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Feasibility study of a green methanol production plant in Norway

Bachelor's thesis in Renewable Energy
Supervisor: Bruno G. Pollet
May 2023

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Bacheloroppgave

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Preface

This thesis is written by two third-year students of renewable energy at the Norwegian University of Science and Technology, NTNU in Trondheim, and is the final thesis to be written in the course "Bachelor thesis renewable energy" with the subject code FENT2900. The original problem description that was written before we had started writing the thesis was more focused on bio-methanol, but as the thesis came to fruition we switched to focus on e-methanol after having a discussion with our supervisor, Professor Bruno G. Pollet. The problem description that was originally drawn up will contain some elements that are not explored as carefully as first planned, and bio-methanol will not be emphasised.

We would like to thank Professor Bruno G. Pollet for the valuable feedback and guidance that was given throughout the semester. We would also like to thank Associate Professor Jacob J. Lamb for providing valuable insight into one of the topics which helped the thesis come together.

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Abstract

Never before have people been as concerned about the environment as they are today. The green transition is more and more discussed in the media with each passing day, and the consensus is that the challenges surrounding global warming must be dealt with as quickly as possible. A major factor in global warming is emissions from fossil sources, especially petrol and diesel used in the transport sector. A possible improvement that could reduce these emissions is using green methanol as a fuel. Green methanol can be used as a low-carbon fuel in vehicles and to synthesise chemicals and other day-to-day items.

This thesis aims to conduct a techno-economical study of a theoretical green methanol plant to find out whether or not it is feasible to establish a green methanol plant in Norway, and if yes, then where? It was decided that the methanol that was going to be produced by the green methanol plant would be e-methanol, which is produced from captured carbon dioxide and green hydrogen. Therefore, renewable energy is needed for the production of e-methanol and green hydrogen. The renewable energy source chosen for this thesis was wind turbines, as they have a high capacity factor. In addition, Norway has a decent amount of wind year-round due to its long coastline. The extra power that the wind turbines could not cover was bought from the grid with a guarantee of origin from renewable sources.

To find the most optimal location for the plant, four locations along the Norwegian coastline with different latitudes were chosen. Different scenarios were applied in the calculations for these four locations to get the best possible solution, where both the electrolyser type used for hydrogen production and the electricity price varied. The electrolysers chosen for this thesis were proton exchange membranes and alkaline electrolysers, and the power prices used in the calculations varied between 0.05-0.1 €/kWh. In addition, two different methanol selling prices, the average spot price and the average contract price, were also used. The calculations are based on a methanol production of 75 000 tonnes a year, and to execute the calculations, the programming language MATLAB was used along with the software Excel.

One of the most important aspects when deciding if a methanol plant in Norway could be feasible is the economic aspect. Five main parameters were calculated to establish the economic feasibility of a green methanol plant in Norway. These were the levelised costs of energy, hydrogen and methanol, discounted payback period, and net present value. The net present value was only positive for a few investigated cases, indicating that it is hard to profit from green methanol. Måløy was the only location that had a positive net present value with the middle power price of 0.08 €/kWh, which is also close to the mean power price in Måløy's price zone. In addition, the levelised cost of hydrogen was lower than the assumed retail price of hydrogen, which indicates that producing the hydrogen would be cheaper than buying it.

When looking at the methanol plant, the CAPEX to OPEX ratio is about the same for the system, both with PEM and alkaline electrolysers. The electrolysers are the most significant contributor to the system's CAPEX and OPEX costs, with wind turbines being the second biggest contributor. For the electrolysers, the biggest OPEX contributor was the compressor, accounting for about 50%. The different scenarios gave a considerable variation in discounted payback time, which varied between 9.1-17.2 years, where the lowest realistic scenario was about 11 years.

Sammendrag

Aldri før har folk vært så opptatt av miljø som i dag. Det grønne skiftet er mer og mer omtalt i mediene for hver dag som går, og det er enighet om at utfordringene rundt global oppvarming må håndteres så raskt som mulig. En stor påvirkende faktor i den globale oppvarmingen er utslipp fra fossile kilder, da spesielt fra bensin og diesel som brukes i transportsektoren. En mulig forbedring som kan kutte ned på disse utslippene er å bruke grønn metanol som drivstoff. Grønn metanol kan brukes som et lavutslipps-drivstoff i kjøretøy, men det kan også brukes til å lage kjemikalier og andre dagligdagse anordninger.

Hensikten med denne oppgaven er å gjennomføre en tekno-økonomisk studie av et teoretisk anlegg som skal produsere grønn metanol for å finne ut om det er mulig å etablere et slikt anlegg i Norge, og hvis ja, hvor? Det ble bestemt at metanolen som skulle produseres av dette anlegget skulle være e-metanol, som blir produsert av fanget karbondioksid og grønt hydrogen. For å lage e-metanol og grønt hydrogen trengs en fornybar energikilde til produksjonen. Den fornybare energikilden som ble valgt for denne oppgaven var vindenergi, ettersom den har en høy kapasitetsfaktor. I tillegg har Norge en anstendig mengde vind året rundt, grunnet sin lange kystlinje. Den ekstra kraften som vindturbinene ikke kunne dekke vil bli kjøpt fra nettet med opprinnelsesgaranti fra fornybare kilder.

For å finne den mest optimale plasseringen av anlegget ble det valgt fire lokasjoner med ulike breddegrader langst den norske kystlinjen. For disse fire stedene ble det brukt ulike scenarier i beregningene for å få best mulig optimalisering, hvor både elektrolysørtypen som ble brukt til hydrogenproduksjon og strømprisen varierte. Elektrolysørene som ble valgt å bruke i denne oppgaven var proton exchange membrane og alkaliske elektrolysører, og kraftprisene som ble brukt i beregningene varierte mellom 0.05-0.1 €/kWh. Det ble også benyttet to forskjellige salgspriser for metanol, en basert på gjennomsnittlig spot-pris, og en basert på gjennomsnittlig kontraktpris på metanol. Beregningene er basert på en metanolproduksjon på 75 000 tonn i året, og for å utføre beregningene ble programmmeringsspråket MATLAB brukt i tillegg til programvaren Excel.

En av de viktigste aspektene når man skal avgjøre om det er mulig å etablere et metanolanlegg i Norge, er det økonomiske aspektet. For å fastslå den økonomiske gjennomførbarheten av et grønt metanolanlegg i Norge, ble det beregnet fem hovedparametere. Disse var levetidskostnad for energi, hydrogen og metanol, diskontert tilbakebetalingstid, samt netto nåverdi. Netto nåverdien var kun positiv for noen av de undersøkte scenariene, noe som indikerer at det er vanskelig å tjene penger på grønn metanol. Måløy var det eneste stedet som hadde positiv netto nåverdi med en kraftpris på 0.08 €/kWh, som også er nær gjennomsnitts-kraftprisen i Måløys prissone. Levetidkostnaden til hydrogen var lavere enn den antatte utsalgsverdien på hydrogen, som indikerer at å produsere hydrogenet vil være billigere enn å kjøpe det.

Når man ser på metanolanlegget er forholdet mellom CAPEX og OPEX omtrent det samme for systemet, uavhengig om PEM eller alkaliske eletrolysører blir brukt. Det som bidrar mest til både CAPEX- og OPEX- kostnadene for systemet er elektrolysørene, etterfulgt av vindturbinene som det nest største bidraget. Det som bidro mest til elektrolysørenes OPEX var kompressoren, som sto for omtrent 50%. De ulike scenariene ga en stor variasjon av diskontert tilbakebetalingstid, som varierte mellom 9.1-17.2 år, hvor det laveste realistiske scenarioet var på rundt 11 år.

Contents

Glossary

Alkali	an expression that can be used about a compound that has a pH bigger than seven.
Anion	Negatively charged ion.
Anode	Positively charged electrode in the electrolyser cell.
Capacity factor	Measurement of a power plants performance, relative to the theoretical highest production. $k = \frac{ActualProduction}{Theoreticalproduction}$
Catalyst	A substance that is used in chemical reactions to increase the speed of the reactions by lowering the energy needed to activate the process. catalysts themselves are not consumed in the reaction.
Cathode	Negatively charged electrode in the electrolyser cell.
Cation	Positively charged ion.
Carbon neutral	Processes that does not contribute to increased amounts of CO_2 in the atmosphere.
Desalination	A process used to remove mineral salts in water.
Diffusion	Movement of molecules from an area of higher concentration to an area of lower concentration.
Endothermic	Describes that a chemical reaction absorbs heat.
Exothermic	Describes that a chemical reaction releases heat.
Full load hours	The amount of hours a power plant needs to produce at full capacity to reach the actual power production.
Greenhouse gas	Gas that absorbs and/or emits infrared radiation.
Guarantee of origin	Electricity in Norway can be bought with a guarantee of origin, meaning that the buyer pays a little extra to ensure that the bought electricity comes from renewable sources.
IEC class	Classification of wind turbines based on wind speeds and turbulence the wind turbine is made to withstand.
Inert gas	Gas that does not react. Can be used for gases that are added to a process to prevent a reaction, or about gases that are present in a reaction without reacting themselves.
Inorganic compound	A compound that does not contain both hydrogen and carbon.
Investment cost	The total capital costs, CAPEX, used for the methanol plant.
Isentropic	A process that takes place without exchanging heat or mass with the environment, and is also reversible.

Natural gas	A gas consisting mainly of methane, but also contains small amounts of butane, ethane and propane.
Organic compound	Most compounds that include carbon. Some exceptions are carbon dioxide, carbon monoxide, carbon salts, and carbides.
Octet rule	A rule stating that atoms maximum can have eight electrons in their valence shell.
Proton	Positively charged particle in the core of an atom, the number of protons in the atoms core decides the atom number of an element.
Selectivity	A catalysts ability to steer a reaction towards a specific product, moles of desired product per mole of catalyst.
Standard electrode potential	
Syngas	A gas mixture that normally consists of hydrogen, carbon dioxide and carbon monoxide. Depending on what the syngas is used for, it may also contain carbon dioxide and methane. The ratio of the substances may vary.

Abbreviations

AACE	Association for the Advancement of Cost Engineering
AEM	Anion exchange membrane
AFUDC	Allowance for funds used during construction
ATR	Autothermal reforming
CAPEX	Capital expenditures
CCS	Carbon capture and storage
CEPCI	Chemical engineering plant cost index
CHP	Combined heat and power
DAC	Direct air capture
DME	Dimethyl ether
DPP	Discounted payback period
FCI	Fixed cost index
FLH	Full load hours
GHG	Greenhouse gas(es)
GHSV	Gas hourly space velocity
HFO	Heavy fuel oil
ICE	Internal combustion engine
IEC	International Electrotechnical Commission
LCOE	Levelised cost of energy
LCOH	Levelised cost of hydrogen
LCOM	Levelised cost of methanol
L-DAC	Liquid-direct air capture
LNG	Liquid natural gas
LRD	Licensing, research and development
MMSA	Methanol Market Services Asia
MTBE	Methyl tert-butyl ether
NOK	Norwegian krone
NPR	Net production rate

NPV	Net present value
OPEX	Operational expenses
PCEC	Protonic ceramic electrolyser cell
PEC	Purchased equipment costs
PEM	Polymer electrolyte membrane or proton exchange membrane, both refer to the same thing, however proton exchange membrane is the functional and polymer electrolyte membrane is the structural name.
POX	Partial oxidation
S-DAC	Solid-direct air capture
SMR	Steam methane reforming
SOEC	Solid oxide electrolyser cell
STP	Standard temperature and pressure
SUC	Startup costs
TLC	Total levelised costs
VAT	Value added tax
WC	Working capital

Symbols

C_{PE}	
E^{rev}	Reversible voltage [V]
F	Faraday's constant, F = F = 96 485.332 C/mol
M_{H_2}	Molar weight of hydrogen in g/mol
N_e	Project lifetime in years
Q_m	Mass flow in tonne/h

Greek letters

α	The lowercase alpha is a scaling exponent, denoting whether or not the increase in equipment cost is lower or higher than the increase in equipment size.
γ	The lowercase gamma is the heat transfer coefficient for ideal gases.
ϵ	The lowercase epsilon denotes the catalyst bed porosity.
η	The lowercase Greek letter eta often denotes efficiency, or irreversible energy losses due to electrode processes in the electrolytic cell
κ	The lowercase kappa is the heat transfer coefficient for real gases.
μ	Mu, a unit to measure length, means micrometre.

Units

Bar	A unit defined as 10^5 Pascal
°C	Degree Celsius, unit measuring temperature
GWh	Gigawatt hour, 10^9 Watt hours
K	Kelvin, SI unit measuring temperature
km	Kilometer, one thousand metres
kt	Kilotonnes, one thousand tonnes
kV	Kilovolt, a thousand volts
L	Litre, one cubic decimetre
Megatonne	Defined as 10^6 tonne
MJ	Megajoule, 10^6 joules
MW	Megawatt, 10^6 Watts
m^3	Cubic meter, SI unit used to measure volume
Nm^3	Normal cubic meter, used to measure gas, defined as 1 m^3 under standard temperature, 0°C, and pressure, 101 325 Pa.
T	Tonne, unit for measuring weight, equal to 1000 kg
TJ	Terajoule, 10^{12} joules
Watt	Unit for measuring power

Chemical formulas

CH_3OH	Methanol
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
e^-	Electron
H^+	Proton
H_2	Hydrogen gas
H_2O	Water
KOH	Potassium hydroxide
NaOH	Sodium hydroxide
O_2	Oxygen gas
OH^-	Hydroxide
SOx	Sulphur dioxide

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1 Introduction

The world's energy demand continues to increase while the emissions of greenhouse gases, GHG, need to decrease if the goals set in the Paris Agreement are to be reached. Fossil energy sources are still the main energy sources in the world. With the high emissions connected to the utilisation of fossil fuels, alternative energy sources need to be put to use as soon as possible [1].

One potential energy source that is worth exploring is green methanol, which can be produced carbon neutrally or with a low carbon footprint. One advantage e-methanol has over bio-methanol is that e-methanol can utilise CO_2 from industry that would have otherwise been emitted into the atmosphere, and this helps lower CO_2 emissions. Today methanol is used in a variety of different applications and day-to-day items. The widespread use of this chemical is one of the reasons why focusing on renewable methanol instead of methanol produced from fossil energy sources is important.

1.1 Methanol demand and usage

Methanol, also known as wood spirit or methyl alcohol, is the simplest of the alcohols and has the chemical formula CH_3OH. It was first produced as a by-product of charcoal production up until the 1920s when the production of methanol from coal was first done. In the 1940s, natural gas was introduced as a medium to produce methanol, and the introduction of fossil sources for production drastically increased the production of methanol. [2]

In 2020 global methanol production was 100 megatonnes and was expected to grow to 120 megatonnes by 2025 and 500 megatonnes by 2050 [2]. This shows that the methanol demand is expected to be constantly increasing in the coming years. The area with the biggest methanol demand is the Asia-Pacific, which is likely due to the growth of the automotive and construction industries [3]. In 2022 China was responsible for consuming about 60% of the world's methanol, in addition to being the biggest contributor to methanol production worldwide. [4]

More than 60% of methanol produced in 2019 was used to manufacture chemicals. These are used to make everyday items such as clothes, car parts, paints, and plastics. Ethylene and propylene, which have traditionally been produced through petrochemical processes, can also be synthesised from methanol, allowing for decarbonisation of these chemicals. [2].

1.1.1 Methanol in the transport sector

Produced methanol can also be used as a fuel by itself, in a fuel blend with gasoline, or further synthesised to methyl tert-butyl ether, MTBE, or dimethyl ether, DME. MTBE is used as a fuel additive both to increase oxygen content and as an anti-knock agent, which helps the fuel combustion process and decreases the emission of carbon monoxide and hydrocarbons [5].

Methanol is commonly used as a fuel additive because of its high oxygen and octane content. These properties make gasoline burn cleaner and significantly lowers exhaust emissions [6]. Methanol could be a great fuel alternative, especially in the maritime transport sector. If another fuel type is to replace fossil fuels, it should be affordable, sustainable and safe. Since methanol can be produced from different feedstock, it is easy to make available on a big scale. Methanol is also a solid competitor in price when compared with liquid natural gas, LNG, and heavy fuel oils, HFO. Methanol is not the most sustainable fuel alternative, but if green methanol is used instead, a much more positive outcome emission-wise could be reached. [7]

The mass-energy density of diesel is 45.5 MJ/kg, and for methanol, this is 22 MJ/kg. An average car in Norway drove 11 000 km in 2022, and an average truck drove 37 000 km. The average diesel consumption for a car is 0.8 L diesel per 10 km, and the average truck uses 5.1 L diesel per 10 km. For cars, this corresponds to an annual energy consumption of 34 034 MJ/year, and for trucks, this is 730

000 MJ/year. 75 000 tonnes of methanol annually corresponds to 1 650 TJ/year, which could replace 48 500 cars or 2 260 trucks.

When comparing emissions from methanol against conventional fuels, both the carbon dioxide and NOx emissions are lower in methanol. Diesel engines operate at a higher combustion temperature than gasoline engines, which is why diesel engines have higher NOx emissions than gasoline engines. Diesel engines also produce more sulphur oxides than gasoline engines, as diesel itself contains a higher amount of sulphur than gasoline. Gasoline engines, on the other hand, emit about 40% carbon dioxide more than diesel engines due to their lower combustion efficiency [8]. An advantage of using methanol instead of gasoline and diesel is that when it is combusted, it does not create any NOx or SOx emissions, in addition to very low emissions of carbon dioxide when compared to that of gasoline and diesel. [9, 10]

1.2 Problem description

To gain a better understanding of what it takes to make use of CO_2 and hydrogen for green methanol production, it would be a good idea to see what it takes to make the production profitable and a viable option. Norway has a long coastline with good wind conditions, which makes it ideal for wind farms. In areas where the power grid can not handle excess production, utilising the energy for hydrogen production is a good alternative to letting the potential energy go to waste. The availability of CO_2 is also a point that needs to be addressed since it is necessary to produce green methanol. This makes the theoretical production plant's location even more crucial. With this in mind, the questions that remain to be answered are as follows: *Is it possible to establish a green methanol plant in Norway? If so, how much would it cost, and where is the most optimal location?*

1.3 Thesis structure

In the list below the thesis' structure is presented in order. This includes an overview of all the most important aspects of the thesis, like location choices, available energy, different production pathways for different products and more.

1. Establish the amount of methanol to be producced by the green methanol plant.
2. Choose some suitable locations to consider for establishing a green methanol plant.
3. Determine the amount of available wind energy at each location.
4. Look into the current production methods for hydrogen gas and evaluate which is most suitable for intermittent energy sources such as wind.
5. Evaluate the different ways to capture CO_2 and determine which is most suitable for this purpose.
6. Determine what production method for green methanol should be considered for the plant.
7. Perform an economic analysis on establishing a green methanol plant, hereunder a wind farm and electrolysis facility.

2 Theory

This section of the thesis will cover the necessary theory to understand the green methanol synthesis process and preceding processes. This includes hydrogen production from water electrolysis, CO_2-capture, and wind energy production. Different production pathways to obtain methanol to better compare the green methanol pathway to conventional production pathways will also be explained.

2.1 Colours of hydrogen

Hydrogen is a gas and can be produced in many ways. To differentiate the hydrogen types, they are given names after colours. Hydrogen itself is a colourless gas, so the colour given to the hydrogen type does not describe the physical appearance of the hydrogen but the way it was produced. There are currently eight main types of hydrogen, green, pink, yellow, blue, turquoise, grey, brown and black. Figure 2.1 gives an overview of the different types, what they are made of and how they are produced. White hydrogen also exists and occurs naturally in nature.

	Terminology	Technology	Feedstock/ Electricity source	GHG footprint*
PRODUCTION VIA ELECTRICITY	Green Hydrogen	Electrolysis	Wind | Solar | Hydro Geothermal | Tidal	Minimal
	Purple/Pink Hydrogen		Nuclear	
	Yellow Hydrogen		Mixed-origin grid energy	Medium
PRODUCTION VIA FOSSIL FUELS	Blue Hydrogen	Natural gas reforming + CCUS Gasification + CCUS	Natural gas | coal	Low
	Turquoise Hydrogen	Pyrolysis	Natural gas	Solid carbon (by-product)
	Grey Hydrogen	Natural gas reforming		Medium
	Brown Hydrogen	Gasification	Brown coal (lignite)	High
	Black Hydrogen		Black coal	

*GHG footprint given as a general guide but it is accepted that each category can be higher in some cases.

Figure 2.1: An overview over the different colours of hydrogen [11].

2.1.1 Black hydrogen

To produce black hydrogen, black coal is used. Black coal, or bituminous coal, is an intermediate of sub-bituminous coal and anthracite and contains 76-86% carbon [12]. Black coal is used and put through a coal gasification process. During the gasification, carbon-rich raw materials are converted into a gas that consists of carbon monoxide, carbon dioxide and hydrogen. This gas is then converted into hydrogen and CO_2, where the CO_2-emissions are released into the air, contributing to the GHG emissions in the Earth's atmosphere. [13]

2.1.2 Brown hydrogen

Brown hydrogen, like black hydrogen, is also produced through coal gasification, but their differences lie in the type of coal that is used. For brown hydrogen production brown coal, also known as lignite, is used. The key difference between black and brown coal is that black coal has a lower ash and moisture content than brown coal. [13, 14]

2.1.3 Grey hydrogen

Grey hydrogen is made from natural gas by splitting it into hydrogen and CO_2. To do this, three reforming methods can be utilised, steam methane reforming, SMR, partial oxidation, POX, or a mix of the two called autothermal reforming, ATR. POX is when oxygen from air is used as the oxidant, while SMR is when water is used as the hydrogen source and oxidant. [15, 16]

Steam methane reforming is the most utilised method when producing grey hydrogen. SMR is an endothermic reaction which uses steam between 700-1000 °C. The steam reacts with methane under a pressure of around 3 to 25 bar, with a catalyst present and produces hydrogen and carbon monoxide as shown in Equation 2.1. Afterwards, a water-gas shift reaction shown in Equation 2.2 happens, where the carbon monoxide and steam react by using the catalyst to produce carbon dioxide and hydrogen. The overall reaction for the SMR process is shown in Equation 2.3. The last step is the pressure-swing adsorption, in which the carbon dioxide and other impurities are removed from the steam, leaving pure hydrogen. [17, 18]

$$CH_4 + H_2O + heat \rightarrow CO + 3H_2 \tag{2.1}$$

$$CO + H_2O \rightleftharpoons CO_2 + H_2 + small\ amount\ of\ heat \tag{2.2}$$

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2 \tag{2.3}$$

Partial oxidation is an exothermic reaction and is normally quicker when compared to SMR. In partial oxidation, the hydrocarbons from the natural gas and methane react with a limited amount of oxygen, which can be either pure oxygen or oxygen from the air, which is not enough to make it oxidise the hydrocarbons fully to CO_2 and water. The reaction primarily produces hydrogen, carbon monoxide and nitrogen if the reaction is done with air in place of pure oxygen and a relatively small amount of CO_2 and other compounds. The chemical reaction for POX is shown in Equation 2.4. Afterwards, in a water-gas-shift reaction, the carbon monoxide and water react to produce CO_2 and more hydrogen, as shown in Equation 2.2. [17, 19]

$$CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2 \tag{2.4}$$

In ATR, POX is first performed to produce heat, hydrogen gas and carbon monoxide as seen in Equation 2.4. It is followed by the SMR reaction, which uses the produced heat from the POX reaction. The SMR reaction takes the remaining hydrocarbons, which in this case is methane, and uses steam to convert it into more hydrogen and carbon monoxide, as shown in Equation 2.1. The overall ATR reaction will then be as represented in Equation 2.5. Subsequently, the water-gas-shift Equation 2.2 takes place to adjust the ratio between carbon monoxide and hydrogen. [18, 19]

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \tag{2.5}$$

Autothermal reforming is when steam reacts with either CO_2 or CH_4 to produce syngas. ATR happens in a single vessel with two individual zones, a reforming zone and a combustion zone. The heat that is released in the exothermic POX reaction balances out the endothermic SMR reaction, which needs heat to be performed. ATR is a process where the necessary heat is produced in the reformer, meaning that all CO_2 is produced inside the reactor. This gives a higher CO_2-capture efficiency than can be achieved by SMR. Because the emissions are more concentrated, CO_2-capturing with ATR generates lower costs than with SMR. Several studies show that the expenses of SMR with capture rates above 90% or more are higher compared to a similar ATR system. [16, 18, 19]

2.1.4 Blue hydrogen

Blue hydrogen is like grey hydrogen, made from natural gas, by splitting it into hydrogen and CO_2 by using either SMR, ATR or POX. What differentiates blue from grey hydrogen, is that for blue hydrogen after the splitting has been executed, the CO_2 from the process is captured and stored through a carbon capture usage and storage process, CCUS, as described in Section 2.4.1. [15]

2.1.5 Turquoise hydrogen

Turquoise hydrogen is produced through pyrolysis, which uses heat to break down a material's chemical composition, in this case natural gas, into hydrogen and solid carbon instead of CO_2, like in grey and blue hydrogen. Turquoise hydrogen is a lot newer compared to the other hydrogen types but is also cheaper than green hydrogen, as splitting methane molecules requires less energy than splitting water molecules. [13, 20]

2.1.6 Green hydrogen

To produce green hydrogen, energy from renewable resources is used. This energy is used to perform electrolysis to split water, which can be further read about in Section 2.3.2 and Section 2.3.1. This results in hydrogen and oxygen, where the hydrogen can be used for the green methanol, while the oxygen can be let into the Earth's atmosphere, with no GHG emissions made. [15]

2.1.7 Yellow hydrogen

Yellow hydrogen, like green hydrogen, is also produced using electrolysis. The difference between the two is that green hydrogen uses a mix of renewable resources for the electrolysis, while yellow hydrogen purely uses solar power to power the electrolysis process. [15]

2.1.8 Pink hydrogen

Pink hydrogen is also produced through electrolysis, but nuclear energy is used as the energy source to power the electrolysis process [15]. The high temperatures of nuclear reactors make them ideal for utilising solid oxide electrolyser cells, SOEC, as they operate at temperatures close to the output temperatures of nuclear reactors. Since many countries already have nuclear reactors that are operational, pink hydrogen might be part of the solution to shifting hydrogen production away from fossil energy sources because of the low carbon footprint. [21]

2.1.9 Hydrogen costs

The levelised cost of hydrogen, LCOH, varies widely depending on the energy source that is used for production. As of 2019, hydrogen from natural gas SMR and gasification of black and brown coal were the cheapest alternatives. Natural gas reforming had an LCOH of 1.47-1.75 €/kg, black coal gasification had an LCOH of 1.66-2.02 €/kg, and brown coal gasification had an LCOH of 1.38-1.75 €/kg. The current average LCOH from wind power in Norway is 4.02 €/kg, which is significantly higher than that of fossil fuels. To decarbonise sectors that have use for hydrogen, low-carbon or carbon-neutral solutions need to be utilised more, paving the way for cleaner hydrogen production. [22, 23]

2.1.10 Summary of the colours of hydrogen

According to IRENA, around 47% of the global hydrogen production was made from natural gas at the end of 2021. The remaining 53% was made up of 27% coal, 22% of oil as a by-product, and 4% from electrolysis. In 2021 the electricity that was used had a global average renewable share of 33%, meaning 1% of global hydrogen output was produced with renewable energy. While it is clear that natural gas-based hydrogen types like grey hydrogen dominate the market today, switching to renewable alternatives is one of the many changes that need to happen if the Paris Agreement of a maximum increase of 1.5°C is to be kept. [24]

2.2 Hydrogen storage and distribution

To account for the excess production of hydrogen, storage and distribution of the gas needed to be taken into consideration. Gaseous hydrogen can be stored in containers, this thesis will consider steel tanks. To be able to store the produced hydrogen, it will need to be compressed to at least 200 bar since this is the lowest operating pressure of such tanks. Distribution of hydrogen would also need a refuelling station to transfer the gas to the means of transportation. It is thought that the hydrogen will be transported by hydrogen tube trailers, these need hydrogen to be compressed to 180 bar or more. Tube trucks can carry approximately 380 kg of compressed hydrogen gas if utilising steel tubes, but composite storage vessels have been developed to carry 560 to 900 kg of compressed hydrogen. [25]

It was assumed that a positive displacement compressor would be utilised to compress hydrogen for storage and distribution, as this is one of the most common compressors for hydrogen. With positive displacement compressors, a given amount of hydrogen is caught before being compressed by a reduction in control volume and then sent on with elevated pressure. [26]

Another option that could be considered for the produced hydrogen is liquefaction. Liquefaction is when a substance is converted from its gas or solid state into its liquid state. To liquefy hydrogen, it is cooled down to temperatures lower than -253°C, and then it can be stored in insulated tanks. The insulated tanks can be picked up by tanker trucks which take them to their site. Then the liquid hydrogen is vaporised into a high-pressure gaseous product that can be used. Although hydrogen in its liquid form is preferred partially as more hydrogen can be transported when it is transported as a liquid compared to as a gas, liquefaction of hydrogen is very energy intensive and consumes about 30% of the energy content of hydrogen. It is also more economical to transport liquid hydrogen as tanker trucks can hold a far greater mass of hydrogen than gaseous tube trailers can. [27]

2.3 Water electrolysis

Water electrolysis is a process where water is split into hydrogen gas, H_2, and oxygen gas, O_2. For all types of water electrolysis, the same total reaction, seen in Equation 2.6, happens in the cell, but the half-cell reactions at the anode and cathode differ depending on the electrolyte in the cell. Another thing all the electrolyser cells have in common is that on the positive anode, oxygen gas is produced, and on the negative cathode, hydrogen gas is produced. [28]

$$H_2O + energy \rightarrow \frac{1}{2}O_2 + H_2 \tag{2.6}$$

To better understand how much energy is needed to dissociate water into H_2 and O_2, the standard electrode potential of the half-cell reaction taking place at the positive anode should be considered. At standard temperature and pressure, Gibbs free energy and standard Gibbs free energy are the same. For the water splitting, the Gibbs free energy is $\Delta\bar{g} = -237 kJ/mol$. Using the Gibbs free energy and isolating E^{rev} in Equation 2.7, one can find the reversible voltage of the electrolyser cell, which is -1.23 V. In Equation 2.7 $\Delta\bar{g}$ is the change in Gibbs free energy, $\Delta\bar{h}$ is the change enthalpy, $\Delta\bar{s}$ is the change in entropy, T is the temperature in Kelvin, K, z is the amount of moles electrons needed per mole of reactant, and F is Faraday's constant. [28]

$$\Delta\bar{g} = \Delta\bar{h} - T\Delta\bar{s} = -zFE^{rev} \tag{2.7}$$

The value of the reversible voltage is the thermodynamic potential needed to split water into H_2 and O_2. However, due to irreversible losses, a higher voltage is actually needed to account for friction in the form of ohmic losses and Tafel losses. Equation 2.8 shows how the cell voltage of electrolyser cells is calculated, where rj is the ohmic losses, and η is the Tafel losses.

$$E^{cell} = E^{rev} - rj - \eta \tag{2.8}$$

2.3.1 Alkaline water electrolysis

The concept of alkaline water electrolysis was first discovered in the 1700s and has been utilised on a large scale since the early 1920s. The anode and the cathode are submerged in an alkaline aqueous solution, usually potassium hydroxide, KOH, or sodium hydroxide, NaOH, separated by a membrane. When the electrolyte used in water electrolysis is an alkaline solution, the half-cell reactions in Equation 2.9 take place [28].

$$\begin{gathered}
\text{Cathode}: 2H_2O(l) + 2e^- \rightarrow H_2(g) + 2OH^-, E^o = -0.83V \\
\text{Anode}: 2OH^- \rightarrow \frac{1}{2}O_2(g) + H_2O(l) + 2e^-, E^o = 0.40 \\
E^o = -0.83V - 0.40V = -1.23V
\end{gathered} \tag{2.9}$$

At the cathode, hydrogen gas, H_2, and hydroxide ions are generated. The hydroxide ions diffuse to the anode, where they oxidise to O_2 and H_2O. The anode and cathode are separated by a microporous separator to separate the hydrogen and oxygen gases. This membrane can be comprised of, for example, asbestos. Figure 2.2 shows a schematic of an alkaline electrolysis cell. [29]

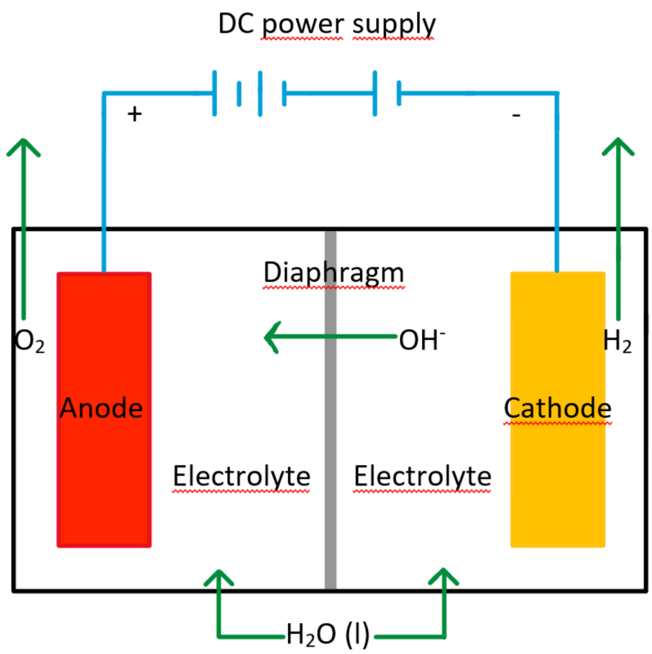


Figure 2.2: Schematic figure showing the structure of an alkaline electrolysis cell.

