UiT The Arctic University of Norway

Faculty of Science and Technology

Department of Physics and Technology

Profitability of green hydrogen production and feasibility of waste heat integration to DHS in the Ísafjörður's energy system

A techno-economic analysis

Elena Dís Víðisdóttir

EOM-3901 Master's thesis in Energy, Climate and Environment 30SP

June 2022

Abstract

Hydrogen production by electrolysis using renewable energy sources is essential for hydrogen to be able to contribute to the green energy transition. Producing the hydrogen on the site of use minimizes the transportation costs and footprint, and utilization of all by-products increases the electric efficiency of hydrogen production. During hydrogen production by electrolysis the chief part of energy losses are in the form of thermal energy or heat. This thesis evaluates the profitability of a small-scale electrolytic hydrogen production in northwest Iceland and the feasibility of waste heat integration to the local district heating system. Here we show that the hydrogen production is profitable for a broad range of operation scenarios, hydrogen selling prices and electricity prices and that the integration of waste heat is feasible to the low temperature district heating plant in Ísafjörður. A sensitivity study is conducted for the calculations, for a optimistic, realistic and pessimistic scenario. The heat integration saves 13, 7 and 2% of the annual power consumption for the district heating plant for each scenario respectively. The waste heat integration affects the efficiency of the electrolyser, increasing it by 3.7% for the optimistic scenario. The economic effects of waste heat integration were found to be small. The heat integration was found to save a maximum of 5% of the DHS annual power costs. The waste heat sale revenue of the hydrogen production was found to be maximum 1.7% of net sales, which are hydrogen and heat sales in this thesis. The financial analysis of the hydrogen production conducted as a sensitivity study of an optimistic, realistic, and pessimistic scenario show that the hydrogen prices required for the project to reach profitability are 1.5 €, 3 € and 6 € per kg hydrogen when electricity prices are up to 24 €/MWh. This thesis is anticipated to spur for further research on the feasibility of hydrogen production with waste heat utilization in cold areas in Iceland, where no geothermal heat is available for district heating.

Acknowledgements

First, I would like to thank my great friends and classmates for the past five years and for making my time in Tromsø unforgettable. It has been priceless to have you all by my side, thank you for teaching me Norwegian (and physics and programming), for the fun days and nights both in school and outside of school. Especially I would like to think my dearest Julie, my rock.

I would like to thank my supervisor Steven Jackson and my co-supervisor Sölvi R. Sólbergsson for solid guidance and ideas during this project. I would like to give special thanks to Ásrún Ýr Kristmundsdóttir for proofreading this thesis and the provided support and pep-talks on the last meters.

Finally, I would like to thank my boyfriend Gauti and my little Styrmir Gautason for being my biggest supporters, and all our family members that visited from Iceland to babysit and help us getting through this process. It is hard to image doing so without all your help.

Table of Contents

Abbreviations

AEC	Alkaline electrolysis cell
BOL	Beginning of life
CapEx	Capital Expenditures
CHP	Combined heat and power
DH	District heating
DHS	District heating systems
EU	European Union
EOL	End of life
GDH	Generation of district heating
h	Hour
H_2	Hydrogen
HE	Heat exchanger
HHV	Higher heating value
HPP	Hydrogen production plant
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
IRR	Internal Interest Rate
KOH	Potassium hydroxide
LCOH	Levelized Cost of Hydrogen
LHV	Lower heating value
LMTD	Logarithmic mean temperature difference
min	Minutes
NPV	Net Present Value
O_2	Oxygen
OH	Hydroxide ions

OpEx	Operating Expenses
PEM	Polymer electrolyte membrane
PEMEC	Polymer electrolyte membrane electrolysis cells
PtG	Power to gas
PtH	Power to hydrogen
PtX	Power to X
SOEL	Solid oxide electrolysis
SOFC	Solid oxide fuel cell
S&M	Sales & Marketing
TRL	Technology readiness level
RES	Renewable energy sources
WACC	Weighted average cost of capital

1 Introduction

The release of carbon dioxide (CO_2) into the atmosphere is threatening the life on earth as we know it. With release of CO_2 and other greenhouse gases, the temperature on earth is rising at unprecedented speed with severe consequences. The goal of the Paris agreement from 2015 is to limit global warming to well below 2°C, preferably 1.5°C, compared to preindustrial levels (1). The goal is widely known and accepted. Despite ambitious plans to reach this goal, there are some unclear details in how to reach it. The International Energy Agency (IEA) has stated that reducing global CO_2 emissions to net zero by 2050 is consistent with reaching the goal of 1.5°C. That requires no less than a complete transformation of how energy is produced, transported, and consumed (2). It is expected that the variety of energy sources in the energy system will increase, and most importantly, the share of renewable energy sources will need to increase drastically. Wind and solar power are two large sectors within renewable energy. As they are fluctuating energy sources the importance of storage technologies is increasing.

There are several ways to store energy. One of them is in the form of hydrogen. Hydrogen is an energy carrier that can be used in various scenarios. Today hydrogen is mostly used in oil refining and fertiliser production, but to have a significant impact on the energy transition it needs to be adopted in sectors where it has been almost completely absent. Such sectors include transport, buildings, and power generation (3).

For hydrogen to be able to contribute to the energy transition it must be produced using renewable energy sources. Today around 75% of the global hydrogen production is from natural gases, accounting for about 6% of global natural gas use. After gas comes coal (due to its dominant role in China) and a small fraction is produced from the use of oil and electricity (4). Green hydrogen production is defined as hydrogen produced by water electrolysis using renewable energy sources. In 2021 the IEA published that ~0,03% of the global hydrogen production comes from water electrolysis (5). With a growing interest in electrolytic hydrogen and declining costs for both electrolysers and renewable electricity the share is expected to increase drastically in coming years (6; 7).

Three of the most common electrolyser technologies commercially available today are alkaline, polymer electrolyte membrane (PEM) and solid oxide electrolysis (SOEL). In this thesis, a literature review on these electrolyser technologies and their properties is undertaken.

During water electrolysis, water is split into hydrogen and oxygen gases under the influence of electricity. The process is energy-intensive, and a significant proportion of the energy consumed is not recovered in the hydrogen production. The losses are in the form of thermal energy (heat), and to increase the efficiency this waste heat should be utilized or integrated into other processes. For the most efficient use of energy all three products should be utilized.

The hydrogen and oxygen produced during electrolysis are in gaseous state. They can be stored under pressure or transported directly to the source of use via a pipeline. The thermal energy or heat created during electrolysis is not commonly utilized. For that reason, there is lack of data from manufacturers and studies on the amount of recoverable heat for further utilization.

In this thesis, the possibility of utilizing the waste heat from electrolytic hydrogen production by integration to a district heating system (DHS) is researched by modelling the technological and economical aspects. A case study is performed based on quantitative and qualitative data obtained from a district heating plant (DHP) in Ísafjörður, Iceland. Ísafjörður was chosen since it is the largest town in Iceland that does not have access to geothermal heat and uses electricity for district heating. Due to uncertainty in the data on the amount of recoverable heat from electrolytic hydrogen production and the uncertainty of development of hydrogen selling prices and electricity prices, a sensitivity study is conducted.

The scope of this thesis is limited to the production of hydrogen through electrolysis, the electrolyser is included in the scope, but other plant components are excluded. Those are: rectifier, water purification unit, gas processing units including compression and storage, and cooling components. It is assumed that the local power company that today operates the DHS, will own the electrolyser. The electrolyser would be installed at the same location as the district heating plant, and it is assumed that the distributor of the hydrogen would build a refuelling station within a ~100m radius of the hydrogen production plant (HPP). The hydrogen could be fed through a pipeline to the place of use and no transportation on tube trailers would be needed. It is expected that the end users of the hydrogen will mainly be heavy transport trucks (350 bar) travelling from and to Ísafjörður. The base scenario electrolyser produces the hydrogen at 30 bars and here it will be assumed that the operator, the power company, sells it in that state to the distributor. The power company and operator of the HPP would utilize all recoverable heat by integration to the DHP. In that manner the power company would increase the energy efficiency of the hydrogen production and save the respective amount of energy that is integrated from the HPP.

The aim of this thesis is to analyse the technical and economic feasibility of hydrogen production and waste heat integration to DHS in northwest Iceland. From the perspective of the DHS and the hydrogen production. The technical feasibility regards the electrical efficiency of the hydrogen production and the amount of recoverable heat as well as the physical integration of heat to the DHS. The economic feasibility for the DHS depends on the installation costs of the heat integration module and the power savings that follow the heat integration. The economic feasibility of hydrogen production depends on the outcome of the financial analysis.

To achieve the aim the following sub-questions below are raised and answered. The answer to these questions substantiates the outcome of potential benefits of hydrogen production with the aim to integrate the waste heat to Ísafjörður DHS.

First the profitability of electrolytic hydrogen production in the local energy system is modelled considering this: Under what market and operating conditions is the hydrogen production profitable, using renewable energy in northwest Iceland? Secondly, the technologic and economic feasibility of the waste heat integration is designed and modelled considering: Where and how should the heat be integrated to the DH grid? These two main analyses and the result from them build up to the feasibility of the project as a whole.

Chapter 2 presents the theories of electrolytic hydrogen production and district heating systems relevant for this thesis. A part of the theory is adopted from own work on project paper, "Literature study on the integration of waste heat from green hydrogen production to district heating systems". The data and methods used in this study are presented in Chapter 3. In Chapter 4 the results of the financial analysis and the technical integration of the waste heat to the DHS are introduced and compared to the findings of previous studies. The conclusion of the thesis is presented in Chapter 5.

2 Theory

The aim of this study is to calculate the effect of waste heat utilization from electrolytic hydrogen production by integration to a DHS. To do so the characteristics of electrolysis must be well understood, both from a technological and economical aspect. This theory includes the basics of electrolysis and compares the most common electrolysis technologies available on the market today. Technical characteristics of the electrolyser's efficiency, lifetime and reliability and operation flexibility are in focus. As the aim is to integrate the waste heat into a DHS, the operation temperature of the electrolyser is included along with the amount of heat that is generated. The operation temperature and other characteristics of various generations of DH systems are introduced, with the waste heat integration in mind. This theory includes the basis economical characteristics of both electrolytic hydrogen production and the operation of the DHS. The economic tools used to calculate the projects profitability are defined.

2.1 General overview of hydrogen

The use of hydrogen as fuel or for energy storage is enjoying a renewed and rapidly growing attention. It is intended to play an important role in the integrated energy system of the future for the transition to net zero emission is to be completed. Globally the various governments including the European Union (EU) have announced intentions to integrate hydrogen amongst other power-to-x (PtX) technologies to achieve climate goals (6). PtX is a term for the conversion of electricity to other energy carriers or chemicals, where X stands for the resulting fuel. Global organisations like the IEA include the use of hydrogen or hydrogen-based electro fuels and power to hydrogen (PtH) in future energy scenarios (7).

Hydrogen can be produced using various technologies that can be driven by various energy sources. Almost all hydrogen production is currently driven by non-renewable energy sources such as natural gases and other fossil fuels (8). In 2019 around 80 million tonnes of pure hydrogen were produced globally. Around 95% were generated from natural gas and coal with the remaining 5% generated as a by-product from chlorine production through electrolysis (Figure 1). Hydrogen production from renewable energy sources, was not significant at that point (9).

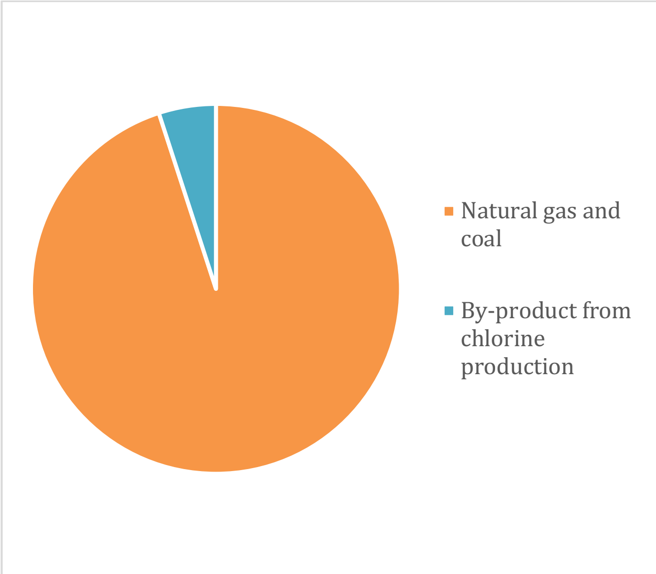


Figure 1: Energy sources for hydrogen production (2019)

The global hydrogen production generates emissions of around 830 million tonnes (Mt) of CO_2 per year (4). Put in context that is roughly equivalent to the total greenhouse gases emitted by Germany in 2018 (10). These numbers along with the IEAs prediction that global hydrogen use will expand from less than 90 Mt in 2020 to more than 200 Mt already in 2030 underline the urgency of kick-starting green hydrogen production. The IEA predicts that global hydrogen use will expand from less than 90 Mt in 2020 to more than 200 Mt already in 2030 (7).

Generally, hydrogen is divided into grey, blue, and green hydrogen, depending on its origins. Fossil based hydrogen produced from conventional steam methane reforming or coal gasification is classified as grey hydrogen and as stated above, it represents the primary source of global hydrogen production. Blue hydrogen is fossil fuel based but includes carbon capture and storage. Lastly, green hydrogen is produced through water electrolysis using renewable energy sources (11). As stated above green hydrogen production has had a very low share of the global production but is expected to grow at high rate in upcoming years. If hydrogen is to be a low or zero emission energy carrier and contribute to climate neutrality, it must be produced with low or zero emissions. This thesis will focus on green hydrogen production by water electrolysis.

2.2 Hydrogen production by electrolysis

Water electrolysis plays a key role in green hydrogen production. It involves separating the water molecule, which consists of two hydrogen atoms and one oxygen atom from each other under the influence of electricity. The overall chemical reaction is given by:

$$H_2O \xrightarrow[Electrolysis]{} H_2 + \frac{1}{2}O_2 \tag{1}$$

To produce 1 kilo of hydrogen gas by electrolysis 9 litres of water are required (12). The by-products are heat and oxygen. On volume basis electrolysers produce half as much oxygen as hydrogen, but on a mass basis oxygen production is eight times higher (13). The hydrogen and oxygen are generated in the form of gas. The hydrogen gas is typically collected and stored in tanks under high pressure. The oxygen gas can be collected for further utilization and stored under high pressure if it is meant for transportation or fed at low pressure through pipelines to the source of use, depending on the distance. During electrolysis some energy is lost in the form of thermal energy or heat. A part of the heat can be recovered and further utilized in other industries or in district heating. Electrolysis with heat recovery leads to a higher total energy efficiency of the hydrogen production (14).

There are multiple known water electrolysis technologies in various stages of maturity. Two main technologies are currently commercially available for hydrogen production, those are alkaline electrolysis cells (AECs) and polymer electrolyte membrane electrolysis cells (PEMECs) or simply PEM for short. Those are both classified as low temperature electrolysis cells and operate at below 100°C (15). Solid oxide electrolysis cells (SOECs) are high temperature electrolysis cells which have not reached the stages of commercialisation, although the development is rapid. These three technologies will be described in more detail in this thesis.

Alkaline Electrolysis

Alkaline electrolysis (hereafter alkaline) is an established, commercially available, and mature technology (17) that has been used for hydrogen production since the 1920s. According to the technology readiness level (TRL) method, ranging from TRL 1-9, AECs is ranked TRL 9 (15).

In AECs no precious materials are required. Two electrodes, typically of steel (cathode) and nickel (anode), are immersed in an aqueous alkaline electrolyte. Common electrolytes are aqueous solutions of potassium hydroxide (KOH_{aq}) or sodium hydroxide ($NaOH_{aq}$). KOH is used more often because of its high electric conductivity. To achieve the high electric conductivity the concentration of the electrolyte is in the range of 20-30% (16).

The chemical reactions are:

$$Cathode\colon\ 2H_2O + 2e^- \rightarrow\ H_2 + 2OH^- \tag{2}$$

$$Anode\colon\ 2OH^- \rightarrow\ H_2O + {}^1/_2\, O_2 + 2e^- \tag{3}$$

$$Overall\ cell\colon\ H_2O \rightarrow\ H_2 + {}^1/_2\, O_2 \tag{4}$$

During the electrolysis process current is applied to the cell and the electrons flow through an external circuit to the cathode and react with the water molecules reducing them into hydrogen molecules (H_2) and hydroxide ions (OH). The hydroxide ion moves through the diaphragm from the cathode to the anode, producing hydrogen gas on the cathode side and oxygen gas at the anode side as illustrated in Figure 2 (16).

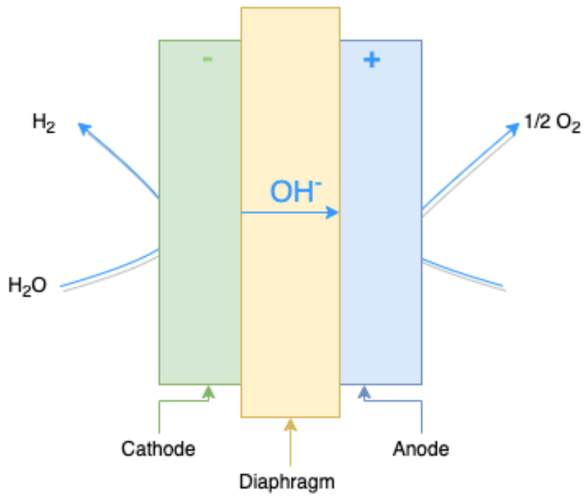


Figure 2: Illustration of AEC

During operation the liquid electrolyte needs to be separated from both the hydrogen and oxygen gases. After separation the electrolyte is recovered, chilled, and recycled into the electrolyser cell. An AEC is operated at temperatures between 60-90°C (12; 17; 18).

The hydrogen gas produced by alkaline electrolysis is of high purity, levels over 99.95%. Typically, the purity level is above 99.99%. The oxygen gas is commonly not of high purity, over 99.9%, without additional purification. AECs typically produce hydrogen at pressures 0-35 bar without additional compression (19; 20; 21; 22; 23).

PEM Electrolysis

The proton exchange membrane (PEM) electrolysis technology is mature and commercially available, ranked at TRL 8-9 (15). In PEMECs water is introduced to the anode side of the cell. When current is applied to the cell the water reduces into hydrogen and oxygen. The hydrogen protons pass through the membrane from the anode to the cathode where hydrogen gas is produced. The oxygen ions do not pass through the membrane and oxygen gas is produced at the anode side (Figure 3).

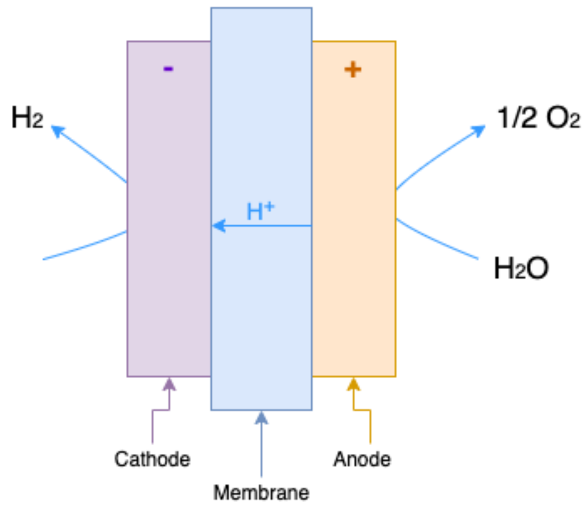


Figure 3: Illustration of PEMEC

The chemical reactions of PEM are:

$$Anode:\ H_2O \rightarrow 2H^+ + {}^1/_2\,O_2 + 2e^- \tag{5}$$

$$Cathode:\ 2H^+ + 2e^- \rightarrow H_2 \tag{6}$$

$$Overall\ cell:\ 2H_2O \rightarrow H_2 + {}^1/_2\,O_2 \tag{7}$$

PEM is built upon proton exchange membrane technology, using solid polymer as electrolyte. The technology depends on the use of precious metals, as iridium and platinum are used as catalysts. The hydrogen gas is produced at elevated pressures up to 30 bar. Due to the near infinite bubble point of the membrane no oxygen enters the hydrogen stream, resulting in higher gas purity compared to AECs, at above 99.9995% purity. The oxygen gas is of high purity and at ambient pressure around 1 bar. PEMECs operate at temperatures between 50-80°C (24).

