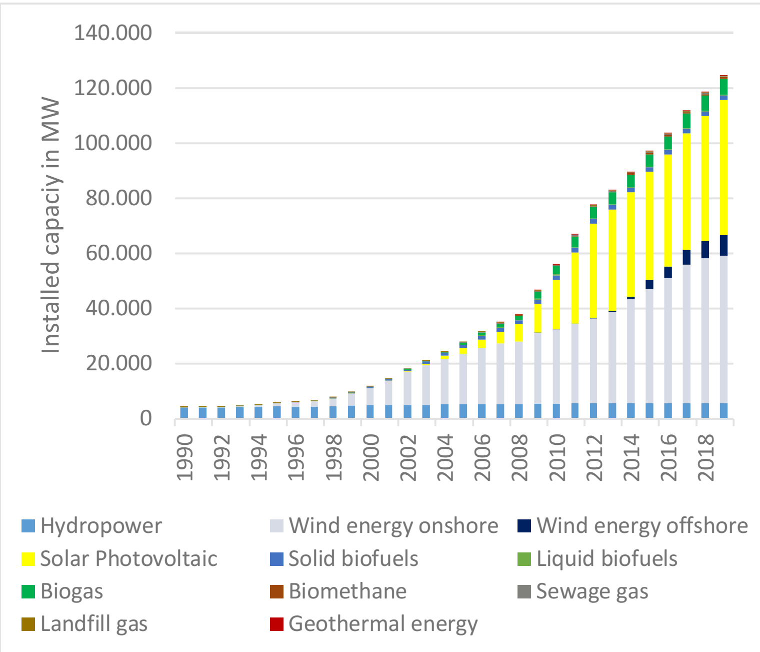

Figure 1 Installed electrical capacity of renewable energy systems from 1990 to 2019 in Germany (Umweltbundesamt, 2020)

Coming back to the big driver of this development in the electricity sector, the EEG. The EEG is a continuously updated subsidizing system. In 2000 the EEG itself was introduced. The current version, the EEG 2017, gets a refurbishment till the beginning of 2021. A general aim is to reduce governmental support until each technology is competitive in the electricity market and not dependent on subsidies anymore. Until then, the German government developed a nowadays quite elaborate support scheme. Besides the support scheme, the EEG itself describes how to generate the required capital for the subsidies. To keep it short, every consumer has to pay a certain amount of tax (specifically in cent per kilowatt per hour (ct/kWh)) with their electricity bill. The higher the consumption, the higher the total amount of tax. The tax itself is re-evaluated and fixed for a whole year. With the end of the year 2020, the first renewables reached the end of their 20-year subsidy period. The big question is; can anything be done with those capacities, or shall new installations replace them?

Increasing the share of renewable in energy economics is per se great, but as Sir Isaac Newton already implied, every action does react. With a more or less constant annual electricity demand in Germany of around 500 Terra Watt hours (TWh) and rising renewable capacities, stripping down redundant conventional power plants became common. In theory, less running conventional power plants resulting in lower emissions. Significant aspect so far, but two of the major renewables (PV and wind) are fluctuating energy suppliers. An increase in installations and also increasing fluctuating effect threatens the security of supply. First of all, there is a seasonal difference in generation. PV, as an example, does not provide much during the winter period. Secondly, there are hourly differences in generation. All in all, the demand side itself is not constant during the day.

Such an effect from a day with high renewable generation to another day with insignificant renewable generation increases in its dramaturgy as the ratio of renewable to conventional increases. Huge conventional power plants, such as coal and nuclear, are slow in reaction time and cannot properly compete with the fluctuating renewables. An over or underproduction can be seen quite often in the German electricity market. A perfect example was the 14^{th} February in 2020. During a quite windy period, a whole day lacked significantly in generation of wind turbines resulting in a lack of generation. An increase of generation out of conventional power plants was either too expensive or simply impossible due to technical and physical regulations/laws. The red curve in figure 2 describes the demand, whereas the other colours are the generation of each energy carrier. Noteworthy are the colours blue (wind power) and yellow (PV) compared to brown, black and grey (fossil fuels). The white area underneath the red curve until the various conventional power plants supply describes a lack in generation of German power plants. During the 14th February 2020, Germany was highly dependent on electricity imports. Usually, such a shortage results in increasing market prices. The peak price at 8 o'clock was 56 Euro per Mega Watt hour (€/MWh), which was at least twice as high as the market price during the 09th February till the 12th February with around 25€/MWh.

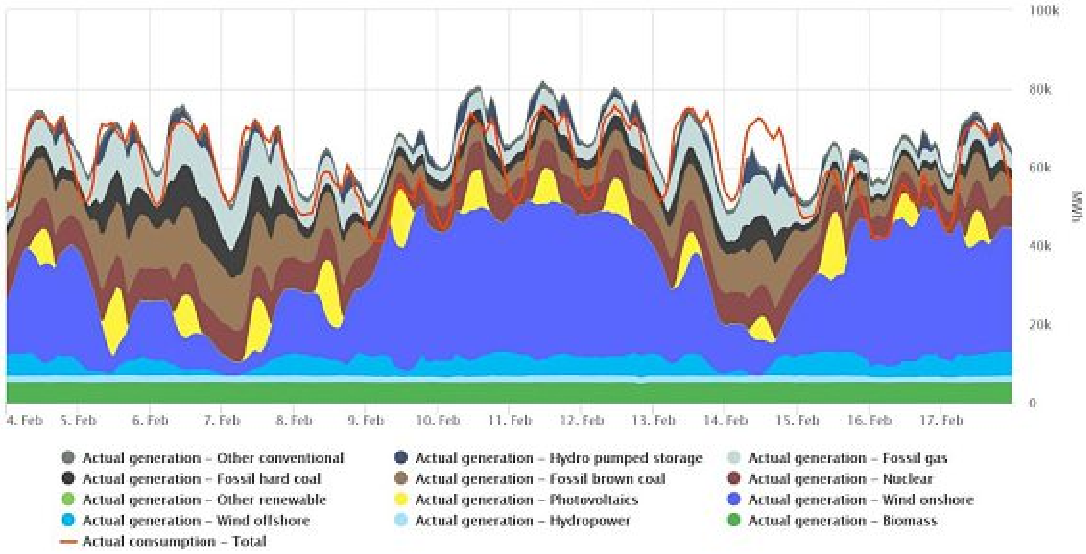

Figure 2 Energy generation and demand in Germany per energy carrier from the 04.02.2020 till the 14.02.2020 (BNetzA, 2020)

Remarkable on this day is the increasing generation of gas-fired conventional power plants (grey). Coal and nuclear-fired power plants are relatively slow in their reaction time. Fast-acting plants, such as natural gas-fired power plants and storage technologies such as hydro pumped storage, are becoming even more critical during low renewable generation days. Arguably, natural gas is the cleanest fossil fuel, but still not emission-free. In the long run, as long as a technology is not close to emission neutrality, natural gas-fired power plants can only be seen as a transitional technology.

During the wintertime, the production out of PV is usually negligible. The production changes dramatically during the summer. From time to time, wind and PV combined can supply Germany's whole demand for several hours. Such a period displayed in figure 3 on the 4th (Saturday) and 5th (Sunday) of July 2020. One should keep in mind that even though the demand could be covered by renewable energy over the day, conventional power plants had to run during the night.

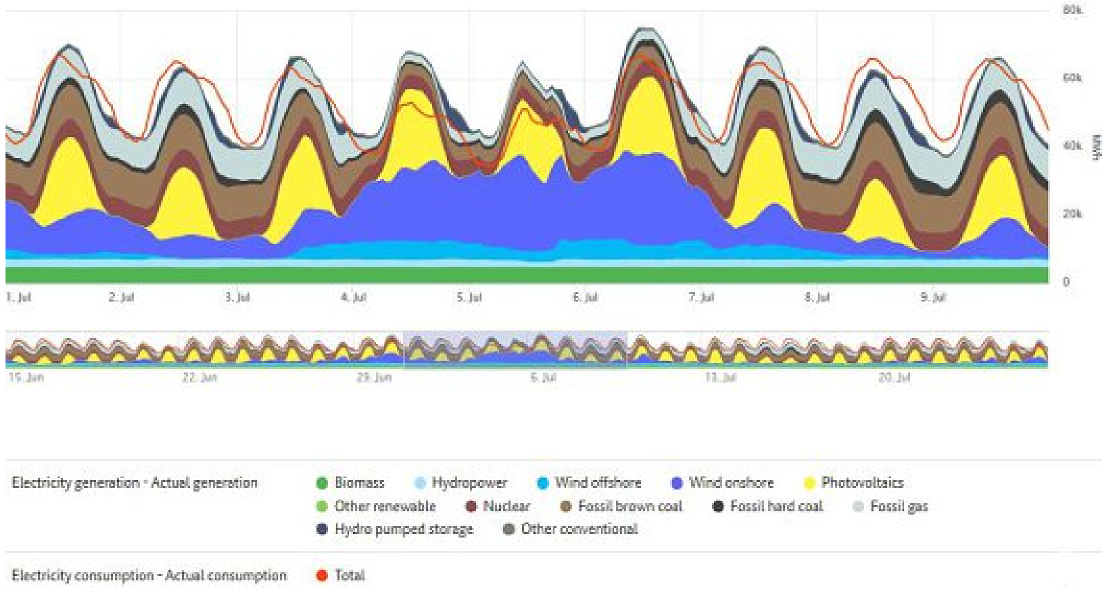

Figure 3 Energy generation and demand in Germany per energy carrier from the 01.07.2020 till the 10.07.2020 (BNetzA, 2020)

If surplus electricity is not exported or used, it is lost. Shutting down renewable capacities to minimize the surplus energy became common. But what if Germany could use this surplus energy during summer during winter times? Sustainable market participants, which can store and release electricity, are needed. One of those participants is battery storage technologies, which do have their pros and cons. While relying on only one technology might not be feasible enough, another technology came into focus: Hydrogen generated in electrolysis. Hydrogen as a matter has some benefits compared to electricity stored in a battery. Therefore, the Federal Ministry for Economic Affairs and Energy of Germany (Bundesministerium für Wirtschaft und Energie - BMWi) took up the cause to implement a strong hydrogen economy in Germany and published a so-called National Hydrogen Strategy. This strategy's first step is to invest around 300 Million Euro (Mil. €) till 2023 into technologies to "get them ready for the market". Several industrial processes and as well the energy sector shall benefit from hydrogen. In total, Germany shall implement 38 measures. The focus itself are those fields of applications, where electrification, in general, seems to be quite complicated. The idea is to generate hydrogen and later use the hydrogen in the electricity sector and ideally in every other sector.

In Germany, the energy economy itself is not the only emitter of emissions. The transportation sector, agriculture, or the industry itself generates a vast amount of GHG emissions. To achieve decent progress in the electricity sector, the National Hydrogen Strategy tries to access other sectors prior. The share of renewables in the electricity sector shall increase up to 65% by 2030. But already today, there are several hours in the year where renewables theoretically could supply the whole demand of electricity. With increasing installations, Germany can expect a surplus. Currently (mostly due to the grid limitations), several renewable plants are shut down during such periods. Arguably a waste of energy. Instead of shutting down renewables, electrolyser could use the electricity to generate hydrogen, usable in other sectors.

With a little bit of background information, Germany's steel industry is responsible for around 7% of the national GHG emissions. (With 1.46 tons (t) of carbondioxide (CO_2) per 1 t steel and 42,1 million tons of steel produced in 2016, 61.4 million tons of CO_2 have been emitted (Wirtschaftsvereinigung Stahl, 2017). Compared to annual emissions of around 900 million tons (Mt) in 2016 in Germany (Umweltbundesamt, 2020)), quite a huge share of the emissions can be led the steel production.. Not all of the emitted emissions can be led back to the energy demand. The used chemical process itself, using carbon monoxide, is responsible for a massive share of the emissions. Iron in its natural form (iron oxide – (FeO)) contains oxygen, and under high temperature, the oxygen reacts with the carbon monoxide and creates carbon dioxide. As an alternative to carbon monoxide, the use of hydrogen is possible. Two hydrogens and an oxygen atom react to water (-vapour). In the end, this implies a massive amount of hydrogen. One of the (probably) main targets of the national hydrogen strategy is revealed and would significantly lower the national emissions. Being competitive in the global market requires cheap hydrogen. With an increasing market ramp-up of the electrolyser and contiguous technologies, the installations' price might drop and become feasible for smaller applications in the electricity sector.

Nevertheless, the electricity market will still be part of this strategy and hopefully benefit from such a development. Eventually, the hydrogen has to come from somewhere with close to zero emissions. Regarding the National Hydrogen Strategy, older and no longer subsidies wind turbines could provide more or less baseload energy for the electrolysis. An economical use for older wind turbines would allow them to be still active and set the demolition later. Allowing reusing the produced hydrogen during the days of so-called dark dulls (no or only a bit of wind and PV generation such as the 14.02.2020) or other sectors or the industry. Hydrogen could be in direct competition with natural gas for heating or gas-fired power plants as well as gasoline/diesel in the transportation sector. Decarbonisation of all sectors is necessary, and hydrogen from renewable electricity can be a part of the solution.

As mentioned in the beginning, such a transformation process should not end after publishing a document. Therefore, as long as the strategy allows hydrogen to become an economically feasible technology, actual actions shall be considered and implemented. Such an implementation is conceivable at a wind park or maybe at a hydropower plant (HPP) of the energy supplier Stadtwerke Ulm (SWU) Energie GmbH (Gesellschaft mit beschränkter Haftung - GmbH). The hydropower plant Böfinger Halde is marketed at the European Energy Exchange (EPEX SPOT) electricity market and therefore is in direct competition with renewables such as wind and PV and conventional power plants. The permission of the HPP Böfinger Halde regarding the Water Management Act is valid till 2023, and several possibilities are under investigation. Concerning the whole energy economics, one should not only consider the electricity sector itself. In comparison with the electricity sector, the heat and transportation sectors are way behind their targets. One can barely see achievements and progress. The district heating and the public transportation sector, future possible hydrogen markets, are under the same horizontal integration of the SWU Energie GmbH. Therefore, with high interest in the economic and ecological feasibility, possible actions shall be analysed and hopefully result in activities.

The core objective of this master thesis is to analyse, whether or not competitive green hydrogen can already be produced in Germany. The use of a load profile of an existing hydropower plant, the hydro power plant Böfinger Halde in Ulm, Germany and combining it with actual electricity market data allows conclusions. By using the available data for a profit and loss calculation, the costs for the hydrogen production can be assumed. An actual production price for green hydrogen is the goal.

Besides the economic discussion, the ecological benefit for several fields of applications of hydrogen will show where hydrogen is best to use to gain the best emissions saving effect.

Existing studies already analysed the benefit of using hydrogen in various fields of applications such as the transportation sector or the heating sector. Nevertheless, even up to date studies, such as Kreydelmeyer et al., Mai 2020 discussed green hydrogen in the transition from conventional energy carriers to renewable energy carriers. The major difference between most studies and the in this thesis used approach is the source of electricity. Usually, the electricity of fluctuating energy systems such as wind and PV are used. In the market ramp up of hydrogen a more continuous production of hydrogen with a higher workload might be better in terms of costs and revenues.

Several steps back in the project development, some background check is necessary. Chapter 2 provides background information, which is later required. The element hydrogen with its characteristics will be analysed. This small element is already implemented on a global scale. It is part of many industrial and also well-known processes. Besides hydrogen, another core part of this investigation is the HPP Böfinger Halde. It is necessary to have a short overview of the physical and technical framework. As the plant participates at the EPEX SPOT, chapter 2 will show the average electricity market price of 2019.

Last but not least, the same chapter will display the horizontal integration of the SWU. It is necessary to find an economic purpose for hydrogen. Ideally, at the same company, possibly improving the environmental image of the SWU.

With the background knowledge gained in chapter 2 about the basics of electrolysis and a hydropower plant, further investigations are possible. In Chapter 3, the target is to go deeper into potential and current developed electrolysis technologies. The several different electrolysis technologies themselves require comparison, and choosing the most fitting electrolysis technology is necessary. Knowing the basics about hydropower, a precise analysis of the HPP Böfinger Halde is essential. Analysing the characteristics of this specific plant will, later on, helps to figure out the value of electricity.

Chapter 4 is dedicated to the combination of both technologies, the HPP, and the electrolyser. Choosing a suitable manufacturer and implementing the electrolyser at the plant site will allow designing a cost perspective. With the costs on one side, chapter 4 will analyse future possible revenues and funding programs.

With the project dimensions, the ecological impacts and benefits can be evaluated. In the profit and loss statement, the project has to show its economic feasibility. Both are the core points in chapter 5. Chapter 6 shortly summarize the results as well as the conclusion.

A core target in Germany is, besides installing renewable energy systems, in the long run, to have an emission-free energy economy. Such a target requires installing a certain amount of flexibilities and storage capacities, such as batteries and electrolysis capacities. While battery technology is no longer an unknown technology, electrolysis holds secrets. This investigation aims to prove if building and operating an electrolyser in combination with a hydropower plant is ecological and economically feasible in the current and future market environment.

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2 Background information

2.1 Hydrogen

2.1.1 Characteristics of the element hydrogen

The lightest element in the universe is hydrogen and contains a proton as well as an electron. In some rare cases, hydrogen can have a neutron, which is then called deuterium. Even less common is the tritium with two neutrons. The hydrogen molecule in its purest form is a combination of two hydrogen atoms (H_2). The pure form itself is relatively rare on earth, and therefore hydrogen usually is in a molecular bond with oxygen, carbon, or minerals. Only a share of 0.12% of the earth's mass is hydrogen (Sicius, 2016). This does not mean, hydrogen in general, is quite rare. As we all know, around 70% of the earth is cover with water, and water consists of two hydrogen atoms and one oxygen atom. Connected to the small share of hydrogen itself is the relatively small atomic mass of 1.008 u. In comparison, the element Iron has an atomic mass of 55.845 u. The H_2-molecule is around 15 times lighter than oxygen (O_2 with 31.998) or nitrogen (N_2 with 28.001). While the melting point lies at -259°C, the boiling point is not that much higher with -252 degree Celsius (°C) (Sicius, 2016). Due to the lightweight and small size, storing and transporting hydrogen is challenging. In general, the norm circumstances for hydrogen are 273.15 Kelvin (K) (or 0°C) and 1013 Million Pascal (MPa)[1]. Under those circumstances, the upper heating value is 3.54 kilowatt per hour per norm cubic meter (kWh/Nm³). The lower heating value is at 3.00 kWh/Nm³.

Another characteristic of hydrogen is the energy density compared to other energy carriers. Hydrogen has a relatively low energy density with 0.0899 kg/Nm³. Comparing hydrogen as an energy carrier with other conventional energy carriers (see Table 1) might reveal the significant problem of hydrogen: Low energy density under normal circumstances.

[1] The difference between those two values can be explained relatively easily. The exothermic reaction of hydrogen with oxygen produces water. At the end of the reaction, water can either be liquid or a vapour/gaseous. As commonly known, the transformation from 100°C liquid water to 100°C gaseous water requires a certain amount of energy. The steam (with its temperature level) captures the energy. Therefore, the upper heating value refers to liquid water at the end of the reaction. The lower heating value refers to gaseous water. Capturing some share of the energy in the exothermic reaction in the gaseous water

Table 1 Energy carriers and their energy density (Linde-Gas-GmbH, 2020)

Energy density per energy carrier		
hydrogen	3.00 kWh/Nm³	33.33 kWh/kg
crude oil	≈ 1 ton oil equivalent (toe) per t	≈ 11.6 kWh/kg
diesel	≈ 10 kWh per litre	≈ 11.9 kWh/kg
gasoline	≈ 8.8 kWh per litre	≈ 12.0 kWh/kg
methanol	4.44 kWh per litre	5.47 kWh/kg
methane	9.97 kWh/Nm³	13.9 kWh/kg

At a direct comparison of hydrogen with methane at norm circumstance, methane has 3.3 times higher energy density. If calculated to the energy density per kilogram, this changes dramatically. Table 1 shows quite well that hydrogen itself does have a high energy density per kg of mass compared to every other conventional energy carrier.

Hydrogen does not smell, and the human eye cannot differentiate hydrogen and normal air. Breathing does not harm the human. Outgoing from that, humans cannot easily recognize hydrogen without suitable gas detection/warning devices. Another fact is, hydrogen heavily tends to stream up due to the lower density than the normal air. Being released at very high pressure, hydrogen itself not only streams upwards rather than in any direction. While eliminating the pressure difference between the ambient pressure and the earlier compressed pressure, hydrogen tends to flow in every direction, even to the ground. In combination with oxygen, hydrogen is quite explosive gas. Between a volumetric share of 4 % up to 75.6% in the normal atmosphere (Seemann, 2020), hydrogen can quickly react. A comparison with methane might show the explosive potential. Methane can explode in the air between a volumetric share of 4% up to 17%, which is a significantly smaller range compared to hydrogen. Another interesting fact is the required minimum ignition energy. Hydrogen only requires 0,019 millijoule (mJ) while methane requires 0.28 mJ (Seemann, 2020). With such a low ignition sensitivity, air - hydrogen mixture can easily ignite already by electrostatic charge or mechanical friction, impact processes, or abrasion processes. Not helpful is the ignition temperature of the hydrogen-air mix as well. If manufacturing equipment on its surface is warmer than 560°C, the gas mixture can explode. Therefore, the same as for methane, manufacturing equipment cannot have a hotter surface than 450°C. Under normal circumstances, an electrolyser and its instalments should not exceed this temperature limit.

As if this would not be enough, a hydrogen flame is barely visible at daylight. While not visible, a hydrogen air gas mixture's flame temperature can reach 2.100 °C, around 200°C higher than methane. While barely being able to see the flame, the heat itself is at least noticeable.

Working with hydrogen, therefore, required continuously instructed personal as well as specialized tools and equipment. As hydrogen tends to stream upwards, an instalment in a building without ventilation might be problematic. The hydrogen gathers at the highest point of the building and might not be detected by portable gas detection devices applied at the workers' chest. The same effect could appear the electrolyser is installed in an accessible special containment. The plant site as well should be separated from the public and possible igniting objects.

2.1.2 Hydrogen production

According to the International Energy Agency (IEA, 2019), the annual hydrogen demand of the world in 2018 has been 105 million tons (Mt). An amount of 45 Mt has been produced in several chemical/industrial processes and were further not separated respectively. The further (pure) used 70 Mt of hydrogen are partly used during refining processes (37 Mt), during the ammonia manufacturing (31 Mt), and negligible others (2 Mt). Compared to the demand of 1975 with less the 20 Mt, the global hydrogen demand is currently and most likely increasing.

The share of hydrogen produced out of fossil fuels around 2010 was an astonishing 96% (Wawrzinek et al., 2007). Interesting is the origin of this energy demand. With around 275 Mtoe (1 Mtoe = 11.63 TWh), the energy demand for hydrogen production matches the total primary energy demand of South Korea or Iran. The production of hydrogen uses around 205 billion m³ of natural gas and 107 Mt of coal. In relation, this equals 6% of the global natural gas use and 2% of the global coal use (IEA, 2019). Both fossil fuels are used and therefore industrialized in the following major processes: steam reformation and partial oxidation. The initial material in the steam reforming is natural gas (CH_4). During the steam reformation, besides H_2, carbon dioxide (CO_2) is produced in the end. The partial oxidation itself uses fossil coal or oil in combination with oxygen (O_2). The total efficiency is said to be around 75-80% for the steam reformation or 70% for the partial oxidation (Klell, Eichlseder, & Trattner, 2018) (p.92-93). With CO_2 or carbon monoxide (CO) as a side product and natural gas or heavy hydrocarbon oil as initial material, the stream reformation and partial oxidation can't be climate neutral. Therefore, it is not a final solution for hydrogen production. According to IEA, each ton of hydrogen is responsible for either 12 t CO_2 during the steam reformation or 19 t CO_2 during the partial oxidation with hydrocarbon fuel (IEA, 2019). Currently, debates about the steam reformation with carbon capture and storage option as transitory technology are held. The side product CO_2 is captured and stored underground. Requiring the storage of annually 830 Mt of CO_2 (IEA, 2019). Nearly as much as Germany emitted in 2016. Germany could use old, exploited oil or gas deposits. Besides the fact, the emissions are captured and therefore do not burden the environment, endless fossil fuels are needed.

Besides the steam reformation, the second most common process is the gasification. This quite complex process requires coal at a high temperature of 800 to 1.000°C and a maximum 40 bar pressure. The gasification itself is a very old process (already used in the 17th century) and does have a low efficiency of around 50%. The main problem with the gasification is the unwanted side products with a volumetric content of approximately 50%, which require the costly cleaning of the gas (Klell, Eichlseder, & Trattner, 2018) (p.94). The whole process requires several steps. First of all, the used substance is dried at a temperature of around 200°C. The water content should be as low as possible. Otherwise, there is a lot of water vapour in the final product. The material is heated up at a temperature of 200° of 500°C without air in the next step. This process is called pyrolysis or thermolysis. By excluding oxygen, the material is split into carbon bonds and hydrogen bonds. Again, if the temperature is too high, unwanted side products such as tar can emerge. In the third step, called the oxidation, the material is burned in an exothermic reaction at a temperature of 500° to 2.000°C. The generated heat is not lost but can be used in the previous and following processes. The exothermic reaction releases energy. The last step is a gasification. By adding carbon, several chemical processes take part (Klell, Eichlseder, & Trattner, 2018) (p.95-110).

Alternatively, biomass gasification could be a possible solution. A process that is still in the research phase. Considering biomass renewable as long as the used biomass is replanted and captures (via photosynthesis) carbon again while growing. While using fossil fuels as input material, subsidies should not be involved.

Even though if the emissions are stored. Nevertheless, conventional hydrogen production is way cheaper than hydrogen production with an electrolyser and renewable electricity. Without subsidies or taxes on the fossil input material, renewable hydrogen might not be competitive and might lose such a direct competition.

Displayed in figure 4 are the main possibilities for producing hydrogen. Green are the renewable solutions while grey requires fossil energy carriers as input material.

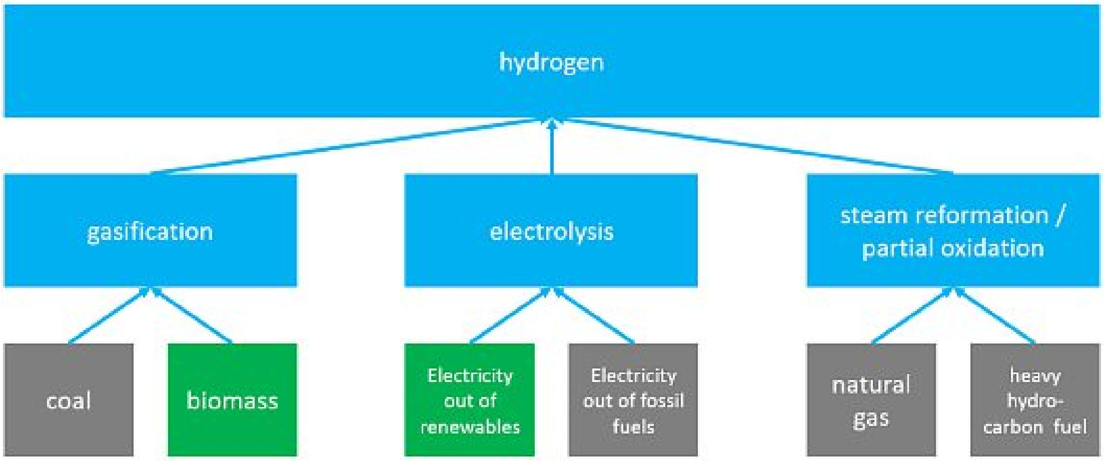

Figure 4 Main possibilities to produce hydrogen out of energy (-carriers) own representation based on (Klell, Eichlseder, & Trattner, 2018) (p.91-100)

2.1.3 The transportation of hydrogen

While generating hydrogen can be considered as one process, storage and transportation as another. It is probably easier to produce hydrogen than to store and transport hydrogen. Currently, the following two established ways are used to store hydrogen. Compressed gaseous hydrogen (GH2) and liquid hydrogen (LH2). The pressure level of GH2 lays at 300 up to 700 bar whereas the LH2 requires a temperature of less than -252.82°C or 20.3 K. In both cases, special containments are needed. Besides the containments, a relatively huge amount of energy is needed for compression and temperature reduction. (Klell, Eichlseder, & Trattner, 2018) (p.110)

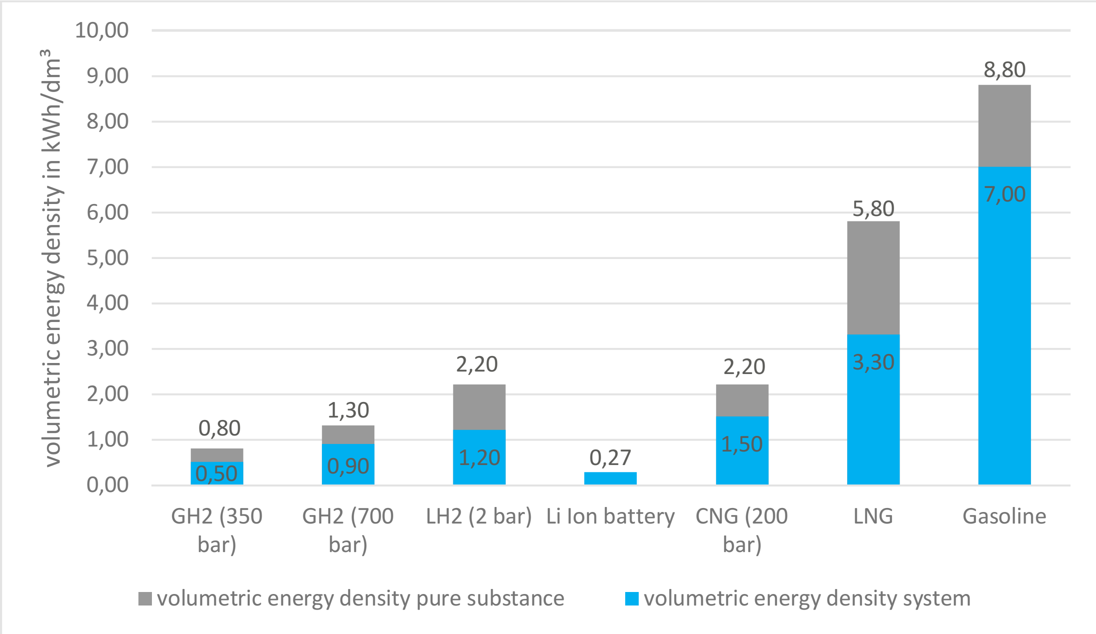

Figure 5 Comparison of the volumetric energy density (Klell, Eichlseder, & Trattner, 2018) (p.111)

In the direct comparison of hydrogen with compressed natural gas (CNG) or liquefied natural gas (LNG), the energy density of hydrogen in any form is lower than its conventional counterpart. Noteworthy is the considerable difference between gasoline and hydrogen, resulting in the low density of hydrogen with 0.0899 kg/m³ in 1 bar. (Under 350 bar, the density of hydrogen is 23.3 kg/m³ and under 700 bar, 39.3 kg/m³. The LH2 at 2 bar has a density of 67.67 kg/m³.) The grey bar is the energy density of the energy carrier in its pure substance. Because a system or storage component is needed, the blue bar describes the energy density of the whole system. This explains why the Lithium (Li) Ion battery has no energy density in its pure substance. Electricity has no density but the system, the battery itself does. Compared with the volumetric energy density of gasoline, the needed space of the battery system in an electrical vehicle (EV) regarding the range criteria is understandable.

