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Hydrogen Hybrid Systems: Bridging the gap between grid capacity and electricity generation

A northern Sweden case study for 2030

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Thesis for the degree of Master of Science in Engineering

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MASTER THESIS

Hydrogen Hybrid Systems: Bridging the gap between grid capacity and electricity generation

A northern Sweden case study for 2030

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Abstract

The expected increase in both consumption and production of electricity strains the Swedish electricity grid, necessitating both reinforcement and expansion. Concurrently, the need to decarbonise heavy industry is becoming more urgent to achieve the EU Climate neutrality goal by 2050, with hydrogen anticipated as a key player. Hybrid energy systems that combine the generation of renewable electricity with green hydrogen production can be an asset when the grid capacity is limited. Its demand in Sweden is driven by the green transition of the steel industry in the north, where RWE, a multinational energy company, is looking at opportunities in offshore wind power. The case study aims to evaluate the business case of a hybrid energy system projected for 2030, that combines the generation of electricity from an offshore wind power plant off the coast of Piteå, with the onshore production of green hydrogen using a PEM electrolyser in Luleå. The effects of varying the available grid capacity are studied in a scenario analysis using the Levelised Cost of Hydrogen (LCOH) as the decisive parameter. The study also aims to determine the effects of integrating a waste heat recovery system, repurposing excess heat into a district heating network. In addition, it also aims to identify the most influential model variables through a cost breakdown and sensitivity analysis. Finally, by accounting for the results and insights gathered from a literature review and through discussions with industry professionals, conclusions concerning the applicability of the results and the competitiveness of the green hydrogen produced is assessed.

The scenario analysis investigates four electrolyser system sizes, based on different available grid capacities. The results suggest that the production of green hydrogen is an economy of scale, with the LCOH ranging from 58 to 68 SEK/kg H_2, for electrolyser peak capacities of 1 060 MW and 560 MW respectively. Each of the four system sizes investigated benefit from a waste heat recovery system, resulting in a 3-4% lower LCOH. The cost breakdown revealed that the electricity from the WPP had the largest contribution to the total costs, accounting for 67-71%, depending on the scenario. The CAPEX of the electrolyser system was the second-largest cost factor, contributing 16-20% to the total costs. To identify the parameters with the largest effect on the results, a sensitivity analysis was performed. Key influencers (in descending order) were LCOE, lifetimes of the electrolyser and the hybrid system, cost of equity, and the electrolyser system CAPEX. Through the sensitivity analysis subsidies and loans also proved to have a great impact on the LCOH. The applicability of the results is determined by four main factors that proved to play an important role when designing the system and constructing the model; the system design, the system scale, geographical location, and the company structure and ownership. The competitiveness in a future hydrogen market is difficult to determine due to uncertainties in factors such as the available hydrogen infrastructure, cost of electricity generation, and the structure of hydrogen agreements. However, despite the uncertainties and assumptions that have shaped the case study, the production of hydrogen from hybrid energy systems such as those studied show promising results with the expected increase in both heat and hydrogen demand in Luleå. Future research could expand the existing knowledge base by investigating different future scenarios and technology variations to understand how hybrid systems can become more cost and resource efficient, thereby strengthening their role in Sweden's future energy system.

Sammanfattning

Den svenska elkonsumtionen och elproduktionen förväntas öka drastiskt de närmsta åren. Detta ställer krav på elnätet som därmed behöver stärkas och byggas ut för att tillvarata den el som förväntas. Parallellt med detta behöver den gröna omställningen av industrisektorn påskydas om EU ska lyckas uppnå klimatmålen till 2050. För att dekarbonisera industriella processer kan grön vätgas användas. Genom att etablera hybridsystem som kombinerar produktion av förnybar elektricitet med grön vätgas kan flera nödvändiga systemnyttor uppnås; elnätet avlastas och el samt vätgas produceras.

RWE är ett multinationellt energiföretag, med särskilt fokus på vindkraft, som har insett möjligheterna för hybridsystem i norra Sverige. De undersöker möjligheterna för en havsbaserad vindkraftspark som skulle kunna kombineras med vätgasproduktion. Denna studie syftar till att utvärdera affärsmodellen för ett sådant hybridsystem. Hybrisystemet i studien planeras till 2030 med en vindkraftspark utanför Piteås kust och en landbaserad vätgasproduktion med PEM-elektrolys i Luleå. I en scenarioanalys undersöks effekterna av att variera den tillgängliga elnätkapaciteten genom att beräkna och använda LCOH som jämförande parameter. Studien syftar också till att fastställa effekterna av att tillvarata restvärme från elektrolysören för användning i ett fjärrvärmenät. Dessutom identifieras de mest betydelsefulla parametrarna genom en kostnadsuppdelning och känslighetsanalys. Slutligen utvärderas resultatets applicerbarhet och konkurrenskraft med stöd från tidigare forskning samt diskussioner med branschkunniga.

Baserat på olika storlekar på elnätsuppkoppling undersöktes i scenarioanalysen fyra storlekar på elektrolyssystem. Det resulterande värdet på LCOH varierarde mellan 58-68 SEK/kg H2 och visade på skalfördelar, med ökad elektrolysörstorlek minskade värdet på LCOH. Samtliga system nyttjade restvärmeåtervinning som sänkte värdet på LCOH med 3-4%. Utifrån kostnadsuppdelningen identifierades elektriciteten från vindkraftparken dessutom som parametern med störst påverkan på resultatet och stod för 67-71% av den totala kostnaden. Därefter följde CAPEX för elektrolyssystemet om utgjorde 16-20% av den totala kostnaden. Vidare utfördes en känslighetsanalys där resultatet var mest känsligt för förändringar av (i fallande ordning) LCOE, livslängd på elektrolysör och hybridsystem, kostnad för eget kapital och CAPEX för elektrolyssystemet. Lån och bidrag hade också stor påverkan på resultatet. Studiens applicerbarhet utvärderades sedan utifrån fyra faktorer; systemdesign, skalbarhet, geografisk placering och företags- samt ägandestruktur. På grund av osäkerheter kring exempelvis framtida vätgasinfrastruktur, kostnader för elproduktion och utformning av vätgasavtal var det svårt att bedöma resultatets konkurrenskraft.

Trots osäkerheter i studiens utformning och antaganden, visar det ökade behovet av värme och vätgas i Luleå på goda förutsättningar för etablering av hyrbidsystem i området. Fortsatt forskning kan dessutom bidra med ökad kunskap genom att exempelvis undersöka olika framtidsscenarier och tekniker. Detta ökar även förmågan att utforma kostnads- och resurseffektiva hybridsystem, vilka kan ha en betydande roll i Sveriges framtida energisystem.

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The report was written jointly by us, Edith Rosell and Sara Lomgren, Master of Science students in Environmental Engineering at LTH. The division of work has been evenly split and we both stand behind the content and conclusions of the study. For specific parts of the report, responsibility has been divided between us based on academic background and subject knowledge. One such example is in the background section where Edith, with more knowledge in process engineering, focused on hydrogen production, and Sara, with more knowledge about energy systems, focused on the Swedish power grid.

Moreover, we would like to extend our gratitude to our supervisor at LTH, Kerstin Sernhed, who helped us develop our initial idea into a feasible master thesis, and the assistant supervisor Martin Andersson, who widened our perspective on possible research areas. Also a big thank you to Hanna Henrikson, our supervisor at RWE, who supported us throughout the writing process and helped us get in touch with the right experts and industry professionals. A final thank you to all the colleagues at RWE, and all the other people we have been in touch with, who helped us with valuable advice and guidance.

Contents

List of Abbreviations

AEL	Alkaline Water Electrolysis
BWRO	Brackish Water Reverse Osmosis
CAPEX	Capital Expenditures
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
OPEX	Operational Expenditures
PEM	Proton Exchange Membrane
SWRO	Seawater Reverse Osmosis
SOEC	Solid Oxide Electrolyser Cell
TSO	Transmission System Operator
WHRS	Waste Heat Recovery System
WPP	Wind Power Plant

List of Symbols

Symbol	Name	Unit
α	Wind speed coefficient	-
γ	Ratio of specific heat under constant pressure to specific heat under constant volume of H_2	-
η_{deg}	Annual efficiency degradation of PEM electrolyser	%
η_{isen}	Isentropic efficiency of compressor	%
η_{HP}	Heat pump efficiency	%
η_{HR}	Technical heat recovery potential	%
η_{motor}	Efficiency of electrical motor for compressor	%
η_{system}	Efficiency of PEM electrolyser system	%
η_{WPP}	Overall wind power plant efficiency	%
ρ_{air}	Density of air	kg/m^3
ρ_{H2O}	Density of water	kg/m^3
A_E	Specific footprint of hydrogen plant	m^2/MW
A_{HEX}	Heat transfer area of heat exchanger	m^2
A_T	Swept area of wind turbine	m^2
COP_{Carnot}	Carnot efficiency	-
COP_{HP}	Coefficient of performance heat pump	-
Cp	Power coefficient of wind turbine	-
c_P	Specific heat capacity of water	$kJ/kg°C$
D	Consecutive days during which P_{min} is not covered	day
E_{BWRO}	Specific energy consumption of brackish water reverse osmosis unit	$kWh/kg\ H_2$
$E_{Compressor}$	Specific energy consumption of compressor	$kWh/kg\ H_2$
E_{PEM}	Specific energy consumption of PEM electrolyser	$kWh/kg\ H_2$
E_{HP}	Specific energy consumption heat pump	$kWh/kg\ H_2$
E_{HS}	Heat storage required	kWh
E_{WPP}	Annual electricity generation by wind power plant	kWh
FW_{PEM}	Specific feed water consumption of PEM electrolyser	$l/kg\ H_2$
H	Mass of hydrogen produced per hour	kg/h
H_{max}	Maximum daily hydrogen production	kg/day
k	Heat transfer coefficient of heat exchanger	$kW/m^2°C$
M_{H_2}	Molar mass flow of hydrogen	kg/mol

N	Number of compressor stages	-
$n_{turbines}$	Number of wind turbines in wind power plant	-
P	Hydrogen delivery pressure of electrolyser	bar
P_{aux}	Power to auxiliary components of electrolyser system	% of $P_{PEM_{peak}}$ and kW
$P_{average}$	Average pressure over compressor	bar
$P_{Compressor}$	Rated power of compressor	kW
P_{DH}	Heat rate to district heating	kW
$P_{DH_{max}}$	Maximum heat load to district heating	kW
P_{PEM}	Power used by electrolyser	kW
$P_{PEM_{peak}}$	Peak capacity of electrolyser	kW
P_{Grid}	Grid connection capacity	kW
P_H	Total heat demand of electrolyser facility	kW
P_{HD}	Specific heat demand of electrolyser facility	kW/m^2
P_{HP}	Heating capacity of heat pump	kW
P_{HP_E}	Electrical power input to heat pump	kW
$P_{HP_{MAX}}$	Maximum heating capacity of the heat pump	kW
$P_{PEM_{min}}$	Minimum load of electrolyser	% of $P_{PEM_{peak}}$
P_{out}	Output pressure of compressor	bar
P_T	Power generated by wind turbine	kW
P_{WH}	Waste heat rate from electrolyser	kW
P_{WPP}	Power produced by wind power plant	kW
q_M	Molar flow rate through compressor	mol/s
R	Ideal gas constant	J/mol K
$T_{average}$	Average temperature over compressor	K
T_{cond}	Condensing temperature of refrigerant in heat pump	°C
$T_{CW_{out}}$	Temperature of cooling water entering electrolyser	°C
$T_{CW_{in}}$	Temperature of cooling water leaving electrolyser	°C
$T_{DH_{return}}$	Return temperature of district heating water	°C
$T_{DH_{supply}}$	Supply temperature of district heating water	°C
T_{evap}	Evaporating temperature of refrigerant in heat pump	°C
T_{in}	Input temperature to compressor	K
T_{min}	Minimum temperature of circulating hot water	°C
T_{out}	Output temperature of compressor	K
$T_{Outdoor}$	Outdoor temperature	°C
U	Wind speed	m/s
V_{HST}	Volume of the hot water storage tank	m^3

W	Hourly volumetric water usage of the hydrogen plant	m^3/h
W_{H2}	Specific water requirement	kg/kg H_2
W_{max}	Max volumetric daily water usage of the hydrogen plant	m^3/day
Z	Compression factor of hydrogen gas	-
z	Height above ground level	m
z_r	Reference height above ground level	m
z_0	Surface roughness	m
x	Compressor ratio per stage	-

Chapter 1

INTRODUCTION

Electrification is projected to play a vital role to reach the European Union's (EU) goal of becoming the first climate neutral continent by 2050 [1] [2]. The global share of electricity in the final energy consumption is forecasted to increase from today's 20% to over 50% by 2050 according to the International Energy Agency's (IEA) Net Zero Emission Scenario (NZE). Solar photovoltaic and wind power are the two forms of renewable energy that are expected to see the largest growth in terms of electricity generation in the coming 5 years, accounting for 96% of future electricity installations [3]. Wind power plays an important role in Sweden's electricity mix, contributing to 25% of its electricity demand in 2022 [4]. In the future its contribution is expected to persist, and even grow, with several companies discussing larger offshore wind power installations. Historically, the onshore development of wind power in Sweden has evolved faster than offshore [5]. As of 2024, the total installed power onshore and offshore was 16 000 MW and 193 MW respectively [6], in which the offshore power is divided between two wind power plants (WPPs).

The Swedish electricity demand is expected to follow the global trend and more than double by 2045, increasing from the current 140 TWh to 330 TWh [7]. The increase in both consumption and production puts pressure on the electricity grid, which needs to be both strengthened and expanded. During the ongoing expansion of the grid, one alternative way to realise new establishments of wind power is through sector coupling using hybrid energy systems. These systems combine two or more energy generation or storage techniques; for example electricity generation from offshore wind power and hydrogen production. Hybrid systems can therefore facilitate the green transition of hard-to-abate sectors, including heavy industry [8].

Hydrogen has been identified as a promising alternative to fossil-based feedstocks, reducing agents, and fuels [9]. Today, hydrogen is mainly extracted from fossil fuels, however in order to decarbonise industries it must be produced from non-fossil sources. This is made possible using renewable electricity to split water into hydrogen and oxygen, in a process called electrolysis.

RWE Renewables Sweden AB (here on out will be referred to as RWE), has recognised the potential for hybrid energy systems in northern Sweden. The company realises the need for both increased electricity generation and hydrogen production to boost electrification and the green transition of the Swedish steel industry (located in Luleå). The following work is a case study inspired by RWE's interest in hybrid system establishments. The study is based on an offshore WPP located off the coast of Piteå, and an onshore hydrogen plant in Luleå. Through the study, the authors hope to convey the possibilities that arise with hybrid systems and the utilisation of hydrogen as an energy carrier. It is also uniquely investigating a large scale hydrogen plant located in a Nordic climate, adding a new perspective to previous research.

The aim of the case study is to evaluate the business case of a hybrid energy system, combining the production of green hydrogen through electrolysis and electricity generation from offshore wind power, in the Bothnian Bay. To asses the business case, a scenario analysis is performed in which the grid availability is varied between four discrete levels. The levelised cost of hydrogen (LCOH) will be used to evaluate the competitiveness of the hydrogen produced by such a system. Just like the levelised cost of electricity (LCOE) is used as an economic measure to asses the cost of generating energy over a project lifetime for e.g. a WPP, the LCOH can be used for hydrogen projects.

To fulfill the aim, the following research questions will be investigated:

- When altering the electricity supply from the WPP to the electrolyser system across multiple scenarios, what is the resulting LCOH?
- How does integrating a waste heat recovery system (WHRS), which repurposes excess heat into a district heating network, influence the LCOH of each scenario?
- By conducting a cost breakdown and sensitivity analysis, which parameters possess the greatest impact on the LCOH?
- Accounting for both the knowledge gained from a literature review and discussions with industry professionals, as well as insights gathered from this case study, what can be said about:
  - the competitiveness of the resulting LCOH on a future green hydrogen market?
  - the applicability of the case study results?

Chapter 2

BACKGROUND

The purpose of this chapter is to provide the necessary information needed to understand the design of the hybrid system and the scenarios of the case study. It starts with an introduction to wind power in Sweden and explains how the Swedish electricity grid is built up. Possibilities and challenges with new establishments of wind power in Sweden are also mentioned. The background then elaborates on how wind power can be coupled with hydrogen in a hybrid energy system. Further, hydrogen as an energy carrier is introduced, as well as its role in Sweden. Lastly, the background includes a short section on previous research and establishments of hydrogen plants of large scale.

2.1 WIND POWER IN SWEDEN

Sweden has seen a major upswing for wind power installations in recent decades; the development of installed power between 2003 and 2022 is shown in Figure 2.1. Onshore installations have clearly progressed faster and in greater magnitude compared to offshore installations.

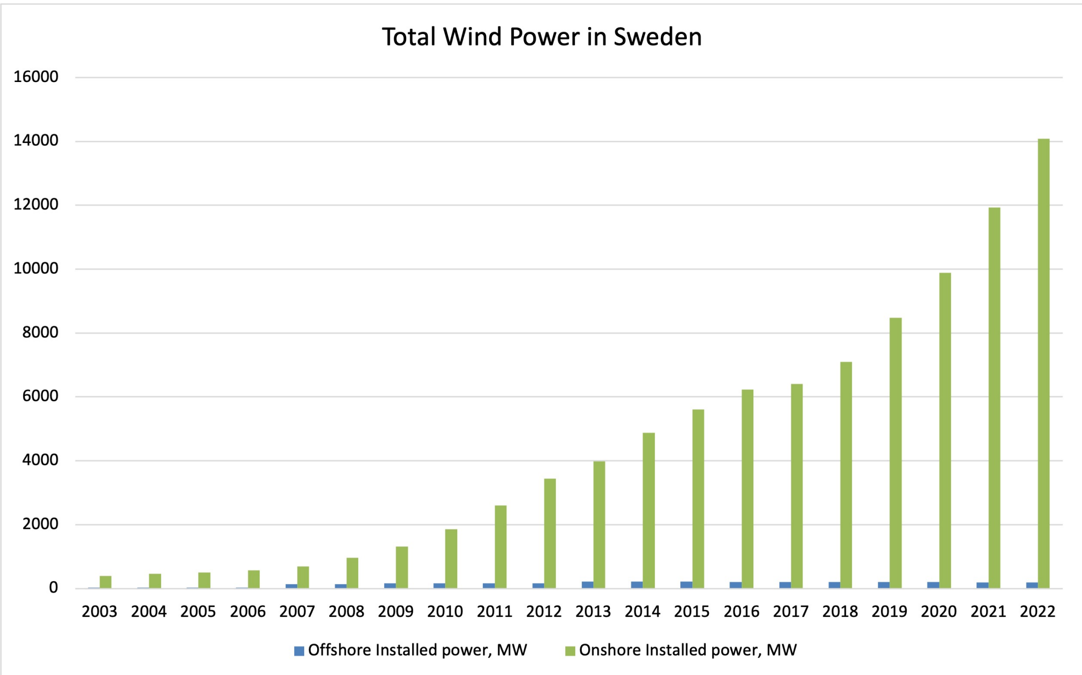

FIGURE 2.1: Historical development of wind power in Sweden, 2003-2022. Official Swedish statistics collected from The Swedish Energy Agency's database for statistics has been processed into the graph [5].

Even though the majority of the current wind power installations in Sweden are located onshore, Sweden has great potential to expand the offshore installations with its long coastline and good wind conditions. According to a study by the Swedish Wind Energy Association, the offshore wind power in Sweden could cover as much as 45% of the electricity demand in 2050 [10]. Further, the wind conditions at sea are generally better than on land, resulting in a higher and more evenly distributed electricity production [10]. Since there are less obstacles that limit the length of turbine blades at sea, larger and fewer turbines can be used to produce the same amount of electricity [10]. Compared to onshore there are also negative aspects of offshore wind power, some being the generally higher investment, transmission, distribution and maintenance costs, as well as tougher construction and maintenance environments. However, these costs have a downtrend and are expected to further decrease in the future [10].

One aspect many new WPP establishments have in common is the long and complex authorisation process, including the application for different permits. During the time period 2014-2019 32% of the authorisation requests (for both on- and offshore WPPs) were declined, however the distribution between them is unknown [11]. The most reoccurring reasons for declining the permits were: municipalities voting no, species protection legislation, and conflicting interests with the military or reindeer husbandry [11]. In Sweden the local municipalities have a veto right and the military force's opinion is always prioritised in these matters, making it hard to grant permits. The general public also have the right to express their opinion on building WPPs during the planning process and thereby affect the municipalities decision. Regarding the general public's opinion, it is commonly more positive for offshore installations since they can be located further away from urban areas and therefore seem less disturbing to the landscape.

A major challenge when establishing new WPPs in Sweden is the lack of available grid capacity, but to realise any projects there needs to be a receiver of the electricity generated. The WPP needs to either be connected to the electricity grid, requiring the necessary capacity to be available, or be an off-grid WPP, requiring an off-grid offtaker. How these possibilities look will be presented in the next section where an outlook of the Swedish electricity grid is covered.

2.2 The Swedish Electricity Grid

The Swedish electricity grid can be divided into three levels; the transmission grid, regional grid and local grid [12]. The transmission grid can be defined as the core of the electricity grid, reaching over the entire country and connecting the Swedish grid to international grids. Further, the regional and local grid could together be described as the Swedish distribution grid, responsible for the transportation of electricity from producer to end-consumer [12]. The regional grid is also the interconnection between the transmission and local grid. The local grid takes over after the regional grid, distributing electricity to end-consumers like households, companies, and public buildings [12]. The three grid levels all have different voltage levels, making them suitable for different consumers and producers. For large electricity producers and consumers like RWE, the transmission or regional grid are best suited [12].

The Swedish electricity grid is also partitioned into four geographical areas, called bidding zones. In Figure 2.2 the four zones are illustrated. Reaching from the north to the south of Sweden the bidding zones are called SE1, SE2, SE3 and SE4, all with different capacity, consumption and production. Historically and at present there is a power shortage in the southern parts of Sweden and an overproduction in the northern parts, resulting in a power flow from north to south [13]. With increased electricity production and demand in the future, there is a possibility that the direction of power flow will change. Due to lacking transmission capacity between the bidding zones, bottlenecks occur and energy prices differ [13]. Further, the surrounding sea is also partitioned into nine different marine capacity zones as illustrated in Figure 2.3.

FIGURE 2.2: Illustration of the four Swedish bidding zones, received through email contact with the Swedish TSO (Svenska Kraftnät).

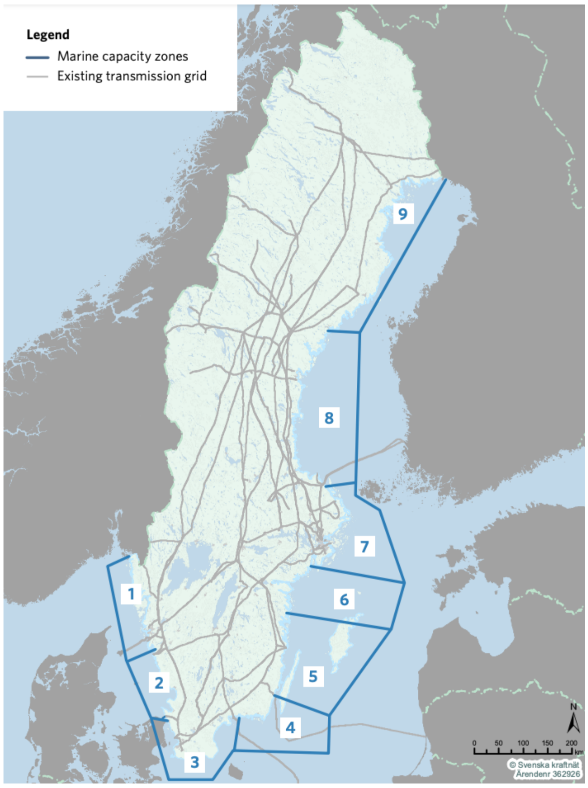

FIGURE 2.3: Illustration of the marine capacity zones in Sweden from the Swedish TSO (Svenska Kraftnät) [14].

To balance the Swedish electricity grid and overcome the bottlenecks, various measures have been implemented, and several more are planned. In 2021 the, at that time, current government assigned the Swedish Transmission System Operator (TSO) (Svenska Kraftnät) the task of providing the details of an expansion of the marine transmission grid in the Swedish economic zone, as well as the respective offshore connection points [15]. The plan was to fund such an investment with state money. However, with the most recent Swedish election, later in 2022, a new government was elected that did not share the same vision as the previous one. Through a new political agreement (Tidöavtalet), the current government presented that every offshore WPP owner had to finance their connecting costs themselves [15]. Thereby the TSO stopped its preliminary investigations for offshore grid expansions.

However, there is still an extensive expansion plan for the transmission grid onshore. For the purpose of this report, focus will be on the north most bidding zone SE1 (see Figure 2.4). SE1 has an excess of electricity production today, but the green transition of the industry as well as new establishments of industry are expected to increase the electricity demand [16]. The TSO believes that the transmission capacity to the area will have to increase as well as more electricity generation is needed for the future [16]. To meet these future demands the TSO has an ongoing project called "Fossilfritt Övre Norrland", which mainly constitutes of two large investment packages known as "Norrlandskusten" and "Malmfälten" [16]. The TSO also has projects to strengthen the transmission capacity to nearby countries, one being Aurora line between Sweden and Finland [12]. A third plan is to strengthen the transmission capacity towards Norway and between SE1 and SE2.