Solid Oxide Electrolysis

Solid oxide electrolysis (SOEL) technology was first introduced in the 1980s. The technology is in many ways different from the two technologies described above, alkaline and PEM electrolysis. The technology is not mature and still in development, TRL 5-6 (15), although it has undergone tremendous development and improvements over the past 10-15 years and large producers such as Bosch aim to make it commercial by 2024 (25).

Solid oxide, unlike the other two technologies, utilizes water in form of steam, operating at high pressure and high temperatures, typically 500-850 °C (Figure 4). The high operating temperatures result in favourable thermodynamics and reaction kinetics enabling significantly higher conversion efficiencies than seen in other electrolysis technologies (16). Unlike alkaline and PEM electrolysers where the input energy is 100% electric, the energy for SOEL comes from both electricity, 79.5%, and heat, 20.5% (15). For that reason, the integration with DH is not favourable as both SOEL and DH systems compete for the same source for input, heat.

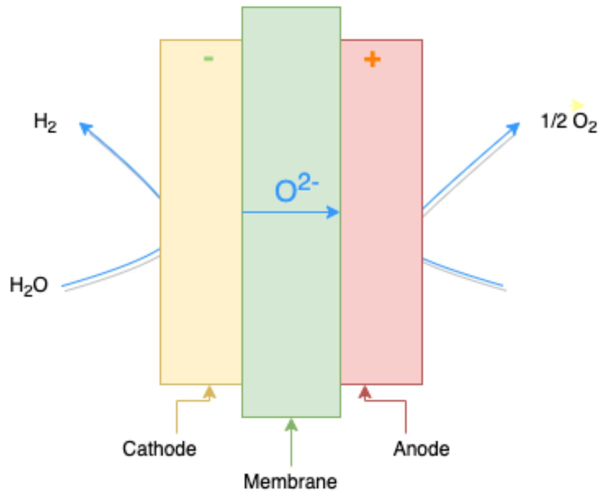


Figure 4: Illustration of SOEC

SOECs has the significant advantage over AECs and PEMECs that it can be operated in reverse, as a solid oxide fuel cell (SOFC) (26). Since SOEL is not favourable for integration with DH systems the technology will not be included in this thesis further on.

2.3 Technical comparison of alkaline and PEM electrolysis

In this thesis the focus is set on the mature technologies alkaline and PEM electrolysis. The following sections provide an overview of the characteristics of each technology, and comparison of the technologies.

2.3.1 Efficiency

The efficiency of an electrolyser is defined for low heating value (LHV) and high heating value of hydrogen (HHV) (6; 27). Efficiency is typically given for electrolyser stack or system. The stack is a series of cells that the hydrogen is produced in, consisting of an anode, cathode, and membrane. The stack is the component of the system that requires the most energy. The system consists of the cell stack, pumps, vents, storage tanks, a power supply, gas separator, and other components (28).

The equations for efficiency are shown below:

$$\eta_{LHV} = \frac{\dot{v_{H_2}} LHV_{H_2}}{P_{el}} \tag{8}$$

$$\eta_{HHV} = \frac{\dot{v_{H_2}} HHV_{H_2}}{P_{el}} \tag{9}$$

Where $\dot{v_{H_2}}$ is the amount of hydrogen produced in Nm^3/h, LHV_{H_2} is the lower heating value of hydrogen (3.0 kWh/Nm^3), HHV_{H2} is the higher heating value of hydrogen (3.54 kWh/Nm^3) and P_{el} is the electrical power consumption of the system in kW.

In a market survey by Buttler and Spliethoff (6) from 2018, where several AEC, PEMEC and SOEC from different manufacturers are reviewed, the cell stack efficiency range for alkaline is from 63-72%. Those efficiency calculations are based on the LHV. Based on the HHV that accounts for ~74-84%. For PEM electrolysers the same survey shows that the specific stack efficiency (HHV) ranges from 71-80%, calculated for stack energy consumption of 4.4-5.0 kWh/Nm^3 (6).

For up-to-date data on cell stack efficiency, a market survey was created for this thesis, collecting information from five large manufacturers. All manufacturers except Cummins are included in Buttler and Spliethoffs market survey as well. The results are shown in Table 1 below. All values in the table are based on the HHV of hydrogen, that will be used for all further efficiency calculations in this thesis. The table shows the production rate in Nm^3/h, and the size or capacity of the electrolyser for each manufacturer. Large scale systems can naturally be expected to be more efficient.

Table 1: Market survey on Alkaline and PEM stack and system efficiency (HHV), production rate and pressure

Manufacturer	**Stack efficiency HHV**	**System efficiency HHV**	**Production rate**	**Pressure**
Alkaline				
NEL AC300 (29)	80-93%	-	300 Nm^3/h	1 bar
Cummins HySTAT100 (20)	-	66%-72%	100 Nm^3/h	10 bar
Sunfire (22)	79-80%	64-65%		5-30 bar
Green Hydrogen Systems (23)	82-85%	75%		35 bar
PEM				
NEL MC200 (29)	74%	-	200 Nm^3/h	30 bar
Cummins HyLYZER400 (20)	82%	73%	400 Nm^3/h	30 bar
SIEMENS energy Silyzer200 (30)	-	60-65%	200 Nm^3/h	35 bar

The efficiency ranges for alkaline in Table 1 are comparable to the ranges shown in Buttlers and Spliethoffs market survey. Although the weight has shifted, there are more manufacturers with system and stack efficiencies in the upper end of the range in the thesis survey, and more manufacturers with efficiencies closer to the lower end in Buttlers and Spliethoffs survey, indicating technological improvements from 2018. The same goes for PEM.

The specific stack efficiency is always higher than the system efficiency. Sánches, et.al show, using a model of alkaline, that the system efficiency is typically 15-20% lower than stack efficiency (22; 23; 31). The data from Sunfire (22) shows a 20% lower system efficiency, which corresponds to Sánches. The system efficiency from Green Hydrogen Systems on the other hand show only around 10% difference between stack and system efficiency.

The stack efficiency of an electrolyser drops over the operating life of the stack. The range of stack efficiency is typically given as a range from the beginning of life (BOL) to the end of life (EOL), defining the lifetime of the stack.

2.3.2 Lifetime

Electrolyser lifetime is an important factor for the economic feasibility and when it comes to the performance of the electrolyser during operating life. Considering the lifetime of an electrolyser it is important to distinguish between stack and plant. Plant lifetime is longer than stack lifetime, this holds true for both alkaline and PEM. Over the lifetime of the plant the stacks are replaced with new ones. E4tech (32) shows that the plant lifetime of alkaline is 20-30 years and that of PEM is 10-30 years in 2014, they predict that the lifetime in 2020 will be 25-30 years for alkaline. Buttler and Splietthoff (6) refer to a plant lifetime of 20 year for PEM and 30-50 years for alkaline.

Stack lifetime is defined by efficiency degradation. Impurity of the water flows can for example have a major impact on stack lifetime. The lifetime given by manufacturers is based on a certain acceptable efficiency drop. Although it will be up to the operator to set his own bar regarding acceptable efficiency drop.

Data on stack lifetime of PEM is inconsistent. E4tech's report on electrolysis in the EU from 2014 (32) claims that both Alkaline and PEM electrolysers have stack lifetimes between 60-90 000 h. Buttler and Spliethoff (6) show that alkaline has 60-90 000h and PEM 30-90 000h and the same is stated in the Norwegian hydrogen strategy (14). The IEA states in The Global Hydrogen Review 2021 (5) that PEM has less stack lifetime than alkaline. In contrary, the International Renewable Energy Agency (IRENA) presents in its Green hydrogen cost reduction report (33) a lifetime of 60 000h for alkaline and 50-80 000h for PEM. The lifetime of the electrolysers reviewed in the thesis market survey (Table 1) is in the same range. Siemens (12) introduces a PEMEC with up to 80 000h maintenance free electrolyser stack operation and a stack lifetime of over 80 000h. Sunfire's (22) AEC has a stack lifetime up to 90 000h.

2.3.3 Operation flexibility

The load flexibility of an electrolyser defines how much a stack can vary its power consumption, and the hydrogen production as following. AECs can operate at load 10-100% although the minimum load is most often at 20%. At load below 10-15% there is a risk of lateral diffusion of hydrogen across the membrane to the oxygen side, resulting in a flammable mixture. For PEMECs there is no minimum load so the electrolyser can operate freely at a load range between 0-100%. The reason is the very low gas permeability of the membrane (6).

The time it takes to start up the electrolyser is an important factor of the operation flexibility. A warm start is defined as start-up from heated stand-by mode, where the system is held at operation temperature and pressure. In standby mode the power consumption of an electrolyser is typically below 1% of its nominal power (6). A cold start is defined as start-up from ambient temperature after a long shut-down. For AECs the warm start-up time is typically within 1-5 min (6; 34; 35), for PEMECs it is within seconds (6; 36). The short start-up time of both technologies makes them ideal for grid stabilization and coupling with energy systems with large shares of fluctuation renewable energy sources (RES), especially PEMECs.

The cold start-up time for a small AECs has been experimented by Dieguez et al., indicating cold start-up times of over 2 hours from 20-70°C, at maximum current density 0.4 A/cm^2 (37). Experiments by Zuberbühler et al. (38), on a larger AECs shows a cold start-up time of 37 minutes at maximum current density 0.43 A/cm^2 from 15-70°C (6). PEMECs have the advantage of a short cold start-up time, between 5-10 minutes. That is due to its compact design and low thermal capacity (6; 15).

Although the operation flexibility of both alkaline and PEM stacks is enough to follow fluctuations of RES as solar and wind power the flexibility of the whole system is limited. The limitations are involved with other factors of the electrolyser such as the compression (9).

2.3.4 Waste heat

The losses that occur in electrolysis are in the form of thermal energy or heat. As the efficiency gets lower the losses increase, although not all the thermal energy is available for utilization as some part of it will always be lost to the surroundings.

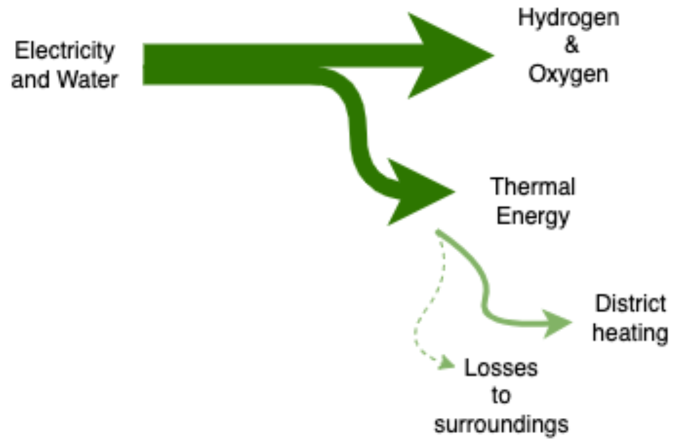


Figure 5: Hydrogen production, materials required and resulting products including energy losses.

Figure 5 indicates that the efficiency of electrolytic hydrogen production can be increased by utilizing the thermal energy, for example by integration to a DHS. As the utilization of waste heat from electrolysis is not common there is a lack of data on the amount of available waste heat from manufacturers. Per email communication, Bjørn Gregert Halvorsen (39), a technology specialist at Nel Hydrogen, states that maximum 20% of the electrolysers input electrical energy is converted to thermal energy during electrolysis. He claims that it is unlikely that all of that can be utilized, as a part of the heat will be lost to the surroundings and can therefore be difficult to capture.

A calculation of waste heat from electrolysis by Saxe and Alvfors (40) shows that 20% of input power becomes heat when power consumption at stack is 4.5 kWh/Nm^3, and 16% when power consumption at stack is 4.25 kWh/Nm^3. Modelling of electrolytic hydrogen production and waste heat by Sánchez, et.al., (31) shows that around 2400kW of waste heat was generated while operating the electrolyser corresponding to a power consumption of 10 kW. That means around 24% of the electrolysers power consumption becomes heat. The Danish Energy Agency (DEA) technology data for renewable fuels (41) lists heat loss from alkaline to be between 17-25% of the total input energy and the recoverable heat for DH to be 12-20%, using 16% for all calculations. The DEA reports that the heat that can be delivered by electrolysis to DHS is between 50-70°C. All agree that it is not realistic to assume that all heat can be captured for further utilization.

2.3.5 Summary

The operation parameters for both alkaline and PEM introduced in previous sections are summarized in Table 1.

Table 1: Typical values of operation parameters from Alkaline and PEM

Technology	**Alkaline**	**PEM**
State of development Technology readiness level (TRL)	Maturity TRL 9 (15)	Commercialisation TRL 8-9 (15)
Operation parameters		
Specific energy consumption of stack (BOL-EOL)[1] (kWh/Nm^3)	4.2–4.8 (6)	4.4-5.0 (6)
Electrical stack efficiency, HHV	73-85% (6; 20; 22; 23; 42)	71-82% (6; 20; 42)
Hydrogen pressure	0-35 bar (19; 20; 21; 22; 23)	30-35 bar (12; 43)
Load flexibility (%)	10-100 (6)	0-100 (6)
Cold start-up times	1-2 hours (6)	~1 min (12) (6)
Warm start-up times	1-5 min (6; 34; 35)	10% per second (6; 12; 36)
Specific energy consumption of system (BOL-EOL)[1]	5.0-5.9kWh/Nm^3 (6)	5.0-6.5kWh/Nm^3 (6)
Electrical system efficiency[2]	51-75% (6; 22; 23)	46-75% (6; 12; 27; 30)
Stack lifetime	50 000-120000h (6; 22; 44)	60 000-100 000h (6; 12; 44)
System lifetime	20-50 years (6; 45)	20 years (6)
Operation cell temperature	60-90°C (12; 17)	50-80°C (12; 17)

[1] BOL – Beginning of life, EOL – End of life

[2] System efficiency includes rectifier, transformer, transformer cooling and gas cooling.

2.4 Economics – investment and operational costs

Electrolytic hydrogen production using renewable energy sources (RES) is still significantly more expensive that fossil-based hydrogen. In the IEA's global hydrogen review from 2021 (5) the levelized cost of fossil-based hydrogen is estimated to be 0.45-1.5 €/kgH_2, depending on regional natural gas prices and disregarding CO_2 costs. In the same report the renewable hydrogen costs are estimated to be 2.7-7.3 €/kgH_2. That is around 70% more expensive.

However, the price for renewable hydrogen is going down quickly following a drastic price reduction of RES over the past years and the reducing prices of electrolysers that have dropped by 60% in price over the past 10 years. In fact, the IEA predicts that electrolytic hydrogen will be compatible with fossil-based hydrogen by 2030 (5).

Following the Russian invasion in Ukraine earlier this year, 2022, the gas price in Europe increased beyond any predictions, and consequently fossil-based hydrogen price increased by 70% in the matter of days (46). The EU has as a result announced a plan, REPowerEU, where the goal is set on making Europe independent from Russian gas by 2030. That includes amongst other things, larger volumes of renewable hydrogen production and imports replacing the gas, reduction of fossil fuel use in all sectors and consequently increasing renewables and electrification (47). All this accelerates the switch to renewable electrolytic hydrogen and urges price reduction.

Buttler and Spliethoffs market survey uses sources from 2015 showing that the capital expenditures (CapEx) for both alkaline and PEM has fallen drastically over the past decades, ranging from 800-1500 €/kW for alkaline and 1400-2100 €/kW for PEM (6). In a report by E4tech on the development of water electrolysis in the EU from 2014 (32), the then current available alkaline electrolyser systems are said to cost 1000-1500 €/kW. Proost (48) states that a CapEx of 750 €/kW is already realistic in 2019 for a single stack 2MW alkaline system. IRENA (33) presents in a report on green hydrogen production from 2020 that the current CapEx for alkaline and PEM as 500-1000 and 700-1400 €/kW. A report by the Department for Business, Energy & Industrial Strategy in the UK on hydrogen production costs in 2021 (49) shows that the CapEx for alkaline in 2021 to be 870-1000 €/kW and for PEM 1100-1400 €/kW. The Danish Energy Agency estimates the CapEx of alkaline electrolysers in 2020 to be 750 €/kW (41). The CapEx of electrolysers is expected to reduce in coming years with higher volume/mass production (economics of scale), supply chain development and technology innovation (32; 49). The EU's target for 2024 is a CapEx of 480 €/kW (alkaline) – 700 €/kW (PEM) (50).

All available data, suggests operating expenses (OpEx) to be 2-5% of CapEx per year, excluding electricity costs (6; 32; 51; 52). There is no distinction between the different technologies. The value is dependent on the scale of the plant. For a 1 MW electrolyser an OpEx of around 5% of the initial CapEx can be assumed (32; 52). Electricity is by far the largest share of the OpEx, according to the IEA renewable electricity costs can make up 50-90% of the total production expenses, depending on the electricity costs and the full-load hours of the electrolyser (3; 5). Due to this fact, the full-load hours are most often limited to times when the electricity price is under a chosen value. A short summary of the CapEx and OpEx values introduces in this section is presented in Table 2.

Table 2: Summary of CapEx & OpEx for alkaline and PEM

Costs	Alkaline	PEM
CapEx (€/kW)	500-1500 (6; 32; 33; 48; 49)	700-1400 (6; 49)
OpEx (% of CapEx per year)	2-3 (6)	3-5 (6)

2.5 Compression and Storage

Hydrogen has very low volumetric density. Compared to other commonly used fuels, it has the lowest, i.e., 0.017 MJ/L at atmospheric pressure. The volumetric density of petrol is 34 MJ/L. Compression or liquification are direct solutions to overcome this obstacle, reaching satisfying energy densities (53). Compression and liquification are both energy-intensive and that reduces the overall efficiency of hydrogen production. Zhao, et.al., (54) found that the costs for hydrogen compression was below 1% of the total cost of hydrogen production.

Multiple hydrogen compressor technologies are available, and it is difficult to determine what is optimal for a specific situation/project. Sdanghi, et.al (55) review summarises the state of the art of the most classical hydrogen compression technologies. Compressors are divided into two main groups, mechanical compressors, i.e., reciprocating, diaphragm, linear and ionic liquid compressors, and non-mechanical compressors, i.e., cryogenic, metal hydride, electrochemical and adsorption compressors.

Mechanical compressors are the most common for hydrogen compression. Reciprocating compressors are the standard choice for compressing hydrogen to high pressures anticipated in storage/transport scenarios. Diaphragm compressors are suitable when compressing hydrogen gas of high purity and low flow rates. Diaphragm failures is the most important drawback of these compressors, caused by high flow rates and high mechanical stress during operation. Linear compressors are primarily used for cooling electronics nowadays but their applicability for large scale hydrogen production is increasing. Ionic liquid compressors were specifically developed to increase compression efficiency of hydrogen gas. The hydrogen can be compressed up to 900 bar in five steps. Ionic liquid compressors have been used in hydrogen fuelling stations and proven to be a high-performance solution (55).