The energy density itself is one possible way to make a comparison. Another way is the heating value itself. Hydrogen has a heating value of 33.3 kWh/kg, whereas gasoline reaches 11.5 kWh/kg and LNG/CNG reaches 13.9 kWh/kg (Klell, Eichlseder, & Trattner, 2018) (p.111). For suitable usage, either way for transportation or storage, hydrogen needs to be compressed. A compression is linked with energy demand and, therefore, should later be addressed.

Summing it up, hydrogen can either be transported as a gas or as a liquid. Depending on the amount and on the transport distance, three possible systems are standard.

Via pipeline: If consumers' density and the demand itself is quite high, pipelines are the most efficient way to transport hydrogen. Common are pipes with a diameter of 10 to 300 mm and an operating pressure of 40 to 70 bar (Töpfler et al., 2017).(p.23)

Via liquid tank truck: as seen in Figure 5, liquefied hydrogen allows the highest energy density. A liquid tank truck is handy if the distance itself is quite huge (<1.000 km). This kind of transportation does have a negative site. The liquefaction requires a higher energy amount than the normal compression. Around 0.96 to 1.2 kWh/Nm³ is required (Töpfler et al., 2017) (p. 12).

Via trailer (truck): If the distance is lower than 200-300 km, the most economical way to transport hydrogen is via a trailer with gas tanks of pressure between 200 to 500 bar. A truck with such a trailer can therefore transport 3.000 up to 12.000 Nm³ (Töpfler et al., 2017) (p. 12).

As an alternative, so-called carrier materials are under current development. The idea is to store hydrogen with chemical bonds or absorptive bonds in so-called “liquid organic hydrogen carriers”. Such carriers could decrease the required storage containment and therefore allow a higher volumetric energy density (Papp et al., 2014). With ongoing research and development, the liquid organic hydrogen carriers are currently not commercialized.

2.1.4 Subsidy programs for hydrogen on a national basis

Based on the government initiative to improve hydrogen in several resorts, the national innovative program hydrogen and electrolysis technology (NIP) was founded. The NIP was already developed back in 2006 and now supplements the national hydrogen strategy. With the incentive to establish a national hydrogen market, the BMWi published Germany's national hydrogen strategy in June 2020. With both the NIP and the hydrogen strategy, the BMWi established subsidy programs. The goal was and is to subsidize several possible future fields of hydrogen, which means the production of hydrogen and the further use of hydrogen in the industry, the transportation sector, the electricity or heat sector. The general goal is the market ramp-up of hydrogen in all sectors until hydrogen technologies are market competitive. With 36 very diverse measures, the market ramp-up shall be successful in two phases till 2030 (BMWi, 2020). Several billion Euros have already been invested and will be invested into the future: Germany shall invest around 7 Billion Euros for the market ramp-up in Germany and an additional 2 billion on an international basis. Some of those measures are the subsidization of electrolysis plants combined with renewable energy systems such as wind turbines. The electrolysis plant must have many full load hours to be economically feasible. Besides the generation, the required infrastructure is subsidized as well (measure 4). On the other side of the generation, the further use in the transportation sector might be interesting, especially for the SWU. With a bus fleet for public transportation, the funding of alternative renewable propulsion technology (measure 6) or the required fuel infrastructure (measure 8) might later be necessary if the production of hydrogen is local. The use of produced hydrogen in the heating sector in conventional boilers or a combined heat and power (CHP) plant is possible (measure 19). With around 100 fuelling stations for hydrogen, future capacities might be useful. A fuelling station directly next to the hydrogen plant might be one of the cheapest possibilities. Therefore, even fuelling stations and the required infrastructure are subsidies (measure 22). A market ramp-up can either be successful if a diverse field of possible technologies is subsidies or if just a specific or the most promising technology is subsidies. Hydrogen in the energy economics will play a role. Some say it is even necessary. The future will show if the national hydrogen strategy and this directive was successful by widely subsidizing various solutions.

2.1.5 Current and further use of hydrogen

The probably most common use of hydrogen in the industry is in the Haber-Bosch-Process. This process revolutionized agriculture in the 19^{th} century. Before this process, the three-field system was the way to grow crops in agriculture. Farmers used one field for summer crops, one for winter crops, and one field could rest for one year. The eponyms of this process realized that if they supply plants with nitrogen, plants can benefit and therefore can prevent the exhausting of the soil. The newly discovered process allows using the fields at any time of the year and increases yield. In the Haber-Bosch-Process, the combination of nitrogen (N_2) and hydrogen (H_2) becomes ammonia (NH_3). A liquid is more comfortable to be applied to the crops and the field than a gaseous substance. Nowadays, the used way is the steam reformation to produce the required hydrogen.

Even not so known process such as hydrogenation is widely used in the industry. Hydrogenation is a process that uses hydrogen to saturate or reduce organic compounds. For example, the process itself is used to hydrogenate coal, in the petrochemical industry (to saturate paraffin) or in the food industry, mostly for vegetable oils.

Another unknown process is the production of (float-) glass. Forming molten glass under a protective atmosphere (mostly hydrogen) into a flat glass can later be used for mirrors, windows in a building, or a windscreen for vehicles. The protective atmosphere out of hydrogen prevents the, for the process needed, liquid tin to oxidize.

As mentioned before, the use of hydrogen in the steel and metal industry is another possible solution. Not only as fuel but as well for hardening, sintering, or gas deterring. The positive impact on the climate itself could be significant. Nevertheless, with the vast amount of steel production, a considerable amount of green or renewable hydrogen would be needed as well.

Being independent of fossil fuels in the future would significantly reduce greenhouse gas (GHG) emissions. On the other side, such a step would require alternative fuels. One of those could be hydrogen due to the variable fields of application. As long as the hydrogen production is done with renewable electricity, the environment would benefit. In a fuel cell, hydrogen can generate electricity, which further allows many possible future applications. In the transportation sector, hydrogen in trains, trucks, coaches, cars seems an obvious solution. Even an application in ships or planes could be possible. Even though in the last two applications, the fuel cell could be redundant. The whole public & private transportation sector could become environmentally friendly in the future. On the other side, the heating sector could benefit as well from hydrogen. The transformation of the natural gas grid to a hydrogen grid is possible. Therefore, hydrogen fired heaters or fuel cell heaters could supply the demand of private households in the future. On a larger scale, gas-fired turbines powered by hydrogen could provide heat via district heating and supply electricity. Such gas-fired turbines would allow additional flexibility in the electricity sector during wind still and cloudy periods. The demand for hydrogen in the future, in general, would exceed the current electrical supply out of renewables. Without taking efficiency into account, the transportation sector itself required in 2018 751 TWh (Umweltbundesamt, 2020). The renewable electrical energy supply in 2019 was around 244 TWh (Umweltbundesamt, 2020). A direct comparison should show that besides relatively high renewable installations in the electricity sector, the transport sector's energy demand exceeds the current supply. The likely future demand for hydrogen requires a considerable investment into renewables (not only in Germany) if the demand in the transportation sector stays the same and should be covered by renewables.

2.2 Renewable electricity generation

The four most common renewable electricity generation technologies are wind power, photovoltaics, biomass/biogas fired engines or turbines, or hydropower. All four technologies are unique and different in the electrical output. Nowadays, several installations are nearly market competitive and therefore perfectly suitable to supply electricity for further use in an electrolyser. In the south of Germany, where Ulm at the Danube is located, only three of those four technologies dominate. Due to the lack of higher wind speeds, wind-powered turbines are quite rare and therefore not common in the south. On the other side, higher solar radiation resulted in a vast amount of PV installations. The geographical occurrences of the alps in the south resulted in a significant number of hydropower plants. The third more or less standard technology is the biomass/biogas fired combustion engines. As PV itself is fluctuating and has relatively low full load hours (FLH), PV in an early stage will not be very suitable combined with an electrolyser. Biogas itself is, to a certain degree, a flexible technology already running on gas itself. It would not make sense to produce gas, burn the gas for electricity, and later use the electricity to produce a gas. Therefore, the remaining technology might be hydropower.

2.2.1 The electricity generation out of hydro power

One of the oldest technology for using energy in a certain way is hydropower. In mere words, hydropower uses the tendency of a medium (water in this case) to be as close as possible to the centre of the earth. Today this force known as gravity, described by a not so unknown physicist called Newton. Newton described every mass exerts the force of gravitation to another mass. A small water molecule compared to the mass of the earth’s core has no other possibility of coming to the earth’s centre. This gravitational force can be converted to mechanical force and later into electrical energy. A turbine allows us to transfer the vertical energy of gravitation into rotational kinetic energy. Power plants can further use rotational kinetic energy in a generator to convert the energy into electrical energy. A generator has several magnetical poles in a circular arrangement. Always in a way, a positive pole is surrounded by negative poles vice versa. A rotating object, which uses the rotating kinetic energy, then ensures a change of the magnetic direction while rotating. In short words, we have a generation of electricity.

A way to calculate the electrical output is by knowing the natural characteristics of the river. Quite substantial is the amount of water, better-called discharge (Q) in cubic meters per second (m³/s), and the height difference the water falls, better-called head (h) in meters (m). To calculate the potential energy, we need to include the mass of water on earth. 1kg of water has a gravitational acceleration (G) of 9.81 Newton (N or m/s²). The medium itself is water, which has a density (ρ in kg/m³) of 1.000 kg/m³.

Therefore, the transformation of the potential energy of water into kinetic energy:

$$P_{kin} = Q \times h \times G \times \rho \tag{1}$$

Unfortunately, every transformation of energy from one form to another has losses. The efficiency η describes how much initial energy can be converted into useful or wanted energy. Energy per se is not gone and therefore not lost but just not applicable in a wanted way. In a hydropower plant, expected losses can be lead back to friction, which results in thermal energy, which is heat. Friction always appears when moving parts need to be kept in a place with bearings. It is impossible to avoid friction and other losses themselves but with specific technical solutions reduced to a minimum. If a process had no losses at all, η would be 1. In a closed system, the energy input cannot exceed the energy output. If only losses occur, η is reduced to a value up to 0 where no useful energy is left. Each part of a hydropower plant is individually designed for a specific plant site, therefore, has a different efficiency, and by adding up those, the total efficiency is calculated:

$$\eta_{total} = \eta_{turbine} \times \eta_{gearbox} \times \eta_{generator} \times \dots \tag{2}$$

As described in Formula 2, the total efficiency (η_{total}) is the sum of the turbine efficiency ($\eta_{turbine}$) multiplied with the efficiency of the gearbox ($\eta_{gearbox}$), multiplied with the efficiency of the generator ($\eta_{generator}$) and other efficiency effecting parts of the hydropower plant

Including the total system efficiency, the correct formula for the electrical energy of a hydro power plant can be calculated with:

$$P_{el} = Q \times h \times G \times \rho \times \eta_{total} \tag{3}$$

In the end, the electrical energy (P_{el}) equals the discharge (Q) multiplied with the head difference (h), the gravitational acceleration (G), the density (ρ) of water and the total efficiency (η_{total}).

2.2.2 The hydro power plant Böfinger Halde

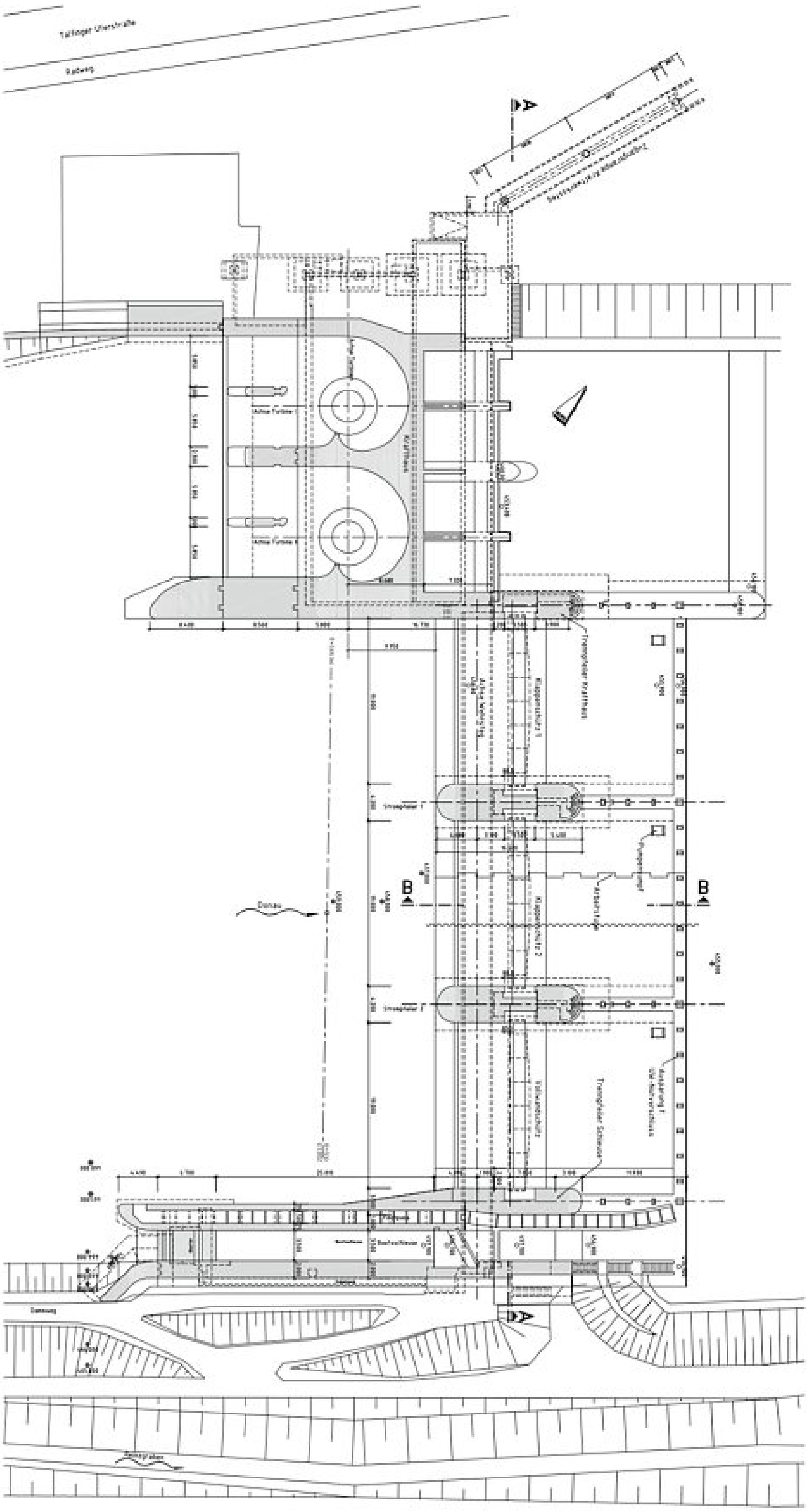

Figure 6 Schematic representation of the HPP Böfinger Halde (Figure provided by SWU Energie GmbH)

The hydropower plant Böfinger Halde located at the Danube in Ulm (Germany), is a run-of-river power plant built-in 1956 (provided by the SWU Energie GmbH). The maximum discharge, which is structurally limited, of the two turbines, is 172 m³/s (provided by the SWU Energie GmbH). Due to a dam, the Danube has a head of 7.25 meters (provided by the SWU Energie GmbH). Those 7.25 meters are the difference between headwater to tailwater. As the (average) total efficiency 0.855 can be determined. Following the P_{el} formula from above, the HPP Böfinger Halde has an installed capacity of 10.46 MW. Such a power might be valid under ideal circumstances, but those never occur. If a river has a large discharge, its head is not the same as during low water. The water level in the tailwater is rising and therefore reducing the head. The tailwater is rising because the riverbed is limited. The higher the discharge, the higher the water level. Arguable the velocity of the water is increasing as well but usually not sufficient enough to compensate for the amount of water. Besides the head, the efficiency of several components is not constant. As an example, a turbine is very efficient in a particular range. Beyond this range, the efficiency drops. The highest ever measured electrical power due to a lower head, therefore was 9.2 mega watt (MW) (data provided by the SWU Energie GmbH).

Concerning constancy, the Danube itself does not have the same discharge every day or hour, and therefore the energy output varies over the year. In the long run, the average electrical work has been around 49.49 GWh (data provided by the SWU Energie GmbH). An easy way to compare several power plants and technologies is the hours/yr. Imagining, one would compress the work in a way the plant itself would run under full capacity until reaching the plant's annual supply. The number of hours until reaching the yearly work are the full load hours a comparison between different plants is possible. The calculation is relatively simple. Dividing the annual work by the installed capacity results in hours/yr. Therefore, the full load hours of the HPP Böfinger Halde is (49.491.000 kWh/ 9.190 kW) 5.385 hours/yr. A PV, for example, lays around 1.000 hours/yr, and a wind turbine onshore could be about 2.000 up to 4.000 hours/yr.

A power plant usually consumes an individual share of generated electricity for generating electricity. Using this consumption is used in the control units or several aggregates regulating the plant. Around 0.2 GWh (provided by the SWU Energie

GmbH) equals its own consumption. The earlier mentioned generation is the net generation (gross generation minus own consumption), the marketable share.

In 2019, generator one underwent a generator revision from May till September, resulting in no generation during these months. Such revision and downtimes are already included in the long term generation, but in 2019 the revision was remarkably long. The HPP generated around 45.89 GWh in 2019 (provided by the SWU Energie GmbH), which is a bit lower than the long-time average. Due to the revision, the data is insufficient. Going back in time, the annual generation in 2015 with around 48.96 GWh (provided by the SWU Energie GmbH)is in the average generation range and allows the use in further investigations. Even in 2015, the HPP hat several downtimes, such as in July and in November. Besides those, the minimum generation seemed to be a little bit more than 2 MW.

In 2015 (Figure 6), the HPP Böfinger Halde displayed the typical characteristics of the Danube in this area. During the wintertime and in the Spring till the beginning of the summer, the precipitation plays a significant role. When the snow in the winter stays in the mountains, the discharge is reduced (in February). In Spring, during the melting season, the stored snow and ice is released and frequently procures floods. The actual discharge in the river is then much higher than the maximum discharge of the turbines. Since 2015, the SWU made no nameable adjustments at the HPP Böfinger Halde

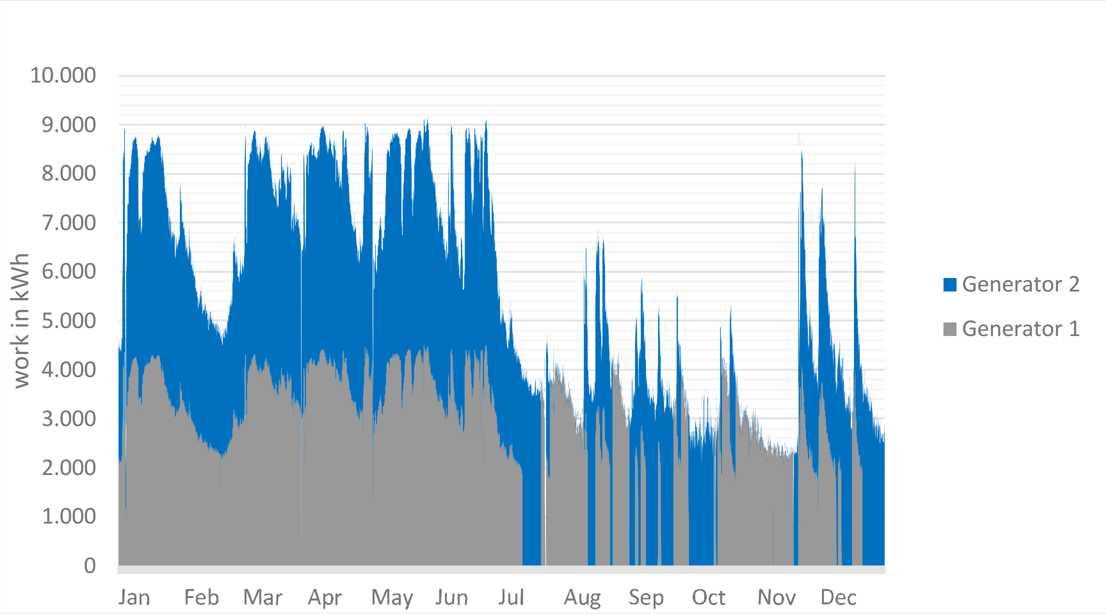

Figure 7 Hourly generation per turbine of the HPP Böfinger Halde in 2015 (own representation, data provided by SWU Energie GmbH)

The HPP Böfinger Halde does serve several markets. Not directly but on the balance sheet. First of all, we have the gross generation. As mentioned earlier, subtracting the own consumption (around 212 MWh in 2015) from the gross production results in useable production. In 2011, with permission, the SWU was able to lift the headwater from 465.75 above sea level to 466.25 meters above sea level.

Regarding the EEG law during that time, HPP with more than 5 MW installed capacity can improve their energy output, but only the share of improved energy output is then subsidies by the EEG. The EEG subsidizes the benefit of this half meter. This half a meter equals 8.75% of the annual generation and does not change over the years. The EEG feed-in tariff is higher than the current electricity market value and therefore has priority. The non-EEG generation is, therefore, around 44.49 GWh (data provided by the SWU Energie GmbH). The SWU Energie GmbH uses energy out of this HPP to supply its offices and infrastructure. In 2019 this SWU Energie GmbH self-consumption laid around 2.73 GWh (data provided by the SWU Energie GmbH). Therefore, the subtraction of the self-consumption is necessary. The amount of self-consumption barely changes from year to year.

Marketable at the EPEX SPOT is the final useable energy of 41.75 GWh (own calculation). The HPP is not able to supply the whole SWU Energy GmbH consumer electricity demand. Therefore, buying some electricity at the EPEX SPOT market is necessary. The electricity of the HPP Böfinger Halde is not sold at the market and later bought again, but rather seen as been purchased there. The results are the revenues are directly linked to the EPEX SPOT market. The EPEX SPOT is the European Power Exchange with the task to provide a platform to trade electricity. Because most countries have different legislation, installed types of power plants, and support schemes, the market price differs. Regulations divide the EPEX SPOT into several regions, minimizing cross-border trading. One region is Germany (with Luxembourg). Long term base-load and peak-load contracts are usually not traded at the EPEX SPOT. The European Power Exchange focuses on Day-Ahead (electricity for tomorrow) and

Intra-Day (electricity for today) contracts. The SWU Energie GmbH rates the electricity for the HPP Böfinger Halde as the Day-Ahead prices.

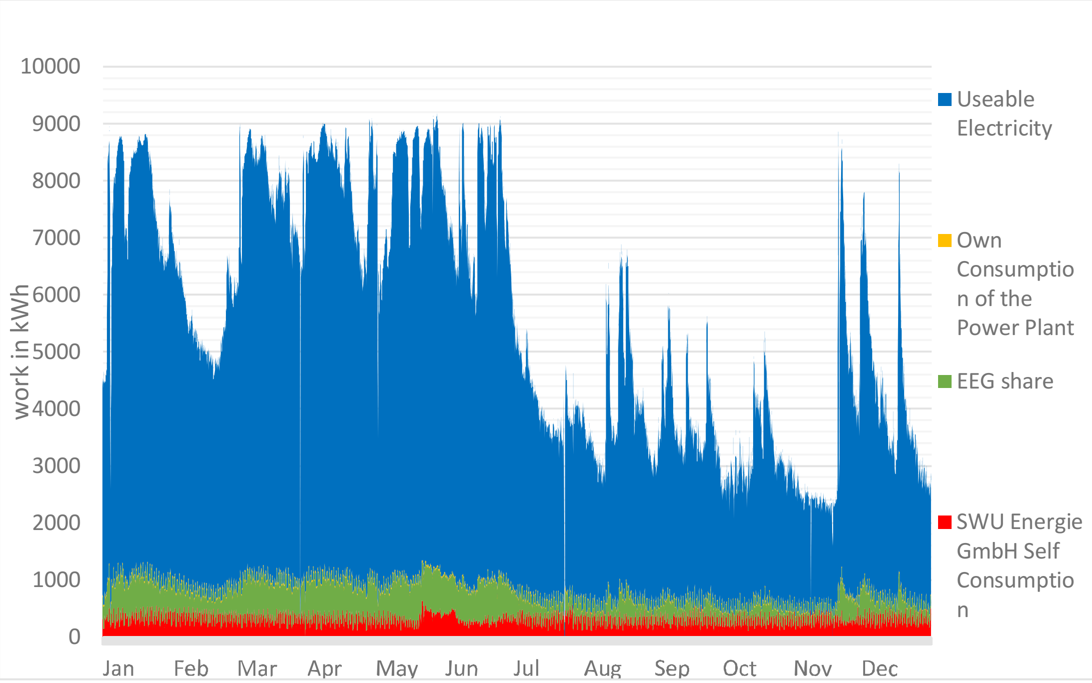

Figure 8 Different marketing shares of the generated electricity of the Böfinger Halde (own representation, data provided by SWU Energie GmbH)

As visualized in the Figure 6 above, the SWU Energie GmbH self-consumption (red) is relatively constant and rather uninteresting. Due to the fixed percentage, the EEG share (green) varies with the total generation. The own consumption (yellow) of the power plant is negligible. It remains the usable electricity (blue).

By combining the EPEX SPOT day-ahead market prices with the hourly generation, the average volume-weighted commission of 2019 was at 3.77 ct/kWh (own calculation). In addition to the market commission, the HPP can receive green electricity certificates with a value of 0.16 ct/kWh (information provided by the SWU Energie GmbH). They are summing up to total revenues of 3.93 ct/kWh for the usable electricity.

The EEG feed-in tariff is according to EEG 2009 § 40 7.22 ct/kWh worth. As the average electricity price is lower than the EEG feed-in tariff, the SWU GmbH sells the 8.75% according to the EEG regulations. The last share, the SWU Energie GmbH self-consumption, is sold at the average electricity price in addition to the current EEG taxation.

2.3 The energy economic in Germany

2.3.1 The household electricity price with its taxation system

In Germany, several laws effect energy economics in general. Besides the energy economic law (Energiewirtschaftsgesetz – EnWG), describing the whole system and the market itself, the early mentioned EEG does play a significant role, especially for renewable energy carriers. The EEG represents the guideline for the implementation of renewables. It is always important to remember the reasons for establishing the EEG. Germany signed the Kyoto Protocol and later the Paris Climate Agreement. The target in both of those agreements is reducing CO2 emissions of a particular share until specific years. The year of comparison is 1990. Outgoing from 1990, the emissions in 2020 shall be at least reduced by 40%, till 2030, the target is a reduction of 55%. In 2050, Germany and many other states shall avoid at least 80% of the GHG emissions. Those Emissions are mostly a result of the use of conventional energy carriers for energy demand. Therefore, besides reducing energy demand, Germany shall increase the renewable share of the energy demand by 18% in 2020, 30% in 2030, and 60% in 2050. The energy economics was one of the most significant pollutant, if not the biggest. As a result of those targets, the EEG was formed with the specific target to subsidize renewables.

Subsidizing may require taxation to fill the financial gap. The tax for the renewables is called "EEG-Umlage" and is calculated every year by the federal network agency. In 2019 the EEG-Umlage had a share of 21% or 6.41 ct/kWh. In 2020, the EEG-Umlage increased up to 6.76 ct/kWh. For 2021 the EEG-Umlage will be fixed at 6.50 ct/kWh. Every consumer, except large industrial consumers, have to pay this taxation for each consumed electricity and is therefore supporting the renewables. In general, even self-supply requires a tariff of 40% of the EEG-Umlage.

A suitable example would be PV on the roof of a household. If the household owner uses some or all of the electricity he produced for his own, he has to pay 40% of the EEG-Umlage for each kWh he consumes. Under certain circumstances, a power plant does not need to pay this tax. One could be if the self-supply construct is older than ten years (2011). The SWU Energie GmbH does exist for quite a long time, as well as this HPP. HPP Böfinger Halde electricity was used for the water distribution of Ulm and Neu-Ulm (on a balance sheet) already when the EEG did not exist yet. With the introduction of the EEG, the legislation introduced the taxation of consumption as well. The legislation allowed the possibility to keep up any self-supply as long as the generator is older than 2014, and the construct of self-supply exists as well longer than 2011 (EEG 2017 §61d S 2). In other words, without this self-supply, the EEG tax would be added when electricity is needed. A considerable benefit nowadays because the EEG taxation lays between 6 and 7 ct/kWh and is said to at least exist for several years.

Another cost driver is the network charge, which can be seen as a toll. The grid infrastructure requires investment and maintenance, resulting in costs paid by the users of this infrastructure. A direct cable supplying the electrolyser lowers the price for energy consumption. Therefore, the electricity price at the SPOT market described in chapter 2.3.1 equals the price for the electrolyser's electricity consumption if the electricity of the HPP Böfinger Halde is used and supplied via a direct cable.

2.3.2 An investigation of the electricity stock market price in Germany

The electricity price at the SPOT market is varying from hour to hour. The reason for that is the supply and demand of electricity, which can change dramatically. In a specific hour of the year, a demand forecast is developed. Such a demand forecast has to be done by every electricity company which delivers consumers. The sum of all defines the forecasted demand. On the other side, every producer has to offer his production forecast and determine a specific price for its electricity. Renewables, which are subsidized by the EEG, are set at 0 €/MW. Now every producer is sorted in the way from low electricity price to high electricity price. This sorting is called the merit order. The production forecast and demand forecast define the electricity price by the last necessary active power plant in this sorted row. Changing demand and supply is resulting in different market prices over the year. One can see such an annual curve in the following Figure 8. The average electricity price in Germany at the EPEX SPOT Day-Ahead in 2019 was 3.767 ct/kWh. Compared with the household electricity price in 2019 of 30.46 ct/kWh (BMWi, 2020), the high amount of levies and taxes in Germany are displayed.

Commonly the average electricity price is compared with the previous or the following years. As an average price smudges reality, it is essential to understand how the price can change from one to another hour. Under specific circumstances, the price itself can become negative. If the supply is much higher than the demand, plant owners try to get rid of their electricity. Usually, such negative prices are a result of a sunny and windy day. Even holidays and the weekend result in relatively low demand and therefore deliver additional potential. During these times, buying electricity, reducing electricity production, or the possibility of storing electricity may be beneficial. With increasing renewable capacities and the lack of flexible storage capacities, the number of hours with negative electricity prices is said to increase in number and increase in strength. As displayed in Table 3, the electricity market price did show several characteristics in 2019:

Table 2 Comparison SPOT electricity market prices in 2019 (Data provided by SWU Energie GmbH)

	hours in 2019
higher than 3.767 ct/kWh	4.526 h
lower than 3.767 ct/kWh	4.232 h
lower than 0.0 ct/kWh	211 h
lower than 1.0 ct/kWh	416 h
lower than 2.0 ct/kWh	660 h
lower than 3.0 ct/kWh	1.899 h
higher than 5.0 ct/kWh	1.406 h
higher than 8.0 ct/kWh	46 h
higher than 10.0 ct/kWh	7 h

The distribution of hours with a price above the average compared to hours lower the average price is nearly equal. While 660 h are lower than 2.0 ct/kWh, more than double the amount (1.406 h) are above 5.0 ct/kWh. Additionally, the comparison of prices lower than 0,0 ct/kWh and prices above 8.0 ct/kWh reveals an uneven distribution. Meaning a lot of hours were in the range of 4.0 to 3.0 ct/kWh. More prices are on the negative extreme than on the positive extreme, meaning negative or relatively low prices are more common than high prices. These price effects might be interesting in later investigations regarding the dimensioning and operation of the electrolyser itself. The ability to increase the load will therefore be more important than the ability to decrease the load. But diminishing the load might not be irrelevant and even pay off.