2.3.2 PEM electrolysis

The concept of proton exchange membrane, PEM, water electrolysis was first introduced in 1967 by General Electric to overcome the challenges that alkaline water electrolysis posed [30]. The cathode and anode are separated by a polymer electrolyte membrane that conducts protons and acts as a reactant barrier to the hydrogen and oxygen gases. When water electrolysis is done in an acidic medium, the half-cell reactions shown in Equation 2.10 take place [28].

$$\begin{aligned} \text{Cathode}: \ 4H^{+} + 4e^{-} &\rightarrow 2H_2(g),\ E^{o} = 0V \\ \text{Anode}: \ 2H_2O(l) &\rightarrow 4H^{+} + O_2(g) + 4e^{-},\ E^{o} = 1.23V \\ E^{o} &= 0V - 1.23V = -1.23V \end{aligned} \tag{2.10}$$

At the anode, water is oxidised to O_2 by forming cations in the form of protons, H^+, at the anode. The protons migrate through the PEM electrolyte to the cathode, where they are reduced to H_2 to complete the electrochemical circuit [29]. A schematic diagram of a PEM electrolysis cell can be seen in Figure 2.3.

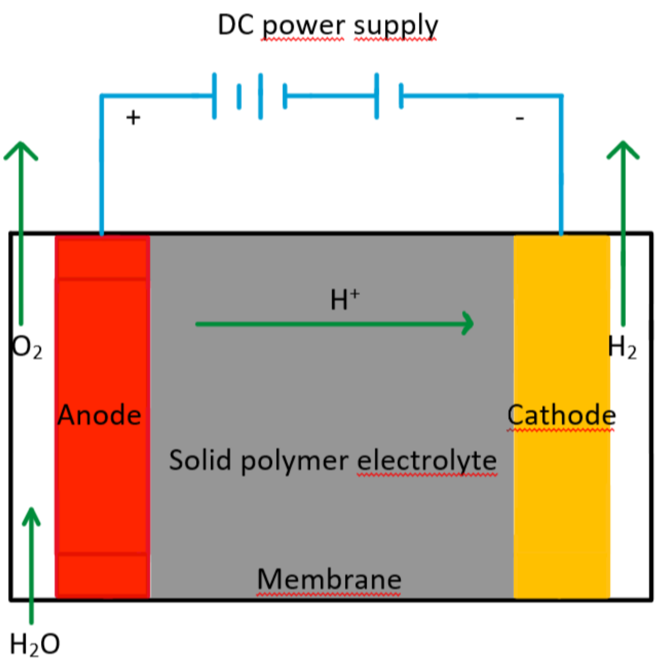


Figure 2.3: Schematic showing the structure of a PEM electrolysis cell.

PEM cells contain a material called iridium. Iridium is a metal belonging to the platinum-metal category and has the highest density of all the elements. Inside the PEM electrolysers, iridium is used as a catalyst, which improves the electrolysers' overall efficiency [31]. A big obstacle when it comes to PEM is the fact that iridium is a scarce element, meaning the PEM costs become pretty expensive. [32]

2.3.3 Anion exchange membrane electrolysis

Anion exchange membrane electrolysers, AEM, like alkaline electrolysers, have hydroxide ions as the charge carriers, and the half-cell reactions in Equation 2.9 are the ones taking place in this type of cell as well. As opposed to alkaline electrolysis, the AEM cell is not submerged in an alkaline solution. H_2O is circulated through the anode side of the cell, where it is reduced to H_2 and H^+. The hydroxide ions diffuse through the AEM to the cathode, where they oxidise to H_2O and O_2. Figure 2.4 shows a schematic diagram of an AEM electrolyser cell. [33]

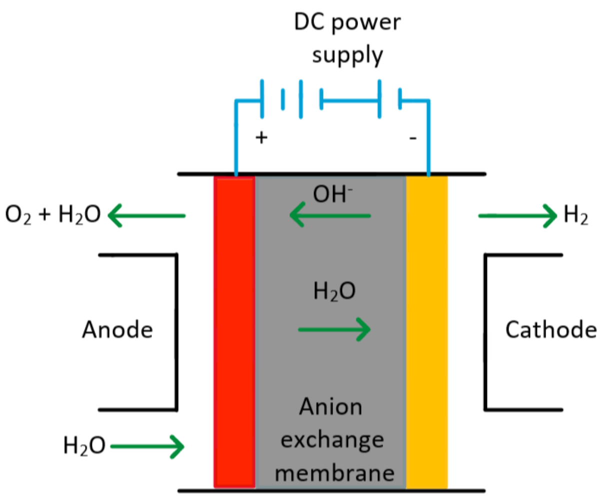


Figure 2.4: Schematic showing the structure of an AEM electrolysis cell.

2.3.4 Solid oxide electrolysis

Solid oxide electrolyser cells are still under development and not currently commercialised at the same scale as PEM and alkaline cells. SOEC operate at high temperatures, from 500-1000°C, enabling lower power consumption.

$$
\begin{aligned}
\text{Cathode: } & H_2O(g) + 2e^- \rightarrow H_2(g) + O^{2-} \\
\text{Anode: } & O^{2-} \rightarrow \frac{1}{2}O_2 + 2e^-
\end{aligned}
\tag{2.11}
$$

At the cathode, H_2O is reduced to H_2 and oxygen ions, O^{2-}. The oxygen ions diffuse through the membrane to the anode, where they oxidise to O_2. The half-cell reactions of the SOEC can be seen in Equation 2.11. To reduce ohmic losses in SOEC cells, the membranes need to be thin, as the oxygen ions diffuse through the defects of the crystal structure in the zirconium membrane. Figure 2.5 shows a schematic diagram of a solid oxide electrolyser cell.

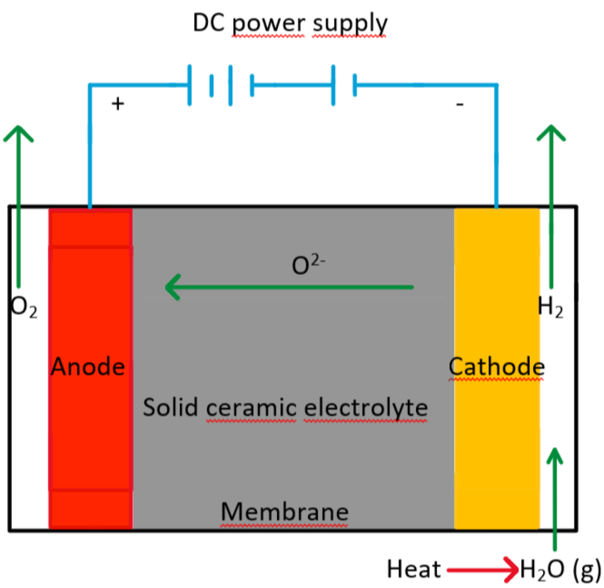


Figure 2.5: Schematic showing the structure of a solid oxide electrolysis cell.

2.3.5 Protonic ceramic electrolysis

As opposed to traditional solid oxide cells that utilise oxygen ions, protonic ceramic electrolyser cells, PCEC, have protons as the charge carriers. Furthermore, dry and pure hydrogen can be produced directly on the fuel electrode (cathode) side, which can reduce the cost of operation. If the pressure on the fuel electrode is increased, it is also possible to omit external compression, thereby increasing the efficiency of the system. Despite these features, PCECs for large-scale hydrogen production is still hindered by the poor stability of the oxygen electrodes. Figure 2.6 shows a schematic diagram of a PCEC. [34, 35]

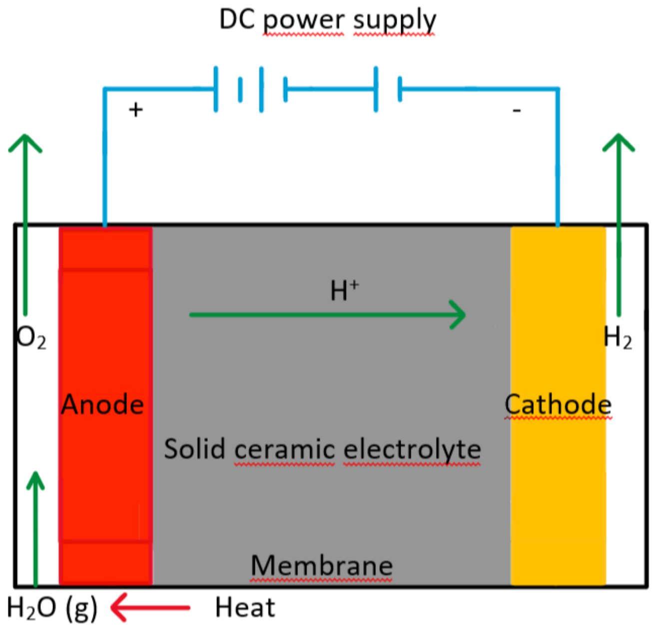


Figure 2.6: Schematic showing the working principles of a PCEC.

The half-cell reactions in the PCEC are the same as in a PEM electrolyser, except for the fact that PCECs operate at temperatures between 400°C and 700°C, meaning that the water is supplied as steam instead of liquid. [35]

2.3.6 Water scarcity

For hydrogen production, water is needed. This water can either be fresh water, desalinated seawater or industrial wastewater. Treatment of fresh water has the lowest costs but is also the least sustainable option of the three. Using wastewater from industrial sources will add more treatment costs than fresh water but will also most likely decrease pipeline and transferal costs, as the water source would be in close proximity to the plant. Desalinated seawater gives a low capital cost compared to the others, making it a viable option for electrolysis. [36].

About 70% of the Earth is covered by water, but only 3% is fresh water, which can be used for drinking but also for electrolysis. But with each passing day, the water sources that keep ecosystems alive, like rivers and lakes, either dry up or get polluted. At the same time, water demand grows with the human population. More than 50% of the wetlands on Earth have vanished, and if this continues, about 60% of the world's population will face water shortages by 2025. [37]

The main cause of water scarcity is drought. Global warming contributes to rising temperatures, resulting in climate changes that cause more frequent and longer-lasting droughts. This again leads to more frequent wildfires and more water scarcity. [38]

About 70% of the world's freshwater is used for agriculture, meaning agriculture is the biggest consumer. Water pollution is also an important reason why many countries are facing water scarcity. The usage of pesticides and fertilisers in agriculture can cause water pollution. Human waste and industrial toxic waste also contribute to water pollution. [37]

In 2021 the average water consumption in Norway was 179 litre/day per person, which is a decrease from the average in 2016 at 183 litre/day per person. This is still a great deal more than the neighbouring countries in the same year, with an average of 105 litre/day per individual in Denmark and Sweden with 140 litre/day per individual. [39, 40, 41]

2.4 Sources of CO_2

When a CO_2 source is needed for a process, fossil fuels are the most common source to utilise. Although this is a reliable source, it is not sustainable for the Earth, making CO_2-capture a better alternative when a CO_2 source is needed. When capturing CO_2, it is mainly taken from two sources. CO_2 can either be separated from the air or it can be captured from industries that release CO_2 in their production. Direct air capture, DAC, is a process used to extract CO_2 from the atmosphere, while carbon capture utilisation and storage, CCUS, is used to extract CO_2 from industries. [42, 43]

2.4.1 CO_2 from industrial processes

When capturing CO_2 from industries, carbon capture and storage, CCS, is most commonly used. CCS starts with separating CO_2 from the produced gases before it is compressed and sent to the storage site through pipelines or road transport. When the CO_2 arrives at the storage site, it is injected deep into the ground for permanent storage. CCUS is also a way to extract CO_2 from industries, where instead of taking the CO_2 to store it underground, it is re-utilised to produce something new. [42]

21st of September 2020, the Norwegian government officially launched a project called Langskip after having done background research on its possibilities since May 2015. Langskip is the Norwegian government's investment in CO_2 management and is a project that will include CO_2-capture from industrial sources, transport and safe storage of CO_2. One of the partaking companies in this project is Hafslund Oslo Celsio, which is going to establish a carbon capture facility at their waste incineration plant in Klemetsrud in Oslo. When the carbon capture facility is established, it will be able to capture up to 400 000 tonnes of CO_2 a year, reducing the city's emissions by 17%. [44, 45]

This project was officially given the green light to start the 29th of June 2022 and was planned to be finished by March of 2026. The project has since had some financial challenges where the original estimated cost from 2015 was 5 billion Norwegian kroner, NOK, which equals about 450 million euro. In 2020 the new estimated cost was 6.8 billion NOK or 612 million euro, and in the summer of 2022, the investment became finalised at 9.1 billion NOK or 819 million euro. Oslo municipality has been obliged to pay 4.5 billion NOK equalling 405 million euro, although they initially agreed to pay 3.1 billion NOK, equivalent to 279 million euro. [46, 47]

2.4.2 Direct air capture

To capture CO_2 from the atmosphere direct air capture, DAC is used. There are two DAC methods that can be used, solid DAC, S-DAC, or liquid DAC, L-DAC. S-DAC is when solid absorbents operate under low pressure and temperatures varying from 80-120°C. L-DAC is when captured CO_2 is released through a series of DAC components, operating at a varying temperature between 300-900°C, with the help of aqueous basic solution. Figure 2.7 shows a graphic summary of how both L-DAC and S-DAC work. [43, 48]

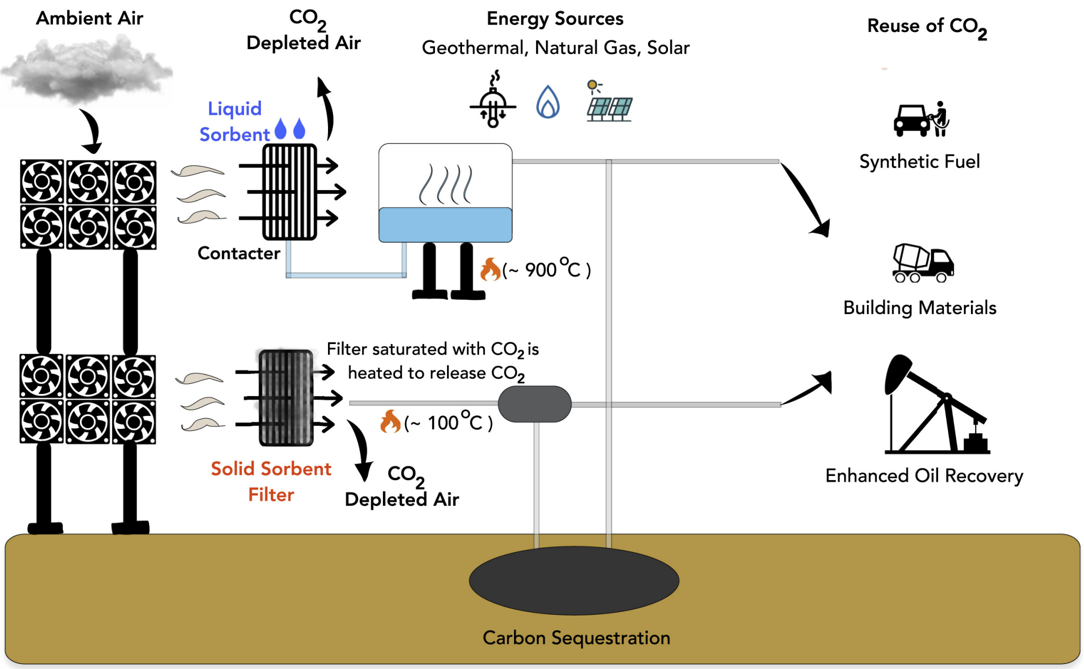


Figure 2.7: Principles of L-DAC and S-DAC [48].

During the S-DAC process, a large-scale collector machine is utilised, where fans draw in air through the machine. Subsequently, the air flowing through the machine goes through filters, where the CO_2 particles are trapped. When the filter is covered in CO_2 particles, the collector closes itself and the temperature increases. The high temperature makes the filter release the CO_2 so it can be either stored or utilised. [49]

When L-DAC is used, the start of the process is fairly similar to that of S-DAC. Fans in a large-scale machine are used to draw air into the machine, where it comes in contact with a chemical solution. The chemical solution binds the CO_2 molecules from the air and is subsequently sent through processes that separate the CO_2 from the solution, purifies, and compresses it. The CO_2 can then be used as feedstock for products or be stored underground. [50]

Even though L-DAC and S-DAC have approximately the same capital expenditure, CAPEX, the preferred method is currently S-DAC. This is because S-DAC is cheaper due to its low operating temperature, and in addition, it has the possibility of utilising waste heat from other processes, which might lead to an additional cost reduction. Because of this, it will most likely continue to be the preferred method for the foreseeable future. The biggest obstacle when it comes to DAC is power consumption. When comparing DAC to carbon capture from industries, carbon capture from industries is more power efficient and is, therefore, the more common choice. [51]

2.5 Methanol production

Methanol can be produced from many types of carbonaceous feedstocks, like natural gas, biomass, CO_2, coal and more. Just like hydrogen, most methanol that is produced today stems from natural gas. Nearly 100% of the total methanol production worldwide stems from fossil energy sources, while only about 0.2% comes from renewable energy sources. [2, 19]

2.5.1 Non-renewable methanol

Methanol can be produced in a lot of different ways, which has led to many different types of methanol. Although there are many types, most of them can still be used for the same purpose and use the same technology. Earlier on, methanol was produced through dry distillation of wood, which is when heat is used on solid materials to produce gaseous products or liquids. Today, methanol is produced almost exclusively synthetically and mainly by two methods. These methods are methanol-synthesis and partial oxidation of hydrocarbons from natural gas. Methanol synthesis is the hydrogenation of carbon monoxide under high pressure with a catalyst present. Hydrogenation is when hydrogen is added to an inorganic or organic compound. The feedstocks that are used to produce methanol include coal, natural gas, biomass and CO_2. [52, 53]

2.5.2 Methanol from natural gas

To produce methanol from natural gas, three production steps need to be completed. The first step is to produce syngas, which in this case consists of H_2, CO and CO_2. The syngas is made with either steam reforming or ATR. POX can also be used, in which CH_4, together with natural gas, is used as the input for oxidation. The next step is to convert the syngas into crude methanol, where methanol synthesis is used. Equation 2.12 and 2.13 shows the hydrogenation of CO, and Equation 2.14 shows hydrogenation of CO_2. These reactions happen under a pressure of between 50-100 bar and a temperature between 200-300°C. The crude methanol then needs to be distilled before it can be used. [19]

$$CO + H_2 \rightleftharpoons CH_2O \tag{2.12}$$

$$CH_2O + H_2 \rightleftharpoons CH_3OH \tag{2.13}$$

$$CO_2 + 3H_2 \rightleftharpoons CH_3OH + H_2O \tag{2.14}$$

One production site for methanol from natural gas in Norway is Equinor's facility at Tjeldbergodden, with an annual production of 900 000 tonnes of methanol. The production facility at Tjeldbergodden accounts for approximately 25% of Europe's methanol production and around 10% of Europe's consumption. [54, 55]

2.5.3 Methanol from biomass and coal

When coal or biomass is used as the feedstock, they are put into a gasifier to produce gaseous products, which include biogas, syngas, hydrogen and alkaline gases. When converting these gaseous products, Equations 2.1, 2.2, 2.15, 2.16 and 2.17 take place. Although both coal and biomass use the same process to make methanol, only biomass-based methanol is renewable. A common problem when using gasification on biomass is the risk of tar and char formation. For some gasifiers, like entrained flow gasifiers, the biomass must be pulverised so the particles are no bigger than 100 μm to avoid tar and char formation. [19]

$$C + H_2O \rightarrow H_2 \tag{2.15}$$

$$C + CO_2 \rightarrow 2CO \tag{2.16}$$

$$C + 2H_2 \rightarrow CH_4 \tag{2.17}$$

The gasification process of biomass, here described for an updraft gasifier, includes four steps, drying, pyrolysis, partial combustion and gasification. In the drying process, the biomass is dried to minimise any external and surface moisture the biomass may carry, as some biomass can have a moisture content of more than 90%. A high moisture content in the biomass is undesirable, as it means more energy is needed in the gasifier to vaporise the water. During the pyrolysis step, heat with a temperature of around 300-650°C is used to split the biomass into small molecules of gas, liquid and char.

When the steam meets the carbonaceous biomass and the combustion reaction, forming CO_2 happens. When the combustion reaction has used up most of the oxygen in the steam, the combustion reaction changes to partial combustion. During the partial combustion, carbon and oxygen gas react and form CO, and then the hot gas, which is a mixture of CO_2, CO and steam, moves into the gasification zone. Once the gas reaches the gasification zone, it reacts with the char in the upper bed, producing CO and H_2, reducing the CO_2 content of the gas. The result of gasification is a syngas containing all the compounds mentioned in this paragraph. [56]

A lot of separate processes are done during the distillation to remove as many harmful substances as possible, where one of the most important ones is the removal of sulphur. Sulphur removal is important as SOx is a highly unwanted product due to its toxicity. High air emissions of SOx can cause harm to both human health and the environment. SOx can decrease the growth of trees and plants if high enough concentrations are released, and it can affect the human respiratory system as well as make breathing difficult even in smaller amounts. These are just some of the many reasons to minimise and, if possible, avoid the production of SOx. [19, 57]

To remove sulphur from the syngas, there are a selection of processes that can be used. One of them is the rectisol process, which is a physical solvent gas treatment process where an organic solvent is used under low temperatures to remove acid gases. Other possibilities for sulphur removal include the sulfinol process, which includes a mix of chemical and physical solvents. [19, 57]

2.5.4 Methanol from CO_2

Methanol production from CO_2 is favourable as it means atmospheric CO_2 is used instead of roaming in the Earth's atmosphere, and there would be no need for storing the captured CO_2. CO_2 is a very stable chemical composition, as its outer shell fulfils the octet rule, making it not naturally react with other compositions and substances. Therefore when making methanol from CO_2, catalysts, a high energy input as well as optimised conditions are needed for the conversion. The CO_2 that would be used for the methanol production can be captured from the air or from industries. To convert CO_2 to methanol, the CO_2 is put through hydrogenation. This process is shown in Equation 2.14 where a catalyst is present. During this process, carbon capture technology can be used, which makes the process more sustainable. [19]

2.5.5 Renewable methanol

Synthesis in a chemical context means the production of a chemical compound by a reaction between simple compounds or elements. E-methanol synthesis is the hydrogenation reaction of carbon monoxide, and it is a great way of re-utilising CO_2. The conditions under the synthesis process use a temperature of 200-300°C and between 35-100 bar. Methanol synthesis is one of the most distinguished CO_2 re-utilisation processes, but as more CO_2 re-utilisation technologies emerge, the price rockets, and so do the production costs for methanol. [58, 59]

Green methanol is a low-carbon methanol that is produced with the help of renewable resources. Both bio-methanol and e-methanol are types of green methanol, where bio-methanol is produced from biomass, as mentioned in Section 2.5.3, and e-methanol is produced from green hydrogen and captured CO_2 with renewable energy. [60]

E-methanol, or electricity-methanol, is produced through four steps, which include electrolysis, carbon capture, conversion and purification. The first step is electrolysis which is used to produce the green hydrogen as mentioned in Section 2.1.6. Subsequently, CO_2 is captured so the CO_2 and hydrogen can be converted into methanol. To convert the hydrogen and CO_2, they are put into a reactor with a catalyst to combine it with methanol, as shown in Equation 2.14. Similarly to the other production methods of methanol, e-methanol also needs to be purified before it can be utilised. [61]

The complete e-methanol production process is shown in Figure 2.8. It starts with producing renewable energy and capturing CO_2. The energy from renewable sources is used to power the electrolysis process to produce green hydrogen gas. Subsequently, methanol synthesis takes place, producing crude methanol and water, as seen in Equation 2.14. The crude methanol is then put through a distillation process before it can be utilised.

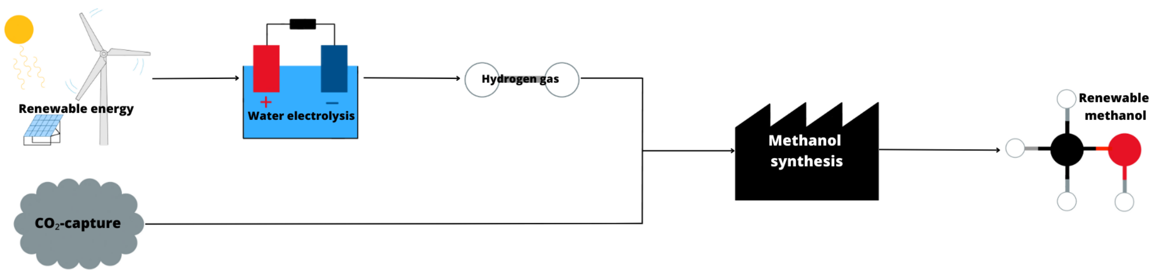


Figure 2.8: Schematic diagram of the production chain for green methanol.

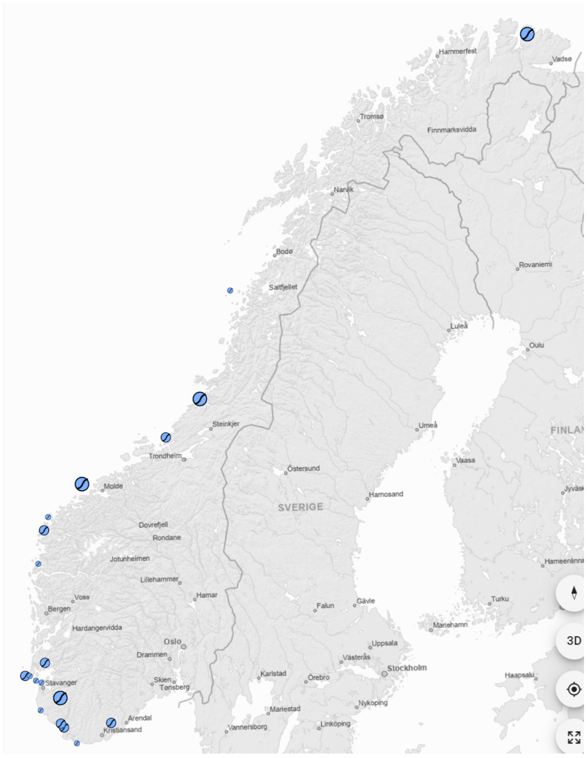
2.6 Wind energy

A wind turbine is used to convert the kinetic energy in the wind hitting the turbine blades, and the generator in the wind turbine converts the mechanical energy into electrical energy. When looking at the theoretical maximum efficiency of a wind turbine this is given by the Betz limit, which states that a wind turbine can not convert more than 59.3% of the kinetic energy provided by the wind. [62]

By assessing the available power from wind based on wind measurements in the areas and theoretical calculations, the possibility of hydrogen production from the establishment of a new wind farm might be assessed. To see what locations might be suitable for establishing a new wind farm, looking at where wind farms have already been built can give a good indicator.

The maps in Figure 2.9 show that most wind farms that have been built and are planned are in Trøndelag and Southern Norway. Figure 2.9a and Figure 2.9b clearly show that it is most common to establish wind farms close to the coast, which is because it is generally windier by the coast than inland [63]. Despite the few wind farms located in Northern Norway, the conditions here are suitable for wind energy as well. For example, the Raggovidda wind farm in Finnmark had 4 447.68 full load hours, FLH, in 2021, which corresponds to a capacity factor of 50.6%, which is high compared to the average in Norway of 30-38%.

(a) Map showing all established (dark green dots) and planned (light green dots) wind power plants in Norway [64].



(b) Map showing all wind farms that have a concession but have not started the building process [64].

Figure 2.9: The biggest dots are wind farms with an installed power of over 100 MW, the medium-sized dots show wind farms with an installed power between 10 and 100 MW, and the smallest dots show wind farms with an installed power of less than 10 MW [64].

3 Methodology

This section of the thesis will explain the approach used to obtain the results shown in the next section. This will include all relevant assumptions, data obtained and calculations made during the writing of the thesis. To simplify calculations, it is assumed that the methanol plant will be at full capacity at all times. This is an unlikely scenario because of fluctuations in available CO_2 and available power for the methanol plant. However, this still gives an indication of whether it would be feasible to establish a green methanol plant. Because of this, it would be necessary to sometimes buy power when the wind turbines do not produce enough, and this power is assumed to be bought with a guarantee of origin to ensure that the power used is still from renewable sources.

3.1 Assumptions

To be able to calculate and estimate values concerning the methanol plant, some assumptions had to be made. The results might not be completely reliable due to this, but it was found that the assumptions were realistic enough. The assumptions that were used are listed below.

- Methanol selectivity of the plant is 63.9% (99.96% if excluding water) [65].
- Catalyst cost is 8.8 €/kg for the $Cu/ZnO/Al_2O_3$ catalyst [66].
- The water type that is used for hydrogen production was not decided, but it was assumed that regardless of the water source, the price would be around 0.002 euro per litre.
- The OPEX of the electrolysers, compressor and methanol plant is assumed to be 4%, and the OPEX of wind turbines is assumed to be 3%.
- Outlet temperature of both alkaline and PEM electrolysers is 55°C [67].
- The CO_2 that will be used for production is bought from industries. It is assumed they have the technology to capture the CO_2 themselves so that the CAPEX for this is not involved in the cost analysis.
- Excess hydrogen is stored on-site, and the buyers pick it up where it is stored.
- Delivery trucks for compressed hydrogen are owned by companies purchasing the gas, so no additional CAPEX or OPEX is considered for transportation.
- Hydrogen selling price is 7 €/kg.

