Green hydrogen production in SE4

- A business case for green large-scale hydrogen in SE4

Petter Håkansson

December 2022

Department of Energy Sciences
Lund University

Supervisors:
Martin Andersson, Lund University
&
Hanna Henrikson, RWE

Examiner:
Marcus Thern, Lund University

Acknowledgements

This Masters Thesis was carried out for RWE Renewables in Malmö, Sweden, and the Department of Energy Sciences at the Faculty of Engineering at Lund University. With this being the last thing I do as a student I want to give thanks to all my friends, family and fantastic people I have met in Lund who has supported me throughout my time as a student. Without you I doubt that I would have been able to finish my degree.

I also want to thank my supervisor Hanna Henrikson at RWE for giving me the opportunity to write the thesis for RWE and for that you always took the time to help with or clarify something when necessary. I would also like to give thanks supervisors starting with Dr. Martin Andersson at LTH. I am especially grateful for the discussions we had regarding how to approach the topic and you have provided me with several valuable insights. Lastly, I would like to thank my examinator Dr. Marcus Thern. Thank you for all the time, effort and feedback that you have dedicated and given to me.

Definitions and abbreviations

AEM electrolyser- Anion Exchange Membrane electrolyser**.**
Alkaline electrolyser – Uses a KOH electrolyte and nickel coated stainless-steel electrodes
Blue hydrogen - Hydrogen produced from fossil resources in combination with CCUS.
CCUS – Carbon capture, utilization, and storage
FCET – Fuel Cell Electric Truck
GHG – Greenhouse gases
Green hydrogen – Hydrogen produced by electrolysis
Grey hydrogen – Hydrogen produced by steam methane reformation.
HYBRIT - HYdrogen BReaktrough Ironmaking Technology
IEA – International Energy Agency
LCOW – Levelized cost of water
LRC - Lined Rock Cavern
Off-grid – No connection to infrastructures such as backbone grids or pipeline-systems
Offshore – Localization at sea
Onshore – Localization on land
SWRO – Seawater Reverse Osmosis

Abstract

As the greenhouse gas emissions keep on increasing the need for solutions to help reduce emissions across all sectors has never been greater. The European Union has pointed out green hydrogen as a step in increasing the sustainability of the energy sector in Europe. Goals has been set to boost the development of hydrogen technology since the green hydrogen production today is only existing in an insufficient scale and to give indications to other technologies fuelled by hydrogen technology.

This report presents an analysis of the feasibility of large-scale green hydrogen production in the southern region of Sweden. The focus has been to give a rough cost estimation of what the production costs would be if the production was in connection with a 1 GW offshore wind farm. Due to the time it would take to establish type of project the costs for the project has been estimated for year 2030. The report specifically gives insight into how the levelized cost of hydrogen is affected by different operating conditions and how the cost is split between the most essential cost components.

A combination of a literature review and collecting of data from interviews was used to set up a rough model of the hydrogen production. The model was then used to calculate the LCOH and give indication about the overall production of hydrogen. The results indicated that it is not possible to reach a LCOH as low as the price targets set by actors on the hydrogen market. The most beneficial LCOH was acquired by using a 1000 MW electrolyser and the smallest storage volume, which resulted in a LCOH of about 26 SEK per kilogram of hydrogen. The reason to why it was difficult to reach a hydrogen cost in the vicinity of the price targets was mainly due to high storage costs and high electricity costs. However, it is also concluded that there are many unknowns in the model, which may make it possible to further lower the costs.

Table of contents

1. Introduction

Globally, the anthropogenic emissions of greenhouse gases (GHG) continue to increase across all major sectors and the energy sector made up 34% of all annual GHG emissions during 2019 (IPCC, 2022). To decrease the GHG emissions it is needed for fossil fuels and energy carriers to be substituted for renewable equivalents. Hence wind and solar power has seen an improved growth in northern Europe in recent years at the expense of coal, oil and gas power plants. The transition to more intermittent power generation has brought new problems, which requires new solutions. One of the more problematic aspects of intermittent power generation is that it is more difficult to balance the production to the consumption compared to traditional power generation. This phenomenon has given rise to electricity prices becoming more volatile. Since the mismatch in production versus consumption is expected to increase in the future there is a need for either shifting the consumption patterns or storing the available energy when there is an excess of production to avoid spikes in electricity prices.

There are several promising technologies and strategies which can help reduce the negative effects from intermittent power production. One of the most promising is to produce green hydrogen by electrolysis and thereby convert electricity into another renewable energy carrier that is cheaper to store. Since the electrolysis demands electricity it can be used to increase electricity demand for hours when there is an excess of production. It is also possible to revert the produced hydrogen back to electricity by utilizing a fuel cell, which makes it possible to also tackle the problem with more demand than the usual power production can supply. Even though this is a promising solution there are some hurdles to overcome before green hydrogen can be established in the scale needed to have an impact. Some examples of these issues are lowering the overall production cost and increasing the overall efficiency of the conversions between energy carriers. Due to the current hurdles for balancing the grid with hydrogen generation, it is more likely for other applications for hydrogen to emerge prior on the market than hydrogen generation for balancing the electrical grid.

Two sectors where green hydrogen is expected to increase in a nearby future is in the transportation and industry sector. These two sectors are heavily reliant on fossil fuels today and are in need for renewable alternatives to reduce its GHG emissions. Hence, an increased utilization of green hydrogen could have a large impact in these sectors. Even though, it may be easier to motivate the switch to green hydrogen in the industry and transportation sector there are still some problems that cannot be overlooked. There is a limited experience of large-scale electrolysis facilities in practice, there is no consensus about which directions to move regarding the transportation of hydrogen between producer and consumer. Without any national infrastructure such as hydrogen pipelines there will probably be a need for power generation in the vicinity of the hydrogen production for locations in the south of Sweden due to that the backbone grid is not capable of providing the needed electricity.

RWE Renewables is globally a company specialising in renewable energy with an installed capacity of 9 GW renewable power generation with 2.6 GW in construction. The company focusses on onshore and offshore wind, utility-scale photovoltaic (PV) solar power and energy storage. As hydrogen is becoming a more and more promising technology and with the need for more renewable energy carriers other than electricity the company is interested in assessing the possibilities for large scale green hydrogen production in Sweden. In collaboration with RWE this thesis will analyse a business case for large scale hydrogen production in combination with an offshore wind farm located outside of Trelleborg.

1.1 Aim

The aim of the thesis is to approximate the cost of a business case for green hydrogen production located in the southern region of Sweden close to Trelleborg. The focus has been on providing a rough cost-estimate to further understand the potentials and difficulties with green hydrogen production. Since a project of this size would need more detailed inquiries, permits and time for construction the costs are estimated for a project to be realized in year 2030 to achieve a more realistic result.

1.2 Research questions

There are multiple variables of importance when analysing a business case. This is especially true for technologies that has not previously been implemented in a larger scale. Hence, this report will mainly focus on the following research questions due to time limitations.

- How does the by-products from the electrolysis impact the overall profitability of the green hydrogen?

- How does limitations in grid capacity impact the LCOH?

- What is the estimated LCOH for the produced green hydrogen and how is it effected by electricity prizes, the size of the electrolyser and the size of the storage?

1.3 Delimitation

There are a large variety of parameters to take into consideration when calculating the cost of producing hydrogen with a few of these being especially difficult to predict for a futuristic scenario (eg. future electricity prices, future costs of electrolysers, storage costs), which has resulted in a lot of assumptions. The made assumptions will be further explained in the report.

Since it is almost impossible to predict which technologies that will be dominant on a relatively early market. One important decision made is that the type of electrolyser has been neglected and instead a zero-dimensional model has been used to calculate with a more general processes of the electrolyser. Hence, no complex relations between reactants, heat and energy have been calculated. The consequence of this decision is that the mass- and heat transfers are being rough estimates of the actual output from the electrolyser.

There are several ways in how to setup a green hydrogen production project regarding everything from selection of power source to different storage and transportation solutions. The chosen project setup in this report focuses on an offshore wind farm as the main source of power and with a lined rock cavern type of storage. Other project setups were considered but due to lack of data for many of these cases and due to the limited time for this thesis the only analysed setup is the one described in the thesis.

Furthermore, there may be some deviations in the LCOH due to a deviation in pricing in comparison from a realistic scenario. Which originates from a limited number of sources providing the data at which components and products are priced. Since the objective of the report has been to provide a rough estimate of the LCOH this has been accepted due to time limitation.

1.4 Disposition

The disposition and content of each chapter are presented in the section below.

Chapter 1 – Acts as an introduction by introducing the topic and provides the fundamentals for the report. The chapter includes the aim of the study together with the research questions and ends in a section that contains the delimitations.

Chapter 2 – Consists of a literature review that introduces the concepts needed to understand green hydrogen production and other areas of importance to the business case. The literature review also presents previous research related to the cost of hydrogen production as well as the current prize targets for hydrogen in Europe.

Chapter 3 – Contains a description of the method used to calculate the costs of the hydrogen production. In more detail the chapter includes explanations about the system design, important assumptions and gives a background to decisions that was made.

Chapter 4 – Presents the results and findings of the calculations. The chapter also includes a sensitivity analysis, which indicates how certain variables affect the hydrogen costs and the uncertainty of these variables.

Chapter 5 – Consists of a discussion of the findings form the literature review, interviews and the results of the calculations.

Chapter 6 – Includes the most important conclusions and findings.

2. Background

In the following chapter fundamental theory for green hydrogen production is presented to provide a better understanding in hydrogen technology as well as act as a point of reference for the upcoming calculations. The first subsections start by giving an insight in the general potential for hydrogen and later in the chapter there is a heavier focus on areas essential in green hydrogen production.

2.1 Hydrogen as an energy carrier

Most of the hydrogen used globally today is produced from fossil-based raw materials. Only about 20% of the hydrogen is being produced with renewable resources. The sector with the largest demand of hydrogen was 2020 the chemical industry with 45 Mt H_2, where circa 75% was used for production of ammonia and the rest was utilized in methanol production. The second largest sector is refineries with a demand of 40 Mt H_2 under 2020. Followed by the steel industry where 5 Mt H_2 was used during 2020, which makes the total global demand of hydrogen under 2020 to be 90 Mt H_2. The International Energy Agency (IEA) predicts this number to grow to a total of 530 Mt H_2 by year 2050, where a threefold increase is expected in the industry sector and the transportation sector is expected to move from negligible amounts to using around 100 Mt H_2. (IEA, 2021)

Hydrogen is seen as an important research area within the European Union (EU). Since it has potential to become a realistic fossil free replacement for many of the fossil-based energy carriers used today. To allow for a rapid development of hydrogen the EU has implemented a hydrogen strategy with important steps leading up to year 2050. The strategy states that during the years 2025 – 2030 at least 40 GW of new electrolysers will be installed within Europe and produce around 10 million tons of green hydrogen yearly. (European Comission, 2020) A hydrogen strategy has been suggested in Sweden as well, which suggests steps up to the year 2045. In the suggested strategy the Swedish Energy Agency (SEA) expects installations of electrolysers to reach 5 GW during the years 2022 – 2030. The increase in hydrogen production is expected to be followed by an increase in the demand from the steel industry as well as demand from refineries in Sweden. (SEA, 2021)

There are a number of different processes in which hydrogen can be produced and the environmental impact of the produced hydrogen is dependent on which process that has been used. As a result, it is common to divide the different ways of producing hydrogen by the environmental impact that it causes. The most common way of producing hydrogen today is by steam methane reformation. This method releases substantial amounts of carbon dioxide to the atmosphere and is usually referred to as grey hydrogen. A way to greatly reduce the carbon dioxide emissions from grey hydrogen without changing the production method is to collect and capture the CO_2 before it leaves the production site. The process of capturing carbon dioxide is referred to as Carbon Capturing, Utilisation and Storage (CCUS) and hydrogen produced from fossil resources in combination with CCUS is typically categorized as blue hydrogen. Another way of producing hydrogen with very low greenhouse gas emissions is by splitting water through electrolysis and this kind of hydrogen is categorized as green hydrogen when the electricity source is renewable. The by products from the water electrolysis are oxygen and heat. (Hydrogen Europe, 2021) During the electrolysis roughly 9 litres of water is used to produce one kilo of hydrogen and in turn 8 kilos of oxygen is produced. (IEA, 2021) Both oxygen and excess heat from the process can have an economic value, which can help with the profitability of the plant.

2.2 Applications of green hydrogen

Hydrogen has many uses and in the following section some of the most likely potential uses for green hydrogen is described. There are multiple ways to utilize hydrogen as an energy carrier. In the following subsections areas are presented where there is potential for an early transition to a higher utilization of hydrogen.

2.2.1 Industry sector

One of the first pilot projects involving green hydrogen production on a larger scale in Sweden is HYdrogen BReakthrough Ironmaking Technology (HYBRIT), which is a project to help reduce the carbon dioxide emissions from the steel industry. The companies that partake in the project are LKAB, SSAB and Vattenfall. The goal of the project is to produce hydrogen, which later will be used for the reduction of steel ores. This was previously done with coke, which meant that large emissions of fossil-based carbon dioxide were released in the process and these emissions can with be avoided if HYBRIT is successful. (Vattenfall, u.å)

The storage solution for HYBRIT is a Lined Rock Cavern (LRC) storage with a volume of 100 m^3 for the pilot project. The storage when the project is fully realised will allows to store 100 000 – 120 000 m^3 of hydrogen with an operating pressure at 250 bar, which is enough to run the industry processes for three to four days. The LRC storage is to be placed 30 m below the ground surface. If the pilot project is successful and this technique is implemented for all steel production in Sweden it has the potential of reducing the annual total carbon dioxide emissions by 10% for Sweden. (Vattenfall, u.å) The cost of the 100 m^3 LRC storage was reportedly 259 million SEK and SEA has contributed with 72 million SEK. (FuelCellsWork, 2021).