FIGURE 2.4: Illustration of the transmission grid projects in SE1, adapted from image by the Swedish TSO [17].

Regarding the current capacity for power input to the grid, it is already reserved by WPPs around Piteå and Skellefteå, leaving no room for new WPPs to connect to the transmission grid in its current state [16]. To meet the demand for more installed wind power, especially offshore, the TSO are aiming to set up an onshore connection point for marine capacity zone 9 in Luleå. The connection point is planned in conjunction with the grid package "Norrlandskusten" and will provide Luleå with another 1.4 GW available for offshore wind power, preliminary accessible in 2029 [15].

The current limitations on the transmission grid, along with increasing demand and projected power production, pose challenges when establishing a new WPP outside Piteå. Currently there is no room for an additional WPP to connect to the electricity grid. There are still insecurities regarding the possibilities to be connected even when Aurora Line, "Norrlandskusten", "Malmfälten" and the grid connection point in Luleå are operating. However, the TSO believes that with the increasing demand and the strengthening of the power lines the possibilities for more WPPs to connect will increase [16]. Still, it is not realistic to assume that a power input connection covering the entire installed capacity of a new WPP is to be granted, considering the competition for grid capacity between WPPs. Thereby only some of the produced power can be expected to be transmitted to the grid, leaving some power unused. A good solution to maximize the WPP's profitability and utilisation is to combine the electricity production with production of hydrogen, in a so called hybrid system.

2.3 HYDROGEN AS AN ENERGY CARRIER

Hydrogen is a clean, energy dense (by weight), and light weight energy carrier primarily used in the industrial sector as a feedstock for various chemical and refining processes. It is naturally occurring on Earth but not in its gaseous phase, and thereby needs to be extracted from other compounds to be utilised as hydrogen gas [18]. The three main extraction processes are reforming of natural gas, gasification of biomass, wood, and coal, and electrolysis of water [18]. For the past 200 years the main feedstocks for hydrogen extraction have been fossil based, dominated by natural gas or coal [9] [8]. If natural gas is the main feedstock the product is often called grey hydrogen, and if coal is the main feedstock it is often called either black or brown hydrogen [19]. The impending green energy transition has meant that the discussion around the production of low-emission hydrogen has become stronger and more common. Fossil hydrogen production combined with carbon capture, utilisation, and storage (CCUS) is included in the low-emission hydrogen category and is called blue hydrogen. However, the two main production routes of low-emission hydrogen are through extraction from biomass or electrolysis of water, where electrolysis of water is most common. The latter is often referred to as green hydrogen, and the former has recently been named turquoise hydrogen [19]. Figure 2.5 summarise the above mentioned colours of hydrogen.

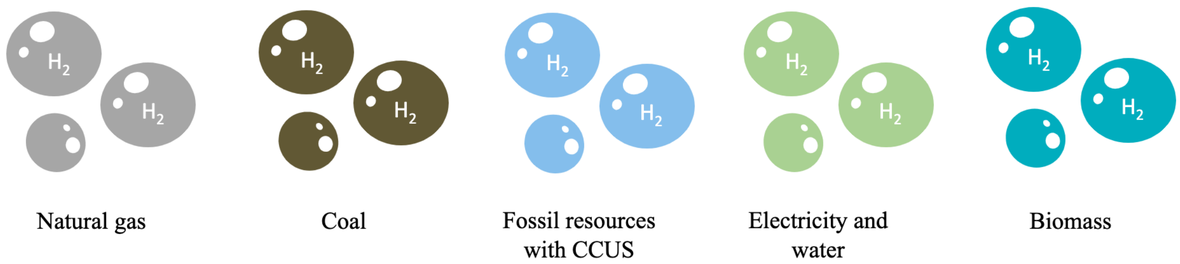

FIGURE 2.5: The different colours or hydrogen. Image by authors.

Despite the increasing interest in low-emission hydrogen it only accounted for around 1 Mt (0.7%) of the global hydrogen production in 2022 [9]. These circumstances provide great potential for improvement in increasing the sustainability of the hydrogen production processes. The IEA is counting on a large number of new projects in the future and believe the global annual production of low-emission hydrogen could reach 20 Mt in 2030 [9]. The drivers for the increasing demand vary between countries; the e-fuel sector is expected to drive the growth of demand in Denmark and Finland, whilst the steel industry will increase the Swedish demand for hydrogen [20]. Currently, the hydrogen production in the Nordics is almost exclusively fossil-based, but with the expected increase in domestic demand, cleaner production technologies will be a necessity in order to reach national and EU climate goals.

Offshore wind has been identified as the most viable renewable energy source for the production of green hydrogen in Northern Europe, in countries that cannot rely on abundant sun [21]. Since Sweden shows promising potential for wind power, but is limited by grid capacity, hydrogen production through electrolysis could be a strong player in Sweden's green energy transition.

2.3.1 ELECTROLYSIS

The electrolysis of water as a means to produce hydrogen and oxygen has been known for several generations, with the first recorded production of hydrogen through electrolysis in 1789 [22]. Over the past two decades it has emerged as a viable technology to produce emission-free, green hydrogen on an industrial scale. The process comprises a chemical reaction that involves the splitting of water molecules into hydrogen and oxygen gas, as shown in Reaction I, through the use of electricity from a renewable source. Anions will be oxidised at the anode (the positively charged electrode), and cations will be reduced at the cathode (the negatively charged electrode). There are several variations of the electrolysis of water, however the overall reaction remains the same and is given in Reaction 1.

$$2\,H_2O\,(l) \longrightarrow O_2\,(g) + 2\,H_2\,(g) \tag{1}$$

Reaction 1 requires an applied cell voltage of 1.23 V in order to produce hydrogen and oxygen gas at room temperature and 1 atm [23]. However, experimentally it has been found that the minimum cell voltage in order to overcome the ohmic resistance and kinetics of the cell components and electrolyte is 1.48 V [23]. Applying an over voltage is also necessary to increase the reaction rate to an acceptable speed [24]. However, this also means that the reaction becomes exothermic. Since the applied cell voltage is increased by at least 20%, a maximum of around 80% of the applied voltage goes towards hydrogen production. The remaining energy produces heat that needs to be removed in order to avoid overheating [24]. This can be achieved using a cooling circuit. Moreover, the waste heat can be reused to increase the system efficiency.

Since the technology is more than 200 years old, several electrolysis processes have been developed over the years, each different in terms of the electrolyte used. The electrolyte is the medium through which the electric current is passed through, that dissociates to form the anions and cations [25]. At present, the four most common electrolysis processes used to produce hydrogen gas are: alkaline (AEL), proton exchange membrane (PEM), anion exchange membrane (AEM), and the solid oxide electrolysis cell (SOEC). Among these AEL has come furthest in terms of technological development.

The development of the hydrogen production process in the 19th and 20th centuries was largely fuelled by the increasing demand for ammonia as a fertiliser, which is produced from hydrogen and nitrogen in the Haber Bosch process [22]. At first AEL systems dominated for large scale green hydrogen production, primarily because of their importance in the chlor-alkali industry [22]. In the 1960s PEM electrolysis of water was idealised and developed as an alternative to AEL electrolysis to bypass drawbacks of the technology [26]. In recent decades the scientific community has recognised the SOEC technology as a promising alternative to both AEL and PEM. The SOEC is expected to become more popular for electrolysis projects after 2030 [27]. However, due to its low technological readiness level, it is not considered an appropriate choice for this particular project. At present, the AEL and PEM technologies are the most applicable water electrolysis processes for the production for green hydrogen from offshore wind power. For this reason, both of them will be explained briefly in the upcoming sections.

AEL: ALKALINE WATER ELECTROLYSIS

In alkaline water electrolysis, a concentrated solution of either sodium hydroxide (NaOH) or potassium hydroxide (KOH) is used as the electrolyte. Typical operating conditions are temperatures between 60 and 90 °C, and pressures below 30 bar [23]. At the cathode water is reduced to hydrogen gas and hydroxide ions according to Reaction 2, and at the anode hydroxide ions are oxidised to water and oxygen gas according to Reaction 3.

$$2\,H_2O(l) + 2\,e^- \longrightarrow H_2(g) + 2\,OH^-(aq) \tag{2}$$

$$2\,OH^-(aq) \longrightarrow H_2O(l) + \frac{1}{2}\,O_2(g) + 2\,e^- \tag{3}$$

The overall process is depicted in in Figure 2.6.

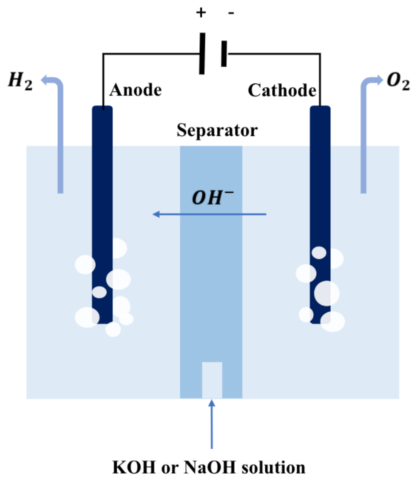

FIGURE 2.6: Schematic figure of alkaline water electrolysis (AEL). Image by authors.

The technology is well-established, mature, and currently requires a lower investment cost compared to all other water-electrolysis processes [23]. However, the main challenges and disadvantages are the limited current densities, the crossover of gases, and the high concentrated liquid electrolyte required in the process [23] [26]. The electrodes are nickel coated stainless steel, and the separator is based on oxide-ceramic materials. The fragility of these separators is the primary reason to the pressure limitations of the AEL process. Some separators can only handle pressures up to 10 bar, due to the increasing risk of explosion because of the reaction between the oxygen and hydrogen products at higher pressures [28].

In the context of integrating AEL systems with green hydrogen production using electricity from an offshore WPP, the main difficulty lies in the slow response time the system has to a fluctuating energy supply [29]. The efficiency of AEL systems often varies between 66 and 74%, and they require a minimum operating capacity of 20% [30] [31]. These electrolysers also have a restart time of 10-60 min, which makes continuous operation the most advisable [30].

PEM: PROTON EXCHANGE MEMBRANE ELECTROLYSIS

The typical operating conditions for PEM electrolysis is a temperature range of 50-80 °C, at pressures around 30 bar [23]. The electrolyte is a solid polymer, like sulfonated polymer membrane [23]. Water will dissociate at the anode, forming hydrogen ions and oxygen gas according to Reaction 4, and hydrogen gas will be produced at the cathode according to Reaction 5.

$$\mathrm{H_2O\,(l) \longrightarrow 2\,H^+(aq) + \frac{1}{2}\,O_2(g) + 2\,e^-} \tag{4}$$

$$\mathrm{2\,H^+(aq) + 2\,e^- \longrightarrow H_2(g)} \tag{5}$$

The overall process can be seen in Figure 2.7.

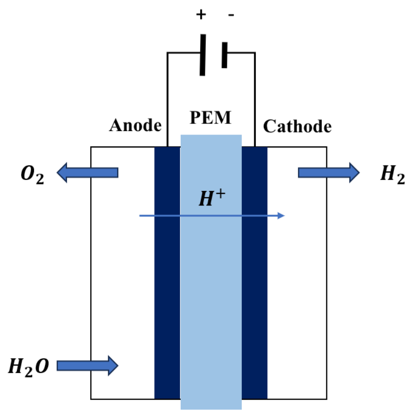

FIGURE 2.7: Schematic figure of the electrolysis of water using a proton exchange membrane (PEM) cell. Image by authors.

The proton exchange membrane transfers the positively charged hydrogen ions from the anode to the cathode. The most widely used membrane is Niafon, because of its high conductivity, current density, mechanical strength, and chemical stability, all of which are imperative for operation at higher pressures [23] [29]. The large active area of the noble metal based electrocatalyst electrodes, along with the lower pH electrolyte, mean that the overall reaction is faster and more efficient when compared to AEL systems [23]. The main disadvantage and challenge with this technology is the cost of the equipment, that can largely be owed to the use of scarce noble metals in the electrodes and the platinum/gold used to coat the separators and end-plates [23].

PEM electrolysers offer several advantages over AEL systems in the context of green hydrogen production from offshore wind power. The average efficiencies are higher than for AEL systems, ranging between 67 and 82%, and the shut down/start up times are significantly shorter [30]. According to the International Renewable Energy Agency (IRENA), start-up times vary between 1 s and 5 min depending on the temperature of the stacks, and a ramp up/down rate of 100%/sec can be achieved [32]. This makes PEM electrolysers better suited than the AEL technology for hybrid systems. Furthermore, these electrolysers only require a minimum load of 5%, but some researchers suggest this load will reduce to 0% by 2025 [31]. Most scientific literature that have modelled power-to-gas systems consider PEM to be the superior choice, and the electrolysis technology that will see the most favourable cost development in future. For this reason, a PEM electrolyser is used for the case study and scenario analysis.

2.3.2 STORAGE ALTERNATIVES

Hydrogen is a difficult gas to store due to its physical properties [18]. Despite this, several ways to store hydrogen both mechanically and chemically have been developed. The chemical storage technologies make use of substances with the ability to carry hydrogen [18]. The hydrogen carrying compound binds with the hydrogen through chemical reactions. When the hydrogen is to be used, chemical reactions regenerate free hydrogen and the carrier compound can be recycled [18]. Ammonia, metal hydrids, chemical hydrids, and carbohydrates are examples of such carriers [18]. Ammonia (NH_3) is a chemical used world wide in industry, and the most common hydrogen carrier. The relatively low vapour pressure of ammonia also makes it easy to store [18]. Although, a major drawback with storing hydrogen as ammonia is the large amount of energy needed to release it [18].

Another alternative for hydrogen storage is cryogenic storage, which increases the volumetric density by liquefying hydrogen [18]. The main challenge with liquid storage of hydrogen is that it must be held below its boiling point of -253°C at atmospheric pressure, making it difficult to maintain the needed temperature. In addition, there are major energy losses in the phase change process; approximately 25-35% of the hydrogen energy is used [33]. However, for the future these losses are estimated to be reduced to around 18% [33].

Less energy is lost if hydrogen is stored as a compressed gas, which is the most common way to mechanically store hydrogen. Depending on the choice of compressor the energy consumption varies between 12-26% of the chemical energy in hydrogen [18]. When the gas is compressed it can, similar to natural gas, be stored inside metal tanks or in natural underground structures [33]. Today the most practical and cost-efficient method to store large amounts of hydrogen is in underground salt caverns, having low leakage risks, construction costs and presence of hydrogen degrading bacteria [33]. Further, storing hydrogen under high pressures reduces the storage volumes needed [33]. There is already an existing hydrogen storage in underground structures in Luleå, operated by Hybrit. It was set in operation 2022 and functions as a pilot project for a future hydrogen storage in Gällivare, Sweden [34]. The storage facility in Gällivare is planned for 2026 and will be a demo facility for hydrogen storage on industrial scale, used for the production of direct reduced iron [34].

Moreover, hydrogen can also be stored in pipelines through line packing [33]. The idea is similar to storing natural gas in pipelines, storing heat in a district heating system or charging and discharging a battery, but simply by injecting or extracting hydrogen gas to/from the pipe system. As of today there is no hydrogen gas pipeline system in place in the Bothnian Bay region. However, Nordion Energy together with Gasgrid Finland are currently working on a project called The Nordic Hydrogen Route [35]. The project includes construction of hydrogen pipelines in the area, see Figure 2.8. The first section is planned to be operating 2030 [35]. In total the project is planning for 1 000 km of hydrogen pipelines in the area, serving a potential hydrogen demand of 65 TWh by 2050 [35]. The project is also part of a larger European project called the Hydrogen Backbone. However, whether the Hydrogen Backbone will be realised or not is still uncertain.

FIGURE 2.8: Illustration of the preliminary hydrogen pipelines in the Bothnian Bay, picture from Nordic Hydrogen Route [35].

2.3.3 APPLICATIONS

At present hydrogen is primarily used for oil refining, steel production, and chemical production [8]. It is a vital gas for the refining industry, an important feedstock for the production of both methanol and ammonia, and has gained recognition as an efficient reducing agent in steel production. As the world begins to transition to cleaner and more sustainable energy sources, hydrogen has gained momentum in new applications as a feedstock for e-fuels, a fuel in the vehicle fleet, and an energy carrier for electricity storage and generation, to name a few [9].

As mentioned previously, the steel industry is predicted to be the primary driver for increased hydrogen demand in Sweden. Traditionally, solid carbon is used as the reducing agent in steel production, resulting in extensive carbon dioxide emissions [36]. Using methane as the reducing agent reduces the carbon emissions by partially replacing them with water vapour, however the use of hydrogen would make the complete decarbonisation of the process possible, with water vapour as the only byproduct [36].

Hydrogen production through electrolysis could also provide ancillary services to the distribution grid through frequency regulation reserves. Among other benefits, this service could be a viable alternative for revenue stacking, and some scientific literature suggests that participating on the ancillary market could increase expected profits for hybrid wind and electrolytic systems [37]. Zheng, Huang, You, *et al.* performed a case study of Denmark and found that the economics of power-to-hydrogen systems could improve by providing frequency containment reserves (FCR) and automatic frequency restoration reserves (aFRR) [37]. Considering the similarities between the electricity markets in Sweden and Denmark (especially DK 2), the profitability of participating in the ancillary market could be assumed to be similar.

The growth of the e-fuel industry is also expected to increase the demand for green hydrogen in the future. The construction of Europe's largest e-fuel facility, Flagship 1, developed by Liquid Wind and owned by the Danish offshore developer Ørsted, commenced in May of 2023 in Örnsköldsvik [38]. Another two facilities are planned in Sundsvall and Umeå. Furthermore, Nordkalk is collaborating with OX2 to develop e-fuel production on Gotland [39]. The continued investment in e-fuel facilities in Sweden can therefore be expected to influence the future demand for green hydrogen.

2.4 Heat management

As mentioned in Section 2.3.1, electrolysis of water is an exothermic reaction releasing heat when producing hydrogen. The generated heat must be removed from the electrolyser system to avoid overheating but can fill multiple purposes in other applications. For example the heat can be used for water purification through thermal water treatment methods, to heat greenhouses for crops or to heat cities through district heating systems. For the purpose of this study the waste heat will be used for district heating.

The district heating network in Luleå is owned by Luleå Energi AB, whom together with SSAB own Lulekraft AB that in turn deliver heat to the system. In 1977 a combined heat and power plant was built in Luleå and brought into operation by 1982 [40]. Since then Lulekraft AB combust process gases from SSAB and the steel production site in Luleå to generate heat and power. The district heating system is therefore closely related to and dependent on the local steel production and its processes. However, SSAB are working towards a transition of their steel production sites to become fossil free. They have already started with their site in Oxelösund and have recently announced a continuation with the site in Luleå [41]. SSAB are planning to build a new, modern, fossil-free steel production system replacing the old blast furnace-based one. It will be operating by 2028, reaching full capacity in the following years [41]. Because of this the current heat source will disappear, but new waste heat sources could potentially aid in replacing this supply.

The future development of the district heating system is unclear, and exactly how it will operate in the future is currently unknown. After discussing the matter with both Luleå Energi AB and Lulekraft AB some information was gathered. In 2017 a dimension requirement was established, stipulating that all customers should dimension their systems for a supply temperature of 80°C. Consequently, Lulekraft AB lowered their supply temperature from the previous 120°C to 115°C for an outdoor temperature of -30°C. This marked the start of lowering the supply temperature on the district heating network and the transition towards a new system. Based on information from SSAB and the loss of process gases, it was understood that the district heating system would shift from a combustion system to a thermal heat recovery system with a lower temperature than the current system. A lower temperature allows for more waste heat utilisation, improving the conditions for waste heat reuse from a large scale electrolyser.

Today the supply temperature in the district heating network varies from 105°C at -30°C to 74°C for outdoor temperatures of 5°C or higher. Luleå Energi AB aims to lower the supply temperature to 99°C by the 1st of January 2026. The lowest supply temperature of 74°C will be kept at its current state to be able to deliver a supply temperature of 65°C to the customers located farthest away, and to eliminate the risk for legionella growth in the water. The highest supply temperature is expected to decrease further until 2030, at which point 90°C is approximated. Between the outdoor temperatures -30°C and 5°C the supply temperature is linearly correlated to the outdoor temperature.

A water based cooling system can be combined with the use of heat exchangers to utilise the waste heat generated by an electrolyser system. Initially the cooling water receives the heat from the electrolyser stacks and through heat exchangers heats the district heating water. Considering that the operating temperatures of both AEL and PEM electrolysers are generally lower than the desired the supply temperature during colder months, heat pumps are a necessity to upgrade the temperature of the waste heat stream [24].

2.5 Water source and treatment

An electrolyser system requires water for two main purposes; as a feedstock and for cooling. Water that is used as feedstock is often referred to as ultrapure, and therefore only contains H_2O, along with H^+ and OH^- ions [42] [43]. Ions and molecules present in water can have a corrosive affect on the electrolyser equipment, causing a decrease in efficiency and increasing rate of degradation [42]. Moreover, most manufacturers (Nel and Cummins, among others), will include a water purification unit in the electrolyser system to ensure the water quality entering the electrolyser stacks fulfills the American Society for Testing and Materials (ASTM) Type I or II [44]. Due to the sensitivity of the electrolyser stacks, the cooling water also needs to achieve certain quality requirements. However, these are not as strict as the quality requirements for the water used as feedstock [42].

The most appropriate water source for an electrolyser system, both for feedstock and cooling water, will vary on a case-to-case basis. Since an electrolyser requires a minimum of 9 l of water per kg of hydrogen produced, the amount of water that needs to be supplied to an electrolyser system is significantly larger than the hydrogen produced [42]. For large scale systems with electrolyser capacities in the 500-1000 MW range the amount of water can exceed $10 \cdot 10^6$ l/day, when accounting for the cooling water need and losses. Considering that these volumes will put a considerable strain on a tap-water network, it is a reasonable assumption that a natural water source should be used for such large scale systems. The hydrogen plant that the following case study looks into is estimated to be in the MW-GW size range, and is located in the Bothnian bay where there is an abundant supply of brackish water [45]. Another company in the area, namely H2 Green Steel, also recently received a permit to withdraw water from Luleälv at a rate of around $173 \cdot 10^6$ l/day for the production of green hydrogen [46].

For brackish water to be used for the production of green hydrogen, dissolved mineral salts must first be removed. Desalination technologies can be divided into two broad categories: thermal and membrane techniques [47]. The thermal techniques use both heat and electricity to vaporise the feedwater, while the membrane techniques use electricity to drive high pressure pumps that force the feedwater through a membrane [47]. Both technologies can be used to purify brackish water [48]. An advantage of the thermal desalination technologies is that they can be powered by waste- or byproduct heat from other operations [48]. The possibility of using the waste heat from the electrolyser system to produce fresh water has been exploited by companies like Alfa Laval, that have developed the HyDuo module [49]. However, reverse osmosis (a membrane-based technology) has dominated the past decade due to its low energy demand, relatively low cost, and membrane durability compared to the other desalination technologies [47][48]. The case study therefore utilises a reverse osmosis unit for the purification of the brackish water.

2.6 FORECASTS ON LCOH

With hydrogen's multiple applications, the interest in researching the development of hydrogen and electrolyser systems has increased drastically in recent decades. There are several publications that present various future forecasts. However, at present the practical implementations are few, with a handful operating on industrial scale. Most of the operating electrolyser systems are much smaller (kW scale) than the size that is relevant for a system like the one in this case study. On the MW-GW scale there are almost no functioning electrolyser facilities, AEL or PEM. The largest hydrogen plant operating at the time of writing is 150 MW in size, located in China, brought on line in 2022 by Baofeng Energy [50]. However, there are several other larger green hydrogen projects in the early planning stages. For example, Statkraft are together with Karlshamn municipality planning an establishment of hydrogen production and storage in southern Sweden [51]. They are planning to make use of 32.5 ha land and electricity from a planned offshore WPP, producing 10.5 TWh annually, to operate an electrolyser [51]. Another project, located within 40 km of Luleå, is H2 Green Steel's 700 MW electrolyser that is expected to be in operation before 2030 [52].

The lack of industry experience for large-scale electrolyser systems makes it difficult to know what to expect regarding the business case and resulting LCOH. Since little can be said about such systems today, even less is known about their future. However, it is a topic of interest and researchers are eager to learn more. Several researchers have thereby published future estimations of the LCOH in 2030. Those presented below will be used in Chapter 7 for comparison purposes and to analyse the results produced by the case study.

Bernuy-Lopez presented LCOH values for a PEM electrolyser system greater than 1 GW in 2030 [53]. For electricity prices of 340 SEK/MWh and 170 SEK/MWh, the resulting LCOHs were 28 SEK/kg H_2 and 16 SEK/kg H_2, respectively. Bernuy-Lopez also mentions that increasing electrical efficiencies will reduce the LCOH to 11 SEK/kg H_2 by 2030, even when considering relatively high electricity prices [53]. However, depending on the electricity price and the electolyser technology used, the LCOH for green hydrogen varies. Sometimes this results in a higher value than the price of EU grey hydrogen (34-40 SEK/kg H_2) and sometimes lower than the US grey hydrogen (22-26 SEK/kg H_2) [53].

Another techno-economic assessment, conducted by Giampieri, Ling-Chin, and Roskilly, focused on offshore wind to hydrogen in the UK, presents LCOH values for 2030 [54]. In all their scenarios the green hydrogen price always remained higher than that of the blue or grey hydrogen. Besides a small onshore hydrogen storage the assessment presented a similar scope to the one of this study. The LCOH varied with the percentage of electricity transmitted from the offshore WPP. For 80-100%, assuming a cost of electricity in line with IRENA's prediction for 2030 of 743 SEK/MWh [55], the LCOH was between 69 SEK/kg H_2 and 92 SEK/kg H_2.