Since this thesis has a limited scope, there were some aspects of the e-methanol production pathway that was not taken into consideration. The red dotted line shows the system boundary in this thesis. As shown in Figure 3.1, carbon capture was not considered, as it was assumed the industry where CO_2 was obtained already had this technology installed, although this is not very likely. Another aspect that was not considered was the storage and distribution of methanol, as the use of methanol was not specified, which makes it difficult to determine the distribution system.

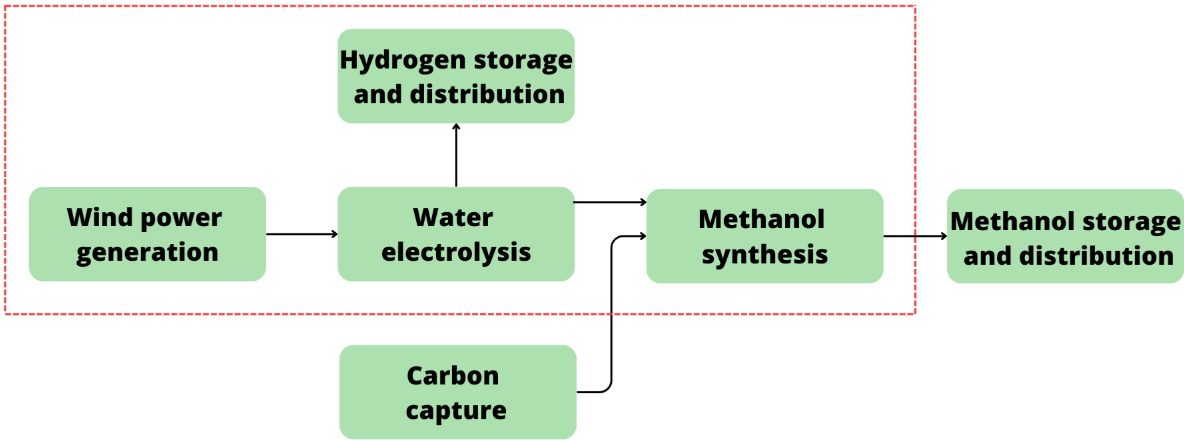


Figure 3.1: System boundary for this thesis.

3.2 Methanol plant specifications

This section will describe the theoretical methanol plant as well as the key parameters needed to calculate the necessary inputs and energy requirements. To calculate the necessary inputs for the methanol plant, the production goal for the plant was set to 75 000 tonnes per year. Equation 2.14 shows that for each mole of methanol created, three moles of H_2 and one mole of CO_2 is required. Based on these stoichiometric relations and the molar weights of each compound, the necessary CO_2 and H_2 inputs were found. The power consumption for methanol production was assumed based on other studies [68]. To calculate the necessary amounts of the reactants, the MATLAB script in Appendix E was used.

The production pathway chosen for the plant is direct hydrogenation of CO_2 to CH_3OH. The most common catalyst for methanol production is a Cu-ZnO-Al_2O_3 because of the high activity and methanol selectivity. Most studies conducted show that the methanol yield from this process is usually >99%, so to simplify the calculations, methanol yield from hydrogenation is assumed to be 100%. The yield of more than 99% is the amount of gaseous products, which means that the water from production is not taken into account. If the amount of water produced is taken into account as well, the methanol yield is approximately 63.9%. [68, 69]

The reactor that was used in this thesis is a loop reactor which operates at a temperature of about 250°C. The feed was mixed and heated before being fed into the reactor and converted over a Cu-ZnO-Al_2O_3 catalyst. The products were then cooled under a pressure of 80 bar, separating the liquids and gases. The gases are then purged of inert gases to prevent build-up of these before going through a recycle compressor and being re-fed into the reactor. The liquids are then cooled further under near atmospheric pressure of 2-4 bar, separating the crude methanol from other liquid products. [65, 70, 71]

The storage and distribution costs for methanol were not considered. This was done because it was assumed that the methanol could be shipped out directly after cooling. Since the use of methanol was not specified, it was difficult to decide which distribution method should have been used, so that is why these two factors were not included in the calculations.

3.2.1 Necessary amount of catalyst

To establish how much catalyst was needed, the gas hourly space velocity, GHSV, which is a measurement of how fast the gas moves through the reactor, was used. To be able to use this approach, an approximation for the porosity of the catalyst bed, ϵ, was needed. Equation 3.1 shows how to calculate the bed porosity, where A, n and B are constants that vary depending on the grain shape, D is the vessel diameter, and d is the grain diameter. For cylindrical catalysts, A is 0.9198, n is 2, and B is 0.3414.

$$\epsilon = \frac{A}{(D/d)^n} + B \tag{3.1}$$

Once the approximation for ϵ was found, the mass of the catalyst needed could be calculated based on GHSV, catalyst density $\rho_{catalyst}$, bed porosity and the mass flow of reactants in kg per hour. Equation 3.2a shows how the GHSV is calculated, and this can be rewritten to calculate the mass of the needed catalyst, as shown in Equation 3.2b.

$$GHSV = \frac{\rho_{catalyst} \cdot (1-\epsilon) \cdot Q_{reactants}}{Mass\ of\ catalyst} \tag{3.2a}$$

$$Mass\ of\ catalyst = \frac{\rho_{catalyst} \cdot (1-\epsilon) \cdot Q_{reactants}}{GHSV} \tag{3.2b}$$

3.2.2 CAPEX and OPEX for the green methanol plant

Estimating the CAPEX of a methanol plant is easier said than done, so the cost estimate of methanol plant parameters was generally based on data available in literature. Using total costs and technical characteristics of previous projects to estimate the cost of a current project is called a top-down estimate. Top-down estimates are generally done with limited information, yielding high levels of uncertainty. According to the Association for the Advancement of Cost Engineering, AACE International Recommended Practice, a study like this would be a Class 5 study, as it is based on limited information about the technical components of the plant. [72, 73]

The CAPEX for the methanol plant is the sum of both direct and indirect costs in addition to other costs related to establishing the methanol plant. Equation 3.3a shows how to calculate CAPEX. The individual posts that make up the total CAPEX for the methanol plant can all be expressed as a percentage of the fixed costs index, FCI, which consists of direct and indirect costs. The fixed costs can also be expressed in relation to the purchased equipment costs, PEC, which simplifies Equation 3.3a into 3.3b. In Equation 3.3a, SUC are the startup costs, WC is the working capital, LRD are costs related to licensing, research & development, and AFUDC is the allowance for funds used during construction. [74]

$$CAPEX = FCI + SUC + WC + LRD + AFUCD \tag{3.3a}$$

$$CAPEX = 6.32 \cdot PEC \tag{3.3b}$$

The PEC is calculated by obtaining data from the literature review. If the capacity of the equipment in the literature is different to the necessary capacity for the methanol plant in this thesis, Equation 3.4a can be used to find the PEC of this methanol plant. The cost of an equipment item with a capacity, X_Y, can be calculated when the cost of the same item $C_{PE,X}$ at another capacity, X_X has been given. The exponent α can, if other information is not given, be set to 0.6. If the cost given in the literature was for another year than 2023, the cost can be recalculated by using the Chemical Engineering Plant Cost Index, CEPCI, as shown in Equation 3.4b. [74, 75]

$$C_{PE,Y} = C_{PE,X} \cdot \left(\frac{X_Y}{X_X}\right)^{\alpha} \tag{3.4a}$$

$$C_{2023} = C_{reference\ year} \cdot \frac{CEPCI_{2023}}{CEPCI_{reference\ year}} \tag{3.4b}$$

The CEPCI consists of weighted averages of many different indices, and it is used as a quick way to evaluate costs for chemical and process industries. Table 3.1 gives the CEPCI values that are needed in this thesis as well as a conversion factor to go from American dollars to euros. [75]

Table 3.1: CEPCI values and conversion factor used in this thesis [75].

Reference year	**2016**	**2018**	**2020**	**2023**
CEPCI	541.7	603.1	596.2	801.4
Conversion	0.91 €/USD			

3.3 Choice of possible locations

To see whether it would be feasible to produce green methanol in Norway, four locations were considered. These locations are spread out across Norway's coastline, as that is usually where one can find the best wind conditions. The locations range from Båtsfjord in the north to Stavanger in the south, as shown in Figure 3.2. These locations all show promise for wind power production, given the wind conditions there.

Figure 3.2: Map showing the locations considered for a green methanol plant.

Another criterion for establishing a green methanol production plant is the availability of CO_2. All four locations lie in proximity to industrial sites that emit CO_2. However, the thesis will in Section 3.7 explore whether the available CO_2 from nearby industry will be enough to cover the necessary amount or if other choices, such as DAC, will need to be utilised.

3.4 Wind power production

To assess the potential of each of the locations, a wind turbine needs to be chosen to attain some key parameters needed to calculate wind energy production. Depending on the mean wind speed in the area, a wind turbine suited to those conditions is chosen based on the International Electrotechnical Commission, IEC classification [76].

After choosing a wind turbine and obtaining the power curve, the efficiency of the wind turbine at different wind speeds can be calculated, and the efficiency curve can be plotted. Equation 3.5a shows how to calculate the efficiency, η_{wind}. In the equation, P_{rated} is the rated power, ρ is the density of the air, A is the swept area, and v is the wind speed. [62]

$$\eta_{wind} = \frac{2 \cdot P_{rated}}{\rho \cdot A \cdot v^3} \tag{3.5a}$$

$$P = \frac{1}{2} \cdot \rho \cdot A \cdot \eta \cdot v^3 \tag{3.5b}$$

Once the efficiency curves for the wind turbines were made, wind data for each of the locations was obtained from Norsk Klimaservicesenter [77]. Here the mean wind speeds over a year with an hourly resolution can be downloaded to calculate the estimated production from wind turbines at the location, using Equation 3.5b. The script used to calculate and plot the efficiency and power curves and the expected production can be seen in Appendix B. The functions used in all the different MATLAB scripts can be seen in Appendix A.

Appendix B shows how the mean wind speed is calculated from the wind data collected. The power curve is then plotted based on available data from the wind turbine manufacturers, which in turn helps calculate the efficiency of the wind turbine. Then the interpolation function shown in Appendix A was used to calculate the yearly production from one wind turbine at each location. The yearly production is then used to calculate the capacity factor and number of FLH of the wind turbines. This is further used to calculate the values from Appendix D.

3.5 Wind conditions at the different locations

Given that the chosen locations all have different wind conditions, the wind turbines used at each of them need to fit the wind conditions there. To decide what wind turbine to use at each location, the basis of the decision was the IEC classes. Since not much data was available on the turbulence intensity at the locations, this parameter was not taken into consideration, and the decision was based solely on the mean wind speed. IEC class III is most suited for low wind speed locations, with an average mean wind speed of up to 7.5 m/s. IEC II class wind turbines are suitable for medium wind speeds, up to 8.5 m/s. The highest class, IEC I, is best suited for high wind speed areas with an annual average wind speed of up to 10 m/s. [76]

3.5.1 Båtsfjord, Finnmark

Figure 3.3 shows the wind in Båtsfjord plotted over each hour of the year. As can be seen from the plot, Båtsfjord rarely experiences wind speeds close to 25 m/s which is one of the more common cut-out wind speeds for wind turbines. Wind data from this location were measured nine metres above sea level, so wind speeds at the wind turbine's hub height might be higher than what is shown.

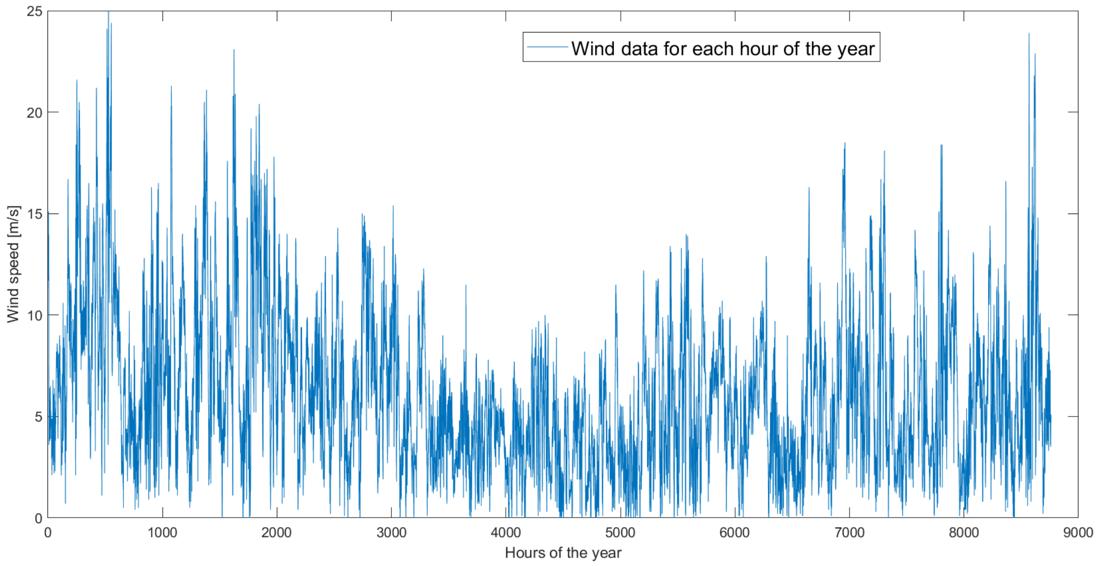


Figure 3.3: Plot showing wind data for Båtsfjord over a year.

Figure 3.4 shows the distribution of wind speeds in a histogram. Båtsfjord experiences most wind with speeds ranging from 2-7 m/s, making it a location with low wind speeds. Based on wind data from 2022, the mean wind speed in Båtsfjord is 6.13 m/s, and the median wind speed based on the same year is 5.4 m/s. According to these numbers, a wind turbine in the IEC III class should be chosen [76].

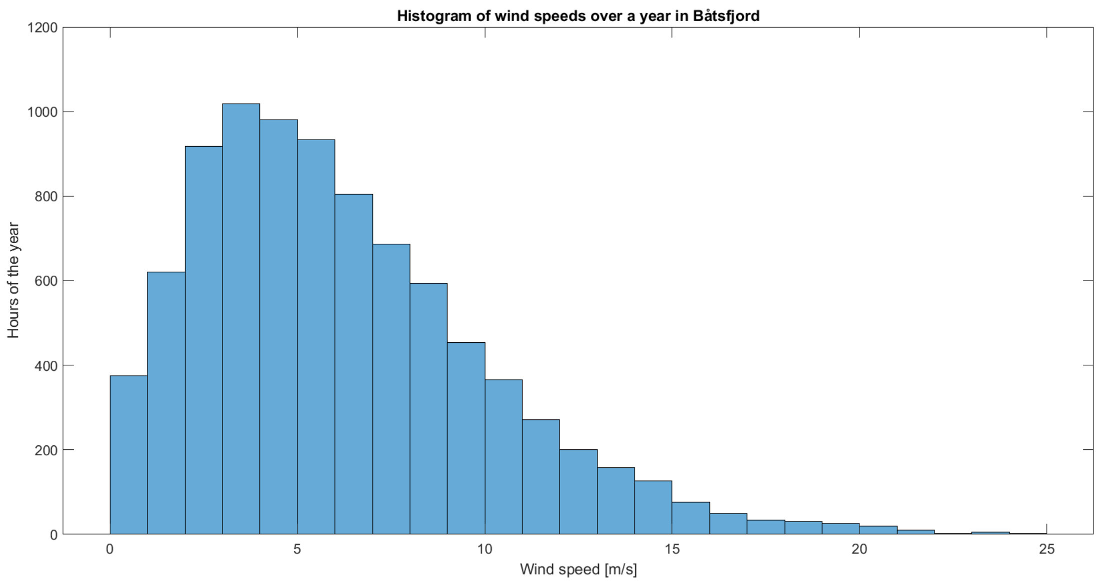


Figure 3.4: Histogram showing the distribution of the different wind speeds in Båtsfjord over a year.

Available data on the wind farms in Finnmark show that wind turbines with rated power close to 3 MW is common [78]. For a wind farm located in Båtsfjord, the Vestas 136-3.45 MW wind turbine was chosen because it belongs to the right IEC class, and is suitable for low- to medium wind-conditions [79]. Figure 3.5 shows the power and efficiency curve of the wind turbine chosen for Båtsfjord.

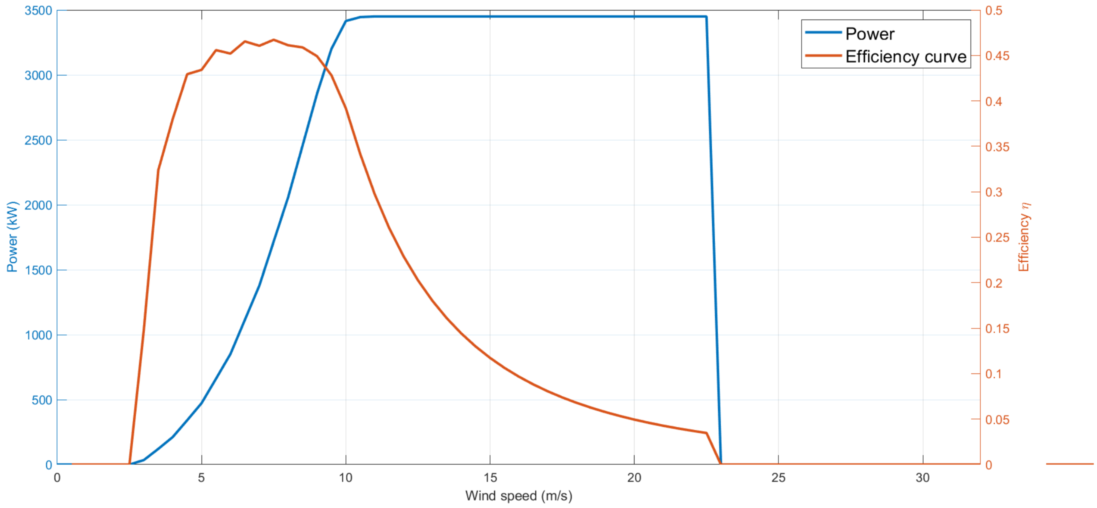


Figure 3.5: Power and efficiency curve of the Vestas 136-3.45 wind turbine [79].

3.5.2 Rana, Nordland

Further south in Northern Norway lies Rana, the biggest industrial municipality in Nordland [80]. Like Båtsfjord, Rana rarely experiences wind speeds close to 25 m/s, but from the plots, Rana appears to have a higher mean wind speed, as seen in Figure 3.6.

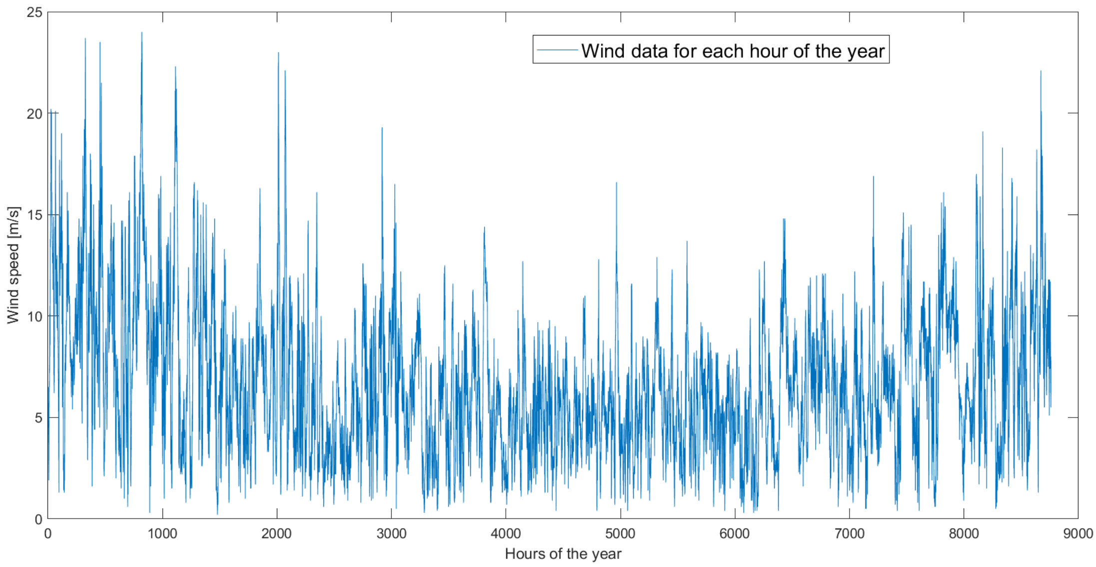


Figure 3.6: Plot showing wind data for Rana over a year.

The histogram in Figure 3.7 shows that Rana has the most wind with wind speeds between 3-7 m/s. The mean wind speed in Rana based on wind data from 2022 was 6.71 m/s, and the median wind from the same year was 6.2 m/s, which also makes Rana a low wind speed location. A turbine from the IEC III class would be recommended here as well, and the rated power of wind turbines in the county varied from 2.3 MW to 5.6 MW. To make calculations easier, the Vestas 136-3.45 MW wind turbine was chosen for this location as well, for power and efficiency curves, see Figure 3.5 [79].

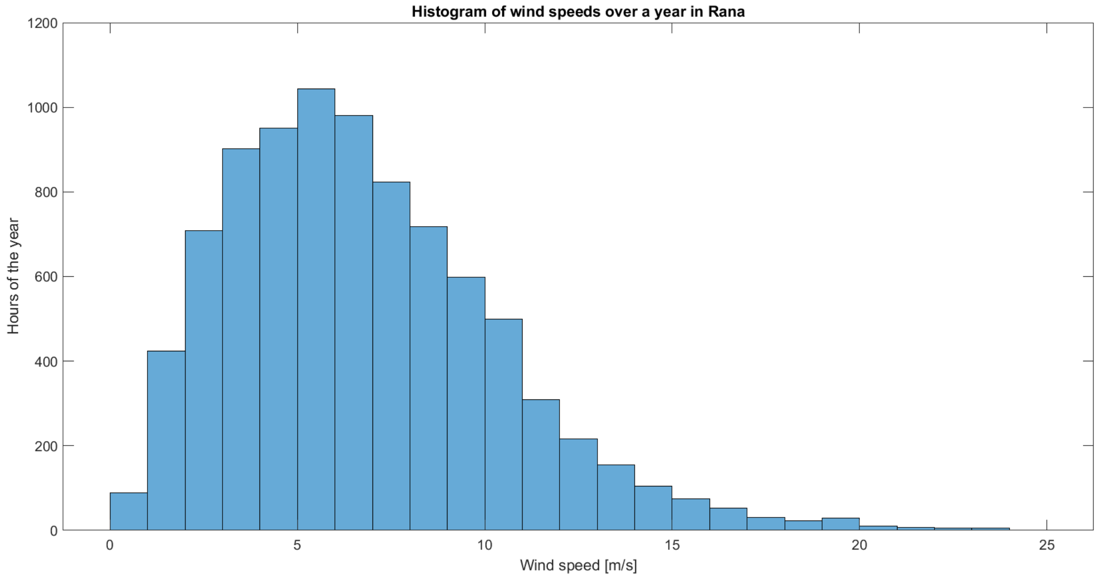


Figure 3.7: Histogram showing the distribution of the different wind speeds in Rana over a year.

3.5.3 Måløy, Vestland

Figure 3.8 shows the mean wind speed in Måløy plotted over each hour of the year. This location has wind speeds ranging from 0 m/s to 30 m/s, but the distribution of wind speeds suggests that the mean wind speed is not very high because of the high amount of hours with low wind speeds.

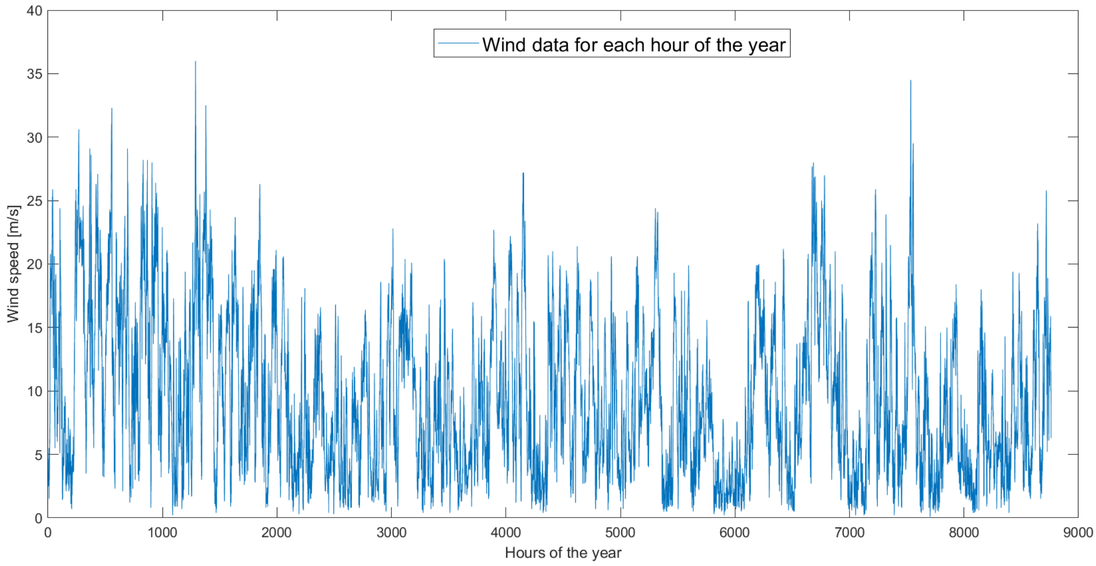


Figure 3.8: Plot showing wind data for Måløy over a year.

The histogram in Figure 3.9 shows that Måløy has the most wind ranging in speed from 2-6 m/s, but it also has many hours of higher wind speeds up to 17 m/s. The mean wind speed in Måløy was 9.47 m/s, and the median wind speed was 8.30 m/s. As the mean wind speed exceeds 8.5 m/s, a wind turbine in the IEC I class would be best suited here. The Vestas V136-4.2 wind turbine was chosen for this location because it is possible to get these suitable for high wind speed areas. [81, 82].

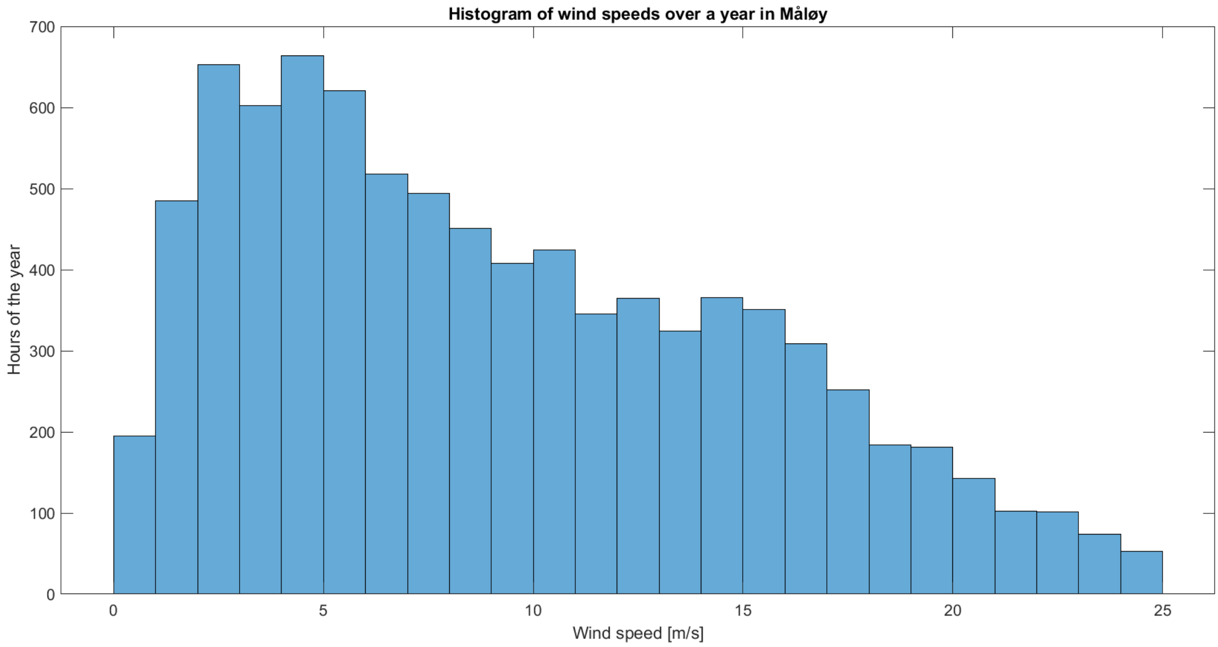


Figure 3.9: Histogram showing the distribution of the different wind speeds in Måløy over a year.

Figure 3.10 shows the power and efficiency curves of the wind turbine chosen for Måløy. As can be seen from the figure, this wind turbine has the highest efficiency for wind speeds in the range of 5-10 m/s, which is good when the mean wind speed is approximately 10 m/s.

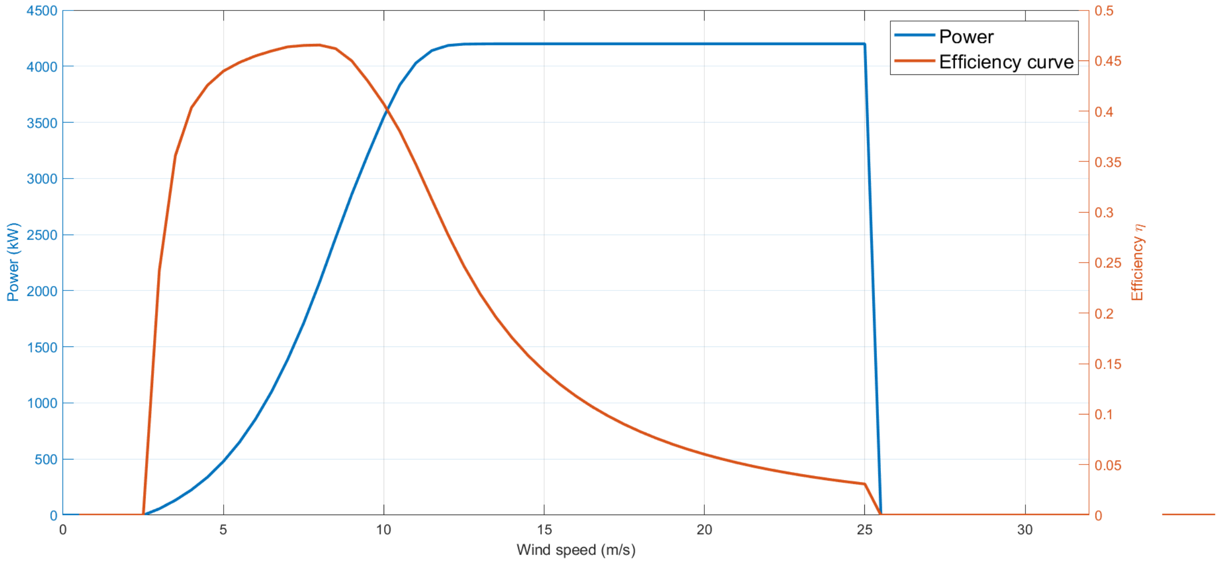


Figure 3.10: Power and efficiency curve of the Vestas 136-4.2 wind turbine [82].

3.5.4 Stavanger, Rogaland

Figure 3.11 shows the mean wind speeds for Stavanger for each hour of the year. This location does experience high wind speeds close to 30 m/s, but most wind data seems to be around 5-10 m/s, suggesting that the mean wind speed is not very high.