2.2.2 Power sector

Hydrogen is not used for electricity production or balancing of the power grid in any scale worth mentioning today, but there is a potential for hydrogen to become an important factor for the power sector in the future. This is mainly because the power grid requires the production of electricity to be equal to the consumption at any given time. Hence, there is a need to store the available energy at certain times and increase production of electricity at other times. This is where hydrogen systems can offer flexibility by producing hydrogen via electrolysis when there is an overshoot of electricity and via a fuel cell convert the energy back to the grid when the demand is greater than the production. The phenomenon with an imbalance between production and consumption is expected to increase with a larger scale of variable and intermittent renewable power sources. Hydrogen can also ease the problem by offering uniform and predictable power production with small to no greenhouse gas emissions when it is used in powerplants or when converted to ammonia and used as a fuel in power plants. (IEA, 2019b)

2.2.3 Transportation sector

The transport sector globally contributes with 23% of the global emission of greenhouse gases and in Sweden this number is closer to a third of the total emissions. (IEA, 2021) (Naturvårdsverket, u.å.). During 2020 the emissions from transportation in Sweden amounted to about 15 million tons of carbon dioxide equivalents. Sweden must decrease its emissions from the transportation sector by an annual average of one million tone CO_2-eqvivalents until 2030 to meet the current goal for 2030, which states a 70% decrease in emissions by year 2030 compared to the emissions in year 2010. The two categories in this sector that contributes with the most emissions are passenger cars and heavy-duty traffic. (Naturvårdsverket, u.å.)

Hydrogen can also reduce emissions in the transport sector if the number of Fuel Cell Electric Vehicles (FCEV) is increased. Since green hydrogen produces negligible GHG emissions when used as a fuel. FCEVs are more suitable for long journeys and heavier loads compared to EVs, which makes hydrogen better as an energy carrier for busses and trucks. The FCEV also has the benefit of longer driving range and faster refuelling than EVs. Hence, hydrogen has the largest potential in a short perspective to reduce the use of diesel in busses and trucks. Hydrogen has previously been tested and determined to function as a fuel for heavy transportation under realistically conditions. Further in the future there is also a possibility for fuel cells in passenger cars with utilization since the refuelling is faster than for batteries. One example of potential passenger cars that could benefit from fuel cells in the future are taxi cars. (IRENA, 2018)

In a simulation based on price indications made by DNV predictions about the energy transition was made leading up to year 2050 and the simulation indicates a gradual market acceptance of hydrogen as a fuel in the transportation sector. The fastest development occurs for trucks and heavy vehicles, where FCEVs is predicted to make out 28% of all new trucks sold in year 2050. Hydrogen will also gain market shares in the passenger car market, but it will move in a slower pace compared to heavier vehicles. Due to the high price of FCEVs currently the first year of hydrogen cars on the European market is predicted to be 2030. (DNV, 2021)

In a study from Gävle university the possibility to use FCEVs in the Gävleborg was mainly dependent on the availability of hydrogen and the cost-competitiveness of hydrogen trucks. In the study it was also determined that the first generation of FCEVs will not be able to with the heaviest trucks and long haul on Swedish roads, but that the first generation of FCEVs could be used for more local applications to avoid the heaviest loads and compete with battery driven trucks. (Zandén Kjellén, 2021)

2.2.4 Electrofuels

Electrofuels utilizes hydrogen that has been produced from an electrolyser and combines the hydrogen with carbon or nitrogen to fabricate a molecule that can later be used as a fuel. The electrofuels often come with beneficial properties, e.g. existing as a liquid at room temperature. For electrofuels that contains carbon it is possible to utilise carbon dioxide as a carbon raw material and the carbon dioxide can be collected from various industry processes. By converting green hydrogen into electrofuels, it would be possible to lower the greenhouse emissions for the agriculture, aviation and road traffic sector in Sweden. Where the agricultural sector could lower its emissions substantially since it uses a lot of ammonia and since fossil-based ammonia is easily substituted with the renewable ammonia the transition is relatively simple. (Nordic Energy Research, 2022)

A study evaluating the potential of electrofuels in Sweden found that there is no shortage of possible carbon sources for producing electrofuels. There might however become an issue with securing the needed electricity when the demand for electrofuels increases. The study found that Sweden could produce DME, methanol or methane to supply the demand from the entire road-based transports in Sweden by year 2030 with regards to available carbon sources. It did however also state that to produce 85 TWh of methanol, which equals the energy demand for all road-based transports during 2014, 164 TWh of electricity would be required. (Hansson, Hackl, Taljegard, Brynolf, & Grahn, 2017)

2.3 Electrolysis

Electrolysis is the process in which green hydrogen is produced by splitting water into hydrogen and oxygen. This process requires energy and is supplied in the form of electricity. The unit in which this reaction takes place is called an electrolyser and there are currently a small range of different types of electrolysers available. However, there are two types of electrolysers that currently are the most market competitive namely alkaline and proton exchange membrane (PEM) electrolysers. Hence, these two variants will have the main focus while moving forward.

2.3.1 Electrolysis with alkaline electrolyser

The alkaline electrolysis is an established technology for hydrogen production with installations up to the megawatt scale. (Grigoriev, Fateev, & Millet, 2020) The electrolysis is characterized by submersion of electrodes into an alkaline liquidous electrolyte consisting of 20-30% of potassium hydroxide (KOH). Another important component is the diagraph separator that separates the two electrodes and works as a separator for the produced gases at the electrodes, which heightens both security and efficiency. The diagraph must also be able to let water and hydroxide molecules trough for the electrolyser to work. Three major issues that are common for alkaline electrolysis are the low partial load range, limited currency density and low operating pressure. (Carmo, Fritz, Mergel, & Detlef Stolten, 2013)

The reactions taking place in the alkaline electrolyser are presented below together with a schematic illustration of the electrolyser in Figure 1.

$$Cathode: 2H_2O + 2e^- \rightarrow H_2 + 2OH^-$$
$$Anode: 2OH^- \rightarrow ½O_2 + H_2O + 2e^-$$
$$Total: H_2O \rightarrow ½O_2 + H_2$$

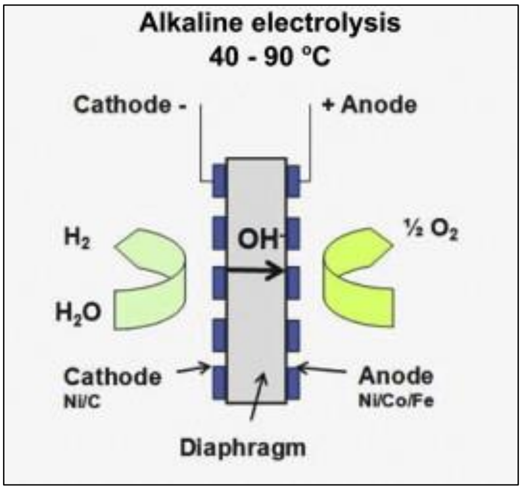

Figure 1. Illustrations of the of the alkaline electrolysis cell.
Figure reprinted from (Carmo, Fritz, Mergel, & Detlef Stolten, 2013) *with permission.*

Figure 2 shows a generic schematic illustration of the components needed for green hydrogen production when using an alkaline electrolyser.

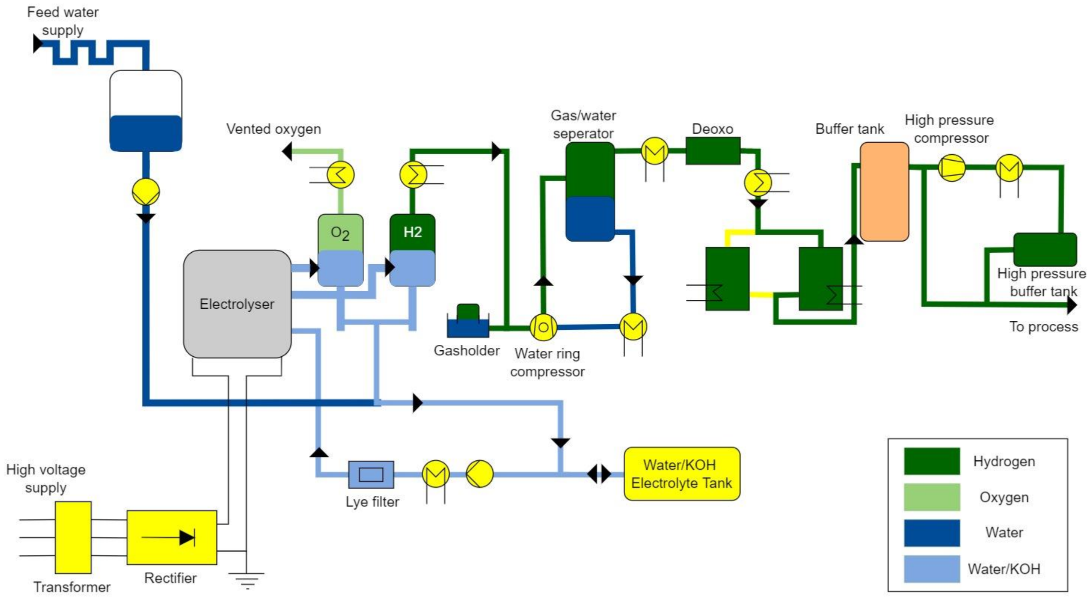

Figure 2. The different components needed in a generic hydrogen plant with an alkaline electrolyser. Image inspiration from (IRENA, 2020)

2.3.2 Electrolysis with PEM electrolyser

The proton exchange membrane electrolyser utilizes a solid polymer electrolyte and offers some benefits in comparison with the alkaline electrolyser. Mainly the fact that the PEM electrolyser can work under a wider range of power input due to a quick response in the proton transport across the membrane since it is not delayed by inertia as in liquid electrolytes. The PEM electrolyser operates at a higher pressure than an alkaline electrolyser, up to 350 bar, which is preferable if the hydrogen is to be delivered at high pressure and thus demanding less energy for compression and less storage volume. The higher pressure does however come as a trade-off since the higher pressure also heightens the risk for cross-permeation. The corrosive and acidic environment provided by the proton exchange membrane requires durable materials. This limits what materials that can be used and currently the preferred materials are often both rare and expensive. Some examples of the elements used in the PEM electrolyser are platinum, iridium and ruthenium. The iridium may cause a scarcity problem in the future since it is one of the rarest minerals in the earth's crust and has an increasing demand since it is used in the manufacturing of LED's. Another undesirable trait of the PEM electrolysis is the presence of vapor in the produced hydrogen stream, which required further dehumidification. (Carmo, Fritz, Mergel, & Detlef Stolten, 2013) The reactions taking place in the PEM electrolyser are presented below together with a schematic illustration of the electrolyser in *Figure 3*.

$$Cathode: 2H^+ + 2e^- \rightarrow H_2$$
$$Anode: H_2O \rightarrow 2H^+ + ½O_2 + 2e^-$$
$$Total: H_2O \rightarrow ½O_2 + 2H_2$$

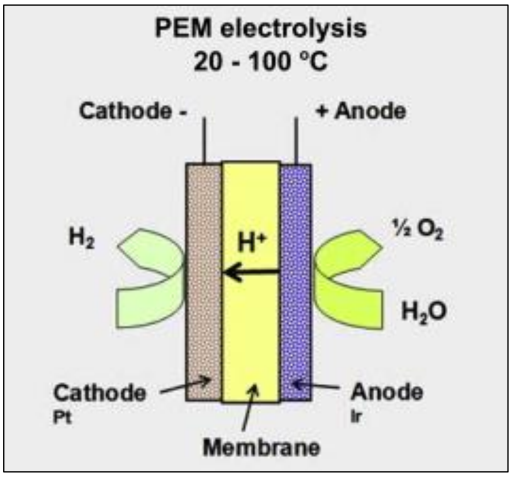

Figure 3. Illustration of a PEM electrolysis cell. Figure reprinted from (Carmo, Fritz, Mergel, & Detlef Stolten, 2013) *with permission.*

2.4 Green hydrogen production

In a public report from the Hydrohub innovation program the CAPEX was estimated for a one-gigawatt green hydrogen plant. This was done for two cases, where the first case is for cost estimates if it would have been commissioned in 2020 and the second case tries to predict costs for a project commissioned in 2030. The CAPEX for the 2020 baseline design for PEM plant was calculated to 1 800 €/kW while the 2030 advanced design was approximated to 830 €/kW. The general plant layout included a connection to a 380 kV connection point with a 1 GW capacity from where wind power was supplied. The electrical losses within the facility were estimated to be 2% of the available electricity. The whole plant was expected to acquire an area of 10 ha. Lastly, the plant was also expected to be a part of the frequency balancing reserve and congestion management of the grid. (Noordende & Ripson, 2020)

2.5 Hydrogen storage

Hydrogen can occur in various phases depending on the temperature and the pressure. At temperatures below -262°C hydrogen is present as a solid with a density of 70,6 kg/m^3 and at higher temperatures hydrogen is gaseous with a density of 0.0899 kg/m^3 at 0°C and 1 bar. Hydrogen can also be present as a liquid with a density of 70.8 kg/m^3 at a temperature of -253°C. At ambient temperature and atmospheric pressure 1 kg of hydrogen takes up a volume of 11 m^3. (Züttel, 2004) Hydrogen has characteristics that complicates storage. One of these characteristics is the ability to react with steel as hydrogen might cause degradation known as hydrogen embrittlement. Hydrogen is also difficult to compress since it has a compression factor that for most of the operational range is greater than one, which means that less hydrogen can be stored in comparison to any gas that acts like an ideal gas. This also means that under the same storage condition less hydrogen can be stored compared to natural gas. (Johansson, Spross, Damaceno, Johansson, & Stille, 2018)

It is possible to store gaseous hydrogen both above ground and underground. For small scale applications there is a greater potential for above ground storage in forms of pressurized storage vessels or liquid hydrogen compared to underground storages (SEA, 2021). For large scale hydrogen storage there is a greater need for underground storage since material and operating costs for above ground storage is rapidly increased for larger volumes. One of the most promising underground solutions is to store hydrogen in salt cavity, which is already used and proven to work in United States (Andersson & Grönkvist, 2019) (IEA, 2019b). Utilizing salt cavities is however not an option in Sweden due to the lack of needed pre-existing geological properties. (SEA, 2021) This makes Lined Rock Cavern (LRC) the most promising solution for large scale storage since Sweden is also lacking other geological conditions for hydrogen storage such as depleted oil or gas fields and aquifers (Andersson & Grönkvist, 2019) (SEA, 2021) (IEA, 2019b) (Johansson, Spross, Damaceno, Johansson, & Stille, 2018). The potential for LRC is greater for hard crystalline rock than for sedimentary bedrocks. This leaves a large share of Sweden with good conditions for LRC storage, but it may be less advantageous to regions like Skåne, Gotland and Öland where the bedrock is mostly sedimentary and therefore cannot utilize higher operational pressures in the storage (Johansson, Spross, Damaceno, Johansson, & Stille, 2018).

