Bachelor's project

NTNU
Norwegian University of Science and Technology
Faculty of Engineering
Department of Energy and Process Engineering

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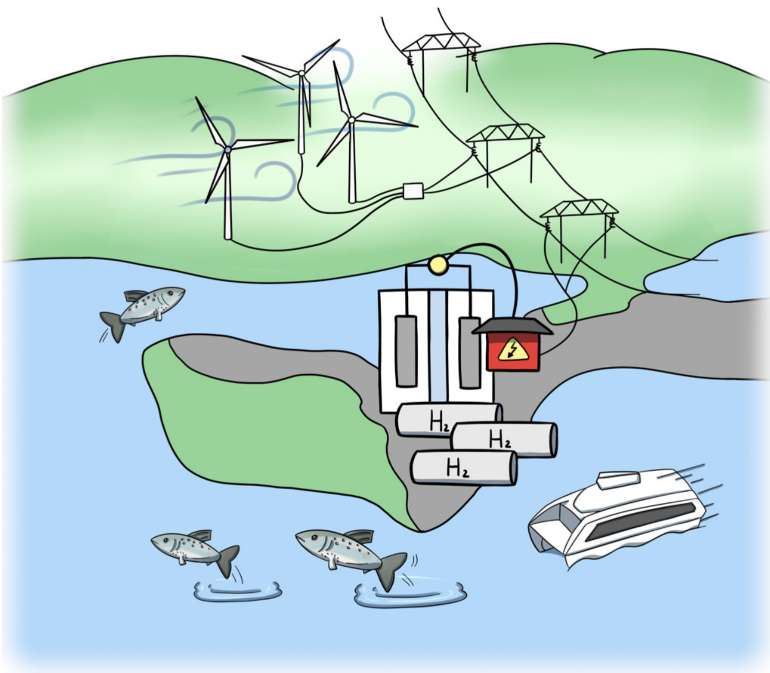
A Feasibility Study of Hydrogen Production at Hitra

Analyzing the Competitiveness of Hydrogen Produced for the Regional Maritime Sector

Bachelor's project in Renewable energy (Fornybar energi)
Supervisor: Bruno G. Pollet (NTNU) and Magnus Runnerstrøm (TrønderEnergi)

May 2020



Made by Ingrid Gunheim Folkestad and Miriam Bjerklund

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Preface

In order to reach the goal of global temperature increase below 1.5 °C, it is important to look at the sectors having the largest share of greenhouse gas emissions, such as the maritime sector. Hydrogen can replace conventional fossil fuels, if it is to be economically viable. As this thesis will show, Hitra is a suitable place for hydrogen production. In the short term, the production can cover the demand for high-speed crafts operating in the region.

The bachelor thesis is the final part of the three year study program *Bachelor in Engineering, Renewable Energy* at the Department of Energy and Process Engineering (Norwegian University of Science and Technology, NTNU). The thesis is written in cooperation between three student; Ingrid Gunheim Folkestad, Torbjørn Heimvik and Jesper Wimann Ingebretsen. The project description was given by TrønderEnegi as a request from Hitra Municipality. The main focus was to conduct an economical analysis of a possible hydrogen production plant. The other limitations were for the students to decide.

We would like to express our gratitude to our supervisor at NTNU, Bruno G. Pollet, for weekly guidance, for providing essential contact information and for support during the process of writing the thesis. We also want to thank our external supervisor from TrønderEnergi, Magnus Runnerstrøm, for providing information, guidance and suggestions from beginning to end. A thank is also given to Hitra Municipality for valuable information anytime needed.

Information and feedback provided by representatives from the hydrogen market have made the results more realistic. A thank is therefore given to Norled, ASKO, AtB, Trøndelag Fylkeskommune, Brødrene Aa, SINTEF, Hydrogenics and Fornybarklyngen. A special thank is given to Henning G. Langås and Bjørn Simonsen from Nel Hydrogen for valuable information and for taking their time to verify some of the results. Further, for motivation during the three years of study, we would like to thank Håvard Karoliussen, associate professor at NTNU. He has always gone the extra mile to help us and other students at the *Renewable Energy* study. Lastly, for motivation and inspirational words during the semester, a thank is given to family and friends.

Trondheim, May 22, 2020

Ingrid Gunheim Folkestad | Torbjørn Heimvik | Jesper Wimann Ingebretsen

Sammendrag

Klimaendringer og global oppvarming krever omstillinger i flere sektorer. Spesielt transportsektoren bidrar med store klimagassutslipp, som skyldes bruken av fossilt drivstoff. Hydrogengass er en energibærer med høy spesifikk energi (energiinnhold per masseenhet), som kan erstatte dette. Når hydrogen forbrennes eller brukes i en brenselcelle slippes det kun ut rent vann.

I denne oppgaven undersøkes mulighetene for å produsere konkurransedyktig hydrogen til den maritime sektoren på Hitra. Dette anses å være et passende sted å etablere hydrogenproduksjon, da området har tilgang på ren energi og det er ekstra kapasitet i strømnettet. Hitra ligger også sentralt i forhold til den regionale maritime industri- og transportsektoren. Området er det geografiske midtpunktet for hurtigbåtsambandet mellom Trondheim og Kristiansund. Etter en ny kontraktsperiode, som kan starte i 2024, vil sambandet høyst sannsynlig operere med hydrogendrevne båter. I tillegg er det mulig at brønnbåter, fôringsfartøy og andre båter som brukes i den regionale havbruksnæringen, på sikt kan driftes med hydrogen produsert på Hitra.

Elektrolyse brukes for å produsere hydrogen- og oksygengass ved å kun bruke elektrisitet og rent vann. Alkaliske og PEM vannelektrolysører (AWEr og PEMWEr) er foreløpig de eneste kommersielle teknologiene, og er derfor brukt som grunnlag i denne rapporten. Forskjellene mellom PEM og alkalisk elektrolyse skyldes først og fremst materialbruk. Den solide polymermembranen som brukes i PEM elektrolysører gjør det mulig å følge effektsvingninger. Dette gjør PEM elektrolysører til et bedre alternativ enn alkalisk elektrolysører når det brukes en varierende effektkilde, som for eksempel vindkraft. Men dette gjør også at PEM-elektrolysører er vesentlig dyrere.

Målet med oppgaven er å undersøke hvorvidt hydrogen kan produseres på Hitra til en konkurransedyktig pris. Dette er først og fremst sett på ved å beregne hydrogenkostnad over levetid, LCOH, for to scenarioer. Det første scenarioet utnytter all tilgjengelig effekt til hydrogenproduksjon, med elektrolysørkapasitet på 10 MW. Det andre scenarioet skal dekke dagsbehovet til to hurtigbåter, som er satt til 2500 kg hydrogen, med en elektrolysørkapasitet på 5.5 MW. Kostnadsdata er innhentet for forskjellige utgiftsposter, som investeringskostnader (CAPEX), ikke-materielle kostnader, vedlikeholdskostnader (OPEX), vann- og strømutgifter. Disse dataene er stort sett hentet fra litteraturstudier, noe som har medført visse antagelser, og ikke fra faktiske markedsaktører. På grunn av dette bør resultatene i rapporten anses som veiledende og ikke eksakte.

Når all tilgjengelig effekt utnyttes er det mulig å produsere 1700 tonn hydrogen per år (4.7 tonn per dag), ved bruk av AWE på Hitra. Ved å bruke PEM-elektrolyse er produksjonen en del lavere. En systemlevetid på 20 år og elektrolysører fra Nel Hydrogen er brukt som grunnlag i disse utregningene. Komprimert gass vil bli benyttet som lagringsform, siden dette er den mest utviklede og kostnadseffektive teknologien. I fremtiden kommer flytende hydrogen til å være et alternativ, men dette er foreløpig for dyrt med tanke på det mulige produksjonsvolumet for hydrogen på Hitra.

Beregningene viser at et elektrolyseanlegg på Hitra kan produsere hydrogen med LCOH-verdier fra 36.4 til 37.8 NOK/kg for AWE, og 39.9 til 42.8 NOK/kg for PEMWE. Dette gjelder for total produksjon og produksjon til kun hurtigbåter. Strøm og nettleie utgjør mellom 61 og 65 % av den totale hydrogenkostnaden. Utregningene er basert på en fast strømpris på 0.24 NOK/kWh (ekskludert MVA), som er et gjennomsnitt av estimerte, fremtidige, elektrisitetspriser for de neste ti årene. For hydrogenpriser mellom 44 og 54 NOK/kg er det beregnet nåverdier på mellom 68 og 156 MNOK for scenarioet med produksjon til kun hurtigbåter. Når all tilgjengelig effekt utnyttes er nåverdiene vesentlig høyere. For begge scenarioene er det beregnet tilbakebetalingstider på 6.3 til 4.2 år for det samme prisintervallet.

Det kommer fram at hydrogen produsert på Hitra ikke vil bli like billig som marin gassolje, som er det vanligste drivstoffet i maritim sektor i dag. Likevel så regner flere aktører med å kunne levere hydrogen til under 50 NOK/kg til dette formålet, noe som også vil være mulig på Hitra. Ved å se på estimerte nåverdier og tilbakebetalingstider bør det altså være mulig å produsere konkurransedyktig hydrogen til den regionale, maritime, sektoren på Hitra. På lengre sikt gjelder dette også for sluttbrukere innenfor landtransport, som lastebiler. Et elektrolyseanlegg på Hitra, som har tilgang til ren energi, vil dessuten kunne produsere miljøvennlig hydrogen med lavt karbonfotavtrykk.

Abstract

Climate change and global warming call for realignments within many sectors. For instance, the transport sector contributes with substantial greenhouse gas (GHG) and particulate emissions, as fossil fuels are used in most cases. Hydrogen, being an energy carrier with high specific energy (amount of energy per kilogram), can replace these fuels. The use of hydrogen does not cause any emissions except from pure water, when used in a fuel cell.

In this thesis, the feasibility of hydrogen production for the maritime sector at Hitra is investigated. It is likely to be an appropriate location for hydrogen production, having access to local wind energy and a transformer with surplus capacity at Sandstad (Hitra Harbor). Hitra is also central for the regional maritime industry and transport sectors. It is the midpoint of the high-speed craft (HSC) connection between Trondheim and Kristiansund, which is likely to be operated by hydrogen powered boats after a new contract period starts in 2024. Additionally, well-boats, feeding carriers and other vessels used in the regional aquaculture industry, can probably be powered by hydrogen from Hitra in the longer term.

Electrolysis is a method to produce hydrogen and oxygen gas from using only water and electricity. Alkaline and PEM water electrolyzers (AWEs and PEMWEs) are the only commercial technologies today, and are therefore of interest in this thesis. The differences between these are mainly caused by the materials that are used. The solid polymer electrolyte membrane used in a PEMWE makes it possible to operate at load-following conditions. This makes a PEMWE advantageous over an AWE when using an intermittent power source as for instance wind energy. However, this also makes PEMWE more expensive.

The objective of this study is to investigate the feasibility and competitiveness of hydrogen production at Hitra. This is mainly carried out through studying costs and calculating the levelized cost of hydrogen, LCOH, for two scenarios. The first scenario exploits all available power to hydrogen production, with an electrolyzer capacity of 10 MW. The second scenario covers a daily demand for two high-speed crafts, set to be 2500 kg of hydrogen, with an electrolyzer capacity of 5.5 MW. Cost data is collected for different expenditure variables, including capital expenditures (CAPEX) for different components, non-material costs, operational expenses (OPEX), water and electricity. The cost data is in general obtained from literature review, entailing some assumptions. It has not been supplied by actual suppliers. Therefore, the results are to be treated as indicative and not exact.

When all available power is exploited, it should be possible to produce 1700 tons of hydrogen per year (4.7 tons per day) by an AWE operating at Hitra. Production from using a PEM electrolyzer is somewhat lower. A system lifetime of 20 years and electrolyzers from Nel Hydrogen are used as a basis for these calculations. The hydrogen is further thought to be stored as compressed gas, as this is the most developed and cost efficient technology. In the future, liquid hydrogen will be an alternative, but this is currently too expensive for the amount of hydrogen that is possible to produce at Hitra.

Hydrogen can likely be produced at LCOH values of 3.72 to 3.86 €/kg for AWE, and 4.08 to 4.38 €/kg for PEMWE. This applies to both total production and production to HSCs only, and covers the costs for hydrogen that is ready to be refueled by a boat. Electricity contributes with approximately 61 to 65 % of the LCOH. Electricity and grid tariffs are therefore very important to consider. The calculations are based on a fixed electricity price of 24.57 €/MWh, excluding VAT, which is an average of projected prices for the next ten years. For hydrogen prices between 4.5 and 5.5 €/kg, net present values of 7 to 16 M€ are found for hydrogen production to HSCs only. When all available power is exploited, this is even higher. Simple payback times are found to be 6.3 to 4.2 years for the same price intervals.

Based on comparison of different fuels, it is evident that hydrogen produced at Hitra cannot match the price of marine gas oil, which is the fuel used in maritime transport today. However, suppliers aim to deliver hydrogen for this purpose at prices below 5.0 €/kg. Based on net present values and payback times found in this thesis, it should be possible to produce hydrogen for the maritime sector at Hitra at a competitive cost. This is also the case for end users within land transport, as trucks, which are interesting in the longer term. Lastly, a production facility at Hitra will have access to green power, and can provide hydrogen with low carbon footprints.

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List of Symbols

Symbol	Unit	Description
$cos(\Phi)$	-	Power factor
C_t	€, kr	Net cash flow
e	$J/kg,\ Wh/kg$	Specific energy
E	$J,\ Wh$	Energy
E_{rev}	V	Reversible voltage
F	$C/mol\ e^-$	Faraday's constant
m	kg	mass
m_g	kg	Amount of produced hydrogen
M	g/mol	Molar mass
n	$mol\ e^-$	Number of electrons
p	bar	Pressure
P	W	Electric Power (real power)
Q	VAR	Reactive power
r	-	Discount rate
r_f	-	Inflation rate
R^2	-	Coefficient of determination
S	J/K	Entropy
S	VA	Apparent power
T	K	Temperature
U	V	Voltage
$vol\%$	-	Percentage of the total volume
V_N	Nm^3	Volume in normal cubic meters
y	y	Years
ΔG	J	Gibbs free energy
ΔH	J	Change in enthalpy
ΔS	J/K	Change in entropy
η_{energy}	-	Energy efficiency
Φ	° or rad	Power angle

Chemical symbol	Description
e^-	Electrone
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_{2-eq}	Carbon dioxide (CO_2) equivalents
CO_3^{-2}	Carbonate ion
H_2	Hydrogen gas
H^+	Proton
H_2O	Water
KOH	Potassium hydroxide
$NaOH$	Sodium hydroxide
O_2	Oxygen gas
OH^-	Hydroxide (ion)

List of Terms and Abbreviations

Term	Description
Acidic solution	A solution with higher concentration of hydrogen ions than water (pH below 7)
Alkaline solution	A solution with lower concentration of hydrogen ions than water (pH above 7)
Alumina	Aluminum oxide is commonly called alumina
Anode	The electrode where the oxidation occurs
Apparent power	The combination of reactive power and real power
Balance of plant	Supporting components and auxiliary systems of a technical facility
Boil-off rate	The amount of liquid that is evaporating from a vessel due to heat leakage. Expressed in % of total liquid volume per unit of time
Bunkering	Filling the fuel containers of a ship/boat. Takes place at a harbor
Catalyst	A substance that increases the rate of a chemical reaction without itself being changed
Cathode	The electrode where the reduction occurs
Coefficient of determination (R^2)	A measure of how well observed outcomes are replicated by a model. 100 % match is reflected by R^2 equal to 1.0
Conduction	Transfer of heat through a substance
Convection	Transfer of heat by gas or liqiud between two areas of different temperature
Corrosion	An irreversible, gradual destruction om materials due to a chemical or electrochemical reaction
Co-electrolysis	An electrolysis which includes CO_2 in the inlet
CO_2 equivalents	A measure used to compare the emissions from various greenhouse gases on the basis of global warming potential
Discount rate	The rate used to discount future cash flows in a discounted cash flow analysis
Electrolysis	A technique that uses a direct electric current (DC) to drive an otherwise non-spontaneous chemical reaction. (Water electrolysis: producing hydrogen gas from water, using electric current
Electrolyzer	The component in which electrolysis occurs
Energy density	The amount of energy per unit of volume. Also known as *volumetric energy density*
Enthalpy	A property of a thermodynamic system, used to describe the amount of heat
Entropy	A property of a thermodynamic system, used to describe the degree of disorder
Fuel cell	A component that converts chemical potential energy (e.g from hydrogen) into electricity
Global warming potential	(GWP). How much heat a greenhouse gas traps in the atmosphere within a given time horizon, relative to CO_2. A higher value of GWP means a higher impact on global warming. A time horizon of 100 years is used in this thesis
Hydrides	Compounds containing hydrogen bonded to metals or metalloids
Hydrofoil	A lifting surface, or foil, attached to the hull of a boat. Makes it possible to travel quickly above the surface of the water.
Inflation factor	A measure of inflation, reflecting the increase in the general price level of goods and services
Inflation rate	The rate of which the average price of goods and services increase over time
Ionic agent	Name of the ion going through the separator
Lo/lo	Lift-on/lift off. Lo/lo ships using on-board cranes when cargo is loaded and discharged

Term	**Description**
Net Present Value	The difference in the present value of cash inflows and the present value of cash outflows over a period of a time
Overflow filling	A refueling process exploiting the pressure difference between a fuel source and the target of an on board storage tank in a vehicle/vessel.
Overvoltages	When the voltage exceeds the maximum value of operating voltage in an electric circuit or part
Oxidation	A molecule/atom/ion losing electrons
Payback time	The time it takes recover recover the initial investments
Radiation	Transfer of heat in the form of waves/particles through space or materials
Reactant	A substance or material added to a system to cause a chemical reaction. It is consumed during the reaction
Reactive power	The *unused* power that is developed by reactive components in an AC circuit/power grid
Real power	The type of power performing the "real work"
Reduction	A molecule/atom/ion gains electrons
Ro/ro	Roll-on/roll-off. Ro/ro-ships are designed to carry wheeled cargo
Specific energy	Energy per unit of mass. Also known as *gravimetric energy density*
Synthesis	A chemical reaction used to produce a chemical substance from another chemical substance
Syngas	Abbreviation for synthesis gas, and is a intermediate in several processes
Well-boat	A fishing vessel with a well or tank for the storage and transport of living fish
Well-to-wheel/wake	An analysis of efficiencies and emissions related to obtaining a fuel (well-to-tank) and using it (tank-to-wheel/wake). Often in a lifetime perspective

Abbreviation	**Description**
AC	Alternating current
AWE	Alkaline water electrolyzer
BEV	Battery electric vehicle
BoP	Balance of plant
CAPEX	Capital expenditures
CCS	Carbon capture and storage
CO_{2-eq}	CO_2 equivalents
DC	Direct current
DCF	Discounted cash flow
DSB	Direktoratet for samfunnssikkerhet og beredskap (Directorate for Civil Protection and Emergency)
EoL	End-of-life (used for technical components)
EU	European Union
FCEV	Fuel cell electric vehicle/vessel
FCH	(FCH JU): The Fuel Cells and Hydrogen Joint Undertaking
GHG	Greenhouse gas
GWP	Global warming potential
HSC	High-speed craft
HSE	Health, safety and environment
ICE	Internal combustion engine
IF	Inflation factor
Kr	Kristiansund (a city in Norway)
LCA	Life cycle assessment
LCOE	Levelized cost of energy
LCOH	Levelized cost of hydrogen
LHV	Lower heating value
MGO	Marine gas oil
NPV	Net present value
NREL	National Renewable Energy Laboratory
NVE	Norges vassdrags- og energidirektorat (The Norwegian Water Resources and Energy Directorate)
OPEX	Operational expenses
PEM	Proton exchange membrane
PEMWE	Proton exchange membrane water electrolyzer (PEM water electrolyzer)
R&D	Research and development
SPE	Solid polymer electrolyte
SPT	Simple payback time
TPT	Total payback time
Tr	Trondheim (a city in Norway)
TTW	Tank-to-wheel/wake
VAT	Value added tax
WTT	Well-to-tank
WTW	Well-to-wheel/wake

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1 Introduction

The use of renewable energy sources as wind, solar and hydro power can alone cover the global demand for power, and reduce the emission of greenhouse gases. However the use of these resources require new infrastructure to handle the fluctuating behavior of wind and variable access to sun. Using energy storage in the electricity grid is considered as a solution to these challenges. This allows excess energy to be stored in periods of surplus production, and used at a later point in time where the production is lower than the demand. One way of doing this is through using hydrogen. Hydrogen can be produced from surplus power, stored for longer periods, and then be used to generate electricity again.

Although renewable resources can provide clean and green energy, there will still be unsolved challenges related to emissions from the transport sector. Use of hydrogen will probably be an important part of solving these challenges. In 2017 transportation (road transport, aviation and maritime transport) accounted for 27 % of the total greenhouse gas (GHG) emissions in the EU [1]. Globally it accounted for about 24 % of the total CO_2 emissions the same year [2]. With other words, transportation technologies need to be improved to reduce global warming.

Battery electric vehicles (BEVs), having zero tailpipe emissions, are becoming more common. This is an important step toward climate neutral transportation, but it will not make up the final solution, due to several challenges. First of all batteries are heavy, which reduces the possible range of any vehicle utilizing it. The charging time of batteries is also a problem in some cases where a schedule is to be followed. Additionally, there are often significant greenhouse gas emissions involved in production and disposal of batteries used in electric vehicles and vessels. The use of hydrogen in cars, trucks, ferries and other maritime applications can be a solution to these challenges. When hydrogen is produced by electrolysis using green power, as by wind energy from Hitra, the only local emissions from usage will be pure and natural vapor. [3]

1.1 International, National and Local Climate Objectives

Both international, national and local policy makers are considering global warming and climate change when proposing new laws, budgets and plans. One of the key targets the European Union has set for 2030, is to cut greenhouse gas emissions with 40 % compared to the 1990 levels. This is also a part of the *Paris agreement*, which aims to keep the global temperature increase below 1.5 °C. In the extension of this, the EU is planning to be climate-neutral by 2050. As mentioned, this will not be possible without changes within the transport sector. Increasing efficiency of current mobility technology and deployment of low-emission transport are important strategies that the EU will follow up on. However the transition toward zero emission vehicles will also need to be accelerated. Through funding and research programs like Horizon 2020 and Haeolus, the EU will work toward a zero emission transport sector that involves usage of hydrogen. [4]

Norway is to be climate neutral by 2030 [5]. As the Norwegian energy production and supply contributes with very low emissions (3 % in 2018), the focus needs to be on other sectors. According to Statistics Norway (SSB), approximately 16.6 million tons of CO_2 equivalents were emitted from the Norwegian transport sector in 2018. This accounted for 32 % of total emissions within Norwegian territory, which were 52 million tons of CO_2 equivalents [6]. As illustrated in figure 1, this is the sector with the larges emissions in 2018, and it is logical to start here in order to reach the goals for 2030.

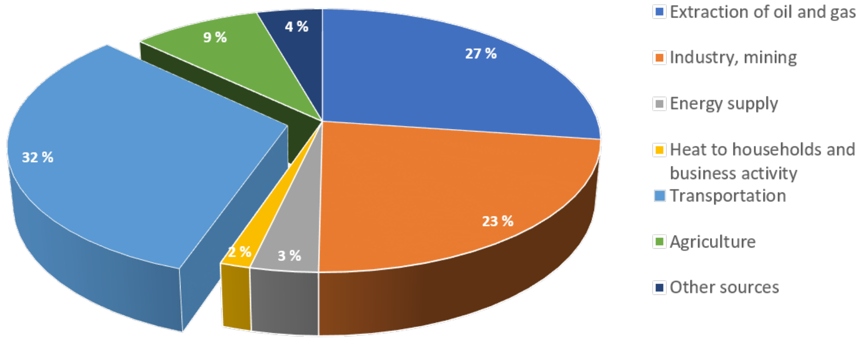


Figure 1: Greenhouse gas emissions per sector (based on CO_2 equivalents). Data from [6].

In Trøndelag county, the numbers are even higher. Approximately 90 % of the actual, direct, emissions in the region are from public transport ([7], data from 2018)[1]. Furthermore, the accumulated emission from the six high-speed crafts that operates in the county equals the emission from more than one thousand public buses. Estimates show that public transportation by sea accounts for 55 to 60 % of the total emissions from public transport sector in the region. In order to reduce these substantial emissions, and make maritime transport a low-emission sector in Trøndelag, hydrogen is considered as a promising solution. A production facility at Hitra would be centrally located in the region, and allow for green and environmentally friendly production of hydrogen. [7, 8]

1.2 The Hydrogen Market

The hydrogen market of today is a shut market, only being an input for industrial production. It is estimated to be at around 70 million tons per year. Hydrogen is normally produced from steam methane reforming (SMR), and is used in numerous sectors. Oil refining accounts for about 33 % of the total use of hydrogen today. Production of ammonia is the second largest area of use, with 27 %. Other industries like producers of iron, steel, glass and electronics are also depending on hydrogen. This means that hydrogen is important for the global economy and our daily lives. Hydrogen as an energy carrier does also have potential in future markets, and use of hydrogen in the transport sector is one of the first steps. There are many new projects with hydrogen as fuel in maritime, flight, train and road transport. [9, 10]

A hydrogen project that is starting to yield a positive result is the hydrogen ferry Water-go-round, that will be used in San Francisco in mid-2020. This will be the first fuel cell ferry in the US and first commercial fuel cell ferry in the world. The demand for ferries can increase ten folds, with cities like Hong Kong and New York, desperately needing to reduce their CO_2 emissions. Japan is also a front runner in the use of hydrogen for transport. For road transport, hydrogen cars and buses have already been in use in several parts of the world, for several years. [9, 11]

[1] In this statistic, emissions related to management accounts, purchase of electronics and investments are not included.

1.2.1 Norway as a Consumer of Hydrogen

Norway produce about 225 000 tons of hydrogen for industry processes, mostly through steam methane reforming. Equinor uses about 112 500 tons at Tjeldbergodden for methanol production and an additionally 5 500 tons are used with natural gas for heating. At Herøya in Porsgrunn about 70 000 tons of hydrogen is used for ammonia production. Both of these facilities are making hydrogen by reforming natural gas, without carbon capture and storage. Norway is not only using hydrogen for industry, they are also expanding into the transport sector, especially maritime transport. Hjelmeland ferry connection is a ferry stretch with a hydrogen ferry, which is going to be commercially used during 2020. The company, Norled, is making their ferries with a consumption of 500 kg hydrogen per day.

Norway is also trying to become a front runner in implementing zero-emission vehicles. A good example is "Oslo Ruter" which has five buses in operation since 2012. According to plan they are going to increase their efforts further and implement ten more buses during 2020. Another example in the transport sector is Asko with their own hydrogen production and hydrogen trucks which are in use since January 2020. A future prognosis done by DNV GL, has estimated a yearly national usage of hydrogen in Norway of approximately 250 000 tons. 75 % of this will be for ammonium and methanol production. The remaining 25 % will be divided between buses, maritime sector, trains and new industrial users. [9, 12]

1.2.2 Norway as a Producer of Hydrogen

Norway has potential when it comes to production of hydrogen. The country has an internationally leading industry in hydrogen production, storage, safety and high competence in research and development. Companies like Nel Hydrogen, Hexagon and HYON are big contributors toward development of hydrogen technologies and sales. Nel Hydrogen for example, which was established in 1927, provide hydrogen solutions for the entire value chain from electrolyzers to hydrogen fueling stations. There are also many initiatives for implementing hydrogen as fuel in transport and large scale industrial processes. [9, 12, 13]

One important factor is that Norway has an abundance of low-cost renewable energy sources. For example, the theoretical wind potential is 1000 TWh/yr onshore. The long coast towards the Norwegian Sea, provides ample access to wind, and contributes to the great wind energy potential. Figure 2 shows a wind chart, where the colors represent different wind velocities. The color is green for large parts of the coast, which means an annual average wind speed of 7.0 to 7.5 m/s. This includes Hitra. The problem is that potential wind farm sites and current wind power farms are in remote areas, with low population. These wind farms will therefore not be used to their full potential, because of low demand and weak grids. Raggovidda wind farm is a good example, where the wind farm has a size of 45 MW, but theoretically can be up to 200 MW. Hydrogen is therefore regarded as a solution for fulfilling the wind farm potential, by being a storage device for the excess energy. The Haelous project is an EU project that explores this idea. Haelous has used Raggovidda as a potential place where hydrogen can be produced from the excess power, and exported to different locations. [12, 14, 15]

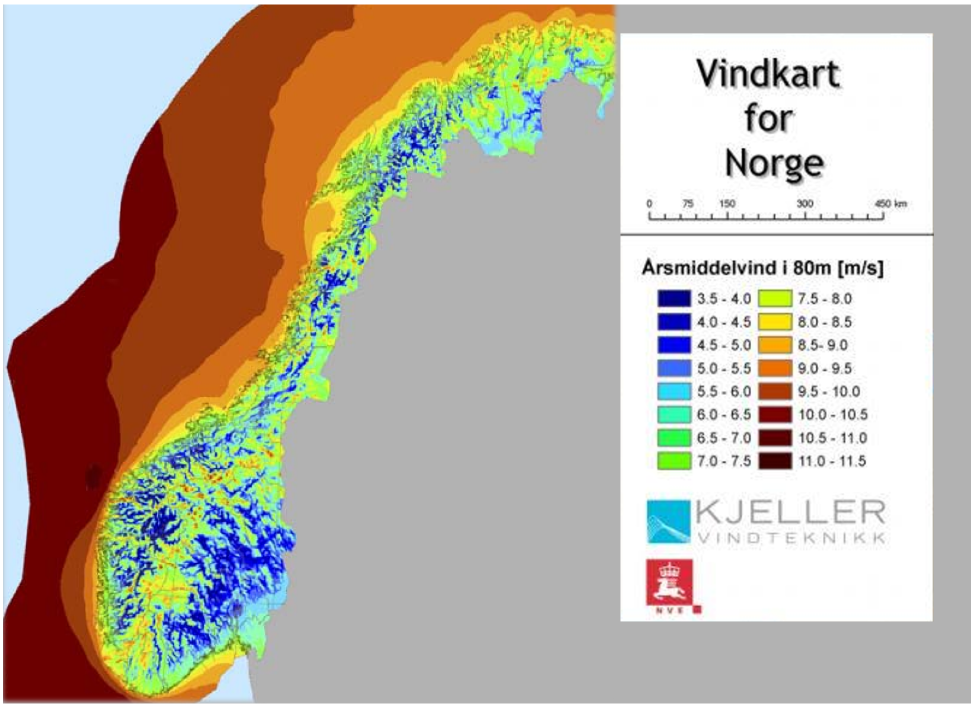


Figure 2: Wind chart for Norway. Adapted from [14].

At the time of writing, Norway has expanded with 42 wind farms according to NVE. Together the wind farms constitute a power capacity of 2582 MW, distributed on 833 turbines. The annual average production is about 8.2 TWh. Statistics shows an exponential grow in total power capacity. In a time period of five years, from 2010 to 2015, it increased from 422 MW to 866 MW. But from 2015 to 2020 the capacity went from 866 MW up to 2582 MW. In 2018, wind power corresponded to 2.6 % of the total power generation, which means a percentage change of 35.8 % from the previous year. According to Statkraft, 16 new wind farms are under construction and the authority has granted licenses for another 36 wind farms. [16, 17]

As one of the new wind farms in 2019, *Hitra 2 Wind Farm* was built as an extension of the older wind farm at Hitra; *Hitra Wind Farm*. Together they represent a power capacity of 148.8 MW, which makes it the eleventh largest in Norway. Other related information for each wind farm can be found in table 1. [18, 19]

Table 1: Key information about *Hitra Wind Farm* and *Hitra 2 Wind Farm*. [18, 19]

	Hitra Wind Farm	**Hitra 2 Wind Farm**
In operation	2004	2019
Operator	Statkraft	Fosen Vind
Annual production [GWh]	138	290
Capacity [MW]	55.2	93.6

1.3 About Hitra

Hitra is a municipality and island located south-west of Trondheim in Trøndelag County, Norway. In figure 3, the red dot represents Hitra Harbor (Hitra Kysthavn). More specifically, Hitra Harbor is located at Jøsnøya, which is commonly known as Sandstad. The main island is about 570 km^2, with a tunnel connection to the mainland. From Trondheim it is possible to reach Hitra by road or sea. The distance is 120 km by road, and the high-speed craft connecting Trondheim and Kristiansund docks at Sandstad 1 hour and 40 minutes from both end points. [20]

Figure 3: The location of Hitra. [21]

With its location, Hitra has contributed to an increased wealth creation in the region. Primarily because of the international trademark *Norwegian Salmon*. Together with the neighboring island, Frøya, the two islands are the largest sites for salmon farming in the world, delivering 260 000 tons of salmon per year. Communication with the municipality reveals that about 60 fully loaded trucks transport salmon out of the region every day. This makes Hitra a suitable hub for the aquaculture industry, but also land transport. With large expansion opportunities, Hitra Harbor also has the equipment for Ro/ro and Lo/lo, which is suitable for shipping. Several operators have also shown great interest to use the harbor as a place of cache, storage, provisioning and crew shifting. [20, 22]

Close to Hitra Harbor, Hitra Industry is located. In 2009 Hitra Municipality bought Jøsnøya, and in 2013 the first industry company, Marine Harvest, confirmed the sale. Three years later, Lerøy Midt also confirmed construction plans of a new factory. Together with Mowi, Lerøy is one of the largest company within aquaculture of salmons in the world, and an important collaborator for Hitra. Several other companies have also confirmed their interest in Hitra Industry. [20, 22]

In accordance with expanding industry, the value in aquaculture industry is predicted to increase. To preserve the community and environment, new and sustainable solutions are required. For instance, the local maritime transport related to this industry will increase and potentially contribute with significant GHG emissions. [20]

1.4 Maritime Transport at Hitra

Like the rest of the Norwegian coast, the maritime transport sector is important for industries and citizens in Trøndelag. Large cargo ships operate on the coast of the region, tourists come to see the Norwegian fjords, high-speed crafts connect island communities with the mainland and different boats are used in the salmon industry. For Hitra the HSC running between Trondheim and Kristiansund is especially important for the citizens. It is used by commuters working in Trondheim or Kristiansund, but does also connect the island to the other islands in the area.

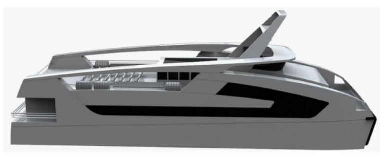
1.4.1 High-Speed Craft: Trondheim - Kristiansund

Today, six high-speed crafts communications are operated within Trøndelag. One of these is between Trondheim and Kristiansund, which is of interest for this thesis because the ferry docks at Hitra. It is considered as one of the longer stretches, at 175 km (95 nm) one way. The boats used today, *MS Terningen* and *MS Tyrhaug*, use marine gas oil (MGO) as there are no other commercial alternatives with low CO_2 footprints. Both battery electrical and hydrogen electrical systems are considered as suitable options, but full implementation will take time. For a HSC it is important to keep the weight down, which is one of the main problems related to the use of batteries; a long range will require large and heavy battery systems. A different option is to use hydrogen. Compared to battery, this is still a new technology in the maritime sector. [8, 23]

The next contract period for the high-speed craft connections in Trøndelag starts in 2024[2]. For the connection between Trondheim and Kristiansund, Trøndelag Fylkeskommune wish for an emission free transport. A study conducted by SINTEF and Greensight in 2017 looked closer on the refueling facilities of hydrogen in Trondheim, Brekstad, Sandstad and Kristiansund. According to the report, Sandstad at Hitra can be a good spot to produce and deliver hydrogen to the HSCs. Today, there is a continuous stretch between Kristiansund and Trondheim, but it could be beneficial to split the connection in two routes: Kristiansund - Sandstad and Sandstad - Trondheim. The report concluded that Sandstad is the only place that has both available area and the needed power capacity to produce sufficient amounts of hydrogen. [25]

In 2017 the industry was challenged by Trøndelag and ten other county administrations to develop low-emission high-speed crafts for the Trondheim - Kristiansund connection. In 2019, several companies representing different consortia presented their results in Trøndelag. There was a major focus on designs that would improve efficiency, where hydrofoil technology was highlighted as a solution. Both batteries and hydrogen were presented as possible energy carriers. Three different consortia, led by Brødrene Aa, Rødne and Selfa Arctic, focused on hydrogen. The concepts they developed are called *Aero 42 H2*, *E-maran* and *Zeff* respectively, which are illustrated in figure 4. [8, 26]

(a) Aero 42 H2, designed by the Brødrene Aa consortia. It is planned to use about 360 kg of H_2 one way. [23]



(b) E-MARAN, designed by the Rødne consortia. It is planned to use about 310 kg of H_2 one way. [27]

(c) ZeFF (Zero emission Fast Ferry) will advantage from hydrofoil technology, and is planned to use about 265 kg of H_2 one way. [28]

Figure 4: Three potential hydrogen powered high-speed crafts that can be used between Trondheim and Kristiansund.

[2] The current contract period ends in 2022 with option 1+1 year. The options makes it possible for the next contract period to start in either 2024, 2023 or 2022. [24]

1.4.2 Aquaculture Industry

As Hitra and the neighboring municipality Frøya are important areas for aquaculture industries, maritime transportation constitutes a large part of the regional transport sector. Several types of boats and ships used in the aquaculture industry, as for instance well-boats, work boats and feeding carriers, can potentially run on hydrogen. Producing hydrogen from electricity will also give some byproducts that the industry can take advantage of. Oxygen and waste heat, which is produced in addition to hydrogen, are for instance valuable resources.

A report by SINTEF presents the possibility of using hydrogen to power a well-boat, which stores and transports living fish, for Nordlaks Smolt AS in northern Norway. Nordlaks own several such vessels and have ordered two battery/gas hybrids which will be delivered during 2020. These are illustrated in figure 5, and can be examples of well-boats that potentially can be powered by hydrogen. In the report from SINTEF it is estimated that these types of well-boats would need approximately 9 GWh, equal to 273 tons of hydrogen, per year. [29, 30]

Figure 5: Two well-boats with battery/gas hybrid propulsion. [29]

1.5 Research Question and Limitations

As described, hydrogen is considered as a possible solution to make maritime transport a zero emission sector in Trøndelag. A production facility for hydrogen would be centrally located at Hitra. Both high-speed crafts and the local aquaculture industry represent a possible demand with a relevant order of magnitude. In addition to these end users, trucks transporting salmon out of Hitra can likely run on hydrogen in the future. Wind power from Hitra would also allow for green hydrogen production, which would be a requirement if the future transport sector is to be defined as low or zero-emission. However, if hydrogen is to be used, the costs for production and use must be in an acceptable order. Based on the information presented so far, and this fact, the following research question has been chosen for the report:

"Can Hitra — having access to local wind energy — produce competitive hydrogen for the regional maritime sector?"

The research question requires several calculations with different limitations, and the expression *competitive* may include several elements. Therefore it is necessary to define the scope of work for the thesis. The thesis focuses on the production part of a possible hydrogen value chain. It describes a scenario of hydrogen production at Sandstad, and aims to give an overview of related costs, benefits and challenges. However, as demand and production are interdependent, possible end users are looked into as well.

Within the maritime transport sector, the main focus will be a possible hydrogen demand for HSCs. In addition, since the aquaculture industry at Hitra is associated with large GHG emissions, maritime vessels like well-boats are of interest as well. Truck transport related to the aquaculture industry is also considered as a possible end user. However, as the production part is the main focus for this thesis, the demand side of the hydrogen value chain is established based on simple calculations and estimates.

Only production, storage and, to a certain extent, filling of hydrogen is included in order to limit the scope of the thesis. This is in compliance with the research question, as hydrogen is thought produced to cover the local demand. Costs for transporting hydrogen out of Hitra, to other filling stations, are not included. However, as a residual production is highly possible, a scenario where some of the hydrogen can be distributed out of Hitra is considered. Further, the thesis only focuses on production of compressed hydrogen from PEM and alkaline water electrolysis. Liquid hydrogen is not looked at, as there a few end users of this today. However, this could be relevant for future scenarios.

Structure

The thesis aims to highlight whether hydrogen produced at Hitra can be feasible and competitive or not. The main part of competitiveness is decided by the price hydrogen is sold for. In turn, this depends on the costs related to hydrogen production and distribution. Costs for production, storage and filling are estimated to find a levelized cost of hydrogen. Additionally, general environmental impacts from production and use of hydrogen are looked into, as this also can affect competitiveness.

Theory about hydrogen in general, production from electrolysis, environmental aspects, HSE and economics is presented to establish a basis for analyses. The methodology for cost calculations is then explained before results are presented and discussed. As most of the data used in this thesis is obtained from literature review, there are some uncertainties related to the results. There is a possibility for missing or overlapping data, which is elaborated further in the methodology section. The findings presented in this thesis should therefore be considered as indicative and not exact.

2 Theory

The theory lays the foundation for the project and forms the basis on which the knowledge and insight are derived from. This makes it possible to preform the project and understand the results. All the concepts, technologies and information necessary to complete the thesis is presented in this section. This includes theory about hydrogen, water electrolysis, storage, economics and HSE. The theory also covers the environmental aspect of hydrogen, which is the part that makes it an interesting substitute for fossil fuel.