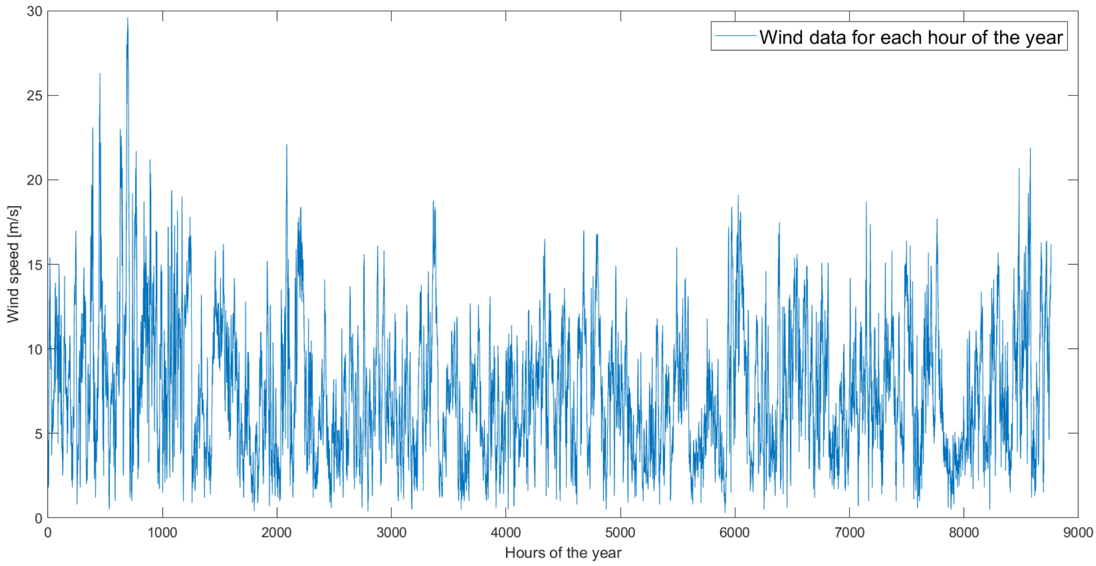


Figure 3.11: Plot showing wind data for Stavanger over a year.

Figure 3.12 shows the distribution of the different wind speeds in Stavanger, and most hours of the year seem to have wind speeds ranging from 3-9 m/s. The mean wind speed in Stavanger was 7.5 m/s, and the median wind speed was 6.9 m/s. Based on these numbers, a wind turbine of the IEC II class should be chosen. Wind turbines in the area have a rated power between 2.3 and 4.2 MW, so the wind turbine chosen for this location was Nordex N117/3600 Delta [83, 84].

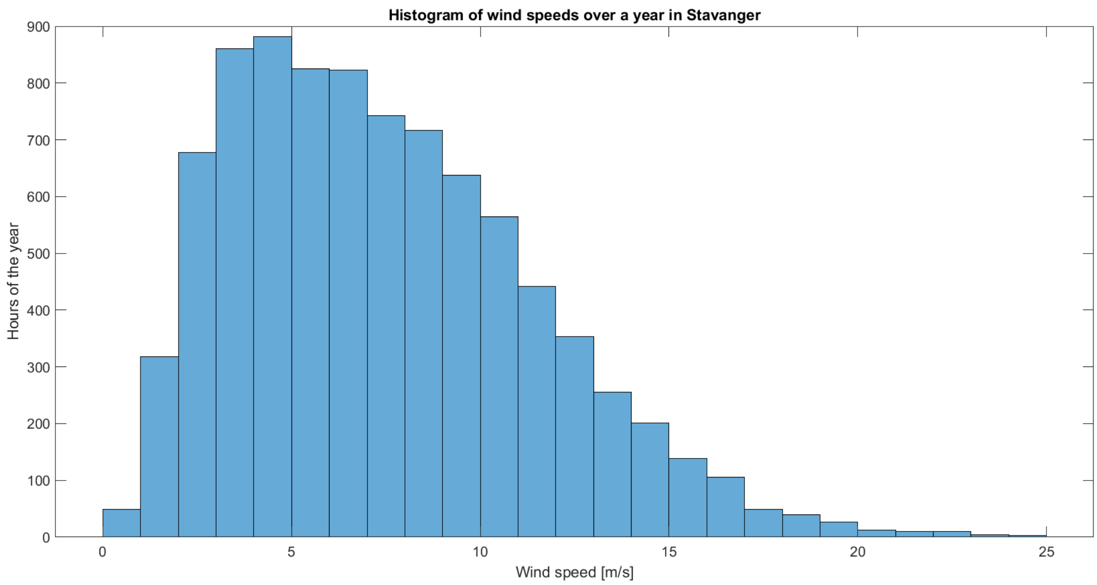


Figure 3.12: Histogram showing the distribution of the different wind speeds in Stavanger over a year.

Figure 3.13 shows the power and efficiency curve of the Nordex 117/3600 Delta wind turbine, which is the wind turbine chosen for Stavanger. It reaches its rated power at approximately 13 m/s, where the efficiency of the wind turbine is approximately 30%.

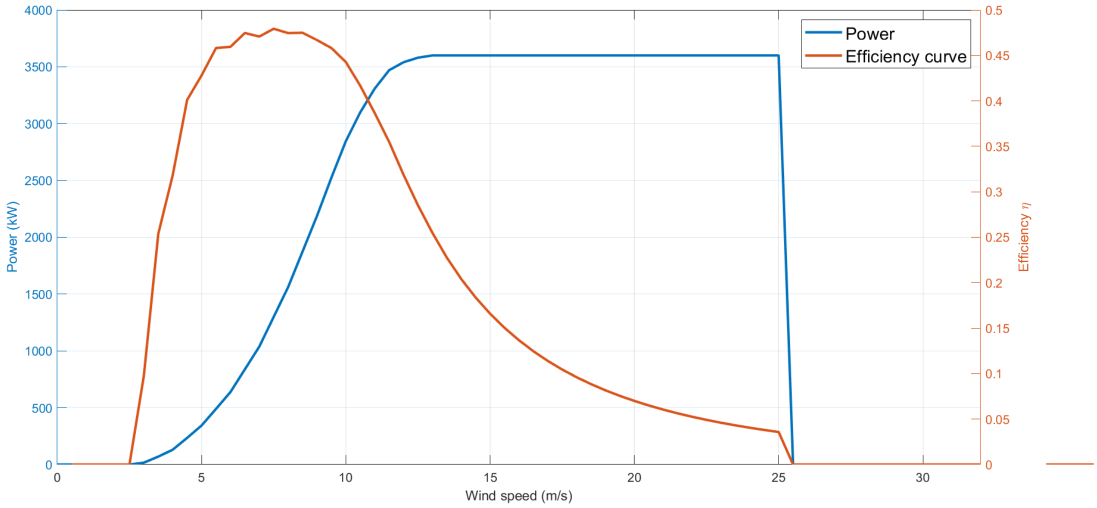


Figure 3.13: Power and efficiency curve of the Nordex 117/3600 Delta wind turbine [83].

3.6 Electrolyser specifications

The two most mature technologies are PEM and alkaline electrolysis, which is why these two technologies will be the focus of this thesis. These are also the most suited for wind power, as they do not require additional heat, since the operational temperatures range from 50°C to 90°C. [67]

AEM, PCEC and SOEC have a few challenges to overcome before they are ready to be applied on a large scale. However, these technologies all show promise for future hydrogen generation. PCEC and SOEC also require the addition of both heat and power to function, making them more suited for other power sources, such as solar or nuclear, that provide heat.

Wind power is an intermittent energy source, and as such, it is necessary with an electrolyser that can adapt to the fluctuations in the wind. The most flexible electrolyser currently available for large-scale use is the PEM electrolyser, making it the most suitable for wind-powered H_2 production. The reason PEM electrolysers are more flexible than alkaline is because they have a significantly lower ramp-up time than alkaline, meaning that it does not take as long to go from low to high production. Alkaline electrolysers are not ideal for wind power, as they have a slow response time and are therefore less flexible than PEM electrolysers. [85]

The electrolysers that will be considered in this thesis are from the Norwegian company NEL, as they have many models to choose from in both PEM and alkaline electrolysers. The module size of NEL's electrolysers ranges from 2 MW to 25 MW, and for this thesis, the largest modules available were chosen. Table 3.2 shows the characteristics of the electrolysers considered in the thesis.

Table 3.2: Characteristics of the chosen electrolysers [86, 87, 88].

Specifications	**M5000**	**A3880**
Technology	PEM	AEL
Module size [MW]	(25.0)	(17.6)
Efficiency [%]	64	67
Max production [Nm^3/h]	4 920	3 880
Water consumption [l/Nm^3]	0.9	1.0
Water consumption [l/kg]	10.01	11.1
Energy consumption [kWh/Nm^3]	4.5	4.4
Energy consumption [kWh/kg]	50.06	48.9
Output pressure [bar]	30	30

Appendix D shows how the necessary amount of electrolyser modules and wind turbines are calculated. First, parameters for both PEM and alkaline electrolysers were found and added to the script. An if statement for each of the electrolysers was put together to be able to calculate the necessary parameters. Among these were water consumption, average power consumption, and net production rate, NPR.

To calculate the number of electrolyser modules, the necessary hydrogen production each hour was divided by the NPR times efficiency of the electrolysers, and then the number was rounded up to ensure the production would exceed the necessary amount. Rounding up necessary electrolyser modules results in excess hydrogen each year, this was included as an extra income source. This then gave the water consumption and electricity need. Once these parameters had been obtained, the function shown in Figure A.2 was used to obtain the number of wind turbines needed, wind energy production vector, and vector of energy that needs to be bought to keep the hydrogen production steady.

3.6.1 Excess hydrogen distribution and storage

Before hydrogen gas can be stored, it needs to be compressed to at least 200 bar, which is the minimum operating pressure of steel tanks, which is the chosen storage option for this thesis. To calculate the necessary compressor work, the outlet temperature of the compressor needed to be found. For isentropic compression, Equation 3.6 gives the coherence between temperature and pressure. T_2 and T_1 are the outlet and inlet temperature of the compressor respectively, and p_2 and p_1 are outlet and inlet pressure. The constant γ is the isentropic coefficient of hydrogen as an ideal gas, which is 1.4 for hydrogen gas.

$$\frac{T_2}{T_1} = \left(\frac{p_2}{p_1}\right)^{\frac{\gamma-1}{\gamma}} \tag{3.6}$$

Once the outlet temperature of the gas had been found, the isentropic compression work could be calculated from Equation 3.7. M_{H2} is the molar weight of hydrogen, and Q_m is the mass flow of hydrogen through the compressor at standard temperature and pressure, STP, each hour in tonnes/hr, and the variable κ is the isentropic coefficient for real gases. From the isentropic compressor work, actual compressor work could be found by dividing it by the efficiency of the compressor, which was set to 75% in this thesis. CAPEX of the hydrogen compressors was calculated based on the installed power of the compressor, and OPEX was set to be 4% of the CAPEX. The compressor energy requirement was set to 1.4 kWh/kg hydrogen. [89, 90]

$$P_{is} = 2.31 \cdot \frac{\kappa}{\kappa - 1} \cdot \frac{T_2 - T_1}{M_{H_2}} \cdot Q_m \tag{3.7}$$

Hydrogen storage tanks were designed to fit excess hydrogen for a week of production, assuming that this would be a reasonable amount. The tank sizes were calculated based on the mass of hydrogen that needed to be stored, and then CAPEX and OPEX were calculated based on the necessary tank volume. For the refuelling station, the total capital cost was based on data found in literature, and to calculate the CAPEX Equation 3.8 was used. In the equation, C_1 is the mass of hydrogen to be refuelled per day, α is the scaling factor, which is 0.7, and γ is the station multiplier, which is 0.6 for gaseous hydrogen stations. [91]

$$CAPEX = 1.3 \cdot 600{,}000\ EUR \cdot \gamma \cdot \left(\frac{C_1}{212}\right)^{\alpha} \tag{3.8}$$

3.7 CO_2 sources at each location

As the carbon source for green methanol production is CO_2, a suitable source of CO_2 needs to be in close proximity to the methanol plant. This section will look into whether such a CO_2 source is present at each location, looking at both renewable and non-renewable options.

3.7.1 Båtsfjord

There is currently a biogas plant in Båtsfjord that releases the CO_2 from its production directly into the atmosphere, making it a possible CO_2 source for a green methanol plant. The current production from the biogas plant is 25 Nm^3/hr, with 60-65% methane, CH_4, and the remaining 35-40% is CO_2. The biogas produced at Liholmen biogas plant is used in a combined heat and power, CHP ,that provides Liholmen and surrounding industry with heat and power. [92]

Another possible CO_2 source for this location is the Melkøya LNG facility in Hammerfest which is currently powered by gas turbines, resulting in about 850 000 tonnes of CO_2 annually. The Melkøya facility is supposed to be electrified in the coming years, so this possibility will not be one that is available in the long run [93]. Another possible future source of CO_2 in this area is the Barents Blue project, which will produce blue ammonia. The annual CO_2 emissions from this project are estimated to be around two million tonnes which would be more than enough for the theoretical methanol plant. [94]

3.7.2 Rana

In Rana, there is a large industrial park called Mo Industripark consisting of many companies, hereunder Elkem Rana AS, that have a ferrosilicon factory with CO_2 emissions of around 300 000 tonnes per year. They are the first smelting plant in the world to implement carbon capture, and the testing of carbon capture on their smelters started in 2022. Along with Elkem Rana, several other companies at Mo Industripark have joined with SINTEF to further examine the possibility of CO_2 capture and utilisation. This makes way for an agreement to purchase some of the captured CO_2 from this cluster of industries, making for a steady supply. [95, 96]

3.7.3 Måløy

Måløy was chosen as a possible location because of the wind conditions, making it ideal for a wind farm. It is a small township in Vågsøy, Vestland County, with an area of 2.2 km^2. When it comes to CO_2 availability, that would need to be brought in from nearby areas, such as Florø or Ålesund, that have more available CO_2. [97, 98].

In Florø, Equinor and Neptune Energy Norway have signed an agreement with Ocean Hyway Cluster to identify which of their processes and supply chains have the highest potential for decarbonisation. Equinor is looking to decrease their CO_2 emissions by 70% by 2040, while Neptune Energy Norway plans to store more CO_2 than is emitted from production and usage of their sold products. The CO_2 from this collaboration might be a future source of CO_2 if an agreement to purchase the captured CO_2 could be reached. [99]

3.7.4 Stavanger

Stavanger is one of the most prominent municipalities in Norway when it comes to the oil and gas industry. Because of this, there are large CO_2 emissions there. One of the largest point emission sites in Norway is the Kårstø process plant with annual emissions of 950 000 tonnes CO_2. This site alone can supply more than nine times the amount of CO_2 needed for the production of 75 000 tonnes of green methanol. [100]

3.8 Economic evaluation

Due to the recent power crisis, power prices have skyrocketed and have been higher than ever before. At NorgesEnergi, the average power price of the last 12 months can be seen for different zones in Norway. The different zones and their borders are shown in Figure 3.14. It is important to note that customers in zone four are exempt from paying the value-added tax, VAT, grid fee and consumption tax. [101]

Figure 3.14: The map shows the different power zones in Norway. Zone 1 is southeast, 2 is south, 3 is mid, 4 is north, and 5 is west [101].

For households in August of 2022, the average power price in Norway was 0.26 €/kWh, while it was 0.098 €/kWh in April of 2023. In Table 3.3, it is clear that the power prices in Norway vary a lot based on location. The power prices are lowest in Northern Norway and the highest in South Norway. The power crisis that started in 2021 made the power prices high and kept them up through a big part of 2021. Only now are they slowly decreasing, although they still vary from day to day. As some power prices had to be selected for the calculations, three power prices were chosen, which were 0.05 €/kWh, 0.08 €/kWh, and 0.1 €/kWh. [101]

Table 3.3: The average household electricity price in øre/kWh from August 2022 compared to April 2023, which was converted into NOK/kWh and then into €/kWh with a conversion factor of 0.09 [101].

Zone	S1	S2	S3	S4	S5	Average price [øre/kWh]	Average price [€/kWh]
August, 2022							
Power price [øre/kWh]	430.36	543.11	23.61	2.82	426.97	285.37	0.26
April, 2023							
Power price [øre/kWh]	138.67	138.67	87.01	40.37	141.13	109.17	0.098

Power intensive industry is industry that requires a lot of power for production purposes. Since this green methanol plant would qualify as such, a lower price rate for electricity can be negotiated with the energy supplier of choice, as well as being exempt from paying grid fees.

For the economic aspect of the thesis, data on CAPEX and OPEX were collected from a range of sources. Establishing a methanol plant requires a significant amount of money, and calculations to see whether the project is profitable are necessary. Some methods of economic evaluation that will be used in this thesis are listed and explained below. Figure 3.15 shows the process of obtaining the necessary data to complete the calculations.

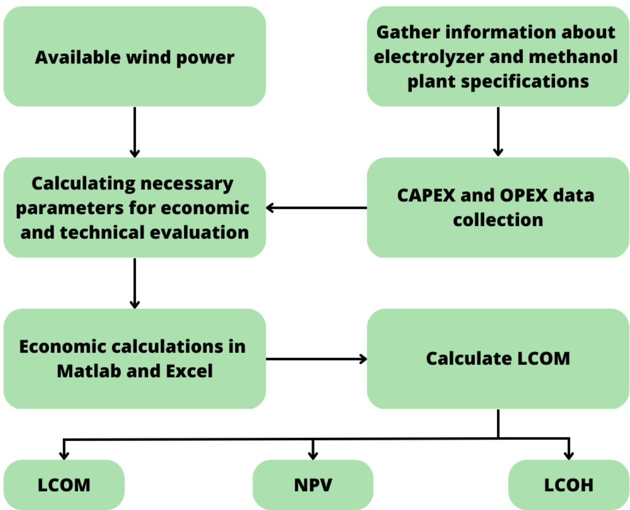


Figure 3.15: Flow chart showing the approach to obtain necessary parameters.

The e-methanol selling price was calculated based on an average of the spot price for methanol from March 2022 to February 2023, which came out to 375 €/tonne. If the contract price of methanol had been used, the selling price of methanol would have been 540 €/tonne. The lower of the two was chosen to make sure that the selling price would not be overestimated. [102]

3.8.1 Levelised costs

The levelised cost of something is the price at which said product needs to be sold for the project to break even. To calculate levelised costs, the total levelised cost, TLC, of the project needs to be calculated, as shown in Equation 3.9. N_e is the lifetime of the project, t denotes years after the plant becomes operational, and r is the return rate.

$$TLC = CAPEX + \sum_{t=1}^{N_e} \frac{OPEX}{(1+r)^t} \tag{3.9}$$

The total levelised cost is the sum of all CAPEX and discounted OPEX over the plant lifetime, which is set to 20 years. Once this has been calculated, the levelised cost can be calculated using Equation 3.10, where X is a product, either energy, hydrogen or methanol in this thesis. E_m is the total amount of product produced each year, which is also discounted. The discount rate is set to be 6% as this seems to be the most common for energy-related projects in Norway.

$$LCO(X) = \frac{TLC}{\sum_{t=1}^{n} \frac{E_m}{(1+r)^t}} \tag{3.10}$$

The levelised costs to be calculated in this thesis are the levelised cost of energy, LCOE, from wind turbines, levelised cost of hydrogen, LCOH, and levelised cost of methanol, LCOM. The LCOE can be used to determine whether or not it is more profitable to utilise the energy produced by wind turbines or buy power from the grid. LCOH can help determine whether it is better to produce hydrogen for methanol production or if it would be more economical to buy hydrogen from a supplier. LCOM can be used to see whether or not the produced methanol will be competitive on the market.

3.8.2 Net present value

The net present value, NPV, of a project determines whether the project is profitable. The method uses the investment cost as well as discounted cash flows to determine if the project would be profitable. When the cash flow for each year is different, NPV is calculated using Equation 3.11a, but when the cash flow is the same each year, Equation 3.11b can be used. A positive NPV means that the project will be profitable with respect to the chosen return rate. To see what return rate makes a project break even, the NPV can be set to zero, and the equation is then solved with respect to r.

$$NPV = -CAPEX + \sum_{t=0}^{N_e} \frac{Cash\ flow}{(1+r)^t} \tag{3.11a}$$

$$NPV = -CAPEX + Cash\ flow \cdot \frac{1-(1+r)^{-N_e}}{r} \tag{3.11b}$$

3.8.3 Discounted payback period

The discounted payback period, DPP, of a project is the time it takes for the project to recover the cost of the initial investment, CAPEX. A shorter payback period is better, as this means the project is profitable. It is preferable to use discounted payback period instead of not discounting the annual cash flows, as this takes the present value of future cash flows into account. To calculate the discounted payback period, Equation 3.12 is used.

$$Discounted\ payback\ period = \frac{CAPEX}{\sum_{t=0}^{N_e} \frac{Annual\ cash\ flow}{(1+r)^t}} \tag{3.12}$$

4 Results

This section will present the results from the calculations and the literature review done previously. This includes both technical specifications, such as the number of wind turbines and electrolyser modules, as well as economic results. The economic results include CAPEX and OPEX for each individual asset and for the entire system, providing the LCOM and NPV of the project. For easier reading, most values have been rounded off, but the full values can be found in the Appendices.

4.1 Technical specifications

The technical specifications form the basis for economic evaluations, and these will therefore be presented before economic results. Technical specifications are largely calculated by the MATLAB scripts in the appendices, but some parts are based solely on data found in the literature review.

4.1.1 Methanol plant

The first thing that was decided was the amount of methanol to be produced, which was 75 000 tonnes of methanol per year. Based on this number, the methanol yield from synthesis and molar weights of compounds, the necessary amount of CO_2, H_2 and catalyst were calculated, as shown in Table 4.1.

Table 4.1: Green methanol plant specifications.

Methanol production (t/yr)	75 000
(t/day)	205.5
Necessary CO_2 (t/yr)	103 000
(t/day)	282.2
Necessary H_2 (t/yr)	14 160
(t/day)	38.8
Needed catalyst (kg)	597.6
Power consumption (kWh/t CH_3OH)	550

4.1.2 Power production from the wind turbines

Table 4.2 shows the total yearly production from the theoretical wind farms at each location, as well as the necessary bought energy and capacity factors of the wind farms. Måløy has the highest production and capacity factor, making it the most suitable for wind power production. Båtsfjord is the location with the lowest wind power production, with 64% of the needed electricity needing to be bought to keep the electrolysers running.

Table 4.2: Calculated parameters for each location with alkaline and PEM electrolysers.

Location	Båtsfjord	Rana	Måløy	Stavanger
Alkaline electrolyser				
Number of wind turbines	16	16	13	16
Produced energy [GWh]	168.9	196.4	250.0	199.3
Bought energy [GWh]	306.0	278.5	224.9	275.6
Capacity factor [%]	35.20	40.90	53.49	40.35
PEM electrolyser				
Number of wind turbines	16	16	13	15
Produced energy [GWh]	165.4	192.5	242.6	188.2
Bought energy [GWh]	288.2	261.2	211.1	265.4
Capacity factor [%]	35.20	40.90	53.49	40.35

Figure 4.1 shows monthly wind power production for each location with alkaline electrolysers. Måløy had the highest mean wind speed and the most hours of wind speeds where the wind turbine operated at its rated power, resulting in the highest production as well.

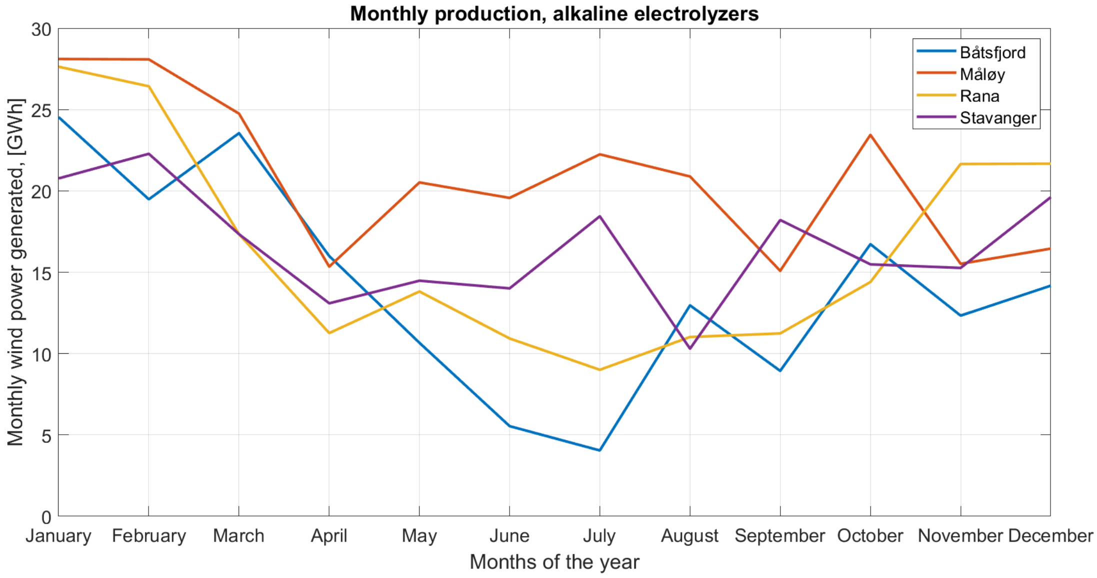


Figure 4.1: Monthly power production for wind turbines powering alkaline electrolysers.

Figure 4.2 shows the wind power production with PEM electrolysers, and one thing worth noting is that for all locations except Stavanger, the production goes down. This can be attributed to the additional wind turbine in Stavanger and the lower number of PEM modules, resulting in a lower total APC.

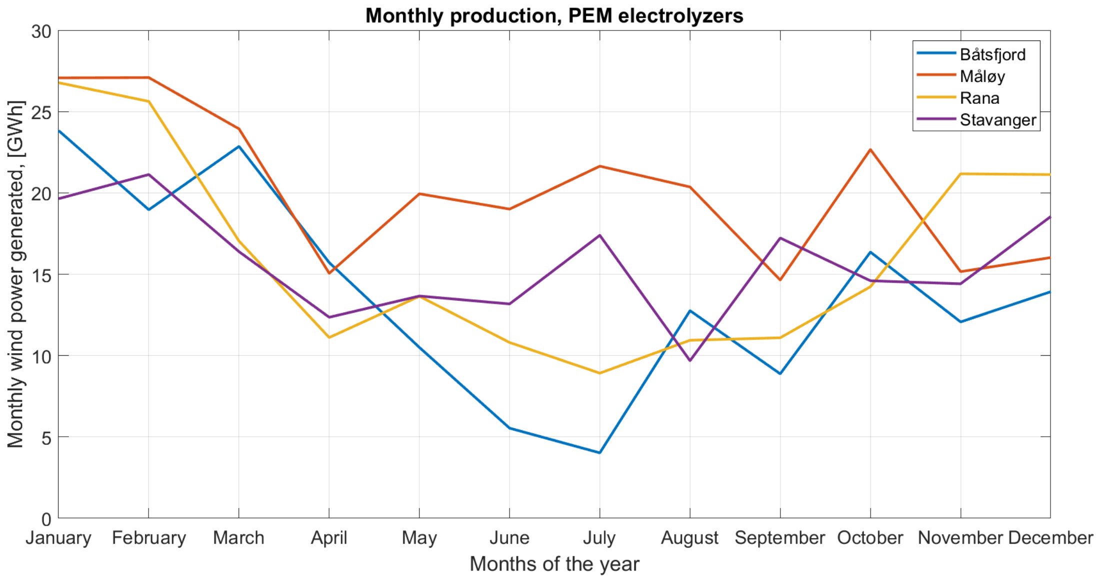


Figure 4.2: Monthly power production for wind turbines powering PEM electrolysers.

The amount of wind power produced is higher than what is shown in Table 4.2, but the max wind power production was set to not exceed the amount needed by electrolysers at any time. This means that some of the electricity is lost as a result of this and is not used to power any appliances. In Båtsfjord and Rana with PEM electrolysers, the total amount of wind power exceeds the amount shown in Table 4.2 by 5 GWh. In Stavanger, the actual production is 2.6 GWh higher, and in Måløy, the production is 8.5 GWh higher.

4.1.3 Levelised cost of energy

To better compare the economic value of the wind turbines at each location, it was decided to look at the levelised cost of energy for the wind turbines. This was done using Equation 3.10, but substituting methanol production with discounted wind power production in kWh. Table 4.3 shows the LCOE for all the different locations. One thing worth noting is that all locations except Stavanger have the same number of wind turbines for both PEM and alkaline. However, the LCOE is the same for Stavanger, regardless of electrolyser type.

Table 4.3: LCOE for the different locations

	Total discounted wind power production [TWh]	Total discounted lifetime costs [M€]	LCOE [€/kWh]
Båtsfjord	1.95	129.70	0.0664
Rana	2.27	129.70	0.0572
Måløy	2.88	128.29	0.0446
Stavanger	2.19	126.88	0.0580

As can be seen from the table, the location with the lowest LCOE is Måløy, which is unsurprising because of the high wind power production here. Båtsfjord has the highest LCOE because of the low production, and Stavanger and Rana both lie in the middle.

4.1.4 Hydrogen production

For electrolysers, the OPEX is a function of the CAPEX and is set to 4% of CAPEX for both PEM and alkaline. The OPEX of electrolysers excludes water and electricity costs since these parameters will vary with hydrogen production, meaning that these were calculated separately. [67]

Table 4.4: Calculated electrolyser parameters for the two electrolyser types [67].

Electrolyser	M5000 (PEM)	A3880 (Alkaline)
Water consumption [L/hr]	16 200	18 000
Average power consumption [MWh/hr]	51.79	54.21
Number of modules needed	6	7
Production rate [Nm^3/hr]	18 900	18 200
Production rate [kg/hr]	1 700	1 600
CAPEX [M€]	123.75	78.54
OPEX excl. water and power, [M€/yr]	4.95	3.14
Lifetime of stack hrs	65 000	65 000

For the following figures, the number of FLH, see Appendix H and G, that most closely corresponded to the given capacity factor of the electrolysers, 64% for PEM and 67% for alkaline, was used as the reference. 6000 FLH corresponds to a capacity factor of 68.5% which is a little higher than the electrolyser capacity factors, but it is the value that was closest. Some of the necessary parameters related to the electrolysers are summarised in Table 4.4.

For both PEM and alkaline electrolysers, the necessary hydrogen production barely exceeded the amount that could be produced by five and six modules, respectively. This resulted in six PEM modules and seven alkaline modules, which in turn gave an excess amount of hydrogen produced. It was decided to sell the excess hydrogen, which meant additional CAPEX and OPEX for storage and distribution, shown in Figure F.2a. For PEM electrolysers, 5.03 million €/year could be gained from the excess hydrogen, and for alkaline electrolysers 1.19 million €/year could be gained, as shown in Figure I.1a.

It was decided to have storage for one week's worth of hydrogen for both PEM and alkaline, resulting in different storage tank volumes. For alkaline electrolysers, the tank needed to store 3 265 kg of hydrogen, and for PEM, 13 769 kg of hydrogen needed to be stored. From these numbers, it is clear that the PEM electrolysers were the most oversized.

In Appendix F, it can be seen that for an entire year, the water consumption of the electrolysis system is 232.7 million and 237.9 million litres per year for PEM and alkaline electrolysers, respectively. As mentioned in Section 2.3.6, the average water consumption per person in Norway is 179 litres per day, which equals 65 335 litres a year. For comparison, this implies that the water consumption used for hydrogen production is equal to 3562 Norwegian individuals' yearly water consumption each year when PEM electrolysers are used and 3641 Norwegian individuals when alkaline electrolysers are used.