The LRC storage has three components. Firstly, the cavern is lined with a sealing layer where the most common material is a steel layer. Secondly, something is needed for pressure distribution to transfer forces from the gas to the rock this is commonly solved by utilizing a concrete layer inbetween the steel lining and the surrounding rocks. Lastly the surrounding rock mass carries the main structural load from the pressurized storage. (Johansson, Spross, Damaceno, Johansson, & Stille, 2018) (Andersson & Grönkvist, 2019) The steel lining inside of the storage ensures that the storage is impermeable. (Johansson, Tengborg, & Durup, 2014). Typically, the LRC is situated somewhere between 100 to 150 meters below ground surface and the maximum operating pressure is commonly ranging from 15 to 30 MPA. The diameter is typically ranging from 35 to 45 meters and the height of the cavern ranges from 60 to 100 meters. (Johansson, Tengborg, & Durup, 2014) Lined rock cavern storages have a relatively small need for cushion gas at around 10%, which allows for 90% of the gas in the storage to act as working gas. (Johansson, Spross, Damaceno, Johansson, & Stille, 2018)

There is one existing LRC storage for natural gas located in Skallen, Sweden. The storage in Skallen is in the form of a cylinder and has a diameter of 35 m and a height of 51 m. It allows for a maximum pressure of 200 bar and if it was to store hydrogen at the same pressure this would mean a total capacity of 740 tons of hydrogen. (Andersson & Grönkvist, 2019) The LRC storage is however relatively untested for hydrogen applications and needs further investigation before it can be implemented in larger scale (Andersson & Grönkvist, 2019) (SEA, 2021).

2.6 Offshore wind power

Offshore wind power is one of the fastest growing technologies for power generation in the world, with a growth rate by almost 30% per year globally between the period 2010-2018. In 2010 the annual installed capacity where just above 1 GW globally and the number for 2018 was 4,3 GW. The largest share of offshore wind turbines (OWT) was installed in European countries and in China. In Europe the northern sea has initially been the main localisation for new offshore project due to high quality wind properties together with relatively shallow waters. In the two coming decades the installations of offshore wind turbines are expected to increase with Europe continuing being the world leader with an installed capacity of 65-85 GW by 2030 if the EU target is achieved. (IEA, 2019a)

For a larger wind farm located more than 10 km from shore is commonly attached to an offshore substation that is in turn connected to an onshore substation. Regarding the offshore connections there are two main technologies namely alternating current (AC) where the current is transported straight to the onshore substation; and direct current (DC) where there initially is a conversion from AC to DC and later conversion back into AC at the onshore substation. For shorter distances the AC transmission is cheaper but over longer distances high-voltage (HVDC) transmission can reduce losses and thereby become the most economical option. (IEA, 2019a).

2.7 The Swedish power grid

To connect to the backbone grid in Sweden the power producer has to apply to Svenska kraftnät (SVK), which has to approve the application and there are certain requirements that must be met. Delivering power to the 220 kV grid requires at least a capacity of 100 MW. While the 400 kV connections require a minimum capacity of 300 MW. In general, it takes about four years from the approval of the application until the connection is in operation according to SVK. (Svenska Kraftnät, 2022) In 2017 SVK investigated the impact of new grid connections between Untra and Hagby in Uppsala respectively Stockholm. The estimated the costs for a new 400 kV cable was found to be around 7.2 million SEK per kilometre and a new 220 kV cable would be in the same range as the 400 kV cable. (SVK, 2017)

As a power producer there is also an annual fee when connecting to the backbone grid. This is split into two price components. The first is a capacity fee that is based on the annual subsribed capacity and specific for every connection point expressed in [SEK/kW]. The second is a energy fee which is derived from the annual power input to the grid and is expressed in [SEK/MWh]. To calculate the energy fee a formula involving the hourly spot price, an added risk component and the loss coefficent for the specific connection point (SVK, 2021). The closest connection point to the backbone grid from a location in the vicinty of Trelleborg is Arrie. This can be seen in *Figure 4*, where the backbone grid with potential connection points is showcased. For the connection point in Arrie the capacity fee is 32 SEK/kW and the loss coefficent is -5.9% (SVK, 2021).

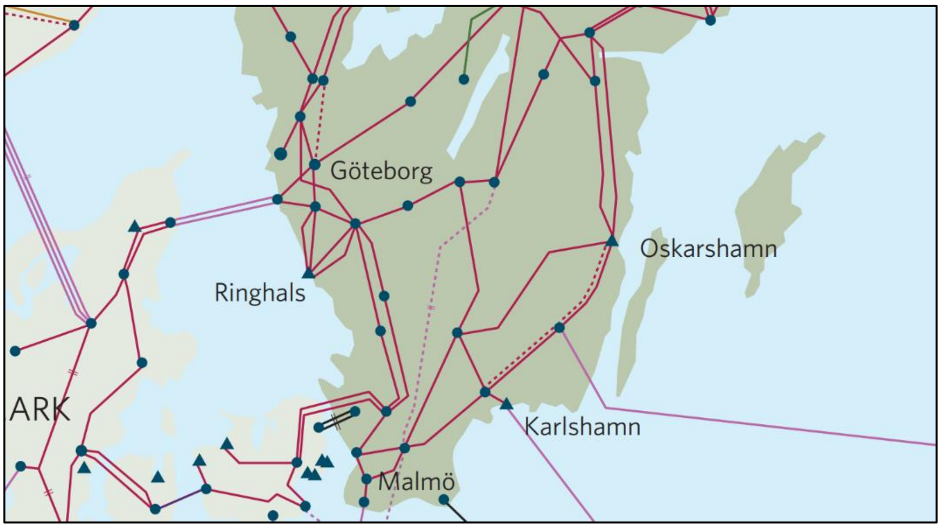

Figure 4. Shows the backbone electricity grid in the southern region of Sweden with connections to adjacent countries. Source: Svenska kraftnät

3. Method

The cost of the produced hydrogen will be presented as LCOH per kilogram hydrogen gas for two cases. This first sector will explain the common conditions used for both cases. Starting with the geographical location for the studied system is described in Figure 5, where an offshore windfarm is located in the economic zone of Sweden at 22 km from shore. The electricity generated from the wind farm will be transported by power cables to an electrolyser located onshore where different shares, depending on which scenario is simulated, of the electricity will be used to produce hydrogen a certain percentage of the time and the remaining time electricity will be sold as electricity. For instances where the electricity is not used for hydrogen production it is sold to the Nordpool market. Hence, there is a need for a connection to the backbone grid with power cables that covers 19.5 km. The costs for the wind farm will not be included in the LCOH. Hence, the sold electricity will also be excluded. One essential difference between case 1 and case 2 is that the cost for the connection to the power grid will not be included in case 1

All the excess heat from the electrolyser up to 20 MW will be sold to a district heating grid. The limitation of how much heat that can be delivered is due to the limits of the local district heating grid, which can only receive a certain amount. In setup the limit has been set to an estimated value of 20 MW. Furthermore, both the investment costs for the connection, including the needed components, and the income from the sold heat will be included in the LCOH. The assumed distance for the electrolyser and the district heating grid is 3 km and the operational costs for the district heating connection is set to 1% of the investment cost. However, the smallest electrolyser size will not be connected to a district heating grid since the heat generated is insufficient to compensate for the investment cost for the connection to the local district heating grid.

Figure 5. Shows the location of the offshore wind farm as well as the hydrogen production and the assumed cable connection to the grid. Source: Map data @ 2022 Google

Different sizes of the electrolyser will be analysed for both cases. Starting with a relative normal size for pilot projects with hydrogen production today at 5 MW. The electrolyser sizes are scaled up in steps shown in Table 1. The largest electrolyser is at 1000 MW, which is thought of as the targeted size in a futuristic scenario. The costs of the electrolysers are on a system level meaning costs for the stack and balancing of the plant such as rectifiers, compressors and cooling components.

Table 1. Shows the different sizes of electrolysers in megawatts.

Scenario	Attribute	Value	Unit
Electrolyser 1	Installed capacity	5	MW
Electrolyser 2	Installed capacity	100	MW
Electrolyser 3	Installed capacity	500	MW
Electrolyser 4	Installed capacity	1 000	MW

The produced hydrogen will be stored in a LRC storage in both cases. The size of the storage will vary in steps to be able to store one day, one week and one month of hydrogen production from the electrolyser as shown in Table 2. Hence, the storage will also differ in relation to the size of the electrolyser. It is assumed that all storages can utilize 90% of the total capacity as working gas. Hence, the storages will be designed to hold an additional 10% to compensate for the cushion gas.

Table 2. The three different storage scenarios used for all cases.

Scenario	Attribute	Value	Unit
Storage 1	Volume	1	Capacity in number of daily productions
Storage 2	Volume	7	Capacity in number of daily productions
Storage 3	Volume	30	Capacity in number of daily productions

3.1 Case 1

The first case is describing an optimal production scenario with the goal of achieving a low LCOH. This was done by assuming the cost of electricity to be equal to the hourly spot price on the Nordpool day-ahead-market. The key assumption in this case is that the storage volumes allow for only utilizing half of the available production hours. This means that only the one-day storage will produce hydrogen during the twelve hours with the lowest electricity price during each day. While the 7-days storage will produce hydrogen during the 84 hours with the lowest electricity prices of every week. Lastly, the 30-days storage will produce hydrogen during the 360 hours with the lowest electricity price.

3.2 Case 2

Case 2 is simulating three scenarios where the grid capacity is poor, which makes it impossible to feed all of the power generated by the offshore windfarm into the power grid. As a consequence, the green hydrogen production is acting as a way of keeping the power input to the grid at levels that the grid can handle by offering flexibility. The case will analyse two sizes of cable connections with varying costs and transmission capacity. The three scenarios can be seen in Table 3. For all the scenarios the cost of electricity is permanently set to 50 SEK/MWh, which is set to this value to represent the production cost of the electricity from the offshore wind farm.

Table 3. The cables and limitations used in case 2.

Scenario	Cable	Maximum input to the power grid
Scenario 1	400 kV	700 MW
Scenario 2	400 kV	300 MW
Scenario 3	130 kV	170 MW

3.3 Processing and conversion of data

In the following subsection assumptions and cost calculations will be further explained in more detail. Furthermore, all calculations were carried out in Microsoft Excel. In order to achieve the most optimized sizes of the hydrogen storages the solver function in Excel was used. Some of the data had to be converted or used to later be put into the economical calculations. The following subsections will give some insight in the assumptions made for the calculations.

3.3.1 Levelized cost of hydrogen

One of the most common ways of determining the costs of hydrogen production is by calculating the levelized cost of hydrogen (LCOH) as shown in Equation 1. This will also be the method used to calculate the cost of the produced hydrogen for both cases.

$$LCOH = \frac{Total\ Costs\ (SEK) - Total\ Revenue\ (SEK)}{H_2\ Annual\ Production\ (kg)} \tag{1}$$

The LCOH can be divided into the following components shown in Equation 2.

$$LCOH = \frac{C_{inv,a} + C_{rep,a} + C_{O\&M} - C_{rev}}{M_{H_2}} \tag{2}$$

where, $C_{inv,a}$ is the annual cost of the investment in SEK, $C_{rep,a}$ is the annualized cost of replacing components during the economic lifetime, $C_{O\&M}$ is annual operating and maintenance cost during in SEK and C_{rev} is the annual revenue from the by-products given in SEK. The annual investment cost is calculated as shown below in Equation 3.

$$C_{inv,a} = \frac{i(1+i)^n}{(1+i)^n - 1} \cdot C_{inv} \tag{3}$$

where i is the nominal interest rate, n is the plant lifetime in number of years and C_{inv} is the total investment cost for components shown in Equation 4.

$$C_{inv} = C_e + C_s + C_c \tag{4}$$

where C_e is the investment cost of the electrolyser, C_s is the investment cost for the storage and C_c is the costs of the needed cables from the wind farm to the electrolyser and the costs of the cables from the electrical grid to the electrolyser.

The annual replacement cost is calculated as shown in Equation 5.

$$C_{rep,a} = \frac{i(1+i)^n}{(1+i)^n - 1} \cdot \frac{C_{rep}}{(1+i)^t} \tag{5}$$

where C_{rep} is the replacement cost and t is the related year.

3.3.2 Economic assumptions

The overall economic lifetime of the hydrogen plant has been set to 25 years while the electrolyser as a singular component has an assumed lifetime of 50 000 h of operation. The discount rate was set to 8%.

3.3.3 Power from the wind farm

Data for historical hourly values of wind speeds together with air densities for a location in the vicinity of the wind farm has been provided by RWE. The hourly wind speeds will be used to calculate the hourly power output from the wind farm, which is done by using Equation 6. In addition, there will be a cut-in and cut-out speed where the power output from the wind farm will be assumed to be zero for values outside of the given interval. The cut-in wind speed is set to 3 m/s and the cut-out wind speed is 30 m/s, which is the same speeds as specified for Vestas 15 MW turbine V236-15MW (Vestas, 2022). The reason for choosing Vestas V236-15MW as a model for the wind turbines is due to the specifications for the turbine being public and the turbine size being in the interval of 15-20 MW, which is where the market aims to increase the turbine sizes to year 2030 (IEA, 2019a).

$$P_{Avail} = \frac{1}{2} \cdot A \cdot \rho \cdot C_p \cdot v^3 \tag{6}$$

where, P_{Avail} is the power output, A is the area of the swept area of the rotors, ρ is the density of the air and v is the wind speed. The sweeping area is set to $A = \pi \cdot \left(\frac{236}{2}\right)^2 \approx 43\,750\ m^2$, where the diameter of the rotors is the same as for the V236-15MW made by Vestas (Vestas, 2022). The C_p value was set to 0.40.