2.1 Hydrogen as an Energy Carrier

Hydrogen (H) is the first element in the periodic table, and the simplest element that exists. Approximately 90 % of all the atoms in the universe, and every sixth to seventh atom in the earth's crust, are hydrogen. In other words, hydrogen is a plentiful resource. [31]

In addition to be something that exists everywhere, hydrogen is a good energy carrier. It can be stored and used to produce electricity, heat and work when needed. For instance, this makes hydrogen useful in the electricity grid and transport sector. The energy in hydrogen can be extracted by combustion or through an electrochemical process occurring in a fuel cell. A vehicle can, for example, use a conventional internal combustion engine (ICE) with hydrogen in stead of diesel or gasoline. Otherwise, it can use hydrogen in fuel cells and become an electric vehicle. The last option is more efficient. In a fuel cell, electricity and heat is produced according to equation 1, the *fuel cell equation*. In this transition, the only outcome except for energy is pure water (H_2O). [32]

$$2H_2 + O_2 \longrightarrow 2H_2O + \text{Electricity} + \text{Heat} \tag{1}$$

To benefit from this relation, the fuel needs to be in the form of pure hydrogen gas (H_2). Unfortunately, most of the hydrogen is bound chemically as for instance in water and methane (CH_4). Energy is needed to reform these substances and separate the hydrogen. Electrolysis is a process where hydrogen is obtained from pure water. This is elaborated in section 2.4. In order to reduce greenhouse gas emissions and reach climate goals, the energy used in electrolysis needs to be green. [31]

2.1.1 Hydrogen in Energy Applications

According to Hydrogen Council, the long term potential of hydrogen is huge. By 2050, hydrogen could cover 18 % of the final, global, energy demand [33]. The opportunities for hydrogen in transport, buildings and power sector are highlighted as the most important ones. In 2030, up to four megatons of hydrogen can potentially be used for heating buildings. In the beginning this would be through blending hydrogen into existing gas networks. In the power sector, hydrogen or ammonia (NH_3) from hydrogen processing, could be used in gas turbines or co-fired in coal power plants. Hydrogen as energy storage could also be useful in the power sector, providing backup power and grid stabilization [10].

The development of a hydrogen based transport sector has been an area of focus and interest for science and engineering the last decades. It is also a merging area of application. In 2018 there where more than 11 000 fuel cell electric vehicles (FCEV) on the roads. This is still a small fraction of the global light-duty vehicle fleet, but the market is growing. There where 56 % more FCEVs in 2018 than in 2017, which is a significant development [10]. According to Hydrogen Council, a market share of 35 % fuel cell electric passenger cars and 30 % fuel cell electric buses is reachable within 2050. [34]

Pure hydrogen or ammonia are currently the most promising candidates for domestic transport and shipping, when climate goals are to be reached within the maritime transport sector. DNV GL has estimated that 186 Norwegian ships can be potential users of hydrogen by 2030. This involves passenger boats, ferries, cruises and vessels used in the fish farming industry. A total demand of approximately 18 000 tons of hydrogen per year can be a reality in 2030, if hydrogen based maritime transportation develops as estimated. [9]

2.1.2 Why Use Hydrogen in the Transport Sector?

A hydrogen vehicle has a fuel cell that exploits the relationship from equation 1. The produced electricity would then be fed into the electric motor, causing wheels or propellers to rotate and create propulsion. There are no tailpipe emissions involved in this process. Another advantage with hydrogen in transport scenarios is the refueling time, which can be 15 times faster, per unit of range, than for a battery electric vehicle using a fast charger. For a car storing hydrogen at 700 bar, which is the standard storage pressure for FCEVs, only three to five minutes would be needed to refuel 5 kg of hydrogen. For a bus having a storage pressure of 350 bar, the refueling of 30 kg of hydrogen would take approximately 15 minutes. According to HYON, it is possible to refuel 600 kg of compressed hydrogen gas per hour [35]. This also applies to hydrogen for maritime applications, and can make hydrogen a better solution than batteries for zero emission solutions. [25, 36]

An advantage that is often highlighted is the specific energy of hydrogen. For transportation it is crucial to carry as much energy as possible and keep the weight as little as possible. This will decide the range of any vehicle. As illustrated in figure 6, hydrogen has a much higher energy density, per kilogram, than other traditional fuels. Based on lower heating value (LHV), hydrogen has a specific energy (gravimetric energy density) of 120 MJ/kg. This is almost three times greater than for normal diesel and marine gas oil (MGO), which have specific energies of about 43 MJ/kg. Li-ion battery cells are also plotted in the bottom left corner of the chart. This battery technology is the most commonly used in BEVs, and the battery cells have a specific energy of 0.7 ± 0.3 MJ/kg and an energy density (volumetric energy density) of 1.8 ± 0.7 MJ/L. [37, 38]

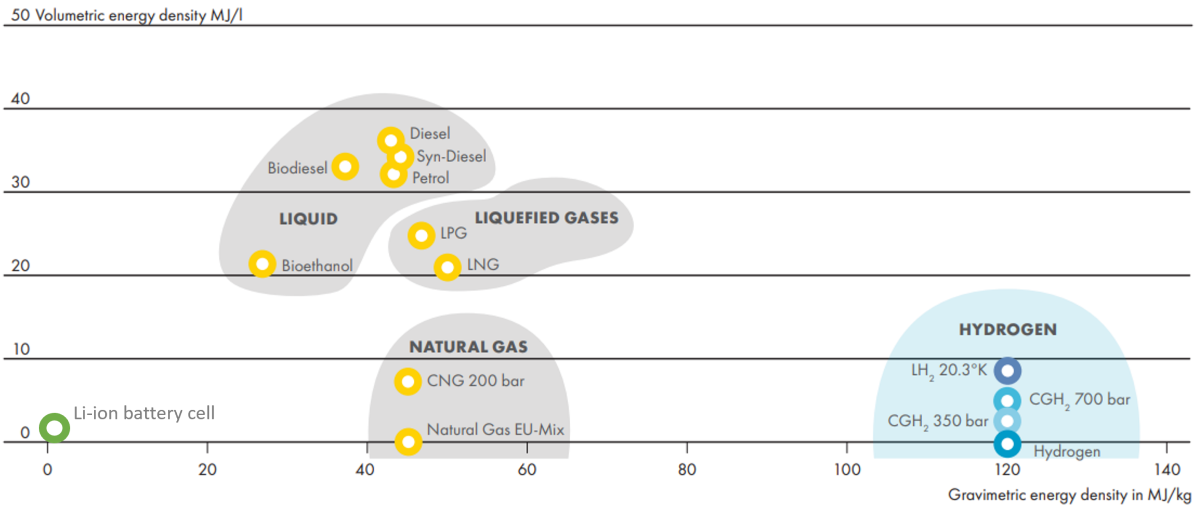


Figure 6: Specific energy (gravimetric energy density) and energy density (volumetric energy density) of different fuels, based on LHV. Hydrogen at 0°C and different pressures at the bottom right corner. Adapted from figure 13 in [39].

Volume is also very important to consider when it comes to fuels for different modes of transport. As illustrated in figure 6, hydrogen has a very low volumetric energy density. At normal conditions (0 °C and 1.013 bar), it is approximately 0.013 MJ/L. In other words, a large volume is needed to carry useful amounts of energy. For instance, 1 kg of hydrogen corresponds to 11 m^3 at room temperature and pressure [40]. In order to store the needed amount of energy, the hydrogen gas needs to be compressed. Another issue to look into is the fact that the storage system, with relatively heavy tanks, has a certain mass and volume. When including the whole system with fuel and storage tanks, the difference in energy density for the various fuels becomes considerably smaller. [9, 37]

2.1.3 Hydrogen Properties and Perspectives

The energy densities of hydrogen are listed in table 2 for different pressures. These values are based on LHV. The highest energy density is achieved when the hydrogen gas is liquefied, but this is only possible at very low temperatures, down to -253 °C. This transition requires much energy.

Table 2: Important properties of hydrogen. Specific energy and energy densities at different pressures and 0 °C, except from liquid hydrogen which is at 1.0 bar and 20.3 K (-252.85 °C). [32]

Property	Value	Unit
Specific energy	120 ($33.\overline{3}$)	MJ/kg (kWh/kg)
Energy density, gas at 1.0 bar	0.013	MJ/L
Energy density, gas at 7.0 bar	4.5	MJ/L
Energy density, liquid at 20.3 K	8.5 (2.36)	MJ/L (kWh/L)

Normal Cubic Meters

When performing calculations on hydrogen and other gases, it is common to use *normal cubic meters (Nm^3)* as a unit for volume. 1 Nm^3 of any gas equals 1 m^3 of the respective gas at a temperature of 0 °C and atmospheric pressure (1.013 bar). Often it is necessary to find the mass of a gas from a given value of the normal cubic meter. In these cases, the ideal gas model can be used to find the relation presented in equation 2. In this equation m represents the unknown mass in kg, V_N the volume given as Nm^3 and M the molar mass in g/mol. [41]

$$m \approx 0.044 \cdot M \cdot V_N \tag{2}$$

For hydrogen gas, H_2, which has a molar mass of approximately 2.0 g/mol, the transition from Nm^3 to kg can be simplified to equation 3.

$$m \approx 0.088 \cdot V_N \tag{3}$$

Perspectives

In order to give an overview of production and usage quantities of hydrogen, The Renewable Energy Cluster in Norway has made a simple illustration. An adapted version of this is shown in figure 7. The values are rough, but credible, estimates based on modern technologies. One ton of hydrogen can be produced by approximately 58 MWh of electricity, from for instance wind power. This is enough to cover the daily demands for one high-speed craft, 20 trucks or 2000 passenger cars. If every passenger vehicle in Norway were to be fuel cell vehicles, the daily demand for hydrogen would be about 1350 tons, only for this purpose (illustrated in figure 8). [42, 43]

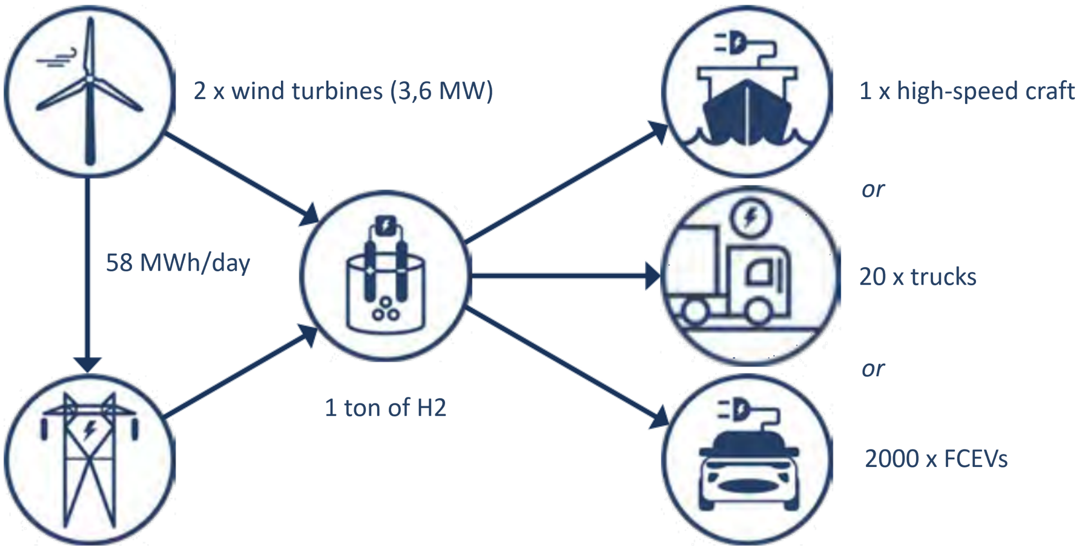


Figure 7: One ton of hydrogen can, approximately, provide the daily needs for one high-speed craft, 20 trucks or 2000 passenger cars. Adapted from The Renewable Energy Cluster. [42]

Figure 8: If every passenger car in Norway were to be run on hydrogen, the daily hydrogen demand would be about 1350 tons. Based on a daily demand of 1.0 ton per 2000 vehicles. Data from [42, 43].

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2.2 Hydrogen in Maritime Transport

Transport by sea is an energy-consuming activity. Therefore, it is important to achieve high efficiency for propulsion systems and improve ship design, to reduce the energy demand. Additionally, it is important to use affordable and emission free fuels. According to the Hydrogen Council, hydrogen can be a competitive fuel for maritime applications before 2030. Small hydrogen powered ferries will be competitive compared to battery electric ferries in situations where short docking times are required. Charging of batteries will take to much time. For larger ferries and speed boats with motor powers up to four megawatt, hydrogen will be attractive because it offers low-carbon solutions and lower weight than battery systems. [34]

The types of hydrogen ferries that can be used between Trondheim and Kristiansund fit this description. The high-speed crafts, which are different variants of the one illustrated in figure 9, will have motor powers of one to three megawatt. A typical well-boat would need approximately 1.5 to 4 MW to propulsion (in average), and could also be a future user of hydrogen fuel. For ships requiring long rang, as for instance container ships, ammonia is considered the most viable low-carbon option. This ammonia can be produced from hydrogen gas. [26, 34]

Figure 9: Aero 42 H2, designed by the Brødrene Aa consortia. This represents a typical high-speed craft that can be used between Trondheim and Kristiansund. [23]

2.2.1 Diesel to Propulsion

Diesel engines are the most common propulsion technology in maritime transport today. This is used by well-boats, ferries as well as fishing vessels and recreational boats. Diesel, or marine gas oil, are fuels made from petroleum distillation, which are used in internal combustion engines (ICEs). These engines usually have efficiencies ranging from 30 to 40 %, which means that most of the energy in the fuel cannot be used to create propulsion. Table 3 shows some relevant properties related to the propulsion systems used in maritime transport today. [30]

Table 3: Some relevant properties for Diesel/MGO in ICE propulsion systems used today.
Values for 15 °C and 1.0 bar. [35, 37]

Property	Value	Unit
Energy density (LHV)	42.7 (11.8)	MJ/kg (kWh/kg)
Density	0.85	kg/L
ICE motor efficiency	30 - 40	%
Tailpipe emissions from combustion	2.64	kg $CO_{2,eq}/L_{Diesel}$

2.2.2 Hydrogen to Propulsion

Ferries and other vessels powered by hydrogen, described in this thesis, will use fuel cells. Fuel cell systems have shown to work well in maritime conditions. However, they require hydrogen with very high purity, which makes the method for hydrogen production important to consider. As for a fuel cell electric vehicle, a hydrogen powered ferry or well-boat will advantage from equation 1. A fuel cell usually has an efficiency of more than 50 %, which means that about half of the energy in the hydrogen gas will be converted to electricity and fed to the electric motor and propeller. Relevant properties for hydrogen fuel cell propulsion are given in table 4. It is important to note that there are energy losses related to converting electricity into kinetic energy in the electric motor, which runs the propeller. This conversion usually has an efficiency of about 70 %. [9, p. 107] [35]

Table 4: Some relevant properties for hydrogen gas to propulsion. [35, 37]

Property	Value	Unit
Specific energy, 0 °C and 1.0 bar	120 ($33.\overline{3}$)	MJ/kg (kWh/kg)
Fuel cell efficiency	~ 50 - 55	%
Tailpipe emissions	0	-

Hydrogen gas will be stored on board a vessel at pressures exceeding 250 bar, to ensure higher energy density. The high pressure and temperature requirements are however making refueling a challenging operation. The refueling time will be of significance for HSCs that need to follow a schedule. The maximum allowed temperature in the storage tanks are what limits the refueling time. In order to allow for short refueling time, it is important to minimize the increase of temperature in the storage tanks. By using heat conduction in the tanks or having residual gas in the tanks before refueling begins, are two possible measures. [35, 44]

2.3 Hydrogen production

The hydrogen production of today comes almost entirely from natural gas and coal. According to the International Renewable Energy Agency, IRENA, about 95 % of the hydrogen was produced by natural gas, oil and coal in 2016 [45]. CO_2 emissions from this production is equivalent to the total emission from Indonesia and United Kingdom combined [10]. Hydrogen can be separated into three different categories, based on production technique, which are grey, blue and green. [46]

Grey hydrogen is produced from natural gas, through steam methane reforming. This is currently the cheapest type of hydrogen, with an estimate of 1.50 €/kg. This price is estimated to increase in the future, but this will depend on politics. If countries in Europe increase the jurisdictions on CO_2 emission, grey hydrogen will become more expensive. [46]

A better environmental solution is blue hydrogen. This hydrogen gas does also come from natural gas through steam methane reforming, but includes carbon capture and storage (CCS). Blue hydrogen is however more expensive than grey. CCS makes up the biggest percentage of the price, because CCS systems are costly. But, as the technology develops, this price is expected to decrease. [46]

Green hydrogen is the most environmentally friendly production method. The hydrogen is produced from water electrolysis, with power from renewable energy. In 2016, only four to five percent of the globally produced hydrogen was made from electrolysis [45]. This has to do with the higher price level, being between 3.5 and 5 €/kg. A large share of the price is caused by the water electrolyzer, which is the component where water electrolysis occurs. However, experts estimate a future decrease of costs due to improved technology. Another significant part of the price is the cost of the renewable energy. [46]

2.4 Water Electrolysis

Water electrolysis is a well established technology to produce green hydrogen. It was first demonstrated in 1789, and almost a century later an industrial synthesis method of hydrogen and oxygen was introduced. By 1902 more than 400 industrial water electrolyzers were in operation. Nowadays, the technology is being used in several industries, such as food industry, power plants and metallurgy. In the view of green hydrogen, water electrolysis is considered as a growing market. Yet, in a long-term perspective the technology of producing high-purity hydrogen and oxygen separately, is in the phase of research and developing. Including some technological challenges, the production also has some economical issues compared to the more common production methods, like steam methane reforming. [47, 48]

In recent years, a lot of work has been done to improve established technology and to reduce the related costs. In addition, development of new technology has also been an area of focus. The most common technique is the alkaline water electrolysis, which has been used in large-scale applications since 1920. A recently developed technology, the PEM electrolysis, is considered as one of the favorable methods for sustainable hydrogen production. Other methods to be mentioned are the solid oxide, molten carbonate and anion exchange membrane electrolysis. [49]

2.4.1 Principles of Water Electrolysis

Despite different electrolyzers having dissimilar structures, they are all based on the same principle: water electrolysis. The production only requires input power and water molecules (H_2O), where the water is dissociated into hydrogen (H_2) and oxygen (O_2) under influence of electricity. This will give the overall cell reaction represented by equation 4. [49]

$$Energy + H_2O \longrightarrow H_2 + {}^1/_2\, O_2 \tag{4}$$

Without the external energy, the process will not happen. This makes it a non-spontaneous reaction. The reversible voltage, E_{rev}, for this process can be calculated from Gibbs free energy, ΔG, according to equation 5. The amount of 1.23 V is the minimum applied voltage required for splitting water into hydrogen and oxygen. In this context n is the number of electrons involved and F is the Faraday's constant. [49]

$$\Delta G = nFE_{rev} \quad \rightarrow \quad E_{rev} = \frac{\Delta G}{nF} = 1.23V \tag{5}$$

Realistically, more energy is required due to other conditions. The scenario in equation 5 is ideal, but with standard conditions entropy is generated. Therefore, it is more suitable to use ΔH, instead of ΔG, in equation 5. Equation 6 shows how the change of enthalpy, ΔH, depends on the temperature, T, and the change in entropy, ΔS. [49]

$$\Delta H = \Delta G + T\,\Delta S \tag{6}$$

At atmospheric pressure, and temperatures typically being below 80 °C, the minimum required voltage would be 1.48 V, known as thermo-neutral voltage. However, depending on the type of electrolyzer, additional energy must be considered due to aspects as various overvoltages and losses. The final voltages is known as the cell voltage. In consideration of this thesis, this topic will not be elaborated any further. But to give a useful presentation of how much the cell voltage deviates from the thermo-neutral voltage, energy efficiency can be calculated according to equation 7. [47, 49, 50]

$$\eta_{energy} = \frac{U_{thermo\text{-}neutral\ voltage}}{U_{cell\ voltage}} \tag{7}$$

2.4.2 Construction of a Water Electrolyzer

All types of electrolyzers are designed to optimize the respective operation conditions, but since the principle of water electrolysis is the same, some of the components have the same role. To simplify an electrolyzer, it consists of two electrodes, an electrolyte, a separator and an external direct current (DC) power source. The positive electrode is called the anode and the negative electrode is called the cathode. Table 5 gives an overview of the different components, and their functions. [49, 51]

Table 5: The function of the components in an electrolyzer. [49, 51]

Component	Function
Electrodes	Both of the electrodes are connected to the external circuit. Anode: Production of oxygen. Cathode: Production of hydrogen.
Electrolyte	Ionic conductivity. Prevent electrons from passing through.
Separator	Ionic conductivity between cathode and anode, or the other way. Separates hydrogen and oxygen. Prevent short circuits between electrodes.
External DC power source	Apply energy to the reactions.

The external power source force the electrons to flow. They are transferred from the anode to the cathode. On the positive electrode, oxygen is oxidized as it loses electrons. On the opposite side hydrogen will gain electrons and be reduced. The reactions happening on the electrodes are called half-cell reactions, and will vary as they depend on the type of electrolyzer. The type of electrolyte and separator is determined from the desired half-cell reaction, and will decide the ionic agent. The ion can either be positive, called cation, or negative, called anion. At the same time as the electrons flow from the anode to the cathode, the ionic agent goes through the separator. On both sides of the separator, the electrolyte contributes to ionic conductivity. The electrolyte can either be solid or liquid, acidic or alkaline. Together, the electrodes, electrolyte and separator is called a cell. When cells are connected in series, the configuration is referred to as a stack of cells. [49, 51]

The Separator

The separator is an important component, that to a large extent defines the operation area of the electrolyzer. It can either be of a porous material, called diaphragm, or of solid material. When an electrolyzer uses a solid separator, it is called a solid polymer electrolyte membrane (SPE membrane), and is mainly used in PEM electrolyzers. [49]

The primary function of the separator is to avoid mixing of hydrogen and oxygen. A high level of hydrogen gas in the oxygen steam can cause an explosion. The lower explosion limit is 4 vol% of hydrogen, but in technical applications the limit is set to 2 vol% [47, 52]. For the diaphragm, it is important to keep equal pressure at both sides. With higher pressure at the cathodic than the anodic side, hydrogen will flow through the diaphragm and into the wrong side. This is referred to as gas crossover. Even though gas crossover is impossible to avoid, running the electrolyzer at optimal load will prevent pressure differences. The operation area is therefore dependent on the ability of the diaphragm to maintain the pressure balance. For a solid separator, different pressure levels do not affect the crossover and it is said to be negligible. The operation area for an electrolyzer with SPE membrane is therefore wider, as it will handle load change better. [51, 52]

Within the given operation area, load change will affect the temperature and pressure levels, and thus the efficiency. Like the rest of the power plant, the electrolyzer has an optimal operation area with an associated load. With lower load, less heat will be developed. On the other hand, when the system is overloaded it will be overheated and additional cooling is needed. Electrolyzers with SPE membrane is the most suitable for overloads, since the performance range is wider. However, load outside the optimal operation area will cause stress for the materials. [52, 53]

2.4.3 Different Types of Electrolyzers

The following sections will give an overview over the different types of electrolyzers that are relevant for this thesis. The focus will primarily be alkaline and PEM water electrolyzers, but other technologies will also be mentioned.

Alkaline Water Electrolysis (AWE)

Alkaline water electrolysis is a mature technology for continuous operation. However, during load-following operations, the electrolyzer suffer from low flexibility. Direct use of intermittent renewable energy sources like wind or solar power, would therefore be a problem. The reason mainly being gas crossover, due to a porous diaphragm. [49, 53]

In the case of an alkaline electrolysis, the water (H_2O) is fed to the cathode. The water molecule is separated into protons (H^+) and hydroxide (OH^-). The protons will react with electrons (e^-) from the external power source, and is recombined into a gaseous form (H_2). The hydroxide ions are passing through the separator to the anode where oxygen arises and water is generated. Like hydrogen, oxygen is in a gaseous form and will leave the electrode. Both reactions can be described as half-cell reactions, shown in equation 8. It also shows the overall cell reaction. [49]

$$\begin{gathered} \textit{Cathode: } 2H_2O + 2e^- \longrightarrow H_2 + 2OH^- \\ \textit{Anode: } 2OH^- \longrightarrow H_2O + {}^1\!/_2\, O_2 + 2e^- \\ \textit{Overall cell: } H_2O \longrightarrow H_2 + {}^1\!/_2\, O_2 \end{gathered} \tag{8}$$

The liquid electrolyte which covers the electrodes is an aqueous solutions of either potassium hydroxide (KOH) or sodium hydroxide (NaOH). Both solutions are alkaline, which has given rise to the name of the electrolyzer. KOH is preferred over NaOH because of higher conductivity. The amount of KOH/NaOH depends on the temperature and pressure. Within the range of 70 - 100 °C and 1 - 3 bar, it will normally be 25 - 30 wt%. The use of the alkaline solution is necessary to provide the ionic conductivity between the electrodes. Figure 10 shows a simplified illustration of an electrolyzer, where the main components are highlighted. [49, 54–56]

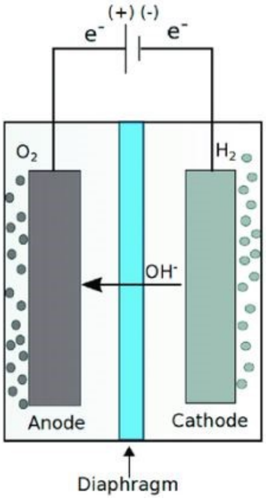


Figure 10: Illustration of alkaline water electrolysis. [57]

The diaphragm splits the cell into two parts. Historically, the most common material has been porous white asbestos, but since 1999 the material has been banned by the EU [58]. This is mainly because of the toxic effects, which could lead to asbestosis and lung cancer. Another problem was the corrosion rate of white asbestos in an alkaline solution, where higher temperature led to faster corrosion and eventually decrease the efficiency. Due to these issues, researchers have tried to develop a suitable replacement, like composite ceramic or different polymer materials, but there is sill room for improvements. [48, 59]

The most common material used in the electrodes is steel plates with nickel treatment, where different metals like cobalt, iron and vanadium are used as additives. Nickel is a suitable material, as it is corrosion resistant in alkaline media and a low-cost metal. [59]

In further development there is one area of interest: the unwanted reduction of KOH in the electrolyte. Due to various types of losses, it has to be periodically replenished. The main reason is carbon dioxide poisoning, a reaction that occurs if carbon dioxide is in contact with the electrolyte. This is happening according to equation 9. A consequence is lower ionic conductivity of the electrolyte solutions, leading to a reduced efficiency. Researchers have developed several solutions to this problem, but none of them are adequate for commercialization. A permanent method is desired, even though the reaction is prevented by continuous circulation of the electrolyte. [60, 61]

$$CO_2 \ poisoning: \ 2KOH + CO_2 \rightarrow K_2CO_3 + H_2O \tag{9}$$

PEM Water Electrolysis (PEMWE)

Developed in 1969, PEM water electrolysis is considered as one of the favorable methods for sustainable hydrogen production. Due to a number of operational advantages, the electrolyzer produces hydrogen with high purity at high energy efficiency, being 80 - 90 %. PEM is an abbreviation for proton exchange membrane, origin from the use of proton as the ionic agent. [49]

Unlike the alkaline electrolyzer, PEM uses an acidic electrolyte which force the water (H_2O) to be fed into the anodic side. The water molecule is then pumped to the anode, where the catalyst spits it into oxygen (O_2), protons (H^+) and electrons (e^-). The oxygen leaves the cell as a gas, the protons travel through the membrane and the electrons are forced through the external power circuit. At the cathodic side the protons and electrons are re-combined to produce hydrogen gas (H_2). Equation 10 shows both half-cell reactions, including the overall cell reaction. [49]

$$\textit{Cathode:}\ \ 2H^{+} + 2e^{-} \longrightarrow H_2$$

$$\textit{Anode:}\ \ H_2O \longrightarrow 2H^{+} + {}^{1}\!/_{2}\, O_2 + 2e^{-} \tag{10}$$

$$\textit{Overall cell:}\ \ H_2O \longrightarrow H_2 + {}^{1}\!/_{2}\, O_2$$

A PEM electrolyzer use a SPE membrane, which causes output gas of high purity. The use of a solid membrane also require additional components, including separator plates and current collectors. The separator plates pump water and transport the produced gases out of the cell. Presently, the plates are made up of titanium, stainless steel and graphite, but unfortunately these materials suffer from different operational drawbacks and high costs. The current collectors provide the electrical current to flow, where the use of porous titanium as material provides satisfying qualities, but also with a high cost. Together the separator plates and current collectors are responsible for about half of the overall cell costs. [49]

In addition to the current collectors, figure 11 shows the electrodes and the membrane. Together, the electrodes and membrane are called the membrane electrode assembly, MEA. It is responsible for approximately a quarter of the costs, mainly due to the use of noble metals as catalysts. For the oxygen and hydrogen evolution reactions, iridium and platinum are used respectively. A perfluorosulfonic acid polymer such as Nafion, is a material that is commonly used for the membrane. It has several advantages, like high durability, high proton conductivity and good mechanical stability. [49]

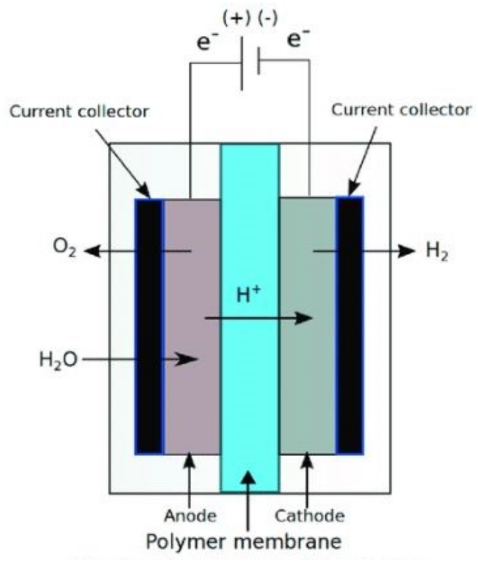


Figure 11: Illustration of PEM water electrolysis. [57]

PEM electrolyzers are suitable for intermittent power sources, mainly because of the solid membrane. The quick response and high operational pressure is also beneficial. The energy from a varying energy source like wind must be used immediately. In case of downtime, the time of a cold-start is desired to be as short as possible. To lower the costs of additional compression, a high operational pressure is also desired. [62]

The quality of the feed water is important for a PEM electrolyzer. It needs to be ultra pure, as the platinum catalyst is easily susceptible to poisoning from impurities. This leads to an irreversible reduction in efficiency, and due to the cost of platinum, the poisoning is undesirable. To solve this problem it is either possible to keep the poisons out of the system or alloy the catalyst with other metals, in order to reduce poisoning. The most efficient way is to keep the water free of impurities, even though it will require a water purification system. Despite this, platinum satisfies many of the other requirements as a catalyst and is suitable for the operational conditions of a PEM electrolyzer. [63, 64]

Anion Exchange Membrane Water Electrolysis (AEMWE)

To overcome the prospects of large-scale hydrogen production, installations at gigawatt scale is required. PEM electrolysis is a mature technology and could be used for scale-up, unfortunately the use of noble metals is an issue. Both the availability and price of the raw material must be considered. Use of alkaline electrolyzers will solve these problems, but due to the operational difficulties this technology is insufficient. Therefore, a new technology is needed to accommodate future needs. [66]

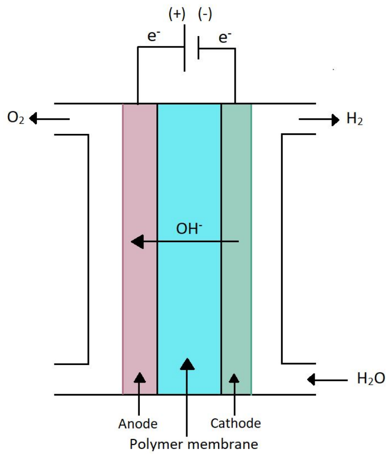


Figure 12: Illustration of anion exchange membrane water electrolysis. Adapted from [57] and [65].

The anion exchange membrane electrolysis can potentially solve this problem, where the benefits from both the PEM and alkaline electrolysis are combined. The design is based on the use of a polymeric membrane with anionic conductivity, but without the use of noble metals. The material costs are therefore much lower. However, the technology is in an early stage of development, and research is needed to make the technology conventional. A simplified diagram of an anion exchange membrane electrolyzer cell is shown in figure 12. [66, 67]

As part of the EU project Horizon 2020, the largest research and innovation program in the world, a team focuses on developing the anion exchange membrane electrolysis. The duration of the project is from January 1, 2020 to December 31, 2022, and is coordinated by Italy. The budget is at 1 999 995 €, and is considered as an important step toward the long-term goal to reach net zero CO_2 emissions in the EU by 2050. The project aims to develop a 2 kW anion exchange membrane electrolyzer with production rate of approximately 0.4 Nm^3/h. [68]

Solid Oxide Water Electrolysis (SOWE)

Solid oxide water electrolysis is a relative new technology, first introduced in the 1980s. Unlike the other techniques, this is categorized as high-temperature electrolysis. As the PEM and alkaline electrolysis will operate at about 80 °C, the operating temperature for solid oxide electrolysis will be at 700 - 1000 °C. The temperature gives the advantage of high efficiency, but the high temperature causes some safety issues. [49, 67, 69]

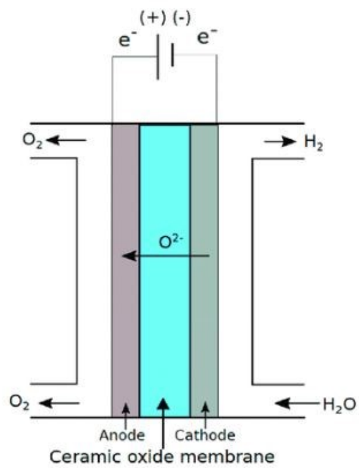


Figure 13: Illustration of solid oxide water electrolysis. [57]

Like the PEM electrolyzer, solid oxide electrolyzers use a solid membrane shown in figure 13. But due to the high temperature the membrane is exposed to damages, such as cracks in the electrolyte, which is made of ceramic. The electrolyzer is capable to handle load changes because of the solid membrane. But since load changes also lead to varying temperature, the lifetime of the cell is reduced because of micro cracks in the ceramic. For this type of electrolyzer, it is important to carry out the start-up and shut-down slowly, while keeping the temperature above 600 °C. Operating with an intermittent source is therefore not preferable. [67, 69]

According to equation 6, high temperature will require less input of electricity, but a higher amount of heat. This is also illustrated in figure 14, where it is possible to see that the electricity demand is reduced sharply as the temperature increase. This gives the technology a big potential, when connecting the electrolyzer to a heat source. [67, 69]

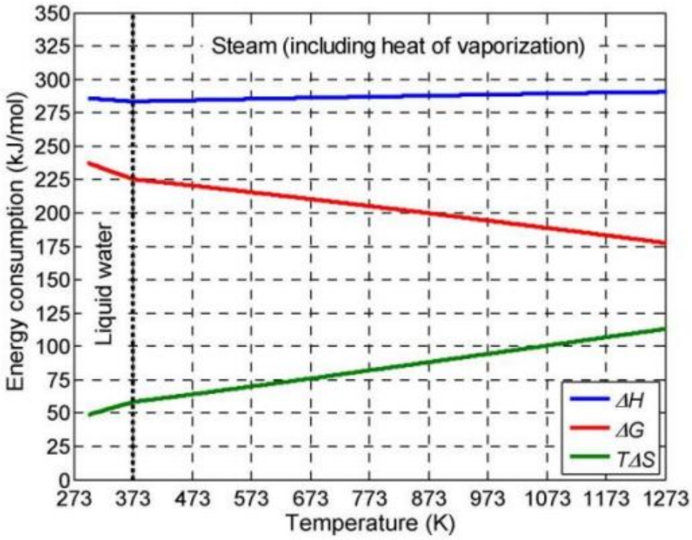


Figure 14: Evolution of the energy consumption of an ideal electrolysis at atmospheric pressure. [70]

Molten Carbonate Water Electrolysis (MCWE)

A molten carbonate electrolyzer is categorized as a high-temperature electrolyzer with an operating temperature at 600 - 700 °C. The molten carbonate fuel cell is said to be the most complex of modern fuel cells, with the use of a molten carbonate electrolyte. When the fuel cell runs in reverse, it operate as an electrolyzer. A general diagram of how the electrolyzer cell is constructed is shown in figure 15. Like the solid oxide electrolyzer, the molten carbonate electrolyzer is mainly used in megawatt sized installations, because of the requirement of high temperature. [71, 72]

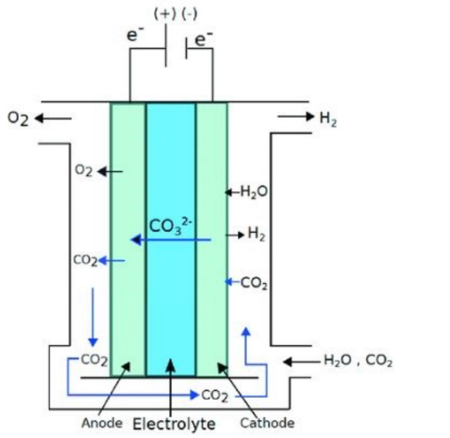


Figure 15: Illustration of a molten carbonate electrolysis. [57]

In addition to water, molten carbonate electrolysis also uses carbon dioxide (CO_2) in the inlet gas. Carbon dioxide is a reactant when the ionic agent, a carbonate ion (CO_3^{-2}), is produced. This gives the possibility of either producing hydrogen or syngas, a mixture mainly consisting of hydrogen and carbon monoxide (CO). It is due to the presence of carbon dioxide at the cathode, that carbon monoxide can be produced in accordance with equation 11. Even though it is possible, the reaction is much slower compared to the water electrolysis. It is therefore more likely to generate carbon monoxide through the reverse water-gas shift (WGS) reaction, shown in equation 12. [71, 73]

$$\textit{CO}_2\ \textit{electrolysis:}\ \ 2CO_2 + 2e^- \rightarrow CO + CO_3^{-2} \tag{11}$$

$$\textit{WGS reaction:}\ \ CO_2 + H_2 \leftrightarrow CO + H_2O \tag{12}$$

In the field of high-temperature electrolysis, the main focus has been solid oxide electrolysis. The focus of research has, however, been shifting towards co-electrolysis of water and carbon dioxide with use of molten carbonate electrolyzers. The result of co-electrolysis is the syngas, which can be used in many areas. However, the cheapest way of syngas production is based on natural gas. It can also be produced by use of other hydrocarbon feedstocks, such as oil and coal. But unlike the co-electrolysis, none of these methods are renewable. [74, 75]

2.4.4 Comparison: Alkaline vs. PEM Electrolyzer

Alkaline and PEM water electrolysis are considered as two of the most commercial and profitable technologies. Therefore, it is useful to compare these two alternatives.