Non-mechanic compressors are not as widely implemented and more on an innovative stage. Cryogenic compressors combine liquification and compression technologies, achieving high pressure at low temperatures with hydrogen at liquid state, not gaseous. Metal hydride compressors are thermally powered, originally referred to as hydrogen refrigerators. Electrochemical compressors are suitable for small amounts of gas at very high pressures. Adsorption compressors is a new emerging technology that is based on adsorption and proceeds by means of system temperature changes (55).

The theoretical energy required to compress hydrogen from 20-350 bar is 1.05 kWh/kg H_2 (56). The efficiency of the compressor defines how much energy it actually takes. A typical set of design parameters for a hydrogen compressor (diaphragm compressor) are shown in Table 3 (54).

Table 3: Typical values of the power consumption of hydrogen compressors

Capacity	190 m^3/h (VN)
Power demand	29,6 kW
Compression	190 bar
Compression power demand per 190 bar	1.73 kWh/Nm^3

Due to its low volumetric density and the pressure of which hydrogen is used at (especially in the transport sector) it is the most efficient to store hydrogen under high pressure. Storage possibilities are diverse, from pressurized storage tanks, pipelines or in underground salt caverns to name a few examples. From storage the hydrogen is transported to the source of use. The transportation method is based on infrastructure, distances/locations and the pressure required and is typically done in tube trailers or via pipelines (9).

Cost of storage and transport

Considering the cost of hydrogen production, the single largest component is the electrolyser itself, the other major components are typically a rectifier, water purification unit, gas processing including storage and compression, and cooling components. According to IRENA (33) these components make up 50-60% of total capital costs. The cost of compression is completely dependent on the target pressure. The national renewable energy laboratory (NREL) (57) report that storage costs for a pipeline scenario are 40% of storage costs of a distributed scenario. The cost of transportation is highly dependent on the transportation method. Zhao, et.al., (54) found that the second largest cost of hydrogen production in the particular project was transport done by road and ferry (tube trailers), accounting for 9-12% of the total costs.

2.6 District heating systems

District heating systems (DHS) are widely implemented and may range from a few houses to large cites or entire regions. The heat can be obtained from different sources, fossil fuels, electricity, geothermal heat, or waste heat from the various industries. The characteristics, temperature, and flow rate, of a DHS can vary between systems. A commonly used categorization of DHSs defined by Lund et al. categorises the DHS in generations based on these characteristics. The definitions are listed in Table 4.

Table 4: Definition of DH network characteristics (15; 58)

Generation of DH	Heat carrier	Temperature
1GDH	Steam	Steam
2 GDH	Pressurised hot water	>100°C
3 GDH	Pressurised hot water	~100°C
4 GDH	Low temperature water	30-70 °C
5 GDH	Water	0-30°C

A study by Werner shows that, in 2015, the heat supply methods for DHS in the EU were recycled heat from fossil combined heat and power (CHP) (~55%), recycled heat from renewable CHP (~17%), the direct use of renewables (~10%) and the direct use of fossil fuels (~17%) (59).

Iceland is, due to its geographical location, in the unique position of having access to geothermal heat around the country. In 2020, 89.6% of all space heating in Iceland was done by geothermal heating through DH systems. In areas where geothermal heat is not available or has not been utilized other heat sources are used. DHS driven by central electric/oil boilers make up for 3.4% of all space heating and the remaining 6.8% are heated by the direct use of electricity through heat exchangers, that is not connected to a DHS (60).

The geothermal DHS in Iceland have varying temperatures and flow rates based on the temperature of the heat source. The DH systems that have centralized electric boilers for heating are operated at relatively low temperatures. Typically, the flow temperature, that is the temperature from the DHP out to the DH grid is around 70°C and the return temperature, from the grid back into the DHP, is around 35°C (Sölvi R. Sólbergsson, CEO, pers.comm.). Those DH systems are categorized as 4th generation, a low temperature DHS.

Low temperature DH systems are well suited for waste heat utilization (15). The waste heat from electrolysis is, as explained in chapter 2.3.4, around 80°C. The heat can be integrated to the return flow of the DHS through a heat exchanger where heat above return flow temperature can be utilized. The return flow can then be topped-up with heat from an electric boiler. In high temperature DH systems this would be more difficult as the return flow temperature is much closer to the waste heat temperature. That could mean that for example a heat pump would be needed to elevate the waste heat from electrolysis to be recovered by the DHS.

2.7 Financial analysis

A financial analysis is the process of evaluating a project, to determine its financial performance. It plays a large role in deciding whether or not to carry out the project as the goal of the financial analysis is to assess if the project is profitable enough to warrant a monetary investment and is used to identify projects for investment (61). That is done by examining the projects financial statement.

Financial statements are summary reports of the financial health of a company. Chief of these include the projects income statement (revenues, expenses, and net income), balance sheet (snapshot in time of assets, liabilities, and shareholder equity) and cash flow statement (cash inflows and outflows through operations, investment, and financing) (62).

Projects are typically financed using a non- or limited recourse financial structure, where the debt and equity used to finance the project are paid back using the cash flow of the project. A company can fund a project of balance sheet, meaning that the project is not included in the company's balance sheet. The funding of a project can be by a loan from either a bank or the company that owns the project, it can as well be funded by shareholders (investors) (62).

The profitability of a project can be calculated from its financial statement using different tools. One of these tools is the net present value (NPV). The NPV is the difference between the present value of cash inflows and the present values of cash outflows over the time period (63). The NPV is defined as:

$$NPV = \sum_{t=1}^{n} \frac{C_t}{(1+i)^t} \tag{10}$$

where C_t is the net cash inflow-outflows during a single period t, i is the discount rate or return that could be earned in alternative investments and n is the number of time periods.

To evaluate the NPV the internal rate of return (IRR) of the project is calculated. The IRR is defined as a discount rate that makes the NPV of a cash flow equal to zero in a discounted cash flow analysis (64). For calculating IRR this formula is used:

$$0 = NPV = \sum_{t=1}^{n} \frac{C_t}{(1+i)^t} - C_0 \tag{11}$$

where C_t is the net cash inflow during the period t, C_0 is the total initial investment costs, i is the discount rate (IRR) and n is the number of time periods.

The weighted average cost of capital (WACC) represents the average after-tax cost of the project's capital from all sources, including common and preferred stock, bonds and other forms of debt (65). It is defined as:

$$WACC = \left(\frac{E}{E+D}r\right) + \left(\frac{D}{E+D}q(1-t)\right) \tag{12}$$

Where E is the projects equity, D is the projects debt, r is the cost of equity, q is the cost of debt and t is the corporate tax rate.

When a financial statement for a future project is calculated the aim should be to have the IRR higher than the WACC to be able to cover the financing of the project. The projects WACC is determined by the cost of the debt or equity. As a result of that, projects that are entirely financed by loan, have the WACC equal to the cost of the loan (~ the interest rates of the loan).

2.7.1 Market

Demand for hydrogen on the market is crucial for the profitability of the project. Market values are in nature dynamic. They are dependent on a variety of factors ranging from physical operating conditions to economic climate and the dynamics of demand and supply. A market analysis is outside the scope of this project, but evidence from the IEA and EU mentioned in chapter 2.3.5 is that demand is set to grow very quickly. The aim of this thesis is to calculate under what market conditions, that is hydrogen selling price and electricity costs, the hydrogen production and waste heat integration is profitable.

The market for the waste heat is much clearer and the market is nowhere near as dynamic as the hydrogen market. The global district heating market is growing (66) but as heat is not sold on an open market it should be looked at on a smaller scale. A local DHS has a stable demand, with seasonal variations as less heating is needed during the warm summer months. The DHS expands if new buildings or industries are built and connected to the DH grid. The share of waste heat in the total heat demand for the local DHS is an important factor, when integration is considered. The market price for the waste heat is not clear. A Danish report on the topic of waste heat integration to DHS assumes the price for waste heat (kWh) to be around 40-50% lower than the average electricity price (kWh) (52).

3 Method

This thesis can be divided into a qualitative part and a quantitative part. The qualitative part consists of literature reviews, research, and comparison of the available technologies for electrolytic hydrogen production and the possibilities for storage and transportation of hydrogen. A review is conducted on the different generations of DH systems including the option of integration of waste heat from electrolytic hydrogen production.

The quantitative part consists of hydrogen production and waste heat integration design calculations and an economic analysis of both the hydrogen production and the integration of the waste heat. The calculations on the hydrogen production and amount of available waste heat are based upon data from previous research and data from manufacturers. The calculations on the effect of waste heat integration are based on hourly data collected in 2019-2021 at the DHS in Ísafjörður, which the case study is built on mass flow, flow temperatures and power consumption of the DHS. Due to uncertainty of some of the data used in the calculations as well as the rapid development of electrolysis technologies this project will conduct a sensitivity study. Three scenarios for the economic analysis will be conducted, an optimistic, realistic and a pessimistic scenario.

3.1 Base scenario electrolyser

The literature review earlier in this thesis on different technologies of water electrolysis, along with the comparison of products from different manufacturers serve as the foundation for the selection of the base scenario electrolyser for the case study. The base scenario electrolyser's selection is based on its characteristics, including efficiency, lifetime of stack and system, operational flexibility, and costs. When selecting equipment, the reliability, availability and experience are key elements along with how the characteristics of the electrolyser fit in with the dynamics of the energy system it will be operated in.

The selection came down to a choice between the two mature technologies alkaline and PEM. The electrolyser will be operated in a stable energy system based on hydropower and fluctuating RES as wind or solar power are not included. Thus, it was concluded that the high operation flexibility and the quick response rates of PEM were not essential. Of the two considered technologies, alkaline is the more mature and a lower costs option. This, along with the fact that the higher operating temperatures of alkaline could be more suitable for waste heat utilization, led to alkaline being chosen for this project.

The AC300 electrolyser from Nel is used for reference in this project. Due to lack of data from the manufacturer some characteristics are assumed based on data from other manufacturers of alkaline electrolysers of the same scale. Some characteristics are calculated using the given values from Nel and in those cases, assumptions have been made on the operating behaviour of the electrolyser. All assumptions made regarding the characteristics of the electrolyser are explained in more detail the following sections.

3.1.1 System efficiency

The manufacturer does not provide the electrolyser's system efficiency. It is assumed here using the stack efficiency and the typical difference between stack and system efficiency given by other manufacturers. As listed in Table 1 the system efficiency is typically 10-20% lower than the stack efficiency. For the base scenario electrolyser, the median value of 15% will be used. This thesis uses the efficiency based on the HHV of hydrogen. Given the efficiency of the stack as 80-93% the system efficiency is 69-80% respectively. That is for hydrogen gas of 30 bar as it is generated in the electrolyser, without additional compression.

Calculating the nominal rated power of the electrolyser it is assumed that the efficiency degradation is in line with the stack lifetime. In that manner the nominal power is calculated using the median value of system power consumption and the maximum production rate. The stack and system efficiency are given in a range from the beginning to the end of stack lifetime. The values used in the sensitivity study are the minimum, median and maximum of the efficiency range, 69, 75 and 80% respectively.

3.1.2 Amount of recoverable waste heat

Waste heat utilization is not very common aspect of water electrolysis. There is a lack of data from both previous research and reviews as well as manufacturers not listing the amount of available heat. But Figure 5 illustrates that the losses of electrolytic hydrogen production are predominantly in the form of thermal energy. Based on this the amount of heat created during electrolysis can be assumed to be equal to the losses. This assumption does not mean that the heat created can all be recovered for utilization or integration to the DHS as is the case in this thesis.

All sources agree on the fact that not all heat is available for utilization as some of it will always be lost to surroundings. With the efficiency range of the stack, 80-93%, it can be assumed that 17-20% of input energy becomes thermal energy (Figure 6). When modelling the hydrogen production and the recoverable waste heat a sensitivity study, using different values for recoverable heat from electrolysis is performed. Those are 5, 10 and 15% of the electrolysers input power. The share of the recoverable heat that can be integrated to the DHS depends on the return temperature of the DHS and the temperature of the waste heat.

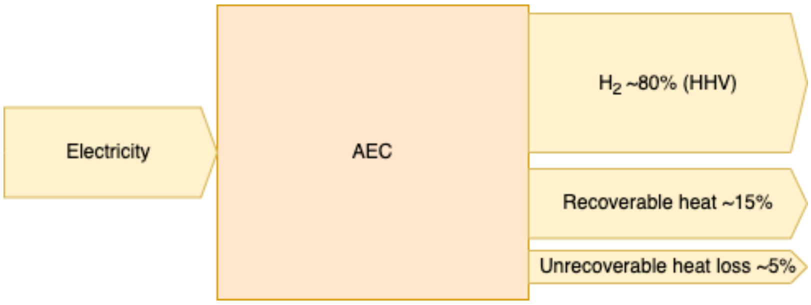


Figure 6: Energy balance of AEC

3.1.3 Summary of operation parameters

The operation parameter of the base scenario electrolyser, presented in earlier sections are summarized in Table 5.

Table 5: Summary of parameters for the base scenario electrolyser (42; 67)

Specifications	
Net production Rate	150-300 Nm^3/h
	324-647 kg/24 h
Production Capacity Dynamic Range	15-100% of flow range
Power Consumption at Stack (BOL-EOL)[1]	3.8-4.4 kWh/Nm^3
Electrical Stack Efficiency	80-93%
Power Consumption of System (BOL-EOL)[1]	4.4-5.1 kWh/Nm^3
Electrical System Efficiency	69-80%
Nominal System Power	1425 kW
Lifetime of plant	25 years
Purity – with optional purification	99.99-99.998%
Delivery Pressure	30 bar
Footprint	~200m^2
Operation Temperature	80°C
Electrolyte	25% $KOH_{(aq)}$ solution
Feed Water consumption	0.9 l/Nm^3
Available heat[2]	5, 10 & 15%

[1] *BOL – Beginning of life*

EOL – End of life

[2] *Sensitivity study based on input power*

3.2 District heating system in Ísafjörður

The district heating system is on a rather small scale. The DH grid (Figure 7) is connected to around 200 homes and a couple of service buildings or stores.

Figure 7: DH grid in Ísafjörður

The central DHP has two electric boilers and an oil boiler, the oil boiler acts as a reserve in the case of maintenance, power outage or power curtailment. The two electric boilers have a total of 2.4 MW installed power and the oil boiler has 3MW installed power. The DH operating system setup is shown in Figure 8.

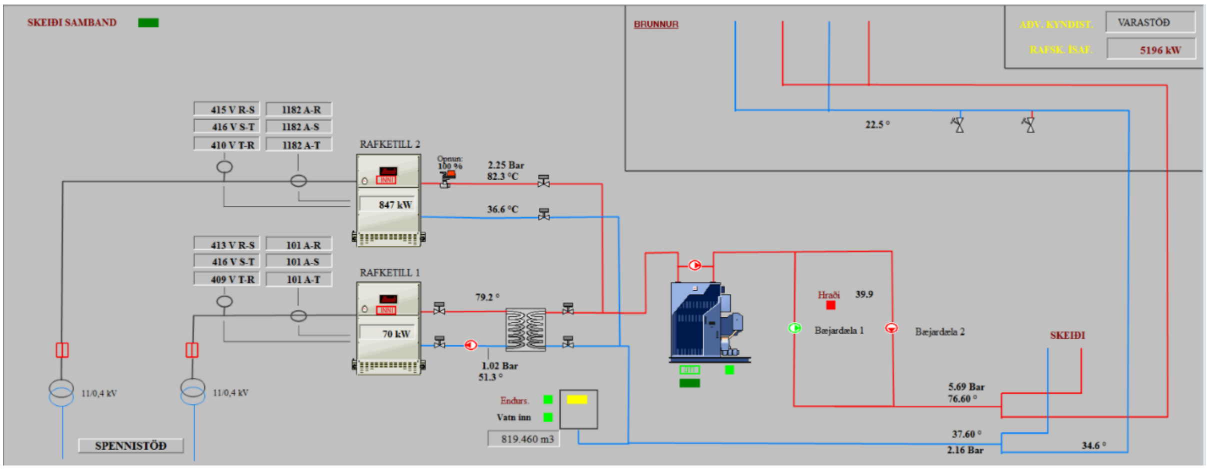


Figure 8: A screenshot of the DHP in Ísafjörður operating system

The return flow enters the DHP at around 35°C (T_{return}). The return temperature is quite stable (Sölvi R. Sólbergsson, CEO, pers.comm.) and will in this project assumed to be constant. The heating is done by the two electric boilers (R1 and R2). R1 heats the water through a heat exchanger and R2 heats the water directly. The flows from the two electric boilers combine with a desired flow temperature of 70°C (T_{flow}). The water flows through the oil boiler although it is only turned on when electricity is not available, as mentioned above. From the DHP the water is pumped into the DH grid.

The operator is looking to decrease the temperature to 68°C at least. The DHS is categorized as a 4th generation DHS, by the definition introduced earlier in this thesis and due to its low temperature, it is well suited for waste heat integration.

3.2.1 Operating data

The dataset used in this thesis is obtained from the operator of the DHP in Ísafjörður. Hourly data on the power consumption of the electric boilers from 2019-2021, presented in Appendix 1, is the main source along with data on the flow/return temperature and curtailable electricity prices for the same period. General information on the DHS and its operation has been collected from the operator as well.

Heat load profile

The heat production, and respectively the electricity consumption, in the DHP is rather stable with very little daily/weekly variation. The variation is seasonal, following the ambient air temperature. The energy consumption high during the cold winter months and low in summer as presented in Figure 9.

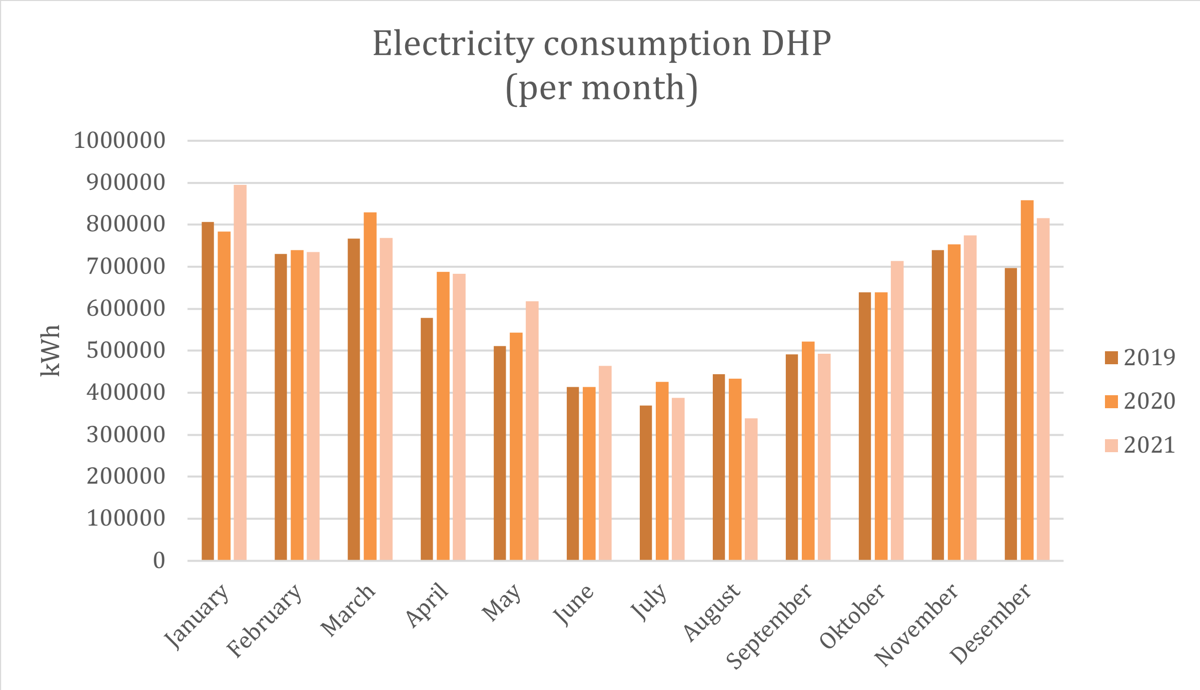


Figure 9: Load curve DHP Ísafjörður Skeiði

The graph shows the seasonal variation and that the heat production is stable between years and rather foreseeable. The production during the winter months (November-March) is close to double of that during summer (June-August). The data does not distinguish between the source of power, electricity, or oil.