4.1.5 Results for the entire system

Figure 4.3 shows some of the parameters that were calculated for the green methanol plant in a graphic abstract, showing material and energy flows within the system. Lines where two values are displayed are where results for PEM and alkaline electrolysers, or results for the locations, differ from one another.

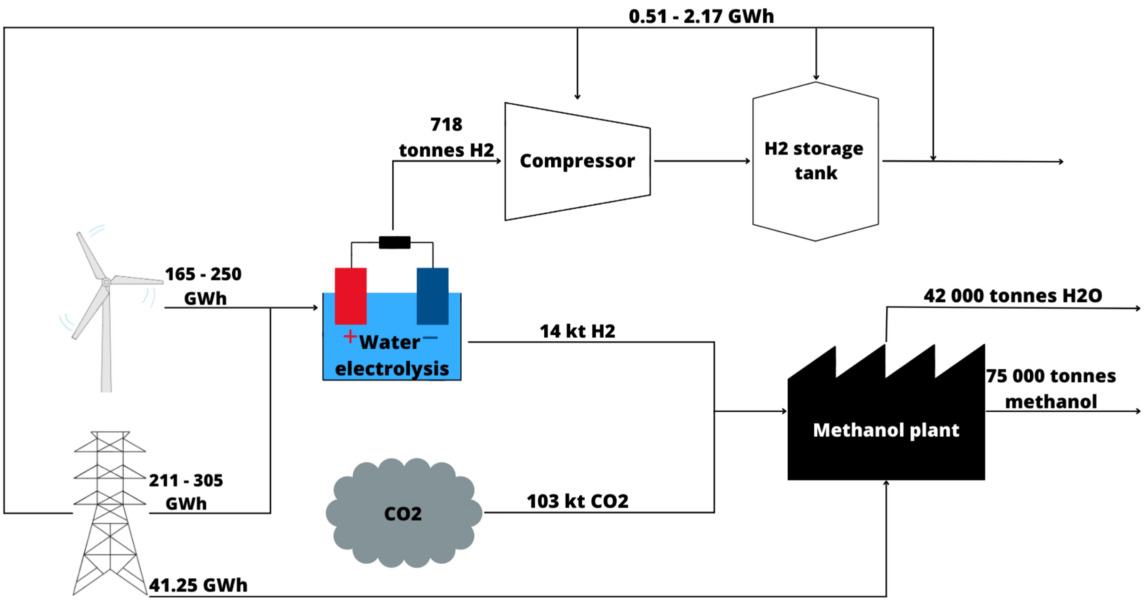


Figure 4.3: Graphic abstract of the green methanol production system.

4.2 Economics

Results of the economic calculations with both PEM and alkaline electrolysers will be presented in this section. CAPEX, OPEX, LCOM, LCOH and more will also be presented with diagrams to substantiate and visualise the results. As mentioned in Section 3.8, two different methanol sales prices have been found, the spot price and the contract price. To really see if a methanol plant based in Norway could be feasible, calculations of NPV using both prices were done.

4.2.1 Production costs of PEM and alkaline

All calculated PEM electrolyser data considering the hydrogen production is shown in Appendix H. The varying factors in Appendix H include electricity price, FLH and water cost. From the tables, it is clear that to get the lowest production cost, the highest amount of FLH is to be used, no matter what the chosen location is. All locations' cheapest production cost is about 4 €/kg, where the lowest is 3.91 €/kg from Måløy at the cheapest electricity price of 0.05 €/kWh, and the highest is 23.00 €/kg from Båtsfjord when the electricity price is at its highest at 0.1 €/kWh. Måløys' highest production cost is 22.81 €/kg at 0.1 €/kWh for electricity, and Båtsfjords' lowest production cost is 3.98 €/kg when the price point of electricity is at 0.05 €/kWh.

In Appendix G, all calculated alkaline electrolyser data considering hydrogen production is represented. The varying factors in the tables in Appendix G are the same as for PEM, meaning electricity price, FLH and water cost. Like with PEM, the highest amount of FLH still gives the cheapest production costs regardless of the location. All locations' cheapest production costs are calculated to be about 3 €/kg, where the lowest is 2.98 €/kg from Måløy at the cheapest electricity price of 0.05 €/kWh, and the highest is 17.69 €/kg from Stavanger when the electricity price is at its most expensive at 0.1 €/kWh. For comparison, The highest production cost from Måløy is 17.22 €/kg at an electricity price of 0.1 €/kWh, and the cheapest production cost from Stavanger is 3.09 €/kg at 0.05 €/kWh for the electricity.

4.2.2 CAPEX vs. OPEX

Figure 4.4 shows CAPEX vs OPEX for the system when PEM electrolysers are used. The total OPEX over the lifetime of the plant is discounted and added together. OPEX accounts for 63% of the total lifetime costs of the system, where most of it can be attributed to the bought electricity. Most of the CAPEX here stems from the electrolysers, followed by the wind turbines.

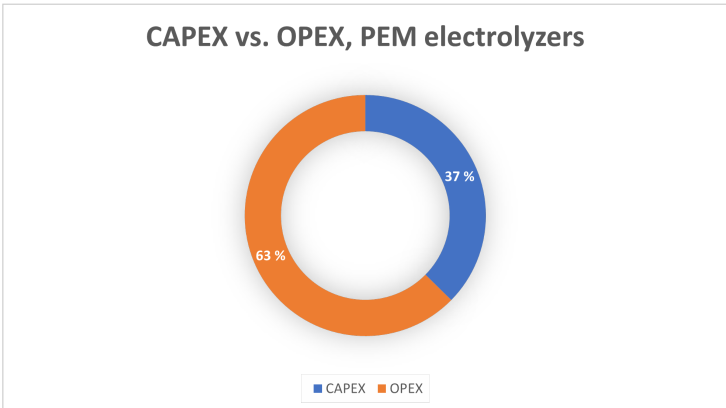


Figure 4.4: CAPEX vs OPEX for the entire methanol plant with PEM electrolysers.

Figure 4.5 shows how much CAPEX and OPEX contribute to the total lifetime costs of the system when alkaline electrolysers are used. The OPEX account for 60%, which is lower than for the system with PEM electrolysers, while CAPEX accounts for 40%.

4.2.3 CAPEX

The CAPEX of the green methanol plant can be seen in Appendix I. When the CAPEX of the PEM system is contrasted against the alkaline system, around 50 million euros is saved in alkaline systems' establishing costs. Although CAPEX was calculated with different electricity prices, the CAPEX remains the same for the same location, no matter if the used electricity price was 0.08 €/kWh or 0.05 €/kWh. The locations where it is most expensive to establish the green methanol plant are Båtsfjord

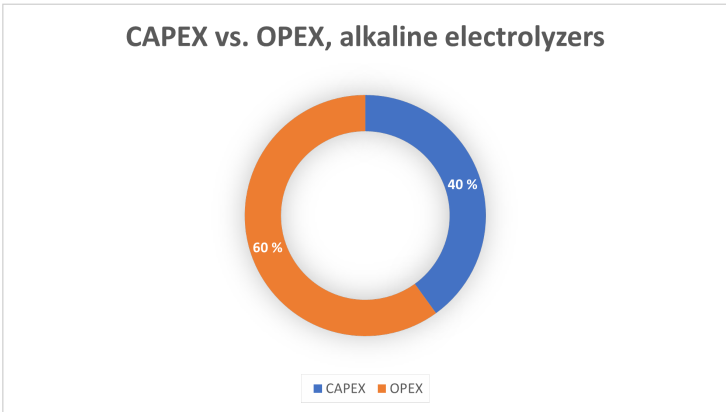


Figure 4.5: CAPEX vs OPEX for the entire methanol plant with alkaline electrolysers.

and Rana when PEM electrolysers are used and Stavanger when the alkaline ones are used. Båtsfjord and Rana also have the same CAPEX in the alkaline scenario, regardless of the electricity price.

Figure 4.6 shows CAPEX distribution for PEM electrolysers. For PEM, electrolysers account for 60% of CAPEX, followed by wind turbines at 30%. Compression, hydrogen storage and distribution, and the methanol plant account for the last 10% of the CAPEX for PEM.

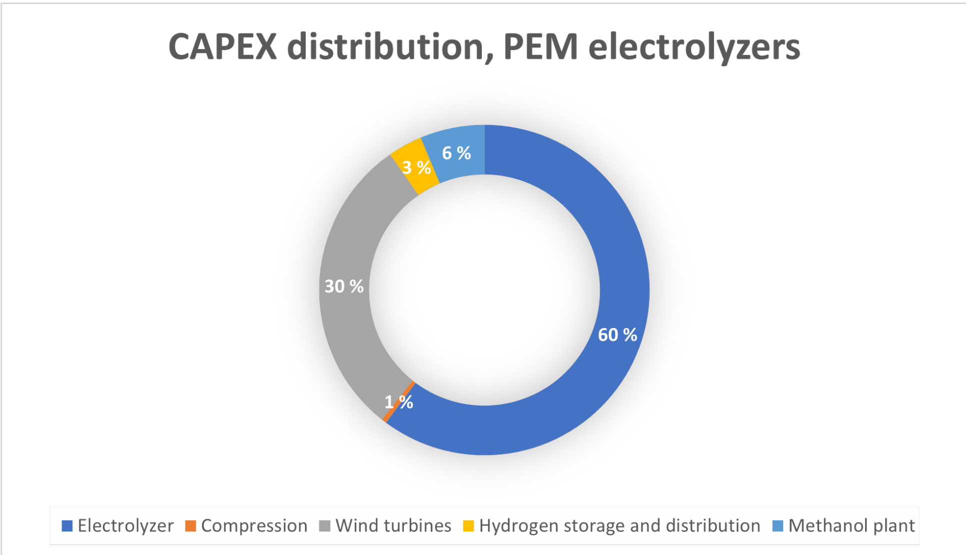


Figure 4.6: CAPEX distribution for the entire methanol plant with PEM electrolysers.

Figure 4.7 shows CAPEX distribution for alkaline electrolysers. The electrolysers only account for 50% of CAPEX, wind turbines account for 40%, and compression, hydrogen storage and distribution, and the methanol plant account for the last 10%.

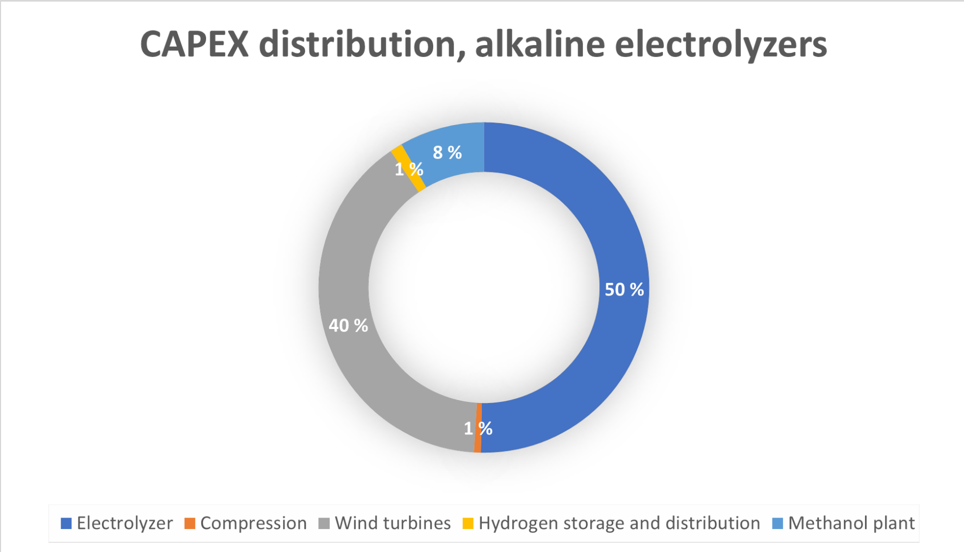


Figure 4.7: CAPEX distribution for the entire methanol plant with alkaline electrolysers.

4.2.4 OPEX

Figure 4.8 shows OPEX distribution for alkaline electrolysers, compressor and wind turbines. The electricity needed to power the electrolysers and compressor is still the highest contributing factor for alkaline electrolysers as well.

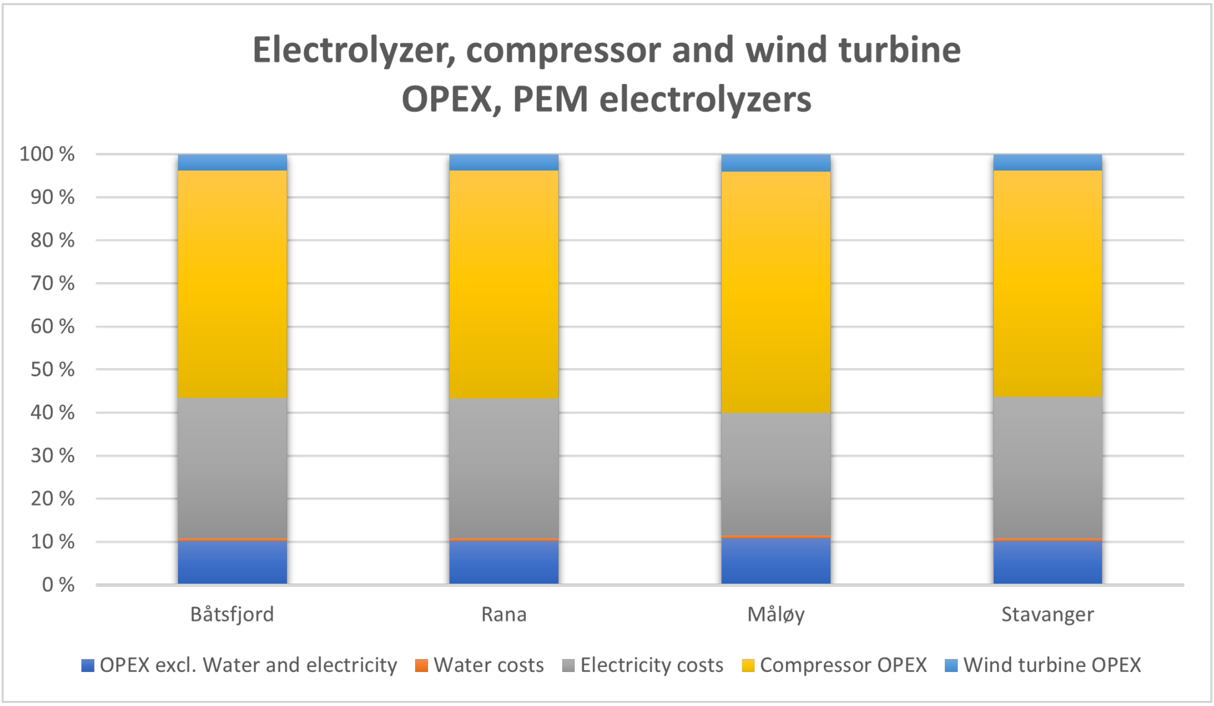


Figure 4.8: OPEX distribution for alkaline electrolysers, wind turbines and compression only.

Figure 4.9 shows which factors contribute most to the OPEX of the PEM electrolysers, wind turbines and the compressor. For all locations, the compressor contributes the most to OPEX, followed by electricity, electrolyser OPEX, wind turbines and lastly, water. Måløy has the lowest electricity costs, as this location has the most wind production, and Stavanger has the highest electricity cost.

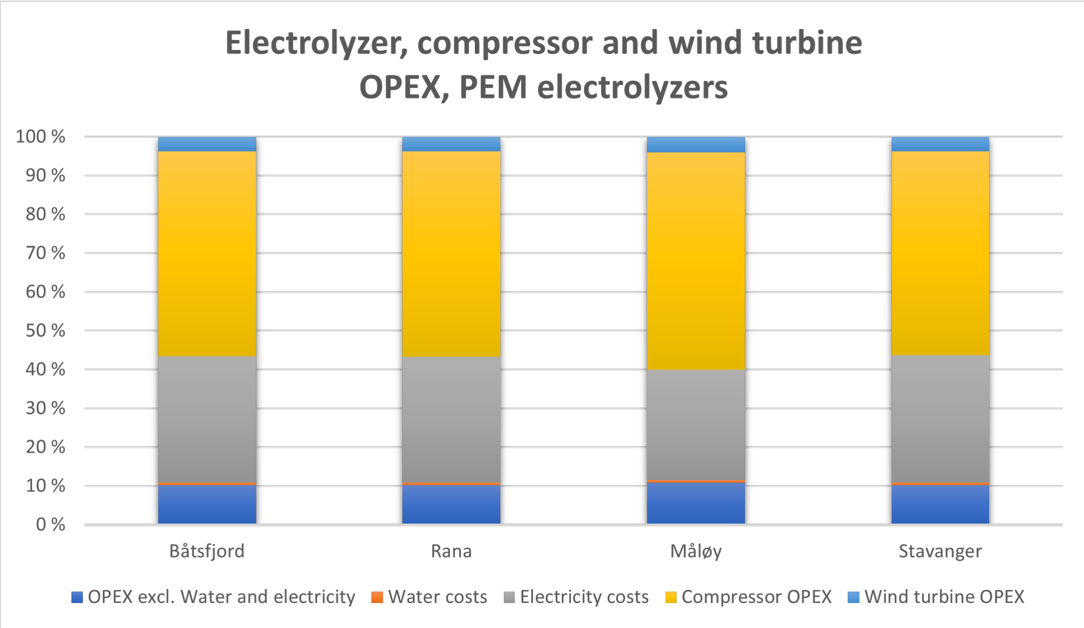


Figure 4.9: OPEX distribution for PEM electrolysers, wind turbines and compression only.

Figure 4.10 shows the OPEX distribution for the entire system with PEM electrolysers. The highest amount of OPEX stems from the electricity consumption of all the components, while electrolyser OPEX is the second highest contributor for all locations. Wind turbines are the third largest contributor of all the components, contributing approximately 1.9 million euro for all locations.

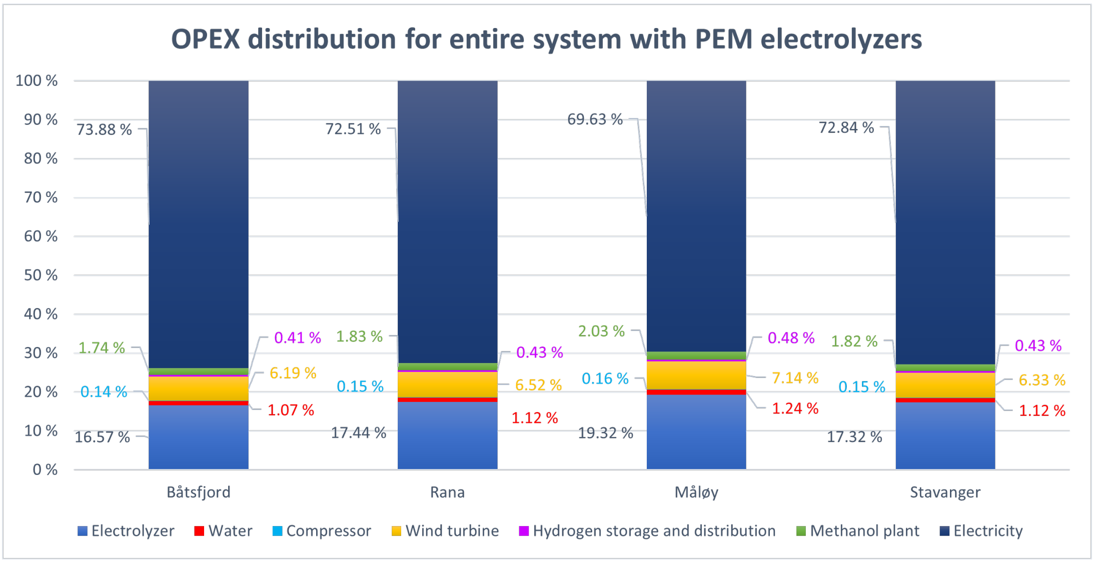


Figure 4.10: OPEX distribution for the entire green methanol plant with PEM electrolysers.

Figure 4.11 shows OPEX distribution with alkaline electrolysers. Electricity consumption also accounts for the highest amount of OPEX here, with an even higher percentage than for PEM. The second largest contributor is electrolysers, followed by wind turbines, like with PEM electrolysers.

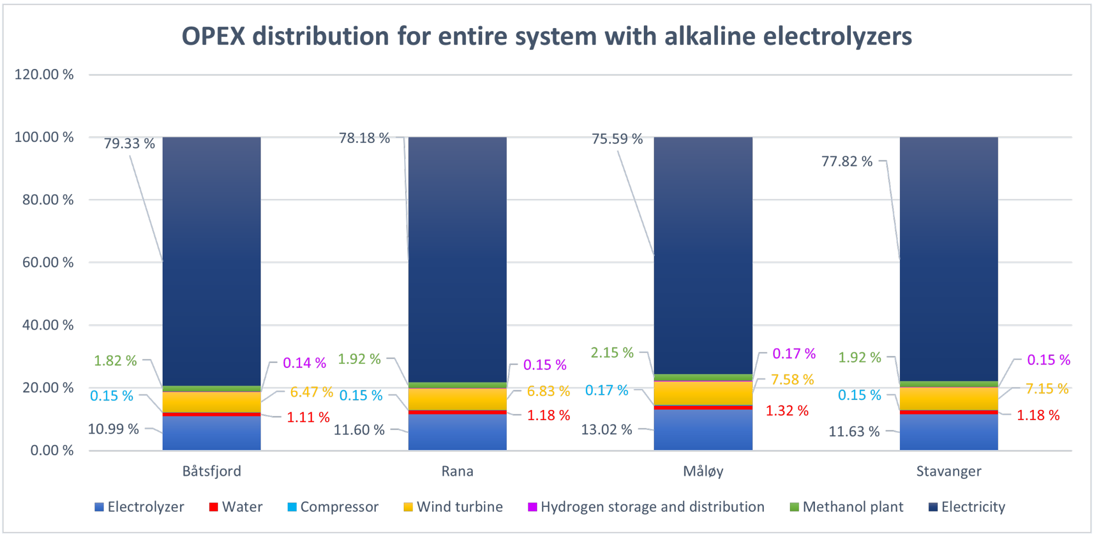


Figure 4.11: OPEX distribution for the entire green methanol plant with alkaline electrolysers.

Figure 4.12 shows which parts of the system account for how much of the electricity consumption with PEM electrolysers. As can be seen from the diagram, the electrolysers account for most of the electricity consumption, ranging from 72.7% in Måløy to 77.9% in Båtsfjord. The second most power-consuming aspect is the methanol plant, which accounts for 14.9 to 18.5% of the total electricity consumption.

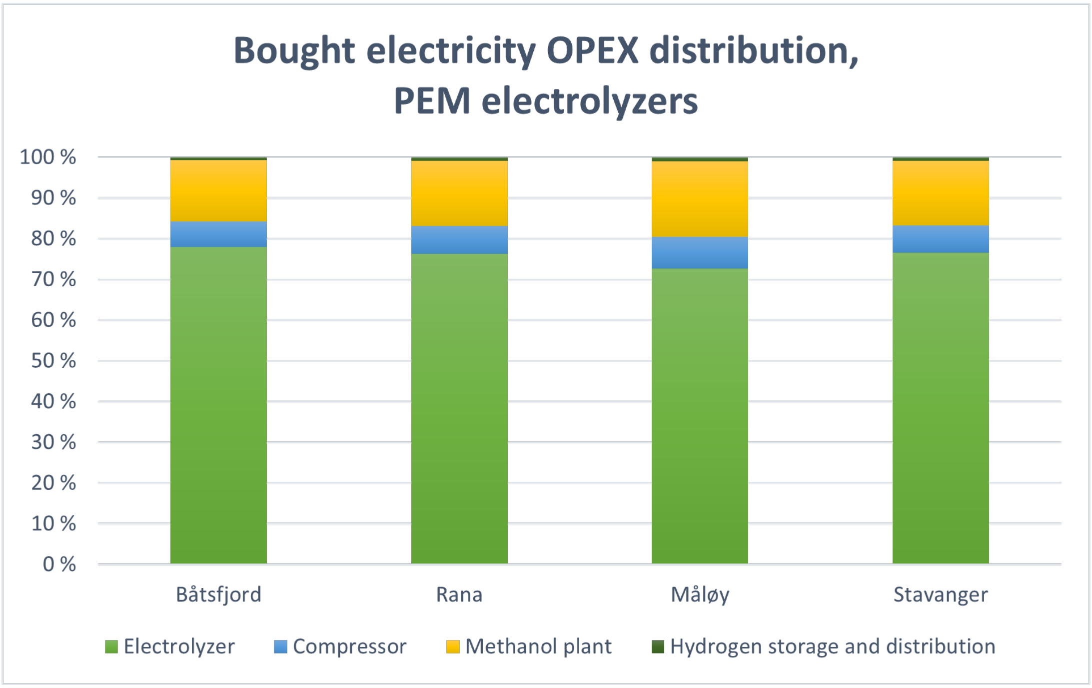


Figure 4.12: Distribution of which parts of the methanol plant contribute most to OPEX by power consumption for PEM electrolysers.

Figure 4.13 shows electricity consumption distribution for alkaline electrolysers, and like with PEM electrolysers, the electrolysers account for most of the electricity consumption. electrolysers account for 74.5 to 79.5% of the total electricity consumption, followed by the methanol plant at 14.5 to 18.1%.

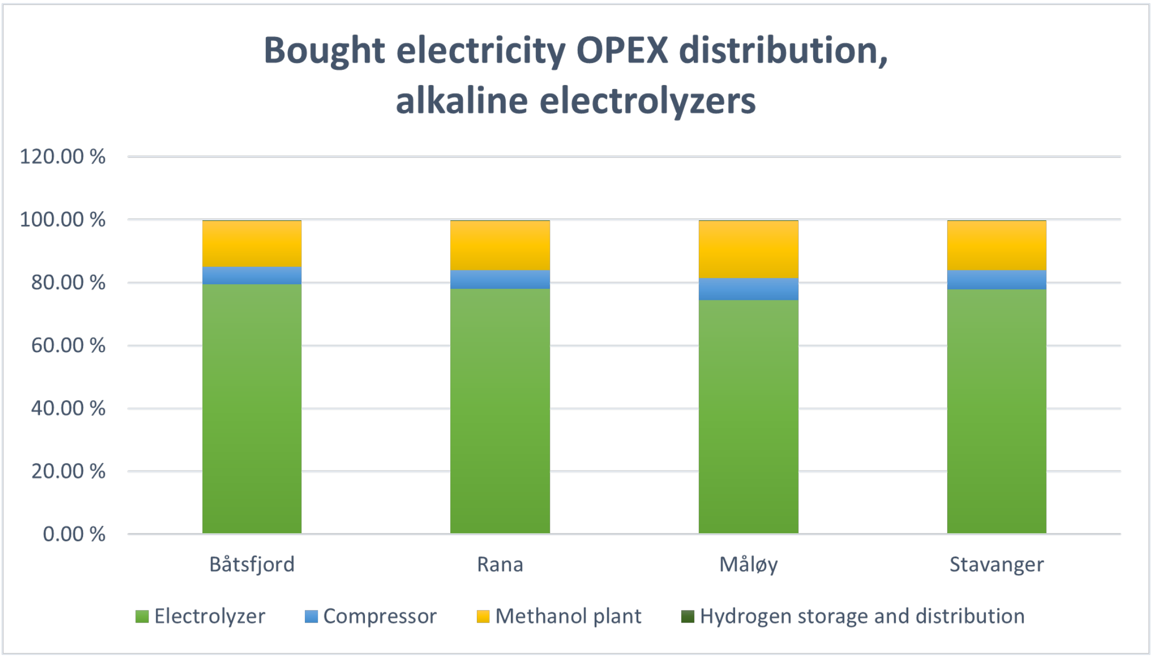


Figure 4.13: Distribution of which parts of the methanol plant contribute most to OPEX by power consumption for alkaline electrolysers.

The OPEX for the entire system is shown in Appendix I. The OPEX with alkaline electrolysers is lower when compared to the OPEX of the system with PEM electrolysers. The cheapest system to operate overall would be Måløy, as its OPEX is lower than the other locations when the same electricity price is used for all locations. The most expensive location to operate is Båtsfjord, regardless of the electricity price.

The OPEX at an electricity price of 0.05 €/kWh Båtsfjord is 2.66 million €/year higher than in Måløy with PEM and 2.80 million €/year higher when alkaline electrolysers are used in the same scenario. In the same scenarios with an electricity price of 0.08 €/kWh Båtsfjord costs 4.25 million €/year more with PEM than Måløy and 4.46 million €/year with alkaline. The difference in OPEX between alkaline and PEM for the same location and the same electricity price is fairly small when compared to the CAPEX differences between the systems. The difference in OPEX for the alkaline and PEM system varies between 2.57-2.85 million €per year when the electricity price is 0.08 €/kWh and between 2.30-2.44 million per year when the electricity price is 0.05 €/kWh.

4.2.5 Levelised cost of hydrogen

The LCOH was calculated for a range of electricity prices and load factors to better see how this would affect the LCOH and these values are shown in Table 4.5. As expected, the higher number of FLH gives a lower LCOH, and lower electricity prices also give a lower LCOH. As seen in Appendix G and H, the annual depreciation of the hydrogen production facility is calculated. This value is not accounted for in further calculations as the entirety of the CAPEX was set to be paid in full before operation of the plant had started.

Table 4.5: *LCOH for different scenarios.*

Electrolyser:	Power price [€/kWh]	0.05						0.08						0.10					
	Load factor [%]	**11.4**	**22.8**	**34.2**	**45.7**	**57.2**	**68.5**	**11.4**	**22.8**	**34.2**	**45.7**	**57.2**	**68.5**	**11.4**	**22.8**	**34.2**	**45.7**	**57.2**	**68.5**
		LCOH [€/kWh]																	
PEM	**Båtsfjord**	13.10	7.16	5.18	4.18	3.59	3.19	13.81	7.86	5.88	4.89	4.30	3.90	14.28	8.33	6.35	5.36	4.77	4.37
M5000	**Rana**	13.00	7.05	5.07	4.08	3.49	3.09	13.64	7.70	5.72	4.73	4.13	3.74	14.08	8.13	6.15	5.16	4.56	4.17
	Måløy	12.78	6.85	4.87	3.89	3.29	2.90	13.31	7.38	5.41	4.42	3.83	3.43	13.66	7.74	5.76	4.77	4.18	3.79
150 MW plant	**Stavanger**	12.95	7.04	5.07	4.08	3.49	3.10	13.60	7.69	5.72	4.74	4.15	3.75	14.04	8.13	6.16	5.17	4.58	4.19
Alkaline	**Båtsfjord**	10.19	5.73	4.24	3.50	3.06	2.76	10.93	6.47	4.99	4.24	3.80	3.50	11.43	6.97	5.48	4.74	4.29	3.99
A3880	**Rana**	10.09	5.63	4.14	3.40	2.95	2.66	10.77	6.31	4.82	4.08	3.63	3.33	11.22	6.76	5.27	4.53	4.09	3.79
	Måløy	8.85	4.91	3.60	2.94	2.54	2.28	9.41	5.47	4.16	3.50	3.10	2.84	9.79	5.84	4.53	3.87	3.48	3.21
123.2 MW plant	**Stavanger**	9.22	5.19	3.85	3.17	2.77	2.50	9.89	5.86	4.52	3.85	3.44	3.17	10.34	6.31	4.97	4.30	3.89	3.62

As seen in Table 4.5, Måløy has the lowest LCOH for all cases, and the lowest LCOH can be found with the use of alkaline electrolysers. The highest LCOH is attributed to Båtsfjord, which coincides with the lower capacity factor for the wind turbines at this location.