Performance and Gas Purity

In the choice of using either an alkaline or a PEM electrolyzer, the energy efficiency is of importance. PEM electrolysis is more efficient than alkaline electrolysis. Under normal conditions, the cell voltage for PEM and alkaline electrolysis is approximately 1.75 V and 1.85 - 2.05 V, respectively. Table 6 gives a range of the typical energy efficiency. Lower efficiency represents greater loss and various overvoltages. Another factor to consider is the purity of the output gas, as some applications require ultra pure hydrogen. Table 6 compares the gas purity of alkaline and PEM electrolysis. [49, 50]

Table 6: Performance and gas purity comparison. [13, 49]

Characteristic	AWE	PEMWE
Energy efficiency	70 - 80 %	80 - 90 %
Hydrogen purity	99.99 %	99.9998 %

Lifetime and Stack Replacement

The lifetime of electrolyzer stacks are usually shorter than the lifespan of other relevant system components in a hydrogen production plant. This is because the stacks suffer from some degradation, which necessitates one or several stack replacements during the lifetime of the system. The degradation causes an increased energy consumption per kilogram of produced hydrogen. The stacks are usually replaced when the energy efficiency drops to 90 % of the nominal value. Table 7 provides with typical lifetime values for alkaline and PEM electrolyzers, including the degradation rate per year. The lifetime of stacks are given for continuous operation. [76, 77]

Table 7: Lifetime comparison. [45, 62, 76–78]

Characteristic	AWE	PEMWE
Lifetime of system [years]	20	20
Lifetime of stack [hours]	60 000 - 90 000	20 000 - 60 000
Lifetime of stack [years]	6.8 - 10.3	2.3 - 6.8
Degradation rate per year [%]	1.0	1.5

Load Range and Dynamic Operations

Due to the different design of the membranes, the operation area is not the same for alkaline and PEM electrolyzers. Table 8 gives typical load ranges as percentage of the nominal value, for both technologies. In general, the PEM electrolyzer is more flexible than the alkaline electrolyzer. In addition to the possibility of operating in stand-by mode with minimal electricity consumption, it can operate at overloads up to 160 % of nominal load for short periods. Table 8 also shows some of the dynamic operation values, like system response and cold-start time. [62, 76]

Table 8: Load range and dynamic operation comparison. [62, 76]

Characteristic	AWE	PEMWE
Load range	15 - 100 % nom. load	0 - 160 % nom.load
System response	Seconds (s)	Milliseconds (ms)
Cold-start time [min]	< 60	< 20

Power Consumption

The pressure inside the stack is important to consider in relation to energy consumption. It is more energy efficient to let the electrolyzer operate at a high pressure than using external, mechanical, compression. Compared to alkaline electrolysis, a PEM electrolyzer is better suited for high pressure, because it can withstand the resulting mechanical stress. The operating pressure in PEM electrolyzers are therefore higher. For instance, the output pressures are usually 1.0 bar (atmospheric pressure) for alkaline electrolysis, and 30 bar for PEM electrolysis.[76]

Costs

The costs of electrolyzers are expected to decrease. But this will require extensive R&D and a growing demand of hydrogen. As a well established technology, the cost of alkaline electrolysis is not expected to decrease as much as PEM electrolysis. Figure 16 shows how future technology will affect the cost of the electrolyzer systems and stack replacement. The prospect shows that the cost levels of PEMWEs will be closer to the costs of AWEs. The figure also shows how costs, per unit of capacity, will decrease as the plant size gets larger. For electrolyzer systems, this is happening up to a certain capacity, where the curves flatten. From this point, the cost saving will be reduced. [62, 76]

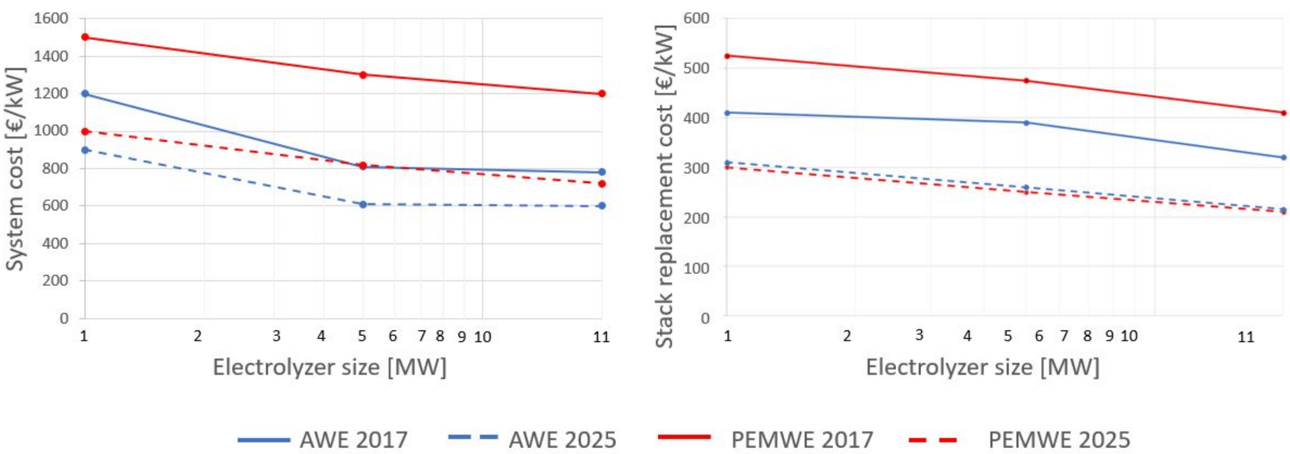


Figure 16: Electrolyzer system and stack replacement cost for AWE and PEMWE in 2017 and 2025. Adapted from [76].

2.4.5 Power Connection and Properties of the Power Grid

An electrolyzer can either be connected to the grid or directly to a power source. For this thesis the possibility of grid connection will be considered. It is important to note that when connecting a load to the grid, it is the power flow in the grid which determine where the energy comes from. Locally produced energy will most likely be consumed locally, but in the case of energy balance deficit in a area, energy from other places will be used to cover the consumption. [79, 80]

Power Triangle

The power grid is an interconnected network that delivers electricity with an alternating current (AC) to different consumers. Therefore, the grid transmits two different types of power: real power and reactive power. [81]

The real power, P, also called true or active power, is the power type which performs the "real work". For an electrolyzer, the amount of real power is of importance. By not performing any useful work, the reactive power is insignificant for an electrolyzer. Despite of this, reactive power, Q, is important for maintaining the function of the grid. To provide a visual relationship between the amount of real and reactive power, the power triangle is used. This is shown in figure 17. The figure also shows another power type, the apparent power, S, which is determined by the amount of real and reactive power. [81]

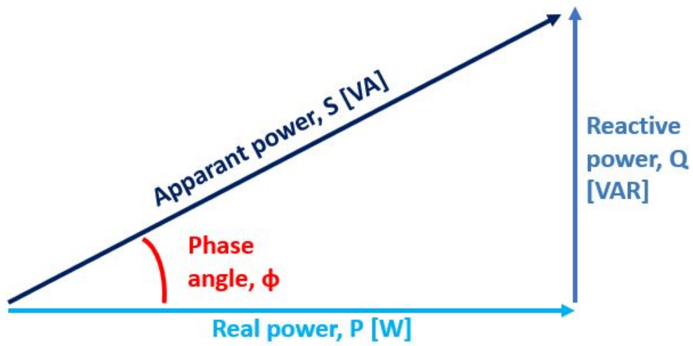


Figure 17: Power triangle. Adapted from [81].

The angle between the vector of real power and apparent power is called phase angle. This is used to define the power factor as the ratio of real power to apparent power, as in equation 13. Theoretically, the value can vary between 0 and 1.0. When reactive power equals to zero, the power factor is 1.0. When real power equals to zero, the power factor is 0. [81]

$$Power\ factor = cos(\Phi) = \frac{P}{S} \tag{13}$$

Transformer and Rectifier

The grid is divided into several voltage levels based on the purpose of the line. High voltages of up to 420 kV are used in power transmission. For distribution grids, lower voltage levels, typically being 66 or 22 kV, are used. A transformer is used to increase, or decrease, these voltage levels with high efficiency. Transformers at substations can decrease the voltages even further, down to either 400 V or 230 V, which is needed for most end users like households. In the transformer stations for local distribution, it is the installed capacity of the transformer which decide how much power can be distributed. The capacity is defined by the apparent power in VA. [80, 82, 83]

Electrolyzers use DC voltage, and not AC which is used in the power grid. Therefore, a rectifier is needed to convert AC into DC when electrolyzers are connected to the grid. This is done before the power is fed to the stacks, with high efficiency. [49, 80, 84]

2.5 Hydrogen Storage

There are different ways to store hydrogen. The most commonly used methods are gas and liquid form. Hydrogen can also be stored through adsorption and in either metal or chemical hydrides. The storage of hydrogen bound to chemicals or metals, or adsorption, is too expensive and underdeveloped technologies. Gas or liquid storage are therefore the only options for this thesis. As shown in figure 6 hydrogen has a high specific energy, but a low energy density. This problem with storage of hydrogen is explained in section 2.1.2. Every method of hydrogen storage requires an extra input of energy. [85]

2.5.1 Compressed Hydrogen

Hydrogen has a low density. Figure 18 gives a representation of hydrogen density at different temperatures and pressure. The gas needs to be pressurized in order to reduce storage volume. Increasing hydrogen density uses a large amount of energy. Pressurizing hydrogen from 1.0 to 30 bar will require 4 - 5 % of the original energy stored in the compressed hydrogen [9]. From 1.0 bar to 350 or 750 bar it requires 9 to 12 % of the energy content of hydrogen, respectively. [85, 86]

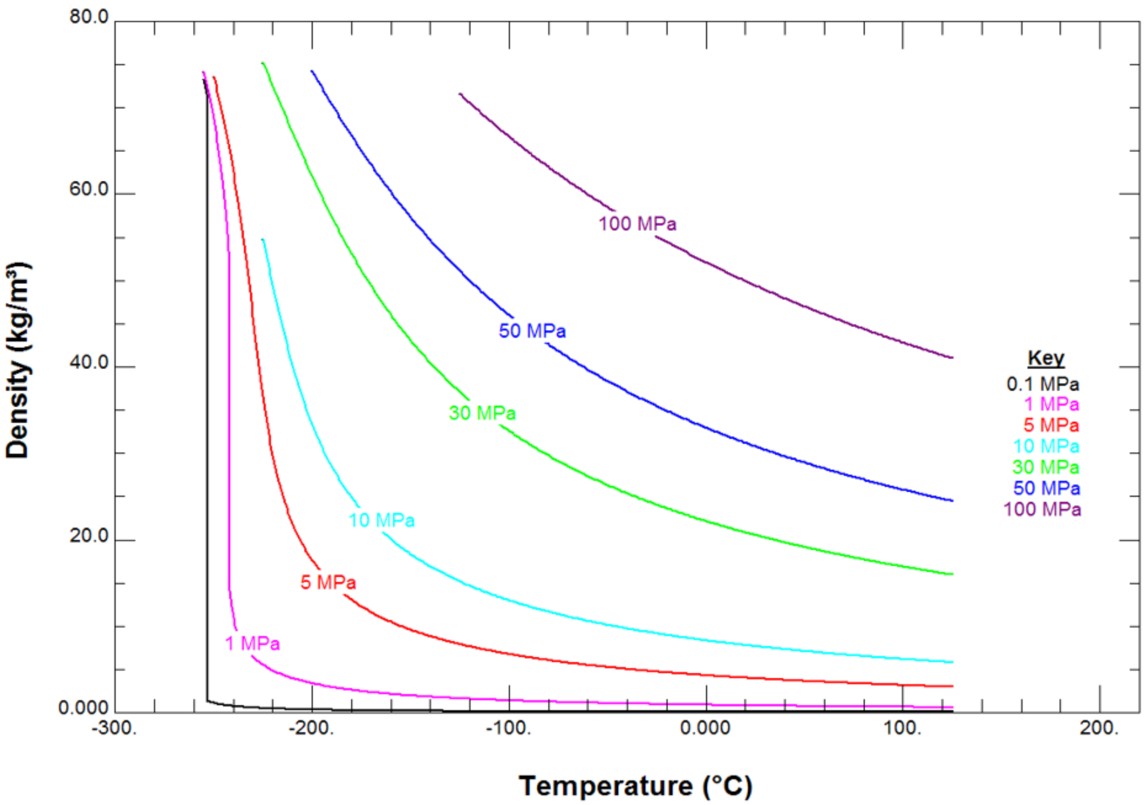


Figure 18: Hydrogen density at different temperatures and pressure. [87]

Storing hydrogen in the form of gas can be done in several different ways. One of the cheapest methods is to store it in underground caverns, like salt caverns. Underground storage can store hydrogen up to 200 bar. This investment is the cheapest because of several factor. For instance it has low construction rate, low leakage rate, fast withdrawal and injection rates, and minimal risks of hydrogen contamination. One drawback is that this storage is geographically locked. [85]

Storage in metallic containers can store gas up to several hundred bar, depending on the material. Steel is normally used as material. If the pressure is increased even further, the material must be of a composite metal. It is important to use the right material, to prevent hydrogen embrittlement from becoming a problem. This is a process where metal will become brittle and fracture from exposure to hydrogen [88]. Storage in metallic containers is more expensive than caverns, but has other advantages. The stability of the storage is greater, the purity of the hydrogen is certain and it is geographically independent. Container storage systems have two components, storage compartments and a compressor to achieve the right pressure. Theory about compressors is not presented in this thesis.[85]

2.5.2 Liquid Hydrogen

Another way of solving the problem with low density, is hydrogen liquefaction. The density of saturated liquid hydrogen at 1.0 bar is 70 kg/m^3. The problem is that it requires a large amount of energy. Changing phase from gas to liquid require up to 30 % of the energy content of hydrogen [86]. This is because the boiling point of hydrogen at 1 bar is -253 °C and hydrogen does not cool down during throttling process for temperatures above -73 °C. Because of the large energy consumption and complicated process of liquefying hydrogen, liquefaction plants are costly. It is a well established technology. Today 10 kwh$_{el}$/kg$_{H2}$ are used, but with improvements and larger plant sizes the extra energy consumption can be reduced to 6 kwh$_{el}$/kg$_{H2}$. The theoretical minimum energy consumption is 2.7 kwh$_{el}$/kg$_{H2}$, at 25 bar. To make liquefaction of hydrogen cost competitive it has to be produced in large quantities, as shown in figure 19. Higher production will lower the cost per kilogram. The blue graph shows that the total capital investment will increase, but with a lower rate, when the hydrogen production is increased. [85]

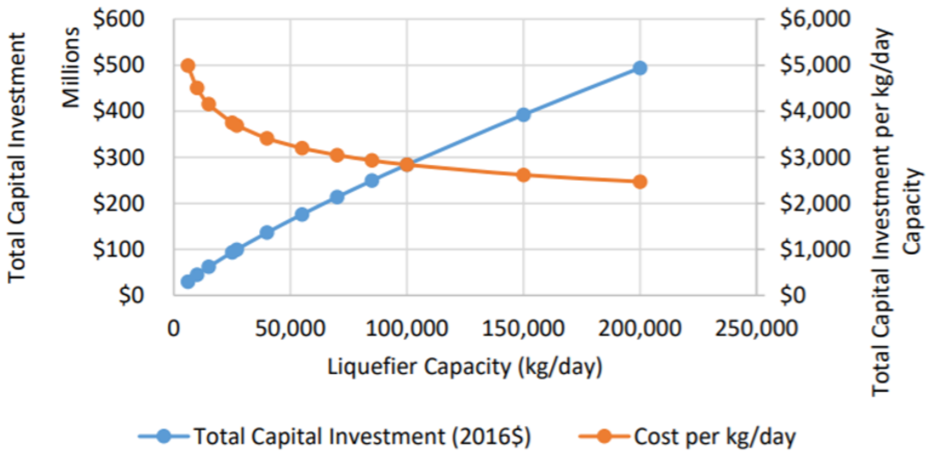


Figure 19: The price of liquefaction of hydrogen. [89]

Liquid hydrogen is normally stored in large spherical tanks. They are structured with double walls, having vacuum in between. This is done in order to minimize heat transfer through convection or conduction. The walls contain additional materials such alumina-coated polyester sheets. This is to shield against heat transfer from radiation. Boil-off rate is another problem with liquid storage, which is usually 0.1 % per day in spherical tanks. The aforementioned contingencies applied to the storage vessel is to decrease the boil-off rate. December 11, 2019 Kawasaki announced the launch of the worlds first liquefied hydrogen carrier. This ship will transport hydrogen from Australia to Japan in 1 250 m^3 tanks. [85, 90]

There are none liquefaction plants in Norway today. If there are any demand for liquid hydrogen, it has to be imported from Europe. There are, however, a few plans for liquefaction plants in Norway. Equinor has a best case scenario with a plant at Tjeldbergodden in 2023 and 2025 as a more realistic target. Also in January 2019 a initiative from Gasnor, Sunnhordland Kraftlag and Kvinnherad Municipitality was launched to make a plant. They are aiming for a capacity of 10 - 20 tons per day, but it is at an early stage of project development. [91]

2.6 Emissions Related to Use of Hydrogen

Hydrogen is considered to be an environmentally friendly energy carrier, especially because there are no direct CO_2 emissions from using it. However, production and use of hydrogen is not without environmental impacts. Hydrogen produced from electrolysis carries the emissions related to the electrical power that is used. Whether the electricity is produced by fossil fuels or renewable power, there are emissions from either combustion of fuels or the production of the power producing components. There are always GHG emissions from the production, manufacturing, transport and end-of-life (EoL) processing of all types of energy systems. This applies to for instance electrolyzers, storage tanks, fuel cells and batteries. This thesis will not present an analysis of environmental impacts for hydrogen production and use at Hitra. That task is too comprehensive for this project. However, this section will introduce some information and previous work on the emissions related to production and use of hydrogen, to give an overview.

2.6.1 Introducing LCA

Life cycle assessment (LCA) is an internationally accepted method, used to evaluate potential environmental impacts of products and services along their whole lifetime (cradle-to-grave). It includes analysis of materials, energy inputs, waste outputs and emissions involved in manufacturing, transport, assembly, operation and EoL actions. The analysis results in an overview of different categories of environmental impacts. The impact category *global warming potential*, GWP, is the only one that is emphasized in this report. The GWP tells how much heat a gas traps in the atmosphere, within a specific time frame (100 years in the cases presented here). In other words, it tells how much impact an emission has on global warming. GWP is given as CO_2 equivalents (CO_{2-eq}). [92]

There are many factors to involve, and many questions to ask, when performing or using a LCA of hydrogen production and usage. The following elements need to be addressed, and defined, in a life cycle assessment [93]:

- The part of the energy system
- The type of electrolyzer or fuel cell
- The production country (with its grid emissions)
- Transport of components
- Types of materials
- Lifetime

This type of analysis must be conducted on specific scenarios. [93]

LCA of Hydrogen Production from Electrolysis

The Journal of Cleaner Production contains a report reviewing 21 different LCA analyses of hydrogen production from electrolysis conducted until 2012 [94]. Different types of electrolyzers, but mostly alkaline, and lifetimes of 40 000 to 60 000 hours where the basis for all of the scenarios. Figure 20 summarizes the results of global warming potentials for hydrogen produced by electrolysis, based on different electricity sources. It shows that hydrogen produced by wind energy has the lowest GWP value of about 1 - 2 kg of CO_2 equivalents per kg of produced hydrogen. Production by electricity from the grid has the highest GWP value, being 31 - 33 kg CO_{2-eq}/(kg H2)[3]. Newer reports also show similar values, being in the area of 30 - 35 CO_{2-eq}/(kg H2). [92–94]

[3] UCTE mix, 2010: 17 % renewable, 29 % nuclear and 54 % fossil power

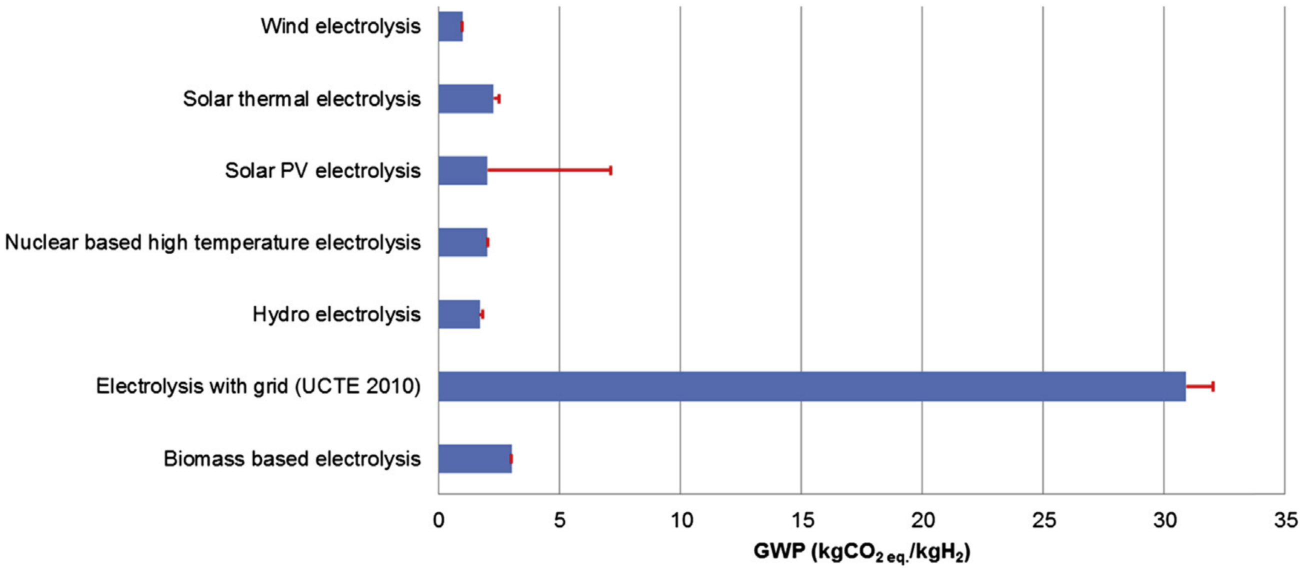


Figure 20: GWP for hydrogen produced by electrolysis (kg CO_{2-eq}/kg_{H2}). Based on 21 different LCA analyses. [94]

The global warming potential of hydrogen from electrolysis is to a very large extent caused by the energy consumption for operation. In a SINTEF report [92] about electrolysis from grid power, 86 % of the GWP value is caused by energy consumed during the operation of the electrolyzer. It could be reduced to 20 - 40 % if the energy source is renewable, which is the case for Hitra and Norway in general, because of a predominance of renewable power. [92]

2.6.2 WTW and Comparison of Different Drivetrains

Well-to-wheel/wake (WTW) analysis is used to compare emissions related to different vehicles, propulsion systems and drivetrains. The term has mainly been used for road transportation, but is transferable to maritime transport and may then be called "well-to-wake". It is often an application of life cycle analysis (LCA), addressing the emissions through the whole life cycle of a specific object, or it can focus on the fuel or energy carrier that is used in the moment. The analysis consists of a well-to-tank (WTT) analysis and a tank-to-wheel/wake (TTW) analysis. WTT takes care of the energy, and related emissions, required to provide energy or fuel to a specific mode of transport. The TTW part focuses on the consumption of the energy in a vehicle or vessel, and the accompanying emissions. These are also known as tailpipe emissions. Vehicles and ships using hydrogen or batteries to run electric motors have zero TTW emissions. [95]

Hydrogen scaling up, a report from the Hydrogen Council, compares the WTW emissions from ICE vehicles, BEVs and FCEVs in the C-segment (compact cars). The result from the comparison is summarized in figure 21, based on average grid emissions in China, the USA, Germany and Spain in 2015. ICE vehicles, using diesel or gasoline for fuel, have large TTW emissions. It is also evident that the emissions from both BEVs and FCEVs are very low, and in the same order of magnitude, when the whole life cycle is included. These relations are transferable to maritime transport as well, as the same technologies are used. This shows that hydrogen can be used to reduce emissions in the transport sector in the same way as batteries. [33]

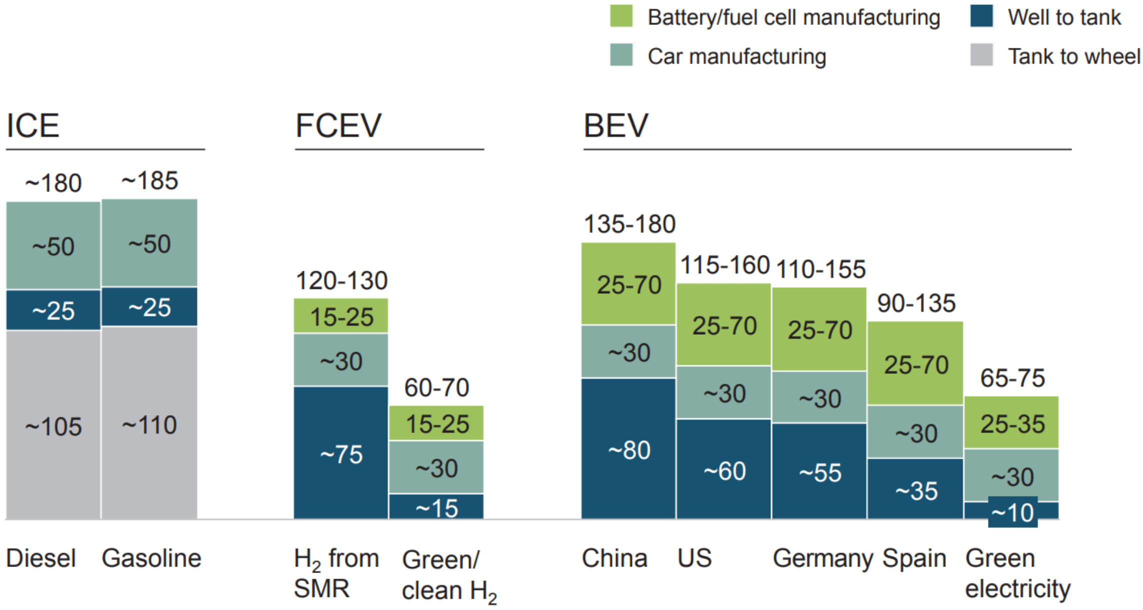


Figure 21: WTW data for ICE vehicles, BEV and FCEV within the C-segment. g CO_{2-eq} per km, 2015. Based on different fuels and electricity mixes, LCA and 120 000 km lifetime. *Source: EPA; A Portfolio of Powertrains for Europe (2010); Toyota Mirai LCA; IVL; Enerdata; expert interviews, via* [33].

Well-to-wheel emissions from BEVs and FCEVs are strongly dependent on the emissions related to the electricity that is used to charge batteries and produce hydrogen. This is often called *grid emissions*. Different sources of energy are considered to have specific emissions, called emission factors. LCA calculations from AIB, the Association of Issuing Bodies, have defined emission factors for coal, natural gas and renewable power as following:

- Electrical power from coal: ~ 1000 g CO_{2-eq}/kWh
- Electrical power from natural gas: 566 g CO_{2-eq}/kWh
- Electrical power from renewable sources: 2 - 46 g CO_{2-eq}/kWh

In order to have low WTT emissions during the lifetime of a vehicle, the electricity used to charge batteries and produce hydrogen should therefore come from renewable sources. Based on calculations from AIB, the electrical power produced in Norway has an emission factor of **18.9 g $\mathbf{CO_{2-eq}}$/kWh** (based on data for 2018). This means that hydrogen produced by Norwegian electricity, from renewable sources, can give low WTW emissions. [96]

WTW Example for Maritime Transport

In order to give a better picture of WTW emissions, an example of a high-speed craft with three different energy systems is described below. Energy to propulsion from diesel/MGO, hydrogen and batteries are compared. In these cases, the energy wells are electricity from Norwegian production and diesel/MGO from a storage tank. The emissions related to the energy wells are 18.9 g CO_{2-eq}/kWh_{el} for electricity and 263 g CO_{2-eq}/kWh_{fuel} for diesel/MGO, based on data from table 3. The well-to-wake emissions are calculated based on the efficiencies of the involved components, which are illustrated in figure 22. The resulting emissions, per unit of usable energy to cause propulsion, are also given in the figure. [23]

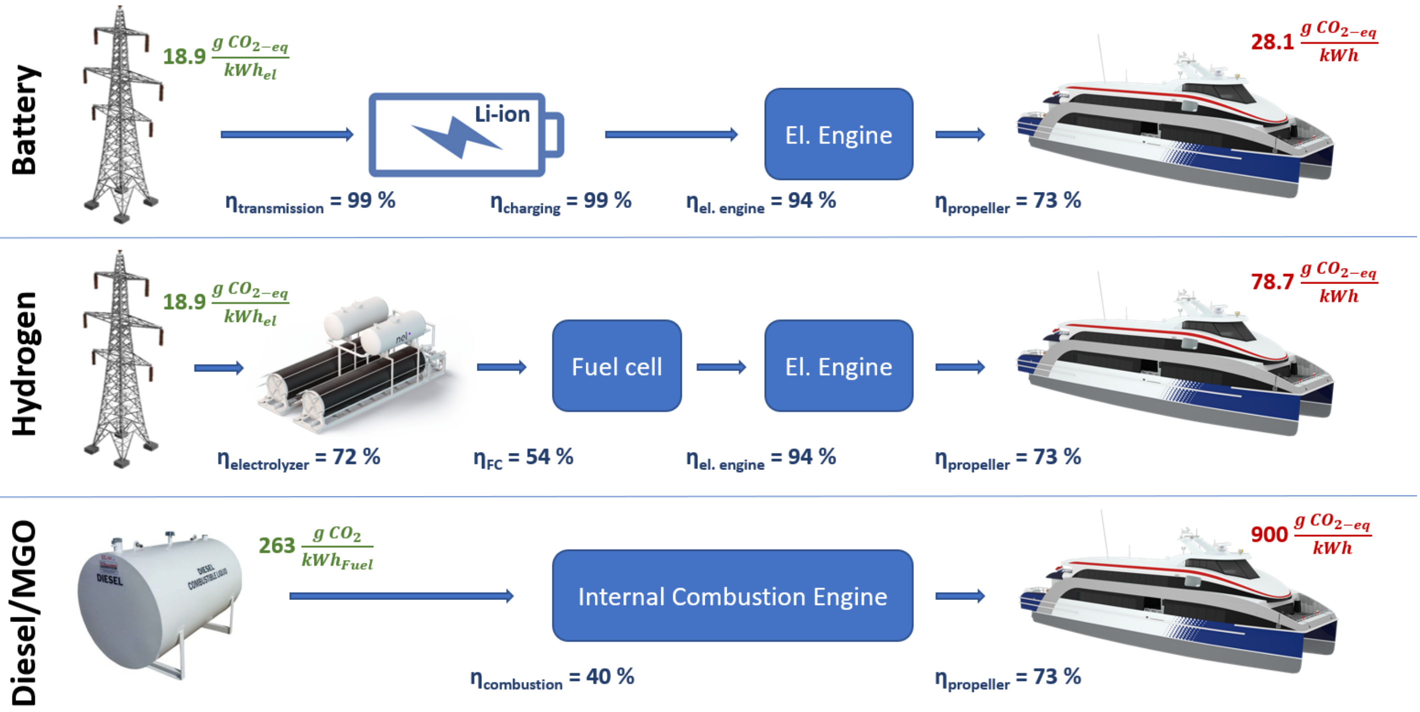


Figure 22: Efficiencies and emissions in conjunction with use of batteries, hydrogen and diesel/MGO in propulsion systems. Based on data from [23].

It is evident that hydrogen and battery propulsion systems have lower emissions of greenhouse gases than diesel propulsion, when the electricity is from Norwegian power. However it is important to note that the production and EoL processing of the system components are not included. Neither is emissions from refining and transport of the MGO. This will add substantial emissions to the WTW values of all these scenarios. When comparing batteries with hydrogen systems, it is important to include the fuel cells and storage tanks for the hydrogen production and usage. In other words, there are several components that have environmental impacts for a hydrogen system than for a battery system. In addition, several components cause a reduction in total efficiency, resulting in lower emissions for battery systems (per unit of useful energy) in figure 22. [23]

2.7 Economics

Calculating if hydrogen production will be competitive is an important aspect of any hydrogen project. The expenses can be divided into two categories, which is capital expenditures (CAPEX) and operational expenses (OPEX). CAPEX is the funds a company uses to acquire, upgrade and maintain physical assets. These assets can be buildings, property, equipment or technology. During normal business, CAPEX expenses are caused by expansion, where the company use funds to further develop the size of the business. OPEX is short term expenses like regular cost for products or a system, which is required for running a business. Other examples of OPEX are rents, payrolls, electricity and water, insurance and funds for research and development. [97–99]

Levelized cost of hydrogen, LCOH

Levelized cost of hydrogen (LCOH) is presented at a per kilogram basis. This makes it easy to compare the cost of different hydrogen projects. LCOH is inspired by levelized cost of energy (LCOE), which allows for comparison of different methods of producing energy. In both of these terms, the "levelized cost" is an important factor. This is the value of which a fixed revenue level throughout the projects lifetime will cause the project to break even. Equation 14 shows how LCOH is calculated. A weakness by calculating LCOH with equation 14 is that the OPEX is assumed constant. This is not the case, as it is always fluctuating each year. The formula also do not take technology advancements into consideration, which can lower costs of equipment. [100, 101]

$$LCOH = \frac{CAPEX + \sum_{k=1}^{n} \frac{OPEX}{(1+r)^k}}{\sum_{k=1}^{n} \frac{m_g}{(1+r)^k}} \tag{14}$$

In equation 14, m_g is the amount of produced hydrogen in kg, n is the economical lifetime in years and r is the discount rate. The discount rate is defined as the rate used to discount future cash flows in a discounted cash flow analysis (DCF). The discount rate express how the value of money is dependent of time. It can also make the difference if an economical investment can be financially viable or not. The lower the percentage, the lower the risk, and vice versa. The lowest discount rate in Norway is 4 %. This is considered risk free. Large companies normally use a rate between 7 and 10 % and small companies use between 10 and 15 %. The discount rate does also take inflation into consideration. [102]

Inflation is a persistent growth of the general prices. This is the same as a drop in the value of the currency. By using equation 15, the approximated worth an amount of finance today will have in a set amount of years, y, can be calculated. IF, is the inflation factor and r_f is the inflation rate. Inflation rate is the rate of which the average price of goods and services increase per year. [103]

$$IF = (1 + r_f)^y \tag{15}$$

Figure 23 illustrates LCOH values in american USD for different production technologies and energy prices. The energy prices are given in parenthesis above each bar, and reflect the method of energy production. For example, solar power is more expensive than wind power. The methods which use water electrolysis, have an electrolyzer CAPEX of 840 USD/kW (750 €/kg). The most interesting LCOH is "Average-cost Wind", which is approximately 4.1 USD/kg (3.7 €/kg). [104]

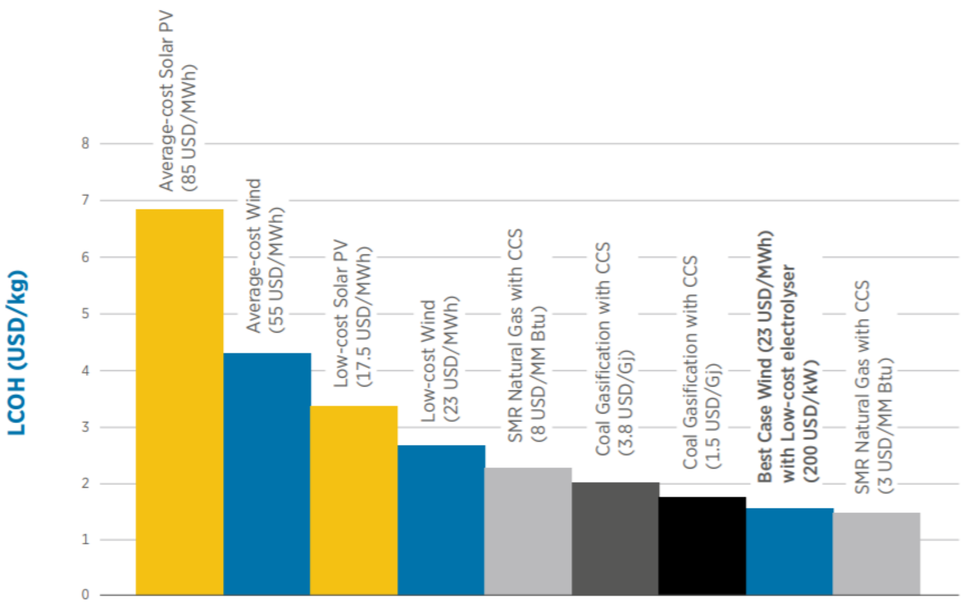


Figure 23: Comparison of LCOH values for different technologies and energy prices. [104]

PEM electrolysis is the most expensive electrolysis technology that are commercially available. The lowest hydrogen price is therefore given with alkaline electrolysis. Figure 24 shows both conservative and optimistic estimates for LCOH in 2030 and 2050, produced from alkaline electrolyzers. The illustrated trend will make hydrogen from electrolysis profitable, and opens up a market for green, renewable, hydrogen [105]. By looking at the costs for hydrogen production in Norway only, the report posted by DNV GL in 2019 present some estimates [9]. With alkaline electrolysis, the price will be 22 - 45 NOK/kg (2.2 - 4.6 €/kg) until 2030. By use of a PEM electrolyzer the cost will be 26 - 52 NOK/kg (2.7 - 5.3 €/kg) until 2030. The electricity and grid cost are the largest contributors to the hydrogen cost. In the coming years, this expense is expected to increase. According to the DNV GL report, the electricity cost can in 2030 contribute with 50 - 70 % of the total cost of hydrogen. [9]

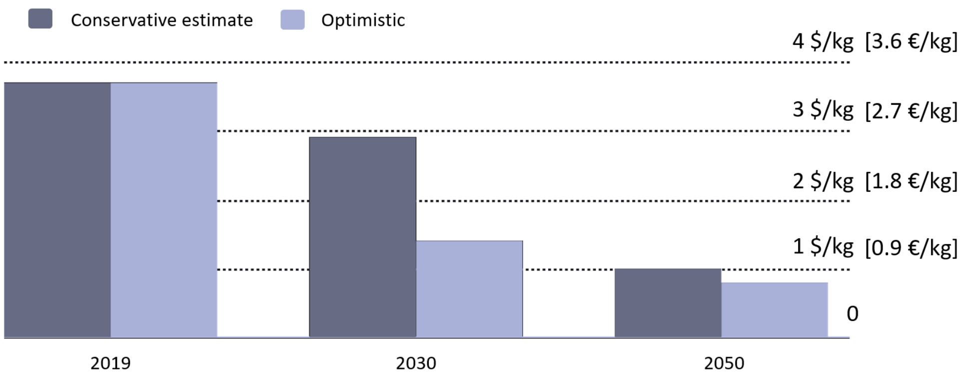


Figure 24: The estimated price, in US$ and Euro, for hydrogen produced from alkaline electrolysis in 2030 and 2050. Adapted from [105] (2019).

Net Present Value and Payback time

The LCOH can be used to check if an investment is financially viable, when used as a basis in a net present value (NPV) analysis. NPV is defined as the difference in the present value of cash inflows and the present value of cash outflows over a period of a time. This can be calculated with equation 16, where C_t is net cash flows during a single period of time, t. NPV is used to analyze the profitability of a project. If the NPV is positive it is assumed that the investment will be profitable and if the value is negative it will result in a net loss. This concept is based on the fact that an amount of money today is worth more than the same amount at a later date. [106, 107]

$$NPV = \sum_{t=1}^{n} \frac{C_t}{(1+r)^t} \tag{16}$$

Another way of checking if a financial investment is profitable or not, is by calculating the payback time. Payback time refers to the amount of time it takes to recover costs from investments or for the investors to brake even. This method is normally used by companies to find out if they should go trough with an investment or project. The shorter the payback time is, the better. The payback time is found from equation 17. The investment, the CAPEX, is divided by the annual cash flow, C_t, which is income minus OPEX. The drawbacks of this equation are that it does not take the time value of money into account and assumes constant cash flows. [108]

$$Payback\ time = \frac{CAPEX}{C_t} \tag{17}$$

2.8 HSE - Health, Safety and Environment

Storing hydrogen can be dangerous. A potential explosion can cause damage for the nearby area, depending on the amount of hydrogen that is involved and the use of safety regulations. That is why there are strict health and safety rules for production of hydrogen. An example is the explosion at an Uno-X station in Sandvika in June 10, 2019. It caused only minor injuries to some passing drivers, as their airbags opened due to the shock wave. The explosion was strong enough to effect a seismic apparatus 28 kilometers away. The cause of the accident was two bolts, which were tightened to loose, causing a leakage and then the hydrogen-air mix was ignited. [109, 110]

The use of fuel cells and hydrogen in maritime vessels is under the jurisdiction of the Norwegian Maritime Directorate (Sjøfartsdirektoratet). The production and storage of hydrogen is under the jurisdiction of Directorate for Civil Protection and Emergency (Direktoratet for samfunnssikkerhet og beredskap, DSB). However, there are no specific health and safety regulation for hydrogen projects in Norway. This creates an unfortunate challenge and makes the health and safety regulations for hydrogen projects convoluted. For instance, safety distances for hydrogen systems are based on other substances. Considering the unique attributes of hydrogen, these safety distances are highly uncertain. The DSB does not have the right amount of statistical data to make a certified safety distance table. [25, 35]

Hydrogen is classified as a flammable gas, in category one and two, in Norway. Flammable gas category one is gas at 20 °C and pressure of 1.013 bar, which can ignite at a mix of 13 % or less with air. Category two is gas which has an explosion area at standard air pressure and temperature and is not flammable gas. This categorization is based on the unique attributes of hydrogen. The gas has a high ignition area from 4 to 75 vol %. Hydrogen requires a low amount of energy to ignite, including a high burning rate, which makes a potential fire difficult to extinguish. Considering the attributes and given categories, hydrogen production facilities has to take into consideration the Fire and Explosion Prevention Act (Brann- og eksplosjonsvernloven) and the Act on the Supervision of Electrical Installations and Electrical Equipment (Lov om tilsyn med elektriske anlegg og elektrisk utstyr). Both these acts have regulations, which also needs to be upheld. [25, 35, 111]

Regulations for Major Accidents

The most important regulation is the regulation for major accidents (Storulykkeforskriften). This is a general regulation for many different substances with different attributes. Regarding hydrogen, the regulation for major accidents applies if the amount exceeds five tons, regardless of whether it is produced on site or transported to the production site. The production is also defined as *notifiable business* (meldepliktig storulykkevirksomhet) and must report every third year. If the amount of hydrogen exceeds 50 tons, the production is then defined as *business with compulsory safety report* (sikkerhetsrapportpliktig storulykkevirksomhet), and must report every year. It is the owner or the people in charge that needs to fulfill the demands of the major accident regulations. There is a list of procedures that must be reported: [25, 112]

- Detailed overview over the different chemicals and how much of each chemical, with safety data sheets
- Detailed plan over the current and planned activities of the company
- Detailed description of the business and the surroundings, with factors which can create a major accident or aggravate the consequences of the accident
- Develop a strategy to prevent and calculate the probability and consequences for major accidents
- Develop an internal contingency plan adjusted to the business size and craft, and warn the relevant emergency services and counties

These are all equally important and must be upheld. The problem is that they make the process of building a hydrogen production site convoluted and prolong the construction time. [25]

3 Methodology

The methodology is important in all types of projects, in order to produce valuable and correct results. This also applies to this thesis. In the following section, the methodology for the bachelor's project is presented to give an insight into how work has been conducted. Strengths and weaknesses of the methods will be pointed out to make the results credible.