A third study, similar to this one, and conducted by McDonagh, Ahmed, Desmond, *et al.*, uses historical wind data and electricity prices to calculate the profitability of a project in the Irish sea [56]. As in this case study they assume a PEM electrolyser and set up 3 cases; all electricity to grid, all to hydrogen and a hybrid system. Their turbines are smaller, the plant is located closer to shore and it includes compression as well as storage of the hydrogen produced. McDonagh, Ahmed, Desmond, *et al.* highlight that for a LCOE of 485 SEK/MWh from the WPP, the resulting LCOH becomes 43 SEK/kg H_2 [56]. Further, the results show that the most profitable option was to sell all electricity to the grid, followed by the hybrid system set up.

IRENA also believe that given an aggressive electrolyser development path and lower electricity costs the LCOH of green hydrogen can reach 11 SEK/kg H_2 in 2040 [57]. If the scale of the technology progresses faster it might become a reality as early as 2030, thereby agreeing with Bernuy-Lopez [53]. However, IRENA present a range of scenarios, for which the LCOH varies between 15-44 SEK/kg H_2 in 2030 [57].

Finally, to get a better perspective on the competitiveness of green hydrogen compared to grey or blue hydrogen, Schelling presents the following estimations on green, blue and grey LCOH in 2030 in Sweden: 16, 30 and 21 SEK/kg H_2, respectively [58]. In Sweden, along with other countries, green hydrogen from new plants is expected to undercut the grey hydrogen even without subsidies, meaning that there is a tipping point coming at the end of this decade [58]. To get a better overview and for comparison purposes the LCOH values from the previous research are summarised in Table 2.1 below.

TABLE 2.1: Estimation of LCOH for green hydrogen in 2030. Schelling also presents estimations for green and grey hydrogen for comparison.

Source	**LCOH 2030 (SEK/kg)**		
	Green	**Blue**	**Grey**
Bernuy-Lopez [53]	16-28		
Giampieri, Ling-Chin, and Roskilly [54]	69-92		
McDonagh, Ahmed, Desmond, *et al.*[56]	43		
IRENA [57]	15-44		
Schelling [58]	16	30	21

Chapter 3

TECHNICAL BACKGROUND TO CASE STUDY

RWE Renewables is a German company that specialises within renewable energy operations worldwide. In Sweden, the company's primary focus has been on developing wind power, both on- and offshore. They currently operate one of the two offshore WPPs in Sweden, namely Kårehamn south of Öland, built in 2013. RWE also has a number of offshore wind power plants being developed in Sweden.

In recent years the company has also seen the potential in developing green hydrogen production. With the increasing demand for green hydrogen as a fuel, feedstock and energy carrier, its production has become more interesting for RWE. The company is currently partaking in around 30 projects in Europe. One of them is located in Lingen and is a pilot project to develop and evaluate the technology. Further, the green transition of the Swedish steel industry is expected to be the primary driver of the growth of green hydrogen demand in the country. This makes the north of Sweden a highly interesting area for the development of green hydrogen production, especially in a hybrid system where it can be combined with intracompany production of electricity.

RWE has recognised the favourable conditions in northern Sweden, and is exploring opportunities in the area. In this report a fictional WPP will be called Park A and is approximated to be located 30 km off the coast of Piteå (as seen in Figure 3.1), with an estimated capacity close to 1.2 GW and 2030 as the year of operational start. Additional aspects that make this area appropriate are that it is outside territorial waters, eliminating the municipalities veto right, and not affecting reindeer husbandry. Advantages also include greater wind speeds compared to onshore, and possibilities of larger wind turbines.

Ideally, all the electricity from the plant would be transferred to the grid. However, the planned connection point in Luleå will not suffice with the estimated capacity, since the location is attractive for other WPPs that also demand grid capacity. Consequently, some of the power produced from the WPP will have to be used for other purposes, such as green hydrogen production through the electrolysis of water, preferably in Luleå were the demand for hydrogen is expected to be high in the coming decade. The extent and magnitude of RWE's green hydrogen production is yet to be determined, and is therefore an interesting and relevant topic of investigation.

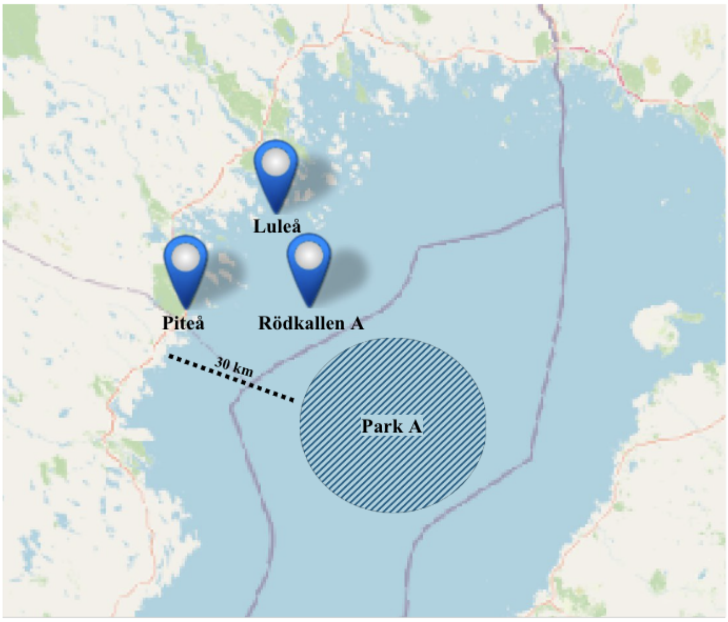

FIGURE 3.1: Location of Park A, nearest weather station Rödkallen A located on the island Rödkallen, distance to shore and the nearby cities Piteå and Luleå. Image produced by authors.

In the following case study the electrolyser is assumed to be located onshore in Luleå and directly connected to the offshore WPP Park A. The green hydrogen production will be evaluated using a PEM electrolyser and transferring the hydrogen as a compressed gas (using a centrifugal compressor) to a hydrogen pipeline. Parts of the Nordic Hydrogen Route are assumed to successfully be operating 2030. It is assumed that the pipe system, at that time, will have enough capacity to cover the hydrogen production of this case study. Any capacity limitations that may arise with other hydrogen producers have not been considered. The pipelines are thereby used for both transportation and storage of the produced hydrogen.

Considering that it seems to be possible to obtain the necessary permits to extract large volumes of brackish water, the following case study will assume that it is taken from a nearby watercourse, and used both for the production of feedwater and cooling water. Due to the seasonal and geographical variability in water quality, the treatment required is difficult to generalise. However, as Taekker Madsen mentions, an electrolyser cannot be damaged by water that is too clean [42]. Therefore, the water used as feedstock and for cooling purposes was purified through brackish water reverse osmosis (BWRO).

In this study the hydrogen system design is adapted to Nordic conditions simply by placing the electrolyser system indoors. The need for additional heating during the colder seasons and possible reusage of waste heat from the electrolyser are also considered in relation to the operating temperature of the equipment.

In Table 3.1 an overview of the specifics of the WPP and hydrogen production system is given. Information about the design, specific figures and methodology can be found either in the previous sections in Chapter 2 or in the following sections in Chapter 5. It should be noted that this information is inspired by RWE's work, but should not be seen as project specifics of a planned WPP. Instead it should be interpreted as case study specifics chosen by the authors of this report. For example, the operational start was set to 2030 to be able to compare the results with literature values published for the given year.

TABLE 3.1: Summary of information on case study.

Information		**Comment**
Location of WPP	30 km, off the coast of Piteå	Offshore WPP
Location of electrolyser	Luleå	Onshore
Installed power	$\sim$1.2 GW	
Annual electricity production	$\sim$5 TWh	
Turbine type	20 MW	
Number of turbines	60	
Electrolyser	PEM	Size varies with scenarios
Water treatment system	BWRO	For both process and cooling water
Compressor	Centrifugal compressor	Size varies with scenarios
Storage and distribution	Pipeline system	
Waste heat utilization	District heating and internal heating system	Existing district heating system in Luleå and planned heating system for facility

Chapter 4

METHOD

The methods used in this case study involved a scenario analysis of WPP Park A. To address the research questions and fulfill the aim four different hybrid scenarios with varying electrolyser system sizes and grid connections were developed and evaluated in a techno-economic analysis. The case study included a literature review combined with the design of an economic model used to calculate the LCOH. The literature review aimed to provide background information about the current state of large scale hydrogen production, the feasibility of such an establishment in Luleå, and an insight on the future outlook for green hydrogen. In addition, it was also used to make estimations on specific energy, water, area requirements, efficiencies, pressures, temperatures, and system design. The main purpose of the literature review was therefore to aid in the design of the economic model.

Databases such as Google Scholar, the online university library LUBSearch, DiVA Portal and Science Direct were primarily used for the research process. In some cases press releases, websites or other online material were used to bridge the gaps in the research. Data has also been collected from authorities, institutions and organisations, and in some cases through online meetings or email contacts with RWE employees or other companies.

The economic model for the techo-economic analysis and LCOH calculation was designed in Microsoft Excel, and is further described in Section 5.2.8 Chapter 5. The model, based on the results from the literature review, was designed solely for the scenario analysis of the case study. A cost breakdown, sensitivity analysis and a comparison to LCOH values from previous research were also carried out. The system boundaries and scope, as well as the case study scenarios, are presented in the following sections.

4.1 SYSTEM BOUNDARIES AND SCOPE

The authorization process and application of the necessary permits to establish and operate a hybrid system, like the one in this case study, were decided to be excluded from the scope. Instead, the scope of the study was determined to begin with the inputs to the electrolyser system: electricity generated from the offshore WPP Park A, electricity from the grid and brackish water from Luleälv. Some of the electricity from Park A was directed towards the transmission grid and some to production of green hydrogen, where this study has its focus. The costs of connecting and utilizing electricity from the grid were included while possible extra costs for infrastructure or cables were disregarded.

From the hydrogen plant, the costs of producing, compressing and transferring the hydrogen to a pipe system were included. With regard to the Nordic conditions and cold climate in Luleå, a WHRS was used to cover the internal heat demand and to transmit the remaining heat to the district heating network. Although, the extra costs of connecting to a hydrogen pipeline and district heating network were excluded, since there are no standard pricing amounts for these at present. Thereby, the transportation of hydrogen and heat to offtakers as well as their utilisation were outside the scope.

Regarding the water treatment, the handling of waste products from the treatment plant was set outside of the scope. McDonagh, Ahmed, Desmond, *et al.*, and Giampieri, Ling-Chin, and Roskilly set similar limits to their scope, excluding the finances of handling waste products [56][54].

The revenue streams from hydrogen as well as heat were included whilst possible revenues from the byproduct oxygen was excluded. The analysis did not consider any subsidies or loans, however they were included in the sensitivity analysis, along with a discussion on their effect. Finally, financial aspects such as taxes and inflation were included. An overview of the scope is presented in Figure 4.1 below.

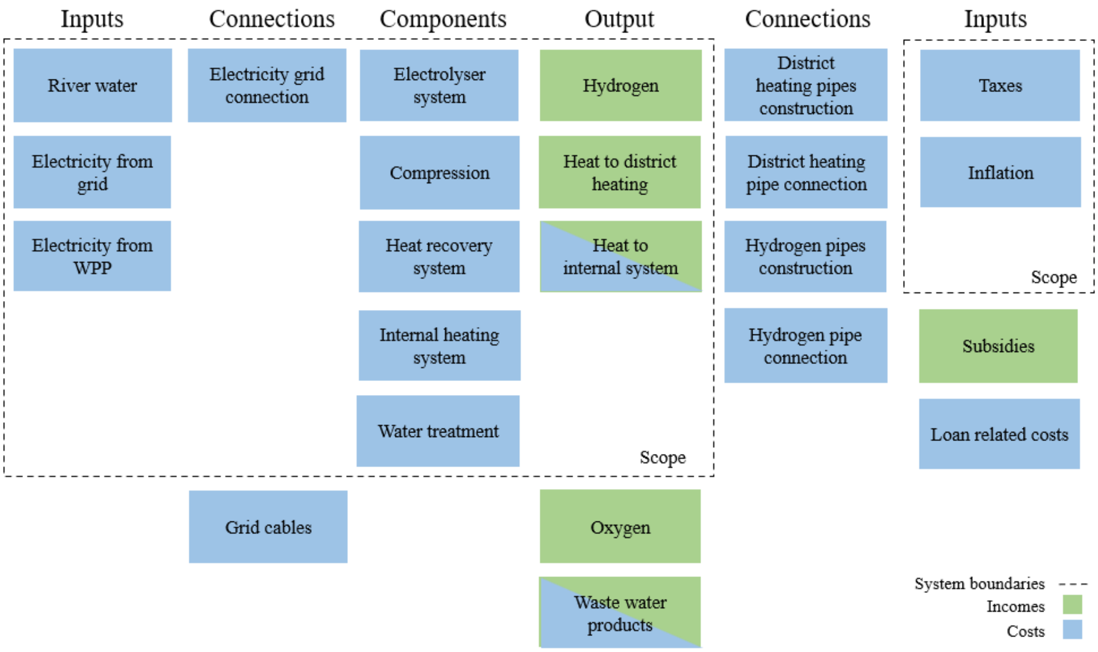

FIGURE 4.1: Illustration of system boundaries and the scope of the study. Regarding the two-coloured box for heat to internal system; all costs were included and the possible savings made compared to another heating system are represented by income. For the waste water box; it is two-coloured due to uncertainties concerning whether waste water products would incur an additional cost or income. Image produced by authors.

4.2 CASE STUDY SCENARIOS

The techno-economic analysis of the hybrid system was based on four different scenarios, all with different amounts of electricity allocated to the transmission grid and green hydrogen production. Before presenting the different scenarios the prerequisites for their determination are described below.

4.2.1 PREREQUISITES

As presented in the background there is currently no available electricity grid capacity for new power plants in the area of Park A. However, the planned grid expansion of an additional 1.4

GW is expected to become available for offshore wind power production in 2029, further referred to as connection point Luleå. No reservations on connection point Luleå have been made yet, and the scenarios of this study have been developed to reflect different sizes of available capacity [15]. Any other future developments of the grid affecting the available capacity have not been considered.

To be able to approximate the available electricity grid capacity for Park A, other offshore WPP establishments had to be accounted for. This was done by using 4C-Offshore's official map for WPP projects offshore [59]. The data was collected on the 19th of February 2024, after which no new publications of WPPs have been considered. According to 4C Offshore five different WPPs are planned in the area, all with different installed capacity and size, amounting to approximately 10 GW installed power [59]. No information has been found on where the different WPPs plan to connect or how much capacity they aim to connect to the grid. For the purpose of this report all WPPs were assumed to connect to connection point Luleå, sharing the available grid capacity with Park A.

According to the TSO the priority order for granting connection to the elecricity grid is based on the degree of maturity of the projects [60]. The classic queue system, where the project owners applied for a specific capacity and the first applied project was first granted connection, is no longer valid. Instead the assigned capacity was based on the available capacity in different zones combined with the maturity of the projects, the most mature project is prioritised [60]. All WPPs are currently in the early planning stages and thereby it was not possible to prioritise them differently. Instead they, as well as Park A, were handled as equally prolonged projects and the available capacity was divided between them based on their projected installed capacity.

4.2.2 SCENARIOS

The following four scenarios were based on assumptions on how many of the five WPPs that will be established and operating around 2030. Due to lack of space in the area it was not considered realistic that more than four WPPs will be granted permission to build in the Bothnian Bay region. Neither did it seem realisitic to assume that Park A would be the only WPP in the area and granted a grid connection large enough to cover its full demand. Therefore, the decision was made to include three hybrid scenarios with different grid connections and electrolyser sizes, and one off-grid scenario called the extreme scenario. For the specific calculations and information on the implementation of each scenario, see Section 5.1.

In the first hybrid scenario, Hybrid Scenario 1, Park A and one of the other WPPs were assumed to be established and operating in 2030. The TSO was assumed to distribute the available grid capacity of 1.4 GW between the two plants. Since they share the same maturity the priority order was waived and a connection capacity corresponding to the WPPs percentage of the total installed capacity was assigned. When determining the assigned capacity, an average value between the maximum and minimum possible grid capacity was chosen by including the largest and smallest WPP respectively. When including the smallest WPP the largest grid capacity could be assigned to Park A and vice versa when including the largest WPP. The available capacity for Park A was then between 370-700 MW. Park A was thereby granted 530 MW grid capacity, resulting in an electrolyser of 560 MW (see Figure 4.2).

In the second scenario, Hybrid Scenario 2, two of the other WPPs were included, three in total when including Park A. The TSO was assumed to assign capacity to the WPPs according to the same reasoning as in Hybrid Scenario 1. Depending on which of the projected WPPs that were excluded, Park A could be assigned a capacity in the range 260-430 MW. For Hybrid Scenario 2 a grid connection of 350 MW was thereby chosen, resulting in an electrolyser capacity of 730 MW (see Figure 4.2).

In the third hybrid scenario, Hybrid Scenario 3, three of the projected WPPs were included in addition to Park A. A grid connection between 210-310 MW was possible to assign to Park A. Again, an average value of the interval was chosen and Park A was assigned a grid connection of 260 MW, resulting in an electrolyser capacity of 820 MW (see Figure 4.2).

In the fourth and final scenario, the Extreme Scenario, no grid capacity was assumed to be available for Park A. Thereby all produced electricity from the WPP was directed towards hydrogen production. As can be seen in Figure 4.2 this demanded an electrolyser capacity of 1 060 MW.

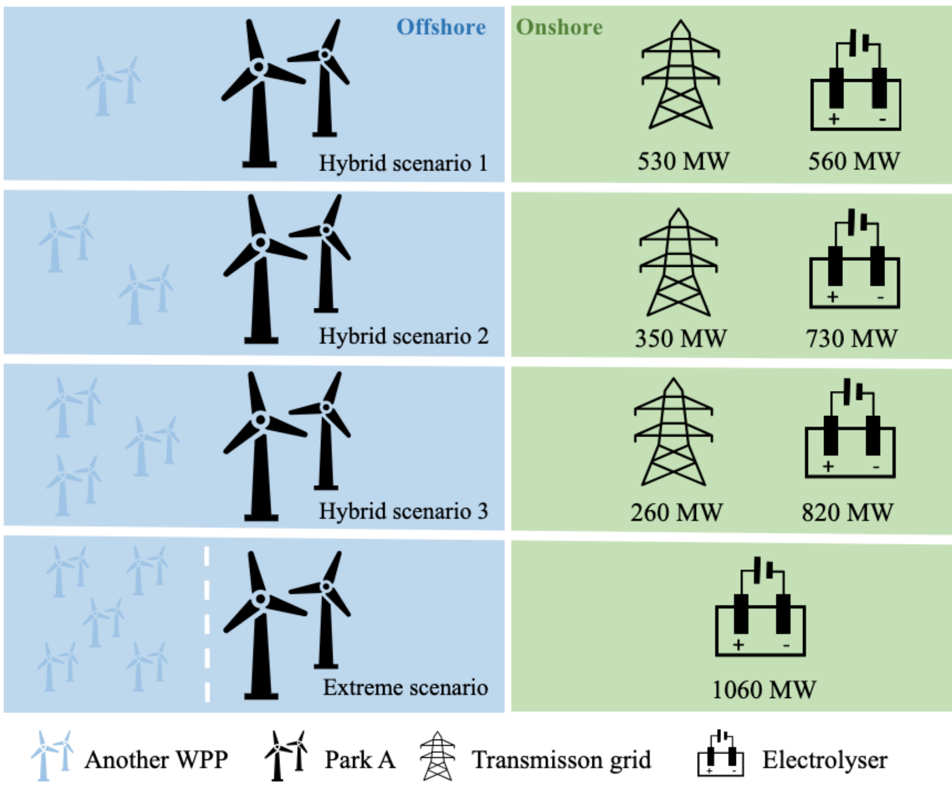

FIGURE 4.2: Overview of the four scenarios included in the case study. Image produced by authors.

Chapter 5

MODEL

Before conducting the LCOH calculations, numerous parameters had to be determined. Examples include component-specific parameters such as electricity usage, investment costs, and operation and maintenance costs. This section will provide an explanation of each step and the assumptions made, beginning with wind energy and leading up to the final LCOH calculation method

5.1 DATA COLLECTION AND MANAGEMENT

In this section the collection and management of data is explained, leading up to the criteria of the model. All equations used are derived by the authors of this report if nothing else is stated.

5.1.1 ELECTRICITY GENERATION

Before looking into the possible electricity generation from the WPP, the technical specifications for the wind turbines to be used had to be determined. The size of wind turbines have grown drastically over the past three decades, increasing in size by more 240 times since 1985 [61]. After consulting with RWE, a turbine size of 20 MW was decided, considering that the WPP is assumed to be operating around 2030. Due to lacking information on available 20 MW prototypes, the technical characteristics of a turbine modeled by Ashuri, Martins, Zaaijer, *et al.* was used [62]. The power coefficient (Cp) was set to 0.45, considering the range 0.4-0.5 given by Mahmoud, Salameh, Makky, *et al.* [63]. All values are displayed in Table 5.1 and have been cross checked with the project team at RWE.

TABLE 5.1: Wind turbine specifications inspired by Ashuri, Martins, Zaaijer, *et al.* [62]. Cp is the power coefficient, inspired by Mahmoud, Salameh, Makky, *et al.* [63].

Wind Turbine Specifications	
Hub height (m)	200
Rated power (MW)	20
Cut-in wind speed (m/s)	3
Nominal wind speed (m/s)	11
Cut-out wind speed (m/s)	28
A_T: Swept area (m^2)	59 396
Cp: Power coefficient	0.45

The Swedish Meteorological and Hydrological Institute (SMHI) have a weather station on the island Rödkallen in Piteå's archipelago, close to the site that RWE have identified (see Figure 3.1). To determine the electricity generation from Park A hourly wind data measurements from Rödkallen were used [64]. The year 2023 was used as a reference year. SMHI and Guttu both imply that 2023 was a representative wind year with normal wind conditions in Park A's area, while the storms Hans, Otto and Babet affected the southern parts of the country [65][66].

The wind index was close to 100% and no significant deviations occurred [65][66]. However, for the year 2023 wind speeds for eight out of the 8760 hours were missing in SMHI's data. To rectify this issue, linear regression was used to approximate the wind speed during the missing hours. Another issue that had to be accounted for, was that the station is only located 1.9 m above sea level. In order to more accurately determine the potential electricity generation, it was necessary to calculate the wind speeds at a height that corresponds to the hub height of the wind turbines used in the WPP. Rogers, Manwell, and McGowan mention two ways of estimating the wind speed at a desired height given data at a reference level, namely the power law profile or the logarithmic law profile [67]. Both were evaluated using the data gathered from SMHI, the log law producing values that were slightly smaller than the power law. Given that the power law is often used in wind engineering to determine vertical profiles, this method was chosen [68]. It uses a wind speed coefficient α to estimate the speed at a height z (m), when the wind speed at a reference height z_r (m) has been given. The relationship is given in Equation 5.1, where U (m/s) is the wind speed [67].

$$\frac{U(z)}{U(z_r)} = \left(\frac{z}{z_r}\right)^{\alpha} \tag{5.1}$$

The power coefficient α can be determined using the surface roughness z_0, which depends on the terrain. For an offshore WPP $z_0 = 0.2$ mm, according to Rogers, Manwell, and McGowan [67]. The formula used to determine α is given in Equation 5.2, also taken from Rogers, Manwell, and McGowan.

$$\alpha = 0.096 \cdot \log_{10}(z_0) + 0.016 \cdot (\log_{10}(z_0))^2 + 0.24 \tag{5.2}$$

When the wind speed at a hub height of 200 m had been calculated, the following step was to find the power extracted from the wind by the wind turbine. Equation 5.3 gives the power P_T (kW) generated by the wind turbine at a specific wind speed U (m/s), given that the air has the density ρ_{air} (kg/m^3) and the wind turbine has a swept area A_T (m^2) and a power coefficient Cp [67].

$$P_T = \frac{1}{2} \cdot \rho_{air} \cdot A_T \cdot U^3 \cdot Cp \cdot 10^{-3} \tag{5.3}$$

The power produced by the entire WPP P_{WPP} (kW) was then calculated by accounting for the number of turbines $n_{turbines}$, the power generated by each turbine P_T, and the overall WPP efficiency η_{WPP}. This relationship is given in Equation 5.4. The efficiency η_{WPP} is a cumulative value accounting for wake losses, power losses in cables, and availability. According to Baas, Verzijlbergh, Dorp, *et al.* wake losses can be as small as 6% or as large as 12-18%, varying significantly with WPP design and turbine size [69]. The effect of the wake losses also change with the strength of the wind. In periods with high winds the wake losses can be disregarded since the wind could still be strong enough for all turbines to produce power at their rated effect. However, for the simplicity of this study the wake losses were assumed to be constant and set to a level low enough to compensate for the possible extra generation of electricity in periods with high wind speeds. The wake losses were thereby assumed to be 12% in the following calculations. Additional losses of 3% were added considering cables, availability and other electrical losses in the WPP system. The overall WPP efficiency η_{WPP} was therefore assumed to be 85%.

$$P_{WPP} = n_{turbines} \cdot P_T \cdot \eta_{WPP} \tag{5.4}$$

When the power output from the WPP for each hour of the year had been determined, an annual electricity generation E_{WPP} (kWh) was obtained as the sum of the electricity output for each hour. This is shown in Equation 5.5.

$$E_{WPP} = \sum_{i=0}^{8760} P_{WPP_i} \cdot 1\ h \tag{5.5}$$

5.1.2 WATER TREATMENT

The electrolyser system will be fed with brackish water from a nearby watercourse that has first been purified using a BWRO unit. Inspiration for the system design was taken from Brannock, Dagg, and Mitchell [70], and is given in Figure 5.1. Assuming that the electro-deionisation unit is contained within the electrolyser system, the freshwater feed was assumed to be 10 kg/kg H_2 (see Section 5.1.3 for further details). The corresponding cooling water required was decided based on that 10 kg blow down is produced, and 25 kg is lost in the recirculating cycle due to evaporation or drift. Depending on the water quality of the blow down there is an opportunity to recycle it, and thereby reduce the amount of raw water required. However, a conservative approach has been adopted in the following case study, and this possibility has not been investigated further. Furthermore, assuming 80% recovery of the raw water input to the BWRO, the brackish water requirement would be 56 kg/kg H_2 [70] [71]. The hourly volumetric water usage of the hydrogen plant W (m^3/h) for each scenario could thereby be calculated using the mass of hydrogen produced hourly H (kg/h), the specific water requirement W_{H2} (kg/kg H_2) and the density of water ρ_{H2O} (kg/m^3) as seen in Equation 5.6.

$$W = \frac{W_{H2} \cdot H}{\rho_{H2O}} \tag{5.6}$$

The maximum daily water usage W_{max} (m^3/day) was also a necessary parameter when determining the size of the BWRO unit. It was determined using the same relationship as seen in Equation 5.6, but replacing the hourly hydrogen production with the maximum daily hydrogen production H_{max} (kg/day).