It can be observed in Appendix H that every PEM electrolyser LCOH value is lower than the production cost for almost all scenarios, except for Båtsfjord, Rana and Stavanger at 6000 FLH with an electricity price of 0.1 €/kWh. In those rows, the production prices are 4.19 €/kg, 4.15 €/kg and 4.13 €/kg, respectively, while the LCOH is 4.37 €/kg, 4.17 €/kg and 4.19 €/kg respectively, which is a difference of 0.18 €/kg, 0.02 €/kg and 0.06 €/kg respectively. Måløy is the only location where the LCOH does not exceed the production costs. With the increasing amount of FLH, the water and electricity costs also increase because this leads to an increase in hydrogen production, which results in an increased need for electricity and water.

Compared with the PEM electrolyser results, the alkaline electrolyser results shown in Appendix G have ten rows where the LCOH value exceeds the production costs. Nine of the rows where the LCOH value overtakes the production costs are when the number of FLH is highest, at 5000 and 6000 hours. The last row where the LCOH is higher than the production cost is in Båtsfjord at 4000 FLH with an electricity price of 0.1 €/kWh. Båtsfjord has a total of five rows where the LCOH is higher than the production price, Rana has three, Måløy has one, and Stavanger has one. The gap between the two values varies from 0.02-0.7 €/kg, where the lowest difference can be found in Båtsfjord and the highest difference can also be found in Båtsfjord. Water costs also increase for hydrogen production with alkaline electrolysers when the FLH increases.

4.2.6 Levelised cost of methanol

To calculate the LCOM, the number of FLH for the electrolysers that were nearest the capacity factor was chosen. For both the PEM and alkaline electrolysers, this was 6000 FLH. The LCOM values for all locations, with electricity prices of 0.05 €/kWh and 0.08 €/kWh, are shown in Appendix I. The table shows that the LCOM value when alkaline electrolysers are used in methanol production is lower when compared to the calculated LCOM value with PEM electrolysers in the process. LCOM is the same regardless of the methanol selling price since the LCOM does not take the methanol sale revenue into consideration.

Regardless of the given electricity price, methanol selling price and the electrolyser type, Måløy's LCOM is the cheapest, while Båtsfjord's is the highest. From Table 4.6, it can be seen that Måløy's cheapest LCOM overall is 0.51 €/kg with alkaline electrolysers at an electricity price of 0.05 €/kWh, and Båtsfjord's highest LCOM is 0.69 €/kg with PEM electrolysers at an electricity price of 0.08 €/kWh. The lowest Båtsfjords' LCOM goes is 0.55 €/kg with alkaline at 0.05 €/kWh for electricity, and Måløys' highest LCOM is 0.64 €/kg with PEM at a price of 0.08 €/kWh for electricity.

Table 4.6: LCOM for different scenarios.

Electrolyser:	**Power price [€/kWh]**	**0.05**	**0.08**
	LCOM [€/kg]		
PEM	**Båtsfjord**	0.59	0.70
M5000	**Rana**	0.57	0.68
	Måløy	0.55	0.64
150 MW plant	**Stavanger**	0.57	0.68
Alkaline	**Båtsfjord**	0.49	0.60
A3880	**Rana**	0.48	0.58
	Måløy	0.45	0.54
123.2 MW plant	**Stavanger**	0.48	0.58

4.2.7 NPV based on the average spot price of methanol

The average methanol selling price based on the Methanol Market Services Asia, MMSA, spot price is 375 €/tonne, corresponding to a revenue of 27.95 million €per year from the produced methanol. From Figure I.1a in Appendix I, it is shown that both when PEM and alkaline electrolysers are used, the NPV for the methanol plant will be negative. The losses are greater when the PEM electrolysers are used at 0.08 €/kWh for electricity, where the biggest loss is -221.58 million €in Båtsfjord, which is a total difference of 41.35 million €from the biggest NPV alkaline loss at -180.23 million €in Båtsfjord. The smallest loss is found at Måløy and has an NPV of -95.46 million €when PEM electrolysers are used and -55.47 million €with alkaline, both occurring at a power price of 0.05 €/kWh. The difference between the two NPV values is 39.99 million €.

As can be seen from Figure I.1a, the OPEX for most cases exceed the revenue from methanol, which is why the NPV is so much on the negative side. However, even in the cases where the methanol revenue exceeds the OPEX, NPV is still negative. This is because the income is so low that it does not exceed the CAPEX of the plant, giving a negative NPV.

In Appendix I, the calculations show that when it is time to replace the stacks of the electrolysers, which happens once every 11 years, meaning once during the lifespan of 20 years of the entire system, it is cheaper to replace the stacks in the alkaline electrolysers than it is to replace the stacks in PEM electrolysers. The difference in replacement costs is 9 million €for the entire stack.

4.2.8 NPV based on the average contract price of methanol

Figure I.1b in Appendix I shows calculations of NPV based on the average contract price of methanol. This sales price gives a significant increase in revenue from the sale of methanol, resulting in a yearly revenue of 40.39 million €. The table shows that this selling price gives a positive NPV for all of the scenarios when the power price is 0.05 €/kWh and for Måløy with alkaline electrolysers with a power price of 0.08 €/kWh.

The highest positive NPV comes from Måløy with alkaline electrolysers and a power price of 0.05 €/kWh, where it is 87.28 million. The most negative NPV with this methanol selling price is -78.85 million, which belongs to Båtsfjord with PEM electrolysers and a power price of 0.08 €/kWh. When comparing PEM with alkaline at the same location with the same power price, the difference in NPV is approximately 40 million. The biggest difference in NPV when comparing PEM and alkaline for the same scenario is 43.80 million in Måløy with a power price of 0.08 €/kWh, and the lowest difference at 36.02 million is in Stavanger with a power price of 0.05 €/kWh.

4.2.9 NPV as a function of methanol selling price

Figure 4.14 shows how NPV changes depending on methanol selling price with alkaline electrolysers. When the lines hit a methanol selling price of 400 €/tonne, the graphs show a nearly linear congruity the rest of the way. Båtsfjord, Rana and Stavanger all hit NPV=0 between 550 and 600 €/tonne, while Måløy hits this point between 500 and 550 €/tonne. These selling prices are close to the current MMSA contract prices of methanol, which was 513 €/tonne in February 2023, but have been as high as 593 €/tonne in April 2022 [102].

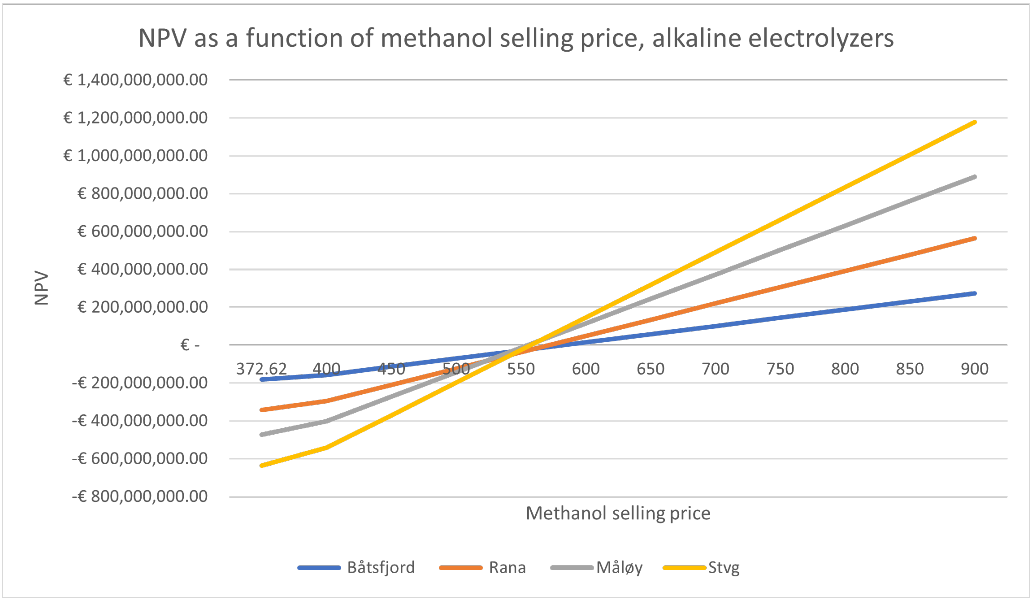


Figure 4.14: Plot showing how NPV changes with methanol selling price with alkaline electrolysers.

Figure 4.15 shows how NPV changes with increasing methanol selling prices with alkaline electrolysers. Here Båtsfjord, Rana and Stavanger reach NPV=0 when the methanol selling price is between 600 and 650 €/tonne, while Rana reaches NPV=0 when the methanol selling price is between 550 and 600 €/tonne.

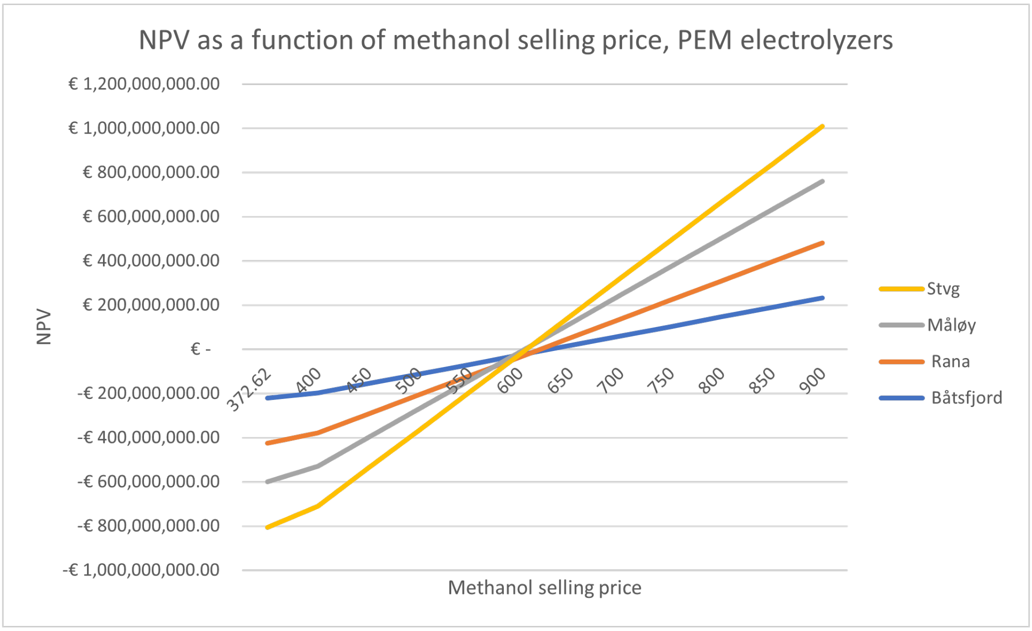


Figure 4.15: Plot showing how NPV changes with methanol selling price with PEM electrolysers.

4.2.10 Discounted payback period

Since the discounted payback period relies on the discounted cash flows that are also used to calculate the NPV, a negative NPV indicates that the discounted payback period will be longer than the project lifetime. The discounted payback period will therefore only be calculated for the scenarios where the NPV is a positive value. Since the average spot price of methanol only provided negative NPVs, the results shown in Table 4.7 are for the cases where the average contract price of methanol was used.

Table 4.7: Discounted payback times for scenarios with positive NPVs.

		Discounted payback period (years)	
Power price		0.05	0.08
Båtsfjord	**PEM**	17.2	-
	Alkaline	8.4	-
Rana	**PEM**	16.2	-
	Alkaline	8.1	-
Måløy	**PEM**	14.2	-
	Alkaline	7.3	12.3
Stavanger	**PEM**	16.1	-
	Alkaline	8.2	-

In Table 4.7, the discounted payback times of the scenarios where the NPV was positive are shown. Cells with a dash indicate a DPP that was higher than the project lifetime of 20 years. The table shows that all cases with a power price of 0.05 €/kWh have a DPP lower than 20 years, but the only location that had a DPP lower than this with a power price of 0.08 €/kWh was Måløy. Måløy also has the lowest DPP with the lower power price, closely followed by Rana and Stavanger, with Båtsfjord having the longest DPP.

5 Discussion

One of the biggest obstacles when doing research for a feasibility study is finding relevant information. Information regarding the scaling of components and economic calculations proved to be more difficult to find than first expected. Several companies today produce green methanol, but data regarding the feedstock for methanol production that is used, system scaling, and financial matters are kept private within the company. Working with a partner organisation could have provided this thesis with more reliable numbers. Therefore some parameters that are used in this study might not be the most accurate but are estimated as precisely as possible.

5.1 Uncertainty around the assumptions

When it comes to the assumptions, it was unrealistic to assume that all the nearby industries that could be used as a CO_2 source for the theoretical green methanol plant could capture the carbon dioxide themselves. Most likely, a DAC or new CO_2 capture system would have to be built along with the green methanol plant, which would increase the CAPEX significantly. As mentioned in Section 2.4.2, it is immensely expensive to build a DAC system, to such an extent that most say that the enormous costs outweigh the positive effects of DAC. DAC is still a relatively new concept, but if the concept of re-utilising waste heat in S-DAC gets implemented, it will likely become a competitive alternative on the market. Therefore this could be a decent option for a future green methanol plant.

As has been recently seen in the Langskip Klemetsrud project, even when using carbon capture from industries, the expenses get significantly high. In this thesis, calculations for the carbon capture process have not been taken into account, meaning the CAPEX and OPEX would get an additional cost of substantial size if it was to be added. For the theoretical green methanol plant, a CO_2 amount of 106 kilo-tonnes per year is needed, which is 26.61% of what the Klemetsrud project is designed to capture. The current cost for the Klemetsrud project of 819 million euro can give a very rough estimate of about 2.42 billion NOK in addition, equal to about 220 million euro.

The retail price of captured CO_2 was set to 25 €/tonne as a rough estimate, but the actual price of CO_2 will vary depending on the demand and the source of the CO_2. CO_2 from fossil fuels will more often than not be cheaper than CO_2 from renewable sources, such as biomass. Because of this, fossil CO_2-utilisation will probably dominate the market for the foreseeable future. Another issue with renewable CO_2 is that it is harder to produce the amounts needed for an industrial-scale methanol plant, which will drive up the price further if the demand is high.

The outlet temperature of hydrogen from the electrolysers was another parameter that it was difficult to find reliable data on. The assumption of an outlet temperature of 55°C was based on data from previous studies, but none of these studies were conducted on the electrolysers that were chosen for this thesis. The outlet temperature of hydrogen was needed to calculate the compressor work for hydrogen storage, so a rough estimate was deemed sufficient for this.

5.2 Technical specifications

Here the assumptions and results regarding the technical specifications of the system will be discussed. Scaling of the different components as well as scaling in accordance with each other will be considered, discussing whether the calculations have found the most optimal composition.

5.2.1 Methanol plant

The first thing that was decided was the amount of methanol to be produced by the methanol plant, which gave way to the scaling of the methanol plant. The literature review that was done revealed that finding information on the scaling of methanol plants was harder than first anticipated. This resulted in some simplifications considering this particular aspect.

The data on the scaling of the methanol reactor was based on used plug flow reactors [66, 103] and fixed-bed reactor [104], which makes the economic results unreliable when the reactor type considered in this thesis is a loop reactor. The size of the reactor was not calculated, as this was a parameter that it was difficult to find reliable data on, so the CAPEX of this was simply calculated from data found during the literature review. Another parameter that was difficult to calculate was the necessary amount of catalyst since no reactor size was found. The method mentioned in Section 3.2.1 is not necessarily the most accurate method for this, but it was deemed sufficient to get an indicator of how much catalyst would be needed for a reactor with the set production.

CAPEX, and subsequently OPEX, for the other components related to the methanol plant were also scaled according to the amount of methanol produced in a year, which contributes to further uncertainty around the reliability of the economic results. For heat exchangers, the scaling variable that is supposed to be used is the necessary surface area. For compressors, the installed power is the scaling variable, separators are supposed to be scaled based on the capacity in m^3, and for distillation, no scaling variable was found. Since all of these components were scaled based on the total methanol production instead of their respective scaling variables, the results might not be as reliable as desired.

For the economic calculations, the CEPCI values were used to convert previous investments to the current value of money, however, it is recommended not to use CEPCI for values more than three years back in time, which leads to even more uncertainty around the economics of the methanol plant.

5.2.2 Electricity from wind power

The wind turbine production was scaled so the wind turbines did not produce more electricity than the electrolysers needed. However, at times they did exceed the electricity needed for hydrogen production. Another thing worth noting is that the wind data collected is not at a higher altitude than eight meters above ground, which means that the actual wind speed of the locations might be higher than predicted. Unless the wind speed exceeds 25 m/s which is the cut-out wind speed for most wind turbines, the higher wind speed at higher altitudes will contribute to higher wind power production. The chosen wind turbines have hub heights ranging from 82 to 134 metres depending on the IEC class and site-specific conditions. Since the wind speed increases with height, especially close to the ground where surface friction is high, wind power production is especially susceptible to errors.

5.2.3 Hydrogen production

PEM electrolysers are the most suitable for intermittent energy sources but have the highest cost, as alkaline electrolysers have been on the market for much longer. In this thesis, the electrolyser plant consisted of either six 25 MW PEM modules or seven 17.6 MW alkaline modules. When using intermittent energy sources, PEM electrolysers are preferred over alkaline modules as they have a shorter ramp-up time and are, therefore, more flexible. This is, however, not an issue that is considered since the electrolysers are assumed to never need to shut down.

This leaves another aspect to be considered if looking at a dynamic model instead of the steady-state model that this thesis has examined. If the electrolysers were to be supplied with energy only from the wind with no input from the grid, the ramp-up time of electrolysers would have had to be taken into consideration. Here, PEM electrolysers pose a significant advantage over alkaline electrolysers since they have a much shorter ramp-up time.

Due to the simple nature of the electrolyser scaling and the big module sizes, the result was an oversized electrolyser for both PEM and alkaline. The needed production barely exceeded the amount produced with one electrolyser module less than what was used in the calculations, which meant that the electrolysers produced far more hydrogen than was necessary. It was decided to sell the excess hydrogen, which brought in extra revenue from hydrogen sales but also contributed to higher CAPEX and OPEX for storage and distribution.

The green hydrogen was decided to be sold in gas form, but is it better to sell hydrogen compressed or liquefied? This would depend on the buyer and what the buyer needs the hydrogen for. If the hydrogen is to be used as fuel, it would need liquefaction, while hydrogen in gas form could be used to operate a gas turbine. If a liquefaction system was to be integrated into the green methanol plant, a larger amount of costs would follow due to a higher demand for needed electricity and the CAPEX and OPEX would rise. As mentioned in Section 2.2, liquefaction is a very energy-intensive process, and although it might be more economical to use liquefaction on the hydrogen, it was decided to deliver it as a gas.

Another thing that could have been considered to increase revenue from the system is storing and selling the oxygen from the electrolysers. This would increase the CAPEX and OPEX of the system because it would bring the need for compressors and storage tanks for oxygen. Depending on the selling price of oxygen, the extra revenue might help push some of the negative NPVs closer to being positive. But if CAPEX and OPEX of oxygen storage and distribution far exceeded the revenue from oxygen, this would bring the NPV even further from being positive. Because of the uncertainty around CAPEX, OPEX and revenue from this measure, it was decided that oxygen would be vented into the atmosphere and not be considered for sale.

As was seen in the results, a total water amount of 232 million litres per year is needed for the green hydrogen production with alkaline electrolysers, while 237.9 million litres per year is needed with PEM electrolysers. This is an immense amount of water, and with water scarcity reaching more countries, this might become a problem in the future. If the temperature rises significantly, drought might hit Norway in the near future, which would imply that water for green hydrogen production is not to be prioritised. The water type that was to be used in this thesis was not specified, but due to the low amount of fresh water available in the world, using either desalinated seawater or wastewater from industrial sources is preferred. As the methanol plant is of substantial size, the most available water resource, desalinated seawater, would most likely be the best water option for hydrogen production.

5.2.4 Scaling of components to fit the methanol production

Since the thesis based the scaling of components to fit a methanol plant capable of producing 75 000 tonnes of methanol per year, it was decided to look into whether the components were scaled appropriately or if a more optimal solution could have been found. The number of wind turbines and electrolyser modules are the components that will be looked into in this section.

The chosen electrolyser modules were from NEL hydrogen, the PEM modules were 25 MW modules, and the alkaline modules were 17.6 MW modules. The desired number of modules was found first by dividing the necessary hydrogen production per hour by the net production rate of the electrolyser, then rounding the number up to make sure the hydrogen production exceeded the necessary amount. This resulted in the electrolysers being oversized, especially the PEM system had a rather high amount of excess hydrogen due to this sizing. To prevent oversizing the electrolysers, smaller modules could have been chosen, which might have resulted in a more optimised system with less excess production and, subsequently, less electricity needed. Since electricity consumption is the biggest contributor to OPEX, this reduction of necessary electricity could contribute to further reducing the LCOM and NPV of the project.

To find the desired number of wind turbines, the hourly electricity consumption of electrolysers was found by multiplying the average power consumption by the number of electrolysers modules and dividing this number by the maximum production of the wind turbine. This number was then rounded up to set the maximum production not exceeding the electricity needed by the electrolysers by too much. This resulted in the need to buy electricity from the grid to keep the hydrogen production going steadily. The bought electricity was set to be with a guarantee of origin to ensure that the hydrogen production could be classified as green.

Another thing to consider is the unlikely scenario of the electrolysers never having a lower production than the NPR or being put on standby. The calculations in this thesis assumed that the electrolysers produced as much hydrogen as they could with 6000 FLH per year, however, this is not something that is common. To improve the results of the hydrogen production calculations, a dynamic simulation where hydrogen production varied with the varying wind power output could have been done. Another option could have been to consider energy storage in the form of batteries to supply electrolysers with electricity when wind production was low.

5.3 Economics

The results of the economic calculations will be presented below. This section will discuss the results of the economic calculations and assess whether the project could be profitable based on NPV and LCOM.

5.3.1 Power

A scenario that was briefly examined but not considered was supplying the whole system strictly with power from the grid because of the high CAPEX of wind turbines. However, in remote or small places such as Båtsfjord in Finnmark, the power grid is not dimensioned to handle very big loads. A 420 kV line from West to East Finnmark has been discussed and given concession, which will better equip the grid to handle loads this size.

The chosen power prices were 0.05, 0.08 and 0.1, which were based on household prices since power prices for industries are a more complicated matter. When looking at the individual prices that were shown in Table 3.3, they vary a lot from location to location, which made it difficult to decide on the prices that were used in the calculations. It was decided that all the prices were reasonably set. 0.1 €/kWh is closest to the mean of the averages that were presented in Table 3.3. 0.05 €/kWh was chosen since it is closer to the prices that would be paid for the electricity in Båtsfjord and Rana, which both are in zone four, which has the cheapest power in Norway due to them being exempt from VAT, grid fee and consumption tax.

0.08 €/kWh was decided as a good medium between the two other chosen prices. What could be improved further would be to add another even higher power price, since as seen in Table 3.3, the power prices can exceed the prices that were used in the calculations. So a scenario with an extremely high electricity price that could show the worst-case scenario could be practical for comparison due to the current situation to see how much of an economic loss higher power prices would contribute.

For all the locations, some excess electricity was generated by the wind turbines, this excess electricity was not considered for production. This contributes to higher OPEX, as this electricity could have been used to power the compressor or other components of the methanol production, lowering the needed electricity. The highest amount of electricity lost because of this not being considered is 8.5 GWh over a year, which could have lowered electricity costs by over half a million euro per year. Since electricity consumption accounts for most of the OPEX, this might help lower both NPV and LCOM.

5.3.2 Alkaline

The reason most of the results are more favourable when using alkaline compared to PEM is that PEM is a newer technology and is more expensive to produce than alkaline. Alkaline electrolysers have had time to mature and are, therefore, not as new on the market and are easier to obtain for a lower price.

There is also a possibility that there are other models than the PEM M5000 and the alkaline A3880 that would suit this hypothetical green methanol plant better. Both the M5000 and the A3880 were chosen due to their high production rate, but there might be other even better alternatives out there from other manufacturers, and more research around this could have been performed.

5.3.3 PEM

PEM electrolysers contain a material called iridium. The problem with iridium is that it is very rare. Therefore when using PEM cells, it is important to take into consideration that the materials that are needed to make the electrolysers are limited. This means that it might be better to choose the alkaline electrolysers over PEM ones in case of an iridium shortage, as no substitutes currently exist. In the future, substitutes might be found, and if that becomes the case switching the current PEM electrolyser models with new ones could be beneficial. Choosing the alkaline electrolysers might be more beneficial, regardless, since all the results for alkaline electrolysers outperform PEM in terms of economics.

5.3.4 Cost reduction

Utilising some methanol in a combined heat and power system, CHP would lower production costs because some of the power needed could come from this instead of being bought. However, this would also result in a lower revenue since the amount of methanol out would decrease. Further cost reduction can be achieved if the water from methanol production is reused in the electrolyser, resulting in lower OPEX for the electrolysers.

Although the chosen electricity prices are realistic choices, it is important to remember that when running a power-intensive industry, lower prices for electricity can be negotiated, meaning there is a possibility of paying even less for the power than the values that were used to complete the calculations. For the electrolysis process, this project would be exempt from paying the grid fees, again due to it being a power-intensive process.

5.3.5 CAPEX

The location where it was most expensive to establish the green methanol plant was tied between Båtsfjord and Rana when PEM electrolysers were used. They both had the same CAPEX since they both, in the PEM and alkaline scenario, need the same amount of wind turbines, and the amount of electrolyser modules does not vary with location. When alkaline electrolysers were used, Stavanger had the highest CAPEX since it needed one more wind turbine in the alkaline scenario than in the PEM, meaning another four million were added to the CAPEX costs.

It was observed in the results that the CAPEX of the PEM system were about 40 million euros more expensive than alkaline ones. This is in part because alkaline electrolysers have existed for a longer time than PEM and have therefore had more time to mature and are cheaper to produce. This means that despite there being more alkaline modules, the PEM system is more expensive because of higher investment costs. Another contributing factor to the high CAPEX of the PEM electrolysers is that the installed capacity is higher, 150 MW for PEM compared to 123.2 MW with alkaline. PEM has higher investment costs per kW installed capacity, this combined with the higher installed capacity, makes for significantly higher investment costs.

5.3.6 OPEX

In the OPEX calculations, the employee's salary was not included in the calculations. Due to this, the OPEX is supposed to be even higher than the results that were gotten. The reason the difference in OPEX between alkaline and PEM for the same location and same electricity price is fairly small when compared to the CAPEX differences between the systems is evidently because it is cheaper to maintain a production plant than it is to build one.

The electrolysers need stack replacements every 11 years, this is once in the lifetime of the electrolysers. Replacing the PEM electrolysers are more expensive than exchanging the alkaline electrolysers. This is because the PEM electrolysers have a higher installed power, and the price per kW of installed capacity is higher than for the alkaline electrolysers, which makes them more expensive to change.

Since the OPEX of every component is a function of the CAPEX, higher CAPEX results in higher OPEX for the system. The OPEX excluding water and power for PEM electrolysers is 1.8 million € higher than for alkaline electrolysers because of high investment costs, but electricity costs for alkaline are lower because of the slightly higher efficiency.

For both the CAPEX and OPEX, one thing that was not considered was the delivery system for the green methanol. Since there are many uses for methanol, the delivery method will vary depending on what it will be used for, and it is, therefore, difficult to estimate how big the investment and operational costs would be. If the produced methanol were to be used for a fixed purpose, the delivery system would be easier to consider, which would give higher CAPEX and OPEX.

5.3.7 Production cost

When looking at the production costs for methanol, and the same electrolyser type and electricity cost are used, there is not a big difference between the locations. But the difference in production cost becomes big when a substantial amount of methanol is produced. For example, with alkaline electrolysers at an electricity price of 0.1 €/kWh, Måløys production cost was 17.22 €/kg, and Stavangers was 17.69 €/kg. That makes a difference of 0.47 €/kg, which is not a lot, but when taking into consideration that an amount of 75 000 tonnes of methanol is to be produced, that 0.47 €/kg becomes a difference of 35.25 million €which is a significant amount.

5.3.8 LCOE

The LCOE of all locations except Måløy was higher than the lowest power price that was chosen, meaning that in this case, it might have been better to supply the electrolysers solely with renewable energy from the grid rather than investing in wind turbines. Since power prices in Norway have been rather high in recent times, the only two places where this low power price might be representative of the market are Rana and Båtsfjord, which both have relatively high LCOE. The other two power prices at 0.08 and 0.1 €/kWh are higher than the LCOE for all locations, indicating that wind power is more profitable than buying power off the grid in these cases.

When considering that the wind data measurements were taken close to the ground and that wind speed increases higher off the ground, the LCOE of all locations might actually be lower than what is calculated here. If more power had been produced with the same amount of wind turbines, the LCOE could have been even lower than the calculations show.

5.3.9 LCOH

In the hydrogen calculations, it was seen that in most cases, the LCOH was lower than the production costs, both for PEM and alkaline electrolysers. But in some instances, this was not the case. This is because when finding the production cost, the total CAPEX and OPEX are divided by the hydrogen production of one year, while LCOM considers the entire lifetime of the electrolysers. LCOM also discounts the future cash flows and gives a better indicator of whether simply selling the produced hydrogen would be profitable compared to the production costs.

The LCOH gives the price hydrogen has to be sold for in order for hydrogen production to break even. LCOH was calculated without considering the rest of the methanol production pathway, meaning it only considered wind turbine and electrolyser costs. For these calculations, the number of FLH of the electrolysers varied from 1000 to 6000, making the hydrogen production vary as well. For these scenarios, the storage and distribution part of the methanol plant was excluded as these values were calculated simply as an indicator of whether hydrogen production would be a viable option instead of buying the necessary hydrogen.

In the appendices related to the calculation of LCOH, the depreciation per year for the hydrogen production facility was calculated. These values were not taken into consideration for the rest of the economic calculations as the entirety of the CAPEX was set to be paid in full before operation of the plant had started.

5.3.10 LCOM

LCOM gives the methanol selling price that is needed for the production to break even with the CAPEX and OPEX calculated. The LCOM was calculated based on the electrolysers running at 6000 FLH, with power prices of 0.05 €/kWh and 0.08 €/kWh. Not including the power price of 0.1 €/kWh was a choice that was made since two of the locations are in Northern Norway, and they will probably not experience such high power prices. The selling price of the e-methanol was found to be 375 €/tonne, meaning if it converted into euro per kilogram, it would be 0.375 €/kg, which is still lower than all of the LCOM values that were found from the calculated results. It is important to note that this is based on the spot price of methanol and not contract prices, which are approximately 200 € higher.

The lowest LCOM was reached in Måløy with an electricity price of 0.05 €/kWh, reaching 0.51 €/kg or 510 €/tonne. This is still a lot higher than the average spot price of methanol, but when comparing it to the contract prices, with an average of 540 €/tonne, this option is competitive on the market. The highest LCOM is found in Båtsfjord with PEM electrolysers and a power price of 0.1 €/kWh, where it was 0.69 €/kWh. The lowest LCOM with PEM electrolysers is in Måløy at 0.05 €/kWh, where it hits 0.55 €/kWh. For the produced methanol to be competitive on the market, the LCOM of the locations with the least amount of wind would have to be a lot lower than what was calculated.

5.3.11 NPV

The NPV of a project says something about whether the project is profitable or not, where a negative NPV indicates that the project will not be profitable, and a positive NPV indicates that it will be profitable based on the desired rate of return. This thesis compares two different methanol selling prices and their effect on the NPV, and these are an average of the methanol spot price and the methanol contract price in Europe given by the MMSA.