The thesis aims to analyze and present the opportunities for hydrogen production from electrolysis at Hitra. Further, as the research question points out, the project will find out whether the produced hydrogen will be feasible and competitive or not for the regional maritime sector. In order to do so, several aspects are looked into. First of all, the thesis focuses on the costs related to production, storage and delivery of compressed hydrogen to high-speed crafts and well-boats. Cost data is obtained from literature and market participants, and calculations on available power and production costs are conducted using Microsoft Excel and MATLAB. Through these calculations, the levelized cost of hydrogen (LCOH) is found, and thus it is possible to find out whether the costs for hydrogen production at Hitra is competitive or not.

The environmental aspect of hydrogen from Hitra is also considered as a factor that may influence the competitiveness. This thesis does not analyze the environmental aspects of a specific scenario with hydrogen production at Hitra. However, theory and research provided by literature is used to establish an overview of the climate effects of hydrogen production.

Figure 25 shows an overview of the objectives and methodology for the project. In general it involves reading and reviewing literature. Data is collected, organized and adapted to the specific scenarios for this thesis. Some information is provided by market participants. But, as essential data is not made available for this thesis, due to competition issues for relevant businesses, the main part of the data is collected from various literature. In some cases, information has been provided by market participants as long as the source of the data would remain secret. This affects the credibility of the data, which can make literature review a better option.

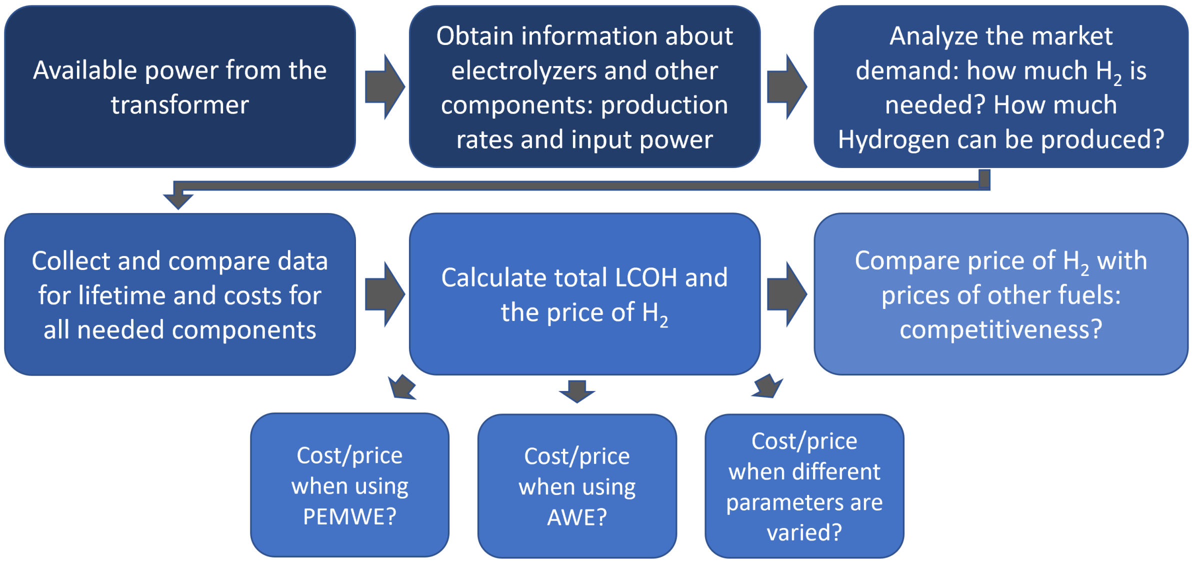


Figure 25: Objectives and methodology of the thesis.

The information on available power to hydrogen production is provided by TrønderEnergi, and is the first step presented in figure 25. Furthermore, data for different electrolyzers is collected to find values for input power and power consumption. From that it is possible to calculate the amount of hydrogen that can be produced. In the same time, an overview of the demand is achieved by reading reports on both conventional and hydrogen powered HSCs, well-boats and other possible end users of hydrogen.

The demand is very important to consider, as there is no need for producing hydrogen that will not be used. The *chicken and egg dilemma* is an analogy that is often highlighted when speaking of hydrogen production and demand. Whether a production facility or the end users of hydrogen should be in place first is definitely something to consider. High-speed crafts are likely to be the first end users of hydrogen at Hitra that will have a significant demand. Therefore, a scenario with production for this purpose only is presented, in addition to a scenario where all available power goes to hydrogen production. The demand is also important to consider as it sets the foundation for the dimensioning of storage capacity. Cost data for all relevant components, installation and building is then found, and used to calculate LCOH for different production scenarios. The resulting production costs are, eventually, compared with other and relevant existing data.

3.1 Available Power

The connection point for the hydrogen production is determined to be the place of the transformer at Sandstad. Figure 26 gives an overview of the location of the transformer and voltage levels in the surrounding area. The green and red lines represent 66 kV and 22 kV, respectively. The green square marked *JØSNØYA* is the transformer 66/22 kV, and the smaller squares marked with *NS [...]* are substations, 22/0.4 kV. Dotted lines represents overhead lines, while the soild lines are cables. [113]

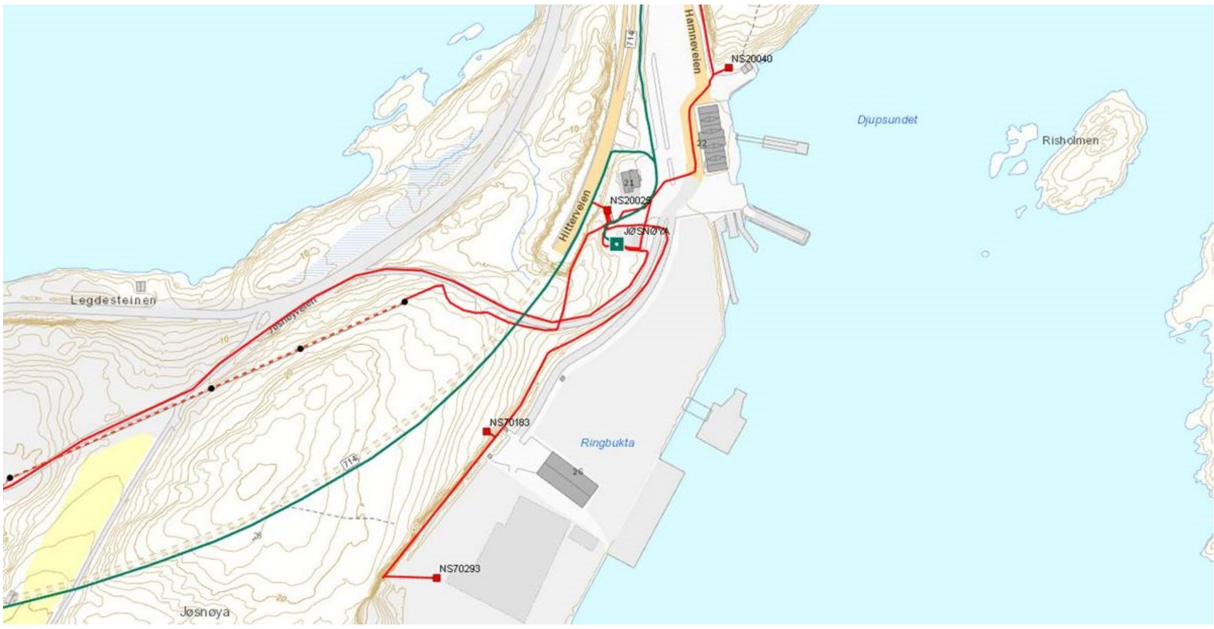


Figure 26: Voltage levels and transformers at Sandstad (Hitra Harbor). [113]

In order to connect a new load to the transformer, there must be surplus energy at the connection point. An overview of the energy consumption is therefore needed. TrønderEnergi has provided with Excel-sheets showing the consumption for 2018 and 2019. The data was given in the form of MWh for every hour during the two years. In addition to the known consumption, Hitra Municipality has a planned, future, load of 8.8 MW. TrønderEnergi also provided information about the power factor and installed capacity of the transformer, being 0.9 and 25 MVA, respectively. Equation 18 is used to calculate the available power, $P_{available}$, at the transformer. Equation 13 from section 2.4.5 is used to convert apparent power to real power. [113]

$$P_{available} = S_{transformer} \cdot cos(\Phi) - P_{consumption} - P_{future\ load} \tag{18}$$

Only the data for 2019 is examined in MATLAB. All the data is divided into 52 weeks, and categorized into 12 months. To make the first week start on a Monday and the last week to end on a Sunday, one day from the 2018 data sheet is added and two days, being at the end of December, are removed from 2019 data sheet. The result is a vector with 8736 elements; one element for each hour. This start-up remains the same for all MATLAB calculations.

The first step is to obtain a useful overview of the surplus power and how it varies from month to month. For this purpose a MATLAB code is made, where the output provides an average week for each month in the form of a visual graph. Appendix A shows all these graphs. The graphs shows a correlation between power surplus and season: during summer months the power surplus is higher compared to the power surplus during the winter. In 2019, March and December were the months with lowest power surplus, with approximately 10.8 MW at the bottom. The graphs also show that during the summer season, the surplus is almost always above 12 MW.

A useful presentation of the surplus power is a histogram showing the number of hours with the corresponding amount of surplus energy. In addition to the graphs in appendix A, the histogram in figure 27 would be helpful in the choice of energy harness limitations. Unlike the graphs, the histogram is based on raw data from 2019, and not averages.

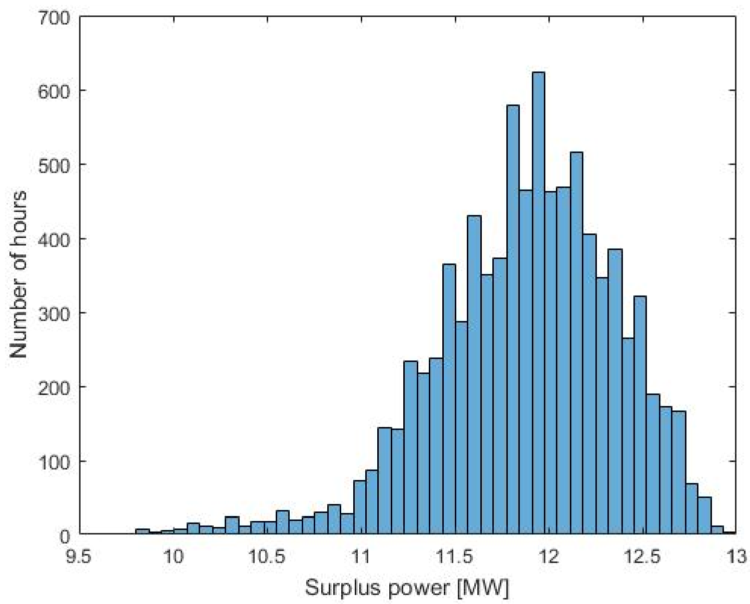


Figure 27: Number of hours with corresponding amount of surplus power.

In order to not oversize the production plant, the upper limit is set to 12 MW based on the graphs in appendix A and the histogram in figure 27. This gives the electrolyzers the opportunity to harness almost all of the available energy, but without many high loads caused by peaks in the surplus power. The available energy is above 12 MW only for short periods. If the electrolyzers are to exploit the highest peaks in surplus power, it could result in destructive stress for the components.

3.2 Selecting Electrolyzers

As explained in the previous chapter, it is decided to dimension the electrolysis plant for 10 MW production. Further, both PEM and alkaline water electrolyzer models are selected to establish two possible production plants. Some of the relevant electrolyzer specifications are found in brochures and articles from different companies, and are compared in appendix B. Most of this data is retrieved straight from the sources, but some specifications are also calculated. In conversions between Nm^3 and kg, equation 3 is used.

The types and specifications of electrolyzers chosen for this thesis are given in table 9. It must be noted that these values, especially *input power*, are approximate. All the selected electrolyzers are from Nel Hydrogen. This is because they seem to have the lowest energy consumption and the highest output rate of hydrogen compared to the other suppliers. These properties will probably make them the most expensive electrolyzers, but that cannot be taken into account in this project. All the companies are secretive with their prices and not willing to share, because of marketing strategies. Therefore it is assumed that prices are the same per kilowatt for each electrolyzer.

For the scenario with 10 MW of only alkaline electrolyzers, two A1000 and one A485 are chosen. This combination equals to a plant size of 10.67 MW. The PEM electrolyzers chosen for a 10 MW facility are five M400 and one M200. This combination equals a plant size of 10.29 MW. It must be noted that these capacities are calculated based on the values from appendix B, and are therefore not precise. For a scenario with hydrogen production for high-speed crafts only, one A300 and one A1000, or three M400 electrolyzers, are possible combinations. All the AWEs from Nel Hydrogen have an aqueous KOH solution of 25 %. [13]

Table 9: Electrolyzers chosen for this project, with key properties. All data is obtained through communication with Nel Hydrogen, taken directly from Nel Hydrogen product brochure, or calculated based on its content. [13, 77]

Type and model	Approximate input power [MW]	Energy cons. [kWh/kg]	Water cons. [l/Nm^3]	Max prod. [kg/day]	Area [m^2]	Output pressure [bar]
Alkaline: A300	1.0	53.4	0.9	633	100	30
Alkaline: A485	2.0	53.4	0.9	1024	225	30
Alkaline: A1000	4.0	53.4	0.9	2049	225	30
PEM: M200	1.0	57.8	0.9	446	100	30
PEM: M400	2.0	57.8	0.9	892	160	30

Table 9 also shows the energy consumption for the electrolyzers, per kilogram of produced hydrogen. This approximate data is revealed through communication with Nel Hydrogen, and applies for the first year of use. This is not the only electricity consumption for a production plant. There are also energy losses in the electrical systems, and energy is required to store hydrogen. Table 10 gives the different values of energy consumption for the rest of the system. There is a difference between the electricity consumption for the external compressors used with alkaline and PEM electrolysis. This is because the output pressure for AWE is 1.0 bar and the output pressure for PEMWE is 30 bar, without external compression. As power consumption for the electrolyzers is given based on an output pressure of 30 bar for both types in table 9, the energy needed for compression from 30 bar is looked at. Compression from 30 bar to 200 bar requires 1.7 kWh/kg. For this project a storage pressure of 300 bar is chosen as a basis, and it is assumed that compression from 30 to 300 bar will need 2.0 kWh/kg.

Table 10: Energy consumption and area footprints of other equipment.

Component	Energy Consumption [kWh/kg]	Area footprint	Source
Storage	-	0.09 m^2/kg (capacity)	[35]
Rectifier and transformer losses	3.41	-	[35]
Compressor/filling (30 bar to 200 bar)	1.7	75 m^2 (20 kg/h)	[35]
Compressor/filling (30 bar to 300 bar)	2.0 (assumed)	-	-

Values from table 9 and 10 can be used to find the total energy consumption, as shown in equation 19. Here *el. losses* is rectifier and transformer losses. The equation gives the outcome of 58.81 kWh/kg for alkaline electrolysis, and 63.21 kWh/kg for PEM electrolysis.

$$e_{total} = e_{electrolyzer} + e_{compression} + e_{el.\ losses} \tag{19}$$

To make sure the size of 10 MW electrolyzer is fitted for the power situation at Hitra, a separate analysis is conducted show the operation area. Graphs for every months, for both alkaline and PEM electrolyzers, are made. The graphs showing the available power and the power consumption lines are plotted in the same diagram. When the graph of available power is within the lines for power consumption for AWE systems, or in the area of the power consumption for PEMWE systems, the electrolyzers can use all of the available power. Figure 28 shows how this is done for January. The black line is the excess power at the transformer. The blue lines are min/max power consumption of the electrolyzers and the red lines are max/min power consumption of the total system. The yellow line represents 12 MW, which is the upper limit for energy harnessing. For PEM electrolysis, Nel Hydrogen only provides with one value for production rate. Hence, only one line representing the power consumption of the electrolyzers, and one representing the total system, are shown.

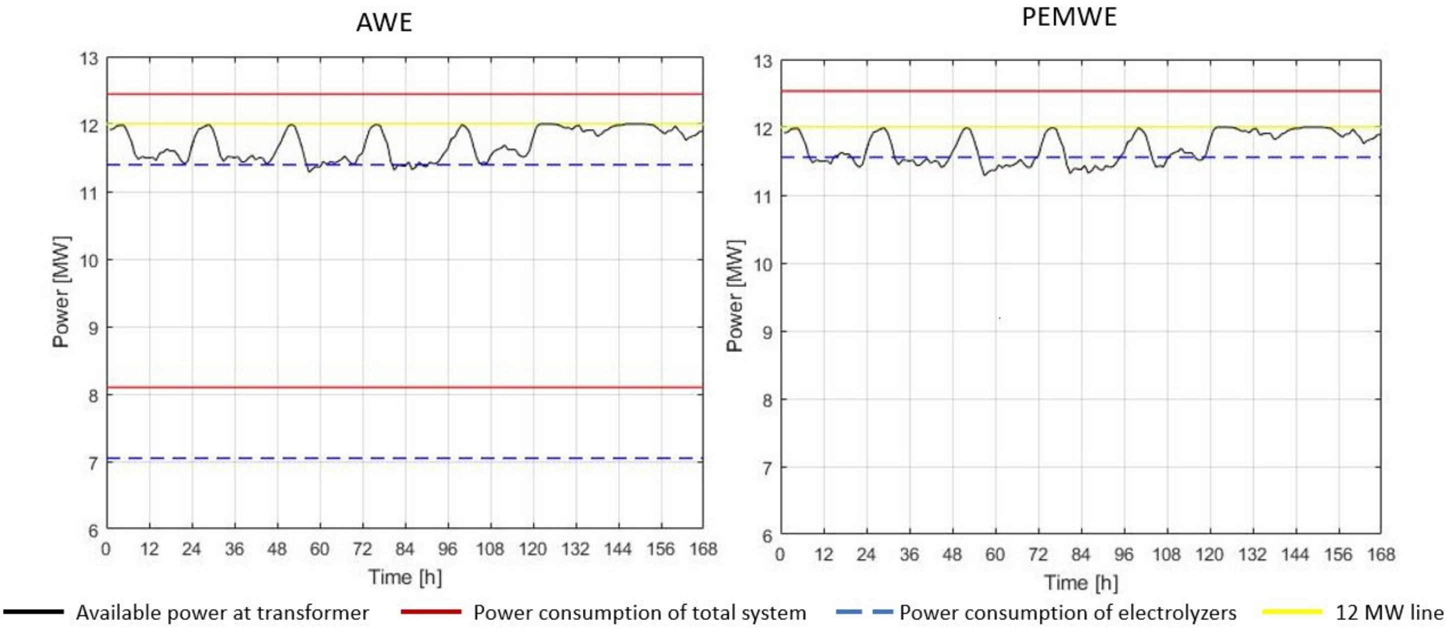


Figure 28: Available power with corresponding production window for AWE and PEMWE (January).

The analysis in figure 28 is based on values for Nel Hydrogen electrolyzers from appendix B and energy consumption data. Equation 20 shows the basis for the calculations. To find the lines for power consumption of the total systems, the total energy consumption, being 58.81 kWh/kg for AWE and 63.21 kWh/kg for PEMWE, are used. To find the lines for power consumption of electrolyzer only, the energy consumption of 54.4 kWh/kg for AWE and 57.8 kWh/kg for PEMWE, are used. The chosen combination of electrolyzers must be taken into account when the production rates are calculated.

$$Power\ consumption\ line = Prod.\ rate\ [kg/h] \cdot e_{total/electrolyzer}\ [kWh/kg] \tag{20}$$

3.3 Hydrogen Production

The hydrogen production is based on electrolyzers from Nel Hydrogen, where the essential data is provided by table 9. No degradation is included in the following calculations of hydrogen production, and the values are therefore only valid for the first year.

By setting the upper limit at 12 MW for energy harnessing, the production is expected to be lower compared with no restrictions. Two MATLAB codes are therefore made to compare these two scenarios. Both of them are based on integration of graphs showing surplus power. In the case of no limitations, the graphs from appendix A are used. In the other case, the code is adjusted with two changes: values higher than 12 MW are set to 12 MW and the electrolyzer is set to be used 98 % of the time. The integration for both cases are done for every month to find the available energy for production. Further, the energy consumption data calculated from equation 19 is used to find the amount of produced hydrogen. The hydrogen production for every months are added together to find the total production for a year. The results are shown in table 11. The hydrogen production for every month are found in appendix C. Production data is also given per week, to give an easier understanding of how the limitations affect the production.

Table 11: Total hydrogen production [ton] in the first year of operation, without and with limitations.

	Production without limitations	Production with limitations
AWE	1753.93	1700.02
PEMWE	1632.85	1581.69

Daily Hydrogen Production

In further analysis, a model showing how much the electrolyzers are estimated to produce day by day is needed. A simplification is made, where an average week for 2019 is generated by MATLAB. The input of the code includes the electrolyzer being used 98 % of the time and an upper limit at 12 MW for production. This week is shown in figure 29 and will represent all weeks of the year.

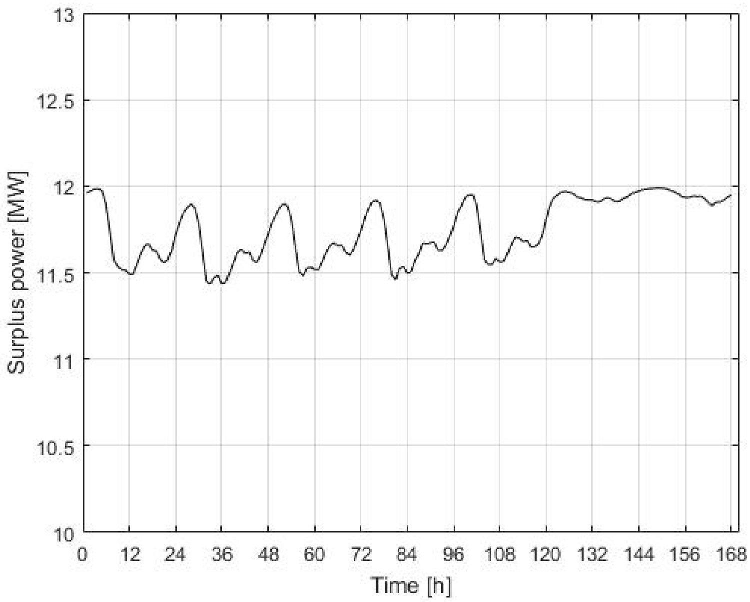


Figure 29: Graph showing surplus power for an average week in 2019.

Integration of the available power and equation 19 is used to find the hydrogen production. Table 12 shows the production in tons, including the differences caused by using alkaline or PEM electrolysis.

Table 12: Hydrogen production [ton] day by day.

	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday	Total
AWE	4.476	4.455	4.468	4.472	4.487	4.574	4.579	31.51
PEMWE	4.164	4.144	4.157	4.161	4.175	4.256	4.260	29.32
Difference	0.3115	0.3101	0.3111	0.3113	0.3123	0.3184	0.3187	2.194

3.4 Demand

This section gives an overview of the possible hydrogen demand at Hitra Harbor, and how the demand and production relates. The analysis will be based on the average week previously presented in figure 29. It is therefore known that this analysis is not a completely realistic presentation for every week, but a good estimate on how the produced hydrogen can be distributed.

3.4.1 Hydrogen Consumption: High-Speed Crafts, Well-boats and Trucks

As a hydrogen producer, Hitra has the possibility to provide both maritime and land based transport sector with hydrogen. In this thesis, the consumption for high-speed crafts, well-boats and trucks will be included. These end users are all being a part of the maritime sector at Hitra.

High-Speed Crafts

As there are no hydrogen powered high-speed crafts in Trøndelag today, some assumptions must be made when deciding a possible hydrogen demand. These assumptions are mainly based on literature review and communication with market participants working on both current and future HSCs for the Trondheim - Kristiansund connection. The high-speed crafts developed by the consortia, which are introduced in section 1.4.1, are estimated to consume between 265 and 360 kg of compressed hydrogen per crossing [23, 27, 28]. The dissimilar demand is caused by different ship design affecting power consumption. In a report posted by SINTEF and Greensight in 2017, a consumption of 400 kg of hydrogen gas was estimated based on current energy demand of approximately 6000 kWh per crossing. Additionally, 50 kg of hydrogen was also needed to insure a buffer in the tank [25].

For further analysis it is assumed a hydrogen consumption of 400 kg for one stretch (one crossing). Appendix D contains the route information for the current HSC connection between Trondheim and Kristiansund. During the weekdays, two boats are running between Trondheim and Kristiansund, and each of them travel three crossings per day. This gives a total hydrogen demand of 2400 kg per day, excluding the hydrogen required for traveling from Trondheim/Kristiansund to Brekstad/Edøy, where the boats are currently located at night. To assume 2500 kg of hydrogen per day would therefore be more suitable, as it includes a good buffer. Even though this information is given for weekdays, the demand of 2500 kg is used in calculations for all days.

Well-boats

For well-boats, data is obtained from a SINTEF report describing the possibility of using hydrogen as fuel in well-boats. This information is used, as none information on well-boats in the area around Hitra was found. The report gives an estimated consumption of 273 tons of hydrogen per year [30]. Dividing the amount by 52, the consumption will be 5.25 tons per week in average.

It was first assumed one filling per week, but this was later adjusted to two fillings after conversations with experts. To store an amount of 5.25 tons on board a boat is unrealistic, as this would take up a huge volume. The recommendation is therefore to have filling of a well-boat two times each week.

Trucks

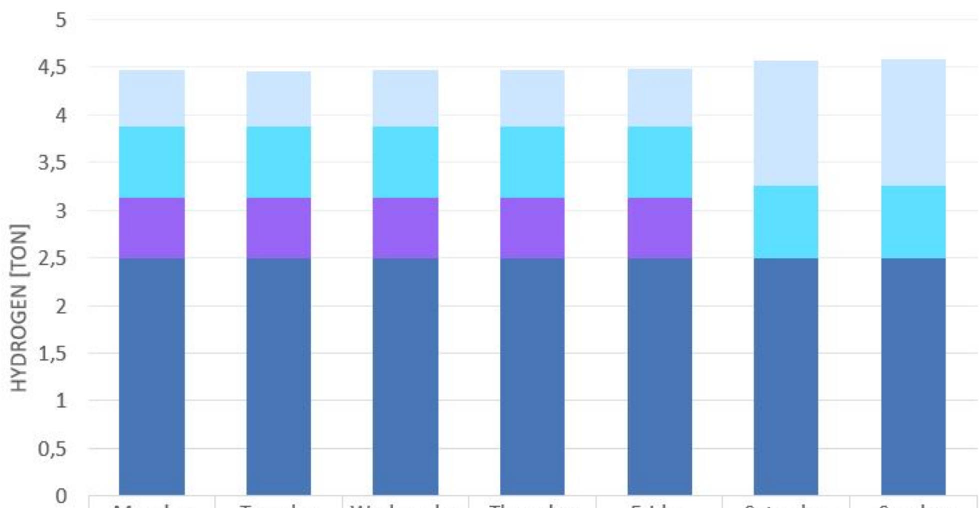
For trucks, a simple assumption is used to calculate the demand: one ton of hydrogen can cover the demand for 20 trucks each day [42]. Related to the salmon industry at Hitra, several trucks departure from Hitra during weekdays. In the scenario where all available power is used for electrolysis, the possibility of covering some of the hydrogen demand these trucks represent is looked at. Hitra has provided with the information that 63 trucks are required per day for salmon transportation, Monday to Friday [114]. Most likely, not all the trucks will be using hydrogen as fuel. It is therefore assumed that 20 % of the trucks can use hydrogen, corresponding to 0.63 tons per day according to equation 21. If all the trucks were to use hydrogen, the total hydrogen demand would be 3.15 tons per day or 15.75 tons per week.

$$20\% \cdot \frac{63\ trucks}{day} \cdot \frac{1\ ton\ H_2}{20\ trucks} = 0,63\ ton\ H_2/day \tag{21}$$

3.4.2 Hydrogen Distribution

The hydrogen can be distributed between high-speed crafts, well-boats and trucks. For this purpose bar graphs are made to visualize different cases. The amount of produced hydrogen from alkaline electrolysis, shown in table 12, is the basis for this analysis, since the method with highest production rate is best suited for this purpose.

Two of the cases include all consumers, but with different numbers of well-boats. Figure 30 represents the demand for two HSCs Trondheim - Kristiansund, one well-boat and 63 trucks departing Hitra every week. Figure E1 in appendix E includes an additional well-boat. Both cases will give some residual hydrogen, but in the case with two well-boats, most of the produced hydrogen is used locally. Since the bar graphs are based on the average week in figure 29, the distribution in figure 30 is used in further analysis. A larger residual buffer is preferred over low delivery reliability.



	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
Residual	0,5959	0,5745	0,5883	0,5918	0,6072	1,324	1,3291
Well boat	0,75	0,75	0,75	0,75	0,75	0,75	0,75
Trucks	0,63	0,63	0,63	0,63	0,63		
HSC	2,5	2,5	2,5	2,5	2,5	2,5	2,5

Figure 30: Hydrogen distribution for two high-speed crafts Tr-Kr, one well-boat and 63 trucks per week.

Another option is to cover more of the total hydrogen demand for trucks, instead of well-boats. This scenario is shown in figure E2 in appendix E. The bar graph shows that from Monday to Friday almost two tons can be used by trucks, corresponding to ten tons per week. If the residual also should be used by trucks, twelve tons per week is available.

Stationary Hydrogen Storage

High-speed crafts, well-boats and trucks are assumed to refuel hydrogen at the harbor, where transportation of fuel is not necessary. Hydrogen to cover this demand will be stored in stationary storage tanks, where the size of the tanks depends on the accumulated amount of produced hydrogen. Based on figure 30, figure 31 is made to visualize how much the storage tanks must hold day by day. Here it is assumed bunkering of well-boat at Wednesday afternoon or early Thursday, and the same for Sunday/Monday. The minimum required storage capacity is determined by the accumulated hydrogen just before the second refuel of the well-boat during the week, with the amount of 5.25 tons of hydrogen. In this figure the *residual* is not included, since it will not be stored in the stationary tanks. The *residual* is assumed to be transported away regularly and used for other purposes, which will require an additional storage tank.

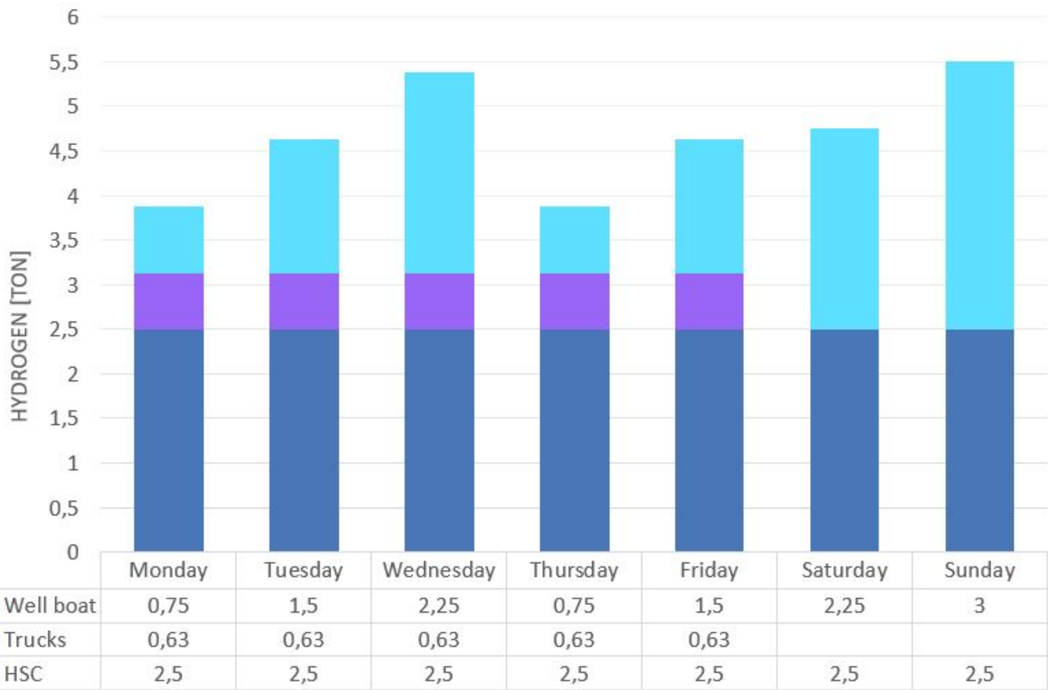


Figure 31: Stationary hydrogen storage day by day.

3.5 Collecting Cost Data - Cost Distribution

There are many components and services involved in a production facility for hydrogen, with associated costs. This section of the methodology chapter presents the methods that are used to obtain this cost data. The different costs are described one after another, and the cost distribution is explained. In general, data is collected from reviewing literature. This entails some assumptions, which will be clarified in the following section.

Costs often depend on production volumes. The focus has therefore been on sources describing hydrogen production in the same order of magnitude as the scenario for this project (approximately 10 MW of electrolyzers). Cost data for small-scale production (in the area of kW), and larger facilities of more than 20 MW installed capacity, are excluded. The different costs are generally given per unit of power (kW), production rates (kg/h or Nm^3/h) or capacity (kg or ton). However, some sources are not providing details for production rates, nor power or installed capacity. In these cases, it is assumed a relationship between production rates, power and energy consumption according to approximate ratios from table B1 in appendix B. The content of the cost data, and what is included in a given value, is also uncertain for some sources. In such cases, a certain content is assumed based on similar cost levels provided by other sources, where the content is known.

The following list shows elements contributing with costs, when planning, building and operating a production facility for hydrogen. This bachelor's thesis aims to include all of these expense items, to build a trustworthy scenario.

- Electrolyzer (PEM and alkaline) and stack replacement after ended lifetime
- Rectifier, transformer, water treatment and gas cleaning
- Compressors, piping, storage tanks and filling equipment
- Electricity (including grid tariffs) and water
- Operation and maintenance costs
- Building process (designing, engineering, installation, building and administration).

3.5.1 Currency and Exchange Rates

Cost data is obtained from sources operating with different currencies, describing cost levels for different years. Currency conversions are conducted according to appendix F. For simplicity, all different currencies (except from British Pounds, GBP) are converted to euros (EUR) according to table F1 with exchange rates from January 1, 2020. Conversions from GBP to EUR are done with exchange rates for specific times, as the ratio between these currencies have varied more than other exchange rates the last five years.

$$1.00 \text{ EUR} = 9.78 \text{ NOK } (01.01.2020)$$

The specific date is chosen because the exchange rates have been relatively stable from 2015 until 2020. This can be seen in figure 32, which shows the ratio between Norsk krone, NOK, and EUR (NOK/EUR) from 2015 until April 2020. The blue dot represent the ratio for January 1, 2020. It should be noted that the exchange rates are very different later in 2020. This is due to low oil prices and the ongoing pandemic of COVID-19, which influence both global and national economy.

Figure 32: Historical exchange rates for EUR/NOK. The blue dot shows the rate for January 1, 2020, when 1.00 EUR was equal to 9.78 NOK. Illustration from XE [115].

3.5.2 Electrolyzer Costs

Electrolyzer costs are divided into CAPEX, OPEX and stack replacement. In this thesis, both alkaline and PEM electrolyzer equipment are looked into. The cost data obtained from literature indicates that PEM electrolyzers in general are more expensive than alkaline electrolyzers.

Electrolyzer CAPEX

CAPEX for both PEMWE and AWE is obtained from different sources, and presented in appendix G. The CAPEX values are found from reviewing a lot of literature and recording the data values as well as information about what the data includes. All this information was first gathered in an Excel sheet, before filtering out the most relevant data which is presented in the appendices.

Two cost categories, for both PEMWE and AWE, are established in order to separate the data provided by different sources in a logical and correct way. One category contains cost data for electrolyzer stack and component costs only. This category excludes ”other costs”, defined as non-material costs related to installation, building, design, engineering and administration. The other category contains cost data for whole systems, including ”other costs”. Both categories includes data for *current* (depending on year of source) and *future* costs for 2025 or 2030. For simplicity, the future costs for all relevant components are defined as costs for 2030. The categories are used because the different sources provide data for dissimilar scenarios, with contents that vary.

Data for electrolyzer systems excluding ”other costs” are used in further analysis. ”Other costs” is treated as a separate expense item, which will be elaborated later in this section. Average cost values for both PEM and alkaline electrolyzers, for current and future technology, are found from the tables in appendix G. This results in the following expenses:

- Average costs for AWE systems, excluding ”other costs”: **585 €/kW** (*current*), **396 €/kW** (*future*).
- Average costs for PEMWE systems, excluding ”other costs”: **842 €/kW** (*current*), **520 €/kW** (*future*).

Electrolyzer OPEX and Stack Replacement

As for CAPEX, stack replacement is found to be more expensive for PEM than for alkaline electrolyzers. The costs for stack replacement are found from literature study only, and data from different sources have been gathered and compared in an Excel sheet. The same assumptions are made for stack replacement as for electrolyzer CAPEX. Stack replacement is not included in the OPEX data, which is obtained in the same way. The following costs for stack replacement and OPEX was found from reviewing literature:

- Stack replacement for AWE: **314 €/kW** (*current*) and **300 €/kW** (*future*).
  Average value from [76, p. 45], [116], [35, p. 10]
- Stack replacement for PEMWE: **370 €/kW** (*current*) and **270 €/kW** (*future*).
  Average value from [76, p. 45], [117], [118, p. 5], [30, p. 21]
- OPEX for both PEMWE and AWE: **2 - 4 % of CAPEX per year**.
  Average data from [76, p. 45], [119, table 2], [30, p. 21]

The OPEX includes general maintenance, cleansing of water purification systems, spare parts and replacement of components like pumps and filters. For alkaline electrolyzers it should also include stirring and replacement of electrolyte. It does not include electricity and water, as these are separate expense items. The OPEX is considered to be fixed and equal to 3.0 % of equipment CAPEX per year, through the whole system lifetime.

3.5.3 Costs for Compression, Storage and Filling

Cost data for compression and filling of storage tanks are found in the same way as for electrolyzers. Some sources give cost data for only compressor systems, or only filling equipment, and others give costs for both compression and filling in total. Generally, the costs provided by the various literature depend on input pressure, output pressure and rates for compression (filling capacity). The cost information and values are presented in appendix H. The tables in the appendix show data taken directly from the different sources, as well as cost values calculated for the specific scenarios of this thesis.

CAPEX for Compression and Filling

Figure 33 illustrates a possible scenario for hydrogen production, storage and supply that can be implemented at Hitra. This is also what makes the basis for costs related to compression, filling and storage. A storage pressure of 300 bar is chosen, as high pressure limits the need for large storage volumes and areas, and pressure levels exceeding 250 bar is needed for high-speed crafts and well-boats. By storing hydrogen at 300 bar, it can be possible to advantage from the pressure difference between the storage pressure and the target pressure of 250 bar, refueling by *overflow filling* [120]. This method of refueling is used as an example in this thesis. In addition, communication with Hexagon, a provider of composite storage tanks, reveals that composite storage tanks at 300 bar are the most cost efficient.

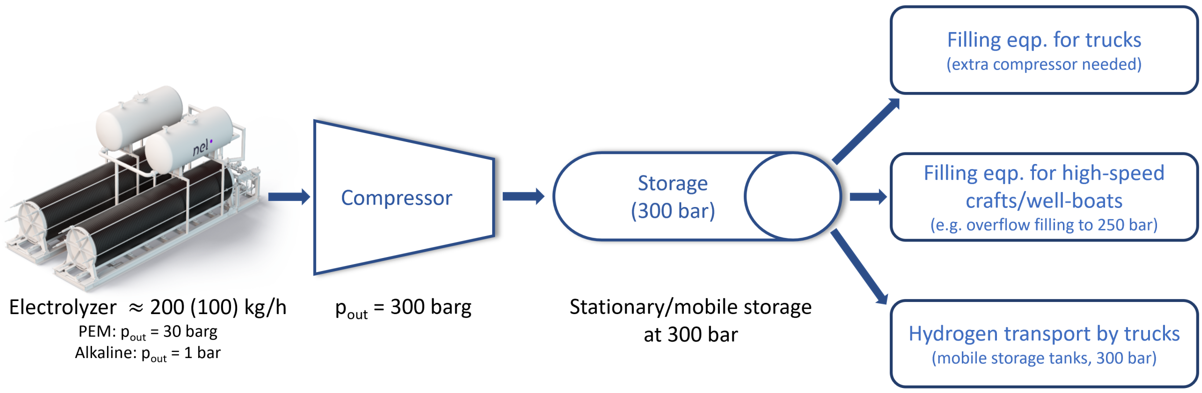


Figure 33: A possible hydrogen production line at Hitra. Hydrogen produced at a rate of approximately 200 kg/h (100 kg/h for high-speed crafts only), compression to 300 bar, stationary/mobile storage and filling of end users.