Mass flow

With relatively constant flow and return temperatures throughout the year, the mass flow varies parallel with the load curve. At full load the mass flow is around 10 kg/s, the average flow during the coldest months in around 7 kg/s and during summer the average is around 4 kg/s as shown in Figure 10.

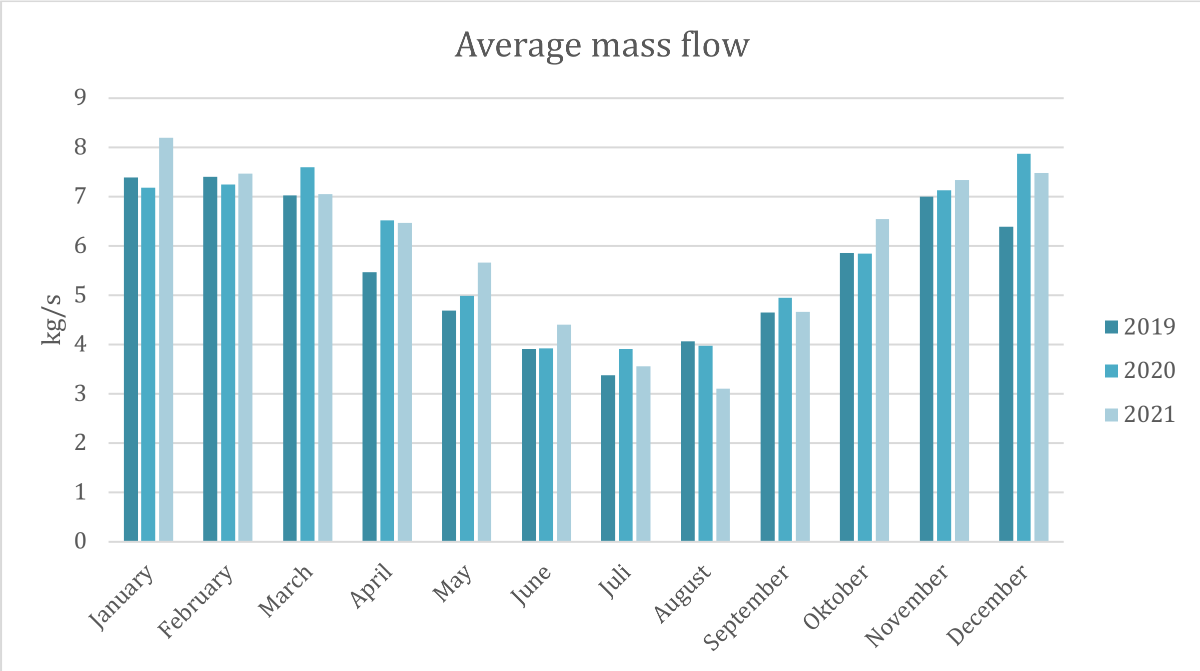


Figure 10: Average mass flow in DHS

Electricity prices for the DHP

The electricity bought for the DHP is so called curtailable power. Curtailable power contracts can be made for up to 2 years ahead of time (Bjarni Sólbergsson, CEO, pers.comm.), where the price per kWh is set per month. The electricity is low cost under the premises that in the case of power shortage on the market the buyers are cut-off and not supplied with power. In that case the buyer, depending on its nature, either shuts-off, or as in the case of the DHP generates its own power (68). As described earlier the DHP has an oil boiler that is used in these cases.

As the Icelandic power system is built up of hydropower and geothermal power, shortage most often occurs due to little precipitation and consequently low water levels in the reservoirs. Shortage has not been common in the Icelandic power system, and it has rarely come to power curtailment. In 2022 from 14th of February to the 4th of April, the DHP power for the DHS was curtailed, during that time many thousands of litres of oil were burnt for heating.

The increasing power demand in Iceland and the installation of new power plants have not gone hand in hand over the last years. Very few power plants on a scale above 10 MW have been built and therefore shortages are expected to occur more often in coming years. For this reason and the fact that all Icelandic power companies in Iceland have set the goal on achieving carbon neutrality by 2040 (69), curtailable power will not be bought for the DHP much longer. What the replacing contract will offer is not known and for that reason the profitability of this project will be calculated for a range of possible power prices. It is expected that the prices will be comparable to the curtailable prices. The power prices for the DHP from 2015-2021 are shown in the graph in Figure 11.

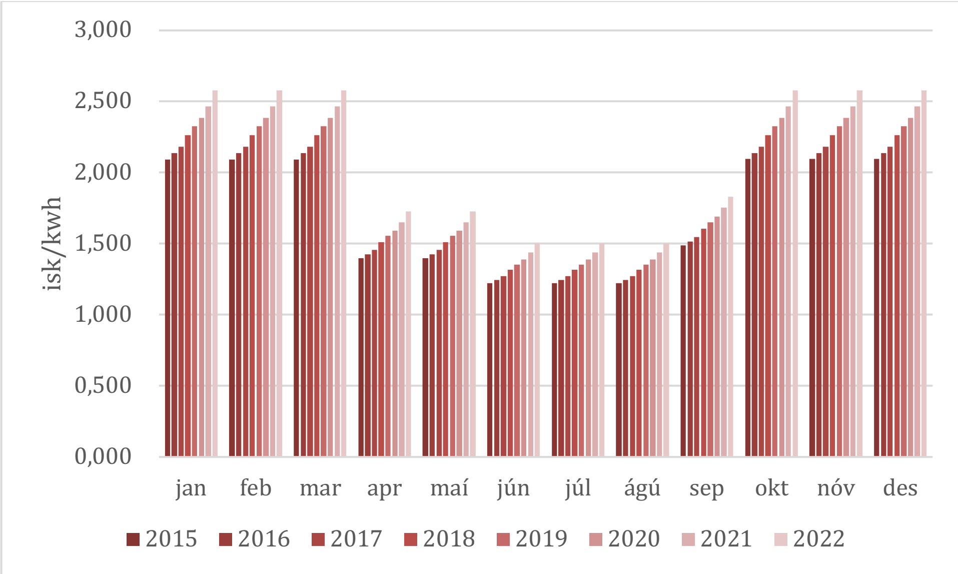


Figure 11: Curtailable power prices DHP

As can be seen from the graph, the price for curtailable power has been stable and the increase between years is ~1%. The winter prices (October-March) are close to 40% higher than summer prices (May-August).

3.3 Integration of waste heat

Potential integration alternatives were evaluated, considering the low temperatures of the DHS and the temperature of the waste heat. The outcome was that it would be optimal using a heat exchanger to integrate the heat straight to the return flow before any heating is done by the electric boilers. This solution is simple to implement to the existing system and would be relatively cheap in terms of equipment costs. The result is illustrated in Figure 12 where the DHS including the waste heat integration is sketched.

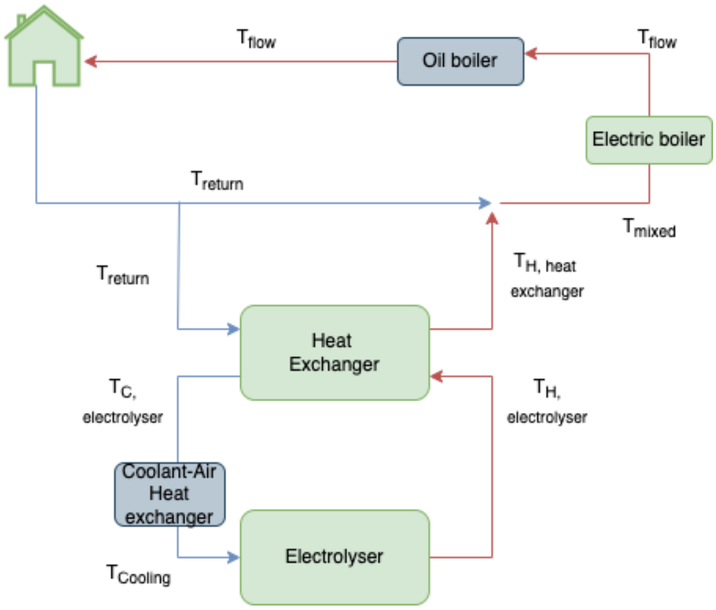


Figure 12: Illustration of DHP with waste heat from electrolyser integrated

The heat exchanger acts as a part of the cooling system for the electrolyser, transferring the heat to the return flow of the DHS. With T_{return} set to 35°C it can be stated that all temperatures above 35°C can be utilized. As heat below 35°C cannot be utilized a coolant-air heat exchanger will be needed for the cooling system of the electrolyser, assuming the cooling water needs to be colder than T_{return}. The coolant-air heat exchanger is assumed to be the standard exchanger supplied with the electrolyser package, designed for the full cooling duty if the DHS system is not *online* for some reason. Here it is here assumed that the electrolyser is designed such that the cooling waters upper limit is around ambient outdoor temperature of 25°C.

As seen in Figure 12, it is only a part of the return flow that gets heated up by the electrolyser. This flow is set constant to 2 kg/s based on the total mass flow shown in chapter 3.2.1. The flow from the heat exchanger is mixed back with the remaining return mass flow, which consequently elevates the temperature. The total mass flow is an important parameter, since the temperature after mixing the water heated by the electrolyser depends on it. The electric boiler then raises the temperature to the desired flow temperature (70°C). The oil boiler is shown in Figure 12, but as mentioned earlier it is only used when the DHP does not have access to electricity.

Formulas for heat integration calculations

To calculate the amount of heat that gets integrated to the DHS equation 10 is used.

$$Q = \dot{m}c\Delta T \tag{10}$$

Where mass flow in kg/s, c is the specific heat of water in J/kg°C and ΔT is the temperature difference between the flow on the warm and cold side of the heat exchanger.

At first the mass flow through the electrolyser side of the heat exchanger is calculated using the three scenarios of available heat from electrolyser and the temperatures, $T_{H,\ electrolyser}$ and $T_{Cooling}$ (25°C). Knowing the mass flow through the electrolyser side, the available heat for integration to the DHS through the heat exchanger is calculated based on $T_{C,\ electrolyser}$. The available heat is calculated for the three efficiency scenarios and for two *possible* $T_{C,\ electrolyser}$, 37°C and 40°C.

Knowing the amount of heat that is available for integration to the DHS for all three scenarios the temperature of the heated water ($T_{H,\ heat\ exchanger}$) is calculated using equation 10. The resulting temperature increase of the total mass flow is based on the total mass flow at each instant and is calculated using equation 11.

$$\dot{m}_{total}T_{mixed} = \dot{m}_{Heat\ Exchanger}T_{H,Heat\ Exchanger} + \dot{m}_{bypass\ return}T_{return} \tag{11}$$

Where $\dot{m}_{total}$ is the total mass return mass flow, T_{mixed} is the temperature of the flow when the water heated by the electrolyser has been returned to the mass flow that passes by the heat exchanger, $\dot{m}_{Heat\ Exchanger}$ is the mass flow through the heat exchanger in, $T_{H,Heat\ Exchanger}$ is the temperature of the water heated by the electrolyser, $\dot{m}_{bypass\ return}$ is the mass flow that passes by the heat exchanger and T_{return} is the temperature of the return flow. All mass flows are in kg/s and temperatures are in °C.

The *physical* size of the heat exchanger is dependent on the amount of heat available for integration in each case. It is calculated using equation 12.

$$Q = U\ A\ LMTD \tag{12}$$

Where Q is the transferable power of the heat exchanger, U is the heat transfer coefficient and $LMTD$ is the logarithmic mean temperature difference. For water-to-water heat exchanger the heat transfer coefficient is typically between 800-1500 W/m^2°C (70). In this case the median value of 1150 W/m^2°C is chosen. The LMTD in equation 12 is calculated as:

$$LMTD = \frac{\Delta T_1 - \Delta T_2}{\ln\left(\frac{\Delta T_1}{\Delta T_2}\right)} \tag{13}$$

where for parallel flow ΔT_1 and ΔT_2 are in this case:

$$\Delta T_1 = T_{H,electrolyser} - T_{H,heat\ exchanger} \tag{14}$$

$$\Delta T_2 = T_{C,electrolyser} - T_{Return} \tag{15}$$

3.4 Financial analysis

To calculate profitability of the project a financial model is made, and sensitivity studies are carried out. The financial model includes the capital and operating costs for the electrolyser and heat exchanger, funding for the project, loans and payments, a deprecation schedule, income statement and cash flow (see Appendix 2). The sensitivity study investigates three different scenarios, optimistic, realistic, and pessimistic. A preliminary investigation on which parameters are the most important was carried out to realise what characteristic should change for each scenario. The values chosen for each scenario represent the minimum, median and maximum values of each of the variable parameters. The variable parameters in the model are the net production rate, the electrolyser price per kW installed, the operating hours per year and respectively the power consumption of the electrolyser, power/electricity costs, hydrogen selling price and the amount of waste heat available. The model assumes that the electrolyser is running on full load during all operating hours.

The financial statement considers the CapEx, OpEx, net sales, cost of sales and taxes. CapEx including purchase of the electrolyser system, heat exchanger, project construction management, installation, and transport. OpEx including sales and marketing (S&M), operation and management (O&M), deprecation, and the overhead. Net sales are in this case hydrogen and heat and cost of sales, which are electricity and water costs, and cost of sales are simply electricity and water costs. The taxes are corporate income taxes, which in Iceland are 20% (71).

The price of the electrolyser is 80% of the CapEx and is calculated using the range 400-1600 €/kW of installed power for the whole system. The range is chosen based on the values of the literature review (chapter 2.3.5). The other CapEx factors are calculated as a percentage of the electrolyser price. Project construction management is assumed to be 5% and installation and transport 20%. It is assumed that the electrolyser is a standard solution, containerized module, that does not require special foundations or a building, which explains the low factor of installed cost, 1.2.

In the financial model the OpEx is 4.2% of the initial CapEx. Where S&M are 2% of net sales, O&M are 3% of CapEx and overhead is 0.5% of CapEx as the project is not assumed to be an independent business unit. It is assumed that the operator, the power company, is the only investor in the project. The model assumes that a loan is taken to finance the project. The loan is equal to the total CapEx of the project. The interest rate is assumed 5% and the term 15 year. As the projects equity is 0% and 100% is debt the WACC for the project is equal to the interest rate of the debt (5%).

A straight-line depreciation schedule over 10 years with the salvage value set to 20% is included in the model. The model uses a constant inflation of 2.5% which is the current target of the Central Bank of Iceland (72). Inflation is applied to hydrogen prices, electricity prices, heat price and the OpEx factors. The selling price for the waste heat is assumed to be 60% of the electricity price for each scenario (52). Although there is history of waste heat utilization from a municipal incineration to the DHS, in that case the waste heat price was equal to the electricity price for the DHP (Sölvi R. Sólbergsson, CEO, pers.comm.). The water costs for the electrolyser is obtained from an official price list from the government on site (73).

The financial statements of the project are entirely dependent on the operation of the electrolyser, its efficiency and production rate. The characteristics of the base scenario electrolyser introduced in chapter 3.1 are used to calculate the production and energy consumption for the variable parameters and assumptions.

3.4.1 Heat integration module

Typically, the cooling system of an electrolyser uses a coolant-air heat exchanger, with cooling temperatures lower than the DHS return temperatures. To be able to integrate the heat to the DHS an extra step of cooling needs to be implemented using a water/coolant-water heat exchanger. This module is not a standard product from the electrolyser manufacturer, it would need to be specially designed for this case, connecting it to the electrolyser and the DHS. In addition to the heat exchanger itself, it is expected that some pipework, valves, instrumentation, and electrical system for opening and closing the valves are needed to connect the heat exchanger. A foundation, enclosure and possible a ventilation system could be necessary. Due to the special design and the additional components required, the cost for the heat integration module is expected to be a factor 5 times (74) the heat exchanger costs. Additionally, the cost of installing the heat exchanger module (i.e, pipework, valves, instrumentation, electrical system, foundation, enclosure and ventilation system) are assumed to be 20% higher than the uninstalled heat integration module costs.

For this thesis a 200kW co current flow water-to-water plate heat exchanger for operating temperatures between 10 and 80°C has been used for reference (75). The costs of an uninstalled appropriate heat exchanger is 650 €. The financial model does not consider the heat exchanger size and costs to change with the amount of heat available for each scenario.

3.4.2 Operation of electrolyser – description of parameters and values

The operation of the electrolyser is fundamental for the profitability of the project. The financial model includes calculations on the amount of hydrogen produced and the amount of energy needed to do so. The operation parameters used in the calculations are listed in Table 6 below.

Table 6: Electrolyser operation parameters

Variables	
Hours per year in operation	3000-8000 h
Power consumption of system	4.4-5.1 kWh/Nm3
Power consumption of system	49-57 kWh/kg
Hydrogen produced	23 kg/h
Amount of waste heat available[1]	5, 10 & 15 %

[1] % of electrolyser power consumption

The number of hours the electrolyser is in operation is up to the operator. The range of operating hours per year is theoretically 0-8760 hours, typically determined by the laws of the market supply and demand. The power consumption of the system defines the efficiency of the system, comparing the value to the HHV of hydrogen and the amount of power needed to produce one unit of hydrogen (Nm^3 or kg). As described in chapter 3.1 the manufacturer does not give the system efficiency for the electrolyser. That causes some uncertainty in values used in this calculation. The efficiency is calculated from the power consumption of the system, presented in the same chapter, 3.1.

As the model assumes that the electrolyser is operating at full load during all operating hours the production rate that is chosen for the model is in the higher end of the given range. The production rate used in the calculation is 85% of the maximum for the base scenario electrolyser or 23kg/h. The yearly power consumption of the electrolyser is calculated using the power consumption of the system per hydrogen unit and the amount of hydrogen produced per year. The amount of heat available is calculated as a percentage of the yearly power consumption of the electrolyser, because as in the case of the system power consumption, the manufacturer did not provide values for the amount of heat available. The model assumes that the full production is reached on the fourth operating year. The electrolyser is operated at 40, 60 and 80% during year 1,2 and 3 respectively.

3.4.3 Operating scenarios

There are three operating scenarios are evaluated, optimistic, realistic, and pessimistic. The realistic scenario is assumed to be the median of the optimistic and the pessimistic values. The variable parameters of each scenario are CapEx, electrolyser operation hours per year, the amount of heat available for integration to the DHS, and the electrolysers efficiency. The values for each scenario are listed in Table 7.

Table 7: Values for each scenario of the sensitivity studies

	Optimistic	**Realistic**	**Pessimistic**
CapEx	400	1000	1600
Operation (h/year)	8000	5500	3000
Available heat [1]	15%	10%	5%
System efficiency, HHV (%)	80%	75%	69%
System power consumption (kWh/Nm^3)	4.4	4.75	5.1

[1] % of electrolysers power consumption

The CapEx range and available heat are chosen based on literature studies, presented in chapter 2.3.5. The operation hour range is set to 3000-8000 hours, assuming 8000 hours per year when in continuous operation. The time is limited to 8000h due to expected downtime for maintenance and possible power outage. It not assumed that the electrolyser will be operated when the power system is running on backup power.