Equation 6 gives the power output for one turbine. The result was multiplied with the required number of 15 MW turbines needed to achieve the installed capacity, which was calculated by Equation 7.

$$P_{installed} = 1000\ MW\ \rightarrow \frac{1000\ MW}{15\ MW} \approx 66\ turbines. \tag{7}$$

With 66 turbines the installed capacity of the wind farm is $66 \cdot 15\ MW = 990\ MW$. The power output scales strongly with the wind speed and may allow for power outputs greater than the rated power of the singular wind turbine in Equation 6. Due to this the power will be regulated when wind speeds exceed values that would generate power greater than the rated power. Hence, the solver function in excel was utilized to find the wind speed at which the rated power was reached which occurred at 10.83 m/s. During the calculations of the rated wind speed the air density was set to 1.35 kg/m^3 since this was the highest value in the data set.

3.3.4 Production volumes

The production per electrolyser stack was determined on an hourly basis by dividing the available energy by the electricity consumption in kWh per unit produced hydrogen given by fact sheets by NEL Hydrogen about their electrolysers. In addition, hydrogen would only be produced when there was enough electricity for the electrolyser to work at more than ten percent of its capacity. The calculations were made as described by Equation 8.

$$m_{prod} = \frac{W_{el}}{\rho} \tag{8}$$

, where m_{prod} is the hourly production given in kg H_2 per hour, W_{el} is the electricity consumption in kWh/Nm^3 and ρ is the density of hydrogen in kg/Nm^3.

3.3.5 Storage capacity

The volume of the hydrogen storage is determined by the maximum daily production of hydrogen, which in turn is dependent on the size of the electrolyser and which production case that is calculated. Hence, multiple sizes of the storages have been used for the different scenarios. Equation 9 was used to calculate the volume of the storage.

$$V = \frac{\frac{m_{production}}{\rho}}{p} \tag{9}$$

where $m_{production}$ is the hydrogen production under the chosen time interval of 1 to 30 days, ρ is the density of hydrogen as a gas of 0.0899 kg/m^3 and p is the pressure given in bar. With the assumption that the storages were made in the form of a cylinder with two half spheres in both ends of the cylinder it was possible to calculate the volume of the storage by Equation 10.

$$V_{cylinder+spheres} = \pi \cdot r^2 \cdot (h - 2 \cdot r) + \frac{4 \cdot \pi \cdot r^3}{3} \tag{10}$$

where h is the height of the cylinder in meters, r is the radius of both the cylinder and the half spheres in meters. To calculate the cost of lining the cavern with steel the inner area of the cavern is needed. Hence, the inner area was calculated by using Equation 11.

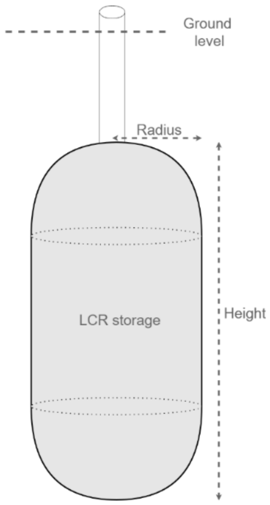

Figure 6. An illustration of the LCR storage.

$$A = \pi \cdot r^2 \cdot (h - 2 \cdot r) + 4 \cdot \pi \cdot r \qquad (11)$$

To avoid randomization of the dimensioning of the storage and the risk of poor structural designs that may fail inspiration has been taken from the LRC storage for natural gas located at Skallen. With Skallen in mind the ratio between the radius and height of the storage has been set to 0.35. The height of the storage has been set to not exceed 100 m. Hence, there is a need for multiple storage units for larger storage volumes. The working gas was assumed to be 90% of the total gas volume. The capacity of the storages for the production case, where 50% of the available electricity throughout the day is used for hydrogen production, can be seen in *Table 4*. The values in the table have been rounded.

Table 4. The storages used in the simulations

Scenario	Capacity [nbr of days]	Total volume [m³]	Number of storages	Radius [m]	Height [m]	Cost [MSEK]
1000 MW	30	2 962 963	11	34.0	97.0	18 006
	7	691 358	3	32.2	92.1	4 560
	1	98 765	1	24.3	69.4	752
500 MW	30	1 481 481	6	33.0	94.2	9 089
	7	345 679	2	29.3	83.7	2 359
	1	49 383	1	19.3	55.1	433
100 MW	30	296 296	2	27.8	79.5	1 941
	7	69 136	2	17.1	48.9	598
	1	9 877	1	11.3	32.2	159
5 MW	30	14 815	1	12.9	36.9	190
	7	3 457	1	7.9	22.7	108
	1	494	1	4.2	11.9	79

A lined rock cavern storage is based on the principle that the rocks and materials above the storage helps with structural properties of the pressurized storage. The pressured gas cannot exert a larger force on the lining than the surrounding rock since this would risk creating cracks and gas leakage. Hence, the density and thickness of the ground layer situated above the storage is important to determine the weight that is applied to the storage. As stated in previous research it is more beneficial to use LRC where the bedrock consists of granite than the more sedimentary bedrocks in Skåne but for the calculations the LCR storage is assumed to be able to handle an operating pressure of 30 bars.

3.3.6 Connection to power grid

To calculate the costs for the connection to the power grid the cost has been divided into two separate parts. The first part is the actual cable connection between the wind farm and backbone grid. The second part is the annual payment for the connection which is made up by a capacity and an energy tariff (SVK, 2021).

The cost for the new cable was calculated using an estimated cost of 9.1 million SEK per kilometre. This number corresponds to the 7.2 million SEK/km that SVK suggested for a new cable connection between Untra and Hagby in Sweden with an assumed inflation of 2% until year 2030. The cost for installation of the power cable from the harbour to the wind farm was assumed to be 15 times more expensive than the land route cable.

The annual cost for the connection point was calculated as shown in Equation 12 with one component depending on the maximum power input and the other taking into account the total delivered energy. Firstly the capacity fee for Arrie was multiplied with the given maximum power input given for each scenario together with the energy fee. The value was then added to the energy fee, which was calculated by adding the spot price of the corresponding hour with the addition set by SVK and then multiplying it by the loss coefficient.

$$(C_{inst} \cdot P_{inst}) + (P_{t,e} + r) \cdot F \qquad (12)$$

where the C_{max} is the maximum capacity in MW, the P_{inst} is the capacity fee for Arrie, the $P_{t,\,e}$ is the spot price for the corresponding hour on the day-ahead market. r is an addition set by SVK due to increased risk and corresponds to 10 SEK/MWh. F is the loss coefficient and for Arrie this is set to -5.9%.

Table 5. The connections costs for case 2.

Scenario	Cable	Maximum input to the grid	Cost per kilometre, land [MSEK/km]	Cost per kilometre, sea [MSEK/km]	Capacity & energy tariff [MSEK/year]
Scenario 1	400 kV	700 MW	9.1	137	22
Scenario 2	400 kV	300 MW	9.1	137	9.2
Scenario 3	130 kV	170 MW	1.5	22.2	2.8

3.3.7 District heating

The excess heat from the electrolysers will be sold at 193 SEK/MWh during November to March and 98 SEK/MWh for the remaining part of the year in accordance with the information from the contact at Trelleborgs Energi. For the same reason the investment cost for the connection to the district heating grid will also be halved since this was to be expected for a customer wanting to connect to Trelleborgs grid.

3.3.8 Cost of water

Water will be needed mainly in the electrolysis but also to cool the electrolyser from overheating. The cost of the feedstock water to the electrolyser was set to 7.4 SEK/m^3 to correspond to the 0.77 \$/m^3 value found in the study of by Caldera and Breyer in which costs for SWRO plants was calculated.

3.3.9 Wind data

The available electricity was calculated from wind speeds for a site located close to the hypothetical location of the offshore wind farm analysed. The dataset was given by RWE and included in the dataset was also the hourly air density. The wind speeds can be seen in Figure 7.

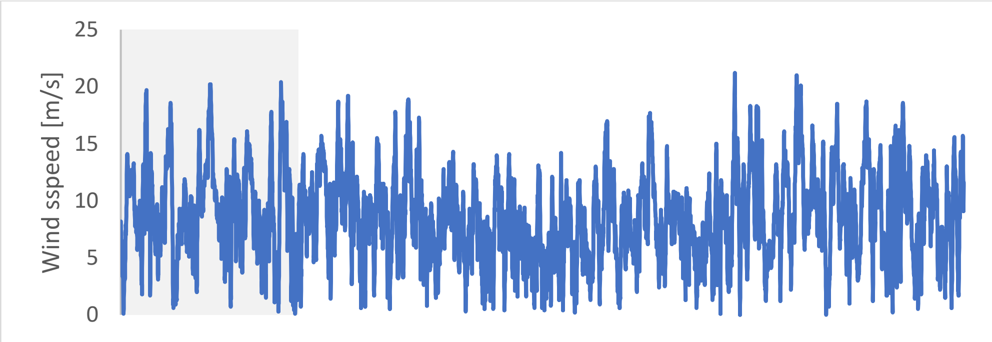

Figure 7. Wind speeds used in the calculations.

3.3.10 Electricity prices SE4

With more renewable power generation it is likely that the electricity will become more volatile in the coming years. Hence, historical hourly electricity prices for year 2021 and are presented in Figure 8. Year 2021 was used in the base case to mimic a futuristic volatile electricity market in turns of price variations.

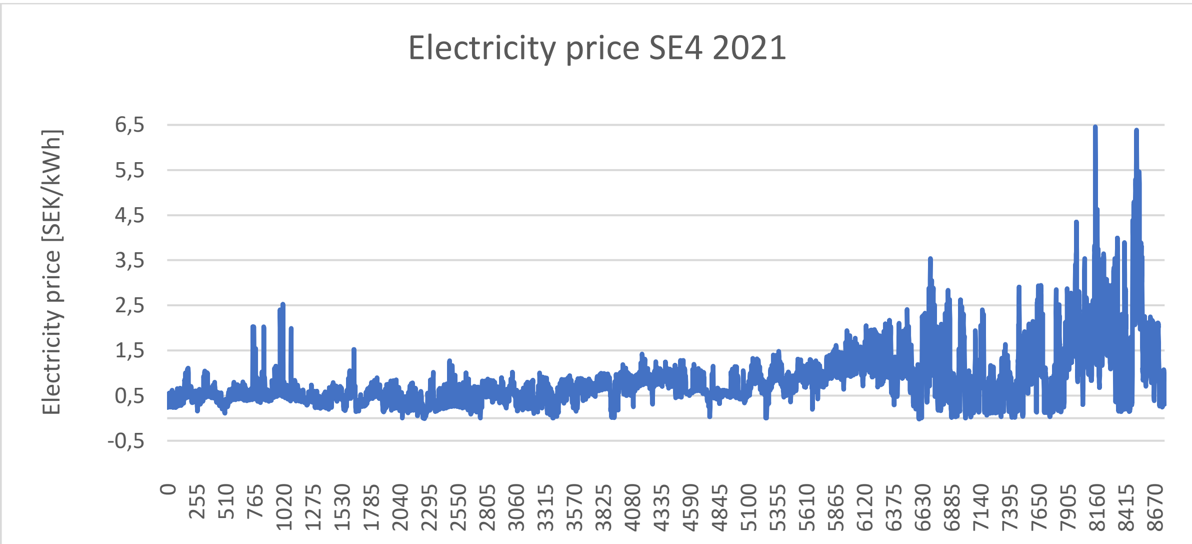

Figure 8. Hourly electricity prices for SE4 during year 2021.

The electricity price has been more stable in the years leading up to 2021 and to illustrate this the years 2018 to 2020 has been plotted in Figure 9. Where, the average price for each hour has been marked with a black line.

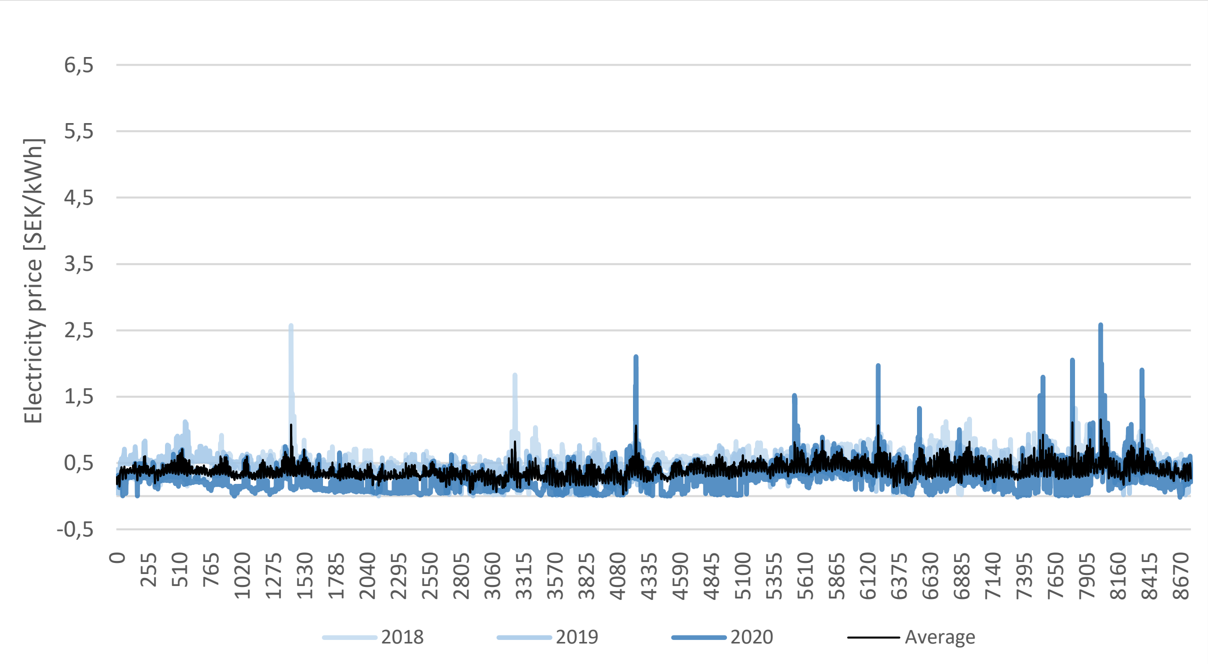

Figure 9. Hourly electricity prices for SE4 during year 2018-2020 with the average price shown in black.