As a basis for cost calculations it is assumed that an alkaline electrolyzer will produce hydrogen at atmospheric pressure (1.0 bar), and a PEM electrolyzer will produce hydrogen with an output pressure of 30 bar. The compression rate (or filling capacity) is dimensioned for the maximum production rate, so that the produced hydrogen can be compressed to 300 bar immediately after production. This eliminates the need for extra storage capacity between the electrolysis and compression stages. As 10 MW of electrolyzers correspond to a production rate of approximately 200 kg/h, this is chosen for the scenario where all available power is used. For hydrogen production to HSCs only, a rate of 100 kg/h is chosen as 5.5 MW of electrolyzers can produce hydrogen at that rate. When adapting the cost data from the literature to the scenarios described here, linear relationships between costs, compression rates and pressure levels are assumed for output pressures between 200 and 500 bar. Linear regression in Excel is used to obtain these relationships.

CAPEX for filling center, obtained from a FCH report from 2017 [76], is chosen as the basis for cost calculations on compression and filling. The cost data is given in table H3 (appendix H). The filling center includes compressor, piping and filling equipment needed to fill gas bundles or tube-trailers. As the report only gives costs for compression levels of 200 and 500 bar, at 100 or 200 kg/h, linear regression are used to adapt the data. Table 13 shows the resulting CAPEX for an output pressure of 300 bar, and filling capacities/compression rates of 100 and 200 kg/h.

Table 13: CAPEX for compression, piping and filling equipment used in this thesis. Calculated with linear regression based on data from [76, p. 51] (2017).

Pressure and filling capacity	Calculated costs [€]
1 bar to 300 bar, at 100 kg/h	2 201 000
30 bar to 300 bar, at 100 kg/h	1 442 710
1 bar to 300 bar, at 200 kg/h	3 140 730
30 bar to 300 bar, at 200 kg/h	2 058 640

CAPEX for Storage

Hydrogen storage is important to consider, as it is an important part of any hydrogen value chain. Storing hydrogen is a challenging task, as described in chapter 2.5, and the related costs are significant. For the project described in this paper, it has been chosen to look at the storage of compressed hydrogen in aboveground tanks or bundles at 300 bar. Both steel and composite tanks are considered for stationary and mobile storage, respectively. The mobile storage tanks can be transported away from the production site by trucks, as indicated in figure 33.

Cost data is collected from various reports, in addition to market participants. The most relevant data for storage CAPEX is presented in table I1 (appendix I), where the costs are given per unit of storage capacity (€/kg). In some sources, the costs are not provided per unit of capacity. In these cases, assumptions are made to convert the cost data. For instance, if the total costs and storage capacity are given, the cost per kilogram is found simply from dividing the total cost by the capacity. In other cases the costs are given per unit of energy. The unit for these data are converted to be per kilogram based on LHV, where the specific energy of hydrogen gas is assumed to be 33.33 kWh/kg. Additionally, the different sources do not always provide details of the material of storage containers or bundles. In these instances, a material (either composite or steel) is assumed based on the given cost level, and information from other sources presenting information on both costs and types of material. Cheap storage is assumed to be steel tanks, and more expensive storage is considered to be composite.

The following CAPEX are chosen for stationary and mobile storage, both at approximately 300 bar, based on average values from various reports and statements from market participants. The costs provided by Hexagon is in the same order of magnitude as the cost data from literature:

- Stationary storage (steel tanks): an average value of **293 €/kg**
- Mobile storage (composite/carbon), provided by Hexagon: **660 €/kg**

To find the total CAPEX for storage, eight tons of hydrogen is planned stored in stationary steel tanks, and two tons in mobile storage vessels (composite), when all available power is used for hydrogen production. This choice is based on analyses of possible market demands, and how the produced hydrogen can be distributed between different end users. This is explained in section 3.4.2. From figure 30 and 31, it appears that this storage capacity probably will be enough to cover the amount of hydrogen that needs to be stored, in addition to a buffer of more than two tons. For the scenario of hydrogen production to high-speed crafts specifically, a storage capacity of five tons in steel containers is chosen. This will be enough to cover the daily demand for two HSCs, in addition to a possible buffer equivalent to one day of production. When less than five tons is produced and stored, the regulation for major accidents can be avoided.

OPEX for Compression, Storage and Filling

Compression, filling and storage systems need some maintenance, oiling and spare parts. These costs are covered by the OPEX. An FCH report states that OPEX for a filling center, including compression, piping and filling equipment, is between 2 and 4 % of system CAPEX. It depends on for instance the size of the facility [76]. Other sources typically say that OPEX is in the area of 2 % of CAPEX for both compression and storage systems [30, 121]. Storage systems for hydrogen usually have a lifetime of 30 - 40 years, and need inspection every 10th to 15th year. An OPEX of 2 % per year covers the costs for this inspection. For this thesis, an OPEX of 2.0 % of CAPEX per year is chosen for compression, filling systems and storage. [76]

3.5.4 "Other Costs" (Non-Equipment)

As the electrolyzer costs are given with different contents, it has been chosen to look at installation and other non-equipment costs as a separate expense item. Therefore, the category ”other costs” covers non-material costs as installation, building, design, engineering and administration. It was possible to find some data on this from various literature. However, there are discrepancies between the cost data obtained from different sources. These data are therefore considered to be too uncertain. Because of this, ”other costs” is rather based on two models from a NVE report about costs in the energy sector [101] and a FCH report about hydrogen production [76].

The investment cost distribution in the NVE model is shown in table 14. It covers the investment cost distribution for thermal technologies without electricity production. This table is used as a basis for technologies that are not covered by thermal power production or bio fuel/fossil fuel to electricity. ”Building/construction costs” and ”Engineering/administration” are in total considered as ”other costs”. [101]

Table 14: Distribution of investment costs. Model from NVE. [101, p. 28]

Component	Percentage of investment costs
Machines and equipment	65 %
Building/construction costs	20 %
Engineering/administration	15 %

The cost distribution from the FCH report is specifically made for electrolyzer plants, as a way of deciding the extent of the investment costs. It is important to note that these cost distributions may vary a lot from project to project. The distribution is presented in table 15, where the value of ”other costs” depend on system capacity. [76]

Table 15: ”Other costs”, percentage of equipment costs. Model from FCH. [76, p. 167]

Project scale	Other costs (% of equipment costs)
1 MW	60 %
2.5 MW	45 %
5 MW	40 %
20 MW	36 %

Both distributions are used in cost calculations in this thesis. The expenses are therefore calculated based on two models: the NVE model [101] and FCH model [76]. As the electrolyzer capacity is 10 MW for this project, other costs are assumed to be 38 % of equipment costs based on the FCH model. Equipment costs are CAPEX for electrolyzer, compression, filling and storage systems.

3.5.5 Electricity Costs, Grid Tariffs and Water Costs

Electricity, grid tariffs and water usage entails regularly costs that depend on consumption. These must be payed regularly throughout the lifetime of the facility. In this thesis, the costs are based on an assumption where the electricity and water consumption is equal every year when all available power is used. In the scenario of production to high-speed crafts only, the electricity consumption is thought to increase with the aging of components. Calculations are based on power data from 2019, as explained in section 3.1, and water consumption for electrolyzer from Nel Hydrogen, given in table 9.

Electricity Costs

Electric power is needed for both electrolyzers and compressors. Data for costs related to electric power are obtained from Nasdaq and Tensio, who has the operational responsibility for the distribution and regional power grids in Trøndelag, via TrønderEnergi. Pricing for both grid tariffs and electricity consumption is given in appendix J.

Grid tariffs comprises a fixed price, an energy price and a power price that depends on power demand and season of the year. Hydrogen production is considered to be exempt from consumption taxes in 2020, according to §3-12-13 in regulation on special fees (Forskrift om særavgifter) [122]. Projected electricity prices from 2021 to 2030 are obtained from a Nasdaq database which gives the prices as €/MWh. Three MWh are subtracted from the obtained values to make them applicable for zone N03, of which Hitra is a part. This is done in accordance with information from TrønderEnergi. The estimated average electricity price for the next ten years are then found and used in calculations on electricity costs. Table 16 shows the relevant electricity costs for the projects described in this thesis, excluding VAT. [123, 124]

Table 16: Relevant cost data for electricity used in this thesis. Excluding VAT. [123, 124]

Category	Price
Fixed price, grid tariff	20 800 NOK/year
Energy price, grid tariff	2.8 øre/kWh
Power price - winter, grid tariff	38 NOK/kW (per month)
Power price - summer, grid tariff	28 NOK/kW (per month)
Energy price, average 2021 - 2030	24.57 EUR/MWh

Water Costs

Water costs are provided by Hitra Municipality and are given in appendix K. The prices consist of a subscription fee and a price for water and drainage. In other words the costs consist of a fixed amount and a part depending on consumption. In this thesis, the drainage costs are excluded as most of the water is considered to be used, and a drainage cost would be very negligible. The following pricing is used when calculating water costs in this project:

- Subscription fee: **80 978.70 NOK** (including VAT)
- Consumption price: **17.93 NOK/m^3** (including VAT)

3.5.6 Building Plot

The costs for buying a building plot on Sandstad, which is the location of a possible electrolyzer plant, are also received from Hitra Municipality. The total price consist of a plot (626.5 NOK per square meter) and a part for infrastructure (209 NOK per square meter). The total costs for a building plot is therefore 835.5 NOK/m^2 corresponding to 85.2 €/m^2. The total price for the hydrogen production facility is found from adding the area footprints of all components, based on data from different sources, and multiply the sum by this value. This data is found in table 9 and 10. Linear relationships between flow rates, capacity and area footprints are assumed, with the exception from compression and filling of which a footprint of 375 square meters is chosen. This corresponds to 100 kg/h based on linear relationship, but has been assumed to cover 200 kg/h as well. [20]

3.6 Lifetime of the Hydrogen Production Plant

It is important to decide the lifespan of the plant, when researching hydrogen projects. Table 17 shows the values for the stack and system lifetime. They are gathered from different sources. Table 18 gives the average intervals for the stack and system lifetimes that are used as basis in this thesis. When calculating the stack lifetime from hours too years, one year has been considered as 8585 hours. This infers an uptime of 98 % for the stacks, because an electrolyzer does not operate every hour during a year. In this project it is decided that the system lifetime for both alkaline and PEM electrolyzers is 20 years. The stack lifetime is decided to be ten years for AWE and seven years for PEMWE. This infers that the AWE scenario will have one stack replacement, while the PEMWE scenario will have two stack replacements. The lifetime for the rest of system, such as the storage containers and compressors is longer than the electrolyzers. Therefore is the lifetime of the production plant based on the lifespan of the electrolyzers.

Table 17: Different system and stack lifetimes for alkaline and PEM electrolyzers.

AWE		PEMWE		Source
Stack lifetime [h]	System liftetime[y]	Stack lifetime [h]	System liftetime[y]	
60 000 - 90 000	20	20 000 - 60 000	20	[62]
80 000 - 90 000	20	40 000 - 50 000	20	[45]
80 000 - 90 000	20	-	-	[76]
60 000 - 90 000	20	20 000 - 60 000	20	[78]
-	-	40 000 - 80 000	-	[92]

Table 18: Average and chosen lifetimes for the hydrogen production plant and stack replacement.

	Alkaline		PEM	
	Stack lifetime [y]	System lifetime [y]	Stack lifetime [y]	System lifetime [y]
Average value, from literature	8.2 - 10.5	20	3.5 - 7.3	20
Chosen for this project	10	20	7.0	20

3.7 Economical Analysis

The cost calculations are based on a project start set to 2020. This is to create an overview of possible costs today. However, a real project is likely to start in 2024 which would influence the costs due to inflation and cost reduction from improved technology. The electrolyzer expenses are predicted to decrease, as seen in figure 16. *Current* prices presented in section 3.5.2 are mostly from 2016. They have therefore been adjusted to 2020-prices, with predicted costs for 2030 as guidelines, in a linear model of cost reduction. Inflation rate with a 2 % increase each year has also been taken into account, which is a standard used in the central bank of Norway [125]. The inflation factor is calculated from equation 15. The new prices for electrolyzers and stack replacement are:

- Costs for AWE systems and stack replacement: **503 €/kW** (*2020*) and **308 €/kW** (*2020*)
- Costs for PEMWE systems and stack replacement: **703 €/kW** (*2020*) and **326 €/kW** (*2020*)

This adjustment is not performed for storage or the compression and filling, because these prices are predicted to be stable. CAPEX is then calculated for the three components, for a plant size of 10 MW. CAPEX for compression and filling are the prices from table 13. The CAPEX for storage is calculated from the costs in section 3.5.3.

The calculated CAPEX does only include equipment. Costs related to installation, building, administration and other non-material expenses, have not been taken into account. These expenses have been labeled as ”Other costs”, and is calculated with two different models. The first model is based on the cost distribution from NVE [101], as described in table 14. The second model is based on the cost distribution from FCH [76], as described in table 15. ”Other costs” does not include the price of the plot. The price per square meter is given in section 3.5.6. The approximate size and price of the plot for the hydrogen production plant, is then calculated with tables 5 and 10.

CAPEX is not the only expense when building and drifting a hydrogen production plant. There are also running expenses each year. Each component has an OPEX which is a percentage of the CAPEX for the equipment. The percentage for electrolyzer, storage, compression and filling are in sections 3.5.2 an 3.5.3. Stack replacement for the electrolyzers, which is also an OPEX, is taken into account as explained in section 3.6. The two other running expenses are water and electricity. The electricity cost is calculated from table 16. The price includes VAT. The water cost is calculated from the prices described in section 3.5.5.

LCOH

The LCOH is calculated by using equation 14. A more detailed version is shown in equation 22. It is decided that the CAPEX would be paid upfront the first year. Normally it is payed in installments, but this project does not delve deep enough into financial theory to cover this. The LCOH is also calculated at three discount rates, which are 4, 8 and 10 %. This is to see how the discount rate effects the LCOH. Degradation of the cell stacks is taken into account, with 1.0 % for the AWE and 1.5 % for the PEMWE, which is shown in table 7. For the case where all available power is used, this infers a decrease in hydrogen production each year, until the cell stacks are replaced.

$$LCOH = \frac{AWE/PEMWE + Strg + Compr/Fill + \sum_{k=1}^{n} \frac{AWE/PEMWE+Strg+Compr/Fill+Wtr+El)}{(1+r)^k}}{\sum_{k=1}^{n} \frac{m_g}{(1+r)^k}} \tag{22}$$

When the LCOH is conducted, three different analyses are performed. First an electricity sensitivity analysis, where the LCOH is dependent on a varying electricity price. This is shown in a graph to show how important the electricity price is. The lower and upper limit are based on a worst and best case scenario for the future price of electricity. Secondly, a net present value analysis is conducted by using equation 16. The cash flow is assumed constant each year. This is performed at different hydrogen prices, and visualized in a graph. This graph gives a representation of how profitable the production is for an array hydrogen prices.

A third analysis looks at the payback time for the plant, for different hydrogen prices. This is carried out with two different methods. To differentiate between the methods, the first method is called simple payback time (SPT) and the second is called total payback time (TPT). SPT is performed by using equation 17. This assumes a constant cash flow each year. Because the SPT does not take time value of money into consideration, the TPT method, is carried out for a more in-depth analysis. This is done by finding the total cost for the project over the lifetime of the plant, and comparing the expenses with the total accumulated profits, for different hydrogen prices. In this analysis, the discount rate is taken into account. When the expenses and profit are approximately equal, the payback time for a specific hydrogen price is found. For instance, if the payback time is twelve years, this infers that everything earned the next eight years is considered as profits, when the lifetime is 20 years. That is because all of the OPEX for the next eight years have already been covered. The payback time for both methods is then shown for an array of hydrogen prices.

Production to High-Speed Crafts Only

When calculating the hydrogen production to high-speed crafts only, the electrolyzer plant is downsized to only cover the need of hydrogen for the HSCs. The high-speed crafts requires 2.5 tons of hydrogen per day, corresponding to a plant size of 5.5 MW. With a lower production rate, the storage capacity is also decreased to five tons, and the composite tanks are not included. The CAPEX and OPEX are calculated in the same way as before. Degradation on the cell stacks are also taken into account when calculating the LCOH. For this scenario, the degradation infers a yearly increase in electricity costs and not a yearly decrease in hydrogen production. That is because there is available power to accommodate for the rise in energy consumption, which is a result of the degradation. The LCOH is analyzed with a NPV and payback time analysis, as explained earlier.

3.8 Comparison of Relevant Fuel Prices and Environmental Aspects

In order to be able to conclude whether hydrogen produced at Hitra can be competitive or not, it is important to have a foundation for comparison. Through literature review, using publicly available statistics and communication with market participants, costs for hydrogen and other relevant fuels are found.

UNO-X in Norway has sold hydrogen gas to cars for a while, but are currently (April 2020) keeping hydrogen refueling stations closed due to an accident that occurred in June 2019. The sale price at their stations has been approximately 72 NOK excluding VAT, and approximately 90 NOK including VAT. A facility owned by Hynion, located at Høvik, operates with a sale price of approximately 108 NOK/kg, including VAT. Communication with AtB, the contracting authority of the HSC connection between Trondheim and Kristiansund, reveals that suppliers aim to deliver hydrogen to buses and ferries at a price below 50 NOK/kg. This excludes Value Added Tax.

The prices for conventional fuel used today, as diesel and MGO, are also interesting to include when studying the competitiveness. To be able to compare costs for different fuels in a correct way, it has been chosen to look at energy available at the propeller, for maritime transport, and at the wheels for road transport. Having this energy output as a unit should make it possible to compare the costs on a fair basis. In other words, simple TTW analyses are conducted for different fuels used for both road transport and high-speed crafts.

The final energy output, usable to cause motion, depends on the efficiencies of all the different components that are involved. For high-speed crafts, well-boats and hydrogen systems in general, the efficiencies from figure 22 are used as a basis. When it comes to road transport, an EEA report [126] states that 25 % of the available energy in the fuel can be used at the wheels to move a car or truck. This applies to efficient ICE vehicles. As a fuel cell is more efficient than an ICE engine it is assumed that 45 % of the available energy in hydrogen can be used to move a hydrogen car or hydrogen truck. The density and specific energy (based on LHV) of different fuels are obtained from Engineering ToolBox [37]. Some of this data is also presented in table 3. [126]

Prices for different fuels that are relevant for road transport, high-speed crafts and well-boats are collected from Statistics Norway (SSB) and AtB. These are presented in table 19 per unit of liters. Conventional diesel is liable for taxes, and available at gas stations. The value presented in the table is the average price, including VAT, from 2015 until February 2020, calculated with data from Statistics Norway. All values in the table exclude VAT, but includes other taxes.

Table 19: Prices for different fuels (excluding VAT).

Fuel	Price (approximate)	Source
Conventional diesel	10.8 NOK/L	[127]
MGO	8.0 NOK/L	[128] (AtB)
Bio diesel (HVO)	14.0 NOK/L	[128] (AtB)

Environmental aspects are also looked into, as this may influence the competitiveness of hydrogen compared to other fuels. As mention, this thesis does not analyze the environmental impacts of a specific scenario of production and usage of hydrogen at Hitra. However, an overview of GHG emissions from production and consumption is established based on theory presented in section 2.6 and general information from literature review. Emission savings for a HSC changing from MGO to hydrogen fuel are calculated based on emission data from figure 22, and an energy demand of approximately 6000 kWh. This is currently the approximate energy consumption per crossing for the Trondheim - Kristiansund connection. [25]

4 Results

The following section presents the results from the conducted analyses. These findings are based on the methods described in the methodology chapter, and the main focus is the economical aspect of the hydrogen production plant. The results are divided into four sections. The first section is based on the scenario where all the available power from the transformer is used to produce hydrogen. The second section is the scenario where the hydrogen production only covers the demand for high-speed crafts. Both PEM and alkaline electrolysis are considered. The last sections compare different fuel prices and take a look at the GHG emissions.

Table 20 gives the plant sizes with the corresponding production of hydrogen per year and per day. The values of annual production for 10 MW plant are gathered from appendix C, and the daily average is equal annual production divided by 364 days. For the case of 5.5 MW plant, the daily production is the same as the demand for HSCs, and annual production is a sum of 365 days. Note that the production rates in table 20 are for the first year of production with no degradation included.

Table 20: Hydrogen production in ton per year and per day, when using all available power and production to HSCs only. This applies to the first year of production.

Plant size	Production per year [ton]	Daily average [ton]
10 MW (AWE)	1 700 [a]	4.7
10 MW (PEMWE)	1 582 [a]	4.3
5.5 MW	913 [b]	2.5

[a] One year equals 364 days (52 weeks), [b] One year equals 365 days

4.1 Economical Analysis - Using All Available Power

Building a hydrogen production plant is expensive. The total CAPEX for full production has been calculated based on two different methods, the FCH [76] and the NVE [101] models. The NVE model is costlier than the FCH model, with a difference of approximately two million euros. The total CAPEX for the Alkaline and PEM electrolyzer is shown in table 21. Table 21 also includes the CAPEX for the different components.

Table 21: CAPEX, in total and per component, for AWE and PEMWE in million euros and million NOK.

		Electrolyzer	Compression and filling	Storage	Building plot	"Other costs"		Total CAPEX	
						FCH	NVE	FCH	NVE
AWE	**[M€]**	5.03	3.14	3.66	0.170	4.50	6.37	16.5	18.4
	[MNOK]	49.2	30.7	35.8	1.66	44.0	62.3	161	180
PEMWE	**[M€]**	7.03	2.06	3.66	0.190	4.84	6.84	17.8	19.8
	[MNOK]	68.8	20.1	35.8	1.90	47.3	66.9	174	194

The CAPEX represents a lot of money. Therefore, the CAPEX is divided into shares and analyzed. Figure 34 gives a representation of the different shares, and their contribution to the total investment costs. For the rest of this section every analysis is based on the FCH model [76] and a discount rate of 8 %, unless otherwise stated. For both scenarios, the electrolyzers constitute a large part of the cost, with AWE at approximately 30 % and PEMWE at approximately 40 %. Storage is also a massive expense, with almost the exact same share for both systems.

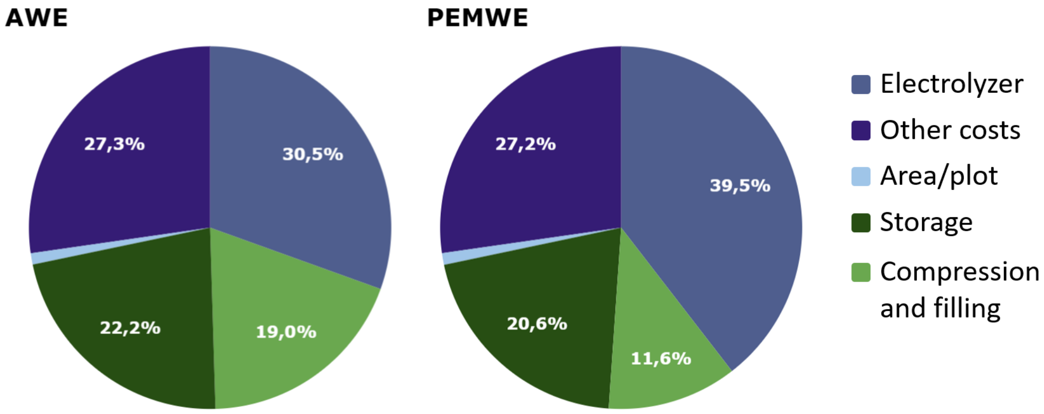


Figure 34: Two sector diagrams, which gives a visual representation of the shares of the total CAPEX.

To keep the electrolysis plant running there are operational and maintenance expenses (OPEX). Table 22 gives how much each component approximately require in OPEX per year for both electrolyzers, in thousand euros (k€) and million NOKs (MNOK). The costs, except the costs for stack replacement, describe an average year of operation. Throughout the lifetime the expenses will vary, due to for instance increasing electricity and water prices. One observation is that the electricity cost is much bigger than the other expenses, and is high a percentage of the total OPEX. Approximately 23 % of the electricity cost is grid rental, the rest is the electricity price. Stack replacement is not added to the total OPEX, because it is a one time expense at year 10 for AWE and a two time expense at year 7 and 14 for PEMWE.

Table 22: OPEX, in total and per item, for AWE and PEMWE in thousand euros and million NOK.

		Electrolyzer	Stack replacement	Compression and filling	Storage	Electricity	Water	Total OPEX[a]
AWE	**[k€]**	151.0	3 079	63.00	73.00	3 978	40.00	4 305
	[MNOK]	1.477	30.11	0.616	0.714	38.90	0.3912	42.10
PEMWE	**[k€]**	211.0	3 267	41.00	73.00	3 978	38.00	4 340
	[MNOK]	2.064	31.95	0.401	0.714	38.90	0.3716	42.44

[a] Stack replacement is excluded in Total OPEX

LCOH

The LCOH for full production is calculated with equation 14, with a lifetime, k, of 20 years. Table 23 shows the LCOH for AWE and PEMWE at three different discount rates, which are 4, 8 and 10 %. This table includes price ranges, where the lower range is based on the FCH model [76] and the upper range is based on the NVE model [101]. The LCOH calculations do also account for a degradation in the cell stacks each year until the cell stacks are renewed. The cost for a discount rate at 8 % is 3.75 - 3.86 €/kg for AWE and 4.25 - 4.38 €/kg for PEMWE. If the degradation is not accounted for, the cost range would have been 3.61 - 3.72 €/kg for AWE and 4.08 - 4.21 €/kg for PEMWE.

Table 23: LCOH price ranges for AWE and PEMWE at three different discount rates in €/kg and NOK/kg.

		r = 0.04	r = 0.08	r = 0.10
AWE	**[€/kg]**	3.48 - 3.56	3.75 - 3.86	3.90 - 4.03
	[NOK/kg]	34.0 - 34.8	36.7 - 37.8	38.1 - 39.4
PEMWE	**[€/kg]**	3.93 - 4.03	4.25 - 4.38	4.42 - 4.58
	[NOK/kg]	38.4 - 39.4	41.6 - 42.8	43.2 - 44.8

It is important to analyze the LCOH. In figure 35, the LCOH is divided into shares. Both figures show that electricity contributes with the largest expenses in production of green hydrogen, constituting with 65 % for AWE and 62 % for PEMWE. It is important to note that water and electricity cost has been separated from the OPEX in figure 35. OPEX is only maintenance on the components in this figure, which includes stack replacement.

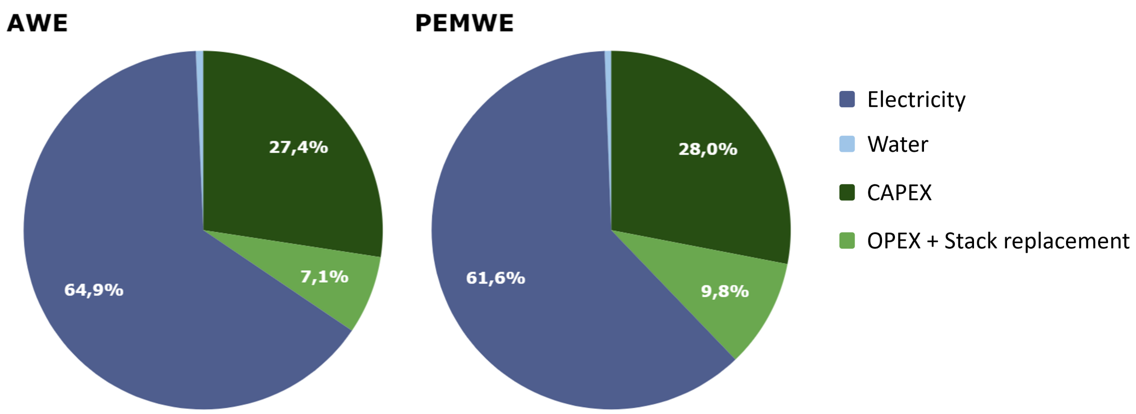


Figure 35: LCOH shares for AWE and PEMWE.

Even though the electricity has the biggest impact on the LCOH, it is also important to look at the contribution of the different components. This is shown in table 24. When the percentages is sum up for alkaline and PEM electrolyzers it will equal the total percentage of CAPEX and OPEX from figure 35. The AWE and PEMWE take up a considerable part of the LCOH, being 13.2 and 19.1 %, respectively. This includes stack replacement.

Table 24: The share of LCOH for the different expense items, including both CAPEX and OPEX.

Component/expense item	AWE [%]	PEMWE [%]
Electrolyzer	13.2	19.1
Storage (steel)	4.7	4.4
Storage (composite)	2.6	2.5
Compression and filling center	6.2	3.9
Plot (area)	0.3	0.3
"Other costs"	7.5	7.6

An analysis has been carried out for varying electricity prices. Figure 36 shows the LCOH at different electricity prices. This was performed by using equation 14, with the electricity price as a varying factor. This is a linear graph based on prices ranging from 18 to 50 €/MWh. This is because the electricity price in 2020 is approximately 18 €/MWh and it is likely increasing in the future. There are two dots marked with diamonds, being the best case and worst case scenario for the electricity price in the future, at 20 and 40 €/MWh, respectively. A triangle is marked at 24.57 €/MWh, which is the price used in the main calculations for LCOH. There are two interesting observations of this graph. First is that the incline is approximately the same for both electrolysis technologies. Secondly, this graph also shows how dependent the LCOH is on the electricity price.

Figure 36: The LCOH at different electricity prices.

NPV Analysis

The LCOH gives an indication on the hydrogen price in €/kg. A NPV analysis, calculated from equation 16, gives a representation of the profitable of the project. Figure 37 shows the profitability at an array of hydrogen prices. The AWE is the most profitable scenario for all prices.

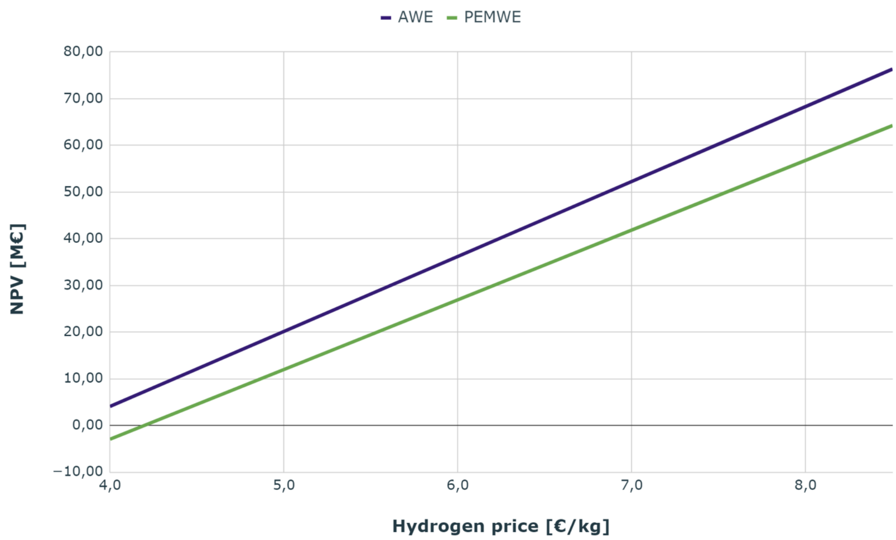


Figure 37: NPV analysis for an array of hydrogen prices, using all available power.

Payback Time

A NPV analysis gives a good indication of how profitable a project can be, but companies also want to know how long it will take before the project is brake even. Figure 38 gives the payback time for an array of hydrogen prices, for both methods. The solid lines show the simple payback times (SPT), where equation 17 is used. The total payback times (TPT) are the dotted lines. These numbers are approximated, and are therefore presented with an equation and corresponding coefficient of determination, R^2. At 5 €/kg, the SPT is 5 years for AWE and 6 years for PEMWE. For TPT, the payback time is 12 years for AWE and 13 years for PEMWE, for the same price.

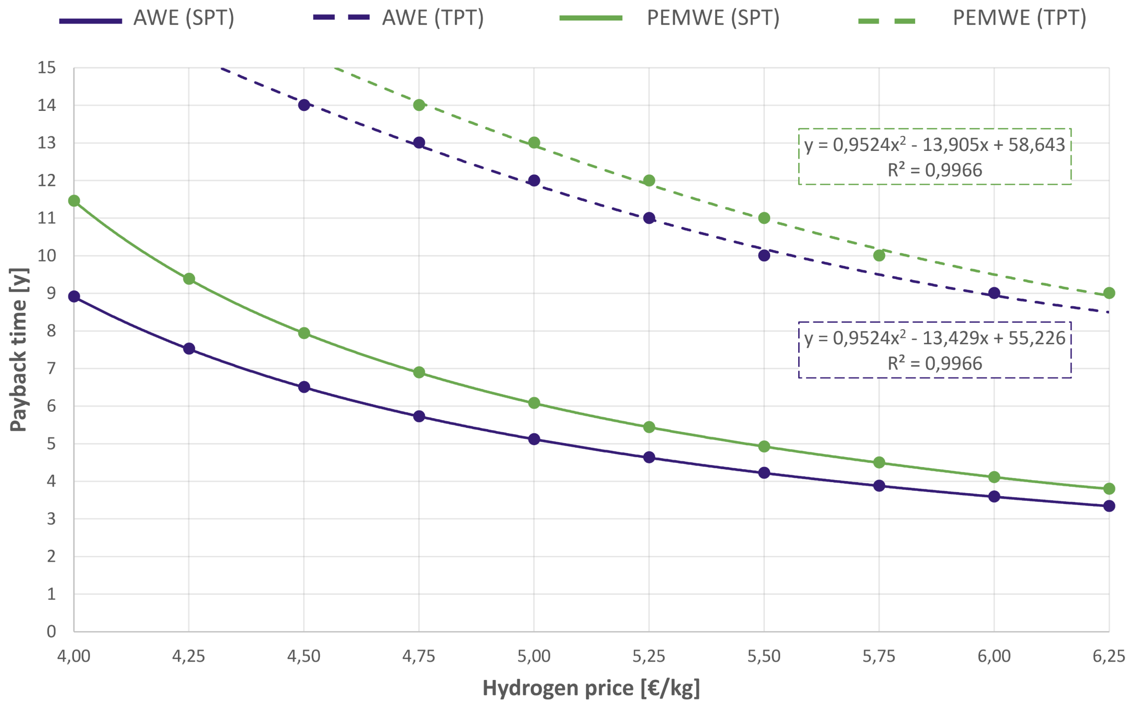


Figure 38: Payback time for an array of hydrogen prices.

4.2 Economical Analysis - Producing Hydrogen to High-Speed Crafts Only

A large amount of hydrogen is produced when all available power is used, as shown in table 20. A market demand for such an amount of hydrogen is highly unlikely. That is why a scenario including only the demand for HSCs is covered as well. There is a high certainty that the high-speed crafts will be the first end users at Hitra. Table 25 shows the CAPEX for the different components and the total CAPEX, which are lower than for the scenario of full production.

Table 25: CAPEX, in total and per component, for AWE and PEMWE (high-speed crafts only), M€ and MNOK.

		Electrolyzer	Compression and filling	Storage	Building plot	"Other costs"		Total CAPEX	
						FCH	NVE	FCH	NVE
AWE	[M€]	2.77	2.20	1.47	0.100	2.44	3.46	8.98	10.0
	[MNOK]	27.1	21.5	14.4	0.978	23.9	33.8	87.8	97.8
PEMWE	[M€]	3.86	1.44	1.47	0.110	2.57	3.65	9.46	10.5
	[MNOK]	37.8	14.1	14.4	1.08	25.1	35.7	92.5	103

The operational expenses for production to HSCs only are given in table 26. The total OPEX per year has been lowered by two million euros, compared to the scenario of full production. The total value does not contain stack replacement, because of the same reasoning as the total OPEX for the full production scenario.

Table 26: OPEX, in total and per item, for AWE and PEMWE (high-speed crafts only) in thousand euros and million NOK.

		Electrolyzer	Stack replacement	Compression and filling	Storage	Electricity	Water	Total OPEX[a]
AWE	[k€]	83.00	1 694	44.00	29.00	2 136	25.00	2 317
	[MNOK]	0.8117	16.57	0.4303	0.2836	20.89	0.2445	22.66
PEMWE	[k€]	116.0	1 797	28.9	29.00	2 295	25.00	2 494
	[MNOK]	1.134	17.57	0.2826	0.2836	22.45	0.2445	24.39

[a] Stack replacement is excluded in Total OPEX

Table 27 gives the LCOH price range. As explained in the previous chapter is the lower price and upper price based on different cost distribution models. This calculation includes a degradation in the cell stacks and shows only the price for a discount rate of 8 %. The degradation this time infers a rise in the electricity usage, as the amount of hydrogen produced must stay constant.

Table 27: LCOH price range for HSC scenario in €/kg and NOK/kg. Discount rate of 8 %.

Electrolyzer	Price range [€/kg]	Price range [NOK/kg]
AWE	3.72 - 3.84	36.4 - 37.6
PEMWE	4.08 - 4.20	39.9 - 41.1

The LCOH gives a good representation on what the hydrogen price should be. Figure 39 shows how profitable the scenario is for an array of hydrogen prices, with the net present value.

Figure 39: NPV analysis for an array of hydrogen prices, production to HSCs only.

There has also been done a payback time calculation for the high-speed craft scenario, this is shown in figure 40. The solid lines are the SPT from equation 17, and the dotted lines shows the TPT. The fitted equation and R^2 is shown for TPT, because these numbers are approximated. At 5 €/kg, the SPTs are 5 years for AWE and 5.5 years for PEMWE. For TPT, the payback times are 13 years for AWE and 14 years for PEMWE, for the same price.

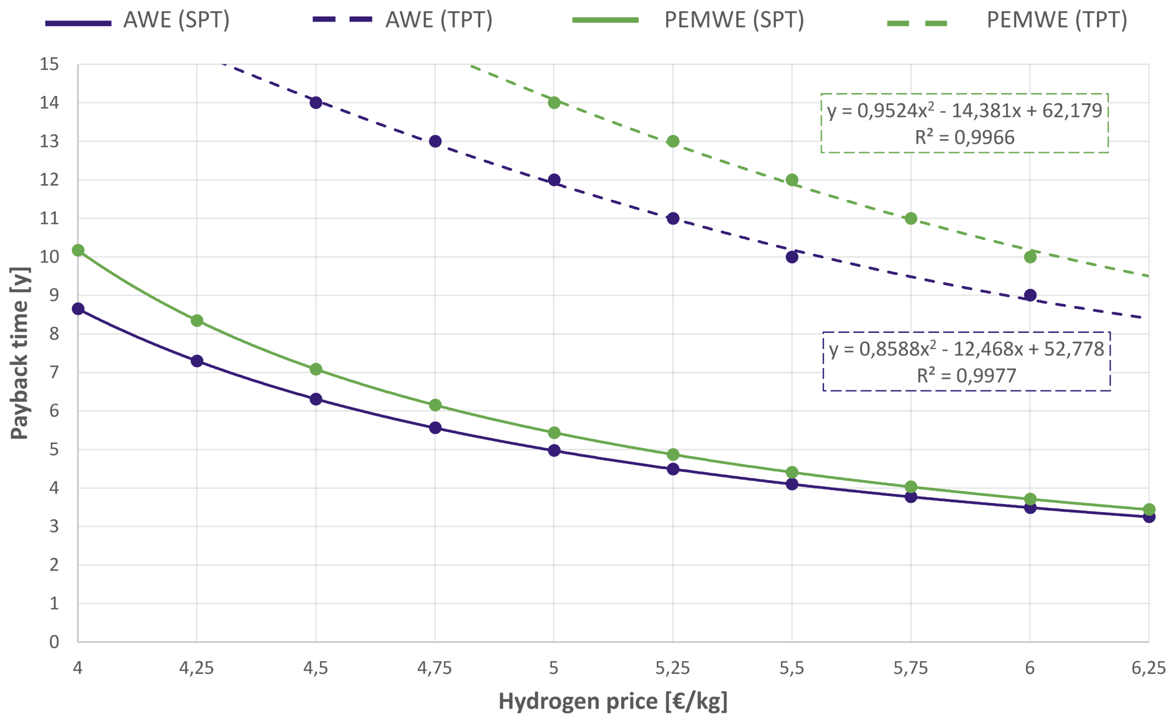


Figure 40: Payback time for an array of hydrogen prices, production to HSCs only.

4.3 Comparison of Fuel Prices

When comparing the costs related to different fuels, different propulsion systems must be taken into account in order to say which one is the most cost efficient. Figure 41 shows the prices for conventional diesel (available at gas stations), MGO, bio diesel and hydrogen when used for two different transport settings: HSCs and road transport (car or truck). The price is presented per unit of energy to move a vehicle or boat, and the efficiencies of the different drivetrains are included. The price per energy output for hydrogen systems depends on the price for the hydrogen delivered to the on board storage tanks. The prices per unit of energy to movement are constant for the other fuels, to make them comparable (see table 19).