3.4.4 Sensitivity study

The sensitivity study considers the profitability of each operation scenario with a broad range of both electricity costs and hydrogen selling prices. The electricity prices are based on the curtailable electricity prices from 2019-2021 presented in chapter 3.2.5 and range from 0 to 24 €/MWh. The hydrogen price range is based on the IEAs (5) review and IRENAs report (33), the range chosen for this thesis sensitivity study is 1-6 €/kg H_2. The results are presented based on the NPV of the project for each case over a range of electricity costs and hydrogen selling prices. When selecting the range of electricity and hydrogen prices the results are considered and the range chosen such that the break-even point for each case is included.

4 Results and Discussion

This section presents the results of the financial analysis of the electrolytic hydrogen production along with calculations on the feasibility of waste heat integration to DHS, in the form of a sensitivity study for three operation scenarios: optimistic realistic and pessimistic. The conditions for which the hydrogen production is profitable are calculated over a range of hydrogen and electricity prices.

4.1 Financial analysis

The financial analysis calculates the NPV of the project over the estimated lifetime of 25 years. It returns sensitivity studies for the three operating scenarios over a range of electricity prices (€/MWh) and hydrogen selling prices (€/kg). Positive NPV indicates that the project is profitable at the corresponding conditions. They are presented in green. The project is not profitable when the NPV is negative, that is presented in red.

As the scope of the project is limited to the electrolyser system and does not include other plant components of a hydrogen production plant the results must be evaluated based on that. The plant components excluded from the study are, a rectifier, water purification unit, gas compression and storage units, and gas cooling. Including these components involves a higher CapEx and higher OpEx, mostly due to electricity costs of the compressor, increasing the cost per unit of hydrogen produced.

The financial statement for the project does not consider that the stack lifetime is shorter than the system lifetime. The stack lifetime is defined by its efficiency degradation as described in chapter 2.3.1 and the frequency of stack replacement is therefore dependent on the operation hours of the electrolyser. Including the stack replacement in the financial analysis would result in CapEx annuity increase (9) .

The results for the optimistic, realistic, and pessimistic scenarios for electricity costs of 0-24 €/MWh and hydrogen price 1-6 €/kg, are shown in Table 8 ,9 and 10. The tables show the NPV, for each hydrogen/electricity price, in thousands of euros (k€). The range for electricity costs and hydrogen prices are chosen such that break-even points of all three scenarios are included in table. For comparison, the average electricity price for the DHS was around 16 €/MWh from 2019-2020. The IEA has reported hydrogen prices from natural gas to be from

0.5-1.6 €/kg depending on regional gas prices and that the production of renewable hydrogen the cost is from 2.7 to 7.3 €/kg (5).

Optimistic scenario

The optimistic scenario uses the optimistic value of the efficiency, CapEx and system power consumption and assumes that the electrolyser is operated on full load 8000h per year. The results from the financial analysis are shown in Table 8 for the chosen range of electricity and hydrogen prices.

Table 8: Profitability of the hydrogen production, optimistic scenario. Green columns show that the project is profitable for the appropriate hydrogen and electricity prices, red column indicate that the project is not profitable.

		Electricity price (€/MWh)						
	NPV (k€)	0	4	8	12	16	20	24
Hydrogen price (€/kg)	1.0	1 100	7440	380	- 1	- 390	- 790	- 1.230
	1.5	2 090	1 730	1 380	1 030	680	310	- 70
	2.0	3 070	2 720	2 370	2 020	1 670	1 320	970
	2.5	4 050	3 700	3 350	3 000	2 650	2 300	1 960
	3.0	5 030	4 680	4 330	3 980	3 630	3 280	2 940
	3.5	6 010	5 660	5 310	4 960	4 610	4 270	3 920
	4.0	6 990	6 640	6 290	5 940	5 590	5 250	4 900
	4.5	7 970	7 620	7 270	6 920	6 580	6 230	5 880
	5.0	8 950	8 600	8 250	7 900	7 560	7 210	6 860
	5.5	9 930	9 580	9 230	8 890	8 540	8 190	7 840
	6.0	10 910	10 560	10 210	9 870	9 520	9 170	8 820

The result shows that for current electricity price, 16 €/MWh the project would be profitable for all hydrogen prices above 1.5 €/kg, as additionally, it would be profitable for the entire range of electricity prices when the hydrogen price is above 2 €/kg. Other studies find that hydrogen price between 2.7 to 7.3 €/kg (5) should be expected as typical for green/electrolytic hydrogen production. The hydrogen prices from the optimistic results are significantly lower.

The model generated for this thesis excludes the components of plant listed in in the second paragraph of this chapter. This partly explains the result showing that the project is profitable for low prices of hydrogen. Another important factor is the range of electricity price included in the study, the average electricity price (curtailable) in this region is 16 €/MWh for 2019-2021. Those prices are relatively low compared to other EU/Nordic countries (76) and due to the stable energy market in Iceland (see chapter 3.2.1) the price is not assumed in this thesis to increase drastically.

Realistic scenario

The realistic scenario uses the median value of the efficiency, CapEx and system power consumption and assumes that the electrolyser is operated on full load 5500h per year. The results are shown in Table 9.

Table 9: Profitability of the hydrogen production, realistic scenario. Green columns show that the project is profitable for the appropriate hydrogen and electricity prices, red column indicate that the project is not profitable.

	Electricity price (€/MWh)						
NPV (k€) / Hydrogen price (€/kg)	0	4	8	12	16	20	24
1.0	- 1 030	- 1 330	- 1 640	- 1 960	- 2 290	- 2 630	- 2 960
1.5	- 280	- 580	- 880	- 1 180	- 1 480	- 1 780	- 2 120
2.0	470	170	- 130	- 430	- 720	- 1 020	- 1 320
2.5	1 200	910	620	330	30	- 270	- 570
3.0	1 890	1 620	1 340	1 060	776	480	190
3.5	2 570	2 300	2 030	1 760	1 490	1 210	930
4.0	3 250	2 980	2 720	2 450	2 170	1 900	1 630
4.5	3 930	3 660	3 390	3 130	2 860	2 590	2 320
5.0	4 610	4 340	4 070	3 810	3 540	3 270	3 000
5.5	5 290	5 020	4 750	4 480	4 220	3 950	3 680
6.0	5 960	5 690	5 430	5 160	4 890	4 630	4 360

The results show that the project is profitable in all cases of the study when the hydrogen price is above 3 €/kg. These results are more in line with previous findings and considering the additional compression, storage and transportation costs that are not included here these results would presumably be closer to the median of the range given by IEA, 2.7-7.3 €/kg (5). Calculating the profitability of the realistic case for electricity prices up to 40 €/MWh (see Appendix 3) the project is profitable for all scenarios when the hydrogen price is above 4 €/kg.

Pessimistic scenario

The pessimistic scenario uses the pessimistic value of the efficiency, CapEx and system power consumption and assumes that the electrolyser is operated on full load 3000h per year. The results of the sensitivity study are presented in Table 10.

Table 10: Profitability of the hydrogen production, pessimistic scenario. Green columns show that the project is profitable for the appropriate hydrogen and electricity prices, red column indicate that the project is not profitable.

		Electricity price (€/MWh)						
	NPV (k€)	0	4	8	12	16	20	24
Hydrogen price (€/kg)	1.0	- 3 300	- 3 500	- 3 710	- 3 910	- 4 110	- 4 310	- 4 510
	1.5	- 2 840	- 3 040	- 3 250	- 3 450	- 3 650	- 3 850	- 4 050
	2.0	- 2 420	- 2 600	- 2 790	- 2 990	- 3 190	- 3 390	- 3 590
	2.5	- 2 000	- 2 180	- 2 370	- 2 550	- 2 740	- 2 930	- 3 130
	3.0	- 1 590	- 1 770	- 1 950	- 2 130	- 2 310	- 2 500	- 2 680
	3.5	- 1 190	- 1 360	- 1 540	- 1 720	- 1 900	- 2 080	- 2 260
	4.0	- 780	- 960	- 1 130	- 1 310	- 1 490	- 1 670	- 1 850
	4.5	- 370	- 550	- 730	- 900	- 1 080	- 1 260	- 1 440
	5.0	40	- 140	- 320	- 500	- 670	- 850	- 1 030
	5.5	450	270	90	- 90	- 270	- 440	- 620
	6.0	860	680	500	320	150	- 40	- 210

For the pessimistic scenario the hydrogen production is not profitable for any hydrogen price below 5 €/kg. Not even when the electricity price is zero.

4.1.1 The effect of each factor of the sensitivity study

The values chosen for each scenario are critical for the results of the financial analysis. Of the factors that vary for each operating scenario, listed in Table 7, the % of heat available for integration to the DHS has the least effect on the profitability of the hydrogen production. The results from chapter 4.2 show that for the optimistic case the sale of heat is around 1.7% when the heat price is 60% of the electricity price and 3% of if heat and electricity prices are equal.

The three remaining factors; operating hours (h/year), CapEx, and system efficiency have larger impact on the result. In the sensitivity study the values of these factors are all simultaneously changed for each operating scenario. To get a better idea of the impact of each factor calculations are done where only one of the three factors is changed at the time. More detailed results for each calculation can be found in Appendix 3, where the NPV values are included.

Operating hours

By only changing the operating hours per year of the pessimistic scenario, from 3000 to 8000 and keeping the other factors unchanged the results are that the project is profitable for electricity values of the range when the hydrogen price is above 3.5 €/kg. For the optimistic scenario when the operating hours are decreased from 8000 to 3000 profitability is reached for all electricity prices when the hydrogen price is above 2.5 €/kg, which is less than half of the hydrogen price for the original scenario. The results for the pessimistic and optimistic scenarios with the changed number of operating hours are shown in yellow in Tables 11 and 12.

Table 11: Optimistic scenario. Comparison of the original scenario and the scenario for 3000 operating hours per year.

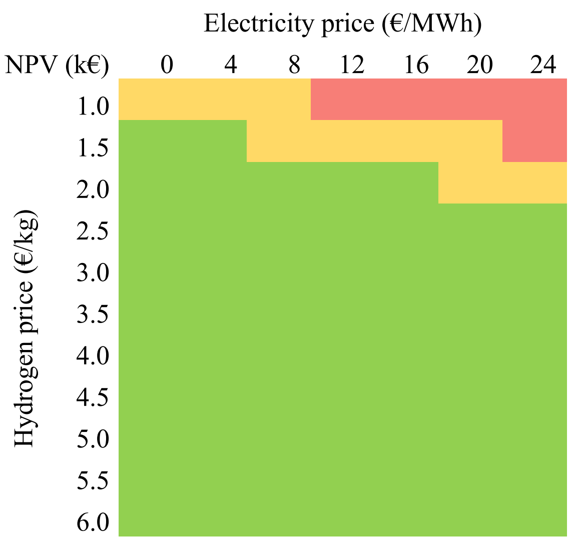
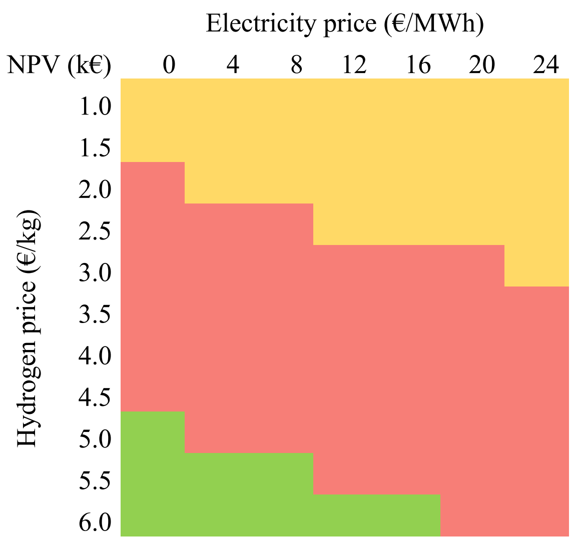


Table 12: Pessimistic scenario. Comparison of the original scenario and the scenario for 8000 operating hours per year



The range of operating hours chosen in this thesis for the sensitivity study is large, but so is the nature of operating hours for many hydrogen production projects. The reason is that the operation of the electrolyser is directly in connected with the demand for hydrogen and the demand for hydrogen is the largest uncertainty factor of the project. Currently the hydrogen demand on site of the case study is close to nothing. But following the predictions of future of green hydrogen and its role in the energy transition by the IEA and EU the demand is expected to increase drastically in coming years (6; 7).

CapEx

The results of changing the CapEx of the optimistic and pessimistic scenarios from 400-1600 and 1600-400 respectively are even more altering than the results from changing the operation hours. For the optimistic scenario profitability is reached for all electricity prices when the hydrogen price is above 3 €/kg. For the pessimistic scenario it is when the hydrogen price is above 2.5 €/kg. The pessimistic scenario becomes profitable for lower values than the optimistic scenario. The results are shown in table 13 and 14 where the profitability of optimistic and pessimistic scenarios are shown, the tables show a comparison of the original scenarios and the scenarios for the changed CapEx values.

Table 13: Comparison of original optimistic scenario, shown in red, and optimistic scenario with electrolyser Capex of 1600 €/kWh, shown in yellow.

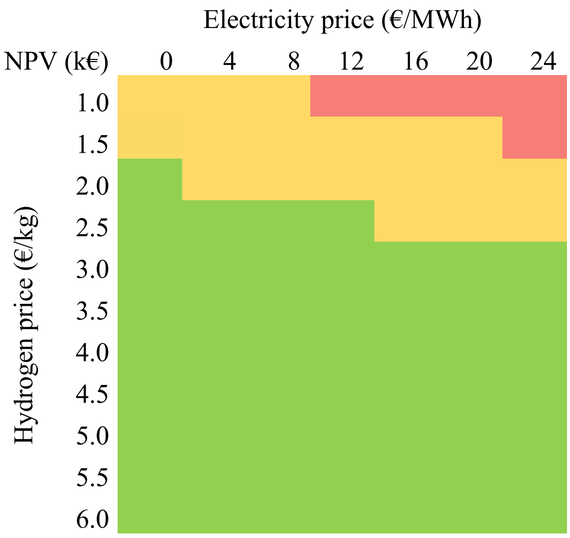
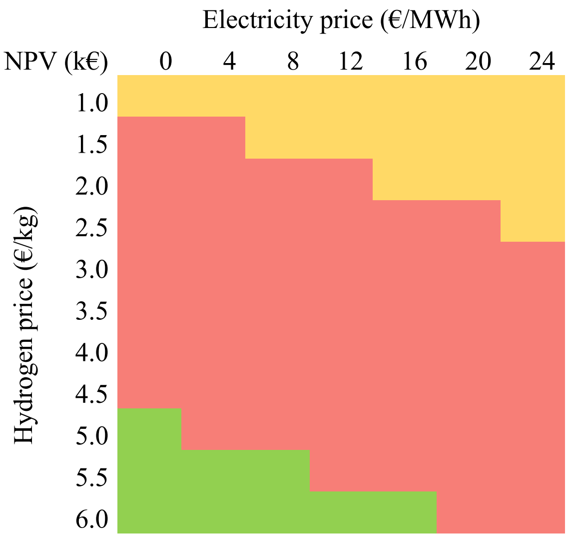


Table 14: Comparison of original pessimistic scenario, shown in red and the pessimistic scenario with electrolyser CapEx of 400 €/kWh, shown in yellow.



This interchange shows the large effect that the CapEx of the electrolyser has on the project's profitability. This large change in result may be attributed to the large range of CapEx chosen for this thesis. It can be argued that the values chosen for the optimistic case are too low. The CapEx range was chosen such that it covers the full range from the literature reviewed. The lower end of the CapEx range is based on IRENAs (33) and the EUs (50) reports and the scale of the electrolyser is not comparable with the thesis case. In the reports large scale >10MW electrolysers are described or targeted, while the electrolyser in this project is between 1 and 2 MW.

As mentioned in chapter 3.4 the CapEx of the base scenario electrolyser is an estimate based on the literature review. In email communication (39) with the manufacturer (NEL) no information regarding the CapEx of the standard containerized electrolyser used for reference in this thesis could be provided. In the literature review one source was found (77) where the price (uninstalled equipment costs) of an 870kW alkaline electrolyser from the same manufacturer was given as 2 000 000 €. That equals a CapEx of 2300 €/kW of installed power which is outside the thesis CapEx range. The profitability calculations for the optimistic scenario using a CapEx of 2300 € shows profitability for all electricity prices when the hydrogen price is above 4 €/kg. The source references to personal contact with NEL from 2021 and it cannot be independently verified for accuracy.

System efficiency

The range of system efficiency researched in this thesis is from 69-80%, The profitability is calculated for the optimistic scenario using the pessimistic efficiency (69%) and the pessimistic scenario is calculated using the optimistic efficiency (80%). The result is shown in Tables 15 and 16, where the original scenario results are shown in red and the new efficiency scenarios are shown in yellow for comparison.

Table 15: Optimistic scenario. Original scenario result is shown in red and optimistic scenario with efficiency 69% is shown in yellow.

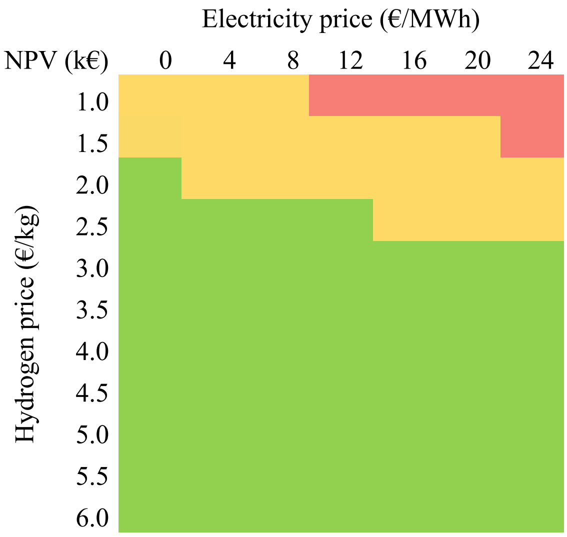
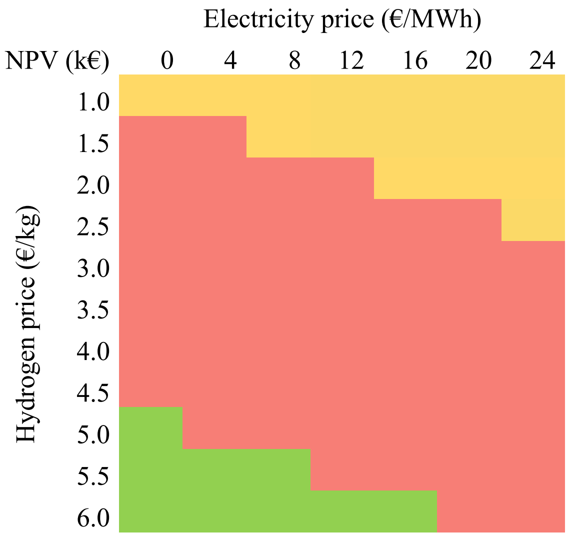


Table 16: Pessimistic scenario. Original scenario result is shown in red and pessimistic scenario with efficiency 80% is shown in yellow.