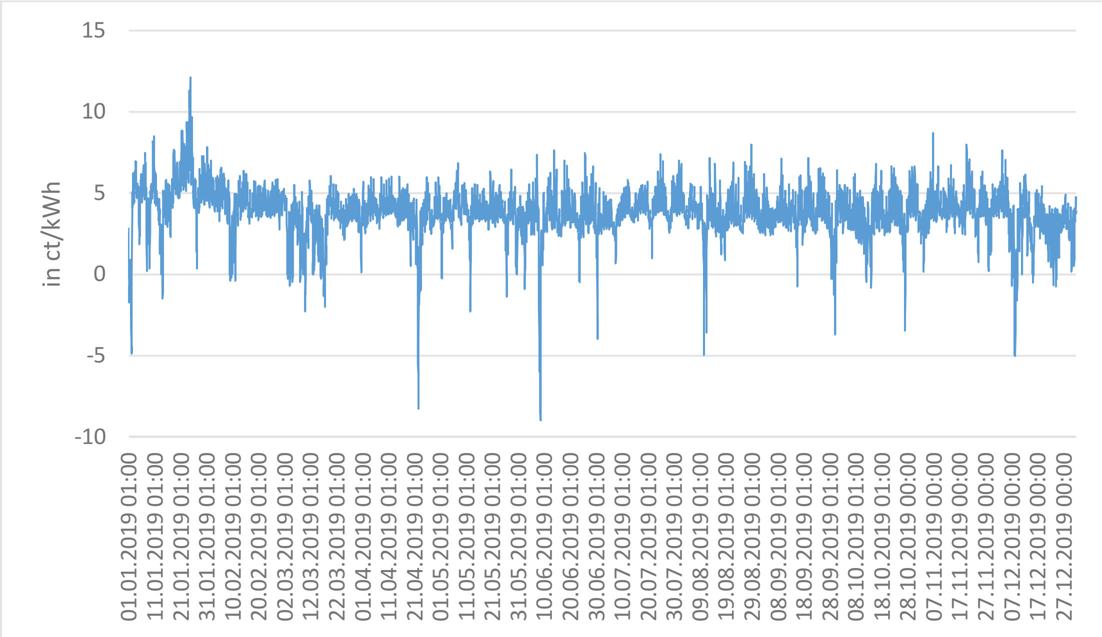

Figure 9 Hourly SPOT day-ahead electricity market prices of 2019 in Germany in ct/kWh (own representation, data provided by SWU Energie GmbH)

Displayed in Figure 9 is such an annual price curve of the EPEX SPOT day-ahead price. Frequently changing prices a a characteristic of the continuously changing production and demand side

2.3.3 Outlook: the future electricity market

While looking at Figure 1, where the installed capacity of renewables from 2000 till 2019 is displayed, one can see a trend. In 2008, the installations seemed to stagnate due to the financial crisis. Such a trend could be seen in 2020 during the severe acute respiratory syndrome coronavirus 2 (SARS CoV 2) crisis. Nevertheless, compared with the subsidy's height and the spot market price reveals, a support scheme will probably still be necessary for several years. The gap is still too big, even more, significant considering if the fluctuating effect. Hopefully, increasing CO_2 certificate prices, resulting in higher generation costs, conventional plants will help close this gap by lifting the average electricity price. Conventional plants will then, to a certain degree, eventually become redundant.

An outlook into the future electricity market is always speculation and therefore strongly connected with being false. In the future, with more renewable capacity, the fluctuating supply of renewables will probably increase. Without storage technologies, the price changes will increase. Natural gas power plants as transitory technology will result in a higher price. With a decent amount of storage capacities, the price might stabilize. Storing is cost-intensive, and therefore, in the end, one can assume that the electricity price itself will increase or at least be stable in both cases.

On the other side, the demand side allows us to draw inferences. Combining the current development and future targets, the demand will probably slightly increase. On the one side, trimming every product to be more efficient than its previous version is quite common. A new fridge should be less energy demanding than an older one. With increasing wealth, the living standard will increase as well, and more and more people, even in Germany, will be able to afford more efficient products. On the other side, a process of electrification can be seen. More and more products shift from primary energy use of fossil fuels to electricity. Best examples are the swift from internal combustion engines to electric vehicles or oil boilers to heat pumps. Even digitalization will be part of increasing electricity demand.

In the past 20 years, a lot changed in energy economics. In the next 20 years and even more will and has to change. A good outlook into the future electricity market would go beyond constraints. The SARS CoV 2 crisis probably rescinded any published forecast. Nevertheless, a price forward curve[2] will be used to have a changing market trend for the next five years. The price forward curve tries to predict the hourly SPOT electricity market prices for 2021 till 2025.

Table 3 Comparison of the SPOT electricity price of 2019 with the electricity price regarding the price forward curve for 2021 till 2025(Analysed with the data provided by SWU Energie GmbH)

	2019	*2021*	*2022*	*2023*	*2024*	*2025*
Average in ct/kWh	3.767 ct/kWh	4.081 ct/kWh	4.411 ct/kWh	4.613 ct/kWh	4.800 ct/kWh	4.869 ct/kWh
hours below 0.0 ct/kWh	211 h	21 h	13 h	33 h	31 h	33 h
hours below 3.0 ct/kWh	1.899 h	1.494 h	1.193 h	1.028 h	969 h	948 h
hours above 5.0 ct/kWh	1.406 h	1.996 h	2.987 h	3.432 h	3.802 h	3.908 h
hours above 8.0 ct/kWh	46 h	0 h	25 h	53 h	172 h	194 h

[2] The price forward curve was provided by the trading department of the SWU Energie GmbH.

A trend shows the average electricity price is said to increase over the years. In the direct comparison with the actual SPOT electricity market prices in 2019, the lack of price extremes is quite impressive. As no one can predict the weather for the next five years, the forecasters cannot take the surplus generation of fluctuating renewables or the lack of renewable generation into account. The price forward curve might help with an average electricity price but will not provide additional information about the development of price extremes, especially in the case of the surplus generation out of renewables.

2.4 The "Stadtwerke Ulm" – local energy supplier in Ulm and Neu-Ulm

Whereas the foundation of the SWU was in 1982, one can find the local energy supplier's roots in 1850. It all started with the wish to have gas-fired streetlights and a gasworks. Later the water supply followed and as the electricity finally came to be known. The city itself decided to transform the street lights to electrical lights. At the turn of the century, the first electrified tram came to Ulm, and later, the first hydropower plant was established. After the first world war, the city of Ulm combined several urban establishments into one centralized establishment and finally formed into a limited liability company in 1982. The shareholders of this company are the cities Ulm and Neu-Ulm.

Under the holding company nowadays, several companies are under horizontal integration. The SWU Energie GmbH is responsible for the energy trading, energy supply, the existing electrical power plants (HPP, PV or CHP) and the water pumping and supply, the heat distribution and heat supply. The Stadtwerke Ulm/Neu-Ulm Netze GmbH is the grid operator and therefore operates the grid service area in Ulm and Neu-Ulm. The grid operation includes the electrical grid (high voltage, medium voltage, low voltage), the gas grid and the water grid. The Gaskraftwerk Leipheim GmbH & Co.KG is a development project about a gas-fired power plant that shall eventually be built as compensation for the nuclear power plant Grundremmingen, which will shut down in 2023. The SWU Telenet GmbH is the internet provider in the service area and provides the internet and the grid. The SWU Verkehr GmbH with the SWU Mobil GmbH is the public transportation operator in Ulm and partly in Neu-Ulm.

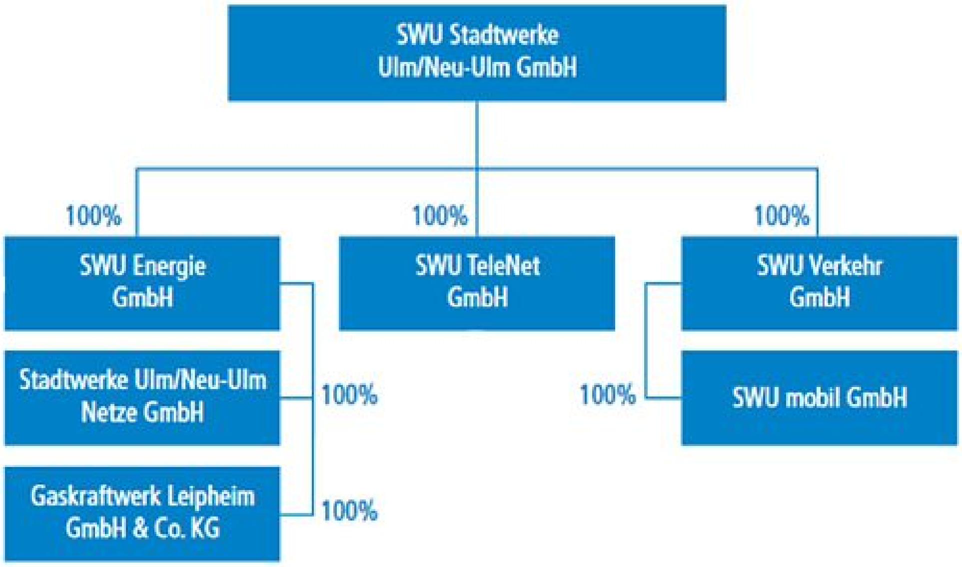

Figure 10 Organigram of the energy supplier SWU Stadtwerke Ulm/Neu-Ulm GmbH (SWU, 2021)

In 2019 1.072 people (SWU, 2020) worked at the local energy supplier supplying 1.16 TWh of electricity, 1.64 TWh of natural gas, 87 GWh of heat and 11.5 Mio m³ of fresh water (SWU, 2020).

In 2019 around 244.3 TWh where generated by renewables in Germany. In other words, 42.1 % of the German electricity was renewable (Umweltbundesamt, 2020). In the service area of the SWU Energie GmbH, the renewable share in 2019 was a little bit higher than the national values. 47.9% were, by the EEG subsidized renewables. With the additional renewable but non EEG share of 6.30%, a total renewable electricity supply of 54.2% was possible (SWU, 2020). In the cities Ulm and Neu-Ulm, the core distribution area of the SWU Energie GmbH, around 185.000 inhabitants are residing. The SWU Energie GmbH sold 1.635 GWh of electricity in 2019 (SWU, 2020).

The company parts with probably one the highest interest in hydrogen might be the public transportation sector. Ulm has several hills; therefore, battery-powered electrical buses might reach their limit. The number of buses in use and the given infrastructure at the depot might as well be a decisive factor against battery-powered buses. Hydrogen could be an environmentally friendly alternative to diesel engines and battery-powered buses. Currently, the SWU uses around 53 buses and 22 trams for transporting 40.8 Mio. passengers on a total transported distance of approximately 5.2 Mio. km (SWU, 2020) .

Besides the public transportation sector, the SWU Energie GmbH itself as a potential consumer of the hydrogen might be interesting. With the district heating grid operation in Neu-Ulm, the heat demand itself is mostly coming from natural gas. In the long run, it is possible to transform the CHP plants to a fuel cell plant providing electricity and heat or using hydrogen fired CHP plant. Until then, the hydrogen could be injected into the gas grid and, on a balance sheet, be used in the CHP plant. The same could be possible for the gas power plant Leipheim. Unfortunately, covering the demand itself with a small electrolyser is impossible, nor might this be the best idea in general regarding other worse pollutants at the market.

Finally, the SWU could convert the car fleet in general into a hydrogen-fired fleet. Under those circumstances, all horizontally integrated parts of the company can benefit. Currently, around 24 trucks are in operation. Twenty-three of those are diesel-powered by ICE (internal combustion engine). One is a CNG (compressed natural gas) truck. Additionally, 91 light trucks with diesel-powered ICE and 5 CNG trucks. As regular passenger cars are 53 powered by diesel, 55 by natural gas, 11 by gasoline and 14 electrical vehicles (EV). Completing the vehicle inventory (excluding buses) with 169 diesel-powered, 61 CNG, 11 gasoline and 14 EVs. A total of 255 vehicles. The average age of the cars, outgoing from the end of 2020, is 8.88 years.

2.5 Technical investigation of the electrolysis - Hydrogen out of renewable electricity

The electrolysis is, besides the conventional methods, another possible process to produce hydrogen. Until now, three major processes are under development or in use:

Alkaline water electrolysis (40 - 90°C)

Polymer electrolyte membrane electrolysis (20 - 100 °C)

High-temperature electrolysis (700 - 1.000°C)

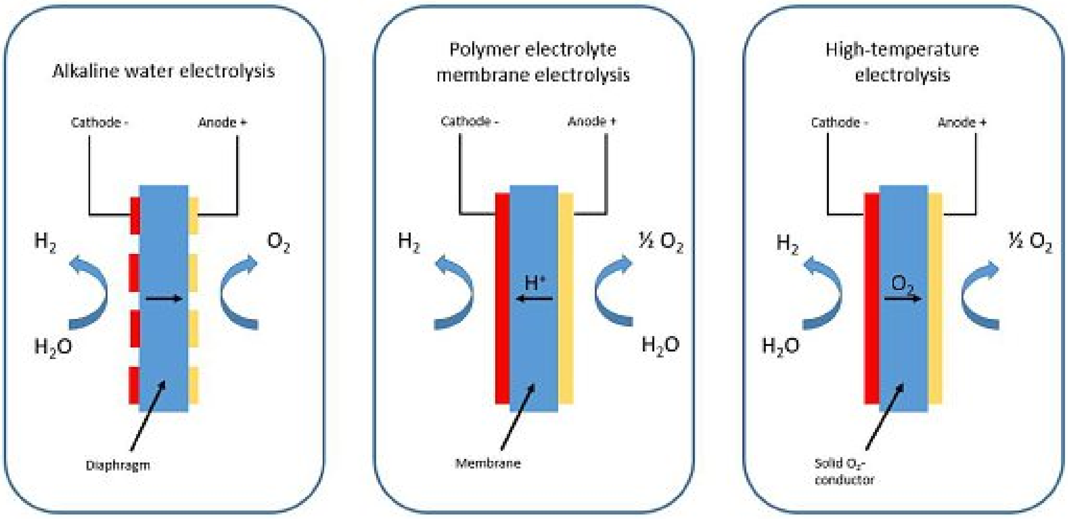

Figure 11 Function principle of the different electrolysis technology (Own representation based on (Töpfler et al., 2017) (p. 211)

All three technologies have some similarities. Besides the electricity, the process itself needs a cathode (-) and an anode (+). Understandably, another initial product is required: pure Water (H2O). In a chemical reaction, water is separated into hydrogen and oxygen. Nevertheless, each chemical reaction varies from process to process.

2.5.1 Alkaline water electrolysis

The alkaline water electrolysis (AEL) is the oldest commercialized process. The cathode and anode are in an alkaline solution, usually potassium hydroxide (KOH), with a concentration between 20 - 40% (Töpfler et al., 2017) (p. 215). The cathode (mostly nickel) and anode (mostly nickel, cobalt or iron) are separated with a diaphragm. The diaphragm is currently made out of a Zirconium dioxide (ZrO_2) – Polysulfone membrane and the only commercialized used membrane (Vogt et al., 2014). In the alkaline solution, the diaphragm allows the transportation of the hydroxide ions

(OH-) from the cathode to the anode. The following formulas can describe the chemical reaction.

Cathode: $2H_2O + 2e^- \rightarrow H_2 + 2OH^-$

Anode: $2OH^- \rightarrow \frac{1}{2}O_2 + H_2O + 2e^-$

Complete reaction: $H_2o \rightarrow H_2 + \frac{1}{2}O_2$

(4)

As seen in the formula above, hydrogen is produced at the cathode, whereas the anode produces oxygen. The process itself requires electricity, which provides the process energy to split the water into oxygen and hydrogen.

2.5.2 Polymer electrolyte membrane electrolysis

Technically, the polymer electrolyte membrane (PEM) electrolysis can be seen as the opposite of the AEL. PEM electrolysers have a cathode (-) and an anode (+), too, but in this case, instead of a diaphragm, a membrane. The diaphragm of the AEL allows the transportation of a hydroxide ion and electron from the cathode to the anode. In the PEM, the membrane only allows a transportation of a proton (H+) and an electron from the anode (+) to the cathode (-). Both the cathode and anode is directly applied onto the membrane. The following formulas can describe the chemical reaction.

Cathode: $2H^+ + 2e^- \rightarrow H_2$

Anode: $H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2e^-$

Complete reaction: $H_2o \rightarrow H_2 + \frac{1}{2}O_2$

(5)

Platinum is usually the cathode material; the anode can either be out of ruthenium, titanium or iridium. The current problem is the acidic environment in the cell itself. The researchers are currently dealing with the acidic environment's aggressiveness and the overvoltage of the anode resulting, together with the oxygen, in corrosion. Therefore oxidized (noble) metals such as ruthenium oxide and iridium oxide might be a solution compared to the pure, noble metals. Both the anode and cathode are coated onto the membrane. The long term reliability is a critical point in product development. Regarding the product progression, the development of the PEM electrolysis with around 25 years is relatively short compared to the AEL (Töpfler et al., 2017) (p.216-218). Due to the development stage, the amount of commercialized applications is relatively low.

2.5.3 High-temperature electrolysis

The high-temperature electrolyser (HTEL) is, regarding product progression, the youngest of those three technologies. As the name presumes, a high temperature is required. At a temperature of around 700 – 1.000 °C, the evaporation's enthalpy is significantly lowered, resulting in higher energy demand due to the temperature increase. A higher temperature level allows a particular share of the required process energy to be delivered by the heat's energy. On the other side, an HTEL can lower the electrical energy demand significantly (Töpfler et al., 2017) (p.218-220). A benefit is, with a higher temperature, catalysts are not required. The following formulas can describe the chemical reaction

Cathode: $O_2 \rightarrow \frac{1}{2}O_2 + 2e^-$

Anode: $2H_2O + 2e^- \rightarrow H_2 + O_2$

Complete reaction: $H_2o \rightarrow H_2 + \frac{1}{2}O_2$

(6)

Right now, the interest in HTEL is increasing. This interest can be lead to significant progress in the development stage itself over the last few years. Interesting is using the equipment itself as electrolysis and fuel cell (to generate electricity out of hydrogen). A combination might lower the costs and opens additional cases of application Nevertheless, the current state of the development process is in the fundamental research about the technology itself (Töpfler et al., 2017) (p.218-220).

The progression of the HTEL stacks is nowadays at the beginning and therefore done manually. Possible materials for the anode are usually Nickel (Ni) compounds. For the cathode lanthanum-strontium-manganate compounds are used. The interconnector separates the oxygen and hydrogen and prevents the oxyhydrogen reaction. The interconnector can be made out of nickel or iron compounds. (Smolinka et al., 2018).

2.5.4 Current and future development potential of all three electrolysis technologies

All three electrolysis technologies are at different stages of development. Each process produces hydrogen, but their application and chemical process vary a lot so that the potential case of the application might be individual. As displayed in table 4, strengths and weaknesses usually come hand in hand with individuality.

Table 4 Strength and weaknesses of the three major electrolysis technologies (Töpfler et al., 2017) (p.220) (Sterner, 2010)

	AEL	*PEM*	*HTEL*
pros	Advanced development	High electrical density	Heat can be uncoupled
	In-field experience	High potential efficiency	Efficiency above 100% regarding the thermos neutral cell voltage
	Catalyst not made out of noble metal	Easy system construction	
	Long term stability	Good part load operation	
	Relatively low investment	Quick system reaction time (grid stability might be possible)	
		Compact design allows high operation pressure	
cons	Low Electrical density therefore high system size	Corrosive environment requires high investment and expensive material	Questionable long term stability (mechanical)
	Not really suitable for part load	Still partly in development	Still in research and development
	Corrosive liquid electrolyte which requires processing		Requires temperature management
	Inconvenient gas cleaning		

The state of development and the number of in-field applications allow a prediction about these three technologies' future. The next step shall be a successful market ramp-up of all three. The problem is obvious; All three vary in their strength and weaknesses and therefore, their field of application differs. The literature- and market analysis published in 2018 done by the national organization hydrogen (NOW) allows different interpretations about all three technologies. A comparison will help for today's status quo and the future (the year 2030 the 1 MW class):

Table 5 Development stage of all three electrolysis technology today and in the future (2030, 1MW class) (Smolinka et al., 2018)

		AEL	*PEM*	*HTEL*
Electrical energy demand (kWh/Nm^3)	today	≈ 4.6 kWh/Nm^3	≈ 4.7 kWh/Nm^3	≈ 3.8 kWh/Nm^3
	future	≈ 4.5 kWh/Nm^3	≈ 4.7 kWh/Nm^3	≈ 3.6 kWh/Nm^3
Operating pressure (bar)	today	≈ 19 bar	≈ 32 bar	≈ 6 bar
	future	≈ 54 bar	≈ 52 bar	≈ 12 bar
Offset time from cold standby (min)	today	≈ 60 min	≈ 10 min	≈ 600 min
	future	≈ 60 min	≈ 5 min	≈ 180 min
Offset time from warm standby (min)	today	≈ 6 min	≈ 2 min	≈ 10 min
	future	≈ 1 min	≈ 0,5 min	≈ 5 min
Electricity density (A/cm^2)	Today	≈ 0.4 A/cm^2	≈ 1.8 A/cm^2	≈ 0.8 A/cm^2
	future	≈ 0.8 A/cm^2	≈ 2.4 A/cm^2	≈ 1.0 A/cm^2
Active cell area (cm^2)	today	≈ 20.000 cm^2	≈ 1500 cm^2	≈ 300 cm^2
	future	≈ 17.500 cm^2	≈ 2000 cm^2	≈ 500 cm^2
Operational lifetime of the stack (h)	today	≈ 55.000 h	≈ 40.000 h	≈ 20.000 h
	future	≈ 65.000 h	≈ 60.000 h	≈ 50.000 h
Operational lifetime of the whole system (a)	today	≈ 27 a	≈ 20 a	No data
	future	≈ 25 a	≈ 23 a	≈ 20 a
Minimal part load (%)	today	≈ 17%	≈ 5 %	≈ 20 %
	future	≈ 18 %	≈ 4 %	≈ 5 %
CAPEX (€/Nm^3/h)	today	≈ 4.000 €/Nm^3/h	≈ 7.000 €/Nm^3/h	≈ 9.000 €/Nm^3/h
	future	≈ 3.000 €/Nm^3/h	≈ 4.000 €/Nm^3/h	≈ 1.800 €/Nm^3/h
CAPEX (€/kW)	today	≈ 900 €/kW	≈ 1.500 €/kW	≈ 2.300 €/kW
	future	≈ 650 €/kW	≈ 750 €/kW	≈ 450 €/kW
OPEX (€/a per kW)	today	≈ 19 €/a per kW	≈ 13 €/a per kW	≈ 33 €/a per kW
	future	≈ 26 €/a per kW	≈ 11 €/a per kW	≈ 12 €/a per kW

The AEL and PEM have nearly the same electrical demand of around 4.6 kWh per produced Nm^3 (displayed in Table 5). Interesting is the gap between those two and the HTEL. The earlier mentioned lower energy demand due to the higher temperature level results in a significantly lower energy demand of 3.8 kWh/Nm^3 hydrogen. The operating pressure might be gripping later on if the operating pressure equals the hydrogen's output pressure. Under the perspective of future use of hydrogen, a higher pressure might come in handy. The ability to stabilize the grid itself was one vision of hydrogen in combination with electrolysis. Analysing the starting duration or offset time, short term grid stability with a cold electrolyser will probably not be possible. Alternatively, if the electrolysis might be warm, secondary reserve or the minute reserve might be possible but not recommended. Concerning the given data, the electrolysis should primarily be used to compensate the residual load (the difference between electricity demand and renewable electricity supply; undersupply and the surplus). Some of the, in Table 5 displayed, values, such as the operational expenditure (OPEX) and capital expenditure (CAPEX) will be needed in the later following profit and loss statement.

At a limited plant site, the energy density, as well as the active cell area, allow an interpretation of the needed space for an electrolyser. Usually, the electrical power of direct current is described by the multiplication of the voltage (U in volt) and the current (I in ampere).

$$P = U \times I \tag{7}$$

By setting the current at a particular value and increasing the voltage, the electrical power will increase. In theory, higher electrical power allows a higher hydrogen output. The only problem is the process of the technology itself limits the voltage. Overvoltage might be possible to a certain degree, but the additional energy will not be used for the electrolyzing process. An overvoltage operation results in more heat generation. Such a heat generation does not provide any benefit for the process and therefore is merely redundant. Each electrolysis technology has a limited electrical density, given in the possible current per cm² of active cell area. By increasing the power of the electrolysis, an increase of the active cell area is necessary. In the future, the electrical density might be increased. Therefore, higher electrical power of the electrolysis results in a higher active cell area, which requires more space at the plant site. The PEM electrolyser is said to have a higher electrical density compared to the AEL. Presumably, a PEM stack is smaller than an AEL stack if the electrical power stays the same.

As an operator of an electrolyser plant, the operational lifetime is one big decision driver. An Investment shall run as long as possible. Nowadays, the operational lifetime of each technology varies, mostly due to the stage of development. One aspect is the durability of the anode and cathode. Understandable, nowadays an AEL lasts 55.000 h or 6.27 years, whereas a PEM electrolyser lasts 40.000 h or 4.56 years, and an HTEL lasts 20.000 h or 2.28 years. In 2030, all three technologies are said to reach at least 50.000 h. Besides the stacks, the whole system should last as long as possible.

Due to the same reasons, the AEL lasts longer than a PEM electrolyser. Currently, there is no data for the HTEL. Again, all three might have the same durability of at least 20 years in 2030. Interesting would be if the stacks themselves stop working after the said amount of hours or increases electricity demand while lowering the output.

Under the perspective of grid stability and control energy, fast-acting electrolysis might come in handy. The offset time from warm standby allows drawing inferences about all three technologies. Summing up, the PEM electrolyser is a fast-reacting electrolysis technology, whereas the AEL and HTEL might prefer a constant operation basis. Another hint for the suitability in the grid stability and control energy might be the minimal part load. The minimal part load describes how low the electrolyser can scale the energy input and the hydrogen output until the system might not run anymore. Another time, the PEM electrolyser is leading this competition with a minimal part load of 5%. AEL and HTEL require a minimum load of 17% and 20%. Besides grid stability and control energy, the minimal part load plays a significant role if the electricity supplier, in this case, the HPP, is oriented at the Day-ahead electricity market. The ability to reduce the electrolysis's energy demand from one hour to the next due to the market prices allows higher flexibility and revenues at the electricity market. On the other side, a fast-acting electrolyser allows increasing the load to 100% if the electricity price drops.

Capital expenditure (CAPEX) is the initial required investment to build and install, in this case, an electrolysis plant. Due to the development stage, the required materials and the market integration, the CAPEX for each technology varies. Understandably the oldest technology, the AEL, currently has the lowest CAPEX of around 900 €/kW or 4.000 €/Nm³/h. As a result of the market research (Smolinka et al., 2018) the PEM electrolyser is said to require an investment of 1.500 €/kW or 7.000 €/Nm³/h followed by the HTEL with 2.300 €/kW or 9.000 €/Nm³/h. This might change significantly till 2030.

Besides the investment, the operational expenditure (OPEX) does play a significant role in a plant operation. The AEL had the lowest CAPEX, but the plant size and required alkaline medium cleaning the OPEX lay around 19 €/a per kW. Regarding Smolinka et al., (Smolinka et al., 2018) the cheapest of all three technologies should be the PEM electrolyser with 13 €/a per kW. The HTEL is due to the development stage currently quite expensive, with 33 €/a per kW. The OPEX of the HTEL is therefore fraught with uncertainties.

While investment and operation is one side of the medal, the system's efficiency is the other. The CAPEX and OPEX are mostly given in €/kW installed capacity. As long as the capacity is the input side and the product hydrogen itself the output site, the amount of produced hydrogen is essential. Helpful might be the efficiency. Regarding Table 1, the lower heating value of hydrogen is 3.00 kWh/kg. In an ideal system, all the inserted energy would be the resulting energy density. Such a case would equal an efficiency η of 1. Unfortunately, some energy is transformed into heat and, therefore, not part of the useful energy in hydrogen. In the first step, this heat is considered heat as losses. Nevertheless, the market survey of NOW-GmbH (Smolinka et al., 2018) provided the electrical energy demand, displayed in Table 3.

By dividing the lower heating value through the electrical energy demand, the system efficiency can be calculated:

AEL: 4.6 kWh/Nm³	results in η = 65 %
PEM: 4.7 kWh/Nm³	results in η = 64 %
HTEL: 3.8 kWh/Nm³	results in η = 79 %

The same can be done with the higher heating value of 3.54 kWh/kg:

AEL: 4.6 kWh/Nm³	results in η = 77 %
PEM: 4.7 kWh/Nm³	results in η = 75 %
HTEL: 3.8 kWh/Nm³	results in η = 93 %

The efficiency can vary from system size to age and as well from manufacturer to manufacturer. Nevertheless, efficiency does tell something about the technology itself. It seems that AEL and PEM, which are already commercialized, are regarding efficiency quite close. Whether to use an AEL or PEM electrolyser will probably be decided by the Investment, the operation costs, plant site circumstances and the plant operation.

2.6 Choosing a proper electrolyser for a hydro power plant

While being honest, only two out of the mentioned three technologies are currently more or less commercialized available. The third technology, the HTEL, is still in development and will not be considered as suitable technology for the HPP. A comparison between the AEL and the PEM electrolyser will be made. The first step will be a look at the energy supplier.

The HPP Böfinger Halde is, as mentioned before, a run-of-the-river power plant, and as the river Danube is not constant in its discharge, the electrical output of the HPP varies. As long as it varies, one could consider the electrical work as partly fluctuating. The reason to define such a power plant as a somewhat fluctuating technology is the changing discharge. As seen in Figure 7, the (usable) electricity supply of the hydropower plant is in a range between 9.1 MW and around 2 MW at its minimum. Yes, the production itself can be changed but only in a negative direction, like wind or PV. Connecting reductions or shutdowns with monetary losses, plant operators try to avoid those. Most hydropower plants are operated to keep the water level of the headwater at a constant level. Such regulations are part of the permission. The permission is strict, and violations result in shutting down the plant. The permission implies that an electricity demand or an electricity price oriented operation, where the plant shortly increases the load while lowering the headwater level, is impossible. The only difference between a hydropower plant and Wind or PV is that a river always has a discharge that can be energetically be used. There is always an electrical output of a hydropower plant. An HPP might be more baseload suitable but still is only generates a part load (23% of its capacity for the HPP Böfinger Halde) during the dry period. As far as the operator cannot increase the generation, an HPP cannot be seen as a biogas plant or other conventional power plants without grossly violating the permission.

Now there are several ways to operate an electrolyser in combination with a hydropower plant:

Option 1: One could be to maximize the hydrogen generation. Such an operation would imply using all the generated electricity, ignoring any price signal at the electricity market and built an 9.1 MW strong electrolyser. Under those parameters, the operator could maximize the hydrogen output, but the full load hours of the electrolyser would be relatively low. The benefit for the market stability would be vanquished.

Option 2: The second possibility is to choose a relatively small electrolyser at a range of 0.5 to 1.0 MW. Such an electrolyser could operate at base load and would probably have the highest possible hours/yr. But again, the market itself would not benefit from such an operation.

Option 3: The third possibility is a mixture of both previous options. If the plant would be in the range of 1.0 to maybe 2.5 MW, the plant could one the one side provide a significant baseload (due to the minimum part load) and as well be oriented at the market price. At a low electricity price, the operator could run the electrolyser at full load. With high prices, the electrolyser could run at minimal part load.

Option 4: The last option is an electrolyser, which is only oriented at the market itself. Meaning, the electrolyser would round anytime; the electricity price is below a certain level. With a low price level, the supply is probably higher than the demand. Under those circumstances, the electrolyser would be useful for the grid. While taking a look at Figure 8, which shows the EPEX Spot day ahead prices in 2019, with a price limitation at 0.0 ct/kWh, the full load hours right now would be relatively low. The capacity of the electrolyser itself would be somewhat irrelevant.