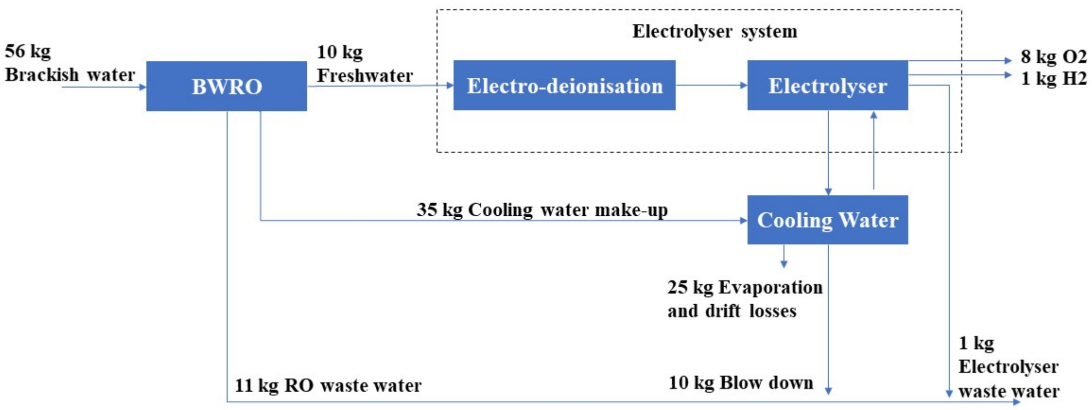

FIGURE 5.1: Water purification system design. Image produced by authors, inspired by Brannock, Dagg, and Mitchell [70].

The energy intensity of seawater reverse osmosis (SWRO) has drastically decreased from 9-10 kWh/m^3 to less than 3 kWh/m^3 in the past decades [44]. With this development a decrease in the specific energy consumption for BWRO has also followed. The energy consumption is highly dependent on the water quality. Hence it would be necessary to conduct measurements to gain deeper insight into the electrical energy use. However, the following case study will rely on average values given in literature for the specific energy consumption. Some sources suggest that the energy intensity of a BWRO unit can be as low as 1.2 kWh/m^3, while others proclaim that it can be as high as 6 kWh/m^3 [72] [73]. In the following study, a specific energy consumption E_{BWRO} of 3 kWh/m^3 was chosen. The specifications for the BWRO unit are given in Table 5.2.

TABLE 5.2: Specifications for the BWRO unit used for calculations.

BWRO Specifications	
W_{H2}: Specific water requirement (kg/kg H_2)	56
ρ_{H2O}: Density of water (kg/m^3)	1000
E_{BWRO}: Specific energy consumption (kWh/m^3)	3

5.1.3 ELECTROLYSER SYSTEM

The amount of hydrogen that can be produced from an electrolyser system is highly dependent on its technical characteristics. Specifications from five of the top 20 global electrolyser manufacturers were used to estimate the technical parameters of the electrolyser system, summarised in Table 5.3 [74]. Based on the information given in Table 5.3, the specific energy consumption E_{PEM} (kWh/ kg H_2), feedwater consumption FW_{PEM} (l/kg H_2), delivery pressure P (bar), ambient temperature range required (°C), and system efficiency η_{system} were determined.

TABLE 5.3: Technical specifications of Cummins, H-TEC systems, ITM Power, Nel and Siemens Electrolyser systems. *Average stack consumption instead of specific energy consumption for the whole system.

Manufacturer	**Model Name**	**Size (MW)**	**E_{PEM} (kWh/kg H_2)**	**FW_{PEM} (l/kg H_2)**	**P (bar)**	**Ambient temperature (°C)**	η_{system}
Cummins[75]	HyLYZER 4000-30	20	<51	-	30	10 - 40	-
H-TEC systems [76]	2 MW HCS	2	53	-	15-30	-20 - 40	75 %
ITM Power[77]	Poseidon	20	50	-	-	-	-
Nel[78]	M5000	25	51*	10	30	10 - 40	-
Siemens[79]	Silyzer 300	17.5	52.2	<10	Project specific	-	>75.5 %

Scaling of PEM electrolyser systems in the future is expected to occur on a modular basis, in which a plant on the MW or GW scale will comprise of smaller stacks/systems. The models given in Table 5.3 are the largest produced by each individual manufacturer as of when this report is written (2024). Most of the manufacturers also mention that their systems can be scaled up to greater than 100 MW in size, by combining the use of several units. This is further confirmed by the large scale systems presented in Section 2.6, that are/will undoubtedly be comprised of several smaller modules. For the purpose of the given case study, it was assumed that even if larger electrolyser systems than those in Table 5.3 are available by 2030, the technical specifications will be similar due to the expected modular nature of large PEM systems.

The electrolyser manufacturers given in Table 5.3 report different operating ranges, varying from 5-100%. Most analyses take the minimum load for a PEM electrolyser system $P_{PEM_{min}}$ as 5% of the peak capacity as a safety measure, to ensure that locally explosive mixtures are avoided [80]. With a load below 5% the oxygen production decreases, increasing the concentration of hydrogen to dangerous levels [81]. The efficiency also drastically reduces below 5%

due to the cross-diffusion of oxygen that is catalysed back to water [81]. For the future, some scientific literature suggests that the minimum load for a PEM electrolyser could be reduced down to 0%, however this will depend on the specific cell and operating design [80]. IRENA predict that the minimum load will remain at 5% for systems produced 2050 [57]. Even if minimum loads lower than 5% will be possible, the effect that ramping up and down will have on the efficiency and flexibility of the electrolyser system is still unknown [82].

One of the advantages with PEM electrolysis over other technologies is that operation at loads higher than the peak capacity $P_{PEM_{peak}}$ is possible over short time periods [32]. IRENA suggests that PEM electrolyser systems could be able to handle 160% of the nominal load by 2025 [32]. However, it is unclear how long the equipment would be able to deal with such power inputs before degradation effects become too severe. Biggins, Kataria, Roberts, *et al.* offer another approach, where it is assumed that a PEM electrolyser can handle an overload of 200% for a maximum of 10 min, corresponding to 117% load over an hour [83]. Considering the uncertainty regarding the overload a PEM electrolyser would be able to handle, an operating range up to 100 % was chosen for the given case study. However, the fact that a PEM electrolyser system is likely to be able to deal with an overload up to 200% can be used as reassurance that the system could accept most of the electricity produced by the WPP, even during periods when electricity production is higher than expected and wake losses are minimal.

When the electricity produced by the WPP does not cover the minimum load, no hydrogen will be produced. Due to the dynamic operating range and fast ramp up and down time of PEM electrolysers, the losses that may come from the electrolyser system having to start and stop depending on the wind conditions are expected to be negligble. When the electricity produced by the WPP does not suffice, it was assumed that the electrolyser system requires 2% of the peak capacity to keep the auxiliary equipment running (e.g. pumps, alarm and control systems), this parameter is called P_{aux}. The 2% requirement does not include any hydrogen production. This value is verified by the fact that the stack consumption given by Nel is lower than the average energy consumption of the other four manufacturers given in Table 5.3 [78]. At times of no or very little wind, this electricity would have to be bought from the grid. Hence a connection to the distribution grid was necessary. An alternative would have been to use a battery for the supply of the auxiliary electricity, however this opportunity has not been investigated further.

The efficiency of the electrolyser system η_{system} will not be constant over time since it is affected by both load and degradation. The stack efficiency is negatively correlated with the load, and reaches a peak at around 20% of the maximum electrolyser load [24]. However, the efficiency changes are relatively small, hence it was assumed that the system had a constant efficiency regardless of the load. Over time the degradation of the electrolyser stacks will also lead to a reduced hydrogen production efficiency. In practice this means that with time less hydrogen and more waste heat is produced with the same energy input. Some manufacturers, like Cummins, claim that the efficiency degrades by less than 1 % per year [75]. For the following calculations, an annual efficiency degradation η_{deg} of 1 % was assumed.

The operating temperature of a PEM electrolyser will lie in the range of 50 °C to 80 °C, as mentioned in Section 2.3.1, and is decided depending on the temperature and flow rate of cooling water. Fragiacomo and Genovese suggest that 80 °C is the nominal operating temperature for commercially available electrolysers today [84]. However, higher temperatures negatively affect the lifetime of PEM electrolysers, hence why the operating range is lower compared to other technologies. IRENA report that next generation PEM electrolysers are expected to perform better under demanding conditions (defined as 70 bar and 80 °C) [57] . For the following case study the operating temperature was chosen to be 80 °C.

The lack of industry experience of operating large scale electrolysers created some difficulty in estimating the footprint of the electrolyser system A_E. IRENA present an estimation of the size of a 1 GW PEM hydrogen plant, being 8-13 ha [57]. However, only 25-35% of the space would be taken up by the hydrogen processing unit. The bulk of the area required would be needed for the electrical equipment (e.g. transformers, switchgears). The engineering estimate corresponds to a hydrogen plant size of 80-130 m^2/MW. In a report published by the European Commission, a target to reduce the footprint of a PEM electrolyser system from 120 m^2/MW in 2017 to 45 m^2/MW by 2030 is mentioned [85]. The report does not specify whether all electrical equipment is included. Furthermore, comparing the estimates by IRENA and the European Commission to the area required by Cummin's, Nel's, and Siemens's containerised solutions given in Table 5.4, it becomes apparent that large scale hydrogen plants are expected to have a large footprint. Reasons for this include safety purposes, control systems, and to accommodate for auxiliary equipment. However, different sources give varying estimates of the area that will be required by balance of plant components, suggesting that the final footprint is highly variable depending on factors such as location and manufacturer.

TABLE 5.4: Area required by electrolyser systems according to different manufacturers (Cummins, Nel, and Siemens), estimations from IRENA and the European Commission.

Source	**Unit Area (m^2/MW)**
Containerised electrolyser system estimaions	
Cummins [75]	8.6
Nel [78]	12.2
Siemens [79]	6.4
Hydrogen plant estimations	
IRENA [57]	80-130
European Commission [85]	45

Considering that all the equipment connected to the hydrogen plant would be negatively affected by the outside climate, especially during the winter months when temperatures in Norrbotten can drop down to -30 °C, it was decided that all the equipment should be placed indoors. Therefore, an average of the plant footprint estimation given by IRENA was used i.e. A_E is 105 m^2/MW [57]. Given the findings presented in this section, the technical specifications used for the given case study were determined as given in Table 5.5.

TABLE 5.5: Electrolyser specifications assumed in the case study. $P_{PEM_{peak}}$ is the peak capacity of the PEM electrolyser.

Electrolyser specifications	
E_{PEM}: Specific energy consumption (kWh/kg H_2)	51.6
FW_{PEM}: Specific feedwater consumption (l/kg H_2)	10
P: Delivery pressure (bar)	30
Ambient temperature (° C)	10-40
Operating temperature (° C)	80
η_{system}: System efficiency (%)	75
η_{deg}: Annual degradation of stacks (%)	1
$P_{PEM_{min}}$: Minimum electrolyser load (% of $P_{PEM_{peak}}$)	5
P_{aux}: Power to auxiliary equipment (% of $P_{PEM_{peak}}$)	2
A_E: Footprint of hydrogen plant (m^2/MW)	105

After determining the technical characteristics of the PEM electrolyser the hourly production of hydrogen was calculated by accounting for the specific energy consumption of the compressor $E_{Compressor}$ (kWh/kg H_2), BWRO unit E_{BWRO} (kWh/kg H_2), heat pump E_{HP} (kWh/ kg H_2), and the specific energy consumption of the electrolyser E_{PEM} (kWh/kg H_2). The predetermined grid connection P_{Grid} (kW) and the auxiliary power P_{aux} (here in kW) has to be removed from the total power output from the WPP P_{WPP} (kW) to calculate the amount of electricity that is directed towards hydrogen production. The hydrogen produced is given by H (kg/h) in Equation 5.7.

$$H = \frac{P_{WPP} - P_{Grid} - P_{aux}}{E_{PEM} + E_{BWRO} + E_{Compressor} + E_{HP}} \tag{5.7}$$

Using the amount of hydrogen produced, the power used by the electrolyser P_{PEM} (kW) could be calculated by subtracting the power to the BWRO unit, compressor, heat pump, and the power to auxiliary components from the power directed towards the hydrogen plant, as seen in Equation 5.8. Performing this calculation for an hour with the highest possible energy production from the WPP allowed for the determination of the peak capacity of the electrolyser $P_{PEM_{peak}}$ (kW).

$$P_{PEM} = (P_{WPP} - P_{Grid}) - (H \cdot (E_{Compressor} + E_{BWRO} + E_{HP})) - P_{aux} \tag{5.8}$$

5.1.4 COMPRESSOR

Due to hydrogen gas' low density, compression is necessary for storage and transportation. In this study the produced hydrogen gas was assumed to be transported and stored, through line-packing, in a future hydrogen pipeline system in the Bothnian Bay (The Nordic Hydrogen Route). The project owners have not yet published any pressure for the coming hydrogen gas pipelines and thereby the inlet pressure has been approximated based on literature. Khan, Young, MacKinnon, *et al.* assume an inlet pressure of 70 bar to pipeline systems [86], however, two other studies believe newer hydrogen pipelines can reach a pressure up to 100 bar [87] [88]. Further, Christensen even studies pressures up to 150 bar for injection into pipelines [89]. In this study the inlet pressure of the pipeline system was assumed to be 100 bar, being the outlet pressure of the compressor P_{out}

With the chosen PEM electrolyser, having an outlet pressure P of 30 bar, a compressor was needed to increase the pressure by 70 bar. However, Walker, Madden, and Thair imply that from 2035 and onwards the PEM electrolyser technology might be so advanced that no compressor is necessary for exporting hydrogen gas to a transmission grid [88]. Regarding the practical implementation of such technology nothing can be said yet and therefore this study relies on the need for a compressor.

Moreover, there are multiple types of compressors. The ones mostly used for large scale operations are mechanical compressors, among which the reciprocating piston and centrifugal compressors are most common [86] [87]. The compressor choice of this study was the centrifugal compressor driven by an electrical motor, and the method for dimensioning it is presented below.

First the number of compressor stages N was calculated according to Equation 5.9 [86]. P (bar) is the delivery pressure from the electrolyser, P_{out} (bar) is the outlet pressure of the hydrogen gas and x is the compression ratio per stage. The result was then rounded up to the nearest integer.

$$N = \frac{log(\frac{P_{out}}{P})}{log(x)} \tag{5.9}$$

An average temperature $T_{average}$ (K) was then calculated, first by calculating the outlet temperature T_{out} (K) according to Equation 5.10 where T_{in} (K) is the inlet temperature to the compressor, γ is the ratio of specific heat under constant pressure to the specific heat under constant volume, and η_{isen} is the isentropic efficiency of the compressor [86].

$$T_{out} = T_{in}\left(1 + \frac{(\frac{P_{out}}{P})^{(\frac{\gamma-1}{N\gamma})} - 1}{\eta_{isen}}\right) \tag{5.10}$$

$T_{average}$ was then calculated by using T_{out} and T_{in} as seen in Equation 5.11.

$$T_{average} = \frac{T_{in} + T_{out}}{2} \tag{5.11}$$

Through Equation 5.12 the average pressure was calculated which together with the average temperature was used to determine the compression factor Z. This was done using tabulated values [86].

$$P_{average} = \frac{2}{3}\left(\frac{P_{out}^3 - P^3}{P_{out}^2 - P^2}\right) \tag{5.12}$$

The next step was calculating the molar flow rate q_M (mol/s) from the mass flow rate by using Equation 5.13, where M_{H_2} is the molar mass of hydrogen (kg/mol) and H_{max} is the maximum mass flow of hydrogen per day (kg/day) [86].

$$q_M = \frac{\frac{H_{max}}{M_{H_2}}}{24 \cdot 60 \cdot 60} \tag{5.13}$$

Further, the rated compressor power $P_{compressor}$ (kW) was computed by using Equation 5.14, where R (J/mol K) is the ideal gas constant and η_{motor} is the motor efficiency [86].

$$P_{compressor} = \frac{N(\frac{\gamma}{\gamma-1})(\frac{Z}{\eta_{isen}})T_{in}(q_M)R\left((\frac{P_{out}}{P})^{(\frac{\gamma-1}{N\gamma})}-1\right)}{\eta_{motor}\cdot 1000} \tag{5.14}$$

Finally a specific energy consumption $E_{compressor}$ (kWh/kg H_2) of the compressor was calculated by using Equation 5.15 [86].

$$E_{compressor} = \frac{P_{compressor}\cdot 24}{H_{max}} \tag{5.15}$$

With the compressor specifics given in Table 5.6 the specific energy consumption was calculated for each scenario.

TABLE 5.6: Compressor specifics used for calculations.

Compressor specifications	
P: Delivery pressure from electrolyser (bar)	30
P_{out}: Outlet pressure (bar)	70
T_{in}: Inlet temperature (K)	305.15
η_{isen}: Efficiency (%)	80
η_{motor}: Motor efficiency (%)	95
x: Compression ratio per stage	2.1
R: Ideal gas constant (J/mol K)	8.314
M_{H_2}: Molar mass H_2 (kg/mol)	0.002
γ: Ratio of specific heat under constant pressure and heat	1.4

5.1.5 WASTE HEAT RECOVERY SYSTEM

As mentioned in Section 2.3.1, the PEM electrolyser will be subjected to an over-voltage in order to reach an acceptable hydrogen production rate. In practice this means that the reaction is exothermic, and the system will produce hydrogen gas as well as heat. As seen in Table 5.5, the system efficiency η_{system} was taken as 75%. The 25% of the incoming energy not used to produce hydrogen is lost as heat in the stacks, pumps, and other auxiliary equipment. Following the assumption made by van der Roest, Bol, Fens, *et al.*, the technical potential for heat recovery η_{HR} was taken as 80% of the heat produced in the system [24]. This corresponds to a heat production using 20% of the input electricity. Accounting for an annual degradation η_{deg} of 1%, the recoverable waste heat was assumed to increase with 1% annually. However, after each stack replacement it was assumed that the stack functionality was restored to the original efficiency. The waste heat rate P_{WH} (kW) could be calculated using Equation 5.16 (P_{PEM} and η_{system} can be found in Section 5.5).

$$P_{WH} = P_{PEM}\cdot(1-\eta_{system})\cdot\eta_{HR} \tag{5.16}$$

The recovered waste heat can be put to use in several ways. Due to the harsh winter climate in the Bothnian Bay, some of the heat could be used to keep the ambient temperature in the production facility at an acceptable level year-round. A rule of thumb employed when calculating the maximum heating need for buildings in northern Sweden is a specific heat demand P_{HD} of 0.06 kW/m^2 [90]. The total heat demand (dimensioned according to the maximum need) P_H (kW) of the electrolyser facility for each scenario could then be calculated using Equation 5.17 (A_E and $P_{E_{PEM_{peak}}}$ can be found in Section 5.1.3).

$$P_H = P_{HD}\cdot A_E\cdot P_{E_{peak}} \tag{5.17}$$

Due to the variable amount of the energy produced from a WPP there will inevitably be time-periods when no hydrogen is produced for several consecutive hours. During these periods no heat will be produced either. A hot water storage tank is therefore necessary for short-term heat storage. The heat storage required E_{HS} (kWh) was determined by the maximum number of consecutive days in which the minimum load is not covered D, and the heating demand of the hydrogen plant, as given in Equation 5.18. In reality, this heat storage will be slightly over dimensioned since the thermal inertia of the building was not considered in the calculations.

$$E_{HS} = D \cdot 24 \cdot P_H \tag{5.18}$$

Using the specific heat capacity of water c_P (kJ/kg °C), the expected temperature of the hot cooling water $T_{CW_{hot}}$ (°C), the minimum temperature of the circulating hot water T_{min} (°C), and the density of water ρ_{H2O} (kg/m^3), the volume of the hot water storage tank V_{HST} (m^3) can be given by the relationship shown in Equation 5.19.

$$V_{HST} = \frac{E_{HS}}{c_P \cdot (T_{CW_{hot}} - T_{min}) \cdot \rho_{H2O}} \tag{5.19}$$

The internal heating need is relatively small compared to the total amount of recovered heat. Considering that Luleå will be in need of new heat sources for the district heating network in the near future, most of the recovered waste heat could be sold. The production of heat for district heating not only adds an extra source of revenue, but it also increases the overall efficiency of the entire system. The heat rate to district heating P_{DH} (kW) was calculated using Equation 5.20.

$$P_{DH} = P_{WH} - P_H \tag{5.20}$$

The temperature of the waste heat and its relation to the outdoor temperature determines whether it can be transferred to the district heating network directly using a heat exchanger, or if it has to be upgraded using a heat pump. The waste heat temperature will remain constant throughout the year, and is assumed to be 79 °C. The supply temperature of the heat transfer fluid in the district heating network will have a minimum value of 74 °C when the outside temperature is above 5 °C. However, it will increase as the outdoor temperature decreases below 5 °C, according to the relationship given in Figure 5.2. Using a plate heat exchanger the temperature approach can be as low as 2 °C, meaning the waste heat does not need to be upgraded when the supply temperature is below 77 °C (i.e. below the dashed blue line in Figure 5.2). When the outdoor temperature drops below -1.6 °C and a larger supply temperature is necessary, a heat pump has to be used to upgrade the waste heat.

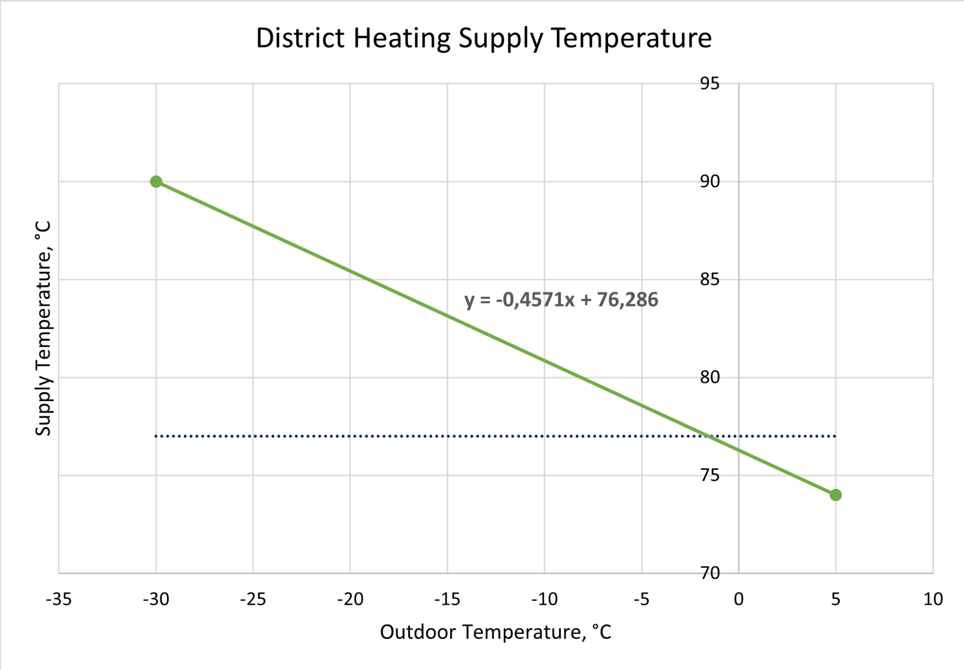

FIGURE 5.2: Estimation of the district heating supply temperatures in Luleå for 2030. A heat exchanger can be used at supply temperatures below the dashed blue line, and a heat pump is necessary if the supply temperature has to be above it. Image produced by authors.