3.3.11 Hydrogen demand for Trelleborg

In an interview with Trelleborg's Energi it was stated that Trelleborg's Energi is tracking the development of hydrogen as an energy carrier carefully and has started to investigate potential applications within the municipality of Trelleborg. One sector where hydrogen was expected to be used in the early stages hydrogen of converting into an increased usage of hydrogen is transportation. The harbour in Trelleborg is believed to be a key element in increasing the hydrogen usage with a large number of heavy transports going into and from the harbour area. An estimated number of trucks that annually travels through the harbour was for year 2025 around 1,5 million. The many trucks going through the area gives an opportunity for the harbour to act as a close-by offtaker with a hydrogen fuel station if parts of the vehicle fleet is converted from traditional internal combustion engines to trucks with fuel cells. The same reasoning can be made for the 30 ships that annually arrives and departs from the harbour, these could further increase the demand of hydrogen if some ships were converted into utilizing fuel cell technology. (Trelleborgs Energi, 2022) As an indication, if 1% of the trucks were to refuel 45 kg each time they passed through the harbour the annual hydrogen demand from the trucks would be 450 tons.

4. Result

In the following section the main findings are presented for both case 1 and case 2 with. The chapter is divided into four sections, where the first section is the results from the literature review and the following two sections are dedicated to present the results from case 1 and case 2. The last part of the chapter is a sensitivity analysis, which showcases how uncertain variables effects the LCOH. The sensitivity analysis is done with conditions similar to case 1 due to time limitations and the fact that many variables are the same for the two cases.

4.1 Future costs of green hydrogen production

The European union has as a step to motivate investments into hydrogen stated a goal of what the market prize for hydrogen of less than 2 EUR per kg H_2. This can be compared to that the price of green and fossil-based hydrogen at the time was 2.5-5.5 EUR per kilo of hydrogen respectively around 1.5 EUR per kilo of hydrogen (EU, 2020). The International Renewable Energy Agency has also drafted a strategic plan to reach a hydrogen price of less than 2 USD per kilo H_2 prior to the year 2030. In the calculations motivating a price below 2 USD the electricity price was set to 20 USD per MWh. Meanwhile, the electrolyser manufacturing company NEL Hydrogen has presented a goal of cost of 1.5 USD per kg H_2 and expects this to be accomplished by 2025. The largest reduction in costs is anticipated to originate from scaling up the electrolysers. (NEL, 2021) One of the more ambitious price targets has been set by the United States Energy department with a goal to reach a levelized price of hydrogen of 1 USD per kilo hydrogen (U.S. Department of Energy, 2021). A complete summation of the prize targets is presented in Table 6.

Table 6. Cost estimations and price targets for green hydrogen from different sources.

Year	2020	2020	2025	2030	2030	2030
Cost of hydrogen	2.5 – 5.5 €/kg	1.4 – 2.75 $/kg	1.5 $/kg	1 $/ kg	1.3 – 3.5 $/kg	< 2 $/kg
Cost of hydrogen [SEK/kg]	24.1 – 53.1	13.5 – 26.5	14.5	9.7	12.6 – 33.8	< 19.3
Source	(EU, 2020)	(Lazard, 2021)	(NEL, 2021)	(U.S. Department of Energy, 2021)	(IEA, 2021)	(IRENA, 2021)

In a report from IRENA where the goal is to identify necessary steps and policies to achieve a competitive hydrogen cost of 1 USD per kg H_2 it was concluded that there are several areas in which cost reductions must be made. An example of how the cost of one kilo hydrogen could be reduced to 1 USD from a scenario reflecting current production with the cost of 4,8 USD was made. This was done by reducing the electrolyser cost by 80%, the electricity price was lowered from 53 to 20 USD/MWh, the efficiency of the electrolyser was increased from 65% to 76%, the full load hours were increased from 3 200 h to 4 200 h, the average lifetime of the electrolyser was increased from 10 to 20 years and the WACC was reduced from 10% to 6%. (IRENA, 2020)

Similarly, the state-of-the-art hydrogen plant that Hydrohub innovation program calculated the CAPEX for have expected improvements for the 2030 scenario. One example of expected improvements in the hydrogen plant is a higher power rating for the electrolysers than those currently on the market. The expectations are that the electrodes and other components will be made from new resources to avoid the scarcest materials. The total installed cost for the 2020 case was 1 400 000 £ for the AWE plant and 1 800 000 £ for the PEM plant, which corresponds to 1 400 £/kW and 1 800 £/kW respectively. For the 2030 case these values were 730 €/kW for the AWE system and 830 €/kW for the PEM system. (Noordende & Ripson, 2020)

4.1.1 Electrolyser costs

Firstly, it should be noted that it is difficult to compare different studies and other sources that estimates costs of electrolysers since much information is confidential and there is often lack of explanation of the system boundaries. Hence, it challenging to be sure of that the costs are for the same type of system. For example, common ways of presenting the cost of the electrolyser are either as a stack and the cost for the system including rectifiers, water purification, compression, and cooling (IRENA, 2020).

The cost of electrolysers is predicted to decrease in the future, both for alkaline and PEM electrolysers. Regarding alkaline electrolysers the main areas for improvements are the electrodes and the diaphragms. More specifically by increasing the current densities from about 0.5 A/cm^2 currently to about 2-3 A/cm^2 and by reducing the thickness of the diaphragm to reduce the electricity consumption as well as improving the efficiency. For PEM electrolysers the bipolar plates, the porous transport layers (PTL) as well as redesigning the stacks. Costs can be reduced by reducing the membrane thickness, removing expensive coatings (e.g. platinum coating on titanium porous sintered PTLs) and redesigning the catalyst coated membranes. (IRENA, 2020)

In addition to cost reduction as a result of research and development improvements the investment cost of electrolysers is also expected to be lowered in the future because of larger stack sizes. As stack sizes increase cost components such as the balancing of plant since some components does not have a linear co-dependency with size. As an example, a compressor that is ten times larger does not cost ten times more, but costs about four times as much. When IRENA studied costs for different electrolyser manufacturers it was found that for the alkaline and PEM electrolyser the stack makes up on average 45% of the costs whereas balance of the system stands for the remaining 55% of the cost. (IRENA, 2020)

Another factor which will help reducing the cost of the electrolysers is the learning by doing concept, which is a concept assuming a reduction in costs per unit as experience increases. There are multiple factors which can reduce costs, e.g. by reduction in production times, lower contribution from fixed costs, standardisation and alternative processing steps. IRENA estimates the costs of electrolysers to drop by 40% until 2030 due to learning rates with the deployed capacity reaching 100 GW and if the deployment is more rapidly a 55% decrease is projected when 270 GW is deployed. (IRENA, 2020)

In Figure 10 the current and predicted costs of alkaline and PEM electrolysers are summarized from different literature sources.

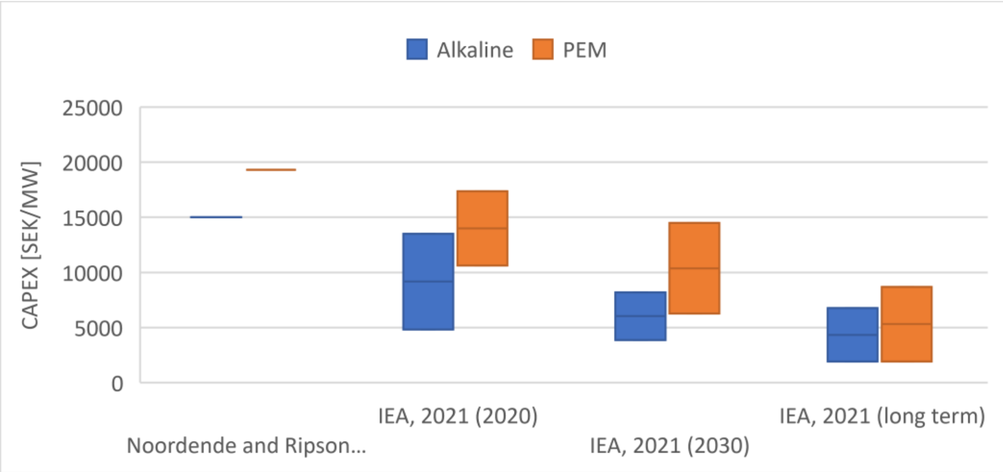

Figure 10. CAPEX for alkaline and PEM electrolysers from literature sources.

4.1.2 Water consumption

Water is needed for the electrolysis partially as a feedstock and partially as a coolant. How the electrolyser is supplied water as a feedstock can vary depending on if the fresh water supply is good in the local area. If a fresh water supply is not available but the production site is in the vicinity to the sea it is possible to utilize reversed osmosis to gain access to desalinated water. The reversed osmosis consumes between 3-4 kWh per m^3, and the cost is around 0.7-2.5 $/ m^3. (IEA, 2021) Past trends in CAPEX for Saltwater reverse osmosis (SWRO) plants was analyzed by Caldera and Breyer. The predicted levelized cost of water (LCOW) for 2030 from a reversed osmosis plant was calculated to be 0.77 USD/m^3 with a price of electricity of 62 USD/MWh_{el} (Caldera & Breyer, 2017).

4.1.3 District heating

Utilising excess heat from industries to decrease the need for new resources is common in Sweden and is a vital part to keep costs low and improve the sustainability. A typical district heating grid operates at temperatures between 65°C and 120°C with an operation pressure of 16 bars. Excess heat from industries is classified into two categories namely: primary excess heat which can be feed into the grid directly and secondary excess heat that needs to be upgraded before reaching the grid. The lower temperature makes the use of secondary excess heat somewhat limited. (Broberg, Backlund, Karlsson, & Thollander, 2012)

By contacting Trelleborgs Energi information about how a potential customer could sell excess heat from their process to the district heating grid at Trelleborgs Energi. From the conversations it was concluded that although Trelleborgs Energi currently do not have any customer that sells excess heat there is an idea in place as how such a contract would be arranged. First, it was expected that if anyone would deliver excess heat to the district heating grid the investment costs would be split equally between Trelleborgs energi and the other company. The company who delivers the heat could then expect a price for the heat equal to half of the price that the Trelleborgs energi buys its energy for. This would correspond to around 193 SEK/MWh during the winter months November to March and 98 SEK/MWh during the rest of the year. (Trelleborgs Energi, 2022)

4.2 Results from Case 1

Depending on the size of the hydrogen storage the production pattern varied as can be seen in Figure 11, where the total yearly production for each electrolyser and storage size are presented. As can be seen in the figure there are some variations in the different scenarios, but in general the annual hydrogen production will be similar no matter the choice of the storage scenario.

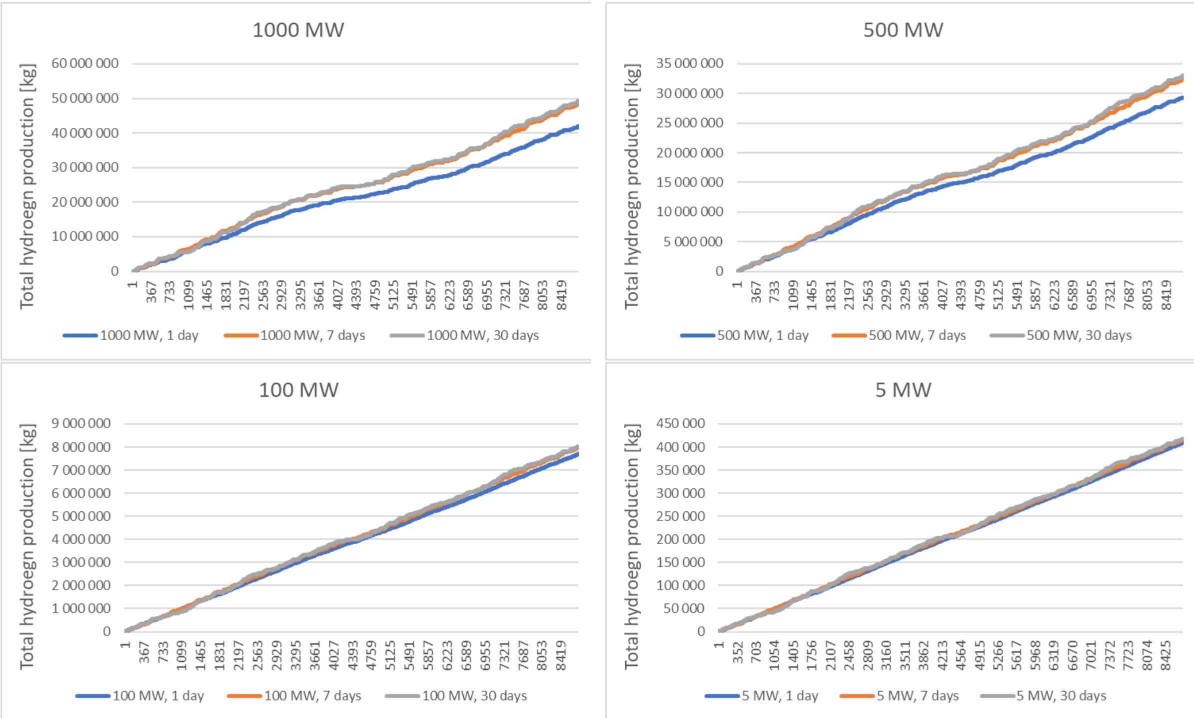

Figure 11. Shows the annual hydrogen production for each electrolyser with all the storage scenarios.

The calculated LCOH for the different storage and electrolyser sizes are presented in *Table 7*. The lowest hydrogen cost was achieved with the largest electrolyser size and the least amount of storage. The lowest cost was 25.65 SEK/kg H_2 for the 1000 MW electrolyser with the least amount of storage. Whereas the highest cost per kg was calculated to be for the 1000 MW electrolyser with the most amount of storage at 398.86 SEK/kg H_2. The result indicates an economy of scale with electrolyser size for smaller storage volumes that gradually decreases and ceases to exist for larger storage volumes.

Table 7. Shows the calculated hydrogen prizes for case 1 with optimal electricity prizes.