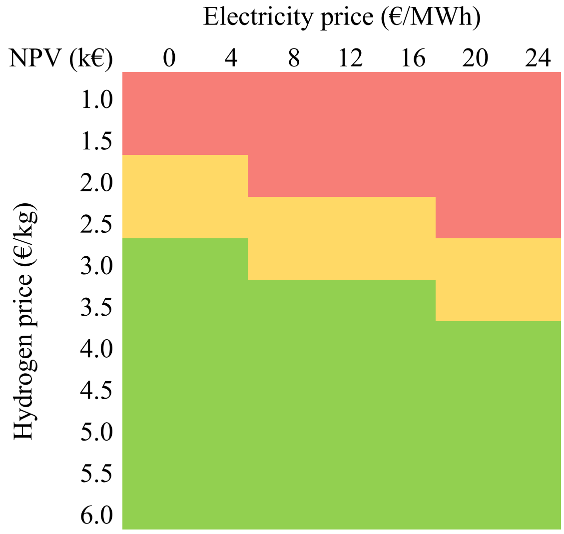
The impact of system efficiency is large as the results show. When switching the efficiency values for the optimistic and pessimistic scenarios the difference between the two scenarios gets significantly smaller. For both optimistic and pessimistic scenarios profitability is reached when the hydrogen price is above 3 €/kg. Similar to the results of switching the CapEx values for the optimistic and pessimistic scenarios

Electrolyser plant estimate

The work of this thesis is limited to the electrolyser and does not consider the other plant components (balance of plant). As mentioned in chapter 2.5 the costs of including plant components (a rectifier, water purification unit, gas processing including compression and storage, and gas cooling components) are estimated to be 50-60% of the total CapEx of plant and the electrolyser stack represents 40-50%. Here the median of this estimate (55%) will be used as the basis to calculate the NPV of a plant using the realistic scenario of this thesis.

An increase of OpEx is also estimated (roughly) in the financial analysis for balance of plant. The largest share of OpEx is the electrical power needed for the compressor. In theory a compressor uses 1 kWh/kg to compress hydrogen gas from 20 bar to 350 bar, 1 kWh/kg equals 3% of the HHV of hydrogen, or around a 3% reduction in the electrolyser's efficiency. Performing calculations on the realistic case of this thesis using 55% increased CapEx and including the components mentioned in the above section as well as the power consumption for compressing the gas to 350 shows that the project becomes profitable when the hydrogen price is above 4 €/kg, compared to the original realistic scenario. Table 17 shows a comparison of the result from the original realistic scenario, in red, and the realistic scenario including the plant components listed in the beginning of this paragraph.

Table 17: Effect of including plant components for the realistic scenario. The original scenario is shown in red and the plant-scenario is shown in yellow.



4.2 Integration of waste heat

The amount of available heat for integration to the DHS depends on the amount of available heat generated during electrolysis and the temperature of the return flow (T_{return}). Figure 13 shows how the heat from the electrolyser is integrated to the DHS using a heat exchanger.

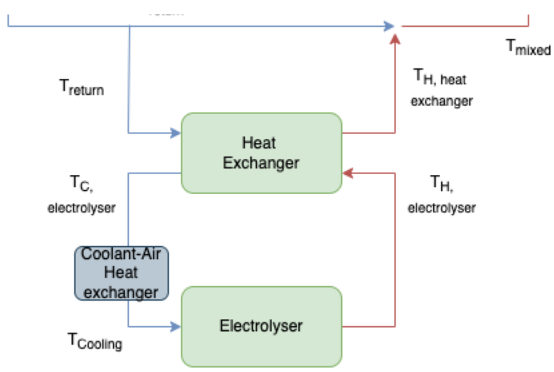


Figure 13: Heat exchanger

As explained in the Method chapter, a sensitivity study is conducted for three different scenarios, regarding available waste heat from the electrolyser. The optimistic, realistic, and pessimistic scenarios consider 15, 10 and 5% of the electrolysers input power to be available for utilization/recoverable. The amount of heat that is available for integration to the DHS is further limited by the T_{return} as temperatures below that cannot be integrated. The DHS in Ísafjörður is a low temperature system, with T_{return} of 35°C, and because of the low return temperature and the electric top-up boiler the DHS is well suited for integration of waste heat. The waste heat from electrolysis is not at really high temperature and for many DHS that have significantly higher flow/return temperatures, as mentioned in chapter 2.6, the integration would not be possible.

The amount of heat available for integration to the DHS is calculated using equation 10 for $T_{C, electrolyser}$ 40°C, the results for each operating scenario*/s* are shown in table 18. $T_{C, electrolyser}$ is determined operation specifications of the heat exchanger. Choosing a lower $T_{C, electrolyser}$ means that more heat is available for utilization, but that would require a larger heat exchanger. Along with the corresponding mass flows of both sides of the heat exchanger and the resulting temperature of the water returned to the DHS ($T_{H, heat\ exchanger}$). The amount of heat available for integration is listed in Table 18 for the three operating scenarios along with the values used for the calculations and the obtainable $T_{H, heat\ exchanger}$ for each case.

Table 18: Available heat and water temperature from heat exchanger

Operating scenario	**Pessimistic**	**Realistic**	**Optimistic**
Waste heat (kW)	71	142	214
Mass flow electrolyser side (kg/s)	0.31	0.62	0.93
Recoverable waste heat (kW)	51.6	103.3	156
$T_{H, heat\ exchanger}$ (°C)	41.2	47.3	53.6

As explained in chapter 3.3 the mass flow on the DH side of the heat exchanger is assumed to be constant. The mass flow on the electrolyser side on the other hand varies with the amount of available heat, as the temperatures on the cold and hot side ($T_{C/H, electrolyser}$) are assumed to be constant. For the pessimistic and realistic case, the mass flow on the electrolyser side, 0.31 and 0.62 kg/s respectively are rather low compared to the mass flow on the DH side. In those cases, it may be expected that some pumping system would be required for the heat exchanger to function, based on the values given by the heat exchanger manufacturer (75). These result show that the maximum amount of heat available for integration to the DHS is 155.6 kW, from the optimistic operation scenario when the electrolyser is operating on full load.

The maximum transferable power of the heat exchanger is assumed to be the same, 155.6 kW. The mass flow of 2 kg/s that is branched off from the total mass flow and heated from 35°C to 41.2-53.6°C for the different operating scenarios, as shown in table 8. The cooling water of the electrolyser is simultaneously cooled from 80°C to 40°C, with variating mass flows as shown in Table 18. The heat profile of the heat exchanger is shown on Figure 14.

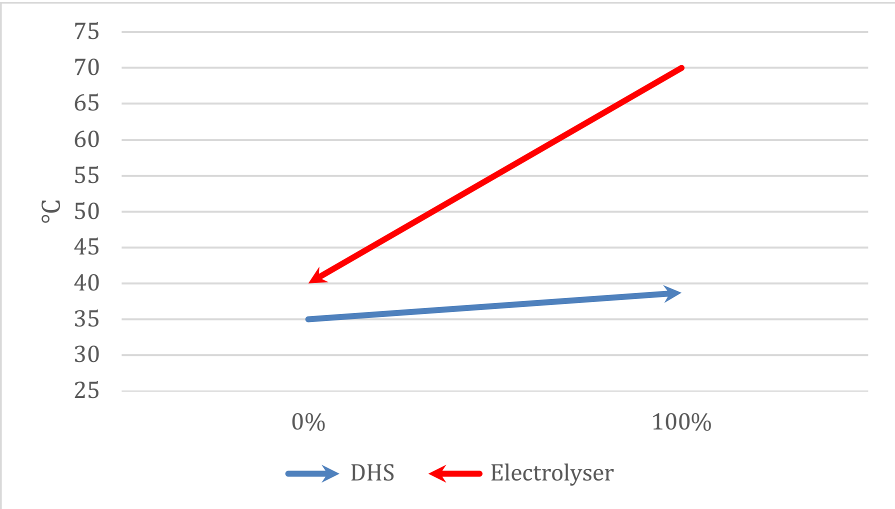


Figure 14: Heat exchanger temperature profile

The size of the heat exchanger is calculated using equation 12 for all three scenarios. The results are 3.7, 7.5 and 11.3m^2 for the pessimistic, realistic, and pessimistic scenario. Those results show that the heat exchanger size is not very large for any of the scenarios.

As the mass flow heated by heat exchanger is only a branch of the total mass flow the T_{mixed} is calculated for each scenario using equation 11. T_{mixed} is the temperature that the total mass flow has when entering the electric boilers and it varies with the total mass flow. In table 19 T_{mixed} is shown for the three operating scenarios.

Table 19: Temperature of flow after heat integration

Operating scenario	Optimistic	Realistic	Pessimistic
T_{mixed} ($\dot{m} = 3$ kg/s)	39.1°C	43.2°C	47.4°C
T_{mixed} ($\dot{m} = 5$ kg/s)	37.5°C	39.9°C	42.4°C
T_{mixed} ($\dot{m} = 8$ kg/s)	36.5°C	38.1°C	39.7°C

The electric boilers top-up the temperature from T_{mixed} to the desired T_{flow} of 70°C. This means that the amount of heat integrated from the electrolyser is saved by the DHP or the electric boilers and this reduces the power consumption of the DHP reduces. Since the mass flow through the DH side of the heat exchanger is constant the temperature increase of that mass is constant for each scenario. But as shown in Table 19 the T_{mixed} varies based on the variation of the total mass flow, increasing the most when the total mass flow is at minimum. The mass flow of the DHS follows seasonal variations as shown on Figure 9 and therefore the share of waste heat is much greater during summer than winter. On the other hand, the operation plan of the electrolyser could be such that it would not be in constant operation, the whole year around. That is not considered here.

The effect of integrating waste heat on the power consumption of the electric boilers is dependent on the amount of accessible heat and no less it is dependent on the number of hours per year the electrolyser is in operation. The amount of heat available for integration to the DHS for the three operation scenarios is shown in Table 20, along with the % of the average yearly power consumption of the electric boilers that would be saved. The average annual power demand of the DHP without heat integration was 7 500 MWh for 2019-2021.

Table 20: Three scenarios for power savings of the DHP including waste heat integration. The values for the original scenarios are highlighted.

	Optimistic (MWh)	% of DHS annual power demand	Realistic (MWh)	% of DHS annual power demand	Pessimistic (MWh)	% of DHS annual power demand
Annual power savings (8000h)	990	13%	710	9%	380	5%
Annual power savings (5500h)	680	9%	490	7%	260	3%
Annual power savings (3000h)	370	5%	270	4%	140	2%

The results show, for the original scenarios, that 2%-13% less power is used directly for heating by the electric boilers when the heat from the electrolyser is integrated. The range is rather large and for the pessimistic scenario where the result is 2% power savings is not significant. For the optimistic scenario the results are 13% power savings per year and for the realistic it is 7%. For those amounts it could be attractive to integrate the heat. Although how attractive that is really comes down to the costs and complexity of the integration.

Utilizing the waste heat from the hydrogen production by integration to the DHS increases the electrical efficiency of the electrolyser. The utilization of the heat improves the efficiency of the electrolyser stack by 3.7%. For example, the optimistic case the stack efficiency is assumed to be 93% (see chapter 3.1.1) integration of the heat does improve the efficiency by 3.7%, to 96.7%.

The economic effect of waste heat integration

In this thesis the price of the heat, sold by the HPP to DHP, is estimated to be 60% of electricity costs at each instant, as explained in chapter 3.4. The electricity price for these calculations is based on the average curtailable power price from 2019-2021, 16 €/MWh. The amount of money saved annually by the DHS when waste heat is integrated is listed for all three scenarios and different number of operating hours in Table 21.

Table 21: Power costs saved by integration of waste heat. The values for the original scenarios are highlighted.

		Optimistic	Realistic	Pessimistic
Annual savings by DHP	8000 h	6 300 €	4 540 €	2 400 €
	5500 h	4300 €	3100 €	1700 €
	3000 h	2400 €	1700 €	900 €
Annual savings by HPP	8000 h	9 500 €	6800 €	3700 €
	5500 h	6500 €	4700 €	2500 €
	3000 h	3500 €	2600 €	1400 €

The annual saving of the DHP in the optimistic scenario (electrolyser operated 8000 h/year) is around 5% of the total cost of electric power consumed by the electric boilers, which is not a lot. But as explained in the end of previous section the attractiveness is strongly related to the costs and complexity of the integration. For comparison the installed cost of the heat integration module is estimated to be 3900 € (see chapter 3.4.1), the annual savings for the DHP for the optimistic (8000 h) scenario is above 50% more than the costs. For the pessimistic scenario (2000 h) the savings are around 20% of the heat integration costs, for all other scenarios the savings are around and above 50% of the costs. The results are that the integration is attractive for all scenarios except the pessimistic (2000 h) scenario, given that the integration is not technically complex.

For the HPP the total costs of yearly electrical power consumption are around 144 000 €, the savings for the same scenario are therefore around 7% of the electricity costs. If the price of the heat would be, as has been in the past, equal to the electricity price per kWh, the savings for the DHP optimistic case would shrink to close to zero. For the HPP on the other hand the savings increase to 11% of the yearly electric power costs of the electrolyser. It must be noted that in the power and € savings calculations the efficiency of the electric boiler has not been accounted for, that should not have a great impact as electric boiler have high thermal efficiency, up to 99% (78).

The earnings of heat sale are a very small share of the project's income or net sales. The net sales include hydrogen and heat sales. The sales of heat are around 1.7% of the net sales of the project for the optimistic scenario, for the pessimistic it is below 1%. As mentioned in chapter 3.4 there is a history of waste heat utilization in this particular DHS. In that case the price per kWh was simply equal to the electricity price per kWh. If that would be assumed to be the case in the financial analysis the share of heat sales would increase from 1.7% to 3% of net sales, for the optimistic scenario.

4.3 General discussion

The results of chapter 4.2 in this thesis shows that heat integration to DHS from hydrogen production has little impact on the economics of both the DHS and the HHP. The DHS savings due to heat integration are around 5% of the average electric power costs of the electric boilers when no heat is integrated, for the optimistic scenario. In the pessimistic scenario the savings are >1%. For the HHP the earnings from heat sale are 1.7% of the net sales for the optimistic scenario. To conclude whether it is profitable to integrate the heat the cost of the integration module is considered. The calculations of this thesis show that the cost of integration (module and installation) is low compared to both savings and the total cost of the project. The physical integration is assumed to be done through a heat exchanger connected to the return flow of the DH grid, the technical complexity of connection to the DH flow is not technically challenging, although there is more uncertainty about the technical challenges of connecting the electrolysers cooling system. As the cooling system comes as a standard module from the manufacturer and would need to be redesigned for the heat utilization.

The work of this thesis is limited to the electrolyser stack, its costs and operation with a focus on the amount of available heat and possibilities for integration to DHS. The thesis case is of small scale as the installed electrolyser/stack power is around 1400 kW, other studies used for comparison and reference are generally based on much larger scales. For example, the studies conducted by IRENA (33) is based on system above >10MW and E4tech (32) studies are based on multi-MW scale systems. Other studies and reviews on required hydrogen price for hydrogen produced by water electrolysis are typically calculated for the balance of plant where the most important components; rectifier, water purification, compression, storage, cooling components and transportation/distribution. The results of those studies show that hydrogen price (production price, without profits) between 2.7 to 7.3 €/kg (33; 32; 49) is needed to reach profitability in green hydrogen production. Comparing the results of this thesis to those numbers all operating scenarios are promising and within that range. Well within that range.

The comparison between this thesis results on the profitability of electrolytic/green hydrogen production and the findings of those studies is not built on equal footing due to the difference in included components. With that in mind it is logical that the results of the thesis show profitability for lower hydrogen prices. On the other hand, the thesis takes on a small-scale project, form which higher costs can be expected.

The effect of each variable parameter of the operating scenarios was individually calculated and the results are presented in chapter 4.1.1. The parameters are the operating hours per year, CapEx and system efficiency. The results showed that switching the optimistic and pessimistic values for each scenario while keeping other operation parameters constant had a large impact. The change of CapEx even resulted in a complete reversal, where the optimistic case became less profitable than the pessimistic one.

Considering the fact that the same company would operate the electrolyser and the DHS at the same location, as is assumed in this thesis, the evaluation of whether to integrate the waste heat or not is to a large extent reliant on the technical complexity and costs of the physical integration. That is the cost of the heat integration module and connection to both systems (DHS and electrolyser). Integration to the DHS in Ísafjörður as it is today would mean that the electric boilers were reliant on curtailable power, but the electrolyser would not. In cases where the DHP power is curtailed the waste heat from the electrolyser would save the DHP much more money since the heat source used in the case of power curtailment comes from oil boilers. In 2022 power curtailments for the DHP varied from 15th of February until 4th of April. Having some source of heat integrated to the DHS reduces all burn of fossil fuels in cases like this.

Here it is also important to note that Ísafjörður is the largest town in Iceland that uses electric boilers for DH. To be able to use the energy in a more sustainable way and to avoid/minimize the direct use of energy for heating the utilization of waste heat from any source is desirable.

Limitations & Strength and Weaknesses

When modelling the electrolysers production rate and power consumption as well as in the financial analysis of this thesis some properties of the base scenario electrolyser are calculated based on assumptions on the behaviour and the relationship of different operating parameters. This is due to lack of available data from manufacturer especially for the relationship between the electrolysers production rate and power consumption, as well as the efficiency difference of electrolyser stack and system.

The lack of data on the amount of recoverable heat from electrolysis in general leads to uncertainty in the thesis calculations. Future studies would include calculations or simulations of the recoverable share of the waste heat generated during electrolysis and the complexity of utilization.

In this thesis it is assumed that the electrolyser is operated on full load at all operating hours, and “shut-off” when not in operation. For a more realistic approach a more detailed operation plan would need to be developed. As briefly mentioned in chapter 2.3.3 the electrolysers power consumption is expected to be around 1% of the nominal installed power when in stand-by mode, that is not included in the calculations of this thesis. The frequency of starts and shutdowns is typically desired to be low, as cold start-up can cause mechanical stress on the equipment and as following cause shorter lifetimes.

5 Conclusion

This thesis attempts to answer the question of the technical and economic feasibility of electrolytic hydrogen production and waste heat integration to DHS in northwest Iceland. This is done by conducting a case study built on literature reviews, data from manufacturers and real data from the DHS. For the case an alkaline electrolyser with the production capacity of 300 Nm^3/h is chosen and the heat is integrated through a heat exchanger to the return flow of the DH grid. The project is found to be technically feasible. The low temperatures of the DHS provide good opportunities for heat integration. Due to uncertainty in the data on the amount of recoverable heat from the electrolyser a sensitivity study is conducted for optimistic, realistic, and pessimistic scenarios. The heat integration saves 13, 7 and 2% of the annual power consumption for the district heating plant for each scenario respectively.

The financial analysis is conducted in the form of a sensitivity study as there is a significant uncertainty in the economic data. Rapid development of technology and expected increase in demand impact the data and the fact that prices are not provided by manufacturers. The sensitivity study is conducted for three operating scenarios, optimistic, realistic, and pessimistic. The variable parameters for each scenario are the number of hours per year that the electrolyser is operated on full load, the CapEx and the system efficiency. Of these parameters the CapEx had the highest impact on the results.

The results from the financial analysis revealed that for the three operating scenarios researched the hydrogen production reached profitability within the set range of electricity and hydrogen prices. For the current (May 2022) electricity price (16 €/MWh) in particular, energy system profitability is reached when hydrogen prices are 1.5 €, 2.5 € and 6 € per kg hydrogen at 30 bar for the optimistic, realistic, and pessimistic scenarios, respectively. That yields for the scope of the case study, which is limited to the electrolyser, excluding plant components (a rectifier, water purification, gas processing and cooling units).