All four options require a different operation as well as a reaction time of the electrolyser. Considering the electrolyser's capacity, the available space at the HPP plant site might limit the general area for an electrolyser. With the same installed capacity, AEL requires more space than the PEM. A shutdown of the electrolyser might be necessary for some options, whereas some options do not even require load changes.

The purpose of an electrolyser for the SWU Energie GmbH at the HPP Böfinger Halde is to, on the one side, generate much hydrogen and increase the revenues in such a way, the operator can avoid low and negative prices. Both points can barely find to another. A baseload operation would require ignoring the electricity prices but would generate the highest amount of hydrogen. A price-oriented production would probably result in low hours/yr and a low hydrogen production but support the market as much as possible. As a benefit-oriented company, the solution might lay in between, which means a nearly baseload running electrolyser that shuts down or reduces the load under specific high price periods.

The possibility to benefit from the reserve market is still open. It is possible to be system beneficial positively (which would mean shutting down the electrolysis, relieving the gird) or negative way (starting the electrolysis, consuming electricity).

A small electrolysis plant's impact under the perspective to be beneficial or useful for the grid is relatively low. As seen in Figure 2, the surplus generation between 10th February and 12th February was in a range of 5 to 10 GW. With increasing numbers of installations, this effect is said to increase. The impact of a single electrolysis plant in south Germany would not at all compensate for this surplus generation. Nevertheless, such smaller projects might help the ramp-up of electrolysis technologies and hydrogen in general. A considerable amount of smaller electrolysers acting beneficially most possibly affects the grid stability.

The current hours with negative prices at the market will probably not allow running the plant strictly reacting to said prices. The reason is, the price signals were quite rare with 211 h in 2019 (BNetzA, 2020), and the full load hours eventually would be relatively low. It is possible to maximize the hydrogen output, but an 8 to 9 MW electrolyser would have relatively low hours/yr. The guarantee economic feasibility, the electrolyser should continuously run on a high load. It is possible to shortly decrease the load while the price increases and even go into overcapacity (if likely) while the price drops significantly.

With the further intention to use an electrolyser for wind power and PV (landside), the following analysis will include general instalments of wind power and PV. Those are widespread assumptions that might fit most of the renewable instalments. Nevertheless, the given criteria and its results for the HPP might only specifically apply to the HPP Böfinger Halde. In general, the following statements for the HPP Böfinger Halde shall be kept in mind: Reaching somewhat around 8.000 to 7.000 hours/yr, the maximum capacity for the electrolyser can only be around 2 MW.

For choosing the proper electrolysis technology, the given parameters have to be analysed. The rating will go from "+" which means suitable, to "0" which means more or less neutral, to "–" which means not applicable. Due to the current stage of the progression, the HTEL was included in this analysis but will not be considered for the HPP Böfinger Halde.

Table 6 Comparison of AEL, PEM and HTEL for the renewable technologies hydropower, wind power and photovoltaic considering the current stage of development of the electrolysers (own evaluation)

Criteria	*Renewable Technology*	*Comment*	*AEL*	*PEM*	*HTEL*
Electrolyser size	Hydro Power	Current workflows shall not be disturbed. The available space is limited	0	+	+
	Wind Power	Wind parks are usually wide spreading. Space should be available for onshore parks. Offshore probably requires a platform and therefore the electrolyser should be compact	0	+	+
	Photovoltaic	Less space for the PV results directly in less installed capacity	-	0	+
Reaction time / load changes	Hydro Power	The discharge is usually quite constant and does not change fast.	+	+	+
	Wind Power	Wind is not constant and can change	-	+	0
	Photovoltaic	The electrical load of a PV can change quite fast due to clouds	-	+	0
Minimal part load	Hydro Power	Depends on the size of the electrolyser. Usually not required unless the plant is electricity price oriented	0	+	0
	Wind Power	Wind can stand still or be quite low	-	+	-
	Photovoltaic	Especially in the wintertime or during sunset and sunrise the load is quite low.	-	+	-

Offset time from cold/warm standby	Hydro Power	Not important unless the plant is oriented in the reserve market	0	+	-
	Wind Power	Might be of interest but still not as much as for the PV	0	+	-
	Photovoltaic	Under normal circumstances daily required	0	+	-
CAPEX vs OPEX	Hydro Power	Until the market ramp-up usually only the CAPEX are subsidies, OPEX Should be low. Later on both should be low	+	+	-
	Wind Power	Until the market ramp-up usually only the CAPEX are subsidies, OPEX Should be low. Later on both should be low	+	+	-
	Photovoltaic	Until the market ramp-up usually only the CAPEX are subsidies, OPEX Should be low. Later on both should be low	+	+	-
Maintenance / Technical effort	Hydro Power	Ideally, the maintenance should be done In-house	0	+	-
	Wind Power	If personal available: Ideally, the maintenance should be done In-house	0	+	-
	Photovoltaic	If personal available: Ideally, the maintenance should be done In-house	0	+	-
Lifetime of the system and the stacks	Hydro Power	High Importance due to long operation time of a plant	+	0	-
	Wind Power	Either during EEG subsidy timeframe or after the EEG, Mostly 20-25 years	+	0	-
	Photovoltaic	Either during EEG subsidy timeframe or after the EEG, Mostly 20-25 years	+	0	-
Environmental impact	Hydro Power	Being close to the ecosystem of a river, water contaminating	0	+	+

		materials should be avoided			
	Wind Power	Offshore, same as hydro power, onshore probably negligible	0	+	+
	Photovoltaic	probably negligible	0	0	0

Eight restrictions were of major importance. First of all, the electrolyser sizes. Dependent on the available space, a more compact electrolyser is preferable to a wide-spreading instalment. Next is the reaction time, the dealing with load changes and the minimal part load. For PV and wind as fluctuating energy systems, this restriction is probably of most significant importance. Besides these, the electrolyser should start from the cold quite quickly, allowing optimized use of green electricity for the green hydrogen production. The HTEL for example, lacks heavily in terms of starting from cold. In combination with a PV, the day could be halfway through until the HTEL is ready for operation. As the target is to produce cheap hydrogen, OPEX and CAPEX should be as low as possible. Coming hand in hand with the OPEX, the maintenance and technical effort displays the possibility to operate the electrolyser without deeply specialized personnel. Ideally, the electrolyser should last as long as possible, allowing repaying the original investment. Finally yet importantly, the environmental impact of an instalment can be, under certain circumstances be of importance.

Going through the evaluation/grading of the three electrolysis technologies for the three energy carriers, different results are visible. In the case of the HPP, the AEL received three positive and 5 neutral grades. The PEM receive seven positive and one neutral grade. The HTEL received three positive grades, one neutral and four negative grades. Under those restrictions, the probably most suitable electrolysis technology for hydropower might be the PEM electrolyser. A PEM electrolyser allows fast load changes, can reduce the load quite correctly, and seems relatively easy and cost-efficient to operate. Another positive aspect is the relatively compact way of construction. It seems the PEM electrolyser even fits for probably most other applications in the wind sector or PV sector. For the wind power plant, the AEL received two positive, four neutral and two negative grades. The PEM received 7 positive, one neutral grad. The HTEL was the worst one with two positive, one neutral and five negative grades. Nearly the same results can be seen for a PV plant. The AEL received two positive, three neutral and three negative grades. The PEM received five positive and three neutral grades. The HTEL, again the worst technology, received one plus, two neutral and five negative grades.

Getting rid of the project-specific blinkers, a broader look at the energy economy's circumstances might help in some cases. Every renewable electricity technology and plant site varies. The national hydrogen strategy thought about the suitability of wind parks in combination with electrolysers directly at the shore. It is quite possible; PEM electrolyser might be the future technology to use surplus electricity in mixture with renewables directly at the plant site. Higher demand in PEM electrolysers results in a scaling effect and allows a market ramp-up to lower the costs precisely as the strategy suggested.

As the PEM electrolyser is probably the most fitting technology, a more in-depth technical investigation about all components might be necessary.

2.7 Technical investigation of the polymer electrolyte membrane electrolyser

The main components are the electrolyser-stacks mentioned in chapter 2, but other parts are compulsory for a proper installation:

Rectifier: As the electricity is coming at altering current and a stack requires direct current, a rectifier is necessary.

Electrolyser stacks: The main component of an electrolyser are the stacks. A proton-transmissible membrane allows the production of hydrogen and oxygen out of water.

Water tank/connection: As mentioned before, the whole process requires water. The purity of the water is of paramount importance. Foreign matter of minerals and other organic substances should not be lead into the stack. As the reaction results in two gasses at a temperature around 60°-80°, the foreign matter will stay in the stack and result in congestion of the stacks. A sophisticated cleaning process is required. Some installations allow the usage of tap water. In such cases, a water processing unit is included.

Oxygen separation: The produced oxygen requires a final treatment until further use or release into the atmosphere. By adding water at the anode side and the membrane only allows a proton's transportation, the oxygen is produced at the anode side. Some of the added water transports the oxygen as well as the generated heat. The oxygen and warm water are circulated into the oxygen separation and a heat uncoupling unit. The now cooled water can later be reinjected into the stack. Now a further use of the oxygen is possible.

Oxygen blower: if the oxygen is not used further, the oxygen is blown into the atmosphere, similar to an exhaust pipe.

Heat uncoupling unit: As said, one of the final products is heat. Heat itself can either be blown into the atmosphere or, be used if there is a demand. Some installations allow uncoupling the heat, allowing a further use in a district heating grid or industrial process. The only negative aspect is the temperature itself. As the process temperature is relatively low, the uncoupled heat may lay around 65°.

Cooling unit: If the heat is not used further, a cooling unit is required, releasing the heat into the atmosphere.

Hydrogen drying unit: As air does not conduct electricity well, some water is on the cathode side. With no hydrogen production, the gas mixture contains some water vapour. Due to purity regulations, the non-hydrogen share has to be as close as possible, near 0%. With the target to use hydrogen for fuel cell vehicles, the non-hydrogen content must be lower than five ppm (parts per million) (ISO, 2012). This implies a hydrogen drying unit. The water vapour is directly connected to the temperature (and pressure). The higher the temperature, the higher the water vapour in the hydrogen gas mix after the cathode. By increasing the pressure, the PEM electrolyser can reduce the water vapour content. One of the first steps in the drying unit is to lower the temperature of the gas mix. The water vapour partly condensates and can be extracted. Usually, the reduced temperature is in the ambient temperature range. This does not require additional energy input and can be done using the ambient air as a cooling substance. The second step is to let the gas flow through the silica gel. The silica gel absorbs and stores the water. (Kast, 1988). If the saturation of the silica gel is reached, the silica gel is replaced or rehashed. In some cases, the rehash is automated.

Gas Compression: The final step in the hydrogen treatment is the gas compression for further hydrogen use. Depending on the further use, the pressure itself varies. Additional storage containments are required if the gas is not lead into a hydrogen pipeline or gas grid. The compression is mostly done mechanically by piston compression.

Control unit: Finally, everything needs to be controlled and monitored. A control cabinet includes all necessary components and securely shuts down the plant automatically in an incident.

Hydrogen blower: In the event of an incident, the hydrogen inside the plant itself is, together with nitrogen, released into the atmosphere.

Plant containment: All of those installations should be in one containment or building. In the 1MW class range, 40 feet shipment containers usually fit all the required components.

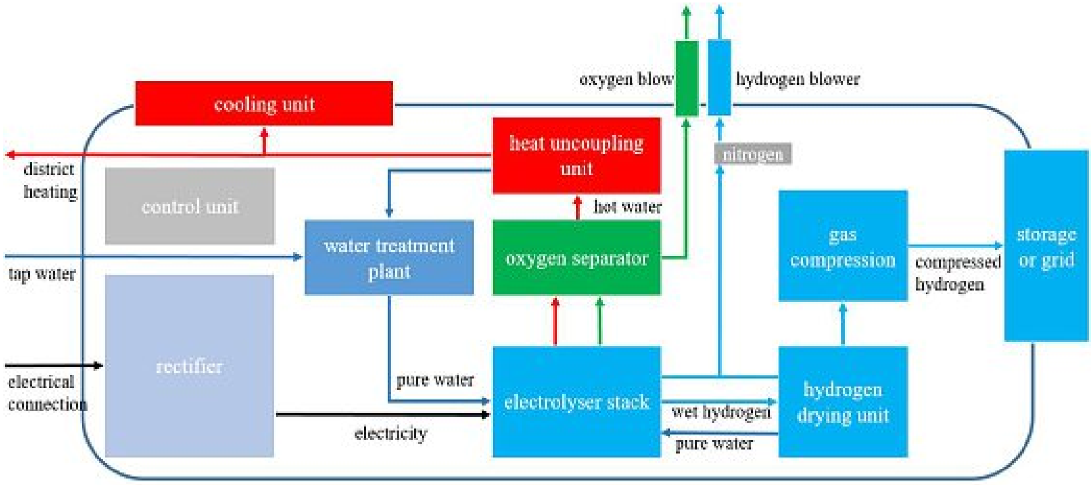

Figure 12 Schematic depiction of a PEM electrolyser (own representation based on (NEL-Hydrogen, 2020)

As seen in Figure 12, the PEM electrolyser requires only a few inputs such as electricity (black) and water (blue) and delivers hydrogen (light blue), heat (red) and oxygen (green). The altering current is converted into direct current in the rectifier (blue-grey and later led to the electrolyser (light blue) stacks. Combined with the tap water, which is cleaned in the water treatment plant (blue) and led into the stacks, the process can happen.

The wet hydrogen leaves the stacks and is dried and compressed before it is finally stored. A particular share of water is gained in the drying process and can be re-used in the stacks. The side products, heat and oxygen, are separated in the oxygen separator(green). The remaining heat, transported in water, goes through the heat uncoupling unit (red) and is either cooled down with a cooling unit or used in a district heating grid.

The control unit and the nitrogen (both grey) are required security instalments.

As the hydrogen itself is the main product and the wanted product, heat and oxygen are useful by-products. The temperature of the heat itself is relatively low with 65°C. If available, it is thinkable to use the heat for preheating of a district heating backflow or in a specialized industrial process. As for the oxygen, further use might be a bit more complicated. The problem with the oxygen could be the water content in the gas. Some industrial processes or for medical purposes sure use oxygen but usually in a pure form.

2.8 Further use of the hydrogen, heat and oxygen

2.8.1 Hydrogen

The hydrogen itself, as the main product, can be used in various ways. While considering geographical and infrastructural occurrences, several possibilities are thinkable.

A hydrogen fuelling station directly at the plant site (pipeline)

Delivering several hydrogen fuelling stations in the area via truck

Injecting the hydrogen into the gas grid

Without further use

With further use on a balance sheet:

For a (natural) gas fuelling station for the gas car fleet of the SWU

For a natural gas-powered CHP plant

Fuelling the bus fleet of the public transportation sector or the SWU. Transporting the fuel via truck to the bus depot.

Fuelling bin lorries or road sweepers in Ulm or Neu-Ulm (BluePower concept)

Delivering a fertilizer company via truck in the industrial area “Donautal”. Examining the demand is necessary.

Delivering other companies via truck in the industrial area “Donautal”. Examining the demand is necessary.

The initial idea to produce hydrogen out of electricity is probably in the interest of the economic benefit. It means, if possible, using cheap electricity-producing expensive emission neutral hydrogen. Besides financial aspects, the further use of hydrogen can be seen under the aspect of environmental benefit. For example, if the bus fleet of the public transportation sector shifts from diesel ICE to the hydrogen-powered electrical engine, the benefit might be higher than a simple injection into the gas grid. The natural gas with further use in the heating sector undoubtedly not an environmental possibility, but is still more friendly than diesel ICEs.

The investigation about an HPP's suitability with an electrolyser does not end after the hydrogen production. It is said that nowadays, many projects fail due to the fact of mission local demand for hydrogen. If the implementation of a PEM electrolyser will be done in the future, the hydrogen demand will be in dry towels.

2.8.2 Heat and Oxygen

Besides blowing the heat into the air, one might use the heat in various ways. Heat itself cannot be transported on a balance sheet and therefore has to be used directly. Ideally, the distance to the consumer has to be relatively small due to the required separate infrastructure. Possible ideas could be:

- District heating for the industrial company "Dana" on the other side of the Danube. Maybe process heat is required as well.
- Connection to the district heating grid of the district "Pfuhl" of the city Neu-Ulm.
- Transporting the heat to the gas decompression station "Steinhäule" on the other side of the Danube. Decompression of gas results in a temperature drops and therefore requires heat.
- District heating for the sewage treatment plant on the other side of the Danube. Eventually, heat is required.

The possibilities for heat usage are limited but still exist. The heat demand itself has to be evaluated and the usability of low temperature as well. Depending on the district heating grid, the backflow is, on a temperature level, relatively high. Especially if the heat consumers are connected in series, securing a decent temperature for the last consumer in the series.

While proper heat usage itself is already problematic at the HPP Böfinger Halde , the use of the probably not so pure oxygen is might be complicated as well. Depending on the purity of the oxygen, several possibilities are conceivable:

Use of the oxygen in industrial processes in the industrial area "Donautal". There might be some consumers. Those have to be evaluated. The transportation itself will then be done via trucks. A cleaning and compression of the oxygen is required.

A sewage treatment plant's efficiency can be increased if the micro bacteria receives additional pure oxygen. The oxygen itself is blown into the clarifying basin (or aeration tank), increasing the basin's efficiency significantly. The next sewage treatment plant is on the other side of the Danube. The transportation can be done via truck or pipeline. As the amount of oxygen is said to be relatively high and the distance quite short, a pipeline seems to be the most suitable variant.

Using pure oxygen for the combustion process in various exothermic reactions, an improvement of the efficiency is possible. At the wastewater treatment plant, sewage sludge is burned. Instead of using the normal air, which contains 78% nitrogen, the sewage plant can improve the burning process efficiency and environmental friendliness by using pure oxygen. As a considerable share of the air is not used in the reaction, as only oxygen is supposed to react, leaving the reaction through the exhaust pipes, heat is transported by the exhausts and mostly lost.

3 Method of approach

After evaluating the usable electricity of the HPP Böfinger Halde, the operation method and the capacity of the electrolyser, the actual electricity consumption of the electrolyser is the required key information. An hourly resolution is usually enough.

The first important statement is the calculation of the electricity used by the electrolyser and the resulting full load hours of the electrolyser regardless of the later plant operation.

The usable electricity of the hydropower plant Böfinger Halde in an hourly resolution, provided by the SWU Energie GmbH, is set in relation to the hourly SPOT Market price (also provided by the SWU Energie GmbH). A specific price limit set at a maximum electricity price value where the electrolyser reduces its power consumption to a load of 10 % results in less electricity consumption. By using this method for every hour in a year, a load profile for the electrolyser can be calculated. Summing up the consumption of the electrolyser of a whole year results in the annual electricity consumption ($W_{Electrolyser}$ in kWh). Dividing it through the installed capacity ($P_{Electrolyser}$ in kW) of the electrolyser, the full load hours (FLH in h) are given.

$$FLH\ (h) = \frac{W_{electrolyser}\ (kWh)}{P_{electrolyser}\ (kW)} \tag{8}$$

If the hourly costs for electricity is necessary (CE_{hourly} in ct), the hourly electricity consumption (EC_{hourly} in kWh) is multiplied with the hourly SPOT market price (MP_{hourly} in ct/kWh). By dividing the CE_{hourly} (which is in ct) through 100, the result is displayed in €. The sum of each CE_{hourly} over a year is the annual costs for the electricity demand (CE_{annual} in ct). By dividing said annual costs for electricity (CE_{annual}) through the annual electricity consumption (EC_{annual} in kwh), the average (annual) electricity price ($EP_{average}$ in ct/kWh) is given.

$$CE_{hourly}\ (ct) = EC_{hourly}(kWh)\ x\ MP_{hourly}\left(\frac{ct}{kWh}\right) \tag{9}$$

$$\sum CE_{hourly}\ (ct) = CE_{annual}\ (ct) \tag{10}$$

$$\sum EC_{hourly}\ (kWh) = EC_{annual}\ (kWh) \tag{11}$$

$$EP_{average}\ \left(\frac{ct}{kWh}\right) = \frac{CE_{annual}\ (ct)}{EC_{annual}\ (kWh} \tag{12}$$

Especially with the full load hours and the average electricity price, a comparison of different instalments is rather simple. By adjusting the plant size and the plant operation with the maximum electricity price the optimal instalment can be found.

The electricity consumption of the electrolyser allows conclusions about the hydrogen production. Hydrogen contains a specific amount of energy (C_{H2}). Nevertheless, some energy is converted into heat during the production process with electricity. The efficiency of an electrolyser ($\eta_{electrolyser}$) is the relationship between the wanted energy content, in this case the energy content of hydrogen (C_{H2} in kWh/kg) and the wanted and unwanted products, this case losses ($\Sigma\ C_{losses}$ in kWh/kg). Dependent on the load of the electrolyser, the efficiency varies due to different heat losses. Therefore, in the second step, an efficiency curve will be used to evaluate the hydrogen production, dependent on the load of the electrolyser itself.

$$\eta_{electrolyser} = \frac{C_{H_2}\ (\frac{kWh}{kg})}{C_{H_2}\left(\frac{kWh}{kg}\right) + \sum C_{losses}\ (\frac{kWh}{kg})} \tag{13}$$

By doing this again on an hourly basis we used before, the result should reflect an actual operation. Finally, the annual hydrogen production (P_{H2} in kg) is the result of the annual electricity consumption ($W_{electrolyser}$ in kWh) and the energy content of the wanted and unwanted products:

$$P_{H_2}(kg) = \frac{W_{electrolyser}\ (kWh)}{C_{H_2}\left(\frac{kWh}{kg}\right) + \sum C_{losses}\ (\frac{kWh}{kg})} \tag{14}$$

In the first and second step, the following results were gained or calculated:

Installed capacity of the electrolyser

Full load hours dependent on the load profile of the electrolyser

Electricity demand of the electrolyser dependent on the load profile

Efficiency of the electrolyser dependent on the load profile

Hydrogen production of the instalment dependent on the load profile

Those results are key information of the revenues and costs during the profit and loss calculation and therefore necessary. The produced hydrogen itself needs a defined sales price.

Information about investment costs as well as the operation and maintenance costs are the other part of the profit and loss calculation. The information gained in the first step completes the required information for the profit and loss calculation. The profit and loss calculation is done with the capital value method. This calculation is based on an interest rate (i), in this case on 3,34 %, which more or less tells you the loss of value of an investment and its revenues over a defined amount of years (n) with several time intervals (t). The main question is, is it better to invest the money into a project or is it better to us it as a bank deposit. As long as the rate of return is higher than the interest rate, the project is profitable.

The capital value (CV) itself is calculated with the following formula:

$$CV = -I + \sum_{t=1}^{n} \frac{R_t - E_t}{(1+i)^t} + \frac{RV_n}{(1+i)^t} \tag{15}$$

The Initial investment (I) is aggregated with the sum of the revenues (R) and the expenditures (E) per time interval and the residual value (RV) at the end of the duration time of the investment (n). The residual value can be negative or positive dependent on the case. A negative residual value means, the instalment requires money the be unbuilt. If the residual value is positive, the instalment can be sold for money.

The cash flow C itself is a result of the revenues minus the expenditures and can therefore is stated as the following.

$$C_t = R_t - E_t \tag{16}$$

It is to be expected, several values, such as the average electricity price and the sales price of hydrogen will change over time. Therefore, additional adjustments will be made to match further trends. A conservative point of view shall underline those trends. At the end. The project shall receive a capital value. A positive capital value defines the project profitability and therefore is a core point of the whole calculation. If the capital value is negative, the project itself is not profitable.

Concerning ecological feasibility, the green hydrogen will be compared to various field of applications. First of all, the emissions of green hydrogen is compared to grey hydrogen. In the second step, green hydrogen is compared the hydrogen with the average electricity mix of Germany. Dealing with the production side is one side of the coin. As hydrogen produces no GHG emissions while burning, the a few field of the demand side will be analysed and compared to conventional energy carriers. In both ecological investigations, the specific amount of produced hydrogen of the electrolyser will be taken into account, to show, how one electrolyser can reduces the emissions.

In the production process of hydrogen, each process requires independent of an electrolyser or the steam reformation, an energy carrier. Said energy carrier is responsible for emissions. Those emissions (EM_{source}) are availed in the form of gram CO_2 Equivalent per consumer Kilowatt-hour. By multiplying these emissions with the energy content of the wanted and unwanted products per kilogram hydrogen, the specific emissions per produced kilogram of hydrogen ($EM_{hydrogen}$) are displayed:

$$EM_{Hydrogen}\left(\frac{gCO_2}{kg\ H2}\right) = EM_{Source} \times (C_{H_2}\left(\frac{kWh}{kg}\right) + \sum C_{losses}\left(\frac{kWh}{kg}\right)) \tag{17}$$

By dividing the $EM_{hydrogen}$ through 1.000, the result is displayed in kg. If the annual CO_2 Equivalent emissions of a specific installation (EM_{annual}) is necessary, the annual hydrogen production (P_{H2}) is multiplied with the specific emission per produced kilogram hydrogen ($EM_{hydrogen}$):

$$EM_{annual}\,(kgCO_2) == P_{H_2}(kg) \times EM_{Hydrogen}\left(\frac{kgCO_2}{kg\ H2}\right) \tag{18}$$

A comparison between each production process in terms of emissions is now possible. More emissions can be saved asides the production process. The most savings can be achieved in the transportation sector. By using hydrogen on the consumption side, for example instead of fuel powered internal combustion engines in fuel cells for cars, coaches or trucks, the effect can be seen. Each vehicle has a specific fuel consumption ($FC_{vehicle}$), usually in litre per 100 km. This consumption can be converted into kg per 100 km. By knowing the specific CO_2 emissions per kg of an energy carrier (EM_{fuel}), the emissions of a vehicle can be calculated:

$$EM_{vehicle}\left(\frac{kgCO_2}{100\ km}\right) = FC_{vehicle}\left(\frac{kg_{fuel}}{100\ km}\right) \times EM_{Fuel}\ (\frac{kgCO_2}{kg_{fuel}}) \tag{19}$$

A comparison with the specific CO_2 emissions of a vehicle type is now possible. Especially the difference (ΔEM) between fuel cell vehicles internal combustion vehicles are essential and shows the emissions savings on the consumption side.

$$\Delta\, EM = EM_{vehicle\ conventional}\left(\frac{kgCO_2}{100\ km}\right) - EM_{vehicle\ fuel\ cell}\left(\frac{kgCO_2}{100\ km}\right) \tag{20}$$

Outgoing from the difference (ΔEM) between the emissions of the internal combustion engine and the hydrogen powered fuel cell, the actual emissions saving of an electrolyser (EEM_{H2}) on the consumption side can be calculated by using the annual hydrogen production (P_{H2} in kg)

$$EEM_{H2} = \Delta\, EM \times P_{H_2}(kg) \tag{21}$$

4 Merging hydropower and the electrolysis

4.1 Combining a hydropower plant with an electrolyser

With the PEM electrolyser as the most suitable electrolyser technology for a hydropower plant, an electrolyser's actual dimension might be necessary. As earlier mentioned, the dimensioning can be done quite differently. It is important to remember; to use only the available electricity and no expensive electricity from the grid. The target is not to use the self-consumption and the EEG part because the generated financial value is far higher than the SPOT market's revenues. Again, the calculation will use the electrical generation, displayed in chapter 2.3.3 of 2015 in further analysis. The electrical generation in 2015 nearly equals the average generation in the last 30+ years. With 41.7 GWh, the useable electricity share for a potential electrolyser is still relatively high. Already included seasonal characteristics shall therefore not distort the results.

While the generation changes over the year, the, for a electrolyser, usable or available electricity market value is 3.77 ct/kWh, insignificantly higher than the average SPOT electricity market price of 3.767 ct/kWh. The HPP seems not very beneficial for the electricity market.

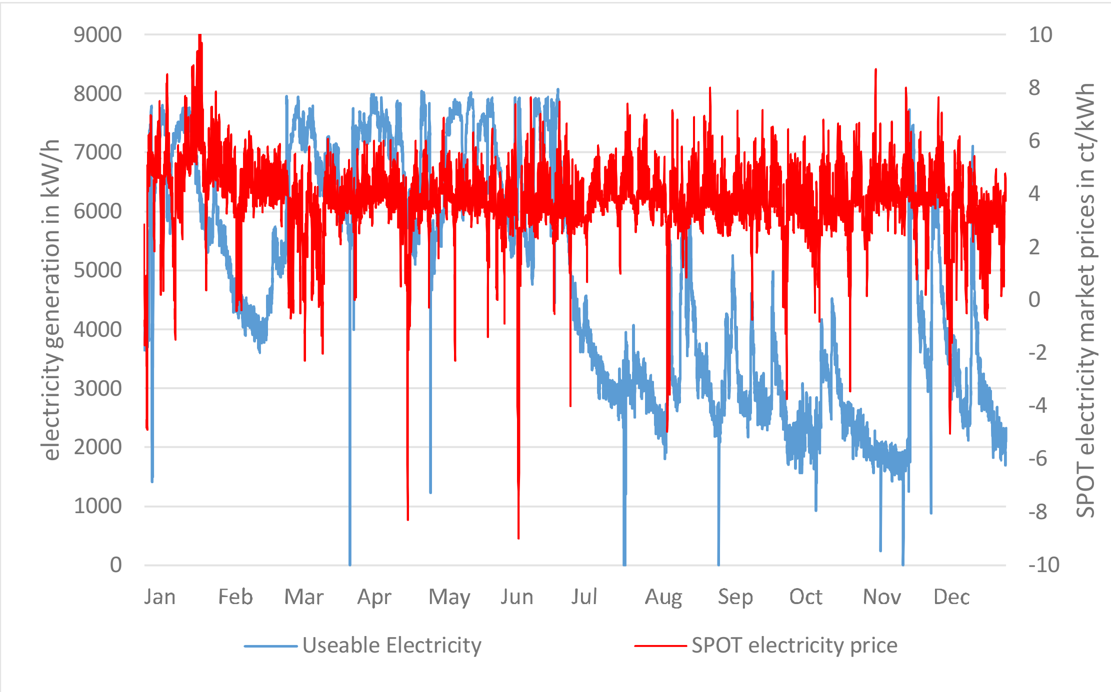

Figure 13 Comparison of the usable electricity generation of the HPP Böfinger Halde (blue) and the SPOT electricity market prices(red) (own representation)

4.1.1 The proper dimension of a polymer electrolyte membrane in combination with the hydropower plant Böfinger Halde

As we did not finalize the electrolyser's dimension, a look at the different earlier mentioned options, already mentioned in chapter 3.3, of running the PEM electrolyser might help to choose a proper electrolyser operation.

Option 1: maximized hydrogen production with a 9.1 MW electrolyser.

Option 2: 0.5 to 1 MW base-load operated electrolyser

Option 3: Mixture of option one and two. A 1 to 2 MW strong electrolyser mostly base-load operated but with reduced electricity demand during high prices.

Option 4: With the target to be useful for the grid, the electrolyser runs only below a market price of 0.0 ct/kWh

From an economic perspective and the idea to enable electrolyser the market ramp-up, as already discussed in chapter 3.3, an ideal way to operate an electrolyser in combination with an HPP would be option two or option three. The dominating conventional hydrogen production is relatively cheap. The price of conventional hydrogen out of natural gas, compared to electricity, is relatively low. The financial benefit for green hydrogen might increase by lowering production during high prices, risking a few hours/yr. Besides the economic perspective, high prices can be connected to more significant conventional electricity production. They are obviously resulting in higher emissions. In general, Germany should avoid emissions, and if not from a financial perspective, then from an ecological perspective, the hydrogen's renewable electricity is far more vulnerable than the hydrogen. Option 3 seems to be the best compromise.