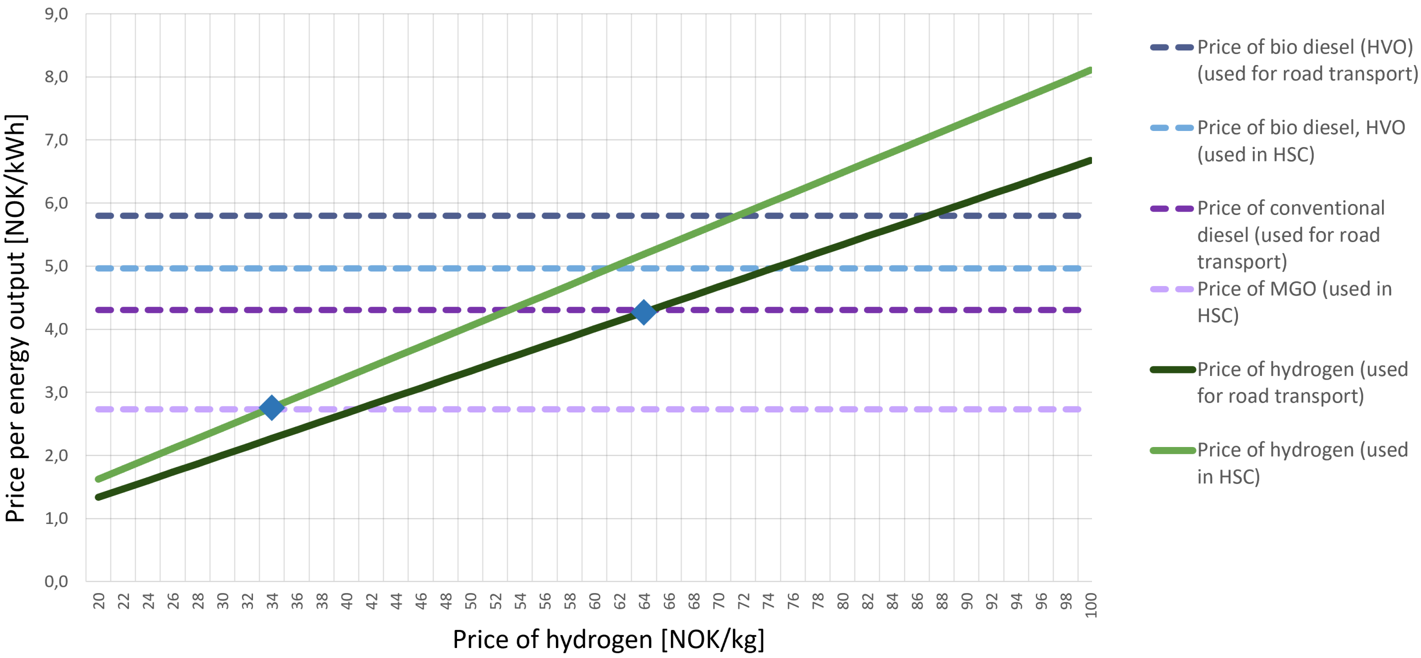


Figure 41: Comparison of different fuel prices, with the actual energy output to propulsion/wheels as unit. Varying price of hydrogen.

Based on figure 41, hydrogen is the cheapest option below prices marked by a diamond. It is cheaper for road transport when the hydrogen price is below 64 NOK/kg (6.53 €/kg). For a high-speed craft, MGO is the absolute cheapest fuel based on this figure. The hydrogen price needs to be below 34 NOK/kg (3,47 €/kg) in order to be a cheaper option.

4.4 Savings of GHG Emissions

Both hydrogen and MGO have related emissions of greenhouse gases when used in a HSC, even though the only *tailpipe emission* from a fuel cell is water vapor. Table 28 shows the emissions related to one crossing between Trondheim and Kristiansund. In the case with MGO as fuel, much of the emission is directly to the atmosphere. For hydrogen, the emission is caused by the production and use of hydrogen in an electrolyzer and fuel cell. Table 29 gives the daily emissions. Every day it is possible to save approximately 14.8 tons of CO_2 equivalents when changing from MGO to hydrogen. It must be noted that emissions from producing hydrogen and MGO equipment is not included. Transport and treatment of MGO is also excluded.

Table 28: GHG emissions for one crossing.

Fuel	GHG emissions [kg CO_{2-eq}]
MGO	5 400
H_2	472.2

Table 29: GHG emissions for one day/three crossings.

Fuel	GHG emissions [kg CO_{2-eq}]
MGO	16 200
H_2	1 416.6

5 Discussion

It is important to reflect on and examine the method and the gathered results in a thesis. Doing this makes it possible to create an overview of the correctness of the results. The discussion section is structured in the same way as the methodology. The available power and possible production volumes are considered first, before looking at hydrogen demand combined with storage. The cost calculations and results are then discussed, in relation with data from other literature, and data on other fuel prices.

5.1 Research Question, Limitations and Areas of Focus

The research question for this thesis, "can Hitra — having access to local wind energy — produce competitive hydrogen for the regional maritime sector?", involves some limitations and assumptions. It also requires a definition of *competitive*. This is mentioned in the introduction chapter and is also elaborated later in this section. In the scenarios presented in this thesis, a production plant for hydrogen is thought connected to the electricity grid through an existing transformer at Jøsnøya (Sandstad). Therefore, it is arguable whether the electricity will originate from wind power produced at Hitra or not. The electricity in the grid is obtained from both renewable and fossil sources, from Norway and other European countries. In 2019, approximately 50 % of the electricity flow across the Norwegian borders was imported energy. The imported energy accounted for approximately 8.8 % of the total consumed electricity in Norway. [129]

It is still reasonable to assume that hydrogen produced at Hitra is green, as most of the electricity produced in Norway is from renewable sources (98 % in 2018). Electricity from Norwegian power plants have an emission factor of 18.9 grams of CO_2 equivalents per kWh. Imported electricity, where the source of origin is unknown, is defined to have an emission factor of more than 500 grams of CO_2 equivalents per kWh according to NVE. Based on this, it is possible to define different carbon footprints for hydrogen production at Hitra. However, as Hitra wind farm is located very close, most of the electricity will probably be from wind power. [96]

Data from table 11 shows that the energy demand for hydrogen production, using all available power, is about 100 GWh per year. The wind farms at Hitra can produce more than 400 GWh of electricity per year. In other words, the production facility could be connected directly to the wind farms, assuring green hydrogen and avoiding grid tariffs. As it is easier to connect the electrolyzers to the grid through an existing transformer, this was chosen as the case for this thesis. In addition, this will probably require less construction and administration work if a production facility is to be built within the next years.

Limitations: Production Method

The focus of this thesis is mainly on the production part of a hydrogen value chain. It has been chosen to look at green hydrogen, produced from PEM and alkaline water electrolysis, as a basis for the project. Grey hydrogen, from steam methane reforming, is excluded as the hydrogen is meant to be used in the transport sector to reduce emissions. The high-speed crafts operating between Trondheim and Kristiansund are supposed to have zero tailpipe emissions in the future. Hydrogen from natural gas would therefore be pointless. Blue hydrogen, from steam methane reforming with CCS, could provide green hydrogen. However, this production method is considered impracticable as there are no industry or supply network that currently use relevant amounts of methane at Hitra. Electrolysis is therefore chosen as the production method, providing green hydrogen from available power in the power grid. Furthermore, electrolysis is often favorable because it produces the most pure hydrogen. For storage, it has been chosen to only consider compressed gas. This is elaborated in section 5.5.

Limitations: Local Demand

Even though the scope of this thesis is limited to the production part of a possible hydrogen value chain, the hydrogen demand is also considered to a certain extent. Production must be seen in relation with consumption. The focus is limited to the local hydrogen demand, to avoid transportation costs. The maritime transport sector is looked at due to the current environmental footprints from this sector. Significant amounts of emissions come from the transport sector in Trøndelag, and transport by sea contributes with almost 60 % of this. In other words, the maritime transport sector is a good place to start when aiming to reduce emissions from the transport sector. Additionally, high-speed crafts, well-boats and perhaps other vessels used in the aquaculture industry represent a demand in a suitable order of magnitude.

There are no existing hydrogen powered well-boats today. Communication with market participants, like Nordlaks, also reveals that there are no concrete plans for this in the nearest future. To use well-boats as an example for this thesis is therefore somewhat unrealistic. However, to reach the climate goals set by the Norwegian government and the EU, hydrogen is likely to be a possible solution in this sector in the future. Nordlaks, which owns and operates several well-boats in Norway, have just bought two new well-boats that will run on liquid natural gas (LNG) and battery power. These are illustrated in figure 5, and represent typical types of ships that can be powered by hydrogen in the longer term. Hydrogen powered well-boats would represent a huge hydrogen demand, and could make the hydrogen market grow significantly.

Trucks are also considered to be possible end users of the hydrogen produced at Hitra. This is not fitting directly within the category of maritime transport, but it is an important part of the aquaculture industry in the region. About 60 trucks leave Hitra every day, to export salmon. There are some challenges regarding this. The market for hydrogen trucks is currently very small, with just a few suppliers around the world. Transporting salmon out of Hitra in hydrogen trucks would also require the possibility of refueling hydrogen along the way. However, this is a possible scenario and other market participants, like Asko, are already using hydrogen for some truck routes.

When using all available power at Sandstad to hydrogen production, there is a possibility of some residual hydrogen after the local demands are covered. Additionally, the local demand is likely to vary from day to day. Therefore, a scenario where residual hydrogen is transported away from the production facility, by truck, is included. This adds costs for storage and transport, but the transport costs are not analyzed in detail as it is outside the scope of this thesis. Having the possibility of transporting hydrogen out of the region is considered to be a smart choice, as it adds a buffer and makes it possible to advantage from future end users. The production could have been dimensioned based on the demand that has been described, but a choice was made to look at the maximum possible hydrogen production. As a result, an overview of the opportunities at Hitra is established.

The hydrogen market of today is small, especially for the transport sector. Whether the end users that are described here will be using hydrogen or not in the nearest future is impossible to say with certainty. This is a problem, as hydrogen production must be motivated by a certain demand. HSCs are probably the most relevant users of hydrogen the next five to ten years. A new contract period for the high-speed craft connections in Trøndelag starts in 2024, and hydrogen is likely to be the energy carrier for the new boats. Because of this, a scenario with hydrogen production to HSCs only is also looked into. This corresponds to approximately 5.5 MW of electrolyzers and a production of approximately 2.5 tons per day. In the beginning this will likely be the most appropriate size of a production plant for hydrogen.

5.2 Analysis and Distribution of Available Power

The methodology for calculating the available power is the first step of finding the power plant size. It is important to reflect on the assumptions that are made, as they have impacts on the resulting LCOH. The main focus during analysis has been the case where all the available power is used, since the limitations of this case were harder to determine. Therefore, this will also be the main focus for discussion. By studying appendix A, the graphs show how the demand for HSCs will be covered regardless season as the available power always exceed 5.5 MW. No upper limit for energy harnessing is therefore necessary in the case of production to high-speed crafts specifically.

5.2.1 Analysis of Raw Data

From the data received from TrønderEnergi, only the consumption data for 2019 were analyzed. It was also possible to use both 2018 and 2019, but an assessment was made, that analysis of the most recent year was enough. As a region with growing population, the power consumption at Hitra will most likely increase every year. Use of data from both 2018 and 2019 to make an average would therefore be insufficient. For analyzing the data from 2019 there was a need for a useful presentation, and graphs seemed reasonable.

All the graphs from analyzing the raw data from TrønderEnergi are shown in appendix A. For further analysis it was important to process this data correctly in a useful way. The graphs show great differences, which made it natural to analyze every month separately. Instead of plotting 52 different weeks, 12 average weeks, one for each month in the year, were used. It was also considered to base the analyses on seasonal average. This way, more of the available power could have been used, but repeating seasonal variations are considered to be uncertain.

By taking into account the future load planned at the transformer, 8.8 MW was used. This was an estimate given by Hitra Municipality, and it is therefore of great uncertainty that this will be the accurate value in the future. It was not received any information on what type of load it will be, the characteristic of the load it therefore unknown. A constant load of 8.8 MW was therefore assumed, but it is very likely that the load would vary. With a lower load during some hours, the hydrogen production could have been increased. The value of the power factor is another uncertainty, as it may vary from hour to hour. No further research was done on this, since it was received by TrønderEnergi. Using a constant power factor is however considered as a usable approach.

5.2.2 Use of 12 MW as Limitation

As a simplification, and to give the electrolyzer approximately constant input power, the upper limit for energy harnessing was set to 12 MW the whole year. Another option is to take advantage of the low energy consumption in the weekend, and raise the limit during Saturdays and Sundays. This way it would be possible to produce more hydrogen. Even though this was not carried out, more energy is available during weekend, hence more hydrogen can be produced on Saturdays and Sundays.

If a limit of 12 is too high or too low is difficult to determine. The available power from fall to spring is under 12 MW almost all the time during weekdays. Based on these months only, a limit between 11.0 MW and 11.5 MW would be more suitable. During summer the limit is fine to use, if not too low. The histogram in figure 27 shows several hours with over 12 MW available, most of them are probably from the summer months. The figure also shows a peek at approximately 12 MW, which substantiates the decision of 12 MW limit, since the peak corresponds to the highest number of hours.

5.2.3 Installed Capacity of Electrolyzers

To determine the exact value of installed capacity, all operation properties were gathered from Nel Hydrogen. Their systems have the advantages of low energy consumption and high output rate of hydrogen. Additionally, Nel Hydrogen appears as a well established company which can deliver electrolysis systems of high quality. The other electrolyzers in appendix B are therefore not considered.

For calculation of installed capacity appendix B is used, where the cells for input power contain calculated values (for Nel Hydrogen). It is therefore a small uncertainty if these values are correct or not. Nel Hydrogen does only provide average values for PEM electrolyzers, and minimum and maximum values for alkaline electrolyzers. The accurate values of the installed capacity of electrolyzers at 10 MW and 5.5 MW are therefore not necessarily totally correct. But on the other hand the energy consumption will vary as the hydrogen production varies, and the values of 10 MW and 5.5 MW seem to fit the specifications for the electrolyzers from Nel Hydrogen.

Installed Capacity - Using All Available Power

The electrolyzers were dimensioned to 10 MW. For alkaline electrolysis this resulted in a combination of two A1000 and one A485, equal to 10.67 MW. The maximum values for input power were used. Since only the average values for PEMWE were given, the combination of five M400 and one M200 gives an average value equal to 10.29 MW. Another option could be to use a higher installed capacity, but as it will be discussed later, PEM electrolyzers have the possibility to run at overload. The combinations for alkaline and PEM electrolyzers are therefore considered to be suited for further analysis.

Of the 12 MW available power, 10 MW is allocated the electrolyzers. The remaining 2 MW is the energy consumption for compressor and filling center, and rectifier and transformer losses. This is not the actual case, but a useful approach. The analysis in figure 28 shows the gap between installed capacity of the electrolyzers and the input power of a total system. Both gaps are less 2 MW, being approximately 1 MW. By use of all available energy up to 12 MW, the installed capacity of electrolyzers could therefore have been greater. But since the uncertainty for this analysis already is of significant magnitude, 10 MW is used in further analysis in order to not oversize the production plant.

To make sure the available power is within the operation area of the chosen combinations, the power consumption was plotted as a constant value together with available power, shown for January in figure 28. When the line for available power is within the interval for minimum and maximum power consumption of the total system, the AWE can use the available energy. Since only one value was given for PEM electrolyzers, the graph contains only one line for power consumption of the total system. It is assumed that the PEM electrolyzers can run at 0 - 160 % of nominal load. This means that as long as the line for available power and line for total power consumption are not too far away from each other, it is assumed that the electrolyzer can use the available energy. The graphs only show January, but the same analysis was done for all months, showing the same results. The chosen combinations of electrolyzers can therefore be used.

Installed Capacity - Producing Hydrogen to High-Speed Crafts Only

A production rate of 2500 kg of hydrogen per day has been used as a basis for the analysis of production to high-speed crafts only. Unlike the other case, the production rate was used to find the size of the electrolyzers. This was done by use of appendix B to find a suitable combination where the maximum (AWE) and average (PEMWE) production were approximately 2500 kg hydrogen. In the case of alkaline electrolysis the combination is one A300 and one A1000, resulting in 5.59 MW and 2682 kg per day. By use of PEM electrolyzers the combination is three M400, which gives 5.61 MW and 2617 kg per day. For further analysis it was therefore assumed an installed capacity of 5.5 MW, since both production rates are over the required demand.

5.3 Hydrogen Production and Demand

Two different MATLAB codes, with different purposes, are used in the calculations of hydrogen production. In this section both methods will be discussed, first by looking at how the annual production is calculated, then the weekly production day by day. All results will be highlighted along the way. In addition to weekly production, the local demands are essential for the chosen storage capacity and will therefore be discussed. Mainly, this section addresses the scenario of using all the available power. The case of covering the demand for high-speed crafts only is discussed at the end.

5.3.1 Electrolyzers Usage and Estimates for Energy Consumption

Some principles are the same for all calculations, like 98 % use of electrolyzers [77]. This information was received directly from an e-mail correspondence with Nel Hydrogen and is considered credible. They stated that all their electrolyzers are designed for continuous operation, and only short maintenance time is required.

The total energy consumption per kilogram of produced hydrogen has a major impact on the production. The largest share is the energy consumption of the electrolyzer, with a share of 90.8 % and 91.4 % for AWE and PEMWE, respectively. The values were gathered from Nel Hydrogen. Their systems for PEM electrolysis use approximately 4.4 kWh/kg more energy than AWE, but since PEMWE is a more complex device than AWE the difference seems reasonable, even though the energy efficiency is higher for PEMWE. High energy efficiency is not equivalent with low energy consumption, it only is a measure of how small the voltage losses are (equation 7).

The energy consumption for both PEMWE and AWE are given based on output pressure at 30 bar. For PEMWE this does not include any external compression as the operational pressure is assumed to be 30 bar. In AWE normal operational pressure is at approximately 1 bar, and external compression is therefore needed. For some AWEs the operational pressure may be a little higher, but this is not the case for the electrolyzers from Nel Hydrogen. They state that all their AWEs require an external compressor to compress the gas from atmospheric pressure (1 bar) to desired pressure level [13]. The values for energy consumption, both for PEMWE and AWE, were received directly from an e-mail correspondence with Nel Hydrogen and are therefore considered credible. These values differ slightly from the values in appendix B, as they also include energy to additional equipment such as purification systems.

The remaining shares of the total energy consumption are rectifier and transformer losses, and energy for compressors. Both are considered small compared to the energy consumption for electrolyzer, but for the final result it is important to use a realistic amount of electricity. If ideal rectifiers and transformers were to be used, the losses would be zero. However, both components have high efficiency and use of 3.41 kWh/kg seems therefore to be of right magnitude. As stated in section 2.5 in theory, 9 % of the energy in hydrogen is used to compress hydrogen from 1 bar to 350 bar, corresponding to approximately 3.0 kWh/kg [86]. To assume 2.0 kWh/kg for compression from 30 bar to 300 bar is therefore considered reasonable. A report by FCH was also used to make this decision, where 1.7 kWh/kg is used for compression from 30 bar to 200 bar [35].

5.3.2 Annual Potential of Hydrogen Production

The analysis of annual hydrogen production was mainly done in order to state the potential of hydrogen at Hitra, but is also used in cost-related calculations. It is important to note that the analysis was conducted based on the graphs in appendix A, where an average week was generated for every month, and not based on the average week in figure 29. This way the calculation included the monthly variations and gives an overview of how big the actual potential is.

Table 20 shows how the limitations affected the annual hydrogen production, with a reduction of approximately 50 tons, corresponding to approximately three percent of the total production. The table also shows how the difference in energy consumption of 4.4 kWh/kg between PEM and alkaline electrolyzers affects the result by approximately 120 tons. Since an AWE has lower energy consumption than a PEMWE, it is reasonable that AWEs produce more hydrogen.

More detailed tables are given in appendix C, where also the monthly and weekly production are included. Note that only the weekly production is fitted for comparison. The results show that in the months with the most available energy, the electrolyzers can produce more compared to the other months. The biggest difference is between August and December, being approximately 1.4 tons per week (table C2, production with limitations).

5.3.3 Considering Hydrogen Storage and Demand

The choice of storage capacity is important for the resulting costs, and it was therefore important to conduct a credible analysis. As a simplification, a MATLAB code was made to generate a visualization of an average week and production day by day. This was used to determine the storage capacity. A more thorough investigation should be conducted to determine whether the chosen capacities are realistic. To begin with, the calculation could look into seasonal variations, or a "worst-case scenario" could be generated. If all the energy is to be used, the storage capacity would need to cover the largest production rate. However, in this thesis only an overview of the storage capacity is given and the average-week production is believed to fulfill the requirements. The weekly production was calculated with both PEM and alkaline electrolyzers. But for sizing of storage capacity, production from AWE was used, as this gives the highest production rate. A slightly too large capacity is desired rather than too small.

Local Hydrogen Demand

In addition to the analysis of daily production, an overview of the local demands are crucial in the choice of storage capacity. It was important to know the daily demand, but also how often the filling happen. The combination of the local demands used in this thesis is not necessarily the best for Hitra. Therefore, it is important to only use this as an example for the hydrogen distribution. However, the choices made in this process did have an impact on the resulting costs.

The chosen hydrogen demand of 2500 kg hydrogen per day for high-speed crafts is based on the same ship design as the current HSCs. Nowadays, new designs are made for the stretch between Trondheim and Kristiansund by the consortia led by Brødrene Aa, Rødne and Selfa Arctic with focus on improved efficiency. It is therefore most likely that the HSCs will require less energy, hence less hydrogen. However, since none of the high-speed crafts are built yet, the estimated hydrogen demands are not entirely certain. Therefore, the current ship design was used as basis for this analysis. The analysis also use the current route information. This might be the case of the next contract period too, but new stretches can be considered. It is therefore a great uncertainty related to how much hydrogen will be needed, as the route is assumed to have an impact of the energy consumption. Due to the great total uncertainty of this analysis, daily variations were not taken into account. On the other hand, all the choices may have overestimated the hydrogen demand for HSCs.

The uncertainty of hydrogen demand for well-boats is even greater than for high-speed crafts. Since no contact was made with the operators of the well-boats in the area around Hitra, information from a report by SINTEF is used as the only source. However, by discussing the problem with the supervisors and SINTEF, 5.25 tons per week seemed in the right order of magnitude. After the discussions, the filling frequency was changed from one to two times per week. Despite the recommendations, the uncertainty is high as there are no current well-boats using hydrogen as fuel. Another concern is the volume of the storage tank aboard the well-boats. It is conceivable that the future boats will have the same available room for fuel tanks as the current design, if not less. A new design will probably aim for a more energy efficient design, hence less weight is desired. But since this is just speculations, a demand of 5.25 tons per day was used.

The information on hydrogen demand for trucks was provided by Hitra Municipality and The Renewable Energy Cluster, both considered credible sources. On the other hand, it is of great uncertainty that 20 % of the trucks will use hydrogen, since none prospects were given. However, it seems reasonable that not all the trucks will use hydrogen. It may happen in the future, but some of them may use battery instead. From the beginning of the project, it was thought to include all trucks used for salmon transport. This would give Hitra Municipality an indication on the possibility of covering the demand for all the trucks and the related costs. Unfortunately, a misunderstanding done by the students resulted in 63 trucks per week, instead of 63 trucks per day. Since this was discovered in the very end of the project period, there was no time to fix it. Instead, to cover 20 % of the total demand for trucks seemed as a useful compromise.

Storage Capacity - Using All Available Power

When using all available power, two of the bar graphs (figure 30 and figure E1 in appendix E) include all consumers; high-speed crafts, well-boats and trucks. The graphs show how the produced hydrogen can cover the demand for two HSCs and 63 trucks per week, including one or two well-boats. In the case where two well-boats are used, the delivery reliability is limited and the case was therefore not used in further analysis. In other words, the base for the chosen storage capacity was two high-speed crafts for Tr-Kr, one well-boat and 63 trucks per week.

To cover more of the total demand for trucks, figure E2 in appendix E was made. The purpose of this figure is to give an overview, and it was therefore not used in any calculations. The total demand at 15.75 tons per week is based on 63 trucks per day (Monday to Friday), resulting in 315 trucks per week. After covering the demand for two high-speed crafts, approximately two tons hydrogen is available every day. By only looking at production Monday to Friday, ten tons can be used by trucks per week, corresponds to approximately 63 % of the total demand. If all days were taking into account, twelve tons are available, corresponding to 76 % of the total demand. This will require an additional storage tank for the four tons of hydrogen produced at Saturdays and Sundays, when there are no salmon transport during the weekend. This way, the amount of four tons can be distributed over the other five days. However, the analysis shows that is it not possible to cover the total hydrogen demand for high-speed crafts and trucks.

The amount of accumulated hydrogen in figure 31 depends on how often the well-boat fills. If the bunkering would happen three, instead of two, times per, week the stationary tanks could have been smaller. But for this analysis, bunkering two times per week is used as a basis. Another concern is the place for bunkering. In this analysis it is assumed bunkering at Hitra Harbor only. However, to use only one place for filling is considered unrealistic. In normal operation, well-boats may bunker several places as they travel far [30]. For the purpose of this thesis, only an overview of the hydrogen demand is given, and the aspect of a location for bunkering has therefore not been considered. However, to use well-boats as end user of hydrogen in this thesis gives an indication on the amount of hydrogen needed.

The stationary buffer is chosen to be approximately 2.5 tons of hydrogen, enough to cover the daily demand for two HSCs. The main reason for a buffer is delivery reliability: even though the production stops, the boats do not stop. So in case of an unexpected maintenance, a buffer is required. If the delivery reliability is desired higher, additional storage tanks must be considered, hence a greater cost related to storage. From conversations with a representative from SINTEF, a normal buffer was said to be equal the demand of one to three days. The chosen buffer may therefore be too small. Total stationary storage is eight tons, including the buffer, but it is of great uncertainty if the tanks cover the production during the whole year. Since the analysis is based on an average week, the real production is greater when the available power is over the average. The volume may be big enough during the winter, but when the production rate is higher, the tanks may be too small. For a more accurate result a more advanced analysis must be conducted. However, the chosen storage capacity is considered reasonable for the purpose of the thesis.

The remaining residual of approximately 0.6 tons per day during weekdays and 1.3 tons per day during the weekend are taken into account. A mobile storage capacity of two tons has been selected to cover this. Due to this choice, the mobile tanks must be transported regularly. Hopefully, two tons storage tank will cover the residual during the whole year. On the other hand, the volume may be too big as it exceeds both 0.6 tons and 1.3 tons.

Storage Capacity - Producing Hydrogen to High-Speed Crafts Only

The storage capacity for the case of production to high-speed crafts only, has been set to 5.0 tons. This choice was uncomplicated, compared to the choice of storage capacities where all the available power is used. The uncertainty in this case is only limited to the hydrogen demand for HSCs and a buffer, both set to be 2.5 tons. For the choice of the buffer, the same argument as earlier can be used in this situation: if the delivery reliability is desired to be higher, additional storage tanks must be considered. However, a buffer of 2.5 tons is also chosen because the regulations for major accidents is avoided when the amount of hydrogen stays below 5.0 tons. This needs to be considered if a larger capacity is to be chosen.

5.4 Electrolysis Technologies

In the selection of electrolysis technology, both alkaline and PEM electrolysis have been considered. All the calculations are done for both cases, since it is impossible to tell which is the most suitable for Hitra. Both AWE and PEMWE are at a commercial stage, and can be provided by most suppliers. In this section these two types of hydrogen production methods will be compared and seen in context with the power situation at Hitra.

In the theory chapter, three less common electrolysis technologies are mentioned. None of these are considered to be appropriate for Hitra in the near future. Anion exchange membrane electrolyzers are at the stage of developing, but will combine the benefits from both PEMWE and AWE. In the future, this could be a better option than PEM or alkaline electrolyzers. Both high-temperature electrolyzers, solid oxide and molten carbonate, require a high heat input if the technologies are to be considered efficient. The electrolyzers operate at 700 - 1000 °C, and the only way to fulfill the necessary temperature condition is to connect the system to a heat source. Waste heat at high temperature from industry is a possible source. If such an industry would be built at Hitra this could be possible, but for now this is not the case.

5.4.1 Should PEMWE or AWE be used at Hitra?

To decide which technology should be used at Hitra, the advantages for both PEM and alkaline electrolysis must be weighed against the possible disadvantages. The main focus of this comparison will be the cost difference and the ability to run in load-following operation.

Before the main comparison some other advantages and disadvantages will be mentioned. PEMWE gives the highest purity of hydrogen [13]. A high degree of hydrogen purity can be important in fuel cells, but due to limitations of the thesis, propulsion system requirements are not considered. Another difference is the pressure levels. PEMWE operate with higher pressure compared to AWE. Hence, the external compression for AWE will require more energy to deliver hydrogen with the same pressure. To minimize the compression costs, the pressure inside the cells is desired as high as possible, since it is more energy efficient to let the electrolyzer operate at a high pressure than use of external compression. In the future, it is likely that both PEMWEs and AWEs can operate at higher pressures.[76]

Cost Difference

The obvious difference between PEMWE and AWE is the cost, where PEMWE is more expensive than AWE. Figure 16 shows the gap between the two technologies, where FCH estimates a difference of approximately 425 €/kW for 10 MW plant size in 2017 [76]. The main reason for this is the costly components and metals in PEM electrolyzers. The separator plates and current collectors are used in PEMWE due to use of a solid membrane, and are components with high costs. On the electrodes, noble metals as iridium and platinum are used as catalysts, which also are related to high costs. AWE do not require any noble metals, instead it use nickel as catalyst with other low-cost metals (cobolt, iron, vanadium) as additives. Because of the liquid electrolyte, AWE does not use as many components as the PEMWE, but on the other hand the liquid electrolyte can cause some operational problem.

In the future, the cost difference between alkaline and PEM electrolyzers can be reduced. PEMWE is more recently developed, hence the costs of materials are greater. A growing demand will reduce the costs, but since the PEMWE is a more complex structure than AWE, the costs will probably always be somewhat higher. [49, 59]

Gas Crossover and Load-Following Operation

In alkaline electrolyzers, a liquid electrolyte and a diaphragm is used instead of a SPE membrane. This can cause gas crossover, for instance when the system use a variable power source. Gas crossover can cause a dangerous level of hydrogen in the oxygen gas, and eventually an explosion if the amount is over 4 vol% [47]. To prevent a conceivable damage, the operational area of AWE is limited. The electrolyzer does not have the possibility of operating in stand-by mode and requires minimum 15 % of nominal load [76]. In addition, significant gas crossovers are impossible to avoid in load-following operations. Even if the electrolyzers operate within the operation area, load-following operations are not desired.

If PEM electrolyzers were to be used at Hitra, the gas crossover problems will not be a concern. These electrolyzers have the advantage of a solid membrane (SPE membrane), where the crossover is said to be negligible [52]. This makes the operational area bigger compared to AWE, with a range of 0 - 160 % of nominal load [76]. PEMWE is also characterized with low system response and cold-start time compared to AWE, which will help the system to use more of the available energy.

Direct use of an intermittent power source, such as wind, makes PEMWE a better option than AWE. This is however not the case for a possible production at Hitra, where the electrolyzers will be connected to a transformer. The electrolyzers will use electricity from the grid, not directly from the wind farms, which makes the power situation at Hitra different. As long as the system is in operating mode, the grid will continue to feed the electrolyzers with power, regardless how much energy that is produced by the wind turbines. This opens up the possibility for AWE, as long the transformer can deliver a constant amount of power. If all the available energy is to be used, the supplied energy is limited by the installed capacity of the transformer. In other words, when all the available energy is used for hydrogen production, the electrolyzers will not operate with a constant energy supply, because the available energy at the transformer will vary. By looking at figure 28 it is possible to see that in order to harness all the available energy, the electrolyzers will have a variable load between 12.0 MW and approximately 11.4 MW. This load change is assumed to cause almost negligible stress for the components in PEMWEs. On the other hand, for AWE a variable load can be devastating for the components, but it is uncertain what kind of impact a load change at 0.6 MW will have.

In the other case, where only the demand for high-speed crafts is covered, the electrolyzers can operate with a constant energy supply. The required power of 5.5 MW can always be covered by the available power at the transformer. To use alkaline electrolyzers in this case is therefore suitable.

5.5 Compressed vs Liquid Storage

It is important to select a financial sustainable storage method, as every storage technology is expensive. Compressed hydrogen is the most cost efficient and developed technology concerning hydrogen storage. Storing hydrogen through adsorption or in either metal or chemical hydrides, are expensive and underdeveloped technologies. The most natural alternative to compressed storage is liquid storage. The main advantage with liquid form is that the amount of hydrogen in one cubic meter is greater compared to compressed form. This is because the density of hydrogen increases drastically in liquid state. At the moment, the process of making liquid hydrogen, it costs too much energy. For example, turning one kilogram of hydrogen gas to liquid form requires 30 % of the final available energy in the hydrogen. In comparison, compressing hydrogen from 1 bar to 350 or 700 bar, requires 9 to 12 % of the available energy in the hydrogen.

The substantial difference in energy consumption, showcases how much further compressed hydrogen has developed as a storage technology. The energy consumption needed for liquid storage, is slowly decreasing. A liquefaction plant with an energy usage of 6 kWh_{el}/kg_{H2} is the next step. That is a large drop from 10 kWh_{el}/kg_{H2}, which is used today. If liquid storage were to compete with compressed storage, there has to be produced a large amount of hydrogen. This is illustrated in figure 19. At least ten tons of hydrogen should be liquefied each day, which is unrealistic for Hitra. There is not enough power or demand to make such a large quantity of hydrogen. Compressed hydrogen is the most developed, cost efficient and energy efficient technology, and is therefore the selected storage method.

The hydrogen market at Hitra will most likely focus on compressed hydrogen in the beginning. The blueprints for the high-speed crafts indicates that most companies will go for compressed hydrogen as fuel source. This will also depend on what is available and most cost efficient from local, national or international hydrogen producers. At the moment, compressed hydrogen is the cheapest and easiest to access. For instance, the hydrogen trucks from Asko run on compressed hydrogen, which is the standard for the few hydrogen vehicles on the roads today.

This thesis also considers well-boats from the aquaculture industry as suitable consumers of hydrogen. They will require a large amount of energy, and liquid hydrogen is probably more suited as fuel than compressed hydrogen, although this thesis has selected compressed hydrogen storage. Further, well-boats are probably only going to use hydrogen in the long term. This weighs in the favor of liquid storage if Hitra will have access to more power, and can produce more hydrogen per day, in the future.

Container Storage

The most cost-effective way to store gaseous hydrogen is in underground caverns, like salt caverns. They can store up to 200 bar. This type of investment is good value for money. The problem is that this type of storage is geographically locked and not applicable for Hitra Municipality, as there are none salt caverns or mining operations in the local area. That is why storage in metallic containers is the only option. Containers are normally composed of steel. These types of containers are good for stationary storage with up to a few hundred bar. Compared to storage in caverns it is more expensive, but the stability is greater and the purity of the hydrogen is certain.

Another type of container which is applicable are metal containers composed of composite metal. Composite containers can store at higher pressures, can be transported and stores a higher amount of hydrogen. The composite metal is stronger and more resistant to embrittlement. That is why composite containers can store at much higher pressure, but they are costlier. By looking at the gathered costs in this thesis, they cost three times than that of steel containers. Composite containers have therefore only been selected for the mobile storage units, and steel tanks are chosen for the main storage.

5.6 Choices and Methodology Related to Cost Data

The data for this thesis is generally collected from literature. It is not based on actual offers from real suppliers of electrolysis equipment. This is important to consider, as different suppliers can provide a variety of system compositions to different prices, depending on the quality, lifetime and efficiency of the equipment. However, both the resulting costs of hydrogen and the cost distribution of equipment, water and electricity seems to be in the correct order of magnitude for an average system.

The cost data from literature is structured based on information obtained directly from the sources, or based on assumptions. The expenses are divided between the following categories:

- Investment costs for components as electrolyzers, storage tanks and compressor systems
- Running operational costs as water, electricity and general maintenance (OPEX)
- Stack replacement after ten years for alkaline electrolyzers, and after seven years for PEM electrolyzers
- Costs for installation, design, building and administration. ("Other costs")

This is carried out to establish an overview of the cost distribution and the sizes of each expense item. The advantage with this is that specific parts of the total hydrogen cost can be analyzed, in order to validate the cost data. In addition, it is very helpful when looking for possible ways to reduce the costs, and it will be an easy operation if some cost data needs to be replaced. On the other hand, there is a chance that some costs end up being missed or counted twice. Especially when the content of a specific value is assumed, which is the case for some of the data. However, there are only made logical assumptions that are controlled against several sources and market participants. Such errors are therefore likely to have small impacts on the total, resulting, cost of hydrogen.

5.6.1 Finding Costs of Electrolyzers

The costs for electrolyzer systems contains CAPEX, OPEX and stack replacements. Most sources presenting cost data for electrolysis give a total cost that includes electrolyzer stack, BoP costs with power electronics, gas cleaning and water treatment, and sometimes also rectifier and transformer. All these parts are therefore assumed to be covered in the CAPEX for an electrolyzer system. The cost values are sometimes very different from source to source, ranging from 384 €/kW to 2000 €/kW for alkaline electrolyzers. This is assumed to be caused by the inclusion, or exclusion, of other non-material costs. Therefore, it has been chosen to separate between two cost categories: one including ”other costs” (installation, designing, building and administration), and one excluding this.

The significant cost difference between the two categories are thought to be caused by ”other cost”. However, this could also have to do with BoP costs. An IEA report prepared for the G20 meeting in 2019 says that the electrolyzer stack is responsible for 50 and 60 % of total system CAPEX, for AWE and PEMWE respectively [10]. The rest are from mainly BoP costs. Another, but older, source from NREL shows that BoP costs may vary considerably, between 34 % and 86 % of total electrolyzer CAPEX [130]. This suggests that the above-mentioned cost difference can be a consequence of different system equipment being included in the data. But in this thesis, the cost difference is said to be caused by ”other cost”.

It was chosen to move on with the cost category that excludes ”other costs”, and treat this as a separate expense item. As most literature give the costs per unit of installed capacity (kW or MW), it was chosen to use this as a basis when comparing and choosing cost data. But some sources provide data at other bases. For instance, one source gives a total electrolyzer cost of approximately 3.3 million euros (32 mill NOK), for a possible plant producing two tons of hydrogen per day [35]. In this case, it is assumed that the electrolyzer capacity is 5 MW, resulting in a cost of 653 €/kW. These types of assumptions is probably not entirely correct. Nevertheless, the cost is likely to be around the estimated level.

As most of the sources are at least two to three years old, predictions for future costs and inflation are taken into account when deciding the cost level in 2020. These estimates are relatively uncertain. It was chosen to use 2016 as the year of the costs from literature, as most of the reports are written around that year. Inflation of 2.0 % per year has been used to find the costs in 2020 currency. The value tends to vary from year to year, but an average of 2.0 % is chosen in accordance with the central bank of Norway to make calculations easier. When using inflation to predict future costs, it is important to note that the inflation rate varies a lot between different sectors. Two percent can be a good estimate when the whole Norwegian economy is considered, but it can be very different for the hydrogen sector specifically. But, as specific inflation rates for hydrogen markets are not found, two percent per year is used.

Estimates for future costs, mostly for 2030, are provided in some literature. This has been used to calculate a cost reduction, from the given cost values that are assumed to be from 2016, to a cost of today (2020). The cost reduction is calculated from a linear function, which is worth reflecting on. Having only two points to consider, it is impossible to know how a cost reduction will occur. However, it is likely that costs will decay exponentially, meaning that the cost reduces more rapidly in the beginning. Anyway, a linear cost reduction is assumed, which probably makes the resulting cost for 2020 somewhat inaccurate.

Based on the assumptions described above, the CAPEX for electrolyzer systems ends up being 503 €/kW for alkaline electrolyzers and 703 €/kW for PEM electrolyzers. Information provided by a representative from Nel Hydrogen showed that the price for alkaline water electrolyzers are in a correct order of magnitude, compared to the actual market today. The price for the PEM electrolyzers turned out to be somewhat low, based on the same source. However, it is very uncertain whether the estimated costs and the information from Nel Hydrogen are comparable, as what these prices cover is unknown. The communication also revealed that the prices vary greatly with system properties and quality.

The difference in CAPEX between AWE and PEMWE is likely to be in a correct order of magnitude, because of similar ratios described in various literature. Figure 16 shows the costs for alkaline and PEM electrolyzer systems based on varying capacities (MW values). It includes costs for 2017 and future estimates for 2025. How system costs are defined, and whether or not other non-material costs are included, is unknown in this context. Therefore, this graph does not necessarily give a good basis for comparison of the actual cost levels. However, it should be possible to compare the ratios between alkaline and PEM electrolyzer costs. For 2017, PEMWE is approximately 1.50 times more expensive than AWE. For 2025, PEM electrolysis is estimated to be only 1.33 times as expensive. The CAPEX found in this thesis shows that a PEMWE costs more than an AWE, with a ratio of approximately 1.40. This is a good match, and can at least make the estimated CAPEX ratio between PEM and alkaline water electrolysis trustworthy.

Stack Replacement Costs and OPEX

The stack lifetimes of ten years for AWE and seven years for PEMWE, are chosen based on average values obtained from literature. The lifetimes are in the upper region for PEM and the middle region for alkaline water electrolysis. This means that the alkaline electrolyzer will reach its lifetime with a higher certainty than for the PEM electrolyzer. However, the chosen values are within the intervals presented by literature. Additionally, the lifetimes are expected to increase in the future. According to a report by IEA, the stack lifetime of an alkaline electrolyzer can be 100 000 hours in 2030, corresponding to approximately 11.5 years of continuous operation [10]. The lifetime of a PEM electrolyzer stack can be up to 90 000 hours in 2030, corresponding to approximately 10.3 years of continuous operation. Having this in mind, the chosen lifetimes are quite probable. [10]

The CAPEX for electrolyzer systems are assumed to include some sort of water purification systems, as a majority of the sources mention this. When planning an electrolysis plant, this can be important to consider more in depth than what has been done in this thesis. Very pure water is required to maximize the lifetime of electrolyzer stacks. This is especially the case for PEM electrolyzers, as the platinum (Pt) catalyst can be easily poisoned from impurities and cause a reduction in efficiency. However, in some cases it can be cheaper to sacrifice high efficiency over longer times and rather replace the stack at an earlier stage, compared to expensive water purification components. This is of course something that needs to be considered for specific projects.