The first price that was considered was the spot price of methanol, averaging at 375 €/tonne methanol. This price gave all negative NPVs indicating that none of the scenarios would be profitable if the produced methanol was sold at this price. The NPVs were negative here since the revenue from the sold methanol and hydrogen did not, or barely, exceeded the OPEX of the system. Since NPV is a function of CAPEX, OPEX and revenue, this means that the total discounted revenue did not exceed CAPEX and discounted OPEX over the project's lifetime.

The second price that was considered was the contract price of methanol, which averaged at 540 €/kWh. With this price, all cases where the power price was 0.05 €/kWh and Måløy with alkaline electrolysers and a power price of 0.08 €/kWh got positive NPVs, indicating that these scenarios would be profitable. In other words, the methanol selling price would have to be close to the contract price of methanol for any of the locations to return a positive NPV.

5.3.12 NPV vs. LCOM

As can be seen from Appendix I, the NPV can become positive even though the methanol selling price is lower than the LCOM of the given scenario. This is because the LCOM only takes the discounted methanol production and CAPEX, and discounted OPEX into consideration. The discounted OPEX can be seen as the NPV of expenses over the project's lifetime. NPV is based on discounted cash flows and revenues, which gives a more positive result than simply looking at produced methanol since this looks at the revenue generated from the methanol instead of price per mass.

Both NPV and LCOM have their advantages, depending on which aspects are desirable to look at. The LCOM gives the break-even selling price of methanol, which is helpful when comparing the current methanol selling price to the potential cost of methanol production. The NPV is more useful to look at whether the invested money, both CAPEX and OPEX, can be earned back by the revenue of the project. With that being said, it can be argued that the most important parameter in relation to the methanol plant is the LCOM. If the LCOM is much higher than the current selling price of methanol, it will be hard to sell despite the obvious advantage of it being based on renewable energy.

5.3.13 DPP

Since DPP is closely tied with NPV, a negative NPV indicates that the DPP will be longer than the plant's lifetime, so the DPP was only calculated for scenarios with a positive NPV. All positive NPVs were found when the methanol selling price was set to the average contract price since this was the price where some LCOM values were lower than the selling price.

Because there has been a lot of uncertainty around the economics of the methanol plant, the DPP is also susceptible to many sources of error. This means that the accuracy of the DPP will be impacted by the assumptions made on the economics of the methanol plant as well, but it still gives an indication of how fast the methanol plant will start to return a profit based on CAPEX, OPEX and revenue from the sold products.

The lowest DPP was found in Måløy with alkaline electrolysers and a power price of 0.05 €/kWh, but as mentioned earlier, Måløy should be considered to have a power price of 0.08 €/kWh because of the price zone it is in. Rana and Båtsfjord, however, can have power prices lower than 0.05 €/kWh, which makes these two locations have the lowest DPP based on realistic power prices in the zones. Måløy has a DPP of 17.1 years when looking at a power price of 0.08 €/kWh, which still makes it a viable location for the green methanol plant. With alkaline electrolysers, Båtsfjord has a DPP of 12.3 years, and Rana has a DPP of 11.8 years. With PEM electrolysers Båtsfjord's DPP is 17.2 years, and the DPP for Rana is 16.2 years.

5.4 Comparison of the different locations

One of the questions posed in the introduction is *"What is the most optimal location?"* which is what this section will look into, both in terms of economics and available power and CO_2 for production. The results from the different locations will be pitted against one another to come closer to an answer.

5.4.1 Wind power

One of the most important deciding factors when finding the most optimal location for the green methanol plant is the available wind power since this decides how much power would have to be bought from the grid, contributing to increased OPEX. Both the LCOE and total wind power produced suggest Måløy as the most optimal location as the only location with an LCOE lower than the lowest power price that was chosen.

If a dynamic simulation of the hydrogen production had been done, another factor to consider would be an even power supply throughout the year, trying to minimise the need for shutting off or putting the electrolysers on stand-by. Båtsfjord is the location with the greatest variation in wind power production, with a little under 25 GWh in January and less than 5 GWh in July. Måløy varies between 28 GWh and 15 GWh, which is still a lot of variation but much less so than for Båtsfjord. The highest production in Rana is 27.6 GWh, and the lowest is 9 GWh which makes for a very uneven load profile. Wind power production in Stavanger varies between 22 GWh and 10 GWh, which is the smallest variation of all the locations.

5.4.2 CO_2 availability

As the carbon source for green methanol production, the availability of CO_2 is another important aspect to consider when looking at a possible location for the green methanol plant. All the locations lie in relative proximity to CO_2 sources that could be utilised for methanol production, but it is important to consider that if the CO_2 is not in very close proximity to the methanol plant, the CO_2 might need to be transported by trucks, boats or longer pipelines which would contribute to increased CAPEX and OPEX.

When it comes to Båtsfjord and Måløy, these are two rather remote locations with few big CO_2 sources in very close proximity. Because of this, additional expenses related to transportation of CO_2 to the production site will have to be considered. Both locations are in proximity to harbours, so sub-sea pipelines or freighters might be considered for transportation rather than trucks. For Båtsfjord, utilisation of CO_2 from gas turbines at the Melkøya LNG plant in Hammerfest could be an option where sub-sea pipelines could be utilised. For Måløy, the most viable option for transporting CO_2 here might be sub-sea pipelines as well if the CO_2 captured by Neptune Energy Norway is to be stored on the Norwegian Continental Shelf. For both Båtsfjord and Måløy, if sub-sea pipelines were to be used, the needed CO_2 could be brought to the production site, while excess CO_2 could be stored underground.

Both Rana and Stavanger have large CO_2 emissions close, so the transportation of CO_2 is not as big of an issue at these locations. Some additional investments would probably be needed to transport the CO_2 from the emission site to the green methanol plant, but the investment costs will probably not be as high as for Båtsfjord and Måløy.

6 Conclusion

This thesis has examined the production chain for green methanol to see whether or not establishing a green methanol plant in Norway would be economically profitable. The amount of methanol to be produced per year was set before other parameters were scaled accordingly. The necessary amount of electrolyser modules to produce the needed hydrogen was calculated, and the amount of CO_2 needed for production was calculated based on stoichiometry. Then wind data from four different locations were gathered to predict possible wind power production, which was used to find the necessary number of wind turbines based on the electricity consumption of the electrolysers.

All in all, green methanol production appears to be very expensive with respect to both CAPEX and OPEX. High investment costs for electrolysers and wind turbines, as well as high electricity costs, are the big contributors to high production costs. Electricity price and methanol selling price appear to be the two most important factors when looking at the economics of the plant.

Depending on power price and location, utilising wind energy for hydrogen production can be a viable alternative to buying hydrogen from suppliers or buying power from the grid. The two locations in Northern Norway, Rana and Båtsfjord, along with Stavanger, all have high LCOEs that exceed the lowest electricity price considered in this thesis. Since Båtsfjord and Rana are in zone four, which historically has a rather low electricity price, buying power from the grid might be more economical than wind power production there. In Stavanger, it is not reasonable to assume that the electricity price will be as low as 0.05 €/kWh, so wind power is probably the best option there as well. For Måløy, LCOE is lower than all the electricity prices considered, meaning that wind power is the best alternative for this location.

The LCOH was calculated for a range of FLH from 1000 to 6000. At 3000 FLH with PEM electrolysers and with alkaline electrolysers at 2000 FLH, the LCOH is lower than the assumed selling price of hydrogen of 7 €/kg for all scenarios. This indicates that producing hydrogen with wind power supplying the electricity is more economical than buying hydrogen for almost all scenarios, the only exception being running the electrolysers at a low capacity. The lowest LCOH was found in Måløy at 6000 FLH with alkaline electrolysers, however since this is zone three, the middle power price of 0.08 €/kWh should be considered, corresponding to an LCOH of 2.84 €/kg. Båtsfjord and Rana are in zone four and can have power prices lower than 0.05 €/kWh, so the lowest LCOH values for these locations are 2.75 and 2.65 €/kWh, respectively.

When considering wind power production, Måløy comes out as the best option regardless of what electrolysers are used. With alkaline electrolysers, the second best location is Stavanger, but with PEM electrolysers, Rana exceeds Stavanger's wind power production by a little. Overall, Båtsfjord comes out as the least optimal location for wind power.

CO_2 availability is another important aspect when considering green methanol production. Stavanger and Rana have the best prerequisites here since major CO_2 sources are not far from these locations. Måløy and Båtsfjord would both require CO_2 to be transported over longer distances which would require additional CAPEX and OPEX that would impact the LCOM and NPV negatively.

All in all, Rana, Båtsfjord or Måløy could all be considered for the green e-methanol plant if the methanol selling price is close to the contract price of methanol. Rana and Båtsfjord have the advantage of lower power prices, significantly lowering the OPEX, while Måløy has the best wind conditions. Stavanger has power prices that exceed the highest price examined in this thesis, which will give an even worse NPV and LCOM because of higher OPEX. Overall the alkaline electrolysers seem to be the best choice regardless of location or power price because of the low CAPEX when compared to PEM, which also results in lower OPEX.

The biggest takeaway from this thesis is the importance of electricity prices, meaning that the production system is vulnerable to increased electrical power prices, especially in locations with lower wind speeds. The LCOM is highly affected by the electricity price since this accounts for such a large percentage of the OPEX. Most of today's methanol economy is covered by methanol produced from fossil fuels, but to reach the goals set in the Paris Agreement, a change has to be made. The technology is readily available, and research and development keep pushing it forward. All that is left to do is utilise the technology and keep making improvements to really get green methanol on the market as a sustainable energy carrier.

7 Further work

This thesis has a limited scope, and the complex e-methanol process has other areas that could still be explored. This section will look into possible improvements or further work that could be done to get more reliable results and better outputs that are scaled to fit each other.

7.1 Methanol plant parameters

For future work, one of the improvements that could be made is simulating the methanol plant instead of basing calculations on a literature review. This way, the results might be more reliable and not as susceptible to errors due to scaling. When simulating the methanol production instead of using data from literature, the parameters are directly tied to the thought methanol plant instead of being based on assumptions made in relation to the scaling of components.

7.2 Excess hydrogen

The excess hydrogen produced could, instead of being sold, have been stored to be utilised when wind power production is low, reducing the amount of electricity that needs to be bought. Since electricity accounts for large amounts of the total OPEX, this would help greatly reduce the costs related to the operation of the production system. Since the methanol plant also accounts for large amounts of electricity consumption, another alternative is to utilise H_2 gas turbines for on-site electricity production, providing clean energy to power compressors or methanol synthesis.

7.3 Power

To better utilise the wind energy that goes to waste in this thesis because of overproduction, energy storage in the form of batteries could have been implemented. This would contribute to lowering electricity costs, as the stored power could have been fed to the electrolysers at times with low wind power production.

For the methanol plant, wind power was used as the main power source. In a further study, instead of relying purely on wind power, the wind farm could be combined with solar panels. Wind turbines also cost a substantial amount, and PVs are cheaper in comparison, but they also have a lower efficiency. This combination would give a more even production year-round and would mean fewer wind turbines are needed.

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A Appendix: Functions used in the MATLAB scripts

```
function V=f_importer_vind(filename)

V=readtable(filename,'delimiter',';');
V=V.Middelvind;
V=V(1:8760,:);
V=replace(V,',','.');
V=char(V);
V=str2num(V);
end
```

Figure A.1: Function for importing wind data from Excel sheet.

```
function [n_turb, prod, buy, expense, sum_exp] = f_prod(prod, APC, pp)
n_turb = ceil(APC/max(prod)) ;
prod = prod * n_turb ;
prod(prod>APC) = APC ;
buy = APC - prod ;
expense = buy * pp ;
sum_exp = sum(expense) ;
end
```

Figure A.2: Function for calculating desired number of wind turbines, production from the number of wind turbines, energy that needs to be bought to keep a steady production, expenses because of the need to buy energy and the sum of these expenses over a year.

B Appendix: MATLAB script for wind calculations

```
close all ; clear ; clc

warning('off')



%%%%%%%%Importing wind data%%%%%%%%
Solvaer = f_importer_vind('Vind_Solvaer.csv');
Stvg = f_importer_vind('Vind_Stvg.csv');
Maloy = f_importer_vind('Vind_Maloy.csv');
Batsfjord = f_importer_vind('Vind_Batsfjord.csv');



%Mean wind speeds at the different locations

mean_solv = mean(Solvaer);
mean_Stvg = mean(Stvg);
mean_Maloy = mean(Maloy);
mean_Batsfjord = mean(Batsfjord);

%Median wind speeds at the different locations

median_solv = median(Solvaer);
median_Stvg = median(Stvg);
median_Maloy = median(Maloy);
median_Batsfjord = median(Batsfjord);


%Data for Vestas V136-3.45 - IEC III

d_Vestas = 136 ; %Rotor diameter [m]
r_Vestas = d_Vestas/2; %Rotor radius [m]
A_Vestas = r_Vestas^2 * pi ; %Swept area [m^2]
p = 1.2 ; %Air density
P_Vestas = 3450; %Rated power [kW]

%Data Nordex N117/3600 - IEC II
```

Figure B.1: First part of the wind MATLAB script.

```
%Data Nordex N117/3600 - IEC II

d_Nordex = 116.8 ; %Rotor diameter [m]
r_Nordex = d_Nordex/2; %Rotor radius [m]
A_Nordex = pi*r_Nordex^2; %Swept area [m^2]
P_Nordex = 3600 ; %Rated power [kW]

%Data Vestas V136-4.2 - IEC I

d_13642 = 136 ; %Rotor diameter [m]
r_13642 = d_13642/2 ; %Rotor radius [m]
A_13642 = pi*r_13642^2; %Swept area [m^2]
P_13642 = 4200 ; %Rated power [kW]


%Vector for wind speeds with an interval of 0,5 in m/s
V_0k5 =0:0.5:36.5 ;

%Vector for power at each wind speed for Vestas V136-3.45 in kW
p_0k5_136 = [0, 0, 0, 0, 0, 0, 35, 121, 212, 341, 473, 661, 851, 1114, ...
    1377, 1718, 2058, 2456, 2854, 3200, 3415, 3445, 3450, 3450, 3450, 3450, ...
    3450, 3450, 3450, 3450, 3450, 3450, 3450, 3450, 3450, 3450, 3450, 3450, ...
    3450, 3450, 3450, 3450, 3450, 3450, 3450, 3450, 0, 0, 0, 0, 0, 0, 0, 0, ...
    0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0];

%Vector for efficiency of the Vestas V136-3.45 at the different wind speeds
n_0k5_136345 = (p_0k5_136*2*10^3)./(p*A_Vestas*V_0k5.^3) ;

%Vector for power at each wind speed for Vestas Nordex N117/3600 in kW
p_0k5_117 = [0, 0, 0, 0, 0, 0, 17, 70, 131, 235, 344, 490, 638, 838, 1038, ...
    1300, 1562, 1875, 2188, 2525, 2846, 3100, 3308, 3470, 3540, 3580, 3600,...
    3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, ...
    3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, 3600, ...
    0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0];

%Vector for efficiency of the Nordex N117/3600 at the different wind speeds
n_0k5_117 = (p_0k5_117*2*10^3)./(p*A_Nordex*V_0k5.^3) ;
```

Figure B.2: Second part of the wind MATLAB script.

```
%Vector for efficiency of the Nordex N117/3600 at the different wind speeds
n_0k5_117 = (p_0k5_117*2*10^3)./(p*A_Nordex*V_0k5.^3) ;

%Vector for power at each wind speed for Vestas V136-4.2 in kW
p_0k5_13642 = [0, 0, 0, 0, 0, 0, 57, 133, 225, 338, 479, 650, 856, 1100, ...
    1386, 1710, 2077, 2472, 2858, 3212, 3548, 3834, 4029, 4140, 4185, 4197,...
    4199, 4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200,...
    4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200, 4200,...
    4200, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0];

%Vector for efficiency of the Vestas V136-4.2 at the different wind speeds
n_0k5_13642 = (p_0k5_13642*2*10^3)./(p*A_13642*V_0k5.^3) ;




%Plotting power curve and efficiency curve
grid on
yyaxis left
plot(V_0k5,p_0k5_117,'linewidth',2)
xlabel('Wind speed (m/s)')
ylabel('Power (kW)')
yyaxis right
plot(V_0k5,n_0k5_117,'linewidth',2)
xlim([0 32])
ylabel('Efficiency \eta')
legend('Power','Efficiency curve','FontSize',14)


%Interpolation to calculate the estimated production from wind turbines

n = 730; %Values to averago t oget monthly capacity factor

%BÅTSFJORD

P_vek_Batsfjord = f_interpoler_vek(V_0k5,p_0k5_136,Batsfjord);
save("P_vek_vind_Batsfjord.mat","P_vek_Batsfjord");
```

Figure B.3: Third part of the wind MATLAB script.

```

%BÅTSFJORD

P_vek_Batsfjord = f_interpoler_vek(V_0k5,p_0k5_136,Batsfjord);
save("P_vek_vind_Batsfjord.mat","P_vek_Batsfjord");

Arsprod_Batsfjord = sum(P_vek_Batsfjord);
Arsprod_Batsfjord_GWh = Arsprod_Batsfjord*10^(-6);

k_Batsfjord = Arsprod_Batsfjord/(P_Vestas*8760);
t_b_Batsfjord = k_Batsfjord*8760;

%SOLVÆR
P_vek_Solvaer = f_interpoler_vek(V_0k5,p_0k5_136,Solvaer);
save("P_vek_vind_Solvaer.mat","P_vek_Solvaer");

Arsprod_Solvaer = sum(P_vek_Solvaer);
Arsprod_Solv_GWh = Arsprod_Solvaer*10^(-6);

k_Solvaer = Arsprod_Solvaer/(P_Vestas*8760);
t_b_Solvaer = k_Solvaer*8760;


%MÅLØY

P_vek_Maloy = f_interpoler_vek(V_0k5,p_0k5_13642,Maloy);
save("P_vek_vind_Maloy.mat","P_vek_Maloy");

Arsprod_Maloy = sum(P_vek_Maloy);
Arsprod_Maloy_GWh = Arsprod_Maloy*10^(-6);

k_Maloy = Arsprod_Maloy/(P_13642*8760);
t_b_Maloy = k_Maloy*8760;

```

Figure B.4: Fourth part of the wind MATLAB script.

```
t_b_Maloy = k_Maloy*8760;


%STAVANGER

P_vek_Stvg = f_interpoler_vek(V_0k5,p_0k5_117,Stvg);
save("P_vek_vind_Stvg.mat","P_vek_Stvg");

Arsprod_Stvg = sum(P_vek_Stvg);
Arsprod_Stvg_GWh = Arsprod_Stvg*10^(-6);

k_Stvg = Arsprod_Stvg/(P_Nordex*8760);
t_b_Stvg = k_Stvg*8760;



```

Figure B.5: Fifth part of the wind MATLAB script.

C Appendix: MATLAB script for plots and histograms

```
close all ; clear ; clc

warning('off')

n = 730 ;

%%%%%%%%Importing wind data%%%%%%%%
Batsfjord = f_importer_vind('Vind_Batsfjord.csv');
Solvaer = f_importer_vind('Vind_Solvaer.csv');
Stvg = f_importer_vind('Vind_Stvg.csv');
Maloy = f_importer_vind('Vind_Maloy.csv');



%%%%%%%% Loading production vectors %%%%%%%%
load("P_vek_vind_Stvg.mat");
P_vek_Stvg_month = sum(reshape(P_vek_Stvg,730,12));
load("P_vek_vind_Maloy.mat");
P_vek_Maloy_month = sum(reshape(P_vek_Maloy,730,12));
load("P_vek_vind_Solvaer.mat");
P_vek_Solv_month = sum(reshape(P_vek_Solvaer,730,12));
load("P_vek_vind_Batsfjord.mat");
P_vek_Bfj_month = sum(reshape(P_vek_Batsfjord,730,12));





%Histogram of wind data
%edges = 0:1:25 ;
%histogram(Maloy,edges) ;
%xlabel('Wind speed [m/s]');
%ylabel('Hours of the year');
%title('Histogram of wind speeds over a year in Måløy');



%Plot of wind data
%hrs = 1:length(Batsfjord);
```

Figure C.1: First part of the histogram and plots MATLAB script.

```


%Plot of wind data
%hrs = 1:length(Batsfjord);
%grid on
%plot(hrs,Stvg)
%ylabel('Wind speed [m/s]')
%xlabel('Hours of the year')
%legend('Wind data for each hour of the year','FontSize',14)



%Plot of daily production
month = 1:12 ;
plot(month,P_vek_Bfj_month*10^(-6), 'linewidth',2)
ax=gca;
ax.FontSize = 14;
ylabel('Monthly wind power generated, [GWh]')
xlabel('Months of the year')
legend('Monthly production Båtsfjord')
xlim([1 12])
xticks([1 2 3 4 5 6 7 8 9 10 11 12])
xticklabels({'January', 'February', 'March', 'April', 'May', 'June', 'July', 'August', 'September', 'October', 'November', 'December'})
grid on
```

Figure C.2: Second part of the histogram and plots MATLAB script.

D Appendix: MATLAB script for hydrogen calculations

```
close all ; clear ; clc

warning('off');

%Loading production vectors for wind

load("P_vek_vind_Batsfjord.mat");
load("P_vek_vind_Maloy.mat");
load("P_vek_vind_Solvaer.mat");
load("P_vek_vind_Stvg.mat");


%Necessary variables:

%Average power price for power-intensive industry in Norway on 2022, Eur/kWh
pp = 0.52 * 0.000878 ;
i = [1:12]' ; %Vector from 1 to 365


M5000 = true ;
A3880 = false ;


%%%%%%%%%%%%%%%%% ELECTROLYZER SPECIFICATIONS %%%%%%%%%%%%%%%%%
```

Figure D.1: First part of the hydrogen MATLAB script.

```
%%%%%%%%%%%%%%%%% ELECTROLYZER SPECIFICATIONS %%%%%%%%%%%%%%%%%

%%%%%%%%%%%%%%%%% PEM ELECTROLYZER %%%%%%%%%%%%%%%%%

%M5000

if M5000 == true
    %Electrolyzer module capacity, MW
    P_elec = 25 ;
    %Efficiency (assumed), %
    Eff = 0.64 ;
    %Net production rate, Nm3/h
    NPR = 4920*Eff ; %Multiplying by Eff to account for capacity factor
    %Necessary electrolyzer capacity, Nm3/day
    H2_prod_Nm = (38.7871*10^3)/0.08988 ;
    %Necessary electrolyzer capacity, Nm3/hr
    H2_hr = H2_prod_Nm / 24 ;
    %Water consumption, L/hr:
    WC = 0.9 * H2_hr ;
    %Water costs, Eur/yr:
    WC_tot = WC * 0.002 * 8760 ;
    %Average power consumption, kWh/hr:
    APC = 4.5 * H2_hr * Eff ;
    %Number of modules needed
    n_mod = ceil(H2_hr/NPR) ;
    %Stack lifetime:
    LT_stack = 65000 ;
end


%%%%%%%%%%%%%%%%% ALKALINE ELECTROLYZER %%%%%%%%%%%%%%%%%

```

Figure D.2: Second part of the hydrogen MATLAB script.

```matlab

%%%%%%%%%%%%%%%%% ALKALINE ELECTROLYZER %%%%%%%%%%%%%%%%%



if A3880 == true
    %Electrolyzer module capacity, MW
    P_elec = 17.6 ;
    %Efficiency (assumed), %
    Eff = 0.67 ;
    %Net production rate, Nm3/h
    NPR = 3880*Eff ; %Multiplying by Eff to account for capacity factor
    %Necessary electrolyzer capacity, Nm3/day
    H2_prod_Nm = (38.7871*10^3)/0.08988 ;
    %Necessary electrolyzer capacity, Nm3/hr
    H2_hr = H2_prod_Nm / 24 ;
    %Water consumption, L/hr:
    WC = 1.0 * H2_hr ;
    %Water costs, Eur/yr:
    WC_tot = WC * 0.002 * 8760 ;
    %Average power consumption, kWh/hr:
    APC = 4.5 * H2_hr * Eff ;
    %Number of modules needed
    n_mod = ceil(H2_hr/NPR) ;
    %Stack lifetime:
    LT_stack = 60000 ;
end

%Returns number of wind turbines needed, production vector, and vector
%of energy that needs to be bought to keep the production steady

%Sets amount of wind turbines so max production doesn't exceed the
%needed energy for hydrogen production
```

Figure D.3: Third part of the hydrogen MATLAB script.

```matlab
%Sets amount of wind turbines so max production doesn't exceed the
%needed energy for hydrogen production

[Bfj_turb, Bfj_prod, Bfj_prod_sum, Bfj_buy, Bfj_buy_sum, Bfj_exp, Bfj_sum_e] = f_prod(P_vek_Batsfjord, APC, pp) ;
[Mal_turb, Mal_prod, Mal_prod_sum, Mal_buy, Mal_buy_sum, Mal_exp, Mal_sum_e] = f_prod(P_vek_Maloy, APC, pp) ;
[Sol_turb, Sol_prod, Sol_prod_sum, Sol_buy, sol_buy_sum, Sol_exp, Sol_sum_e] = f_prod(P_vek_Solvaer, APC, pp) ;
[Stvg_turb, Stvg_prod, Stvg_prod_sum, Stvg_buy, Stvg_buy_sum, Stvg_exp, Stvg_sum_e] = f_prod(P_vek_Stvg, APC, pp) ;



Bfj_month = sum(reshape(Bfj_prod,730,12));
Mal_month = sum(reshape(Mal_prod,730,12));
Sol_month = sum(reshape(Sol_prod,730,12));
Stvg_month = sum(reshape(Stvg_prod,730,12));


%Plot of monthly production
month = 1:12 ;
plot(month,Bfj_month*10^(-6), month, Mal_month*10^(-6), month, Sol_month*10^(-6), month, Stvg_month*10^(-6), 'linewidth',2)
ax=gca;
ax.FontSize = 14;
title('Monthly production, PEM electrolyzers')
ylabel('Monthly wind power generated, [GWh]')
xlabel('Months of the year')
legend('Båtsfjord', 'Rana', 'Måløy', 'Stavanger')
xlim([1 12])
xticks([1 2 3 4 5 6 7 8 9 10 11 12])
xticklabels({'January', 'February', 'March', 'April', 'May', 'June', 'July', 'August', 'September', 'October', 'November', 'December'})
```

Figure D.4: Fourth part of the hydrogen MATLAB script.

E Appendix: MATLAB script for methanol calculations

```
close all ; clear ; clc


% STOICHIOMETRIC CALCULATIONS

m_met = 75000 ; %Amount of methanol to be produced, tonnes/yr
M_met = 32.04; %Molar weight of methanol, g/mole
M_CO2 = 44.01; %Molar weight of CO2, g/mole
M_H2 = 2.016; %Molar weight of H2, g/mole
M_h2o = 18.015 ; %Molar weight of H2O, g/mole

m_met_day = m_met/365 ;
m_met_hr = m_met/8760 ;

n_CO2 = 1 ; %Moles of CO2 per needed permole of methanol produced
n_H2 = 3 ; %Moles of H2 needed per mole of methanol produced
n_h2o = 1 ;



%Stoichiometric amount of CO2 needed to produce the given amount of
%methanol, tonnes/yr
m_CO2 = (n_CO2 * M_CO2 * m_met/M_met)/0.639 ;
%Amount of CO2 needed, tonnes/day
m_CO2_day = m_CO2/365 ;
%CO2 needed, tonnes/hr
m_CO2_h = m_CO2/8760;
m_CO2_sec = m_CO2_h/3600 ;

%Stoichiometric amount of H2 needed to produce the given amount of
%methanol, tonnes/yr
m_H2 = (n_H2 * M_H2 * m_met/M_met)/0.639 ;
%Amount H2 needed, tonnes/day
m_H2_day = m_H2/365;
%H2 needed, tonnes/hr
m_H2_hr = m_H2/8760;


%Stoichiometric amount of H2O as a result of
```

Figure E.1: First part of the methanol MATLAB script.

```
%Stoichiometric amount of H2O as a result of
%direct hydrogenation of CO2
m_h2o = n_h2o * M_h2o * m_met/M_met ;
m_h2o_day = m_h2o/365 ;
m_h2o_hr = m_h2o/8760 ;


%Calculating the mean sales price of methanol
Salesp = [414, 453, 396, 378, 392, 367, 374, 358, 350, 330, 329, 342, 361] ;

salexp_avg = mean(Salesp) ;

feed_hr = (m_H2_hr+m_CO2_h)*1000 ;

%Space time yield (STY) of methanol, kg mehanol/L
%catalyst * h

cat_dens = 1.2 ; %Density of catalyst, kg/L

eps = 0.9198/1.5^2 + 0.3414 ; %1.5 = catalyst diameter/catalyst height (pellets)

m_cat = ((cat_dens/10^(-3))*(1-eps)*feed_hr)/10500 ;

L_cat = m_cat/cat_dens ;
```

Figure E.2: Second part of the methanol MATLAB script.

F Appendix: Excel sheets for economic calculations

Electrolyzer technology	Module size (MW)	System size (MW)	Production rate (Nm3/h)	Production rate (kg/h)	Max daily production (kg/day)	Max annual production (t/yr)	Water consumption (l/hr)	Water consumption (l/yr)	Energy consumption (kWh/Nm3)	Energy consumption (kWh/kg)	Output pressure (bar)	Module size (m2)
PEM	25	150	29520	2653.2576	63678.1824	23242.537	26568	232735680	4.5	50.0667557	30	3 284.4
Alkaline	17.6	123.2	27160	2441.1408	58587.3792	21384.393	27160	237921600	4.5	50.0667557	30	770

PEM module	CAPEX system cost 2023 (€/kW)	Total CAPEX (€)	OPEX (4% of CAPEX) (€/yr)	Stack replacement cost 2023 (€/kW)	Total stack replacement cost (€)	Load range (hr/yr)	Lifetime stack (hrs)	Lifetime stack (years)	Lifetime electrolyzer (years)
M5000	€ 825.00	€ 123,750,000.00	€ 4,950,000.00	€ 262.50	€ 39,375,000.00	5694	45000	7.9	20

Alkaline module	CAPEX system cost 2023 (€/kW)	Total CAPEX (€)	OPEX (4% of CAPEX) (€/yr)	Stack replacement cost 2023 (€/kW)	Total stack replacement cost (€)	Load range (hr/yr)	Lifetime stack (hrs)	Lifetime stack (years)	Lifetime electrolyzer (years)
A3880	€ 637.50	€ 78,540,000.00	€ 3,141,600.00	€ 246.50	€ 30,368,800.00	5694	65000	11.4	20

Compressor (30->60 barg) CAPEX (€)	Power consumption (kWh/kg)	Power consumption per hour, PEM (kWh/h)	Power consumption per hour, alkaline (kWh/h)
€ 1 043 000	1.1	2918.58336	2685.25488

(a) Excel sheet calculating CAPEX and OPEX for electrolyzers.

Location	CAPEX €/kW	Number of wind turbines, PEM	Number of wind turbines, alkaline	Rated power wind turbine, MW	Total CAPEX wind farm PEM, €	Total CAPEX wind farm, alkaline, €	OPEX PEM, 3% of CAPEX, €/yr	OPEX alkaline, 3% of CAPEX, €/yr
Båtsfjord	€ 1,117.00	16	16	3.45	€ 61,658,400.00	€ 61,658,400.00	€ 1,849,752.00	€ 1,849,752.00
Rana	€ 1,117.00	16	16	3.45	€ 61,658,400.00	€ 61,658,400.00	€ 1,849,752.00	€ 1,849,752.00
Måløy	€ 1,117.00	13	13	4.2	€ 60,988,200.00	€ 60,988,200.00	€ 1,829,646.00	€ 1,829,646.00
Stavanger	€ 1,117.00	15	16	3.6	€ 60,318,000.00	€ 64,339,200.00	€ 1,809,540.00	€ 1,930,176.00

(b) Excel sheet for calculating wind turbine CAPEX and OPEX.