Now that the electrolyser's operation is precise, the scaling of the electrolyser should be evaluated. As the idea of option 3 was to operate the electrolyser partly as a base-load plant, the maximal capacity of the electrolyser can be in a range of 2 MW to 3 MW. Without going into the possible maximum, an electrolyser with a total of 1 MW, maybe 2 MW, would probably allow the earlier mentioned compact installation in a 40 feet container. The 2 MW solution already requires two 40 feet containers. In the beginning, a PEM electrolyser with around 1 MW might be enough. Helpful is a shout estimation about the produced hydrogen. At this stage, the demand for hydrogen itself is unknown. Nevertheless, there might be potential at the SWU.

The public transportation sector of the SWU has 55 buses, which annually drive approximately 50.000 km. As a diesel bus consumes (internal calculations) 52 l/100 km, the annual diesel demand equals 1.430.000 l/a. The energy density of hydrogen per kg is around three times higher than the energy density of diesel (52/3 = 17.33). Additionally, a fuel cell itself has a two times higher efficiency than an ICE (17.33/2 = ~9). Consumption of 9 kg/100 km seems to be a good estimation. If the distance and the number of buses stay the same, the hydrogen demand should be around 250 t annually.

With roughly 4.5 kWh/Nm³ H2 or 50 kWh/kg of electrical demand during production, The SWU would annually require around 12.38 GWh to produce all the hydrogen for its bus fleet. By dividing the electricity demand by 7.000 hours/yr, a required capacity of around 1.77 MW is necessary.

If the whole bus fleet of the SWU is supposed to be fed by an electrolyser at the HPP, a 1 MW electrolyser would not be enough. Luckily, the whole ICE fleet will not be converted to a fuel cell fleet from one day to another. It is possible to dimension the entire infrastructure (such as pipes, cables or storage units) for a 2 MW electrolyser but install the second MW after the demand increases.

4.1.2 Manufacturer of a containerized electrolyser for the hydropower plant Böfinger Halde

The amount of available electrolyser manufacturers with a production capacity in the range of 1 MW is relatively low. Although, the containerized installation seems to be a suitable solution for a (PEM) electrolyser. Such a containerized solution might be a pre-state of series production and therefore should nearly be sophisticated and standardized. Some of the specialized manufacturers are:

NEL-hydrogen:
With their M Series containerized available as the model MC 250 and MC 500. The model number tells the net production of hydrogen in Nm³ per hour. With a said electricity demand of 4.5 kWh/Nm³, the installed capacity can be

assumed with 1.125 MW for the MC 250 and 2.25 MW for the MC500.. (NEL-Hydrogen, 2020)

H-tec:

With their H-TEC SERIES: ME 450/1400. Again the model number tells the net production of hydrogen. This time the chosen unit is kg/d, which equals 210 Nm³ per hour. The electricity demand is said to be 4.9 kWh/Nm³. The stacks allow being operated in a range of 0.2 to 1.4 MW (Recognizable in the type specification) (H-Tec-Systems, 2020). This solution can be compared to the MC250.

iGas-energy:

With several PEM electrolysers between 5 to 205 Nm³ of hydrogen per hour, iGas-energy has a portfolio of a possible installed capacity between 75 to 2070 kW. The series gEl 160-1250 PEM MD has an installed capacity of 1050 kW, produces 160 Nm³/h of hydrogen and has a specific system electricity demand of 5.4 kWh/h. Interesting is the information about the stack efficiency. The electrical demand is between 4.47 and 4.71 kWh/Nm³ hydrogen (iGas-energy, 2020).

ArevaH2gen:

With several PEM electrolysers between 10 to 200 Nm³ of hydrogen per hour. This means a possible installed capacity with 80 to 1.600 kW. With an installed capacity of 1.200 kW the ELYTE 150 produces 150 Nm³ of hydrogen per hour. The efficiency is given in stack consumption with 4.4 kWh/Nm³ and in system consumption with 4.8 kWh/Nm³ of hydrogen (ArevaH2gen, 2020).

Siemens:

The manufacturer Siemens offers a PEM electrolyser as well. The newest product is the Silyzer 300, which surrogated the Silyzer 200, which had 1,25 MW installed electrical capacity. This series allows a hydrogen production of 100 up to 2.000 kg (9 Nm³/h to 179.8 Nm³). The available datasheet does lack information about this product. (Siemens, 2020).

Other manufacturer:

Hydrogenics:

With their series HYSTAT™ 60 OUTDOOR. This manufacture provides several smaller solutions going from a 24 Nm³/h solution up to a 60 Nm³/h solution. Again the type specification allows information about hydrogen production. The installed power of this electrolyser is said to be 515 kW. The total power consumption per Nm³ is a bit higher than the others with 5.2 kWh (hydrogenics, 2020). It has to be said that this solution is an AEL and does fit quite nicely into a 40 feet container. By having a comparable capacity with the NEL-hydrogen installation and the H-tec installation, hydrogenics requires two containers.

HydrogenPro; does not give any information of their products on their website

IHT; the Swiss company does not provide any further information about their portfolio

Sunfire; has a 150 kW electrolyser called SUNFIRE-HYLINK HL40, seems to be a AEL

Tianjin Mainland Hydrogen Equipment; hast several electrolysers in their portfolio from a 5 Nm³/h electrolyser to an 800 Nm³/h of hydrogen. This manufacturer specialized in alkaline electrolysers.

In the following comparison (Table 7) of the manufacturers, it is essential to analyse the electrical demand per Nm³ of hydrogen. Some manufacturers define the electricity demand per Nm³ of hydrogen by the electricity needed per stack. Some manufacturers give a total efficiency or energy demand, which probably includes the compression, cleaning, and other controlling units of the installation. A look at Table 7 shows specific information about suitable PEM electrolyser solutions.

Table 7 Comparison of different PEM electrolyser manufacturers (data provided by manufacturer)

	NEL hydrogen[3]	*H-tec*[4]	*iGas energy*[5]	*Areva H2 gen*[6]	*Siemens*[7]
Product	MC 250	ME 450/1400	gEl 160-1250 PEM MD	E200	Silyzer 300
Installed capacity	1.250 kW	1.000 kW	1.050 kW	1.600 kVA	

[3] Based on available formation of (NEL-Hydrogen, 2020)
[4] Based on available formation of (H-Tec-Systems, 2020)
[5] Based on available formation of (iGas-energy, 2020)
[6] Based on available formation of (ArevaH2gen, 2020)
[7] Based on available formation of (Siemens, 2020)

Hydrogen production	249 Nm³/h	210 Nm³/h	160 Nm³/h	200 Nm³/h	9 Nm³/h to 179.8 Nm³
Hydrogen purity	99.9995%	99.9 up to 9.999%	99.9 up to 9.999%	99.9 up to 9.999%	9.999%
System efficiency		74 %	68 % - 74 %		75 %
Stack power consumption	4.5 kWh/Nm³	4.5 kWh/Nm³	4.7 kWh/Nm³	4.4 kWh/Nm³	
Syst. power consumption	5.1 kWh		5.4 kWh	4.7 kWh/Nm	
Delivery pressure	30 bar	up to 30 bar	up to 40 bar	Up to 35 bar	
H_2O demand	222 l/h	350 kg/h		< 400 l/hr	10 l/kg H_2
Capacity range	10-100%	0.2 – 1.4 MW	10-100%		5-100%
Ambient Temperature	-20 to +40 °C	-15 to +35 °C		+3 to +40 °C	
Heat uncoupling		max 65°C; Return flow max. 55°C			
Dimensions (W X D X H)	Electrolyser: 12.2m x 2.5m x 3m Rectifier: 6.1m x 2.5m x 3m	12m x 3m x 3.5m		12m x 3m x 3.5m	
Weight		25 t			

In Table 7 displayed product types of several manufacturers only provide a limited set of information. Several of these pieces of information are quite interesting and allow a comparison. While the installed capacity might be in the same range, the hydrogen production itself varies. Not clearly explained is the plant operation itself. Interesting is the ability to adjust the hydrogen purity, which in all cases, can be increased to very high purity, allowing further use in fuel cells. In terms of stack power consumption, the electricity demand in kWh per Nm³ is nearly the same for all manufacturer. In terms of the whole system, more significant gaps are seen. These pieces of information allow a calculation about the system efficiency of those installments. Coming to the plant operation itself, the delivery pressure, the water demand, and the capacity range as well as the ambient temperature at which the electrolyser can be operated, are similar to the information given by the literature. Summing up, all given information are quite identical, independently to the manufacturer.

4.1.3 Manufacturer of a containerized hydrogen storage unit

One idea was to use the produced hydrogen to fuel the vehicle fleet of the SWU. As long as the hydrogen is not directly used or fed into the gas grid, a storage unit is required at the plant site and the fuelling station. As the product should, in the first step, be stored at the plant site and later be transported via a truck, a hydrogen storage system is required at the HPP Böfinger Halde. By assuming a daily production with around 500-600 kg of hydrogen, a storage unit should cover two days or have a storage capacity of approximately one ton. As already mentioned in chapter 3, only two storage possibilities are available. Compressed gaseous hydrogen with a pressure of 350 up to 700 bar or liquefied hydrogen. Which storage possibility finally fits the most is usually defined by the transportation distance and (partly) by the available space. Compressed hydrogen does have a lower energy density than liquefied and therefore requires more space for the same energy density. On the other hand, liquefied hydrogen requires quite a lot of energy to reach the point of liquefying. In the end, two cost drivers are compared:

The costs for compression/liquidizing a certain amount of hydrogen

versus

The costs of transporting a specific volume of hydrogen

Knowing that the distance between the HPP and the possible future fuelling station will be less than 10 km, the regular compression with maybe 350 or 700 bar might be enough. The transport itself will then go through a heavily urbanized area, which precludes a pipeline. Essential might be the pressure level on the demand side. Short distances to the consumers might be pivotal to avoid crowded streets or additional required infrastructure such as pipelines.

The Market research done for this study revealed a quite unserved market. With several industrialized gas producers and distributors such as Linde and AirLiquide remains the question, if those companies deliver a storage system to a direct competitor. On the other side, only a few manufactures deliver a containerized storage unit with decent operation pressure. One of those manufacturers is the company NPROXX offering a product with an operating pressure between 20 to 500 bar (maximum 625 bar) and a usable capacity of around 1 ton. The storage containment is a 40 feet container and contains numerous smaller modular vessels. Another manufacturer is called Hexagon Purus. Hexagon Purus as well produces modular vessels that can be combined into a containerized storage unit. Compression up to 700 bar is possible. The vessels can be installed in a 10 feet or up to a 45 feet container. Containerized storage systems are usually used to transport hydrogen with a truck, train, or ship. Due to standardization, a containerized instalment allows various future fields of application and transportation.

A compression of the hydrogen is compulsory. The required energy demand for the compression shall receive a closer look. If something requires energy but does not contribute to a higher energy content of the hydrogen, the whole system's efficiency is reduced. The necessary mechanical energy is converted to heat, which cannot be used during the decompression in later steps. All gas compressions require the same amount of energy, but as the energy density or heating value of the various gases differs, the specific energy demand varies. In simple words, one cubic meter of hydrogen contains less energy than one cubic meter of methane at the same pressure and temperature. So in relation, if the energy required for the compression stays the same, the compressed gas's specific energy differs between various gasses (Grote, Bender, & Göhlich, 2018).

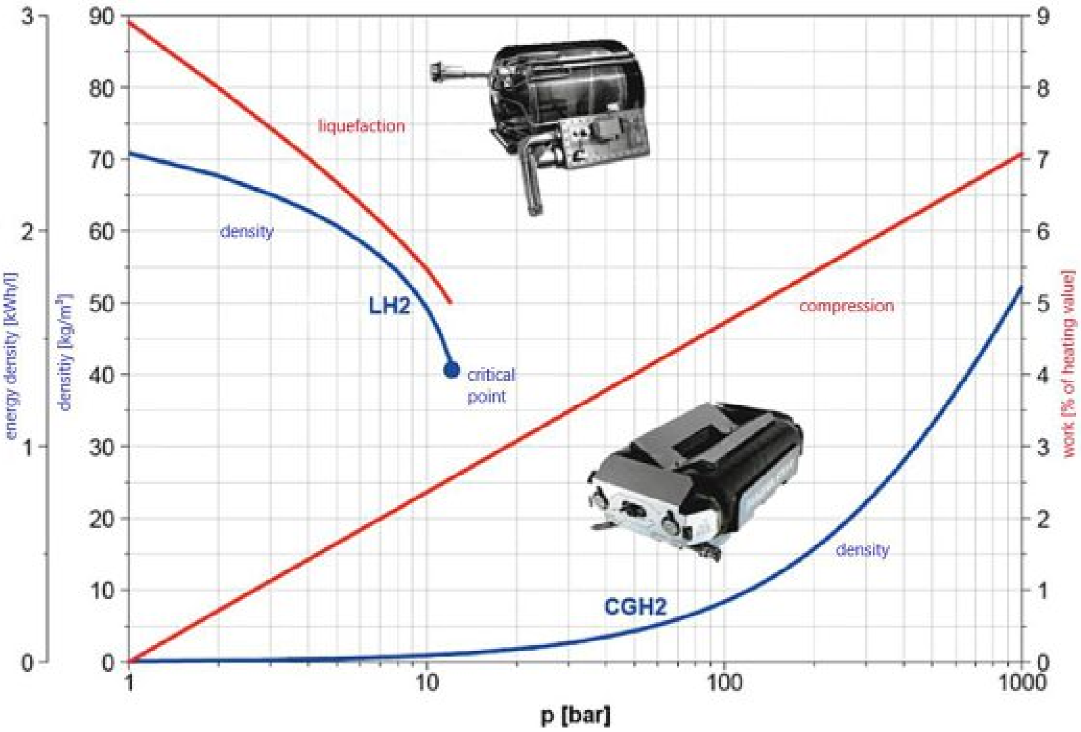

Figure 14 Comparison of the energy density with the required work during compression or liquefaction (Klell, Eichlseder, & Trattner, 2018) (p.110)

According to the literature (Klell, Eichlseder, & Trattner, 2018) (p.110-117), the required compression energy for hydrogen from 1 bar to 100 bar is around 4.75% of the heating value, whereas the compression from 1 bar to 500 bar is about 6.4%. As the electrolyser already delivers hydrogen at a certain pressure level of 10 to 40 bar, the compression's additional required energy is relatively tolerable. Nevertheless, the compression itself might have a total efficiency of 95%-96%, which should be concerned regarding the whole system's efficiency.

Coming back to the containerized hydrogen storage system. The compression itself does require a certain amount of energy. Somehow the hydrogen needs to be transported, ideally to fuel the bus fleet. This could either mean filling a truck with a gas storage containment at the electrolyser or exchanging a filled storage unit with an empty one. Here comes the problem with the hydrogen energy density and system energy density. The market researched showed a significant issue concerning the transportation of the produced hydrogen. The 20 feet containerized hydrogen storage system of NPROXX, which allows a pressure of 500 bar, can store around 518 kg of hydrogen. On the other side, the required containments themselves have a tremendous weight of 10 tons. The transport and lifting of the vehicle itself requires heavy machinery or specialized infrastructure. Alternatively, two storage systems already mounted on a low bed trailer could where. One of those trailers is at the plant side and filled while the other one is at the demand side. The significant point is the price of such a storage unit. An estimated price of 270.000 € per 20 feet container seems to be customary in the market. The efficiency for transporting the hydrogen usually has to be considered in the whole system efficiency. Highly dependent on the amount of transported hydrogen, the efficiency for transportation and distribution will decrease the system efficiency to around 97% (IEA, 2015). In the future, locally produced hydrogen A second solution for storing the hydrogen has to be considered. As the HPP plant site is limited, an alternative location for the electrolyser in the area around the HPP might become interesting. But before this specific possible storage near the HPP undergoes some analysis, the production itself and the electrolyser's efficiency shall be further analysed.

4.1.4 Efficiency and energy demand of a polymer electrolyte membrane electrolyser

The energy demand, as well as the efficiency, seem to be highly dependent on the operating mode of the electrolyser. The study done by Geert Tjarks (Tjarks, 2017) (p.81-105) shows the energetical contemplation of PEM electrolyser with all required auxiliaries. He showed, the energy demand per produced hydrogen varies, depending on the electrical current density. Between a current density of 1 A/cm² to 3 A/cm² the energy demand increases from 44.44 kWh/kg to 61.11 kWh/kg or 3.99 kWh/ Nm³ to 5.44 kWh/ Nm³. Scaled for the commercial use, the electrolyser is usually operated at a range of around 3 A/cm² while at maximum capacity, implying a higher efficiency under part load.

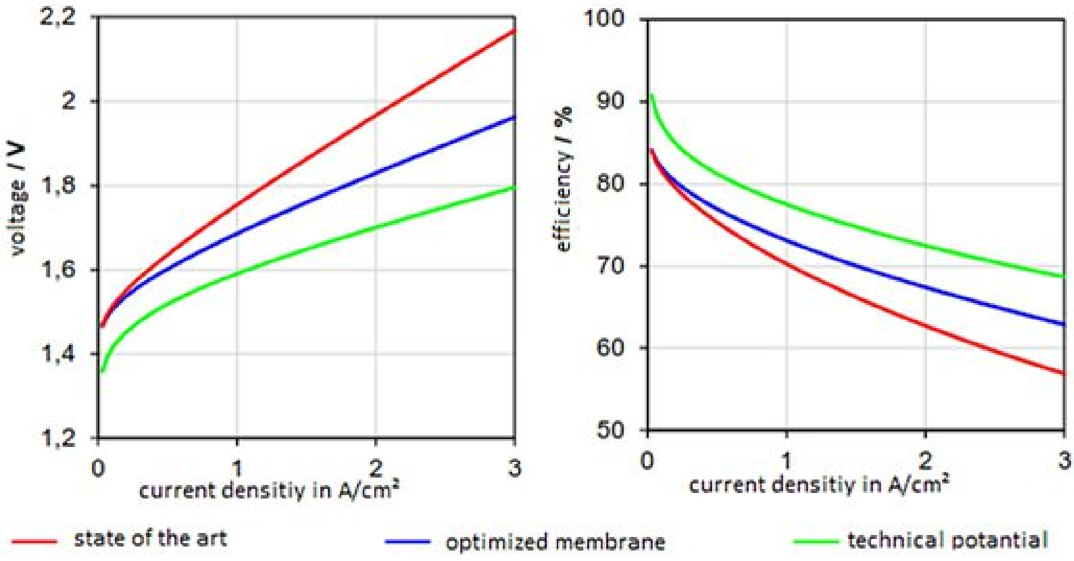

Figure 15 Comparison of the energy demand and efficiency (lower heating value) with the electrical current density of a PEM membrane (Tjarks, 2017) (p.101)

As displayed in Figure 15, the efficiency of a membrane decreases with increasing current density. As the electrolyser's membranes' surface is limited, a higher load results in a higher current density. It might be better to operate the plant on part load (maybe 80%) having a higher efficiency than at full load with lower efficiency. Some manufacturers allow their electrolyser to go into overcapacity; some manufacturers do not have an overcapacity. It might be possible, the electrolyser with an overcapacity operate at their so-called maximum load at an actual load of, let's say 80%. Allowing them to lower their current density per membrane surface and increase their efficiency on the paper. Nevertheless, you have to pay the whole infrastructure for the overcapacity, which in the end might cost the same as a plant that does not have an overcapacity.

Compared to the hydrogens' lower heating value, the state of the art membrane efficiency varies from 75 % at 0,5 A/cm² to 62% at 2 A/cm² and 58% at 3 A/cm². Implying an electricity demand (only of the membrane/stack) of:

4.00 kWh at 16% load

4.84 kWh at 66% load

5.17 kWh at 100% load

The given efficiency in Figure 15 only includes the efficiency of a membrane in a PEM electrolyser at optimal pressure and a temperature level of 80°C (Tjarks, 2017) (p.105) Imaginable, the efficiency of the whole system varies with the efficiency of the membrane itself. Auxiliaries are running, such as the control unit, and regardless of the hydrogen output, consume electricity. While the cell has a low energy demand at a low current density, the ratio of produced hydrogen (with its lower heating value) compared to the auxiliaries' energy demand results in relatively low system efficiency. Such an effect is displayed in Figure 16.

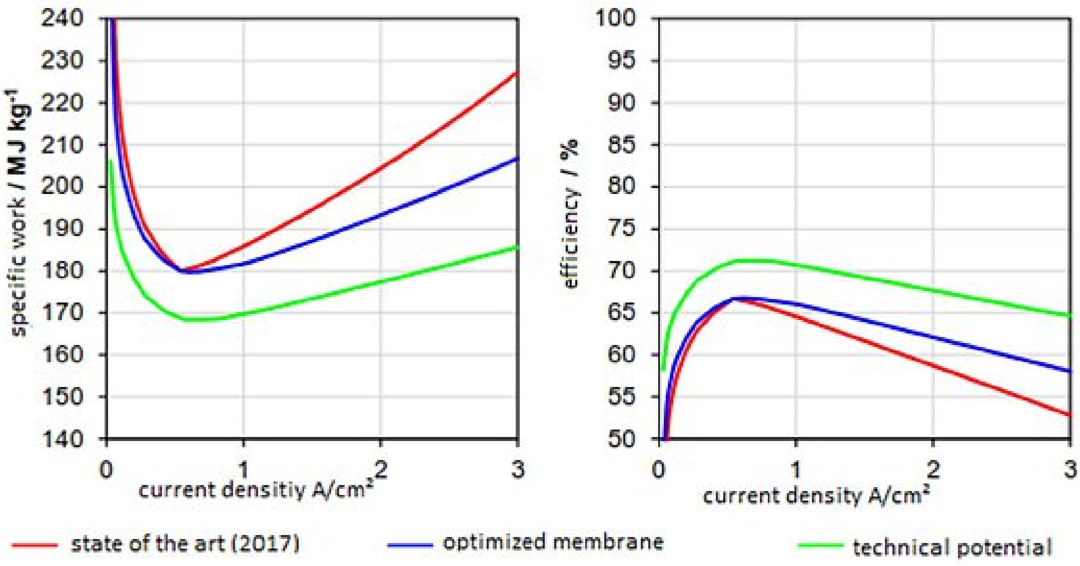

Figure 16 Total system specific work and efficiency of an electrolyser in relation to the electrical current density (Tjarks, 2017) (p.105)

Concerning the lower heating value of hydrogen, regarding Tjarks (Tjarks, 2017) (p.105), the state of the art PEM electrolyser's efficiency lies in 66% at 20% load and 53% at 100% load. Between a partial load of 66% and 100% load, the efficiency only varies from 58% to 53%. The efficiency is directly linked to the lower heating value of hydrogen, which lies at 3,00 kWh/Nm³. Outgoing from Figure 16, the required electricity demand for 1 Nm³ of hydrogen would be:

4.50 kWh at 16% load

5.17 kWh at 66% load

5.66 kWh at 100% load

Comparing the membrane and system electricity demand per Nm³ of hydrogen reveals a demand for the auxiliaries of around 0,5 kWh/Nm³, nearly constant regardless of the total H_2 production per hour. The provided information from Tjarks (Tjarks, 2017) (p.105) allows the modelling of the efficiency curve of a PEM electrolyser where the maximum current density of 3 A/cm² is reached at the electrolyser's full capacity.

Table 8 specific work and load of a state of the art PEM electrolyser in tandem with the current density (own calculation based on (Tjarks, 2017) (p.105)

current density	*specific work in MJ/kg*	*specific work in kWh/kg*	*specific work in kWh/Nm³*	*load in %*	*efficiency in %*
0	0	0	0	0%	0%
0,1	240	66.67	5.99	3%	50%
0,2	200	55.56	4.99	7%	60%
0,3	186	51.67	4.64	10%	65%
0,4	182	50.56	4.54	13%	66%
0,5	180	50.00	4.50	17%	67%
0,6	180	50.00	4.50	20%	67%
0,7	181	50.28	4.52	23%	66%
0,8	182	50.56	4.54	27%	66%
0,9	183	50.83	4.57	30%	66%
1	185	51.39	4.62	33%	65%
1,1	187	51.94	4.67	37%	64%
1,2	189	52.50	4.72	40%	64%
1,3	191	53.06	4.77	43%	63%
1,4	193	53.61	4.82	47%	62%
1,5	195	54.17	4.87	50%	62%
1,6	197	54.72	4.92	53%	61%
1,7	199	55.28	4.97	57%	60%
1,8	201	55.83	5.02	60%	60%
1,9	203	56.39	5.07	63%	59%
2	205	56.94	5.12	67%	59%
2,1	207	57.50	5.17	70%	58%
2,2	209	58.06	5.22	73%	57%
2,3	211	58.61	5.27	77%	57%
2,4	213	59.17	5.32	80%	56%
2,5	215	59.72	5.37	83%	56%
2,6	217	60.28	5.42	87%	55%
2,7	219	60.83	5.47	90%	55%
2,8	221	61.39	5.52	93%	54%
2,9	223	61.94	5.57	97%	54%
3	225	62.50	5.62	100%	53%

Table 8 is a direct translation of the in Figure 16 displayed efficiency curve. A state of the art PEM electrolyser efficiency varies with the current density of the stack and the specific work either in MJ/kg or kWh/kg or in kWh/Nm³. As the limit of a stack is said to be at 3 A/cm³, the load can be assumed to be 100%. Outgoing from this value, the load can be assumed for every current density. The efficiency itself is now calculated, as described earlier, by the specific work and the lower heating value of hydrogen. The values displayed in Table 8 allow a relatively precise calculation about the efficiency in combination with the load of the PEM electrolyser.

As mentioned earlier, the electrolyser shall maximize hydrogen production as well as benefit the electricity market. A containerized electrolyser described in chapter 4.1.2 shall be used for a load profile analysis. It is essential to differentiate between two types of electrolysers mentioned in chapter 4.1.2. Some of those electrolysers can operate in overcapacity; some simply can't. From a technical perspective, an electrolyser's capacity is limited by the membrane surface and the membrane's electrical current density. The electrical density cannot exceed an absolute value, and the membrane cannot magically increase. Some electrolysers overcapacity can only be the deviation between the typical point of operation (maybe 80% or 2.4 A/cm² of membrane surface) and full load. This implies the earlier mentioned trick of higher efficiency at a lower load than a competitor that runs at 100%. All electrolyser shall be used as if the maximal (over-)capacity is the status quo. The reason is, every PEM electrolyser can be operated at part load as well run at maximal load. The difference is the price. Manufacturers provide limited information about their price, whereas the literature usually provides a rough price in €/kW installed capacity. Assuming a higher electrolyser capacity with the ability to go into overcapacity would increase the investment.

4.1.5 Load profile of an electrolyser in combination with the hydro power plant

The for the electrolyser usable electricity, the not EEG or own consumption share, of the HPP Böfinger Halde varies heavily over the year. During the late summer and autumn months, the usable electricity drops to 2 MW or 3 MW with smaller peaks. Those smaller peaks are a result of rainfalls resulting in a higher discharge.

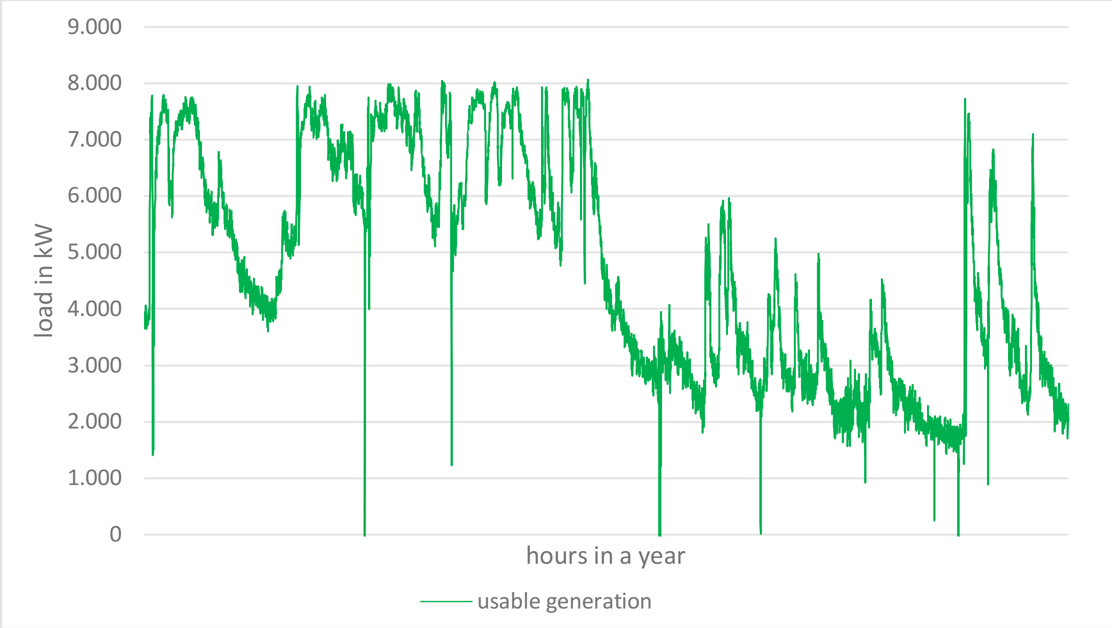

Figure 17 Usable electricity generation of the HPP Böfinger Halde of the year 2015 as the reference year (own representation, data provided by SWU Energie GmbH)

Combining the electrolyser with the HPP load profile allows two possible ways of operation while being beneficial to the electricity market.

The electrolyser can always run at part load, 80%, reduce the load during high prices and increase the load during very low prices (variant one) or

run at full load and reduce its load during high prices (variant two).

While the second variant is better for the electricity market, the full load hours will be lower than the variant one. How high is the difference between both operation variants? Can the average electricity price be significantly lowered due to a higher load during negative prices?

In such a simulation, the upper limit was set at an electricity price of 5.0 ct/kWh. The lower limit at an electricity price of 0.0 ct/kWh. As maximum capacity a 1.250 kW electrolyser such as the MC250 from NEL Hydrogen was used. The partial load was set to be at 1 MW (80%). The specific workload out of Table 9 was implemented into this simulation to analyse the difference due to efficiency.

In the partial load variant one, the full load hours dropped below 6.000 h. The reason for that is apparent: Lack of hours with prices below the lower limit of 0.0 ct/kWh.

Compared to variant two, which has around 7500 hours/yr, the plant itself is precisely approximately 20% less busy.

A significant difference between variant one (see Table 9) and variant two (see Table 10), can be seen at the annual demand. While the yearly demand for variant two is 23% higher than for variant one, the consumed electricity value is 30% higher. The simulation showed the average electricity price is lower with around 0.2 ct/kWh for variant one than variant two. This means the average production cost per produced kg of hydrogen for variant one is 12.3 ct cheaper than variant two. While the full load hours and the annual electricity demand stays at the same level over the years, the weighted average price of the consumed electricity is in both cases nearly equally increasing. This effect is due to the price trend of the used price forward curve. At this stage, it is necessary to mention, the actual electricity price at the EPEX SPOT is 0.16 ct/kWh lower than the weighted average electricity price for the electrolyser. The electricity is sold to regional consumers with a specific "100% green electricity" tariff who are paying slightly more, benefitting the HPP Böfinger Halde.