Electrolyser size	1-day storage	7-days storage	30-days storage
1000 MW	25.65	48.74	398.86
500 MW	26.79	36.76	177.39
100 MW	30.13	31.44	69.42
5 MW	53.59	55.82	73.37

To further understand how the LCOH is impacted of each cost component the diagrams in Figure 12 shows the shares that each cost components makes up of the total cost of hydrogen. The diagrams show that for the one-day storage electricity price is the main cost driver. Further, for the larger quantities of storage the main cost driver changes and storage cost rapidly becomes the most dominant cost driver of the LCOH for all electrolyser sizes.

Figure 12. Shows the shares of each component in the costs.

4.3 Results from Case 2

Case 2 focuses on how hydrogen production can make use of excess electricity from the wind farm when there are limitations in the transmission capacity to the backbone grid. In the three following scenarios situations where a limited amount of electricity can be sold as electricity and the remaining available electricity is used for hydrogen production. The general result of case 2 is that when hydrogen production is used for production flexibility the LCOH is increased compared to the costs in case 1.

4.3.1 Scenario 1

Figure 13 shows the yearly production for a scenario where the power grid can only receive 700 MW of electricity. Hence, the electricity used for hydrogen production is the remaining part of the available capacity when the wind farm produces more than 700 MW electricity. Consequently, the 500 MW electrolyser produces more hydrogen than the 1000 MW, due to the modelling of the electrolyser does not allow for hydrogen production when the produced electricity is below 10% of the installed capacity of the electrolyser. Hence, the 500 MW electrolyser ends up with an higher availability than the 1000 MW electrolyser.

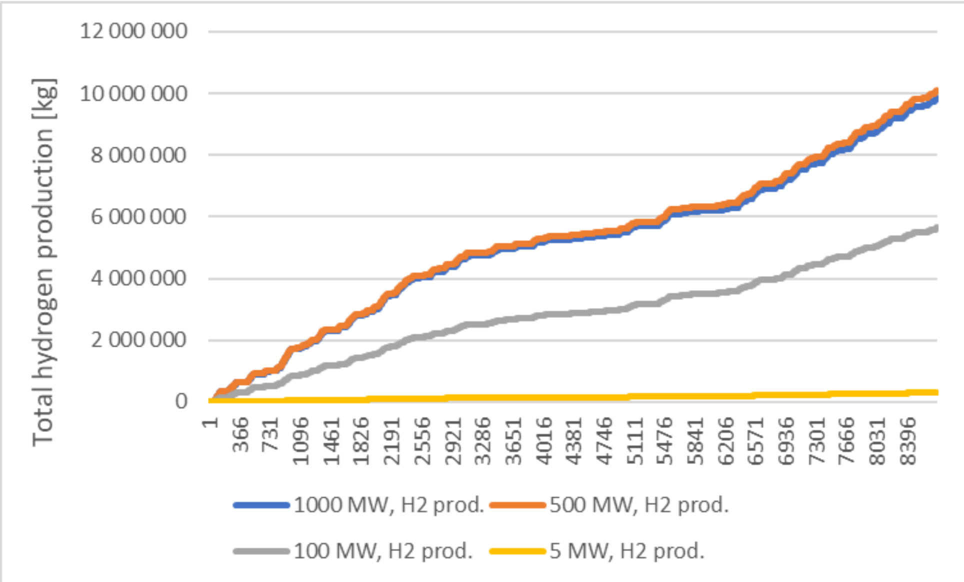

Figure 13. The yearly hydrogen production when the electrolyser can utilize up to 300 MW of electricity.

The LCOH for when the connection to the power grid allows for transmission of 700 MW is presented in Table 8. The lowest hydrogen cost is achieved for the 500 MW in combination with the one-day storage with a price of 61.02 SEK/kg H_2. This is indicating that the largest electrolyser cannot be fully utilized in this scenario. Hence, the 500 MW electrolyser would be the most cost-efficient option during these conditions.

Table 8. Shows the LCOH for when the electrolyser can utilize up to 300 MW of electricity.

Cable Connection: 400 kV, 700 MW			
Electrolyser size	**1 day storage**	**7 days storage**	**30 days storage**
1000 MW	65.00	101.16	228.82
500 MW	61.02	78.85	141.17
100 MW	84.91	92.19	114.48
5 MW	1 124.86	1 133.86	1 159.70

4.3.2 Scenario 2

The yearly hydrogen production for the different electrolyser sizes is shown in Figure 14 when the power grid connection is restricted to 300 MW of the available electricity. With more energy available for the hydrogen production the larger electrolysers are less inhibited, where the largest electrolyser is the electrolyser size that produces the most hydrogen.

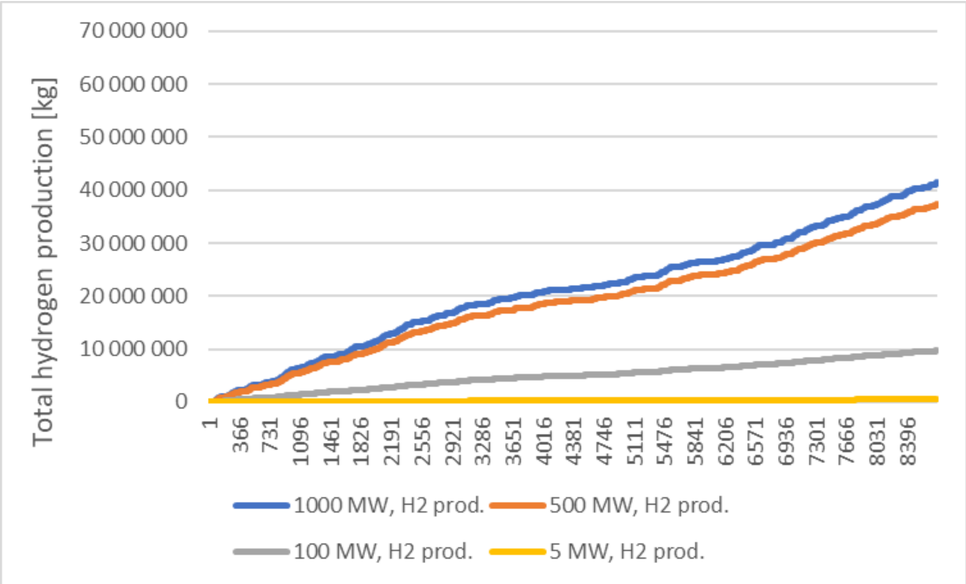

Figure 14. Shows the yearly hydrogen production when the electrolyser can at most utilize 700 MW of electricity.

When analysing the costs, the lowest LCOH is achieved for a smaller storage volume together with the larger sizes of electrolysers. The LCOH for all storages and electrolyser are presented in *Table 9*, where the lowest LCOH is 34.26 SEK/kg H_2. This changes for the larger storage volumes where the 500 MW electrolyser becomes the more cost-efficient option. Since the capital cost scales faster for the larger electrolyser.

Table 9. Shows the LCOH for when the electrolyser can at most utilize 700 MW of electricity.

Cable Connection: 400 kV, 300 MW			
Electrolyser size	**1 day storage**	**7 days storage**	**30 days storage**
1000 MW	34.26	42.88	73.28
500 MW	34.46	39.29	56.18
100 MW	58.44	62.68	75.64
5 MW	631.88	637.05	651.88

4.3.3 Scenario 3

In the third scenario when the grid connection is restricted to 170 MW of electricity at any moment the larger electrolysers produce the most hydrogen, which can be seen in Figure 15. The annual hydrogen production is similar to the production for case 1, see Figure 11.

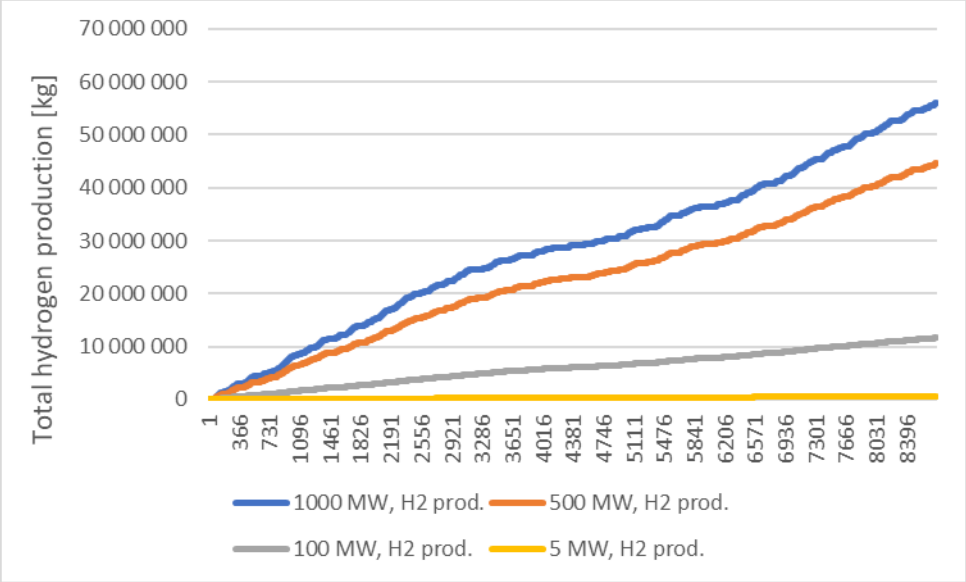

Figure 15. Shows the yearly hydrogen production when the electrolyser can at most utilize 830 MW of electricity.

The two lowest LCOH's are 27.20 and 27.31 SEK/kg H_2 with the one-day storage with the 1000 MW and 500 MW electrolyser respectively. These values are significantly lower than the previous scenario where the more expensive 400 kV cable was used, which can be seen by comparing the values found in Table 10 to the values in Table 9. Mainly due to that more hydrogen is being produced as more electricity is used for electricity in this scenario. Hence, lowering the LCOH.

Table 10. Shows the LCOH for when the electrolyser can at most utilize 900 MW of electricity.

Cable Connection: 130 kV, 170 MW			
Electrolyser size	**1 day storage**	**7 days storage**	**30 days storage**
1000 MW	27.31	33.67	56.11
500 MW	27.20	31.24	45.35
100 MW	30.93	34.45	45.24
5 MW	122.63	126.92	139.24

4.4 Sensitivity analysis

It is difficult to calculate a price for hydrogen in a futuristic scenario due to a large number of uncertainties in the variables used in the calculations. Hence a sensitivity analysis has been carried out according to Table 11, where the values used in the sensitivity analysis are presented. The sensitivity analysis has been made by calculating a new LCOH when specific parameters are changed. The new LCOH is then compared to the LCOH for case 1. The LCOH from case 1 will be called the base case throughout the sensitivity analysis. In addition, a brief motivation will be offered to the choices made for each variable to explain the reasoning behind the chosen values. The values for the sensitivity analysis are presented in Table 11.

Table 11. The values used in the sensitivity analysis.

	Base case	Sensitivity analysis, Low	Sensitivity analysis, High
Operational costs			
Electricity	***Year 2021***	Year 2018-2020	500 SEK/MWh
Wind speed	***Year 2021***	Year 2019-2021	
By-product related			
District heating price	***193 SEK/MWh*** ***98 SEK/MWh***	164 SEK/MWh 83.3 SEK/MWh	222 SEK/MWh 113 SEK/MWh
Investment related			
Electrolyser	***5 000 SEK/kW***	4 250 SEK/kW	5 750 SEK/kW
District heating	***18 000 000 SEK/km***	0 SEK	36 000 000 SEK/km
Storage	***Using calculated***	Using HYBRIT	-

4.4.1 Wind speeds

For the base case the wind data for year 2021 was used to give a more realistic indication of the hydrogen cost. However, this may not be representative of how the wind speeds for an average year will turn out. Hence the average wind speeds for years 2019 to 2021 was also used to calculate the LCOH. The result is shown in Table 12. The cost is lowered for the largest storage volume and for the other instances there is more variation, which is probable a consequence of the offset between wind speeds and spot prices.

Table 12. Change in LCOH expressed in percentage compared to the base case when an average wind speed for year 2019 to 2021 is used to calculate the LCOH.

Electrolyser size	1 day storage	7 days storage	30 days storage
1000 MW	8.8%	2.4%	-0.4%
500 MW	7.2%	1.3%	-3.0%
100 MW	2.8%	0.2%	-2.3%
5 MW	-1.5%	-1.6%	-2.3%

4.4.2 Electricity price

During 2021 the electricity price was highly volatile with exceptionally large price variation during the winter last quarter of the year. The hourly spot price in SE4 during 2021 can be seen in Figure 8. With more renewable power generation the spot prices are likely to stay volatile during the coming decades, but since this is not a given the average spot price in SE4 during

2018 to 2020 has been used to indicate what a less volatile market can do to the LCOH. The average price together with the hourly spot price for each year can be found in Figure 9. The change in percentage is presented in Table 13, where a significant change is achieved by switching the electricity price. The largest decrease in LCOH is seen for the 30-days storage, which indicates in an overall lower electricity price. Hence, proving that a low electricity price is an essential factor for keeping the cost for the hydrogen production low.

Table 13. Change in LCOH expressed in percentage compared to the base case when an average spot price for 2018-2020 is used to calculate the LCOH.

Electrolyser size	1 day storage	7 days storage	30 days storage
1000 MW	-28.9%	-45.1%	-85.6%
500 MW	-33.0%	-35.1%	-74.4%
100 MW	-38.3%	-25.3%	-42.8%
5 MW	-35.2%	-26.7%	-18.6%

For both case 1 and case 2 the cost of electricity is set to the corresponding hourly spot price on the day-head market. This is arguably not the most realistic way of determining the cost of running the electrolyser. Another option is to use a constant value of the levelized cost of electricity since the electricity is delivered from an offshore wind farm the cost of electricity was set to 500 SEK/MWh in Figure 14. The production pattern stayed the same in the calculation even though there are no hours that are more beneficial for production. The results in *Table 14* shows a small cost reduction for smaller storages and electrolyser sizes. While larger storages and electrolyser sizes shows an insignificant price increase.

Table 14. Change in LCOH expressed in percentage compared to the base case when the electricity is priced at 500 SEK/MWh.

Electrolyser size	1 day storage	7 days storage	30 days storage
1000 MW	-0.3%	2.8%	0.4%
500 MW	-5.4%	1.9%	0.5%
100 MW	-12.9%	-1.9%	0.1%
5 MW	-7.7%	-1.4%	-0.3%

4.4.3 Electrolyser cost

As mentioned in Section 2.8.1 there are multiple components which may influence the electrolyser price in the future and how these developments effect the price of the electrolysers in the future is difficult to predict. Hence a sensitivity analysis was conducted for variations in electrolyser costs, even though Figure 12 shows that the electrolyser cost is relatively small in comparison to the storage and electricity cost.