When the above-mentioned lifetimes are reached, the electrolyzer stacks needs to be replaced. The costs for stack replacement are decided based on the same assumptions that are described for electrolyzer system cost. Both inflation and cost reduction are taken into account, resulting in 308 €/kW for AWE and 326 €/kW for PEMWE in 2020 currency. Comparing with stack replacement costs from figure 16, the ratios between PEM and alkaline electrolyzers seems to be in the correct order of magnitude. For 2017, PEMWE stacks are about 1.22 times more expensive than AWE stacks. For 2025, the costs are approximately the same. The values chosen for this thesis shows a ratio of approximately 1.06, which is a good indication that the cost differences are correct.

OPEX for electrolyzer systems is chosen to be 3.0 % of the equipment CAPEX each year, for the whole plant lifetime of 20 years. This is used in calculations of both PEM and alkaline electrolyzer cost, and is meant to include general maintenance, cleansing, spare parts and replacement of smaller components. The percentage is quite low, as it is assumed that the facility will need relatively little maintenance. In this thesis, the OPEX is fixed every year. This is an unrealistic scenario as the need for maintenance can occur at very different times. Additionally, these costs tend to increase with the aging of the components. However, 3.0 % is in the middle of the values obtained from literature, and should therefore be a good estimate. Furthermore, the OPEX percentage of total costs usually becomes lower when the production volumes increase. The percentage could therefore be a fitting choice for a facility of 10 MW.

The choice of using 3.0 % in calculations of OPEX for both PEM and alkaline water electrolysis is debatable. The two technologies have different requirements for maintenance, spare parts and cleansing, and the costs will therefore be somewhat dissimilar. The OPEX is usually greater for alkaline electrolyzers, due to maintenance of corrosive electrolyte. An unwanted reduction of KOH occurs in the electrolyte, mainly because of CO_2 poisoning as shown in equation 9. This necessitates maintenance through stirring, and sometimes refilling, the electrolyte. Because of these extra requirements, the OPEX percentages should perhaps be higher to give a more precise cost estimate. But, as this influences the resulting total hydrogen cost to a very small degree, 3.0 % is chosen to make it easier to carry out the calculations.

5.6.2 Choosing Costs for Compression and Filling

Several different sources are used to obtain cost data for compression, and the data is compared in appendix G. For the calculations in this thesis, it was chosen to look at costs for a *filling center*, provided by a FCH report, including compressor, piping and filling equipment [76]. The report defined the filling center as the "physical infrastructure needed to fill gas bundles and/or tube-trailers". Based on this, it is assumed that the costs for compression to storage pressure, filling stationary storage tanks and filling of high-speed crafts or well-boats, are included. However, it is unknown what kind of, and how many, end users that are taken into account in the FCH report. Therefore, a filling station for trucks would likely add some additional costs, due to extra filling equipment and compressors.

The compression and filling costs are decided based on an output pressure of 300 bar, and two different input pressures: an input pressure of approximately 1.0 bar (atmospheric pressure) for production with AWE, and 30 bar for production with PEMWE. The chosen compression rate, or filling capacity, is 200 kg/h as this corresponds to approximately 10 MW of electrolyzers. In other words, this will make it possible to compress all the produced hydrogen at maximum production. The estimated costs resulted in a difference of approximately one million euros between alkaline and PEM electrolysis. This is much capital for an extra compression stage from 1.0 to 30 bar. However, the costs tend to level out as the input pressure increases.

As the data from literature does not provide costs for the specific scenario described in this thesis, with compression to 300 bar and 200 kg/h at maximum production, some assumptions are made. It is assumed a linear relationship between different compression rates and the respective costs, for the same pressure intervals. Then, a linear relationship between different pressure intervals are assumed for the same compression rates. This is not entirely correct. From reviewing literature, it is evident that costs, per unit of rate, are generally decreasing when the compression rates are increased. When output pressure increases, the costs are generally increasing with a lower gradient, at least until 500 bar. This is above the pressure levels that are interesting for this thesis. As gradients for these relationships are unknown, linear relationships are used as a basis. The resulting costs for compression are therefore not precise, but still usable.

OPEX for Compression Systems

An OPEX of 2.0 % of compression CAPEX per year is used in this thesis. This is a low percentage, but it is at the levels presented in literature. It is meant to cover simple maintenance, oiling, cleaning and some spare parts. Even though these costs are easy to forget, they must definitely be included in the cost calculations. For normal operation, without any accidents or unforeseen events, the OPEX should be covered by this yearly costs with a good margin. However, a production facility for hydrogen, as the one described in this thesis, is completely dependent on compressor and filling systems as long as the production is running.

If compressor equipment is removed for maintenance, the production must be stopped, if there are no extra in reserve. In this thesis, the production is estimated to run 98 % of the time during a year. That leaves approximately 170 hours available for maintenance that requires the production to stop. If accidents or unforeseen events occur, causing the need for expensive and time consuming maintenance, this could affect the production over a longer period of time. It could therefore be relevant to add the costs for replacement equipment. This has not been done in this thesis. However, it should be weighted against the possible loss in income from non-produced hydrogen.

5.6.3 Obtaining Cost Data for Storage

From reviewing literature it is clear that there are two common storage methods that are relevant for this thesis. Compressed hydrogen can usually be stored in steel vessels or composite tanks, which are the types that are used in this thesis. The two different categories are referred to as steel or composite tanks, but the construction of the storage vessels are often complex and consist of different materials. A storage pressure of 300 bar is used as a basis in this thesis. This is because Hexagon, which is a market participant within hydrogen storage, revealed that their storage technology is most cost efficient for pressures around 300 bar. In addition, the relatively high pressure will minimize the need for large spaces to place the vessels. Another factor to consider is that this pressure is higher than what is needed on board a HSC, which can make it possible to refuel by overflow filling.

Most of the produced hydrogen from the scenarios presented in this thesis will be stored in stationary steel tanks. In addition, some storage capacity in mobile composite tanks is included to handle residual production. For composite tanks, a price of 660 €/kg is used in cost calculations. This data is acquired from Hexagon, and is expected to be credible. For the steel tanks, a cost of 293 €/kg is used. This is an average of data obtained from various literature, and is therefore more uncertain. As some of the sources lack information on material types and pressure levels, a cost is assumed to represent steel tanks if the value is in the lower layer of all the cost data. Another simplification that is made, is the assumption that the costs for storage pressures of 200 and 300 bar are the same. This is probably not the case, even though the difference only will be caused by extra use of material. A higher pressure will often result in a higher cost, and it can therefore be argued that the cost for steel tanks should be somewhat higher. However, some sources describe storage costs that are lower than the chosen value as well.

An OPEX of 2.0 % of storage CAPEX per year is used in the cost calculation. This value should reflect some maintenance and inspection, that will occur every 10th to 15th year. A storage system can last for 30 to 40 years, without much need for maintenance or spare parts. As the plant lifetime described here has a lifetime of 20 years, the storage tanks are still usable after the hydrogen production has stopped. These systems could for instance be sold, and give some income. This is not accounted for, but it could reduce the net costs for hydrogen storage.

5.6.4 Defining Non-Material Costs - Cost Distribution

Installation, engineering, design, building and administration costs are treated as a separate expense item, referred to as ”other costs”. Two models, from a NVE report [101] and a FCH report [76], are used to estimate these costs. The detailed content of the categories from these models are uncertain, but both models cover the above-mentioned categories to a large extent. The distribution model from FCH is considered to be most credible, as it is meant for hydrogen production through electrolysis specifically. The NVE model is more general, and used for a variety of technologies related to energy production.

Construction work, for the actual assembly of the electrolysis plant, is not included when using the FCH model [76]. It is excluded because this cost varies depending on the labor of different countries. No data was found for a case similar to the one described here. Whether the NVE model [101] includes this or not is unknown. The total hydrogen cost is a bit higher when this model is used, being 3.86 €/kg compared to 3.75 €/kg for the FCH model (based on AWE, 8 % discount rate and production from all available power). Therefore, construction work is perhaps included. However, as this is very uncertain, it is assumed to be excluded in this thesis. The assembly of the possible hydrogen production plant will probably happen during relatively short time, so that costs related to construction labor will have a very small impact on the total hydrogen price.

Training of personnel and general labor for operating the electrolyzer plant is not considered. This could be included in maintenance costs (OPEX), but is assumed to be excluded in this report. To what extent labor is needed on a fixed basis to operate the facility, during the whole system lifetime, is unknown. In this thesis, this is assumed to be superfluous and therefore not representing high costs. However, this is definitely something that needs to be investigated more thorough if a project is to be carried out.

Considering HSE

The actual costs for administration and installation, specifically, are unknown. Although it is the total value of ”other costs” that is used in cost calculations, and the total sum that affects the hydrogen cost, it could be an idea to consider these two categories separately. As explained in section 2.8, HSE is important to consider. There are no current specific health and safety regulations for hydrogen production in Norway. Therefore, much planning and work needs to be conducted to collect regulatory data from different directorates, and adapt this to the specific project at Hitra. It is therefore likely that HSE related measures and reporting will cause higher administration costs than what is already included.

When all available power is used to hydrogen production, the regulation for major accidents will apply due to accumulated hydrogen from production and storage exceeding five tons. The production will also be defined as *notifiable business*, requiring supervision and reporting every third year. What impact this will have on the administration costs, and total hydrogen cost, is difficult to estimate. For the scenario of production to high-speed crafts only, the regulation for major accidents is avoided as produced and stored hydrogen will be less than five tons at all times. The administration costs in this scenario are therefore probably very small, and probably covered by ”other costs”.

5.6.5 Considering Electricity and Water Costs

Both electricity and water costs depend on consumption, which again depends on production rates. The hydrogen production through the whole lifetime of 20 years is based on the available power calculated from data for 2019. Therefore, the actual water and electricity usage and costs are not entirely precise.

Electricity Costs

Data for electricity costs are collected from a Nasdaq database and Tensio via TrønderEnergi. Projections of the electricity prices for the next ten years are used. There are therefore some uncertainties related to this. In the cost calculations, the average electricity price of 24.57 €/MWh (excluding VAT), is used as a basis. This should take some future increase of the price into account. However, as the price may increase even more, especially after 2030, a sensitivity analysis is conducted for the LCOH at different electricity prices.

Today, hydrogen is exempt from consumption taxes. This reduces the energy price for grid tariffs with 16.13 øre/kWh (0.016 €/kWh). In the future, this exemption can be repealed. If this happens, the hydrogen costs can be affected negatively. Such cases need to be considered, and a scenario where this happens should perhaps be included in a cost calculation. It is unknown to what extent the exemption affects the resulting hydrogen cost.

Water costs

Water costs are calculated based on a consumption of 0.9 liters of water per Nm^3. This value is specified for the Nel Hydrogen electrolyzers, both PEMWE and AWE. However, it is unknown whether this value represent a maximum, minimum or mean value. The value is considered to be a mean value, as other sources also states that the consumption usually lies in the area of 1.0 L/Nm^3 and never higher than 1.7 L/Nm^3 [131]. Anyway, the cost of water has a very little effect on the total hydrogen cost, as seen in figure 35. If the water consumption is set to be a bit higher, the difference will probably not be visible.

The calculations on LCOH are based on the water prices at Hitra, which applies to 2020. The water price is, with other words, said to be fixed and equal every year. This will not be a real case, as the prices are updated regularly, and the consumption depends on production which varies. However, the development is probably having a negligible effect on the hydrogen costs the next 10 to 20 years. Although this is the most likely scenario, it is important to remember that pure fresh water is the most vital resource when producing hydrogen from electrolysis. It is also a lack of fresh water many places in the world today, which makes it important to prioritize the area of applications for this precious resource. Anyway, this is not considered to be a challenge for Hitra.

The value of water, and therefore also the price, have increased steadily since the start of the millennium in European countries. Due to population growth and climate change, there has been high pressure on the renewable fresh water resources in this period. In Norway, the water and sewage systems need renewal in many municipalities. There are estimates showing that this can cause the water prices to increase with as much as 140 % from 2017 to 2040. The price increase will vary between the municipalities. But even with this growth, the costs for water will likely be small compared to other expense items for an electrolysis plant. [132, 133]

5.6.6 Exchange Rates and Inflation

All exchange rates used in this thesis are from January 1, 2020, unless otherwise stated. This is done because of two reasons. Firstly, it is easier to keep control over the conversions that way, and original values can easily be found. Secondly, the exchange rate between the most used rates, as for instance NOK to EUR, have been relatively steady the last five years.

The results from this thesis is based on a project start in 2020. This is done to establish an overview of costs, based on a monetary value that is relatable. However, a project will likely not start before 2024, when the next contract period for the high-speed crafts in Trøndelag starts. The exchange rates at this point of time can be very different, and may have a significant impact on the investment costs, depending on which suppliers that are used. Additionally, inflation must also be considered to give a more precise cost prediction.

5.7 Analyzing LCOH

There are drawbacks and uncertainties with the LCOH equation. First of all the CAPEX is paid upfront the first year. This is not the case in normal business transactions of this scale. It is not normal for a company to have that amount of equity. From a business perspective, the CAPEX should be paid in installments during a set amount of years. This thesis does not cover the economical theory to take into account the loan, which an owner of the electrolysis plant must acquire, in the calculation of the LCOH. Furthermore, there are several running expenses which are assumed constant. These expenses are the OPEX for the components, water cost, electricity cost and stack replacement. In reality, they are not constant and will be a source of error for the levelized cost of hydrogen.

Lifetime

The lifetime of the hydrogen production plant has been set to 20 years. This covers the shortest lifespan between all the components, which is for the electrolyzers. During the system lifetime of an electrolyzer, the cell stacks must be replaced. The chosen stack lifetimes are seven years for PEMWE and ten years for AWE. This means that the two stacks for AWE and three stacks for PEMWE, will have exploited their lifetime during the total lifespan of the hydrogen production plant. In other words, almost every cent used on the stack replacement will be used to the fullest.

Selecting Discount Rate

In calculating the LCOH, a discount rate must be selected. In this thesis there has been chosen three different rates. This is to analyze the effect the discount rate has on the LCOH. The first is 4 %, which represents the lowest risk. It has been selected as the minimum limit by the Norwegian government for state municipal projects [101]. The next percentage is 8 %, which is the most commonly used rate for these types of projects. The last rate is 10 %, which is used as an upper limit. That is because companies which involve themselves in these types of projects normally use discount rates between 7 and 10 %. More detailed analyses on the LCOH are therefore conducted based on a discount rate of 8 %.

5.7.1 LCOH - Full Production

The total CAPEX for the full production scenario came at a price range of 16.50 - 18.38 million euro for AWE and 17.78 - 19.80 million euro for PEMWE. PEM water electrolysis is the most expensive option. Figure 34 gives a clear indication that the electrolyzers are the most expensive equipment. Interestingly does storage take an almost equal share of the total CAPEX for both electrolyzers, being approximately 20 %. This show how expensive storage is. It is interesting to see how little the plot of land cost compared to the other expense items. It has little to none effect on the final costs. The model from FCH [76] differ from project to project, but it gives an indication on what the "other cost" could be. In figure 34, "other cost" is 27 % of the total Capex. This percentage is uncertain, it could be larger or smaller, but it is not unreasonable.

The operational expenses for each year are shown in table 22. As expected the electricity is the largest cost. The OPEX for the components are small compared to the electricity. The stack replacement is also a large expense, almost as much as the electricity. But the replacement will only happen once for AWE and twice for PEMWE, while the electricity will be a yearly expense.

For the scenario of full production the LCOH is calculated to be 3.75 - 3.86 €/kg for AWE and 4.25 - 4.38 €/kg for PEMWE, with a discount rate of 8 %. As expected, judged only by price, alkaline electrolyzer is the best option. At a discount rate of 10 %, the LCOH increases, and it decreases for a rate of 4 %. An observation in table 23, shows the price for alkaline water electrolysis at a rate of 10 % to be cheaper than PEM water electrolysis at a rate of 4 %. This also weighs in the favor of AWE. Another interesting remark is how the degradation off the cells affects the LCOH. When degradation is left out the calculations the LCOH is 3.61 - 3.72 €/kg for AWE and 4.08 - 4.21 €/kg for PEMWE. There is a significant drop at about 0.14 €/kg. This shows how important it is to keep the electrolyzers well maintained. Furthermore it is important to see what the LCOH consists of. Every LCOH analyzed, discussed and referred to from this point forward, is based on a discount rate of 8 % and the FCH model [76].

Figure 35 gives a visual representation of how the LCOH is divided into shares. For alkaline and PEM electrolyzers, the combined CAPEX and OPEX for the components are approximately 35 % and 38 %, respectively. Table 24 gives a better presentation of how the CAPEX and OPEX shares combined, constitutes to the LCOH. The electrolyzers take up a considerable part of the LCOH. PEMWE is again shown to be more expensive than AWE with a difference of six percentage points. From this, the difference in expenses seems even more distinct. This is because of the extra stack replacement for PEM electrolysis. Storage in table 24, is divided into two parts: steel and composite. The important thing to note here, is that the steel containers are meant to store eight tons of hydrogen, while the composite containers are meant to store two tons. The composite containers will store one fourth of the amount that the steel containers will store, but still cost half of the steel containers. This shows expensive the composite containers are, and how expensive storage is in general.

Furthermore, there is a difference in the LCOH shares of compression and filling for the two technologies. This is because of the different output pressures of alkaline and PEM electrolyzers. The cost of the plot and water have little impact on the LCOH with a combined percentage of 1 %. "Other cost" constitutes an almost equal share for both alkaline and PEM water electrolysis, which is to be expected, but this is the post with the most uncertainty. In reality it can be higher or even lower, but it is almost impossible to predict. The largest share of sector diagrams in figure 35 is the electricity cost at approximately 65 % for AWE and 62 % for PEMWE. Based on cost distribution for hydrogen, as explained in section 2.7, it should be between 50 and 70 % of the LCOH. This gives a good indication that the calculated LCOH is reliable.

When the electricity cost constitutes to such an enormous amount of the LCOH, a sensitivity analysis has been conducted, as shown in figure 36. As the electricity price is predicted to rise in the future, a worst case scenario where the price is 40 €/MWh is used as an upper limit. The LCOH was calculated to be 4.93 €/kg for AWE and 5.52 €/kg for PEMWE. This is too expensive for hydrogen produced from water electrolysis. A best case scenario is an electricity price of 20 €/MWh, which was used as a lower limit. This time the LCOH was at 3.40 €/kg for AWE and 3.88 €/kg for PEMWE. This analysis shows how dependent green hydrogen is on the electricity price, as explained in section 2.3. The available power is assumed to be the same every year throughout the lifespan of the plant. This is a parameter not considered in the electricity analysis, which makes it uncertain.

Approximately 23 % of the electricity cost is grid rental. This cost could be avoided if a production plant were to be connected directly to a power producer, such as a wind farm. However, this would add other expenses as for instance transportation, construction and regulation devices. Whether this would result on lower values of LCOH, or not, is unknown.

NPV and Payback Time

The calculated LCOH, gives a good indication on the hydrogen price. Figure 37 shows a net present value analysis of the full production scenario. This graph shows that AWE is the most profitable electrolyzer in this project. At a hydrogen price of 5 €/kg the NPV is approximately 20 million euros for alkaline electrolyzers and 12 million euros for PEM electrolyzers. An uncertainty with this analysis is that it assumes a constant cash flow, which certainly is not the case. The amount of expenses and income will vary greatly during the plants lifetime. It is also an uncertainty related to the selected discount rate at 8 %.

The payback time for the plant has been calculated using different hydrogen prices. The most interesting prices are between 4.5 and 5.5 €/kg, where the payback time is between 4 and 8 years for the simple payback time (SPT), and between 10 and 14 years for the total payback time (TPT). At every hydrogen price, the payback time is one year less for AWE than PEMWE. This is another economical aspect which favors the AWE. Both of these methods assume a constant cash flow, which is a source of error. The cash flow will not be constant during the lifespan of the plant. The difference between the methods is that the TPT takes the time value of money into consideration. This infers a more precise result, but it is still only indicative and not an exact result.

5.7.2 LCOH - Production for High-Speed Crafts

The full production scenario will likely produce more hydrogen than the market demands. A downsized plant where the production is only for the high-speed crafts are therefore a more suitable option. Table 25 shows the values of the CAPEX, both in total and per component. Comparing these expenses to the full production is interesting. When the plant size is decreased by approximately half, the costs are decreased accordingly. One exception is the storage, it has reduced by 60 %. This is because this scenario only have storage with steel containers. The OPEX in table 26 has also decreased by half compared to the full production scenario. The CAPEX and LCOH shares are also almost equal.

The LCOH price range for the high-speed crafts scenario, is 3.72 - 3.84 €/kg for AWE and 4.08 - 4.20 €/kg for PEMWE. This scenario also shows that AWE is the best option from a financial perspective. Comparing the LCOH to the full production scenario, shows that the price for both alkaline and PEM electrolyzers decreases. It is expected that the cost will rise with lower production, not drop off. An explanation, can be that the hydrogen production is the same and not decreasing because of increased energy consumption (degradation). In the scenario of full production, the hydrogen production goes down, because there is not enough energy available to upheld the same amount of hydrogen production. When producing to high-speed crafts only, there is enough energy available to upheld the same amount of hydrogen production, when the degradation occurs. These two methods, that are used to account for the yearly degradation, causes the difference in the resulting values of LCOH. Which one is the most accurate is uncertain.

The price gap between AWE and PEMWE has also been shortened for production to HSCs specifically. An explanation can be that the electrolyzers produce the same amount of hydrogen. Using all available power, on the other hand, the alkaline electrolyzer produce more hydrogen than the PEM electrolyzer, because of different energy consumption. Therefore, with the same amount of produced hydrogen, the price gap between the electrolyzers is shortened.

A NPV and payback time analysis has also been conducted for this scenario. Figure 39 shows that AWE is the most profitable electrolyzer. A hydrogen price of 5 €/kg gives a NPV of approximately 11.5 million euros for AWE and approximately 8.5 million euros for PEMWE. This shows that there are room for profit at reasonable hydrogen prices. The payback times are different in this scenario compared to the scenario of full production. When the hydrogen price is between 4.5 and 5.5 €/kg, the payback time is from 4 to 7 years for the STP and from 10 to 14 years for the TPT.

5.7.3 LCOH Comparisons

One of the reasons to calculate the LCOH is to compare different methods of producing hydrogen, and find out if it is economically viable. Several different sources give an indication on what the LCOH should be, approximately, to be cost competitive. For example, section 2.3 states that green hydrogen has an estimated cost between 3.5 and 5 €/kg, of which every LCOH in this thesis is within. The source can therefore validate the findings. However, this source does not state what is accounted for in the numbers. In this project, construction of a plant producing hydrogen that is ready to be fueled, is taken into account. The source neither states the discount rate and type of electrolyzer.

Figure 24 gives a LCOH of under 3.6 €/kg. It is stated that this LCOH is for AWE, but what else it contains is not known. By comparing this with the calculated LCOH, it is cheaper, by around 0.50 €/kg. This source gives a good indication that the estimated LCOH is dependable. Comparing the LCOH with the estimated prices from DNV GL is another indication that the LCOH is valid. The calculated LCOH is again between the interval, which is 22 - 45 NOK/kg (2.2 - 4.6 €/kg) for AWE and 26 - 51 NOK/kg (2.7 - 5.3 €/kg) for PEMWE. The problem is that it is not stated what these numbers contain, but they give an indication that the LCOH is in the right range.

Figure 23 gives a LCOH of 3.7 €/kg, powered from wind. This is another interesting figure, which the calculated LCOH coincide with. This number contains an energy and electrolyzer cost which are almost equal to the ones used in this project. Another producer of hydrogen, which is Asko, has a cost of 34 NOK/kg [128]. As these costs is in the range of the LCOH, it be concluded that the calculations in this project are reliable.

5.8 Is Hydrogen Produced at Hitra Competitive?

The first and most obvious way of deciding whether the hydrogen can be competitive or not, is to look at the competing alternatives. In this thesis it is chosen to compare the prices of different fuels. The produced hydrogen is considered to be competitive if it can produce the same amount of energy to a propulsion system, as conventional fuels, for approximately the same price. This is a very simple, but probably applicable, idea. Different drivetrains are required for the different fuels, as there are dissimilar components with varying efficiencies involved. This is taken into account when comparing different fuel prices. In addition, the two categories of *road transport* and *high-speed crafts* (including well-boats) are separated.

Based on the efficiencies obtained from various literature, hydrogen systems have higher efficiencies than ICE systems. In the calculations it is found that a FCEV is more efficient than a hydrogen powered boat. It is also found that ICE engines have significantly higher losses of energy than hydrogen systems in general. Calculations conducted for this project show that diesel/MGO systems are somewhat more efficient for HSCs than for road vehicles. This is partially because a high efficiency of 40 % is used in calculations for high-speed craft engines, according to figure 22, and a low efficiency of 30 % is used for engines in road vehicles. However, as these categories are treated and compared separately, and the differences are minor, the comparison in figure 41 gives a useful overview.

The comparison in figure 41 shows that hydrogen has the same costs as diesel and MGO prices today, at hydrogen prices of 64 NOK/kg (6.53 €/kg) and 34 NOK/kg (3.47 €/kg) for vehicles and HSCs respectively. It should be noted that hydrogen is competitive at a higher price for use in road transport, than for use in high-speed crafts. This is due to higher prices for conventional diesel than for MGO, and a significant difference in efficiencies between FCEVs and ICE vehicles.

Results from comparing different fuel prices show that it is not possible to match the price of hydrogen produced at Hitra with with the current price of MGO. A price of 3.47 €/kg is below the best scenario of LCOH, being 3.72 €/kg (alkaline electrolysis and 8 % discount rate). However, it should be possible to deliver hydrogen to high-speed crafts for a price below 50 NOK/kg, or approximately 5 €/kg, which is what other suppliers aim to achieve. Production by alkaline electrolysis is calculated to give a net present value between 7 and 12 million euros (68 to 117 million NOK), with a hydrogen price between 4.5 and 5 €/kg. This is for the scenario with production to HSCs only. Using all available power to hydrogen production, the NPV is the double. For both cases, a payback time of five to ten years is possible, based on simple payback time (SPT) calculations presented in figure 38 and 40. Having this in mind, the hydrogen produced at Hitra can be claimed to be competitive.

It is also likely that hydrogen produced at Hitra can be competitive for trucks and cars. In these cases, the hydrogen must be cheaper than 6.53 €/kg, according to figure 41. But it must be noted that filling stations for trucks are not included in the LCOH calculations conducted in this thesis. Neither is transport costs for the hydrogen that is thought to be sent out from Hitra. Data from the Renewable Energy Cluster and DNV GL show that filling station and transport usually add 1.0 to 1.3 €/kg, each, to the hydrogen price [9, 42]. Based on this, hydrogen is the cheapest alternative when the produced hydrogen has a price below 5.5 €/kg (approximately 1.0 €/kg subtracted from 6.53 €/kg). This applies to filling of trucks at Hitra, or transporting the hydrogen to an existing filling station outside the region. A price below 5.5 €/kg is likely to be possible, based on the NPV values from figure 37.

When transporting the hydrogen to a new filling station, for instance in Trondheim, the hydrogen can be cheaper than conventional diesel for a production price below 4.5 €/kg. This is also possible, but with NPV values lower than 12 million euros. However, hydrogen produced at Hitra will, with relatively high certainty, be cheaper than for instance hydrogen sold for 72 NOK/kg (excluding VAT) at UNO-X. Therefore it can be said that hydrogen is competitive in several cases, especially when compared to other hydrogen prices that applies today. But as described above, this depends on the basis for comparison. It is, for instance, cheaper to use MGO instead of hydrogen when these two alternatives are considered in isolation.

Bio diesel is a fuel that usually has a very low climate footprint, and can be considered as an alternative to MGO and conventional diesel for road transport. From figure 41 it is evident that bio diesel is more expensive than conventional fuel for both road transport and high-speed crafts. Hydrogen is therefore likely to be a more competitive alternative for both cases, for production costs found in this thesis.

5.8.1 Competitiveness Due to Environmental Benefits

One of the main reasons to look at hydrogen in the transport sector, is that hydrogen powered modes of transport have zero TTW emission and are generally related to low emissions. For the high-speed craft connection between Trondheim and Kristiansund, there is also a wish for emission free solutions. With the current technologies, this leaves two possible propulsion systems: battery electric or fuel cell electric. Even though both technologies give no tailpipe emissions, the lifetime impacts of all system components must be considered in order to give a total picture of environmental impacts. For this, a WTW and LCA analysis need to be carried out for the specific scenario, which is outside the scope of this thesis. However, probable amounts of emissions found from reviewing literature should be discussed to give an overview.

Figure 22 illustrates a simple WTW analysis, comparing battery, hydrogen and MGO propulsion systems. From this figure, it is evident that battery and hydrogen systems are related to much lower emissions than MGO. However, LCA emissions from producing equipment is excluded in this figure, which makes it a little imprecise. Hydrogen scaling up has done a similar WTW analysis, covering the lifetime of different components. Figure 21 illustrates this, where internal combustion, battery electric and fuel cell electric vehicles are compared. Even though this is for land transport, it is transferable to boats and high-speed crafts. The figure shows that WTW emissions are quite equal for BEVs and FCEVs, when the total lifetime is considered: both having about 70 grams of CO_2 equivalents per kilometer. From this, battery and hydrogen propulsion can be said to have approximately the same, small, global warming potential. Further, it must be noted that there are other categories than GWP value that affects climate and environment that are not included in these examples.

Even though batteries and hydrogen are two energy carriers, which seem to have relatively equal emissions, there are some disadvantages with battery systems. For instance, batteries are heavy and their charging time is significantly higher than the refueling time of hydrogen or conventional fuels. Because of this, batteries are probably not very relevant for the high-speed craft connection between Trondheim and Kristiansund, or such maritime transport in general. As long as large storage volumes can be handled, hydrogen can be regarded as more competitive. On the other hand, hydrogen as an energy carrier requires more components than battery systems. This can make both hydrogen drivetrains, and value chains in general, more vulnerable than battery operation.

The emission factor for electricity produced in Norway is 18.9 g $CO_{2,eq.}$/kWh according to NVE [96]. From this, it will be possible to save approximately 14.8 tons of CO_2 equivalents for the high-speed craft connection between Trondheim and Kristiansund, each day, if hydrogen replaces the marine gas oil. This calculated value does, however, not include emissions from producing the components. Neither does it include emissions from refining and transport of MGO to the location of bunkering. This will add some more emissions for the use of both hydrogen and MGO. But the ratio between the emissions are likely in the correct order of magnitude, which means that the saved emissions should give a correct overview. Another factor to consider is the sulfur content of MGO, which is higher than what is permitted for land transport. Emission of sulfur dioxide from combustion is harming for both environment and human health. This will be entirely removed if MGO is replaced by hydrogen, which is a big advantage. [23]

There are some uncertainties related to the theory that is used to establish the overview of emissions, as for instance which electricity mixes that are used in the WTW examples. As electricity produced at Hitra, and in Norway in general, has a low emission factor, the hydrogen produced by electrolysis here will have low emissions. The lifetime emissions of electrolysis are very dependent on the source of the electricity consumed during operation. In some cases, this can contribute with more than 80 % of the total lifetime emissions. According to figure 20, and based on a Norwegian power mix of hydro and wind power, hydrogen produced at Hitra is likely to have a GWP value of less than 5 kg of CO_2 equivalents per kilogram of produced hydrogen. This does not take the usage of hydrogen into account. However, the hydrogen can be defined as a climate friendly fuel based on this, as the major part of the total GWP value is a result of the electricity consumption for hydrogen production.

With all this in mind, and the requirement of emission free transport, hydrogen can be a very good candidate to replace other fuels. Considering both the levelized costs of hydrogen found in this thesis, and the above-mentioned environmental benefits, hydrogen can be argued to be a competitive fuel for the regional maritime sector at Hitra. However, the data, information and results presented in this thesis are based on thought scenarios. Many factors can differ if a real project like the one described is to be carried out. This can affect the feasibility.

5.9 Argumentation for Hydrogen Production at Hitra

It is important to look at related costs and environmental aspects, but also the general benefits, of being a new producer of hydrogen. Hitra can be known as a central location in a newly established hydrogen community in Norway. As a consequence, maybe even more people will be aware of Hitra and look to the region for inspiration. A new production facility could mean growing wealth creation in the region. The profits of selling hydrogen also play an important role in the big picture.

New Contract Period for High-Speed Craft Connections

In 2024 the new contract period for the HSC connections in Trøndelag may start. No decisions for where the ferries will refuel hydrogen, or charge batteries, have been made yet. It is therefore very important for Hitra to be active in the process and showcase the opportunities for hydrogen production at this location. Another report has also pointed out Sandstad, at Hitra, as the only place with both available area and power for hydrogen production, for the ferry connection between Kristiansund and Trondheim [25]. In other words, Hitra has a big opportunity to be a hydrogen supplier for the high-speed crafts between Kristiansund and Trondheim.

Aquaculture Industries as Important Collaborators

The salmon industry at Hitra is of great interest, as it contributes to the international trademark *Norwegian Salmon* and is considered a significant part of the Norwegian export. The drawback is the considerable amount of GHG related to the industry. If Hitra decide to produce hydrogen, the region has a unique opportunity to push the industry into a cleaner operation. It is here important to remember the *chicken and egg dilemma* analogy. As long the conventional fuel for well-boats is competitive, the industry will not strive for another option. It is therefore important to present an option with the benefits of competitiveness and renewable production.

Hitra could also benefit from the byproducts from electrolysis. Oxygen and waste heat can be used directly in the aquaculture industry. Local access to these, important, resources, could be beneficial for the salmon industry. Hitra would also gain from this collaboration, in a financially way. In the thesis this aspect has not been looked into, but can possible reduce the hydrogen price.

Growing Industry at Hitra

For land transport, only trucks related to the salmon industry have been considered in this thesis. However, other industries may also use hydrogen for road transportation. With an expanding industry at Jøsnøya, the potential for hydrogen powered trucks and cars can also grow. If Hitra would expand a possible hydrogen market, the new established industries could therefore be potential collaborators. On the other hand, the only way from Hitra to the mainland is through a tunnel and one somewhat unsafe road (Fylkesvei 714). This road has a limited capacity, which could counteract an increased number of trucks. A possibility is to consider to use maritime transport as a replacement. For the purpose of this thesis, no research is done on this subjects. However, it is important to have an overview of the consequences of growing industry and the potential that may be brought with it.

6 Conclusions

The objective of this study is to give an overview of costs and opportunities for hydrogen production at Hitra. In addition, it is meant to describe some advantages and challenges related to production and use of hydrogen, both in general and for maritime transport specifically. The ambition appears through the research question, which reads as follows:

"Can Hitra — having access to local wind energy — produce competitive hydrogen for the regional maritime sector?"

The methodology used to answer this is mainly based on literature review. Cost data is obtained from various sources and adapted to the specific cases for this thesis. CAPEX, OPEX and cost distribution is found for an electrolysis plant using PEM or alkaline water electrolyzers. A lifetime of 20 years is set as a basis for the production plant, which produce compressed hydrogen as this is the most mature type of storage today. In order to make the results credible, they are compared with information from various reports. However, there are discrepancies in cost data from different sources, making it difficult to establish a correct overview of the costs. Therefore, assumptions have been made. The findings presented here should be considered as indicative and not exact.

The results are generated for two different cases. The first case involves using all the available power from the transformer at Sandstad to produce hydrogen. 10 MW of electrolyzers is thought to cover a demand for high-speed crafts, some trucks transporting salmon out of Hitra and one well-boat per week. In addition, some residual hydrogen is assumed. It must be noted that there are uncertainties related to the magnitude of the demand for these end users, although some probable values are set in order to size the facility. The second case involves producing hydrogen to HSCs specifically, from 5.5 MW of electrolyzers. This case is established, because high-speed crafts are likely to be the first end users having a demand for hydrogen of a relevant magnitude.

An electrolysis plant at Hitra is feasible, and can deliver competitive hydrogen to the regional maritime sector, depending on the basis of comparison. It is also possible that the energy source can be renewable energy from wind power. When it comes to type of electrolyzer, alkaline is found to be the most competitive alternative based on price. But PEMWE is regarded as the best option when the technology and efficiency are seen in isolation. It can keep a stable production rate even though the load is varying, without the risk of destruction or need for much maintenance, unlike an alkaline electrolyzer. In an overall evaluation, based on the cost levels, technology and general conditions at Hitra, alkaline electrolysis is considered to be the best option.

Exploiting all available power to hydrogen production, it is possible to produce approximately 1700 and 1580 tons of hydrogen each year, for alkaline and PEM electrolysis respectively. This conclusion is based on an uptime of 98 % and responds to an average production rate of approximately 4.7 tons per day for AWE, and 4.3 tons per day for PEMWE. When the production is meant to cover the demand for high-speed crafts only, a daily production of 2.5 tons, equal to approximately 900 tons per year, is set as a basis. The demand is likely to be lower, due to improved technology and ship design in the future. However, this will not have a significant effect on the hydrogen cost as the production size will be reduced accordingly.

The levelized cost for hydrogen is found to be within 3.72 to 3.86 €/kg (36.4 to 37.8 NOK/kg), for alkaline electrolysis with a discount rate of 8 %. This applies to the case using all available power, and the case with production to HSCs only. It reflects the cost of hydrogen that is ready for bunkering in a high-speed craft. The LCOH is somewhat uncertain, but from comparing with other values and typical cost distributions from literature, it is concluded to be in the correct order of magnitude.

From comparing different fuel prices, it turns out that it is not possible to produce hydrogen that is cheaper than MGO at Hitra. MGO, which is the fuel used for the HSC connection between Trondheim and Kristiansund today, is very cheap. Looking at prices only, hydrogen needs to be cheaper than the

LCOH found in this thesis in order to be competitive. However, other potential suppliers expect to be able to deliver hydrogen to high-speed crafts for 5 €/kg or less (less than 50 NOK/kg), excluding VAT. It is very likely that hydrogen produced at Hitra can reach prices below this. For instance, a price of 4.5 to 5.0 €/kg can give a net present value between 7 and 12 million euros (68 to 117 million NOK). This corresponds to a payback time of five to six years, and applies to the scenario with production from alkaline electrolysis to HSCs only. When using all available power, the NPV is higher. From this, it is concluded that hydrogen produced at Hitra can be competitive for the regional maritime sector. The hydrogen is also likely to be cheaper than the conventional fuel used for trucks and cars, both when refueling at Hitra Harbor or other places in the region.

Another aspect that is looked into in order to respond to the research question is the environmental effects of hydrogen from Hitra. Hydrogen gas has a huge advantage over MGO and other fossil fuels when it comes to emissions of greenhouse gases. If hydrogen is to replace MGO, the tailpipe emissions from the high-speed crafts will drop to zero. Taking into account that there is a small emission factor from Norwegian electricity, the emission savings from the HSC connection (Tr-Kr) can be 14.8 tons of CO_2 equivalents per day. Similar savings will apply to land transport as well, making hydrogen produced at Hitra competitive due to environmental benefits.

Hitra is also a good location for hydrogen production, because of the significant maritime traffic in the region. As Sandstad at Hitra is the midpoint of the high-speed craft connection between Trondheim and Kristiansund, a production facility here will be centrally located. In addition, the region is experiencing a growth in industry, especially within aquaculture. In the long term, this industry can represent a high demand for hydrogen, which can be used by, for instance, well-boats and other smaller vessels. With other words, Hitra definitely has the opportunity of being in the forefront of applying hydrogen to the maritime transport sector.

7 Recommendations and Future Work

The thesis was written during one semester at university, and the duration limited the scope of the thesis. Some aspects are therefore not included, but can be of great interest. The following section is written to add some further comments to the report, and will also include some recommendations for future work. A second section will look into some aspects which are likely to be important for the growing hydrogen market in Norway in general, for the years to come.

7.1 Recommendations for Hitra

The work in this thesis shows that Hitra can produce hydrogen for the regional maritime sector, at a competitive price. The costs and available power were given with some uncertainties, and a more advanced analysis is recommended for some parts of the calculations to give more accurate results. However, the results are considered credible and can be used to argue for hydrogen production at Hitra. In addition to the work presented in this thesis, more analyses are recommended before a production plant is to be built.

Area Footprint and Location of Production Plant

An overview of the size of the plant can be important in the planning period. Based on the calculated footprints done in the thesis, presented in table 30, the results are 1950 m^2 and 2175 m^2 for AWE and PEMWE, respectively, in the case where all available power is used. In the case where only the demand for high-speed crafts is covered, the total areas are 1150 m^2 and 1305 m^2 for AWE and PEMWE, respectively.