Table 9 Variant 1: Results of a 1.25 MW PEM electrolyser, which reacts to the electricity price of 2019, 2021 to 2025 (results of own calculations)

	2019	*2021*	*2022*	*2023*	*2024*	*2025*
annual el. demand PEM	7.6 GWh	7.7 GWh	7.5 GWh	7.5 GWh	7.4 GWh	7.5 GWh
full load hours	6.060	6.152	5.985	6.007	5.912	5.968
min. el. Price in ct/kWh	0.0	0.0	0.0		0.0	0.0
max. el. Price in ct/kWh	5.0	5.0	5.8	6.1	6.3	6.5
generated H_2 in kg	138.639	130.325	126.881	127.321	125.352	126.510
kWh/kg hydrogen	59.18	59.01	58.97	58.98	58.96	58.97
hours with min load	1422	1227	1463	1436	1572	1493

hours with max load	211	21	13	31	31	33
value for the electricity	257.337 €	292593 €	303.593 €	318.837 €	321.987 €	330.894 €
weighted average el. price in ct/kWh	3.40	3.80	4.06	4.25	4.36	4.44

Table 10 Variant 2: Results of a 1.25 MW PEM electrolyser which partly reacts to the electricity price of 2019, 2021 to 2025 (results of own calculations)

	2019	*2021*	*2022*	*2023*	*2024*	*2025*
annual el. demand PEM	9.3 GWh	9.6 GWh	9.3 GWh	9.3 GWh	9.2 GWh	9.3 GWh
full load hours	7.478	7.653	7.441	7.464	7.342	7.414
min. el. Price in ct/kWh	0.0	0.0	0.0	0.0	0.0	0.0
max. el. Price in ct/kWh	5.0	5.0	5.8	6.1	6.3	6.5
generated H_2 in kg	150.165	153.591	149.441	149.903	147.512	148.915
kWh/kg hydrogen	62.25	62.29	62.24	62.25	62.22	62.24
hours with min load	1.422	1.227	1.463	1.436	1.572	1.493
hours with max load	7.332	7.527	7.291	7.315	7.179	7.261
value for the electricity	335.202 €	378.722 €	391.404 €	410.415 €	413.659 €	425.070 €
weighted av. el. price	3.59 ct/kWh	3.96 ct/kWh	4.21 ct/kWh	4.40 ct/kWh	4.51 ct/kWh	4.59 ct/kWh

Now back to our previous questions: How high is the difference between both operation variants? Can the average electricity price be significantly lowered due to a higher load during negative prices?

As long as the price forward curve does not display price extremes very well, this answer might have some uncertainties. The efficiency at 80% load is regarding Table 8, around 56% outgoing from the lower heating value of hydrogen. The efficiency at

100% load is relatively insignificantly lower with 53%. Nevertheless, for variant one, around 59 kWh per kilogram of hydrogen is required, while for variant two, on average, 62 kWh per kilogram, hydrogen is needed. These 3 kWh or not even 5% probably won't justify operating a PEM electrolyser in efficiency compared to the investment (and the target to generate cheap green hydrogen). 12.3 ct per kg of hydrogen is something but cannot compete with the lack of 1.000 to 1.500 hours/yr or 33 t of hydrogen. But the average electricity price can be lowered without a doubt. Suppose the trend of more and more price extremes will continue and affect the operation of the electrolyser. In that case, a significant difference can happen and result in lower prices for hydrogen production.

The difference between the sum of hours with minimal load and hours with maximal load do not match 8760 h. The reason for that is the downtimes of the HPP Böfinger Halde. Running the electrolyser with electricity from the grid would be way too expensive.

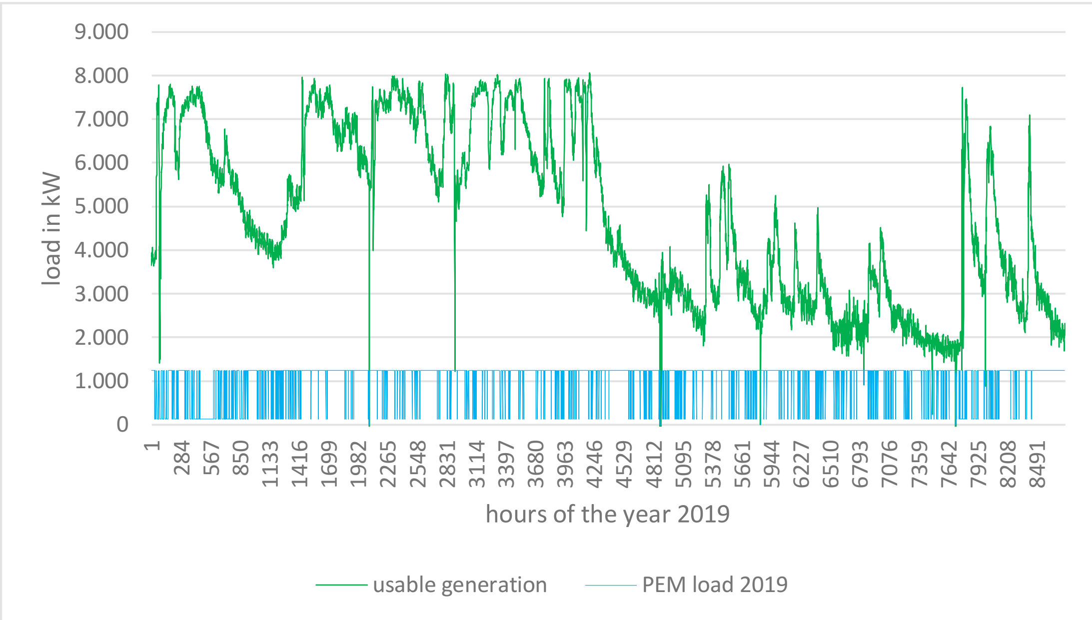

Figure 18 Usable generation of the HPP Böfinger Halde compared to the load profile of the electrolyser in 2019 (results based on own calculation)

Displayed in Figure 18 is the load profile of a 1.25 MW electrolyser, which reduces the load if the electricity price exceeds 5.0 ct/kWh, combined with the usable generation of the HPP Böfinger Halde (variant two). Remarkable is that the electrolyser's load changes are quite frequent at the beginning of the year and during the period of low production. This effect might be caused by wind turbines, which are said to produce a lot of electricity in the stormy autumn season and the late winter.

Taking a closer look at Figure 18, the best period for a revision of the electrolyser would be during the HPP revision or at the beginning of the year around January or February. During these months in 2019, the electricity price is quite often above the set limit of 5.0 ct/kWh, and the electrolyser would be at minimal load. In the previous investigation, a revision of the electrolyser was not yet concerned. A period of 336h (2 weeks) might be enough for an annual smaller electrolyser revision. The production of two weeks at full load would equal around 8.250 kg of hydrogen.

As out of interest, the same simulation was done for two 1.25 MW PEM electrolysers. The plant shall run as described in variant two, where the plant reduces the load only during periods of high electricity prices. As the usable generation of the HPP Böfinger Halde is lower than the maximum capacity of the PEM during the end of the year 2019, the result will vary from the previous investigation.

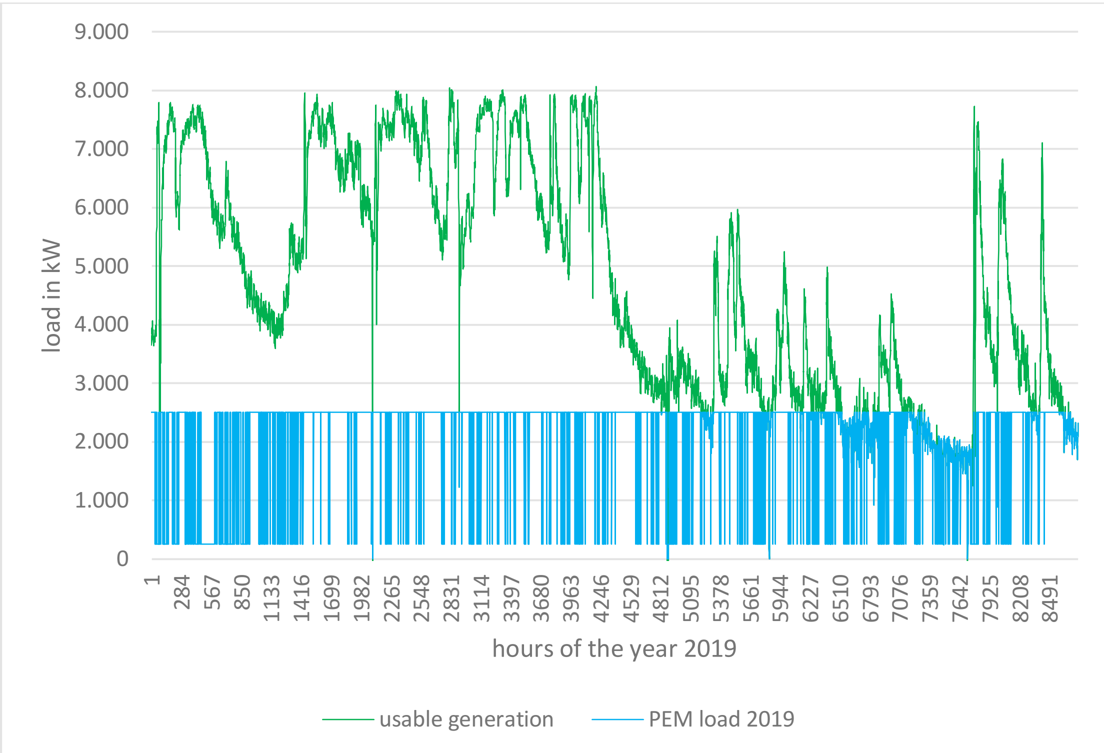

Figure 19 Usable generation of the HPP Böfinger Halde compared to the load profile of two 1.25 MW electrolyser in 2019 (results based on own calculation)

As displayed in Figure 19, the second electrolyser is still running quite a lot. Only for two months, the load for the second electrolyser is decreased. It is possible to time the electrolyser's revisions during this period and lower downtime due to usable electricity. It has to be said, the used generation of the HPP Böfinger Halde is the actual generation of the plant during a year where the total generation matches the long term average generation of the HPP. This means every year can be very different compared to the used data. A result would be; the second electrolyser might be entirely redundant for several days or even months if the generation of the HPP is lower than the average production or vice versa.

Table 11 Results of two 1.25 MW PEM electrolyser which partly reacts to the electricity price of 2019, 2021 to 2025 (results based on own calculation)

	2019	*2021*	*2022*	*2023*	*2024*	*2025*
annual el. demand PEM	18.2 GWh	18.8 GWh	18.2 GWh	18.3 GWh	18 GWh	18.2 GWh
full load hours	7.309	7.505	7.293	7.308	7.190	7.269
min. el. Price in ct/kWh	0.0	0.0	0.0	0.0	0.0	0.0
max. el. Price in ct/kWh	5.0	5.0	5.8	6.1	6.3	6.5
generated H_2 in kg	295.217	302.719	294.419	295.076	290.453	293.461
hours with min load	1.422	1.227	1.463	1.437	1.573	1.493
hours with max load	6.263	6.566	6.336	6.321	6.192	6.311
value for the electricity	654.262 €	742.013 €	766.762 €	803.120 €	809.956 €	832.965 €
weighted average el. price in ct/kWh	3.58	3.95	4.21	4.40	4.51	4.58

The difference between a single 1.25 MW PEM electrolyser and two is very slight despite lower production during several days in the autumn of 2019. The difference in output is in the range of 5.000 kg. Having two electrolysers would allow a better plant regime. There is always one electrolyser producing hydrogen and securing the supply.

4.2 Implementation of the electrolyser at the plant site

At the HPP Böfinger Halde, the plant site is limited. The available area around the HPP is permanently used as well only under specific circumstances. A closer look at the plant site itself shall help finding a suitable place for a containerised PEM electrolyser.

The parking lot in the tailwater in the northeast is for mobile cranes during revisions of the wire or in an emergency. During those two cases, the mobile crane lifts pipe closures in front of the wire to build up a temporary wire. The usable space for an electrolyser on the parking lot is therefore limited as in a case of emergency, a mobile crane cannot relocate the electrolyser. At the headwater side near the transformers, the concrete area is for the flotsam and the required excavator. It may be possible to locate the electrolyser there, but the amount of flotsam is enormous and therefore reserved for this purpose during a flood. A few meters upstream, before the transformers, the free area is used to water boats.

Directly at the HPP, the available space is partly usable. Arguably the effect on the publicity would be significant, having an electrolyser directly at the HPP. But besides the 40 feet container of the electrolyser, the storage system in a 40 feet container (or comparable size) should be located and accessible or transportable. One alternative is the sheds upstream of the transformers. The SWU mainly owns those. The lease contracts are long-term contracts. Finding a suitable plant site for the electrolyser near the HPP is problematic.

Figure 20 Overview of possible electrolyser positions at the HPP Böfinger Halde (LIDS of the SWU Energie GmbH, 2021):

Besides the available area, the safety aspect should be concerned as well. While the insurance for the electrolyser itself (to replace it) might be relatively low, the insurance for unforeseen events such as explosions and fires might be tremendous. In an interview with the insurance partner of the SWU, several things became apparent. If the installation of the PEM electrolyser is in the closer area around the HPP, an unforeseen event, such as an explosion, might damage the HPP as well. This would increase the threat for the HPP and therefore increase the insurance for the HPP significantly. An alternative plant site might be more suitable and thinking outside the given limitations at the HPP site might provide a better solution. Not so far away, on the other side of the river, the natural gas transfer station "Steinhäule" might give the space and necessary infrastructure. At this location, most of the required natural gas for Ulm and Neu-Ulm is extracted from the long-distance natural gas pipe. This infrastructure is comparable to a high voltage to medium voltage transformer station for natural gas—a perfect location for hydrogen injection into the gas grid.

Besides the available gas infrastructure on-site, other positive side effects might be beneficial in the implementation process. At this transfer station, the natural gas is decompressed and results in a gas temperature drop. To warm up the natural gas and, more importantly, all required instalments and auxiliary equipment, heat is applied. The heat demand itself is comparatively low, with a baseload demand of around 50 kW thermal. Uncoupling the heat of the electrolyser and using it for the decompression might be a feasible solution.

Besides a solution for the heat, the oxygen, as earlier mentioned, could be used in the wastewater treatment /sewage plant Steinhäule. The distance itself is relatively short and might be in a range of 300 m, depending on where the sewage plant's oxygen storage system is located.

Now back to the main point. One of the most exciting parts of this infrastructure is the available storage capacity. Natural gas is traded partly comparable to electricity. The price itself varies and sometimes storing might be economically feasible. Another point is the price for the maximum demand. Again, same as electricity, the demand of natural gas has to be paid the required amount (working price) and for the maximum demand (demand rate). A storage system can lower the maximum demand and save money. At the transfer station Steinhäule are two storage systems. Each of those storage systems is a battery of pipes dug in the underground. Each pipe has a diameter of 1420 mm (19,5 mm wall thickness) and a length of 104 m for the storage system 1 and 252 m for the storage system 2. The storage system 1 contains 13 pipes and storage system 2 includes 11 pipes. Both systems can handle a pressure of 80 bar.

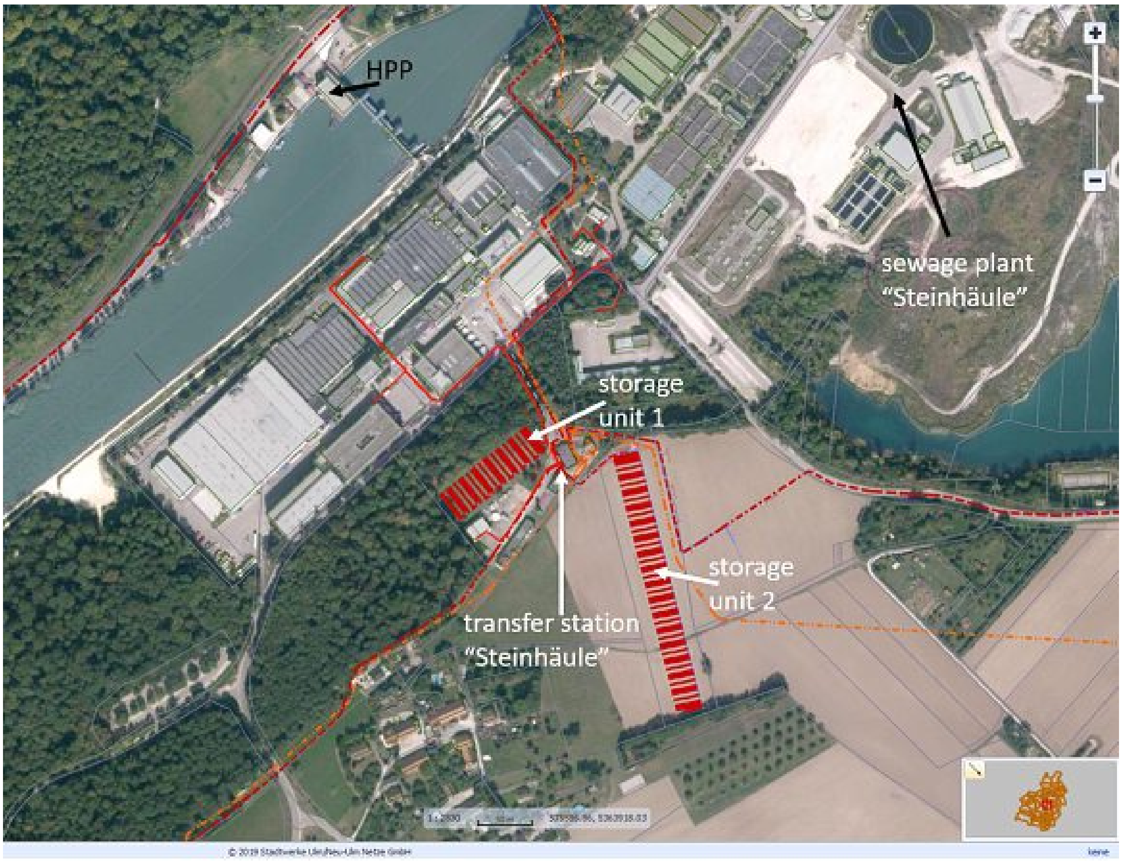

Figure 21 Overview of the HPP Böfinger Halde and the natural gas transfer station Steinhäule. (red and orange are gas pipes in the ground) (LIDS of the SWU Energie GmbH, 2021)

In total, both storage systems have a volume of around 6.177 m³. At norm circumstance, with an hourly production of 210 Nm³, both storage systems are filled in about 29h with no pressure applied. By increasing the pressure, the system can store more hydrogen. As a real gas does not behave like an ideal gas, the density does not double with a doubled force. Being on the safe side, a force of 70 bar would increase the density to a value of around 6 kg/m³ of hydrogen (Klell, Eichlseder, & Trattner, 2018) (p.110). While starting at 0.0899 kg/m³ under norm circumstances, the pressure increases the density 67 times. This means the storage system could contain around 38.000 kg of hydrogen. Storage unit 1 can include 12.5t (filled in 515 h), and storage unit 2 can have 25.6 t (filled in 1056 h). Quite a bit more than the earlier investigated containerized storage system.

In an interview with the operator of those storage systems, the stored gas contains around 800 MWh of natural gas. Bringing it into account, this would supply Ulm and Neu-Ulm's demand for approximately one hour in the winter. The current use for those storage systems is to buffer winter months. This kind of seasonal storage works so that it is filled during warm periods. The gas demand is low (heating in the private housing sector is barely required) and releases the gas back into the grid, lowering the demand during cold periods. It is said, this operation generates around 40.000 to 80.000 € per year. The storage system does not have any compression unit and only works with the grid's pressure via the long-distance pipe. In the beginning, it might be suitable only to use the smaller storage unit 1 and have the storage unit 2 used for the normal natural gas operation. It should be possible to operate one storage system with natural gas and one storage system with hydrogen as both storage systems were not built in the same year. Storage unit 2 was built several years later, as the financial benefit of storage unit 1 was decent. Ideally, some instalments and auxiliaries have to be adapted.

Another problem might be purity. Currently, these storage systems contain natural gas. Supposing a use of hydrogen in the transportation sector. In that case, the hydrogen requires a purity of 99.999% (ISO , 2012). This means either the storage system needs to be emptied entirely to a vacuum and then filled with hydrogen or the storage system is filled several times until the natural gas content in the system is close to zero. It requires an investigation; wheatear the system can handle a vacuum or if the refilling several times is more economic feasible.

4.3 Capital expenditure of a polymer electrolyte membrane electrolyser at the hydropower plant Böfinger Halde

4.3.1 Cost perspective - Required infrastructure for the implementation at the hydropower plant Böfinger Halde

One possibility for an electrolyser is, as earlier mentioned, directly at the HPP plant site. It is still worth to analyse the feasibly of an electrolyser directly at the plant, without the benefits of the transfer station Steinhäule. Therefore, the first cost perspective will be done without the possibility of the transfer station. While information about the technical aspects and components are accessible, the price is not. A price inquiry is necessary to have a feeling about the price range at least. The evaluated prices of the market survey done by Now GmbH done in their study "IndWEDe" might give an answer. The CAPEX nowadays is in a range of 1.500 €/kW for a PEM electrolyser. The problem with an average value comes with the vagueness of the investigated capacity. There is no information if the survey included large-scale installations of several MW or small scale installations with only a few kW.

The electrolyser, which mostly comes in a 40 ft. container, requires additional infrastructure:

Table 12 Required additional instalments for an electrolyser at the HPP Böfinger Halde (own estimations)

Category	*Description*	*Price assumptions*
Containerized PEM electrolyser	A price for a containerized PEM electrolyser is not accessible nor provided by any manufacturer. Literature and the market survey (Smolinka et al., 2018) name a price of 1.450 to 1.550 €/kW. As the electrolyser is supposed to uncouple the heat and the oxygen shall be further used, additional costs are likely. The price will therefore be set to 1.600 €/kW The price assumption is for a 1.25 MW PEM electrolyser.	2.000.000 €
Hydrogen storage and fuelling infrastructure.	A storage containment for the produced hydrogen if the hydrogen is not fed into the gas grid. A 20 feet container can store around 500 kg of H_2 at 500 bar.	270.000 €
Foundation electrolyser	The foundation (optional a strip foundation) where the electrolyser can be installed on.	5.000 €
Foundation hydrogen storage system	The hydrogen storage system itself requires a foundation were it should be installed on.	5.000 €
Mobile Crane	For the installation/positioning of the electrolyser on the foundation. (8 hours)	3.500 €
Electrical Connection	The connection to the bus bar or the low-voltage main distribution board. This requires installation work in the HPP as well as the routing of cables to the electrolyser.	12.000 €
Network Connection	The plant itself shall give and receive information to the HPP as well to the grid	1.000 €

	control centre. (excavation together with electrical connection)	
Tap water connection	As the plant requires tap water, the connection shall me done using the HPP tap water. (excavation together with electrical connection)	1.500 €
Waste water connection	Maybe a connection to waste water is required due to an automatic cleaning process of the water treatment installation.	1.000 €
Gas grid connection	If the hydrogen is feed into the gas grid, a pipeline is required. (150 m distance)	35.000
Fence (around 65m)	The instalment itself should be separated with a fence to prevent vandalism and keeps the distance between the publicity and the instalment.	6.000 €
Gate for the fence	To allow the accessibility to the electrolyser.	2.000 €
Optional: A hydrogen fuelling station	Fuelling station for private cars. Ideally subsidised and therefore nearly cost neutral	t.b.d.
Optional: A district heating grid connection and the district heating grid	If the heat is uncoupled and can be used somewhere else, the heat has to be transported.	t.b.d.
Optional: Oxygen compression & storage containment	If the oxygen is not blown into the air, a compression unit as well as a storage containment including a fuelling station would be required.	t.b.d.

4.3.2 Cost perspective - Required infrastructure for the implementation at the transfer station Steinhäule

As earlier evaluated, the second possible site for the electrolyser is at the transfer station Steinhäule. Still, the instalment requires additional infrastructure:

Table 13 Required additional instalments at the transfer station Steinhäule (own estimations)

Category	*Description*	*Price assumptions*
Containerized PEM electrolyser	A price for a containerized PEM electrolyser is not accessible nor provided by any manufacturer. Literature and the market survey (Smolinka et al., 2018) name a price of 1.450 to 1.550 €/kW. As the electrolyser is supposed to uncouple the heat and the oxygen shall be further used, additional costs are likely. The price will therefore be set to 1.600 €/kW The price assumption is for a 1.25 MW PEM electrolyser.	2.000.000 €
Foundation electrolyser	The foundation (optional a strip foundation) where the electrolyser can be installed on.	5.000 €
Mobile Crane	For the installation/positioning of the electrolyser on the foundation. (8 hours)	3.500 €
Electrical Connection	The distance between the electrolyser increased to around 1.500 m.	Cable: 19.500 € Work: 23.400 €
Transformer, power switching station	Electricity with a power of 1.000 kW should not be transported at 400 V over a distance of around 1.5 km. The generators at the HPP generate at 5 kV. Therefore, the connection will be made at the 5 kV bus bar. This requires a transformer at the transfer station Steinhäule. The capacity of the transformer is set with 2.000 kVA.	100.000 €
Network Connection	The plant itself shall give and receive information to the HPP as well to the grid control centre. (excavation together with electrical connection)	1.000 €
Tap water connection	As the plant requires tap water, the connection shall me done using the HPP	2.000 €

	tap water. (excavation together with electrical connection)	
Waste water connection	Maybe a connection to waste water is required due to an automatic cleaning process of the water treatment installation.	1.500 €
Gas grid connection	If the hydrogen is directly fed into the gas grid, a pipeline is required. (150 m distance)	5.000
Adjustments at the storage system	The storage system itself needs to be perpetrated for the further use with hydrogen.	10.000 €
Optional: Fence (around 65m)	The transformer station is already a high security area. A fence might not be necessary	6.000 €
Optional: Gate for the fence	To allow the accessibility to the electrolyser.	2.000 €
Optional: A hydrogen fuelling station	Fuelling station for private cars. Ideally subsidised and therefore nearly cost neutral. This requires a suitable position at the transfer station.	t.b.d.
Connection to the heating grid at the decompression station	If the heat is uncoupled and can be used to warm the axillaries at the decompression station	10.000
Optional: Oxygen compression & storage containment *Alternative: Direct pipe to the Sewage plant* *And required auxiliaries at the feed in side*	If the oxygen is not blown into the air, a compression unit as well as a storage containment including a fuelling station would be required. A rule of thumb is a price of 550€/ m³. The excavation width is 0.6 m, the depth around 1 m and with a length of 275 m. A pump or compressor with additional auxiliaries is required at feed in side.	t.b.d. 90.750 € 10.000 €

4.4 Operational expenditure of a polymer electrolyte membrane electrolyser in combination with the hydropower plant Böfinger Halde

The OPEX for a PEM electrolyser was already discussed in chapter 3.1.4 and lay around 13 €/kW today and maybe at 11 €/kW in the future. Being on a conservative side, an OPEX of 15 €/kW with a cost increase of 1.5% per year is a feasible compromise. It is somewhat unclear what the OPEX, regarding the market survey (Smolinka et al., 2018), include. With certain unclearness, the OPEX will only have the labour work to monitor the electrolyser and revise the electrolyser and will be called operating and maintenance cost.

4.4.1 Costs for the electricity, water consumption and other costs

In general, the consumed electricity is, according to the EEG 2017 paragraph 61d, completely tax-free. With the current EEG. This does not have the be case for any other renewable plant and therefore distinguishes this plant from any PV or wind power plant. As earlier mentioned, this electricity is used for a local 100% green electricity tariff with a slightly higher price than the SPOT market price. The HPP Böfinger Halde receives additional revenues of 0.16 ct/kWh on top of the SPOT market price.

As already discussed in chapter 4.1.5, the consumed electricity in 2019 would have generated a revenue of 3.59 ct/kWh if the 1.25 MW PEM electrolyser was not installed at the HPP. As the price reaches 4.59 ct/kWh till 2025, a price increase of nearly 28% in 7 years would equal a price increase of around 4% per year. Outgoing from that, the weighted average price would reach 7.86 ct/kWh in 2041. As the future is uncertain but the used PFC does not include the price extremes as the actual price currently has and therefore the price increase will be 3 % annually outgoing from 4.0 ct/kWh in 2021.

The target is to have a constant load factor of 7.500 hours/yr per year. In this case, a 1.25 MW PEM electrolyser's annual electricity demand is at 9.38 GWh. This matches quite well the load profile in chapter 4.1.5 and shall be kept constant over the project runtime of 20 years.

The water consumption itself has to be considered as well. As the HPP is not connected to the water grid and has its own groundwater well with relatively low water conveying capacity, the maximum water demand an evaluation. The groundwater well supplies the lubrication of the turbine bearing and the toilet's and sink's service water. Two redundant operated 1 kW pumps are currently installed and are said to run around 5 minutes per hour.

The 1,25 MW PEM electrolyser has, according to the product sheet of NEL hydrogen, a demand of 222 l/h or 3.7 l/min. This demand should easily be covered by those two pumps in the groundwater well. The additional costs of pumping will be neglected. Outgoing from 2 kW installed capacity and 8760 h with an electricity price of 4 ct/kWh, the costs of the freshwater are 700.80 € per year

If the PEM electrolyser is installed at the gas transfer station Steinhäule, the water consumption is secured. This transfer station has a connection to the freshwater grid. As the infrastructure is already given, only the additional demand will cause additional costs. The current price for a cubic meter of water is 1.70 €. If the electrolyser with 1.25 MW installed capacity consumes 222l/h of freshwater, one can calculate total water consumption of 1.945 m³. Including the price per cubic meter, annual costs of 3.306 € can be expected. The price for freshwater will go through the same price increase of 1.5% annually.

The wastewater costs will be neglected.

Metering: The PEM electrolyser requires at least three different metering systems:

The electricity consumption will be metered with a 1/4h intelligent metering system.

The water demand has needs metering.

The hydrogen production needs metering.

Additionally, the heat needs metering.

Data transmission: As the plant itself needs to be controlled constantly, data transmission with information about the plant is required.

Insurance: An unknown cost driver is the insurance. In an interview with the insurance broker of the SWU, there are two big cost drivers. First of all, machine insurance is for the plant itself if there is any failure. Secondly, fire insurance is compulsory. If there is any failure and the electrolyser might explode or start to burn, other establishments in the surrounding might suffer or start burning as well.

4.5 Hydrogen revenues of a 1.25 MW polymer electrolyte membrane electrolyser in combination with the hydropower plant Böfinger Halde

As a hydrogen production is thinkable, the big question about possible revenues requires an answer:

The electrolyser can feed into the gas grid; one option is to use the natural gas price as possible revenue. Technically, a particular share of 2% of hydrogen is acceptable. The current natural gas price (December 2020) lies at around 14 €/MWh or 1.4 ct/kWh. This would equal the price of 0.47 €/ kg. Which is not feasible for the electrolyser at all. As a comparison, the conventional hydrogen out of natural gas is produced for 4.5 ct/kWh or 1.5 €/kg (Bukold, 2020). As the electricity consumption price is already at 4.0 ct/kWh and the efficiency is around 60%, the PEM electrolyser will not be competitive with conventional hydrogen or even natural gas.

Hydrogen is, such as biogas, environmentally friendly and selling it the same way might be possible. The production costs for biogas are in a range of 5 to 9 ct/kWh. This equals a price of 1.67 to 3 €/kg, which is significantly higher than natural gas. The previous estimation shows that 6.66 ct/kWh are the minimum to at least cover the electricity costs. If the infrastructure and the PEM electrolyser itself are for free, this might work; otherwise, the price must be higher.