The LCOH was only barely affected by an 15% increase and decrease in electrolyser investment cost, which can be observed in Table 15. where a 15% increase and decrease of the electrolyser price was used to simulate the change in LCOH as a consequence of electrolyser costs. The change in LCOH due to electrolyser price fluctuations is relatively small- The largest change in LCOH is for the 1000 MW electrolyser with one-day storage where the change in LCOH is 0.0023 SEK/kg H_2, which is a percental change less than 0.01%. The small change in LCOH due to electrolyser price indicates that the electrolyser cost will not be a major risk factor for uncertainty. The results are expected when regarding the share that the electrolyser makes up of the total LCOH.

Table 15. The change in LCOH with a 15% increase or decrease in electrolyser costs compared to the base case.

Electrolyser size	1-day storage	7-days storage	30-days storage
1000 MW	(+-) < 1%	(+-) < 1%	(+-) < 1%
500 MW	(+-) < 1%	(+-) < 1%	(+-) < 1%
100 MW	(+-) < 1%	(+-) < 1%	(+-) < 1%
5 MW	(+-) < 1%	(+-) < 1%	(+-) < 1%

4.4.4 Storage costs

One of the largest cost components is the LCR storage, which heightens the necessity to get accurate costs for storage. However, there is a lack of existing large scale hydrogen storages in Sweden and relatively few relevant sources about the costs for large scale hydrogen storage in general. This makes it difficult to estimate the storage costs with a satisfying confidence. In addition, the design and capacity of the LCR storage relies heavily on the existing geological conditions. Hence, it may be possible to increase the pressure within the storage and thereby reducing the cavern volume which in turn also lowers the costs. However, the opposite reasoning with lower operation pressure and increased costs may also be true.

One existing LCR storage in Sweden is the one which has been built in the HYBRIT project. The volume of this storage is 100 m^3 with an operating pressure of up to 250 bars, which allows it to store around 100 000 – 120 000 m^3 of hydrogen. The total costs of the hydrogen storage were roughly 250 million SEK. The sensitivity analysis was carried out by using the same cost per unit storage as the HYBRIT storage, e.g. 250 MSEK/100 000 m^3 = 2 500 SEK/m^3, this factor was then multiplied with the need for hydrogen storage for each case. The result can be seen in Table 16. The LCOH is lowered for almost all scenarios and significantly lowered for the larger storage volumes. However, it should be noted that the cost per cubic meter scales linearly and is likely to a poor estimate for the larger storage volumes.

Table 16. The LCOH when storage costs for the HYBRIT project is used.

Electrolyser size	**1-day storage** **[**SEK/kg H_2**]**	**7-days storage** **[**SEK/kg H_2**]**	**30-days storage** **[**SEK/kg H_2**]**
1000 MW	25.76	26.83	37.35
500 MW	27.00	26.84	34.54
100 MW	29.45	27.82	33.72
5 MW	30.19	28.01	33.62

The change in percentage between the base case and when using the 2 500 SEK/m^3 is presented in Table 17. The storage cost has a large impact on the final LCOH, which is expected since the storage cost is a large fraction of the overall LCOH. Hence, any change in the storage cost will have a relatively large impact on the LCOH. The significant difference in LCOH between the basecase and the HYBRIT factor is likely due to the error which occurs due to linear scaling of the HYBRIT storage cost.

Table 17. The change in percentage in the LCOH with HYBRIT storage costs.

Electrolyser size	**1-day storage**	**7-days storage**	**30-days storage**
1000 MW	0.4%	-44.9%	-90.6%
500 MW	0.8%	-27.0%	-80.5%
100 MW	-2.3%	-11.5%	-51.4%
5 MW	-43.7%	-49.8%	-54.2%

4.4.5 District heating price

The sales of excess heat help reducing the LCOH and for the 1-day storage it reduces the LCOH by two to five percent. The financial compensation for the excess heat was set in conversation with Trelleborgs Energi and at the time of the conversation they had no external producer of excess heat connected to the grid. Hence, the heat prices that has been used for the excess heat are a rough estimate of what Trelleborgs Energi thought would be fair compensation and is likely to smaller changes if a real deal would be made with an energy producer. To showcase how a change in financial compensation may affect the LCOH a 15% increase and decrease was applied to both components in the excess heat price. The change in LCOH can be seen in Table 18, where all increases in LCOH is due to a 15% decrease in the economical compensation and the reduction is due to an increase in compensation. Overall, there is no significant impact on the LCOH from a 15% change in excess heating price. The reason for this is probably due to the fact that financial gains from selling the excess heat is relatively small compared to other cost drivers.

Table 18. The change in LCOH for a 15% increase and decrease in income from excess heat.

Electrolyser size	1-day storage	7-days storage	30-days storage
1000 MW	(+-) 0.7%	(+-) 0.3%	(+-) 0.0%
500 MW	(+-) 0.7%	(+-) 0.5%	(+-) 0.1%
100 MW	(+-) 0.6%	(+-) 0.6%	(+-) 0.2%

4.4.6 District heating investment cost

To sell the generated excess heat there is a need for a suitable district heating grind in the vicinity of the location for the electrolyser. Without the possibility to connect to a local grid the excess heat is discarded without bringing any additional income stream contributing to a lower LCOH. It would also mean that the need for investing in connecting pipes and heat exchangers disappears and hence lowers the investment cost. Table 19 shows the percental change in LCOH for case 1 when the there is no connection to a district heating network and with no financial gains from the sale of excess heat, where the 5 MW electrolyser is excluded since it does not have a connection to a district heating grid in its base case. Without the sale of excess heat the LCOH for all electrolyser increases.

Table 19. Change in percentage for LCOH when the excess heat is vented.

Electrolyser size	1-day storage	7-days storage	30-days storage
1000 MW	4.5%	2.1%	0.2%
500 MW	4.2%	2.8%	0.5%
100 MW	2.5%	2.3%	0.9%

The current praxis is that Trelleborg Energi shares half of the investment costs when a new facility is offering to sell its excess heat. In the base case the investment for a connecting pipeline between the electrolyser and the district heating grid is halved due to this fact. In Table 20 the percental change in LCOH when the hydrogen project carries all investment cost for the connection to the district heating grid is presented. The larger the electrolyser is the less of an impact this has on the LCOH and at most this increases the LCOH by around 2%

Table 20. Increase of LCOH expressed in percentage when all investment costs for the connection to the district heating is carried by the project.

Electrolyser size	1-day storage	7-days storage	30-days storage
1000 MW	0.5%	0.2%	0.0%
500 MW	0.6%	0.4%	0.1%
100 MW	2.1%	1.8%	0.7%

5. Discussion

In the following chapter a discussion about the results from the calculations is presented together with discussions about important aspects of green hydrogen production. The focus will be on a discussion of how the calculated LCOH corresponds to the price targets set by actors on the market, how the costs of components are believed to develop, the importance of the by-products, how the business case has been set up and potential alternatives. Lastly, there is a general discussion about what to consider when moving forward with similar projects.

5.1 LCOH from case 1 and case 2

When hydrogen is produced during the lowest electricity prices on the day-ahead market with a capacity factor of 50% the LCOH from case 1 indicates that it is possible to achieve a LCOH ranging from 25.7 SEK/kg H_2 to 53.6 SEK/kg H_2 for the smallest storage volume. The 7-days storage provided a LCOH that ranged from 31.4 SEK/kg H_2 to 55.8 SEK/kg H_2. The largest storage resulted in a LCOH between 69.4 SEK/kg H_2 and 398.9 SEK/kg H_2. The main conclusion from case 1 is that being able to choose between an improved range of spot prices does not compensate for the additional costs for an increased hydrogen storage volume. Hence, the design of a hydrogen plant with the intention to minimize the LCOH the storage should be kept as small as possible.

Case 2 analysed how the LCOH is affected by limitations in the power grid and showed that when with increased amounts of the available electricity from the wind farm being sold directly to the power grid the LCOH increases for all sizes of electrolysers.

5.2 LCOH compared to price targets

The hydrogen price from case 1 indicates that it may be possible to produce hydrogen to a LCOH of around 26 SEK/kg H_2 in the best case with the used project setup. The production cost for the analysed hydrogen project is high when comparing the costs to the price targets set by NEL Hydrogen, IEA and IRENA, where the goal is somewhere between around 10 – 20 SEK/kg H_2. When the price targets have been calculated the electricity price is usually lower than what has been used during the LCOH calculations. The electricity prices for the price targets are typically set to somewhere around 200 SEK/MWh to 400 SEK/MWh, meanwhile the average spot price during 2021 was roughly 820 SEK/MWh. Another important cost component is the hydrogen storage, which often differs between cost estimations due to pre-existing conditions and the need for storage. Further, the discount rate used in the analysed cases is somewhat exaggerated in comparison to most other cost estimations. This further complicates the comparison with previous cost estimations and price targets.

5.3 Expected trend in costs

With large scale green hydrogen production currently being early in its' development and implementation the production costs are expected to decrease drastically in the future compared to today's levels. How great the price reduction will be is however as with everything happening in the future impossible to predict. As mentioned earlier in section 2.8.1 the costs of electrolysers are expected to decrease in the future due to improved materials in the electrodes and diaphragms, larger stack sizes and gained experience. It is likely that costs for other hydrogen components such as the LCR storage will also show a reduction in costs with gained experience and technical development in the future. It should be noted that this is the current trend with several policies in place to speed up the development of hydrogen solutions and the focus of politicians can shift in the future.

5.4 Business case setup

One essential factor when calculating the cost of hydrogen production is the business case setup and how the system boarders are drawn. For instance, depending on the design and the choice of determining factors two otherwise similar hydrogen plants may differ in which scenarios it is economically beneficial to produce hydrogen. As an example, for case 1 the determining factor for when hydrogen production is desired is when the electricity price is at its' lowest, but the electrolyser could just as well be set to produce hydrogen when there is enough electricity to power the electrolyser. Both these design choices make sense for the system, but naturally the LCOH will be different. How to choose the determining factors for when to produce hydrogen can be difficult to establish.

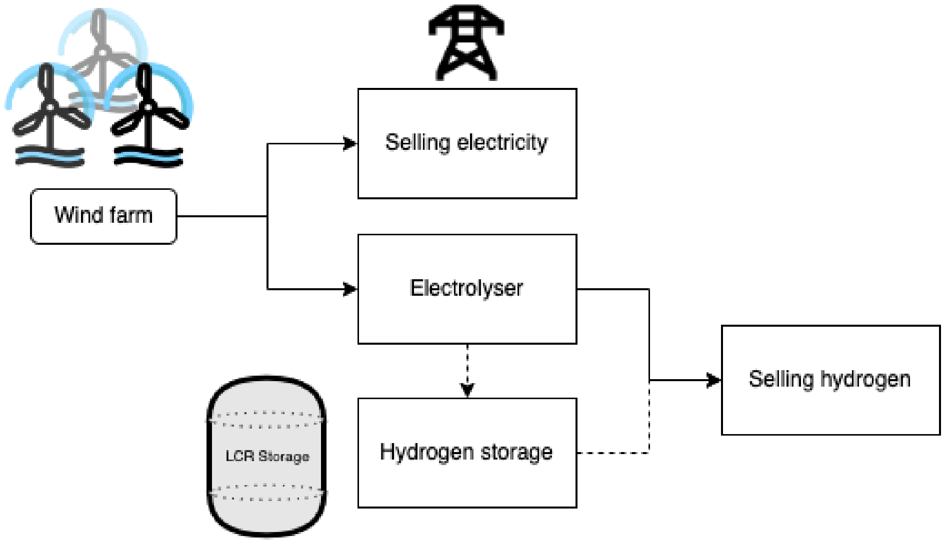

Figure 16. Illustrates a basic summary of the business case.

For green hydrogen production one critical issue is how to weight between producing hydrogen or selling the electricity directly to the grid. One way to approach the problem is to view electricity and hydrogen as two potential products and let the profitability at each time interval determine which one of these to produce and sell. With the starting point in the sketch in Figure 16 the logic was explained as follows. How to determine if either electricity or hydrogen should be the end-product was done by comparing the hydrogen price to the electricity price times the efficiency of the electrolyser as presented in Equation 13 below. If the hydrogen price is greater than the electricity price times the efficiency of the electrolyser then producing hydrogen is preferred over selling the electricity. The opposite is true if the hydrogen price is lower than the electricity price times the efficiency of the electrolyser.

$$If \begin{cases} H_2\ price > power\ price \cdot \eta_{electrolyser} & \rightarrow Sell\ hydrogen \\ H_2\ price < power\ price \cdot \eta_{electrolyser} & \rightarrow Sell\ electricity \end{cases} \quad (13)$$

The complexity of the decision can be increased further by introducing storages for either or both the electricity and the hydrogen. This would introduce the option of selling each energy carrier at a later time if there is a possibility of a more beneficial price in the future. The option to store either electricity or hydrogen opens up interesting possibilities when choosing the determining factors for the business case. Both the electricity and hydrogen can be sold either on an energy market dependent on demand and supply or be covered in a power purchase agreement (PPA), where the energy is sold at a set price. Hence, a business case in which all these parameters are weighted against each other would quickly become both complex and interesting.

5.5 Importance of by-products

For case 1 the sales of excess heat reduced the LCOH with at most 0.30 SEK/kg H_2. This corresponds to a less than a 1% cost reduction of the total LCOH. The 0.30 SEK/kg H_2 reduction was for the 100 MW electrolyser and for larger electrolysers the cost reduction from sales of excess heat was even less.

In a discussion with Trelleborgs Energy about the by-products they stated that it is difficult to find a financial value in the oxygen gas that is produced as a by-product from the electrolysis. This is mainly due to the that the oxygen market was already regarded as saturated. Further, an oxygen provider usually must achieve a certain quality standard for the produced oxygen, which further complicates the sales of the oxygen. Trelleborgs energy did however express interest in utilizing the produced oxygen in other processes that are important for the municipally of Trelleborg without gaining any economic benefit for the oxygen. One of the mentioned processes was to utilize the oxygen in the district heating power plant to achieve a cleaner combustion process and at the same time improve the conditions for CCUS with a higher concentration of CO_2 in the flue gases. Another potential use of the large excess of oxygen would be to use it in the wastewater treatment plant, where oxygen is used to keep an optimal climate for bacteria and microbes that break down contaminants in the water.