Overall, the result show that for a broad range of scenarios the project is financially attractive. The utilization of waste heat does not have significant effect on the economics of either the DHS or the HPP, but the effect on the electric efficiency of the hydrogen production is significant. Therefore, the prospects for this type of project could be expected to be feasible for DHS in northwest Iceland.

5.1 Future work

The most important future tasks are:

- **Financial calculations for the balance of plant**
  Calculating the profitability for the balance of plant, the same model could be used by implementing the missing plant components; a rectifier, water purification system, gas processing units, including compression, and drying, and storage units. The profitability of the plant gives a more realistic view of the profitability.
- **Forecast of hydrogen demand**
  A forecast of the expected hydrogen demand in Iceland would be a helpful tool for concluding the size of electrolyser.
- **Hydrogen lager on site**
  Calculation on the required hydrogen stock on site in order to be able to cover for expected downtime for maintenance.
- **Hydrogen fuel cell as back-up power**
  As one of the largest issues regarding reaching the goal of a fossil fuel free community by 2050 (69) in the northwest part in Iceland is the need to replace the oil boilers and diesel engines that act as back-up in the case of power outage for the DHS and power system respectively. A study is needed on the available options and the feasibility of replacing the oil boilers of the DH systems with hydrogen fired boilers and the diesel engines with hydrogen fuel cells. As well as calculations of the amount of hydrogen and lager sizes that those would require.

Appendix 1 - Operating data

The operating data for the DHS, is in the form of hourly logged data from the DHP in Ísafjörður over three years 2019-2021. Samples of the data are for reference below.

Datetime	Rafskaut 1 Skeiði
01.01.2019 00:00	1.003,20
01.01.2019 01:00	1.147,36
01.01.2019 02:00	1.155,36
01.01.2019 03:00	1.127,36
01.01.2019 04:00	1.116,40
01.01.2019 05:00	1.106,88
01.01.2019 06:00	1.099,12
01.01.2019 07:00	1.108,72
01.01.2019 08:00	1.107,36
01.01.2019 09:00	1.095,52
01.01.2019 10:00	1.119,28
01.01.2019 11:00	1.138,64
01.01.2019 12:00	1.172,96
01.01.2019 13:00	1.208,16
01.01.2019 14:00	1.188,64
01.01.2019 15:00	1.173,52
01.01.2019 16:00	1.177,20
01.01.2019 17:00	1.157,92
01.01.2019 18:00	1.172,32
01.01.2019 19:00	1.158,80
01.01.2019 20:00	1.163,20
01.01.2019 21:00	1.135,52
01.01.2019 22:00	1.096,64
01.01.2019 23:00	1.058,56
02.01.2019 00:00	872,40
02.01.2019 01:00	977,12
02.01.2019 02:00	957,84
02.01.2019 03:00	949,36
02.01.2019 04:00	943,76
02.01.2019 05:00	934,40
02.01.2019 06:00	946,08
02.01.2019 07:00	945,92
02.01.2019 08:00	1.027,68
02.01.2019 09:00	975,92
02.01.2019 10:00	981,28
02.01.2019 11:00	980,40
02.01.2019 12:00	989,44
02.01.2019 13:00	995,60
02.01.2019 14:00	983,84
02.01.2019 15:00	950,64
02.01.2019 16:00	972,72
02.01.2019 17:00	966,56
02.01.2019 18:00	944,72
02.01.2019 19:00	1.005,12
02.01.2019 20:00	971,28
02.01.2019 21:00	948,32
02.01.2019 22:00	932,72

02.01.2019 23:00	914,64
01.07.2020 00:00	493,76
01.07.2020 01:00	451,36
01.07.2020 02:00	444,72
01.07.2020 03:00	446,80
01.07.2020 04:00	483,44
01.07.2020 05:00	471,12
01.07.2020 06:00	476,24
01.07.2020 07:00	484,72
01.07.2020 08:00	508,64
01.07.2020 09:00	497,68
01.07.2020 10:00	456,08
01.07.2020 11:00	470,40
01.07.2020 12:00	467,04
01.07.2020 13:00	510,96
01.07.2020 14:00	478,16
01.07.2020 15:00	464,72
01.07.2020 16:00	465,20
01.07.2020 17:00	491,20
01.07.2020 18:00	504,80
01.07.2020 19:00	570,88
01.07.2020 20:00	545,12
01.07.2020 21:00	569,28
01.07.2020 22:00	537,68
01.07.2020 23:00	544,48
02.07.2020 00:00	230,16
02.07.2020 01:00	484,96
02.07.2020 02:00	434,24
02.07.2020 03:00	454,40
02.07.2020 04:00	477,36
02.07.2020 05:00	493,20
02.07.2020 06:00	491,84
02.07.2020 07:00	508,56
02.07.2020 08:00	571,76
02.07.2020 09:00	505,76
02.07.2020 10:00	523,04
02.07.2020 11:00	535,12
02.07.2020 12:00	564,40
02.07.2020 13:00	595,52
02.07.2020 14:00	478,56
02.07.2020 15:00	483,76
02.07.2020 16:00	453,36
02.07.2020 17:00	453,44
02.07.2020 18:00	497,76
02.07.2020 19:00	506,24
02.07.2020 20:00	512,96
02.07.2020 21:00	468,80
02.07.2020 22:00	456,32

02.07.2020 23:00	473,60
01.12.2021 00:00	1.153,12
01.12.2021 01:00	1.109,44
01.12.2021 02:00	1.108,56
01.12.2021 03:00	1.083,36
01.12.2021 04:00	1.119,04
01.12.2021 05:00	1.114,56
01.12.2021 06:00	1.116,32
01.12.2021 07:00	1.148,40
01.12.2021 08:00	1.222,48
01.12.2021 09:00	1.210,32
01.12.2021 10:00	1.168,48
01.12.2021 11:00	1.206,40
01.12.2021 12:00	1.210,32
01.12.2021 13:00	1.221,04
01.12.2021 14:00	1.204,64
01.12.2021 15:00	1.194,40
01.12.2021 16:00	1.188,32
01.12.2021 17:00	1.216,48
01.12.2021 18:00	1.241,44
01.12.2021 19:00	1.281,36
01.12.2021 20:00	1.281,44
01.12.2021 21:00	1.233,76
01.12.2021 22:00	1.175,68
01.12.2021 23:00	1.169,76
02.12.2021 00:00	1.058,40
02.12.2021 01:00	1.105,36
02.12.2021 02:00	1.095,44
02.12.2021 03:00	1.098,40
02.12.2021 04:00	1.107,04
02.12.2021 05:00	1.085,68
02.12.2021 06:00	1.078,08
02.12.2021 07:00	1.086,40
02.12.2021 08:00	1.140,24
02.12.2021 09:00	1.088,96
02.12.2021 10:00	1.075,52
02.12.2021 11:00	1.066,64
02.12.2021 12:00	1.088,40
02.12.2021 13:00	1.079,68
02.12.2021 14:00	1.074,80
02.12.2021 15:00	1.076,00
02.12.2021 16:00	1.052,88
02.12.2021 17:00	1.062,80
02.12.2021 18:00	1.091,84
02.12.2021 19:00	1.149,76
02.12.2021 20:00	1.179,28
02.12.2021 21:00	1.089,28
02.12.2021 22:00	1.071,04

Appendix 2 – Financial model

The financial model from excel showing the data from the first years of operation, the years not shown follow the same pattern that can be recognised. Here the parameters of the optimistic scenario are listed.

		Scenarios:
		Opt = 400
		Real = 1000
Cost per kW installed [€/kW]	**400,00**	Pess = 1600

CAPEX	kW	%	**716.400**
Electrolyser	*1425*		*570.000*
Heat exchanger	*200*		*3.900*
Project construction management		*5%*	*28.500*
Installation and transportation		*20%*	*114.000*

Terms	
Interest Rate	5%
Term (years)	15
Loan Amount	712.500
Annual Payment	$68.644

								Year
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Principal at beginning of period	712.500	679.481	644.811	608.408	570.185	530.050	487.908	443.660
Payment	68.644	68.644	68.644	68.644	68.644	68.644	68.644	68.644
Interest for period	35.625	33.974	32.241	30.420	28.509	26.502	24.395	22.183
Principal at end of period	679.481	644.811	608.408	570.185	530.050	487.908	443.660	397.199
Downpayment	33.019	34.670	36.403	38.223	40.135	42.141	44.248	46.461

Investment	570.000
Project construction management	28.500
Installation and transportation	114.000
Total	**712.500**
Salvage Value	142.500
Type	Straight Line
Depreciation Period (year)	10

					Year			
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Depreciation Schedule	57.000	57.000	57.000	57.000	57.000	57.000	57.000	57.000

Assumptions		
Corporate Income Tax Rate	20%	
S&M as % of Sales	2%	
% Loan	100%	
% Equity	0%	
Cost of Debt	5%	
Cost of Equity	10%	*Im not using this, since I assume that there will be no inves*
WACC	5%	
Inflation	2,5%	

Variables		
Hours per year in operation	3.000	*3000 - 5500 -8000*
Power consumption of system (kWh/Nm3)	5,10	*4,4-4,75-5,1 Gives system efficiency of 69-75-80%*
Power consumption of system (kWh/kg)	56,66	
Hydrogen produced (kg/h)	23,00	
Hydrogen produced (kg/year)	69.000	
Yearly power consumption of electrolyser (GWh/year)	3,91	
Amount of waste heat available (% of yearly power)	5%	
Amount of waste heat available from electrolyser(kWh)	195.480	
Amount of waste heat avaiable for integration to DHS (kWh) Tce = 40°C	142.701	
Electricity price (€/kWh)	0,0160	
Water costs (€/m3)	0,280	
Selling price waste heat (€/kWh)	0,010	
Selling price hydrogen (€/kg)	2,70	

Operation plan year 1,2 and 3	
Year 1	40%
Year 2	60%
Year 3	80%

Income Statement

			Year
	1	2	3
Net Sales	**75.271**	**115.700**	**154.267**
H2	*74.520*	*114.575*	*152.766*
Heat	*751*	*1.126*	*1.501*
Cost of Sales	**25.195**	**37.710**	**50.226**
Electricity costs	*25.021*	*37.532*	*50.043*
Water costs	*174*	*178*	*183*
Gross Profit	**50.075**	**77.990**	**104.042**
OPEX	**68.535**	**74.412**	**80.216**
Sales & Marketing (% of sales)	*1.505*	*2.314*	*3.085*
Operation & Maintenance (% of CAPEX)	*8.597*	*12.895*	*17.194*
Overhead (% of CAPEX)	*1.433*	*2.203*	*2.937*
Depreciation	*57.000*	*57.000*	*57.000*
EBIT	**- 18.460**	**3.578**	**23.825**
EBITDA	**38.540**	**60.578**	**80.825**
Other Income (Expenses)	**- 35.625**	**- 33.974**	**- 32.241**
Interest Expense	*- 35.625*	*- 33.974*	*- 32.241*
Income Before Tax	**- 54.085**	**- 30.396**	**- 8.415**
Taxes	-	-	-
Net Income	**- 54.085**	**- 30.396**	**- 8.415**
Adjustments to reconcile net income to net cash	**23.981**	**22.330**	**20.597**
Depreciation	57.000	57.000	57.000
Loan received for purchase of equipment	712.500		
Purchase of equipment (incl. installation)	- 712.500		
Principal Payments of loan	- 33.019	- 34.670	- 36.403
Net Cash Flow	**- 30.104**	**- 8.066**	**12.182**
Discounted Cash Flow	- 28.670	- 7.316	10.523
Net Present Value	**469.349**		
Internal interest rate	**28,28%**		

Appendix 3 – Effect of each factor in sensitivity study

Table 22: Pessimistic scenario for 8000 operating h/year

	Electricity price (€/MWh)						
NPV (k€) — Hydrogen price (€/kg)	0	4	8	12	16	20	24
1.0	- 1 872	- 2 353	- 2 849	- 3 387	- 3 924	- 4 461	- 4 999
1.5	- 780	- 1 258	- 1 737	- 2 217	- 2 708	- 3 235	- 3 773
2.0	312	- 167	- 645	- 1 124	- 1 602	- 2 081	- 2 568
2.5	1 394	925	446	- 32	- 511	- 989	- 1 468
3.0	2 424	1 980	1 525	1 058	581	103	- 376
3.5	3 422	2 985	2 547	2 106	1 654	1 190	716
4.0	4 416	3 982	3 545	3 108	2 670	2 232	1 782
4.5	5 404	4 971	4 538	4 105	3 668	3 231	2 793
5.0	6 392	5 959	5 526	5 093	4 660	4 227	3 791
5.5	7 379	6 946	6 513	6 080	5 647	5 214	4 782
6.0	8 363	7 933	7 501	7 068	6 635	6 202	5 769

Table 23: Optimistic scenario for 3000 operating h/year

		Electricity price (€/MWh)						
	NPV (k€)	0	4	8	12	16	20	24
Hydrogen price (€/kg)	1.0	- 197	- 343	- 488	- 636	- 793	- 956	- 1 119
	1.5	212	67	- 79	- 224	- 370	- 515	- 663
	2.0	604	469	329	185	40	- 106	- 251
	2.5	978	845	712	579	443	303	158
	3.0	1 349	1 217	1 086	954	821	688	554
	3.5	1 719	1 588	1 456	1 325	1 193	1 061	929
	4.0	2 089	1 958	1 827	1 695	1 563	1 432	1 300
	4.5	2 456	2 326	2 195	2 065	1 934	1 802	1 671
	5.0	2 824	2 694	2 563	2 432	2 302	2 171	2 040
	5.5	3 192	3 061	2 931	2 800	2 669	2 539	2 408
	6.0	3 560	3 429	3 299	3 168	3 037	2 907	2 776

Table 24: Pessimistic scenario 80% efficiency

Electricity price (€/MWh)

Hydrogen price (€/kg)

NPV (k€)	0	4	8	12	16	20	24
1.0	- 197	- 377	- 556	- 744	- 946	- 1,147	- 1,349
1.5	212	33	- 147	- 326	- 506	- 689	- 889
2.0	604	436	262	83	- 96	- 276	- 455
2.5	978	814	650	484	312	134	- 46
3.0	1.349	1.187	1.024	860	696	532	361
3.5	1.719	1.557	1.395	1.232	1.070	906	742
4.0	2.089	1.927	1.765	1.603	1.440	1.278	1.116
4.5	2.456	2.295	2.134	1.973	1.811	1.648	1.486
5.0	2.824	2.663	2.502	2.341	2.179	2.018	1.856
5.5	3.192	3.031	2.870	2.708	2.547	2.386	2.225
6.0	3.560	3.399	3.237	3.076	2.915	2.754	2.593

Table 25: Optimistic scenario for 69% efficiency

		Electricity price (€/MWh)						
	NPV (k€)	0	4	8	12	16	20	24
Hydrogen price (€/kg)	1.0	- 1.872	- 2.261	- 2.660	- 3.081	- 3.517	- 3.952	- 4.387
	1.5	- 780	- 1.168	- 1.556	- 1.943	- 2.334	- 2.734	- 3.162
	2.0	312	- 76	- 464	- 852	- 1.240	- 1.627	- 2.015
	2.5	1.394	1.014	628	240	- 148	- 536	- 924
	3.0	2.424	2.065	1.699	1.325	943	556	168
	3.5	3.422	3.068	2.713	2.359	1.998	1.630	1.254
	4.0	4.416	4.065	3.711	3.356	3.002	2.647	2.292
	4.5	5.404	5.053	4.702	4.351	4.000	3.645	3.291
	5.0	6.392	6.041	5.690	5.339	4.988	4.637	4.286
	5.5	7.379	7.028	6.677	6.327	5.976	5.625	5.274
	6.0	8.363	8.014	7.665	7.314	6.963	6.612	6.261

Table 26: Optimistic scenario CapEx 1600

		Electricity price (€/MWh)						
	NPV (k€)	0	4	8	12	16	20	24
Hydrogen price (€/kg)	1.0	- 1.872	- 2.261	- 2.660	- 3.081	- 3.517	- 3.952	- 4.387
	1.5	- 780	- 1.168	- 1.556	- 1.943	- 2.334	- 2.734	- 3.162
	2.0	312	- 76	- 464	- 852	- 1.240	- 1.627	- 2.015
	2.5	1.394	1.014	628	240	- 148	- 536	- 924
	3.0	2.424	2.065	1.699	1.325	943	556	168
	3.5	3.422	3.068	2.713	2.359	1.998	1.630	1.254
	4.0	4.416	4.065	3.711	3.356	3.002	2.647	2.292
	4.5	5.404	5.053	4.702	4.351	4.000	3.645	3.291
	5.0	6.392	6.041	5.690	5.339	4.988	4.637	4.286
	5.5	7.379	7.028	6.677	6.327	5.976	5.625	5.274
	6.0	8.363	8.014	7.665	7.314	6.963	6.612	6.261

Table 27: Pessimistic scenario CapEx 400

		Electricity price (€/MWh)						
	NPV (k€)	0	4	8	12	16	20	24
Hydrogen price (€/kg)	1.0	- 197	- 377	- 556	- 744	- 946	- 1.147	- 1.349
	1.5	212	33	- 147	- 326	- 506	- 689	- 889
	2.0	604	436	262	83	- 96	- 276	- 455
	2.5	978	814	650	484	312	134	- 46
	3.0	1.349	1.187	1.024	860	696	532	361
	3.5	1.719	1.557	1.395	1.232	1.070	906	742
	4.0	2.089	1.927	1.765	1.603	1.440	1.278	1.116
	4.5	2.456	2.295	2.134	1.973	1.811	1.648	1.486
	5.0	2.824	2.663	2.502	2.341	2.179	2.018	1.856
	5.5	3.192	3.031	2.870	2.708	2.547	2.386	2.225
	6.0	3.560	3.399	3.237	3.076	2.915	2.754	2,593

Table 28: Optimistic scenario CapEx 2300

		Electricity price (€/MWh)						
	NPV (k€)	0	4	8	12	16	20	24
Hydrogen price (€/kg)	1.0	-3.653	-4.057	-4.490	-4.926	-5.361	-5.797	-6.232
	1.5	-2.550	-2.938	-3.329	-3.728	-4.135	-4.571	-5.006
	2.0	-1.458	-1.846	-2.234	-2.622	-3.010	-3.403	-3.802
	2.5	-367	-754	-1.142	-1.530	-1.918	-2.306	-2.694
	3.0	725	337	-50	-438	-826	-1.214	-1.602
	3.5	1.809	1.427	1.041	653	266	-122	-510
	4.0	2.856	2.489	2.116	1.738	1.356	969	582
	4.5	3.863	3.508	3.151	2.788	2.420	2.046	1.668
	5.0	4.861	4.506	4.152	3.797	3.443	3.084	2.720
	5.5	5.858	5.504	5.149	4.795	4.440	4.086	3.732
	6.0	6.846	6.495	6.144	5.793	5.438	5.084	4.729

Table 29: Realistic Scenario including plant components

		Electricity price (€/MWh)						
	NPV (k€)	0	4	8	12	16	20	24
Hydrogen price (€/kg)	1.0	- 2.432	- 2.738	- 3.066	- 3.396	- 3.726	- 4.056	- 4.387
	1.5	- 1.675	- 1.969	- 2.265	- 2.568	- 2.884	- 3.214	- 3.544
	2.0	- 924	- 1.218	- 1.512	- 1.806	- 2.100	- 2.400	- 2.705
	2.5	- 173	- 467	- 761	- 1.055	- 1.349	- 1.643	- 1.937
	3.0	577	283	- 11	- 305	- 599	- 893	- 1.186
	3.5	1.320	1.032	740	446	152	- 142	- 436
	4.0	2.035	1.758	1.477	1.192	902	609	315
	4.5	2.725	2.456	2.186	1.912	1.633	1.350	1.063
	5.0	3.411	3.142	2.873	2.605	2.336	2.065	1.788
	5.5	4.095	3.828	3.559	3.291	3.022	2.753	2.485
	6.0	4.774	4.508	4.242	3.976	3.708	3.439	3.171

Table 30: Realistic case, electricity price up to 40 €/MWh

		Electricity price (€/MWh)				
	NPV (€)	24	28	32	36	40
Hydrogen price (€/kg)	1.0	- 2.959	- 3.293	- 3.626	- 3.960	- 4.293
	1.5	- 2.116	- 2.450	- 2.783	- 3.117	- 3.451
	2.0	- 1.316	- 1.619	- 1.941	- 2.274	- 2.608
	2.5	- 566	- 863	- 1.160	- 1.459	- 1.766
	3.0	185	- 112	- 409	- 706	- 1.004
	3.5	928	638	341	44	- 253
	4.0	1.631	1.358	1.078	791	498
	4.5	2.317	2.045	1.774	1.502	1.226
	5.0	2.998	2.729	2.460	2.188	1.916
	5.5	3.677	3.408	3.139	2.871	2.602
	6.0	4.356	4.087	3.818	3.550	3.281

6 Bibliography

1. **United Nations.** The Paris Agreement. *United nations Climate Change.* [Internett] United nations, 2015. https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement.