The last possible revenue is the hydrogen price at a fuelling station. Currently, the price of 1 kg hydrogen lays a 9.5 €. Deducting the fuelling station's operational costs, the maximum deliverance price may lay in an area of 7 €/kg hydrogen. The transportation and the fuelling infrastructure need a deduction as well. According to literature, the price for transporting hydrogen (10 to 100 km) lay in a range of 0.25 – 0.79 €/kg of hydrogen (Balzow, Jenne, Jörissen, Schlumberger, & Schwarz, 2017). Maybe leaving a price of 6 €/kg or 18 ct/kWh. Regarding Bukold, green hydrogen can currently be produced at 16.5 ct/kWh or 5.5 €/kg (Bukold, 2020).

As long as there is a hydrogen demand in the closer area around the electrolyser, the most feasible way to generate revenues would be to sell the hydrogen to fuelling stations.

4.6 Other possible revenues of a 1.25 MW polymer electrolyte membrane electrolyser at the hydropower plant Böfinger Halde

4.6.1 Oxygen supply of a polymer electrolyte membrane electrolyser

With water (H_2O) usage to produce hydrogen, the other final product has to be oxygen (preferable O_2). One oxygen atom weighs 16 times more than one hydrogen atom. Meaning one oxygen atom weighs 8 times more than a hydrogen molecule. So if 24.32 kg per hour of hydrogen is produced in a 1.25 MW PEM electrolyser, around 194.5 kg of oxygen is produced. 1 kg of oxygen equals 1.4291 Nm³, implying an oxygen production of approximately 278 Nm³ per hour or 11.4 Nm³ oxygen per kg hydrogen.

Without blowing the oxygen into the air, further use at the sewage plant might be feasible. Depended on the amount of required oxygen, a pipeline to the sewage plant might be the best option. The distance between the electrolyser at the transfer station Steinhäule and sewage plant gate is around 275 m. The SWU and the sewage plant should sign long-term contracts to secure the pipeline's investment and probably additional auxiliaries such as a pump.

Currently, no negotiation with the sewage plant was achievable.

4.6.2 Heat supply of a polymer electrolyte membrane electrolyser

The heat supply of a PEM electrolyser was not given at any manufacturer datasheet. Nevertheless, the MC 450/1400 from H-tec allows drawing some conclusions. The maximum temperature which can be uncoupled is at 65°C. The temperature is in correlation to the stack temperature of the electrolyser itself and its optimal operating temperature. The maximum backflow temperature can lay at 55°C. As every containerized PEM electrolyser has a cooling system installed, one can assume there is no use for the heat cannot and it is not entirely required in any previous steps.

Again, Tjarks (Tjarks, 2017) (p.59) provided some helpful information about the required heat of an electrolyser and the heat losses. As we know, with increasing electrical current density, the efficiency drops. Some electrical energy cannot be used in the process itself and is simply converted into heat. Nevertheless, a certain amount of heat is still needed. Dependent on the set operating temperature level of the electrolyser, the system requires a certain amount of energy for reaching and holding the set operating temperature level.

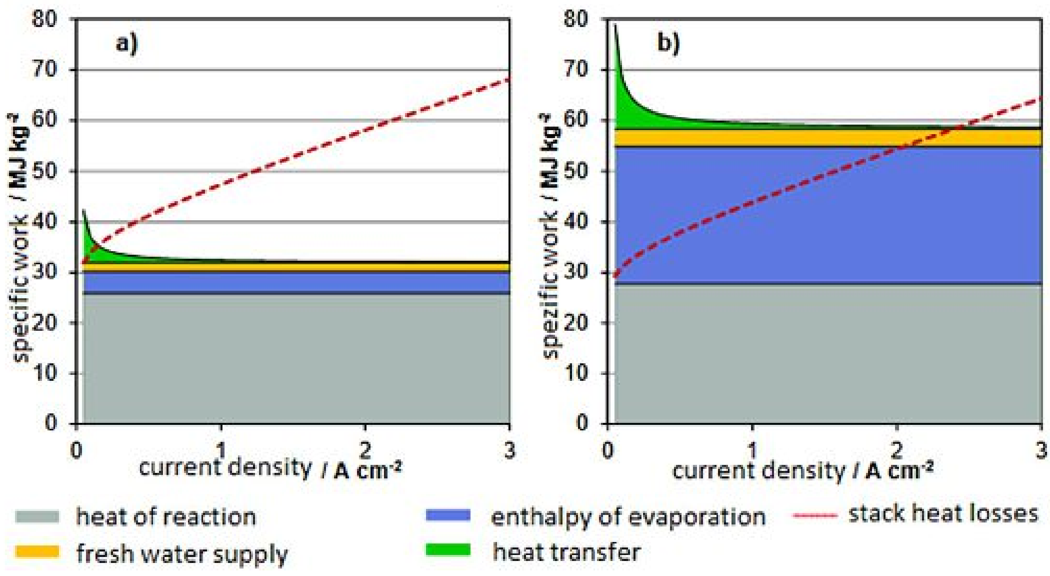

Figure 22 Specific losses of the heat capacity in a PEM electrolyser at an operational temperature level of a) 50°C and b) 80°C (Tjarks, 2017) (p.59)

As displayed in Figure 22, the stack heat losses vary from around 30 MJ/kg to approximately 65 MJ/kg concerning the electrical current density. In other words, around 8.33 kWh up to 18 kWh per kilogram hydrogen are stack heat losses that need to be cooled down via a fan or used in a heat exchanger for further use in the district heating.

A 1.25 MW PEM electrolyser's hydrogen production was already calculated and resulted in roughly 180.000 kg/a or approximately 24 kg/h. With 7000 hours/yr, the plant itself mostly runs at full load and therefore, an estimation with 65 MJ/kg or 18 kWh/kg should be enough. Transferring 100% of the stack heat loss for further use, a 1.250 kW PEM electrolyser's thermal capacity is at an astonishing level of 433 kW or 34% of the installed electrical capacity. Over the year, a supply of around 3.2 GWh of heat might be theoretically possible at 100% heat exchange.

Approximately 3.5 ct/kWh are used in the SWU internal calculation for the district heating grid's heat supply. With the idea to use the heat for preheating the natural gas in the decompression process. The heat demand and the region's natural gas demand are directly linked and therefore undergo seasonal differences. Nevertheless, not all of the PEM electrolyser's excess heat can be used for the decompression process. On the other side, outgoing from the PEM electrolyser's maximum capacity, 100% of the heat demand of the decompression process can theoretically be covered.

4.6.3 Participation in the reserve market

It is possible to participate in the reserve market to additional be beneficial in terms of grid stability. Without going into detail, the electrolyser can participate in the secondary reserve and the minute reserve market. The electrolyser alone cannot, due to the targeted operation mode, participate in the primary reserve. In the primary reserve, the electrolyser has to provide positive and negative reserve energy. By lowering the electricity demand of the electrolyser, it is thinkable to provide positive secondary reserve energy in a range of 1 MW. The revenues are very uncertain and not constant at all. Revenues of 30 to 40 T€ for providing the capacity might be thinkable. Additional payments are achievable by delivering the actual work.

The HPP could provide the negative primary reserve capacity (by reducing the production, reducing the actual electricity feed into the grid). In contrast, the electrolyser could provide the positive capacity (decreasing the consumption and therefore provide electricity for the grid stability). This might not work due to the regulations of the primary reserve in terms of reactivity. The HPP might be to slow while reducing its production.

4.7 Funding programs for hydrogen infrastructure

Several ministries in Germany promoted hydrogen and the required hydrogen infrastructure with funding programs. In a wide range, different, very strictly and very open designed programs were developed and subsidized. The general goal is to improve the competitiveness of hydrogen with other conventional technologies and fuels.

Table 14 funding programs according to the national innovation program (NIP) (NOW-GmbH, 2020)

	funding	*target*
Public fuelling stations	up to 50% for the fuelling station up to 40% for electrolysers at the fuelling station (green hydrogen!)	Infrastructure for 60.000 hydrogen cars and 500 commercial vehicles till the end of 2021
FCEV in car fleets (till 31.01.20)	up to 40% of the additional invest compared to ICE vehicles	To activate or generate a demand at the market for FCEV

Commercial vehicles – waste collectors and road sweepers (till 15.10.20)	100% of the additional invest compared to ICE vehicles 100% for the additional maintenance infrastructure 100% for adjusting the fuelling infrastructure	Investment grant to activate or generate a demand at the market for FCEV commercial vehicles
Autarkic supply of critical infrastructure (till 15.10.20)	Up to 40% of the additional invest	Smaller FC (less than 100 kW_{el}) for autarkic supply of critical infrastructure
Electrolyser for producing 100% green hydrogen (till 20.11.20)	More than 250 kW_{el} electrolyse Up to 45% for the investment plus the infrastructure	Market ramp up for electrolyser Production of 100% green hydrogen which shall later be used in the transportation sector

These programs are exciting in combination with a PEM electrolyser at the HPP Böfinger Halde and the later use of the hydrogen at the SWU. All of those programs are outdated. A lot of the programs in Table 14 have already been proclaimed in 2019 and again in 2020. In an exchange of information with the project executing organisation and due to the fact, the in summer 2020 refurbished NIP, nearly all of the funding programs will be proclaimed again in the closer future.

5 Ecological and economic benefit

5.1 Ecological benefit of a hydropower plant in combination with a polymer electrolyte membrane electrolyser

The most suitable electrolyser in combination with a hydropower plant is a PEM electrolyser. The PEM electrolyser allows to quickly reduce and increase the load and therefore be beneficial for the grid during increasing fluctuating renewables such as wind or PV. Suppose the renewables continue their development in installations on a theoretical basis. In that case, a PEM electrolyser with an HPP avoids the use of conventional power plants if the PEM load is reduced during high prices or during low supply of PV or wind. The impact of a small installation with 1.25 MW compared to the full installed capacity is relatively low. With a ramp-up of the electrolyser technology followed by decreasing installation costs, more and more electrolysers will find their way into the electricity market.

Besides the production of hydrogen, as long as resources are required, the manufacturing of the electrolyser with its material has to be considered.

5.1.1 Production of the hydrogen: Comparison of CO_2 emissions of conventional hydrogen with green hydrogen

Conventional (grey) hydrogen produced with the stream reformation out of natural gas is said to produce around 398 g/kWh (Bukold, 2020) of hydrogen. Each kg of hydrogen therefore is responsible for 13.27 kg of CO_2.

The production of hydrogen out of electricity produces emissions as well. Every renewable technology competes against conventional power plants in Germany's electricity market and suppresses or avoids the use of other conventional power plants regarding their load profile. Other renewable participants are not concerned with this analysis. The so-called avoidance factor is given in CO_2-Equivalent because each GHG emission has a different impact and it is easier to compare them if they are calculated back to CO_2. The avoidance factor for an HPP lays at 736 g/kWh CO_2-Equivalent (Lauf, Memmler, & Schneider, 2019). In theory, by taking the electricity of an HPP, conventional power plants have to compensate for the production and produce 736 g/kWh. This tells us that the electricity out of an HPP is very vulnerable in terms of GHG emission avoidance. As we require 62.30 kWh/kg of hydrogen, we produce a total CO_2-Equivalent production of 45.85 kg per kg hydrogen.

In a direct comparison, one might think, the hydrogen production out of natural gas 13.27 kg CO_2 per kg hydrogen) It is environmentally friendlier to use a hydropower plant's electricity, which has to be compensated by conventional power plants and, therefore, responsible for 45.86 kg CO_2 per kg hydrogen.

With increasing renewable capacity, a relatively massive share of the used electricity is not compensated by conventional power plants. Dependent on the point of view, the calculation can be done very differently. The emissions of an HPP itself are said to be at be 2.70 g/kWh CO_2-equivalent (Lauf, Memmler, & Schneider, 2019). A demand of 62.30 kWh per kilogram of hydrogen an HPP emits 0.17 kg per kg hydrogen. (This equals the specific emission of 5 g/kWh hydrogen.) The emissions do not include the emissions for the production of the PEM electrolyser itself. These emissions have to be included but should not increase the value dramatically for an electrolyser lifespan of 20 years. A side product of the PEM electrolyser (conventional and renewable) is heat. If useable, the heat could compete against a natural gas boiler and therefore avoids additionally 202 g/kWh (BAFA, 2019) summing it up to savings of 545 t of CO_2-equivalent per year.

Table 15 CO_2 Emissions of different ways to produce hydrogen (own calculation based on (BAFA, 2019))

	conventional. (avoiding factor)	*elect. mix Germany 2019*	*steam reformati on*	*HPP[8] electricity*	*heat uncoupling [9](18 kWh/kg)*
gCO_2/kWh H_2	736	401	398	2.7	- 202.00
gCO_2 per kg H_2	45.860	24.982	13.265	168	-3.636
$kgCO_2$ per kg H_2	**45,8**	**25,0**	**13.3**	**0.17**	**-3,64**
annual CO_2 in kg[10]	6.879.041	3.747.345	1.989.801	25.250	-545.400
annual CO_2 in t	6.879	3.747	1.989	25	-545

[8] Wind power onshore emits 10.497 g/kWh CO_2 equivalent and PV emits 66.73 g/kWh CO_2 equivalent
[9] Possible heat uncoupling with a rate of 18 kWh/kg competing against a natural gas boiler
[10] Outgoing from a hydrogen production of 150t per year

In direct comparison, the steam reformation produces fewer emissions than outgoing from the avoiding factor using conventional electricity. Even the emissions of the electricity mix of Germany in 2019 with 401 g/kWh (Umweltbundesamt, 2020) are higher than the steam reformation (even by including the heat uncoupling benefit). Significantly lower is the isolated contemplation of the HPP itself. With very low specific emissions, the HPP can only produce roughly 1 % of the emissions compared to the steam reformation. Including the heat uncoupling, the HPP is even able to save more emissions than producing.

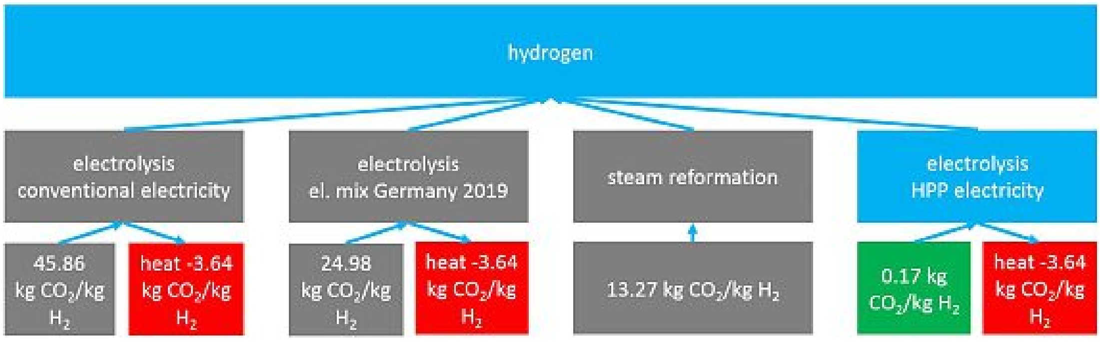

Figure 23 Emissions in kg CO_2 per kg of hydrogen during different ways to produce hydrogen (own representation based on Table 15)

5.1.2 Further use of the hydrogen compared to conventional counterparts – Gas grid injection

The environmental benefit does not end after the production. Various field of applications are thinkable:

- In industrial processes
- Injected into the gas grid (as natural gas replacement) and later be used for heating in a gas boiler, for gas power plants or for CHP plants
- In the transportation sector, competing diesel or gasoline cars and trucks

The environmental benefit concerning the use of hydrogen in industrial processes would exceed this thesis. If hydrogen competes against coal or natural gas, such as in steel production, the benefit is the saving of emissions during the process, excluding the emissions of the hydrogen production. As long as the production emits less than the actual process, the environment can benefit from it.

By injection into the gas grid, hydrogen competes against natural gas. As already mentioned, around 202 g/kWh are emitted if natural gas is burned in a modern boiler at about 100% efficiency. This value can change due to the efficiency of the boiler! Alternatively, natural gas can be used in natural gas-fired power plants or a CHP power plant. The classic gas-fired power plant has relatively high emissions of 570 to 750 g/kWh compared to the emissions of the CHP with 420 to 480 g/kWh (O'Donoughue et al., 2014). The difference between both types is the CHP's ability to uncouple the heat, use it in a district heating grid, and generate more energy (heat and electricity) out of the same amount of natural gas, equalling higher total efficiency. If the natural gas is now replaced by hydrogen, those emissions can be saved on a balance sheet.

The annual production of the 1.25 PEM electrolyser is around 150 t. This equals outgoing from the lower heating value (33.33 kWh/kg), a total supply of 5 GWh. A boiler running on hydrogen with the same efficiency would now avoid 1.000 t of CO_2 over a year. Approximately the annual storage capacity of 80.000 beeches (rule of thumb: 12.5 kg/a per beech).

5.1.3 Further use of the hydrogen compared to conventional counterparts – Transportation sector

The probably most practical further use of the hydrogen out of the HPP Böfinger Halde is perhaps the use in coaches, trucks, bin lorries, road sweepers or passenger cars. Apart from the fact that exciting vehicles are running on an ICE powered by hydrogen, the more common application is a vehicle with a fuel cell (FC) + hydrogen tank, a small battery and an electrical engine. The fuel cell continuously provides the electricity stored in the battery until required in the electrical motor. In general, a fuel cell electric vehicle (FCEV) can be seen as an EV despite the fact, the battery is much smaller and the electricity is coming from the fuel cell.

Table 16 Emission comparison of different vehicle types (data based on various sources)

	demand per 100 km	*demand per km*	*emissions per km*
ICE car (diesel)	6 l/100 km	600 Wh/km	159 g/km[11]
EV car (mix 2019)		140 Wh/km	60 g/km[12]
EV car PV		140 Wh/km	9 g/km[13]

[11] Outgoing from 2.65 kg of CO_2 per litre diesel (Deutscher Bundestag, 2019)
[12] Outgoing from the German electricity mix in 2019 with 427 g/kWh (Umweltbundesamt, 2020)
[13] Outgoing from the total lifecycle emissions of PV with 66 g/kWh (Lauf, Memmler, & Schneider, 2019)

FCEV car (steam ref.)	1 kg/100 km	333 Wh/km	133 g/km[14]
FCEV car (HPP)	1 kg/100 km	333 Wh/km	13.5 g/km[15]
ICE truck	35 l/100 km	3.500 Wh/km	927 g/km
FCEV truck	7.5 kg/100 km	2.497 Wh/km	95 g/km
ICE coach (public)	52 l/100 km	5.200 Wh/km	1.378 g/km
FCEV coach (public)	9 kg/100 km	2.997 Wh/km	122 g/km

In general, an FCEV running on green hydrogen can save up to 90% of the emissions an ICE vehicle would produce. Even the EV emits more than the FCEV if Germany's electricity mix powers the EV. Only purely solar electricity fuelled EV has fewer emissions than an FCEV running on green hydrogen. If the whole hydrogen of 150 t per year would fuel a single FCEV, the FCEV could drive approximately 15 Mio. km. With savings of 145 g/km compared to the ICE diesel car, the FCEV could save 2.220 t of CO_2 per year. The same done for the coaches saves (1.9 Mio. km and 1.256 g/km) 2.386 t of CO_2 per year. A big problem is the use of conventional grey hydrogen produced with the steam reformation. By using grey hydrogen in an FCEV, the emissions are nearly as high as in an ICE and result in no benefit to the environment. The use of grey hydrogen is not advisable.

Comparing the savings in the transportation sector with the heating sector's savings, the use of hydrogen in the transportation sector seems far more reasonable. This might change if the hydrogen does not compete against a natural gas boiler but against a heating oil fired boiler.

5.1.4 Environmental impact of the platinum

Extracting conventional fuels out of the ground and later burning them are responsible for a huge amount of human-made emissions. The extraction and the burning whiteout doubt transform the landscape and even destroy it. The current mostly used battery technology is based on lithium iron bonds. Besides Lithium, cobalt is required and therefore is highly debated due to the fact; it is a limited natural resource. Resources are usually in the soil and require an intrusion into nature, destroying nature.

[14] From figure 24
[15] Outgoing from the total lifecycle emissions of HPP with 25 g/kWh (Lauf, Memmler, & Schneider, 2019) and an electricity demand of 52 kWh per kg hydrogen

Nevertheless, batteries can be recycled and if feed with green electricity, batteries savour a very green image. The so said very clean and environmentally friendly electrolyser only requires water and therefore, as well, has a very positive impression. But, as the battery, the electrolyser also requires natural resources. The AEL requires potassium, nickel, cobalt, iron and/or zirconium. Zirconium itself on earth is not as rare as it seems to be but is widely distributed at a low concentration. The PEM electrolyser requires platinum, another rare metal. Platinum itself is a relatively expensive metal with around 27.000 €/kg, nearly half the price of gold (~48.000 €/kg). Due to the high price, the recycling management is said to work for platinum with a rate of 60 to 70% (Schmidt, 2015). Nevertheless, platinum has to come from somewhere if the demand is increasing. In 2013 73 % of the around 190 t extracted platinum had its origin in South Africa, followed by the Russian confederation with 12.9% (Schmidt, 2015). South Africa mostly covers the increasing international demand. The huge problem is the rigorous intercourses with the South African rural, agriculture-dependent population. Around 70 Million litres of groundwater are daily pumped up (Bahadur, Leifker, & Lincoln, 2018), mainly for cooling and reduction of the rise of the dust. The problem in the mining areas is the already existing water scarcity. The aluminium, uranium or other toxic minerals contaminated water pollutes the groundwater and farming land. Besides the groundwater, the industrial complexes are guilty of polluting the air with dust and sulphur dioxide.

In areas where platinum is to be expected, the rural populace is either relocated or forced to work in the mines without any social compensation. The whole mining is very critical. Besides the social problems, the environmental impact of platinum in South Africa are another huge problem. The primary energy carrier in South Africa is coal. This results in even more significant CO2 emissions of 9.18 t per capita than China, Brazil or India (Bahadur, Leifker, & Lincoln, 2018). The literature does not provide o detailed information about the emissions of the platinum mines. Besides emissions, the vast amount of moved earth might show the problems with platinum. With a content of platinum in a range of 5.37 g to 3.42 g per ton (Mining Technology, 2020) and an annual production of 139 t, around 25.9 Million tons to 40.6 Million tons of soil are moved and searched annually in South Africa.

If the electrolyser has a capacity of 1 MW and operates at 400 V, we have a current of 2.500 A. If the maximal electrical is 3 A/cm², 833.3 cm² is the required membrane area. The literature provides an amount of around 1.0 mg/cm² (Langemann, 2016) which adds up to 0.833g of platinum for a 1 MW PEM electrolyser. With a maximal electrical current of 2 A/cm², the platinum demand is around 1.25 g per 1 MW. Concerning the lifetime of a stack with around seven years, a 20-year operation requires three stacks and therefore, the platinum demand is three times higher. After several hours of operation, the platinum itself is corroded and therefore no longer suitable as a catalyst. Recycling of those membranes is, to a certain degree, possible. The platinum and other rare metals can be extracted and reused.

5.1.5 Environmental impact due to the transportation of the final products

In the usual well to wheel discussion, the effect of the transportation is usually a big point if the natural gas or crude oil is transported via ship several thousand kilometres over the globe and even further. Arguably, the green hydrogen out of the electrolyser is supposed to be produced close to its demand. The hydrogen transport itself shall ideally be quite short and will mostly be done by a truck.

The containerized storage unit from chapter 4.1.3 weighted 10 t and could carry a bit more than a half-ton of hydrogen. Assuming a truck could take two units, around one ton of hydrogen would be moved. Such transportation is very similar to the ones to a normal fuel station with the difference of the amount of a transported fuel. A single truck can carry way more conventional fuel (maybe 30.000 l) than a hydrogen truck. Those 30.000 l of diesel equal around 300 MWh, whereas the 1 t of hydrogen only has an energy content of 33 MWh. The fuel consumption of a diesel ICE truck may lay in a range of 50l per 100 km. This might be higher than average, but the last few kilometres of such transportation are usually in urbanized areas and therefore stop and go traffic, increasing the consumption.

If the transport is 100 km long, one litre of diesel in an ICE truck can transport 666 kWh or 20 kg of hydrogen while producing around 2.6 kg of CO2. This means one kg of transported hydrogen is responsible for 130g of CO_2 per 100 km. One litre of diesel in an ICE truck can transport 6 MWh or 600 l of diesel while producing around 2.6 kg of CO_2. So said, one kg of transported diesel is responsible for 4.3 g of CO_2 per 100 kg. Quite a vast difference, but we only took into perspective the last few kilometres for diesel. Hydrogen itself is nearly emission-free until it is transported, whereas diesel has a very long and emission intense journey until reaching the fuelling station. Nevertheless, if the hydrogen is produced and then transported, why not consider a fuel cell-powered truck for transportation?

5.2 Economic feasibility of the electrolyser combined with a hydropower plant

Environmental friendliness is one side of the coin; the other is economic feasibility. First of all, a project shall generate more revenues than costs. A profit and loss analysis regarding the SWU standards was made. The target was to see if such a project can be economically feasible in the current market situation and, if so, at what price can the hydrogen be produced. The price of hydrogen at the fuelling stations is at 9.50 €/ kg. As the fulling station operator and the transporter have costs and want to generate revenues, the actual sales price before transportations has to be lower. The Centre of Solar energy and Hydrogen Research Baden-Württemberg (Zentrum für Sonnenenergie- und Wasserstoff-Forschung Baden-Württemberg ZSW) already discussed such a topic. In a calculation about the maximal acquisition costs (Balzow, Jenne, Jörissen, Schlumberger, & Schwarz, 2017), the costs are highly dependent on the distance and the annual demand at the fuelling station. The maximal acquisition costs are displayed in Table 17 for two cases of daily demand

Table 17 Acquisition costs for hydrogen at the fuelling station and at the plant site (based on (Balzow, Jenne, Jörissen, Schlumberger, & Schwarz, 2017)

	price for 212 kg/d	*price for 420 kg/d*
Sales price at the fuelling station	9.50 €/kg	9.50 €/kg
Maximal price at the fuelling station	6.05 €/kg	7.05 €/kg
Maximal price at the production site with a transport distance of 10 km	5.80 €/kg	6.80 €/kg
Maximal price at the production site with a transport distance of 50 km	5.56 €/kg	6.56 €/kg
Maximal price at the production site with a transport distance of 100 km	5.26 €/kg	6.26 €/kg

Two calculations were made: one for the electrolyser at the HPP Böfinger Halde and one at the transfer station Steinhäule. For both calculations, the following parameters were the same:

The profit a loss calculation uses the net present value method.

The plant itself is built and finished in 2022 (year 0) and start to produce hydrogen in the year 2022; the project runtime is 20 years + the initial year 2022

The revenues increase annually with -0.5% (it is actually a decrease) for all sales (hydrogen, heat and oxygen)

The electricity costs increased annually at a rate of 3.0% regarding the price forward curve, starting at 4 ct/kWh in 2022 and reaching an electricity price of 5.22 ct/kWh in 2031 and 7.22 ct/kWh in 2042.

The O&M cost increase is set at 1,5% annually. The operation and maintenance have annual costs of 15 €/kW. The insurance fee is unknown. Therefore, the yearly fee was at 15€/kW in total.

The interest rate is, according to SWU standards, 3.34%

The costs according to Table 13 & 14 without the options was used as the investment in year 0

In year seven and year 15, the stacks were exchanged or refurbished. The costs for the stacks change in both years was 250 €/kW. A cost decrease was not taken into account.

5.2.1 Electrolyser at the hydropower plant Böfinger Halde

If the PEM electrolyser installation is done directly at the HPP plant side, the project struggles to gain additional benefits from heat or oxygen sales. Besides a lack of sales, the extra investment for (a single) storage system increases the investment. It is worth mentioning; the hydrogen sales price was set at 5 €/kg, which is still lower than the price evaluated in Table 17. The total investment, as displayed in the appendices, is nearly 2.95 Mio. €, including the stack exchange in year seven and fifteen. €. Additional Investment such as the fuelling station or a transport lorry might be necessary. The annual revenues in year 0 start at 810.000 €.

Nevertheless, the project rate of return is 3%, with a capital value of -34.000 € after 20 years (see Appendix 1). The investment is paid off after twelve years. In general, the project provides revenues until year fifteen (2037). As the electricity price reaches a level of around 6.0 ct/kWh, the costs for producing hydrogen exceed the continuously dropping hydrogen sales. In the year 2037, the hydrogen price at that time declined to 4.52 €/kg. This effect explains the dropping accumulated cash value (grey) and the relatively low capital value after 20 years. Still, under these conservative assumptions at year 15, the capital reaches nearly 0.5 Mio. € until the stack refurbishment has to be paid. At the point where the cost exceeds the revenues, an alternative operation strategy might be suitable. If the average electricity price exceeds the 6.0 ct/kWh border, the annual hydrogen production should be lowered while avoiding high prices. This would surely lower the revenues, due to the fact, less hydrogen is produced, but as well reduces the costs to a certain amount because less electricity is consumed.

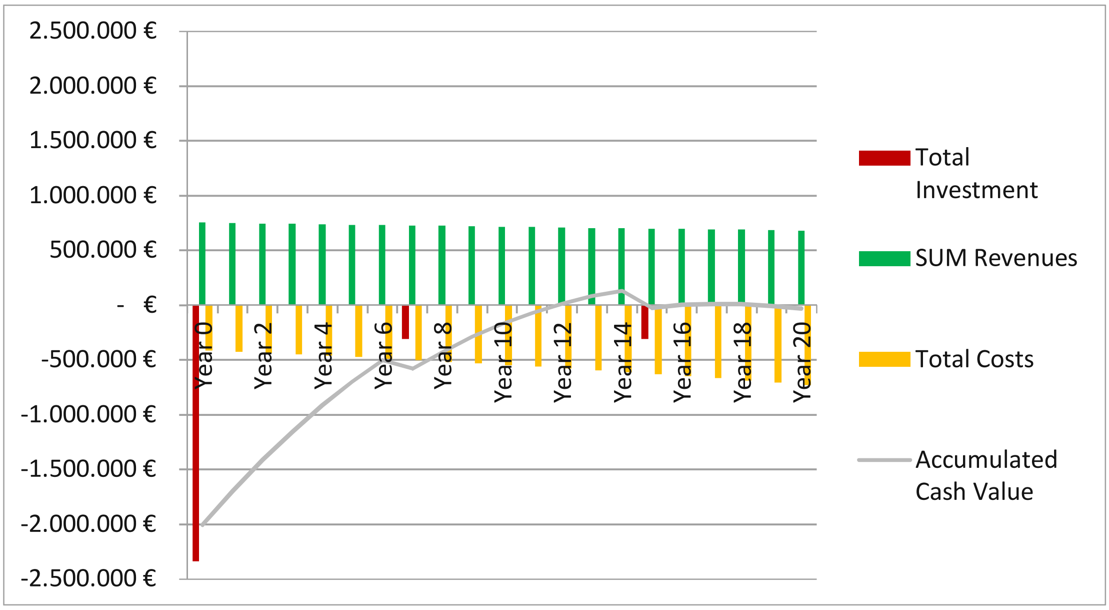

Figure 24 Profit and loss statement of the PEM electrolyser at the HPP Böfinger Halde (own representation)

5.2.2 Electrolyser at the transfer station Steinhäule

A PEM electrolyser at the transfer station is optimized compared to the electrolyser at the HPP Böfinger Halde. In general, the PEM installation directly at the HPP may, to a certain degree, be copied to any other hydropower plant and maybe even to a wind park.

By locating the PEM electrolyser at the transfer station Steinhäule, the heat is used and therefore sold. Arguably, with sign contracts, the oxygen can be transported and sold to the sewage plant. In this case, the oxygen purity might not be of great concern. For the cost-benefit analysis, the oxygen sales, as well as the required infrastructure, were included in the calculation. Nevertheless, no detailed information exchange with the sewage plant operator was possible.