The dimensions of the heat exchanger could be determined using the maximum heat load to district heating $P_{DH_{max}}$ (kW), given in Equation 5.20. A plate heat exchanger is chosen to allow for the small temperature approach, and because its footprint is significantly smaller than a shell-and-tube unit of the same heat load. The heat transfer area A_{HEX} (m^2) is one of the main parameters required to be able to estimate the cost of the unit(s). Since the mass flow rate will vary depending on the load of the electrolyser, several heat exchanger units will be necessary in order to allow for efficient operation. For the case study at hand, the maximum heat exchanger area has been calculated for the sake of simplicity. It was calculated using the log mean temperature difference *(LMTD)*, the heat transfer coefficient k (kW/m^2 °C) and $P_{DH_{max}}$ (kW), as seen in Equation 5.21 [91].

$$A_{HEX} = \frac{P_{DH_{max}}}{k \cdot LMTD} \tag{5.21}$$

Further, the $LMTD$ is the logarithmic average of the temperature difference between the hot and cold streams in the heat exchanger. It is defined by the relationship given in Equation 5.22, in which $\Delta T1$ is the temperature difference between the hot inlet and the cold outlet, and $\Delta T2$ is the temperature difference between the hot outlet and the cold inlet. For the case at hand, the hot inlet and outlet are the cooling water from the electrolyser ($T_{CW_{in}}$ and $T_{CW_{out}}$), and the cold inlet and outlet are the return and supply streams for a district heating network ($T_{DH_{return}}$ and $T_{DH_{supply}}$), all in °C [91].

$$\begin{aligned} \Delta T1 &= T_{CW_{in}} - T_{DH_{supply}} \\ \Delta T2 &= T_{CW_{out}} - T_{DH_{return}} \\ LMTD &= \frac{\Delta T1 - \Delta T2}{ln\frac{\Delta T1}{\Delta T2}} \end{aligned} \tag{5.22}$$

The industrial heat pump had to be dimensioned to be able to upgrade waste heat from a temperature $T_{CW_{in}}$ of 79°C to the maximum district heating supply temperature $T_{DH_{supply}}$ of 90°C. The coefficient of performance of the heat pump COP_{HP} will determine the amount of electricity required to upgrade the waste heat. It will vary depending on the district heating supply temperature, which in turn will depend on the outdoor temperature, as introduced earlier. SMHI have gathered the average hourly temperature for 2023 at their weather station called Luleå-Kallax Flygplats, which could be used to determine when the use of a heat pump would be necessary [92]. The outdoor temperature fell below -1.6°C during 38% of the year, meaning the waste heat temperature would have to be upgraded to > 77°C during more than four months in a similar year. However, a total of 60 data points were missing from the 2023 data set. To amend this an average of the temperature before and after the missing data point was used. The supply temperature was determined using the relationship pictured in Figure 5.2, also given in Equation 5.23, in which $T_{Outdoor}$ is the outdoor temperature in °C.

$$T_{DH_{supply}} = -0.4571 \cdot T_{Outdoor} + 76.286 \tag{5.23}$$

When the supply temperature of the district heating network need to exceed 77 °C, i.e. the heat pump has to be used, the Carnot efficiency COP_{Carnot} could be determined using Equation 5.24. T_{cond} and T_{evap} are the condensing and evaporating temperatures of the refrigerant in the heat pump in °C, respectively [93].

$$COP_{Carnot} = \frac{T_{cond}}{T_{cond} - T_{evap}} \tag{5.24}$$

The heat pump efficiency η_{HP} can then be used to determine the actual COP_{HP} using the relationship given in Equation 5.25.

$$\eta_{HP} = \frac{COP_{HP}}{COP_{Carnot}} \tag{5.25}$$

The average hourly electrical input required could then be calculated using the last COP_{HP} relationship given in Equation 5.26, in which P_{HP} is the heating capacity and P_{HP_E} is the electrical power input to the heat pump in kW [93].

$$\begin{aligned} COP_{HP} &= \frac{P_{HP}}{P_{HP_E}} \\ COP_{HP} &= \frac{P_{HP_E} + P_{DH}}{P_{HP_E}} \\ P_{HP_E} &= \frac{P_{DH}}{1 - COP_{HP}} \end{aligned} \tag{5.26}$$

The heat pump had to be dimensioned according to the first relationship given in Equation 5.26, with COP_{HP} and electrical power input P_{HP_E}. The maximum heating capacity of the heat pump $P_{HP_{MAX}}$ (kW) is then found using the maximum COP_{HP}. These conditions arise when the supply temperature has to be 90 °C, and the electrolyser is running at its peak capacity, i.e. producing the maximum amount of waste heat.

To optimise operation, the electrical input to the heat pump, had to be taken from the power produced by the WPP. Since this value will vary depending on the load on the electrolyser system, and the temperature upgrade required, a maximum value of the specific energy consumption of the heat pump E_{HP} (kWh/kg H_2) was used to ensure that enough electricity was always available. It was calculated using the power input to the heat pump P_{HP_E} (kW) during the hour of the greatest waste heat production, when maximum heat upgrade is necessary, and the hydrogen produced by the electrolyser system over the same hour H (kg). The relationship is presented in Equation 5.27.

$$E_{HP} = \frac{P_{HP_E} \cdot 1\,h}{H} \tag{5.27}$$

The WHRS has been visualised in Figure 5.3, including the heat exchanger (HEX), heat pump, and heat storage tank (HST). Component specific parameters concerning the operation and maintenance of the system have not been investigated further than what has been described in this section.

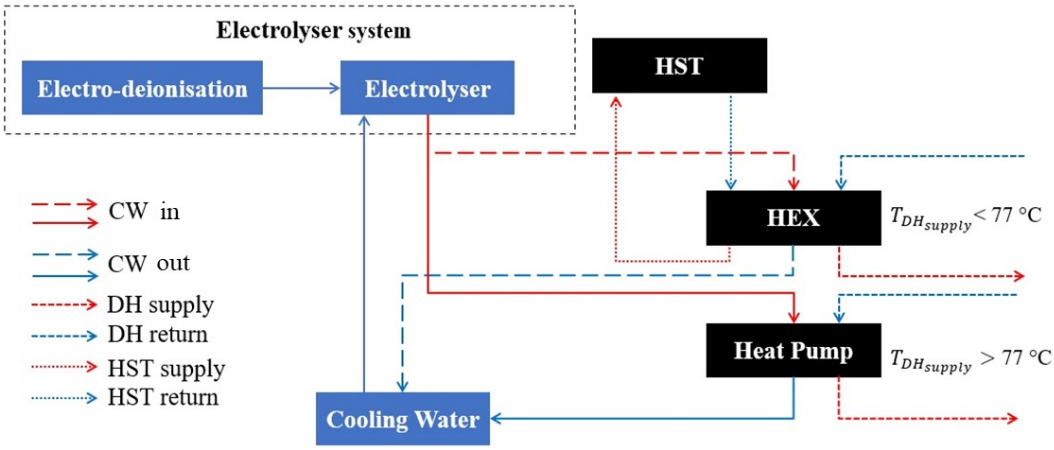

FIGURE 5.3: Simplified flow-sheet diagram of the waste heat recovery system (WHRS). Heat exchanger given as HEX and heat storage tank given as HST. Image produced by authors.

The constants used to calculate the specifications for the heat storage tank, heat exchanger, and heat pump are summarised in Table 5.7. The heat transfer coefficient was taken from The Engineering Toolbox [94], and verified with experts at Alfa Laval. The value for T_{min} was chosen according to guidelines by the Swedish Planning and Building Act to reduce the risk of legionella growth [95]. The cold and hot cooling water temperatures were decided using the assumption that the temperature difference should be 5 °C in order to reduce the rate of degradation of the equipment [96]. The district heating return temperature will vary with time, however for simplicity purposes it was taken as a constant value according to Jonsson and Miljanovic [96]. The assumptions for the evaporating and condensing temperatures of the refrigerant in the heat pump were taken from Jonsson and Miljanovic, and the heat pump efficiency was estimated given the assumptions made by Zuberi, Hasanbeigi, and Morrow [96] [97].

TABLE 5.7: Waste heat recovery system (WHRS) specifications.

Waset heat recovery system specifications	
P_{HD}: Specific heat demand (kW/m^2)	0.06
c_P: Specific heat capacity of water (kJ/kg°C)	4.2
ρ_{H2O}: Density of water (kg/m^3)	1000
k: Heat transfer coefficient (kW/m^2°C)	4
T_{min}: Minimum temperature of water circulation (°C)	50
$T_{CW_{in}}$: Cooling water (in/hot) (°C)	79
$T_{CW_{out}}$: Cooling water (out/cold) (°C)	74
$T_{DH_{return}}$: District heating (return) (°C)	50
$T_{DH_{supply}}$: District heating (supply) (°C)	74-90
T_{evap}: Evaporating temperature of refrigerant (K)	$T_{CW_{out}}$ - 10
T_{cond}: Condensing temperature of refrigerant (K)	$T_{DH_{supply}}$ + 5
η_{HP}: Heat pump efficiency	60%

5.1.6 CRITERIA

The energy output from the WPP was allocated to the transmission grid and an onshore electrolyser according to the scenarios described in Section 5.1.1. However, since wind speed varies with time, the energy produced from the WPP will not be constant. For this reason the allocation of electricity varied on an hourly basis. The precise allocation was determined by a number of criteria drawn up in order to maximize profits. To ensure a profitable set-up, the day ahead prices for the corresponding hours during 2023 were used to determine when electricity to the transmission grid and electrolysis should be prioritised. A minimum price was set to define the point at which it is more economical to produce hydrogen, rather than selling electricity to the grid. In this project, it was assumed to be 5 % of LCOE, corresponding to 35 SEK/MWh. The criteria have been described more in detail below.

1. If the hourly day-ahead price was higher than the minimum selling price, the primary goal was to maximise the electricity input to the grid. The remaining energy was used for hydrogen production.

2. If the hourly day-ahead price was lower than the minimum selling price, the primary goal was to maximise the production of hydrogen. If the electrolyser capacity could not receive all the power produced by the WPP it was assumed that the electricity generation could be ramped down.

3. When the WPP did not produce enough electricity to reach the minimum load of the electrolyser system, the electricity required to cover the demand of the auxiliary equipment was bought from the day ahead market with reference to the hourly prices for 2023.

5.2 TECHNO-ECONOMIC ANALYSIS

Based on the resulting model, a techno-economic analysis was performed to evaluate the business case of the hybrid energy system scenarios. In the literature review for the techno-economic analysis values of different currencies were encountered. To be able to compare the results they had to be converted into one common currency, in this case the Swedish krona (SEK). This was done by using the average exchange rates for 2023, provided by the Swedish central bank [98]. All costs and incomes were converted according to the currencies given in Table 5.8 below.

TABLE 5.8: Average exchange currencies for 2023 [98].

Currency	Echange currency SEK (Sweden, Krona)
1 CAD (Canada, dollar)	7.8637
1 EUR (Euroland, Euro)	11.4765
1 GBP (Great Britain, Pound)	13.1979
1 USD (USA, dollar)	10.6128

Furthermore, all values provided for years prior to 2030 were recalculated for the year 2030 using the inflation rate. The annual inflation rate was determined to be 2% and remain constant over the project lifetime. The Swedish Central Bureau of Statistics presents the annual inflation rate's development over time and it can be seen that the inflation rate for 2020-2023 has been abnormally high [99]. Thereby an assumption was made with regard to the annual inflation rate between 1990-2000 where it varied between 0-4%. The 2% inflation rate is also in line with the Central Bank of Sweden's inflation goal of 2% [100].

All the energy prices, such as the electricity price and district heating price, and the cost of brackish water were assumed to be constant over the project lifetime. This due to the high level of uncertainty concerning the future development of these prices. Their sensitivity to e.g. technological development, market signals, consumer demands, inflation or politics were hard to estimate and thereby excluded.

Another factor disregarded in the techno-economic analysis is the escalation rate of the operational expenditures (OPEX). No study could be found including an escalation rate of OPEX when calculating the LCOH. Due to little experience in the operation of an electrolyser and a hybrid system similar to the one of this case study, this factor was excluded from the analysis.

In the following sections the focus will be on the capital expenditures (CAPEX), OPEX and lifetime of the components included in the system design.

5.2.1 WATER RELATED COSTS

The costs of BWRO are hard to estimate since they vary between sites, with local water quality and over seasons [101]. While limited information is available in previous research on BWRO, there has been a significant amount of recent publications and research focusing on SWRO. Thereby, estimations for SWRO were used to approximate the costs of BWRO. Values from two different reports were used in the approximation of the BWRO's CAPEX and OPEX, see Table 5.9.

TABLE 5.9: Summary of SWRO cost estimations.

Source	Year of estimation	Type of water treatment	CAPEX USD/(m^3/day)	
			LOW	HIGH
Caldera and Breyer [102]	2030	SWRO	715	1 603
Khan, Al-Attas, Roy, *et al.* [103]	2021	SWRO	2 116	3 720

Caldera and Breyer estimate values for 2030 where the high and low case of SWRO are based on learning curves with different approximations of the annual online capacity [102]. Khan, Al-Attas, Roy, *et al.* assume a total capital cost of 1.86 million USD/(500 m^3/day) and 80 million USD/(37 800 m^3/day) for a SWRO plant in 2021, corresponding to the range given in Table 5.9 [103].

Further, the cost of BWRO is generally lower compared to SWRO due to the lower water salinity [101]. With this information the BWRO unit's CAPEX was determined to be in the lower price range, and an estimate for 2030 was used to provide the most representative value for the case study. A CAPEX of 1 000 USD/(m^3/day), 10 610 SEK/(m^3/day), was selected.

The OPEX is commonly given in relation to CAPEX and the total cost. According to Ghaffour, Missimer, and Amy, CAPEX is expected to cover 75% of the total costs, with the remaining 25% allocated to OPEX [101]. For a 25% OPEX the corresponding value was calculated to be 330 USD/(m^3/day), 3 500 SEK/ (m^3/day). CAPEX was assumed to be an one-time investment while OPEX an annual cost.

Depending on the scenario, the capacity needed for the BWRO will vary. To determine the specific cost for each scenario Equation 5.28 was used. W_{max} (m^3/day) is the maximum capacity needed for the BWRO. CAPEX and OPEX given in SEK and SEK/year respectively.

$$\begin{aligned} CAPEX &= 10\,610 \cdot W_{max} \\ OPEX &= 3\,500 \cdot W_{max} \end{aligned} \tag{5.28}$$

In addition to the water treatment costs there were also costs related to the water used. Brackish water is cheap and estimated to cost 0.24 SEK/ m^3, after discussion with the local district heating company Lulekraft AB, who also use large amounts of brackish water for cooling purposes.

Finally, the economic lifetime of the BWRO system was assumed to be long enough to cover the entire lifespan of Park A, i.e. 30 years. The same was used by Caldera and Breyer, and was therefore deemed appropriate [102].

5.2.2 ELECTROLYSER SYSTEM COSTS

The electrolyser systems that are dimensioned in the following case-study are significantly larger than the systems that have been commercialised at the time of writing. Several organisations, institutes, and specialists have made various predictions on the future costs of these systems. However, it should be taken into consideration that the estimations vary depending on the assumptions made, and the cost will ultimately depend on factors such as supply, demand, inflation, and technological maturity.

Several authors have estimated the costs of PEM electrolyser systems for 2030. The literature that has been used for cost predictions in the following case study are all based on systems that, at present, are considered "large-scale", i.e. > 10 MW. Dinh, Leahy, McKeogh, *et al.* present a viability assessment for hydrogen production from an offshore wind farm using a 90 MW PEM electrolyser system in 2030, with a cost of 600 EUR/kW [104]. This value was assumed after considering present manufacturer costs and a future outlook. Schmidt, Gambhir, Staffell, *et al.* consulted 10 different experts and projected the cost of a PEM electrolyser system in 2030 [105]. When assuming production scale up and a 10-fold increase in Research and Development (R&D) funding, the cost could range between 604 and 792 EUR/kW [105]. Furfari and Clerici present the case that further technological development and increased market volumes could reduce the cost of a PEM electrolyser down to between 360 and 500 EUR/kW by 2030 [82]. IRENA suggest as a result of a thorough literature review, that the system cost of a green hydrogen plant larger than 10 MW will be less than 200 USD/kW by 2050 [57]. IRENA also mention that the system cost in 2020 was (on average) 1 050 USD/kW. Using linear interpolation, the expected cost in 2030 would then be 767 USD/kW. These values have been summarised in Table 5.10, using the exchange rates mentioned in the beginning of this Section.

TABLE 5.10: Overview of electrolyser system CAPEX and OPEX values.

Source	CAPEX (2030)		Average	OPEX
	LOW	HIGH	(SEK/kW)	(% of CAPEX/year)
Dinh, Leahy, McKeogh, *et al.* [104].	600 EUR/kW		6 890	2
Schmidt, Gambhir, Staffell, *et al.* [105].	604 EUR/kW	792 EUR/kW	8 010	-
Furfari and Clerici [82]	360 EUR/kW	500 EUR/kW	4 930	-
IRENA [57],[32]	767 USD/kW		8 140	2

One of the main challenges with making a cost estimation of an electrolyser system is the inconsistency of system boundaries across scientific literature [57]. Furfari and Clerici, Dinh, Leahy, McKeogh, *et al.*, and Schmidt, Gambhir, Staffell, *et al.* do not specify the system boundaries [82] [104] [105]. However, since all three sources refer to PEM technology in a general sense, and do not specify costs of balance-of-plant components separately, it was assumed that the CAPEX values presented in Table 5.10 include the full electrolyser system, which is comprised of:

- Electrolyser stack
- Water demineraliser/deioniser
- Gas analyser, separator and separating vessels
- Scrubber or gas purifiers
- Recirculating pumps
- Transformer, rectifier, control panel

Taking an average of the CAPEX values provided by Furfari and Clerici, Dinh, Leahy, McKeogh, *et al.*, and Schmidt, Gambhir, Staffell, *et al.* gives a value of 6 610 SEK/kW for 2030 [82] [104] [105]. This is substantially smaller than the 2030 IRENA prediction of 8 140 SEK/kW. However, the value from IRENA is estimated using linear interpolation of the predicted CAPEX for 2050 [57]. Since IRENA does not provide a specific value for 2030, the other sources were considered more reliable to base a CAPEX estimation on. Therefore, a CAPEX of 6 610 SEK/kW was used for the techno-economic analysis. The initial investment cost for the electrolyser system was calculated using the peak capacity of the electrolyser $P_{PEM_{peak}}$ (kW), as seen in Equation 5.29, CAPEX given in SEK. An OPEX of 2 % of the initial CAPEX was also chosen, considering that both IRENA and Dinh, Leahy, McKeogh, *et al.* predict the same [32] [104]. The OPEX for each scenario was calculated using the second relationship in Equation 5.29, given in SEK/year.

$$
\begin{aligned}
CAPEX_{PEM} &= 6\,610 \cdot P_{PEM_{peak}} \\
OPEX_{PEM} &= 0.02 \cdot CAPEX_{PEM}
\end{aligned}
\tag{5.29}
$$

The annual degradation of the stacks ultimately means that they have a shorter lifetime than the rest of the system. The stack lifetime will depend on several factors, among which water quality plays an important role [57]. Typically, a lifetime in the range 60 000-110 000 h is predicted for 2030 [104]. IRENA, along with most other techno-economic analyses and electrolyser manufacturers, suggest 80 000 h, or approximately 10 years of operation, to be an appropriate choice [57] [75]. The operating hours of the electrolyser system will vary with each scenario depending on the available grid capacity assumed, and the peak capacity of the system (since it in turn affects the minimum operating load). However, assuming that the operating hours is not the sole reason to the degradation of the stacks, a lifetime of 10 years was assumed for every scenario.

The system lifetime for PEM electolyser systems is more difficult to estimate, since the technology has only recently been deployed on a commercial scale. The lifetime of Park A is predicted to be at least 30 years, hence the goal was to design a hybrid system in which the hydrogen plant operates for the same amount of time. In a technology outlook from 2018, IRENA estimate a lifetime of 20 years for 2025 [32]. However, in an IRENA report from 2020 only the stack lifetime is mentioned, and an indication of system lifetimes reaching that of AEL systems is stated [57]. Although the system lifetime of a PEM electrolyser has to be further validated, AEL electrolyser systems have been shown to reach lifetimes above 30 years [32]. Assuming that PEM electrolyser systems will reach this level of robustness with time, a lifetime of 30 years was assumed.

The stack replacement necessary after 80 000 hours will incur an additional capital cost lower than the initial investment. IRENA predict it to be 210 EUR/kW by 2025, corresponding to 2 410 SEK/kW [32]. Accounting for a 2% annual inflation rate it is 2 661 SEK/kW 2030. Other sources suggest that the replacement cost is 40% of the initial electrolyser cost, which would correspond to 2 644 SEK/kW in the given case study [106]. Taking into account the similarity between them, an average of 2 652 SEK/kW was chosen for 2030. Considering a system lifetime of 30 years, and a stack replacement approximately every 10 years, the stacks would need to be replaced twice within the technical lifetime of the electrolyser system. The cost will vary with electrolyser peak capacity $P_{PEM_{peak}}$ (kW), according to Equation 5.30. CAPEX$_{stack}$ given in SEK. This value will be affected by inflation for the stack changes in 2040 and 2050, which was accounted for in the model.

$$CAPEX_{stack} = 2\ 652 \cdot P_{PEM_{peak}} \tag{5.30}$$

5.2.3 COMPRESSOR COSTS

After researching previous literature it became apparent that data for compressor CAPEX and OPEX was quite sparse, something Christensen also highlights in his study [89]. Commonly the CAPEX and OPEX costs of the compressor seems to be included in the overall costs of the hydrogen production system, making it hard to identify and express the costs individually. However, Christensen presents two equations that can be used to estimate the costs and Khan, Young, MacKinnon, *et al.* a third one [89] [86]. The exact method for compressor cost estimations thereby varies between different sources and numerous ways to calculate the CAPEX can be found. In this study Equation 5.31 was used, given by Khan, Young, MacKinnon, *et al.* and providing a similar result to one of the equations given by Christensen. The cost per kW was re-estimated from 2019 CAD into 2030 SEK by the given currencies and the annual inflation rate. The uninstalled costs are given in SEK, $P_{Compressor}$ (kW) is the rated power of the compressor and SF a scale factor set to 0.8335 in accordance with Khan, Young, MacKinnon, *et al.* [86].

$$Uninstalled\ costs = 30\,152 \cdot P_{Compressor}^{SF} \tag{5.31}$$

Further, an installation factor *IF* was used to determine the total installed cost. The indirect costs were assumed to contribute with an additional 40% of the total installed cost, resulting in a compressor *CAPEX* (SEK) given by Equation 5.32. *IF* was determined to be 2 as is done by Khan, Young, MacKinnon, *et al.*[86]. The economic lifetime of the compressor was assumed to be 15 years and the compressor OPEX (SEK/year) to be 10% of the CAPEX value (se Equation 5.32), based on Khan, Young, MacKinnon, *et al.*'s values. Other sources have presented lower OPEX percentages, more similar to what Khan, Young, MacKinnon, *et al.* assumes for the operation and maintenance costs only. In the 10% OPEX both labour costs, and indirect operation and maintenance costs are included, resulting in the slightly higher value.

$$\begin{aligned} CAPEX_{Compressor} &= Uninstalled\, costs \cdot IF \cdot (1 + 0.4) \\ OPEX_{Compressor} &= 0.10 \cdot CAPEX_{Compressor} \end{aligned} \tag{5.32}$$

5.2.4 COSTS RELATED TO NORDIC ADAPTATION

The harsh winters that the hydrogen plant will be subject to creates the need for a insulated and heated facility, in which the ambient temperature is kept above 10 °C all year round. There are several construction companies that deliver these types of buildings, one of them being Tectum Byggnader AB [107]. Using the specific price per m^2 of their largest off-the-shelf solution, an estimate of the CAPEX for the facility could be determined for each scenario. Considering the inflation rate, and that the cost is 1 819 SEK/m^2 at the time of writing, the cost for 2030 was estimated to be 2 049 SEK/m^2. The OPEX for such a facility was assumed negligible in comparison. The CAPEX (SEK) for each scenario was found using the plant footprint A_E (m^2/MW), and the electrolyser peak capacity $P_{PEM_{peak}}$ (kW), as seen in Equation 5.33.

$$CAPEX_{Facility} = 2\,049 \cdot A_E \cdot P_{PEM_{peak}} \cdot 10^{-3} \tag{5.33}$$

The heat storage tank was expected to have an investment cost directly related to its volume. Over the past 6 years at least two large scale heat storage tanks have been built in Sweden; one in Luleå and one in Gothenburg, both of which will be used to store heat for the local district heating network [108] [109]. Their specific costs were 3 333 SEK/m^3 (2022) and 6 818 SEK/m^3 (2018) respectively. Considering the yearly inflation rate, the average specific cost estimate for 2030 would be 6 276 SEK/m^3. After discussing with LuleKraft AB, who operate the heat storage tank in Luleå, the same OPEX assumption as for the facility was assumed, i.e. it is negligible in comparison to the investment cost. The total CAPEX (SEK) for the heat storage tank for each scenario was then calculated using the volume of the heat storage tank V_{HST} (m^3), as seen in Equation 5.18. The lifetime was assumed to be the same as that of the hybrid energy system.

$$CAPEX_{HST} = 6\,276 \cdot V_{HST} \tag{5.34}$$

Most of the recovered waste heat will be sold to the district heating network in Luleå. This will provide an extra source of revenue, besides the production of hydrogen. Since the supply and demand of heat varies over the year, the district heating prices also change throughout the year. The result is a higher price during the colder months and a lower price as the outdoor temperature increases. Luleå Energi AB's energy price for district heating for company costumers in 2024 are presented in Table 5.11 below.