Table 30: Area footprint distribution for production plant.

m^2	All available power		Power for high-speed crafts only	
	AWE	PEMWE	AWE	PEMWE
Electrolyzer	675	900	325	480
Compression and filling	375	375	375	375
Storage	900	900	450	450
Total	1950	2175	1150	1305

A visualization in figure 42 is made to give a useful presentation of a total, possible, footprint at Hitra Harbor, not a suggestion for an actual location. The areas are given by alkaline electrolysis, where the two colors represent the two cases of production. The illustrations show all area footprints added to make two rectangles. However, the different components as storage, piping and filling are likely to be located at different places, but in the same area. It is important to note the scale of the map, where the blue line corresponds to 50 m.

Figure 42: Total area footprint given by AWE, location Hitra Harbor. Based on a screenshot from Norgeskart made by Kartverket. [134]

Figure 42 shows only the footprints of the components. Required safety distances are not considered, and due to lack of health and safety regulation for hydrogen projects in Norway, none estimated are given. However, it is reasonable to believe the safety distance is of considerable magnitude and it is recommended to take a deeper look at what the regulations would mean for the location of plant. The actual location is determined by the total area, but also by the place of filling. Costs related to transportation of hydrogen from production plant to filling area or pipelines are desire to be as small as possible. For maritime transport, a hydrogen plant close to the harbor is therefore the best. If the hydrogen would also be delivered to trucks or stored in mobile storage vessels, turning area must also be considered. Even if the plant would produce hydrogen for high-speed crafts, some sort of turning area is necessary in case of maintenance.

Coordination of Production with the Schedule of the Operators

If well-boats, high-speed crafts or other ships were to bunker at Hitra, the logistics will be very important to consider. The production needs to be coordinated with the demand. At the time of bunkering, the available hydrogen in the storage tanks needs to cover the demand. If not, the schedule of the high-speed crafts/well-boats will be delayed, which is certainly not wanted. Another parameter is the filling time, mostly determined by the pressure in the storage tank. With a higher pressure right before filling, the filling time will be reduced. This could be especially important of the HSCs with a tight schedule. For this purpose it is therefore recommended to obtain an overview of the schedules of the operators, and coordinate the production accordingly.

For all types of boats with a schedule, the delivery reliability is important. All delays must be avoided. It is therefore important in case of downtime, to have easy access to a buffer tank. It is important for Hitra to decide how high the delivery reliability can be in their case as a hydrogen supplier. In addition, it is important to considered the regulation for major accidents (Storulykkeforskriften), if the amount of hydrogen exceeds five tons.

Analysis of Shipping Lane - Opportunity for Expansion

For the purpose of this thesis only high-speed crafts and well-boats were considered. However, the potential may cover a much wider market. For Hitra to deliver hydrogen to any maritime vessels in the shipping lane, Hitra must produce an enormous amount of hydrogen. In that case, hydrogen is most likely to be stored as liquid hydrogen, not compressed. Even though this only may be relevant for the longer term, an overview of the potential market can be a motivation for establishing a hydrogen production plant of considerable size. By use of the website *Kystdatahuset*, an overview of the number of boats/ships sailing through the shipping lane can be generated, as shown in figure 43. In this figure, a crossing line (red line) has been made, and every boat/ship crossing that line within the chosen time period is counted. The line is located northeast of Sandstad in Trondheimsleia. In the analysis, maritime vessels with a length under 24 m is excluded as they are categorized as pleasure boats, and the number is strongly depended on the season and weather. [135]

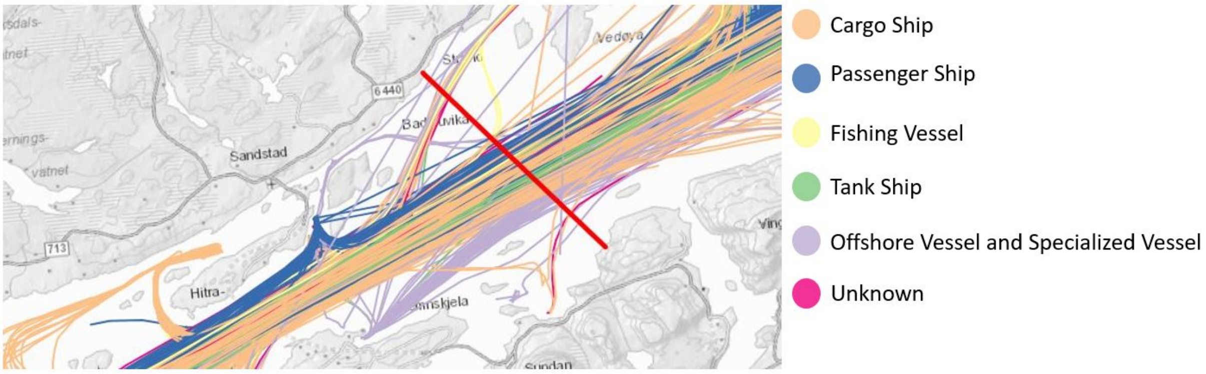


Figure 43: Analysis of Trondheimsleia. Screenshot from Kystdatahuset, the labels are made afterwards [135].

The analysis in figure 43 shows the number of vessels in the time period of April 2019 - May 2019. In total, there are 1 504 vessels, where 794 of them are cargo ships and 281 of them are passenger ships. A deeper analysis shows that the fishing industry runs 347 of the boats (well-boats, fishing vessel, fish farm support vessel), where 176 of them are well-boats. *Kystdatahuset* can also provide with statistics over other types of ships, including what time of day the vessels are crossing the crossing line. A more thorough analysis of the traffic should be done to get an overview of possible maritime users of hydrogen. [135]

Analyzing Impacts on Climate - LCA

This thesis gives some glimpses of general climate impacts from hydrogen production and usage. However, it does not provide a total analysis of the possible scenarios at Hitra specifically. In order to give an entirely correct overview of the environmental benefits and challenges for hydrogen production at Hitra, a comprehensive LCA should be implemented. This LCA should also include other impact categories than GWP. A thorough well-to-wake analysis should also be considered for HSCs powered by hydrogen from Hitra, and compared with use of batteries or MGO. This will probably give a better understanding of the actual climate impacts of hydrogen in the regional transport sector.

7.2 Future Work for the Norwegian Hydrogen Market

The Norwegian economy is strongly dependent on oil. When the oil price goes down, the same does the Norwegian currency as shown in figure 32. Norway is in a unique position to slowly out-phase the large support pillar that oil is, and diversify the economy. A market that is slowly building potential and has been explored thoroughly in this thesis, is the hydrogen market. As stated in the introduction, Norway should start producing hydrogen with wind farms in remote locations, to fully utilize the 1000 TWh/y wind power potential. There should be more projects like Haelous, to demonstrate the technology. Even though green hydrogen is on the rise, the largest proportions of the hydrogen production in Norway comes from industries. CCS should be installed at fabrics where hydrogen is produced as byproduct, and make the grey hydrogen blue. If the CCS is good enough, maybe the CO_2 emission will almost be as low as for green hydrogen. The government should make CCS mandatory for the industries with hydrogen production.

Liquid storage

When it comes to storage of hydrogen, compressed hydrogen is the only economical viable option at the moment. When the demand of hydrogen increases, liquefaction should become the general consensus, when it comes to storage. This will require large production sites, with at least ten tons of hydrogen per day, to be economically viable. The larger the production volume the cheaper the liquid storage will be per kilogram. As liquid hydrogen is costlier, this will infer that the hydrogen will be more expensive. As discussed in section 2.5, there is a huge development in the liquefaction technology, with the energy required to liquefy hydrogen slowly decreasing and closing in on the theoretical minimum. This will probably decrease the cost in the future. As of today there are none liquefaction plants in Norway, but there are plans for the future, with Equinor at Tjeldbergodden and Gasnor in Kvinnherad.

Safety

The safety standards at hydrogen production plants and filling depots are high. A good example is the accident at a Uno-X station in Sandvika, causing only minor injuries. The problem is that there are none safety regulations which cover all sides of hydrogen production and consumption. To make the process of building a production plant easier, there should be made one specified safety and regulation act, which covers only hydrogen. Another problem is that there are no specified safety distance tables for hydrogen sites, they are currently based on other substances. The safety distances is therefore situational based and gives companies extra administration work, when building hydrogen sites. The DSB does not have the statistical data to make a certified safety distance table. These two reasons are why the government, with the DSB, should establish a plan for safety and regulation act for hydrogen. This may also help to make the the hydrogen cheaper, because of lower administration costs.

Raising the Awareness of Hydrogen

A problem hydrogen is facing, is that not many people care about hydrogen in the general public. The media coverage is low and it is rarely mentioned in politics. Enova has already given patronage to Hywind Tampen, with several hundred millions. This created a little media storm. If support from Enova were to be given a hydrogen project, this will probably help the hydrogen market grow. Other ways to increase support for hydrogen, is by lowering taxes and fees which affects hydrogen production. This will make the hydrogen cheaper and a more attractive solution to fossil fuels. There should also be implemented more taxes and fees on existing fuels. Fuels for maritime transport, as marine gas oil, should be covered by more taxes, because it is extremely cheap and difficult to compete with. Another good measure is to expose the Norwegian public with hydrogen vehicles, for example hydrogen buses and cars.

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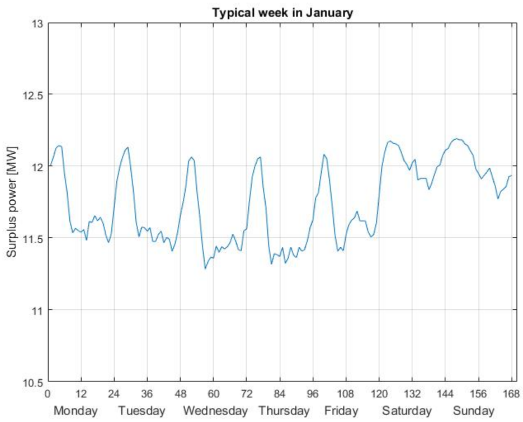
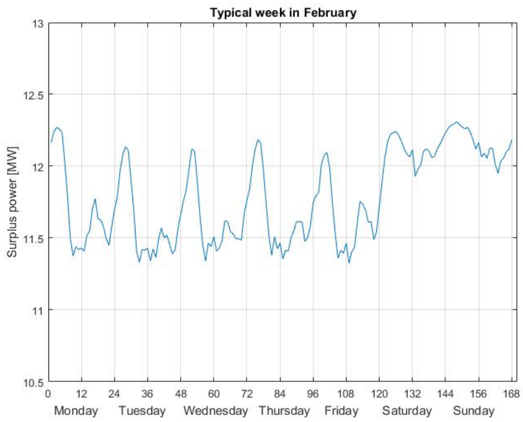
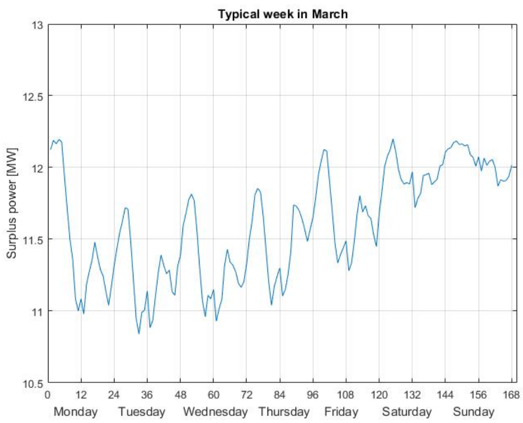
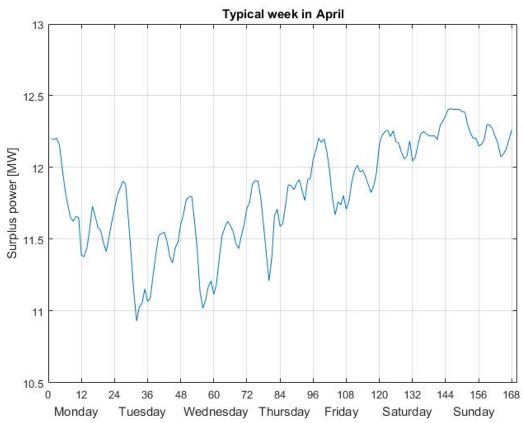
Appendix A

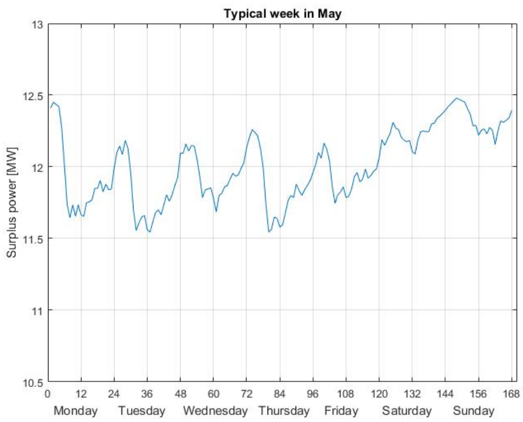
Available Power for Hydrogen Production

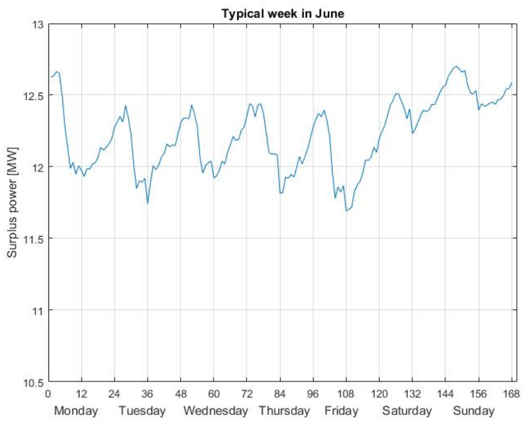


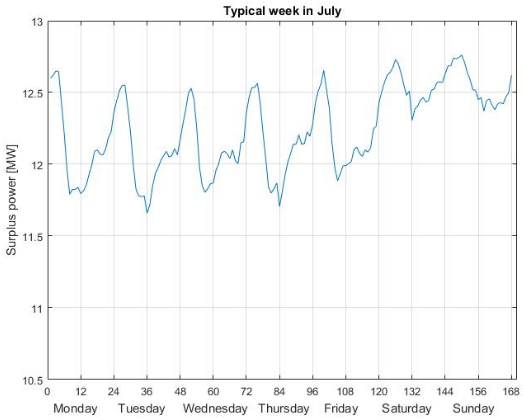




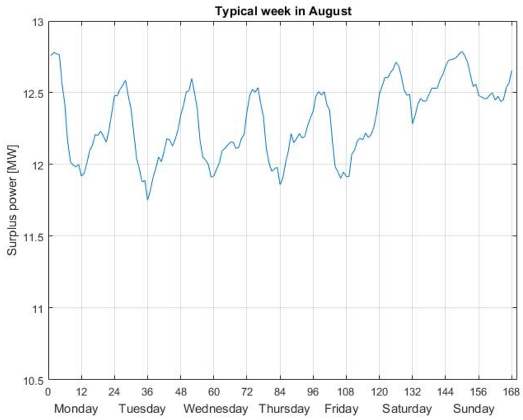




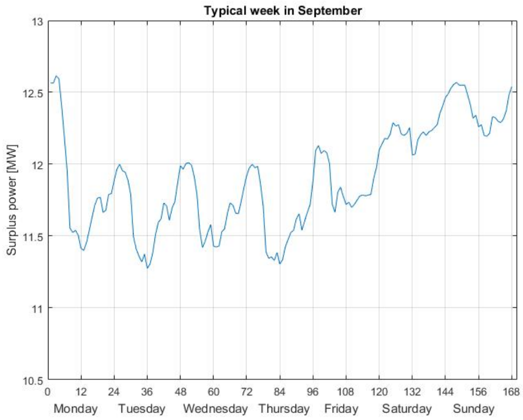




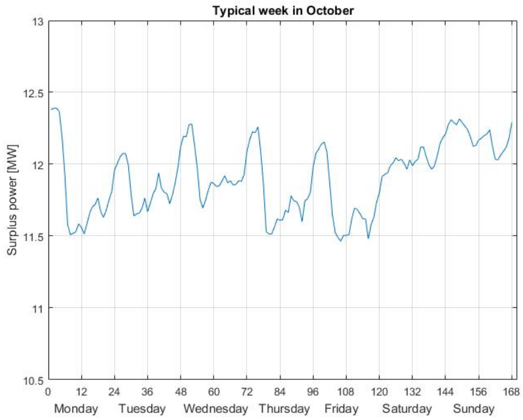
Typical week in July
Surplus power [MW]
Monday Tuesday Wednesday Thursday Friday Saturday Sunday



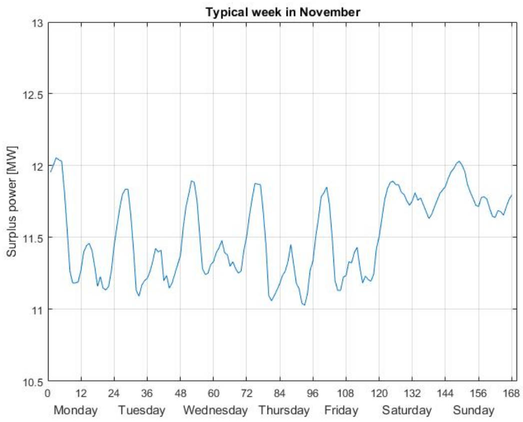
Typical week in August
Surplus power [MW]
Monday Tuesday Wednesday Thursday Friday Saturday Sunday



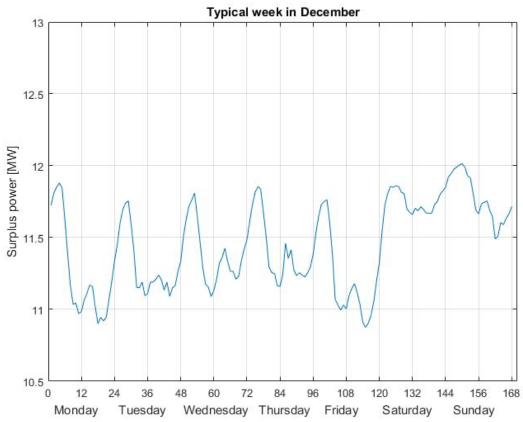
Typical week in September
Surplus power [MW]
Monday Tuesday Wednesday Thursday Friday Saturday Sunday



Typical week in October
Surplus power [MW]
Monday Tuesday Wednesday Thursday Friday Saturday Sunday



Typical week in November
Surplus power [MW]
Monday Tuesday Wednesday Thursday Friday Saturday Sunday



Typical week in December
Surplus power [MW]
Monday Tuesday Wednesday Thursday Friday Saturday Sunday

Appendix B

Specifications for Relevant Electrolyzers

Table B1: Specifications for electrolyzers from different suppliers. Colored cells contain data sourced directly from the respective company. White cells contain calculated data. Single numbers represent average or nominal values, and intervals represent minimum and maximum values.

Company/ supplier	Type and model	Production rate/flow rate [Nm^3/h]	Production rate/flow rate [kg/h]	Daily production[1] [kg/day]	Input power [MW]	Energy consumption[2] [kWh/kg]	Output pressure[3] [bar]	Source
Hydrogenics	Alkaline: HySTAT®-100-10	100	8.8	212	0.5	56.8	10	[131]
Hydrogenics	PEM: HyLYZER®-1,000-30	1000	88	2112	5	56.8	30	[131]
Hydrogenics	PEM: HyLYZER®-5,000-30	5000	440	10 560	25	56.8	30	[131]
Nel Hydrogen	Alkaline: A300	150 - 300	13.2 - 26.4	316.8 - 633.6	0.66 - 1.32	43.2 - 50.0	1 - 200	[13]
Nel Hydrogen	Alkaline: A485	300 - 485	26.4 - 42.7	633.6 - 1024	1.32 - 2.13	43.2 - 50.0	1 - 200	[13]
Nel Hydrogen	Alkaline: A1000	600 - 970	52.8 - 85.4	1258 - 2049	2.64 - 4.27	43.2 - 50.0	1 - 200	[13]
Nel Hydrogen	Alkaline: A3880	2400 - 3880	211 - 341	5064 - 8185	10.6 - 17.1	43.2 - 50.0	1 - 200	[13]
Nel Hydrogen	PEM: M200	207	18.2	437	0.938	51.5	30	[13]
Nel Hydrogen	PEM: M400	413	36.3	872	1.87	51.5	30	[13]
ITM Power	PEM: HGas2SP	256	22.5	540	1.34	59.6	20	[136]
ITM Power	PEM: HGas3SP	384	33.8	810	2.01	59.7	20	[136]
McPhy	Alkaline: McLyzer 200-3	200	17.6	422	1.00	51.14	30	[137]
McPhy	Alkaline: McLyzer 400-3	400	35.2	844	2.00	51.14	30	[137]
McPhy	Alkaline: McLyzer 800-3	800	70.4	1690	4.00	51.14	30	[137]

[1] One day = 24 hours.
[2] Average value for PEMWE from Nel Hydrogen. Value for nominal flow for electrolyzers from Hydrogenics and McPhy.
[3] Output pressure for AWE from Nel Hydrogen includes external compression.

Appendix C

Hydrogen Production

Hydrogen production without and with limitations are presented in table C1 and C2, respectively. Limitations are defined as 98 % electrolyzer usage and 12 MW limit for energy harnessing. Both tables give data for alkaline and PEM electrolysis, where column two and three give monthly and total production. In column four and five the monthly production is divided by the respective number of weeks to find the average production for a week.

These data are generated by a code made in MATLAB, based on consumption data received by TrønderEnergi. The code divides the input data into months, where the number of weeks in each month are set to either four or five. The months with five weeks are January, June, August and November, while the months with four weeks are February, March, April, May, July, September, October and December. This distribution gives 52 weeks. Unfortunately this makes column two and three not fitted for comparison. Column four and five are better for this purpose.

Table C1: Hydrogen production without limitations.

	AWE	PEMWE	AWE	PEMWE
	Per month [ton]		Per week [ton]	
January	166.72	156.12	33.34	31.02
February	133.88	124.56	33.47	31.14
March	131.71	122.54	32.93	30.63
April	134.22	124.88	33.56	31.22
May	136.37	126.87	34.09	32.72
June	173.49	161.42	34.70	32.28
July	139.05	129.38	34.76	32.34
August	174.72	162.56	34.94	32.51
September	135.11	125.70	33.77	31.43
October	135.18	125.77	33.80	31.44
November	163.52	152.14	32.71	30.43
December	129.96	120.91	32.49	30.23
Total	1753.93	1632.85	-	-

Table C2: Hydrogen production with limitations.

	AWE	PEMWE	AWE	PEMWE
	Per month [ton]		Per week [ton]	
January	162.75	151.42	32.55	30.28
February	130.52	121.44	32.63	30.36
March	128.72	119.76	32.18	29.94
April	130.10	121.05	32.53	30.26
May	132.03	122.84	33.01	30.71
June	166.32	154.74	33.26	30.95
July	133.08	123.82	33.27	30.95
August	166.52	154.93	33.30	30.99
September	130.85	121.74	32.72	30.43
October	131.70	122.53	32.92	30.63
November	160.15	149.00	32.03	29.80
December	127.28	118.42	31.82	29.60
Total	1700.02	1581.69	-	-

Appendix D

Route Information for Trondheim - Kristiansund Today

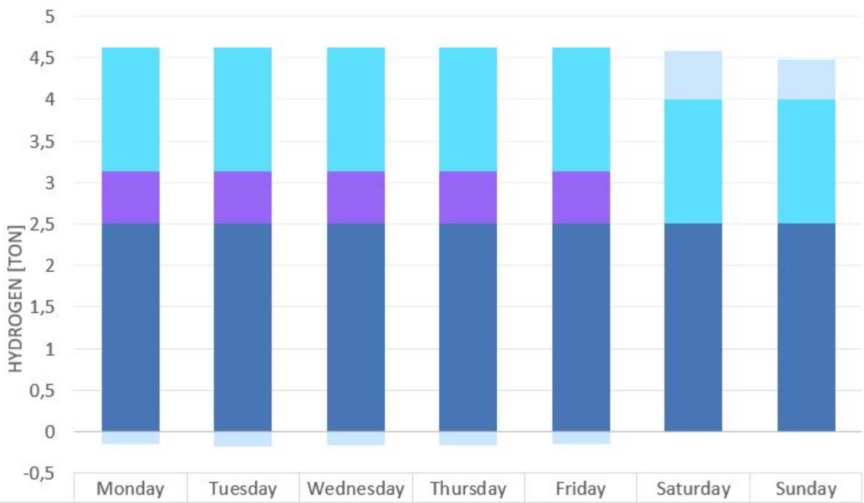
Table D1 shows departure and arrival times for the current high-speed craft connection between Trondheim and Kristiansund. It also shows where the two boats operating the route are located at night. The table is obtained from [25], with information from AtB.

Table D1: Current route information, with departure and arrival times, for the high-speed craft connection between Trondheim and Kristiansund (800/805). This route information applies to weekdays. [25]

	Boat 1	**Boat 2**
Location for night	Brekstad	Edøy
Departure	Trondheim - 08.10	Kristiansund - 08.00
Arrival	Kristiansund - 11.40	Trondheim - 11.25
Resting	20 min.	50 min.
Departure	Kristiansund - 12.00	Trondheim - 12.15
Arrival	Trondheim - 15.35	Kristiansund - 15.40
Resting	55 min.	50 min.
Departure	Trondheim - 16.30	Kristiansund - 16.30
Arrival	Kristiansund - 20.00	Trondheim - 20.00
Location for night	Edøy	Brekstad

Appendix E

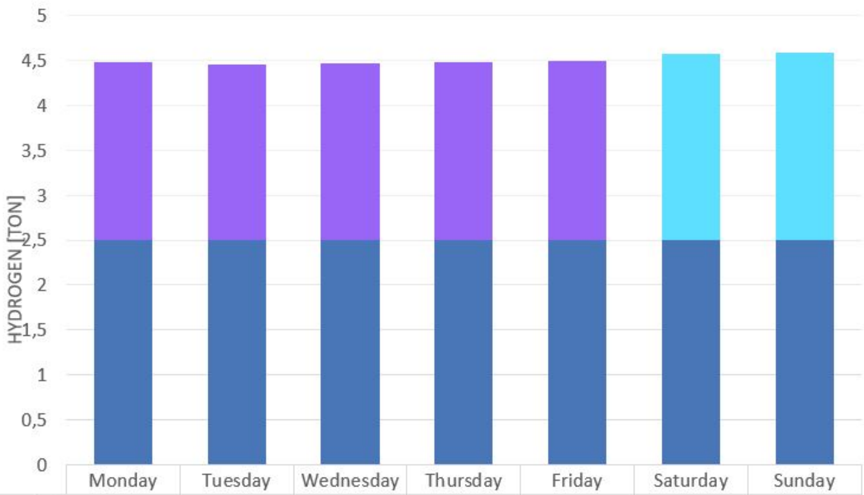
Hydrogen Distribution: Two High-Speed Crafts (Tr-Kr), Two Well-Boats and 63 Trucks per Week



	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
Residual	-0,1541	-0,1755	-0,1617	-0,1582	-0,1428	0,574	0,4791
Well boat	1,5	1,5	1,5	1,5	1,5	1,5	1,5
Trucks	0,63	0,63	0,63	0,63	0,63		
HSC	2,5	2,5	2,5	2,5	2,5	2,5	2,5

Figure E1: Hydrogen distribution for two high-speed crafts, two well-boats and 63 trucks per week

Hydrogen Distribution: Two High-Speed Crafts (Tr-Kr) and Trucks Monday to Friday



	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
Residual						2,074	2,0791
Trucks	1,9759	1,9545	1,9683	1,9718	1,9872		
HSC	2,5	2,5	2,5	2,5	2,5	2,5	2,5

Figure E2: Hydrogen distribution for two high-speed crafts and trucks

Appendix F

Currency Rates Used in Calculations

Table F1 gives an overview of the most common currency rates that are used in this thesis. All currency conversions are conducted for average rates from January 1, 2020 (01.01.2020), with the exception of conversion to/from British Pounds (GBP) which are done for specific dates/years. The exchange rates have been stable from 2015 to 2020, and the averages are close to the rates from January 1, 2020, for all relevant currencies with the exception of GBP.

Table F1: Currency rates used in calculations. From 01.01.2020. [115]

	NOK	EUR	USD
1.00 NOK	1.00	0.102	0.114
1.00 EUR	9.78	1.00	1.12
1.00 USD	8.74	0.893	1.00

Appendix G

CAPEX for AWEs and PEMWEs

This section presents cost data for both PEM and Alkaline water electrolyzers, obtained from different sources. CAPEX is given in different tables for total system costs, including the costs for cell stacks, power electronics, gas conditioning and Balance of Plant (BoP). Some sources give the costs for scenarios including installation, building, designing and engineering, and other sources give data for scenarios where these costs are excluded. Both scenarios are shown in this appendix, where non-material costs as installation, building, design, engineering and administration are defined as ”other costs”. Several reports have also given estimates for future costs, which are also presented here.

As the costs provided by the different sources are given in different currencies, all currencies are converted to Euro (€, EUR) according to appendix F.

CAPEX for Alkaline Water Electrolyzers

Table G1 and G2 compares CAPEX estimates for alkaline water electrolyzers, including ”other costs”, for *current* and future technology respectively. CAPEX estimates for alkaline electrolyzers, excluding ”other costs”, are shown in table G3 and G4 for *current* and future technology respectively. *Current* is defined by the year in the column named "Data from (year)", which is the actual year of the respective costs. Future costs are estimates for 2025 or 2030.

Table G1: *Current* CAPEX for AWEs. Including ”other costs”.

Value [€/kW]	Data from (year)	Source
830	2017	[76, p. 46]
1000 - 2000	2014	[62, p. 3]
1000 - 1200	2017	[39, table 8]
740 - 1300	2015	[78, p. 28, 56]
1000 - 1200	2014	[138, p. 13]
Average: 1110 €/kW		

Table G2: Future (2025/2030) CAPEX for AWEs. Including ”other costs”.

Value [€/kW]	Data from (year)	Source
600	2017	[76, p. 46]
900 - 1400	2014	[62, p. 3]
370 - 850	2014	[138, p. 13]
Average: 787 €/kW		

Table G3: *Current* CAPEX for AWEs. Not including ”other costs”.

Value [€/kW]	Data from (year)	Source
384	2011/2015	[116]
447 - 1250	2018	[10, p. 44]
600	2016	[121, p. 103]
441	2015	[119, table 2]
653	2019	[119, table 2]
Average: 585 €/kW		

Table G4: Future (2025/2030) CAPEX for AWEs. Not including ”other costs”.

Value [€/kW]	Data from (year)	Source
268	2011/2015	[116]
357 - 759	2018	[10, p. 44]
360	2016	[121, p. 103]
Average: 396 €/kW		

CAPEX for PEM Water Electrolyzers

Table G5 and G6 compares CAPEX estimates for PEM water electrolyzers, including ”other costs”, for *current* and future technology, respectively. CAPEX estimates for PEM electrolyzers, excluding ”other costs”, are shown in table G7 and G8 for *current* and future technology respectively. *Current* is defined by the year in the column named "Data from (year)", which is the actual year of the respective costs. Future costs are estimates for 2025 or 2030.

Table G5: *Current* CAPEX for PEMWEs. Including ”other costs”.

Value [€/kW]	Data from (year)	Source
1300	2017	[76, p. 46]
1500	2016	[121, p. 103]
1860 - 2320	2017	[62, p. 3]
1900 - 2300	2017	[39, table 8]
1300 - 3290	2015	[78, p. 28]
2230	2018	[139, p. 7]
1860 - 2320	2014	[139, p. 13]
Average: 1887 €/kW		

Table G6: Future (2025/2030) CAPEX for PEMWEs. Including ”other costs”.

Value [€/kW]	Data from (year)	Source
900	2017	[76, p. 46]
1000	2016	[121, p. 103]
1250 - 2200	2017	[62, p. 3]
250 - 1270	2017	[39, table 8]
480 - 1270	2014	[139, p. 13]
Average: 1058 €/kW		

Table G7: *Current* CAPEX for PEMWEs. Not including ”other costs”.

Value [€/kW]	Data from (year)	Source
855	2014	[117, p. 11]
600	2016	[121, p. 103]
982 - 1607	2016	[10, p. 44]
850	2019	[9, p. 20] (Provided by Nel Hydrogen)
663	2017	[30, p. 21]
1014	2017	Market participant
920	2015	[119, table 2]
535	2016	[118, p. 5]
Average: 842 €/kW		

Table G8: Future (2025/2030) CAPEX for PEMWEs. Not including ”other costs”.

Value [€/kW]	Data from (year)	Source
410	2014	[117, p. 11]
400	2016	[121, p. 103]
580 - 1340	2016	[10, p. 44]
350 - 600	2019	[9, p. 20] (Provided by Nel Hydrogen)
340	2016	[118, p. 5]
Average: 520 €/kW		

Appendix H

Costs for Compression and Filling

CAPEX for compression and filling is obtained from different sources and presented in this appendix. The following tables contains cost data for total filling center (including compressors, piping and filling equipment), only compressors and only refueling equipment. Both cost data taken directly from a source and calculated costs are presented. All currency conversions are conducted according to appendix F.

CAPEX for Compressor

Table H1 shows examples of costs for different compressors, obtained from several reports describing different scenarios. Compressor costs are depending on pressure levels (input and output pressure), as well as compression rates (flow rates) given as Nm^3/h or kg/h. Both costs for the specific scenarios that are described in the respective reports, and costs calculated for a production rate of 200 kg/h, are presented in this table.

Table H1: Costs for compression, depending on pressure levels and compression rates.

Pressure and compression rates, given by source	Additional information	Costs, directly from source[a] [€]	Costs, calculated for 200 kg/h[a b] [€]	Source
10 bar to 450 bar at 120 Nm^3/h	120 $Nm^3/h \approx 11$ kg/h	300 000 240 000	5 454 545 4 363 638	[121, p. 104] (2015)
450 bar to 900 bar at 120 Nm^3/h	120 $Nm^3/h \approx 11$ kg/h	120 000 96 000	2 181 818 1 745 454	[121, p. 104] (2015)
1 bar to 250 bar at 7.5 m^3/min	7.5 $m^3/min \approx 38$ kg/h at 1.0 bar and 15°C	380 835	2 004 395	Market participant (2017)
1 bar to 200 bar, 1 ton H_2/day	Approximately 41 kg/h	367 200	1 791 220	[35, p. 10] (2019)
High pressure (> 200 bar), 0.5 ton H_2/day	Approximately 20 kg/h	359 805	3 598 050	[35, p. 10] (2019)

CAPEX for Filling and Piping

Costs for filling equipment are presented in table H2. The different sources include dissimilar and unknown scenarios, but the cost data may give an indication of the cost levels.

Table H2: Costs for filling equipment.

Component(s)	Additional information	Costs, directly from source [€][a]	Source
Refueling station	Probably for hydrogen cars/buses/trucks	700 000 420 000	[121, p. 104] (2015)
Dispenser and pipe	High uncertainty. For a 5 MW facility, approximately 2 ton/day production	612 000	[35, p. 10] (2019))
Refueling station	Per module	918 000	[30, p. 21] (2017)

[a] Two values are given by some sources and represent current costs (highest value) and estimates for costs in 2030 (lowest value).
[b] A linear relationship between compression rates and costs for the same pressure levels is assumed.

CAPEX for Filling Center

Table H3 shows cost data for a filling center, obtained from a FCH report. The filling center is ”the physical infrastructure needed to fill gas bundles and/or tube-trailers” [76, p. 50], and includes the compressors, piping and filling equipment. The costs depend on input and output pressure in addition to filling capacity (compression rate). Table H4 contains calculated costs, based on data from table H3. A linear relationship between costs, pressure levels and filling capacity is assumed.

Table H3: CAPEX for filling center in total (compression, piping and filling equipment), obtained directly from [76, p. 51] (2017).

Pressure and filling capacity	Costs [€]
1 bar to 200 bar at 100 kg/h	1 986 000
1 bar to 200 bar at 400 kg/h	4 959 000
1 bar to 500 bar at 100 kg/h	2 631 000
1 bar to 500 bar at 400 kg/h	6 569 000
30 bar to 200 bar at 100 kg/h	1 351 000
30 bar to 200 bar at 400 kg/h	3 373 000
30 bar to 500 bar at 100 kg/h	1 626 000
30 bar to 500 bar at 400 kg/h	4 061 000

Table H4: CAPEX for filling center in total (compression, piping and filling equipment). Calculated with linear regression based on data from [76, p. 51] (2017).

Pressure and filling capacity	Calculated costs [€]
1 bar to 300 bar at 100 kg/h	2 201 000
30 bar to 300 bar at 100 kg/h	1 442 710
1 bar to 300 bar at 200 kg/h	3 140 730
30 bar to 300 bar at 200 kg/h	2 058 640

Appendix I

Costs for Hydrogen Storage

Table I1 shows cost data for compressed hydrogen gas storage, obtained from different sources. The costs depend on pressure levels and the material used in the storage vessels.

Table I1: Costs for hydrogen storage, obtained from different sources. For different pressures and materials (steel and composite).

Type/comment	Pressure level	Costs[a] [€/kg]	Source
Unknown material	200 bar	225	[121, p. 104] (2015)
Unknown material	450 bar	1600 960	[121, p. 104] (2015)
Unknown material	900 bar	2 200 1320	[121, p. 104] (2015)
Steel tanks	200 - 300 bar	170	[30, p. 21] (2017)
Steel tanks	50 bar	470	[76, p. 51] (2017)
Steel bundles	200 - 350 bar	470	[76, p. 51] (2017)
Unknown material Including installation	350 bar	890	[139, p. 7] (2020)
Pressurized tank. 0.1 - 10 MWh, 33.3 kWh/kg$_{H_2}$	-	179 - 298	[78, p. 51] (2015)
T4: Composite/Carbon. Transportable modules	300 bar	660	Hexagon (market participant)
Unknown material Based on 1 800 kg capacity	200 bar	686	[35, p. 10] (2019)

[a]Two values are given by some sources and represent current costs (highest value) and estimates for costs in 2030 (lowest value).

Appendix J

Costs for Electricity

This section presents the costs and prices related to electricity. These costs include grid tariffs with energy price, power prices and a fixed price, in addition to prices for consumed power. All cost data are given in NOK, øre or euro, excluding VAT.

Grid Tariffs/Costs

The grid tariffs depend on whether a customer is a private person or a company, in addition to the magnitude of the energy demand, power demand and voltage levels. Prices and cost data for grid tariffs are obtained from Tensio. The grid tariff used in this thesis is ”NM3-1: business with measured power, high voltage” (”Effektmålt næring, høyspenning”), and include the following prices: [123] (February 1, 2020)

- Fixed price: **20 800 NOK/year**. This includes a statutory add-on to Enova.
- Energy price: **2.8 øre/kWh**.
- Consumption tax: 16.13 øre/kWh.[4]
- Power prices, which depend on the magnitude of power demand and varies with the seasons. An overview of power prices is given in table J1.

Table J1: Power prices for the grid tariff (NM3-1). [123]

Power [kW]	Price - Winter[a] [NOK/kW (per month)]	Price - Summer[b] [NOK/kW (per month)]
0 - 500	45	35
500 - 1000	42	32
>1000	38	28

[a]Winter months: January, February, November and December.
[b]Summer months: March, April, May, June, July, August, September and October.

Energy Prices/Costs

Table J2 shows projected electricity costs (in EUR/MWh) from 2021 to 2030. The data is obtained from Nasdaq. Hitra is located in zone N03, and 3.0 EUR/MWh is therefore subtracted from the original price according to estimates from TrønderEnergi.

Table J2: Projected electricity prices for 2021 to 2030. Based on data from Nasdaq (March 24, 2020). [124]

Year	Electricity prices (from Nasdaq) [€/MWh]	Electricity prices (estimates for zone N03) [€/MWh]
2021	20.55	17.55
2022	22.70	19.70
2023	24.90	21.90
2024	25.60	22.60
2025	27.95	24.95
2026	29.02	26.02
2027	30.99	27.99
2028	31.17	28.17
2029	31.32	28.32
2030	31.47	28.47

[4]Hydrogen production from electrolysis is exempt from consumption taxes in 2020.

Appendix K

Costs for Water at Hitra

The costs for the water that is used to produce hydrogen depend on the fees and prices set by a municipality or private supplier. Table K1 shows water and drainage fee regulations for Hitra Municipality in 2020. The total water price is calculated from equation K1

$$\text{Total price} = (\text{Subscription fee}) + (\text{Measured or stipulated consumption}) \cdot (\text{Water/Drainage price}) \tag{K1}$$

Table K1: Water and drainage fee regulations for Hitra Municipality in 2020. Data provided by Hitra Municipality administration.

Subscription fee		Water price [NOK]		Drainage price [NOK]	
Category	**Volume [m^3]**	**Excl. VAT**	**Incl. VAT**	**Excl. VAT**	**Incl. VAT**
1	0 - 300	2 699.29	3 374.11	2 289.80	2 862.25
2	301 - 900	8 097.87	10 122.34	6 869.40	8 586.75
3	901 - 2700	16 195.74	20 244.68	13 738.80	17 173.50
4	2701 - 5400	32 414.80	40 518.50	27 477.60	34 347.00
5	>5400	65 782.96	80 978.70	54 955.20	68 694.00
Consumption price					
Price per cubic meter		14.34	17.93	12.02	15.03

A Feasibility Study of Hydrogen Production at Hitra

NTNU
Norwegian University of
Science and Technology

TrønderEnergi