	Storage tank capacity, kg H2	CAPEX tank, €	OPEX tank, €/yr	CAPEX compressor, €	OPEX compressor, €/yr	Compressor power requirement, kWh/yr	CAPEX fueling station, €	OPEX fueling station, €/yr	Fueling station power requirement, kWh/yr	Electricity costs, 0.05 €/kWh	Electricity costs, 0.08 €/kWh	Total CAPEX, €	Total OPEX, 0.05 €/kWh, €/yr	Total OPEX, 0.08 €/kWh, €/yr
PEM	13769	€ 4,395,890.94	€ 21,979.45	€ 274,754.24	€ 10,990.17	1005104.672	€ 2,251,810.02	€ 90,072.40	1168000	€ 108,655.23	€ 173,848.37	€ 6,922,455.20	€ 231,697.26	€ 296,890.40
Alkaline	3265	€ 1,042,383.90	€ 5,211.92	€ 65,136.96	€ 2,605.48	238352.9167	€ 813,453.19	€ 32,538.13	272728	€ 25,554.05	€ 40,886.47	€ 1,920,974.05	€ 65,909.57	€ 81,242.00

(a) Excel sheet calculating CAPEX and OPEX for H2 storage and distribution.

Reference:	https://www.sciencedirect.com/science/article/pii/S2212982020300688#bib0145	https://www.sciencedirect.com/science/article/pii/S0306261915009071#s0025	https://www.sciencedirect.com/science/article/pii/S0360319922002415#sec2	**Value for the thought methanol plant**
Plant capacity (t/year)	1 825 000	481 800	99 993	75 000
Reference year	2018	2016	2020	2023
PEC literature				
Compressors	€ 17,950,000.00	€ 12,150,000.00	$ 4,058,552.00	-
Heat exchanger	€ 19,340,000.00	€ 10,962,000.00	$ 701,153.00	-
Reactor	€ 16,430,000.00	€ 270,000.00	$ 17,310,772.00	-
Separator	€ 420,000.00	€ 351,000.00	$ 139,767.00	-
Distillation	€ 4,680,000.00	€ 432,000.00	$ 3,903,918.00	-
PEC recalculated				
Compressors	€ 1,149,828.15	€ 3,070,799.95	€ 3,777,521.59	€ 2,666,049.90
Heat exchanger	€ 3,126,247.95	€ 4,751,477.19	€ 709,368.75	€ 3,938,862.57
Reactor	€ 3,772,999.00	€ 2,952,519.21	€ 10,004,626.46	€ 3,362,759.11
Separator	€ 116,807.44	€ 208,724.25	€ 148,490.38	€ 158,007.36
Distillation	€ 916,188.63	€ 209,358.66	€ 4,018,411.84	€ 1,714,653.04
SUM	€ 9,082,071.18	€ 11,192,879.27	€ 18,658,419.02	€ 12,977,789.82

Necessary CO2 (tonnes/year)	Buying price of CO2 (€/tonne)	Expenses because of bought CO2 (€/yr)
106425.2716	€ 25.00	€ 2,660,631.79

Needed cataclyst, kg	Cost of catalyst, €/kg (changed every 3 years)	Total catalyst costs
597.6152436	8.8	€ 5,259.01

OPEX excl. Power	Power needed	Expenses due to bought power, 0.08 €/kWh	Expenses due to bought power, 0.05 €/kWh
€ 519,111.59	41250000	€ 3,300,000.00	€ 2,062,500.00

(b) Excel sheet calculating CAPEX and OPEX for the methanol plant based on literature. [66, 103, 104]

G Appendix: Excel sheets for electrolyzer and wind calculations alkaline

Investment (€)	Subsidies (%)	Investment incl. Subsidies, electrolyzer + compression (€)	Investment, elec., compr and wind, (€)	Depreciation period (yr)	Depreciation per year (€)	Hydrogen volume per hour (Nm3/hr)	OPEX electrolyzers, excl. water and power (€/yr)	Water costs (€/yr)	Specific energy consumption (kWh/Nm3)	Electricity price (€/kWh)	Electricity costs (€/yr)	Total OPEX (€/yr)	Full load hours (h/yr)	Power (MW)	Production cost per kg, (€/kg)	LCOH, (€/kg)
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.08	€ 3,009,009.43	€ 8,054,681.43	1000	123.2	€ 17.44	€ 10.93
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.08	€ 6,018,018.86	€ 11,118,010.86	2000	123.2	€ 8.90	€ 6.47
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.08	€ 9,027,028.29	€ 14,181,340.29	3000	123.2	€ 6.05	€ 4.99
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.08	€ 12,036,037.73	€ 17,244,669.73	4000	123.2	€ 4.63	€ 4.24
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.08	€ 15,045,047.16	€ 20,307,999.16	5000	123.2	€ 3.77	€ 3.80
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.08	€ 18,054,056.59	€ 23,371,328.59	6000	123.2	€ 3.20	€ 3.50
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.05	€ 1,880,630.89	€ 6,926,302.89	1000	123.2	€ 17.31	€ 10.19
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.05	€ 3,761,261.79	€ 8,861,253.79	2000	123.2	€ 8.77	€ 5.73
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.05	€ 5,641,892.68	€ 10,796,204.68	3000	123.2	€ 5.92	€ 4.24
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.05	€ 7,522,523.58	€ 12,731,155.58	4000	123.2	€ 4.50	€ 3.50
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.05	€ 9,403,154.47	€ 14,666,106.47	5000	123.2	€ 3.64	€ 3.06
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.05	€ 11,283,785.37	€ 16,601,057.37	6000	123.2	€ 3.07	€ 2.76
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.1	€ 3,761,261.79	€ 8,806,933.79	1000	123.2	€ 17.53	€ 11.43
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.1	€ 7,522,523.58	€ 12,622,515.58	2000	123.2	€ 8.99	€ 6.97
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.1	€ 11,283,785.37	€ 16,438,097.37	3000	123.2	€ 6.14	€ 5.48
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.1	€ 15,045,047.16	€ 20,253,679.16	4000	123.2	€ 4.72	€ 4.74
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.1	€ 18,806,308.95	€ 24,069,260.95	5000	123.2	€ 3.86	€ 4.29
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.1	€ 22,567,570.74	€ 27,884,842.74	6000	123.2	€ 3.29	€ 3.99

(a) Economic calculations for Båtsfjord with alkaline electrolyzers.

Investment electrolyzers and compression (€)	Subsidies (%)	Investment incl. Subsidies, electrolyzer + compression (€)	Investment, elec., compr and wind, (€)	Depreciation period (yr)	Depreciation per year (€)	Hydrogen volume per hour (Nm3/hr)	OPEX electrolyzers, excl. water and power (€/yr)	Water costs (€/yr)	Specific energy consumption (kWh/Nm3)	Electricity price (€/kWh)	Electricity costs (€/yr)	Total OPEX (€/yr)	Full load hours (h/yr)	Power (MW)	Production cost per kg, (€/kg)	LCOH, (€/kg)
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.08	€ 2,758,333.63	€ 7,804,005.63	1000	123.2	€ 17.41	€ 10.77
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.08	€ 5,516,667.26	€ 10,616,659.26	2000	123.2	€ 8.87	€ 6.31
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.08	€ 8,275,000.90	€ 13,429,312.90	3000	123.2	€ 6.02	€ 4.82
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.08	€ 11,033,334.53	€ 16,241,966.53	4000	123.2	€ 4.60	€ 4.08
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.08	€ 13,791,668.16	€ 19,054,620.16	5000	123.2	€ 3.74	€ 3.63
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.08	€ 16,550,001.79	€ 21,867,273.79	6000	123.2	€ 3.18	€ 3.33
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.05	€ 1,723,958.52	€ 6,769,630.52	1000	123.2	€ 17.29	€ 10.09
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.05	€ 3,447,917.04	€ 8,547,909.04	2000	123.2	€ 8.75	€ 5.63
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.05	€ 5,171,875.56	€ 10,326,187.56	3000	123.2	€ 5.90	€ 4.14
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.05	€ 6,895,834.08	€ 12,104,466.08	4000	123.2	€ 4.48	€ 3.40
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.05	€ 8,619,792.60	€ 13,882,744.60	5000	123.2	€ 3.62	€ 2.95
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.05	€ 10,343,751.12	€ 15,661,023.12	6000	123.2	€ 3.05	€ 2.66
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.1	€ 3,447,917.04	€ 8,493,589.04	1000	123.2	€ 17.49	€ 11.22
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.1	€ 6,895,834.08	€ 11,995,826.08	2000	123.2	€ 8.95	€ 6.76
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.1	€ 10,343,751.12	€ 15,498,063.12	3000	123.2	€ 6.10	€ 5.27
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.1	€ 13,791,668.16	€ 19,000,300.16	4000	123.2	€ 4.68	€ 4.53
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.1	€ 17,239,585.20	€ 22,502,537.20	5000	123.2	€ 3.83	€ 4.09
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 141,241,400.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.1	€ 20,687,502.24	€ 26,004,774.24	6000	123.2	€ 3.26	€ 3.79

(b) Economic calculations for Rana with alkaline electrolyzers.

Investment (€)	Subsidies (%)	Investment incl. Subsidies, electrolyzer + compression (€)	Investment, elec., compr and wind, (€)	Depreciation period (yr)	Depreciation per year (€)	Hydrogen volume per hour (Nm3/hr)	OPEX electrolyzers, excl. water and power (€/yr)	Water costs (€/yr)	Specific energy consumption (kWh/Nm	Electricity price (€/kWh)	Electricity costs (€/yr)	Total OPEX (€/yr)	Full load hours (h/yr)	Power (MW)	Production cost per kg, (€/kg)	LCOH, (€/kg)
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.08	€ 2,268,856.92	€ 7,294,422.92	1000	123.2	€ 17.27	€ 9.41
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.08	€ 4,537,713.84	€ 9,617,599.84	2000	123.2	€ 8.77	€ 5.47
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.08	€ 6,806,570.76	€ 11,940,776.76	3000	123.2	€ 5.94	€ 4.16
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.08	€ 9,075,427.68	€ 14,263,953.68	4000	123.2	€ 4.52	€ 3.50
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.08	€ 11,344,284.60	€ 16,587,130.60	5000	123.2	€ 3.67	€ 3.10
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.08	€ 13,613,141.52	€ 18,910,307.52	6000	123.2	€ 3.10	€ 2.84
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.05	€ 1,418,035.58	€ 6,443,601.58	1000	123.2	€ 17.17	€ 8.85
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.05	€ 2,836,071.15	€ 7,915,957.15	2000	123.2	€ 8.67	€ 4.91
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.05	€ 4,254,106.73	€ 9,388,312.73	3000	123.2	€ 5.84	€ 3.60
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.05	€ 5,672,142.30	€ 10,860,668.30	4000	123.2	€ 4.42	€ 2.94
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.05	€ 7,090,177.88	€ 12,333,023.88	5000	123.2	€ 3.57	€ 2.54
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.05	€ 8,508,213.45	€ 13,805,379.45	6000	123.2	€ 3.01	€ 2.28
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.1	€ 2,836,071.15	€ 7,861,637.15	1000	123.2	€ 17.34	€ 9.79
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.1	€ 5,672,142.30	€ 10,752,028.30	2000	123.2	€ 8.84	€ 5.84
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.1	€ 8,508,213.45	€ 13,642,419.45	3000	123.2	€ 6.00	€ 4.53
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.1	€ 11,344,284.60	€ 16,532,810.60	4000	123.2	€ 4.59	€ 3.87
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.1	€ 14,180,355.75	€ 19,423,201.75	5000	123.2	€ 3.74	€ 3.48
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 140,571,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.1	€ 17,016,426.90	€ 22,313,592.90	6000	123.2	€ 3.17	€ 3.21

(a) Economic calculations for Måløy with alkaline electrolyzers.

Investment (€)	Subsidies (%)	Investment incl. Subsidies, electrolyzer + compression (€)	Investment, elec., compr. and wind, (€)	Depreciation period (yr)	Depreciation per year (€)	Hydrogen volume per hour (Nm3/hr)	OPEX electrolyzers, excl. water and power (€/yr)	Water costs (€/yr)	Specific energy consumption (kWh/Nm	Electricity price (€/kWh)	Electricity costs (€/yr)	Total OPEX (€/yr)	Full load hours (h/yr)	Power (MW)	Production cost per kg, (€/kg)	LCOH, (€/kg)
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.08	€ 2,732,056.92	€ 7,858,152.92	1000	123.2	€ 17.73	€ 9.89
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.08	€ 5,464,113.84	€ 10,644,529.84	2000	123.2	€ 9.03	€ 5.86
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.08	€ 8,196,170.76	€ 13,430,906.76	3000	123.2	€ 6.13	€ 4.52
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.08	€ 10,928,227.68	€ 16,217,283.68	4000	123.2	€ 4.68	€ 3.85
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.08	€ 13,660,284.60	€ 19,003,660.60	5000	123.2	€ 3.81	€ 3.44
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.08	€ 16,392,341.52	€ 21,790,037.52	6000	123.2	€ 3.23	€ 3.17
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.05	€ 1,707,535.58	€ 6,833,631.58	1000	123.2	€ 17.61	€ 9.22
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.05	€ 3,415,071.15	€ 8,595,487.15	2000	123.2	€ 8.91	€ 5.19
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.05	€ 5,122,606.73	€ 10,357,342.73	3000	123.2	€ 6.01	€ 3.85
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.05	€ 6,830,142.30	€ 12,119,198.30	4000	123.2	€ 4.56	€ 3.17
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.05	€ 8,537,677.88	€ 13,881,053.88	5000	123.2	€ 3.69	€ 2.77
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.05	€ 10,245,213.45	€ 15,642,909.45	6000	123.2	€ 3.11	€ 2.50
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 54,320.00	4.5	0.1	€ 3,415,071.15	€ 8,541,167.15	1000	123.2	€ 17.81	€ 10.34
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 108,640.00	4.5	0.1	€ 6,830,142.30	€ 12,010,558.30	2000	123.2	€ 9.11	€ 6.31
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 162,960.00	4.5	0.1	€ 10,245,213.45	€ 15,479,949.45	3000	123.2	€ 6.21	€ 4.97
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 217,280.00	4.5	0.1	€ 13,660,284.60	€ 18,949,340.60	4000	123.2	€ 4.76	€ 4.30
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 271,600.00	4.5	0.1	€ 17,075,355.75	€ 22,418,731.75	5000	123.2	€ 3.89	€ 3.89
€ 79,583,000.00	0 %	€ 79,583,000.00	€ 143,922,200.00	20	€ 3,979,150.00	29520	€ 3,141,600.00	€ 325,920.00	4.5	0.1	€ 20,490,426.90	€ 25,888,122.90	6000	123.2	€ 3.31	€ 3.62

(b) Economic calculations for Stavanger with alkaline electrolyzers.

H Appendix: Excel sheets for electrolyzer and wind calculations PEM

Investment (€)	Subsidies (%)	Investment incl. Subsidies, electrolyzer + compression (€)	Investement elec., compr. And wind, (€)	Depreciation period (yr)	Depreciation per year (€)	Hydrogen volume per hour (Nm3/hr)	OPEX excl. water and power (€/yr)	Water costs (€/yr)	Specific energy consumption (kWh/Nm3)	Electricity price (€/kWh)	Electricity costs (€/yr)	Total OPEX (€/yr)	Full load hours (h/yr)	Power (MW)	Production cost per kg (€/kg)	LCOH, (€/kg)
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.08	€ 2,865,654.71	€ 9,718,542.71	1000	150	€ 22.91	€ 13.81
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.08	€ 5,731,309.41	€ 12,637,333.41	2000	150	€ 11.63	€ 7.86
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.08	€ 8,596,964.12	€ 15,556,124.12	3000	150	€ 7.86	€ 5.88
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.08	€ 11,462,618.82	€ 18,474,914.82	4000	150	€ 5.98	€ 4.89
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.08	€ 14,328,273.53	€ 21,393,705.53	5000	150	€ 4.86	€ 4.30
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.08	€ 17,193,928.23	€ 24,312,496.23	6000	150	€ 4.10	€ 3.90
-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.05	€ 1,791,034.19	€ 8,643,922.19	1000	150	€ 22.79	€ 13.10
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.05	€ 3,582,068.38	€ 10,488,092.38	2000	150	€ 11.50	€ 7.16
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.05	€ 5,373,102.57	€ 12,332,262.57	3000	150	€ 7.74	€ 5.18
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.05	€ 7,164,136.76	€ 14,176,432.76	4000	150	€ 5.86	€ 4.18
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.05	€ 8,955,170.95	€ 16,020,602.95	5000	150	€ 4.73	€ 3.59
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.05	€ 10,746,205.14	€ 17,864,773.14	6000	150	€ 3.98	€ 3.19
-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.1	€ 3,582,068.38	€ 10,434,956.38	1000	150	€ 23.00	€ 14.28
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.1	€ 7,164,136.76	€ 14,070,160.76	2000	150	€ 11.71	€ 8.33
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.1	€ 10,746,205.14	€ 17,705,365.14	3000	150	€ 7.95	€ 6.35
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.1	€ 14,328,273.53	€ 21,340,569.53	4000	150	€ 6.07	€ 5.36
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.1	€ 17,910,341.91	€ 24,975,773.91	5000	150	€ 4.94	€ 4.77
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.1	€ 21,492,410.29	€ 28,610,978.29	6000	150	€ 4.19	€ 4.37

(a) Economic calculations for Båtsfjord with PEM electrolyzers.

Investment (€)	Subsidies (%)	Investment incl. Subsidies, electrolyzer + compression (€)	Investement elec., compr. And wind, (€)	Depreciation period (yr)	Depreciation per year (€)	Hydrogen volume per hour (Nm3/hr)	OPEX excl. water and power (€/yr)	Water costs (€/yr)	Specific energy consumption (kWh/Nm3)	Electricity price (€/kWh)	Electricity costs (€/yr)	Total OPEX (€/yr)	Full load hours (h/yr)	Power (MW)	Production cost per kg (€/kg)	LCOH, (€/kg)
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.08	€ 2,618,232.79	€ 9,471,120.79	1000	150	€ 22.88	€ 13.64
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.08	€ 5,236,465.57	€ 12,142,489.57	2000	150	€ 11.60	€ 7.70
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.08	€ 7,854,698.36	€ 14,813,858.36	3000	150	€ 7.84	€ 5.72
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.08	€ 10,472,931.15	€ 17,485,227.15	4000	150	€ 5.95	€ 4.73
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.08	€ 13,091,163.94	€ 20,156,595.94	5000	150	€ 4.83	€ 4.13
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.08	€ 15,709,396.72	€ 22,827,964.72	6000	150	€ 4.07	€ 3.74
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.05	€ 1,636,395.49	€ 8,489,283.49	1000	150	€ 22.77	€ 13.00
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.05	€ 3,272,790.98	€ 10,178,814.98	2000	150	€ 11.48	€ 7.05
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.05	€ 4,909,186.48	€ 11,868,346.48	3000	150	€ 7.72	€ 5.07
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.05	€ 6,545,581.97	€ 13,557,877.97	4000	150	€ 5.84	€ 4.08
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.05	€ 8,181,977.46	€ 15,247,409.46	5000	150	€ 4.71	€ 3.49
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.05	€ 9,818,372.95	€ 16,936,940.95	6000	150	€ 3.96	€ 3.09
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.1	€ 3,272,790.98	€ 10,125,678.98	1000	150	€ 22.96	€ 14.08
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.1	€ 6,545,581.97	€ 13,451,605.97	2000	150	€ 11.67	€ 8.13
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.1	€ 9,818,372.95	€ 16,777,532.95	3000	150	€ 7.91	€ 6.15
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.1	€ 13,091,163.94	€ 20,103,459.94	4000	150	€ 6.03	€ 5.16
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.1	€ 16,363,954.92	€ 23,429,386.92	5000	150	€ 4.90	€ 4.56
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 186,451,400.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.1	€ 19,636,745.91	€ 26,755,313.91	6000	150	€ 4.15	€ 4.17

(b) Economic calculations for Rana with PEM electrolyzers.

Investment (€)	Subsidies (%)	Investment incl. Subsidies, electrolyzer + compression (€)	Investment elec, compr and wind, (€)	Depreciation period (yr)	Depreciation per year (€)	Hydrogen volume per hour (Nm3/hr)	OPEX excl. water and power (€/yr)	Water costs (€/yr)	Specific energy consumption (kWh/Nm3)	Electricity price (€/kWh)	Electricity costs (€/yr)	Total OPEX (€/yr)	Full load hours (h/yr)	Power (MW)	Production cost per kg (€/kg)	LCOH, (€/kg)
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.08	€ 2,160,909.50	€ 8,993,691.50	1000	150	€ 22.75	€ 13.31
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.08	€ 4,321,819.00	€ 11,207,737.00	2000	150	€ 11.50	€ 7.38
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.08	€ 6,482,728.50	€ 13,421,782.50	3000	150	€ 7.76	€ 5.41
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.08	€ 8,643,638.00	€ 15,635,828.00	4000	150	€ 5.88	€ 4.42
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.08	€ 10,804,547.50	€ 17,849,873.50	5000	150	€ 4.76	€ 3.83
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.08	€ 12,965,457.00	€ 20,063,919.00	6000	150	€ 4.01	€ 3.43
-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.05	€ 1,350,568.44	€ 8,183,350.44	1000	150	€ 22.66	€ 12.78
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.05	€ 2,701,136.87	€ 9,587,054.87	2000	150	€ 11.41	€ 6.85
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.05	€ 4,051,705.31	€ 10,990,759.31	3000	150	€ 7.66	€ 4.87
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.05	€ 5,402,273.75	€ 12,394,463.75	4000	150	€ 5.79	€ 3.89
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.05	€ 6,752,842.19	€ 13,798,168.19	5000	150	€ 4.66	€ 3.29
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.05	€ 8,103,410.62	€ 15,201,872.62	6000	150	€ 3.91	€ 2.90
-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.1	€ 2,701,136.87	€ 9,533,918.87	1000	150	€ 22.81	€ 13.66
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.1	€ 5,402,273.75	€ 12,288,191.75	2000	150	€ 11.57	€ 7.74
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.1	€ 8,103,410.62	€ 15,042,464.62	3000	150	€ 7.82	€ 5.76
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.1	€ 10,804,547.50	€ 17,796,737.50	4000	150	€ 5.94	€ 4.77
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.1	€ 13,505,684.37	€ 20,551,010.37	5000	150	€ 4.82	€ 4.18
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,781,200.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.1	€ 16,206,821.25	€ 23,305,283.25	6000	150	€ 4.07	€ 3.79

(a) Economic calculations for Måløy with PEM electrolyzers.

Investment (€)	Subsidies (%)	Investment incl. Subsidies, electrolyzer + compression (€)	Investment elec, compr and wind, (€)	Depreciation period (yr)	Depreciation per year (€)	Hydrogen volume per hour (Nm3/hr)	OPEX excl. water and power (€/yr)	Water costs (€/yr)	Specific energy consumption (kWh/Nm	Electricity price (€/kWh)	Electricity costs (€/yr)	Total OPEX (€/yr)	Full load hours (h/yr)	Power (MW)	Production cost per kg (€/kg)	LCOH, (€/kg)
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.08	€ 2,657,526.85	€ 9,470,202.85	1000	150	€ 22.73	€ 13.60
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.08	€ 5,315,053.70	€ 12,180,865.70	2000	150	€ 11.52	€ 7.69
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.08	€ 7,972,580.55	€ 14,891,528.55	3000	150	€ 7.79	€ 5.72
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.08	€ 10,630,107.41	€ 17,602,191.41	4000	150	€ 5.92	€ 4.74
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.08	€ 13,287,634.26	€ 20,312,854.26	5000	150	€ 4.80	€ 4.15
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.08	€ 15,945,161.11	€ 23,023,517.11	6000	150	€ 4.05	€ 3.75
-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.05	€ 1,660,954.28	€ 8,473,630.28	1000	150	€ 22.61	€ 12.95
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.05	€ 3,321,908.56	€ 10,187,720.56	2000	150	€ 11.41	€ 7.04
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.05	€ 4,982,862.85	€ 11,901,810.85	3000	150	€ 7.67	€ 5.07
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.05	€ 6,643,817.13	€ 13,615,901.13	4000	150	€ 5.80	€ 4.08
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.05	€ 8,304,771.41	€ 15,329,991.41	5000	150	€ 4.68	€ 3.49
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.05	€ 9,965,725.69	€ 17,044,081.69	6000	150	€ 3.94	€ 3.10
-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 53,136.00	4.5	0.1	€ 3,321,908.56	€ 10,134,584.56	1000	150	€ 22.80	€ 14.04
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 106,272.00	4.5	0.1	€ 6,643,817.13	€ 13,509,629.13	2000	150	€ 11.60	€ 8.13
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 159,408.00	4.5	0.1	€ 9,965,725.69	€ 16,884,673.69	3000	150	€ 7.86	€ 6.16
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 212,544.00	4.5	0.1	€ 13,287,634.26	€ 20,259,718.26	4000	150	€ 6.00	€ 5.17
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 265,680.00	4.5	0.1	€ 16,609,542.82	€ 23,634,762.82	5000	150	€ 4.88	€ 4.58
€ 124,793,000.00	0 %	€ 124,793,000.00	€ 185,111,000.00	20	€ 6,239,650.00	29520	€ 4,950,000.00	€ 318,816.00	4.5	0.1	€ 19,931,451.39	€ 27,009,807.39	6000	150	€ 4.13	€ 4.19

(b) Economic calculations for Stavanger with PEM electrolyzers.

I Appendix: Excel sheet calculating LCOM and NPV

Power price, €/kWh	Location	Total CAPEX wind, methanol, PEM electrolyzers, €	Total CAPEX wind, methanol, alkaline electrolyzers, €	Total OPEX PEM 6000 FLH, €/yr	Total OPEX alkaline 6000 FLH, €/yr	Stack replacement cost PEM, €	Stack replacement cost alkaline, €	Catalyst cost, €	Yearly methanol production, tonnes/yr	Methanol selling price, €/tonne	Revenue from methanol sale, €	Potential revenue from excess hydrogen PEM, €	Revenue from excess hydrogen alkaline, €	LCOM PEM, €/kg	Net present value, PEM	LCOM alkaline, €/kg	Net present value, alkaline
0.08																	
	Båtsfjord	€ 206,351,645.02	€ 155,097,163.87	€ 32,490,050.02	€ 29,932,473.89	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 372.62	€ 27,946,155.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.70	-€ 221,584,045.17	€ 0.60	-€ 180,230,379.29
	Rana	€ 206,351,645.02	€ 155,097,163.87	€ 31,005,518.51	€ 28,428,419.09	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 372.62	€ 27,946,155.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.68	-€ 204,564,040.37	€ 0.58	-€ 162,978,989.22
	Måløy	€ 205,681,445.02	€ 154,426,963.87	€ 28,241,472.79	€ 25,471,452.82	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 372.62	€ 27,946,155.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.64	-€ 172,190,453.72	€ 0.54	-€ 133,222,158.85
	Stavanger	€ 205,011,245.02	€ 157,777,963.87	€ 31,201,070.90	€ 28,351,182.82	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 372.62	€ 27,946,155.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.68	-€ 205,466,610.88	€ 0.58	-€ 164,773,895.29
0.05																	
	Båtsfjord	€ 206,351,645.02	€ 155,097,163.87	€ 24,214,288.79	€ 21,909,310.27	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 372.62	€ 27,946,155.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.59	-€ 126,669,170.45	€ 0.49	-€ 88,205,324.67
	Rana	€ 206,351,645.02	€ 155,097,163.87	€ 23,286,456.60	€ 20,969,276.02	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 372.62	€ 27,946,155.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.57	-€ 116,027,008.33	€ 0.48	-€ 77,423,205.88
	Måløy	€ 205,681,445.02	€ 154,426,963.87	€ 21,551,388.27	€ 19,113,632.35	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 372.62	€ 27,946,155.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.55	-€ 95,455,711.27	€ 0.45	-€ 55,468,919.17
	Stavanger	€ 205,011,245.02	€ 157,777,963.87	€ 23,393,597.34	€ 20,951,162.35	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 372.62	€ 27,946,155.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.57	-€ 115,915,504.17	€ 0.48	-€ 79,896,243.51

(a) Excel sheet calculating LCOM and NPV with the average spot price of methanol.

Power price, €/kWh	Location	Total CAPEX wind, methanol, PEM electrolyzers, €	Total CAPEX wind, methanol, alkaline electrolyzers, €	Total OPEX PEM 6000 FLH, €/yr	Total OPEX alkaline 6000 FLH, €/yr	Stack replacement cost PEM, €	Stack replacement cost alkaline, €	Catalyst cost, €	Yearly methanol production, tonnes/yr	Methanol selling price, €/tonne	Revenue from methanol sale, €	Potential revenue from excess hydrogen PEM, €	Revenue from excess hydrogen alkaline, €	LCOM PEM, €/kg	Net present value, PEM	LCOM alkaline, €/kg	Net present value, alkaline
0.08																	
	Båtsfjord	€ 206,351,645.02	€ 155,097,163.87	€ 32,490,050.02	€ 29,932,473.89	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 538.55	€ 40,391,250.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.70	-€ 78,847,240.63	€ 0.60	-€ 37,486,120.08
	Rana	€ 206,351,645.02	€ 155,097,163.87	€ 31,005,518.51	€ 28,428,419.09	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 538.55	€ 40,391,250.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.68	-€ 61,819,781.17	€ 0.58	-€ 20,234,730.02
	Måløy	€ 205,681,445.02	€ 154,426,963.87	€ 28,241,472.79	€ 25,471,452.82	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 538.55	€ 40,391,250.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.64	-€ 29,446,194.51	€ 0.54	€ 14,351,630.15
	Stavanger	€ 205,011,245.02	€ 157,777,963.87	€ 31,201,070.90	€ 28,351,182.82	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 538.55	€ 40,391,250.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.68	-€ 62,722,351.67	€ 0.58	-€ 22,029,636.08
0.05																	
	Båtsfjord	€ 206,351,645.02	€ 155,097,163.87	€ 24,214,288.79	€ 21,909,310.27	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 538.55	€ 40,391,250.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.59	€ 16,075,088.76	€ 0.49	€ 54,538,934.54
	Rana	€ 206,351,645.02	€ 155,097,163.87	€ 23,286,456.60	€ 20,969,276.02	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 538.55	€ 40,391,250.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.57	€ 26,717,250.88	€ 0.48	€ 65,321,053.33
	Måløy	€ 205,681,445.02	€ 154,426,963.87	€ 21,551,388.27	€ 19,113,632.35	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 538.55	€ 40,391,250.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.55	€ 47,288,547.93	€ 0.45	€ 87,275,340.04
	Stavanger	€ 205,011,245.02	€ 157,777,963.87	€ 23,393,597.34	€ 20,951,162.35	€ 39,375,000.00	€ 30,368,800.00	€ 5,259.01	75000.00	€ 538.55	€ 40,391,250.00	€ 5,025,523.36	€ 1,191,764.58	€ 0.57	€ 26,828,755.03	€ 0.48	€ 62,848,015.70

(b) Excel sheet calculating LCOM and NPV with the average contract price of methanol.

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