The total investment is around 100.000 € lower and lays at 2.85 Mio. €. Combined with revenues of 830.000 € in year null, the project rate of return is an astonishing 13,83% (see Appendix 2). Reaching an amortization after four years, the capital value after the project runtime of 20 years is at 1.231.000 €. The additional revenues due to heat sales (30.000 €) and oxygen (61.000 €) dramatically increase the project profitability. Nevertheless, even in this case, the high electricity price lowers the project profitability in the last years.

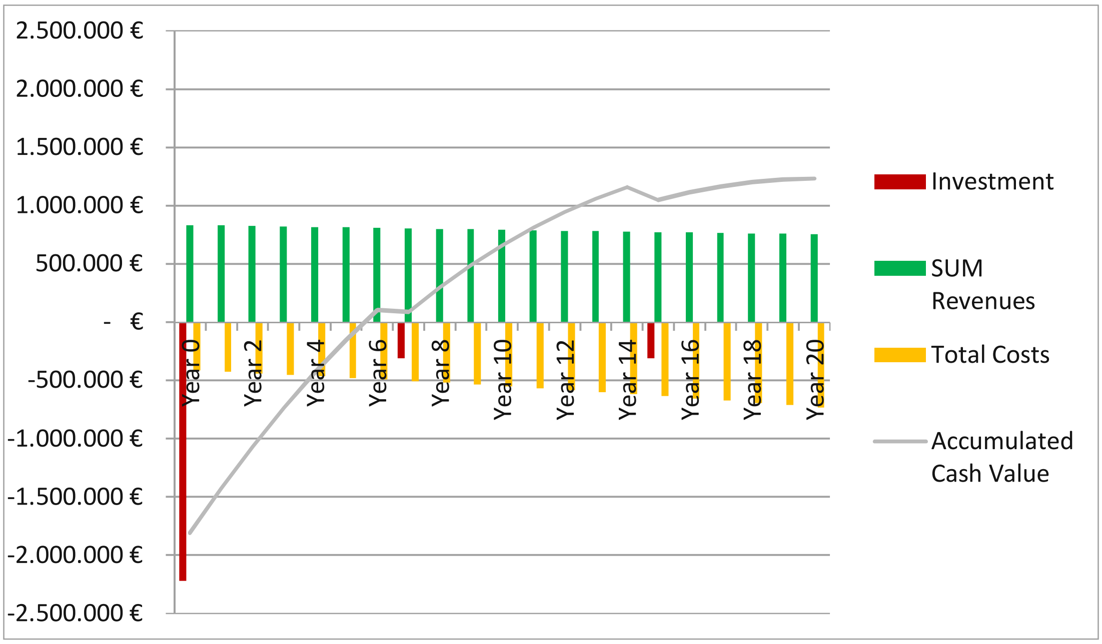

Figure 25 Profit and loss statement of the PEM electrolyser at the transfer station Steinhäule (own representation)

5.2.3 Sensitivity analysis

A sensitivity analysis, if done correctly, can be a great indicator of a project's feasibility. One way to prove the feasibility is to lower the revenues by reducing the produced product's sales price. Both calculations were initially done with a sales price of 5 €/kg of hydrogen, which is according to Table 18, around 0.26 €/kg lower than an assumed maximal sales price. The price of 5 €/kg was set to have a decent buffer between the maximum sales price. Such a buffer can be quite comfortable in terms of investment increases or operation cost increases. A project might still be feasible as long as the capital value is positive after the project runtime.

In the first step, the said price for the hydrogen was adjusted. As every other factor stays the same, the earlier explained trend during the last years of operation due to the increasing electricity price is still impacting the results. In both cases, the hydrogen price drop says the same, meaning a price decrease of 0.5% per year. For the HPP PEM electrolyser, the lowest possible sales price for the hydrogen is already reached due to the fact, the capital value is negative. If the PEM electrolyser is installed at the transfer station where additional revenues can be achieved, an even lower hydrogen price might be possible due to the higher profitability. In this case, the sensitivity analysis showed that at a price of 4,44 €/kg of hydrogen in year 0, the project is barely economically feasible with a negative capital value of 8.000 €. In year 20, the price dropped to 4.02 €/kg (instead of 4.52 €/kg).

Alternatively, hydrogen revenues can decrease over time. As the capital value is already negative for the electrolyser at the transfer station, a hydrogen price drop of 0,46% allows the project to gain a positive capital value. The PEM electrolyser at the transfer station allows a hydrogen price decrease of 1.75% annually, resulting in 3.51 €/kg in 2042.

A third possibility is to adjust the electricity price trend. While the price in year 0 (2022) starts at 4.00 ct/kWh, the annual electricity price increase remains at 3.00%. As the PEM electrolyser's profitability at the HPP is already quite tight, the maximal annual price increase cannot go up anymore. Apparently, at an annual increase of 2.95% the capital value starts to become positive. This yearly increase of 2,95% results in an electricity price of 6.01 ct/kWh in 2036 and 7.15 ct/kWh in 2042. Under the condition that the PEM electrolyser is installed at the transfer station, the annual electricity price increase can reach 4.53% resulting in a price of 7.44 ct/kWh in 2036 and 9.70 ct/kWh in 2042.

6 Conclusion

Hydrogen might be a solution for various problems concerning the energy transition in Germany and the sector coupling. The future importance of hydrogen is undeniable, but it is still at the beginning of the, hopefully successful, integration process. Coming hand in hand with the low density of hydrogen, a bit of a storage and transportation problem remains. Nevertheless, the various future fields of applications and as the development around the use of hydrogen can generate a huge demand for hydrogen. As long as renewable energy systems produce the hydrogen either with biogas or via electrolysis, hydrogen can have its part in battling the climate crisis.

Out of the three known electrolyser technologies (AEL short for alkaline electrolyser, PEM short for polymer electrolyte membrane electrolyser and HTEL short for high-temperature electrolyser) only the PEM electrolyser seems to be compatible with the fluctuating electricity production of renewable energy systems. Reasons, therefore, are relatively simple. The PEM can continually decrease and increase its electricity demand, adapting the renewable energy system load relatively fast while still being able to run at a minimal load of around 10% to 20% or even start-up from cold quite quickly.

To be more specific, just two of the major renewable energy systems should be taken into perspective while analysing an electrolyser's implementation: Hydropower and wind power. For the PV, the lack of full load hours might be a problem in Germany's geographical region. For biomass, well, producing a gas, burning it in an internal combustion engine and later use the electricity to produce a gas again seems quite contentious. While the market ramp-up of electrolysers is still initially, the costs for an electrolyser are higher until a certain degree of mass production is possible. Due to relatively high investment and an already existing pressure on the hydrogen sales price, only a few adjusting screws are available: low costs for the electricity consumption and high full load hours. While the costs for electricity production are, more or less, equal for PV, wind and hydro, the full load hours of these three technologies vary enormously. If planned correctly, an HPP provides a kind of baseload generation – ideal for an electrolyser.

The hydropower plant Böfinger Halde in Ulm at the Danube with 9.1 MW installed capacity was used to analyse a PEM electrolyser's economic and ecological feasibility in combination with the said hydropower plant. A 1.25 MW electrolyser was installed with the target to run as a baseload plant, producing as much as possible hydrogen and being price-oriented, meaning to shut down during high electricity prices and participate in the secondary reserve market. Because of this operation, the containerized PEM electrolyser runs at approximately 7.300 full load hours, producing 150t of hydrogen per year. Even with a total investment of around 3.0 Mio. € and with average electricity costs of 4 ct/kWh in the year 2022 (+3% increase per year), the electrolyser can produce 1kg of hydrogen at a price of around 5 €/kg. Compared to a possible sales price of around 6 €/kg, the electrolyser seems to be economic feasible. Two plant sites for the electrolyser where analysed. One directly at the HPP and one close to a natural gas transfer station. In the second case, the heat and the oxygen could be used as well. Advisable is a complete use of all products of possible. Such an operation increases the revenues. Understandably, the electrolyser at the natural gas transfer station performed better in the profit and loss statement. With a relatively high amount of full load hour, provided by the HHP, the electrolyser can be operated economic feasible. The most significant problems, the storing and the demand side remains. In this specific investigation, a natural gas storage system in the transfer station Steinhäule fits the requirements and allows at least storing the hydrogen. Additionally, negotiations are thinkable to use the produced oxygen in a sewage plant on the other side of the river. Even use for the excess heat is possible. By using all the electrolyser products (heat hydrogen and oxygen) and using existing natural gas storage capacities for this specific plant site at the transfer Station, the economic feasibility improves and allows an even lower price for the hydrogen. The investigation showed an increasing electricity price (with at least staying revenues for the hydrogen) can be buffered to a certain degree.

The produced 150 t green hydrogen per year, benefit the environment in two ways. hydrogen is used in several processes and mostly produced via steam reformation out of natural gas. The steam reformation is responsible for around 13,3 kg CO_2 per kg H_2. In comparisons, the electrolyser with HPP electricity is responsible for around 0,2 kg CO_2 per kg H_2. Meaning, without including a benefit from the heat-usage of the electrolyser, the production of 150 t H_2 with green electricity can save 1.950 t of CO_2

per year. Nevertheless, the steam reformation produces fewer emissions compared to an electrolyser running with conventional electricity or even the electricity mix of Germany in 2019. The other benefit for the environment is at the consumption side. The probably environmental friendliest way to use hydrogen is the use in the transportation sector. The savings, compared to conventional fuels is huge. While an diesel powered car is responsible for 15,9 kg/100 km, the fuel cell vehicle (powered with HPP hydrogen) emits 1,35 kg/ 100km. As a fuel cell vehicle uses around 1 kg of hydrogen per 100 kg, the fuel cell vehicle could drive 15.000.000 km with 150 t of hydrogen for our electrolyser. By doing so, around 2.200 t of CO_2 can be saved. By converting the public transportation sector (52 coaches) of the local energy supplier in Ulm to fuel cell coaches, the whole amount of hydrogen could quickly develop a sustainable public transportation sector.

Nevertheless, besides emission savings, the requirement of e.g. platinum for the electrolyser has to be considered. Most of the, in the stacks used, platinum has its origin in South Africa. The platinum mines are responsible for ground water pollution and are said to suffer from proper worker protection. Therefore a proper recycling process for old stacks, to reuse the platinum, should be compulsory.

From a technical and economic perspective, an electrolyser can provide several benefits. Before installing an electrolyser to produces green hydrogen, several requirements have to be fulfilled:

The demand side of the hydrogen has to be clear. Ideally, signed long-term contracts at the same company or horizontal integration provide some project safety.

An additional use for the excess heat would be ideal. A problem remains with the relatively low-temperature level of 65°C, making it barely useful for district heating. Maybe preheating the backflow or in industrial processes.

An additional use for the oxygen, ideally without improving the oxygen's purity, can boost the economic feasibility.

Cheap storage solutions and possible short distances to the demand side are crucial.

A suitable and secure plant site due to the fact, hydrogen is quite flammable and therefore needs to be handled with care.

Last but not least, the water supply. Usually, a containerized electrolyser has a water purification but the water still has to come from somewhere.

In the long run, while achieving the climate goals, hydrogen will be a player in the energy economy and, on a large scale, even might solve long term electricity storage difficulties, as mentioned in chapter 1. At the current stage and with the new reworking of the EEG 2021, resulting in a tax exemption, all renewable power plants can generate hydrogen relatively cheap. Due to a rather non-transparent market, the demand side remains a problem. A clear recommendation can be given: Unless there is a stable demand side concerning hydrogen in a closer area around a (preferably hydropower) plant, the plant operator should consider the operation of an electrolyser. A feasibility improvement is possible by finding consumers for the heat and the oxygen. Again, a price oriented hydrogen production, without lowering the full load hours to much, should still be a core objective while operating the electrolyser

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List of abbreviations

Abbreviations

1	A	ampere
2	AEL	alkaline water electrolysis
3	°C	degree Celsius
4	CAPEX	capital expenditure
5	CNG	compressed natural gas
6	CH_4	methane (natural gas)
7	CHP	Combined Heat and Power
8	CO	carbon monoxide
9	CO_2	carbon dioxide
10	Ct	Euro cents
11	dm	decimetre
12	EEG	Erneuerbare Energien Gesetz (Renewable Energy Law)
13	EnWG	Energiewirtschaftsgesetz (Energy Economic Law)
14	EPEX SPOT	European Energy Exchange
15	EV	electric vehicle
16	FeO	iron (lat. Ferrum) oxide
17	FLH	full load hours
18	G	gravitational acceleration
19	g	gram
20	GH_2	Compressed gaseous hydrogen
21	GHG	Greenhouse gas
22	GmbH	Gesellschaft mit beschränkter Haftung (Limited Liability Company)
23	GW(h)	giga Watt (hour)
24	h	head
25	H_2	hydrogen
26	H_2O	water
27	HPP	hydro power plant
28	HTEL	high-temperature electrolysis
29	I	current in ampere
30	ICE	internal combustion engine
31	IEA	International Energy Agency
32	K	Kelvin (temperature)
33	Kg	kilo gram

34	KOH	potassium (lat. Kalium) hydroxide
35	kW(h)	kilo Watt (hour)
36	LH_2	liquid hydrogen
37	Li-Ion	lithium ion
38	LNG	liquefied natural gas
39	m	meter
40	mJ	Millijoule
41	MPa	Million Pascal
42	Mt	million tons
43	Mtoe	million tons oil equivalent
44	MW(h)	mega Watt (hour)
45	N	Newton
46	Ni	nickel
47	NIP	Nationales Innovationsprogramm Wasserstoff- und Brennstoffzellentechnologie
48	Nm^3	norm cubic meter
49	NOW	Nationale Organisation Wasserstoff (national Organisation hydrogen)
50	O_2	oxygen
51	OH^-	hydroxide ions
52	OPEX	operational expenditure
53	P	power
54	PEM	polymer electrolyte membrane
55	P_{el}	electrical power
56	P_{kin}	kinetic power
57	ppm	parts per million
58	PV	photovoltaic(s)
59	Q	discharge
60	SARS CoV 2	severe acute respiratory syndrome coronavirus 2
61	SWU	Stadtwerke Ulm (energy supplier in Ulm)
62	t	tons
63	toe	tons oil equivalent
64	TW(h)	terra Watt (hour)
65	U	voltage in volt
66	V	volt
67	yr	year

68	ZrO_2	zirconium dioxide
69	η	(gre.: eta) efficiency
70	ρ	(gre.: rho) density
71	€	Euro

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Appendixes

Economic Feasability		Date:	13.10.2020				
Electrolyser at the HPP Böfinger Halde				Capacity electrolyser	1.250 kW	price hydrogen	5 €/kg
				annual electricity demand	9.375.000 kWh	price heat	3,5 ct/kWh
		Revenue increase	-0,50%	annual FLH	7500	price oxygen	
Project Runtime	21	Electricty price increase	3,00%	annual hydrogen production	150.000 kg	price electricity in 2022	4,00 ct/kWh
Start in the year	2022	Cost increasement	1,50%	operation and maintenance	15 €/kW		
		Interest	3,34%	insurance (maschine)	10 € €/kW		
				insurance (fire)	5 €/kW		

Price of electricity	
in 2024	4,24
in 2026	4,50
in 2031	5,22
in 2036	6,05
in 2042	7,22

		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Investment 1	electrolyser	2.000.000 €							312.500 €			
Investment 2	foundation electrolyser	5.000 €										
Investment 3	storage system & fuelling infrast.	270.000 €										
Investment 4	foundation storage system	5.000 €										
Investment 5	mobile crane (for the installation)	3.500 €										
Investment 6	electrical connection 400 V	12.000 €										
Investment 7	network connection	1.000 €										
Investment 8	tap water connection	1.500 €										
Investment 9	waste water connection	1.000 €										
Investment 10	gas grid connection	35.000 €										
Investment 11	fence (around 65 m)	6.000 €										
Investment 12	gate for the fence	2.000 €										
Investment 13												
Investment 14												
Investment 15												
	SUM Investment	**2.342.000 €**	- €	- €	- €	- €	- €	- €	**312.500 €**	- €	- €	- €
Revenues 1	hydrogen sales	750.000 €	746.250 €	742.519 €	738.806 €	735.112 €	731.437 €	727.779 €	724.140 €	720.520 €	716.917 €	713.333 €
Revenues 2	heat sales	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Revenues 3	oxygen sales	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
	SUM Revenues	**750.000 €**	**746.250 €**	**742.519 €**	**738.806 €**	**735.112 €**	**731.437 €**	**727.779 €**	**724.140 €**	**720.520 €**	**716.917 €**	**713.333 €**
Costs 1	electricity consumption	375.000 €	386.250 €	397.838 €	409.773 €	422.066 €	434.728 €	447.770 €	461.203 €	475.039 €	489.290 €	503.969 €
Personal costs 2			- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Personal costs 3			- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
	SUM O&M Costs	375.000 €	386.250 €	397.838 €	409.773 €	422.066 €	434.728 €	447.770 €	461.203 €	475.039 €	489.290 €	503.969 €
Cost 1	operation and maintanace	18.750 €	19.031 €	19.317 €	19.606 €	19.901 €	20.199 €	20.502 €	20.810 €	21.122 €	21.439 €	21.760 €
Cost 2	water consumption	700 €	711 €	721 €	732 €	743 €	754 €	765 €	777 €	789 €	800 €	812 €
Cost 3	Insurance (maschine)	12.500 €	12.688 €	12.878 €	13.071 €	13.267 €	13.466 €	13.668 €	13.873 €	14.081 €	14.292 €	14.507 €
Cost 4	Insurance (fire)	6.250 €	6.344 €	6.439 €	6.535 €	6.634 €	6.733 €	6.834 €	6.937 €	7.041 €	7.146 €	7.253 €
Cost 5	metering (electricity)	800 €	812 €	824 €	837 €	849 €	862 €	875 €	888 €	901 €	915 €	928 €
Cost 6	metering (gas)	800 €	812 €	824 €	837 €	849 €	862 €	875 €	888 €	901 €	915 €	928 €
Cost 7	logistic/transportation		- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Cost 8			- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
	SUM Costs	39.800 €	40.397 €	41.003 €	41.618 €	42.242 €	42.876 €	43.519 €	44.172 €	44.834 €	45.507 €	46.190 €
	SUM Total Costs	**414.800 €**	**426.647 €**	**438.840 €**	**451.391 €**	**464.308 €**	**477.604 €**	**491.289 €**	**505.375 €**	**519.873 €**	**534.797 €**	**550.158 €**

		Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
											4,52 €
		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Investment 1	electrolyser					312.500 €					
Investment 2	foundation electrolyser										
Investment 3	storage system & fuelling infrast.										
Investment 4	foundation storage system										
Investment 5	mobile crane (for the installation)										
Investment 6	electrical connection 400 V										
Investment 7	network connection										
Investment 8	tap water connection										
Investment 9	waste water connection										
Investment 10	gas grid connection										
Investment 11	fence (around 65 m)										
Investment 12	gate for the fence										
Investment 13											
Investment 14											
Investment 15											
	SUM Investment	- €	- €	- €	- €	**312.500 €**	- €	- €	- €	- €	- €
Revenues 1	hydrogen sales	709.766 €	706.217 €	702.686 €	699.173 €	695.677 €	692.198 €	688.737 €	685.294 €	681.867 €	678.458 €
Revenues 2	heat sales	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Revenues 3	oxygen sales	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
	SUM Revenues	**709.766 €**	**706.217 €**	**702.686 €**	**699.173 €**	**695.677 €**	**692.198 €**	**688.737 €**	**685.294 €**	**681.867 €**	**678.458 €**
Costs 1	electricity consumption	519.088 €	534.660 €	550.700 €	567.221 €	584.238 €	601.765 €	619.818 €	638.412 €	657.565 €	677.292 €
Personal costs 2		- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Personal costs 3		- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
	SUM O&M Costs	519.088 €	534.660 €	550.700 €	567.221 €	584.238 €	601.765 €	619.818 €	638.412 €	657.565 €	677.292 €
Cost 1	operation and maintanace	22.087 €	22.418 €	22.754 €	23.095 €	23.442 €	23.793 €	24.150 €	24.513 €	24.880 €	25.254 €
Cost 2	water consumption	825 €	837 €	849 €	862 €	875 €	888 €	902 €	915 €	929 €	943 €
Cost 3	Insurance (maschine)	14.724 €	14.945 €	15.169 €	15.397 €	15.628 €	15.862 €	16.100 €	16.342 €	16.587 €	16.836 €
Cost 4	Insurance (fire)	7.362 €	7.473 €	7.585 €	7.698 €	7.814 €	7.931 €	8.050 €	8.171 €	8.293 €	8.418 €
Cost 5	metering (electricity)	942 €	956 €	971 €	985 €	1.000 €	1.015 €	1.030 €	1.046 €	1.062 €	1.077 €
Cost 6	metering (gas)	942 €	956 €	971 €	985 €	1.000 €	1.015 €	1.030 €	1.046 €	1.062 €	1.077 €
Cost 7	logistic/transportation	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Cost 8		- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
	SUM Costs	46.882 €	47.586 €	48.299 €	49.024 €	49.759 €	50.506 €	51.263 €	52.032 €	52.813 €	53.605 €
	SUM Total Costs	**565.970 €**	**582.246 €**	**599.000 €**	**616.245 €**	**633.997 €**	**652.271 €**	**671.081 €**	**690.445 €**	**710.377 €**	**730.897 €**

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Interest	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
	1,000	0,968	0,936	0,906	0,877	0,849	0,821	0,795	0,769	0,744	0,720
Profit minus Loss	- 2.006.800 €	319.603 €	303.679 €	287.416 €	270.804 €	253.833 €	236.491 €	- 93.734 €	200.647 €	182.120 €	163.174 €
Cash Value	- 2.006.800 €	309.273 €	284.366 €	260.438 €	237.455 €	215.380 €	194.179 €	- 74.476 €	154.271 €	135.501 €	117.481 €
Accumulated Cash Value	- 2.006.800 €	-1.697.527 €	-1.413.161 €	-1.152.723 €	- 915.268 €	- 699.888 €	- 505.708 €	- 580.185 €	- 425.914 €	- 290.413 €	- 172.932 €

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Interest	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
	0,697	0,674	0,652	0,631	0,611	0,591	0,572	0,554	0,536	0,518
Profit minus Loss	143.796 €	123.971 €	103.686 €	82.928 €	- 250.820 €	39.928 €	17.656 €	- 5.151 €	- 28.510 €	- 52.439 €
Cash Value	100.183 €	83.579 €	67.644 €	52.353 €	- 153.227 €	23.604 €	10.100 €	- 2.851 €	- 15.272 €	- 27.182 €
Accumulated Cash Value	- 72.749 €	10.830 €	78.475 €	130.828 €	- 22.399 €	1.204 €	11.305 €	8.453 €	- 6.819 €	- 34.001 €

Capital Value:	- 34.001 €	Project rate of return	2,96%
		Amortisation	19 Years

Appendix 1 Profit and loss statement for the PEM electrolyser at the HPP Böfinger Halde

Economic Feasability
Electrolyser at the transfer station "Steinhäule"

Date 13.10.2020

Project Runtime	21	Revenue increase	-0,50%
Start in the year	2022	Electricty price increase	3,00%
		Cost increasement	1,50%
		Interest	3,34%

Capacity electrolyser	1.250	KW
annual electricity demand	9.375.000	KWh
annual FLH	7500	h
annual hydrogen productio	150.000	kg
operation and maintenance	15	€/kW
insurance (maschine)	10 €	€/kW
insurance (fire)	5	€/kW

annual heat supply transfe	850.000	KWh
annual heat supply rest	2.390.000	KWh
annual oxygen supply	1.710.000	Nm³
price hydrogen	15	ct/kWh
price hydrogen	5	€/kg
price heat	3,5	ct/kWh
price oxygen	0,03	€/Nm³
price electricity in 2022	4,00	ct/kWh

Price of electricity	
in 2024	4,24
in 2026	4,50
in 2031	5,22
in 2036	6,05
in 2042	7,22

4,52 €

		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Investment 1	electrolyser	2.000.000 €							312.500 €								312.500 €					
Investment 2	foundation electrolyser	5.000 €																				
Investment 3	storage system & fuelling infrast.	- €																				
Investment 4	foundation storage system	- €																				
Investment 5	mobile crane (for the installation)	3.500 €																				
Investment 6	electrical connection 400 V	42.900 €																				
Investment 7	transformer	1.000 €																				
Investment 8	network connection	1.000 €																				
Investment 9	tap water connection	2.000 €																				
Investment 10	waste water connection	1.500 €																				
Investment 11	gas grid connection	5.000 €																				
Investment 12	fence (around 65 m)	- €																				
Investment 13	gate for the fence	- €																				
Investment 14	adjustment storage system	10.000 €																				
Investment 15	connection to the heating grid	50.000 €																				
Investment 16	oxygen gas grid to sewage plant	90.750 €																				
Investment 17	oxygen auxiliaries	10.000 €																				
	SUM Investment	**2.222.650 €**	- €	- €	- €	- €	- €	- €	**312.500 €**	- €	- €	- €	- €	- €	- €	- €	**312.500 €**	- €	- €	- €	- €	- €
Revenues 1	hydrogen sales	750.000 €	746.250 €	742.519 €	738.806 €	735.112 €	731.437 €	727.779 €	724.140 €	720.520 €	716.917 €	713.333 €	709.766 €	706.217 €	702.686 €	699.173 €	695.677 €	692.198 €	688.737 €	685.294 €	681.867 €	678.458 €
Revenues 2	heat sales to transfer station	29.750 €	29.601 €	29.453 €	29.306 €	29.159 €	29.014 €	28.869 €	28.724 €	28.581 €	28.438 €	28.296 €	28.154 €	28.013 €	27.873 €	27.734 €	27.595 €	27.457 €	27.320 €	27.183 €	27.047 €	26.912 €
Revenues 3	heat sales rest		- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Revenues 4	oxygen sales	51.300 €	51.044 €	50.788 €	50.534 €	50.282 €	50.030 €	49.780 €	49.531 €	49.284 €	49.037 €	48.792 €	48.548 €	48.305 €	48.064 €	47.823 €	47.584 €	47.346 €	47.110 €	46.874 €	46.640 €	46.407 €
	SUM Revenues	**831.050 €**	**826.895 €**	**822.760 €**	**818.646 €**	**814.553 €**	**810.480 €**	**806.428 €**	**802.396 €**	**798.384 €**	**794.392 €**	**790.420 €**	**786.468 €**	**782.536 €**	**778.623 €**	**774.730 €**	**770.856 €**	**767.002 €**	**763.167 €**	**759.351 €**	**755.554 €**	**751.777 €**
Costs 1	electricity consumption	375.000 €	386.250 €	397.838 €	409.773 €	422.066 €	434.728 €	447.770 €	461.203 €	475.039 €	489.290 €	503.969 €	519.088 €	534.660 €	550.700 €	567.221 €	584.238 €	601.765 €	619.818 €	638.412 €	657.565 €	677.292 €
Personal costs 2			- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
Personal costs 3			- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
	SUM O&M Costs	375.000 €	386.250 €	397.838 €	409.773 €	422.066 €	434.728 €	447.770 €	461.203 €	475.039 €	489.290 €	503.969 €	519.088 €	534.660 €	550.700 €	567.221 €	584.238 €	601.765 €	619.818 €	638.412 €	657.565 €	677.292 €
Cost 1	operation and maintanace	18.750 €	19.031 €	19.317 €	19.606 €	19.901 €	20.199 €	20.502 €	20.810 €	21.122 €	21.439 €	21.760 €	22.087 €	22.418 €	22.754 €	23.095 €	23.442 €	23.793 €	24.150 €	24.513 €	24.880 €	25.254 €
Cost 2	water consumption	3.300 €	3.350 €	3.400 €	3.451 €	3.502 €	3.555 €	3.608 €	3.662 €	3.717 €	3.773 €	3.830 €	3.887 €	3.946 €	4.005 €	4.065 €	4.126 €	4.188 €	4.250 €	4.314 €	4.379 €	4.445 €
Cost 3	Insurance (maschine)	12.500 €	12.688 €	12.878 €	13.071 €	13.267 €	13.466 €	13.668 €	13.873 €	14.081 €	14.292 €	14.507 €	14.724 €	14.945 €	15.169 €	15.397 €	15.628 €	15.862 €	16.100 €	16.342 €	16.587 €	16.836 €
Cost 4	Insurance (fire)	6.250 €	6.344 €	6.439 €	6.535 €	6.634 €	6.733 €	6.834 €	6.937 €	7.041 €	7.146 €	7.253 €	7.362 €	7.473 €	7.585 €	7.698 €	7.814 €	7.931 €	8.050 €	8.171 €	8.293 €	8.418 €
Cost 5	metering (electricity)	800 €	812 €	824 €	837 €	849 €	862 €	875 €	888 €	901 €	915 €	928 €	942 €	956 €	971 €	985 €	1.000 €	1.015 €	1.030 €	1.046 €	1.062 €	1.077 €
Cost 6	metering (gas)	800 €	812 €	824 €	837 €	849 €	862 €	875 €	888 €	901 €	915 €	928 €	942 €	956 €	971 €	985 €	1.000 €	1.015 €	1.030 €	1.046 €	1.062 €	1.077 €
Cost 7	data transmission	240 €	244 €	247 €	251 €	255 €	259 €	262 €	266 €	270 €	274 €	279 €	283 €	287 €	291 €	296 €	300 €	305 €	309 €	314 €	318 €	323 €
Cost 8			- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €
	SUM Costs	42.640 €	43.280 €	43.929 €	44.588 €	45.257 €	45.935 €	46.624 €	47.324 €	48.034 €	48.754 €	49.485 €	50.228 €	50.981 €	51.746 €	52.522 €	53.310 €	54.110 €	54.921 €	55.745 €	56.581 €	57.430 €
	SUM Total Costs	**417.640 €**	**429.530 €**	**441.766 €**	**454.360 €**	**467.322 €**	**480.663 €**	**494.394 €**	**508.526 €**	**523.072 €**	**538.044 €**	**553.454 €**	**569.315 €**	**585.641 €**	**602.446 €**	**619.743 €**	**637.548 €**	**655.874 €**	**674.739 €**	**694.157 €**	**714.146 €**	**734.722 €**

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Interest	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
	1,000	0,968	0,936	0,906	0,877	0,849	0,821	0,795	0,769	0,744	0,720	0,697	0,674	0,652	0,631	0,611	0,591	0,572	0,554	0,536	0,518
Profit minus Loss	- 1.809.240 €	397.365 €	380.994 €	364.286 €	347.231 €	329.817 €	312.034 €	- 18.631 €	275.312 €	256.348 €	236.966 €	217.153 €	196.894 €	176.177 €	154.987 €	- 179.191 €	111.127 €	88.428 €	65.194 €	41.408 €	17.055 €
Cash Value	- 1.809.240 €	384.522 €	356.764 €	330.094 €	304.470 €	279.854 €	256.207 €	- 14.803 €	211.678 €	190.728 €	170.609 €	151.291 €	132.743 €	114.937 €	97.844 €	- 109.469 €	65.694 €	50.585 €	36.089 €	22.181 €	8.841 €
Accumulated Cash Value	- 1.809.240 €	-1.424.718 €	-1.067.954 €	- 737.860 €	- 433.390 €	- 153.536 €	102.671 €	87.868 €	299.547 €	490.274 €	660.883 €	812.174 €	944.916 €	1.059.853 €	1.157.698 €	1.048.229 €	1.113.923 €	1.164.508 €	1.200.597 €	1.222.778 €	1.231.619 €

Capital Value:	1.231.619 €	Project rate of return	13,83%
		Amortisation	5 years

Appendix 2 Profit and loss statement for the PEM electrolyser at the transfer station Steinhäule