The economic benefits from the by-products are not essential for the hydrogen cost. However, the sale of excess heat helps reducing the cost and the oxygen shows potential to be become important for other processes. As it currently stands the impact of the by-products are not significant for the profitability of the hydrogen project, but this could change if the economic value of the oxygen was increased in the future.

5.6 Uncertainties

The sensitivity analysis shows there are variables that greatly impacts the LCOH and most of these variables can be argued to have a relatively high uncertainty. Two examples are the electricity prices and the storage costs, which are the two dominant cost components. Starting with the electricity price. It is difficult to predict how the price on electricity will develop up until 2030. The common belief is that more intermittent power production is likely to bring a higher volatility to the electricity prices. Meaning that price spikes in the spot prices will be more abundant. This was the main reason to why the electricity prices for 2021 was used in the simulations since it contained a relatively volatile electricity price compared to the years before. It is however not a given that the power market will become more volatile since the market is greatly affected by several factors, where e.g., new political directives could move the market in another direction and providing a more stable electricity price. It is not a given that the electricity cost will stay in the present price range, which has been shown during the current year with spot prices reaching seasonal records in SE4.

The sensitivity analysis also shows that the hydrogen storage impacts the LCOH greatly and when the cost factor for the HYBRIT project was used it gave a substantial decrease in the LCOH. It is difficult to determine if the HYBRIT value is more accurate than the formula used to calculate the cost of the LRC storage used in the simulations. On one hand it is based on a real project but it is constructed in a relatively small scale. Further, the values for the HYBRIT storage are based on an operating pressure of 250 bar. It is probably not possible to construct a LRC storage that can handle operating pressures in that range for the analysed project due to the geological conditions in southern part of Sweden. The great decrease in storage costs compared to the base case indicates that it is necessary further investigate the storage costs to eliminate this uncertainty if a similar project is to be realized in the future.

Lastly, it is necessary to mention that the model used to describe the processes in the electrolyser is only good for rough estimates. Hence, for a more comprehensive understanding of how the hydrogen production act during different conditions a more detailed model must be used. The result from the calculations can at best be seen as rough estimates.

5.7 Further studies

The calculations made in this report are rough estimates of both costs and the mass transports. Hence more detailed and site-specific studies are needed to determine the overall profitability of a similar project. Due to the time limitation certain areas and topics has only been touched briefly in this report but these would still be interesting to investigate further. Some examples are how exaggerated price spikes on the spot market would affect the LCOH to simulate a more volatile electrical market. It would also be interesting to analyse how the hydrogen cost would be affected when it is carrying all costs of the wind farm and then also can include the sales of the electricity from the wind farm. The last example could also be combined with batteries or other types of storages to try to investigate how the ability to storage energy can be used to gain advantages when selling the hydrogen.

6. Conclusions

The interest in green hydrogen is currently massive and the general conclusion from the report is that the cost estimations show that hydrogen in a best-case scenario can be produced to a cost of around 26 SEK/H_2 with a capacity factor of 50%. The storage costs together with the electricity price are the two dominating cost drivers for the LCOH. In general, the hydrogen storage should be kept as small as possible to reduce costs. The sales of by-products are not essential for the overall profitability of the hydrogen plant, but both the excess heat and the oxygen can be used to increase the sustainability in other sectors. Lastly, given the setup used in the two cases it is unlikely to achieve a hydrogen cost in the same range as the targeted hydrogen prices for 2030.

References

Andersson, J., & Grönkvist, S. (2019). Large-scale storage of hydrogen. *International Journal of Hydrogen Energy, 44*(23), 11901-11919.

Broberg, S., Backlund, S., Karlsson, M., & Thollander, P. (2012). Industrial excess heat deliveries to Swedish. *Energy Polcy, 51*, 332-339. doi:https://doi.org/10.1016/j.enpol.2012.08.031

Caldera, U., & Breyer, C. (2017). Learning Curve for Seawater Reverse Osmosis Desalination Plants: Capital Cost Trend of the Past, Present, and Future. *Water Resource Research*, 10523-10538. doi:https://doi.org/10.1002/2017WR021402

Carmo, M., Fritz, D. L., Mergel, J., & Detlef Stolten. (2013). *A comprehensive review on PEM water electrolysis.* International Journal of Hydrogen Energy, Volume 38, Issue 12.

DNV. (2021). *ENERGY TRANSITION OUTLOOK 2021 - A global and regional forecast to 2050.*

EU. (2020). *A hydrogen strategy for a climate-neutral Europe.* Brussels: European commission. Retrieved from EU hydrogen policy Hydrogen as an energy carrier for a climate-neutral economy: https://www.europarl.europa.eu/RegData/etudes/BRIE/2021/689332/EPRS_BRI(2021)689332_EN.pdf

European Comission. (2020). *COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS - A hydrogen strategy for a climate-neutral Europe.* Brussels: European Union. Retrieved from https://op.europa.eu/en/publication-detail/-/publication/5602f358-c136-11ea-b3a4-01aa75ed71a1/language-en

FuelCellsWork. (2021). *SSAB, LKAB and Vattenfall started building a rock cavern storage facility for storing hydrogen.* Retrieved 05 14, 2022, from https://fuelcellsworks.com/news/ssab-lkab-and-vattenfall-started-building-a-rock-cavern-storage-facility-for-storing-hydrogen/

Grigoriev, S., Fateev, V., & Millet, P. (2020). Current status, research trends, and challenges in water electrolysis science and technology. *International Journal of Hydrogen Energy, 45*(49). doi:https://doi.org/10.1016/j.ijhydene.2020.03.109

Hansson, J., Hackl, R., Taljegard, M., Brynolf, S., & Grahn, M. (2017). The Potential for Electrofuels Production in Sweden Utilizing Fossil and Biogenic CO2 Point Sources. *Frontiers in Energy Research , 5* . Retrieved from https://doi.org/10.3389/fenrg.2017.00004

Hydrogen Europe. (2021). *COP26 Special Hydrogen Report.* Retrieved from https://hydrogeneurope.eu/wp-content/uploads/2021/11/HE_Hydrogen_Report_2021_FINAL.pdf

IEA. (2019a). *Offshore Wind Outlook 2019.* International Energy Agency.

IEA. (2019b). *The Future of Hydrogen Report: Seizing today's opportunities.* International Energy Agency. Retrieved from https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf

IEA. (2021). *Global Hydrogen Review 2021.* International Energy Agency. Retrieved from https://iea.blob.core.windows.net/assets/5bd46d7b-906a-4429-abda-e9c507a62341/GlobalHydrogenReview2021.pdf

IPCC. (2022). *Climate Change 2022, Mitigation of Climate Change.* Intergovermental Panel on Climate Change. Retrieved from https://report.ipcc.ch/ar6wg3/pdf/IPCC_AR6_WGIII_FinalDraft_FullReport.pdf

IRENA. (2018). *HYDROGEN FROM RENEWABLE POWER TECHNOLOGY OUTLOOK FOR THE ENERGY TRANSITION.* Retrieved from https://www.irena.org/-/media/files/irena/agency/publication/2018/sep/irena_hydrogen_from_renewable_power_2018.pdf

IRENA. (2020). *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal.* Abu Dhabi: International Renewable Energy Agency.

IRENA. (2021). *MAKING THE BREAKTHROUGH Green hydrogen policies and technology costs.* Abu Dahbi: International Renewable Energy Agency. Retrieved from https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_Hydrogen_breakthrough_2021.pdf?la=en&hash=40FA5B8AD7AB1666EECBDE30EF458C45EE5A0AA6#:~:text=The%20electrolyser%20investment%20cost%20for,Based%20on%20IRENA%20analysis.

Johansson, F., Spross, J., Damaceno, D., Johansson, J., & Stille, H. (2018). *Investigation of research needs regarding the storage of hydrogen gas in lined rock caverns. Prestudy for Work Package 2.3 in HYBRIT Research Program 1.* School of Architecture and the Built Environment , Department of Civil and Architectural Engineering. Stockholm: KTH Royal Institute of Technology.

Johansson, J., Tengborg, P., & Durup, J. (2014). *Storage of highly compressed gases in underground Lined Rock Caverns – More than 10 years of experience.*

Lazard. (2021). *LAZARD'S LEVELIZED COST OF HYDROGEN ANALYSIS.* Lazard. Retrieved from https://www.lazard.com/media/451779/lazards-levelized-cost-of-hydrogen-analysis-vf.pdf

Naturvårdsverket. (u.å.). *Inrikes transporter, utsläpp av växthusgaser*. Retrieved 03 15, 2022, from https://www.naturvardsverket.se/data-och-statistik/klimat/vaxthusgaser-utslapp-fran-inrikes-transporter/#:~:text=Stor%20utsl%C3%A4ppsminskning%20fr%C3%A5n%20personbilar%20under,9%2C4%20miljoner%20ton%202020.

NEL. (2021, 01 21). *Nel CMD 2021: Launches 1.5 USD/kg target for green renewable hydrogen to outcompete fossil alternatives*. Retrieved 03 15, 2022, from https://nelhydrogen.com/press-release/nel-cmd-2021-launches-1-5-usd-kg-target-for-green-renewable-hydrogen-to-outcompete-fossil-alternatives/

Noordende, H., & Ripson, P. (2020). *Public report Gigawatt green hydrogen plant.* Amersfoort: Institute for Sustainable Process Technology. Retrieved from https://ispt.eu/media/Public-report-gigawatt-advanced-green-electrolyser-design.pdf

Nordic Energy Research. (2022). *Hydrogen, electrofuels, CCU and CCS in a Nordic context.* Retrieved from http://norden.diva-portal.org/smash/get/diva2:1635032/FULLTEXT01.pdf

SEA. (2021). *Förslag till Sveriges nationella strategi för vätgas, elektrobränslen och ammoniak.* Bromma: Swedish Energy Agency. Retrieved 03 01, 2022, from https://www.energimyndigheten.se/remissvar-och-uppdrag/

Svenska Kraftnät. (2022, 07 10). *Anslutning till transmissionsnätet*. Retrieved from https://www.svk.se/om-kraftsystemet/om-systemansvaret/verktyg-for-systemdrift/anslutning-till-transmissionsnatet/

SVK. (2017). *UNDERLAG FÖR SAMRÅD FÖR BEFINTLIG 22O KV-LEDNING.* Sundbyberg: Svenska kraftnät.

SVK. (2021). *Transmissionsnätstariffen*. (Svenska Kraftnät) Retrieved 08 22, 2022, from https://www.svk.se/aktorsportalen/anslut-till-transmissionsnatet/transmissionsnatstariffen/

Trelleborgs Energi. (2022). (P. Håkansson, Interviewer)

Trelleborgs Energi. (2022, 03 11).

U.S. Department of Energy. (2021, 06 07). *Secretary Granholm Launches Hydrogen Energy Earthshot to Accelerate Breakthroughs Toward a Net-Zero Economy*. Retrieved from Department of Energy: https://www.energy.gov/articles/secretary-granholm-launches-hydrogen-energy-earthshot-accelerate-breakthroughs-toward-net

Vattenfall. (u.å). *HYBRIT: A unique hydrogen storage facility in Luleå is taking shape*. Retrieved from https://group.vattenfall.com/press-and-media/newsroom/2022/hybrit-a-unique-hydrogen-storage-facility-in-lulea-is-taking-shape?_t_id=zlPIiBBqfnEM_tAzDzj3Tg%3d%3d&_t_uuid=ncraLkDMRHmDfsqjOYBzJg&_t_q=hybrit&_t_tags=language%3aen%2csiteid%3aec6448d4-f3c8-47b9

Vestas. (2022). *Vestas Offshore portfolio*. Retrieved 04 07, 2022, from https://nozebra.ipapercms.dk/Vestas/Communication/Productbrochure/OffshoreProductBrochure/v236-150-mw-brochure/?page=6

Zandén Kjellén, P. (2021). *Hydrogen and heavy trucks in Gävleborg.* Gävle: Faculty of Engineering and Sustainable Development Department of Building Engineering, Energy Systems and Sustainability Science.

Züttel, A. (2004). *Hydrogen storage methods* (Vol. 91). Naturwissenschaften.

Appendix

A1 – Variables used in case 1 & 2

Table 21. The values used in the calculations for case 1 and case 2.

Water related		
Water consumption	9.00	**litre/kg H_2**
LCOW	7.4	**SEK/(m^3)**
Oxygen related		
Production oxygen	8.00	**kg O_2/kg H_2**
Density	1.33	**kg O_2/m^3**
Price (oxygen)	0.00	**SEK/kg O_2**
District heating related		
Price (high) nov-mar	193	**SEK/MWh_{th}**
Price (low) apr-okt	98	**SEK/MWh_{th}**
District heating connection_inv	18 000 000	**SEK/km**
District heating maximum capacity	20	**MW**
Electricity to H2		
Efficiency	98%	**-**
Conversion electricity to H_2	50.06	**kWh/kg H_2**
Wind turbines		
Number of turbines	66.00	**nbr**
Installed capacity	15.00	**MW**
Power coefficient (Cp)	0.40	**-**
Cut-in Speed	3.00	**m/s**
Cut-out Speed	30.00	**m/s**
Rated speed	10.83	**m/s**
Hydrogen related		
Density	0.0899	**kg/m^3**
Storage related		
Length connection tunnel	200	**m**
Ratio: Working gas Vs. Cushion gas	90%	**-**
Pressure	30	**bar**
Electrolyser related		
Price_electrolyser_inv	5 000	**SEK/kW**
Lifetime	50 000	**h**
Distances related		
Distric heating	3.00	**km**
Cable to wind park	22.00	**km**
Cable to backbone grid	20.00	**km**
Grid connection related		
400kV	9 131 341	**SEK/km**
400kV	136 970 114	**SEK/km**
130kV	1 480 455	**SEK/km**
130kV (at sea)	22 206 828	**SEK/km**