TABLE 5.11: District heating energy prices, excluding VAT, per season in Luleå for the year 2024 [110]. The prices represent the customer prices for companies.

Season	Months	Energy Price (excl. VAT) (SEK/MWh)
Summer	June-August	196
Spring/Autumn	Mars-May/September-November	256
Winter	December-February	404

The values presented in Table 5.11 were used as estimations to calculate the annual revenue from the heat. These values suggest a somewhat higher revenue than it would realistically be, since they include fees to the network owner and transmission costs. However, due to the uncertainty of the development of district heating in Luleå and the market price for heat, these values were used to at least reflect the seasonal changes in income from waste heat. In the case study, these prices were set to be static over the project lifetime, even though they have historically seen an increase in Sweden [111]. Additionally, the price of district heating in Luleå is currently very low compared to the rest of Sweden. This is expected to change as the steel industry transitions to fossil-free production. Using the selling price to estimate the income from heat is therefore justified by the fact that the value of waste heat is expected to increase in the future, considering both historical trends and the impending green transition of the steel industry. Nevertheless, the effect that changes in the district heating selling price could have on the LCOH have been analysed in the sensitivity analysis.

Further, any connection costs to the district heating network were disregarded. At the time of writing there are no external heat producers except from Lulekraft AB, and after discussing the matter with them and Luleå Energi AB, no further insight on how such a fee or agreement would be designed in the future was gained. Therefore, for the purpose of this study, these costs were assumed to be negligible. Additional revenues depending on the quality of the heat generated were also disregarded. The annual revenue from the heat could be estimated using Equation 5.35.

$$Heatrevenue = \sum_{i}^{8760} P_{DH} \cdot district\ heating\ energy\ price \tag{5.35}$$

The investment required for the plate heat exchanger(s) was estimated using an average price of 3 440 SEK/m^2, given by a representative from Alfa Laval. In practice, the total heat exchanger area will be divided between several units, and optimised according to the operation of the electrolyser facility. The OPEX was estimated to be relatively low, considering that gasket replacement and cleaning would only be necessary on average every 10 years over the 30 year lifetime. Assuming that such services would imply a cost of 2% of the initial CAPEX, an annual OPEX of 2%/10 years (0.2%/year) was used. This assumption is in line with that made by Jonsson and Miljanovic [96]. With a 2% annual inflation, the CAPEX in 2030 and annual OPEX could be calculated using the heat transfer area A_{HEX} (m^2), as seen in Equation 5.36, CAPEX in SEK and OPEX in SEK/year.

$$\begin{aligned} CAPEX_{HEX} &= 3\,955 \cdot A_{HEX} \\ OPEX_{HEX} &= 0.002 \cdot CAPEX_{HEX} \end{aligned} \tag{5.36}$$

The investment cost for the industrial heat pump will depend on the maximum heating capacity $P_{HP_{MAX}}$ (kW). Zuberi, Hasanbeigi, and Morrow present a relationship to calculate the

CAPEX in which a scale factor is used [97]. The specific price SEK/kW decreases with an increased heating capacity according to Equation 5.37. The values given by Zuberi, Hasanbeigi, and Morrow have been adjusted to SEK, and the annual inflation rate.

$$CAPEX_{HP_{spec}} = 15\,045 \cdot P_{HP_{MAX}}^{-0.113} \tag{5.37}$$

The annual OPEX was estimated to 1% by Zuberi, Hasanbeigi, and Morrow, hence the same was assumed for the given case study [97]. The CAPEX in SEK and OPEX in SEK/year for the heat pump could thereby be calculated using Equation 5.38.

$$\begin{aligned} CAPEX_{HP} &= CAPEX_{HP_{spec}} \cdot P_{HP_{MAX}} \\ OPEX_{HP} &= 0.01 \cdot CAPEX_{HP} \end{aligned} \tag{5.38}$$

The lifetime of an industrial heat pump can vary between 15 and 25 years [97]. For the purpose of the case study it was taken as 15 years, being in the lower range of what Zuberi, Hasanbeigi, and Morrow assumes [97].

5.2.5 SUBSIDIES

Green hydrogen has not yet become competitive on the hydrogen market, commonly being more expensive than the other hydrogen types. Subsidies are therefore granted to some projects to promote its role on the market and strengthen its competitiveness. The European Commission has, through the European Hydrogen Bank, launched a pilot auction for hydrogen subsidies in late 2023 [112]. They directed 800 million EUR to support the production of renewable hydrogen in Europe by, through subsidies, filling the gap between the consumer and producer price of hydrogen. In the auction the bids were based on a proposed price per kilogram of hydrogen with a maximum of 4.5 EUR/kg H_2 (circa 52 SEK/kg H_2). The selected projects and accepted bids receive the subsidy on top of market revenues for up to ten years. The auction closed in February 2023 and the results are to be published. A second auction will be launched in 2024 [113]. However, the maximum bid limit can be expected to decrease as the market for green hydrogen improves, leaving the development of such a subsidy quite uncertain.

A similar incentive is taken in the UK through their Net Zero Hydrogen Fund. The results from a first Hydrogen Allocation Round (HAR1) has just been published, granting 11 hydrogen projects subsidies per MWh of hydrogen produced [114]. A second Hydrogen Allocation Round (HAR2) is, at the time of writing, open for application. No information is given concerning a possible third round or the future of the subsidies. The 11 projects granted financial support will be provided it through a weighted average strike price of £241/MWh [114]. Assuming a lower heating value of hydrogen of 33.3 kWh/kg H_2, and the given currencies, the strike price ends up at circa 106 SEK/kg H_2. The price is weighted depending on the total volume of hydrogen produced by the specific project over the project's contract period (a low carbon hydrogen agreement contract). The subsidy is related to the natural gas price, which is set as a reference price, and could thereby vary over the project lifetime. The projects will receive the subsidy as they start operating, and the first project is expected to be brought to operation in 2025 [114].

On the national level, financial support from Naturvårdsverket and Klimatklivet have been granted to projects simliar to Park A and the coupled electrolyser system. Klimatklivet is partly financed by the European Union's fund, NextGenerationEU, and supports investments in fossil free technology working towards the green transition [115]. Two Swedish energy companies were recently granted financial support through Klimatklivet, namely Sveriges vindkraftkooperativ (Svef) and Skellefteå Kraft. Svef received 24 million SEK to produce green hydrogen from excess electricity from wind power, while Skellefteå Kraft got 39 million SEK to start fossil free hydrogen production aiming to replace aerofuel and diesel in heavy road transport [116].

Whether these subsidies or similar ones will exist and be assigned to this project remains unknown. From the Swedish and European perspective it is not very likely that the hybrid system will receive any subsidies that would have a considerable affect on the LCOH, thereby no subsidies were included in the analysis. However, their effect is evaluated in the sensitivity analysis.

5.2.6 CAPITAL STRUCTURE

For the capital structure of the LCOH calculation, assumptions regarding loan, equity, and interest rates had to be made. The calculation was based on the fact that loan-related costs are not dealt with on a project basis at RWE. This assumption was made based on discussions with experts at RWE who have more knowledge about LCOH calculations and the course of action for investments of this size. However, the investment would indirectly be financed through loans taken at the company level (for multiple projects), unburdening the individual investments from debt-related costs.

The cost of equity was difficult to specify. Through calculation it was determined to be 4.78% using Equation 5.39 [117]. The risk-free rate was then set to 2.20% in accordance to the average weekly values provided by the Swedish National Debt Office for 2024 so far (8th April 2024) [118]. Further, the equity risk premium was collected from country specific numbers published by Professor Damodaran at NYU and assumed to be 4.60% [119]. The beta parameter is a measure of security in relation to the broader securities market. Beta can be expressed as levered or unlevered, the first including debt in the capital structure and the latter removing debt from the capital structure [120]. Since no debt was included in this case analysis the unlevered beta was chosen. Again, the actual value was estimated based on Professor Damodaran's publications with beta values given for different industrial sectors. For this case analysis the industrial sector chosen was "Green & Renewable Energy" that had an unlevered beta of 0.56 [121], implying a low market sensitivity [120].

$$Cost\ of\ Equity = Risk\text{-}free\ Rate + Beta \cdot Equity\ Risk\ Premium \tag{5.39}$$

However, the "Green & Renewable Energy" sector may be too well-established given the uncertainties surrounding the development and establishment of green hydrogen technology. This implies a much higher equity risk premium or beta value. Discussing this matter further with experts at RWE it was concluded that a cost of equity of 7-12% would be more valid for this case study. These values are also in line with what Haug and Wieshammer present for hydrogen pipeline investments [122]. They conclude that a reasonable cost of equity for hydrogen networks are between 8.5-12.5%. Therefore, the cost of equity used for the case study was 8%.

In addition, the depreciation rate, tax rate and electricity taxes and fees had to be estimated.

With the economic lifetime of 30 years for the hybrid system the depreciation rate was determined to be 3.33% using Equation 5.40 below.

$$Depreciation\,rate = \frac{\frac{100}{Lifetime}}{100} = \frac{\frac{100}{30}}{100} = 3.33\% \tag{5.40}$$

The company taxation was taken from the Swedish Tax Agency and determined to be 20.6% according to the tax rate of 2023 [123]. An electricity tax of 415 SEK/MWh was added on the electricity bought from the distribution grid [124] [125]. The electricity tax was based on the electricity tax rate in Luleå municipality, which is lower compared to other locations in Sweden. Additional tax exemptions for hydrogen production through electrolysis were not valid for the presented scenarios in this study and thereby excluded.

Today an electricity certificate fee and a grid fee are also added on top of the electricity price and taxes. However, the electricity certificate fee system is expiring and will end in 2035 [126]. In addition, the electricity certificate fee is very low, around 5 SEK/MWh, and only applicable for the first five years of the project lifetime. Therefore it is assumed to be negligible and excluded from the analysis. Finally, a grid fee towards the distribution grid was considered. For the grid connections given in the scenarios the annual grid fee was set to 1 400 000 SEK/year as a fixed cost. An additional power fee of 187 000 SEK/(MW of power held available for the project) and an electricity transfer cost of -7 SEK/MWh were also included. The numbers were based on Vattenfall's 2024 tariffs for large company clients connected to the regional grid in Norrbotten county [127].

5.2.7 LCOE

The electricity that is bought from the grid will be purchased for the market price. The majority however, bought from the WPP, will be purchased for its LCOE. The electricity directed from the WPP towards the hydrogen plant was assumed to have a price equal to the LCOE, so as to not destruct the WPPs profitability. Due to confidentiality reasons RWE could not provide an exact value of LCOE for Park A. Instead, an average value from different LCOE calculations and estimations of offshore WPPs for 2030 were used. The IEA present three different scenarios and corresponding estimations of LCOE [128]. The scenarios illustrates different levels of climate engagement and actions taken to counteract global warming. For example, the most ambitious scenario is the NZE scenario, striving to keep global warming below 1.5°C and assuming that the United Nations sustainable development goals are reached. For all three scenarios the IEA concludes a LCOE of 45 USD/MWh in 2030,i.e. around 480 SEK/MWh [128].

Rapacka presents LCOE values for offshore WPPs to be built in the time period 2025-2030 in Swedish waters [129]. In the southern waters the LCOE is around 40 EUR/MWh, around 460 SEK/MWh, while in the northern waters of the Bothnian Bay it rises up to 49-60 EUR/MWh, around 560-690 SEK/MWh. In Table 5.12 a summary of all values follow.

TABLE 5.12: Summary of estimations of LCOE for offshore WPP from different sources and for different years.

Source	Year	LCOE 2030 (SEK/MWh)
Rapacka [129]	2025-2030	560-690
IEA [128]	2030	480

However, the team at RWE expect a higher value of LCOE for offshore wind in northern Sweden in 2030. The numbers discussed were in the magnitude of 1 000 SEK/MWh, considering the cold climate and the extra construction/investment costs that follow. This value is much larger than the estimations made for a similar location by Rapacka, and far from the values the IEA present for 2030. Given this, the LCOE was determined to be 700 SEK/MWh in this study, in between the literature values found and RWE's predictions. After further discussion with the RWE team the minimum selling price of electricity to the grid was set to 35 SEK/MWh, corresponding to 5% of the chosen LCOE as mentioned in Section 5.1.6.

5.2.8 LCOH

To calculate the LCOH a simplified model was created in Microsoft Excel , inspired by a method presented by Lazard but adapted to the specifics of this study (e.g. Swedish tax rates) [130]. The expenditures and revenues of hydrogen production were summarised over the project lifetime, starting at year 2030 and reaching until 2060. For the calculations the estimated values (previously presented in this chapter), were further processed to be representative for the corresponding year, the size of electrolyser and the grid connection available. Microsoft Excel's financial functions listed below were used for the calculations.

- Future value = FV (interest rate, number of periods, present value, type)
- Net present value = NPV (interest rate, cash flows)
- Internal rate of return = IRR (cash flows, initial guess)

The first calculation step was to determine the annual hydrogen production over the 30 year lifetime. This was done by assuming an annual degradation rate of 1%, which recovered every 10 years when the electrolyser stacks were replaced, and then adding up the annual productions into one cumulative amount of hydrogen. The same procedure was carried out for the annual and cumulative production of waste heat, with an escalation rate matching the degradation of the stacks.

Secondly, a total investment cost, CAPEX, was calculated based on the estimations given. For the components that required cost estimations for a year after 2030, re-estimations for the specific year were necessary and performed using the FV function in excel. For the compressor and stacks, replacements costs were included every 15 and 10 years. The net present value of the CAPEX was found using the NPV function for all the annual CAPEX values, and used to calculate the annual depreciation by multiplying it with the depreciation rate. Using the FV function the depreciation could then be estimated for the 30 year lifetime.

The calculations continued by determining the OPEX. The operation and maintenance costs of the electrolyser system was assumed to be unaffected by the stack replacements. Again, the

FV function was used to estimate the OPEX development over time. By subtracting the annual OPEX from the revenue, the earnings before interest, taxes, depreciation and amortisation (EBITDA) was found. The incomes considered in this project were the revenue gain form the hydrogen produced and the generated waste heat.

Hydrogen was assumed to be sold for the calculated LCOH value while the heat was sold to the district heating network for market price. It is likely that a market price of hydrogen will stabilise in Luleå in the future. This price could possibly be both higher or lower compared to the LCOH, and thereby affect the revenue. The calculated LCOH should not be seen as an estimation of the market price, only as the necessary price of hydrogen to achieve a net zero profit.

From the concluded EBITDA, the annual cost of tax was calculated by subtracting depreciation and multiplying it with the company tax rate. A net equity cash flow was found through subtracting the annual tax from EBITDA. For the first year the initial investment cost was added. Through Excel's IRR function and with the net equity cash flow, the internal rate of return was calculated.

Finally, to make the calculation process iterative and find a final LCOH a solver function was added according to a pre-determined cost of equity. The resulting IRR was set to be equal to the cost of equity by determining a new value of LCOH. The process was repeated for each scenario.

Chapter 6

RESULTS

In this chapter, the results of the case study are presented. Additionally, the cost breakdown and sensitivity analysis are explained, and their results are conveyed. Short comments on the results follow, but for further analysis of the results, see Chapter 7.

6.1 CASE STUDY RESULTS

The results obtained after performing the LCOH calculations for each of the four scenarios are summarised in Table 6.1, and visualised in Figure 6.1. Two LCOH values have been calculated for each scenario to show the effect of utilising a WHRS. For the given case study, the WHRS system includes the heat exchanger and the heat pump, since they allow the heat produced by the electrolyser system to be re-used and sold to the district heating network. The heat storage tank is assumed to remain for both cases.

TABLE 6.1: Resulting LCOH for each scenario, with and without a WHRS.

Scenario	Hybrid 1	Hybrid 2	Hybrid 3	Extreme
Electricity Grid Capacity (MW)	530	350	260	0
Electrolyser capacity (MW)	560	730	820	1060
LCOH (SEK/kg H_2)	66	63	62	58
LCOH w/o WHRS (SEK/kg H_2)	68	65	64	61
% increase in LCOH w/o WHRS	3	3	3	4

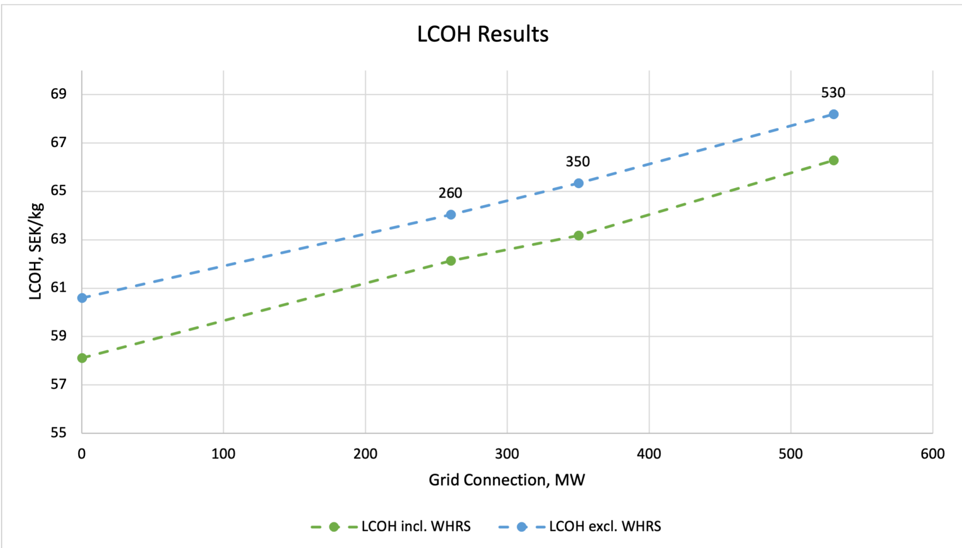

FIGURE 6.1: LCOH results for all scenarios, with and without a WHRS.

The results clearly indicate that green hydrogen production becomes more profitable when the size of the facility and electrolyser system increases. According to Figure 6.1, the relationship between LCOH and system size/capacity seems to be linear. Whether this trend continues and is true for system sizes outside this range, i.e. larger than 1 060 MW and smaller than 560 MW, remains unknown.

Further, the resulting LCOH is higher when the WHRS is excluded for all four scenarios (see Figure 6.1); each LCOH without the WHRS is at least 3 % higher than the corresponding value with a WHRS. This proves that the revenue gained by selling heat to the district heating network is higher than the added investment cost of the WHRS. The LCOH also decreases with a larger electrolyser capacity, implying that the production of hydrogen becomes more competitive when the electrolyser system size increases. The lowest LCOH achieved is 58 SEK/kg H_2 when there is no available grid capacity, with an electrolyser capacity of 1 060 MW, and a WHRS is incorporated. The largest LCOH of 68 SEK/kg H_2 is achieved when the grid capacity is 530 MW, the electrolyser size is 560 MW, and a WHRS system is excluded. This implies that by increasing the size of the electrolyser and including a WHRS, the LCOH can be reduced by as much as 15 %.

The increased LCOH with a smaller system size, and thereby larger available grid capacity, could partially be owed to the decreased run time of the electrolyser as more capacity becomes available on the grid. The total annual run time of the electrolyser system for each scenario is given in Table 6.2. For the smallest system size, i.e. Hybrid Scenario 1, hydrogen is only produced 50% of the year. The remaining hours the energy output from the WPP is either too low, or the electricity generated is prioritised to the grid, leaving too little to satisfy the minimum load. The results from the Extreme Scenario show that the electricity output of the WPP is high enough to satisfy the minimum load 88% of the year. This is a remarkable difference to the Hybrid Scenarios, that have run times that are between 27 and 43% shorter. The difference in annual run time also affects the amount of hydrogen produced per MW of installed electrolyser capacity, which is significantly lower for Hybrid Scenario 1 compared to the Extreme Scenario.

TABLE 6.2: Annual run time of the electrolyser system and hydrogen production for each scenario. The hydrogen production is given in ton/MW installed electrolyser capacity during the stack lifetime (10 years).

Scenario	Electrolyser System Size (MW)	Electricity Grid Capacity (MW)	Run Time (h/yr)	Run Time (% of year)	Hydrogen Production (ton/MW)
Hybrid 1	560	530	4390	50	595
Hybrid 2	730	350	5215	60	655
Hybrid 3	820	260	5595	64	687
Extreme	1060	0	7687	88	793

The costs with the largest effect on the LCOH are the CAPEX of the electrolyser system and the electricity costs resulting from the intracompany purchase of electricity from the WPP. This has been visualised in Figure 6.2, in which the LCOH cost breakdown for Hybrid Scenario 2 is shown. The cost of electricity from Park A contributes to 70% of the total costs, a clear majority. The second largest contributor is the CAPEX of the electrolyser with 16% of the total costs, corresponding to as much as 80% of the total CAPEX incurred over the system lifetime. The CAPEX of all the auxiliary equipment (in this case, auxiliary refers to all the equipment that is not the electrolyser system and the facility in which it is placed) only represents 4% of the total CAPEX. The total OPEX of the hydrogen plant, excluding the cost of water and electricity, constitutes 10% of all the costs, divided equally between the electroyser system and the auxiliary equipment. This in turn means that all the auxiliary equipment have a relatively large effect on the OPEX, compared to the CAPEX. The water costs, as well as the electricity costs from the grid and their relevant taxes, are small enough to be considered negligible.

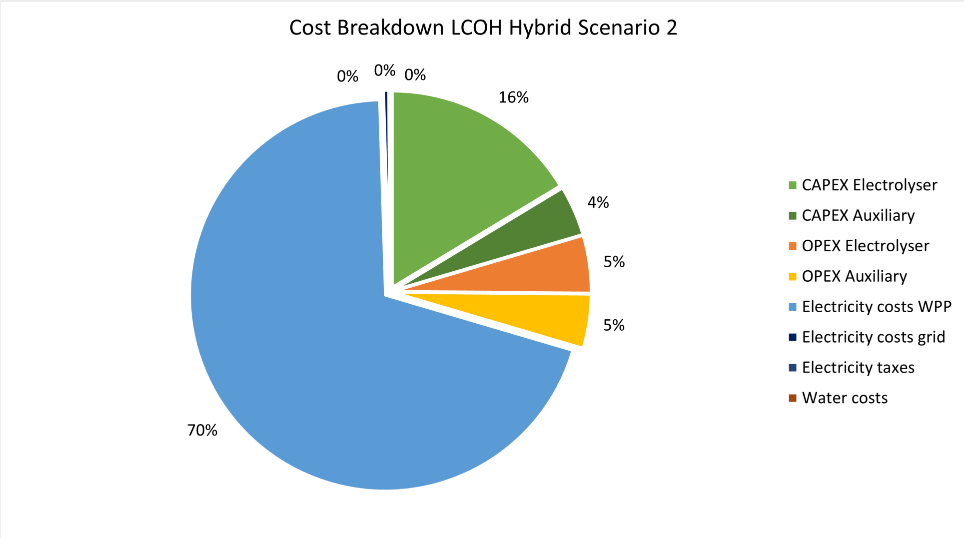

FIGURE 6.2: Cost breakdown of LCOH for Hybrid Scenario 2. Percentage per category is presented. The electricity costs from grid, electricity taxes and water costs are all 0% and thereby cannot be seen in the pie chart.

The cost breakdowns for the remaining three scenarios can be found in Appendix A. The distribution of the costs is almost the same for all the scenarios, with the cost of electricity from the WPP constituting 67-71%, and the CAPEX of the electrolyser system 16-20%. The OPEX of the electrolyser system and auxiliary equipment, along with the CAPEX of the auxiliary equipment, all varied between 4-5%. The cost of electricity from grid, taxes, and water costs all remained at 0%.

6.2 Sensitivity Analysis

In the process of collecting data and creating the LCOH model for the case study numerous assumptions were made, all of which have been presented in Chapter 5. The level of certainty in the assumptions varies depending on, for e.g., knowledge gained from the literature review, and the consensus within scientific literature. The future outlook and prospects of the technologies used in the model also affected the reliability of some of the estimations made. The impact of each respective assumption on the LCOH is also different, necessitating the use of a sensitivity analysis.

Due to the vast number of assumptions made in order to generate the model described earlier, it was considered unreasonable to include all of them in the sensitivity analysis. In order to pick out which parameters to include, a preliminary analysis was conducted, in which each independent variable was altered within a reasonable range. The range varied for each parameter, and was determined based on the values found in the literature review. Contrary to a classic"sensitivity analysis, in which each variable is varied up and down by the same amount, this method felt more true to the changes that the modelled hybrid system could be subjected to. Parameter changes resulting in a LCOH differentiating with 0-1 SEK/kg H_2 from the reference value were determined to have a low effect on the results. Further, a deviation of 1-3 SEK/kg H_2 was deemed to have a medium effect, while a deviation of more than 3 SEK/kg H_2

was deemed a large effect on the LCOH results.

The level of certainty and the evaluation of the individual parameter's effect on the LCOH results were used as a basis to determine which parameters to include in the sensitivity analysis. For example, parameters determined to have a low certainty combined with a high effect were included. Electricity taxes and fees, along with the district heating price, were included despite their low effect due to an interest in studying them further. In Table 6.3 a summary of the certainty level, effect evaluation and inclusion in the sensitivity analysis is presented.

TABLE 6.3: Summary of case study assumptions, their level of certainty, effect on the LCOH results, and whether or not included in the sensitivity analysis.