2. **IEA.** Net Zero by 2015. A Roadmap for the Global Energy Sector. [Internett] May 2021. https://www.iea.org/reports/net-zero-by-2050.

3. **IEA.** *Technology Roadmap; Hydrogen and Fuel Cells.* Paris : International Energy Agency, 2015. OECD.

4. **IEA.** *The Future of Hydrogen; Seizing today's opportunities.* Paris, France : IEA, 2019.

5. **IEA.** *Global hydrogen review 2021.* Paris : International Energy Agency, 2021.

6. *Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: A review.* **Alexander Buttler, Hartmunt Spliethoff.** 3, Munchen : Renewable and Sustainable Energy Reviews, 02 2018, Renewable and Sustainable Energy Reviews, Vol. 82, ss. 2440-2454.

7. **IEA.** *Net Zero by 2050. A Roadmap for the Global Energy Sector.* Paris : IEA, 2021.

8. *A comprehensive review on PEM water electrolysis.* **Marcelo Carmo, David L. Fritz, Jurgen Mergel, Detlef Stolten.** 12, 22 April 2013, International Journal of Hydrogen Energy, Vol. 38, ss. 4901-4934

9. **IRENA.** *Hydrogen; A renewable energy perspective.* Abu Dhabi : IRENA, 2019.

10. **Data commons.** Data commons. *Carbon dioxide emissions per capita in Germany 2018.* [Internett] Data commons, 2018. https://datacommons.org/place/country/DEU?category=Climate#Carbon-dioxide-emissions-per-capita.

11. *Green Hydrogen in Europe - A regional assessment: Substituting existing production with electrolysis powered by renewables.* **G. Kakoulaki, I. Kougias, N. Taylor, F. Dolci, J. Moya, A. Jager-Waldau.** 15 January 2021, Energy Conversion and Management, Vol. 228, s. 113649.

12. **Siemens energy.** Overview of the PEM Silizer Family. *Siemens Energy NEB, GIZ Workshop.* s.l. : Siemens Energy, 30 09 202.

13. **Berenschot.** *Oxygen synergy for hydrogen production.* Netherlands : Berenschot. TNO innovation for life, 2019.

14. **Norwegian Ministry of Climate and Environment.** *The Norwegian Government's hydrogen strategy; towards a low emission society.* Oslo : Norwegian Ministry of Climate and Environment, 2021.

15. *Power-to-hydrogen & district heating: Technology-based and infrastructure-oriented analysis of (future) sector coupling potentials.* **Hans Böhm, Simon Moser, Stefan Pushnigg, Andreas Zauner.** 11 April 2021, International Journal of Hydrogen Energy, ss. 31940-31951.

16. *Hydrogen production by PEM water electrolysis - A review .* **S. Shiva Kumar, V. Himabindu.** 3, December 2019, Materials Science for Energy Techologies, Vol. 2, ss. 442-454.

17. *Modeling of advanced alkaline electrolyzers: a system simulation approach.* **Ulleberg, Øystein.** 1, Miami : Hydrogen Energy Publications, 01 2003, International Journal of Hydrogen Energy, Vol. 28, ss. 21-33.

18. **DEA.** *Technology Data - Renewable fuels: Technology descriptions and projectrions for long-term energy system planning.* s.l. : Danish Energy Agency and Energiet, 2017.

19. **Nel Hydrogen.** Atmospheric Alkaline Electrolyser. *Nel Electrolysers.* [Internett] 2022. [Sitert: 10 May 2022.] https://nelhydrogen.com/product/atmospheric-alkaline-electrolyser-a-series/.

20. **Cummins.** Cummins. *Hydrogen generation. Storing power, naturally.* [Internett] Cummins, n.d. [Sitert: 27 april 2022.] https://www.cummins.com/new-power/applications/about-hydrogen.

21. **Bloom Energy.** Bloom Energy Electrolyzer Data. [Internett] 2022. [Sitert: 10 May 2022.] https://www.bloomenergy.com/wp-content/uploads/electrolyzer-data-sheet.pdf.

22. **Sunfire.** Sunfire Factsheet HyLink Alkaline. [Internett] 10 November 2021. [Sitert: 10 May 2022.] https://www.sunfire.de/files/sunfire/images/content/Sunfire.de%20(neu)/Sunfire-Factsheet-HyLink-Alkaline-20210111.pdf.

23. **Green Hydrogen Systems.** HyProvide A series brochure. [Internett] February 2021. [Sitert: 10 May 2022.] https://liquiline.no/wp-content/uploads/2021/02/HyProvide-A-series-brochure-1.pdf.

24. *The effects of ionomer content on PEM water electrolyser membrane electrode assembly performance.* **Wu Xu, Keith Scott.** 21, Newcastle : International Association for Hydrogen Energy, November 2010, International Journal of Hydrogen Energy, Vol. 35, ss. 12029-12037.

25. **Bosch.** Bosch. *Bosch.* [Internett] 15 03 2022. [Sitert: 15 03 2022.] https://www.bosch.com/stories/sofc-system/.

26. *Waste heat utilization in reversible solid oxide fuel cell system for electrical energy storage: Fuel recirculation design and feasibility analysis* . **Van-Tien Giap, Young Sang Kim, Young Duk Lee, Kook Young Ahn.** 29, Aachen : Elsevier, June 2020, Journal of Energy Storage, Vol. 29.

27. *Hydrogen production From Water Electrolysis: Current Status and Future trends.* **Alfredo Ursua, Luis M. Gandia, Pabli Sanchis.** 2, s.l. : IEEE, 20 June 2011, Proceedings of the IEEE, Vol. 100.

28. **Cummins.** Electrolyzers 101: What they are, how they work and where they fit in a green economy. *Cummins Newsroom: Hydrogen Technologies.* [Internett] Cummins, 16 November 2020. [Sitert: 20 May 2022.] https://www.cummins.com/news/2020/11/16/electrolyzers-101-what-they-are-how-they-work-and-where-they-fit-green-economy.

29. **Nel Hydrogen.** Nel Hydrogen Electrolysers. [Internett] 2022. https://nelhydrogen.com/wp-content/uploads/2022/01/Electrolysers-Brochure-Rev-D.pdf.

30. **Siemens Energy.** Overview of the PEM Silyzer Family. *Siemens Energy.* [Internett] 30 September 2020. [Sitert: 10 May 2022.] https://4echile-datastore.s3.eu-central-1.amazonaws.com/wp-content/uploads/2020/10/10132733/20200930-SE-NEB-PEM-Electrolyzer-and-Applications_EW.pdf.

31. *Aspen Plus model of an alkaline electrolysis system for hydrogen production.* **Mónica Sánchez, Ernesto Amores, David Abad, Lourdes Rodríguez, Carmen Clemente-Jul.** 7, s.l. : Elsevier, 7 February 2020, International Journal of Hydrogen , Vol. 45, ss. 3916-3929.

32. **Bertuccioli, L., Chan, A., Hart, D., Lehner, F., Madden, B., and Standen, E.** *Development of Water Electrolysis in the European Union.* E4tech Sarl. Cambridge, UK : Element Energy, 2014.

33. **IRENA.** *Green Hydrogen Cost Reduction; Scaling up Electrolysers to meet the 1.5°C climate goal.* International Renewable Energy Agency. Abu Dahbi : IRENA, 2020. ISBN: 978-92-9260-295-6.

34. *Innovative power-to-gas plant concepts for upgrading of gasification bio-syngas through steam electrolysis and catalytic methanation.* **Régis Anghilante, Christian Müller, Max Schmidt, David Colmar, Felix Ortoloff, Reinold Spörl, Annabelle Brisse, Frank Graf.** 183, Irbid : Elsevier, 1 March 2019, Energy Conversion and Management, Vol. 183, ss. 462-473.

35. *Current status, research trends, and challenges in water electrolysis science and technology.* **S.A. Grigoriev, V.N. Fateev, D.G. Bessarabov, P. Millet.** 49, s.l. : Elsevier, 2 October 2020, International Journal of Hydrogen Energy, Vol. 45, ss. 26036-26058.

36. *Electrolyser technologies: PEM vs Alkaline electrolysis .* **Cockerill, Rob.** Oslo : NEL hydrogen , n.d. .

37. *Thermal performance of a commercial alkaline water electrolyzer: Experimental study and mathematical modeling.* **P.M. Diéguez, A. Ursúa, P. Sanchis, C. Sopena, E. Guelbenzu, L.M. Gandía.** 24, s.l. : Elsevier, December 2008, International Journal of Hydrogen Energy, Vol. 33, ss. 7338-7354.

38. *Verbundprojekt Power-to-Gas - Errichtung und Betrieb einer Forschungsanlage zur Speicherung von erneuerbarem Strom als erneuerbares Methan im 250 kWel Maßstab.* **Zuberbühler u, Specht M, Stürmer B, Brinner A, Brellochs J, Feigl B. et al.** 2014, Schlussbericht zum Teilvorhaben.

39. **Halvorsen, Bjørn Gregert.** Nel Hydrogen; ask an expert. *Email conversation.* 14 February 2022.

40. *Advantages of integration with industry for electrolytic hydrogen production .* **Maria Saxe, Per Alvfors.** 1, Aalborg : Elsevier, January 2007, Energy, Vol. 32, ss. 42-50.

41. **Danish Energy Agency (DEA).** Technology Data for Renewable Fuels. *Projects and models; Technology Data.* [Internett] March 2018. https://ens.dk/en/our-services/projections-and-models/technology-data/technology-data-renewable-fuels.

42. **Electrolysers, Nel Hydrogen.** *The World's Most Efficient and Reliable Electrolysers.* Oslo : number one by nature, 2021.

43. **Nel Hydrogen .** Nel Hydrogen PEM Electrolyser. *Nel Hydrogen Electrolysers.* [Internett] 2022. [Sitert: 10 May 2022.] https://nelhydrogen.com/product/m-series-3/.

44. *State-of-the-art of commercial electrolyzers and on-site hydrogen generation for logistic vehicles in South Carolina.* **Hamacher, M. Felgenhauer and T.** 5, s.l. : Elsevier, 2015, International Journal of Hydrogen Energy, Vol. 40, ss. 2084-2090.

45. **Løkke, Jon André.** Nel Q4 Presentation. *Nel Hydrogen WP content* . [Internett] 18 February 2021. [Sitert: 10 May 2022.] https://nelhydrogen.com/wp-content/uploads/2021/02/Nel_2020_Q4_Presentation.pdf.

46. **Le, Minh Khoii.** Press release; Cheap, secure, and renewable - Europe bets on green hydrogen to fix energy woes . *Rystad Energy* . [Internett] 21 March 2022. https://www.rystadenergy.com/newsevents/news/press-releases/cheap-secure-and-renewable-europe-bets-on-green-hydrogen-to-fix-energy-woes/?utm_campaign=&utm_content=&utm_medium=&utm_source=linkedin.

47. **European Union.** *The offical website for the European Union.* [Internett] 8 March 2022. https://ec.europa.eu/commission/presscorner/detail/en/ip_22_1511.

48. *State-of-the art CAPEX data for water electrolysers, and their impact on renewable hydrogen price settings.* **Proost, Joris.** 9, 15 February 2019, International Journal of Hydrogen Energy, Vol. 44, ss. 4406-4413.

49. **Department for Business, Energy & Industrial Strategy.** *Hydrogen production Cost 2021.* Department for Business, Energy & Industrial Strategy. London : Crown Copyright, 2021.

50. *Scaling-up Innovations on Renewable Hydrogen Production and Use* . **Biebyuck, Bart.** Brussels : Fuel cells and hydrogen joint undertaking, 2021. European Hydrogen Forum .

51. **Luca Bertuccioli, Alvin Chan, David Hart, Franz Lehner, Ben Madden, Eleanor Standen.** *Study on development of water electrolysis in the EU.* Fuel Cells and Hydrogen Joint Undertaking. s.l. : E4tech Sárl with Element Energy Ltd, 2014.

52. **Dansk Fjernvarme F&U-konto.** *Power-to-X og fjernvarme.* s.l. : Dansk Fjernvarme, 2021.

53. *Overview of Storage Development DOE Hydrogen program.* **Thomas, George.** 9-11 May 2000, US DOE Hydrogen Program 2000 Annual Review, ss. 1-14.

54. *Life cycle cost analysis: A case study of hydrogen energy application on the Orkney Islands.* **Guanling Zhao, Eva Ravn Nielsen, Enriqu Troncoso, Kris Hyde, Jesús Simón Romeo, Michal Diderich.** 19, s.l. : Eslevier, 12 April 2019, International Journal of Hydrogen Energy, Vol. 44, ss. 9517-9528.

55. *Review of the current technologies and performances of hydrogen compression for stationary and automotive applications.* **G. Sdanghi, G. Maranzana, A. Celzard, V. Fierro.** Belfast : s.n., March 2019, Renewable and Sustainable Energy Reviews, Vol. 102, ss. 150-170.

56. **USA, Department of energy.** DOE Hydrogen sand Fuel Cells Program Record. [Internett] 26 October 2009. [Sitert: 20 May 2022.] https://www.hydrogen.energy.gov/pdfs/9013_energy_requirements_for_hydrogen_gas_compression.pdf.

57. **National Renewable Energy Laboratory.** *Hydrogen Station Compression Storage and Dispensing Technical Status and Costs. System Integration.* s.l. : NREL for U.S Department of Energy Hydrogen and Fuel Cells Program, 2014. NREL/BK-6A10-58564.

58. *Future district heating systems and technologies: On the role of smart energy systems and 4th generation district heating.* **Hendrik Lund, Neven Duic, Poul Alberg Østergaard, Brian Van Mathiesen.** Part A, s.l. : Energy, 15 December 2018, Vol. 165, ss. 614-619.

59. *International review of district heating and cooling.* **Werner, Sven.** 15 October 2017, Energy, Vol. 137, ss. 617-631.

60. **Orkustofnun.** Hlutur orkugjafa í hitun húsnæðis byggt á rúmmáli alls hitaðs húsnæðis á Íslandi 1952-2020. *Orkustofnun.* [Internett] Orkustofnun, 2020. [Sitert: 11 April 2022.] https://orkustofnun.is/orkustofnun/gagnasofn/talnaefni/.

61. **Investopedia.** Financial Analysis. *Corporat Finance &Accounting; Financial Statements.* [Internett] Investopedia, 15 March 2022. https://www.investopedia.com/terms/f/financial-analysis.asp#:~:text=Financial%20analysis%20is%20the%20process,to%20warrant%20a%20monetary%20investment..

62. **Investopedia.** Project Finance. *Corporate Finance & Accounting; Debt.* [Internett] Investopedia, 20 August 2021. [Sitert: 20 May 2022.] https://www.investopedia.com/terms/p/projectfinance.asp#:~:text=The%20debt%20and%20equity%20used,interests%20held%20as%20secondary%20collateral..

63. **Investopedia.** Net Present Value (NPV). *Investopedia Corporate Finance & Accounting.* [Internett] Investopedia, 29 August 2021. [Sitert: 13 May 2022.] https://www.investopedia.com/terms/n/npv.asp.

64. **Investopedia.** Internatl Rate of Return (IRR). *Investopedia Corporate Finance & Accounting.* [Internett] Investopedia, 24 February 2022. [Sitert: 13 May 2022.] https://www.investopedia.com/terms/i/irr.asp.

65. **Investopedia.** Weighted Average Cost of Capital (WACC). *Investopedia Corporate Finance & Accounting; Financial Ratios.* [Internett] Investopedia, 02 May 2022. [Sitert: 13 May 2022.] https://www.investopedia.com/terms/w/wacc.asp.

66. **IEA.** District Heating. *District Heating.* [Internett] IEA, November 2021. https://www.iea.org/reports/district-heating.

67. **Nel Hydrogen.** Nel Hydrogen Electrolysers; The Worlds Most Efficient and Reliable Electrolysers. [Internett] 2018. http://img-admin.exponews.com.au.s3.amazonaws.com/exhibitors/e/nel-electrolysers-brochure-2018-pd-0600-0125-web_18041145.pdf.

68. **Landsvirkjun.** Heildsölumarkaðurinn - Skerðanleg orka. *Landsvirkjun.* [Internett] Landsvirkjun, January 2022. https://www.landsvirkjun.is/heildsolumarkadurinn.

69. **Grænvangur.** Kolefnishlutlaust Ísland 2040. *Grænvangur.* [Internett] Grænvangur, 2021. https://graenvangur.is/kolefnishlutlaust-island-2040/.

70. **Engineering page.** Typical overall heat transfer coeficients (U-values). [Internett] 2022. [Sitert: 8 April 2022.] https://www.engineeringpage.com/technology/thermal/transfer.html.

71. **Skatturinn.** Atvinnurekstur, framtal og álagning. Álagningaseðill og forsendur 2022. *Skatturinn.* [Internett] 01 2022. [Sitert: 27 04 2022.] https://www.skatturinn.is/atvinnurekstur/framtal-og-alagning.

72. **Central Bank of Iceland.** Central Bank of Iceland. *Inflation.* [Internett] Central Bank of Iceland, March 2022. [Sitert: 28 April 2022.] https://www.cb.is/other/inflation/.

73. **Ísafjarðarbær.** Gjaldskrá Vatnsveita. *Ísafjarðarbær allar gjaldskrár.* [Internett] 01 01 2022. https://www.isafjordur.is/is/stjornsysla/gjaldskrar-og-reglur/allar-gjaldskrar.

74. **Engineering, Cost.** Project Estimation Techniques . *Cost Engineering.* [Internett] Cost Engineering, n.d. . https://www.costengineering.eu/project-estimation-techniques.

75. **Mc Donald Water Storage.** Plate heat exchanger 200kW. [Internett] 2022. https://mcdonaldwaterstorage.com/product/plate-heat-exchanger-200kw/.

76. **European Union.** Electricity prices (including taxes) for household consumers, second half 2021. *Electricity price statistics.* [Internett] EU, April 2022. https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_price_statistics.

77. *Implementation of water electrolysis in Vaxjö's combined heat and power plant and the use of excess heat.* . **Hepperger, Floran Von.** s.l. : Linnæus University, June 2021.