Assumption	Certainty	Effect on LCOH result	Included in Sensitivity Analysis
Wind Power Plant			
Turbine physical characteristics	high	medium	no
Wind data	medium	high	no
Cumulative losses after WPP	medium	low	no
Power coefficient of turbine	medium	high	yes
Hybrid system lifetime	medium	high	yes
Water Treatment System			
Water requirement	medium	low	no
Specific energy consumption of BWRO	medium	low	no
CAPEX	medium	low	no
OPEX	medium	low	no
BWRO lifetime	medium	low	no
Price of water	high	low	no
Electrolyser System			
Specific energy consumption	medium	medium	yes
Hydrogen delivery pressure	high	low	no
Ambient temperature range	high	low	no
Degradation rate	medium	medium	yes
Operating range and minimum load	low	low	no
Auxillary energy consumption	low	low	no
Footprint of electrolyser	low	low	no
Stack replacement cost	medium	low	no
CAPEX	low	high	yes
OPEX	medium	medium	yes
Electrolyser system lifetime	low	high	yes
Stack lifetime	high	medium	no
Compressor			
Hydrogen pipeline pressure	medium	low	no
Inlet temperature of compressor	medium	low	no
Compressor efficiencies	medium	low	no
CAPEX	medium	low	no
OPEX	low	low	no
Compressor lifetime	medium	low	no
Waste Heat Recovery System			
System efficiency	medium	high	no
Potential for heat recovery	medium	low	no
Heating demand of building	medium	low	no
Heat transfer coefficient of heat exchanger	high	low	no
Operating temperature	medium	low	no
Minimum temperature of water circulation	high	low	no
District heating temperatures	high	low	no
CAPEX heat exchanger	high	low	no
OPEX heat exchanger	low	low	no
Lifetime of heat exchanger	medium	low	no
CAPEX heat pump	medium	low	no
OPEX heat pump	medium	low	no
Lifetime of heat pump	medium	low	no
CAPEX building	medium	low	no
CAPEX storage tank	medium	low	no
Lifetime of building and storage tank	medium	low	no
District heating price	low	low	yes
Capital Structure			
LCOE	medium	high	yes
Minimum selling price of electricity	low	medium	yes
Electricity taxes and fees	low	low	yes
Subsidies	low	high	yes
Inflation	high	medium	yes
Cost of equity	high	high	yes
Company taxation	high	low	no
Company loan	medium	high	yes

In the following sections the range in which the selected parameters were altered within and results from the sensitivity analysis are presented. The sensitivity analysis was only conducted on one of the scenarios, Hybrid Scenario 2. Due to the similarities in the distribution of costs between the scenarios, it is considered enough to illustrate the result's sensitivity to independent variables on one out of the four scenarios. The same trends are expected to be applicable for all four scenarios.

6.2.1 WIND POWER PLANT ASSUMPTIONS

Two parameters concerning the WPP and its estimations were evaluated further in the sensitivity analysis. It was the power coefficient, *Cp*, of the chosen wind turbines and the economic lifetime of the hybrid system. The chosen *Cp* for the case study was 0.45 based on a range of 0.4-0.5 provided by Mahmoud, Salameh, Makky, *et al.* [63]. However, the performance of wind turbines is expected to increase and thereby a *Cp* higher than what Mahmoud, Salameh, Makky, *et al.* used was deemed interesting to evaluate. A *Cp* of 0.55 was chosen for the sensitivity analysis.

In the case study the economic lifetime of the project was set to 30 years, to equal the economic lifetime of Park A. For the sensitivity analysis the economic lifetime was changed to 20 and 40 years. For the analysis of a 40 year economic lifetime, re-investments of several of the system components was included at year 30. The following components were in the reference case assumed to have a lifetime of 30 years; electrolyser system, water treatment unit, and heat exchanger. It was not considered reasonable to push the lifetime even further and cover a 40 year economic lifetime. However, possible incomes from resale were excluded, hence the resultant LCOH for the 40-year economic lifetime is probably too high.

6.2.2 ELECTROLYSER SYSTEM ASSUMPTIONS

Several parameters in the electrolyser system have a considerable effect on the LCOH, including the specific energy consumption, degradation rate, CAPEX, OPEX, and system lifetime.

The specific energy consumption affects the amount of hydrogen produced in relation to the electricity used by the system, and was chosen as the average of the values given by four of the five electrolyser manufacturers presented in Table 5.3. The lowest value of 50 kWh/kg H_2 is given by ITM Power, and the highest of 53 kWh/kg H_2 by H-TEC systems [77] [76]. For the case study a value of 51.6 kWh/kh H_2 was chosen, but for the sensitivity analysis the specific energy consumption was varied between 50 and 53 kWh/kg H_2.

Another parameter with a significant effect on the LCOH is the stack degradation. Over the project lifetime it affects both the production of hydrogen and heat, shifting the source of revenue. The efficiency degradation used for the case study was taken from Cummins, that claim an annual degradation of less than 1% [75]. For the sensitivity analysis this value was varied between 0.5 and 2%.

The CAPEX of the PEM electrolyser system is the most significant contributor to the initial investment cost of the hydrogen plant. Its value is also one of the hardest to estimate, due to the various factors that it is affected by, including technological maturity, competitiveness, scale, geography, etc. For the case study, a value of 6 610 SEK/kW was used after analysing forecasts by various scientific articles. The range from which the average was taken was 4 930-8 010

SEK/kW, and for the sensitivity analysis the CAPEX was varied between these values. The annual OPEX of the system was taken as 2% of the CAPEX, since no source suggested a different value. However, it could be that this value underestimates the operation and maintenance costs since it is based on studies performed in more temperate climates than in Luleå. On the other hand, since little is known about large scale PEM electrolyser systems, it could be that 2% is an over-estimation for the operation and maintenance required. Therefore the OPEX was varied between 1 and 4% for the sensitivity analysis.

The lifetime of the electrolyser system is also a source of uncertainty. Since no electrolyser systems of the size dimensioned in this report have been built at the time of writing, little is known about their lifetime and possibilities of refurbishing older equipment. The system lifetime for the given study was estimated to 30 years given that the WPP is expected to remain in operation for a 30 year period. Considering that 30 years may be an optimistic lifetime for the electrolyser system, and that 20 years is given as the current estimate by IRENA, the lifetime was adjusted to 20 years in the sensitivity analysis to analyse how the LCOH would be affected [32]. In practice this meant that an entirely new system would be bought year 20. However, a re-sale value was not included after 30 years, hence it is possible that the resultant LCOH is slightly higher than it would be.

6.2.3 WASTE HEAT RECOVERY ASSUMPTIONS

Few of the WHRS parameters had a large enough uncertainty or effect to be considered viable for the sensitivity analysis. However, parameters that effect the production and use of waste heat, like the specific energy consumption, have been mentioned in the previous Section 6.2.2. The district heating selling price is the only WHRS-specific parameter varied in the sensitivity analysis since there were uncertainties concerning its magnitude and how it may change over the project lifetime. The price was increased and decreased with 15% in the sensitivity analysis, maintaining the seasonal variation.

6.2.4 CAPITAL STRUCTURE ASSUMPTIONS

As expected, the cost of electricity from the WPP and thereby the LCOE makes up the majority of the costs (see Figure 6.2). The chosen LCOE value in the case study was 700 SEK/MWh, and for the sensitivity analysis it was varied both up and down. The lower LCOE value was inspired by Rapacka's estimation for offshore wind power in the Bothnian Bay for 2025-2030, and the IEA's estimation for offshore wind power in 2030 [129] [128]. The higher LCOE value was based on the discussions with experts at RWE that expect a higher LCOE value due to the Nordic climate and higher costs. The values chosen for the sensitivity analysis were then 560 SEK/MWh and 1 000 SEK/MWh.

Coupled with the estimation of LCOE was the minimum selling price of electricity from the WPP towards the electricity grid. This parameter was important for the criteria of the analysis and also proved to have a medium effect on the results. In the case study it was set to 5% of the LCOE, and varied between 0-10% in the sensitivity analysis.

In addition to the electricity price, taxes and fees were applied. In Figure 6.2 it can be seen that these showed little effect on the results, but their future outlooks were very uncertain and thereby the parameter was included in the sensitivity analysis. In the sensitivity analysis, the grid fee towards the distribution grid remained unchanged from the case study. The electricity tax, initially set at 415 SEK/MWh and representing a tax-exempted value in the case study, was adjusted. A lower tax exemption, corresponding to the tax rate applied in many other municipalities in Sweden (535 SEK/MWh), was assumed. Additionally, a scenario with full tax exemption was analysed.

In the case study no green subsidies were included. However, there are some subsidies provided in UK, Europe, and Sweden which are interesting to implement to illustrate how green subsidies would affect the result. Three different types of subsidies were implemented, each one inspired by one of the above mentioned countries/regions. Based on the UK, a subsidy of 10 SEK/kg H_2 was implemented over the project lifetime, which is much lower than the 106 SEK/kg H_2 currently provided in the UK. This choice was made since the case study did not include the correlation to the natural gas price, hence it seemed more realistic to adopt a conservative approach for Sweden. The second subsidy given was inspired by the EU subsidy of around 52 SEK/kg H_2 for the first ten years of the project lifetime. For this case study 30 SEK/kg H_2 was used instead. Lastly, a cumulative subsidy was applied to lower the CAPEX, based on the Swedish subsidies provided. 40 million SEK was assumed to be granted.

The cost of equity proved to have a significant effect on the LCOH since it sets the requirements of the investment. As mentioned previously in Section 5.2.6 there were many uncertainties in the estimations, demanding further studies through the sensitivity analysis. Considering both the calculated value and the range discussed with RWE the cost of equity value was varied between 6% and 10%.

As with subsidies, loans were excluded from the case study but included in the sensitivity analysis. The purpose was to illustrate how loans could effect the resulting LCOH for projects that are financed through project specific loans instead of company loans, like RWE. To evaluate this the debt was set to be 70% of the net present value of the total CAPEX, and the cost of debt was set to 4%.

Finally, a parameter that exhibited unexpectedly moderate effects on the results was the inflation rate. Since a different outcome was expected, the parameter was studied further. For the initial LCOH calculations the inflation rate was chosen as 2%, and for the sensitivity analysis it was varied between 1-3%.

6.2.5 RESULTS OF SENSITIVITY ANALYSIS

The results of the sensitivity analysis are presented in Figure 6.3 below. After changing the above mentioned parameters to the given values, the final LCOH was recalculated. In total, the calculated LCOH values varied between 46-80 SEK/kg H_2, in comparison to the reference value of 63 SEK/kg H_2. The lowest value represents the most subsidised LCOH (30 SEK/kg H_2 for 10 years), and the highest value the LCOH with the highest cost of electricity (LCOE). In addition, the combined effects of parameter changes were studied. An optimistic case where the parameters included in the sensitivity analysis were changed to the average of their most positive result and the reference value was evaluated. In the same manner a pessimistic case was created. The economic lifetimes of both the hybrid system and the electrolyser system were excluded as well as subsidies and loan, both of which are not included in the reference case to start with. This resulted in a LCOH range of 53-83 SEK/kg H_2.

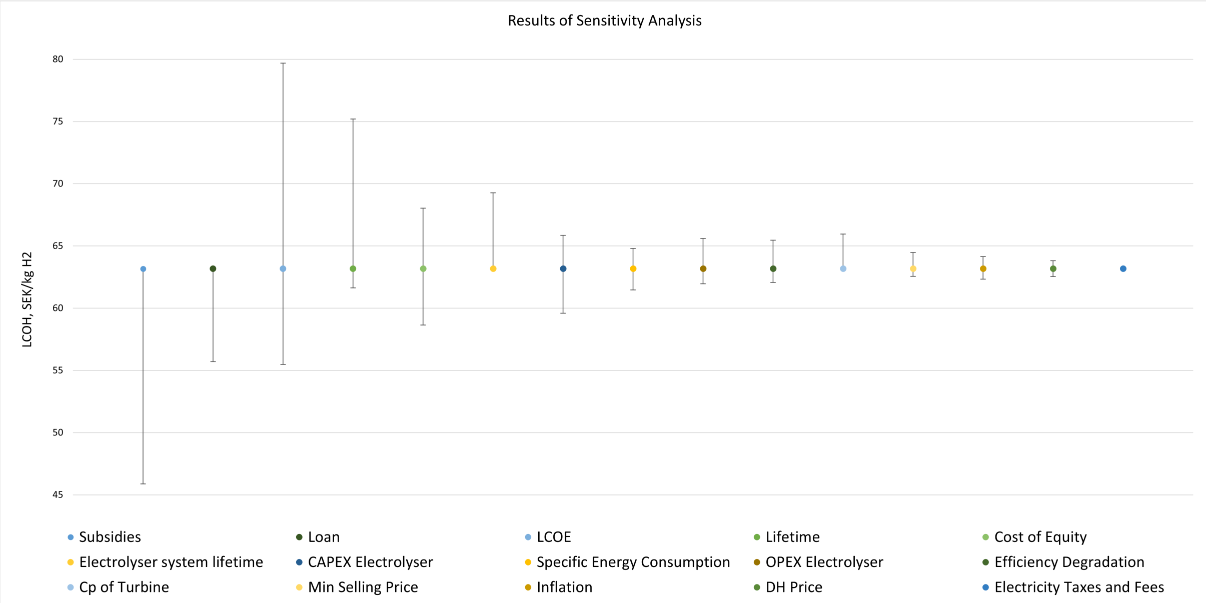

FIGURE 6.3: Results of sensitivity analysis. The figure illustrates the change in LCOH from the reference value when changing the parameters in the sensitivity analysis.

As seen in Figure 6.3 the LCOH was the most sensitive to subsidies, loans, LCOE, economic lifetimes, and cost of equity. Subsidies had a particularly large effect on the results when 30 SEK/kg H_2 was received over the first 10 years. The inclusion of loans also had a large impact on the results since less taxes are paid on the revenues and instead interest is paid to the bank. The differences between company tax and interest rate makes it favorable to take loans. The significant impact that LCOE has can be explained by its large contribution to the total costs (see Figure 6.2). Regarding the economic lifetime of the hybrid system, it can be concluded that a prolonged lifetime resulted in a higher LCOH value, whilst a shortened lifetime gave the opposite results. This can be explained by the extra capital expenditures necessary and their relatively large effect on the results (see Figure 6.2). However, since the possibility of resale was not evaluated for a longer lifetime, it could be argued that the comparison is unfair. Concerning the electrolyser system lifetime, a shorter lifetime resulted in a higher LCOH, explained by the same reasoning as before.

Another parameter that proved to have a medium effect on the result was the *Cp* of the wind turbine. Despite the increased performance of the wind turbine, the resulting LCOH was higher compared to the case study results. The result was surprising, since such a change often is accompanied with a higher system efficiency. However, with the higher turbine efficiency the electrolyser size became much larger, almost as large as in the extreme scenario. This without prioritising the production of hydrogen more, results in less hydrogen produced per installed MW of electrolyser capacity, and thereby an increased LCOH value.

Among the other parameters analysed in the sensitivity analysis, all the estimations regarding the electrolyser proved to have a greater impact than external parameters such as minimum selling price of electricity, inflation, district heating prices, and taxes. Most notably, the CAPEX had the largest effect of the parameters connected to electrolyser system that were studied. The minimum selling price showed a small effect on the result even though quite large changes were made. This could be explained by the fact that it did not change the size of the electrolyser or the electricity bought from grid. However, the electricity to the electrolyser changed and thereby affected the amount of hydrogen produced. The tax rate was both increased, but more interestingly, also set to zero. Despite a significant variation of the parameter, the results remained negligible. In contrast, a relatively small change in the specific energy consumption proved to have a much larger impact on the result (see Figure 6.3), indicating how different parameters affect the result.

Finally, the inconsistency of varying different parameters in the sensitivity analysis should be noted. As mentioned previously, all the chosen variables were individually re-evaluated and given new boundary values. These were set in accordance to what is presented in Section 6.2.1-6.2.4, and mainly based on the literature review of this work. For the purpose of this study the method was deemed reasonable and best suited, in comparison to varying each parameter up and down by the same amounts.

Chapter 7

DISCUSSION

The discussion is partitioned into four main sections. To begin with, a discussion on the methods used and the implications of the choices made is presented. It continues with a comparison of the case study results to previous research, and a discussion regarding the applicability of the results to other projects. The discussion on applicability includes four topics that proved to be of great importance to the result. These were: system design, scalability, geographical aspects, and company structure and ownership. Finally, the discussion is rounded off with suggestions on future research.

7.1 METHOD

The results produced using the various methods introduced in Chapter 4 are highly influenced by the assumptions and estimations made, some of which could have been attained through other means. The choice to complement scientific literature with a LCOH model was necessary due to the lack of available data from PEM electrolyser pilot schemes, and the confidential nature that any such data inherits. Performing a case study combining the knowledge from scientific literature with semi-specific site data, and constructing a general LCOH model, was the most valuable method to evaluate the business case. The findings can serve as a knowledge base for the design of future projects, and possibly fill the gap in scientific literature for hydrogen plant designs in regions with a colder climate.

The calculations and research performed in order to dimension and design the entire system would have been more accurate if site-specific wind data had been used. Due to both confidentiality reasons and a lack of such wind data, an estimation and extrapolation of online-available data from a nearby weather station had to suffice as the basis for potential power generation by a WPP. However, the data was validated by SMHI and Guttu both implying that it was representative for a normal wind year [65] [66]. Although, with climate change and new WPP installations in the area, the wind conditions will most likely change in the future. Even though the results would have been more relevant for the specific case if more site-specific wind data had been available, they still stand as a comparative analysis between various system sizes. Similarly, the design of the water purification system would have been more accurate if it were based on water-quality tests from nearby water courses. However, due to the relatively low effect that both the CAPEX and OPEX costs of the water treatment unit had on the final result, it could be argued that such insights would have had little effect on the final outcome of the financial analysis.

The nature of the case study meant that the geographical location of the hydrogen plant was undecided. This created difficulties when estimating costs that depend on the available infrastructure, such as the additional costs that would be incurred by cables from relevant transformer stations and district heating pipe installments. These could not be determined due to the uncertainties in where the plant would be located, and what infrastructure would be available. This meant that the costs were excluded from the analysis altogether. The effect that they could have on the results have not been analysed. However, since these types of installations are well-known and commercialised, the possibility that they would add a significant additional cost that creates a large deviation in the LCOH is slim.

The nature of the techno-economic analysis performed also meant that all operational parameters have been disregarded. This in turn means that the model was not optimised for the most convenient operation. For example, in practice it is unlikely that all the stacks will be replaced in one year. Instead, to spread out costs and make the production of both hydrogen and heat more even, they are more likely to be replaced over the course of a longer time period. Any additional costs that such operational choices would lead to have been disregarded from the analysis. Another vital assumption that has been made, is that the district heating network will always be able to receive all the waste heat produced by the electrolyser system. The heat production will not be constant due to the fluctuating operation of the electrolyser system, hence the district heating network will inevitably require other energy sources for balancing purposes. The same reasoning is valid for the variable operation of hydrogen, and its transportation and storage in pipelines. The operational requirements of the district heating network, and the hydrogen pipe system, have therefore been disregarded.

When designing the LCOH model, a choice to include heat, water and electricity costs as static parameters was made. The uncertainty surrounding the future cost development of these parameters makes them difficult to estimate. Their volatility depends on several unpredictable factors, including the future development of the energy system, and the global political climate. Considering that costs related to the electricity purchased from the grid and water consumption constituted less than 1% of the cost breakdown, it is unlikely that they would cause a significant effect on the LCOH, even if they were to be increased drastically. The price of district heating on the other hand could affect the LCOH to a more considerable extent. The most probable future scenario is that the value of waste heat in Luleå increases as SSAB transition to fossil free production, in which case the given LCOH is an over estimation, and the LCOH could be lower than that determined. In summary, it is highly improbable that the cost of heat, water and electricity would remain static over the project lifetime, but due to the lack of other plausible methods to model their respective changes, it seemed the most appropriate.

The chosen method and all the assumptions and estimations that it entails have without a doubt shaped the nature of the results. The case study could have become more specific by basing power and energy calculations on data instead of scientific literature, and it could have been made more general by basing values on a broader literature base.

7.2 Comparison of Results to Previous Research

The results produced by the LCOH model can be contrasted to those presented in Chapter 2 in order to determine how they measure up in a future green hydrogen market. However, it is important to remember that even though the LCOH is a common parameter used to compare the cost-effectiveness of hydrogen production methods, the initial assumptions and surrounding conditions can have an immense impact on the final value. This argument is strengthened by the impact that the cost of electricity proved to have on the case study results in the sensitivity analysis given in Section 6.2. When comparing results between studies, the cost of electricity is therefore also taken into consideration.

The LCOH results span from 58-68 SEK/kg H_2, and are thereby in the upper range of the price interval presented in Chapter 2, above both the blue and the grey values given by Schelling for 2030 [58]. The results are most similar to those of Giampieri, Ling-Chin, and Roskilly, being 69-92 SEK/kg H_2, which are specific to green hydrogen production from offshore wind power in the UK, and consider a cost of electricity slightly higher than that assumed by this case study [54]. The range of LCOH values presented by Bernuy-Lopez are significantly smaller than those obtained by this case study, which are 200 to 400% larger. However, the cost of electricity assumed in this case study is also 200-400% larger, matching the difference in LCOH values. A similar argument can be made for the difference in LCOH values between this case study and that presented by McDonagh, Ahmed, Desmond, *et al.*, who present a value of 43 SEK/kg H_2 given a cost of electricity that is 30% smaller [56]. Given the lowest LCOH result obtained in the sensitivity analysis, 46 SEK/kg H_2, the result align with those of McDonagh, Ahmed, Desmond, *et al.* [56]. The LCOH of 46 SEK/kg H_2 is correlated to a subsidy of 30 SEK/kg H_2 over the first 10 years of the project lifetime, an optimistic assumption when considering the Swedish subsidy system. Even though it is interesting to point out the great effect subsidies can have on the LCOH, it is important note that it is only a redistribution of costs from the investor to someone else. However, given the significant effect on the results it could be a strong economic incentive for investors, despite high electricity prices.

Among the studies reviewed in the previous research Schelling uniquely focused on Sweden, presenting a LCOH value of 16 SEK/kg H_2, contrasting those obtained in this study the most [58]. To draw conclusions concerning which study is most representative, the scope and cost of electricity would have to be compared, none of which have been given by Schelling [58]. However, considering the significant difference in values, and that cost of electricity constituted the largest portion of the cost breakdown given in Figure 6.2, it is fair to assume that Schelling had a more optimistic approach on future electricity costs than the case study conducted.

It is clear that the cost of electricity is one of the most influential parameters to affect the LCOH, and care should be taken before comparisons are made. As has been made clear by this comparison, the assumptions concerning the cost of the electrolyser system is not the main reason to the grave differences to the LCOH; the cost of electricity is. To make an even more fair comparison between results the methodologies and scopes also have to be closely compared, which has not been done by the authors of this report.

The competitiveness of the hydrogen produced will largely depend on the cost of electricity. In a green hydrogen market where most (if not all) hydrogen plants are subject to similar electricity costs to those assumed for this case study, the produced hydrogen could definitely be considered competitive.

7.3 Applicability of Results

The value of the results produced by the case study can partially be determined based on their applicability to other projects and potential hydrogen plants. The four main factors that affect the applicability of the results are; the system design, their scalability, the effect of the geographical location, and the structure and ownership of the company making the investment in question. When referring to the size of electrolyser systems, "large" scale refers to the size range investigated in this case study and beyond, and "small" to systems smaller than that investigated in this case study.

7.3.1 SYSTEM DESIGN

The case study only evaluates how the LCOH is affected by the size of the electrolyser system and the use of a WHRS. Moreover, the analysis does not investigate any technological alternatives, for any of the system components. Since such an evaluation has not been performed, a more cost- and energy efficient system design would be possible with different unit operations. Some examples are the use of a dual loop cooling system to remove excess heat more efficiently, or a cascaded heat pump with a higher *COP*.

The results are not applicable to cases using different system components, and the model is not easily adapted to scenarios using widely different technology. The choices in the case study were made considering the geographical location, and the direction in which the scientific community are expecting green hydrogen production to take, and should be treated as such.

7.3.2 SCALABILITY

The large scale production of green hydrogen has the potential to become competitive with blue and grey hydrogen as costs decrease with economies of scale [57]. The results of the case study suggest such an effect, despite relatively high electricity costs, as the LCOH decreases with larger system sizes. Due to the nature of the assumptions made, it is possible that the effect of an economy of scale has been underestimated.

Scale factors are generally an important parameter to incorporate to account for economies of scale. For some equipment, like the compressor and heat pump, these were readily available due to the maturity and commercialisation of the technology. The CAPEX for the electrolyser also indirectly reflects this effect, since all the forecasts used to determine it expect the technology to become cheaper with increased size and technological advancement. However, an explicit scale factor was not used to differentiate the investment cost of the electrolyser system between the various system sizes. Despite the exclusion of a scale factor, the LCOH decreased as the electrolyser capacity increased. If a scale factor had been included, the result would most probably have shown even greater differences in the LCOH between the different scenarios.

The scale-up rate of PEM electrolyser systems has not yet reached the system sizes dimensioned and investigated in this case study. Therefore there is little-to-no experience whether scaling up will lead to an economy of scale such as that shown in this study, and that is suggested by several other sources (such as IRENA [57]). One factor that could hinder the expected development of larger system sizes is the new engineering challenges related to heat and power management that will inevitably arise. Suggestions for how these can be dealt with have been presented in the case study, but must be investigated further to allow for safe and efficient operation of the given system sizes.

The results suggest a linear relationship between the system size and LCOH. This can be explained by the exclusion of both threshold factors and scale factors (for most of the equipment) within the range investigated. Whether this trend is true for system sizes smaller than 560 MW and larger than 1 060 MW is difficult to determine. For smaller system sizes, the LCOH could deviate to either plateu or increase in a more exponential manner. An increased LCOH could be caused by reduced revenues due to difficulties in; achieving acceptable hydrogen production efficiencies with a fluctuating power supply, or repurposing small amounts of waste heat. However, smaller system sizes may also make the logistical challenge easier, allowing for the electrolyser to be placed near strategic infrastructure that decreases the initial investment cost. With a smaller system continuous production could also become easier since the minimum load would decrease, allowing for more hydrogen to be produced in relation to the system size, thereby decreasing the LCOH. The relationship between LCOH and larger system sizes is even harder to estimate due to the many uncertainties caused by the lack of industry experience. Using the results to estimate the LCOH of a system size outside the range investigated in the study should therefore be done with caution, and it should be noted that threshold factors that have not been accounted for in the case study could affect the relationship between the system size and LCOH.

7.3.3 GEOGRAPHICAL ASPECTS

The geographical aspect is important to consider when interpreting the results, and the LCOH will vary depending on factors such as electricity prices, water availability, and subsidies. The results of this study are therefore not applicable for all locations.

As has been mentioned previously, the electricity price has proven to significantly affect the LCOH. An electrolyser system in the size range investigated in the case study demands a large power connection to the electricity grid, and thereby also significant electricity generation. At present, there is an overproduction of electricity in the northern parts of Sweden, providing optimal conditions for a large electrolyser system that can consume excess electricity. However, moving to the southern parts of Sweden and comparing electricity bidding zone SE1 with SE4, the circumstances change remarkably. Compared to SE1, the electricity supply in SE4 is sparse and the market price of electricity is relatively high. Contrary to SE1 there is an overconsumption, or at least a higher demand than supply, creating a less optimal location for a large scale electrolyser system. However, when considering a hybrid system like those modelled for the case study, in which electricity is bought directly from a WPP, the profitability might be higher in SE4. The LCOE values for offshore WPP in in the southern regions of Sweden are generally lower since the climate is more temperate. For example, Rapacka presents a LCOE difference of at least 100 SEK/MWh when comparing offshore WPP's between southern and northern Swedish waters in 2025-2030 [129].

Another geographical aspect affecting the profitability of an electrolyser system is the water source. Sweden has good water resources both in terms of available volumes and price. Additionally, the quality of the river water in northern Sweden is high and little treatment is necessary. In other geographical areas with limited water availability, it is possible that water sources are prioritised for the production of tap- and drinking water, rather than as sources for process water. Depending on the site, the degree of the necessary water treatment will vary, thereby also affecting its share of the total CAPEX. The water quality, quantity and price should therefore be considered before applying the results to other projects and plants, to ensure the water resources and treatment are similar to that assumed in this case study.

A third example of how geographical aspects will affect the LCOH is through hydrogen markets. This case study is not solely based on a Swedish hydrogen market, but more so a European or global one. No measures or adaptations for a future Swedish hydrogen market were incorporated, except from the choice of transporting and storing hydrogen in pipelines. The Nordic Hydrogen Route, which is assumed to be built, could in the future be part of the Hydrogen Backbone. With this assumption, a connection to a broader market including 25 EU member states, Norway, the UK, and Switzerland is made. Since the Hydrogen Backbone is under development the results of this study could, in terms of transportation and storage, be applicable for projects similar in terms of also aiming to be a part of the Hydrogen Backbone. However, it should be noted that the future of the Hydrogen Backbone is still uncertain, and whether it results in an international hydrogen market remains to be seen.

One final aspect directly correlated to geographical areas and nations are politics and policies, both of which have been disregarded in this study. Neither the European nor Swedish the political landscape have been considered, generalising the results and making them comparable to studies that have approached this issue similarly. The subsidies included in the sensitivity analysis were inspired by Sweden, UK and EU, not binding the results to a specific country. The electricity taxes considered were on the Swedish level, but since they proved to have negligible effect in the cost breakdown given in Figure 6.2, the results can be applied on a broader basis.

The LCOH will inevitably vary with geographical location. The conditions, both physical and political, shape the additional costs that the hydrogen plant is subjected to. Despite the impact of geographical location, the results of this case study could be applicable to hybrid systems located in areas with similar conditions in terms of electricity price, water quality and availability, storage and transportation, and political climate.

7.3.4 COMPANY STRUCTURE AND OWNERSHIP

The structure of the company investing and owning the hybrid system is also important to consider when analysing the results and their value in a different context. When making investments of this scale the ownership and company structure have a significant affect on the assumptions made and thereby the resulting LCOH. This case study was based on the assumption that RWE would own the entire hybrid system, both the WPP Park A and the coupled hydrogen plant. Any alternative ownership structures were not analysed in this study. Other ownership configurations include that the hybrid system could be divided between different companies, adding additional owner costs and possibly affecting electricity supply agreements. There could also be agreements where one company owns the system and another operates it.

In this case study the electricity bought from the WPP was assumed to be sold for the same price as the LCOE of the WPP, without added taxes. However, large electricity consumers commonly make power purchase agreements (PPA) with the power supplier to guarantee supply and negotiate the electricity price. With a PPA lower than the LCOE the profitability of the hydrogen plant would increase remarkably. Considering that the WPP Park A is assumed to be selling electricity to the transmission grid until the price drops below 5% of the LCOE (35 SEK/MWh) and then selling it to the electolyser system, a PPA between 35-700 SEK/MWh could be argued to be more representative. Such a scenario also increases the profitability of both systems.

Regarding the WPP profitability, the LCOE is the minimum price that the electricity generated has to be purchased for for the investment to break even. An electricity price above the LCOE is therefore desirable to make a net profit. After discussing the minimum selling price to the grid with RWE, it was agreed to be set to 5% of LCOE. At hours with day-ahead prices lower than that, the wind turbines would instead be turned away from the wind to stop its production.

The decision was based on the reasoning that some hours, when electricity is sold to the grid at prices higher than LCOE, the WPP will make enough profit to cover the opposite loss of profit when sold to a price lower than LCOE. With that said, the hourly lowest accepted selling price of electricity was much lower than the LCOE.

Keeping the same reasoning in mind, LCOE can be argued to be a too high electricity price for the intracopmany purchase of electricity from the WPP to the hydrogen plant. Depending on the ownership structure and the level of cooperation between the two systems a lower PPA could be agreed upon. For the business case for hydrogen production even a small reduction of the cost will have major effect, lowering the resulting LCOH. As was seen in the sensitivity analysis (Section 6.2) the LCOH proved to be the most sensitive to changes in LCOE.

Besides strengthening the business case of the hydrogen plant, the hybrid energy system also increases the level of resource utilisation of the WPP. The idea of the hybrid system originated from a will to utilize as much wind energy as possible in Park A, in other words, avoiding to turn away the wind turbines from the wind. Since all electricity cannot be transferred to the grid, the excess was transferred to the electrolyser system to increase the hybrid system profitability and to allow for an additional revenue for the WPP. Thereby, the two business cases, if operated correctly, promote each other. Hybrid systems can therefore be a key element to establishing both more wind power and hydrogen production.

The company structure also affects the basis on which the investment is financed. The case study assumes that RWE does not take project specific loans to finance the investment, and thereby interest rates, debt and amortisation were excluded from the original analysis. This might not be the case for other investors and companies. If so, the before mentioned parameters (and possibly others) should be accounted for. When considering debt, cost of debt, and amortisation, the LCOH can be expected to decrease, as seen in the sensitivity analysis, since the taxable income is reduced as a result of interest payments. The effect on the LCOH is highly dependent on the interest rate and the size of the loan. However, the choice for a loan can clearly be a strategic one, in order to reduce the cost of hydrogen production.

Another company specific parameter that affects the results is the cost of equity. As seen in Section 6.2, the cost of equity was one of the parameters the LCOH results were the most sensitive to. The parameter reflects the estimated risk of the investment, where a higher cost of equity is chosen for an investment with higher risk. Today, the green hydrogen technology is still in the commercialisation process, and the market has not yet established. As the technology and market become more mature the risk level of the investment decreases and the cost of equity can be pushed down. The development is fast and the forecasts uncertain, which makes it difficult to estimate a suitable cost of equity for 2030 and onwards. A good example of a technology with a history of quick development and increased technological maturity is wind power, where much has changed market- and technology-wise over the last 30 years.

To summarise, the company structure and ownership impact the results of investments of this kind and size. The results of this case study are most applicable and best compared to results of similar studies considering a large well established company, no external ownership and no project loans. It does not reflect the financial situation of a start-up or a smaller company.

7.4 Future Research

To further deepen the analysis it would have been interesting to include several other parameters. For example the political landscape and policies, comparisons between different component options, system design configurations, forecasts of electricity prices, additional revenues, social- and environmental aspects, among others. In this last section of the discussion, future research ideas are presented and briefly discussed.

In the case study the political landscape and its effect on hybrid systems profitability and possibility of establishing was disregarded. Politics play a major part in the level of ambition and direction of the green transition in Sweden. Today, the political landscape in Sweden is disunited in the development of the future energy system. The course taken by the government will shape new policies, possibly affecting the outlook for green hydrogen. For future research it would have been interesting to include some political aspects by, for example, basing subsidy levels, grid connection possibilities or future hydrogen infrastructure on different political landscape scenarios.

The development course of the Swedish energy system will impact the electricity prices. Forecasting and simulating these changes, creating different scenarios and applying them to the case study could increase its applicability. Even though the electricity bought from the grid proved to have little effect on the LCOH (as seen in 6.2), a change in the electricity price would affect the number of hours electricity is directed to the grid rather than the electrolyser system, thereby affecting the LCOH. In a future forecast it would also have been interesting to include the other WPP's from 4C Offshore, since wind power cannibalism might occur that pushes down the prices and the profitability of Park A.

On the discussion of prices and profitability, it could be worthwhile investigating the incorporation of the byproduct oxygen as an additional revenue stream. In this case study no consideration was taken to the generated oxygen, regarding either its cost or its income. This was due to lacking knowledge of oxygen off-takers in the area of the hybrid system, which therefore also requires further exploration. Since there are several large scale hydrogen production sites planned in the nearby area (e.g. H2 Green Steel and Hybrit), large volumes of oxygen will be produced in the near future. Finding a purpose for the generated oxygen as a feedstock, resource, or product itself is of great interest. However, for the investment to be profitable the additional infrastructure CAPEX and relevant transportation costs would have to be less than the resultant income. This in turn would be affected by its area of application and the corresponding quality requirements. For example, the quality requirements for oxygen that is to be used in healthcare services, and thereby also costs of processing, are higher than if it is to be used for marine environmental improvement measures.

The analysis could also be deepened by looking into alternate electrolyser technologies, and how it would affect the possibility of contributing to the ancillary market (aFRR and FCR services). In this study a PEM electrolyser was chosen. With its quick ramp up- and down-time it would be well suited to operate on the frequency market, thereby adding an extra source of revenue to the hybrid system. Considering the significant contribution that the CAPEX of the electrolyser system had to the cost breakdown (in Figure 6.2), it would also be interesting to evaluate the possibility of using the AEL or SOEC technology instead. Perhaps the AEL technology, demanding a more continues power supply, could be combined with battery storage and lower the CAPEX cost, while providing both aFRR and FCR services.

It could also be valuable to look at other forms of water purification. Depending on the water source and the demand for waste heat, using thermal water purification instead of a membrane based technology could result in energy savings and increased system efficiency. This is especially applicable in a case where the SOEC technology is used, due to the relatively high temperatures that the process demands compared to AEL and PEM. The profitability of the hybrid system could also be further evaluated in a scenario where the energy company responsible for the district heating could accept low-temperature waste heat, eliminating the need to invest in heat pumps. The income would most probably decrease, as the quality of the waste heat decreases, however it could still prove to be a worthwhile investment.

There are also several aspects, more difficult to measure, that would have been interesting to include in the analysis. These include the project's environmental and social "costs". For example how the surrounding nature is affected, emissions, and effect on wildlife and water streams. Also the environmental costs of using rare earth metals. In addition, public opinion, attitude and acceptance towards hydrogen production plants and hybrid systems could be included. It is possible that the acceptance for wind power could be strengthened by coupling it to an electrolyser system in a city like Luleå where the steel industry is important.

The entire life cycle perspective could also be an interesting topic for future research. In the scope of this study end of life (EoL) and possible reuse or recycling of material and components was excluded. Considering the different component lifetimes some might be functional to reuse at the end of the system lifetime while others could be recycled. At present little is known about the EoL for electrolyser systems since it is a relatively new market and technology, in the early stages of commercialisation. However, it is still important to consider these aspects when investing in large, costly projects.

Finally, green hydrogen is expected to become a key component in the future energy landscape due to its wide application base. The uses of hydrogen covered in this study are centered around the industry drivers in Sweden. Seeing to the use of hydrogen on a more global scale, its application areas are far more wide-spread. Together with CCUS, it has the potential to enable the decarbonisation of heavy transport; most notably by sea, through the production of e-methanol. Furthermore, its application in power generation, energy storage, and heavy industry (like the production of steel and cement) creates the possibility of emission reductions over the entire lifecycle of the relevant product. With its broad application base, its future expansion and development seems almost inevitable. Any and all investigation into its efficient production, storage and use is therefore relevant for future research.

Chapter 8

CONCLUSION

The case study set out to evaluate the business case of a hybrid energy system that combines generation of electricity from offshore wind power with onshore production of green hydrogen in the Bothnian Bay. The main findings are summarised below.

- The hybrid system exhibits the characteristics of an economy of scale, where investing in a larger system results in a lower LCOH. The case study results produced a LCOH in the range 58-68 SEK/kg H_2 for systems in the corresponding size range of 1 060-560 MW.
- Integrating a WHRS that repurposes excess heat to a district heating network lowers the LCOH for each scenario with 3-4%. This implies that the additional investment cost associated with the WHRS is lower than the heat revenue.
- One of the more significant findings to emerge from this study is the impact of the LCOE (cost of electricity from the WPP) and the CAPEX of the electrolyser system, that together comprised up to 86% of the resulting costs. The LCOE contributes with 67-71% of the total cost, while the CAPEX of the electrolyser contributes with 16-20%.
- The sensitivity analysis performed on 15 of the case study parameters for Hybrid Scenario 2 showed that the LCOH is most sensitive to LCOE, lifetimes of both the electrolyser and the hybrid system, cost of equity and CAPEX of the electrolyser. Depending on the parameter that was altered (excluding subsidies and loan), the reference LCOH of 63 SEK/kg H_2 varied between 56 and 80 SEK/kg H_2. For three of the remaining parameters, being specific energy consumption, efficiency degradation, OPEX of the electrolyser, and *Cp* of the turbine, the LCOH varied between 61 and 66 SEK/kg H_2. Notably, changes in the minimum selling price, inflation rate, district heating price, and electricity taxes and fees had little effect on the LCOH. Including subsidies and loans into the analysis showed that both can have a considerable effect on the LCOH, reducing it down to as low as 46 SEK kg H_2.
- An initial comparison of the case study results to previously published future LCOH values suggests that the production of hydrogen in a hybrid system like the one designed is non-competitive. However, when accounting for the differences in the assumptions concerning the cost of electricity, the assessment is hampered. It thereby becomes clear that the case study circumstances are crucial for the outcome, and the investment's profitability is determined by surrounding conditions.
- Another important finding of the case study is that the resulting costs and possible income streams are site-specific. A change in surrounding circumstances (water source, electricity generation, heat offtaker, hydrogen infrastructure etc.) affects the applicability of the results. In addition, company structure and ownership will influence the capital structure of the investment, for e.g. the cost of equity, loans, and intracompany agreements.

The findings can primarily serve as an early stage feasibility study for RWE's project possibilities in northern Sweden. The study can also be seen as a source of inspiration to how hybrid energy systems of this kind can be adapted to Nordic conditions, as well as the possibilities to repurpose waste heat. The study is unique in solely investigating electrolyser systems of a larger magnitude, in an attempt to learn more about how they can be designed and their potential profitability. It also strives to model the production of hydrogen based on external conditions, like wind and temperature data, and electricity prices from the day-ahead market.

Despite the specificity of the results to their particular circumstances, large-scale electrolyser systems show promise in aiding Sweden's green energy transition. Hybrid energy systems can effectively utilise excess electricity, bridging the gap between the available grid capacity and potential power supply. The case study results suggest that the simultaneous production of green hydrogen and renewable electricity in northern Sweden can be highly beneficial. The business case is also strengthened by the demand for both hydrogen and new heat sources for district heating in Luleå, especially as the steel industry transitions toward fossil-free production.

The most important limitations of the case study lie in the difficult nature of forecasting the development of hydrogen infrastructure, electrolyser technology, the Swedish energy system, and their corresponding costs. The results could thereby be complimented by a study that evaluates how the business case of the hybrid energy system could be affected by different future scenarios. To broaden the applicability of the case study, research into different possible system configurations that, for e.g. utilise the oxygen as a byproduct, waste heat for water treatment, or the electrolyser system as a provider of ancillary services is needed. The versatility of hydrogen as an energy carrier, feedstock and fuel opens up for a wide range of possible applications and future research areas. The hybrid system investigated in this case study is only one example of many possibilities.

Appendix A

Cost Breakdown of Scenarios

In Figures A.1, A.2, and A.3, the cost breakdown for Hybrid Scenario 1 and 3, along with the Extreme Scenario, have been presented.

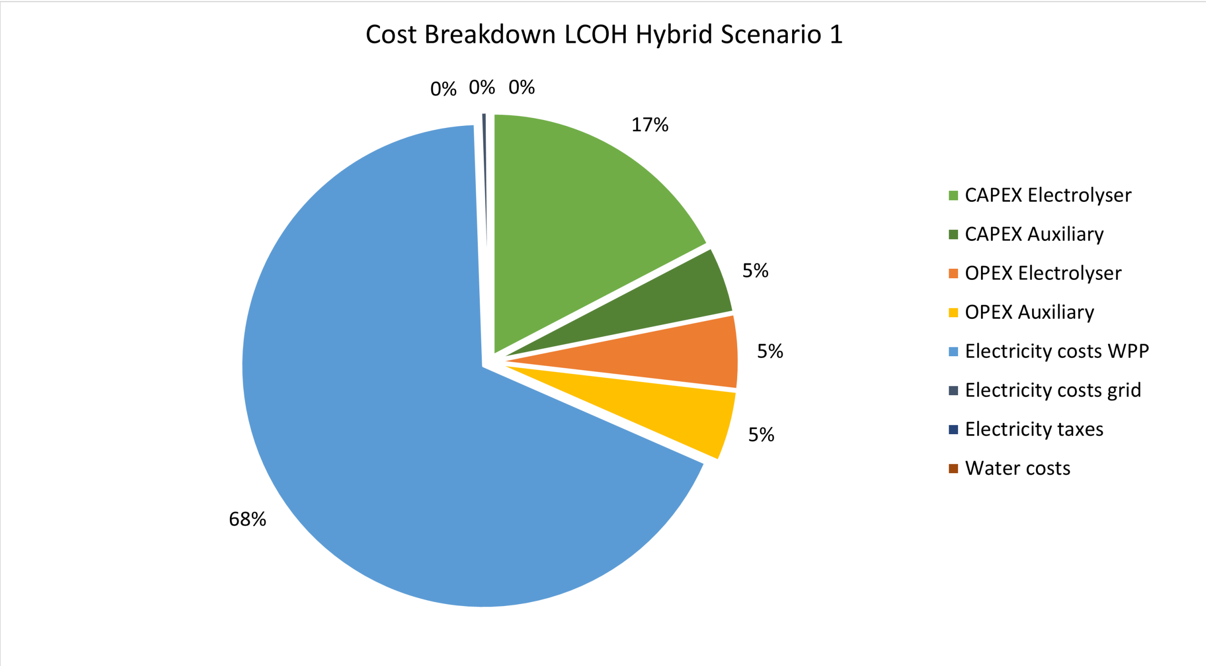

FIGURE A.1: LCOH Cost Breakdown for Hybrid Scenario 1.

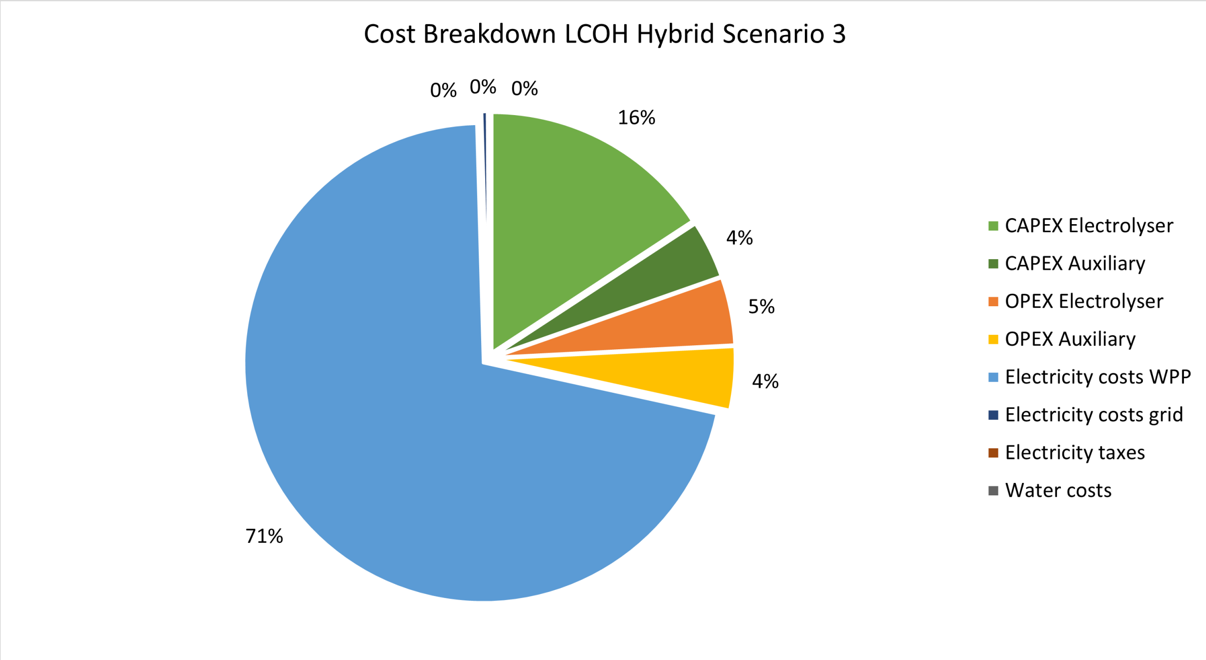

FIGURE A.2: LCOH Cost Breakdown for Hybrid Scenario 3.

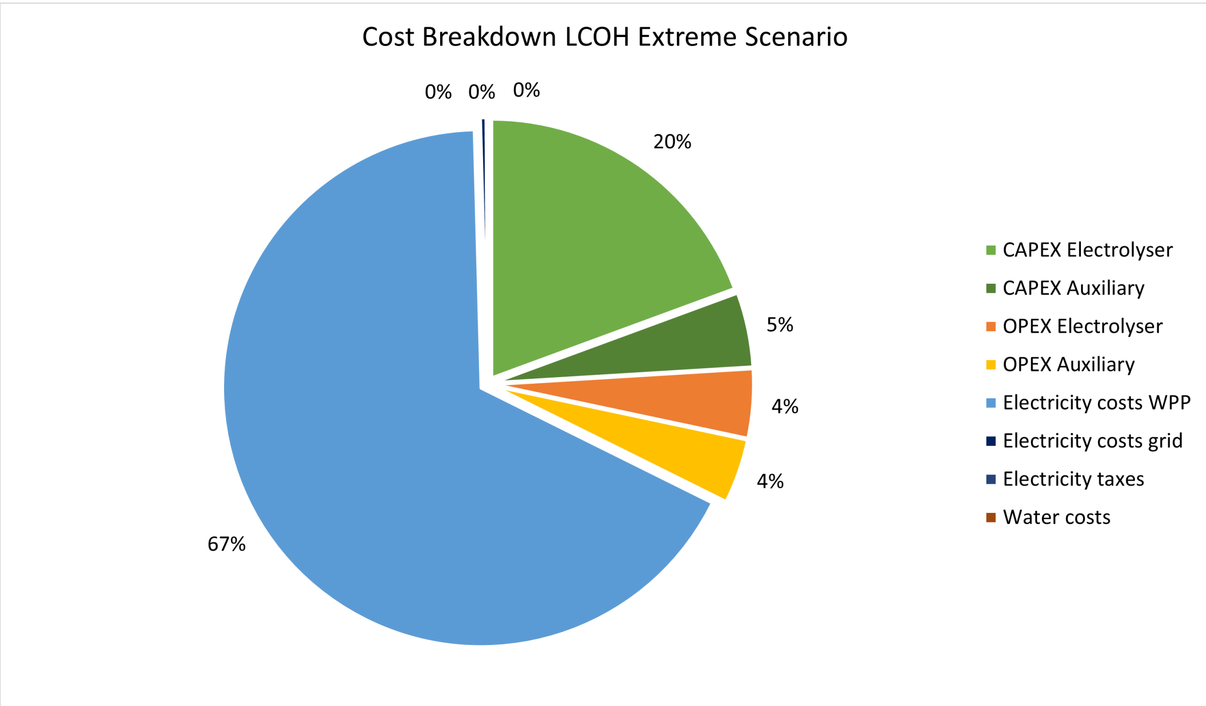

FIGURE A.3: LCOH Cost Breakdown for Extreme Scenario.

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